Student Poster Competition
2023 IEEE PES General Meeting
Orlando, Florida USA
July 16-20, 2023

Poster Categories:
- Advanced Computational Methods for Power System Planning, Operation, and Control
- Asset Management
- Communication & Control in Energy Systems
- Cyber & Physical Security of the Smart Grid
- Dynamic Performance and Control of Power Systems
- Electric Machines and Drives
- Emerging Software Needs for the Restructured Grid
- Integrating Renewable Energy into the Grid
- Intelligent Monitoring & Outage Management
- Market Interactions in Power Systems
- Operation & Control
- Power Electronics
- Power System Modeling & Simulation
- Smart Cities
- Smart Grid Technology
- Smart Sensors
- Substation and Distribution Automation
- System-Wide Events and Analysis Methods

IEEE PES Student Activities Subcommittee
Sridhar Chouhan, Ph.D., Anthony Deese, Ph.D., Paras Mandal, Ph.D., and Luke Dosiek, Ph.D.
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<td>Rafin</td>
<td>S M Sajjad Hossain</td>
<td>Graduate</td>
<td>PM-Assisted Sub-Harmonic Synchronous Machine</td>
<td>Electric Machines and Drives</td>
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<td>STP168</td>
<td>Rafy</td>
<td>Md Fazley</td>
<td>Graduate</td>
<td>Distributed Control and Testbed Validation for Cyber-Power Distribution System Security and Resiliency</td>
<td>Cyber &amp; Physical Security of the Smart Grid</td>
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<td>STP169</td>
<td>Rahman</td>
<td>Jubeyer</td>
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<td>Steady-state Multi-timescale Modeling and Operation of Small Modular Reactors</td>
<td>Power System Modeling &amp; Simulation</td>
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<td>Rai</td>
<td>Astha</td>
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<td>Rajendran</td>
<td>Sarangan</td>
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<td>Power System Modeling &amp; Simulation</td>
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<td>Ramirez Orrego</td>
<td>Jorge</td>
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<td>Security-Constrained AC Unit Commitment Via Decomposition</td>
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<td>Ratnakumar</td>
<td>Rajan</td>
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<td>Δ-AGC for Improved Power System Electromechanical Oscillation Damping</td>
<td>Dynamic Performance and Control of Power Systems</td>
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<td>Ren</td>
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<td>Battery Bidding Strategy under Uncertainty Considering Market Practical Situations</td>
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<td>STP175</td>
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<td>Retna Kumar</td>
<td>Aravind</td>
<td>Graduate</td>
<td>HydroFlex: Maximizing the Economic and Environmental Benefits of Hydropower Generation</td>
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<td>Rodriguez</td>
<td>Luis</td>
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<td>Portable Power Station with Several Source of Energy for Emergencies</td>
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<td>Rodriguez</td>
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<td>Synthesizing Inertia through the Concept of Virtual Frequency</td>
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<td>STP179</td>
<td>Saad Karsani</td>
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<td>Intelligent Monitoring &amp; Outage Management</td>
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<td>Sahoo</td>
<td>Satyaprajna</td>
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<td>Shen</td>
<td>Daniel</td>
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<td>Valuing Uncertainties in Wind Generation: An Agent-Based Optimization Approach</td>
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<td>STP186</td>
<td>Shi</td>
<td>Ranyu</td>
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<td>Shiuab</td>
<td>Salman Siddique</td>
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<td>Detection and Analysis of Oscillations Using SCADA Data</td>
<td>System Wide Events &amp; Analysis Methods</td>
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<td>Siddique</td>
<td>S M Shahnewaz</td>
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<td>STP189</td>
<td>Singh</td>
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<td>Amirhossein</td>
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<td>STP192</td>
<td>Stuhlmacher</td>
<td>Anna</td>
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<td>Assessing the Resilience of an Optimal Water Pumping Strategy to Provide Frequency Regulation</td>
<td>Smart Cities</td>
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<td>STP193</td>
<td>Su</td>
<td>Jinshun</td>
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<td>A Risk-Averse Model for Balancing Wildfire Risks and Power Outages due to Public-Safety Power-Shutoff</td>
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<td>STP195</td>
<td>Su</td>
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<td>Tabassum Trisha</td>
<td>Tambiara</td>
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<td>Cyber-Attack Detection in AC Microgrid Based on Unsupervised Machine Learning Based Algorithm</td>
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<td>STP201</td>
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<td>STP202</td>
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<td>STP204</td>
<td>Trujillo</td>
<td>Marena</td>
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<td>Operability of a Power System with Synchronous Condensers and Grid-Following Inverters</td>
<td>Dynamic Performance and Control of Power Systems</td>
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<td>STP205</td>
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<td>Sensitivity Analysis on Green Hydrogen as Energy Storage: A Techno-Economic Case study</td>
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<td>STP206</td>
<td>Vahedi</td>
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<td>A Temperature-Informed Data-Driven Approach for Behind-the-Meter Solar Disaggregation</td>
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<td>STP207</td>
<td>Valencia Zuluaga</td>
<td>Tomas</td>
<td>Graduate</td>
<td>Cost Sharing Mechanism with Statistical Learning for Peer-to-Peer Energy Trading (This poster is on the same paper that was accepted for the general session)</td>
<td>Market Interactions in Power Systems</td>
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<td>STP208</td>
<td>Varghese</td>
<td>Sushant</td>
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<td>Multi-Interval Real-Time Dispatch With High Renewable Penetration: Impacts on Generator Investment Incentives in PJM in 2050</td>
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<td>Vemalaiah</td>
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<td>An Energy Efficient Network Reconfiguration in Active Distribution Network by Incorporating Losses from Converter-Based DGs</td>
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<td>STP210</td>
<td>Vijay Iswaran</td>
<td>Giritharan</td>
<td>Graduate</td>
<td>Developing an Equivalent Reduced Feeder Model for Power System Studies</td>
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<td>Michael</td>
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<td>Data-Driven Approaches for Digital Twinning of a Solar Photovoltaic Plant</td>
<td>Emerging Software Needs for the Restructured Grid</td>
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<td>Online Model-Free Chance-Constrained Distribution System Voltage Control using DERs</td>
<td>Power System Modeling &amp; Simulation</td>
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<td>Capacity Expansion Planning for wind Power Based on Data-Driven Approximation Approach</td>
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<td>Learning-Based, Safety and Stability-Certified Microgrid Control</td>
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<td>STP216</td>
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<td>Comparison of Accuracy of Capacity Credit Definitions for Resource Adequacy Accreditation</td>
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<td>STP217</td>
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<td>A Bilevel EV Charging Station and DC Fast Charger Planning Model for Highway Network Considering Dynamic Traffic Demand and User Equilibrium</td>
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<td>STP218</td>
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<td>Market Interactions in Power Systems</td>
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<td>STP219</td>
<td>Wang</td>
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<td>Defense Against Dynamic Residential Load Demand Attack Using Robust Multi-Agent Reinforcement Learning and Game Theory</td>
<td>Cyber &amp; Physical Security of the Smart Grid</td>
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<td>STP220</td>
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<td>STP221</td>
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<td>A Practical Urban Distribution Network Planning Method with Geographic Information System</td>
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<td>Voltage Stability Analysis of a Weak Power System involving DERs – A Bayesian Parameter Estimation Approach</td>
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<td>Improved Solution Procedure for Power Quality Assessment of Nonstationary Waveforms</td>
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<td>Asymmetrically Reciprocal Effects and Congestion Management in TSO-DSO Coordination through Feasibility Regularizer</td>
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<td>Deep Reinforcement Learning for Cybersecurity of Distributed Energy Resources</td>
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<td>Load Shifting for HVACR Systems Using Automated Demand Response and Interpolative Precooling</td>
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<td>Carbon Emissions Resulting from Different Power Flow Models</td>
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<td>Learn Dynamic Hosting Capacity Based on Voltage Sensitivity Analysis</td>
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<td>Interpretable Detection and Localization of False Data Injection Attacks Based on Causal Learning</td>
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<td>STP241</td>
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<td>Fault Location on Distribution Cables Using Traveling Waves: a Field Data Study</td>
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<td>A Short-term Load Forecasting Methodology for Behind-the-Meter DERs based on Machine Learning</td>
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<td>Integrating the Energy Flexibility of Variable Speed Heat Pump in Home Energy Management Systems</td>
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<td>STP245</td>
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<td>An Efficient Neural Solver for Two-Stage DC Optimal Power Flow with Guaranteed Feasibility</td>
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<td>STP249</td>
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<td>STP250</td>
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<td>Degradation and Thermal Runaway Prognosis Based on Real-world Battery Operation Records</td>
<td>Intelligent Monitoring &amp; Outage Management</td>
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<td>Cunzhi</td>
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<td>Hierarchical Deep Learning Model for Degradation Prediction per Look-Ahead Scheduled Battery Usage Profile</td>
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<td>Yuqi</td>
<td>Graduate</td>
<td>Cost-effective Harmonic Estimation in Medium Voltage Distribution Networks</td>
<td>Power System Modeling &amp; Simulation</td>
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<td>STP253</td>
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<td>Strategic Bidding of Hydroelectric Producer in Integrated Energy and Reserve Market</td>
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<td>STP254</td>
<td>Zhu</td>
<td>Qi</td>
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<td>Event-Driven Non-Invasive Multi-Core Cable Current Monitoring Based on Sensor Array</td>
<td>Communication &amp; Control in Energy Systems</td>
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<td>Daniel</td>
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<td>Hardware Implementation of DC Protection Algorithms</td>
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<td>STP256</td>
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<td>Duan</td>
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<td>Large-signal Stability Analysis Using Takagi-Sugeno Fuzzy Model Theory for Fractional Frequency Transmission System</td>
<td>Flexible AC Transmission Systems</td>
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<td>STP258</td>
<td>Zunnurain</td>
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<td>Real-time Charging Scheduling for Electric Vehicle Aggregators in the Ancillary Service Market</td>
<td>Market Interactions in Power Systems</td>
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<td>STP259</td>
<td>Zhu</td>
<td>Yuxuan</td>
<td>Graduate</td>
<td>Power Network Fault Location Based on Voltage Magnitude Measurements and Sparse Estimation</td>
<td>Intelligent Monitoring &amp; Outage Management</td>
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</tbody>
</table>
A Digital Twin-Based Approach for Fault Diagnosis and Performance Improvement of Complex PV System

Mahmoud S. Abdelrahman and Osama A. Mohammed

Abstract—In the realm of solar power generation, photovoltaic (PV) panels are used to convert solar radiation into electrical energy with the help of different assets. They are subjected to the constantly changing state of the environment, resulting in a wide range of defects. These defects should be discovered and remedied as soon as possible so that the PV panels' efficiency and durability are not compromised. The long-term reliability of PV modules is crucial to ensure the technical and economic viability of PV as a successful energy source. Therefore, regular monitoring, accurate diagnosis, optimal operation, and high-quality maintenance are challenging and critical for any PV plant for high-efficiency production and improved system performance. In order to deal with all these challenges, we propose the Digital Twin (DT) technology as an integrated solution that can cover every asset in the PV system. DT with the new advanced technology of analytics as machine learning and artificial intelligence provides simulation capabilities to forecast, optimize and estimate states in order to enhance the physical PV system performance, productivity, optimal operation.

Index terms—PV System, Digital Twin, Fault Diagnosis, and Performance Improvement.

I. INTRODUCTION

Over the past decade, the global cumulative installed Photovoltaic (PV) systems capacity has grown exponentially. Looking forward, PV deployment will continue to grow as the global energy portfolio transitions more towards renewable energy. Nevertheless, it is also a fact that there are still a number of challenges associated with solar power plants in terms of the output, operations, and efficiency of the plants. PV system production may be impacted by several factors including solar resources, module age, and different types of events, which result in financial/technical losses. In addition, lack of information can be led to several obstacles such as distinguishing between underperformance between PV modules and other components. Existing solutions, which depend on expensive, extra sensing devices and high installation and maintenance costs limit the adoption of these solutions in existing PV plants. Additionally, missing information received from sensors or faulted assets will negatively impact the final decision as well as the low speed of system response to recover. Compared with existing solutions, the digital twin model, which is continuously updated and synchronized, provides near real-time status updates, working conditions, and operational challenges that are playing out in real-time in the field. The DT will not only introduce a virtual replica of assets of the PV system for state estimation and prediction but also will introduce the appropriate scenario of operation during events such as asset loss or asset failure to guarantee the continued operation. The candidate optimal scenario of operation will be selected in real-time or even faster-than-real-time, if high-performance computing is used.

II. PHYSICAL AND DIGITAL TWIN IMPLEMENTATION

A. Features and DT model using C-LSTM

Convolutional Neural Networks (CNNs) provide benefits for choosing desirable features and Long Short-Term Memory (LSTM) networks have demonstrated strong sequential data learning capabilities.

B. Fault Diagnosis

Faulty operation of the system can be detected by continuously comparing the system performance (CBM: Y) with the reference behavior (RBM: Y*).

C. Fault Diagnosis

The DT What-If capability and contingency analysis engine alongside with digital twin replica can propose a real-time reconfiguration solution for safe operation after an emergency or event.

D. Fault Diagnosis

The candidate optimal scenario of operation will be selected in real-time or even faster-than-real-time, if high-performance computing is used.
Rule-Based Power and Energy Management System For Shipboard Microgrid With HESS To Mitigate Propulsion and Pulsed Load Fluctuations

Mahmoud S. Abdelrahman, Hossam Hussein, and Osama A. Mohammed

Abstract—A power and Energy Management System (P/EMS) is crucial to Microgrid’s effective practical and reliable operation. In the Shipboard Microgrid (SMG), the load demand is dominated by the high penetration of propulsion loads, which is very dynamic. Some particular loads in naval ships draw very high power for very short periods. A hybrid application of battery and supercapacitor is proposed to cater to the energy consumed by pulse load in a naval ship and for backup purposes. The system proposed in this model is a stand-alone SMG with a Photovoltaic (PV) and Hybrid Energy Storage System (HESS). A rule-based energy supervision and power allocation technique have also been presented considering the specific fuel consumption of diesel engine generators and the characteristics of hybrid energy stored sources (battery and supercapacitor) of the entire SMG. The simulation studies using MATLAB/Simulink software indicate that the proposed P/EMS strategy enables management of power and energy contributions of hybrid resources on the ship. In addition, a reasonable allocation of power among HESS units, which can effectively smooth out the load power fluctuations of the proposed SMG has been introduced.

Index terms—Shipboard Microgrid, Hybrid Energy Storage System, Power and Energy Management

I. INTRODUCTION

Microgrids are defined as local electrical networks, including generation, storage, and critical loads, able to operate in grid-connected and in islanding operations. In this sense, a Shipboard Microgrid (SMG) typically runs in islanded mode while at sea and in grid-connected mode when arriving at the seaport. The SMG, in contrast to the terrestrial microgrid, must consider several limitations that are different from those of terrestrial microgrids and cannot be immediately applied. For instance, some particular loads in naval ships draw very high power for very short periods of time such as Electromagnetic Aircraft Launching Systems, and electromagnetic weapons. Using HESS, the oversizing of shipboard generators just to meet the pulse loads can also be avoided. For the integration of RES and HESS into different applications, DC microgrids are emerging as a growing solution. Therefore, a proper energy and power management system is essential in the microgrid to utilize the energy sources effectively as well as economically.

II. SMG MODEL AND P/EMS DESCRIPTION

A. SMG Model

Figure 1(a) gives the overall structure of the SMG integrated with a P/EMS. The ship loads have the characteristics of high dynamics, periodicity, uncertainty, and high dependence on the marine environment, which consists of propulsion load, ship service load, and pulsed load. The rated load demand of the propulsion operation can take up to 90% of the whole power capacity of the power generated, however, in this work we assumed almost 50% of the total demand of the ship. The diesel generators are connected to the AC bus while renewable energy sources and ESSs are integrated into the DC bus. In DC SMG, the power generated by diesel generators is transformed into DC and sent into the DC bus using rectifiers.

B. P/EMS Scheme Description

The proposed P/EMS scheme is shown in Figure 1(b). HESS is used to store extra power generated while high irradiances are present or to keep a steady supply of electricity to meet load demand when low irradiances are present. If the BES supplies power, the SOC drops, then it must be recharged with power from the PV and/or the main generator to maintain the appropriate SOC. If the BES is recharged, the SOC rises and the BES will supply energy more frequently going forward, resulting in savings in the generator fuel consumption.

III. SIMULATION RESULTS

Figure 2 illustrates the obtained results for a specific scenario. As shown in the figure, in the first period, the PV supplies the load and charges the battery. When the irradiation decreased, the PV power decreased, and the imbalance is small. Hence the ESS supplied this difference. At $t=1.5 \text{ sec}$, the propulsion load is connected, and the HESS supplied the ramp due to the slow response of the generator. During this period, the load is supplied from PV, the battery, and the generator. When the pulsed load is connected at $t=3 \text{ sec}$, the main contributors to fulfill the pulsed requirements are the SC and battery according to the power-split scheme.
Extreme Wind Gust Impact on UK Offshore Wind Turbines: Long-Term Return Level Estimation

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Abstract—With climate change, the frequency of exposure of a wind turbine (WT) to extreme weather events (EWE), beyond those for which they were designed, may increase, leading to decreasing operational performance and physical damage to the turbine structure. Given this, there is a need to investigate the location of future planned offshore wind farms (OWF) to ensure resilience to future wind extremes. The research presented covers the UK exclusive economic zone (EEZ) and uses the 2.2km UK Climate Projection 2018 (UKCP18) hourly maximum wind gust dataset. Two future scenarios corresponding to 2021-2040 and 2061-2080 are considered for future planning analysis. Changes in extreme wind loading defined by 50-year return period, hereafter $U_{50}$ are investigated. Both risk ratio (RR) and relative change (RC) calculations have been used to define recommended locations from the achieved wind gust threshold corresponding to a $U_{50}$. As a result, the East region has a 71.4% increase in the 2021-2040 scenario. Regions in the North have a 99.6% increase in desired OWF siting locations in the 2061-2080 scenario. In both scenarios, the South region has a decreased number of suitable future locations to site OWF. Index Terms-- Climate change, Extreme high wind gust, Offshore wind farms, Spatial planning.

I. OVERVIEW

We investigated the extreme wind loading risk on WT structures using $U_{50}$. The statistical characterization of extreme wind gusts is assessed using multiple distributions, with the Beta distribution being found to most accurately predict the hourly wind gust corresponding to $U_{50}$. The calculation has been done on the historical and the two future scenarios.

II. 50-YEAR RETURN PERIOD USING CLIMATE CHANGE SIGNALS

The research considered the changing magnitude of the $U_{50}$ wind gusts event in the future by calculating the percentage of increasing the number of desired OWF locations (negative RC) to the number of undesired locations (positive RC) see Fig 1 and Table I. As a result, the East and North regions show more desired locations in 2021-2040 and 2061-2080, respectively.

The RR is used to investigate the probability of exceeding the baseline thresholds, see Fig 2. RR > 1 indicates the desired region for siting future OWF. In 2021-2040, Most RR > 1 lay in the East and North regions. In 2061-2080, the dominant RR > 1 lay in the North region. The RR results conform with RC calculations for recommended future OWF siting.

![Figure 1. RC in wind gusts corresponds to $U_{50}$. (a) 2021-2040 relative to 1981-2000, (b) 2061-2080 relative to 1981-2000, and (c) 2061-2080 relative to 2021-2040 within the EEZ. The green lines represent the current and already planned locations for UK OWF.](image)

![Figure 2. Box plot for RR of wind gust (m/s) corresponding to $U_{50}$ in 2021-2040 and 1981-2000 (blue), RR between 2061-2080 and 1981-2000 (green).](image)

| TABLE I REGION RECOMMENDATIONS. |
|-------------------|---|---|---|---|
| Regions           | East | South | West | North |
| Increasing negative RC compared to positive | 71.4% | -99.4% | 52.8% | 48.2% |
| $2021$-$2040$ relative to $1981$-$2000$ | 28.6% | 4.4% | 56% | 99.6% |
| $2061$-$2080$ relative to $1981$-$2000$ | 30% | 99.4% | 38.8% | 78.4% |

(Work was partially supported by the Schlumberger Foundation Faculty for the Future program)
Electricity Theft Detection for Smart Homes with Knowledge-Based Synthetic Attack Data

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Abstract—The recent evolution of machine learning may allow the automatic detection of electricity theft only from the patterns of meter readings. Electric consumption heavily relies on many factors, e.g., the lifestyle of the day and the weather, and thus the accuracy of detection is questioned. We propose an electricity theft detection (ETD) framework for smart homes with knowledge-based synthetic attack data. This allows training of the attack classifier only from the legitimate power consumption data, i.e., without attack actions and associated labels. We identified five attack patterns as the knowledge which consisted of smart attacks and legacy attacks.

I. ETD WITH SYNTHETIC ATTACK DATA

A house has an electric meter for accounting purposes. The household has to pay the bill based on the accumulated power counted by the meter. An attacker may physically access the power distribution board under the electric meter and steals the power from the house to make the household pay the bills (Fig. 1) on their behalf. An attacker may also steal the power from an outlet if it is physically accessible outside.

![Power Distribution Board with connected sample appliances](image1)

Fig. 1. A: Power Distribution Board with connected sample appliances. B: Scenarios of electricity theft attacks. Power distribution boards and cables are deployed behind walls and are usually not visible. An attacker uses the pre-deployed cable in a complex building or the outside plug for stealing electricity. Depending on the theft pattern, we identify five classes of attacks.

To detect such electricity theft attacks, we take the approach of monitoring power consumption with enough granularity in both time and power domains at the power aggregation point. We explore the possibility of synthetic attack data deployed to validate machine learning applications for identifying the attack types only from legitimate electricity consumption patterns.

Figure 2 shows the framework of our synthetic attack data learning for electricity theft detection. Let us consider \( x \) – a vector of power consumption. This vector contains the power consumption of each timeslot in the time order. For example, \( x \) may represent a power consumption of a certain day, and the \( i \)-th element \( x_i \) corresponds to the power usage at \( i \)-th minute from the beginning of the day. In this case, \( x \) has 1440 elements: i.e., \( 60 \times 24 = 1440 \). In supervised learning, we assume that each \( x \) has a corresponding label \( y \) for training a classification model for power consumption patterns. In our case, we can assume that label \( y = 0 \) as a benign case, \( y = 1 \) as a Baseload attack, \( y = 2 \) as a Weakload attack, and so on.

In the real, practical scenario, we will only get a collection of \( x \) from a house as a result of long-term monitoring, and we will not get real attack-enabled cases with labels. However, many power-stealing cases can be simulated just by arithmetically adding stolen power as a power consumption. Let \( x_A \) be a vector of stolen power by an attacker. As we assume the attacker changes the stealing power based on the consumption of the house, \( x_A \) is a function of \( x \) and attacking parameters \( \theta \); e.g., \( x_A(x, \theta) \). Depending on the attack cases, i.e., depending on the label \( y \neq 0 \), we can consider different stolen power vectors: \( x_A(y, x, \theta(y)) \). Finally, we can get the labeled dataset as follows.

\[
(x', y) = \begin{cases} 
(x, 0) & y = 0 \\
(x + x_A(y, x, \theta(y)), y) & y \neq 0
\end{cases}
\] (1)

Supervised machine learning models can be applied to the collection of \( (x', y) \).

II. DISCUSSION AND FUTURE WORKS

We have proposed ML model training with synthetic attack data based on the knowledge for detecting and classifying electricity theft attacks for smart homes. On this framework, we found that Gradient Boosting gives promising results over our comprehensive evaluation of various machine learning models.

In future work, we can define other types of attacks along with the five attacks we defined. We can also study other homes or include other electricity consumption patterns for Evil-Twin attacks. (https://iplab.naist.jp/publications/)
Cyber-Attack Exposure Analysis for DER Networks

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Abstract—Distributed Energy Resources (DER) systems are increasingly being deployed in the smart grid environment. They include solar panels, electric vehicles, controllable loads, and integrated sensors. DER system’s exposure to the Internet expands significantly its attack surface and needs addressing. Attack graphs and attack trees are commonly used techniques for modeling system security. Nevertheless, both techniques are not scalable for DER networks. Access graphs have been proposed as an alternative method for modeling a smart grid architecture [1]. They primarily use CIM data objects to model the trust between systems. This paper applies the proposed exposed analysis framework[1] to evaluate the exposure of DER systems. A set of security mechanisms along with a set of privileges and a CIM representation of the information within the system are defined. The exposure graph of the system will be developed and the exposure metric will be computed to determine the attack surface of the system. Different applications of the exposure metric will be explored.

I. INTRODUCTION

With the massive integration of DER and other systems, the power grid is quickly evolving from a utility-centric structure to a distributed smart grid. The attack surface of the grid is also increased significantly due to the exposure of DER systems to the Internet. A complete exposure analysis is needed to establish the different risks and threats, to which DER systems are exposed. Attack trees and attack graphs are commonly used techniques but they are not scalable for DER systems. Access graphs have been proposed as an alternative for evaluating the exposure of smart grid architecture. Our research applies the Cyber attack exposure evaluation framework proposed in [1] to DER networks. The objective of our methodology is to produce an exposure graph for DER networks and to compute exposure metrics that can be used to improve the security of DER systems.

II. METHODOLOGY

Step 1 Cyber Risk Identification: The set of security mechanisms (SM) available in the system is identified. Security mechanisms are used to restrict the system’s use to only a secure state, such as encryption, authentication, VPN access, access control, etc. The set of privileges (P) which identifies the set of available states in the system is also defined. The privilege could either be user access or system access (admin) to a set of data objects or information objects (IO). DERFunction is a class within the CIM model, that describes functions that the DER is capable of handling. Some DERFunction’s information objects are: connectDisconnect, voltageRegulation, reactivePowerDispatch, realPowerDispatch, etc.

This paper utilizes the threat modeling process introduced by Microsoft[2] to identify the security mechanisms. The process first requires the identification of users, processes, data flows, entry/exit points, and data stores within the architecture. Next, each of the data flows is reviewed for possible spoofing, tampering, repudiation, information disclosure, denial of service, and escalation of privileges. The threat modeling process begins with the development of a data flow diagram (DFD) which is then utilized to identify trusted boundaries and identify potential untrusted input.

Step 2 Exposure Graph Development: The relationship between the security mechanisms (SM), privileges (P), and information objects (IO) is formalized to develop the exposure graph G = (SM, P, IO, A, E) with A being the set of potential attackers within the systems and E the edges. Node A is connected to all possible systems accessible by the attacker. An edge weight of 1 is allotted to represent the attacker’s effort required to bypass a security mechanism (SM). The nodes SM are connected to the nodes P. The weight 0 is applied if the security mechanisms fail. Each information object IO node is connected to the P nodes.

Step 3 Exposure Evaluation: The exposure metric (exp) is computed through the analysis of all security mechanisms (SM) utilized to protect the privileges (P) that either produce or consume the information object (IO). The number of attack paths and the path lengths are components used in such calculation.

Step 4 Metric Evaluation: The exposure metric will be computed for a DER architecture at its normal state, without any added security mechanism. Then, the exposure metric will be recomputed after adding enhancement E1 alone, enhancement E2 alone, and when both enhancements are applied. The proposed enhancements for this evaluation would include:

- E1-Application layer authentication + encryption at the DER sensor/controller level
- E2-Multi-factor authentication at the utility DER Management System

REFERENCES

Probabilistic Data-Driven Pseudo-Measurement Model

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Abstract—Continuous monitoring of electrical grids requires real-time measurement data. The disruption in the measurement process, devices, and communication systems can lead to distorted signals. To address this issue, this paper proposes a multi-variant deep mixture network (MVDMN) to construct the measurement information in the look-ahead times in the form of conditional probability density functions (CPDFs) as the full statistics information.

Keywords—Pseudo-measurement, distribution network, deep learning, conditional probability density function (CPDF).

I. INTRODUCTION

As one of the most critical energy forms in today’s, it is crucial to continuously monitor the electric grids. Thus, measurement devices within low-time resolution sampling rates are demanding. However, interruption in the measurement devices such as the time-delay, malfunction of devices, asynchronous measurements, etc., can lead to the unobservability and lack of measurement devices and brings us a huge challenge: How can we monitor the electric grids without online measurement information? The potential solution is the pseudo-measurement model [1]. The previous pseudo-measurement models are probability density function (PDF) based models and artificial intelligence (AI)-based models. The existing pseudo-measurement models are not applicable: 1) provide a measurement for the large-scale network-level measurements; 2) Noise model-free performance; 3) accurate performance in highly noisy conditions; 4) provide full-statistic information of the measurement signals with application in monitoring, and control, protection, etc.; 5) capability to perform with a limited number of data; 6) ability to perform with low computational cost. To address these challenges, this work establishes a deep neural network-based structure to provide the measurement signals for a large-scale unbalanced distribution network considering high renewable energy penetration. To this end, a deep network is developed based on modified loss function, perturbation-based loss function, and spatial-temporal features learners structure.

II. METHODOLOGY

Let us denote to $X^i_1 \in \mathbb{R}^{n \times m}$ is the set of time-varying variables measurements. The pseudo-measurement model projects a function $f^p(X^i_1)$ outputs $\hat{X}^i_1$ with the minimum difference with $X^i_1$. In the probabilistic pseudo-measurement, $f^p(X^i_{1-T+1\mid 1})$, where $T$ shows look-back time steps and $N$ represents look-ahead time steps. This work establishes a multi-variant deep mixture network (MVDMN) with a modified loss function.

$$f^\text{loss}_{\text{MVDMN}} = \log\left(\sum^T_{t=1} \exp\left[\log c^i_{1x}\right]\right) - \alpha_1 \log\left(\alpha_2 \sigma_{ix} - \frac{1}{\sigma_{ix}}\right) + \alpha_3 \log\left(\sum^T_{t=1} \exp\left[\log c^i_{1x}\right]\right) - \frac{1}{\alpha_{ix}} - \alpha_4 f_{\text{sign}}\left(-\nabla x \log\left(\sum^T_{t=1} \exp\left[\log c^i_{1x}\right]\right)\right) - \frac{1}{\alpha_{ix}} - \alpha_1 \log\left(\alpha_2 \sigma_{ix} - \frac{1}{\sigma_{ix}}\right)$$

(1)

The designed process for the pseudo-measurement model implementation is shown in Fig. 1.

III. NUMERICAL EXAMPLE

Figure 2 shows a sample of generated PDF for a voltage magnitude obtained by the proposed pseudo-measurement model and compared the actual values with the predicted measurement values.

Fig 1. Overview of proposed MVDMN-based probabilistic pseudo-measurement.

Fig 2 Proposed probabilistic pseudo-measurement model output: voltage magnitude.

REFERENCE

Enhancing the Stability of a DC Microgrid Under Pulse Load using Hybrid Energy Storage Control Strategy

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Abstract—Although DC microgrids are becoming more and more common, they still face challenges with instability brought on by supply and demand imbalance. The solution to this problem frequently involves the use of energy storage devices such as batteries. When exposed to transients, batteries risk having their lifespans shortened. A supercapacitor (SC) with a higher power density and faster response time could be used as a potential workaround for this restriction. In order to increase the stability of DC microgrids and thereby increase their reliability and resilience, it is possible to combine the advantages of batteries and supercapacitors. The integration of both batteries and supercapacitors enables DC microgrids to effectively manage both steady state and transient conditions. By combining the complementary characteristics of these energy storage units, the DCMG can achieve higher stability and reliability. In order to mitigate these effects, the main goal of this research paper is to investigate how supercapacitor (SC) voltage deviation affects the stability of DC microgrids and to suggest a controller design method that makes use of typical PI controllers and power management techniques. The stability and reliability of the DCMG can be improved, ultimately resulting in better performance and greater efficiency of the microgrid system, by analyzing the effects of SC voltage deviation and putting into place the necessary control measures. According to sets of results, the proposed scheme has been successful in preventing DC bus voltage ringing regardless of variations in SC operating voltage, maintaining MG stability.

Keywords—Microgrid, PI controller, supercapacitor (SC), Battery, voltage regulation

I. INTRODUCTION

A microgrid is a self-sustaining power system that incorporates distributed energy resources and loads. Using a DC microgrid (DCMG) is often more cost-effective since many renewable energy sources (RESs), loads, and energy storage devices operate using DC power. The inherent DC nature of these components allows for greater efficiency and reliability, leading to improved performance and reduced operating costs. However, the uncertain nature of RESs may lead to some issues related to stability and resilience when dealing with specific loads such as pulse load. Which will have a huge impact on system voltage, and power imbalance. A battery storage system may be the appropriate solution for a steady-state phase in a microgrid. However, when faced with transient events such as pulse load, a supercapacitor energy storage system can be more effective. Integrating both systems into one hybrid energy storage system can provide suitable energy management for the microgrids. By using the benefits of both energy storage systems, the microgrid can achieve enhanced stability and reliability even when dealing with specific loads such as pulsed loads.

II. PROPOSED CONTROL

The dynamic response of a DC microgrid (DCMG) is significantly influenced by the control and modeling of DC/DC converters. Fig.1 illustrates the control structure adopted for the microgrid. If the power from renewable energy exceeds the load and the SOC of the ESS exceeds the SOCmax, the MPPT mode is switched to PI mode and generates gating signals for the boost converter. In the presence of a pulse load, the supercapacitor manages the high-frequency power while the battery handles the steady phase. The supercapacitor can also handle transients.

III. RESULTS

Fig.2 shows how the system responds to sudden load changes and the resulting effect on the DC bus voltage. By implementing our control strategy, the DC bus voltage can experience smoother transitions with reduced fluctuations.
Distributed Software-Defined Network Architecture for Smart Grid Resilience to Denial-of-Service Attacks

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Abstract—An important challenge for smart grid security is designing a secure and robust smart grid communications architecture to protect against cyber-threats, such as Denial-of-Service (DoS) attacks, that can adversely impact the operation of the power grid. Researchers have proposed using Software Defined Network frameworks to enhance cybersecurity of the smart grid, but there is a lack of benchmarking and comparative analyses among the many techniques. In this work, a distributed three-controller software-defined networking (D3-SDN) architecture, benchmarking, and comparative analysis with other techniques is presented. The selected distributed flat SDN architecture divides the network horizontally into multiple areas or clusters, where each cluster is handled by a single Open Network Operating System (ONOS) controller. A case study using the IEEE 118-bus system is provided to compare the performance of the presented ONOS-managed D3-SDN, against the POX controller. In addition, the proposed architecture outperforms a single SDN controller framework by a tenfold increase in throughput; a reduction in latency of > 20%; and an increase in throughput of approximately 11% during the DoS attack scenarios.

Index Terms—software-defined networking, cyber security, network security, cyber-physical systems, power systems

I. INTRODUCTION

Over the past decade, smart grid (SG) system cybersecurity has grown. Power grid cybersecurity study focuses on operation technology (OT) and information technology (IT) system reliability. An interdependent software-defined network (SDN) management framework for SG communications is also evolving. Traditional power systems are often protected by isolated and uncoordinated equipment that provides ad hoc solutions to each protection issue. Power system state estimation study provides other solutions [1]. These techniques can be effective, but they are not integrated to interact online, making them vulnerable to distributed cyber-attacks, denial-of-service (DoS), distributed denial-of-service (DDoS), man-in-the-middle (MITM), and false data injection (FDI) [2]. These attacks can affect data from several grid levels and disrupt system service. A unified way to recognize multiple SG layer attacks is still needed. ONOS-managed D3-SDN is compared to the POX controller, a common alternative. Other papers [3], [4] have proposed a distributed SDN architecture for smart grids, but none have compared its performance to the single controller method used in POX controller-based literature as this work.

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Table I: Average Latency Results for POX (Legacy) Networks versus ONOS Networks.

<table>
<thead>
<tr>
<th>Network Type</th>
<th>Avg. UDP Latency (µs) (User Datagram Protocol)</th>
<th>Avg. TCP Latency (µs) (Transport Control Protocol)</th>
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<tbody>
<tr>
<td>ONOS</td>
<td>28.727</td>
<td>28.846</td>
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<tr>
<td>POX</td>
<td>37.876</td>
<td>42.345</td>
</tr>
</tbody>
</table>

II. CASE STUDY

The ONOS managed flat, three-controller, distributed SDN (D3-SDN) and POX controller approaches were compared in a case study. Table I and Figure 1 show that ONOS-managed D3-SDN has lower latency and greater throughput resilience during DoS attack. Table II shows our cross-layer ensemble corrdet (CECD-AS) algorithm classification performance.

Fig. 1: Throughput Resilience During DoS Attack

Table II: Performance results for FDI, DoS, and MITM attacks (FDI: False Data Injection attacks, DoS: Denial of Service attacks, MITM: Man In The Middle attacks)

<table>
<thead>
<tr>
<th>Attack type</th>
<th>Accuracy $\mu_{AC} \pm \sigma_{AC}$</th>
<th>Precision $\mu_{PR} \pm \sigma_{PR}$</th>
<th>Recall $\mu_{RE} \pm \sigma_{RE}$</th>
<th>F1-score $\mu_{F1} \pm \sigma_{F1}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>MITM</td>
<td>92.48 ± 0.20</td>
<td>91.65 ± 0.29</td>
<td>86.41 ± 0.28</td>
<td>88.91 ± 0.24</td>
</tr>
<tr>
<td>FDI</td>
<td>99.95 ± 0.010</td>
<td>99.46 ± 0.044</td>
<td>99.87 ± 0.011</td>
<td>99.61 ± 0.039</td>
</tr>
<tr>
<td>DoS</td>
<td>99.88 ± 0.007</td>
<td>99.75 ± 0.009</td>
<td>99.80 ± 0.016</td>
<td>99.78 ± 0.008</td>
</tr>
<tr>
<td>FDI-DoS</td>
<td>99.63 ± 0.008</td>
<td>98.43 ± 0.026</td>
<td>99.95 ± 0.004</td>
<td>99.20 ± 0.015</td>
</tr>
</tbody>
</table>

REFERENCES

Suppressing the Net-load Duck-Curve with East-West Solar Array Orientation

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Abstract—This paper compares the difference between East-West and South PV array orientations, and demonstrates how the East-West PV orientation is considerably beneficial in solving the evening ramping of the netload curve of the CAISO network. Simulations were done with Aurora Solar’s Helioscope.

I. INTRODUCTION

Massive solar energy system deployment is causing an unwanted shape in the net demand, known as the “duck curve,” which deepens during the peak solar injection hours at noon and ramps up toward the evening. As a result, there is excess production that cannot be delivered during the solar peak hours and some of the demand that cannot be met when solar production is declining and expected to be replaced by traditional generating plants with low ramp rate.[1] One way to reduce the high ramp of the netload in the evening is to look at the orientation of the array. In the US, Solar PV generates more energy hence saves more money on utility bills if pointed southward. [2] However, there is a need to solve the risk of solar energy curtailment in the midday, and network stability in the evening ramp. Helioscope simulation shows that the east-west array orientation is a considerable solution.

II. METHODOLOGY

The solar curve of a south oriented solar array tends to have a steep ramp in the morning and evening, and a high peak in the midday. However, an east-west oriented solar array has a more distributed output and produces more during the evening when the netload is ramping up.

This was simulated on Helioscope using a 100 kWp PV solar system located in Sacramento California with coordinates of 38° 34' 51.82" N, 121° 29' 38.02" W. In the first simulation, all the 100 kWp were made to face the south, while in the second simulation, 50 kWp PV were made to face east and 50 kWp PV were made to face west.

III. RESULT

Table 1 shows the difference in the output of the two orientations. Although the annual production of the south oriented array is higher than that of the east-west oriented array, there is curtailment risk during the peak solar hour hence reducing the financial benefit of the solar system.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>East-West</th>
<th>South</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size (kWp)</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Yield (MWh)</td>
<td>152.5</td>
<td>165.2</td>
</tr>
<tr>
<td>Performance Ratio</td>
<td>83.2%</td>
<td>78.9%</td>
</tr>
<tr>
<td>Shading Loss</td>
<td>0.2%</td>
<td>5.6%</td>
</tr>
</tbody>
</table>

Table I. RESULT COMPARISON

From fig 3, above, the total energy gained from 4PM to 8PM by using an east-west orientation rather than a south orientation is calculated to be 2.13 MWh per annum for the 100 kWp system. If the 100 kWp system is scaled up to 100 MWp, the energy gained in this duration would be significant enough to help in mitigating the evening ramp of the netload hence increasing system reliability.

<table>
<thead>
<tr>
<th>Duration</th>
<th>East-West (MWh)</th>
<th>South (MWh)</th>
<th>Difference (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4PM-5PM</td>
<td>7.08</td>
<td>6.88</td>
<td>0.20</td>
</tr>
<tr>
<td>5PM-6PM</td>
<td>4.03</td>
<td>2.88</td>
<td>1.14</td>
</tr>
<tr>
<td>6PM-7PM</td>
<td>1.36</td>
<td>0.58</td>
<td>0.78</td>
</tr>
<tr>
<td>7PM-8PM</td>
<td>0.02</td>
<td>0.01</td>
<td>0.01</td>
</tr>
<tr>
<td>Total</td>
<td>12.53</td>
<td>10.17</td>
<td>2.36</td>
</tr>
</tbody>
</table>

Table II. EVENING GENERATION COMPARISON

REFERENCES

Fig. 1. CAISO Duck Curve.

(a)  
(b)  

Fig. 2. Solar PV Orientation (a) East-West, (b) South.

Fig. 3. Solar PV Curve.
An impact study of grid connected devices on distribution system protection

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Abstract—The increased use of electric vehicles, renewable energy resources and storage units has contributed to complications in radial distribution system protection. To understand these complications the authors are studying the impact of edge devices on distribution systems during faults. This paper discusses studies performed on the IEEE 34-node test feeder which focused on the effect on radial system protection of electric vehicles and storage utilizing vehicle-to-grid technology.

Index Terms—Electric Vehicles, Storage Systems, Net Metering, Distribution system.

I. INTRODUCTION

In distribution network protection, particularly radial system protection [1], recloser-fuse protection schemes are commonly used [2]. Reclosers are commonly employed to protect the main feeder with a certain number of reclosing attempts. On the other hand, fuses are commonly used for protection of laterals and load taps from the main feeder.

Today’s power systems are changing rapidly. The introduction of renewable energy resources has caused uncertainties in protection coordination, power control and other areas in power systems [2]. Renewable energy resources also induce a need for residential storage units due to the uncontrollable availability of these resources [3]. Additionally, electric vehicle companies are now promoting the use of EVs as residential storage units by simply plugging in the EV into the house. One of the technologies used to harness renewable energy and utilize residential storage is a net metering scheme.

The net metering scheme is a utility metering scheme for customers that have PV, storage units or vehicle-to-grid setup [4]. In the net metering scheme, the power for the consumer is bidirectional with respect to the grid, where the customer can consume from or provide power to the grid using PV panels or residential storage units. In net metering, the consumption or supply of power depends on the setup and other factors (e.g., PV power, power prices and state of charge).

Although controllers of inverters in storage units or electric vehicles do not contribute a high percentage of the short-circuit current, inverters can contribute to transients that may affect small residential fuses, circuit breakers or other equipment on distribution feeders. Inverters such as those used in vehicle-to-grid and residential net metering schemes can also be one of the causes of bidirectional current flow during transients. Unusual transients or bidirectional current flow for short periods can cause stress and wear to fuses. This stress and wear may increase the probability of failure or misoperation of protection equipment in future events.

II. APPROACH

In some transient studies, there might be a need for customer-side load models. Customer-side load models could be study-specific. For example, in short circuit studies, the customer-side load models may include a vehicle-to-grid or battery storage unit for residential systems.

This research studies the effect of loads on distribution protection schemes when loads are simulated using customer-side load models, instead of using the primary side load models employing usual uniformly distributed load models. The scope of this work focuses on simulating the effect of electric vehicles utilizing the vehicle-to-grid connection as well as residential storage units, such as those used in residential renewable applications.

Some of the lumped loads on laterals in the IEEE 34 node test feeder model [1], are replaced with distribution transformers and customer-side load models and simulated in the PSCAD transient simulator (PSCAD). In addition, a vehicle to grid battery model is added to the customer-side load models.

III. CASE STUDIES

Several case studies were performed which represent light and heavy loading. For each case study, normal and fault scenarios were simulated. The normal and fault currents were analyzed to determine the impact of the loads on protective devices.

REFERENCES

Resilient Power Sharing in a 100% Inverter-Based Power System Under GPS Spoofing Attacks

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The increasing integration of inverter-based resources (IBR) in the power grid requires new control and power sharing algorithms for grid-forming (GFM) and grid-supporting (GS) IBRs. Frequency droop has been employed for power sharing, but it has certain disadvantages, e.g., frequency changes, power quality issue, slow response, and the possibility of circulating current between IBRs [1], [2]. This abstract builds on our prior work on angle droop [3] and provides additional evidence of its performance.

An IBR microcontroller uses its crystal oscillator to create a phase reference for angle droop. However, crystal time drift adversely impacts angle droop. Therefore, references [3], [4] propose using GPS for precise timing. However, this creates a GPS spoofing vulnerability for angle droop. A GPS spoofing attack disrupts power sharing. Therefore, angle droop must become resilient to such attacks.

This paper builds upon the GS power sharing controller proposed in [3] to make it resilient to GPS spoofing attacks. Fig. 1 shows the proposed resilient GS controller. The state-space model of the GS power sharing controller is derived in its linear operating region. Using this, a linear state observer is designed to estimate the GS voltage angle. Finally, an integral control loop is designed to correct the GS voltage angle using its estimated value and mitigate the GPS spoofing attack.

The performance of the proposed method is evaluated using time-domain simulations case studies on the IEEE 9-bus benchmark system in PSCAD/EMTDC software. Fig. 2 shows the FIBPS operation under a GPS spoofing attack on the GS units at buses 1 and 3. This figure shows that the proposed method effectively recovers the voltage angles of both GS units after the attack, reducing voltage angle error by 14.17% in GS1 and by 45% in GS2.

REFERENCES

This work is supported in part by the National Science Foundation (NSF) under award ECCS-1953213, in part by the State of Virginia’s Commonwealth Cyber Initiative (www.cyberinitiative.org), and in part by the U.S. Department of Energy’s Office of Energy Efficiency and Renewable Energy (EERE) under the Solar Energy Technologies Office Award Number 38637 (UNIFI Consortium led by NREL). The views expressed herein do not necessarily represent the views of the U.S. Department of Energy or the United States Government.


Real-Time Locational Marginal Price Forecasting: A Transformer-Based Approach

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Abstract—This paper presents a transformer-based forecasting model for the real-time locational marginal price (LMP). The high nonlinearity of the real-time LMP makes it challenging to achieve accurate predictions using existing models from the literature. However, the transformer-based model has shown promising results in capturing complex patterns of real-time LMP. Our model has been trained and tested on NYISO market data, where we selected features such as hourly real-time LMP, day-ahead LMP, and demand forecasting. Our results showed that the model was able to accurately predict most of the spikes in the real-time LMP in the hour-ahead task, while still performing well in the day-ahead forecasting task. Overall, the developed transformer-based model presents a robust solution for efficient real-time LMP forecasting.

Index Terms—Electricity price forecasting, time-series forecasting, deep learning, locational marginal price

I. INTRODUCTION

Electricity price forecasting has been investigated heavily in the past years, but as per these reviews [1] [2] it appears that the research area is still not yet saturated. Generally, there are three main types of price forecasting, short-term, mid-term, and long-term, where they focus on forecasting hours ahead, days to months ahead, and years ahead respectively. The horizon changes based on the needed application, our focus in this study is the short-term horizon as it has the highest influence on the day-ahead and real-time market operations.

Transformers, a recent deep learning models originally developed for natural language processing tasks, has proven to have superior performance, it has been modified and used in many different applications. One of those is time-series forecasting, where PatchTST Transformer [3] has emerged as one of the best models, achieving lower forecasting errors than other recent transformers. To solve our task, which is categorized under time-series forecasting, we leveraged the power of PatchTST transformer along with a customized loss function to predict the real-time LMP for the NYISO market. Figure 1 shows the pipeline of the developed solution.

The study was performed using data collected from NYISO over the span of five years (2017-2021), four years for training and validation and one year for testing. Real-time LMP, day-ahead LMP, and demand forecasting were chosen as features due to their direct influence on the real-time LMP. A look-back window of 336 hours (14 days) and the prediction horizon of 24 hour-ahead were considered. The data were normalized before being fed into the model and the LMP features were log-transformed to reduce the impact of the extreme spikes on the model predictions. A customized loss function was utilized during training to improve the predictions for the intended application of the model. Figure 2 shows a snapshot of the prediction results for the duration of one week in jun-2021.

Fig. 1. Pipeline of the proposed solution.

![pipeline](image)

Fig. 2. An example of the predictions made by the developed model.

REFERENCES


Assessment of Inverter-Based Microgrid Control Performance Under Communication Latency Using Cyber-Physical Co-Simulation Platform

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Abstract— Smart grids are cyber-physical systems (CPS) that integrate the communication network with the existing power system infrastructure. The increasingly relevant role of communication in the operation and control of power systems leads to the dependence of performance on the communication network. This work presents an interdependent study that considers both the physical system and the communication network. Here, we developed a cyber-physical co-simulation platform that integrates power and communication networks using OPAL-RT and Network Simulator (NS-3). The network emulation in NS-3 can mimic the communication network, and the central controller runs in an asynchronous process with the real-time power system simulation in OPAL-RT. The impact of communication latency on the frequency response of an inverter-based microgrid with centralized secondary control was studied and tested through the NS-3. The real-time simulation results proved the need for modeling the communication infrastructure between the primary and the secondary control layers for controlling the frequency of an isolated microgrid which is not has been focused on the MG’s frequency control studies. Furthermore, the results verified that the delay in communication between the primary and secondary control layers adversely affects the frequency stability of the inverter-based microgrid.

Keywords— Cyber-physical systems (CPS), Real-Time Co-simulation, Network simulator (NS-3), Microgrid, Centralized secondary control.

I. THE PROPOSED ARCHITECTURE OF THE CYBER PHYSICAL CO-SIMULATION PLATFORM

The proposed architecture of a cyber-physical co-simulation platform implemented on Smart Grid Testbed with detailed IP addresses is presented in Fig. 1, and it integrates the following components:

- Machine-1: OPAL-RT simulator for real-time simulation of the inverter-based MG including all the local controllers of the physical system.
- Machine-2: Linux OS contains NS3 for communication network emulation and Docker containers to transfer data between OPAL-RT and network nodes in NS3. Two containers are created to connect to two communication nodes of inverters, and the UPD/JP protocol is used for interfacing between the communication model in machine 2 and the physical system that runs on OPAL-RT in machine 1.
- Machine-3: MATLAB/Simulink is used to implement the centralized secondary controller and a Modbus TCP server to connect to the two containers in machine2 that represent the clients.

II. KEY RESULTS

The information exchange between the physical system and the central controller through the proposed communication model is presented in Fig. 2. In addition, the impact of changing the communication delay within the communication model in NS3 on the MG’s frequency response can be demonstrated in Fig. 3.

An adaptive control scheme can be implemented for compensating the effect of the communication delay on the system’s frequency stability. Moreover, different cyber-attack scenarios can be implemented in the proposed platform.

This work was partially supported by a grant from the US Department of Energy grant # DE-NA0004016 and the National Science Foundation grant#2113880. The authors are with the Department of Electrical and Computer Engineering, Florida International University, Miami, FL, USA (e-mail: mohammed@fiu.edu)
Risk-Averse Constrained Deep Reinforcement Learning Volt-Var Control in Unbalanced Modern Distribution Networks

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Abstract—With the increasing penetration of distributed energy resources (DERs), the operation of modern distribution networks (MDNs) encounters drastic challenges. The volt/var control (VVC) concept has been determined as a valuable solution for an advanced control strategy in the operation of MDN to satisfy voltage requirements, reduce emissions, enhance the performance of the distribution system, and avoid extra expenses. This paper provides a novel VVC framework based on a safe deep reinforcement learning (SDRL) algorithm to avoid unsafe conditions during the learning process that lead to equipment damage or divergence in an unbalanced distribution network. Unlike the existing DRL techniques for VVC, we optimize policies so that their worst-case performance satisfies the constraints. The additional safety value is regarded as a safety measure to address the constraints’ satisfaction and achieve a trade-off between reward and safety through two separate signals.

Keywords—Volt-var control, deep reinforcement learning, safe deep reinforcement learning, modern distribution networks.

I. INTRODUCTION

Two of the greatest challenges in the control and operation of modern distribution networks (MDNs) are voltage stability and a high amount of power loss. The effective volt/var control (VVC) problem has been considered a vital solution to tackle voltage deviation and minimize power loss while reducing wear and tear of voltage regulating devices in MDNs. Existing control architectures for the VVC problem can be categorized into two main groups: model-based methods and data-driven methods. Due to the complexity and stochastic behavior of MDNs, model-based methods for VVC are not practical anymore since they are computationally demanding and do not guarantee optimal performance in a real-time control environment. On the other hand, data-driven approaches based on artificial intelligence techniques, specifically deep reinforcement learning (DRL), are the potential candidates for strategic autonomous VVC. Based on such data-driven methods, an intelligent controller can find a control scheme from interactions with a system-like simulation model by using a large amount of operating data. This interaction is enabled through the Markov decision process (MDP). In this paper, a constrained-based safe deep reinforcement learning (CBSDRL) framework for VVC has been proposed to learn the optimal control strategy and maintain safety through two separate signals namely reward and reward constraint. Unlike the existing model-free VCC algorithms we optimize policies so that their worst-case performance satisfies the constraints with an extra safety measure called safety critic. Through the safety-critic signal, we approximate the distribution of safety-cost to achieve risk control given different levels of $CVaR_{\alpha}$.

Fig. 1. a constrained-based safe deep reinforcement learning framework for VVC.

II. PROPOSED METHOD

DRL is an area of machine learning for solving control tasks based on the MDP that deals with the study of how intelligent agents should perform actions in an environment to maximize the cumulative reward. In standard MDP, an intelligent decision maker called the agent learns its optimal policy ($\pi$) based on a trial and error process, especially in the first interactions. However, this type of learning jeopardizes the safety and reliability of the distribution network since some actions chosen in exploratory policy may lead to systems divergence or violation and cause equipment damage. Therefore, solving the optimization problems through a constrained base Markov decision process (CMDP) while taking into account the physical operation constraints helps to improve the security and safety of power systems. Therefore, in this paper, a CBSDRL framework for VVC is proposed to make sure that every exploration during the learning process is also constraint-satisfying by handling two different functions for reward and reward constraints. The CBSDRL is defined as a tuple: $(S, A, R, R_\alpha, d, \gamma)$ where $S, A, R, R_\alpha, d$, and $\gamma$ represent state space, action space, reward function, reward constraint, safety threshold, and discount factor, respectively. In this framework, the agent optimizes the stochastic policy by maximizing the expected discounted reward, $F(\pi)$, subject to the value of $CVaR_{\alpha}$ such that the safety cost remains lower than the fixed boundary of $d$ while maximizing the expected entropy term, $-\log(\pi_t)$:

$$\max_{\pi} F(\pi) = \mathbb{E}\left[\sum_{t=1}^{\infty} \gamma^t R(s_t, a_t)\right]$$  \hspace{1cm} (1)

s.t. $CVaR_{\alpha}(C) \leq \tilde{d}$ and $\mathbb{E}\left[-\log(\pi_t)\right] \geq h \forall t$.  \hspace{1cm} (2)

Moreover, 4 different neural networks namely $Q_1, Q_2, Q_3, V_c$ have been used to estimate the critic and safety critic functions, respectively. Ultimately, it is expected to get a robust optimal policy with a low constraint deviation likelihood for the VVC problem.
Using Automation to Create an All-Members Screening Process

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Abstract—To add large loads to municipal utilities, each load request must be individually evaluated by a study conducted by an engineer to determine if current transmission infrastructure can handle the new load addition. This project will create an All-Members screening process with the goal of creating a repeatable annual study performed using transmission planning models to determine the increase in load each municipal utility can reliably serve. This poster will showcase the All-Members study automation using preexisting software and Python programming.

Index Terms—Municipal Utilities, transmission infrastructure, Python Programming, load additions

I. ALL-MEMBERS SCREENING PROCESS

The process of automating an All-Members screening process for a municipal power agency with several municipal utilities will be performed using PSSE and TARA. The need for automation has arisen to address the ongoing changes to the grid. As the world moves towards a more sustainable future the grid has been advancing to include more renewables. Integrating renewables requires more man hours from engineers than ever before, and we have already seen this in the industry. Ten utility companies in the upper Midwest have already built more than eight-hundred miles of high voltage transmission since 2004. Meanwhile, the workforce within the power industry is aging without as many young engineers to fill in the gaps. To implement a solution to the additional work required to update the grid. To combat the problem of having more work to do than ever before with fewer people, we have turned towards automation. Specifically, we have created an All-Members Screening Process that will study changes that can be made to the grid in order to implement more renewable and more transmission. We found that a lot of our engineers were doing repetitive tasks in their work. A large portion of their work is done by software and then it is a matter of analyzing the data that is output by the software. Therefore, in order to save the engineers’ time we automate the repetitive tasks that take up so much of the engineer’s time. These tasks are things such as loading files into software, running the software, and putting the results of the simulation into an excel file. This can all be automated using Python.

The Regional Transmission Organizations (RTOs) create five-year cases in PSSE for Summer and Winter peak conditions. The Summer peak is used to assess voltage violations and thermal loading limits. Thermal loading limits will also be assessed using high generation dispatch (i.e., wind or other generation), where needed. The Winter Peak case is used typically for assessing voltage concerns for winter-peaking.

II. AUTOMATING THE STUDY PROCESS

A. Automating the Study Using Python

Next, changes will be made to the model and ancillary simulation input files. Any generation local to or near the relevant transmission area will be taken offline as needed. Approved Projects and Spot Loads will be added to the models, then Auto-Singles which are transmission lines, transformers, or shunts, will also be added. Contingency definition (Con) files based on the requirements of NERC Standard TPL-001, Table 1, from the RTOs will be used as applicable [1]. All Agency load buses will be compiled into a subsystem for steady-state screening. Individual Agency member utility subsystems will be analyzed using Power-Voltage (P-V) and First Contingency Incremental Transfer Capability (FCITC) Analyses. Monitor Files will be used for each criterion.

B. Creating an All-Members Screening Report

The All-Members Screening Report will be compiled by collecting all of the P-V and FCITC limits. Then, the effective margin or deficit will be noted for easy reference in the future. For the P-V limits, the bus name and number will be noted. For FCITC limits, the transmission line or transformer will be noted. The end goal for this study process is to create a script that can run completely autonomously in the background to compile a report that can be accessed by an engineer at any time. As the files are updated the simulation will rerun and can be run overnight and outside of typical working hours. An engineer with other day-to-day tasks to do could easily spend over a year running these simulations and compiling results. Our goal is to save a large amount of time and effort by automating this task.

REFERENCES

Quantum-Enhanced DC Optimal Power Flow

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Abstract—Harrow-Hassidim-Lloyd (HHL) is a quantum computation algorithm that can solve a system of linear equations in a logarithmic time scale; hence, an exponential speed-up over best-known classical computers, which have polynomial time complexity, is accessible. This paper studies the integration of HHL into the DC optimal power flow problem. Optimality conditions are formulated as a system of equations in the form of $Ax = b$ that is solved by HHL. The performance of HHL for $A$-matrices appearing in DCOPF problems is discussed. The initialization of HHL for encoding data from classical data to a quantum state in an efficient manner is also investigated. The impact of HHL calculation error on DCOPF convergence and solution accuracy is analyzed. Qiskit module is used to test the HHL-based DCOPF problem on a 3-bus system. The impact of quantum computers and HHL errors on DCOPF is simulated for the IEEE 14-bus system.

Index Terms—Quantum computing, DC optimal power flow, Harrow-Hassidim-Lloyd algorithm, HHL Initialization, quantum computing error.

I. PROPOSED MODEL OUTLINE

One of the most useful quantum computing algorithms is Harrow-Hassidim-Lloyd (HHL) which can solve systems of linear equations in logarithmic time. HHL algorithm uses a quantum phase estimation circuit and a rotation gate to calculate the eigenvalues of a matrix and the inverse of the eigenvalues, respectively. HHL puts all eigenvalues of a linear system into an entangled qubit state, using quantum Fourier transformation. This is the main reason for the exponential speed-up of HHL over classical algorithms. A DCOPF KKT optimality conditions using Newton-Raphson method are formulated in the form of a system of linear equations as $Ax = b$ that is solved using HHL. The limitations, and challenges of HHL for the DCOPF application, such as initialization strategy, encoding classical data into quantum states, and the impact of quantum computers and HHL errors on DCOPF convergence are analyzed.

II. HHL ALGORITHM

The quantum circuit required for implementation of HHL on a quantum computer:

Fig. 1. Generation cost function values for different scenarios.

III. NUMERICAL RESULTS

Classical simulations are carried out on Matlab, and the Qiskit module in Python is used to run the HHL algorithm.

This work was supported by the National Science Foundation under Grant ECCS-1944752.

A. Case 1: HHL Iteration and Initialization Analyses

Fig. 2. 3-bus simulations with and without HHL initialization for ten demand scenarios

TABLE I. SIMULATION TIME IN SECONDS

<table>
<thead>
<tr>
<th>Feature</th>
<th>Min.</th>
<th>Max.</th>
<th>Avg.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exact quantum</td>
<td>249</td>
<td>395.4</td>
<td>308</td>
</tr>
<tr>
<td>Quantum signal processing</td>
<td>1.73</td>
<td>2.728</td>
<td>2.322</td>
</tr>
</tbody>
</table>

HHL initialization is a deterministic factor in the efficiency of the proposed algorithm in terms of solution time.

B. Case 2: Quantum Error Analysis

Current quantum computers suffer from errors due to hardware and algorithms problems.

TABLE II. 14-BUS SYSTEM RESULTS UNDER QUANTUM ERROR SCENARIOS

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Type (error %)</th>
<th>HHL-based DCOPF iteration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1 (c = 0)</td>
<td>5</td>
</tr>
<tr>
<td>2</td>
<td>1 (c = 10)</td>
<td>13</td>
</tr>
<tr>
<td>3</td>
<td>1 (c = -10)</td>
<td>14</td>
</tr>
<tr>
<td>4</td>
<td>2 (r = 5)</td>
<td>Not converged</td>
</tr>
<tr>
<td>5</td>
<td>2 (r = 10)</td>
<td>Not converged</td>
</tr>
</tbody>
</table>

Even though the algorithm did not converge for scenarios 4 and 5, power generation and cost values are close to the exact values obtained in scenario 1.

Fig. 3. Generation cost function values for different scenarios.

The proposed algorithm obtained acceptable results even with ±10% errors. Newton-Raphson convergence tolerance may need to be slightly larger to guarantee convergence under larger quantum computing errors.
Application of Neural Ordinary Differential Equations to Power System Frequency Dynamics

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Abstract—The integration of increasingly distributed energy resources (DERs) makes the grid more dynamic. The power system network control, supervision, and protection require a system dynamics model. The current modeling approach uses a synchronous generation-based model which cannot capture the dynamics of a converter-dominated power grid. Therefore, this research aims to apply computationally efficient and accurate neural Ordinary Differential Equations (NODEs) to model and infer the critical states information of the power system frequency dynamics. The NODEs-based framework is implemented in Python and trained using a system designed in MATLAB by generating C-code and then interfacing with python. The trained model with a log square chirp signal can predict the states under square as well as a step excitation signal, which validates the applicability of the NODES-based framework to model the frequency dynamics of the future power grids.

I. BACKGROUND
With the integration of Distributed Energy Resources (DERs), the swing equation-based power system model is unable to accurately model the complex power system. On the other hand, the demand for the validated model has increased drastically to ensure uninterrupted and quality electrical power along with the concern of blackouts and cybersecurity. Therefore, this research aims to design an accurate and computationally efficient dynamic model for DERs by testing the feasibility of Neural Ordinary Differential Equations (NODEs) [1]. Moreover, the design of NODEs based framework that solves the differential equation with input dynamics is presented here as a novel approach.

II. KEY FIGURES

Fig. 1: Proposed Overall NODEs based Framework.

Fig. 1 shows the proposed framework to model the power system frequency dynamics using the NODEs-based framework. The power system frequency dynamics model designed in MATLAB/Simulink is interfaced with Python by generating C-code to produce the training data sets and the NODES-based framework is designed in Python. The NODES-based framework in python learns the power system frequency dynamic system using training data sets of states such as a change in frequency ($\Delta \omega$) and rate of change of frequency ($\Delta \dot{\omega}$) under the application of log chirp as the excitation signal and the model is validated by comparing the states under square and step excitation signal.

III. FINDINGS, CONCLUSIONS, AND FUTURE WORK

Fig. 2: Trained states from NODES-based framework represented by blue color compared with true states from MATLAB/Simulink system represented by green color.

The results from the research show that the trained model under log chirp as an excitation signal is able to model the power system and accurately predict the states of the power system network under the square wave and step excitation signal with errors less than $10^{-3}$ p.u. Also, the research shows that the computational time to predict each state is $3.12 \times 10^{-5}$ s for each sampling data which is $\times 4$ less than the time required in MATLAB. This shows that NODEs based framework is able to accurately model the power system frequency dynamics without any prior system information. The research will be expanded to test its effectiveness in complex power system networks and will validate its applicability to control the frequency in the future.

REFERENCES

Reinforcement Learning based Frequency Control for Power System Frequency Dynamics

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Abstract—This work proposes a reinforcement learning (RL) based approach for fast frequency support in power systems that incorporates the dynamic nature of the grid. The proposed method utilizes a neural network controller based on a soft actor-critic (SAC) algorithm to learn an optimal control policy for frequency support. The controller is trained using a Simulink model of the reduced order frequency dynamics power system. Real-time measurements of the reduced order frequency dynamic model are estimated with an extended Kalman filter and utilized by the proposed approach to determine the optimal control policy for fast frequency support. The effectiveness of the proposed method is demonstrated through its performance in response to a disturbance to prevent frequency threshold violations and comparison with the existing frequency support approach Model Predictive Control (MPC). The results show that the proposed frequency method can effectively and efficiently provide fast frequency support in power systems and outperforms MPC in terms of response time and control performance. The proposed approach can significantly improve the frequency stability and reliability of the power systems providing a promising solution to the growing challenges of frequency support in the power grid.

I. INTRODUCTION

Over the years, a significant percentage of electricity generation sources has transitioned from conventional synchronous generators to renewable generators like wind and PV systems, in the last decade [1]. With this, there has been a decline in the power grid inertia, making a power system more sensitive to disturbances and frequency variation. This is making frequency stability in the power grid more challenging. With the power grid becoming more dynamic in nature, there is a need for an effective model-free data-driven approach for frequency support in RES integrated power grid.

II. KEY FIGURES

Fig. 1 shows the detailed framework of the proposed frequency support method. Three main blocks in the framework are Environment, State estimation filter, and SAC RL-based controller. The environment block comprises reduced order frequency dynamics of the power system [2]. The second block is the state estimation filter to estimate accurate state values, i.e., change of frequency ($\Delta \omega$) and rate of change of frequency (ROCOF) ($\Delta \dot{\omega}$), from the noisy state measurements obtained from the environment. In this research, an extended Kalman filter has been used to estimate state values. The final block is SAC RL-based controller which continuously interacts with the environment and develops optimal policy to generate optimal control action for the frequency support.

Fig. 2 shows the response of the controllers on the frequency dynamics at the load change of 0.4 p.u at 1 s. From this, we can observe that SAC RL-based controller can effectively reduce the nadir of the $\Delta \omega$ and also $\Delta \dot{\omega}$ and outperforms MPC in terms of frequency support.

III. CONCLUSIONS AND FUTURE WORK

In the paper, SAC RL-based controller was designed for fast frequency support in reduced order frequency dynamics of the power system. The performance of the proposed method was compared with the model-based approach MPC. The proposed method was able to perform effectively and better than MPC to reduce the nadir of $\Delta \omega$. In the future, we plan to scale the proposed method to larger power system models and analyze its performance with RES and non-synchronous frequency response.

REFERENCES


Impact of Commercial EV Loads on the Power Grid with Efficiency Contingency Factors

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I. EXTENDED ABSTRACT

In recent years, the presence of electric vehicles (EVs) in the power grid has experienced a substantial growth. The proliferation of commercial EV loads within the grid is expected due to their promising potential in reducing fossil fuel dependency, combating climate change, and generating substantial savings within the transportation sector. Despite their promising prospects, uncertainties exist regarding the potential impact of high EV loads. Particularly, those associated with commercial EV fleets in the conventional power grid. The extent to which these loads will affect the grid depends on the vehicle operational needs of commercial businesses, drivers regulated hours of service stipulated by the Federal Motor Carrier Safety Administration (FMCSA), and the efficiency contingencies (EC) that commercial vehicles must contend with. The dispatch times, driving ranges, charging costs, and hours of service, which are influenced by the commercial business system of operations and FMCSA regulations, play a pivotal role in determining the hourly charging profiles of commercial EV loads. Commercial EV fleets must adhere to strict scheduling procedures to ensure timely pick-up and delivery times. Moreover, EC factors include, but are not limited to, aerodynamic drag, rolling resistance, and traffic flow inertia, which all result in the loss of battery range and have a considerable impact on the charging load profiles of commercial EVs. These behaviors increase the consistency and prominence of high commercial EV charging loads during certain hours of the day. As commercial EV loads in the power grid increase, the likelihood of undervoltage and phase angle disturbances also increases. These disturbances could have adverse effects on the power grid, leading to high peak demand hours and rolling blackouts. Therefore, there is still a need to further explore the impact of commercial EV loads and EC factors on the power grid, to (1) further enhance knowledge of the potential impacts onto the grid, (2) develop a method of utilizing insufficient data acquisitions of EV loads, and (3) pave a path to a sustainable and resilient power grid infrastructure.

This paper examines the potential impact of commercial EV loads on an electric power grid. An IEEE 118-bus topology, illustrated in Fig. 1, serves as the baseline topology to conduct four case study simulations that utilize different EV load injections. The four cases are as follows: (i) Case 1: no EV load injection, (ii) Case 2: commuter EV load injection, (iii) Case 3: commercial EV load injection, and (iv) Case 4: commercial EV load injection with EC factors. The commercial EV load injection profiles contain 24-hour deterministic charging load, which aligns with the commercial business’s vehicle operation schedule and FMCSA hours of service regulations. The case studies are carried out using the power flow analysis simulation toolbox within MATPOWER. The voltages per unit and phase angles are analysed and compared throughout the power flow case studies, thereby offering further insight into the dynamic effects of commercial EV loads on large conventional power grid systems.

Fig. 1. Base EV load injection topology.

REFERENCES

Transmission and Distribution Systems Coordination using the Design Structure Matrix

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Abstract—The proliferation of distributed energy resources (DERs) is radically changing power system infrastructure planning and operation paradigms. Moreover, DER impacts are reaching the bulk system level and causing a shift in roles and responsibilities at the transmission and distribution (T&D) interface. These changes necessitate active coordination and planning across the T&D interface. However, many research studies do not capture all aspects of function coordination and miss opportunities to minimize tasks repetitions and to improve overall systems’ operation efficiency. In this paper, we apply the design structure matrix (DSM) method to analyze and model the interdependencies of the T&D system interactions. Using DSM clustering and partitioning techniques, we systematically identify coordination opportunities to optimize grid planning. Effectiveness of the proposed DSM method is demonstrated by representing and improving the coordination of T&D operational functions.

Index Terms—design structure matrix, smart grid architecture, transmission-distribution coordination, systems engineering

I. INTRODUCTION

Developing and operating modern low-carbon electricity systems present a substantial opportunity to reduce the greenhouse gases emissions [1]. However, as electrical grids escalate in scale and complexity, it becomes necessary to find an effective way to manage and reduce the risks associated with designing new systems, or introducing modifications to existing systems. Recently, there has been an increasing interest in studying complex power systems using Systems Engineering (SE) methodologies to manage the complex and often hidden interactions between its different components [2], [3]. In [4], the interactions and dependencies between technical and business domains in smart grids were analyzed using the design structure matrix DSM, which is a SE modeling tool used to represent and analyze elements interactions within complex systems [3]. In this work, we address the transmission and distribution (T&D) coordination using the DSM approach.

II. T&D SYSTEM DESIGN

The DSM is used to represent the power systems functions to analyze the functional grid structure, improve coordination and reduce feedback loops. The importance of this analysis stems from its role to define system boundaries and limitations, i.e., what the grid can and cannot do [2]. System elements and their interactions (relationships) are mapped in the DSM using a square $N \times N$ matrix, where $N$ is the number of system elements. One of aspect structure complexity reduction can be measured using the Feedback Reduction ($FR$) score, based on the reduced of feedback relationships after partitioning in comparison with the original number of feedback relationships

$$FR = \frac{\sum_{u \in D} u_{i,j} - \sum_{u \in D'} u_{i,j}}{\sum_{u \in D} u_{i,j}}$$

where $D, D'$ are the original DSM and partitioned DSM, respectively. The element $u_{i,j} = 1$ if there is a feedback relationship, and zero otherwise. Fig. 1 depicts the DSM after partitioning and clustering the elements. The partitioned DSM has a $FR$ score of 11.54%. Moreover, three modular subsystems were identified in the DSM model after partitioning, referred to as $S_1$ (red block), $S_2$ (blue block), and $S_3$ (orange block).

The DSM-based method of functions re-grouping and clustering serves first to highlight the important patterns in system architecture, which is an essential step to enhance grid planning modularity and coordination. Second, the systematic approach enables better understanding of the architectural trade-offs and benefits from specific design choices. Third, the identified subsystems provide important insights on which operations coupling should be analyzed and modeled by power system designers and planners.

Fig. 1: T&D operation coordination partitioned DSM

III. CONCLUSION

This work presented the DSM method as a SE tool to systematically investigate the existing coupling and coordinate the T&D functions in order to eliminate unnecessary feedback loops. Consequently, the need to make assumptions and revisit designs are reduced as inherent feedbacks are improved. The DSM is used to represent the interdependencies of the T&D operational functions. As a result, subsystem clusters are identified where function relationships require coordinating. Furthermore, feedback loops were reduced using DSM clustering and partitioning techniques. The results confirm the benefit of using SE tools to better understand T&D coordination.

REFERENCES


PMU-Timescale Topology Identification of Sub-station Node-Breaker Models using Deep Learning

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Abstract—In an actual power system, the bus-branch model used in a state estimator is usually derived from the substation node-breaker model. Therefore, incorrect topology information in the substation node-breaker model will cause the state estimation results to deteriorate. This poster presents a bus-branch topology identification framework for substation node-breaker models. The proposed method employs phasor measurement unit (PMU) data to identify the intra-substation connectivity at very high speeds. PMU data from Dominion Energy, a power utility in the U.S., is used to validate and test the proposed topology identification framework on the IEEE 30-bus system. The results demonstrate the applicability of the proposed framework for different cases in which varying levels of measurement noise are present under partial system observability provided by PMUs.

Index Terms—Deep learning, node-breaker model, phasor measurement unit, state estimation, topology identification

I. INTRODUCTION

There is a growing interest in using node-breaker models for monitoring in power systems. As such, many transmission operators have started transitioning their network models from bus-branch to node-breaker models. One of the key power system operation tasks that relies heavily on correct topology is state estimation. Accurate real-time knowledge of the topology ensures reliable state estimation results.

Due to the wide-spread availability of phasor measurement units (PMUs), several transmission operators are using linear state estimation (LSE) to monitor their system. Currently, the bus-branch model is used for performing LSE. In a bus-branch model, all the lines at a certain voltage level are connected to one point-of-connection inside the substation, called a bus. However, each substation is composed of several components, such as switches, circuit breakers, and transformers that are modeled separately in the node-breaker representation of the substation. Hence, each terminal of these components can be modeled as one node in the system and subsequently one bus can be composed of numerous nodes (Figure 1).

In this work we try to identify the topology of a substation with multiple outgoing transmission lines using deep neural networks (DNN) based on PMU data. We use different levels of measurement noise to show the robustness of deep learning model against extreme scenarios. Also, we show that it is possible to accurately identify the topology of the node-breaker model with limited observability.

Figure 1: Node-breaker model graph

In an ideal scenario, all these nodes will be connected to each other through closed breakers and switches and have the same voltage phasor. However, events such as breaker failure, system faults, scheduled maintenance, and even power flow control, can split one bus into multiple buses with different voltage phasors by opening/closing a set of circuit breakers. This will change the topology of the substation by splitting it into multiple buses. If the split-bus situation is not correctly reported to the topology processor, the bus-branch model used in state estimation will be erroneous.

Even though PMUs report phasors in real-time, circuit breaker status is usually not reported. Therefore, it is difficult to know the topology of the substation at PMU timescale directly from the data. Here, we propose a deep learning framework that identifies intra-substation connectivity even when only some of the lines of the substation are measured by PMUs. Simulation results in Figure 2 show that our proposed DNN based topology identification is able to always accurately identify the topology of the node breaker model with 99% accuracy beating another classifier model namely support vector machine (SVM) for standard and extreme measurement noise levels (i.e., Model 1 and Model 2 respectively).

Figure 2: DNN and SVM combination identification results for Error Model 1 and Error Model 2

Combination identification for $\mathcal{P}=1$ available PMUs in each substation

<table>
<thead>
<tr>
<th>PMU node</th>
<th>PMU node</th>
</tr>
</thead>
<tbody>
<tr>
<td>S: Switch</td>
<td>CB: Circuit Breaker</td>
</tr>
<tr>
<td>T: Transformer</td>
<td></td>
</tr>
</tbody>
</table>

Figure 2: Node-breaker model graph

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Enhancing Grid Resilience Through Intentional Islanding by Reinforcement Learning on Graphs

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Abstract—Intentional islanding refers to the deliberate isolating of self-sustaining islands within a threatened power network during disruptions, with the aim of enhancing the grid resilience. In this study, a reinforcement learning (RL) model with graph neural networks (GNNs) as a policy network to perform intentional islanding is developed, which offers real-time switching control, and online deployment ability. The islanding process is formulated as a Markov decision process, where the optimal switching policy is learned using the graph-based RL (GRL) approach. The environment of the GRL is a simulated power network that is facilitated by an interface to the standard openAI Gym framework. Results on the modified IEEE 24-bus transmission test system show that GRL-based intentional islanding could contribute to the self-recovery of the grids after the disruption.

I. INTRODUCTION

The proposed methodology uses RL and GNNs to create stable islands in a power system while ensuring voltage stability and reducing power mismatch, by modeling the interconnections between different components of the electrical grid as a graph. The agent uses GNNs to analyze the current states and decide which parts of the grid to isolate, thereby forming self-sustainable islands while maintaining the voltage stability and minimizing the power mismatch. Using GRL for intentional islanding can improve the decision-making process by providing a more accurate representation of the interconnections between buses of the grid, handling uncertainty, and incorporating expert knowledge.

This work focuses on enhancing the resilience of the transmission network by using GRL-based intentional islanding. The main objective is to minimize power flow mismatch during each reconfiguration action, by formulating the reconfiguration problem as a Markov Decision Process. The optimal control policy is then learned over the graph by using the RL approach. To account for the impact of topology on decision-making and the interaction between generation and demand at different buses, the transmission network is modeled as a graph in the learning space, along with its state variables. The graph neural network is proposed as the policy network, which can effectively learn the optimal control policy.

II. GRL TRAINING OF THE AGENT

The Power System Simulator for Engineering (PSS/E) software is used to model power transmission networks as an environment and perform power flow simulations for different switching actions. To integrate the PSS/E software with the standard openAI Gym framework, a Python interface has been developed. This interface allows the PSS/E to be used as an environment within the Gym framework, which provides a standardized interface for GRL algorithms to interact with the environment. As shown in Fig. 1, it includes measurements of voltage and power mismatch, which are important indicators of the network’s health and stability.

III. RESULTS & DISCUSSION

To test the developed intentional islanding agent, an outage at the transmission line (15, 21) is simulated as shown in Fig. 2. The policy network returns a suitable action for the outage scenario, resulting in opening lines (14, 16), (16, 19), (3, 9), (4, 9), (6, 10), (5, 10) after the disruption, thereby forming three operating islands, as depicted in Fig. 2. Bus 1, bus 16, and bus 23 on each island are considered as swing buses. In PSS/E, the maximum number of possible islands in the grid would be fewer than the number of swing buses, because the island detection is performed based on the swing bus in each zone.

Figure 1. Block diagram representation of the RL algorithm used for intentional islanding

Figure 2. IEEE 24-bus test system with an optimal islanding solution.
Abstract—Synthetic grids are fictitious power system models which are statistically similar to actual grids, but do not contain non-public data and hence can be freely shared. This poster introduces a method for tuning generator dynamics for a realistic synthetic grid based in Hawaii. It uses statistics of an actual grid to create a stable system by including a machine model, exciter, and governor.

Keywords—Synthetic grid, Generator dynamics, Statistics, Control system, Model tuning and validation.

I. MODEL PARAMETER DETERMINATION

The parameters in the generator dynamics should be determined to make the synthetic dynamics of power systems. This chapter briefly introduces the method for determining the parameters of generator dynamics, such as machines, excitors, and governors.

A. Machine model

There are several types of machine models in the power systems. Among the machine models, this poster uses the GENROU model that is generally used for gas and coal turbines. The synthetic parameters for this model were obtained by determining the parameter relationships using the EI case [1].

B. Exciter model

The most general model in [1] is the PI control type model called ESST4B. The possible parameter sets in the acceptable range are gathered according to the open-loop and closed-loop frequency response [3]. The parameter sets satisfying stability criteria (gain margin, phase margin, and damping ratio) shown in Table 1 are selected.

C. Governor model

The TGOV1 governor model is a simple and fundamental model according to [2]. There are parameters in the TGOV1, related to the droop and time constants. In this poster, the time constants are determined by using the statistics obtained from the actual system and the droop is set to 0.05.

II. VALIDATION OF THE MODELS

The synthetic Hawaii power grid is used for validation. It consists of 39 generating units, 1.15GW of generation, and 1.14GW of load. It was tested by introducing a 3-phase balanced fault, changing the exciter set point, and removing a generating unit from the system. Also, the single machine infinite bus system is used to verify the performance of the exciter model.

A. Machine model validation

The machine model should have sufficient synchronizing and damping torque so that the response after disturbance converges to the equilibrium within a few seconds. Rotor angle profile is shown in Fig 1. It shows a well-damped and stable response.

B. Exciter model validation

The exciter model is validated by analyzing the voltage response after a fault. The response of the generator which uses tuned exciter converges more quickly to the set voltage than to the untuned model’s response. The result of voltage profile of SMIB system is shown in Fig 2.

C. Governor model validation

When the power imbalance fault such as a generator outage or load change occurred at the power systems, the governor should control the generator power appropriately to maintain the frequency. The result is shown in Fig 3. The frequency converges to the equilibrium and shows a stable response after the largest generator outage.

REFERENCES

Impact of Forced Oscillations on Transient Stability

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Abstract—While there has been significant progress in the last few years to understand the physics of forced oscillations (FO) and identify the FO source, characterize the FO impact on small signal stability and design strategies to mitigate FO; there is a gap in literature in relation to understanding the impact of FO on large-disturbance stability. This paper aims to understand this unexplored topic by analyzing the transient stability in a system under FO. The pre-fault power system dynamics with FO converges to a limit cycle and we use this property to identify the key factors impacting the critical clearing time of a fault in a system under FO. We show that in a system with FO, the critical clearing time of a fault depends on the FO frequency, FO amplitude and fault instant, complicating the transient stability analysis. Following this, an algorithm is presented to perform transient stability assessment in the presence of FO for a generic power system. Results on the SMIB and the Kundur 2-area test system are used to illustrate the impact of FO on transient stability and the results demonstrate that forced oscillations close to the dominant modes have the potential to reduce the critical clearing time of a fault by more than 20%.


I. INTRODUCTION

Over the past decade, the power grid is being subjected to increased and sustained forced oscillations (FO). These oscillations are being suddenly induced due to an external mechanism, which is not under the control of the power system operator. The primary sources of these FO include malfunctioned control valves or faulty measurement equipment of steam and hydro turbines, cyclic load variations [1], failure of hardware in governor, exciter or PSS controls [2] and in the wake of increasing renewable penetration, improperly designed converter control schemes. Additionally, due to variability and uncertainty in renewable resources such as wind power, FO are being induced due to periodic fluctuations, as well as due to structural factors of the wind turbine [3].

Though FO can occur at a range of frequencies, it is typically the lower values of frequency close to inter area modal range (<0.5 Hz) that are most problematic if not suppressed. If these FO frequencies are close to values of inter area mode of a region, it can lead to amplifying oscillations across the system due to resonance [4]. On November 29, 2005, a 20 MW FO in Alberta led to 200 MW oscillations in certain California inter-tie lines [5]. This was due to resonating effect of FO frequency closely matching the 0.25 Hz inter-area mode in the western interconnection [5]. Further, if the location of FO is close to one end of inter area mode, its system wide effect may be exacerbated despite good damping. This trend was observed on January 11, 2019, in sections of eastern interconnection when a faulty control input to a combined cycle power plant in Florida, led to a FO of 0.25 Hz (in close proximity to one end of interarea mode of the region) [6]. These FO can contribute to large scale blackouts [8], equipment failure [15] and power quality issues.

Research has been conducted by several groups in the last decade or so to understand the underlying physics of FO, identify its source, its effects on small signal stability of the system, as well as strategies to mitigate it. [8] studies the uniqueness of FO component properties and wave shapes to discriminate it from modal oscillations including ways to mitigate it, demonstrated through a multi machine network. [9] derives that a system FO shape is a weighted sum of modal amplification factor and modal rotation factor of each system natural mode. In [10], ISO New England technologists describe the successful implementation of Dissipating Energy Flow Method to locate sources of oscillations in their Oscillation Source Locating application. The accurate estimation of location of FO through a sophisticated data driven algorithm, using Robust Principal Component Analysis is shown in [11]. A comprehensive review of existing FO location methods is presented in [12] along with their advantages and drawbacks. [13] analyzes the potential drawbacks of an energy flow-based method to accurately detect source of a FO. In [14], a novel control strategy is proposed to mitigate FO using E-STATCOM. [15] proposes a source location algorithm to track the source of FO using the oscillation mode angle and a control strategy to somewhat mitigate FO by utilizing BESS.

Despite the extensive research done on this topic, all the studies assume a small-signal model of the power grid in their analysis of FO and this model is not valid for large-signal behavior of the grid. Thus, there is a gap in literature in relation to assessing and characterizing transient stability in the presence of sustained FO. This is particularly important in the
Dynamic Modeling and Real-Time Control of Hydropower Units for Frequency Regulation

Maryam Baghkarvasef, Student Member, IEEE, and Masood Parvania, Senior Member, IEEE

Abstract—To maintain a stable frequency, power grids need effective frequency regulation mechanisms. These mechanisms ensure that power supply and demand are balanced in real-time operation. In this paper, we study the capability of hydropower units to provide frequency regulation in power systems. Hydropower units are well-suited for frequency regulation in power systems due to their fast response and ramping. However, these units are complex systems that depend on the availability and flow of water to operate, which makes their modeling and control a challenging task. This study proposes a real-time frequency control model that addresses the real-time variations in load while respecting the dynamics of different components in the hydropower unit. The findings reflect the efficiency of the proposed controller in deploying the potential of the hydropower unit to maintain the system frequency for different load scenarios.

I. FREQUENCY REGULATION BY HYDROPOWER UNITS

The schematic of the proposed frequency control model for hydropower units is presented in Fig. 1. The hydropower unit represents a system consisting of a hydraulic turbine to produce mechanical torque; a generator that converts the mechanical energy into electrical energy; an automatic speed governor that regulates the rotation speed of the hydraulic turbine; and a servomotor that controls the gate position to regulate the water flow into the turbine.

the calculated error, the speed governor, as a PI controller, generates a gate position signal for the servomotor in [4], which adjusts the guide vane positions of the hydraulic turbine to produce the required power output, as expressed in [10].

\[ \min \left( \int_t^T (f(t) - 1) \right), \] (1)
\[ \text{s.t.} \]
\[ \dot{q}(t) = (h_x(t) - h_x(t) - h_x(t)) \frac{A}{L}, \]
\[ \dot{q}(t) = (h_x(t) - h_x(t) - h_x(t)) T_w, \]
\[ h_x(t) = \left( \frac{q(t)}{G(t)} \right)^2, \]
\[ P_h(t) = q(t) h_x(t) - \beta G(t) (f(t) - 1), \]
\[ M \dot{f}(t) = P_h(t) - P_{load} - D f(t), \]
\[ P_{ref}(t) = k_f (f(t) - 1) + k_2 \int_t^T (f(t) - 1), \]
\[ e(t) = P_{ref}(t) - P_h(t), \]
\[ G_{ref}(t) = k_p e(t) + k_i \int_t^T e(t), \]
\[ G(t) = \frac{1}{t_{scre}} k_g (G_{ref}(t) - G(t)). \] (10)

II. RESULTS

Simulations are conducted on a typical test hydropower system using synthesized data electricity load. A discretization method along with a model predictive control solution consisting of 600 steps, each with a 60-second receding horizon, is used to reformulate and solve the proposed problem in [10]. Fig. 2 shows the frequency response provide by the hydropower units for 25 time steps. The results demonstrate the key performance of the proposed control model to enable the hydropower unit to capture the frequency drop within seconds and keep the system frequency between 59.5 and 60.5 Hz, thereby avoiding severe load shedding. The proposed model rapidly adjusts the frequency to its nominal value while also maintaining the load balance.
Offshore Energy Islands: the newest candidate in Europe’s offshore grid development plans

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Abstract—This paper defines and provides an overview of energy islands, which are artificial or natural islands where different types of technologies are interlinked to provide a significant amount of low- or zero-emissions energy to the onshore grid. The paper categorizes both different types of only-electrical energy islands and multi-purpose energy islands. Furthermore, it compares and evaluates them in terms of technological maturity, cost, and space requirements, as well as their impact on technical and operational challenges of the grid, such as active power sharing, inertia provision, frequency control, black-start capability, and grid forming.

Index Terms—Energy Island, HVDC, AC/DC grids, offshore grids, decarbonization, offshore wind

I. INTRODUCTION

Despite being an old concept, artificial offshore energy islands are getting increasing attention due to the European decarbonization plans for 2030 [1] and 2050 [2]. Particularly, the governments of Belgium, Germany, the Netherlands and Denmark agreed on reaching 150 GW of offshore wind installed capacity in the North Sea by 2050 [3]. In order to have such an enormous amount of wind generation delivered to consumers, huge investments in offshore grids and connections are needed. For this purpose, the TSOs from Belgium (Elia) [4] and Denmark (Energinet) [5] will build two artificial energy islands and interconnect them with an HVDC link.

II. METHODOLOGY

Firstly, this paper defines and classifies different types of energy islands. An energy island is an artificial or natural island where different types of technologies are interlinked to provide a significant amount of low- or zero-emissions energy to the onshore grid. As most of the renewable offshore projects are related to electricity generation from a Renewable Energy Source (RES), energy islands are distinguished based on the electrical design to transmit electricity to the onshore grid. Three types of energy islands are listed:

• Offshore RES generation with AC transmission lines.
• Offshore RES generation with AC and DC transmission lines.
• Offshore RES generation with AC and DC transmission lines and electric storage applications.

In the context of energy islands as multi-energy and multi-purpose systems, the above mentioned categories can be extended with:

• Energy island with power-to-X technologies.
• Energy island with LNG terminals.
• Energy island with harbours.

Considering that many combinations between the energy carriers and the electrical design can exist, this paper the paper categorizes and compares energy islands in terms of technological maturity, cost and space requirements. In fact, an energy island aims to enhance the energy exchanges of a particular area. Nevertheless, there is no universal design for such applications. Their design needs to be chosen carefully based on the peculiar characteristics of the selected part of the system. In this context, the paper analyses different electrical design aspects in detail. Each energy island can be represented through standardized building blocks connected different ways to each other. The paper discusses the advantages and disadvantages of each topology consisting of such building blocks and compares them.

Lastly, the impact of building an energy island on the technical and operational challenges of the grid is assessed. Issues such as active power sharing, inertia provision, frequency control, black-start capability and grid forming are evaluated for each topology.

In conclusion, the paper aims at two main objectives:

• Giving an overview of the current energy island projects and categorizing them.
• Serving as a reference for future research on energy islands.

REFERENCES

Particle Swarm Optimization Based Demand Response Using Artificial Neural Network Based Load Prediction

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Abstract—A new optimization method for Demand Response (DR) using Particle Swarm Optimization (PSO) is developed and validated where load prediction is done using Artificial Neural Network (ANN). The electrical load and climatological data of a residential area in Austin, Texas are used as the inputs of the ANN. Then, the outcomes with the day-ahead prices data are used to solve the load shifting and cost reduction problem. The results indicate that, the proposed model demonstrates the capability to optimize demand response and improve accuracy in load prediction, thereby reducing the cost and peak load.

Index Terms—demand response, differential evolution, artificial neural network, load forecasting, particle swarm optimization, smart grid.

I. INTRODUCTION

Demand response (DR) programs can incentivize end-users to change their electricity usage patterns, thereby reducing costs and optimizing grid operation. The article explores different approaches to implementing DR programs, including adaptive consumption pricing, incorporation of energy storage systems, and the use of electrically-driven water facilities. The particle swarm optimization (PSO) algorithm is presented as an effective means of solving large-scale nonlinear optimization problems in DR management. The article also highlights the importance of short-term load forecasting for efficient control of spinning reserve, unit commitment, and evaluation of sales or purchase contracts. Artificial neural network (ANN) models are shown to be effective in short-term load forecasting, and a multi-layer feed-forward ANN model is used to predict short-term load based on electric power consumption and climatological data in a residential area in Austin city. Simulation results are presented, and conclusions are given.

II. PROBLEM FORMULATION AND METHODOLOGY

The article describes a methodology for load forecasting and demand response (DR) in a residential area in Austin, Texas. Hourly electric power consumption data is obtained from the Electric Reliability Council of Texas (ERCOT), and local climatological data is extracted from the National Centers for Environmental Information database. Day-ahead hourly prices are obtained for data preprocessing and feature selection. The article utilizes an artificial neural network (ANN) to predict day-ahead electric load using inputs such as average wind speed, outside temperature, and hourly power consumption of previous hours. The article proposes a PSO-based DR methodology to minimize load shifting and energy operation costs, while a differential evolution (DE) algorithm is used for comparison. PSO and DE are population-based, derivative-free meta-heuristic algorithms with a simple model and few parameters. The article uses a mathematical model to formulate the PSO problem, and the objective function includes two normalized terms, load shifting and cost, with weighting coefficients to provide a set of solutions based on energy management capabilities and preferences. The article provides equations for computing the hourly energy operation cost and the total load shift in a day. Day-ahead hourly prices are used as inputs for both the PSO and DE algorithms.

III. RESULTS

This paper proposes a multilayer feed-forward artificial neural network (ANN) model for predicting day-ahead load and a Particle Swarm Optimization (PSO) algorithm for demand response (DR) program. The model is trained using Stochastic Gradient Descent (SGD) optimizer and achieves a near correlation with the real load with a low value of Mean Square Error (MSE). The PSO algorithm is used to shift the load and reduce operating costs, achieving cost reductions between 4.62% to 8.57% and peak load reductions up to 17.9%. The PSO algorithm is compared to the Differential Evolution (DE) algorithm and is shown to be superior in performance. Table I provides the results of these two algorithms for operating cost reduction and percentage of peak load reduction. Peak load of the predicted load is 60511.469KW and the corresponding cost of energy is 31389.529 $. Both algorithms reduce cost and peak load. However, PSO shows better results in cost and peak load reduction.

<table>
<thead>
<tr>
<th>Algorithm</th>
<th>Total cost ($)</th>
<th>Percentage of cost reduction</th>
<th>Percentage of peak load reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSO</td>
<td>28929.995</td>
<td>7.83</td>
<td>22.32</td>
</tr>
<tr>
<td>DE</td>
<td>30723.182</td>
<td>2.12</td>
<td>15.75</td>
</tr>
</tbody>
</table>
Advanced Grid Operations with Real Time Machine Learning
Ashley Beard, Dr. Stephen Bayne, Dr. Stephen Bukowski
Idaho National Laboratory, Texas Tech University

Advanced Grid Operations, AGO, aims to answer the questions, “Given what we know now about communication systems, power system modeling, and machine learning, how can we innovate traditional over current protection methodology to make the grid more reliable?”

Today’s traditional over current protection methodology is facing challenges as a result of the growth in renewable energy and distributed generation; however, using modern technologies, there are innovative solutions to these problems. Advanced Grid Operations researches possible solutions by using a Real Time Digital Simulator to create a repository of fault data to train a machine learning algorithm. Using a machine learning algorithm in tandem with a traditional over-current protective relay will give power engineers two points of confidence when assessing faults on utility grids. Ultimately, machine learning protective relaying can provide additional information to help solve several protection problems that arise with a growing electrical grid.
Hydropower Generation Forecasting Using a Deep Learning LSTM Model

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Abstract—With the push for more reliance on renewable energy sources, accurate renewable power generation forecasting is becoming increasingly important, as it helps utilities balance generation and demand. We propose a Hydropower Generation Forecasting (HGF) model trained to predict the power generation of a Hydropower unit using long-short-term-memory (LSTM). We present a case study in which 50 years of historical power generation and weather data from the Grand Coulee Dam were used to train and test the HGF model’s accuracy.

I. DEEP LEARNING MODEL ARCHITECTURE

The HGF model takes a (24 x 6) vector as an input corresponding to 24 hours of six historical weather data series. Using multiple climate input vectors provides context for the weather data at the hydropower plant. This gives the model an awareness of long-term climate changes, like a drought, for example, that might affect hydropower generation. The HGF network diagram can be seen in Fig. 1.

![Network Diagram](https://via.placeholder.com/150)

Fig. 1. Architecture of the proposed Hydropower Generation Forecasting model (HGF)

The deep neural network architecture consists of three LSTM layers and two FC layers. Long short-term memory (LSTM) is a specific recurrent neural network (RNN) component that facilitates time series forecasting using and remembering data from previous time steps. The output from three LSTM layers feeds directly into a FC layer whose output is filtered through a rectified linear unit (ReLU) activation function. This enables the prediction of hydro-power generation’s inherently non-linear time series. A final FC layer compiles the learned information from the previous layers and controls the shape and form of the forecast output vector.

II. CASE STUDY RESULTS

The model was trained to forecast the hydropower generation for the Grand Coulee dam in Washington State. Its accuracy was measured by comparing the model’s prediction root mean squared error (RMSE) and mean absolute percentage error (MAPE) to that of two other LSTM prediction models that were tested during the development of the final HGF model. Table I contains the results.

<table>
<thead>
<tr>
<th>Model</th>
<th>Performance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constrained HGF</td>
<td>RMSE 215.418, MAPE 0.10674</td>
</tr>
<tr>
<td>Simple HGF</td>
<td>RMSE 207.444, MAPE 0.08127</td>
</tr>
<tr>
<td>Final HGF</td>
<td>RMSE 206.145, MAPE 0.07973</td>
</tr>
</tbody>
</table>

The constrained HGF model is a version of the final HGF that does not use precipitation data as an input feature. Its input size is (24 x 4) as it uses 24-hour time steps and one less feature in its predictions. The simple HGF model has a similar architecture to the final HGF except that it only uses two LSTM layers and does not use weather data. It also used 24-hour time steps, so its input size is (24 x 1). The final HGF model was more accurate than the constrained and simple HGF models, suggesting that using relevant historical weather data can improve prediction accuracy.

![Forecast Accuracy](https://via.placeholder.com/150)

Fig. 2. A week of actual and predicted generation values. This depicts the accuracy of the HGF model’s hourly power generation predictions and demonstrates the model’s capacity to capture generation trends.
A Reinforcement Learning based Defense Investment Strategy Optimization in Smart Grid

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Abstract—This paper proposes a Reinforcement Learning (RL) based methodology using Markov Decision Process (MDP) and Q-Learning, enabling a system defender to model, analyze, and determine the optimal security policy for a multi-action defense investment scenario.

Index Terms—CPS, Smart Grid, Cybersecurity, STRIDE, Attack-Defense tree, Reinforcement Learning.

I. INTRODUCTION

Over the past few years, cyber attacks targeting CPS critical infrastructure, such as Smart Grids, have become more effective. Given the complexity of the grid and sophistication of present-day cyber attacks, quantification of risk assessment along with security resource allocation proves to be a bottleneck in cybersecurity planning. Various research has implemented different methodologies for solving the cybersecurity resource optimization issue. However, most of the existing research does not consider the dynamic nature and the intricate cyber-physical interactions of the grid. Therefore, a stochastic and heuristic methodology is required to overcome this research gap and allow a system defender to dynamically evaluate and optimize the defense investment strategy.

II. PROPOSED METHODOLOGY

An overview of the proposed methodology is shown in Fig. 1. The smart grid system model is defined as an RL environment, with attacker and defender as the agents interacting with the environment. STRIDE-ADT is implemented on the system models to vulnerabilities and attack access points, thereby formulating the relevant attack paths. Using Attacker cost, Defender Cost, and Attack Probability estimation following [1], a Cost Factor (CF) is calculated for each attack cost, thereby formulating the relevant attack paths. Using Attacker cost, Defender Cost, and Attack Probability estimation following [1], a Cost Factor (CF) is calculated for each attack cost.

Based on the STRIDE-ADT formulation, the defense investment strategy is abstracted into: seven states (S ∈ {No Action, Spoofing, Tampering, Repudiation, Information Disclosure, Denial of Service, Elevation of Privileges}), and, three defense control actions (A ∈ {Wait, Reset, Upgrade}). The Bellman Optimality Equation (BOE), combined with the Cost Factor equation (BOE + CF) to analyze the cost impact of each defense action on the optimal policy as specified in [2], is used to express the maximum state value functions for the three possible defense actions, where, π is optimal policy for control action a ∈ A. RL with Q-Learning is applied to determine the state-action value Q(π(s^n), a), for the (BOE + CF) equations derived for each defense action. First, the Q-table is initialized, then an action is chosen and performed, the expected reward is determined, and finally, the Q-table is updated. This process is repeated until the value function is maximized. By solving the Q-Learning algorithm, we will be able to find the optimal policies for each defense action for any given state. This process is then repeated for all attack paths obtained from STRIDE-ADT, and the results provide the defender with the cybersecurity investment strategies to optimally allocate resources in order to prevent cyber intrusions.

The proposed framework uses synthetic CPS smart grid models to demonstrate the implementation and practical feasibility. We have considered a 3-bus power system model to evaluate the performance of the proposed algorithm and determine the optimal defense investment strategies.

REFERENCES


Abstract—Voltage deviations are of great concern for microgrids, which, compared to conventional grids, are characterized by their smaller size, different voltage levels, and line characteristics. Due to their smaller size, microgrids are prone to large and rapid voltage deviations. Further, voltage is sensitive to both active and reactive power, requiring taking into consideration this input coupling to achieve adequate and robust control action. This poster will discuss a model-free, reinforcement-learning-based voltage support approach for a microgrid.

Index Terms—Voltage support, reinforcement learning, soft actor-critic.

I. PROPOSED APPROACH

In this project, we propose the use of the soft actor-critic (SAC), an off-policy reinforcement algorithm to provide voltage support using an energy storage system (ESS). The objective is to minimize the difference between a nominal voltage and an actual voltage along with inverter currents i.e., maximize the following reward accumulated over the future.

\[
r_t = -[(v_{cd} - v_{ref})^2 + R_{1i}i_{invd}^2 + R_{2i}i_{invq}^2]
\]

The block diagram for SAC, along with the benchmark, is shown in Fig. 1. The dq-transformed voltages and current, along with past control inputs and a reference voltage, are passed to the SAC agent as observations. Both the actor and critic of the SAC agent have a long-short term memory (LSTM) layer as a feature extractor that provides the LSTM state. The LSTM state is then passed to the fully connected layer to compute the action or Q-value. The agent interacts with the microgrid, and data is stored in the buffer. During the training phase, data is sampled from the buffer, and the neural networks (both actor and critic) are updated. The updated actor then interacts with the microgrid, more data is collected, and the process repeats.

II. KEY RESULTS

Fig. 2 (a) displays the d-component of the voltage during a load change, demonstrating that the use of ESS with SAC significantly reduces voltage deviation. The reduction is approximately five times greater than when the ESS is not used. Fig. 2(b) shows the required inverter currents. Smaller magnitude of d-component is utilized since we have used larger weights for d-component as compared to q-component.

This work is supported by the U.S. Department of Energy under grant number DE-SC0020281, and National Science Foundation (NSF) grant numbers MRI-1726964 and OAC-1924302. The work at Sandia (Ujjwol Tamrakar) is supported by the US Department of Energy, Office of Electricity, Energy Storage Program. SNL is managed and operated by NTESS under DOE NNSA contract DE-NA0003525.

III. CONCLUSION AND FUTURE WORK

The proposed SAC-based approach provides dynamic voltage support and reduces the voltage deviation by approximately five times. The average computational time is very small compared to the sample time of the agent, which is 100µs.

We also checked the time to compute the action by the agent and found that it takes about 1.72 µs for each time-steps. This time is very small compared to the sample time of the agent, which is 100µs.
Solar Panels Installation Planning in Residential PV Systems Using GIS

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Abstract—Recently, many countries worldwide have been concerned about environmental problems. One of the important keys to solving the problem is renewable energy. In Japan, high solar rooftop penetration has been installed in the system to respond to electricity and clean energy demand. This research focuses on applying Geographic Information System (GIS) technology and the high installation of solar panels in the residential distribution system. In addition, this research applied a high-resolution of solar radiation map based on the existing area for a more accurate solar panel installation location with GIS technology, to proceed with the solar panels’ best orientation and tilt angle at the targeted area. The results show that solar radiation in the summer season has the maximum data when the panel faces southwest at 9 degrees tilt angle. The total solar radiation per year will be applied for further work to achieve the future residential distribution system planning.

Keywords—Geographic Information System, GIS, distribution system planning, solar energy, photovoltaic, Solar Radiation

I. INTRODUCTION

GIS technology is a powerful tool for assessing solar power based on existing areas and specific dates and times. The program simulates the targeted area to model and divide data to layer. With GIS, the Land-Use data such as abandoned areas, agricultural areas, and farmland data can be extracted from an aerial photograph [1]. GIS technology can be applied to the distribution system model to evaluate the solar power from each solar rooftop in a residential area that installs solar panels in every house [2]. Nowadays, the residential PV systems have significantly increased to achieve the 2050 carbon-neutrality goal. Japanese government persuades new households to use electricity for the entire house. Therefore, power systems will increase renewable energy by 50-60%.

In this work, the optimal solar panel installation at the targeted area has been considered to find the best location to install the solar rooftop at the specific area with GIS technology. The suitability of the tilt angle and orientation depends on the area of the solar panel. For this reason, solar radiation simulation before installation is important for the best efficiency output [3]. This work applied aspect and function together with a solar radiation map one-day simulation in the summer season.

II. Methodology

GIS technology was applied to this work to create the solar radiation map from the targeted research area, Jono, located in Kitakyushu city, Fukuoka, Japan. The aerial photograph of the targeted area was used to create Digital Surface Model (DSM) layer. The DSM layer contains the elevation of the surface area of the research area’s terrain and the surrounding objects. The spatial analysis function in ArcGIS program can extract the solar radiation map in the targeted residential area at a specific date and time. This work used high-resolution aerial photograph for more accurate solar radiation data.

The high-resolution DSM layer can create an accurate solar irradiation map and obtain the solar irradiation value from each solar panel. The aspect function and slope function from the GIS program defined the proper solar panels’ installation location. The aspect function simulated the solar rooftops’ orientation and tilt angle from the slope function from the targeted area.

III. SIMULATION RESULTS AND FUTURE WORK

Fig. 1 shows the graph of direction, tilt angle, and total solar radiation on 19th July 2019 from 08:00 to 18:00 in the summer with sunny day conditions. The dots in the graph shows the 406 panels from solar rooftops in the research area. Each color shows the panel’s direction by blue, orange, grey, yellow, and green, representing northeast, northwest, south, southeast, and southwest. The results show that from 8:00 to 18:00, the total solar radiation’s maximum data is in the southwest direction and 9 degrees tilt angle. The south orientation has the highest total solar radiation. The tilt angle from 3 to 20 degrees has a high amount of total solar radiation. In future work, the one-year solar radiation data from each panel will be applied to find the best location for installation. The aim is to support future residential PV systems.

Fig. 1 The graph of total solar radiation, tilt angle and orientation

REFERENCES


Net-Zero Emission for Multi-Energy Campus System

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Abstract—The energy sector, as one of the largest contributors to global greenhouse gas emissions, is becoming manageable, especially in institutions such as university campuses that are also proponents of clean energy. A net-zero emission solution is proposed and demonstrated on a multi-energy campus system pursuing optimized energy and emission costs. The university at focus, via scheduling their existing onsite co-generators, high-efficiency steam boilers, utility purchase, and sizing the solar photovoltaic (PV) installation and renewable energy credit (RECs) purchase to pursue carbon neutrality, as well as energy cost minimization is studied. Three cases are executed to compare the electricity and steam provision, PV sizing, RECs purchase, as well as emission and energy cost tradeoffs to demonstrate the proposed net-zero emission solution. A two-step linear programming (LP) process is proposed to decouple the unit commitment problem and the economic dispatch problem by leveraging practical operating constraints while minimizing demand charge and load profile impacts, effectively rendering an annual total campus cost savings.

I. INTRODUCTION

A major topic of research in the scientific community is the impact of global climate change on society and the planet due to increasing CO₂ levels in the atmosphere. Initiatives have been developed to reduce CO₂, including implementing a net-zero approach defined commonly as any carbon produced being offset by removing carbon elsewhere. University campuses are well-populated energy hubs with closely distributed loads and onsite generations, serving as perfect locations for pioneer studies on emission reduction. The main objective of this study is to identify the energy sector emissions of a university campus and explore the potential of achieving net-zero carbon emissions. The focus is on reducing campus emissions from the multi-energy provision, i.e., both steam and electric energy.

II. MODEL DESIGN

A two-step LP based optimization model is constructed for an annual campus carbon emission minimization study, leveraging PV panel deployment, the campus’s current energy supply from local utilities, including RECs, onsite combined heat and power (CHP) co-generators, and high-efficiency boilers. The first LP step minimizes the problem objective function without considering the onsite generators’ minimum dispatch constraints determine units’ commitment statuses. The second LP step checks if any unit is operated below its minimum operation rates to eliminate inefficient unit operations deemed by facility operators and reruns the problem with such predetermined on/off statuses.

Three cases were investigated considering the tradeoffs between energy and carbon emission costs. The first case optimally schedules existing energy resources to explore the monetary cost and emission-saving potential; the second case schedules existing energy resources while considering roof-mounted, canopy, and ground-mounted solar panels to seek net-zero emission feasibility; the third case further determines the optimal amount of RECs to maximize energy and emission cost savings, while satisfying the definition of a net-zero emission campus. The results of the three cases can be seen in Figure 1.

Fig 1. Cases’ Total Emission and Energy Cost Comparison

<table>
<thead>
<tr>
<th>Energy</th>
<th>Emission</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>$4.25</td>
</tr>
<tr>
<td>Case 2</td>
<td>$4.51</td>
</tr>
<tr>
<td>Case 3</td>
<td>$8.72</td>
</tr>
</tbody>
</table>

III. FUTURE WORKS

This study investigates the solar PV integration into a campus multi-energy system and the use of REC purchases to pursue net-zero carbon emissions, while optimizing the energy and emission utility costs. As renewable energy penetration increases, REC and renewable energy costs are expected to decrease, making carbon neutrality more economically feasible.

Future work can be done to improve the modeling of this study, including using hourly RECs and refined hourly energy consumption profiling. In this work, the cost of RECs was assumed constant throughout the year. As improvements are made to the REC market, including moving to an hourly timestep, better decisions can be made on when and how many RECs should be purchased to achieve more economical net zero emissions. The hourly energy consumption of the campus could be improved, as the current method uses the utility bills and hourly profile from HOMER Grid. Work is underway to use time of use intervals in utility bills to generate more accurate hourly profiles.
Data-driven Piecewise Linearization for Three-Phase Power Flow in Distribution Grids

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Abstract—The rapidly growing number of distributed energy resources is increasing uncertainty and variability in distribution system operations. At the same time, better access to measurement data is enabling new, data-driven methods for state estimation and analysis. Compared with the traditional model-based power flow (PF) linearization approach, the data-driven PF linearization approach can address the issue of missing model parameters and varying operating conditions by directly leveraging feeder data. In this poster, we will introduce our work on the data-driven piecewise PF linearization approach. A data-driven piecewise linearization approach is proposed for the distribution three-phase stochastic power flow (SPF). Next, we propose a data-driven topology-adaptive piecewise PF linearization approach, which inherently adapts to topology changes in the distribution system. Numerical tests demonstrate that the proposed approaches can tackle the issues of data collinearity and correlation, as well as achieve satisfactory calculation accuracy with high computational efficiency, even under system topology changes.

Keywords—Active distribution network, data-driven, piecewise linear regression, stochastic power flow

I. INTRODUCTION

The stochastic power flow (SPF) method is an essential tool to analyze the uncertainties in active distribution networks, in which the Monte Carlo (MC) method is a promising way to consider the correlation of random variables and the three-phase characteristic. The piecewise PF linearization can improve the efficiency and accuracy of the MC method. Compared with the traditional model-based PF linearization method, the data-driven approach can address the issue of missing model parameters and varying operating conditions by directly leveraging feeder data. Therefore, we propose a data-driven PF linearization approach for three-phase SPF calculation. Unfortunately, topology changes pose a significant challenge to existing data-driven methods. To address this issue, we propose a data-driven topology-adaptive piecewise PF linearization approach.

II. METHODOLOGY

We propose an improved K-plane regression algorithm to achieve a three-phase piecewise linear power flow (LPF) model considering the collinearity of the training data and the nonlinear nature of the PF model. The K-piecewise function to be obtained is $y = \tilde{w}^T_j \tilde{x}_k$, $k = 1, ..., K$, and the error function is

$$\sum_{i=1}^{N} \min \left[ \left( \tilde{w}_k^T \tilde{x}_i - y_i \right)^2 + \gamma \left\| x_i - \mu_k \right\|^2 + \alpha \left\| \tilde{w}_k \right\|^2 \right],$$

where $\mu$ is the cluster center, $\tilde{w}$ is the coefficient. The error function can be decreased through the following iteration:

**Input:** \([x_i, y_i], ..., [x_i, y_i]\)

**Output:** \([\tilde{w}_k, \mu_k], ..., [\tilde{w}_k, \mu_k]\)

**Begin**

Step 1: Initialize $c = 0$, \((\tilde{w}_k^0, \mu_k^0), ..., (\tilde{w}_k^0, \mu_k^0)\) and $S_k^0, ..., S_k^0$.

Step 2: Find $\tilde{w}_k^{c+1}, \mu_k^{c+1}, k = 1, ..., K$ as follows,

$$\tilde{w}_k^{c+1} = \left( \tilde{X}^T \tilde{X} + \alpha I \right)^{-1} \tilde{X}^T \tilde{y}, \quad \mu_k^{c+1} = \frac{1}{\left| S_k \right|} \sum x_i.$$

Step 3: Find $S_k^{c+1}, k = 1, ..., K$ as follows,

$$S_k^{c+1} = \left\{ x_i | k = \arg \min \left[ \left( \tilde{w}_k^{c+1} - y_i \right)^2 + \gamma \left\| x_i - \mu_k^{c+1} \right\|^2 \right] \right\}.$$

Step 4: Termination Criteria:

**If** $S_k^{c+1} = S_k^c, \forall k$, **then** stop.

**Else** $c = c + 1$, **go to Step 2**.

**end**

Based on the trained piecewise LPF model, we propose an online three-phase SPF calculation process that incorporates the Nataf transformation and the MC method with the following steps: 1) Generate the data samples $x$ from a certain distribution. 2) Determine the partition $f$ of each data sample with $f = \arg \min_i \left[ \left\| x_i - \mu_k \right\|, k = 1, ..., K \right]$. 3) Calculate the LPF for each data sample with $\tilde{y} = \tilde{w}_k x$. 4) Aggregate all data samples to obtain the three-phase SPF.

Furthermore, to adapt to topology changes in the distribution system, we propose a data-driven topology-adaptive piecewise PF linearization approach. We define a topology-identifying variable $x_{\text{topo}}$, which can be the voltage magnitude at a small subset of nodes or the PF of a subset of branches. Then we use both the power injection $x$ and the topology-identifying variable $x_{\text{topo}}$ to cluster the data according to the system topology and train the LPF model, without requiring explicit information about the topology status.

III. KEY RESULTS AND CONCLUSIONS

Numerical analyses were tested using the three-phase unbalanced IEEE 123-bus distribution system. The results show that the SPF results of the proposed approach match well with the benchmark method based on backward-forward sweep, even though the computation time of the proposed approach is only about 1/37 of the benchmark. This illustrates the accuracy and efficiency of the proposed SPF calculation approach. When tested with the training data obtained from 5 topologies, we observe that in the training process, the topology-adaptive approach can cluster the training data into groups corresponding to different topologies. In the PF calculation process, it can pick up the right topology for a given state and calculate the PF accurately. This indicates its promising implementation value under topology changes.

REFERENCES


Saturation Effects in Equitable Demand Response Tariff Design

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Abstract—While residential consumers’ electricity demands are becoming increasingly responsive to prices due to growing awareness and adoption of smart home management devices, they cannot respond to price changes indefinitely. Modeling this saturation effect in consumer price responses is crucial to ensure that demand response will not add excessive energy cost burdens. This paper proposes an optimization model to design price response events while ensuring energy equity considering the income status and the response saturation effect of each consumer. The proposed method formulate the tariff design problem as a mixed integer non-linear optimization model to achieve a demand reduction target while minimizing the energy burden. We use real-world datasets in the case study to obtain the personalized electricity price, energy consumption, and energy burden for each consumer and find the effectiveness of personalized tariffs in reducing energy burdens. By comparing the results with and without saturation effects, we conclude that modeling saturation effects can effectively reduce the energy burden in demand reduction response events.

Index Terms—Demand response; saturation effect; energy equity; tariff design; social characteristics

I. INTRODUCTION

Consumers’ price response express saturation effect due to their personally social demographics [1], i.e., they will continue to consume a particular demand regardless of whether the price rises or falls to a certain extent. The saturation effect is highly personal and largely affect energy equity during demand response (DR), which bring new challenges to the equity tariff design. This paper use energy burden to measure energy equity and model saturation effects based on a piecewise linear model, then formulate the tariff design problem as a mixed-integer non-linear programming problem with the goal of achieving a demand reduction target while ensuring energy equity.

II. MODEL AND FORMULATION

Fig. 1 shows consumers’ price response with saturation effects. The dynamic electricity tariff is designed as three types of prices during load peak, load valley, and normal load period, thus, consumers’ price response model can be formulated and linearized by four line segments with integer variable and segment constraints.

![Fig. 1. Consumer’s prices response with saturation effect.](image)

The price design problem is formulated to minimize the difference between response energy burden and the average and the difference between the response price and the baseline, which keeps the energy equity and avoid extra burden in consumers. The model also satisfies price cap and demand reduction constraints, where demand is represented by a price response function.

\[
\min \| (E_{i,t} - E_{ave,t}) \|, \quad \forall i \in N_{low} \\
E_{i,t} = D_{i,t}(\pi_{i,t}) * \pi_{i,t} / I_i \\
s.t. \sum_{i \in N} D_{i,t} \leq \alpha * \sum_{i \in N} D_{i,t,0}, \forall t \in T \\
E_{i,t} \leq \theta * E_{ini,t} \\
piecewise linear function constraints
\]

III. CASE STUDY

We use dataset from Low Carbon London (LCL) project and Commission for Energy Regulation (CER) Smart Metering project, which includes social survey data and demand data. Tariff results (Fig. 2) show consumers’ actual energy cost under saturation effect and reflect high-income consumers receives high prices. Energy burden results show high-income consumer bear more risk in DR event. Comparisons without the saturation effect (Fig. 3) show outrageous prices for high-income consumers in the absence of saturation, which imposes additional costs on them.

REFERENCES

Abstract—This paper proposes a clustering-based two-stage framework for evaluating the small-signal stability risk (SSSR) caused by the uncertainties of power systems. In the first stage, through a fast K-medoids clustering (FKMC) algorithm, representative samples (RSs) can be selected from massive uncertainty samples. The risk levels of RSs are determined by eigenvalue analysis, and then the convex hull (CH) of each risk level can be established. Through iteration, the CH-based small-signal stability risk regions (SSSRRs) can continuously extend to be more accurate. In the second stage, the established SSSRRs are updated when the uncertainty distributions and correlations change. Based on the SSSRRs established in the first stage, the risk levels of most new samples can be labeled. Then, a density-based spatial clustering of applications with noises (DBSCAN) algorithm is introduced to detect outliers from the unlabeled samples. RSs are selected from the remaining non-outlier samples by the FKMC. Finally, the SSSRRs are updated based on the outlier and new RSs. Through the proposed framework, the probability of different risk levels can be evaluated, and the risk regions can be visualized.

I. INTRODUCTION

Stable operation under significant uncertainties has become a severe challenge for modern power systems. Small-signal stability analysis, as an essential part of power system operation and planning, usually relies on steady operating conditions. However, the operating condition would be easily changed by the uncertainties of RESs, thereby resulting in a risk of small-signal stability. In this paper, a clustering-based two-stage probabilistic small-signal stability assessment (PSSSA) framework is proposed. The major contributions are summarized as follows.

1. Through the proposed framework, the probability of different SSSRs caused by uncertainties can be provided, and the corresponding risk regions can be visualized for the guidance of risk mitigation.

   2. An FKMC method is adopted to improve the efficiency of constructing the CHs of SSSRRs. With the assistance of a DBSCAN algorithm, the constructed SSSRRs can be updated efficiently to adapt to different distributions of uncertainties.

II. PROBABILISTIC PSSSA FRAMEWORK

The main procedure of the proposed framework includes two stages, i.e., FKMC-CH-based PSSSA and visualization, and DBSCAN-based SSSRR update, as shown in Fig. 1. The goal of the first stage is to construct the regions of different risk levels in a multidimensional space composed of uncertainties. The goal of this stage is to update the previously established SSSRRs for the adaption of new scenarios.

III. CASE STUDY

The effectiveness of the proposed PSSSA framework is verified by the results (Fig. 2 and Tab. I) in a modified IEEE-68 bus power system with three PMSGs.
Boosting Power System Operation Economics via Closed-Loop Predict-and-Optimize

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Abstract—Generally, system operators conduct the economic operation of power systems in an open-loop predict-then-optimize (O-PO) process; the uncertainties are first predicted as accurately as possible; given the predictions, system operators resolve optimization models such as unit commitment (UC) to determine optimal plans for pursuing operation economics. However, the operation economics could suffer from the open-loop process because its predictors myopically seek to improve the immediate statistical prediction errors instead of the ultimate operation cost. To this end, we developed two frameworks based on the idea of closed-loop predict-and-optimize (C-PO). The frameworks train cost-oriented predictors tailored for system operations by (i) feeding the induced operation cost back to the predictor training phase and (ii) targeting at minimizing the operation cost (instead of the statistical errors). Furthermore, the embeddability of the trained predictors is utilized to form a prescriptive UC model, which can simultaneously provide the predictions and UC decisions with enhanced operation economics. Using real-world data, the C-PO frameworks are evaluated on 6-bus, IEEE 24-bus, IEEE 118-bus, and large-size 5655-bus systems illustrate the potential economic and practical advantages of the presented C-PO.

Index Terms—Unit commitment, operation economics, prescriptive analytics, predict-and-optimize.

I. INTRODUCTION

GENERALY, power system economic operation is conducted in a O-PO process, as shown in Fig. 1(a):

- The renewable energy sources (RES) and system reserve requirements are predicted as accurately as possible.
- Taking the predictions as inputs, a deterministic UC problem is solved to determine the optimal day-ahead operation plan.
- Based on the UC decisions, an economic dispatch (ED) problem is tackled for real-time operation in the face of actual available RES power. The operation goal is to achieve a minimum operation cost.

However, due to the nonlinearity of power systems, a statistically more accurate prediction may NOT lead to a better operation economics, as illustrated in Fig. 2.

To this end, we presented to close the open-loop between the predictions and the optimizations. Specifically, two C-PO frameworks are developed [1], [2]. As shown in Fig. 1(b), their core is feeding the induced operation costs back to the prediction phase, in which the prediction quality is assessed via the induced costs. As a result, cost-oriented predictors that tailored for the optimization tasks can be obtained. Afterwards, the predictors are embedded into the deterministic UC model, forming a prescriptive UC model that can conduct predictions and enhanced optimizations simultaneously.

II. MAJOR RESULTS

Using real-world data, the C-PO frameworks are evaluated on 6-bus, 24-bus, 118-bus, and large-size 5655-bus systems. The results show that C-PO can outperform O-PO with 0.5%-5.0% improvements on average daily operation cost.

REFERENCES

Modified Eigen Decomposition based Interval Analysis (MEDIA) for Power System Dynamic State Estimation

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Abstract—The Bayesian approach has been employed in the dynamic state estimation (DSE) of a power system. However, the complexity of the noise sources makes it challenging to quantify measurement and process noise using probability density functions (PDFs). To overcome this difficulty, the authors of this paper propose a modified eigen decomposition-based interval analysis (MEDIA) method, which uses bounds instead of PDFs to quantify the noise. Furthermore, this method employs the eigen decomposition method to reduce the negative impact of the overestimation problem.

Index Terms—Dynamic state estimation, eigen decomposition, interval analysis, state estimation.

I. INTRODUCTION

A modified eigen decomposition-based interval analysis (MEDIA) method is proposed for the dynamic state estimation (DSE) of power systems and quantify their uncertainty using interval analysis. The interval analysis is introduced to the power system DSE, whereby users only need to provide bounded intervals of noises. The MEDIA method can significantly reduce the negative impact of the overestimation problem in DSE compared to other interval analysis methods. Hard boundaries of states are calculated in the proposed MEDIA method instead of estimated PDFs in Bayesian-based filters, which guarantees inclusion of the true states.

II. PROPOSED ALGORITHM FOR INTERVAL ANALYSIS DSE

A. Eigen-Decomposition based Interval Analysis (EDIA) Method

To suppress overestimation of the FBP due to the wrapping effect and dependence problem during the DSE of a linear system, eigen decomposition is applied in (1) to transform the original states $x_k$ into $x_k'$, where $Q$ is the right eigenvector matrix of $A$.

$x_k' = Q^{-1}x_k$

(1)

$$x_k' = Q^{-1}A x_k' + Q^{-1}B u_k + Q^{-1}w_k$$
(2.a)

$$y_{k+1} = C x_k' + D u_{k+1} + v_{k+1}$$
(2.b)

By introducing the auxiliary variable $x_k'$, the novel state become independence to each other in the prediction function (2.a).

B. Modified EDIA (MEDIA) Algorithm

To estimate states in nonlinear systems, the MEDIA method is proposed to separate system’s linear and nonlinear terms. The resulting MEDIA algorithm can be implemented as follows.

MEDIA:

\[
\begin{align*}
&\text{initialize } x_0 \\
&x_0' \leftarrow Q^{-1}x_0
\end{align*}
\]

for $k = 1$ to $k_{end}$

\[
\begin{align*}
&\text{initialize } \\
&x_{k+1} \leftarrow [-\infty, \infty] \\
x_{k+1}' \leftarrow [-\infty, \infty]
\end{align*}
\]

EDIA updates:

\[
\begin{align*}
x_{k+1} &\leftarrow x_{k+1}' \cap (A x_k' + Q^{-1}B u_k + Q^{-1}w_k) \\
x_{k+1} &\leftarrow x_{k+1}' \cap (Q x_{k+1}')
\end{align*}
\]

Apply FBP:

\[
\begin{align*}
x_{k+1} &\leftarrow x_{k+1} \cap (h(x_k, u_k) + w_k) \\
y_{k+1} &\leftarrow y_{k+1} \cap (g(x_{k+1}, u_{k+1}) + v_{k+1}) \\
x_{k+1} &\leftarrow x_{k+1} \cap g^+(y_{k+1}, x_{k+1}, u_{k+1}, v_{k+1}) \\
x_k &\leftarrow x_k \cap (h^+(x_{k+1}, x_k, u_k, w_k)) \\
x_{k+1}' &\leftarrow x_{k+1}' \cap (Q^{-1}x_{k+1}')
\end{align*}
\]

III. CASE STUDIES

The performance of the proposed algorithm is verified on the IEEE 118-bus system with a sub-transient generator model.

Fig. 1. Estimated states using the proposed MEDIA method during the transient responses.

IV. CONCLUSIONS

The proposed MEDIA method can estimate dynamic states of a generator in real time and generate guaranteed hard boundaries for each estimated state. Compared with the conventional methods, the proposed MEDIA method can reduce the overestimation problem in high-order control system of synchronous machines and give narrower intervals.
Network Pricing for Multienergy Systems Under Long-Term Load Growth Uncertainty

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Abstract—The long-term uncertainty of multi-energy demand poses significant challenges to the coordinated pricing of multiple energy systems (MES). This paper proposes an integrated network pricing methodology for MES based on the long-run-incremental cost (LRIC) to recover network investment costs, affecting the siting and sizing of future distributed energy resources (DERs) and incentivizing the efficient utilization of MES. The stochasticity of multi-energy demand growth is captured by the Geometric Brownian Motion (GBM)-based model. The kernel density estimation (KDE) method is used to perform the probabilistic optimal energy flow (POEF) to obtain energy flows under uncertain load conditions. The performance of the proposed methodology is validated on a typical MES. The proposed pricing method can stimulate cost-effective planning and utilization of MES infrastructures under long-term uncertainty, thus helping reduce low-carbon transition costs.

Index Terms—Flexible demand, multi-energy system, network pricing, uncertainty

I. INTRODUCTION

Multi-energy systems have been recognized as a cost-effective way to create a sustainable and low-carbon future. Many factors can cause long-term uncertainty in MES planning. Load growth uncertainty has been regarded as one of the most crucial determinants. Use-of-system (UoS) charge is one such economic signal to recover network investment costs and affect network use by customers. An LRIC-based network pricing method is designed in this paper to produce forward-looking nodal UoS charges that not only reflect the utilization of MES but affect the sizing and siting of customers.

II. METHODOLOGY AND DEMONSTRATION

As shown in Fig. 1, the simulated growth rate trajectories are sufficiently dispersed around their averages so that they represent a wide range of possible future scenarios. To illustrate the effectiveness of the proposed POEF model, the PDFs of example branches and pipelines are simulated using the Monte-Carlo method, the parametric method and the proposed adaptive KDE method, as shown in Fig. 2. The PDFs generated from the proposed method can highly align with the simulated probability density distributions under the Monte-Carlo simulation, particularly in the tail part. The results demonstrate the effectiveness of the proposed adaptive KDE-based model in fitting the PDF of energy flows.

Fig. 1. Realizations of GBM-based overall electricity peak demand in 10 years. Simulated sample paths are 2000.

Fig. 2. The PDFs of power flows through branch 1.

III. CONCLUSION

This paper proposes an LRIC-based network pricing methodology to guide the development of future demand under the long-term uncertainty of load growth. The proposed method can not only use nodal charges to reflect the utilized capacity of MES but also provide a forward-looking price signal that reflects the expected investment costs of MES to supply uncertain multi-energy demand. Through price signals, the proposed pricing method enables better utilization of the MES network by encouraging efficient siting and sizing of future multi-energy demand and generation.
Wind Power Scenario Generation Using Graph Convolutional Generative Adversarial Network

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Abstract—Generating wind power scenarios is very important for studying the impacts of multiple wind farms that are interconnected to the grid. We develop a graph convolutional generative adversarial network (GCGAN) approach by designing GAN’s hidden layers to match the underlying spatial and temporal characteristics. We advocate the use of graph filters to embed the spatial correlation among multiple wind farms, and a one-dimensional (1D) convolutional layer to represent the temporal feature filters. The proposed graph and feature filter design significantly reduce the GAN model complexity. Numerical results using real wind power data from Australia demonstrate that the scenarios generated by the proposed GCGAN exhibit more realistic spatial and temporal statistics than other GAN-based outputs.

Index Terms—Wind power, Graph convolutional generative adversarial network, Spatio-temporal data generation.

I. GRAPH CONVOLUTIONAL GAN (GCGAN)

In this paper, we suggest an enhancement of the GAN-based [1] wind power generation approach by using graph convolutional network (GCN) to produce the correct spatial relations among multiple wind farms. To develop the proposed GCGAN approach, we model the hidden layers of GAN’s generator and discriminator to consist of both graph filters in spatial dimension and feature filters in temporal dimension.

Let \( L \) denote the total number of hidden layers in the generator, and \( X^{(\ell)} \in \mathbb{R}^{N \times K_{\ell}} \) represent the input data matrix with \( K_{\ell} \) features per layer \( \ell \in \{1, \ldots, L\} \). For each layer \( \ell \), using the matrix \( W^{(\ell)} \in \mathbb{R}^{K_{\ell} \times K_{\ell+1}} \) as the trainable feature filter parameters, we can represent it as

\[
X^{(\ell+1)} = \sigma(A X^{(\ell)} W^{(\ell)}), \quad \ell = 1, \ldots, L \tag{1}
\]

where \( \sigma(\cdot) \) denotes the nonlinear activation function.

To consider spatial correlation, we propose to use an exponential transformation on the correlation coefficients, by setting the \((i,j)\)-th entry of the graph filter as

\[
A_{i,j} = (e^{\|G_{i,j}\|} - 1)/(e - 1) \tag{2}
\]

where the fractional term is normalized to be within \([0,1]\).

For temporal correlation, we consider the matrix multiplication term \( \tilde{X}^{(\ell)} = X^{(\ell)} W^{(\ell)} \) in (1) as the output of feature filtering. We use a 1D convolution filter of length \((2M_{\ell} + 1)\) with trainable weight coefficients \( \{W_{-M_{\ell}}, \ldots, 0, \ldots, W_{M_{\ell}}\} \). This way, the \(j\)-th column of matrix \( \tilde{X}^{(\ell)} \) can be formed by

\[
\tilde{X}^{(\ell)}_{\cdot,j} = \sum_{m=-M_{\ell}}^{M_{\ell}} X^{(\ell)}_{\cdot,j-m} W_{m}, \tag{3}
\]

and this filter output is used to construct each GCGAN layer as \( X^{(\ell+1)} = \sigma(A \tilde{X}^{(\ell)}) \). This way, the full filter matrix is reduced to a small 1D filter of fixed length.

II. RESULTS

We first compare the computational time for the proposed GCGAN with the DCGAN-based models. Table I shows the proposed GCGAN based on temporal filter is significantly faster than DCGAN using convolutional layers. In addition, we compare the time series data generated by each GAN model with that of the actual historical data. Fig. 1 compares sample daily outputs generated by DCGAN and GCGAN for two selected wind farms whose geographical proximity has led to a high level of correlation at 0.925. While the DCGAN outputs show an opposite trend at certain hours, the GCGAN ones maintain high similarity throughout the day.

Table I

<p>| Comparison of the training time per epoch and the total training time for convergence. |
|-----------------------------------------|-----------------|-----------------|</p>
<table>
<thead>
<tr>
<th>DCGAN</th>
<th>GCGAN</th>
</tr>
</thead>
<tbody>
<tr>
<td>Training Time per epoch</td>
<td>6.21 s</td>
</tr>
<tr>
<td>Convergence Time</td>
<td>594.7 s</td>
</tr>
</tbody>
</table>

![Fig. 1. Comparison of sample wind power scenarios generated by DCGAN (left) and GCGAN (right) for two selected wind farms that are geographically close and highly correlated.](image)

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Stability Analysis of Virtual Synchronous Machine

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Abstract—This work analyzes the stability of a grid forming (GFM) virtual synchronous machine (VSM) converter in the alpha-beta frame. An impedance scan is performed for the VSM and compared to the derived impedance of the analytical converter model. The generalized Nyquist criterion (GNC) is utilized to assess the stability of the converter at different grid strengths. Lastly, time domain simulations are performed and compared to the analytical results.

Index Terms—grid forming, VSM, Nyquist criterion

I. INTRODUCTION

To facilitate the transition to systems that are providing a majority of their generation from renewable sources, it will require a shift towards grid forming (GFM) technology. Most of the currently installed converter based generation is provided from grid following (GFL) sources. GFL converters rely on a phase locked loop (PLL) to synchronize with the grid and it has been widely shown that they are unstable in weak grids. GFM converters do not utilize a PLL to synchronize with the grid. Some GFM converters such as VSM, are modeled to operate as a synchronous generator. The objective of this work was to develop an analytical model of a VSM converter and verify its fidelity against a simulation based model.

II. METHODOLOGY/RESULTS

The converter output impedance is derived following the procedure that is outlined in [1], but adapted for a VSM:

\[ Z_{VSC} = \begin{bmatrix} Z_{11} & Z_{12} \\ Z_{21} & Z_{22} \end{bmatrix}. \]

Based on a grid impedance matrix \( Z_g \) and the converter impedance \( Z_{VSC} \), the loop gain of the system is found:

\[ L = \frac{Z_g}{Z_{VSC}}. \]

The GNC is applied by finding the eigen-values of the loop gain:

\[ \lambda_1, \lambda_2 = \text{eig}(L). \]

The system is analyzed for a grid impedance of \( L_g \) is 6.4 mH. The Nyquist plot in Fig. 1 is shown for the obtained eigen-values at the specified grid impedance. The Nyquist plot shows that the system will be unstable considering that \( \lambda_2 \) encircles the critical point. The model is then simulated in MATLAB Simulink. The active power oscillations in Fig. 2 show an unstable system, which was also observed from the Nyquist plot of the analytical model.

Fig. 1. Nyquist Plot, Grid Impedance \( L_g=6.4 \text{ mH} \)

Fig. 2. VSM Active Power Response, Grid Impedance \( L_g=6.4 \text{ mH} \)

REFERENCES

**Abstract**—State-of-charge (SoC) dependent bidding allows merchant storage participants to incorporate SoC-dependent operation and opportunity costs in a bid-based market clearing process. However, such a bid results in a non-convex cost function in the multi-interval economic dispatch and market clearing. We show that a simple restriction, the equal decremental-cost ratio (EDCR) condition, on the bidding format removes the non-convexity, making the multi-interval dispatch of SoC-dependent bids a standard convex piece-wise linear program. And a numerical example is presented to demonstrate a higher profit margin with an SoC-dependent bid over that from an SoC-independent bid.

**Index Terms**—Multi-interval economic dispatch, SoC-dependent bid, convexification, individual rationality, locational marginal pricing, temporal locational marginal pricing.

I. INTRODUCTION

There have been recent proposals that allow storage participants in the wholesale electricity market to submit state-of-charge (SoC) dependent offers and bids. Such bids incorporate SoC-dependent operation and opportunity costs of merchant storage participants into bidding parameters submitted to a bid-based market clearing process. In that way, the central market clearing can produce an economic dispatch program that schedules the battery SoC within a range favorable to the battery’s health and the storage’s ability to capture future profit opportunities under uncertainty.

However, SoC-dependent bids and offers result in a non-convex optimization for the multi-interval dispatch in the electricity market, causing computationally expensive market clearing processes, especially when we have large amounts of storage participating in the market. Such nonconvexity also distorts the current locational marginal pricing (LMP) signals, requiring out-of-the-market uplifts in the day-ahead and real-time markets to support the dispatch-following incentive.

This paper aims to uncover causes of nonconvexity from SoC-dependent bids and offer simple remedies that convexify the multi-interval economic dispatch to conform with standard market clearing and pricing processes.

II. A SUFFICIENT CONDITION CONVEXIFYING MULTI-INTERVAL DISPATCH

We propose a sufficient condition to convexify the market clearing problem for the one-shot dispatch. A toy example is illustrated here to give intuitive virtualization of the convexification procedure.

**Theorem 1.** If a storage participant’s bid-in parameters satisfy the equal decremental-cost ratio (EDCR) condition,

\[
\frac{c_k^e - c_{k-1}^e}{c_k^o - c_{k-1}^o} = \eta_k^e \eta_k^o, \quad \forall k,
\]

under non-negative LMPs, the total cost of a storage dispatch over multi-interval for the given initial SoC \(s_1\) is a piecewise linear convex function of \(g^c := (g_1^c)^T\) and \(g^o := (g_2^o)^T\):

\[
F(g^c, g^o; s) = \max_{j \in \{1, \ldots, K\}} \{\alpha_j(s) - c_j^e \mathbf{1}^T g^c + c_j^o \mathbf{1}^T g^o\},
\]

where \(\alpha_j(s) := -\sum_{k=1}^{j-1} \frac{\Delta c_k^e (E_k - E_1)}{\eta_k^e} - \frac{\epsilon_j (s - E_1)}{\eta_j^e} + h_c(s),\)

\(h_c(s) := \sum_{i=1}^{K} \mathbb{I}\{s \in \mathcal{E}_i\} \left(\frac{\epsilon_i (s - E_i)}{\eta_i^e} + \sum_{k=1}^{i-1} \frac{\Delta c_k^e (E_k - E_1)}{\eta_k^e}\right)\)

illustrated here to give intuitive virtualization of the convexification procedure.

**Fig. 1:** Top: SoC-dependent cost of storage in the 2-interval dispatch (left: non-convex true cost; right: convex EDCR cost. Middle: SoC-dependent bid (left: true SoC-dependent marginal cost; right: EDSR bid. Bottom: the composition of storage cost function with the affine function \(g_1 = -g_2\) (left: non-convex true cost; right: convex EDCR cost).

\(^*\mathbb{I}\{s \in \mathcal{E}_i\}\) is indicator function, which equals to 1 when \(s \in \mathcal{E}_i\).
Uncertainty Error Modeling for Non-Linear State Estimation With Unsynchronized SCADA and \( \mu \) through Measurements

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I. PROBLEM STATEMENT

Smart grids require enhancements to state estimation reliability in the face of low measurement redundancy, unsynchronized measurements, and dynamic load profiles. Micro phasor measurement units (\( \mu \)PMUs) facilitate co-synchronized measurements with high granularity, albeit at an often prohibitively expensive installation cost. Supervisory control and data acquisition (SCADA) measurements can supplement \( \mu \)PMU data, although they are received at a slower sampling rate. Increasing dynamics at the distribution level exacerbate uncertainty error associated with this asynchronicity. This must be accounted for to ensure energy management system reliability in the face of increasingly dynamic distribution systems.

II. PROPOSED TIME-VARYING WEIGHT MATRIX APPROACH

In weighted-least-squares static state estimation, the best state vector estimate is determined by minimizing the weighted norm of the residual, represented with the cost function:

\[
J_{CME}(x) = \|z - h(x)\|^2_W = [z - h(x)]^T W [z - h(x)]
\]

where \( W \) is the inverse covariance weight matrix.

Analysis of real \( \mu \)PMU data has shown that Ornstein–Uhlenbeck stochastic processes sufficiently describe time-varying loads, and that decay rates \( \theta_i \) can be estimated. A stochastic differential equation of the \( i \)-th load apparent power can be obtained,

\[
dS_i(t) = -\theta_i S_i(t) dt + \sigma_i W_i(t)
\]

The variance of the discrete-time Gaussian variable \( S_i[k] \) is then found recursively and incorporated into an updating, time-varying weight matrix \( W(t) \), illustrated in Fig. 1.

III. CASE STUDY

Validation was performed in MATPOWER on the 33-bus distribution system from Baran and Wu, with OU processes used to model each load in 6 hour simulations. Various levels of SCADA asynchronicity and measurement redundancy were explored. Random errors with distribution \( X \sim \mathcal{N}(0,1) \) were applied to all measurements.

With the time-varying weight matrix \( W(t) \) incorporated into the state estimation measurement model, significant improvement in false (FPR) instances of error detection were observed. State variable accuracy also improved, as illustrated in Fig. 2.

<table>
<thead>
<tr>
<th>SCADA Sampling Rate</th>
<th>FPR Without Update</th>
<th>FPR With Update</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 s</td>
<td>47.17%</td>
<td>0.00%</td>
</tr>
<tr>
<td>2 s</td>
<td>64.49%</td>
<td>5.23%</td>
</tr>
<tr>
<td>4 s</td>
<td>81.22%</td>
<td>12.84%</td>
</tr>
</tbody>
</table>

Fig. 1. Comparison of \( J_{CME} \) paths when weight matrix \( W \) values are static (blue) and when \( W(t) \) values are updated (orange).

Fig. 2. Comparison of state variable estimate accuracy
Integrating RTO and Utility Processes in Planning and Cost Allocation

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Abstract—This work aims to support industry planning needs by developing software tools that facilitate long-term planning while exploring interdependencies within regional transmission organizations’ (RTOs) interconnection queues, transmission expansion processes, capacity markets, and interregional transmission considerations. Additionally, the study aims to implement a reliability evaluation tool that coordinates with a long-term expansion planning application, explicitly accounting for utility-scale renewables, storage, and distributed energy resources (DERs). The tools will be tested using large-scale industry-size models, developing results to illustrate relationships between investment robustness, resource adequacy, and operational flexibility. The study also focuses on developing a new approach incorporating investment robustness in identifying benefits, specifically in identifying shortcomings in existing cost allocation schemes.

Index Terms—planning, investment, reliability, adequacy, uncertainty, optimization.

I. INTRODUCTION

Transmission planning is a critical component of ensuring reliable electricity service and competitive power markets. The increased environmental, economic, and political uncertainties impact power system planning, requiring innovative computational tools to explore future scenarios and determine the investments needed to satisfy electricity demands. While some planning tools are common among regional transmission organizations (RTOs), a few RTOs have implemented coordinated expansion planning (CEP) optimizer tools. CEP has the potential to facilitate benefit identification and improve the cost allocation process. By leveraging the benefits of CEP optimizers, RTOs can better manage transmission planning challenges, improve reliability, and ensure a cost-effective deployment of new resources. Additionally, within RTOs, there are planning-related synergies between interconnection queues, long-term planning processes, interregional issues, and capacity procurement mechanisms. This leads to the need to find ways new software can facilitate long-term planning while exploring interdependencies within the whole planning process, including cost allocation.

II. RESEARCH OBJECTIVES AND APPROACHES

This work addresses resource and transmission investment planning methods focusing on four research objectives. Initially, an industrial summary will be developed to determine how new software tools can assist with long-term transmission planning by interacting with planners throughout the nation to identify RTO needs within and interdependencies between the various planning functions used today. The second objective is to implement a resource adequacy (RA) evaluation tool that works alongside the Adaptive Coordinated Expansion Planning (ACEP) application, which differs from traditional CEP formulations by using stochastic programming to consider uncertainty across a set of scenarios. Fig. 1 shows an overview of the proposed integration approach. The third objective is to test the implemented tools using large-scale industry-size models and develop results that capture the relationships between investment robustness, resource adequacy, and operational flexibility. Lastly, the study aims to develop a new approach to cost allocation that takes investment robustness into account when identifying benefits.

![Fig. 1. Design approach for the integration of RA and resilience evaluation with the ACEP tool.](image)

III. BENEFITS AND POTENTIAL USES

This research provides benefits to RTOs, transmission owners, electric utilities, public policymakers, and other stakeholders by enabling exploration across a full spectrum of investment portfolios under a wider set of performance attributes. Given the capital-intensive nature of infrastructure, the ongoing transformation of centralized thermal units to wind, solar, storage, and DERs, and the related declining energy costs and rising flexibility costs, industry adoption of our tools may result in multi-billion dollar impacts. Efforts to assess and identify cost allocation methods will provide insight into distributing benefits related to those impacts.
Structured Learning for Optimal Frequency Control: Stability and Steady-State Economic Dispatch Guarantees

Wenqi Cui\textsuperscript{1} Yan Jiang\textsuperscript{1} Baosen Zhang\textsuperscript{1} Yuanyuan Shi\textsuperscript{2} Jorge Cortés\textsuperscript{3}

Abstract—As more inverter-connected renewable resources are integrated into the grid, frequency stability may degrade because of the reduction in mechanical inertia. A common approach to mitigate this degradation in performance is to use the power electronic interfaces of renewables for frequency control. Since inverter-connected resources can realize almost arbitrary control law, they are not limited to reproducing linear droop behaviors. Reinforcement learning has emerged as a popular method to design and optimize nonlinear controllers. It is difficult, however, to enforce performance guarantees from the learned controllers.

We bridge the gap between neural network-based controller design and provable guarantees on transient stability as well as steady-state performances. Using the Lyapunov function of the power system, we propose structured neural-proportional-integral (Neural-PI) controllers that guarantee the stabilizing of frequency to the nominal value. If communication between neighbours is available, we further extend the controller to distributedly achieve economic dispatch at the steady state. We explicitly characterize the stability conditions and engineer neural networks that satisfy them by design. Experiments show that the proposed methods outperform optimal linear droop as well as other state-of-the-art learning approaches.

Index Terms—Frequency control, Stability, Economic dispatch, Reinforcement learning, Neural networks

I. INTRODUCTION

Due to the shift from conventional generation to renewable resources, there has been noticeable degradation of frequency dynamics. Conventional linear droop controllers are proven to stabilize the system, but can be far from optimal. Since inverters are solid state electronic devices, they can implement almost arbitrary control laws by quickly adjusting their power setpoints. Then a natural question arises: are there other control laws that still guarantee the stability of a system with synchronous generators, but have more optimal performance compared to linear droop response?

To break the unenviable position of not fully utilizing the capabilities of inverters for frequency control, a number reinforcement learning (RL) approaches have been proposed. Specifically, (deep) neural networks are often used to parameterize the controllers and RL is used to train them. The key challenge in using RL is to guarantee that learned controllers are stabilizing, that is, frequencies in the system would reach a stable equilibrium after disturbances in the system.

We propose a structured neural-PI controller that has provable stability guarantees and achieves steady-state optimal resource allocation. Using Lyapunov functions, we show the key structure to achieve the performance guarantees are monotonically increasing functions. We construct monotone neural networks that are proven to universally approximate all monotone functions. This way, transient performances can be optimized by the training of monotone neural networks, while stability and steady-state optimality are inherently guaranteed by design. The structure of the proposed approach is illustrated in Fig. 1. Details and code can be found in [1]–[3].

II. NUMERICAL RESULTS

Case studies show that the proposed neural-PI control outperforms those with linear controllers and unconstrained neural network controllers.

REFERENCES

Privacy-Preserving Operation of Interconnected Distribution Networks with Soft Open Points

Xueyuan Cui, Zhifeng Liang, Yun Chai, Wenjin Chen, Ruoying Yu, Guangchun Ruan

Abstract—Existing centralized operation scheme can hardly apply to IDNs because of the privacy concerns. Two types of sensitive information should be properly protected: the inner parameters of networks and inter-communication variables of SOPs. To address this issue, this paper proposes a novel privacy-preserving operation model to run IDNs in a distributed manner. In particular, we establish the iterative optimization policy for SOPs using the second-order conic programming and alternating direction method of multipliers (ADMM). This policy is able to efficiently secure the inner parameters. As for the protection of inter-communication variables, an encryption communication strategy based on Paillier Cryptosystem is then developed and integrated within the iterative update process in ADMM.

I. PROPOSED PRIVACY-PRESERVING METHOD

A. ADMM-Based Iterative Optimization Policy

The interconnected distribution network is given as

\[ \min_{x} \sum_{m=1}^{M} F(x_m) \quad (1) \]

subject to

\[ H(x_m) = 0 \quad \forall m \in [1, 2, \ldots, M] \]
\[ G(x_m) \geq 0 \quad \forall m \in [1, 2, \ldots, M] \quad (2) \]
\[ y_m = y_{m, \text{SOP}_1} + y_{m, \text{SOP}_2} \quad i \in \Omega_{\text{SOP} \cap \Omega_{\text{N}}} \quad (3) \]

The augmented Lagrangian function of (1)–(2) is represented as

\[ L(x_m, y_m, \lambda) = \sum_{m=1}^{M} F(x_m) + \lambda \left( \sum_{m=1}^{M} y_m \right) + \frac{\rho}{2} \left( \sum_{m=1}^{M} y_m \right)^2 \quad (4) \]

where \( \lambda \) is the Lagrange multiplier (i.e., dual variable) and \( \rho > 0 \) is the learning rate.

\[ x_t^{t+1} = \arg\min_{x} \left[ F(x) + \frac{\rho}{2} \| y + \gamma^t + 1_M \mu^t \|_2^2 + \frac{1}{2} \Gamma^t (y - y^t) \right] \quad (5) \]

\[ \lambda_t^{t+1} = \lambda_t^t + \rho (1_M^t y^t) \quad (6) \]

where \( 1_M \times M \) is the all-one matrix with dimension \( M \times M \), and \( I \in \mathbb{R}^{M \times M} \) is the identity matrix.

The criteria for iteration termination are given as

\[ \{ \begin{array}{l}
1_M^t y_{t+1} \leq \zeta_1 \\
\| y_{t+1} - y^t \|_2 \leq \zeta_2
\end{array} \quad (8) \]

B. Paillier Cryptosystem-Based Encrypted Communication

By utilizing the additive encryption feature, the encryption communication strategy at each iteration is illustrated in

II. CASE STUDIES

The optimal voltage deviation after convergence of the proposed model is equal to the one of central optimization, which is lower than the objective value without SOP. The primal and dual residuals converge to 0 after 30 iterations, during which the encrypted message is always random.
Transient Stability Analysis of Grid-Forming Inverters with Power System Simulation

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Abstract—The grid-forming (GFM) converter acts as a controllable voltage source and is independent of the phase-locked loop (PLL) function. It consists of a constant voltage/frequency (V/F) control augmented with the power synchronization loop (PSL) to facilitate the synchronization of renewable energy sources (RESs) with the electrical network without using the PLL device. In this poster, a grid-forming control scheme is implemented to analyze the power system transient stability problem when the penetration rate of the inverter-based RESs is high. A line-to-ground fault is considered and the transient behavior of the grid-connected inverter with different controller parameters is analyzed and the efficiency of the controller design in transient stability improvement is observed. Moreover, by harnessing the power of a progressive power system simulation software named ePHASORsim, the active and reactive power of a grid-connected converter is controlled. The proposed control scheme under the ePHASORsim software can help future research contributions on the application of multiple paralleled GFM inverters operating in the utility grid.

Keywords—grid-forming inverters, renewable energy sources, transient stability analysis, ePHASORsim

I. INTRODUCTION

The implementation of GFM converters is one of the major ideas investigated in the literature to attenuate stability problems under a high penetration rate of renewables. The coordination of GFM converters in a power system is another challenging area that must be investigated in future research. Each GFM converter works at its specific operating point and is connected to RESs with different characteristics and unpredictable behavior. Therefore, the contribution of each GFM converter in frequency regulation when a perturbation happens would be a complicated problem that has to be solved in future modernized power grids. In this poster, the application of the grid-forming droop model in power system stability improvement is discussed.

II. CONTROLLER MODEL

The P-f and Q-V control loops of the grid-forming control model which adjust the voltage magnitude and phase angle are illustrated in Fig. 1. When a contingency happens in the power system, the output power of paralleled grid-forming inverters will be increased. Accordingly, the P-f control decreases the phase angle (θ) and prevents the excessive increase of the active power. The Q-V droop control can adjust the inverter voltage E or control the point of common coupling (PCC) voltage by the proportional-integral (PI) controller.

III. EXPECTED RESULTS

The power system frequency, output active power of the inverter, and the d component of the output current before and after a line-to-ground fault at t=0.8s, considering different values of inertia (J) and damping coefficient (D_p) are shown in Fig. 2. As can be seen, the controller parameters have a direct impact on the transient behavior of the system. Moreover, by increasing the value of the parameters, the frequency nadir is decreased which shows the transient stability improvement. Our objective is to show the interplay between the inverter control parameter and the transient behavior of the grid through extensive simulations.

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Fig. 1. The controller P-f and Q-V control loops.

Fig. 2. Power system frequency, inverter output active power, and I_d.
Modeling the Commercial Activity of an Aggregator in an Electricity Market

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Abstract—In this paper the commercial activities that an intermediary agent called aggregator can offer to the system operator through an electricity market are studied. The activities offered by the aggregator are the energy supply from distributed and renewable energy sources, as well as the complementary reserve service that helps to balance the supply and demand of the power system. The aggregator coordinates sources of energy production and demand from electric vehicle (EV) users connected to electricity distribution systems (EDS). To simulate the commercial activity between the system operator and the aggregator, a multi-objective mathematical model was used. In the optimization process the system operation cost is minimized and the economic revenues that the aggregator receives for the services provided are maximized. The modeling considers the degradation of the batteries when providing the complementary backup service. The test system has a demand of 200 MW supplied by a 14-bus centralized hydrothermal system, 5 renewable energy sources provided by the aggregator, and distribution systems hosting 1000 electric vehicles. The results show that both the aggregator and the system operator obtain economic benefits from their interaction.

Keywords—Aggregator, System Operator, Electric Vehicles, Optimization.

I. INTRODUCTION

Fig. 1 show the role of the aggregator for to model and simulate the management of an aggregator with the aim of minimizing the total cost of system operation and maximizing its revenues.

\[ \text{Marginal cost (USD/MW)} \]

The average marginal cost of the system for each time interval equivalent to 1 hour.

III. CASE STUDY

A. Test system

The test system is a 14-bus high-voltage, customized system supplying a demand of 200 MW. The generating fleet managed by the operator includes centralized generation sources that operate with natural gas, coal, fuel and a hydroelectric plant. The system also has 5 renewable energy sources managed by the aggregator.

B. Results

Fig. 2 shows the average marginal cost of the system for each case. In blue, the marginal costs are high when the figure of the aggregator is not considered. On the other hand, when considering the figure of the aggregator, there is a decrease in the marginal cost during peak consumption hours since the aggregator takes the high marginal cost as a market signal to disconnect the load of the EVs during those hours.

The revenues of the aggregator come from the production of photovoltaic generation sources, reaching 20 kUSD per day. This happens because it is prioritized in the dispatch because it has a lower cost compared to dispatchable generation. Finally, we can observe that the income from the voluntary load disconnection service amounts to approximately 7 kUSD per day, representing 17% of the aggregator’s income.

IV. FUTURE WORK

This poster showing a modeling of the trading activities of an aggregator in an electricity market finding a common ground between the aggregator and the system operator.

For the present study the coordination strategies of EVs and the electricity market will be improved under a stochastic analysis. Also, the depth of discharge and discharge cycles will be incorporated into the battery degradation model.
A Vector autoregression Framework for Cybersecurity Analysis of Short-term Load Forecasting

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Abstract—Short-term load forecasting (STLF) predicts the load for a short time horizon concerned for secure operation and scheduling purposes. As a data-driven application, the STLF model may be prone to cyber threats on input variables, such as, temperature anomaly, resulting in inaccurate decision-making. This work aims to propose a model-based cybersecurity framework for anomaly notification. Considering a weather map of load stations in an area, the vector autoregression (VAR) model is analyzed for STLF, indicating a model-based detection. As the VAR model is only built on historical load data, it can be used for comparative analysis with existing STLF model outputs to detect an anomaly. The feasibility of the proposed VAR framework for cybersecurity is validated on historical ERCOT load.

Index Terms—Short-term load forecasting, decision-making, vector autoregression, cybersecurity

I. INTRODUCTION

Short-term load forecasting (STLF) is a critical task for secure operation and planning, such as, generator scheduling, which ranges from one hour to a week. Weather, calendar-related variables, and historical load are some input variables where temperature data is an essential variable in STLF since many loads, e.g., air conditioning, depend on that. Moreover, the temperature is collected from external services, which increases the anomaly risk. Intelligence attacker is able to generate adversarial examples to deliberately fool the model, e.g., over/under-forecasting of load that impact the security of the power system and market price [1]. Most of the detection schemes are statistical tests for anomalies where AI-powered attackers are able to bypass them. This work intends to analyze the STLF to provide a detection framework based on the coupling relation of load stations representing physical constraints. An STLF area is the summation of various loads based on weather stations. This provides us with a geographical distribution of load that follows weather pattern, so there is a list of load time series distributed based on the weather [2]. We can adapt a forecasting model using VAR as a multivariate time series analysis in this fashion. In the VAR model, each variable is a linear function of past lags of itself and past lags of the other variables. The VAR process of order (lag) $p$ defines as $Y_t = \mu + \Phi_1 Y_{t-1} + \cdots + \Phi_p Y_{t-p} + \epsilon_t$, where $Y_t$ is an $(n \times 1)$ vector of variables, $\Phi$ is $(n \times n)$ coefficients matrix, $\mu$ is an $(n \times 1)$ vector of intercepts, $\epsilon_t$ is an $(n \times 1)$ vector of unobservable (iid zero-mean), and $p$ is the lag number. Regarding the weather station frame, the VAR process provides an STLF model of each station based on its lags and other stations’ lags. Historical load is the only variable in the proposed VAR model. Since the model has no input relating to temperature, it no longer suffers from false temperature and can be used as an anomaly model-based detection in STLF. That is, a comparison between the existing model, which includes temperature, calendar, and so on, and VAR output is carried out to observe anomalies. The proposed framework is illustrated in Fig. 1.

![Fig. 1. The proposed framework.](image-url)

II. RESULT AND DISCUSSION

The framework is applied to the ERCOT hourly summer 2020 historical load, including eight weather-based stations. Each VAR model uses all other stations’ load data. This work intends to validate the feasibility of the VAR model for STLF. Table 1 shows the accuracy of the VAR model forecasting indicated by root-mean-square deviation (RMSE). A short horizon provides better forecasting results for some stations for a fixed lag step. Thus, it can be a possible approach for a comparative analysis. In future work, we will apply statistical analysis to reduce the complexity by pairing correlated stations and then apply malicious scenarios to validate the framework.

<table>
<thead>
<tr>
<th>Lag</th>
<th>Horizon</th>
<th>RMSE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>COAST</td>
<td>EAST</td>
</tr>
<tr>
<td>6</td>
<td>2</td>
<td>205.9</td>
</tr>
<tr>
<td>6</td>
<td>6</td>
<td>362.9</td>
</tr>
<tr>
<td>6</td>
<td>12</td>
<td>626.8</td>
</tr>
</tbody>
</table>

Table 1. VAR model results.

REFERENCES


Electric Vehicle Delivery Routing and Charging in Road Transportation and Power Distribution Systems

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Abstract—Electric Vehicles (EVs) offer a promising alternative to traditional fuel-powered vehicles due to their zero-emission feature, reduced maintenance needs, etc. Furthermore, the increasing demand for parcel delivery poses challenges for EV transportation to meet requirements of e-commerce. Besides, as more EVs hit the road, the relationship between the road transportation and power distribution systems becomes increasingly important to manage power demand. This paper presents a novel iterative multistage model that links EV delivery routing and EV charging management, by considering constraints of the road transportation and power distribution systems.

Index Terms—EV Routing, Incentives, Bi-level Programming, Distribution Locational Marginal Prices.

I. PROPOSED MODEL

The proposed model is an iterative multistage problem, which is composed of three main stages, as shown in Fig. 1. In the first stage, the delivery allocation and detailed delivery routing of EVs are addressed by minimizing the traveled distance and operating costs, respectively. In this stage, technical and economic constraints of EVs are considered, such as battery degradation, acceleration- and speed-dependent power consumption, penalty for delay, tolls and incentives for availability time. The problems are stated by means of mixed-integer linear programming. In the second stage, the interconnection between the road transportation and power distribution systems is iteratively developed. This is done by adapting EV routing results to time periods, and calculating incentives for availability time based on Distribution Locational Marginal Prices (DLMPs) and estimated power limits at charging points. Finally, the third stage is presented as a bi-level programming model by means of non-linear programming. At the upper level, the EV demand aggregator determines the best charging strategy by minimizing charging costs based on the DLMP derived from the lower-level problem and considering energy requirements of EVs. The lower-level problem involves a DLMP-based market clearing process that minimizes the total power distribution system operation cost, which is modeled using AC power flow and considers both conventional and renewable generators, baseload demand, and connection to the main grid.

In summary, the proposed model enables the EV demand aggregator to find the best solution in terms of cost/benefits by managing the EV charging. It does so by managing energy requirements from EV delivery routing, charging EVs at the lowest DLMPs, and iteratively calculating incentives to try to modify EV charging behavior.

This work was supported by ID2021-122579OB-I00, MICIN/AEI/10.13039/501100011033, SBPLY/21/180501/000154 and 2022-PRED-20679 Grants.

Fig. 1: Iterative Multistage Proposed Approach.

II. REPRESENTATIVE RESULTS

The proposed model is tested on a 284-intersection road map and 119-bus power distribution system, linked by 80 charging points, using 2000 vehicles. The proposed model improves the EV demand aggregator profits by 33.34% compared to the no-incentive case (contrasting the first iteration with the iteration yielding the best outcome), as in Fig. 2a. The total hourly EV power demand is shown in Fig. 2b. Particularly, without incentives, EV demand profiles are more pronounced, as EVs connect to charge only for necessary time to charge. Alternatively, with incentives, EV demand spreads over longer periods due to availability. Fig. 2c depicts the EV demand and DLMP differences at charger 76, while Fig. 2d shows the number of EVs connected to the charger. In the absence of incentives, the EV demand profile has the same shape as the EVs connected due to no availability time. Conversely, with incentives, the EV demand aggregator charges EVs at lower DLMPs, especially during 14:00-16:00 h and 2:00-5:00 h.

(b) Total EV demand.
(c) EV demand and DLMPs.
(d) EVs connected.

Fig. 2: Key Results.

1 The terms ”Without Incentives” and ”With Incentives” ("w/o I." and "w/ I." in abbreviated form) refer to the first iteration and best solution found.
Operational Challenges of Hybrid Power Plants and Modeling Recommendations

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Abstract—This paper reviews potential operational challenges facing hybrid power plants. A hybrid power plant may contain different type of sources, e.g., solar photovoltaics (PVs), battery energy storage systems (BESS), etc. Real-world operation has witnessed many challenges, e.g., overvoltage at fault recovery, oscillations during solar PV ramping up, large phase angle change during fault, etc. There are many other potential challenges. These challenges will be reviewed. This paper also presents recommendations on how to test hybrid power plants to catch those potential operational challenges in the planning stage.

Index Terms—Inverter-based resources, hybrid power plants, operational challenges.

I. INTRODUCTION

Hybrid power plants consisting of various types of inverter-based resources (IBRs) are becoming more and more popular. For example, for a large solar PV farm, a BESS of one third of the size may be employed to provide desired frequency responses to fulfill the grid requirements. Reactive power compensation devices, such as STATCOM, are often used in a wind farm to provide voltage support. Furthermore, multiple solar PVs are often interconnected to the grid at the same bus or at a close proximity. In March 2021, NERC published a reliability guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants [?]. BESSs are commonly coupled with solar and wind sources. NERC’s guideline defines a hybrid power plant (HPP) as a generating resource consisting of multiple IBRs behind a single point of interconnection (POI). The guideline recommends to improve study processes by considering high penetrations, studying stressed operating conditions, etc.

II. CHALLENGE 1: PLANT-LEVEL CONTROL
COMMUNICATION DELAYS CAUSED ISSUES

A. Oscillations in voltage and var

It is known that a large volt-var gain in plant-level control in addition to the communication delay can introduce oscillations. The IBR SSO TF paper [?] has given a simple explanation using a simplified representation of volt-var relationship.

Most recently, a real-world solar PV 0.1-Hz var oscillation event (occurring when solar PV real power ramped to 80% nominal) has been presented and analyzed in [?]. High real power exporting level is shown to increase the voltage to reactive power sensitivity. This explains why oscillations may appear when real power ramps up. [?] has also analyzed the ratio between the real power and voltage. Due to the power control, the ratio has a very small gain in the low frequency region. This explains why oscillations may appear in voltage and var, but not in real power.

Fig. 1: Dynamic responses for a line tripping event. The communication delay are 150 ms for both PV and BESS.

To validate this phenomenon, 150 ms communication delay is assumed between the plant-level control to the PV inverter and the BESS inverter. The dynamic event is line tripping which leads to the decrease of short circuit ratio (SCR) from 4 to 3. The parameter of plant-level voltage control plays a big role. In this case, the gain of the voltage control is $7 + 56/s$. Fig. 1 shows that 2-Hz oscillations appear after the line tripping. The real and reactive power are presented using the same scale. It can be seen that the oscillations in real power are insignificant compared to those in reactive power and voltage.

III. SUMMARY AND CONCLUSION

This article presents a collection of operational challenges that can face HPPs consisting of multiple IBRs. A total of seven operational challenges have been described, along with the modeling recommendations.
A Data-Driven Polynomial Chaos Expansion-Based Method for Microgrid Ramping Support Capability Assessment and Enhancement

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Abstract—Microgrids (MGs) provide ramping support to the main grid during heavy-load periods. However, uncertain renewable energy sources (RES) and electric vehicles (EVs) may affect the ramping support capability (RSC) of an MG. This paper employs a data-driven sparse polynomial chaos expansion (DDSPCE)-based method to evaluate the hour-by-hour RSC of an MG. The DDSPCE model is used to identify the most influential random inputs, and a scheduling method of BESS is developed to enhance the RSC. Simulation results in the modified IEEE 33-bus MG show that the proposed method takes less than 3 minutes for evaluating and enhancing the hourly RSC.

Index Terms—Data-driven sparse polynomial chaos expansion (DDSPCE), electric vehicle (EV), global sensitivity analysis, microgrid, ramping support capability, renewable energy sources (RES)

I. METHODOLOGY

This paper employs the probabilistic continuous power flow equation (1) to compute an MG’s RSC:

\[ f(\varphi, \lambda, x) = f(\varphi, x) - \lambda b = 0, \tag{1} \]

where \( f(\varphi, x) \) is the deterministic continuous power flow, and \( x \) describes the random inputs from RES and EVs in the MG. The formulation of the probabilistic RSC reads:

\[
\max \lambda \\
\text{s.t.} \quad f(\varphi, x) - \lambda b = 0, \quad \lambda > 0, \quad \text{Other physical constraints.} \tag{2}
\]

The DDSPCE method uses a sparse finite degree model \( \hat{\lambda} = g(x) \) to approximate the stochastic model (2) with a target stochastic response \( \lambda \) and a random input vector \( x \) (1):

\[
\hat{\lambda} = g(x) = \sum_{i=1}^{N} c_\beta \psi_\beta(x), \tag{3}
\]

where \( \psi_\beta(x) \) is calculated as (2):

\[
\psi_\beta(x_1, \ldots, x_D) = \prod_{i=1}^{D} \left( \sum_{k=0}^{p_\beta} \lambda x_i^k \right), \tag{4}
\]

and \( C = [\ldots, c_\beta, \ldots]^T \in \mathbb{R}^{N_\beta} \) is expressed as:

\[
C = (\Psi(X)^T \Psi(X))^{-1} \Psi(X)^T \lambda. \tag{5}
\]

When the DDSPCE model (3) is built with \( \psi_\beta(x) \) and \( C \), the Sobol’ index of each random variable can be expressed as:

\[
S_\alpha = \left( \sum_{\beta \in A, \beta \neq 0} c_\beta^2 \right) / \left( \sum_{\beta \in A, \alpha \neq 0} c_\beta^2 \right), \tag{6}
\]

which indicates the influence of a random variable on \( \hat{\lambda} \).

This work was supported by Natural Sciences and Engineering Research Council (NSERC) Discovery Grant, NSERC RGPIN-2022-03236.

II. SIMULATION RESULTS

In the modified IEEE 33-bus MG with four PVs, WTs, EV stations, and diesel generators, Fig. 1 shows RSC \( \lambda \) distributions for selected time slots using the DDSPCE method, and Fig. 2 presents Sobol’ indices of random variables. Using BESS to mitigate dominant influencers, post-smoothing RSC \( \lambda \) distributions narrow, resulting in a higher RSC\(_{95\%}\) compared to pre-smoothing.

![Fig. 1. Distributions of pre-/post-smoothing RSC in selected time slots.](image1)

![Fig. 2. Sobol’ index for each random input and the dominant influencer.](image2)

<table>
<thead>
<tr>
<th>TABLE I</th>
</tr>
</thead>
<tbody>
<tr>
<td>PRE-/POST-SMOOTHING RSC(_{95%}) OF THE TEST MG.</td>
</tr>
<tr>
<td>Hour</td>
</tr>
<tr>
<td>-------</td>
</tr>
<tr>
<td>Pre-smoothing RSC(_{95%}) (MW)</td>
</tr>
<tr>
<td>Post-smoothing RSC(_{95%}) (MW)</td>
</tr>
<tr>
<td>RSC(_{95%}) increment (MW)</td>
</tr>
</tbody>
</table>

III. CONCLUSION

The proposed DDSPCE-based method can accurately evaluate the RSC of an MG and pinpoint dominant uncertainty sources. The BESS smoothing method efficiently enhances the RSC\(_{95\%}\) of an MG.

REFERENCES

The Need for Equitable Coordination in Multi-agent Power Systems

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Abstract— Increasing penetration of distributed energy resources is fueling the evolution of our centralized electric grid to a multi-agent system. System-level performance of multi-agent networks greatly depends on the communication and computational capabilities of nodes (customers). The equitable representation of customers with limited access to communication bandwidth (e.g., caused by sporadic internet access) or computational power (e.g., due to the age of their device) is not well-understood. To this end, this paper investigates equity in the context of multi-agent power systems and showcases the adverse impacts of overlooking struggling nodes. The case studies leverage the Consensus + Innovations approach to simulate the behavior of a multi-agent power system.

Index Terms—distributed optimization, energy aggregation, energy equity, energy justice, multi-agent systems

I. INTRODUCTION

The evolution of the electric power grid is driven by connectivity and autonomy. Multi-agent optimization methods fit well to facilitate information fusion by establishing a collaborative framework among agents to solve problems through local computations, and communications [1]. In a multi-agent system, communication between agents is crucial to the performance of distributed optimization methods [2]. Sporadic and weak connectivity can widen the energy equity gap and further impact marginalized agents of future multi-agent energy systems. We intend to draw readers’ attention to the impact of (computation and communication) access inequities on system-level coordination.

II. MATHEMATICAL MODELS

A. Energy Aggregation Problem

We adopt a multi-agent view of the electric network. The aggregation problem seeks to minimize the system-level energy cost while persevering the supply-demand balance and satisfying the physical limitations node’s assets.

B. Consensus + Innovations Approach

The Consensus + Innovations approach aims to find solutions for the energy aggregation problem in a fully distributed manner. In this iterative approach, agents collaborate to solve the energy aggregation problem.

C. Disruption Modeling

This paper promises to examine the need for equitable aggregation by considering two scenarios for struggling agents (nodes): (i) lack of access to reliable communication and (ii) sporadic communication in the face of physical disruptions. Under unreliable communication, agents use the last communicated information in upcoming iterations. During physical disruptions, each agent lose communication and physical connections with some neighbors and skip the communication between disrupted physical lines.

III. SIMULATIONS & RESULTS

We evaluated our algorithm using the IEEE 118 bus (node) test system. We simulate disruptions by breaking several agents off at a specific iteration during Consensus + Innovations update process.

<table>
<thead>
<tr>
<th>Communication Line</th>
<th>Physical Power Line</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Disruption</td>
<td>Disruption</td>
</tr>
<tr>
<td>Disrupted and Recovered</td>
<td>Scenario 1</td>
</tr>
<tr>
<td>Disrupted but Not Recovered</td>
<td>Scenario 2</td>
</tr>
</tbody>
</table>

TABLE II

NUMBER OF ITERATIONS UNTIL CONVERGENCE FOR FIVE SCENARIOS UNDER TWO SETS OF DISRUPTION AND RECOVERY ITERATIONS.

<table>
<thead>
<tr>
<th></th>
<th>Disruption 50, Recovery 150</th>
<th>Disruption 20, Recovery 400</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 0</td>
<td>295</td>
<td>295</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>305</td>
<td>555</td>
</tr>
<tr>
<td>Scenario 2</td>
<td>387</td>
<td>N/A</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>295</td>
<td>314</td>
</tr>
<tr>
<td>Scenario 4</td>
<td>315</td>
<td>314</td>
</tr>
</tbody>
</table>

IV. CONCLUSION

This paper investigates energy equity in the context of multi-agent power systems and demonstrates the adverse impacts of overlooking struggling nodes. The case studies utilize the multi-agent Consensus + Innovations approach to simulate the behavior of a multi-agent power system under two cases: lack of access to reliable communication and lack of access to reliable communication in the face of physical disruptions. Our simulation results show that ignoring struggling agents can result in system-level disruptions.

REFERENCES

A Group of Single-Ended Time-Domain Line Fault Location Methods Using Breaker Operation Information

Mengzhao Duan, Student Member, IEEE, Yu Liu, Senior Member, IEEE, Ze Liu, Xinchen Zou, Zhongtao Guan
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Abstract—This paper proposes three single-ended time-domain fault location methods for AC transmission lines. The traditional impedance based single-ended fault location methods usually assume that the system is homogeneous or the remote source parameters are known, which are not always satisfied. In addition, the phasor measurements are required, which need a relatively long measurement time window (typically more than one cycle). The proposed methods utilize the additional information brought by the operation modes of circuit breakers. The proposed methods only require instantaneous voltage and current measurements at the local end, and do not need any remote side information. Specifically, the line models considering lumped or distributed parameters are utilized, formulating three fault location methods. The effectiveness of the proposed methods is verified via numerous case studies in PSCAD/EMTDC, with different fault types, locations and resistances, and the results prove that the method with full consideration of distributed parameters presents the best accuracy. The methods only require a short data window within half a cycle (10 ms) and a relatively low sampling rate of 4kHz.

Keywords—Line fault location, single-ended measurements, time domain, Bergeron model, distributed parameters

II. KEY RESULTS

(a) Case 1: Low Imp AG faults
(b) Case 2: Low Imp BC faults
(c) Case 3: Low Imp BCG faults
(d) Case 4: Low Imp ABC faults

Fig. 1 Low Imp faults

<table>
<thead>
<tr>
<th>Fault Type</th>
<th>Case 1: Low Imp AG</th>
<th>Case 2: Low Imp BC</th>
<th>Case 3: Low Imp BCG</th>
<th>Case 4: Low Imp ABC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time Window</td>
<td>0.0619</td>
<td>0.0655</td>
<td>0.0571</td>
<td>0.0667</td>
</tr>
<tr>
<td>Sampling Rate</td>
<td>0.2393</td>
<td>0.0571</td>
<td>0.0702</td>
<td>0.0619</td>
</tr>
<tr>
<td>PSCAD/EMTDC</td>
<td>100 ohm</td>
<td>300 ohm</td>
<td>300 ohm</td>
<td></td>
</tr>
<tr>
<td>Time Window</td>
<td>0.0560</td>
<td>0.0833</td>
<td>0.0571</td>
<td>0.0833</td>
</tr>
<tr>
<td>Sampling Rate</td>
<td>0.0619</td>
<td>0.0667</td>
<td>0.0619</td>
<td>0.0667</td>
</tr>
<tr>
<td>PSCAD/EMTDC</td>
<td>100 ohm</td>
<td>300 ohm</td>
<td>300 ohm</td>
<td></td>
</tr>
</tbody>
</table>

Table 1. Results of the average fault location error(%) 5 test cases

This work is sponsored by National Natural Science Foundation of China (No. 51807119) and Key Laboratory of Control of Power Transmission and Conversion (SJTU), Ministry of Education (No. 2022AB01). The support is greatly appreciated.
Quantum-Powered Battery Scheduling

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Abstract—The power distribution system is facing a growing concern to meet the demands of the rapidly increasing number of power distribution components, which requires the utilization of advanced computation methods. As the number of batteries integrated into the grid continues to rise, scheduling multiple battery energy storage systems in the most efficient manner poses a rising obstacle. The topic of this paper is the development of a quantum-enhanced power grid. This paper addresses the optimal scheduling problem for a vast number of batteries by utilizing a constrained quadratic model (CQM) on D-Wave's hybrid CQM solver. Using Tesla Powerwalls, numerical simulations show the scalability of the model and encouraging outcomes for future research.

Index Terms—Battery scheduling, quantum computing, optimization, trend.

I. INTRODUCTION

On the horizon, power system managers will require cutting-edge computational approaches to manage the growing complexity of the power grid and the convoluted structure of system models, particularly at the distribution level, and within the context of smart grids. Power grid management and optimization, including Optimizing battery scheduling is an intricate task, and as the number of variables involved in the problem increases, such as the quantity of power plants and sources of renewable energy, the computation time required to solve it grows exponentially [1]. Quantum Computing (QC) is a method of computation that utilizes quantum behavior and has proven to be practically useful in different domains [2]. In this study, a Quantum Annealing (QA) solution is proposed to explore its potential in optimizing battery scheduling.

II. MODEL OUTLINE AND FORMULATION

Quantum annealing (QA) is a probabilistic optimization technique that falls under the umbrella of adiabatic quantum computation. It makes use of various quantum phenomena, such as quantum entanglement, superposition, and tunneling, to achieve its objectives. QA is particularly appropriate for addressing problems with a discrete search space by searching for the global optimum of an objective function [3].

We propose a novel approach for solving the battery scheduling problem by developing a quantum-compatible model. Unlike the traditional MIP-based methods, this approach is based on QA and utilizes a Constrained Quadratic Model (CQM). The proposed model has been implemented on a D-Wave quantum computer and by employing a blend of classical heuristics and QA techniques, the objective function is minimized.

This model aims to minimize the total scheduling cost (1) subject to charging, discharging, and load balance constraints.

\[ \min \sum_t \rho_t \sum_i (p^{ch}_{it} - p^{dis}_{it}) \tau \]  

(1)

where \( \rho \) is associated with the electricity market price.

III. NUMERICAL RESULTS

Branch-and-cut via CPLEX is used for classical simulations, while D-Wave's Ocean SDK and LeapHybridSolver were utilized for QA simulations. The viability of the proposed method for battery scheduling was evaluated through simulations on Tesla Energy's integrated lithium-ion battery systems.

An instance of the charging/discharging schedule for a simulated battery is illustrated in Figure 1. As anticipated, the battery charges and discharges during off-peak and peak hours, respectively. The comparison between the classical and hybrid CQM solvers is illustrated in Figure 2. For a small number of batteries, the conventional technique shows a relatively fast computation time. However, as the number of batteries increases, the computation time exponentially increases. On the other hand, the hybrid CQM solver presents a more linear trend, where the computation time increases linearly with an increase in the number of variables and constraints.

![Figure 1. Battery charging/discharging schedule](image1.png)

Figure 1. Battery charging/discharging schedule for a simulated battery. The trend of computational time in classical and quantum solvers

It can be inferred that the QC approach is likely to provide a quicker solution than the conventional method when dealing with a large-scale problem.

IV. REFERENCES

Optimizing Future Overhead Line Networks for Flexible and Resilient Operation

Omer Elmogamer, Member, IEEE, Konstantinos Kopsidas, Senior Member, IEEE.

Abstract— In the past years, there has been an increase in the power generation to meet the ever-increasing power demand. However, most of the existing Overhead transmission line (OHL) are expected to reach their critical maximum power transfer limits in the future. This forced utilities to optimize the existing OHL corridors by Uprating and/or Upgrading methods (UUM) the existing (aged) OHL. Applying UUM, such as Re-Conductoring and Re-tensioning, can result in changes to the climatic stress, mechanical weight, and electrical loading on the OHL components. Hence, the aim of this study is to examine increasing the power transfer capacity of OHLs by applying UUM and the effects of those methods on the reliability, resilience and ageing of the OHL components. To achieve the aim of this study, an analytical tool was built to quantify and assess the effects of the UUM on the reliability, resilience, and ageing of the OHL components. The results of a case study of Uprating a 138 kV steel pole OHL via Re-tensioning and Re-conductoring are presented in this study, highlighting the impact of each UUM on the OHL components.

Keywords— Overhead Lines, Reliability, Resilience, Ageing, Re-conductoring, Re-tensioning, Asset Management.

I. MOTIVATION

There has been a substantial increase in renewable energy sources (RES) in the past years worldwide. This increase has prompted the power utilities to increase the power transfer capabilities of their existing network to meet the ever-increasing demand for new (RES) connections. However, due to the clean energy shift agendas, most of the existing overhead transmission lines are expected to reach their critical maximum power transfer limits in future. To avoid the expensive solution of building new OHL and reduce the carbon footprint, power utilities are urged to optimize the existing transmission corridors by implementing flexible UUM to increase the network’s power transfer capacity. Applying UUM on OHLs, such as Re-conductoring and Re-tensioning to optimize power transfer of transmission corridors, could result in changes to the climatic stress, mechanical weight, and electrical loading on the OHL components (Towers, insulators, conductors, foundation, etc.) consequently impacting their reliability and life expectancy. The degree of impact of the various UUM on the stresses (weather, mechanical, electrical/thermal) on the OHL components vary based on three main aspects, (1) the selected UUM, (2) the OHL design (Tower height, span length, top tower geometry, etc.), and (3) the present condition/health of the OHL components. Consequently, different UUM would affect existing OHL’s reliability/life expectancy differently.

II. AIM

This study aims to quantify the effects of increasing the power transfer capacity of OHLs via Re-conductoring and Re-tensioning on the reliability, resilience and life expectancy of support structures (steel poles), insulators, and conductors. The study will also examine how OHL asset management (maintenance) methods can be utilized to mitigate the negative effects of the UUM on the OHL components To achieve this aim, an analytical tool was developed to quantify the effects of the UUM on the OHL ageing mechanisms (thermal ageing, corrosion, and vibration fatigue) and their impact on the OHL components’ lifetime expectancy. The tool considers the probabilistic stresses due to climatic loading associated with different return periods and the OHL components’ material strength to assess the risks of the UUM.

III. RESULTS AND DISCUSSION

The results of the case study of Uprating a 138 kV (221.8 MVA) steel pole OHL via Re-tensioning and Re-conductoring are presented in the paper. The results have shown that re-tensioning this pole with Drake from 20% to 25% RBS could increase the conductor’s risk of thermal ageing (96.2% remaining tensile strength), reduce its reliability by 17.6% and shorten its expected lifetime by 38.7%. However, changing the conductor from Drake to Triple Bundle (3x) Plover increases OHL’s system resultant climatic and mechanical loadings posing increased stresses on the supporting (steel) poles to a level that reduced their reliability by 96.7% and life expectancy by 87-94 Years. These findings are shown in Figure 1. Comparing the most robust steel grade, S450 (Yellow bars in Figure), with the weakest, S235 (Blue bars, in Figure), shows the steel poles’ reliability/life expectancy dependency on the pole’s material strength. The stronger the material (Yellow bars), the lower the impact on reliability/life expectancy when compared to the weaker material (Blue bars).
Online Output-based Inertia Estimation of Modern Power Systems

Mohamed Elnasry, Student Member, IEEE, Amarsagar Reddy Ramapuram Matavalam, Member, IEEE, Pranav Sharma, Member, IEEE, and Venkataramana Ajjarapu, Fellow, IEEE

I. PROBLEM STATEMENT
Physically, the concept of system inertia is related to its ability to suppress energy fluctuations caused by possible disturbances and external events. This feature is inherently provided in conventional power systems by rotors of synchronous generators. The overall inertia of modern power systems is drastically impacted by the penetration level of converter-based resources (CBRs). The intermittent output of CBRs and dependence on weather conditions affirm the need for a real-time inertia estimation approach. This can help the transmission system operators (TSOs) be continuously aware of the system inertia changes and take suitable control actions. This paper proposes a Koopman-based data-driven tool for approximating temporal dynamics.

II. IMPLEMENTATION OF PROPOSED FRAMEWORK
Using Koopman analysis, the observables are written as:

\[
\begin{bmatrix}
\omega(t) \\
\Delta P(t)
\end{bmatrix} = \begin{bmatrix} V^\omega \\ V^P \end{bmatrix} e^{\Lambda t} \Phi^T(x_0)
\]

where \(V^\omega\), and \(V^P\) are the Koopman eigenmodes corresponding to the observables \(\omega\), and \(\Delta P\) respectively. \(\Lambda\) is a diagonal matrix of the eigenvalues, and \(\Phi\) is a vector of the corresponding eigenfunctions. (1) is used to rewrite the swing equation and estimate the inertia constant as follows:

\[
\hat{M} = G_2 \times G_1^T
\]

Such that \(G_1 = V^\omega \Lambda e^{\Lambda t} \Phi^T(x_0)\), \(G_2 = V^P e^{\Lambda t} \Phi^T(x_0)\), and \(\hat{M} = [\hat{M}_1, ..., \hat{M}_N]^T\).

III. SIMULATION RESULTS
The proposed approach is tested with the two-area Kundur system. 16.67s long data blocks of 60Hz sampled rotor speeds and electrical power (1000 samples) are provided to the algorithm to test the estimation accuracy. Moreover, the inertia constant is changed manually to verify the ability to continuously track inertia changes. Fig. 2 shows that the proposed algorithm successfully captures the changes in the inertia. The following percentage matrix gives the accuracy of the estimation:

\[
\%error = \begin{bmatrix}
4.27 & -8.43 & 11.50 & -2.10 \\
1.7 & 2.2 & 2.90 & 0.70 \\
3.60 & -14.00 & -5.80 & -13.70 \\
0.67 & 2.37 & 1.19 & 0.89
\end{bmatrix}
\]

the \(i^{th}\) column corresponds to the \(i^{th}\) machine, and the \(i^{th}\) row corresponds to the \(i^{th}\) 100s of simulation.

IV. CONCLUSION AND FUTURE WORK
Inertia is estimated by extracting the temporal dynamics following ambient load disturbances. The nonlinear system is lifted into a truncated finite dimensional linear operator. The proposed algorithm is data driven since it needs no prior knowledge of the model. Moreover, the inertia changes are continuously estimated online. The regional inertia estimation based on the tie-line bus frequency is left for future research. Once the regional inertia is estimated, various inertia supplier controls can be employed, such as the virtual inertia with energy storage systems to improve the overall system stability. This work is a first step toward offering a non-conservative power system inertia tracker to ensure stable operation without inflating the operational cost.
I. INTRODUCTION AND PROBLEM DESCRIPTION

Distributed energy resources (DERs) have become more popular for individuals to own due to their increasing affordability, economic benefits, and sustainability impacts. However, ownership of DERs requires one to have enough available capital to invest in a DER and own a home to install it. Additionally, as more DERs come online, utilities are forced to make infrastructure upgrades which are disproportionately financed by rate-payers who do not own DERs, as they pay proportionately greater bills than those with behind-the-meter production. A community energy system (CES) presents a solution to these inequities in that it allows a household to subscribe to a system without having to own the land or roof it resides on, or initial investment costs. Moreover, programs exist to subsidize low-income households to participate in CES through reduced subscription fees. If an aggregator was able to include a CES in wholesale electricity market bidding, they may be able achieve greater economic returns and further reduce home energy burden, the percentage of monthly income spent on energy bills.

II. PROPOSED METHODOLOGY

We propose a two step framework that first seeks to maximize revenue from wholesale electricity market participation of aggregated resources including CES and then minimize energy burden for households as seen in Fig. 1. The first step aggregates solar PV and battery electric energy storage systems (BESS) to participate in the day-ahead electricity markets and regulation up and down markets in a mixed-integer linear programming problem. The problem maximizes revenue of the aggregated resources by bidding into various markets while considering constraints of the each units, forecasted PV generation, and market bid parameters. The second step distributess portions of revenue derived from the first step to CES subscribing households on a priority basis, where reducing the most burdened households’ energy payments takes precedence before equally distributing credits.

III. RESULTS AND DISCUSSION

The market participation model was run for varying generation and market conditions with varying aggregated resources. A case for 500 kW of BESS and 200 kW of solar PV was aggregated to generate $457 in revenue for July 15, 2022. The same system was run over the entire month to generate monthly revenue. 20% of aggregator monthly income was returned to CES subscribers. This reduced all previously burdened households’ energy burden (burden ≥ 6%) to less than 5% (Fig. 2). All subscribing unburdened households also experienced significant decreases in energy burden reduction, with an average reduction by 2.47% with a standard deviation of 1.55% across all homes. Including a CES in aggregator market participation opens a new form of revenue that can be returned to homeowners and help relieve historic inequities for low-income households. This work allows aggregators to maximize their revenue while also prioritizing equity.

Fig. 1. Seasonal bids on an hourly basis.

Fig. 2. Distribution of return based on different bid strategies.
Complete formulation of the capability curve of synchronous generators in OPF models

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Abstract—In many optimization problems based on optimal power flow formulations, the steady-state operation characteristics of synchronous generators are modeled in an approximate manner. The standard approach is to represent the power production limits of the machine by means of independent maximum and minimum bounds on active and reactive power outputs. Few models have been proposed based on the generator capability curve. Most of them, however, do not include the parts of the curve corresponding to stability limits or, if so, they oversimplify its representation. This work proposes a formulation for the complete capability curve of the machine, including the exact modeling of its generator stability limits. The accuracy of the proposed formulation is tested by solving a maximum loading condition problem. In this optimization problem, a homotopy modeling technique is used to drive the synchronous generator to its operating limits.

I. PROPOSED FORMULATION OF LIMITS

Assuming a silent-pole synchronous generator $g$, the proposed formulation for the operational limits related to its capability curve is as follows:

$$p_g^G \leq p_g^{G, \text{max}}$$

$$p_g^G \geq p_g^{G, \text{min}}$$

$$\left( p_g^G \right)^2 + \left( q_g^G \right)^2 \leq \left( \frac{v_g \cdot p_g^{G, \text{max}}}{e_g} \right)^2$$

$$e_g \leq p_g^{E, \text{max}}$$

$$e_g \geq p_g^{E, \text{min}}$$

$$\cos \delta_g^{\text{st}} = \frac{1}{4} \cdot \left( -\frac{e_g}{v_g} \cdot \frac{X_{qg}}{X_{dg} - X_{dq}} \right)$$

$$+ \sqrt{\left( \frac{e_g}{v_g} \cdot \frac{X_{qg}}{X_{dg} - X_{dq}} \right)^2 + 8}$$

$$\sin^2 \delta_g^{\text{st}} + \cos^2 \delta_g^{\text{st}} = 1$$

$$p_g^{G, \text{st}} = \frac{e_g \cdot v_g}{X_{dg}} \cdot \sin \delta_g^{\text{st}}$$

$$+ \left( v_g \right)^2 \cdot \left( \frac{1}{X_{qg}} - \frac{1}{X_{dg}} \right) \cdot \sin \delta_g^{\text{st}} \cdot \cos \delta_g^{\text{st}}$$

$$p_g^G \leq p_g^{G, \text{st}} - 0.1 \cdot \frac{S_{Bg}^G}{S_B}$$

where variables $p_g^G$ and $q_g^G$ are the active and reactive output powers, $e_g$ is the magnitude of the internal voltage, $v_g$ is the magnitude of the terminal voltage, $\delta_g$ is the angle between internal and terminal voltages, $X_{dq}$ and $X_{qg}$ are the direct- and quadrature-axis synchronous reactances, and $S_{Bg}^G$ and $S_B$ are the power base for the generator and the system, respectively. Equations (1)-(9) represent the maximum (1) and minimum (2) turbine powers, stator current limit (3), over-excitation (4) and under-excitation (5) limits, and the stability limit (9). This last limit is defined by subtracting 10% of the machine rated power from the active power corresponding to the theoretical stability limit, which is computed by (6)-(8), where super-index “st” denotes the theoretical stability limit.

II. TEST CASE

The proposed formulation is tested by solving the following maximum loading condition problem (MLCP):

Maximize $z = \lambda$

s.t.

$$p_d^D = \lambda \cdot \cos \varphi$$

$$q_d^D = \lambda \cdot \sin \varphi$$

Power balance constraints (power flow equations)

Constraints (1)-(9)

The test system consists of a synchronous generator supplying a single load $(p_d^D, q_d^D)$ through a transmission line. In order to explore the whole operating range of the machine, the MLCP is solved for the entire spectrum of load power factor values ($\varphi \in [-\pi/2, \pi/2]$). The solutions obtained are depicted in Figure 1 as green crosses. Dotted lines are the limits modeled by equations (1)-(9).

It can be concluded that the proposed formulation is able to cover the complete capability curve.
Abstract—This study investigates power outage duration and power outage occurrence in the state of California using historical weather data. The annual number of extreme weather events is on the rise, creating a dramatic increase in weather-related power outages. To better understand the relationship between weather variables and power outage characteristics, multiple machine-learning methods are investigated to predict power outage duration and occurrence. Weather-related power outages create a paradigm shift for electric utilities and system operators. Extreme weather and its impacts are inherently difficult to predict, yet preparedness can mitigate damages, e.g. repairs, replacements, and maintenance. Accordingly, such predictive models would aid in power system preparedness and restoration efforts.

Index Terms—power outage, weather, machine learning

I. INTRODUCTION

The intensity and frequency of extreme weather events are on the rise [1]. For 2022 alone, the National Oceanic and Atmospheric Administration (NOAA) reports that the United States (U.S.) experienced 18 weather-related events exceeding one billion or more losses. While between 1990-2021, the annual average was 7.9 events.

The urgency to understand extreme weather events and be proactive in restoration and system repairs is evident, given that 83% of major reported power outages in the U.S. between 2000-2021 were attributed to weather-related events. In this context, a major reported power outage is an outage that impacts at least 50,000 customers in a single region. Additionally, there was an increase of 64% more major reported outages in 2011-2021 than in 2000-2010, with approximately 78% of outages in 2011-2021 being caused by weather-related events. This research focuses on California, which has the third highest frequency of weather-related power outages [2].

II. DATA PROCESSING

Power outage data and historical weather data for California are used in this study. The power outage data is from [3], a team who scrapes utility outage data from power providers and aggregates the outages across the U.S. at the city and county levels. Power outage duration was calculated based on outage start and end times for every city-county pairing (power outage duration data set). Further, the power outage data was expanded to one minute intervals to create a binary data set for when a power outage is occurring (1) and normal operations (0) (power outage occurrence data set). For both data sets, the number of customers impacted are calculated and combined with the historical weather data as independent variables.

The historical weather data was queried from the National Solar Radiation Database based on each county’s population centroid, determined by the U.S. Census. The data was then merged at the county level for both power outage data sets.

III. METHODOLOGY

For power system restoration efforts, power outage duration is predicted, and for power system preparedness, power outage occurrences are predicted using an array of machine-learning algorithms for regression and classification. The methods used in this study are provided in Table I.

<table>
<thead>
<tr>
<th>Model</th>
<th>Dependent Variable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multivariate Linear Regression</td>
<td>Power Outage Occurrence</td>
</tr>
<tr>
<td>Multivariate Logistic Regression</td>
<td>Power Outage Duration</td>
</tr>
<tr>
<td>Multivariate Linear Ridge Regression</td>
<td>Power Outage Occurrence</td>
</tr>
<tr>
<td>Multivariate Logistic Ridge Regression</td>
<td>Power Outage Duration</td>
</tr>
<tr>
<td>Multivariate Linear LASSO Regression</td>
<td>Power Outage Duration</td>
</tr>
<tr>
<td>Multivariate Logistic LASSO Regression</td>
<td>Power Outage Occurrence</td>
</tr>
<tr>
<td>Random Forest</td>
<td>Power Outage Duration</td>
</tr>
<tr>
<td>Support Vector Machine</td>
<td>Power Outage Duration</td>
</tr>
<tr>
<td>Feed-Forward Neural Network</td>
<td>Power Outage Duration</td>
</tr>
<tr>
<td>Adaptive Boosting (Adaboost)</td>
<td>Power Outage Occurrence</td>
</tr>
<tr>
<td>Stochastic Gradient Boosting</td>
<td>Power Outage Occurrence</td>
</tr>
</tbody>
</table>

Aside from Linear and Logistic Regression, each of the respective models uses cross-validation to determine the optimal model parameters, while the neural network implements hyperparameter tuning. Numerous evaluation metrics are applied to the models for comparison. Distribution reliability metrics, such as System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Frequency Index (CAIFI), are calculated and compared between the predicted and actual data to determine the weather related impacts on reliability.

REFERENCES


This research was funded by the National Science Foundation Graduate Research Fellowship Program.
I. EXTENDED ABSTRACT

Sustained outages cause billions of dollars in economic damages and threaten the health and safety of the public, so there is a clear need to mitigate these outages. Many outage mitigation technologies have been developed to enable a continued supply of electrical power to consumers in distribution networks facing a regional outage, but they are inequitably distributed. One opportunity for addressing this problem is by expanding upon an emerging class of disaster-resilience projects known as Resilience Hubs (RHs). Cities are actively developing RHs as community centers augmented for emergency communication, disaster relief, and carbon emissions reduction, and often specifically site RHs in disadvantaged communities. Many RHs plan to include backup power systems for serving their building’s critical electrical loads during grid outages.

We posit that backup power-equipped RHs can surpass just serving their own loads to serve electrical load in its neighboring feeders by islanding the sub-system from the main utility during sustained outages. In doing so, RHs can provide targeted sub-regional outage mitigation for communities vulnerable to the consequences of disaster-induced power outages and for those unable to adopt outage mitigation technologies on their own. But serving backup power to local communities introduces new social and technical considerations for RH planning – what are the societal outcomes of this outage mitigation, and can the distribution grid equipment support this mode of operation? So we ask: how can RH planners evaluate the tradeoffs of power system technologies considering these social facets and technical constraints?

In this paper, we present a Grid-Aware Tradeoff Analysis framework (GATA) that includes power systems constraints in a decision analysis to help identify the best power system technologies for a RH and highlight the tradeoffs between them. This sociotechnical analysis is an alternative to the least-cost optimization which is currently performed by RH planners. GATA incorporates the operational, financial, environmental, and social goals RH planners have by combining power systems analysis and decision analysis in a novel way.

Out of the decision analysis tools available for choosing a configuration for RH backup power systems, multi-objective optimization approaches take away the RH planner’s freedom to decide acceptable tradeoffs between goals, whereas multi-criteria decision analysis (MCDA) allows policymakers to weigh many considerations for a set of limited choices determined by external constraints. We build on prior MCDA work for backup power system technology selection by adding a detailed high-resolution distribution network grid reliability assessment. We use circuit-theoretic current-voltage three-phase power flow (TPF) to model AC network constraints and inform us of any voltage or line and transformer violations while supplying backup power. We choose TPF over other power system analyses like microgrid expansion planning, time-domain analysis, or AC optimal power flow, because TPF considers AC power flow constraints with the data available to RH planners and without unnecessary modeling complexity.

Figure 1 depicts the GATA framework. GATA takes input on the distribution network, energy technology selection, and expected system performance. It then outputs the best (non-dominated) viable backup power systems options for RH planners to select between. GATA first uses TPF to evaluate the reliability constraints for a generic power source \( P \) at the RH to serve electricity to a predetermined set of nodes \( L_{RH} \) during outages. It then enumerates a set of backup power systems \( S \) that could serve as \( P \) during a sustained outage. It finally calculates each backup power system’s performance along several criteria to run an MCDA and find the non-dominated options \( S_{ND} \subseteq S \).

By merging decision analysis and power system analysis methods, we develop the first high-resolution distribution grid analysis tool which includes social, economic, reliability, and environmental considerations, to evaluate backup power system choices for RHs and network resiliency microgrids. It is the first tool with an equity-aware valuation of outage mitigation, capturing the differing value of electricity served to loads with different needs. We demonstrate GATA on a case study based on RH projects underway in Richmond, California.

This research is funded by the National Science Foundation grant 2053856.
Cyber-resilient self-triggered distributed control of networked MGs against multi-layer DoS attacks

Pudong Ge, Boli Chen and Fei Teng

Abstract—Networked microgrids with high penetration of distributed generators have ubiquitous remote information exchange, which may be exposed to various cyber security threats. This paper, for the first time, addresses a consensus problem in terms of frequency synchronisation in networked microgrids subject to multi-layer denial of service (DoS) attacks, which could simultaneously affect communication, measurement and control actuation channels. A unified notion of Persistency-of-Data-Flow (PoDF) is proposed to characterise the data unavailability in different information network links, and further quantifies the multi-layer DoS effects on the hierarchical system. With PoDF, we provide a sufficient condition of the DoS attacks under which the consensus can be preserved with the proposed edge-based self-triggered distributed control framework. In addition, to mitigate the conservativeness of offline design against the worst-case attack across all agents, an online self-adaptive scheme of the control parameters is developed to fully utilise the latest available information of all data transmission channels. Finally, the effectiveness of the proposed cyber-resilient self-triggered distributed control is verified by representative case studies.

Index Terms—Resilience, networked microgrids, distributed control, self-triggered networks, denial of service (DoS)

I. PROBLEM FORMULATION

The networked MGs discussed in this paper are controlled under a hierarchical framework, as shown in Fig. 1, which relies on more complex information network. Hence, DoS attacks could simultaneously occur on communication links for inter-MG data sharing, measurement and actuation channels for intra-MG aggregation and distribution respectively. Here, we consider data unavailability issues affecting all channels, and propose a novel scheme that addresses multi-layer DoS attacks targeting the neighbouring communication, sensor measurement and control actuation channels of networked MGs with hierarchically controlled DERs to regulate frequency, which specially features a unified notion of Persistency-of-Data-Flow (PoDF), a self-triggered ternary controller enables asynchronous data collection and processing and an adaptive scheme reducing conservativeness.

II. RESILIENT CONTROL

The adverse effects of multi-layer DoS attacks can be classified as "identifiable" and "non-identifiable" in terms of the induced conservativeness, as shown in Fig. 2. More specifically, the "identifiable" means those DoS attacks can be noticed before control command calculation using timestamps (e.g., communication and measurement DoS), while the "non-identifiable" means the actuated commands are not updated as desired due to DoS attacks that block the next actuation attempt (e.g., actuation DoS). The "non-identifiable" effects come always with actuation DoS attacks and are mitigated by using an adaptive mechanism, which brings extra conservativeness. Besides the desired effects, such separation of identifiable and non-identifiable effects can effectively avoid the over conservative design using the fully worst scenario owing to intensive DoS attacks are a low-frequency event.

III. RESULTS

We compare the performance shown in Fig. 3 with existing methods. Control performance deteriorates under either neighbouring DoS attacks or local DoS attacks (see (a) to (b)), and the degradation becomes more significant when local DoS attacks are introduced (see (b) to (c)). Considering only the neighbouring-communication-attack can not nullify the effects of local DoS attacks (see (e) to (f)).
Virtual Real-Time Photovoltaic Power Plants

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Abstract—Active electric power distribution networks, (ADNs) containing a variety of distributed energy resources (DERs) such as solar photovoltaic (PV) power plants create additional complexity and uncertainty in system operations and management. Existing real-time digital simulations of ADNs typically do not capture associated power generation uncertainty and geospatial complexities for studies to be realistic. Besides, having several real-time hardware-in-the-loop assets with real-time digital simulators is challenging and expensive. This study presents a new concept for creating multiple virtual real-time (RT) PV plants over a geographical area using virtual RT weather stations and a digital twin of a physical real-time PV plant.

Keywords—Digital twins, distributed energy resources, PV plants, real-time simulation, virtual PV plants, weather stations

I. INTRODUCTION

Due to such driving factors as well as the ever-rising energy demand, there is a progressive shift towards the incorporation of active distribution networks and the accompanying utilization of distributed energy resources (DERs) in the modern electric distribution system. These distribution system changes lead to added operational and management complexity. To aid in operational and management tasks in the grid along with other distribution system tasks such as energy forecasting [1], planning and distribution system studies, new grid technologies are to be introduced in a reliable, computationally efficient and cost-effective manner.

The potential of AI implementation in distribution system studies is frequently limited by the quality of data available on system behavior as well as cost, computational and modeling challenges involved to generate operational data for various scenarios. Historically, if a PV plant’s generation and dynamics is to be studied over a geographical area, physical PV plants had to exist, and its operational data is needed. This creates limitations on the scalability of research studies due to cost and data limitations. The generation of realistic operational datasets and testing these datasets on real-time virtual testbeds is therefore an imminent need. Digital twins (DTs), a real-time or faster than real-time replicas of real-world ADNs, including solar photovoltaic (PV) power plants are used to bridge this gap [2]. By utilizing AI and DT technology realistic PV plant data can be generated in real-time over a selected geographical area.

II. RESULTS

The process flow to develop real-time virtual PV plants (V-RT-PVP) is shown in Fig. 1. Results for the following will be seen in the poster.

A digital twin of a physical real-time PV plant is primarily used to estimate and/or predict PV power generation using a data-driven approach, here, echo state network (ESN) models. PV-ESN DTs are utilized to predict real-time PV power generation at a 1 MW solar site at 30, 60 and 90 second intervals.

Real-time solar irradiance data from physical weather stations and temporospatial solar irradiance dynamics is further captured over a geographical area in intelligent mutation approaches to generate virtual real-time weather stations (V-RT-WSs) and accompanying streams of solar irradiance over geographical conditions.

Mutated weather data streams from V-RT-WSs are fed into PV-ESN DTs to create real-time virtual PV plants. The study shows the creation of 10 real-time virtual real-time PV plants over a geographical location utilizing real-time inputs from a 1 MW PV plant and three physical weather stations.

III. CONCLUSION

A data-driven method to estimate DER generation, in this case PV power generation, over a geographical location through the utilization of existing measurement sites and power generation sources is presented. The methodology is advantageous in that it has low added cost, complexity or additional resources other than already existing physical weather stations and PV plants at the respective sites, along with being easily scalable. The real-time data insights can be used to assist system operators and/or for power distribution system studies such as planning, operations and management and hardware-in-the-loop testing by integrating it into virtual testbed models of a distribution system.

REFERENCES


Voltage Support in Offshore Wind Farm Based on Model Predictive Control

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Abstract—Power quality issue is one of the major concerns for integration of offshore wind power to the electric grid which requires a stable voltage at Point of Connection (POC) of the offshore wind farm. Model predictive controller (MPC) can predict the behavior of the system and adjust the control signal accordingly. So, a suitable model-based controller is required to support the POC voltage within the operational constraints. This poster presents model predictive control with the aim of voltage support to the grid integrated offshore wind system.

Index Terms—POC, Model predictive control, voltage support

I. BACKGROUND

Offshore wind power plants are subjected to dynamic environmental conditions causing power fluctuations. The rapid penetration of offshore wind farms has challenged the voltage stability of the power systems. Since offshore wind farms are located far away from the load centre the short circuit ratio is small and the grid at connection point is weak [1]. Offshore wind farm are required to meet some specific system requirement which includes specific voltage range at POC. So POC voltage control of offshore wind requires advance control system that operate under dynamic and variable operating conditions [1].

II. PROPOSED FRAMEWORK

Model predictive control is one of the emerging technologies in the field of penetration of renewable energy to the grid. MPC uses the system model to predict about the output behavior. It works along the finite horizon to minimize the cost function while satisfying the constraints. MPC has an excellent ability to handle constraints and predicting system dynamics over the duration of its working status [2]. It can provide a robust control even during the uncertainties and disturbances to ensure that the system remain stable. MPC works by using a predictive model of the wind farm’s dynamics to optimize control actions over a finite time horizon. It has the ability to provide reliable and effective voltage control than the traditional methods because MPC considers the constraints and limitations of the system, such as the maximum output capacity of the wind turbines and the capacity of the electrical grid.

Fig. 1: represents the MPC connected to wind turbine power plant. MPC works to minimize the voltage deviation at the POC. A simplified model will be utilized within the proposed MPC framework as a predictive model. State estimator derives the states that cannot be directly measured from wind turbines with the voltage and currents at the inputs. The optimizer then works to predict the control action with an aim to minimize the cost function derived based on the voltage control requirement and constraints. The controller determines the regulation commands for ESS. ESS are usually preferred because of its ability to respond quickly to the voltage changes and exchange the reactive power when needed [3]. Energy storage system (ESS) will be used to initiate the control action. Reference POC voltage is fed to MPC as a set-point.

III. CONCLUSION

Overall MPC can be used to minimize the voltage deviation by predicting the system dynamics over the finite horizon and also remaining within the constraints.

IV. ACKNOWLEDGEMENT

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Implementation of Real-time Oscillation Monitoring System Using SEL Synchrowave

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Abstract—The sustained or growing oscillations due to interaction of various dynamic components in a power system can result in unwanted tripping of transmission lines or generators and can even lead to equipment damage. Under extreme conditions, this could cascade into devastating blackouts. In this work, various oscillation monitoring algorithms developed at Washington State University have been implemented using SEL’s Synchrowave platform such that they can be easily adapted by the industries for real-time monitoring and analysis of their system for such oscillations.

Keywords—Oscillation monitoring, modal analysis, Synchrowave

I. REAL-TIME OSCILLATION MONITORING SYSTEM

The availability of phasor measurement units (PMUs) has enabled a number of measurement-based algorithms for system wide stability analysis. The computational complexities of many of these measurement-based algorithms depend on the number of PMUs. Two algorithms, Fast Frequency Domain Decomposition (FFDD) and Fast Stochastic Subspace Identification (FSSI), were developed at Washington State University which speed up the ambient oscillation monitoring algorithms thereby enabling their real-time use for monitoring and control. FFDD is a frequency domain-based method while FSSI is a time domain-based method. These fast ambient oscillation detection algorithms together with a suite of ringdown analysis algorithms, called Event Analysis Engine, constitute the WSU Oscillation Monitoring System (WSUOMS).

Schweitzer Engineering Laboratory (SEL)’s Synchrowave Platform [1] is a high-performance time-series platform for power system operations and analytics. It helps to manage and analyze the PMU data and provides operators with situational awareness and intelligent notifications.

In this work, the time synchronized PMU data stream is obtained from the Syncrowave by each of the three engines viz FFDD, FSSI and Event Engine of WSUOMS tools. The ambient analysis engines, FFDD and FSSI continuously calculate the system modes independently using the PMU data. Event engine checks for ringdown event in the system and starts modal analysis only if it encounters an event in the data. The modal analysis results computed by these algorithms are displayed in Synchrowave and are also archived for post-event analysis. These engines also work together to send an alarm or alert to the operator during a low damping event using Synchrowave’s alarm feature so that a timely necessary action can be taken.

Fig. 1. Block diagram of WSUOMS

Fig. 2. Synchrowave implementation of WSUOMS

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REFERENCES

Control Interactions of Droop-based Grid-forming Converters in Weakly Connected Offshore WPPs

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Abstract—This study looks into the control interactions of grid-forming control (GFC) methods in weakly connected offshore wind power plants (WPPs). Droop-based GFCs with cascaded voltage and current control loops are modelled, analyzed and studied in a multi-converter scenario. The results present insights on control interactions between these converters and suggest potential solutions to prevent them via control tuning. Time-domain simulation results show that with proper tuning of the controllers, they can operate without control interactions in operating conditions like steady state, load changes, and faults.

Index Terms—Grid-forming control, stability, weak grids, low inertia, offshore WPP.

INTRODUCTION

Grid forming converters are essential for further integration of power-electronics interfaced generation like WPPs as they provide a voltage and frequency reference, essentially “forming” a grid. However, these converter controls can interact with each other leading to power oscillations, eventually resulting in oscillatory instability. Avoiding such control interactions are crucial for reliable operation of modern power systems. This could be achieved by proper control tuning following the study of the nature of interactions and their sources. A general method could be finding out the source of interactions via eigen-properties of the state matrix of the system under consideration.

This research studies droop-based GFC method (Control diagram in figure 1) in weak grid connection cases. In a system with multiple droop-based GF-converters, our research provides a good insight on how these control methods interact with each other in weak grids. We also present a method to solve the arising issues by proper control tuning.

PRELIMINARY RESULTS

A system with two droop-based GFCs connected to a weak grid is considered to study their control interactions. Figure 2 provides results on how the GFCs interact and how such interaction issues could be solved by proper converter tuning.

In the first case (figure 2a), we are using non-identical droop-controlled GFCs where there is a control interaction leading to power oscillations of around 70 Hz in frequency and 0.03 pu in amplitude. We tuned the converter controls in our system so as to avoid these interactions. The second case (figure 2b) presents the response of identical converters after appropriate tuning.

Further, a study of the GFCs’ response to a fault is done and presented in figure 3. Similar to the load change case, the GFCs oscillate during FRT when they’re not properly tuned; however with tuning solutions, there oscillations could be omitted. Here, both the GFCs supply to the fault without any voltage and power limit violations. However, this is a case without any current limiting scheme in the control; thus excessive rise in reactive power output from both the converters can be seen. Cases with current limiting schemes will be added to this study for the full poster.

Fig. 1: Schematic of droop-based GFC.

(a) Untuned controllers with power oscillations. (b) Tuned controllers to avoid oscillations.

Fig. 2: Response to load changes. 20% of total power added at \( t = 1 \) s. The powers in y-axis are based on smaller of the two converter’s nominal power.

(a) Untuned controllers with power oscillations. (b) Tuned controllers to avoid oscillations.

Fig. 3: Response to 3-phase bolted fault. Subjected to a 3-phase bolted fault at \( t = 0.4 \) s. Fault is cleared at \( t = 0.5 \) s.
Systematic Cause & Consequence Identification for EVCS Accident Investigation

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Abstract—A novel 5Ws&1H-based accident investigation framework to deal with cyber-attack-related incidents in an electric vehicle charging station (EVCS) is proposed in this paper. Also, it propounds a stochastic anomaly detection system (ADS) to identify the function failure in the station entities as a post cyber event analysis.

Index Terms—Accidents, anomaly detection system, charging station, cyber-attacks, forensic investigation.

I. PROPOSED 5WS&1H-BASED INVESTIGATION FRAMEWORK

Lack of forensics capability in an EVCS may lead to serious consequences, especially when a mishap is caused by a cyber-attack. Further, presence of multiple entities in the complexed charging ecosystem marks a challenge for the investigation team to determine which entity is compromised and how. Besides, it provides capability to industry to inculcate future cybersecurity measures in their standards/protocols.

The incident responders can use the 5Ws&1H to prepare and report their findings in an investigation that includes the six key questions to analyze the cyber incident scene. 5Ws&1H is defined as, (1)Who: it identifies the attacker and the entity under attack, (2)What: it specifies the system failure or attack target, (3)When: it describes the date and time of the cyber incident, (4)Where: it provides the cyber event location or attacker’s route, (5)Why: it describes the hazardous behavior that causes such behavior, (6)How: it explains the attack strategy used by the attacker.

II. STOCHASTIC ANOMALY DETECTION SYSTEM

Mathematically, this model can be formulated to differentiate normal and abnormal behaviors in accordance to the Bayesian statistics and probability theory such that,

\[ P(E|A_{ec}) = \sum_{o=1}^{k} \sum_{c=1}^{k} P(E|A_{co})P(A_{ec})P(A_{co}), \quad c \neq o. \]  

Then, by Bayes’ theorem,

\[ P(B_{c2}|A_{11}) = \frac{P(A_{11}|B_{c2})P(B_{c2})}{P(A_{11})}. \]  

In general,

\[ P(B_{co}|A_{ec}) = \frac{P(A_{ec}|B_{co})P(B_{co})}{P(A_{ec})}, \quad c \neq o. \]

It is to be noted that all transmitted signals or messages \( A_{ec} \) are mutually exhaustive such that,

\[ \sum_{c=1}^{k} \sum_{o=1}^{k} P(A_{ec}) = 1. \]

For the normal operation, \( c = o \), and for error or abnormal behavior \( E \), \( c \neq o \).

As a result, these frameworks can be used to detect a cyber event and investigate an incident by identifying the root causes of aberrant station entity behaviors.
Abstract—The objective of this work is to develop and illustrate a functional system of data development and probabilistic adequacy assessment to enable planners to evaluate the reliability of their generation and transmission systems and use this evaluation to inform planning-related decision-making.

Index Terms—NERC Standard TPL-001-4, probabilistic adequacy, reliability.

I. INTRODUCTION

According to the North American Electric Reliability Corporation (NERC), a reliable bulk power system is defined as one that is able to provide the electrical needs of its end-use customers, even during unexpected equipment failures and other events that reduce the amount of available electricity. [1]

Security and adequacy are two concepts that are incorporated into the reliability of a bulk power system. Security refers to the capability of the system to withstand sudden disturbances while maintaining the performance standards set by NERC in TPL-001-4 [2]. Adequacy refers to the ability of the system to continue to supply the aggregate demand of electricity, even during scheduled and unscheduled outages [3].

Probabilistic adequacy evaluation focused on generation, known as resource adequacy assessment, is well-developed. This project will focus on composite probabilistic adequacy assessment, which includes both generation and transmission, and will provide a summarized end-to-end process that accounts for the need to include newer technologies, such as renewables and storage.

II. PROJECT GOALS

A. Software

Various research and commercial-grade software packages are available to perform probabilistic adequacy assessments. Tools will be selected and used for illustrating a composite probabilistic adequacy assessment. This selection will be based on a comparison of the tools’ capabilities, such as the reliability indices that are computed, the way the tool handles technologies such as wind and solar generation, and the input and output characteristics of the tool which impact its ability to integrate with industry standard software such as PSS®E.

B. Data Calculations

In order to calculate reliability indices for a system, the outage data for components in that system need to be transformed into long-term (steady-state) contingency probabilities which can then be used as input into the chosen probabilistic adequacy assessment tool. Work has been done to develop the Contingency Probability Estimation Tool (CPET), a Matlab tool that calculates the probabilities of NERC contingencies P1-P7 based on outage data from NERC’s Transmission Availability Data System (TADS) and Generating Availability Data System (GADS) [4]. Contingency probabilities will be calculated by CPET from outage data and then will be used as input to the chosen probabilistic adequacy assessment tool.

C. Illustrate and Inform Decisions

The end-to-end composite probabilistic adequacy assessment will be performed on a subset of a company’s power system. This will illustrate the use of the chosen probabilistic adequacy assessment tool and the data developed from CPET, and will show the added decision-making value the company gains from performing this assessment. For example, given different transmission expansion options, the assessment might show how each option will affect the reliability of the system as a whole.

This project will also show the value added to various generation and transmission decisions by probabilistic adequacy assessments. Possible examples of this include providing a meaningful metric to measure how much thermal generation can be retired as off-shore wind generation expands in order to maintain the same level of adequacy, identifying the optimal mix of generation sources, or developing contingency plans for unexpected outages.

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Bulk Power System Support from Collaborative Multi-Microgrid Systems

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Abstract—Distribution systems containing multiple microgrids with high generating capacity have high potential for increasing overall system resiliency in the face of adverse conditions. In order to fully access the potential benefits of such systems, robust algorithms are required that can operate with multiple failures within the power or communication infrastructure. In this study we evaluate a collaborative autonomy algorithm designed to provide voltage support to the bulk power system. The study explores how sudden changes to the communication topology impact the effectiveness of the algorithm to support the bulk power system, and how multiple collaborative regions which do not communicate with each other will impact the stability and effectiveness of the total support provided. The algorithm is evaluated on models of a real distribution and communication system. It is simulated using a HELICS based cyber-physical multi-agent co-simulation framework.

Index Terms—collaborative autonomy, power distribution systems, cyber-physical, co-simulation, NS-3, HELICS, GridLAB-D

I. CO-SIMULATION

The goal of the Co-Simulation Platform is to enable analysis of distribution grid and microgrid control algorithms that involve communication, specifically distributed algorithms.

The platform uses HELICS at its core to coordinate several different simulation programs. The physical power system is simulated using GridLAB-D, the communication system is simulated with ns-3, and the controllers and other logical agents are separate python programs.

II. POWER AND COMMUNICATION SYSTEM MODELS

The physical and cyber models are based on the system operated by Chattanooga’s utility, EPB. The physical power system is modeled in GridLAB-D. It includes a meshed sub-transmission network having three sub-transmission substations and two distribution substations. It includes five feeders and three microgrids. To model the effects of voltage support on the point of common coupling with the bulk power system (BPS), the BPS is modeled using the simplifying assumption that it can be modeled as a Thévenin equivalent on each of the three phases without mutual coupling. The low voltage contingency is modeled by increasing the Thévenin reactance.

The communication model is modeled in NS-3 from the real fiber network that supports the same power system.

III. COLLABORATIVE AUTONOMY FOR GRID SUPPORT

Grid support mode is triggered when the voltage or frequency on the bulk power system is outside of the normal range. In particular, we studied a collaborative autonomy algorithm for providing support to the BPS voltage in the case that a contingency on the BPS results in abnormally low voltages which may indicate an impending voltage collapse. The algorithm is designed to limit potential points of failure and therefore contribute to greater overall resiliency for the power system. It does this by eliminating any dependency on a central point of failure and shifting the burden of observation and control to distributed agents such as microgrid controllers. These agents only communicate with each other in a peer-to-peer rather than a hierarchical relationship. The study evaluates collaborative autonomy where all agents communicate with each other and where agents are limited to communication within regions. The study explores how sudden changes to the communication topology impact support, and how the stability and effectiveness of support for the BPS may be impacted if multiple collaborative regions which do not communicate are supporting the same system.
Abstract—This work formulates a stochastic optimization problem for the PSPS (SPSPS) with a tunable risk-averseness parameter. We use the SPSPS framework to generate optimal load-shedding and shut-off decisions for both the IEEE 14-bus and RTS-GMLC transmission grids. An online wildfire risk prediction is used to dynamically update component wildfire risk values. This online prediction is expected to result in less conservative shut-off decisions than shut-off decisions based on the daily wildfire risk forecasts released by the United States Geological Survey (USGS).

Index Terms—Optimal Power Shut-off Problem, Distributed Energy Resources, Wildfire Risk Mitigation, Optimal Power Flow

I. INTRODUCTION

An electric utility’s most notable short-term strategy to proactively reduce wildfire ignition probabilities is public safety power shut-offs (PSPS). PSPS achieves Pareto optimal trade-offs between the cumulative wildfire risk of all energized grid-connected components (loads, transmission lines, generators, stationary storage units, etc.) and the total load served. This dual objective optimization strategy outperforms two commonly used heuristics in the field: the area and transmission line heuristics. However, PSPS still isolates communities from essential services [1]. The authors in [2] developed the optimal PSPS problem that de-energizes grid components based on wildfire risk. In addition to de-energization, DERs may be able to provide emergency backup generation to high-risk areas by strategically placing the DERs. Fig. 1 shows wildfire risk, \( \tilde{\Pi} \) a scenario based approach is used. A set of five representative demand scenarios (\( \Omega^{\text{DA}} \)) are obtained using a tree scenario reduction algorithm which results in the approximation \( \Pi \in \mathbb{R}^{[\Omega^{\text{DA}}]} \) of \( \tilde{\Pi} \). The probability of occurrence of a given scenario \( \omega \in \Omega^{\text{DA}} \) is denoted by \( \pi_\omega \). Optimal power flows are calculated using a mixed-integer DC-OPF method with unit commitment and storage constraints. The demand balance for each demand scenario is given in (4). The space of feasible shut-off decisions is dictated by component interaction constraints in (5). The SPSPS problem is given by,

\[
\max (1 - \beta) \mathbb{E} [\Pi] + \beta \text{CVaR}_\epsilon
\]

s.t. \( \Pi_\omega = \sum_{t \in T} \left( \frac{1}{\mathbb{E}^\omega} x^\top_{t,\omega} D_{t,\omega} + \frac{\alpha}{\mathbb{E}^\omega} R_{t,\omega}^{\text{Tot}} \right), \forall \omega \in \Omega^{\text{DA}} \) (2)

\[
R_{t,\omega}^{\text{Tot}} = \sum_{i \in \mathcal{H}} \left( x^\top_{t,\omega} R_{i,\omega}^D + z^\top_{t,\omega} R_{i,\omega}^G + z^\top_{t,\omega} S_{t,\omega}^\top R_{i,\omega}^S + z^\top_{t,\omega} R_{i,\omega}^C + z^\top_{t,\omega} R_{i,\omega}^N \right) (3)
\]

\[
\sum_{g \in \mathcal{G}_i} p_{ij}^g + \sum_{j \to i} \sum_{s \in \mathcal{S}_i} \left( x^\top_{t,\omega} R_{i,\omega}^{\text{dis}} + \sum_{s \in \mathcal{S}_i} x^\top_{t,\omega} R_{i,\omega}^{\text{char}} - \sum_{d \in \mathcal{D}_i} x^\top_{t,\omega} D_{i,\omega}^d \right) = 0 (4)
\]

\[
z^\top_{i,\omega} \geq x_{i,\omega}, \quad z^\top_{i,\omega} \geq z^\top_{i,\omega}^G, \quad z^\top_{i,\omega} \geq z^\top_{i,\omega}^S, \quad z^\top_{i,\omega} \geq z^\top_{i,\omega}^C, (5)
\]

for all \( d \in \mathcal{D}_i, g \in \mathcal{G}_i, s \in \mathcal{S}_i, (i, j) \in \mathcal{L}, \ i \in \mathcal{N}, \omega \in \Omega^{\text{DA}} \) where the subscript \( i \) indicates the \( i \)-th demand or generation at node \( i \), \( x_{i,\omega} \) is the proportion of load shed, \( p_i \) and \( R_{i,\omega} \) are power injection and wildfire risk with the superscript representing the appropriate component. Furthermore, \( z^G, z^S, z^C, z^D \) are a binary variable that represents shut-off decisions. Finally, power injection feasibility constraints are also included.

II. PROBLEM FORMULATION

This work aims to maximize an objective function with two weighted sums as shown in (1). The inner weighted sum consists of a weighting parameter \( \alpha \) in (2) that represents a trade-off between the mean-scaled total demand served and wildfire risk. Total wildfire risk at time \( t \) is the sum of the risk of all active components (3). The outer weighted sum of the objective with weighting parameter \( \beta \) is the balance between the expected SPSPS objective and its \( \epsilon \) quantile expected shortfall or CVaR. Mathematically, we define \( \text{CVaR}_\epsilon(\tilde{\Pi}) = \max_{\nu} \left\{ \nu - \frac{1}{\epsilon} \mathbb{E} \left[ \max \left\{ \nu - \tilde{\Pi}, 0 \right\} \right] \right\} \). To reduce the computational complexity of taking the expectation of random tradeoff between the total demand served and

REFERENCES


Accurate Single-Ended Fault Location for Cable-OHL Hybrid Transmission Lines

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Abstract—This paper proposes two single-ended fault location methods for cable - overhead line (OHL) hybrid transmission lines. Three phase voltage and current phasors at only the local terminal are required. First, the well-known Eriksson fault location method is modified as the proposed method 1, to improve the fault location performance in this situation, where the lumped parameter line model is adopted. Afterward, the fully distributed parameter line model is considered in the proposed method 2, to further enhance the accuracy of line model; the fault location can be solved via the Newton’s iterative methods. In numerical experiments, the two proposed methods present higher accuracy of fault location than the traditional Eriksson method, with various fault types, fault locations and fault resistances. The proposed method 2 demonstrates the highest fault location accuracy among all three methods.

Index Terms—Single-ended, fault location, hybrid transmission line, cable, distributed parameter line model

I. PROPOSED METHODS

Take the fault happened in section 1 (showed in Fig.1) as example to show the derivations of proposed methods.

![Fig. 1. qh-sequence network with fault on section 1](image)

Modifying the equations in [1], the fault location can be calculated as (1),

\[ l_f = \frac{(a_1 + a_2 b_1 + b_2) \pm \sqrt{(a_1 + a_2 b_1 + b_2)^2 - 4(a_1 - a_2 b_1 + b_2)}}{2} - l_i \]  

The line impedance of section 2 is combined into the source at the \( H \) terminal (with the equivalent source impedance \( Z_{2eq} \)). The definitions of other parameters in (1) needs modification based on [1] accordingly.

\[ Z_{2eq} = Z_{1h} + l_f(R_{eq} + j\omega L_{eq}) \]  

For the proposed methods 2, it can be observed from Fig.1,

\[ \bar{I}_{hq} - g(\bar{V}_q, \bar{I}_q, l, R, L, C) = 0 \]  

To get the value of \( \bar{V}_{h} \) and \( \bar{I}_{h} \), considering the fully distributed parameter line model. The relationships among sending and receiving end voltages and currents of sequence q can be described as follows,

\[ \begin{bmatrix} \bar{V}_l \\ \bar{I}_l \end{bmatrix} = g(\bar{V}_q, \bar{I}_q, l, R, L, C) \]  

The detailed expression of \( g(\cdot) \) is,

\[ g(\cdot) = \begin{bmatrix} \cosh(p) - Z_p \sinh(p) \\ -\sinh(p) Z_p \cosh(p) \end{bmatrix} \]  

where \( Z_p = \sqrt{(R + j\omega L)(j\omega C)} \).

Then the values of \( \bar{V}_h \) and \( \bar{I}_h \) can be expressed as functions of fault location \( l_f \) and fault resistance \( R_f \), showed as followed.

\[ \begin{bmatrix} \bar{V}_{hq} \\ \bar{I}_{hq} \end{bmatrix} = g(\bar{V}_{eq}, \bar{I}_{eq}, l_f + l_f, R_f, Z_{eq}, C_{eq}) \]  

\[ \bar{I}_{hq} = \bar{I}_{hq} - \bar{I}_{eq} \]  

\[ \bar{V}_{hq} = g(\bar{V}_{eq}, \bar{I}_{eq}, l_f, R_f, Z_{eq}, C_{eq}) \]  

where \( \bar{I}_{eq} = \bar{P}_{eq}(3R_f) \) for the single phase A to ground fault.

III. NUMERICAL EXPERIMENT

A-G faults on a 200 km cable-OHL hybrid transmission line with 100ohm fault resistance are showed. The results of the pseudo solution identification of the proposed method 1 and 2 and a comparison among various fault location methods, are presented.

![Fig. 8. Results of the estimated fault location under two guesses](image)

![Fig. 9. Results of the relative errors on the over-head line](image)

![Fig. 10. Results of the relative errors on the cable](image)

REFERENCES

Inverter Voltage Support for Ac Heating and Fast Charging of Electric Vehicles

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Abstract—Electric vehicles (EV) can withdraw significant amounts of electric power for ac heating and fast charging in subzero environments. This in turn can cause large voltage fluctuations and cycling of voltage-regulator tap changers which are ubiquitous in distribution grids. To study such detrimental impacts, this paper develops a load model that depends on the state of charge and temperature of battery packs to capture the aggregated impact of EV fleets on power grids.

Then, a feedback control strategy is engineered to leverage the capabilities of commercial photovoltaic inverters to mitigate voltage fluctuations and tap-changer cycling. These advances are demonstrated using the IEEE 13 node test feeder.

I. EV FLEET LOAD MODEL

We developed model that captures the power that is withdrawn by a fleet of EVs from a radial distribution grid, q.v., Fig. 1. This model is useful to predict via simulations the fluctuation of node voltages and cycling of tap changers which implies mechanical wearing of electrical contacts. The modeling effort is novel because it considers both ac-heating and fast-charging processes of EV battery packs which have not been considered in the literature pertaining to the integration of EVs [1].

Paper based upon work funded by the Electric Power Research Center at Iowa State University.

II. CASE STUDY: EV FLEET LOAD MODEL AND INVERTER VOLTAGE SUPPORT

We are interested in quantify the power requirements of a distribution feeder as in Fig. 1 when (i) the voltage fluctuates outside of the utilization range with respect to the nominal voltage [2] and (ii) the tap changers of voltage regulators cycle during a day with a base-load demand and a PV inverter interacting with an EV-fleet that withdraw power during a subzero temperature environment. Notably, the reactive power \( Q_s \) in the first scenario is zero while in the second scenario it oscillates between \( \pm 95 \text{kVar} \). The results show positive improvements when the inverter supports the voltage \( V_p \).

Fig. 1. Notional distribution feeder with distributed energy resources.

Fig. 2. PV and EV fleet integration in winter. (a)–(e) Scenario 1 and (f)–(j) scenario 2.

REFERENCES
Generation Investment Equilibrium among Multiple GENCOs using Modified PMP

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Abstract—This letter proposes a mathematical model for solving the generation expansion problem of multiple generation companies (GENCOs). This model is developed assuming a simultaneous-move game among GENCOs. Each GENCO maximizes its total profit of selling the electricity to the market minus the investment cost of new generation units with incomplete information on the opponents’ decisions over general graphs. We assume one system operator (SO) who works as a single agent to complete the power flow and voltage angles calculation. To solve the proposed non-cooperative simultaneous game, a modified Proximal Message Passing (PMP) algorithm is implemented. The numerical results are carried out on IEEE-5 bus and IEEE-24 bus test cases and the results show the effectiveness of the model and the solution algorithm.

Index Terms—Strategic Generation Expansion Planning, Non-cooperative Simultaneous Game, Modified PMP.

II. Proposed Approach

GENCOs’ Problem

\[ \max \sum_{k=1}^{K} \sum_{i=1}^{I} \left( c_{i,k} x_{i,k} + \frac{p_{i,k}^2}{2} \right) \]

SO’s Problem

\[ \max \sum_{k=1}^{K} \sum_{i=1}^{I} \left( -f_{i,k} x_{i,k} - \frac{p_{i,k}^2}{2} \right) \]

(GENCOs’ Update)

\[ \text{prox}_{\lambda/2} \left( p_{i,k} \right) = \arg \min_{p_{i,k}} \left( \| p_{i,k} \|_2^2 + \lambda / 2 \| \nabla f_{i,k} \|_2^2 \right) \]

(SO’s Update)

\[ \text{prox}_{\lambda/2} \left( p_{i,k} \right) = \arg \min_{p_{i,k}} \left( \| p_{i,k} \|_2^2 + \lambda / 2 \| \nabla f_{i,k} \|_2^2 \right) \]

Fig. 1. LP-box reformulation

Fig. 2. Equilibrium Algorithm of Multi-GENCOs’ Generation Expansion

IV. Results

Table I GENCOs Profit and Generation Expansion Result of the 5-Bus Example System

<table>
<thead>
<tr>
<th>Unit</th>
<th>Output (MW)</th>
<th>Investment Decision</th>
<th>Profit (M$)</th>
<th>Operational Cost (M$)</th>
<th>Expansion Cost (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G1</td>
<td>80.0</td>
<td>1</td>
<td>278</td>
<td>100</td>
<td>31057.7</td>
</tr>
<tr>
<td>G2</td>
<td>340.0</td>
<td>1</td>
<td>147</td>
<td>100</td>
<td>18710</td>
</tr>
<tr>
<td>G3</td>
<td>822.9</td>
<td>1</td>
<td>165</td>
<td>100</td>
<td>-165</td>
</tr>
<tr>
<td>G4</td>
<td>257.5</td>
<td>0</td>
<td>0</td>
<td>2574.6</td>
<td>0</td>
</tr>
</tbody>
</table>

The simulation results obtained by solving the problem using LP-box PMP is the same results if this problem is solved by the Matpower. This shows the proper search of the optimum result of the LP-box PMP algorithm. Note that the standard PMP cannot solve this problem.

Table I shows the expansion result of the strategic units. In the centralized planning case, the generation expansions are the same as the strategic generation expansion of GENCOs and therefore results to the same social cost.

The nodal prices for bus 1-5 are 16.97 $/MWh, 26.37 $/MWh, 29.99 $/MWh, 39.89 $/MWh and 10.00 $/MWh correspondingly.

Table II GENCOs Profit and Generation Expansion Result of the 24-Bus Example System

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Candidate Unit</th>
<th>Investment Decision</th>
<th>Profit (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GENCO a</td>
<td>G15</td>
<td>0</td>
<td>278</td>
</tr>
<tr>
<td>GENCO b</td>
<td>-</td>
<td>-</td>
<td>147</td>
</tr>
<tr>
<td>GENCO c</td>
<td>G13</td>
<td>1</td>
<td>-165</td>
</tr>
<tr>
<td>GENCO d</td>
<td>G14</td>
<td>1</td>
<td>-165</td>
</tr>
</tbody>
</table>

Table II shows the expansion result of the strategic units. This corresponds to 1068 M$yr social cost. In the centralized planning case, i.e., the case where the whole system is planned by a central body which minimizes the social cost of the system, only GEN 13 is expanded, and the social cost is 9705 M$yr.

The primal residual shows the feasibility of the solution, and the dual residual represents the distance between current solution and the optimal solution. The curve of primal and dual residual in the distributed iterations reflect the convergence of the algorithm directly.

The modified PMP solves this problem in less than 300s which is less than the running time of the CPLEX solver. However, as the network grows, CPLEX is unable to solve the equilibrium with large scales in acceptable time. In this case, the modified PMP can be considered as an approach for solving these problems.

V. Conclusions

✓ A non-cooperative simultaneous game is proposed based on Nash equilibrium and duality theorems for the generation expansion equilibrium problems among multiple GENCOs.
✓ LP-box reformulation is adopted to deal with the discrete decision variables and a modified PMP is implemented to find the equilibrium solution.
✓ The performance of the proposed calculation framework has been verified on the IEEE-5 test system and IEEE-24 test system.
Sig2Vec: Dictionary Design for Incipient Faults in Distribution Systems

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Abstract—There are extremely high demands on power equipment fault detection and diagnosis at the equipment level. At the system level, the proportion of renewable energy in the grid is increasing year by year. The morphological structure of distribution grids is also very different from the past. Meanwhile, the new power electronics-based generation equipment and loads have a great impact on the fault characteristics of power equipment, resulting in a significant challenge in power equipment’s incipient fault (IF) detection. Therefore, this paper designs a dictionary for an easy understanding of distribution systems waveforms and for achieving accurate IF detection. To reduce the IF identification complexity, the electric signal waveforms are first translated into vectors through the Sig2Vec technique and are then assembled into a waveform dictionary. We deploy a classical pre-training model to classify IFs and show this model is suitable for the proposed dictionary. It is learned that the types of IFs directly affect the high-dimensional characteristics clusters in the proposed general-purpose IF detection method. Furthermore, the proposed method is compared with a machine learning classifier and a probabilistic language model. The results demonstrate the proposed method can effectively detect incipient faults through waveform understanding.

Index Terms—Sig2Vec, incipient fault, signal dictionary, distribution systems.

I. PROPOSED METHODOLOGY: IF-PTM

Due to the intrinsic and extrinsic complexity of IFs in distribution systems, it is hard to represent an IF with various operating conditions and scenarios. Therefore, we incorporate the idea of a dictionary in computer science into this representation task. The idea of designing a power system waveform signal dictionary stems from the concept of word vector in natural language processing, presented in Fig. 1. Features extracted from time/frequency domains vary from each other when used to detect faults in multiple types of equipment. This could be a mathematical disaster when dealing with multi-dimension data, especially when different power systems equipment is involved. To address this issue, we develop a distributed representation of the waveforms. There is no specific significance in this vector, but it contains rich information when viewed as one vector. The vector can be realized through a designed IF pre-training model (IF-PTM). The proposed IF-PTM has three contributions:

• A ready-to-use IF detection model has excellent parameter initialization. This enhances the IF-PTM generality and convergence speed.
• An efficient approach of normalization when viewed on a small dataset, avoiding model overfitting.

Fig. 1. The overall power system waveform processing flow.

II. NUMERICAL RESULTS

We use different methods to predict whether a permanent failure will occur. We compare the proposed PTM with Logistic Regression and N-gram methods. We have chosen ten different sizes of windows from 1 to 10. Different window sizes mean that future predictions are made based on different historical units.

Fig. 2. Evaluation index for different methods in IF detection. The value in brackets indicates the size of the window.
Optimal Power Flow with Realistic Generator Capability Curves

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Abstract—A method for incorporating realistic generator capability curves (GCC) into the constraints of the optimal power flow (OPF) problem is proposed. The steady-state equivalent circuit of the synchronous machine is added as a branch in the branch flow model (BFM) of the nonlinear power system equations. Semi-definite programming is used to formulate a computationally efficient, convex relaxation of the BFM-based OPF with the GCC constraints. This enables the inclusion of nonlinear GCC equations which vary with terminal voltage magnitude and include the impact of rotor saliency and stator resistance. Numerical verification and case studies are provided.

Index Terms—convex optimization, power flow, power systems, steady-state, synchronous generators

I. INTRODUCTION

Optimal power flow (OPF) is a powerful tool used by power system operators to improve economic operation while enforcing physical and operational constraints. Conventional OPF studies typically use rectangular (minimum and maximum) limits to constrain the real and reactive power output (P and Q) of generators. However, the shape of the actual feasible operating set of synchronous generators in the PQ-plane, or generator capability curve (GCC), is much more complicated in practice (see Fig. 1). In this work, we demonstrate how realistic GCCs can be incorporated into the constraints of a computationally efficient, semi-definite programming-based, convex relaxation of the OPF problem.

The shape of the GCC of a synchronous generator, as shown in Fig. 1, is determined by the intersection of several steady-state operating limits [1]. These constraints include thermal limits such as maximum stator winding currents, maximum rotor field winding currents, and stator end core heating limits that occur in round-rotor machines due to under-excited operation (not shown in Fig. 1). Limitations of the excitation system such as a minimum rotor field winding current or self-excitation current limit may also impact the shape of the GCC. Steady-state stability limits (SSSL) are also typically included in manufacturer GCC data. Finally, the controls of under-excitation limiters (UEL) in the automatic voltage regulator and protective equipment, such as loss-of-excitation (LOE) relays, can introduce additional constraints in the GCC. Many of these constraints are nonlinear, and obtaining analytical expressions for them in the PQ-plane can be difficult or intractable, especially when effects of rotor saliency and stator resistance are included. Additionally, most of these constraints depend on the values of other variables (e.g., terminal voltage magnitude or coolant pressure).

The branch flow model (BFM) is an alternative, yet equivalent, form of the nonlinear power flow equations [2]. Furthermore, the BFM can be used to obtain a convex relaxation of the OPF problem based on semi-definite programming (SDP). This formulation uses the voltage and current magnitudes squared and power flows on each branch as variables. We show that by adding the steady-state equivalent circuit of a synchronous generator as a branch in the BFM-based OPF, we can directly model the GCC as constraints in the optimization problem. A detailed description of the equations governing these constraints along with numerical case study results will be provided in the full poster.

Fig. 1. Steady-state capability curve of a salient-rotor synchronous generator.

REFERENCES

Co-Simulation Based Wholesale Market Emulations

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Abstract—The power grid is transitioning to a more integrated and complex system with increasing flexible energy resources at the distribution level. Although such flexible resources presents a huge potential towards enhancing the operational efficiency, improper coordination can cause critical issues impacting the security of electricity supply. Co-simulations is an emerging technique towards analyzing the impact of coordination schemes across different conventional analysis domains. These simulations are complicated, with a high barrier to entry in running them. This work presents MATPOWER-based interfaces for emulating wholesale market operations to minimize the barriers for evaluating the system-level impacts of coordination-designs.

I. INTRODUCTION

With increasing complexity and demand of the power grid, co-simulations have become necessary to address the multi-faceted problems that arise. With increased penetration of distributed energy resources (DERs) comes unknown impacts on both the wholesale energy market and the overall stability of the grid. Simulation of the wholesale market requires co-optimization of energy and reserves and multi-settlement solutions across both day ahead and real time markets. Simplifying the process of emulating the wholesale market would empower users to explore the impact of their proposals and further narrow the gap between ideas and implementation.

II. FRAMEWORK FOR WHOLESALE MARKET EMULATION

In order to run a full market simulation, MATPOWER and Matpower Optimal Scheduling Tool (MOST) requires data describing the zonal requirements, as well as load profiles and renewable generation forecasts, for the time period being simulated. The wrapper interface enables such requirements, either through communication with the co-simulation tool HELICS, or through local configuration/data files. The wrapper compiles and properly formats the necessary data, then runs the use case specified by the user.

The user can also utilize a number of functions and settings defined within the wrapper to customize their simulation to fit their needs. These functions include day ahead (DA) market simulations with unit commitments and reserves, which can then be utilized towards a real time (RT) market simulations, distribution system operator (DSO) level flexibility through block-/curve-based bidding, power flow simulations to check the system states, and more.

This work is funded as a part of the Grid Modernization Laboratory Consortium’s HELICS+ project. The code-base is available for users through an open-source repository: https://github.com/GMLC-TDC/MATPOWER-wrapper

III. USE CASE DEMONSTRATION

As a demonstration, an 8-bus model of the ERCOT region of Texas with historical data spanning 2016 was fed into the wrapper. One of the DSO’s were given a flexibility profile between 0% and 20%, which was demonstrated to be partially utilized during low-cost times and fully utilized during high cost times in response to market incentives (see Figure 2).

A second set of simulations set between August 12th and August 16th demonstrates the effect of flexibility on Location Marginal Prices (LMPs) in both the DA and RT markets. Increased flexibility resulted in peak load reduction and thereby reduced spikes in LMPs (see Figure 3).

To demonstrate the impact of misrepresenting flexibility, the LMP spread between DA & RT markets was determined for a case that that included DSO’s flexibility in both DA & RT market as compared to a RT market only case. When flexibility was not accounted for in the day ahead market, there was a significant increase in the variance of the LMP spread, indicating market inefficiency (as shown in Figure 4).
Abstract—Modern distribution networks are undergoing several technical challenges, such as voltage fluctuations, because of high penetration of distributed energy resources (DERs). This paper proposes a deep reinforcement learning (DRL)-based Volt-VAR co-optimization technique for reducing voltage fluctuations as well as power loss under high penetration of DERs. A stochastic policy optimization based soft actor critic (SAC) agent is proposed to configure the optimal set-points of the reactive power outputs of the inverters. The performance of the proposed model is verified on the modified IEEE 34-bus system and compared with a base case scenario with no reactive supply by inverters, and a local droop control approach. The results demonstrate that the proposed framework outperforms the conventional droop control method in improving the voltage profile, minimizing the network power loss, and reducing grid operational cost.

Index Terms—Distribution grids, deep reinforcement learning, soft actor critic, Volt-VAR optimization.

I. PROPOSED DRL APPROACH

It proposes a sample efficient DRL algorithm called soft actor critic (SAC) with continuous actions to learn a stochastic VVO policy. The proposed SAC agent coordinates among PV and BES inverters with their continuous reactive power outputs, and controls the active power charging/discharging the BESs based on the load demand. By optimal scheduling of intra-hour of smart inverter outputs, the proposed approach improves the voltage profile and reduces the power loss of the distribution system.

II. CASE STUDY

The performance of the proposed intelligent agent is validated on the modified IEEE 34-node test feeders. In the test system, nine aggregated PV inverters with a total maximum generation of 52% of the total demand and four aggregated BESs inverters with a total maximum capacity of 37% of the total PV generation are installed on the primary feeder. The load and PV profiles are taken from a real-world dataset with a PV installation site at Henderson, Nevada, USA [1].

III. VOLTAGE FLUCTUATION MINIMIZATION

Fig. 1 depicts the voltage variations in each node at time 2.00 PM using different scheduling and control methods. It is observed that in the base case scenario and droop control approach, the voltage fluctuation is high due to insufficient coordination among the inverters. However, the proposed SAC agent-based approach demonstrates better performance in regulating the feeder voltages compared to other approaches as it can effectively coordinate among the participating inverters for reactive power supply.

IV. POWER LOSS MINIMIZATION

Fig. 2 represents the power losses in IEEE 34-bus test case for all three scenarios. It demonstrates that compared to local droop control, DRL agent based VVO approach has less power loss that justifies the performance of the proposed method. This is because the proposed DRL agent can effectively control the output power injection/absorption by the DER inverters.

V. CONCLUSION

This paper has proposed a soft-actor critic (SAC) algorithm based DRL approach for VVO co-optimization in distribution grid with inverter-based resources. The agent interacts with the environment and adaptively chooses the optimal active/reactive schedules of BESs inverters and reactive power schedules of PV inverters to regulate grid voltages and reduce power losses in the network. The performance of the proposed framework was compared with the base case scenario, and with a local droop control of the inverters. The simulation results validated the superior performance of the proposed method compared to the other optimization approaches, in terms of improving the voltage profiles, and reducing the network power losses.

REFERENCES

Abstract—A data-driven identification framework is proposed to obtain a sparse parameter-varying (SPV) impedance model for power converters in DC microgrids. To this end, an $\ell_0$ regularization problem is formulated to learn coefficient functions of the parametric impedance model of a converter under test (CUT). In addition to providing an accurate estimation, the proposed method obviates the need for frequent perturbation of the system for online stability monitoring.

Index Terms—DC microgrid, small-signal impedance, sparse identification, stability monitoring

I. MAJOR CONTRIBUTION

Online impedance identification for DC microgrids require continuous perturbation of the system at each operating point due to the small-signal nature of the impedance model to be identified. To improve the run-time efficiency and alleviate computational needs of impedance-based online stability monitoring of DC microgrids, a sparse impedance identification framework is proposed for power converters as shown in Fig. 1.

II. SPV IMPEDANCE MODEL

First, frequency scanning driven by pseudo-random binary sequence (PRBS) excitation is utilized to collect small-signal impedance data at multiple operating points of the converter under test (CUT), which will be split into training and testing datasets. The parametric impedance model at each operating point is then obtained by fitting a transfer function to the impedance data, which is obtained by $Z_{trd}(s) = \sum_{i=1}^{m} \frac{a_i}{s+b_i}$.

Each coefficient of the transfer function is a function of the steady-state operating point of the CUT, defined by the capacitor voltage ($V_c$) and inductor current ($I_L$). By formulating an $\ell_0$ regularization problem, each coefficient function of the transfer function is approximated as a sparse linear function of the monomials of $V_c$ and $I_L$ using a training dataset selected form the collected measurements. This will result in the sparse parameter-varying (SPV) impedance model.

III. KEY RESULTS

The SPV impedance model constructed for a bidirectional battery charger is compared with its measured counterpart in Fig. 2 at a specific operating point of the CUT that is selected from the testing set. The SPV impedance model closely conforms to its measured counterpart with only a small error around the peak frequency.

IV. FUTURE WORK

The proposed identification is performed offline. Therefore, the future work may include online parameter estimation of the small-signal impedance model.

Fig. 1: Data-driven impedance estimation framework to obtain SPV impedance model

Fig. 2: Validation of the SPV impedance model against its measured counterpart ($V_c=391.28$ V, $I_L=-3.27$ A)
Analysis and Mitigation of Cascading Failure Spatial Propagation in Real Utility Outage Data

Shuchen Huang, Student Member, IEEE, and Junjian Qi, Senior Member, IEEE

Abstract—In this paper, the spatial propagation of cascading failures is studied for real utility outage data from Bonneville Power Administration (BPA). The spatial propagation features based on geographical distances are revealed by the proposed analysis method. Furthermore, a critical component identification method is proposed based on a new metric that combines the information of the expected number of outages and that of the spatial distance. A cascading failure mitigation strategy is further proposed based on the upgrading of the identified critical components. The effectiveness of the proposed mitigation strategy in terms of suppressing spatial propagation is validated on the 14-year real utility outage data from BPA.

Index Terms—Blackout, cascading failure, interaction matrix, mitigation, real data, spatial propagation, utility outage data.

I. SPATIAL PROPAGATION ANALYSIS METHOD

Based on the 14-year real outage data from Bonneville Power Administration (BPA), the component (transmission line) interactions between generations $g$ and $g+1$ in cascading failures are organized into an interaction matrix $B_g$, which is estimated in [1] by the expectation maximization algorithm. The algorithm estimates $B_g$ by updating $P_{ij}^{m,g}$ for each cascade $m$, which is the probability of component $j$ outage in generation $g+1$ following the component $i$ outage in generation $g$. The distance between component $i : i_1 \rightarrow i_2$ and component $j : j_1 \rightarrow j_2$ is defined as $d_{ij} = \min \{d_{i_1j_1}, d_{i_1j_2}, d_{i_2j_1}, d_{i_2j_2}\}$, where $d_{ij}$ is the shortest geographical distance between bus $k$ that belongs to component $i$ and bus $l$ ($k$ and $l$ are, respectively, a bus of component $i$ and component $j$).

Then the spatial distance between the outage components in two successive generations $g$ and $g+1$ of cascade $m$ can be calculated based on the final $P_{ij}^{m,g}$ as:

$$d_{g \rightarrow g+1}^{(m)} = \sum_{j \in F_g^{(m)}} \sum_{i \in F_g^{(m)}} P_{ij}^{m,g} d_{ij}, \quad (1)$$

where $F_g^{(m)}$ and $F_{g+1}^{(m)}$ are the sets of components fail in generation $g$ and $g+1$ of cascade $m$, respectively.

The total spatial distance between the outages in cascade $m$ over $G$ generations can be further calculated as:

$$d_{g \rightarrow g+1}^{(m)} = \sum_{g=0}^{G-1} d_{g \rightarrow g+1}^{(m)}, \quad (2)$$

Then the average spatial propagation velocity from generation $g$ to generation $g+1$ can be calculated as:

$$\bar{v}_{g \rightarrow g+1} = \frac{1}{M_{g \rightarrow g+1}} \sum_{m=1}^{M_{g \rightarrow g+1}} d_{g \rightarrow g+1}^{(m)}, \quad (3)$$

This work was supported by the National Science Foundation under CAREER ECCS-2110211.

II. CRITICAL COMPONENT MITIGATION

The expected number of outages $s_{r,i}^{g}$ for component $i$ after the outage of component $r$ in generation $g$ is calculated based on $B_g$ and the corresponding subgraph, which starts with component $r$ and includes $N_{r}^{g}$ components. Then we combine $s_{r,i}^{g}$ with the corresponding spatial distance to calculate a new metric, the expected spatial propagation $I_d^{g}(r)$:

$$I_d^{g}(r) = \sum_{r=1}^{N_{r}^{g}} s_{r,i}^{g} \bar{v}_{r,i}. \quad (4)$$

The total spatial propagation $I_d(r)$ of over all generations is:

$$I_d(r) = \sum_{g=0}^{G-1} I_d^{g}(r). \quad (5)$$

The two sets of critical components, $C_e$ based on the expected number of outages [1] and $C_d$ based on the proposed $I_d(r)$, are chosen for mitigation. In Fig. 1, the complementary cumulative distributions of $d_{g \rightarrow g+1}^{(m)}$ with and without mitigation are shown. Compared with $C_e$ mitigation, the proposed $C_d$ mitigation can more significantly suppress spatial propagation. To better reveal the spatial propagation properties, the outages from successive generations are grouped. Fig. 2 shows $\bar{v}_{g \rightarrow g+1}$ for the grouped generations with and without mitigation. In the figure, the proposed $C_d$ mitigation has the smallest $\bar{v}_{g \rightarrow g+1}$, validating the effectiveness of the proposed mitigation strategy.

REFERENCES

Scalable and Privacy-Preserving Distributed Energy Resource Control Over Cloud-Edge Computing

Xiang Huo, Graduate Student Member, IEEE, Mingxi Liu, Member, IEEE

Abstract—The extensive adoption of distributed energy resources (DERs) poses unprecedented challenges to power distribution networks. Particularly, managing a large population of grid-tied controllable devices is prone to control scalability crises and privacy breaches. To address this, we propose a novel decentralized privacy-preserving framework with cloud-edge computing that achieves scalability, ensures privacy, and improves computation efficiency in controlling DERs. The DER control is formulated into a constrained optimization problem and solved via the projected gradient method. Cloud computing and secret sharing are seamlessly integrated into the proposed decentralized computing to achieve privacy preservation. Simulation results demonstrate the effectiveness of the proposed method in DER control applications.

I. INTRODUCTION

Large-scale deployment of distributed energy resources (DERs) has proven efficacy in lowering carbon emissions and offering grid-edge services. Though integrating DERs into power grids can provide multifarious benefits, the high penetration of DERs raises surging challenges on the scalability and privacy of existing control strategies. Therefore, this work focuses on the design of a scalable and privacy-preserving algorithm that offers efficient, secure, and accurate solutions for large-scale DER control problems.

II. METHODOLOGY

The DER control problem is formulated into a constrained optimization problem that aims to minimize line loss, solar photovoltaic (PV) curtailment cost, and energy storage system (ESS) degradation costs. The optimization problem is solved in a decentralized fashion using the projected gradient method (PGM). The computing structure of the proposed privacy-preserving algorithm is shown in Fig. 1.

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![Fig. 1. Two-layer privacy-preserving computing structure for DER control in distribution networks.](image)

By integrating secret sharing (SS) into the decentralized PGM, the proposed approach aggregates and controls DERs with privacy guarantees against honest-but-curious agents and external eavesdroppers. In the distribution network layer, the decision variables of all DERs are updated concurrently, and only data masked by SS are transmitted from buses to the servers on cloud. In the cloud computing layer, the servers aggregate the masked data and distribute them back to the corresponding buses. Within the two-layer setting, the proposed approach protects DER owners’ private data, including the DERs’ generation, consumption, and daily electricity usage.

III. SIMULATION RESULTS & CONCLUSION

The simulations were conducted on a 13-bus distribution network. The baseline load profiles are shown in Fig. 2(a). Fig. 2(b) and Fig. 2(c) present the active power generations and the charging/discharging power from the solar PVs and ESSs, respectively. The power flows of 12 lines are shown in Fig. 2(d). The proposed algorithm achieves privacy preservation via a cloud-computing architecture for DER control in distribution networks. Simulation results verified the applicability of the proposed approach on an IEEE 13-bus test feeder with controllable ESSs and solar PVs. Moreover, the designed methodology can be readily used in general large-scale decentralized optimizations in the context of privacy preservation provisions.

![Fig. 2. The optimal and privacy-preserving DER control on the IEEE 13-bus distribution network.](image)

(a) Heterogeneous baseline loads of 24 houses. (b) Solar power injection of houses. (c) Charging and discharging power from 24 ESSs. (d) Power flows of 12 lines in the distribution network.
Abstract—This paper proposes an adaptive dc bus voltage control technique based on a fuzzy-PI controller. Moreover, a performance comparison between fuzzy-PI and conventional proportional-integrator (PI) controllers is performed based on a MATLAB/Simulink model. The results show that the fuzzy-PI controller has a faster response and less overshoot compared to conventional PI controllers. Additionally, the proposed controller can efficiently stabilize the dc bus voltage during load variation portions.

Keywords—Fuzzy logic controllers, Microgrids, Renewable Energy resources.

I. INTRODUCTION

PI controllers are commonly used to control microgrids and regulate DC bus voltage. However, these controllers necessitate precise mathematical models and their performance is affected by the operating conditions of any system, parameter variations, the nonlinearity of the system components, and load and generation changes. In contrast, the fuzzy logic controller (FLC) has demonstrated advantages over conventional controllers. The FLC establishes a nonlinear relationship between system input and output. With their experience-based knowledge of the system's behavior, these controllers can be easily tuned to achieve the desired system performance with fewer mathematical difficulties.

II. SIMULATION AND RESULTS

The system under study includes a PV system with a Li-ion battery as a storage device. A conventional PI controller controls the PV system without any MPPT technique. The main objective of this paper is to utilize the battery to stabilize the dc bus voltage and provide the load with the required power if needed. The battery converter is controlled by a Fuzzy-PI controller. The main goal here is to design a robust fuzzy-PI controller that stabilizes the DC bus voltage during load variations while comparing fuzzy-PI and conventional-PI controllers.

A detailed simulation study-based DC microgrid was created to design the proposed controller. Several simulation cases were done to analyze the controller's response after selecting the fuzzy limits and membership function. During the first case, the system response was checked under different step variations in the reference dc voltage. The variations, including high and small step variations, started at 80 volts and went up to 170 volts as shown in Fig. 1. In the second case, the load demand was doubled in a repeated sequence while maintaining the dc bus voltage at 140 volts, as shown in Fig. 2.

Fig. 1. DC bus voltage comparison

Fig. 2. Load variation scenario

III. CONCLUSION

Different simulation cases have been performed to design and compare fuzzy-PI controllers’ performance with standard PI controllers. The proposed controller can efficiently stabilize the dc bus voltage under different voltage reference variations and during pulse load conditions. Furthermore, based on a comparison study, the fuzzy-PI controller outperforms the conventional PI controller in terms of response time, overshoot, and simplicity.
Fast Perturbation-Based Extremum-Seeking Control for Frequency Support in Low Inertia Microgrids

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Abstract—Fast Perturbation-based extremum-seeking control (FPESC) is an adaptive and robust control technique that is emerging as a solution to limitations of the classical time-scale separation-based PESC scheme such as poor transient performance. This research presents FPESC for fast-frequency support (FFS) of low inertia microgrids. FPESC is acting as a virtual inertia unit and maintains the desired quality of service by limiting frequency and rate-of-change-frequency (ROCOF) under sudden load variation for the system that emulates microgrid limiting frequency and rate-of-change-frequency (ROCOF) under virtual inertia unit and maintains the desired quality of service by supporting the frequency of a weak grid.

Index Terms—Extremum-seeking control, microgrids, fast-frequency support

I. DESIGN METHODOLOGY OF FPESC FOR FFS OF MICROGRIDS

Microgrids incorporate a large number of non-synchronous, invert-based generation called distributed energy resources (DERs), they lack in primary frequency control mechanism which exists in conventional generating units therefore, they are more vulnerable to frequency stability issues. Fig 1. (a) shows the FPESC scheme for FFS of microgrid where FPESC consists of the following parts 1) Hammerstein Plant (HP: system representing microgrid frequency dynamics); 2) output filter (OF); 3) adaptive phase compensator (APC); 4) gradient estimator; and 5) optimizer.

1) Working principle of FPESC: Control loop of FPESC starts by perturbing the best estimate of control signal \( \hat{u} \) using periodic perturbation. The modulated signal \( u \) probes the gradient of system performance metric \( f(.) \) where \( F_o(s) \) represents the dynamics of the system. The components of the OF \( (F_1(s) & G(s/\omega)) \) improve the attenuation of the \( F_o(s) \) to allow the system to utilize a significant amount of perturbation. APC minimizes the phase shift of the system in order to ensure stability. The signal \( y \) passes through HPF to filter out mean value from \( y \), the resultant signal is demodulated to find the current gradient of \( f(.) \), LPF and integrator are used to filter out noise and update gradient of \( f(.) \), respectively. The speed of convergence of FPESC can be set using adaptation gain \( k \).

2) FPESC design assumptions: The components of the OF and APC can be selected as \( F_1(s) = (s + \alpha)^r \), \( G(s/\omega) = 1/(s/\omega + \alpha)^r \), \( APC = ((k\omega T + 1)/(Ts + 1))^p \). Where, \( F_o(s)F_1(s) \) is biproper and \( F_1(s)G(s/\omega) \) can be proper. The \( \omega, \omega_h, \) and \( \omega_l \) can be selected as 10-20 times of system natural frequency \( \omega_n \). The relative degree of the system is known and represented as \( r \).

3) Design of FPESC for microgrid frequency support: The performance metric of the microgrid is min \( f(.) = (x^T Q x + \Delta p R \Delta p) \), goal: limit frequency deviation/ROCOF during load change, \( x = [\Delta \omega, \Delta \omega']^T \) represents states of the system \( (\Delta \omega: \text{change in frequency}, \Delta \omega': \text{ROCOF}) \), \( \Delta p_t \) is FESC output. Where \( Q = [Q_{11} 0; 0 Q_{22}] \) and \( R \) are the weights associated to system states \( (Q_{11}: \Delta \omega, Q_{22}: \Delta \omega') \) and control input with range:0-1, \( R=0.001 \) is the weight of the FPESC output. The FPESC parameters are selected as \( \omega = \omega_h = \omega_l = 20 \times (\omega_n = 5 \text{ rad/s}), r = 2, \alpha = 1.2, \rho = r + 1 = 3, k = 0.5, T = 1/\omega_l, k = 300 \).Fig 1. (b) shows the performance comparison of FPESC with traditional MPC (horizon length = 50, sampling time = 0.02 s) to provide FFS in a microgrid. The performance metric for FPESC \( (Q_{11} = 0.1, Q_{22} = 1) \) and MPC \( (Q_{11} = 1, Q_{22} = 0.1) \) is same as mentioned above where the weights are selected to minimize frequency deviation in both cases. The load change (0.75 p.u.) occurs at 10 s and microgrid frequency deviates from the nominal value, the FPESC generates good control effort to minimize frequency deviation and ROCOF as compared to MPC.
I. Motivation

The increasing frequency of extreme weather events and the ongoing climate crisis have accelerated the adoption of green resources for energy production. Nuclear and renewable resources (solar, wind, etc.) are the major players in the clean energy mix. In addition to decarbonization, sustainable use of energy through diversification is also gaining traction in the energy industry. This has led to the concept of integrated energy systems (IES) where different energy sectors are considered holistically to improve efficiency and reliability. An IES consists of multiple energy sources to supply different end uses such as electricity, heating, transportation, etc. Two other inter-related developments that have bolstered the IES concept are the materialization of the small modular reactor (SMR) technology and the promotion of green hydrogen production. The IES enables localized energy production and consumption, and could be conceived as distributed energy resources (DERs) in the distribution network (DN). The co-simulation studies pertaining to DN power flow and IES thermo-electric studies have not been explored much in the literature. We aim to address this research gap by incorporating physics-based modeling and control of IES in response to the varying electrical demand of the DN. Additionally, a reinforcement learning framework for the control of IES generation in response to the DN demand is formulated.

II. Methodology

The distribution network is modeled using the opensource distribution system simulator (OpenDSS) with OpenDSSDirect as the API which facilitates the python based environment development. The multi-domain model of the IES which encapsulates the thermo-fluid, electrical and mechanical behavior of the “system-of-systems” is modeled in Dymola using the Modelica language using available opensource libraries. The python interface for Dymola is exploited for co-simulation with the DN model.

The IES is represented as a generator in the DN model. The physics-based model in turn consists of an SMR based nuclear resource supplying electricity to the grid through the balance of plant (BOP) and a high temperature steam electrolysis (HTSE) which produces hydrogen from the steam using electrolyzers. The HTSE which utilizes both thermal and electrical energy functions as a flexible electrical load in the system. The tightly coupled IES has one point of common coupling (PCC) with the DN. Therefore, despite the multiple energy and material exchange within the IES, it is perceived as a generator by the DN. The control and co-ordination of the IES subsystems are maintained by the supervisory controller which determines the control setpoints for lower level (subsystem) controllers. The optimal dispatch signals (here DN demand) is sent to the supervisory controllers.

III. Simulation and Preliminary Results

To validate the developed framework, we consider a 34-bus distribution network modified with placement of solar photovoltaic units and an IES with PCC at bus ‘828’ of the DN. The IES with an SMR rated at 160 MW (thermal) and a HTSE of 53 MW (electrical) is considered for the study.

Fig. 1: Overall system architecture and simulation environment

Fig. 2: A step change in power demand by the grid is the input to the IES. The supervisory control sends setpoint to HTSE and BOP. The corresponding controls function to deliver required demand.

Fig. 3: The load following capability of the BOP with grid demand
Detection of Falsified Commands on a DER Management System

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Abstract—To effectively manage potential adverse impacts of distributed energy resources (DERs) on distribution feeder voltages, DER management systems (DERMS) are being deployed. Deployment at remote substations and dependence on communication channels, makes DERMS controllers an easy target for cyber attackers. Falsification of DERMS control commands or minor changes in DERMS algorithm can cause severe overvoltages which can damage equipment, trip inverters, and cause undesirable operation of voltage regulating devices. A detailed cyber physical model for DERMS is designed to identify potential cyberattack paths. A two-tiered intrusion detection system (IDS) is proposed to detect and mitigate the cyberattacks in the cyber layer itself while preventing any adverse impacts on the physical power systems layer.

Keywords—Cyberattacks, cyber-physical models, distributed energy resource management systems, intrusion detection.

I. METHODOLOGY

A detailed cyber physical systems (CPS) model of a distributed energy resource management system (DERMS) has been developed using Python, OpenDSS and Simulink which communicate via the open-source OPC communication. This model was used to identify potential cyberattack paths impacting either the cyber layer or the DERMS controller’s algorithm itself. It was found that through minimal changes in the DERMS optimization algorithm, a cyber attacker can optimally dispatch DERs in such a manner as to indirectly influence the non-remote control capable voltage regulating devices present in the distribution feeder as well. This can significantly increase cyberattack severity leading to a blackout.

A two-tiered intrusion detection system (IDS) consisting of a centralized cyber layer-based tier and a de-centralized inverter-based tier has been developed to detect and mitigate all types of cyberattacks in the cyber layer itself. The centralized tier uses a combination of message authentication codes (MAC), time stamp and advanced encryption standard (AES) based encryption to detect falsified data packets as shown in Fig. 1. Upon detection, the IDS notifies the operator through an alarm, automatically drops the malicious data packets, and commands the inverters to start operating in unity power factor mode. The decentralized tier uses machine learning algorithms to detect cyberattacks targeting the DERMS controller directly.

II. RESULTS

Quasi-static time series simulations at a 30-second time resolution were run on the DERMS CPS model of the IEEE 13 and 123 node test feeders. As can be seen in Fig. 2, the cyberattack (red lines with triangles) first lowers the voltages by making the DERs to absorb reactive power, which causes the automatic voltage regulators (AVRs) to move to higher tap positions and the capacitor banks to turn ON. In the second stage, the combined impact of AVRs, capacitor banks and high reactive power injections from DERs causes severe overvoltages. The proposed IDS (green lines with ‘Y’) easily identifies these malicious packets through differences in MAC codes and prevents overvoltages in the power systems layer.

REFERENCES


Fig. 1. Cyber layer based centralized intrusion detection system.

Fig. 2. Cyber layer-based detection and mitigation of cyberattacks.
There has been a great interest in harnessing electrical energy from renewable sources to mitigate climate change. Offshore wind power is a major renewable energy source, and the North-Sea has become the focal point of this development in Europe. More than 200 GW of wind capacity is required in this Sea basin to meet Europe’s climate goal, a tenfold rise from today. This will require building a vast electricity infrastructure offshore, and the High voltage dc (HVDC) technology is foreseen to be the right technology for this purpose.

An HVDC link can either have a monopolar or a bipolar configuration. A large number of such links in the vicinity are foreseen to be connected to form an HVDC grid. Most such HVDC grids have considered either monopolar or bipolar configurations, maintaining a balance operation on the DC side of the AC/DC system. However, these studies do not allow the system operation with a mix of two configurations and, therefore, limit the optimal operation of the system. Similarly, in the case of network expansion planning, this exclusive (or balanced) operation limits the freedom in topology optimization. As there is a significant difference in the cost of a monopolar and a bipolar line, the overall cost of the topology can be reduced by allowing mixed configuration.

Therefore, the authors have developed an optimal power flow (OPF) model (‘PowerModelsMCDC.jl’) for unbalanced HVDC networks where both poles of bipolar converters, the transmission line, and the metallic return conductors are explicitly modeled (as in Fig. 1). The grounding impedance of the HVDC converter stations, e.g., rigid grounding versus high impedance grounding, is taken into account such that the correct voltage profile of the metallic return conductor is obtained and can be used as an optimization constraint. The AC network is modeled as a balanced network, as in high voltage AC networks, voltage unbalance is usually not significant. The HVDC converters are modeled generically, including converter station transformers, harmonic filters, and converter losses as provided in [1].

In this context, the power-voltage (P-V) formulation, which is most common, fails to capture nodal current balance in the neutral terminal and causes numerical issues due to the low magnitude of the neutral conductor voltage. Therefore, the DC grid is modeled in terms of voltage and current variables i.e. the I-V formulation. The developed optimization model is implemented as an extension of the open source ‘PowerModelsACDC.jl’ package [2], built-in Julia/JuMP [3] and uses the ‘PowerModels.jl’ package [4] for the modeling of the balanced AC system. The multi-conductor modeling functionality is inspired by the models included in the package ‘PowerModelsDistribution.jl’ [5].

Fig. 1. A multi-terminal HVDC grid with mixed monopolar and bipolar configurations

REFERENCES
Abstract—This paper compares a black-start simulation using a grid forming converter and a synchronous generator in Jeju Island. Grid-forming converters have advantages such as flexibility in voltage and phase angle control, soft start capability without requiring startup voltage, and mitigation of overvoltage during startup. The simulation results show the effectiveness of using grid-forming converters for black-start.

Keywords—Grid-Forming, Blackstart, Softstart, Grid Synchronization, Virtual Synchronous Machine (key words)

I. INTRODUCTION

Black-start is the process of self-starting and restoring a regional power system without an external power supply following a blackout. Synchronous generators play a major role during black-start recovery as they provide voltage and phase angle stability of the system frequency and other lines by generating voltage and frequency in the grid as a voltage source.

Traditionally, the restoration strategy in a power system that heavily relies on synchronous generators involved starting a large synchronous generator and supplying power radially to the load. However, the increasing proportion of environmentally friendly renewable energy sources has led to a decrease in the proportion of large synchronous generators and an increase in converter-based resources. As a result, changes occur in the dynamic characteristics of synchronous generator-centered systems, and a different perspective is required to maintain the same level of reliability and resilience as before.

Most renewable energy sources are currently interconnected with the power grid through grid-following converters. Grid-following technology is dependent on the robustness of the system's voltage and frequency and is designed and operated based on robustness assumptions. Therefore, renewable energy sources using grid-following technology cannot contribute to black start.

However, a grid-forming converter that can form voltage and frequency within the power system can enable renewable energy sources to self-start. Furthermore, it allows for control of voltage magnitude and phase angle, and soft start is possible without requiring startup voltage, providing advantages in mitigating overvoltage that may occur during startup. In addition, if multiple converter devices participate in black start, the recovery time can be shortened. Since there is sufficient capacity of renewable energy sources compared to the past, if converter devices equipped with grid-forming control are strategically deployed in the power system and have sufficient capacity to provide ancillary services, a flexible black-start strategy can be established.

II. APPROACHES

To demonstrate the potential contribution of converter based resources to black start, an experiment of black start using grid-forming energy storage system (ESS) within Jeju Island simulation is conducted.

III. SIMULATION RESULTS AND CONCLUSION

Table I

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Fig. 1. Comparison of Blackstart using GFM and Synchronous Generator

Fig. 1 illustrates the results of the system recovery process. It shows that the synchronous generator experiences overvoltage during the energization process with the power transmission line, whereas the grid-forming converter, which has the advantage of soft start, is stably energized. Furthermore, when the system is recovering due to the Ferranti effect, the voltage level is maintained at 1.05 p.u or higher in normal conditions. Upon energizing the power transmission line, it can be confirmed that the voltage is stably energized through the soft start. It is also observed that the system is recovered within a stable range even when synchronizing with the starting load and the preferred supply generator.
An Enhanced Situational Awareness Tool for Resilience-Driven Restoration with DERs

Linli Jia, Student Member, IEEE, Anurag K. Srivastava, Fellow, IEEE

Abstract—With large amount of behind-the-meter(BTM) distributed energy resources (DERs) integrated in power system, estimating distributed generation and cold load pick-up (CLPU) is getting more challenging, especially in case of outages caused by extreme adverse events. This work proposes a resilience-driven restoration scheme using the most updated information from an integrated and enhanced situational awareness tool (ESAT). The main functions of ESAT include BTM load estimation, DER estimation and disaggregation, CLPU estimation, and network topology estimation with de-energized islands, that are realized through kernelized Bayesian state-space inference (KBSI) with Markov Chain Monte Carlo (MCMC) and multiple optimization algorithm. The proposed work provides solutions to establish informed restoration schemes considering resilience criteria for a quick recovery of high-priority loads. The performance of ESAT is demonstrated using actual field datasets and validated using the emulated real scenarios on a benchmark model, and the effectiveness of the ESAT-driven restoration scheme is validated by the resilience scores for an expected threats.

Index Terms—Distributed energy resources, behind-the-meter, photovoltaic, resiliency, outage restoration, situational awareness

I. PROPOSED FRAMEWORK FOR RESILIENCE-DRIVEN RESTORATION INFORMED BY ESAT

The proposed framework for resilience-driven restoration with ESAT is shown in Fig.1. By efficiently harnessing the diverse set of data from multiple sensors, ESAT transforms the uncertainty to probability, estimates the BTM PV power generation and gross load, which is further used for cold load pickup (CLPU) estimation. In case of possible event strikes, BTM PV power and network topology estimation through ESAT could participate in power system outage preparation and restoration plan.

To estimate the outage network, outage notifications from smart meters is assumed available, and therefore the energized and de-energized section of the network are identified from planning topology by real-time power flow data. As to solar power aggregation, assume islands are formed with the help of grid-forming DERs after an outage, and everything lying inside a switch delimited area should be aggregated for restoration purposes. This identifies the net power of the aggregated DER resources, actual load demands, and controllable resources of each island. With above information, a two-stage resilience-driven restoration algorithm is proposed. In the first stage, a resilience-driven resource coordination strategy triggered by event-alerts guarantees that BESS is fully charged before events. In the second stage, a DFS-based method and a set of resiliency metrics are used to sort out the optimal restoration solution.

![Fig. 1: Developed ESAT for Resilience-Driven Restoration](image)

II. VALIDATION OF PROPOSED FRAMEWORK AND SUMMARY

The developed enhance situational awareness tool (ESAT) and resilience-driven restoration methods were validated in a revised IEEE 123 node test case. The PV model was created from hourly PV data collected by an Utility in Spokane, WA, USA. Assuming two faults happened simultaneously, the topology estimation model provides an accurate outage area.

The test case indicates that with the developed ESAT, the BTM PV participates in power supply after event strikes and thus reduce load lost, which is also verified by resilience metric scores. Future work will be validating the performance of ESAT in a utility test feeder network with more DERs for further assessment.
RoCoF Constrained Unit Commitment Considering Spatial Difference in Frequency Dynamics

Jiahao Liu, Student Member, IEEE, Cheng Wang, Member, IEEE, Tianshu Bi, Fellow, IEEE

Abstract—This paper proposes a RoCoF constrained unit commitment model so as to enhance the frequency stability in operation time-scale, where the spatial difference in frequency dynamics is considered and the RoCoF constraint is enforced for each node. The maximum of node RoCoF is approximated by two terms, i.e., the initial post-disturbance node RoCoF and the maximum of the center of inertia (COI) RoCoF. Analytical expressions of the node initial RoCoF under typical disturbances are derived. Then, a tractable relationship between the node initial RoCoF and the working status of generators is obtained by the piecewise linearization approach. Simulation results carried out on the IEEE 39-bus system demonstrate the proposed model can limit the node RoCoF in an economic and accurate manner. The adaptability to renewable power generation and online application are also discussed.

Index Terms—Frequency dynamics, inertia, RoCoF, frequency spatial difference, unit commitment

I. INTRODUCTION

Power system stability has been threatened by the penetration of large-scale renewable power generation (RPG) and the replacement of synchronous generators. It is crucial to restrict the post-disturbance RoCoF via the optimization of the power system operation strategies, e.g., unit commitment (UC). Existing RoCoF constrained UC methods focus only on COI frequency dynamics, without reflecting the frequency spatial differences in the post-disturbance stage. Even if the COI RoCoF is satisfactory, the RoCoF of some nodes may still go beyond the limit, which would cause the power system frequency collapse.

In this work, the RoCoF constrained UC considering spatial difference in frequency dynamics is proposed, so as to confine the maximum of the post-disturbance node RoCoF. To the best knowledge of the authors, it is the first work to improve the early-stage of the post-disturbance node frequency dynamics through optimizing UC decisions.

II. PROPOSED ROCoF CONSTRAINED UC METHOD

The post-disturbance node initial RoCoF is determined by three physical processes: the instant allocation of the disturbance power, the formation of the node frequency, and the generator rotor dynamics. The node initial RoCoF expressions under three typical disturbances are derived in this work, i.e., the load disturbance, the line switching disturbance, and the generator turbine disturbances. Taking the load disturbance as an example, the expression is shown as:

\[
S_{g,n}^{D} = \frac{E_{g}U_{g}Y_{g}^{GD} \sin \left( \delta_{g} - \theta_{n} - \gamma_{g,n}^{GD} \right)}{\sum_{g'}E_{g'}U_{g'}Y_{g'}^{GD,n} \sin \left( \delta_{g'} - \theta_{n} - \gamma_{g',n}^{GD} \right)} - \left( \delta_{g} - \theta_{n} \right) - \gamma_{g,n}^{GD},
\]

where \( S_{g,n}^{D} \) is the well-known synchronizing power coefficient (SPC) describing the disturbance power allocation; \( F_{n} \) is named as the node frequency formation coefficient (FFC); \( H_{g} \) is the generator inertia.

Then, the node initial RoCoF expressions are reformulated, where the impacts of the UC decision variables, including the working status and operating points of generators, are explicitly shown. The complex relationship between the node initial RoCoF and the UC decision variables is linearized in a mixed integer linear form. Tricks such as the loop-up table, piecewise linearization, and direct current (DC) power flow are used in this linearization.

Finally, the node RoCoF constrained UC model is established, where both the derived node initial RoCoF expressions and the COI maximum RoCoF formula are incorporated to restrict the maximum RoCoF of the critical nodes. A conservative estimation about the maximum RoCoF is preformed, which would provide an additional safety margin for the UC strategies against serve disturbances and can avoid the mistrip of RoCoF-based relay due to various field errors.

III. CASE STUDIES

The proposed model is validated in the modified IEEE 39-bus system. The proposed UC model is named as NUC. The TUC, CUC, and NUCo are the traditional UC, COI RoCoF constrained UC, and over linearized version of NUC, respectively. As the COI RoCoF could not reflect the spatial difference of the node RoCoF, the CUC has no driving force to commit more generators compared with TUC, and the node maximum RoCoF would exceed the limit. The NUC can limit the node maximum RoCoF by adjusting the working status and operating points of generators.

Fig. 1. UC results of (a) generator outputs and (b) actual maximum RoCoF at node 22 under node 03 disturbance.
Abstract—With the displacement of synchronous generation by inverter-based resources (IBRs), power systems could face the challenge of reduced inertia since IBRs do not inherently contribute to system inertia. Therefore, there is rising interest in monitoring system inertia in real-time applications for situational awareness. In addition, a growing number of IBRs can provide fast frequency responses (FFR) in the form of synthetic inertia and P-f droop. It is desirable to quantify the contribution of these FFR controls as equivalent inertia. This paper proposes a probing-based inertia estimation method using a PV-battery hybrid power plant in the Kauai Island power system. The method is validated under different operating conditions.

Index Terms—inverter-based resources, inertia estimation, probing signal, hybrid power plant

I. INTRODUCTION

Decarbonization goals and falling costs of renewable generators have precipitated the retirement of conventional fossil-fueled synchronous generation and the integration of inverter-connected renewable generation. With fewer synchronous units online, power systems could experience the challenges of reduced inertia since inverter-based resources (IBRs) do not inherently contribute to system inertia due to the lack of rotational mass. System frequency could experience high-magnitude deviations under low-inertia conditions, leading to increased under-frequency load shed operations. Therefore, it is important to monitor real-time inertia to maintain grid reliability.

This paper proposes a probing-based inertia estimation method using the PV-BESS plants on the Kauai Island. A small amount of active power is injected into the system from the BESS as probing signal and frequency dynamics are measured. A linear model between system average frequency and injected probing power is estimated using system identification techniques. System inertia is estimated by calculating the RoCoF of the step response of the identified model. The magnitude of the probing signal is small compared to the regular output power provided by BESS in hybrid plants, so this approach can be stacked with other BESS-based grid services.

II. TEST RESULTS

This section will present case study results of validating the proposed probing-based inertia estimation method using the 50-bus simulation model of Kauai island. To mimic the ambient frequency noise in the Kauai Island grid, load fluctuations modeled by Gaussian noise are injected at load buses. The magnitude of load fluctuations is determined based on the actual measurements captured by Universal Grid Analyzers (UGAs) deployed on the Kauai Island.

A simulation test is performed by injecting a series of Hann signals with a duration of 2s as probing signals. The inertia estimates with different probing magnitude are compared in Figure 1. For each probing magnitude, the blue cross mark represents the single estimate from each probing signal injected during the probing test period. The red dot represents the average over all the single estimates in the same series of injected probing signals. The dashed lines represent the theoretical system inertia. It is observed that a well-chosen probing magnitude and multiple probing injections during a short period of time could improve the accuracy of the inertia estimation accuracy. These key findings could help with the design of a suitable probing implementation plan in field applications.

Figure 1 Comparison of different probing magnitude
Design of Dynamic Prices for Retailers
Based on User Equilibrium

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Abstract—Dynamic prices vary with the grid load, reflecting the
generation cost. In this paper, a bi-level model for the design of
dynamic prices for a retailer is proposed. In the upper level, the
retailer designs the price to maximize profits considering the
response of loads. In the lower level, the interactive load
behavior is characterized by the user equilibrium (UE) model.
Compared with the common Nash Equilibrium (NE), UE gains
an obvious advantage in managing a large number of flexible
loads. The bi-level model is transformed into a mixed integer
program using the Karush-Kuhn-Tucker (KKT) conditions.
Then an efficient algorithm is proposed based on the branch-
and-price method. The designed dynamic price can reflect the
actual response of loads and maximize the retailer’s profits,
which is validated in numerical examples.

Index Terms—demand response, user equilibrium, dynamic
prices, bi-level programming, branch and price

I. EQUILIBRIUM ANALYSIS UNDER KNOWN DYNAMIC
PRICES

A. Problem Description

![Diagram of retailer and known dynamic price](Figure1.png)

Fig.1. Demand Response Procedure Under Known Dynamic Prices

B. NE Analysis

An NE of an aggregative game is a profile \( \mathbf{p}^* \) of actions
with the property that for each load \( a \in \mathcal{A} \),
\[
c_a(\mathbf{p}_a, \mathbf{p}^*-a) \leq c_a(\mathbf{p}_a, \mathbf{p}^*-a) \quad \forall a \in \mathcal{A}
\]
(1)

II. USER EQUILIBRIUM

UE aims to analyze types of loads in interactions, rather
than the individual behavior via NE. In that way, a unique
lowest cost in type \( k \) loads must exist at equilibrium.,

\[
\mu_k - c_{k,j} = \begin{cases} 
= 0, & n_{k,j} > 0 \\
\leq 0, & n_{k,j} = 0
\end{cases} \quad \forall k
\]
(2)

III. BI-LEVEL DESIGNING MODEL

![Diagram of retailer and equilibrium grid load](Figure2.png)

Fig.2. Bi-level architecture of the proposed model

IV. CONCLUSIONS

In the smart grid, the dynamic price is a significant DR
policy to utilize the potential of small-scale but numerous
loads. To design it, a bi-level model is proposed. It gains
advantages. 1) Compared with NE, UE is easily formulated to
a convex problem with a large number of loads, which leads
to the KKT conditions applied in the lower level. 2) Compared with the existing design of retail prices, the
dynamic price can reflect the actual response of loads. In the
future, the distributed energy resources and the competition
between multiple retailers can be further studied.
Simulation of Forced Oscillation and Study of Resonance in 240-Bus System

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Abstract— Forced oscillation (FO) in power system will be major issue if this event occurs and delay in mitigating it would lead to cascading blackouts. Locating source and mitigating FO is one of the biggest challenges and it’s even more tough to find FO source during resonance condition. In this research, study of FO in resonant condition is carried on. Simulation of FO using DSATools is done in 240 bus system during resonance and its effect in the system, its interaction with system modes, mode shape and oscillation, participation of generators in that mode and effect of change of damping of the system is studied. 240 bus system is taken from 2021 IEEE-NASPI Oscillation Source Location (OSL) Contest.

Keywords— Forced Oscillation, system modes, damping, resonance.

I. FORCED OSCILLATION IN RESONANCE CONDITIONS

Modern power system is very complex as it is interconnected and vast. As power system grow has grown bigger, the more it has been difficult to troubleshoot the stability issue. Many natural oscillations in the power system are faced in the system but those oscillations have been damped out by the system damping, however sometimes poorly damped oscillations are seen when the system damping is not sufficient enough to damp out which is one of instability issues seen in power system. When there are external factors, failure of control systems, load fluctuations, line tripping, equipment failures, etc. then it starts to oscillate the system mode which will create periodical disturbance in the system, and the only way to mitigate FO is to locate source and mitigate the reason causing FO or say remove the source. However, it has been difficult to locate the source when there are resonance conditions; situation where FO frequency matches with inter-area mode frequency and system starts to oscillate with high amplitude and all other generators along with source starts to oscillate leading to wide-area oscillations making difficult to locate the source.

In this paper, FO is simulated in resonance conditions in 240 bus system, model taken from 2021 IEEE-NASPI Oscillation Source Location (OSL) Contest, shown in Fig.1 below, injecting sinusoidal oscillations in one of the many generators, in inter-area mode frequency to create resonance. Effect of resonance in inter-area modes, local modes, effect of damping changes in FO and locating the source, effect in different nearby and farther generators to source generators, their participation in the specific FO frequency mode is studied here. The main motive to carry this research is to get the idea about how FO is affecting system and its element and get the hint to locate the source based on the system information we have.

Using Transient Security Assessment Tool (TSAT), Small signal Analysis Tool( SSAT) software, FO case is created and analyzed using available feature in those software. Source is selected with highest participation factor in that specific mode, SSAT is used to monitor the participator factor of generators in different mode and used to find inter-area mode in the system, also stability of modes. Once FO case is setup, its effect on the nearby generators, participating generators, system modes, and damping in resonance condition is studied.

![Fig.1 240-bus system](Image)

Fig.1 240-bus system

II. ACKNOWLEDGEMENT

I would like to acknowledge, Gregory C Zweigle and Md Arif Khan from SEL and my colleagues Bikal Pudasaini and Habib Wajid for their support.

REFERENCES

Impacts on Solar Inverter Response of Impedances in Electric Distribution Line with Grid Voltage Oscillation

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Abstract—High penetration level of PV energy have introduced technical challenges, including voltage stability and power output quality, to the electric network. Smart PV inverters could mitigate those issues using their grid supporting functions, yet the voltage control and power output quality can be influenced by the distribution line impedances. This work highlighted the impact of X/R ratios to the inverter and the grid using P-HIL laboratory as a testbed. Two impedance circuits were installed at different locations to mimic the distribution system. The results indicated that volt-var control will be more effective with high X/R, while the low X/R will cause the real power oscillation to the grid.

Index Terms—impedance circuit, grid stability, volt-var, smart inverters, oscillation, X/R ratio

I. INTRODUCTION

High penetration level of solar energy have become a major challenge for the electric grid which is necessary to be addressed in order to optimize the benefits of renewable energy. Although smart photovoltaic (PV) inverters can alleviate these issues with their benefits of grid supporting functionalities and real-time monitoring, the performance and the effectiveness of inverter voltage control and the power output quality at the grid can be influenced by a ratio of reactance to resistance (X/R) between in electric distribution line [1], [2]. Consequently, it is crucial to analyze the different combinations of resistive and reactive elements in the distribution network to understand their influence on performance of the inverter volt-var control and overall power quality of the grid.

II. EXPERIMENTAL SETUP

In this work, a power Hardware-in-the-loop (P-HIL) test facility has been used as a testbed which its configuration is shown in Fig. 1. Two residential PV inverters are connected to the grid simulator and each inverter is connected to its own PV power supply. To observe the effect of different resistance and inductance combinations to the power quality and grid stability, two impedance circuits were designed and integrated to P-HIL test facility in two different locations to represent the impedance in the local electric distribution lines. This causes different receiving voltages seen by two inverters. In this work, we considered X/R ratio of 3.5 and 0.5 as high and low ratio, respectively. The volt-var settings were operating to observe the ability of inverter voltage control. The grid voltage was randomly varied every 1,3, and 5 seconds within a range of 116.5 to 124.5 V to represent extreme grid voltage oscillations.

Fig. 1. A high-level diagram of P-HIL setup with impedance circuits.

III. RESULTS AND DISCUSSION

Key findings are that the ability of voltage control of the smart PV inverters is influenced by the line impedance tied to the inverter end and can be enhanced by the high X/R ratio which is shown in Fig 2(a). Combining with the aggressive volt-var control, the inverter was able to alleviate the voltage fluctuation with the fastest response time of 2 seconds. Another finding demonstrated in Fig 2(b) showed that low X/R ratio connected to the grid could lead to the real power instability which the effect might be exacerbated when multiple inverters are tied to the same point of common coupling or when the grid has higher imported total PV power.

Fig. 2. A comparison of grid and inverter responses under different X/R configurations

REFERENCES


A Novel Noise Resilient Coherent Group Identification using Mode Phase Difference

Karan Katariya, Ravi Yadav, Student Member, IEEE, Ashok Kumar Pradhan, Senior Member, IEEE, Prabodh Bajpai, Senior Member, IEEE

Abstract—In this article, a novel matrix pencil based mode phase difference approach is proposed for identifying coherent generator groups in power system. The approach allows coherency tracking for different modal frequency bands and low frequency electromechanical oscillations emanating in different control areas. An illustration of the applied approach is performed on 11 bus 2 area Kundur test system.

Index Terms—matrix pencil, mode phase, coherent generators, phase measurement unit

I. INTRODUCTION

Real-time monitoring and control of system level disruptions and renewable induced fast dynamics require wide-area monitoring, protection, and control (WAMPC) solutions. WAMPC employs PMUs with better dynamic resolution and synchronized data transfer compared to the SCADA. However, processing, transfer, and storage of PMU data introduces noise impurities in the phasor trends, which effects the performance of conventional analytic solutions. Matrix pencil is a noise resilient approach that gives accurate estimate of low frequency mode parameters and coherent generator groupings for low frequency oscillations.

II. PROPOSED APPROACH

The time-stamped PMU data \( y(t) \) can be expressed as
\[
y(kT_s) = x(kT_s) + n(kT_s) \quad (1)
\]
\[
= [Y]_{A \times B} \approx \sum_{i=1}^{M} R_i z_i^k + n(kT_s) \quad (2)
\]
\[
= [U]_{A \times A} \left[ \sum_{A \times B} [V]_{B \times B}^H \right] \quad (3)
\]
\[
= [Y_1]_{A \times P} \times [Y_2]_{A \times P} \quad (4)
\]

where \( A = N-P \), \( B = P+1 \), and \( k = 0 \), to \( N-1 \). The matrices \([U]\) and \([V]\) are unitary matrices. The matrix \( \sum \) is a diagonal matrix with the singular values of matrix \([Y]\) in descending order. To filter the noise \( n(t) \), a matrix pencil approach exploits the structure of a matrix pencil of the noiseless underlying signal \( x(kT_s) \) by obtaining the eigenvalues \( z_i \) of \( [Y_2]^H [Y_1] \). The mode-phase \( \phi_i = \arg(R_i) \) can then be obtained using (2).

The variance in the eigen values is inversely proportional to the SNR = \( \sigma_x^2/\sigma_n^2 \). For \( P = N/3 \) to \( N/2 \), the variance in the eigenvalues which are perturbed due to noise is minimized, such that 45dB SNR is obtained which is required for application based on PMU data.

The matrix pencil based mode phase difference (MPD) of the two signals \( x_1 \) and \( x_2 \) can be computed as (5)
\[
\phi_{x_1,x_2} = \arg(R_{1i}) - \arg(R_{2i}) \quad (5)
\]
where \( \phi_{x_1,x_2} \in [-\pi, \pi] \)

The MPD method is a new technique for the coherent group identification which can implemented using PMU data at phasor data concentrator (PDC).

III. RESULTS

The proposed method is validated on 11-bus 2 area Kundur test system. At \( t = 0.1s \), single line to ground fault is created which is cleared after 2 cycles and second tie-line between bus 7-8 is tripped. The topology modification initiated the inter-area oscillation of 0.53 Hz with mode damping of -4.461%. Using the proposed method, the MPD is calculated as shown in the Fig.1b. It can be observed that using MPD, G1 and G2 are oscillating together and in a similar way G3 and G4 are oscillating together as shown in the Fig.1a. The method is also tested for 240-bus western electricity coordinating council (WECC) system and found to be accurate.

![Fig. 1: (a) Coherent group of generators, and (b) mode phase difference](image)

Fig. 1: 11-bus 2 area Kundur test system

![Fig. 2: 11-bus 2 area Kundur test system](image)

Fig. 2: 11-bus 2 area Kundur test system

IV. CONCLUSION

In this article, the matrix pencil based MPD approach is proposed for the identification of coherent groups in a power system using noise infested PMU data. As far as available literature is concerned, this work proposes a novel approach, based on MPD method. This approach will provide information about coherent group changes, arising from network topology modifications.
Interval-Based Individual Household Load Forecasting Using Bayesian Deep Learning

Devinder Kaur, Shama Naz Islam, Md Apel Mahmud, Md Enamul Haque

Abstract—With the popularization of smart meters, it has become easier to manage demand side at the individual household level by employing applications such as load forecasting. However, uncertainty in the load consumption profiles is a major challenge for individual household load forecasting (IHLF) methods caused by key factors such as varying user behavior, weather, and calendar variables. Therefore, the load profiles first need to be modeled systematically in order to achieve effective forecasting results. An integrated load forecasting framework is presented in this work by first modeling the temporal data features (interval-wise) of load consumption profiles using Gaussian mixture model (GMM) clustering technique. The extracted information is then fed to the Bayesian deep learning-based Bidirectional long short-term memory (BiLSTM) method to generate probabilistic forecasts.

Index Terms—Bayesian deep learning, energy forecasting, load clustering

I. INTRODUCTION

An effective load forecasting technique for residential consumers can contribute towards grid stability and operational planning. However, user consumption variability and data granularity has made it challenging to predict the load accurately at individual level, especially for short-term time horizons [1]. To address this challenge, an expectation-maximization (EM)-based Gaussian mixture model (GMM) clustering algorithm is utilized to group temporal load profiles for individual households at the interval level to aid IHLF method accuracies.

II. PROPOSED METHODOLOGY

The Fig. 1 presents the flow chart for the proposed methodology. As shown, after performing exploratory data analysis, the proposed technique is mainly divided into two stages, namely, clustering stage, and forecasting stage. Using clustering stage, each household’s historical load consumption is clustered interval-wise into different groups. Using the extracted temporal features, data subsequences are created and then utilized by Bayesian BiLSTM method to make one-step ahead intra-cluster predictions, as reflected in the forecasting stage.

The implementation of the proposed framework is done using real time consumption data from Ausgrid [2] acquired for one year with the interval of 30 min. Fig. 2(a) demonstrates cluster formation using GMM algorithm for 3 number of clusters for 12 AM. Fig. 2(b) shows the predictions made from cluster no. 1 using Bayesian BiLSTM method at 90%, 50% (predictive mean), and 10% quantiles. Furthermore, Table I presents the aggregated prediction error results for all the 48 intervals during a day with and without GMM method.

(a) Cluster formation using GMM (b) Predictions from cluster 1 using Bayesian BiLSTM method

Fig. 2. Implementation demonstrations for one interval (12 AM) for one year.

<table>
<thead>
<tr>
<th>Method</th>
<th>RMSE</th>
<th>MAE</th>
<th>Pinball</th>
<th>Winkler</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bayesian BiLSTM</td>
<td>0.3049</td>
<td>0.2186</td>
<td>0.2568</td>
<td>3.075</td>
</tr>
<tr>
<td>GMM+Bayesian BiLSTM</td>
<td>0.1561</td>
<td>0.1672</td>
<td>0.2152</td>
<td>2.961</td>
</tr>
<tr>
<td>%age improvement</td>
<td>48.8%</td>
<td>23.51%</td>
<td>16.19%</td>
<td>3.707%</td>
</tr>
</tbody>
</table>

III. CONCLUSIONS

The proposed method achieves effective forecasting results with the help of GMM clustering. In specific, 48.8% and 23.51% of percentage improvements are reported in the deterministic root-mean square error (RMSE), mean-absolute error (MAE), respectively. In addition, a satisfactory performance of probabilistic errors, namely, Pinball and Winkler are also reported.

REFERENCES

EXTENDED ABSTRACT

This article aims to discuss the challenges and opportunities related to wind power production in the current scenario of global energy demand and climate change.

The problem tackled in this work is how to optimize the wind farm layout, in order to maximize power production levels, while considering the “Wake Effect” phenomenon that causes a speed reduction of the wind in subsequent turbines. The used model is called Bastankhah, which uses the yaw angle of the turbine to improve the calculation of the velocity deficit in the wake. The yaw angle is incorporated into the equation for the normalized velocity deficit, which is modified to account for the effect of yaw on the wake.

The model can then calculate the Annual Energy Production (AEP) that depends on a number of factors, such as wind speed at the project site, the model and capacity of the wind turbines, the quantity of generators installed, and the effectiveness of the turbine’s power generation. Also, a key challenge to efficiently foster the wind power penetration into the power generation mix worldwide is how to effectively spread the turbines along a given limited area with ultimate goal of optimizing the wind farm production levels, taking into account the multiple physical effects that impact the wind-to-power dynamics, in particular the so-called wake effect.

Regarding the numerical experiments, it can be seen that table I analyzes the impact of wake effect on turbines, with lower values of distance between turbines resulting in higher wake losses.

<table>
<thead>
<tr>
<th>α \ Y</th>
<th>0</th>
<th>15</th>
<th>50</th>
<th>75</th>
<th>100</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>82.49%</td>
<td>83.41%</td>
<td>90.39%</td>
<td>95.51%</td>
<td>98.48%</td>
</tr>
<tr>
<td>5</td>
<td>91.17%</td>
<td>91.43%</td>
<td>93.63%</td>
<td>95.77%</td>
<td>97.62%</td>
</tr>
<tr>
<td>10</td>
<td>96.01%</td>
<td>96.07%</td>
<td>96.58%</td>
<td>97.17%</td>
<td>97.83%</td>
</tr>
<tr>
<td>15</td>
<td>97.75%</td>
<td>97.77%</td>
<td>97.94%</td>
<td>98.15%</td>
<td>98.41%</td>
</tr>
<tr>
<td>20</td>
<td>98.56%</td>
<td>98.57%</td>
<td>98.64%</td>
<td>98.73%</td>
<td>98.85%</td>
</tr>
</tbody>
</table>

Finally, the last case study describes an experiment to optimize the layout of a wind farm in Rio Grande do Norte, Brazil, using the Julia Programming package called Flowfarm.jl. The study compares the optimized layout with two benchmarks: an evenly-spaced layout and the actual layout of the wind farm. The aim is to calculate the energy produced by the wind farm and compare the results. The optimized layout takes into account the wind speed and direction, and the optimizer searches for the layout with the least wake effect. The results show that the optimized layout improved energy production by roughly 15% compared to the evenly-spaced layout and 1.5% compared to the actual layout. The improvements are due to the fact that the optimizer seeks to minimize the wake effect and maximize free wind flow, leading to higher energy production. The study highlights the importance of optimizing wind farm layouts to increase energy production and efficiency.

<table>
<thead>
<tr>
<th></th>
<th>AEP (MW)</th>
<th>Improvement (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseline Case</td>
<td>1.14</td>
<td>15.21</td>
</tr>
<tr>
<td>Real Case</td>
<td>1.30</td>
<td>1.5</td>
</tr>
<tr>
<td>Optimal AEP</td>
<td>1.32</td>
<td>-</td>
</tr>
</tbody>
</table>

In conclusion, this article intends to understand the relation between the free wind and wake effect. Also, the importance of a well designed wind farm must be considered. With this approach, it is possible to produce more energy in the wind farm in the same physical space.
A Physics Informed Neural Networks Approach to Detect Faults in DC Microgrids

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Abstract—Fault detection in Microgrids (MGs) can bring many benefits for operation and reliability of the power distribution. Accurate fault location can reduce the failure costs and assist fast recovery of the system. Therefore, it will also increase the consumers’ satisfaction and help to improve the power delivering quality. DC Microgrids (MGs) have received much attentions in the recent years due to their advantages over AC MGs. This paper proposes a new framework for fault detection in DC MGs. Physics Informed Neural Network (PINN) as a deep machine learning algorithm is adopted to build a mapping model for predicting the DC MG behavior in event of a fault. Then, another machine learning classifier is taken into consideration for determining type and location of the faults. Accordingly, a framework is presented to show how to deal with fault detection in DC MGs based on the PINN approach.

Index Terms—DC Microgrids, protection, machine learning algorithm, PINN.

I. INTRODUCTION

DC MGs have many advantages when comparing with AC MGs like no reactive power control, synchronous issues and frequency regulations, lack of the skin effect in DC cables and lower power loss, natural working mode with renewable energy resources such as solar power panels and energy system storage, fewer redundant converter steps, simpler control and more efficient and lighter in weight for on-boards applications. Therefore, many academic and industrial institutions are performing projects about DC MGs throughout the world [1]. In this regard, fault detection is a serious and indispensable task for promoting DC MGs development to a new level.

Traditional fault detection methods in AC MGs cannot be applied for DC MGs due to inherent differences of DC systems like lack of frequency, low line impedance, absence of zero-crossing current, low inertial characteristics, etc. Therefore, new methods should be used for the DC fault detection. Additionally, machine learning algorithms have been adopted to detect faults in the DC MGs. However, most of the proposed methods are based on supervised learning algorithms which their accuracy is highly sensitive to data quality and availability. Unfortunately, lack of the sufficient labeled data and uncertainties of the power systems in practical environment diminish the performance and accuracy of such machine learning methods.

PINN is type of deep learning machine learning algorithm that incorporates the physical laws governing a system into the loss function [2]. Generally, PINN requires less data and can take the stochastic nature of the problem.

In this paper, a framework is presented for taking the advantage of PINN for accurately detect the faults in DC MGs (see Fig. 1). In this regard, a surrogate model may be build first to remove the Simulink model and increase the execution speed. Then, the output of this model is fed to another machine learning algorithm to determine occurrence of a fault and its potential type and location.

II. CONCLUSION

A PINN based fault detection for DC MGs has been adopted to deal with limited available data and uncertainties in the power system.

REFERENCES

Operation of an Electric Vehicles Fleet under a Utility Propagated Market Mechanism

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Abstract—Large-scale adoption of Electric Vehicles (EVs) creates multiple opportunities for their utilization as ancillary service providers to the secondary distribution system. Their is considerable potential of monetizing EVs operation through an aggregator based model that will provide services to the distribution system and operate under contract with local utility, following a voltage-based cost structure. Our study demonstrates this concept through simulation on a small town’s 4.4 kV secondary distribution system. Financial gains are thereafter projected from this operation.

I. INTRODUCTION

Ownership of EVs is expected to grow significantly in the coming years. As the size of our EV fleet grows, it will put additional congestion on secondary distribution systems, in terms of localized overloads due to EV chargers and voltage unbalances due to day-time charging patterns. This study evaluates how an aggregated fleet of EVs, in a small sized town can take advantage of regional load variations between residential areas and commercial down-towns to reduce the aforementioned issues and get compensated by local Utility against this service.

II. SCOPE OF STUDY

A subset of Pullman’s secondary distribution system is used to simulate this study. Area under study consists of a large university campus that is predicted to have a characteristic day-peaking office load, and an associated residential hostel area, which is predicted to have a characteristic late evening peak residential load. Following scenarios are simulated:

1) Aggregator convinces 5 EV owners to charge their vehicles at lightly loaded residential nodes during day hours and on university campus during night times.
2) Same as Case 1 with additional PV penetration in residential areas that will create voltage variation.
3) 120 kW fast charger are utilized to charge EVs during pre-forecasted 4-hour intervals.
4) Adaptive fast charging is utilized, in a load following manner such that power drawn from a target bus does not exceed a set threshold.
5) Vehicle to grid, where the aggregator facilitates charging at residential nodes during night times and discharging at university campus nodes during peak day-hours. Roundtrip efficiency of 85% is considered.

III. COMPENSATION MECHANISM

1) Voltage Based Nodal Price: The utility will compensate the aggregator through a voltage based cost curve, that is designed to pay a lower amount at higher voltage to encourage vehicles charging at nodes of excess power and a higher amount at nodes of lower voltages to discourage additional charging load. It is noted that voltage variations will naturally occur across the distribution system because of varied load patterns, spot PV penetration and EVs charging.

2) Congestion Relief Reward: The aggregator will be compensated for peak load reduction against the kWhs it is able to feed at highly loaded nodes through Vehicle-to-Grid and for the kWhs of EV charging demand that it is able to offset from the same highly loaded nodes. Compensation mechanism is based on the Present Worth of a distribution substation upgrade, that the utility will defer for 5-years, after contracting the congestion relief service to the aggregator. The $/kWh charge will be applied based on peak capacity allocation factor (PCAF), that will allocate the cost of deferred upgrade to only peak hours where it was required.

IV. RESULTS

Benefits summarized in the below table, are calculated by taking the difference between the cost of charging EVs fleet at the highest priced node of the system and the cost of charging after implementing the aggregator’s charging schemes mentioned earlier. Congestion relief reward in $/kWhs is distributed through hours of the day according to PCAF and added to the calculation based on the actual kWhs relief provided by aggregator.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Daily Savings</th>
<th>Yearly Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case-1, Facilitated EV Movement</td>
<td>$ 7.88</td>
<td>$ 2,876</td>
</tr>
<tr>
<td>Case-2, PV Penetration</td>
<td>$ 10.42</td>
<td>$ 3,803</td>
</tr>
<tr>
<td>Case-3, Fast Charging</td>
<td>$ 12.28</td>
<td>$ 4,482</td>
</tr>
<tr>
<td>Case-4, Adaptive Fast Charging</td>
<td>$ 16.61</td>
<td>$ 6,062</td>
</tr>
<tr>
<td>Case-5, Vehicle to Grid</td>
<td>$ 6.8</td>
<td>$ 2,482</td>
</tr>
</tbody>
</table>

V. CONCLUSION

Measurable dollar value was gained through aggregator’s operation, however more ancilliary services must be explored and quantified for better ROI.

ACKNOWLEDGMENT

Supported by DOE award: DE-IA0000025 for the UI-ASSIST project.
Optimal Power Sharing in DC Microgrids for Rural Electrification
Rabia Khan, Student Member, IEEE, and Noel N. Schulz, Fellow, IEEE

Abstract—Rural electrification is a global concern that needs to be addressed. Energy poverty harms human health and the environment due to excess usage of conventional resources. The most feasible option for rural electrification is using renewable energy resources through DC microgrids. In this paper, an islanded DC microgrid consisting of clusters of nanogrids is modeled using the branch flow model. The optimization algorithm is proposed to manage the power-sharing among neighbors. Each nanogrid is independent and can operate as both a prosumer and a consumer. The nanogrids utilize resource sharing and usage diversity to form a distributed microgrid architecture. The research aims to dispatch optimal power at each nanogrid to help in peer-to-peer energy sharing.

Index Terms—DC Microgrids, Rural Electrification, Branch Flow Model

I. INTRODUCTION

MILLIONS of people in the world lack electricity access with more than 80% belonging to remote rural areas. They depend on fossil fuels to fulfill their demands [1]. Rural electrification is important to mitigate energy poverty and improve socio-economic status of the society [2]. Rural electrification through grid extension in remote rural regions is expensive. Instead, the stand-alone and integrated microgrids are cost-effective. The highly distributed microgrid architecture is more efficient than centralized. Therefore, the research area is focused on DC microgrids with photovoltaic (PV) and batteries for rural electrification.

The designing, planning, and operation of a power system can be done using optimal power flow (OPF), which is non-linear NP-hard, and, non-convex. Low et al. proposed the branch flow model (BFM) and used conic relaxation. In our work, the BFM is used to implement the optimal power sharing in clustered nanogrids with distributed generation distributed storage (DGDS) architecture.

II. MODELING OF DC MICROGRID SYSTEM

The DC islanded microgrid system consists of clustered nanogrids for better efficiency, high reliability, usage diversity, and power-sharing features. Each nanogrid is an autonomous system. Each nanogrid has a roof-top solar PV panel, a battery, and a DC load. The power from i)PV panel is \( P_{\text{gen}} \), ii) the battery is \( P_{\text{Batt}} \), and iii) load demand is \( P_{\text{load}} \). The power dispatch and voltage magnitude square at the external DC bus are \( P_i \) and \( v_i \) respectively. The two nanogrids are connected to form a block of (DGDS) architecture, shown in Fig. 1.

III. PROPOSED ALGORITHM

A. Distribution Losses

Distribution losses in the systems are shown in Fig. 3a. They are zero when no power is shared and high when power sharing is maximum.

B. Scheduled Power

The power dispatch and consequently the power sharing is more when the load demand is high as shown in Fig. 3b.

Fig. 1: Framework of connected nanogrids

Fig. 2: Proposed Algorithm For Power Dispatch Strategy

Fig. 3: Distribution losses in the system
DoS and DM Cyber-attacks in Digital Substation: Impact Analysis

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Abstract—The prevalence of information and communication technology in modern power grids renders them more susceptible to cyber-attacks, which can lead to significant operational and security challenges. It is critical to assess the efficiency of cyber threats and their impact on systems. However, this task is complex and demanding. In practical terms, it may be unfeasible or impossible to conduct such evaluations on actual infrastructure systems.

In this paper, we present the laboratory capabilities of FIU’s smart grid testbed research facility, which is an integrated hardware-based AC/DC system designed to simulate a complete Cyber-Physical smart grid framework. Our research focuses on the substation automation system, specifically examining the security vulnerabilities of IEC 61850 and evaluating the effects of Denial of Service (DoS) and Data Manipulation (DM) attacks on the physical system. Two forms of DoS attacks, flooding and GOOSE poisoning, are investigated, and we conduct a case study of a transmission line fault under the proposed protection scheme. Our discussion includes a comparison and evaluation of the impact of DoS cyber-attacks on the physical system. Experimental results indicate that the DoS attacks have a significant impact on the protection scheme’s dependability and security, highlighting the need for the development of detection and mitigation techniques to overcome the vulnerabilities of IEC 61850.

Keywords—DoS, Flooding Attack, GOOSE Poisoning Attack, Protection Relays, Power System, Smart Grid Testbed, IEC61850.

I. CYBER THREATS AND ADVERSARY MODEL

IEC 61850 can be victim of different attacks, including DoS, eavesdropping, replay, man-in-the-middle, and password cracking attacks. In this context, our primary interest is in those attacks that render the protection system unavailable and that change the message contents.

Various vulnerabilities of IEC 61850 can be exploited to cause cyber-attacks such as DoS and DM. An intruder who intercepts the data network traffic, sniffs and collects the data packets can easily access the GOOSE data frame. From there, they can extract important information such as stNum, sqNum, APPID, destination MAC address, etc. which can be used to launch DoS and DM attacks. To develop our adversary model, we assumed that the attacker sniffed, collected, extracted the GOOSE data, and then launched the DoS and DM attacks. The DoS attack involved broadcasting GOOSE data frames with an extremely high stNum, while the DM attack involved changing the message contents.

II. EXPERIMENTAL RESULTS

We conducted a study to assess the effects of DoS and DM attacks on a suggested protection scheme under a three-phase fault. The DoS attack targets the subscriber protection relay R6, which sends a contaminated GOOSE message with a high stNum. This attack puts the availability of the protection relay at risk, as it prevents the reception of block signals from relay R11 by relay R6. Fig. 2 shows a scenario of three-phase fault applied on TL-0560 when a DoS attack was performed on R6. As a result, and due to the DoS, R6 didn’t receive the blocking signal from R11. Therefore, R6 sent a trip signal to the associated CB. Consequently, the busbar BB0320 lost all the power from the generation, which resulted in preventing the service for the other loads connected to the healthy feeders.

The DM attack was performed to cause the circuit breaker associated with R6 to trip. The attack was conducted by broadcasting the GOOSE data frame with a changed Boolean data field to 0x01.

REFERENCES


Abstract—The aim of this research is the effectiveness of synchronous generator’s governor control using Lyapunov’s function-based control strategy; compared with traditional governor control strategy. From this research, we anticipate more effective and safe control of synchronous generator in fault situation.

Keywords—Nonlinear control, Synchronous generator, Governor, Power system fault, Power system stability

NOMENCLATURE AND ABBREVIATIONS
SMIB – Single machine infinite bus power system

I. INTRODUCTION
Traditionally, the power generation and control have been based on PID control method; it was effective in traditional power system case. However, recently many nonlinear equipment are applied on grids, the system become more complex and more complicated for calculation and control; that is, traditional control methods are showed limitations of maintenance of synchronous generator’s stability. To overcome this problem, in this paper, this research suggests Lyapunov’s function-based synchronous generator’s governor controller for stability maintenance enhancement. As the comparative study, a single machine infinite bus system case is suggested.

II. LYAPUNOV FUNCTION
If the system is linear time invariant, the stability of system can be checked easy by using system’s eigenvalue; if the system is non-linear system, we can check the stability of the system’s eigenvalue by using indirect method. However, the indirect method is based on linearization, in some cases, sometimes we can’t determine the stability of the system. To overcome this problem, Lyapunov suggested Lyapunov’s stability theory make researchers and engineers enable to determine the stability of the system. In this paper, the Lyapunov’s equation is solved by using Sylvester equation.

III. PROBLEM STATEMENT
In this paper, the simulation and controller modeling is conducted on the single machine infinite bus (SMIB) power system; the infinite bus is the power grid so vast that its voltage and frequency remain constant independent of the amount of actual and reactive power drawn or supplied. When the excitation voltage of an alternator operating in parallel with an infinite bus is altered, the power factor of the machine changes. In this system, fault occurred on 40% point of transmission line length from slack bus and cleared after 50 cycles. And simulation is conducted during 5 seconds.

IV. RESULTS AND DISCUSSIONS
From this simulation, we got results as shown Figure 1, exciter applied Lyapunov’s function based excitation controller is more stable compared with traditional system; that is, in future system and multi-generators are connected with grid, our controller can work well.

Figure 1. The comparative study result of Lyapunov’s function-based controller on generator’s exciter

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This work was supported by Korea Institute of Marine Science & Technology Promotion(KIMST) grant funded by the Ministry of Oceans and Fisheries(KIMST-20210629).
Reinforcing Fault Diagnostic Classification Model using DCGAN-based Synthetic Images

Dongjoo Kim, Student Member, IEEE, Le Xie, Fellow, IEEE

Abstract—Power distribution facilities’ insulation functionality can degrade due to factors such as thermal, electrical, mechanical, and environmental stress, leading to issues such as heat generation, electromagnetic waves, light, cracks, erosion, and vibration sound. Detecting and preventing these issues in advance is essential. Optical cameras are the most accurate method for defect detection, but they are relatively expensive and have limitations in detecting defect images through total investigation. A DCGAN-based power facility data augmentation algorithm was developed to increase the accuracy of the classification model by using artificial data similar to reality. A case study confirmed that training the classification model with artificial defect data improves accuracy.

Index Terms—defective detection, GAN, synthetic images

I. INTRODUCTION

Cutting-edge deep learning-based image recognition and cognitive technology have made visual intelligence increasingly significant in defect diagnosis across industries, including the power sector. Developing facility defect detection technology using visual intelligence is challenging due to infrequent defect occurrences. To tackle this issue, we have developed a GAN-based power facility data augmentation technology that generates synthetic data resembling real-world data. This study evaluates the efficacy of this technology by creating artificial images of power distribution faults using DCGAN and applying it to classification model. Our case studies involve using both normal and damaged line pole insulator images at the distribution level, evaluating effectiveness using a ResNet-based classification model, and assessing performance using the Confusion Matrix and ROC curves.

II. SYNTHETIC FAULT IMAGE GENERATION USING GAN

A. Data Preparation and Training Details

![Fig. 1. Framework of synthetic fault image generation using GAN.](image)

Due to the infrequent acquisition of line insulator fault images, a limited number of data were used for the training process. To improve the quality of the model, we excluded unnecessary or suspicious data and images with obstructions around the LP insulator from the training set. Due to the small number of original datasets, only high-quality data was used, leading to a lack of data. To address this, we generated artificial fault images using DCGAN. The Fig.1 is a framework of synthetic fault image generation and fig.2 shows a synthetic defective image created through this method.

![Fig. 2. Synthetic defective images generated through DCGAN](image)

We used ResNet, a deep learning model known for its excellent performance in classifying natural images. ResNet addresses the problem of lost gradients in deep models by using skip-connections for residual learning. We chose ResNet-18 based on recent cases using it as a feature extractor in ImageNet-1k classification, where it outperformed models with more parameters. To classify normal vs. damaged insulators, we used cross entropy as the loss function, in anticipation of adding a new defect type later. Stochastic Gradient Descent (SGD) was used for optimization.

B. Synthetic Results and Validation

<table>
<thead>
<tr>
<th>Case</th>
<th>Test Accuracy (%)</th>
<th>AUC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>90.8</td>
<td>0.95</td>
</tr>
<tr>
<td>Case 2</td>
<td>93.5</td>
<td>0.95</td>
</tr>
<tr>
<td>Case 3</td>
<td>96.3</td>
<td>1.00</td>
</tr>
<tr>
<td>Case 4</td>
<td>96.7</td>
<td>1.00</td>
</tr>
</tbody>
</table>

The case study found that adding artificial defect images created with GAN to the dataset improved accuracy and AUC values compared to the baseline model.

III. CONCLUSION

This research examined the effectiveness of ResNet-18-based power distribution facility fault diagnostic classification models that include artificial data generated by GAN. Different ratios of artificial data were tested, and the results showed that augmenting with artificial data improves model performance and accuracy when defect images are scarcer than normal images. Future work will explore the effectiveness of training models with artificial data in multi-class classification for other types of defects such as cracks, arcs, and damaged parts.
HILs for wind turbine design based on deep learning

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Abstract—Currently, researchers are focused on improving the accuracy of wind turbine modelling by applying various methods to construct wind power curve models. However, the complex nonlinear relationship between wind speed and wind power leads to the lack of accuracy in the current wind power curve modelling. This paper proposes a wind turbine modelling strategy based on an artificial neural network technique to address this challenge to reflect the output's dynamic characteristics. The performance of the proposed model is verified via a real-time digital simulator (RTDS). The obtained results confirm the applicability of the proposed deep learning-based wind turbine model. Furthermore, the comparative analysis with the existing optimized power curve model shows that our designed approach obtained better results.

Keywords—Wind turbine modeling, Machine learning, Real-time simulation

I. INTRODUCTION

The output of a wind turbine is typically estimated along its power curve, which shows the relationship between the wind speed and the turbine's power output. However, the power curve of a wind turbine can be inaccurate for some reasons. One common issue is that the turbine may not be operating at its optimal conditions. Another reason is that the power curve may not accurately reflect the actual environment under which the turbine operates. Overall, while the power curve can be a tool for estimating a wind turbine's performance, many factors should be considered to get a more accurate picture of the turbine's actual performance. Further, the algorithm has to construct considering data patterns to reflect output characteristics. Therefore, this paper applied machine learning based on the CNN-BiLSTM algorithm, combining CNN and BiLSTM.

II. APPROACHES

Wind turbines would be modelled based on artificial neural network techniques. To complement the existing fixed power curve, we applied an algorithm considering the spatiotemporal characteristics of various data. The proposed strategy can derive a similar real output value through the trained wind turbine model tremendous wind scenarios. We uses hardware-in-the-loop simulation (HILs) to verify the wind turbine model through the controller, where the learning model is saved and a real-time simulator. The HILs configuration is depicted in Fig. 1.

III. SIMULATION RESULTS AND CONCLUSIONS

In a case study, the active power of each wind turbine model is compared by inputting 60 sec of wind condition data. As shown in Fig. 2, simulation results show that the proposed wind turbine model power tracking values are similar to the actual power generation. In addition, regarding the error rate through evaluation metrics, the proposed model shows improved features compared to other wind turbine models (Table 1). Therefore, it is expected that through the proposed method, accurate grid analysis reflecting the dynamic characteristics of wind farms can be achieved when constructing wind farms.

![Fig. 1. HILs configuration for simulation](image)

![Fig. 2. Comparison of wind turbine active power](image)

<table>
<thead>
<tr>
<th>Case</th>
<th>Method</th>
<th>MSE</th>
<th>RMSE</th>
<th>MAPE</th>
<th>WAPE</th>
</tr>
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<tbody>
<tr>
<td>1</td>
<td>Previous</td>
<td>2181.9</td>
<td>147.71</td>
<td>25.26</td>
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<tr>
<td></td>
<td>Proposed</td>
<td>290.95</td>
<td>17.05</td>
<td>3.63</td>
<td>2.18</td>
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</table>
A Study on Performance Assessment of Co-located Synchronous Condenser and IBR

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Abstract—As the generation mix in the power system is changing, the need for additional facilities and control is increasing due to concerns about power system stability. In particular, IBRs have a limited overcurrent capability which can lead to weak grid strength. To address this issue, synchronous condensers can be used to provide large short circuit current and inertia. In this study, a performance assessment was conducted to compare the performance of synchronous generators with co-located synchronous condensers and IBRs. The goal was to achieve a comparable result that overcomes the limitations of IBRs.

Keywords—synchronous condenser, inverter-based resources, overcurrent capability, power system stability

I. INTRODUCTION

The increasing use of renewable energy sources, such as solar and wind power, has led to the adoption of inverter-based resources (IBRs) in power systems. One of the main challenges associated with integrating high levels of IBRs into the power system is the loss of synchronous inertia, which is essential for maintaining system stability. Additionally, IBRs typically have a limited current capability due to the nature of their power electronics. When the current capability of IBRs is reached, the system can become unstable, resulting in voltage fluctuations and potential blackouts. This is especially true in power systems with high levels of IBRs, where the impact of inverter limitations can be significant. As a result, there is a need for synchronous condensers in power systems.

Synchronous condensers are rotating machines that are typically used to provide reactive power support to the power system. They have a high current capability and can help to compensate for the limited current capability of IBRs. By providing reactive power support, synchronous condensers can help to maintain system stability and prevent voltage instability, which can lead to power outages. Additionally, synchronous condensers compensate for the lack of inertia in IBRs.

The proposed solution is to co-locate synchronous condensers with IBRs to achieve a comparable overcurrent capability to that of synchronous generators, which would enable the system to perform similarly to synchronous generators. This solution aims to solve several issues caused by the low overcurrent capability of IBRs.

II. KEY RESULTS

To assess the performance of the co-located synchronous condenser and IBR, performance of synchronous generator is further compared for variable conditions as shown in Fig. 1.

Fig. 1. Single-unit operation configuration of (a) the SG case (b) the co-located SC and IBR case.

Fig. 2 show the result of the event when three phase fault occurred at the load bus and Fig. 3 shows the result when additional load was connected.

Fig. 2. Voltage result between SG and co-located SC and IBR.

Fig. 3. Frequency result between SG and co-located SC and IBR.

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Investigation and Comparison of Phasor and EMT-based Models for Inverter-based Resources

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Abstract— With the increasing use of inverter-based resources (IBR) such as renewable energy resources, the dynamic characteristics of power systems are changing from those based on synchronous generators. Previous power system analyses were mostly conducted using phasor domain simulation environments to observe dynamic phenomena, such as electromagnetic oscillations in synchronous generators. However, as the proportion of renewable energy resources increases, the influence of inverter characteristics on the system becomes more significant, requiring the need for electromagnetic transient (EMT)-based analysis. Phasor domain simulations can only observe phenomena up to around 10Hz in the low-frequency band and assume a three-phase balance, making it difficult to obtain accurate results in systems where the impact of IBR control characteristics is significant. The control frequency range of IBR exists from low-frequency to high-frequency bands, and EMT-based analysis is becoming more necessary as it can model the entire frequency range using the sequence components of voltage and current, which can be similar to actual IBR.

Keywords— renewable energy resources, electromagnetic transient, phasor, control frequency range, power system oscillation

I. KEY RESULTS

In this study, a system was constructed to compare the control characteristics of fault ride through for EMT and Phasor models according to grid strength. The Phasor-based model of the IBR used the REEC_A model for electrical control and the REGC_A model for inverter modeling, based on WECC recommendations, and the EMT-based model utilized a two-level voltage source inverter model to compare the results in situations with SCR 3 and 2.

Fig. 1. Comparison of FRT response in strong grid for IBR

Fig. 2. Comparison of FRT response in weak grid for IBR

Inverter-based equipment relies on control algorithms, and PLL control performs synchronization with the power system. The PLL control measures the magnitude and phase of the voltage at the point of interconnection and tracks the d-axis component of the point of interconnection to be zero. Therefore, inverter-based equipment that tracks the voltage at the point of interconnection through PLL control will experience control instability if it loses synchronization within a weak power system.

Fig. 3. Comparing the stability of IBR and detecting resonance according to the robustness of the power system

The figure above compares the output of inverter according to the robustness of the power system. It can be observed that 6Hz resonance occurs in weak power systems. However, it is not possible to conduct synchronous instability analysis due to the absence of the PLL model in the phasor domain environment.
Efficient and Low Cost Technique for Converting Solid Waste to Bioenergy in Urban Centers

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Abstract: The global power sector is facing a growing challenge of reducing Greenhouse Gas (GHG) emissions, while also increasing access to sustainable energy. This paper proposes an efficient comprehensive approach to reduce emissions from power plants and generate syngas as a renewable source of energy for domestic heating. To meet this challenge, the proposed approach utilizes synthetic solid waste, organic waste materials, and flue gas from power plants, and more economical and scalable technologies such as cold trap cryogenic distillation, catalytic conversion, and the water-shift technique to generate syngas. In addition, the potential of using renewable energy sources such as solar and wind to reduce the cost of power production and decrease carbon emissions is discussed. The proposed approach has the potential to meet Sustainable Development Goals, such as reducing GHG emissions, increasing energy access and efficiency, reducing poverty, creating economic opportunities, and improving access to clean water and sanitation.

Keywords: GHG emission, Renewable energy, Solid waste, Sustainable Development Goals, Syngas, Flue, Cogeneration power plants.

I. MODEL DEVELOPMENT

MATLAB’s built-in differential equation solver, ODE45, was used to simulate a process of fuel flow, carbon dioxide recovery from flue gas, syngas generation from carbon dioxide, energy requirements, and power (heat and electricity) generation from syngas, as in Fig. 1.

II. KEY RESULTS

The heat energy generated by the combustion of syngas can be used to generate electricity in the form of turbines. For example, if 1kg of syngas is combusted, the amount of heat energy produced can range from 2-5MJ. Compared to other renewable energy sources such as wind and solar, syngas combustion is more efficient as it produces a higher amount of heat energy for the same mass of fuel, as shown in Fig. 2. Compared to solar and wind power, syngas is cost-effective to manufacture and requires less land. It can also be used to produce electricity on a much larger scale, as seen in Fig. 3. A viable and economical technique for commercializing syngas for domestic heating and electricity generation is the use of natural gas-fired cogeneration plants, as suggested by Gao et al, as in [1]. These plants have a high efficiency rate of up to 90% [2], resulting in lower fuel costs which makes the commercialization of syngas more economical.

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Investigating Protection Challenges on Distribution Systems Self-Healing

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Abstract—Due to its characteristics to be radial and extensive, distribution networks are susceptible to de-energizing many customers during an outage event. Through distribution network reconfiguration (DNR) techniques, self-healing (SH) provides a solution to partially or entirely restore impacted customers. However, the SH approach must change the network configuration to restore customers within minutes after the fault occurs. The need for speed does not allow full consideration of other network aspects, such as protection settings and how relays will be impacted after restoration. This paper analyzes and discusses the impacts of distribution networks SH on protection performance. The results present optimal restoration for different fault locations and which protection elements would have tripped in each relay after the restoration.

Keywords—Adaptive Protection, Outage Restoration, Reconfiguration, Self-Healing, Smart Grids.

I. ACTIVE DISTRIBUTION SYSTEMS

The term grid topology refers to the way the network is built. On the other side, grid configuration implies how the grid is operated. When reconfiguration is performed to restore the service after an outage, it is also called self-healing. Studies on SH are typically concerned with processing time, the number of impacted customers, outage duration, and power quality. An important aspect that has not been considered in depth is how the proposed restoration solution impacts the pre-defined protection devices and settings [1].

II. RESEARCH DESCRIPTION

The present research investigates the interaction between traditional SH solutions and protection schemes. A MILP problem is formulated for SH and tested on a modified IEEE 33-node distribution network [2], presented in Fig. 1. Table I shows the protection settings calculated for each relay based on the system configuration presented by the base case scenario. The protection scheme considers elements 27, 32, 50, and 51 in each relay.

III. KEY RESULTS

The results are based on a steady-state analysis and aim to highlight how the protection settings respond to the changes in power flow and short-circuit levels the restoration brings to them after the reconfiguration process. Table II shows the five different study cases and their fault location, as well as the obtained power flow results for $R_C$ after the restoration, where Case 0 is the baseline scenario before any fault or reconfiguration. It should be noted that T and N stand for trip issued and not issued, respectively. $R_C$ was able to protect its new zone for minimum short-circuit levels for all cases. However, it is possible to observe that the restoration solution for Case 1 would have caused an undervoltage and reverse power flow trip on $R_C$, while Case 3 would have caused an element 27 trip and Case 4 an element 32 trip. Based on $R_I$ performance, Cases 2 and 5 would have successfully restored the system without causing new tripping.

IV. FUTURE WORK

The results show the need to either develop more flexible protection schemes with an adaptive protection approach or embedding protection settings as constraints of the SH model. Besides these aspects, the methodology validation must be made with time-domain studies, so the voltage and current waveforms and power systems dynamics can be fully considered. As a continuation of the current study, the MILP problem will be tested under high-density coordination (HDC) and discusses the impacts of distribution networks SH on protection performance. The results present optimal restoration for different fault locations and which protection elements would have tripped in each relay after the restoration.

TABLE I. RELAYS’ SETTINGS.

<table>
<thead>
<tr>
<th>Settings</th>
<th>Relay</th>
<th>Location</th>
<th>$R_D$</th>
<th>$R_I$</th>
<th>$R_F$</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Node 0</td>
<td>0</td>
<td>2</td>
<td>8</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Branch 0</td>
<td>0.1</td>
<td>7.8</td>
<td>26.27</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>CT</td>
<td>2500</td>
<td>400</td>
<td>100</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>PT</td>
<td>7500</td>
<td>7300</td>
<td>7300</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>ANSI 59</td>
<td>$V_I$</td>
<td>108</td>
<td>108</td>
<td>108</td>
<td>-</td>
<td>kV</td>
</tr>
<tr>
<td>ANSI 32</td>
<td>$P_I$</td>
<td>-0.5</td>
<td>-0.5</td>
<td>-0.5</td>
<td>-</td>
<td>MW</td>
</tr>
<tr>
<td>ANSI 50</td>
<td>$U_I$</td>
<td>6.2</td>
<td>8.7</td>
<td>19.6</td>
<td>-</td>
<td>%</td>
</tr>
<tr>
<td>ANSI 51</td>
<td>$T_D$</td>
<td>1.33</td>
<td>0.50</td>
<td>0.50</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>ANSI 59</td>
<td>$V_I$</td>
<td>132</td>
<td>132</td>
<td>132</td>
<td>-</td>
<td>V_Load</td>
</tr>
</tbody>
</table>

Fig. 1. IEEE 33-Node Distribution Network.

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REFERENCES


Low-Order System Frequency Response Model of a Low-Inertia Power System

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Abstract

I. EXTENDED ABSTRACT

The massive penetration of converter-interfaced elements based on voltage source converters (VSCs) will fundamentally change power system operation and dynamic performance [1]. Smaller time constants of converters introduce new interactions in the electromagnetic time domain, which require electromagnetic transient (EMT) simulation tools for power system analysis. However, inherently high-order converter models and EMT simulations are computationally inefficient for bulk power system dynamic analysis. Therefore, a significant amount of research has arisen in recent years that tackle the problem of accurately representing the behavior of converter-based power systems while simultaneously allowing larger integration step sizes as well as fundamental frequency simulation (RMS) tools, still the key in bulk power system dynamic analysis.

AC system frequency is an essential characteristic of AC electric power grids and the global indicator of generation-load balance. In the seminal paper by Anderson and Mirheydar [2], it was shown that the average system frequency behavior could be relatively accurately simulated with low-order system frequency response (SFR) models, which essentially aggregate the whole system into a single equivalent machine with inertia, damping, and turbine control actions, and neglect all but the largest time constants. SFR models are simple, have a small number of parameters, and they are intuitive to use. Additionally, because they are linear, they can be used for defining constraints in power system optimization problems. However, since converter control is significantly faster than conventional turbine governing systems, the conventional SFR models need to be revisited to find an adequate representation of converter dynamics in grid-scale active power control.

We present SFR models of three typical VSC control schemes, shown in Fig. 1: active power controlled grid-following VSC with droop, DC voltage controlled grid-following VSC with droop and active power controlled virtual synchronous machine with droop. The proposed SFR models are verified against detailed EMT simulations on IEEE 9-bus benchmark system for up to 100% converter penetration.

The main conclusions are:

- PLL dynamics of grid-following VSCs cannot be neglected in low-inertia scenarios [3];
- virtual inertia of a virtual synchronous machine can be algebraically added to the synchronous inertia;
- virtual inertia of grid-following VSC cannot be algebraically added to the synchronous inertia due to a time lag caused by PLL dynamics and frequency estimation filtering.

Final poster might include two additional SFR models of grid-forming schemes with synchronization based on DC voltage imbalance.

REFERENCES

Towards Sustainable Marine Transportation: Greenhouse Gas and Acoustic Emission Reduction

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Abstract—Sustainable marine transportation calls not only for greenhouse gas (GHG) emission reduction, but also for acoustic emission mitigation. The latter is essential to protect certain marine species against the life-threatening impact of underwater radiated noise (URN) emanating from ships, that could undermine their primary life functions. We propose a comprehensive optimal voyage scheduling model for all electric ships (AESs), that incorporates an accurate model of ship electric network, confines GHG emission, and keeps URN in check via speed regulation along with embedding a new path selection feature that enables avoiding particular sensitive habitats. We illustrate the effectiveness of the proposed model in curbing URN levels and GHG emissions with numerical case studies involving an 18-node ship test system.

I. INTRODUCTION AND METHODOLOGY

Historically, maritime transportation has played a pivotal role in global trade. With the recent advancements in ship manufacturing technologies (AES in particular), this role has become even more pronounced as more than 80% of trade goods are currently carried over the seas. Thereby, an environmentally sustainable maritime transportation could be instrumental to global emission mitigation, promoting healthier societies, and preserving natural ecosystems. Though current policies in this regard are mainly driven by GHG reduction, of importance is also mitigating the acoustic emissions. As a point in case, URN could pose danger to certain marine mammals which rely on sound to navigate, communicate, and locate prey.

Majority of recent literature on optimal voyage scheduling of AESs have focused on limiting GHG emissions and incorporating ES devices to promote operational flexibility. They relate the propulsion load to AES cruising speed, treating them as flexible loads controlled by speed regulation, while mainly neglecting the impact of ship electric network constraints. In addition, URN limitations are not considered in the literature. We bridge this research gap by proposing a comprehensive voyage scheduling model that incorporates the AES electric network constraints, and confines both GHG and URN within allowable limits. The URN is calculated through Ross’s classical power law model and controlled through speed regulation as well as introducing a novel path selection capability that enables circumventing particular sensitive habitats by choosing amongst different alternative paths. To further elaborate, the proposed voyage scheduling problem minimizes the AES operation cost subject to the physical constraints imposed by the electric power network, operational limits of generators and energy storage (ES) devices, as well as constraints pertinent to voyage, URN, propulsion load, and the energy efficiency indicator for GHG emissions. To promote computational tractability, we also approximate the nonlinear relationships for URN, propulsion load, and fuel consumption with piecewise linear functions, leading to a mixed-integer second-order cone programming problem which proves convergence to global optimum and computationally efficient solutions.

II. RESULTS HIGHLIGHTS

For the 18-node AC shipboard test system with 4 generators, 2 ES devices, 4 propulsion motors, services loads, and assuming a 12-hour scheduling horizon, the shortest route of 153 [kn.hr] is selected for Case 0 where URN and electric network limitations are neglected (see Fig. 1). However, with the URN and network limits imposed (Cases 1 and 2), the optimal path selection capability embedded in voyage scheduling problem opts a longer alternative route of length 157 [kn.hr] to avoid violating the more strict URN limit of the shorter path. This is complemented with increased cruise speed to meet the voyage timeline constraints, which, in turn, increases the propulsion load. The increased propulsion load in Cases 1 and 2 is supplied by an optimal combination of generators and ES devices, in compliance with emission limitations.

Fig. 1. Optimal values of the ship’s (a) cruising speed, (b) propulsion power, and (c) URN level, for Cases 0–2.
Investment Planning to Enhance Resilience of Power Systems against Extreme Weather Events

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Abstract—With the increasing frequency of natural catastrophes, operators must prioritize improvements in the existing electric power grid infrastructure to enhance the grid’s resilience. Grid resilience may be increased by upgrading transmission system infrastructure through hardening and investing in distributed generation. However, traditional transmission system planning approaches focus on the long-term cost of expected occurrences and try to improve system reliability. Resilience to extreme weather events necessitates lowering the impacts of high-impact low-probability (HILP) occurrences, defined by the tail probability of the event impact distribution. Designing and constructing a robust transmission network might be prohibitively expensive. Given the budget constraint, this paper proposes a two-stage stochastic optimization framework, which includes the first stage, which minimizes the planning cost, and the second stage, minimizing the operational cost, where the operations comprise generation dispatch and restoration. Investment considerations include transmission line hardening and distributed generation installation. To alleviate computational complexity without sacrificing solution quality, a representative scenario sampling method is used, and dual decomposition techniques are implemented to solve the optimization problem in a reasonable time. Finally, the overall framework is tested on standard IEEE test cases.

Index Terms—stochastic optimization, power system resilience, line hardening, distributed generation

I. INTRODUCTION

With the expansion of the power system and the strengthening of interconnection, maintaining the safe and stable operation of large power systems during extreme weather events is becoming increasingly challenging. Blackouts induced by catastrophic events have occurred worldwide in recent years, such as the heatwaves in Pacific Northwest (2021), Hurricane Ian in Florida (2022), and the Turkey-Syria earthquake and California Flooding (2023) [1]. The economic losses due to Hurricane Ida were more than $55 billion in Louisiana alone due to wind and storm surge damage, with an additional $23 billion flooding damage in the Northeastern US [2]. These disasters emphasize the need to strengthen power system resilience, especially given the growing frequency of such extreme weather events due to climate change. However, traditional transmission system planning methods often only consider the long-term cost of projected occurrences and seek to improve system reliability by not incorporating the effect of the high-impact, low-probability (HILP) events that define extreme weather events [3]. To properly integrate the consequences of HILP events, infrastructure resilience planning must be guided by risk rather than just predicted costs. Nevertheless, it necessitates a probabilistic analysis of a wide variety of scenarios with a higher level of uncertainty.

In addition, the planning decisions must be valid throughout the range of unpredictable weather events, drastically increasing the computational complexity. Unlike our previous work [4], which is risk-based planning for distribution system resilience enhancement, this research provides a resilient enhancement planning framework for transmission systems forming a risk-based two-stage stochastic optimization problem. The problem is mixed-integer linear programming (MILP) where the first-stage decisions are infrastructure planning decisions optimized to limit the consequences of HILP occurrences, and stage-2 decisions simulate the operational phase and solve the optimal system response for the resources allocated in the first stage. Hence, we utilize a risk-averse two-stage stochastic optimization framework minimizing the first-stage planning cost and the trade-off cost associated with the expected value of the second stage and $CVaR_{\alpha}$ of the second stage.

$$\min \ c^T \mathbf{x} + (1 - \lambda)\mathbb{E}(Q(\mathbf{x}, \xi)) + \lambda CVaR_{\alpha}(Q(\mathbf{x}, \xi)) \quad (1)$$

where $c^T \mathbf{x}$ is the first stage planning cost such that $\mathbf{x} \in \{x_h, x_d\}$ represents two different planning decisions a) line hardening decision, $x_h$ b) DG siting and sizing decision, $x_d$, $\lambda$ is the risk multiplier or the risk trade-off parameter, and $Q(x, \xi)$ is the second stage cost.

REFERENCES

Secondary Control of Multi-Terminal DC Systems Incorporating Center of DC Voltage and Power Sharing

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Abstract—This paper proposes a secondary control approach for multi-terminal DC (MTDC) systems that utilizes the center of DC voltage as a reference signal. The proposed method extracts the center of DC voltage as a system-global parameter to facilitate secondary control design in MTDC systems. The effectiveness of the proposed algorithm is demonstrated with a 5-terminal MTDC system connected to an offshore wind farm using the PSCAD/EMTDC simulation tool.

Keywords—Center of DC, MTDC, Secondary control, Voltage regulation, Power sharing

I. KEY ALGORITHM AND EQUATIONS

We propose utilizing the center of DC voltage that accounts for the power direction and weights the rated power of each converter, as depicted in Figure 1.

![Fig. 1. Concept of secondary control considering center of DC](image)

The center of DC voltage $V_{COD}$ can be obtained using the converter’s rating as follows:

$$V_{COD,SE} = \frac{\Sigma_{i \in NSE} p_{rated,i} \cdot v_{dc}^i}{\Sigma_{i \in NSE} p_{rated,i}}$$ (1)

$$V_{COD,RE} = \frac{\Sigma_{j \in NRE} p_{rated,j} \cdot v_{dc}^j}{\Sigma_{j \in NRE} p_{rated,j}}$$ (2)

$$V_{COD} = \frac{V_{COD,SE} + V_{COD,RE}}{2}$$ (3)

where $V_{COD,SE}$ and $V_{COD,RE}$ represent the center of DC voltage at the sending and receiving terminals, respectively.

The proposed secondary controller is designed as a supplementary controller to the primary controller.

$$v_i^* = v_i^{ref} + (V_{COD}^* + V_i^{ps}) + \left(\frac{p_{ref,i} - p_{out,i}}{R_i}\right)$$ (4)

$$V_{COD}^* = \alpha \int (v_{cod}^{ref} - V_{COD}) dt$$ (5)

$$V_i^{ps} = \beta_i \int \left(\sum_{j} \left(\frac{p_{out,j}}{R_j} - \frac{p_{ref,j}}{R_j}\right)\right) dt$$ (6)

II. KEY RESULTS

A. System Configuration

The 5-terminal MMC-MTDC system, as shown in Figure 2, was simulated using the PSCAD/EMTDC simulation software to verify the proposed control.

![Fig. 2. 5-terminal MTDC system for simulation studies](image)

B. EMT Simulation Results

Figure 3 shows the variations in DC voltage and power at each terminal under the influence of proposed primary and secondary control strategies.

![Fig. 3. Simulation results during primary and secondary control](image)
Robust Optimization Scheduling of Virtual Power Plants Considering Reserve Service

Abstract—This study proposes a robust optimization modeling to maximize the profits of Virtual Power Plant (VPP) operators by considering the uncertainty of renewable energy output and electricity market prices. VPP operators can participate in the energy and spinning reserve markets by aggregating distributed energy resources, also for this study, VPP operators is assumed to be a price-taker. A robust optimization problem was formulated using two steps. The optimal operation of each distributed energy resources in each scenario is determined by considering a different range of uncertainties through the corresponding robust optimization model.

Keywords—Virtual Power Plant, market price uncertainty, solar power plant uncertainty, robust optimization

I. INTRODUCTION

The composition of power generation facilities has changed rapidly to distributed energy resources such as renewable energy, energy storage system, and distributed generation. VPP means operating various types of distributed energy resources as a single generator using ICT technology. When a VPP operator participates in the wholesale electricity market, uncertainty factors to be considered include uncertainty about the output of renewable energy and uncertainty about the price of the wholesale electricity market. This is because the bidding strategy of operators varies depending on the accuracy of the prediction and is directly related to profits. In this paper, form VPP operator’s point of view, the optimal operation method for maximum profit by participating in the energy market and spinning reserve market was presented. In addition, considering the uncertainty of the amount of renewable energy generation among the resources composed of VPP and the uncertainty of the market price for optimal operation, the robust optimal operation method that can maximize profits even in the worst forecasting situation is presented.

II. ROBUST OPTIMIZATION MODELING

Solar power plants, distributed generation such as microturbines, and energy storage system (ESS) were aggregated and modeled to from VPP. VPP’s revenue can be obtained through hourly bid volumes and prices in the energy and spinning reserve market. The operating cost of VPP considers the start-up cost and fuel cost of distributed generation and the cost of battery abrasion of ESS. In addition, it was formulated as a MILP-based model to solve the problem linearly. Considering the uncertainty of the predicted solar power generation and market price, the robust optimal operation method can solve the problem by dividing it into two steps.

\[
\min \sum_{t=1}^{T} \{R(p_t^i)\}
\]

\[
U_{\lambda pv} = \left\{ \lambda_t^f: \frac{\lambda_t^f - \lambda_t^e}{\lambda_t^e} \leq k_{\lambda}, \frac{|p_{pv,t} - \overline{p}_{pv,t}|}{\overline{p}_{pv,t}} \leq k_{pv} \right\}
\]

In the first step, in order to consider the worst situation, the problem can be solved so that the minimum profit is generated within the uncertainty range for the uncertainty variable, the solar power generation and the market price. At this time, the uncertainty range can be set differently depending on the situation according to the level of the VPP operator’s forecast.

\[
\max \sum_{t=1}^{T} \{R(p_t^i) - C(p_t^i)\}
\]

In the second step, the VPP operator’s profit maximization problem can be solved by treating the uncertainty variable obtained in the first step as a constant. In this way, we can present distributed generation and ESS scheduling that will yield maximum profit for worst-case forecast solar power generation and market prices.

III. EXPERIMENT RESULTS

Scenarios were classified according to the uncertainty range, and the respective VPP bids are as follows. This can suggest various ways to optimally operate resources according to the forecast level from the VPP operator’s point of view.

Fig. 1. Total bids of VPP by Scenarios
Analysis of the Contribution of Thermal Energy Storage to Increasing CHP Flexibility

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Abstract—Climate change has impacted global energy supplies and electricity infrastructure, and in response, the Korean power sector is rapidly increasing the share of renewable energy. However, the Korea’s generation mix plan has a large share of nuclear power plants (NPPs) and combined heat and power (CHP) plants which are inflexible during heat supply mode. In this study, we aim to analyze the economic effect of thermal energy storage (TES) by expanding CHP-system’s flexibility. The unit commitment (UC) simulations are conducted for the real Korean power system. The simulation result shows that the generation cost is saved as the TES capacity increases.

Keywords—Combined Heat and Power, Thermal Energy Storage, Spinning Reserve, Unit Commitment, Renewable Energy, MATLAB Simulation

I. INTRODUCTION

The Korean government plans to increase the annual share of clean energy. The variable renewable energy (VRE) make the net-load pattern possess a duck-curved shape [1], and requires changes in the operating reserve structures [2]. In Korea, the electrical output of CHP is restricted from adjusting below a specified minimum level for stable heat supply. The ever-increasing share of VRE requires a CHP system to expand flexibility. A TES is one of the promising options for expanding the flexibility of CHP systems, and this study aims to analyze the effect of TES on the future power system.

II. SIMULATION

The UC formulation was implemented as a mixed integer programming approach. The optimization code was developed in MATLAB environment. The heat and electrical output of the CHP and the heat charge/discharge of the TES are optimized to meet the heat demand. Simulations were performed on the Korean power system for 2030. Fig. 1 shows the load, net-load, VRE’s output and heat demand for a weekend in winter. Fig. 2 shows the spinning reserve requirements. The method of determining spinning reserve requirement was adopted from [3].

Scenarios are configured at A(50%), B(100%), C(150%), and (200%) of current installed TES capacity (1,467Gcal/h), and the simulation results are shown in Fig. 3 and 4. The increase in TES capacity has led to a reduction in operating costs of power system. During high VRE hours, CHPs were de-committed and TES supplied the heat demand, leading to an increase in the share of generation from nuclear power plants with lower fuel costs.

Fig. 1 Load, VRE, net-load and heat demand in winter 2030

Fig. 2 Hourly spinning reserve requirement in winter 2030

Fig. 3 UC Simulation Results

Fig. 4 The Generation Cost Results

III. CONCLUSION

In this study, we verified the economic effect of TES on power system. For this purpose, we optimized operating costs of power system constrained by heat sector. The TES is capable of providing power system flexibility, resulting in operating cost savings. Based on this simulation study, our future study will be a techno-economic analysis on an electric boiler which can couple power and heat sectors.

ACKNOWLEDGMENT

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Dynamic Ramping of Retrofitted Coal-Fired Power Plants: Basic Formulation and Tightened Approximation

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Abstract—Decarbonization initiatives play a major role in avoiding worldwide climate change effects. One of the effective actions is expected to upgrade existing aged coal-fired plants to retrofitted coal-fired plants by installing pollution reduction technology for emission reduction. Besides this merit, retrofitted coal-fired units can enable faster ramp rates and achieve lower minimal output power levels, which substantially relieves the peak regulation stress. In this paper, we focus on the dynamic ramp rate characteristics and then derive a new family of nonlinear ramping margin formulations of retrofitted coal-fired units. Moreover, we further tighten proposed nonlinear ramping margins to be a set of linear constraints with a minor inner approximation error. Results of case study validate the effectiveness of the proposed dynamic ramping margin formulation for retrofitted coal-fired power units.

Index Terms—Dynamic ramping, retrofitted coal-fired units, ramping margin formulations, power system flexibility.

I. INTRODUCTION

To mitigate climate change, it is essential for a progressive phase-out of some outdated coal-fired power plants, or to upgrade existing aged coal-fired plants as retrofitted coal-fired plants by installing pollution reduction technology. This pollution reduction technology can mainly reduce sulfur dioxide (SO₂) emissions by a scrubber, or a flue gas desulfurization system, etc. For such refined coal-fired power plants, we name as the retrofitted coal-fired power plants.

II. PROPOSED RAMP RATE AND MARGIN FORMULATION

The ramping limit is a linear function of the generating output of the unit. In this regard, the appropriate dynamic ramp rates $v_i^j$ (%/min) at time $t$ can be reasonably treated as a linear function of output generation power of retrofitted coal-fired power plants, which yields

$$v_i^j = \begin{cases} a \cdot r_i^j - b, & r_i^j \leq d \\ c, & r_i^j > d \end{cases}$$

where parameter $c$ is determined by the enhanced ramp rate of retrofitted coal-fired units, while parameters $a$, $b$, and $d$ are estimated from historical ramping data, minimum load level and $d=(c+b)/a$; and $r_i^j$ refers to the percentage of $P_{Gi}/P_{Gi,max}$.

![Diagram of proposed dynamic ramp rates](image)

III. CASE STUDY

To distinguish coal-fired units with different dynamic ramp rates, the proposed dynamic ramp rates and corresponding economic dispatch (ED) solutions are comparable.

![Diagram of ramping boundaries](image)

IV. CONCLUSION

Our proposed linear ramping constraints of retrofitted coal-fired power plants with larger output power boundaries contribute to addressing economic dispatch problems of retrofitted coal-fired plants with lower production costs and better accuracy.
Comprehensive Optimization Model for Siting and Sizing of DG Units and Shunt Capacitors Considering Uncertain Fault Risk

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Abstract—In a distributed system, the installation of distributed generators (DGs) and shunt capacitors (SCs) can improve normal operation conditions and meet load demands during fault situations. This paper proposes a comprehensive optimization model for the siting and sizing of DG units and SCs, considering the normal operation conditions, investment cost, and the risk of uncertain faults. The optimization goal for normal operation conditions is to minimize the bus voltage deviation and power losses. A risk model of uncertain faults is proposed using the conditional value-at-risk method to quantify potential load shedding. Additionally, the Monte Carlo Simulation is applied to generate a vast number of possible fault location and load quantity scenarios. The backward reduction algorithm is then applied to reduce the number of scenarios while achieving a trade-off between accuracy and efficiency. The proposed model is solved via YALMIP and GUROBI, and the case study of the IEEE 33-bus system demonstrates the effectiveness of the proposed model in optimizing normal operation conditions and reducing potential load shedding.

Index Terms—backward reduction, comprehensive optimization model, conditional value-at-risk, scenario generation, siting and sizing.

I. INTRODUCTION

This paper addresses the siting and sizing problem of distributed generators (DGs) and shunt capacitors (SCs) in a distributed system. The problem is formulated as a comprehensive optimization model, in which the normal operation condition, the investment cost of DG units and SC, and the risk of uncertain fault are considered. To quantify the potential shedding load, the conditional value-at-risk (CVaR) method is used to build a risk model of uncertain fault. In addition, the scenario generation and reduction method are also proposed. The contributions are summarized as:

1) A comprehensive optimization model is proposed. Its objective is optimizing the normal operation condition (i.e., bus voltage deviation and power loss), minimizing the investment cost and potential shedding load.

2) A risk model of uncertain fault based on CVaR is built to quantify the potential shedding load caused by a future fault.

3) The scenario generation method based on Monte Carlo Simulation and backward reduction algorithm is proposed to realize the balance between accuracy and efficiency.

II. PROBLEM FORMULATION

The mathematical formulation of the comprehensive optimization model is presented in this section. The objective function is shown as follows.

\[
\min f = y_1 \cdot \left( \sum_{t \in \mathcal{T}} \xi_t \cdot \Delta u + \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{E}} \sum_{j \in \mathcal{N}} p_{\text{loss}_{ij}} \right) \\
+ y_2 \cdot \left( \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{E}} \sum_{j \in \mathcal{N}} \left( a \cdot P_i \cdot b \cdot k_j^2 \right) + \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{E}} \sum_{j \in \mathcal{N}} \left( d \cdot k_j \cdot \text{num}_j + e \cdot k_j^3 \right) \right) \\
+ y_3 \cdot \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{E}} \sum_{j \in \mathcal{N}} \left( \frac{e^{\left[ \text{real}_{ij} \right]} - e^{\left[ \text{off}_{ij} \right]}}{1 - e^{\left[ \text{off}_{ij} \right]}} \right)
\]

(1)

III. CASE STUDIES

The optimal investment strategy for the IEEE 33-bus system involves installing DG units at buses 14, 24, 25, 30, 32, and SC at buses 8, 14, 30, 32. The rated active power of the DG units is 1MW, 0.6MW, 0.5MW, 0.9MW, 0.5MW, and the rated reactive power of SC is 0.4Mvar, 0.25Mvar, 0.5Mvar, 0.3Mvar, respectively. The bus voltage and branch power loss are shown in Fig. 1 and Fig. 2, respectively. Additionally, Fig. 3 illustrates the changes in potential shedding load as the risk-averse parameter varies.

Fig. 1. Bus voltage of IEEE 33-bus system before and after installing the DG units and SC

![Fig. 1. Bus voltage of IEEE 33-bus system before and after installing the DG units and SC](image1)

Fig. 2. Branch power loss of IEEE 33-bus system before and after installing the DG units and SC

![Fig. 2. Branch power loss of IEEE 33-bus system before and after installing the DG units and SC](image2)

Fig. 3. Potential shedding load VS. risk-averse parameter

![Fig. 3. Potential shedding load VS. risk-averse parameter](image3)
A Comparative Study of AI-Based Models for Incipient Fault Classification in Power System

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Abstract—The AI-based classification models have attracted much attention for power engineering study due to their reliable modeling performance. This study employs several AI-based classification models, including Convolutional Neural Network (CNN), Long-Short-Term Memory (LSTM), and Recurrent Neural Network (RNN), to identify and classify incipient faults occurred in several types of power equipment in an extra-high voltage substation. Test results show that the AI-based models outperform the classic machine learning algorithm such as Naïve Bayes (NB) in incipient fault classification.

Keywords—Incipient equipment faults, substation, AI-based model, fault classification

I. OVERVIEW

The identification of incipient faults has presented as a new challenge in power engineering studies. Despite the remarkable advancements in data acquisition techniques, condition monitoring systems still face difficulties in effectively detecting the early-stage equipment failures in a modern substation equipped with a variety of power apparatus. This study proposes a novel strategy for identifying incipient fault components in transmission networks by the integration of advanced time-frequency analysis (TFA) techniques and the AI-based methods. The strategy includes abnormality detection and historical event check which can rapidly screen recorded network disturbance events out from the database. Subsequently, a multi-synchrosqueezing transform (MFSST) is applied to assess the measured voltage and/or current signals and reconstruct the incipient fault component in the time domain. MFSST is an improvement of short-time Fourier transform and it can alleviate the effect of frequency energy dissipations that concentrates those blurry time-frequency ridges. The extracted time-frequency fault components of the voltage or current waveform are then used as inputs to the artificial intelligent model for classifying incipient fault labels and identify the power equipment that causes the incipient fault.

II. STRATEGY OF INCIPIENT FAULT CHARACTERIZATION

A. Incipient Fault Component Extraction

The data in this study are obtained from four power quality monitors located at a transmission-level industrial park in Taiwan. Two types of data are analyzed for extracting fault features, which are the time-frequency matrix and the reconstructed time-domain waveform of the incipient fault, as shown in Fig. 1. Firstly, MFSST is adopted to decompose the normal and abnormal measured signal into a time-frequency matrix, where the influence of phase angle can be neglected. Next, by extracting the abnormal signal assessed by MFSST, the incipient fault component in the time-frequency domain is determined, as shown in Fig. 1(b). Then, the inverse MFSST is performed to reconstruct the detected incipient fault signal in time domain, as shown in Fig. 1(c). Upon examining the results of MFSST, a few unexpected frequency components are collected, such as the 24-Hz low-frequency component in

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Fig. 1(b). Finally, feature extraction techniques are applied in the time-frequency data and time-domain reconstructed waveform since abnormalities may exist in both datasets.

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Fig. 1. Incipient cable fault components assessed by MFSST.

(a) Measured time-domain voltage waveform of the incipient cable fault

(b) Time-frequency ridges representation of the incipient cable fault

(c) Reconstructed incipient cable fault components in time-domain

B. Incipient Fault Classification Using AI-based Models

The performance of incipient fault classification is substantially affected by the training of AI-based models and the relevance of features of the identified fault. To extract prominent features from the time and time-frequency domain data, several methods such as standard deviation, mean, and Shannon entropy are employed. In this study, the AI-based models of CNN, LSTM, and RNN are adopted to classify the incipient faults of the substation power apparatus, including cables, circuit breakers, transformers, arresters, and insulators. Results are then compared with those obtained by the classic machine learning method such as NB.

III. RESULTS AND DISCUSSION

Identifying incipient equipment faults in power systems remains as a challenge for electric utilities. The ongoing approach involves the run-to-failure strategy, relies on engineers’ prior knowledge of non-typical behaviors to act upon failure. To enhance fault diagnosis effectively, this study aims to achieve predictive fault classification based on data analytics. Table I presents the classification accuracies of the AI-based models employed in the study. It is seen that the Naïve Bayes model provides less accuracy in identifying incipient fault labels based on the input features. On the other hand, advanced AI-based models yield more accurate classification results.

---

TABLE I. CLASSIFICATION ACCURACIES OF AI-BASED MODELS

<table>
<thead>
<tr>
<th>Models</th>
<th>NB</th>
<th>CNN</th>
<th>LSTM</th>
<th>RNN</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accuracy</td>
<td>84.4%</td>
<td>96.42%</td>
<td>95.89%</td>
<td>95.89%</td>
</tr>
</tbody>
</table>

---
Coordination of Power and Transportation Networks: An Inverse Optimization Based Pricing Approach

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Abstract—The growing prevalence of electric vehicles (EVs) is enhancing the coupling of power distribution network (PDN) and transportation network (TN). Based on the inverse optimization (IO) approach, this paper proposes a holistic pricing paradigm to manage the power-traffic flows towards the least-cost social optimum state with minimum extra user charges. First, a coordinated operation model is established which assigns the traffic flows and schedules the power generation within the grid operation and EV routing and charging constraints. Second, a novel decentralized bi-level decomposition algorithm is designed to tackle the computational complexities. Third, based on the coordinated operation results, an IO-based minimum charge pricing method is proposed, which minimizes the charging fees, plug-in fees and road tolls for EVs. Finally, real-world urban network-based case studies verify the effectiveness of the model and algorithm and underline the merits and necessity of the pricing method.

Keywords—electric vehicle, power-traffic coordination, inverse optimization, bi-layer decomposition, optimal pricing.

I. KEY CONTRIBUTIONS

We propose a holistic method for coordinating the coupled power distribution and urban transportation networks (CPTNs):

1) An inverse optimization-based pricing model is for the first time proposed for coordinating the EV flows in CPTN. Different from the existing works, the proposed charging and road toll pricing method can minimize extra user charges while aligning the CPTN flows to attain social optimum at the network equilibrium state, and offers a unique approach to include all feasible pricing schemes.

2) To obtain the social optimum state, a holistic CPTN operation model is proposed, which calculates traffic flows and power generation schedules within grid operation and EV routing and charging (R&C) constraints. In the proposed model, the unrealistic assumptions are removed and charging demand is endogenously captured in an accurate manner. The model is proved necessary in reducing the system cost and promoting the renewable generation.

3) A decentralized bi-level decomposition algorithm is proposed to tackle the CPTN computational complexities and preserve the data privacy of power and transportation operators. The effectiveness of the CPTN solution method is validated and visualized for practical case studies.

This work was supported by the Science and Technology Program of SGCC under Grant 5400-202099508A-0-0-0-00.

II. MAIN RESULTS

The numerical simulations on a real-world TN have validated the effectiveness of the proposed model and solution algorithm. As depicted in Fig. 1.a), the outer-layer algorithm converges after 8 iterations. The path generation process of inner-layer for the first outer-layer iteration is depicted in Fig. 1.b). As compared in Table I, the total operation cost for CPTN is 4.2% higher than that of the uncoordinated operation, and the renewable generation output is much less curtailed as shown in Table II. In Table III, the proposed pricing paradigm can significantly reduce the extra user charges while retaining the expected social optimum state.

![Fig. 1. Convergence of the proposed bi-layer decomposition algorithm](image)

**TABLE I - OPERATION COSTS IN DIFFERENT CASES ($)**

<table>
<thead>
<tr>
<th>Cost ($)</th>
<th>Coordinated Operation</th>
<th>Uncoordinated Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transport network operation</td>
<td>13373.12</td>
<td>13980.35</td>
</tr>
<tr>
<td>Power network operation</td>
<td>23175.2</td>
<td>24199.18</td>
</tr>
<tr>
<td>Total operation</td>
<td>36548.3</td>
<td>38179.53</td>
</tr>
</tbody>
</table>

**TABLE II - RENEWABLE POWER GENERATION IN DIFFERENT CASES (MW)**

<table>
<thead>
<tr>
<th>DRG</th>
<th>Coordinated Operation</th>
<th>Uncoordinated Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>$#8$</td>
<td>30.08</td>
<td>25.78</td>
</tr>
<tr>
<td>$#36$</td>
<td>27.4</td>
<td>24.86</td>
</tr>
<tr>
<td>$#50$</td>
<td>26</td>
<td>23.07</td>
</tr>
</tbody>
</table>

**TABLE III - CHARGES IN DIFFERENT CASES ($)**

<table>
<thead>
<tr>
<th>Marginal social cost pricing (traditional)</th>
<th>Minimum charge pricing (proposed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Road tolls</td>
<td>4738.62</td>
</tr>
<tr>
<td>Plug-in fees</td>
<td>6972.20</td>
</tr>
<tr>
<td>Electricity fees</td>
<td>5401.24</td>
</tr>
<tr>
<td>Total charge</td>
<td>17112.05</td>
</tr>
</tbody>
</table>
Learning to Optimize Distributed Optimization: ADMM-based DC-OPF Case Study

Meiyi Li, Soheil Kolouri, Javad Mohammadi

Abstract—The decision-making paradigms of future energy systems are increasingly becoming decentralized and multi-entity/agent. The Alternating Direction Method of Multipliers (ADMM) has been widely used to address the computational needs of decentralized decision-making problems, e.g., optimal power flow (OPF). In this paper, we propose a novel data-driven method to accelerate the convergence of ADMM for decentralized DC-OPF, where our optimizer will learn the iterative behavior of agents to produce a high-quality feasible solution. The proposed method utilizes the gauge maps to enforce feasibility with respect to agents’ local constraints while iteratively penalizing violations of the shared constraints. We used the IEEE 57-bus system to showcase the performance of the proposed method. Our experimental results demonstrate significant run-time reduction to showcase the performance of the proposed method. Our approach does not require post-processing steps to improve system-level constraints. Unlike restoration-based methods, our approach provides a near-optimal solution and satisfies node-level and system-level constraints. Further, we will design each agent to predict the convergence value of local variables by communicating with neighbors. All agents collaborate to accelerate the convergence of ADMM for solving the DC-OPF problem. In our multi-agent setup, each agent may control its local constraints, i.e., \( \xi \), \( u_{\text{other}} \), \( \lambda \). We will keep the ADMM iterations to improve the feasibility of coupled constraints. We reformulate the problem to a problem whose variables are \( x^{\hat{u}} \) through gauge mapping and reconstruction. Then we relax the reformulated problem to a problem whose variables are \( u^{\hat{u}} \) according to local equality constraints. We reformulate the problem to a reduced-size problem only relying on \( u_{\text{local}}^{\hat{u}} \). Then we relax the reformulated problem to a problem whose variables are \( u_{\text{local}}^{\hat{u}} \) with only upper and lower bounds. Finally, we learn the optimal solution \( u_{\text{local}}^{\hat{u}} \) through gauge mapping and reconstruction. We will use the IEEE 57-bus system to showcase the performance of the proposed method. Our experimental results demonstrate significant run-time reduction to showcase the performance of the proposed method. Our approach does not require post-processing steps to improve system-level constraints. Unlike restoration-based methods, our approach provides a near-optimal solution and satisfies node-level and system-level constraints.

I. INTRODUCTION

In this paper, we propose a learning-based method to accelerate the convergence of ADMM for solving the DC-OPF problem. In our multi-agent setup, each agent may control one or a collection of nodes. The proposed method allows each agent to predict the convergence value of local variables by communicating with neighbors. All agents collaborate to provide a near-optimal solution and satisfy node-level and system-level constraints. Unlike restoration-based methods, our approach does not require post-processing steps to improve feasibility because local constraints are enforced by design through a gauge mapping method, and coupled constraints are penalized by ADMM iterations.

II. LEARNING-ACCELERATED ADMM

Pseudo code of the proposed learning method for ADMM is given in Algorithm 1. The proposed method includes three steps for each iteration. First, each agent uses its neural approximator to predict the local optimal solution. Second, agents share the updated coupled variables with neighboring agents. Finally, Lagrangian multipliers will be updated.

We will keep the ADMM iterations to improve the feasibility of coupled constraints. Further, we will design each neural network’s structure to guarantee its output satisfies the local constraints, i.e., \( \xi \), \( u_{\text{other}} \), \( \lambda \). Therefore, we adopt the \( \mathcal{LOOP} - \mathcal{LC} \) model proposed in [1] for each neural network \( \xi \). The \( \mathcal{LOOP} - \mathcal{LC} \) model learns to solve optimization problems with hard linear constraints. By applying variable elimination and gauge mapping, the \( \mathcal{LOOP} - \mathcal{LC} \) model could produce a feasible and near-optimal solution. The application of the \( \mathcal{LOOP} - \mathcal{LC} \) model to the proposed method (as shown in Fig. 1) is explained below:

Algorithm 1 Proposed learning method for ADMM

Input: DCOPF ADMM problem parameters, e.g., \( N \) neural network \( \xi \); Initial value of \( u^{i} \), \( i \in N \), \( \lambda \).

Output: Distributed solution \( u^{i+1} \) to DC-OPF.

while Convergence criteria unmet do
for \( i \in N \) do
Generate a prediction \( u^{i+1} = \xi(x^{i}, u_{\text{other}}^{i}, \lambda^{i}) \)
Receive \( u_{\text{other}}^{i+1} \) from all neighboring agents
Update Lagrangian multipliers \( \lambda^{i+1} \)
\( k = k + 1 \)
end for
end while


Fig. 1. We adopt the \( \mathcal{LOOP} - \mathcal{LC} \) model proposed in [1] for each neural network \( \xi \), \( i \in N \). First, we divide the variables into two parts where dependent variables \( u_{\text{local}}^{i} \) are determined by independent variables \( u_{\text{local}}^{i} \) according to local equality constraints. We reformulate the problem to a reduced-size problem only relying on \( u_{\text{local}}^{i} \). Then we relax the reformulated problem to a problem whose variables are \( u_{\text{local}}^{i} \) with only upper and lower bounds. Then, use neural network to predict the optimal solution \( u_{\text{local}}^{i} \). Finally, we will obtain a \( u^{\star} \in S_{\text{local}}^{i} \) through gauge mapping and reconstruction.

Real-time pricing and dispatch of virtual power plants using a DDPG-based approach with data-driven behavior estimation

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Abstract—Leveraging the flexibility of customers is an appealing way to tackle the flexibility deficiency confronted by the virtual power plant (VPPO) in real-time energy management (RTEM), which drives the need to utilize demand response (DR) approaches to instruct customer consumption modification. By imposing high-resolution dynamic price signals, real-time pricing (RTP) can manage customers according to the actual operating conditions and wholesale market rates. However, undesirable consumption adjustments of customers under a given price may adversely affect the system operation, which necessitates the integration of precise customer behavior models into RTEM when determining the imposed price. Therefore, we design an RTEM framework, in which customer behavior is accurately anticipated based on a Gaussian mixture model (GMM). To deal with the computation difficulty of embedding the nonlinear and nonconvex GMM into a model-based RTEM scheme, a deep reinforcement learning (DRL) scheme is implemented to realize RTEM. Since DRL has no requirement for convexity, the GMM can be integrated into the RTEM process by interacting with the DRL agent as the environment, which is computationally efficient to deploy in real-time. Meanwhile, as several decision variables in RTEM are continuous in physical nature, a deep deterministic policy gradient (DDPG) algorithm with continuous action space is applied to avoid deviation of real-time decisions. Numerical studies demonstrate that GMM exhibits superior performance in behavior modeling and the DDPG algorithm obtains higher utility compared with four deep Q-learning-based algorithms.

Keywords—Real-time energy management; Virtual power plant; Real-time pricing, Deep deterministic policy gradient

I. THE DDPG-BASED RTEM FRAMEWORK

The proposed RTEM framework is illustrated in Fig. 1. The RTEM problem studied is an economical dispatch (ED) problem, which emphasizes computationally efficient to make decisions with optimality guarantees. And the RTP is applied to motivate customers’ consumption modification. As a prerequisite for accurate determination of RTP, a GMM is proposed to precisely capture the complex customer behavior under a given price. Treated as the environment of the proposed DRL framework, the edge controller can estimate the response of elastic load under the imposed RTP given by VPPO, and passes the corresponding reward to the DRL agent.

Besides, the DRL agent is deployed in the VPPO to tackle the RTEM problem. Given the state which consists of the estimated fixed load, the wholesale market price, and the baseline load of the elastic load, the agent makes RTEM decisions, including the output of self-owned distributed generators and the RTP imposed to customers.

Since in terms of physical nature, several decision variables of RTEM are continuous, DDPG is applied to avoid decision deviation caused by action space approximation. And, as the main computational cost of the proposed framework lies in the offline training stage, and the trained agent can make online decisions, the proposed framework is computationally efficient to deploy in real-time decision-making.

![Fig. 1. The illustration of the DDPG-based RTEM framework.](image)

A. Customer behavior estimation comparison

The comparison of the Wasserstein distance shows that the GMM can capture the real behavior of elastic loads better than the compared analytical model.

<table>
<thead>
<tr>
<th>TABLE I. THE WASSERSTEIN DISTANCE COMPARISON</th>
</tr>
</thead>
<tbody>
<tr>
<td>The proposed GMM method</td>
</tr>
<tr>
<td>0.93</td>
</tr>
</tbody>
</table>

B. Utility differences of different DRL approaches

The skewed-left histograms shown in Fig. 2 indicate the DDPG-based approach can achieve higher utility for VPPO than four other value-based DRL approaches.

![Fig. 2. The VPPO’s utility differences between the proposed method and other four DRL methods.](image)
Peer-to-Peer Trading Platform Incorporating Demand Response Paradigm Using an Iterative Two-Stage ADMM Approach

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2 Power and Energy Systems, Idaho National Laboratory, Idaho Falls, ID, USA
3 Department of Electrical Engineering, Université de Technologie de Compiègne, Compiègne, France.

Abstract—Transactive energy frameworks optimally schedule the energy pattern of the participants to improve the social welfare of the market. Peer-to-peer (P2P) trading platforms model the interactions between the different market players to develop a competitive deregulated structure. Demand Response (DR) is another conventional optimization problem which aims to optimally decide the consumption pattern of the customers to reduce the cost of the electricity and peak demand on the system. In this work, we present a two-stage optimization framework to combine the P2P and DR problems in the form of an iterative fashion using the ADMM and Mixed Integer Linear Programming (MILP). The first stage optimizes the DR framework based on the utility and P2P price while using the MILP to find the optimal schedule of the participants. The second stage optimizes the P2P market based on the demand schedule of the first stage using the ADMM optimization.

Index Terms—ADMM, MILP, P2P trading, demand response

I. INTRODUCTION

Transactive energy frameworks refer to an intelligent energy utilization platform to enhance the welfare of the participants while ensuring the system’s stability. P2P refers to an autonomous trading mechanism between the participants having excess renewable power (Photovoltaic (PV) energy, battery energy storage system, and wind energy system) termed as prosumers and the consumers situated in the same physical network. DR is another well known optimization framework where customers adjust their schedulable assets based on the market price [1].

II. METHODOLOGY AND RESULTS

The suggested framework consists of a two-stage optimization. In the first stage the participants adjust their demand schedule based on the utility and the average P2P price. This research uses the MILP to solve the mixed integer linear programming. The second stage uses the ADMM approach to find the optimal P2P price based on the DR schedule of the participants. Figure 1 shows the flow chart for the proposed iterative two stage optimization.

Fig. 1. Proposed iterative two stage optimization for P2P-DR framework using MILP and ADMM.

III. CONCLUSIONS

This research proposes an iterative two stage optimization framework for combining the P2P and DR optimization problems using MILP and ADMM approach. First stage involves optimizing DR problem based on the second stage optimal decision variables. Similarly, P2P stage optimizes the price vector based on the optimal DR schedule computed in the first stage.

Fig. 2. Convergence of objective functions for prosumers and customers.

REFERENCES
Laxity-Aware Scalable Reinforcement Learning for Building HVAC Control

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Abstract—This paper presents a novel method for exploiting the demand flexibility of flexible loads to reduce electricity costs and contribute to grid operations. We define the concept laxity to measure the flexibility of HVAC systems and provide a control strategy for a group of HVAC systems. The proposed framework uses aggregated flexibility and electricity price information to schedule the total power rate, and the constraints augmented least-laxity-first (LLF) rule to recover individual HVAC power rates from the total power rate. The experimental results demonstrate that the proposed method achieved better temperature control and electricity cost savings compared to baseline methods.

Index Terms—HVAC systems, flexibility, power grid, reinforcement learning

I. INTRODUCTION

In recent years, the increasing penetration of renewable energy sources and growing electricity demand have posed significant challenges for power grid operations [1]. To address these challenges, one promising solution is exploiting the demand flexibility in controllable loads, such as HVAC systems in residential buildings [2]. This approach can help reduce electricity costs and contribute to grid operations. Recent studies have proposed the concept of flexibility envelope for quantifying the flexibility potential of residential buildings [3], but lack an efficient control method for operating HVACs.

In this context, we first define the laxity of each HVAC operation request to measure the time-specific HVAC flexibility. The system operator then aggregates the laxity information and reports it to the controller. The reinforcement learning (RL) based controller only uses the aggregated laxity and electricity price information to schedule the total power rate of the HVAC systems. Finally, the aggregator employs the constraint-augmented LLF rule to recover individual HVAC power rates from the total power rate.

II. CASE STUDY

To evaluate the effectiveness of our proposed method (Proposed), we conducted experiments using real-world weather and electricity price dataset. We test our method on an aggregation of 10 HVAC systems for 96 time steps, and compare its performance in terms of total energy consumption and temperature control with baseline methods: model predictive control (MPC) and a centralized RL-based (centralized RL) control method.

Figure 2 illustrates the total power rate for each time step. Note that MPC is a model-based method, both Proposed and centralized RL are model-free. Our proposed method closely follows the power rate schedule of MPC, tending to avoid energy consumption during times of high electricity prices. Figure 3 shows the temperature for the 10 residential buildings. The results clearly demonstrate that with Proposed, the temperature is maintained much closer to the target temperature with a lower standard deviation.

Fig. 2. Total power rate.

Fig. 3. The red line shows average temperature and standard deviation, and the blue line is target temperature with (a) Proposed and (b) centralized RL.

REFERENCES

Forced Oscillation Localization using PMU Data based on Recovered Dynamic Responses

Shaohui Liu, Student Member, IEEE, Hao Zhu, Senior Member, IEEE, and Vassilis Kekatos, Senior Member, IEEE

Abstract—Wide-area dynamic studies are of paramount importance to ensure the stability and reliability of power grids. In this work, we propose a comprehensive data-driven framework for inferring the forced oscillation sources using synchrophasor measurements. To achieve this goal, we first recover dynamic responses in the small-signal regime using fast-rate ambient data collected during normal grid operations. The oscillation source is recovered on the oscillation mode in frequency domain by fitting a least square problem. The result has been established via model-based analysis of linearized second-order swing dynamics under relaxed conditions. Numerical validations demonstrate its applicability to realistic power system models including nonlinear, higher-order dynamics with control effects using the IEEE 68-bus system.

Index Terms—Power system dynamic modeling, forced oscillations, synchrophasor measurements.

I. PROPOSED METHODOLOGY

We consider the small-signal analysis of dynamic responses using the classical second-order generator model [1, Ch. 9]. The state only includes the rotor angle and speed (frequency) vectors, \( \delta, \omega \in \mathbb{R}^N \) for a total of \( N \) generators. The second-order model could also be viewed as a simplified, reduced model representation under higher-order dynamics due to governor and excitation controls [1, Ch. 12]. The linearized model follows the swing equation as

\[
\begin{align*}
\dot{\delta} &= \omega \\
M \ddot{\omega} &= -K \delta - D \omega + u
\end{align*}
\]

(1)

Note that the linearized model is a linear time-invariant (LTI) system, and the system’s dynamic response to a power deviation input \( u \) is fully characterized through the impulse response. Assume the system is lossless, and with homogeneous damping. Additionally, the normal operation condition satisfies ambient assumptions, as proposed in [3]. With disturbance input at \( k \)-th generator, the impulse response of \( \ell \)-th generator rotor frequency \( T_{u_k,\omega_\ell}(\tau) \) can be recovered by the cross-correlation of the ambient measurements in angle \( \delta \), and frequency \( \dot{\omega} \) at the input/output location pair of interests:

\[
T_{u_k,\omega_\ell}(\tau) = -\frac{2\gamma}{\alpha} C_{\omega_k,\omega_\ell}(\tau) = -\frac{2\gamma}{\alpha} \frac{d^2}{d\tau^2} C_{\delta_k,\delta_\ell}(\tau).
\]

(2)

Under the oscillation condition, the oscillation input at \( j \)-th location could be modeled as a sinusoidal function \( u_j \triangleq A_j \cdot \cos(\omega_f \cdot t + \phi_f) \). Note that in frequency domain the system response equals the multiplication of input function and impulse response. Thus, the oscillation source localization problems could be modeled as a least-square-based optimization problem

\[
\arg \min_{1 \leq \ell \leq N} \min_{F(u_j) \in \mathbb{C}} \| F(u_j) \cdot F(T_{u_j,\omega_k})(\xi^*) - F(\dot{\omega})(\xi^*) \|^2_2
\]

where \( \xi^* = \arg \max_{\xi} \| F(\delta)(\xi) \|^2_2 \)

(3)

by fitting the unknown parameters \( \{\omega_f, A_f, \phi_f\} \) using estimated impulse response \( T_{u_j,\omega_k}(\tau) \). Note that an efficient localization algorithm can be defined by the closed-form solution of 3.

II. KEY RESULT

The proposed localization algorithm was tested on the IEEE 68-bus with 16 generators. The simulated data was generated by PST in Matlab [2]. Fig. 1 shows the effectiveness of estimating frequency response using ambient measurements. Table I shows the effectiveness of the proposed oscillation localization algorithm using estimated frequency response.

<table>
<thead>
<tr>
<th>frequency</th>
<th>no ambient</th>
<th>w/ ambient</th>
<th>frequency</th>
<th>no ambient</th>
<th>w/ ambient</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.14Hz</td>
<td>100%</td>
<td>100%</td>
<td>0.57Hz</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>0.43Hz</td>
<td>93.8%</td>
<td>87.5%</td>
<td>0.71Hz</td>
<td>100%</td>
<td>93.8%</td>
</tr>
</tbody>
</table>

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Fig. 1. Frequency response estimation assuming disturbance at generator 1.

REFERENCES

Advisory Tool for Managing Failure Cascades in Systems with Wind Power

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Abstract—Integration of the less predictable wind power elevates the risk of congestion-induced failure cascades. Due to wind power’s high variability and failures’ fast propagation, we must understand the cascade patterns and their relations to sudden wind reduction to advice operators during such extreme events.

This paper concerns the resilience of systems with wind power upon wind reduction by evaluating the potential of corrective actions, such as generation and load dispatch, on minimizing the effects of transmission line failures. We propose a Markovian model to predict cascade failures with a 10-fold reduction in computation cost of flow equations. Three functions (grid, consumer-centric loss, and resilience impact) are used to statistically evaluate the criticality of initial contingent failures and wind reductions. Our model is learned with Monte Carlo, convex optimization, and adaptive selection, illustrated on the IEEE-30 and IEEE-300 bus systems with both DC and AC models. We highlight the impact of wind reductions and propose physically implementable solutions. Our model may be used in on-line operations for congestion management.

Index Terms—wind power, cascade failure, influence model

I. METHODOLOGY: THE INFLUENCE MODEL

The influence model (IM) is a Markovian model that, given the network profile at each time step, computes the link failure and load shed probability at all links and buses. The probabilities and weights are derived from statistical information from simulated scenarios. We experiment on three corrective actions: no action (exp 1), generation re-dispatch for full service (exp 2), and generation re-dispatch subject to load shed cost minimization — called smart scheduling (exp 3). Fig. 1 and Fig. 2 illustrate the setup and Fig. 3 illustrates the intuition behind the Influence Model. The influence factors \(d_{ji}\) and \(e_{ji}\) in Fig. 3 are obtained through convex optimization.

Fig. 1: Labeling of buses, 1, 2, 3, 4, . . . and transmission lines, \(l_1, l_2, l_3, . . .\).

Fig. 2: Increase in the net system load due to wind reduction featured in simulations. Wind Reduction.

II. KEY RESULTS

A. Model efficiency and structural patterns

The Influence Model predicts link failure and load shed with a 10-fold time reduction and > 90% accuracy for most cases. The trained model revealed system-wide structural patterns. We identified critical links that have high levels of influence on many other links or buses (i.e. high \(d_{ji}\) or \(e_{ji}\) value).

B. Corrective actions for loss minimization

Smart scheduling is highly effective in preserving links and minimizing load shed during a cascade. It reduces the cost of load shed by as much as 90%, while completely avoiding link failures in the IEEE-300 system, as shown in Fig. 6.

C. Applicability as an on-line advisory tool

Operators may use the IM to understand the criticality of links and contingency scenarios and predict losses. The IM also helps them to assess the impact of sudden wind reduction when there is a pre-existing link failure and quickly identify the most effective action to minimize losses during a cascade. Fig. 6 illustrates the resilience impact of various actions under DC and AC models.

Fig. 3: State of the transmission line \(l_i\) and the load at bus \(i\) are determined by the state of all lines, \(l_1, l_2, . . .\), in the network. \(l_i = 1\) denotes that the link is alive, 0 otherwise. The influence from link \(j\) to link \(i\) and the influence form link \(j\) to bus \(i\) is weighted by the pairwise influence \(d_{ji}\) and \(e_{ji}\), respectively.

Fig. 4: Grid-Centric Loss.

Fig. 5: Consumer-Centric Loss.

Fig. 6: Resilience impact under 3 corrective strategies for DC and AC models.

We thank MIT UROP, MITEI, and the Advanced Research Projects Agency-Energy, US Department of Energy (DE-AR0001277) for support.
Model Predictive Control Based Voltage Regulation Strategy Using Wind Farm as Black-Start Source

Weipeng Liu, Member, IEEE, Yutian Liu, Senior Member, IEEE, and Lei Wu, Fellow, IEEE

Abstract—A coordinated voltage regulation method based on model predictive control (MPC) is proposed in this paper for utilizing wind farms (WF) as black-start (BS) source to start up a thermal generating unit. The reactive power regulation devices with different dynamic response characteristics including wind turbine generators (WTGs), energy storage system (ESS), and static var generator (SVG) are coordinated by the proposed MPC to handle disturbances caused by ancillary machine start during the BS process. The reactive power sharing between WTGs is optimized to maximize the dynamic reactive power reserve. The capabilities of ESS and SVG in providing sufficient dynamic reactive power against disturbances are also fully exploited, which helps accelerate voltage recovery after disturbances. The impact of active power on bus voltage variation due to low \(X/R\) ratio is also considered. The reactive power and active power of WTGs and ESS are coordinately controlled for handling voltage disturbances without harming frequency control.

Index Terms—Black-start, energy storage system, model predictive control, voltage regulation, wind power generation.

I. CONTROL FRAMEWORK TO ENABLE WIND FARMS AS BLACK-START SOURCES

The system using a WF, together with an ESS and a SVG, as BS source is shown in Fig. 1. Using WF as BS source is actually to form an isolated grid by ESS and WTGs. ESS needs to have grid support capability to generate frequency and voltage reference. In this paper, ESS and WTGs are operated in master-slave mode. ESS is served as master to generate reference frequency and voltage for WTGs to follow. Starting up ancillary machines will cause voltage and frequency disturbances simultaneously.

The control framework of using WF as a BS source is shown in Fig. 2. The \(f\)-control optimally dispatches the active power references for the ESS \(P_{ref}^{ESS}\) and individual WTGs \(P_{ref}^{WT}\), which are proportional to the available active power of individual WTGs. When ancillary machine start begins, the bus voltages will drop. The \(V\)-control can detect the voltage disturbances by measuring the bus voltages in real time. At each sampling instant, the measured bus voltages are used to update the voltage sensitivity coefficients and the prediction model for improving their accuracy. The optimal reactive power references for individual WTGs \(Q_{ref}^{WT}\), SVG \(Q_{ref}^{SVG}\), and ESS \(Q_{ref}^{ESS}\) are derived from the \(V\)-control with minimized voltage deviations. The impact of active power on voltage variation is considered in this paper. The active power references for individual WTGs \(P_{ref}^{WT}\) are also adjusted by \(\Delta P_{WT}\) to achieve precise control performance.

Fig. 1 System structure using WF as BS source

Fig. 2 Control framework of using WF as BS source

II. OPTIMIZATION DESIGN

The coordinated voltage control for enabling WF to provide BS capability includes two control modes according to whether the voltage constraints of PCC bus and terminal buses of WTGs are violated: (i) Normal control mode: In this mode, voltages of all buses in WF are within their limits. The objective is to minimize the voltage deviation and maximize the dynamic reactive power reserve of ESS and SVG for handling potential disturbances. The active and reactive power outputs of WTGs are controlled together, and the influence of WTG active power output is estimated by voltage sensitivity coefficient \(\partial V/\partial P\). (ii) Corrective control mode: As starting up an ancillary machine will cause voltage drop, this mode is activated when the bus voltage limits are violated. The main objective is to correct bus voltages and meet the LVRT requirements by dynamic reactive power supports of ESS and SVG. The capabilities of WTGs and ESS in simultaneously providing reactive and active power are fully exploited by considering their converter capacity limits.
Annual Benefit Analysis of Integrating the Seasonal Hydrogen Storage into the Renewable Power Grids

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Abstract—There has been growing interest in integrating hydrogen storage into power grids with high renewable penetration levels. In this paper, an annual scheduling model (ASM) for energy hubs (EH) coupled power grids is proposed to investigate the annual benefits of seasonal hydrogen storage (SHS). Each energy hub consists of hydrogen storage, electrolyzers, and fuel cells. The electrical and hydrogen energy can be exchanged on the bus with the energy hub. The physical constraints for both grids and EHs are enforced in ASM. The proposed ASM considers the intra-season daily operation of the EH coupled grids. Four typical daily profiles are used in ASM to represent the grid conditions in four seasons. Both the intra-season and cross-season hydrogen exchange and storage are modeled in the ASM. Hence, the utilization of hydrogen storage is optimized on a year-round level. Numerical results indicate that seasonal hydrogen storage can effectively save the annual operation cost and reduce renewable curtailments.

Index Terms—Electricity and hydrogen coordination, Energy hub, Power System Annual Scheduling, Seasonal Hydrogen Storage

I. ASM OF EH COUPLED GRIDS

The objective of the annual operation is to minimize the total operation cost including generator operational cost, startup cost, and no-load cost. To consider the short time period electrical-hydrogen exchange operations, the ASM uses four typical days to describe the daily operations in four quarters. Specifically, we assume the renewable generation and load profiles are the same for all days in a quarter. The daily operation constraints such as generator maximum and minimum power limits, ramping, reserve, transmission line power limits, and power balance equations are included.

The fuel cells and electrolyzers maximum power capacity, and hydrogen storage capacity are also considered in the model. To consider the seasonal electrical-hydrogen exchange operation, the stored hydrogen at different quarters is modeled.

$$E_{\text{eqtd}} = E_{\text{eqd}}^0 + \sum_{t \in T} \left( \sum_{e \in E(n)} \eta_e P_{eqt} - \sum_{f \in F(n)} P_{fq}/\eta_f \right) \ast (d - 1) + \sum_{t \in T} \left( \sum_{e \in E(n)} \eta_e P_{eqtr} - \sum_{f \in F(n)} P_{fq}/\eta_f \right) \forall g, q, t, d$$  \hspace{1cm} (1)

II. CASE STUDIES

The hourly conventional generation at 20% wind penetration level for 4 typical days is shown in Figs. 1.

Fig. 1. The Conventional Generation in different Quarters.

The simulation results for EH-ASM are compared with annual scheduling model without hydrogen integration (T-ASM) and shown in Tables I and II.

Table I. EH-ASM Simulation Result at 50% Wind Penetration Level

<table>
<thead>
<tr>
<th>Quarters</th>
<th>Wind Curtailment (MWh)</th>
<th>Conventional Generation (MWh)</th>
<th>Average Power Flow Percentage (%)</th>
<th>Total Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarter 1</td>
<td>2.13*10^5</td>
<td>2.68*10^6</td>
<td>38.2%</td>
<td>193.59M</td>
</tr>
<tr>
<td>Quarter 2</td>
<td>5.27*10^5</td>
<td>3.01*10^6</td>
<td>41.5%</td>
<td></td>
</tr>
<tr>
<td>Quarter 3</td>
<td>5.27*10^5</td>
<td>4.14*10^6</td>
<td>41.3%</td>
<td></td>
</tr>
<tr>
<td>Quarter 4</td>
<td>7.15*10^5</td>
<td>2.52*10^6</td>
<td>39.6%</td>
<td></td>
</tr>
</tbody>
</table>

Table II. T-ASM Simulation Result at 50% Wind Penetration Level

<table>
<thead>
<tr>
<th>Quarters</th>
<th>Wind Curtailment (MWh)</th>
<th>Conventional Generation (MWh)</th>
<th>Average Power Flow Percentage (%)</th>
<th>Total Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarter 1</td>
<td>2.17*10^5</td>
<td>2.80*10^6</td>
<td>37.6%</td>
<td>211.61M</td>
</tr>
<tr>
<td>Quarter 2</td>
<td>5.49*10^5</td>
<td>3.09*10^6</td>
<td>40.0%</td>
<td></td>
</tr>
<tr>
<td>Quarter 3</td>
<td>7.33*10^5</td>
<td>4.27*10^6</td>
<td>40.8%</td>
<td></td>
</tr>
<tr>
<td>Quarter 4</td>
<td>3.01*10^5</td>
<td>2.80*10^6</td>
<td>39.9%</td>
<td></td>
</tr>
</tbody>
</table>
Peer-to-Peer Joint Electricity and Carbon Trading with Carbon-aware Distribution Locational Marginal Pricing

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2Wanger Institute for Sustainable Energy Research, Illinois Institute of Technology, Chicago, 60616, USA

Abstract—This paper proposes a novel Peer-to-Peer (P2P) joint electricity and carbon (E&C) trading model to co-optimize the energy and carbon emissions permit transactions considering the trading preferences in the distribution network. To realize the secure and low-carbon network operation, a decomposable carbon-aware distribution locational marginal pricing (CDLMP)-based operation service pricing scheme of the distribution system operator (DSO) is proposed to guide the P2P transactions among prosumers. In practice, the coordination between the P2P market and the DSO is cast as a bi-level Nash-Stackelberg game. Case studies illustrate the effectiveness of the proposed method in motivating "grid-friendly" and "low-carbon" P2P trading.

I. INTRODUCTION

As the distribution network continues to integrate more distributed energy resources, carbon trading has emerged as a promising solution to promote local decarbonization and accommodate these resources [1]. Given that user-sides are a major contributor to emissions within the energy supply chain, it is imperative to develop a distribution electricity and carbon (E&C) market that incentivizes user participation in the transition to a low-carbon energy system [2].

To facilitate more efficient and sustainable peer-centric E&C trading in today’s distribution systems, this paper addresses two critical issues: (1) Coordinating the peer-to-peer (P2P) joint E&C trading while promoting user-side participation (2) Developing an economic incentive scheme for the DSO to encourage "grid-friendly" and "low-carbon" P2P transactions that respect network operation constraints.

II. P2P JOINT E&C MARKET FRAMEWORK

Fig.1 shows the framework of the proposed bi-level market-clearing scheme for P2P joint E&C trading and DSO operation services. The upper-level problem is a DSO’s operation service pricing model based on the carbon-oriented optimal power flow (COPF) model. The COPF model ensures network security and incorporates a carbon emission flow routine to track the emission distribution across the P2P transactions, as shown in Fig.2. The DSO is viewed as an operation service provider and provides operation service prices (i.e., the network usage charge $\lambda^{\text{NUC}}$ and the nodal carbon tax price $\lambda^{\text{CTP}}$) to guide P2P trading based on carbon-aware distribution locational marginal prices (CDLMP). Then, the updated network carbon intensity $\rho$ and the excess carbon emissions settlements $R$ are sent to the lower level P2P market. If the P2P transactions violate the constraints of the distribution network, the DSO will advise the relative agents to make trading adjustments $\Delta P$ in the next iteration.

In the lower level, the P2P joint E&C trading is executed in a fully distributed manner. The equilibrium of the P2P joint market is reached based on the l(p)-box ADMM protocol. Once the P2P market is settled, the trading results will be sent to the DSO to optimize the operation service in the distribution system. The iterative process between the upper level and the lower level repeats until the coordinated clearing has converged.

III. CASE STUDY

Our proposed P2P joint E&C trading scheme is verified on a modified IEEE 33-bus system in 24 hours. Table I demonstrates that the proposed mechanism (P2P_E&C) outperforms others in enhancing social welfare and reducing carbon emissions. These include the traditional electricity trading without a carbon trading (Tra_E) and the sequential electricity trading before a carbon trading (Seq_E_C).

<table>
<thead>
<tr>
<th>TABLE I</th>
<th>COMPARISON OF DIFFERENT MARKETS’ CLEARING OUTCOMES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market mechanism</td>
<td>Tra_E</td>
</tr>
<tr>
<td>Total social welfare [$$]</td>
<td>70.74</td>
</tr>
<tr>
<td>Total traded carbon emission permits [tCO2]</td>
<td>\</td>
</tr>
<tr>
<td>Total excess carbon emission [tCO2]</td>
<td>1.06</td>
</tr>
<tr>
<td>Total Cost of nodal carbon tax [$$]</td>
<td>14.32</td>
</tr>
<tr>
<td>Total network usage charge [$$]</td>
<td>8.48</td>
</tr>
</tbody>
</table>

REFERENCES


A Novel Probabilistic Solar Generation Forecast Model Based on Copula Theory

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Abstract—Traditional probabilistic solar power forecast models, such as models based on the persistence ensemble, are often unreliable in extreme weather conditions. Hence, their inaccurate forecasts threaten the reliability of the power grids when consistent and precise forecasts are needed. Using copula theory, this work proposes a novel probabilistic solar irradiance forecast model that takes into account the correlation of meteorological variables, which is rarely dynamically investigated when generating probabilistic forecasts. Meteorological data that share similar characteristics are grouped according to weather scenarios. The copula theory is implemented to estimate multivariate joint distributions between meteorological variables for distinct weather scenarios, from which an uncertainty dataset for meteorological data is generated. The data is used for forecast using machine learning-based algorithms. Case studies with real-world data have shown that the developed model significantly increases the accuracy of forecasts in extreme weather conditions compared to the benchmark in the literature.

Index Terms—Copula theory, data analytics, data correlation, probabilistic solar generation forecast

I. INTRODUCTION

The increase in the integration of solar-powered generation is anticipated to lead to substantial changes in power grids, necessitating improved operational and planning procedures. An accurate solar generation forecast is seen as a vital step in these operational enhancements and is especially critical for maintaining the real-time load and generation balance. The use of Copula theory to assess the temporal and spatial correlation between different meteorological features represents a novel method for accounting for uncertainty in weather forecasting [1]. However, such models are often unreliable in extreme weather conditions, as the data correlation is never dynamically modeled based on weather conditions.

This work fully addressed this problem by dynamically modeling the temporal correlations of different variables based on meteorological circumstances, thus improving the adaptability of the developed predictive model to rapidly changing weather conditions. Compared to traditional approaches, the developed method generates more accurate forecasts with smaller prediction intervals. Case studies with real-world data have proven that solar irradiance is accurately predicted with the developed model in all weather conditions, and the developed model increases the accuracy of forecasts by 70%, compared to the benchmark method of the persistence ensemble.

II. CASE STUDIES

The developed model was tested during the 2022 American-Made Solar Forecasting Competition, which was sponsored by the US Department of Energy. Day-ahead solar irradiance forecasts were generated for diverse locations across the U.S. over the period of four weeks. Figure 1 illustrates an example of the forecasts that were generated with the developed method. These results demonstrate the effectiveness of the developed model in accurately forecasting solar irradiance for different locations and in various weather conditions.

![Real world solar irradiance forecasts for a location in Mississippi.](image1)

![Real world solar irradiance forecasts for a location in Washington.](image2)

Fig. 1. Examples of real-world forecasts

REFERENCES

Hierarchical Transmission Network Topology Processing

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Abstract—The modern power system transmission network operation is highly dynamic due to the high penetration of inverter-based resources and active systems. The state-of-the-art (SOTA) transmission network topology processing (TNTP) based on the supervisory control and data acquisition (SCADA) system is inefficient for modern power system operational applications. A hierarchical approach for TNTP (H-TNTP) based on substation configuration identification using the branch current and node voltage measurements is proposed to overcome the shortcomings of the SOTA approach. A modified two-area four-machine power system model with two grid-connected solar Photovoltaic (PV) plants is utilized as the test bed and simulated in the Real-Time Digital Simulator (RTDS). Furthermore, the proposed H-TNTP is utilized to demonstrate the improved performance of energy management system (EMS) operational applications.

Index Terms—Artificial intelligence, transmission network topology processor, PMU, substation configuration identification

I. INTRODUCTION

The modern power system transmission network operation is highly dynamic due to the high penetration of inverter-based resources and lumped effect of distribution level modernization. Thus, fast transmission network monitoring is required to maintain the reliable operation of the modern power system. The current transmission network topology processing (TNTP) is based on the supervisory control and data acquisition (SCADA) system, which is inefficient for modern power system operational applications. A hierarchical TNTP approach (H-TNTP) [1] is presented including substation configuration identification [2], as shown in Fig. 1. H-TNTP utilized branch current and node voltage measurements from any measurement infrastructure to derive substation configuration on Levels 1 and 2 at each measurement frame. All updated substation BBMs are used to form Network BBM in Level 3. All typically used substation arrangements were considered in the proposed approach development. The updated Network BBM is similar to the SOTA approach TNTP output. The H-TNTP with phasor measurement units (H-TNTP-PMU) is implemented considering two classification algorithms namely logical decision-making (LDM) and artificial neural network (NN). The results verify the fastness of the proposed approach compared to SOTA approach as shown in Table I.

This research was funded by US NSF grants CNS 2131070 and the Duke Energy Distinguished Professor Endowment Fund.

Fig. 1. The proposed three-level hierarchical TNTP (H-TNTP) approach considering substation X,M and Y as examples

<table>
<thead>
<tr>
<th>TABLE I</th>
</tr>
</thead>
<tbody>
<tr>
<td>COMPARISON OF TNTP WITH TNTP-SOTA AND H-TNTP-PMU APPROACHES</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Factor</th>
<th>TNTP-SOTA</th>
<th>H-TNTP-PMU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Computation Time (μs)†</td>
<td>3.249</td>
<td>2.269</td>
</tr>
<tr>
<td>Measurement collecting rate</td>
<td>2kHz</td>
<td>33.3kHz</td>
</tr>
<tr>
<td>Time synchronization</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Paralel processing</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Substation isolator operations are included</td>
<td>No</td>
<td>Yes</td>
</tr>
</tbody>
</table>

† Computational time calculated on a system with : Intel Xeon(R) Gold 3.5GHz with 63.7GB RAM

REFERENCES


Predictive Coordinated and Cooperative Voltage Control for Systems with High Penetration of PV

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Abstract—This study proposes a predictive coordinated and cooperative voltage control method in a power distribution system with high penetration of photovoltaic (PV) units. Solar power forecasting is applied to predict voltage changes, which are used to set the VR tap positions and capacitor switch status to prevent large voltage fluctuations. The fine-tuning of voltage adjustment is then achieved by cooperative control of PV inverters to maintain a uniform voltage profile across the system. The proposed method is tested on a modified IEEE 123-node test feeder with high penetration of PVs using real measurement data and compared with the base case. Simulation results demonstrate the effectiveness of the integrated voltage control, as well as the enhancement from the predictive control through solar power forecasting-enabled voltage change estimates [1].

I. INTRODUCTION

Recently, the penetration of photovoltaic (PV) in power systems has increased and the high penetration of PVs can significantly affect the performance of a distribution system, especially on the system’s voltage profile. Voltage problems may occur due to the power flow from PVs in the reverse direction to the substation which can be reduced by using traditional voltage control methods. The use of voltage regulators (VRs) is very common in distribution systems with the purpose of correcting voltage drops. The difficulties in coordinating voltage regulation devices under high DER penetration drive utilities to have more stringent grid connection requirements and increase the need for voltage control methods with a high level of coordination and interaction among the different controllers. This research proposes a predictive coordinated and cooperative voltage control method to determine the number of taps for multi-nested Voltage regulators by using a real solar power generation profile.

II. PROPOSED CONTROL METHOD

A. Cooperative inverter control

In a system with a sufficient level of DG penetration, DGs’ reactive powers can also be used for voltage control or reactive power compensation. In such cases, the cooperative control law is:

\[
\alpha_q = \frac{d_i \alpha_q - \beta \frac{\partial f_{vi}}{\partial \alpha_q}}{d_i + \beta \frac{\partial f_{vi}}{\partial \alpha_q}}
\]

where \( \beta \) is the instantaneous binary communication \( d_i = B_{ij}/\sum_{j=1}^{N} B_{ij} \), \( \alpha \) is the percentage of the available reactive power to be generated by each PV and \( f_{vi} \) is objective function for having minimum voltage change.

B. Coordinated Voltage Regulator Control

In order to steer tap changes of VRs, instead of \( \Delta V \) which is used in localized control, the algebraic sum of the voltage deviations from the rated voltage in the subset of nodes downstream of the VR is used as a metric:

\[
CVVI = \sum_{i=1}^{n} (V_i - 1)
\]

The control uses CVVI’s calculated for the corresponding subset of nodes for each VR to adjust their taps in the following fashion: If CVVI is positive for the corresponding VR, its tap is increased by one; if it is negative, it is decreased by one. The change is performed for the VR with the largest absolute value for each phase in each iteration. The procedure is performed periodically and changes continue until \( |CVVI_i| \leq G_i \), where \( G_i \) is a threshold defined based on the system’s performance.

C. Predictive voltage control

After acquiring the solar power forecast using the gradient boosting method, the changes in voltages as a result of changes in the PV power output can be predicted as below:

\[
\Delta V_i = \sum_{j=1}^{n} (R_{ij} + jX_{ij}) \times \Delta P_j
\]

The voltage changes are then added to the corresponding voltages in the expression for CVVI calculation for predictive control.

III. SIMULATION RESULTS

The proposed predictive coordinated and cooperative voltage control method is applied to a modified version of the IEEE 123 system with high penetration of PVs and compared with local/cooperative control using VDI as a measurement index, defined as \( VDI = \sum_{i=1}^{n} |1 - V_i| \). The results are shown in Table 1.

<table>
<thead>
<tr>
<th>Evaluation Criteria</th>
<th>Local/Cooperative Ctrl</th>
<th>Proposed Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>VR1.a</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR1.b</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR1.c</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR2.a</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR2.b</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR2.c</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR3.a</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR3.b</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR3.c</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>VR4.a</td>
<td>-1</td>
<td>1</td>
</tr>
<tr>
<td>VR4.b</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>VR4.c</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total Steps</td>
<td>45</td>
<td>25</td>
</tr>
<tr>
<td>Mean VDI</td>
<td>2.919</td>
<td>0.1997</td>
</tr>
<tr>
<td>Max VDI</td>
<td>3.325</td>
<td>0.0666</td>
</tr>
</tbody>
</table>

IV. CONCLUSION

The proposed control uses forecasting methods to determine VR tap changes and maintain the voltage profile within a desired threshold. The improvement in the system voltage profile compared to local control is achieved by eliminating the uncoordinated operation of VRs, thereby reducing the number of tap changes and resulting in a better margin for cooperative control. The VDI is used to numerically quantify the performance of both cases. The proposed control reduces VDI by more than 90 percent with small variations near zero.

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Trainable Variational Quantum-Multiblock ADMM Algorithm for Generation Scheduling

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Abstract—This poster proposes a two-loop quantum-classical algorithm for generation scheduling that combines quantum computing, machine learning, and distributed optimization. The algorithm uses a trainable quantum approximate optimization algorithm (T-QAOA) to solve the QUBO on a quantum computer and employs a 3-block quantum alternative direction method of multipliers (QADMM) to coordinate QUBO and non-QUBO solutions. The T-QAOA achieves the QUBO solution in a few quantum-learner iterations instead of the hundreds required for a quantum-classical solver, and the outer 3-block ADMM obtains the original problem’s solution. The aim is to use small, noisy quantum computers with limited qubits to solve practical power system optimization problems.

Index Terms—Quantum computing, variational quantum algorithm, machine learning, distributed optimization, generation Scheduling.

I. INTRODUCTION

This study presents a novel trainable two-loop quantum-classical optimization algorithm for generation scheduling. The generation scheduling problem is decomposed into one QUBO subproblem and two non-QUBO subproblems. The QUBO subproblem is solved on quantum computers using the inner QAOA loop. The iterative interactions between the quantum circuit and classical optimizer are represented as sequential time series-type information. To determine the optimal quantum circuit variational parameters, a scalable deep recurrent neural network acts as an optimizer and mimics the iterative trace between QPU and a conventional computer. The proposed trainable QAOA (T-QAOA) converges after a predetermined number of iterations, with a proper sampling technique, instead of the hundreds to thousands of iterations that may be required by the conventional QAOA. An outer 3-block quantum-ADMM (QADMM) loop is devised to coordinate the QUBO and non-QUBO subproblems of generation scheduling. The inner loop learner remains unchanged at each outer QADMM iteration. The effectiveness of the proposed trainable two-loop algorithm is demonstrated through numerical results on both a real quantum computer and quantum simulator.

II. TRAINABLE QAOA

We aim to train a learner to play the role of an optimizer for QAOA to update the variational parameters. The expectation value $F(\vec{\gamma}, \vec{\beta})$ of problem Hamiltonian is used as the cost function with respect to parameterized state $|\psi(\vec{\gamma}, \vec{\beta})\rangle$ evolved from the QAOA circuit. To choose an optimizer architecture, the QAOA cost function and parameters evaluations are translated over several quantum-classical iterations as a sequential learning problem. Recurrent neural networks (RNNs) are a type of neural network commonly used to process such sequential information. RNNs are networks that take an input vector, create an output vector, and possibly store some information in memory for later use. A particular type of RNN framework that is used for the problem at hand is long-short-term memory (LSTM) which has outperformed other RNN architectures in many applications. Fig. 1 shows the structure of the proposed T-QAOA.

III. SIMULATION

The system includes three units supplying a demand of 160 MW, 500 MW, and 400 MW at three consecutive hours. An LSTM optimizer is trained for eight iterations with 800 observations and tested with 200 observations. The optimal status of units and the cost for each scenario are provided in Table II. The optimal on/off status and the operation cost obtained are the same for all scenarios. Fig. 2 portrays the reduction of the constraint residual for all scenarios at every ADMM iteration. The residual approaches to the stopping criterion after 25 iterations. In S2 and S3, at every outer ADMM iteration, a hybrid quantum-classical interaction is conducted to find the optimal QAOA variational parameters. Though starting from the same initial point, the LSTM optimizer is trained to terminate after 8 interactions, while the SGD optimizer needs 86 iterations on average to converge. Fig. 3 shows the step-by-step moving toward an optimal point in S2 and S3 in the last ADMM iteration, which takes 65 iterations for SGD to converge.

Fig. 1. Unrolled proposed trainable QAOA diagram.

Fig. 2. QADMM residual for 3-unit generation scheduling problem.

Fig. 3. Contour plot of expectation function for 3-unit system.
Expansion Planning of a Virtual Power Plant by Coalition with Decentralized Energy Resources

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Abstract—We consider a virtual power plant (VPP) that expands its capacity by forming a coalition with decentralized energy resources (DERs) such as conventional and renewable power plants, as well as with energy storage systems and flexible demands. The VPP competes with rival VPPs to aggregate the energy resources to its own portfolio. This problem is formulated as a three-stage stochastic bi-level model, where the expected profit of the VPP is maximized in the upper-level problem, while the lower-level problems deal with the decisions of each DER regarding the selection of VPP. In the first stage, the VPP manager places bids to secure each DER auction. The second stage involves decisions to determine the DER auctions, forming the VPP coalition and the procurement of power from the day-ahead market. Uncertainties in this stage include rival bid prices and reserve prices of DER auctions. Finally, in the third stage, the expanded VPP determines its optimal operation and manages uncertainties related to renewable energy production levels and market prices. The conditional value-at-risk (CVaR) is incorporated into the model as a risk metric to deal with the profit risk associated with the decisions of the VPP manager. The duration of the coalition forming is mid-term, spanning one month. To reduce the computational burden of the problem, the variability of parameters such as market prices and renewable energy production levels (both solar and wind) is modeled using representative days generated by a clustering K-medoids method.

Index Terms—virtual power plant, renewable energy, distributed energy resources, coalition, auction forming, bi-level problem, three-stage stochastic programming

I. MOTIVATION AND AIM

The emergence of VPPs has offered a promising solution in electricity markets by integrating and optimizing the use of diverse DERs. A significant advantage of VPPs is their ability to enable DERs, particularly those with low capacity, to participate in the wholesale market, and compete with larger generators. This, in turn, leads to increased revenue and incentives further investment in sustainable and renewable technologies. Therefore, the aim of this study is to maximize the revenue of a VPP by expanding its capacity through coalition formation with DERs in auction processes, while taking into account the associated risk.

II. PROPOSED METHOD

The VPP can sign temporary contracts with DERs by procuring their services through an auction process competing with other VPPs. In the auction, each VPP submits a single bid confidentially, and the DER accepts the highest bid price. This work considers auctions for conventional generators, renewable generators, energy storages, and flexible demands. Once the coalition between the VPP and the DER is established, the VPP’s energy management system can make strategic decisions to maximize its profit. To model this problem, a three-stage stochastic non-linear bi-level programming problem is implemented. The resulting non-linear problem is transformed into an equivalent single-level mixed-integer linear programming problem using the Karush-Kuhn-Tucker optimally conditions and exact linearization techniques.

The stages of the decision making process are threefold:
1) In the first stage, the VPP owner decides on a bid price to submit to each auction taking all uncertainties into consideration.
2) Once the offer of rival VPPs and reserve prices of DERs are known, the DERs set the capacity to sell to each VPP.
3) In the third stage, after the renewable energy levels and market prices are known, the VPP decides the scheduling of the different units.

III. CASE STUDY AND RESULTS

We consider a VPP consisting of a conventional power plant, a wind power unit, a storage system, and a flexible demand, that increases its capacity by forming a coalition with DERs. The behavior of the VPP is analyzed for two different months, namely January and July of 2020. Ten scenarios and four representative days are considered to model uncertainties and variabilities of parameters, respectively.

Fig. 1 shows the different configuration of the VPP manager in each scenario. With a confident level of 0.95 we obtain a revenue of €1,051,470 and a CVaR of €981,400 in the first case (Jan. 2020), and a revenue of €1,445,850 and a CVaR of €1,375,200 in the second case (Jul. 2020).

This work was supported by grants PID2021-126566OB-I00 and PRE2019-090125 funded by the Spanish Ministry of Science and Innovation MCIN/AEI/10.13039/501100011033 and by ERDF EU “A way of making Europe”, and by grant SBPLY/21/180501/000154 funded by the Junta de Comunidades de Castilla-La Mancha and by the ERDF.

Fig. 1. Coalition forming of VPP for two different periods.
Dynamic Matching in Power Systems with Deep Reinforcement Learning

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Abstract—In this study, we propose a scalable and efficient learning-based solution for the dynamic matching of flexible loads. The key feature of our solution is combining a simple rule-based function and a learnable component to achieve the aforementioned properties. The output of the learnable component is a probability distribution over the matching decisions for the individual loads. The proposed model enables the learning algorithm to find an effective matching policy that satisfies the loads’ servicing preferences. We present extensive simulations to show that the learning algorithm learns an effective matching policy for different generation-consumption profiles despite the complexity reduction. We show that the learning-based solution exhibits significantly better performance compared to standard online matching heuristics such as Match on Arrival, Match to the Highest, and Match to the Earliest Deadline policies.

I. MOTIVATIONS AND PROPOSED FRAMEWORK

Decentralized operation of the power systems is a feasible and effective approach to integrating renewable energy sources (RES). In a decentralized operation, flexible loads can match and trade with the local RES to supply their energy requirements, which promotes the integration of RES while introducing cost-saving opportunities to flexible loads. However, the uncertainties in RES generation and the sequential arrival of loads make the matching problem challenging. Hence, the main goal is to find an online solution that can match uncertain supply and flexible loads. Hence, we propose a dynamic matching framework for power market operation in local communities and a Deep Reinforcement Learning (DRL) approach to learning an online matching policy. The structure of the matching framework with DRL is shown in Fig. 1. The proposed model consists of an agent that uses a policy gradient approach to output a matching policy at each time step. Based on the observations of load and generation, the matching policy matches the active loads to the available supply sources while prioritizing the RES. At the end of the market, the matching policy is updated based on the overall social welfare to improve the matching efficiency.

II. RESULTS

The following online matching algorithms are considered to evaluate the matching performance of the learning algorithm:

- Match on Arrival (MA) algorithm: this algorithm matches the supply sources to the arriving loads.
- Match to the Highest (MH) algorithm: this algorithm matches the supply sources to the loads with the maximum willingness to pay value.
- Match to the Earliest Deadline (MED) algorithm: this algorithm matches the supply sources to the loads with the earliest deadlines.
- Learning Algorithm 1 (LA1): it denotes the vanilla policy gradient learning algorithm.
- Learning Algorithm 2 (LA2): it denotes the actor-critic algorithm of type AC-1.
- Offline Optimal Algorithm (OOA): this is the optimal solution calculated using the actual realization of the load and RES generation over the period of the market.

The simulations are conducted for a variety of load-generation scenarios, and the results reflect that the learning algorithms of both types achieve the highest average social welfare among the online solutions across most of the scenarios. It is found that the learning solution can take a balanced strategy to ensure the most utilization of RES generation with respect to the quality of service constraints of loads.

<table>
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<th>Scenario</th>
<th>Algorithm</th>
<th>MA</th>
<th>MH</th>
<th>MED</th>
<th>LA1</th>
<th>LA2</th>
<th>OOA</th>
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<td>Scenario 3 ($)</td>
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<td>260.2</td>
<td>266.9</td>
<td>267.1</td>
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<tr>
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<tr>
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<td>158.8</td>
<td>180.9</td>
<td>184.8</td>
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Probabilistic Solar Forecasting using Deep Learning

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Abstract—Solar forecasting is crucial for the efficient and reliable operation of power systems with high penetration of solar photovoltaic (PV) generation. Accurate solar forecasts can help grid operators to optimize their dispatch strategies, balance the supply and demand of electricity, and maintain grid stability. In recent years, probabilistic solar forecasting has drawn a lot of attention since it includes additional information about the level of uncertainty, rather than a point forecast, by predicting multiple quantiles of the distribution. This paper studies deep learning (DL) based long short-term memory (LSTM) network solar forecasting method. Predicting solar energy is a crucial aspect of designing the necessary photovoltaic systems, and machine learning techniques are now the most preferred for this goal. In this work, the sequential DL technique is constructed using historical weather and solar parameters. All DL hyperparameters are tweaked with Keras (TensorFlow).

Index Terms—Deep Learning, Solar Forecasting, Photovoltaic, Renewable Energy, Multi-core Parallel Processing, Big Data, Supervised Learning, Long Short-term Memory (LSTM) network

I. INTRODUCTION

Global energy demand is rising, and thus it worsens environmental impact. Renewable energy constitutes an effective supplement to traditional energy sources. Thus recent years there have been significant global investments in alternative energy research. Renewable energy sources like solar energy have being actively used as the world’s energy issue worsens. However, renewable energy is strongly weather-dependent, and thus highly intermittent as well as not dispatchable. Therefore, developing accurate forecasting models for PV power production is a useful answer to this issue. In recent years, deep learning techniques have shown great potential in solar forecasting due to their ability to learn complex patterns and relationships in the data. PV data sets from the real world are used to assess the models’ viability and efficacy. In this work, we propose a deep learning based long short-term memory (LSTM) framework for accurate solar forecasting.

II. METHODOLOGY

By using meteorological stations and geostationary meteorological satellites, observations or satellite remote sensing can be used to gather historical sun radiation data. This research primarily examined and evaluated the DL method’s efficacy in solar forecasting. Flowchart is shown in Figure 1.

III. RESULT

This proposed model is simulated to run a 24-hours predictions. Figure 2 compares actual and forecasted solar for the next 24 hours using the proposed method. Most of the time of the day, forecasted solar is close to actual solar.

IV. CONCLUSION

In this paper, the authors proposed a probabilistic solar forecasting approach based on deep learning, specifically quantile regression LSTM networks. Experimental results demonstrate that the proposed method is able to provide acceptable level of accurate and reliable probabilistic forecasts of solar power. Thus the proposed approach has the potential to be used in practical applications for the efficient and reliable operation of power systems with high penetration of solar PV generation.
Evaluating the Impact of Electric Vehicle Charging & Demand Management on Rural Kansas Grid: An Integrated Transmission & Distribution Analysis

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I. INTRODUCTION

The steady increase in transportation electrification & the consequent electric vehicle charging demand (along with other distributed resource penetration) is becoming one of the influential factors in power system planning & operation decisions [1]. Efforts such as FERC order 2222 only magnify the need for new policies & practices to cope with these changes [2]. The recent FERC order 2222 calls for the modifications to the policy/practice barriers that prevent the participation of aggregators in the ISO/RTO markets [2]. These reforms will in turn open the doorway for data sharing that can facilitate the integrated operation of T&D systems.

![Diagram showing interactions between entities](https://example.com/diagram.png)

Fig. 1. Status of interactions between different entities

As shown in figure 1, a coordinated two stage approach is required to facilitate the aggregator participation in wholesale market while abiding by the distribution system operational requirements. Furthermore, the effectiveness of deploying such schemes needs to be considered within a given system. In this work the focus is to study the impact of electric vehicle (EV) charging demand (representative of distributed resource) penetration & the effectiveness of aggregator-based charge scheduling. For this a two-stage integrated transmission & distribution analysis is used. The test system used will be a modified version of the real rural Kansas network. The aggregator-based EV charge scheduling framework and preliminary results are presented in the following sections.

II. TWO-STAGE FRAMEWORK & TEST SYSTEM

The two-stage process used for EV scheduling & aggregator participation in wholesale market is given below,

**Stage 1:** In this stage a day ahead market process is considered to have taken place and the locational marginal prices ($\lambda_{BA}^{L,K,t}$) are available for every $t^{th}$ transmission node for every $k^{th}$ time interval in the corresponding horizon. These prices in turn can be used by the aggregators for scheduling.

**Stage 2:** The load at any node $i$ in transmission system is in turn represented using a distribution network in this stage. This facilitates more detailed analysis for scheduling without violating distribution system constraints. The participating EV customers in the distribution network will be scheduled by the corresponding aggregators. A decentralized load scheduling algorithm (proposed in [3]) is used in this work. The novelty of the proposed scheduling algorithm is the ability to obtain near optimal schedule without information interchange between the aggregators (as they compete amongst each other).

III. PRELIMINARY ANALYSIS

A preliminary analysis was done on an IEEE 13 bus system distribution system and proposed methods improve the system performance in terms of reduced losses and tap operations when compared to existing methods, as in Fig. 2 (a) & (b).

![Diagram showing tap operations and system power loss](https://example.com/diagram.png)

(a) number of tap operations  
(b) system power loss

Fig. 2. Results from preliminary distribution system analysis.

For the final poster, a modified rural Kansas transmission system will be used as the test system for stage 1 & to perform distribution system studies the transmission node loads will be represented using Iowa 240-bus test system. Also, the benefit metrics such as adjusted production cost will be used to evaluate the impact on the transmission system.

REFERENCES

Model-Free Approaches for Improving Situational Awareness in Low-Observable Distribution Systems

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I. INTRODUCTION
The integration of distributed energy resources (DERs), such as photovoltaic (PV) panels and electric vehicles, into power distribution systems has rendered these systems crucial for reducing carbon emissions in both the electric power and transportation industries. However, the low observability of these systems resulting from insufficient communications infrastructure and a lack of metering devices poses a significant challenge, especially as DERs become more widespread. This challenge impedes decision-making and control necessary for reliable and secure distribution grid operations. Emerging approaches based on machine learning (ML) and other data-driven methods have gained prominence in power systems research to alleviate this issue. Nevertheless, most studies using data-driven techniques in the extant literature assume (i) complete knowledge of the system model, including network topology and parameters, which may not always be reliable, complete, or even accessible, and (ii) sufficient data required to train the ML models, which are rarely available in practice, especially at low-voltage system levels (i.e., secondary distribution). This poster presents two data-driven approaches aimed at improving situational awareness in low-observable distribution systems, specifically in the “last mile” of the grid where DERs are becoming prevalent. The approaches allow for enhancing visibility into system states (i.e., voltages) without relying on prior knowledge of the distribution network model.

II. SUMMARY
The proposed methods are categorized as model-free because they do not require knowledge of the physical network model; instead, they rely on the geospatial coordinates (longitude and latitude) of distribution grid nodes. The first approach explores the potential of cable television (CATV) networks as an untapped sensing source to enhance the observability of the local distribution grid, as illustrated in Fig. 1. It employs a supervised-learning framework based on random forests to estimate voltages at unobservable grid nodes using voltage measurements from CATV sensors [1]. The second approach introduces a low-rank matrix completion technique for voltage estimation, using the parameter-less singular value shrinking algorithm. [2]. The matrix formulation depends on whether single snapshot or time-series voltages are of interest, leveraging the sparsity of distribution grid measurements.

Both methods are evaluated on the test system taken from the SMART-DS data set, which consists of over 1,000 nodes with varying PV levels. The voltage estimate results from both model-free approaches exhibit high accuracy, demonstrating their effectiveness (see Fig. 2 exemplifying the results of the second approach).

REFERENCES
Provision of Energy and Frequency Containment
Ancillary Services in Unit Commitment

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Abstract—This work focuses on operational system flexibility for secure operation in low-inertia systems. A lack of synchronous resources operating in the grid can lead to security issues in the case of outages by violating frequency needs such as RoCoF, nadir, and q-s-s. Ancillary services such as inertia, PFR, and EFR, will be considered to provide this flexibility.

Index Terms—low-inertia, frequency containment, unit commitment

I. METHODOLOGY

The model corresponds to a Frequency-Constrained Unit Commitment (FSUC) formulated as a Mixed-Integer Second-Order Cone Program (MISOCP) [1]. The methodology optimally clears a market of ancillary services for frequency control, while explicitly considering the participation of different providers of ancillary services such as inertia, PFR, and EFR. This central dispatch schedules the necessary frequency security ancillary services considering that the largest dispatched unit in the system can face an outage. The objective function minimizes fuel costs; private constraints limit the provision of energy and ancillary services from different market players; while system-wide constraints, associated with system’s requirements, determine the total requirements to meet demand and ancillary services provision. Through the relaxed version of this problem, we calculate prices of the different elements of the system [2], [3].

II. RESULTS

A. Case Study

The GB electricity system is considered in a 2030 scenario that corresponds to the ‘Leading the way’ scenario within National Grid’s 2022 Future Energy Scenarios depicted in [4]. Generation mix represents: six types of thermal units in which CCGT and OCGT can provide PFR. Two types of energy storage, PHES that can provide PFR; and BESS, that can provide EFR. Three types of renewables (onshore wind, offshore wind and solar PV) are also modeled, which can only provide energy. A typical operational week is considered.

B. AS Provision and Prices

For most of the operative hours, there are low-inertia levels, which makes PFR, EFR and synchronous inertia to be valuable for the system. High RES penetration hours create low energy prices. However, as can be seen in Fig. 1, during these low-inertia hours, ancillary services markets exhibit importance, increasing their prices.

Fig. 1. Ancillary services prices.

III. CONCLUSIONS

Frequency response services play a key role for low-inertia operating conditions, providing the necessary frequency security for the system and creating economical incentives to market players. For future work it would be important to understand the relation between these frequency security services and other services such as secondary reserve, as these services can compete with each other in a multi-period framework.

REFERENCES

Abstract: Off-grid and on-grid charging stations are essential in increasing the use of electric vehicles (EVs) in remote places while reducing the grid burden in urban areas. In this work, the dual active bridge-based isolated EV charger is reported, which is integrated with the PhotoVoltaic (PV) and grid. PV Power is uncertain due to dynamic solar irradiance; hence depending upon the real-time power of PV, EVs may draw the power from the grid. The current control algorithm guarantees an uninterrupted charging profile with controller robustness and stability for bi-directional EV charging by utilizing renewable energy and Utility Grid supply. The different analyses with only PV, grid, and PV and grid are reported in this work. This system was implemented in the Typhoon Real-Time environment to validate the controller’s performance.

Keywords: Dual Active Bridge, Distributed Energy Sources, Electrical Vehicle, and PhotoVoltaic.

1. INTRODUCTION

The growing global awareness for a pollution-free environment and continuous research in EV charging with renewables will lead to a rise in the number of Plug-in-Electrical vehicles (PEVs) in the near future. To meet the increased peak demand with the intermittent integration of PEVs into the power system, distributed energy sources, especially PV-based sources, may play a significant role.

This system uses the power converter to integrate the PV and grid at the common DC Bus. The Electric Vehicle (EV) charging is connected to the same DC bus with the Dual Active Bridge (DAB) converter as depicted in figure 1. The LC resonant filter is used for the soft switching of the converter. It can support the grid during peak time using a bidirectional EV charger. The phase shift-based control technique is used at a constant duty cycle. The output power is controlled by adjusting the phase between both converters. At the 90° phase shift, the power transfer will be maximum. The control strategy of the EV charger is shown in the figure. The actual current and RMS current is compared, and the associated error is fed to the PI controller. It generates the carrier wave angle using '[(f/0.047)/Ts]/360' and appropriate gain. Further, the carrier wave generator generates the carrier wave with a phase shift. Carrier wave generator generates the carrier wave with a phase shift. This phase shifted carrier wave is compared with the constant reference 0.5. which is generate the PWM pulse for each bridge.

2. CONTROL STRATEGY OF THE GRID AND PV SYSTEM

The Control strategy of the PV and grid system is shown in figure 2. The PV system is operated at the MPPT. The PV voltage and current are taken as input for the Maximum Power Point Tracking (MPPT) controller, and it generates the required duty cycle for the PV converter. The grid voltage regulator regulates the DC bus voltage, gives the reference current I_q output, and I_p is taken to zero for only active power transfer. The current regulator generates the modulation index in the dq-domain, which further generates the abc references for the grid inverter. The abc references are used to generate the PWM to appropriately operate the grid-side inverter.

3. REAL-TIME SIMULATION RESULT

The system is validated on the real-time typhoon interface at a step-size of 0.2us. The result of the DAB-based EV charger is depicted in figure 3. The Grid Side Converter maintains the DC bus voltage of 120. The EV battery voltage is 98V. The EV is being charged at a 12A constant current, which is settled within 0.4 sec. The Charging current is controlled by the phase shifting of the pole voltage of two converters. The phase difference is observed in figure 3, and the secondary is leading with the primary as observed in figure.

ACKNOWLEDGEMENT

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Loss Minimization through local Volt-Var control

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Abstract—In recent years, the drive for renewable energy has increased substantially. By nature, these renewable energy sources are widely distributed, causing many new challenges to arise. This poster will cover a scalable solution for Volt-Var control. Where the goal of this controller is to do optimization through loss minimization. The claim of scalability comes from the locality of the controller. No communication or coordination need to take place between any of the inverter-based resources. Meaning that no data mapping needs to be created and troubleshoot nor is it required to build up new communication architectures to accomplish the optimization objective.

Keywords—Volt-var control, Solar PV inverters and Distribution systems.

I. INTRODUCTION: CONTROL PHILOSOPHY

The objective of the local Volt-Var controller (VVC) is loss minimization. Where the VVC measures the bus voltage it is installed on, and the upstream current. The controller uses the upstream current as the objective function to be minimized and the measured bus voltage as the state variable indirectly. Where the bus voltage is altered by the VVC by adjusting the available Var (Q) output of the inverter-based resource. This minimal architecture solves the scalability problem created with the high penetration of the renewable energy resources.

The algorithm used to adjust Q is a combination of an extremum seeking (ES) algorithm and a Steady State Error (SSE) algorithm. This forms two control loops with the SE running every 5-10 seconds and the SSE running every 10-20 iterations of SE. The SE is an advanced disturb and observe algorithm. By summing a small sine wave to the measured voltage, using a dynamic voltage droop curve to calculate the Q setpoint, reading the new bus voltage, and using a butter-worth filter to remove some of the magnitude response due to the sin wave perturbation. Essentially, if the magnitude of the current reduced, the response is not filtered out and the Q base setpoint remains where it is for the next iteration. If the magnitude of the current increased, this response gets filtered out and the Q base setpoint adjustment in this sub-optimal direction is reduced.

The graph shows that the Q setpoint will “take two steps forward and one step back”. The number of steps taken forward happens to be proportional to the magnitude of the current change. As the minimum current is approached. The change in current at each perturbation gets smaller, so the steps forward and backward get smaller.

II. DATA REQUIREMENTS

The scalability of the local VVC comes from two chosen concepts. Low data requirements and no distributed or centralized communication architecture. Per inverter, this VVC only needs four measurements and one command. Inverter kW, kVar, bus voltage, upstream line current, and a Q setpoint to the inverter. Because this is a local VVC, this controller only needs to be applied directly to each available inverter-based resource. No model and no communication are needed for any kind of coordination.

III. RESULTS

Through cooperative validation with Avista Labs in Spokane WA, the controller showed a -0.2% to 8.65% efficiency gain under several scenarios. The collaborative testing covered under voltage, base line, and over voltage scenarios. The -0.2% is a negligible performance decrease, the lack of performance can be contributed to the PV inverters not having enough capacity to significantly adjust bus voltage against the stiff connection to the utility.
Analyzing the Impact of Distributed Energy Resources on Bulk Power Systems

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Abstract—The transition from conventional generation to renewables has been continuously increasing during the past few decades. A considerable percentage of these renewables include Distributed Energy Resources (DER) which are distributed in smaller individual capacities throughout the network that may not even be visible to the Bulk Power System (BPS). This work provides a novel approach to modeling and analysis of the impact of DERs on BPS performance using four different models of the distribution system. The proposed models are tested in the IEEE 37-bus system along with the transmission-distribution (T-D) interface. The results of this work will be highly beneficial for power system planners and operators in appropriate decision-making to maintain a reliable power system.

Keywords—distributed energy resources, impact modeling, bulk power system, distribution system modeling

I. INTRODUCTION

The deployment of Distributed Energy Resources (DERs) to the existing power systems brings out ample environmental and technological benefits, however, the planning, control and operation of power system are getting more complex due to their intermittency. So far, the most common practice of adding DERs to the system is embedding them within the distribution system as a passive load and analysing the impacts on the Bulk Power System (BPS). This practice can no longer be accepted due to the increasing integration of DERs and their varying impacts on different installations in the electrical system [1]. Hence, an explicit modeling of loads and DERs is required in a predetermined planning horizon.

Further, the impact of variability of DERs on distribution and transmission system operations will be dependent upon a number of factors including the DER type, size and location. In order to fully understand the impact, relevant time series simulations are required for distribution and transmission systems separately and considering them together through a transmission and distribution (T-D) interface [2].

II. METHODOLOGY

In this work, the solar PV generation is considered as the DER type and the system is analyzed using four different models as shown in Fig. 1. The first model (Fig.1a) is the current practice of the distribution utilities where the load and Distributed Generations (DG) are lumped together when analyzing the impact on BPS. In the second model (Fig. 1b), DGs are aggregated together and separate models for loads and DGs are built. Further, in a distribution system there will be different types of customers, hence according to their significance, different feeders are selected and separated load and DG models are built for each feeder in model 3 (Fig. 1c). For both model 2 and 3, the equivalent feeder impedances should be calculated using a proper method. In model 4 (Fig. 1d), all the loads and DGs in the distribution system are modeled as they exactly are. This will be more accurate and can be used as a benchmark to analyze the impact of the other models.

Annual hourly load data are obtained from a rural area in Kansas and distribution system simulations are done in IEEE-37 standard bus system with OpenDSS interfaced with MATLAB. Then the impact on the transmission system will be analyzed with PSSE simulations by considering the distribution system results through a T–D co-simulation.

REFERENCES

Optimization of Cryptocurrency Miners’ Participation in Ancillary Service Markets

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Abstract—The energy demand of the proof-of-work computation used in cryptocurrencies has witnessed significant growth in the U.S. and many other regions around the world. In this work, we model the operation of a cryptomining facility with heterogeneous mining devices participating in ancillary services. We propose a general formulation for the cryptominers to maximize their profit by strategically participating in ancillary services and controlling the loss of mining revenue, which requires taking into account the disparity in the efficiency of the mining machines. As a special case of our problem, we investigate cryptominers’ participation in frequency regulation, and a risk-aware algorithm is proposed to jointly minimize the cost and the risk of participating in ancillary services. Simulation results based on real-world ERCOT traces highlight the advantage of our proposed algorithms.

Index Terms—frequency regulation, cryptocurrency mining, ancillary services, electricity market.

I. INTRODUCTION

According to White House, cryptomining currently consumes 0.9% to 1.7% of total electricity in the U.S., and it is still rapidly growing. At the same time, there is a growing need for flexibility in the electric grid to provide ancillary services due to the intermittent nature of renewable energy sources. Unlike most other demands, cryptomining demand can have much stronger flexibility during times of need when the grid is stressed. Participating in ancillary services has not been wildly adopted by cryptomining facilities, given the sophisticated mechanisms and technology set up. However, such participation could be a substantial source of revenue for mining facilities. For example, during December 2022, a mining facility in Texas earned over $4.9 million in demand response credits, constituting 30% of its total revenue. At the same time, grid operators are also anticipating such participation, and have a strong need to better understand the behavior of cryptominers when they participate. In this work, we propose a general formulation for the cryptominers to optimize their operation with ancillary service participation, and control their loss of mining revenue.

II. PROBLEM FORMULATION

We consider \( c = [c_i]_{i=1}^N \) as the ancillary service profile of the cryptomining facility at time \( t \). After submitting its decision \( c \), the cryptominer receives a signal from the grid operator to deploy a certain fraction \( \epsilon \) of its committed capacity. Then, the cryptominer decides which type of cryptomining devices to shut down in order to fulfill its deployed capacity. At each time slot, we solve the following optimization problem:

\[
\begin{align*}
\min_{c} & \quad \mathbb{E}_\epsilon \left[ \sum_{i=1}^{N} c_i (\epsilon_i r - p_i) \right] + \lambda \text{Var} \left[ \sum_{i=1}^{N} c_i (\epsilon_i r - p_i) \right] \\
\text{s.t.} & \quad c \in F_c,
\end{align*}
\]

where \( c_i (\epsilon_i r) \) captures the loss of revenue induced by stopping mining cryptocurrency due to the deployment at the \( i \)th ancillary service program, and \( c_i p_i \) is the revenue of participating in program \( i \). Here the second term of the optimization problem captures the uncertainty of the information, and its impact is limited by the control variable \( \lambda \).

III. CASE STUDY

The above optimization problem can be expressed as a standard quadratic convex optimization, and we can obtain an analytical solution to it. From the results shown in Fig. 1, based on an experiment conducted over one week in the summer of 2022 with two demand response programs, price-responsive and reg-up, we make the following observations. When \( \lambda \) is increased above zero, i.e. less risk is taken, we observe less fluctuations in the profit, yet less average profit as well, as shown in the legend of the figure (\( \lambda = 0.0004 \)). This means that while hours of negative profit were avoided, many opportunities to earn profit were also squandered due to the particular risk-averse approach adopted. This highlights the importance of profit-risk balancing in the cryptocurrency mining participation in ancillary services.

Fig. 1. (top) Profits using summer 2022 data under two approaches: risk-unaware (\( \lambda = 0 \)) and risk-aware (\( \lambda = 0.0004 \)). (bottom) The trade-off between average profit and variance for increased \( \lambda \).
Simulation Studies on Slack Participation in Distribution Systems with Expanded DER Penetration

Zachary Minter, Student Member, IEEE, Karen Miu, Member, IEEE

Abstract—Increased adoption of distributed energy resources (DER), particularly photovoltaics (PV), challenges existing assumptions of distribution system analysis and single slack bus models. In this paper, multiple slack allocation models are considered, most notably one using source commons to electrically and topologically group network components. Simulated case studies were performed on an unbalanced, multi-phase 38-bus distribution system based on real-world utility data to show the impact of the different models and the effect time-varying parameters such as PV generation and load demand can have on source common formation.

Keywords—distributed energy resources, photovoltaics, distribution power system analysis, slack modelling, DER expansion

I. INTRODUCTION

The rapid expansion of DER calls into question the long-term viability of power system infrastructures and renewable energy economic models. Traditional distribution power flow analysis considers a single source (i.e., substation) being responsible for all system losses. However, DER contributions should be evaluated as they make up a larger portion of the energy profile. Previous slack bus models have used a limited number of distributed generators with controllable outputs, not reflective of current DER-centric growth. More recently proposed clustering approaches often may not account for network structure and power flows. As DER injections increase, it is important to know their individual and collective impact.

In this paper, multiple slack allocation methods are presented. A clustering scheme utilizing network structure and power flow data is introduced. Comparative simulation studies using different DER and loading scenarios are performed on a 38-bus system based on utility data. This work shows how an understanding of slack allocation can have significant implications on planning and operations decisions.

II. SLACK ALLOCATION MODELS

The different models capture slack participation, varying in DER and power flow data used. The models considered, quantified by participation factor metrics, include:

- Active Generation Model
  Each source is proportionally assigned slack responsibility based on generated output.

- Net Power Injection Model
  Only sources injecting positive net power into the grid are assigned slack responsibility.

- Generator Commons Model
  Groups the network into contiguously connected sets of nodes and branches supplied by the same set of sources.

Post-processes power flow data to determine slack responsibility per common (example shown in Figure 1).

![Figure 1. Select equations to compute source commons participation.](image)

- Clustering
  A means of managing large numbers of DER, source commons are clustered based on an algorithm using minimum node and maximum customer constraints within each cluster. This also identifies potential regions of control for distribution system operations, associating locally connected customers and sources.

III. SIMULATION CASES

A multi-phase unbalanced 38-bus, 88-node test system with different levels of PV injection amongst phases is used to evaluate the slack allocation models. Figure 2 shows the commons formed and participation per phase using the Generator Commons Model. A few observations:

- Size, number of commons, and participation level of multi-phase sources varies amongst phases and over time, requiring repeated evaluation of slack allocation per phase.

- More sources injections into the network increases the source common profile complexity, indicating DER expansion requires further evaluation techniques.

- Greater source common complexity occurs with more instances of positive nodal net injections, particularly during low loading, high PV times. This leads to more potential grid control regions and grid management strategies.

![Figure 2. Source commons for 38-bus case. Size of commons, number of commons, and participation per source varies](image)

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Resilient Power Sharing in a 100% Inverter-Based Power System Under GPS Spoofing Attacks

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The increasing integration of inverter-based resources (IBR) in the power grid requires new control and power sharing algorithms for grid-forming (GFM) and grid-supporting (GS) IBRs. Frequency droop has been employed for power sharing, but it has certain disadvantages, e.g., frequency changes, power quality issue, slow response, and the possibility of circulating current between IBRs [1], [2]. This abstract builds on our prior work on angle droop [3] and provides additional evidence of its performance.

An IBR microcontroller uses its crystal oscillator to create a phase reference for angle droop. However, crystal time drift adversely impacts angle droop. Therefore, references [3], [4] propose using GPS for precise timing. However, this creates a GPS spoofing vulnerability for angle droop. A GPS spoofing attack disrupts power sharing. Therefore, angle droop must become resilient to such attacks.

This paper builds upon the GS power sharing controller proposed in [3] to make it resilient to GPS spoofing attacks. Fig. 1 shows the proposed resilient GS controller. The state-space model of the GS power sharing controller is derived in its linear operating region. Using this, a state observer is designed to estimate the GS voltage angle. Finally, an integral control loop is designed to correct the GS voltage angle using its estimated value and mitigate the GPS spoofing attack.

The performance of the proposed method is evaluated using time-domain simulations case studies on the IEEE 9-bus benchmark system in PSCAD/EMTDC software. Fig. 2 shows the FIBPS operation under a GPS spoofing attack on the GS units at buses 1 and 3. This figure shows that the proposed method effectively recovers the voltage angles of both GS units after the attack, reducing voltage angle error by 14.17% in GS1 and by 45% in GS2.

REFERENCES

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Gradient-Enhanced Physics-Informed Neural Networks for Power Systems Operational Support

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Abstract—Recent research has applied deep learning to speed up the resolution of complex power flow issues, resulting in promising outcomes. However, to ensure practical applications of these models avoid frequency fluctuations and grid instabilities, the dynamic nature of power systems must be considered. Direct application of dynamic system models based on differential equations in control or state estimates is computationally costly. In this poster, we propose a machine learning method to approximate power system dynamics in near real-time using gradient-enhanced physics-informed neural networks. The proposed gPINN framework encodes the physical laws governing power systems and can train without generating costly data. The paper demonstrates the potential of this approach in predicting rotor angles and frequency in a single-machine infinite bus system and a three-bus power network, as well as uncertain parameters like inertia and damping, in a range of power system applications.

Index Terms—Deep learning, power system dynamics, physics-informed neural networks, optimal power flow, transfer learning

I. INTRODUCTION

Advancements in renewable energy, deregulated markets, and communication and control systems have created a broader range of operating scenarios and potential risks for power networks. To address these challenges, machine learning methods like Deep Learning (DL) has been successfully applied in power systems. However, previous works have fundamental flaws, such as not considering dynamics and mostly being applied to steady-state power flow. Power systems are dynamic, and steady-state behaviors alone cannot reliably control their operations.

Simulating the dynamic response of a power network requires solving complex nonlinear differential-algebraic equations (DAEs), posing a hindrance to performing real-time dynamical assessments. Scientific machine learning has introduced innovative approaches to understanding differential equations, providing an efficient alternative to traditional numerical solvers. However, the current DL-based framework for learning and simulating the dynamic behavior of a power network is limited to the single-machine infinite bus (SMIB) system and lacks robustness and generalization capabilities. In this work, we propose a method that utilizes physics-informed neural networks to simulate power system dynamics in multi-machine systems while being more generalizable and requiring less training data.

This poster are demonstrating the efficacy of gPINN models in finding solutions to the swing equation and a three-bus network and estimating unknown parameters. Specifically, our model uses deep learning to reliably calculate solutions to the swing equation and accurately estimate uncertain power system parameters from limited measurements. Additionally, our proposed model can quickly generalize to different initial conditions through transfer learning, allowing operators to use the model as an advisory tool to simulate a wide variety of possible system states.

II. SIMULATION RESULTS

A. Forward ODE Problem - Prediction Accuracy in Capturing Power System Dynamics

![Forward ODE Problem](image)

Fig. 1: Example of the predicted $\delta(t)$ (left) and corresponding $\omega(t)$ (right) in three cases. As expected, the prediction error increases as the distance into the future increases.

B. Inverse Problem of ODE - Discovery of Inertia and Damping Coefficients

![Inverse Problem](image)

Fig. 2: Inferring both $m_i$ and $d_i$ throughout training. The black dots in (a) show the observed locations of $\delta$.

C. Three-bus power network

![Three-bus network](image)

Fig. 3: Example of predicted variables for three-bus power network.
Minimum Capacity of Fast Frequency Reserve to Maintain Grid Frequency of Korea Power System

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Abstract—This paper proposes minimum capacity of fast frequency response (FFR) for maintaining power system frequency during voltage induced frequency event. Using static type of fast frequency, iterative method that increases capacity of FFR until Korean power system frequency meet predefined minimum frequency is used for estimating minimum capacity of FFR.

Keywords—fast frequency response, voltage induced frequency event.

I. INTRODUCTION (HEADING I)

Traditionally power system operator consider outage of largest generation unit as main contingency from a frequency perspective. However the story can be different as inverter-based resources increasing drastically, especially photovoltaic generator. Although grid code about low voltage ride through (LVRT) capability has been established including korea, most of inverter-based resources connected before grid code changed have no LVRT capability. So, massive outage of inverter based resource induced by low voltage can be occur which cause supply-demand imbalance resulting in frequency decrease.

Of course, frequency event doesn’t matter if operator ensure sufficient amount of primary reserve and inertia. But, when capacitor factor of renewable increases especially in daytime, net load decrease by behind the meter photovoltaic generation resulting in reduction of the number of synchronous generator which supply primary reserve to power system and inertia. So, different ancillary service is needed to compensate inertia and primary reserve shortage. In this background, some operators make fast frequency response such as ERCOT, AEMO, Eirgrid, etc. Fast frequency response of each operators have somehow difference in name and objectives. For example, AEMO’s fast frequency reserve is called as “very FAST FCAS” and its duration is about a few second while ERCOT fast frequency reserve has 15 minutes duration. And Eirgrid’s fast frequency reserve, also KPX which is operator of Korean power system, cover both dynamic and static fast frequency reserve. Dynamic fast frequency reserve has continuous operation with droop rate while static fast frequency response reserve has discontinuous operation with trigger frequency. Demand response can be typical static fast frequency response when demand response meet fast frequency reserve specification.

KPX which is operator of Korean power system consider fast frequency response as one of options for alternating synchronous generator’s ancillary service when renewable penetration is increased. Especially, static FFR is much simple than dynamic FFR, KPX intend to use static FFR before dynamic FFR. In this background, this paper estimate minimum static FFR capacity for maintaining frequency of Korean power system when massive outage of inverter-based generation occur.

II. ESTIMATING MINIMUM CAPACITY OF STATIC FAST FREQUENCY RESERVE

A. Worst Case Scenario requiring static FFR

Voltage induced frequency event which indicate massive outage of inverter-based resources in this paper is critical when renewable penetration is high. That is why this paper use 4 off-peak system data whose net load are 40GW, 45GW, 55GW each and behind the meter generation is about 15GW. By N-1 criterion, worst case scenario is searched that 3-phase fault on Sinnamwon Bus. Result from simulation indicate about 5 GW renewable generation trip by transient low voltage. This event is much larger than outage of largest generation unit whose size is 1.5GW. Although grid code clarify that grid frequency should be over 59.7Hz when N-1 contingency happen, this paper assume voltage induced frequency event as special case which is exception of grid code and grid frequency should be over 59.4Hz which can induce additional outage of inverter-based generator in Korea power system.

B. Minimum capacity of static FFR

Iterative method that the capacity of static FFR is increased 50MW until frequency nadir over 59.4Hz is used, and result of minimum capacity and frequency response is as shown. “Not Necessary” means that grid frequency is already over 59.4Hz without static FFR. “Unable” means that grid frequency can’t be over 59.4Hz with additional static FFR which has 2s delay time for operating. 2s delay time is least performance that is barely meet FFR specification of Korean power system grid code.

<table>
<thead>
<tr>
<th>IE(GW)</th>
<th>CF[%]</th>
<th>70%</th>
<th>85%</th>
</tr>
</thead>
<tbody>
<tr>
<td>271</td>
<td>1050</td>
<td>85%</td>
<td>unable</td>
</tr>
<tr>
<td>308</td>
<td>not necessary</td>
<td>1100</td>
<td></td>
</tr>
<tr>
<td>357</td>
<td>not necessary</td>
<td>200</td>
<td></td>
</tr>
</tbody>
</table>

* CF: Capacitor Factor, IE: Inertial Energy

Figure 1 Minimum capacity of static FFR

Figure 2 Frequency response of Korea power system, CF=70%
Time-Synchronized State Estimation Using Graph Neural Networks in Presence of Topology Changes

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Abstract—Recently, there has been a major emphasis on developing data-driven approaches involving machine learning (ML) for high-speed state estimation (SE) in power systems. The emphasis stems from the ability of ML to overcome difficulties associated with model-based approaches, such as linear state estimation, due to their limited effectiveness in handling non-Gaussian measurement noise. However, topology changes pose a stiff challenge for performing ML-based SE because the training and test environments become different when such changes occur. This paper overcomes this challenge by formulating a graph neural network (GNN)-based time-synchronized state estimator that considers the physical connections of the power system during the training itself. The proposed approach is evaluated using the IEEE 118-bus system. The results indicate that the GNN-based state estimator outperforms the model-based linear state estimator and a regular deep neural network-based state estimator in the presence of non-Gaussian measurement noise and topology changes.

Index Terms—Graph neural network (GNN), Machine learning (ML), State estimation (SE), and Topology change.

I. GRAPH NEURAL NETWORK-BASED STATE ESTIMATION

We propose a time-synchronized graph neural network (GNN) for solving the state estimation (SE) problem using phasor measurement unit (PMU) data. The proposed approach uses a combination of graph convolutional network (GCN) and graph attention network (GAT) layers to learn the physical connections in the power grid and the importance of data within the graph. Fig. 1 illustrates the proposed GNN-based SE architecture.

II. SIMULATION RESULTS

We showcase the robustness of the proposed GNN-SE approach to non-Gaussian noise in the PMU measurements and topology changes compared to the model-based linear state estimation (LSE) and a regular deep neural network (DNN)-based SE, which is a data-driven approach, for the IEEE 118-bus system.

We depicted the distribution of sample estimation error separately for voltage magnitude and phase angle for LSE, DNN-SE and GNN-SE in Fig. 2 considering non-Gaussian measurement noise, where $T1$ to $T5$ refers to the outages of the top five lines of the system that have the highest power flowing through them. The figure indicates that the LSE and DNN-based SE fail to provide consistent estimates since the distributions of sample estimation errors for both magnitudes and angles spread out over the horizontal axis. Conversely, in the proposed GNN-based SE, the corresponding error distributions overlap one another to a greater extent indicating that the proposed approach is relatively immune to non-Gaussian measurement noise and topology changes.

Fig. 1. Proposed GNN-SE - Input: graph-based data with initial feature values $x_v$ obtained from PMUs. Hidden layers: features of every node (orange nodes) are updated in parallel by aggregating neighboring nodes' information (yellow nodes) in each hidden layer $k$. Output: the final graph representation with state estimates $\hat{y}$ that are obtained by applying a linear transformation to the final hidden layer.

Fig. 2. Comparing density of estimation error of LSE, DNN-SE and proposed GNN-SE for outages of the top five lines of the IEEE 118-bus system that have the highest power flowing through them; (a), (c) and (e) compare the magnitudes, while (b), (d) and (f) compare the angles.
An Efficient Algorithm for Solving ISO-DSO Coordination Parametric Programming Problem

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Abstract—This paper presents a highly efficient algorithmic solution for the coordination problem between independent system operators (ISOs) and distribution system operators (DSOs) in radial distribution networks. The DSO sorts generating units in order of increasing cost and systematically incorporates them one-by-one while adjusting line capacities, until the last unit is activated. The proposed algorithm achieves a one-shot solution and outperforms existing algorithms in terms of time efficiency.

I. MOTIVATION

In order to encourage competition in the wholesale market by incorporating distributed energy resources (DERs), Order No. 2222 was issued by the US Federal Energy Regulatory Commission [1]. However, this integration of many small DERs into the wholesale market creates challenges for independent system operators (ISOs), such as increased complexity, computational burden, and the potential for voltage/thermal violations in the distribution grid due to aggregator-controlled DERs not being properly monitored by system operators. To address these issues and ensure the secure and reliable operation of the distribution grid, it is important to consider the role of the distribution system operator (DSO) in coordinating the participation of DERs in the retail market [2]. Previously, we proposed a coordination framework that relied on parametric programming [3]; however, solving the parametric programming problem can be time-consuming. As a result, this abstract presents an efficient solution algorithm.

II. SOLUTION ALGORITHM

Each DSO submits its bid-in cost function to the ISO’s economic dispatch problem. The bid-in cost function of the DSO i, $c_{i,t}^{dso}$, to be submitted to ISO (where $q_{i,t}^{dso}$ is the bid-in power quantity of this DSO to the ISO), is determined by following optimization problem (for single-period DSO markets) [3]:

$$
c^{dso}(p^{dso}) = \min_{p^{agg}} \sum_{i \in G} c_i^{agg}(p_i^{agg})$$

s.t. $p^{dso} \leq \sum_{i \in G} p_i^{agg}$

$p_i^{agg} \in S^{agg}$, $\forall i \in G$

$p^{agg} \in S^{Dis}$

(1)

where, the set $G$ represents all of the aggregators in the DSO. $S_i^{agg}$ is the search space that’s defined by the operational constraints of each individual aggregator. $S^{Dis}$ is the search space defined by the physical constraints of the DSO, which relates to the distribution system. The vector $p^{agg}$ consists of $p_i^{agg}$ values.

Equation (1) represents a parametric linear optimization problem that is parameterized by a single variable, $q_{i,t}^{dso}$, in the case of a single-period DSO market. The objective function of the equation is the sum of the convex bid-in cost functions from aggregators, and all of its constraints are linear.

Consider a scenario in which there are $n$ dispatchable distributed generation aggregators within a DSO. These units are sorted in order of increasing marginal costs, i.e., $c_1^{agg} < c_2^{agg} < c_3^{agg} < \ldots < c_n^{agg}$. The process begins with aggregator 1, which is the cheapest unit which is located in node $n$. Let’s define the shortest path from that node to the substation and include a set of branches that encompasses all such paths as $l_{n,s}$. The branch with the minimum capacity is selected as $F_k$. A comparison is made between $F_k$ and aggregator 1’s capacity $p_1^{agg}$, and the smaller of the two values determines the first breakpoint, i.e., $\min(F_k,p_1^{agg})$. This value determines the price and amount of power that the DSO can provide with this price. Subsequently, $\min(F_k,p_1^{agg})$ is subtracted from the capacity of all the branches in the route of aggregator 1. Aggregator 2, which is the next cheapest unit, is then included, and the process is repeated until all aggregators have been included. The resulting bid-in cost function for a system containing four DDG aggregators is presented in Fig. 1. A mathematical proof can be provided using KKT conditions.

REFERENCES


Abstract—Extreme weather events, the leading cause of power outages, are projected to rise due to climate change. Implementing preventative actions prior to these events can avert millions of dollars in losses and prolonged power disruptions. An optimal day-ahead stochastic approach is developed in this paper to identify critical substations based on their significance to the power system, measured by their expected imposed costs due to flooding. Critical substations are protected a day before the incident using tiger dams, considering available resources like crew teams, time, and tiger dams, to minimize load curtailment and structural damages. The proposed model takes into account both transmission and distribution substations, and their correlation. The efficiency of the proposed model is tested on a 24-bus system containing 24 transmission substations and 40 distribution substations.

Index Terms—Power substations, grid resilience, flooding, stochastic optimization, resource allocation.

I. PROPOSED MATHEMATICAL MODEL

A stochastic resource allocation optimization problem to determine how to protect substations using tiger dams a day ahead of a flood is presented. The proposed approach aims to minimize the expected imposed cost to the system. In the suggested model, the probability of protecting substations located in more severe flood regions is higher. Additionally, substations supplying a significant amount of demand or with expensive structures, whose damage would cause substantial loss to the system, are given a higher priority for protection. The optimization problem is constrained to network connections, crew team scheduling, energy not supplied cost of substations, and required time to install a tiger dam at each substation.

II. DISTRIBUTION AND TRANSMISSION CORRELATION

Protection decisions for distribution and transmission substations should consider the interconnections between them, as distribution substations are supplied by transmission substations. Protecting transmission substations without ensuring the availability of connected distribution substations is not cost-efficient, nor is protecting distribution substations without securing the supplying transmission substations.

III. POWER GRID RESILIENCY IMPROVEMENT BY SWITCHING

Transferring loads between neighboring distribution substations using normally open points can reduce the energy not supplied of the system. Switching provides greater flexibility in load management, allowing for the load to be transferred between neighboring substations and enabling the demand to be served by safer substations.

IV. SIMULATION RESULTS

The model identifies critical substations in the transmission and distribution systems and allocates crew teams to each substation. The impact of coordinating transmission and distribution systems is evaluated by comparing the results with a decentralized approach. According to the results, the coordinated approach leads to a reduction of 9.17% in power outages and 24.07% in cost, which is the primary objective of the proposed model. However, it is noticed that the outage duration increases by 15.37% compared to the decentralized approach. The resiliency improvement through switching is tested considering three normally open points, and the results show a load curtailment and cost reduction of 3.23% and 0.55% through closing two of these switches, respectively. Having more normally open points within the system, greater resiliency can be achieved.

The proposed algorithm significantly improves the power system's resiliency, as demonstrated by a 26.19% reduction in the power outage, 36.34% reduction in outage duration, and 41.22% reduction in cost compared to the no-protective action scenario in the worst-case scenario.
Abstract—Proliferating solar PV generations in distribution networks poses technical challenges to system operators including voltage variations and generation variability and uncertainty. Volt/VAr Optimization (VVO) and Demand Response Program (DRP) are among the most effective techniques to overcome the aforementioned challenges. Although VVO and DRP utilize some common sources and may impact each other, they have been solved separately. Also, in the studies that combine VVO and DRP, loads have been modeled using fixed impedances, which can cause some errors. In this paper, a novel look-ahead co-optimization framework for VVO and DRP is proposed to simultaneously schedule active and reactive resources in distribution grids with high penetration of PV generations and voltage-dependent loads. A chance constraint optimization approach is used to model uncertainties of PV generation for the optimal scheduling of real and reactive power. The proposed framework is verified using the modified IEEE-37 node system with added PV systems, batteries, and flexible loads. The simulation results demonstrate the effectiveness of the proposed framework to achieve peak shaving and loss minimization.

Index Terms—Distribution grids, Volt/VAr Optimization, demand response program, and chance constraint optimization.
Factor Analysis of JEPX Spot Prices Fluctuation using GIS

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Abstract— JEPX (Japan Electric Power Exchange) is the only electricity market in Japan, and the prices are fluctuating depending on the date. The authors developed the forecasting method for JEPX spot prices using geographic information system (GIS). In this paper, the authors evaluated the relationship between the population-weighted temperature data and the JEPX spot prices in the Kyushu area and between the forecasted amount of solar power generation and JEPX spot prices in the Kyushu area. The trends in prices are different; hence the evaluation was divided into morning and evening, and daytime. As a result, there is a relationship between the prices and the forecasted amount of solar power generation in the daytime. In addition, there is a relationship between the prices and population-weighted temperature data in the morning and the evening depending on the season.

Keywords—Japan electric power exchange, Geographic information system, Spot prices

I. DERIVATION OF JEPX SPOT PRICE EXPLANATORY VARIABLES USING GIS

The spot prices of JEPX are determined by the relationship between supply and demand; hence the authors derived the variables that explain the supply and demand using GIS [1]. It is possible to derive the explanatory variables that has close relationship with prices by using GIS. The population-weighted temperature data that explained the demand for air conditioners was derived by mapping the population data and the forecasted temperature data on GIS. In addition, the forecasted amount of solar power generation was derived by mapping the introduced amount of solar power generation data and the forecasted solar radiation data on GIS.

II. RELATIONSHIP BETWEEN EXPLANATORY VARIABLES AND JEPX SPOT PRICES

The authors evaluated the relationship between the population-weighted temperature data and the spot prices and between the forecasted amount of solar power generation and the spot prices. The evaluation period is from January 2021 to December 2021. The authors obtained daily fluctuation of population-weighted temperature data, forecasted amount of solar power generation, and prices using (1) – (3). In (1) - (3), \( T \) is the population-weighted temperature data, \( S \) is the forecasted amount of solar power generation and \( P \) is the spot prices in the Kyushu area. Subscript \( f \) is the fluctuation of the day, \( da \) is the average value of the day, \( ma \) is the average value of the month, \( dt \) is the total value of the day and \( mt \) is the total value of the month.

\[
T_f = \frac{T_{da}}{T_{ma}} \quad (1)
\]

\[
S_f = \frac{S_{dt}}{S_{mt}} \quad (2)
\]

\[
P_f = \frac{P_{da}}{P_{ma}} \quad (3)
\]

The trend of JEPX spot prices varies depending on the time of day. Especially, the price fluctuations during the nighttime are less compared to the morning, evening, and daytime; hence the nighttime was excluded from this evaluation. In this paper, the authors used the data from 5:30 to 9:00 and 17:30 to 19:30 as morning and evening data, and the data from 9:30 to 17:00 as daytime data. Moreover, the authors used the data from Mar. to May as spring data, Jun. to Aug. as summer data, Sep. to Nov. as autumn data, and Dec. to Feb. as winter data.

Tables 1 and 2 show the correlation coefficients between the price fluctuations and the population temperature data fluctuations and between the forecasted amount of solar power generation fluctuations and the price fluctuations. In the morning and evening, there is a correlation between the prices and the population-weighted temperature data in winter and summer. This is because the power consumption of the air conditioner is a large factor in determining the prices in the morning and evening. In the daytime, there is a correlation between the prices and the forecasted amount of solar power generation in all seasons. This is because the amount of solar power generation is a large factor in determining the price in the daytime.

<table>
<thead>
<tr>
<th></th>
<th>Spring</th>
<th>Summer</th>
<th>Autumn</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Morning and</td>
<td>0.15</td>
<td>0.46</td>
<td>-0.2</td>
<td>-0.55</td>
</tr>
<tr>
<td>evening</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Daytime</td>
<td>-0.05</td>
<td>-0.12</td>
<td>-0.22</td>
<td>-0.36</td>
</tr>
</tbody>
</table>

Table 1. Evaluation of the population-weighted temperature data

<table>
<thead>
<tr>
<th></th>
<th>Spring</th>
<th>Summer</th>
<th>Autumn</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Morning and</td>
<td>-0.48</td>
<td>0.13</td>
<td>-0.45</td>
<td>0.09</td>
</tr>
<tr>
<td>evening</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Daytime</td>
<td>-0.78</td>
<td>-0.37</td>
<td>-0.71</td>
<td>-0.43</td>
</tr>
</tbody>
</table>

Table 2. Evaluation of the amount of solar power generation

III. CONCLUSION

The authors show the correlations between population-weighted temperature data and prices, and between the forecasted amount of solar power generation and prices. This factor is expected to affect the price forecasting; hence this factor will be considered in the future.

REFERENCES

Designing an Optimal Photovoltaic System for Peak Demand Reduction

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Abstract—This research aims to design a photovoltaic (PV) system for a small city. A challenge is determining the optimal PV size, which requires technical and financial analyses including fixed and variable costs, energy, and peak demand charges. We discovered peak loads in this city mainly occur in the morning during winter and partially in spring and fall when there is little to no PV generation. So, excess energy can be stored in a battery to meet peak demand when PV generation is low. Traditional approaches are limited, as they rely on historical data and do not account for uncertainty. In this study, we are proposing a novel architecture to find the optimal size of the PV and battery with consideration for peak demand reduction.

Index Terms—Photovoltaic, Battery, optimal sizing, peak demand reduction

I. INTRODUCTION

Growing demand for renewable energy is increasing the economic and technical viability of photovoltaic (PV) systems and their integration into the power grid. One of the main challenges is finding the appropriate size of PV systems. It is worth noting that installing a PV system not only lowers electricity energy purchased from the grid but also should reduce peak demand. Energy purchase reduction can be done by PV at any time of PV operations, while peak demand reduction needs more analysis because the PV generation may not coincide with peak demand hours. To address this, excess energy generated during low-demand periods can be stored in a battery, which can then be used to meet peak demand during high-demand periods.

II. PROPOSED FRAMEWORK

Goal of this research is to design a PV system for a small city in Kansas, US. The hourly load demand and actual solar irradiance data are gathered for three years from 2019 to 2021. Fig. 1 shows the electricity load demand for January 23, 2019 as an example of daily load profile. According to the Fig. 1, the peak demand occurs early in the day and there is no solar irradiance at that time. Therefore, PV installation does not help in peak demand reduction. Based on our data analysis, on most days of winter and some days of fall and spring, PV generation in the peak demand hours is negligible or zero. Fig. 2 demonstrates the electricity load demand after installation of a PV of 2MW. This shows that there is no peak reduction on that winter day. In order to address this, batteries can be used as a complement to PV systems, storing energy during off-peak hours and discharging it at peak demand. For example, on this day, a battery can be discharged at the beginning of the day to reduce the peak and be charged late in the day. Accordingly, determining the optimal size of a battery for a specific photovoltaic system can be a challenging process, as it depends on various factors such as load variations and PV system characteristics. Therefore, this research project will focus on developing an innovative methodology to determine the optimal battery size for a given application. This will be done while taking into account electricity demand variations. Research findings can guide the design and development of PV-battery systems.
Reliability Analysis of DWPT Electric Vehicle Charging in Electrified Transportation Networks

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I. EXTENDED ABSTRACT

The development of electric vehicles (EVs) has caused power distribution grids, and subsequently transportation networks, to diversify in their operation to accommodate the necessity of EVs to recharge. This has required system operators to begin accounting for additional load demands from EVs, while also developing mitigation strategies in utilizing distributed energy resources to decrease the use of fossil fuels. In recent years, there has been advancements in battery technology that have allowed EV capacities to become more reliable, sustainable, and economical in their functionality. However, the recharging process has yet to be perfected when compared to internal combustion engine refuelling times. The refuelling time of EVs depends on the capacity of the EV battery system, the charging level of the charging system, and the state-of-charge (SOC) of the EV. The two types of charging systems that are currently deployed are wired power transfer systems and wireless power transfer systems (WPT). Both require EVs to be stationary, or static, to allow energy to be transferred. However, there is a sub-category of WPT known as dynamic wireless power transfer (DWPT) systems which allows the EV to recharge while it traverses a transportation network. This infrastructure requires sequentially aligned transmitter pads to be embedded within transportation networks and the installment of a receiver pad underneath the chassis of the EV, as presented in Fig. 1. This type of charging infrastructure has the potential to decrease EV battery sizes, but it could also impact the grid negatively when introduced in large penetration levels. Thus, this proposed work seeks to determine the reliability of a DWPT transportation network as it is introduced into a power distribution grid at varying penetration densities.

To determine the reliability of DWPT transportation networks in power distribution grids, historical traffic flow data is utilized to determine the density of EVs traversing the roadway [1]. This will allow for an accurate load demand profile that is based upon real-world traffic scenarios. In Fig. 2, the proposed approach of placing four separate DWPT charging systems is presented throughout an IEEE 33-Bus power system. Each DWPT system will be simulated individually and will disperse the load demand from the EVs across the indicated bus locations. Then an analysis of loss of voltage probabilities (LOVP), which is translated from loss of load probabilities, will determine whether the system has become unreliable for a 24-hr period [2]. This will enhance the understanding of DWPT electrified transportation networks so power grid operators can have the flexibility to mitigate load demand profiles.

REFERENCES

Leveraging Battery Storage and Solar for Reliability and Peak Shaving in Rural Circuits

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Abstract—Utilities consider rural areas the most vulnerable portion of their system. These areas are not only typically the worst-performing circuits within a territory, but are also more susceptible to weather and longer outage times. We propose combining distributed energy resources (DERs) in rural systems to increase reliability as well as reduce the peak load on the grid. While uniformly distributing these devices, voltage is evaluated to ensure system operation will remain within standards.

Index Terms—DERs, peak shaving, reliability, rural circuits

I. IMPLEMENTATION ON IEEE 37 NODE TEST CIRCUIT

The IEEE 37 Node Test Feeder creates more certainty in model construction versus a real distribution circuit like the previous work in [1]. In this work, the goal was to expand on previous efforts and ensure the results can be duplicated.

Fig. 1. IEEE 37 Node System

Python and OpenDSS were used to place DERs following the process below. Meters were placed to monitor the voltage and power at each node. Along with the storage, a storage controller was driven by Python to have more granularity and drive peak shaving.

1) Define options for DER capacities and Skip values
2) Iterate through loads, stopping based on the Skip value
3) Build a power array of evaluated loads and a total sum
4) Proportionalize the individual loads and total load
5) Use the proportion to create DER sizes for the nodes
6) Distribute new DER in the same proportion as loads

II. RESULTS

The first set of results was derived from the impact of the battery storage. Arbitrary values of 2000kW of storage and a Skip value of 2 were chosen. This created 7 storage units and a change in peak of 3.99%, as shown in Figure 2.

Fig. 2. Substation Meter - 7 Storage

Solar and storage were added to improve peak shaving based on optimal uniform placement from an array of values. The ideal configuration resulted in 2000kW in storage, 200kW of solar, and a Skip value of 5. The peak changes by 12.53%, which is shown in Figure 3. Given this configuration, an outage can be accommodated by the battery for at least an hour, depending on when the outage occurs.

Fig. 3. Substation Meter - Optimization

III. CONCLUSION

Optimal placement the DERs can improve peak shaving. Integrating these devices also improves reliability with localized alternative generation sources. This process validates that the work in [1] can be replicated on other circuits and produce similar results.

REFERENCES

Robust Voltage-Reactive Power Support using GAN-DRL Architecture for Grids with IBRs

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Abstract—Maintaining a consistent voltage profile is crucial for grid operators during regular system operations and emergencies. In many cases, they use model-free approaches in the form of machine learning-based models to provide network situational awareness and decision support systems such as voltage-reactive power (Q-V) grid service. However, these model-free methods rely heavily on the input system state, making them vulnerable to inaccuracies and inefficiencies when faced with perturbations in the input state, such as incorrect measurements through phasor measurement devices or improper data transmission. Therefore, a Generative Adversarial Neural Network with Deep Reinforcement Learning (GAN-DRL) Architecture is proposed as a robust approach for supporting Q-V scheduling decisions made by system operators. This architecture includes an additional layer for robustness which consists of two artificial neural networks - the Generator and the Discriminator. The system is trained and verified on the modified IEEE 30-bus transmission system with aggregated IBRs. The results demonstrate that the proposed model provides robust support against perturbed system states for voltage stability during grid operation.

Keywords—Inverter-based resources, Neural network, Reactive power, Voltage control

I. ROBUST GAN-DRL FOR Q-V SCHEDULING

A power system network can be partitioned into local zones for operational planning and maintenance. As presented in the overall system layout in Fig. 1, the robust framework uses the network partitions to provide decision-making support for Q-V scheduling. The system framework consists of a Generative Adversarial Network (GAN) block that detects and responds to input data perturbations and a Deep Reinforcement Learning (DRL) block that recommends actions to maintain the Q-V profile. The DRL block comprises an actor-critic neural network model that uses the Deep Deterministic Policy Gradient (DDPG) algorithm. The actor network selects the appropriate action, and the critic network assesses the action’s effectiveness [1].

II. DEPLOYMENT OF ROBUST GAN-DRL FRAMEWORK

The modified IEEE-30 Bus system with three zones is considered for case study. The simulation applies scaled loading and wind generation conditions using load and wind profiles from the Bonneville Power Administration (BPA) for 2020 [2]. In addition, four buses, namely 7, 8, 12, and 21, have been installed with aggregated inverter-based resources (IBRs) to enhance the system’s reactive power capability. The system’s state is captured by the magnitude of the positive-sequence voltage at each bus, measured by phasor measurement units. During the simulation scenario presented in Fig. 2, the system state in Area 2 was perturbed, leading to voltage measurement deviations at buses 12, 14, 15, 16, and 17. As a result, the DRL took drastic measures by requiring IBR3 to contribute more reactive power. Without the GAN, the DRL decision for IBR3 was approximately 3250 KVAR, while the initial system state only needed 500 KVAR from IBR3. After deploying the GAN generator model for Area 2, the DRL could adjust IBR3’s action to approximately 500 KVAR by denoising the input state.

REFERENCES
Abstract— The world is being pushed to explore for new sources of power generation to fulfill the growing demand for electric power as demand grows and the cost of electricity continues to rise. Increased use of renewable energy in the energy mix has prompted significant R&D initiatives in recent decades. The island condition of Puerto Rico opens the possibility to integrate ocean energy technologies as power sources. In this work oscillating water columns (OWC) is analysed in the context of integrate these systems as part of coastal erosion mitigation projects. The scenario is the northeast coast of the island. Energy potential is considered and economic feasibility.

I. INTRODUCTION

The ocean, vast and strong, has long been regarded as one of our planet's most important renewable energy sources. Concerns over rising oil prices in the 1970s cleared the way for a concentrated drive to develop renewable energy technologies. Significant advances have been achieved in systems capable of turning wave kinetic energy into electrical energy in a more efficient and cost-effective manner as we attempt to reduce global fossil fuel dependence. Furthermore, as these technologies' commercialization progresses, many resource assessment studies have been conducted in the last decade. An OWC system of 2.28Mw is considered for the northeast coast of Puerto Rico.

II. Methodology

To estimate the potential of generation on for the proposed system:

- First, we analyze the Energy of Waves on Puerto Rico area from San Juan Buoy for 2021 [2]
- Getting the sampling H and T conditions:

<table>
<thead>
<tr>
<th>Wave Condition</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.5m</td>
<td>10</td>
</tr>
<tr>
<td>1.0m</td>
<td>5</td>
</tr>
<tr>
<td>1.5m</td>
<td>2</td>
</tr>
<tr>
<td>2.0m</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 1: Time of occurrence of H and T wave conditions

- Calculate the Probability of occurrence of a height (H) and time condition (T).
- Find the value of average significant height given by the sum of all events divided by the number of occurrences.
- Calculate the energy production due proposed system for the comparing with an existing project.
- Calculate the return of investment.
- Verify the interconnection viability with PSSE In this work, the possible development of an OWC system on Puerto Rico is analyzed for the northeast coast of Puerto Rico.

III. RESULTS

\[0.5(H^2)T = kW/m \quad 0.5(22)10 = 20kW/m\]

\[2.28MW = 20000MW/24h\]

With an estimated cost of the project of $111,318,552.00.

Selling energy at proposed rate of $0.12:

\[\$111,318,552 \times \$0.12/kwh = 927,654,603 \text{kwh}\]

IV. CONCLUSIONS

This project is not attractive from the economical point of view because a extend period for return from investment. Constructed structures for shore erosion mitigation, can allow make the project feasible because this scenario can drop costs for development. The ocean energy generated in Puerto Rico is low compared with other geographic zones as the area Mutriku project is constructed. The project can be connected to a 38kv transmission with no mayor complications.
OUC Gardenia Grid Integration Laboratory: Overview and implementation

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Abstract—Orlando Utilities Commission (OUC) serves the City of Orlando and surrounding areas. It has a goal of achieving 100% solar energy by 2030. The full penetration of solar energy requires advanced controls and operations of the power grid. To develop and test the advanced control functionalities, OUC has established the Grid Integration Laboratory (GIL). This paper presents a detailed description of GIL developed by the OUC in coordination with the University of Central Florida. The equipment, communication protocols, operation modes, and algorithm are discussed and an overview of the challenges and problems in implementation is presented. Additionally, “solar smoothing” as one of the operation modes is discussed and showcased in greater detail to show the effectiveness of the control algorithm. In addition, the algorithm also handles equipment failure by isolating faults and re-dispatching resources. It is hoped that the knowledge learned from the industry testbed can be shared, reused, and enhanced through the exchange of our experience.

Index Terms—Solar Power, Microgrid, Control, Battery, Photovoltaic (PV), renewable energy sources (RES), electric vehicle (EV), energy storage system (ESS)

I. INTRODUCTION

This study presents a detailed description of the GIL including connected equipment, communication protocols, and control algorithm alongside an overview of the different objectives and operational modes defined within this project. Also, an implementation of solar smoothing as one of the modes is demonstrated to showcase the effectiveness of the control algorithm in improving the microgrid functionality. Additionally, some challenges of the microgrid operation including communication issues and equipment failure are discussed [1].

II. GRID INTEGRATION LABORATORY (GIL)

The Grid Integration Laboratory at Gardenia consists of several devices which need to be managed optimally based on the operation mode and availability of resources. In this section, we first list all the equipment that comprises the Laboratory. Then the communication between the controller and the equipment is discussed in detail. And finally, we introduce the different operation modes incorporating different objectives and requirements. The overall operation scheme of the GIL is depicted in Fig. 1.

A. Modes of Operation

The GIL includes several different operation modes for the main controller. These operation modes focus on different scenarios and input data to optimally manage all the dispatchable assets in the Microgrid for optimal control based on the objectives. In this section, we explain the different operation modes in detail including the conditions, requirements, and the different manageable assets. The operation modes include EV Demand Mitigation, Solar Smoothing, Contingency Events, and Time of Use Optimization [2].

REFERENCES


Model Reduction and Translation for Coordinated Expansion Planning Studies
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Abstract—With typical power systems having thousands of buses, network models must be reduced; however, this poses a problem for co-optimized expansion planning (CEP) as it identifies investments on “equivalent” buses and lines that do not directly map to the actual infrastructure in the full model. This work aims to develop an integrated grid reduction and translation package to enable the use of CEP on large industry-grade planning models. Three major steps are taken in this research: reduction, expansion, and translation. The methods developed in this project will be applicable to both deterministic and uncertain CEP formulations and benefit regional transmission organizations, transmission system operators, and policy studies.

Index Terms—Co-optimized expansion planning, network reduction, model translation

I. INTRODUCTION

Power system generation and transmission planning is a crucial aspect of the energy industry that determines the optimal allocation of resources to meet energy demand while ensuring reliability, security, and efficiency. As the industry shifts towards renewable energy sources, such as utility-scale wind and solar, and distributed resources, the need for accurate and efficient planning becomes increasingly important. However, computations can become intractable when the network size, investment years, conditions per year, or candidate investments become too numerous, requiring the reduction of planning models to 500-1000 buses. This reduction necessitates the translation of reduced model investments back to the full model, which can be a complex process. The general scheme of this process is presented in Fig. 1.

II. NETWORK REDUCTION FOR PLANNING PURPOSES

Based on the study objective, a range of zones and boundary buses can be established on the full network. Power transfer distribution factors (PTDFs) and K-means clustering are used to identify zones with similar buses. These designated zones are subsequently ranked according to their proximity and connectivity to the study area, and distinct reduction criteria can be applied to each rank. Following the identification of the buses that are to be preserved, a reduction methodology can be executed to downsize the network. This reduction results in the emergence of equivalent buses and lines, representing the reduced part of the network. The flow limits of equivalent lines are required to run CEP on the reduced network. The accuracy of the reduced model is evaluated based on the power flow of the retained lines. The overall process of reduction is illustrated in Fig. 2.

1) Line Limit Estimation: The limits for equivalent lines are estimated based on a least square error optimization problem that matches the transfer capacities between buses in the reduced network to the ones in the full network. Once we have a reduced model with accurate transmission limits, we apply CEP to obtain an expansion planning solution. The essence of this approach is that the generation investments identified on the reduced model are heuristically mapped to the full model.

2) High-Fidelity Translation (HFT): After generation mapping, secondary transmission expansion planning is performed on the full model. This initial TEP uses a linear programming formulation, and it is called high-speed translation (HST). HFT approach uses the HST solution as a “warm start” to limit candidate lines, and applies mixed integer linear program (MILP) to choose from discrete line designs commonly used in industry to obtain a highly accurate translation.

III. CONCLUSION

As a result of this work, CEP can be seamlessly applied to large-scale industry networks and integrated into planners’ tool sets to identify the most efficient network designs.
Two-Stage Deep Reinforcement Learning for Distribution System Voltage Regulation and Peak Demand Management

Yansong Pei Student Member, IEEE, Yiyun Yao, Junbo Zhao, Senior Member, IEEE, Fei Ding, Jiyu Wang

Abstract—The growing integration of distributed solar photovoltaic (PV) in distribution systems could result in adverse effects during grid operation. This paper develops a two-agent soft actor critic-based deep reinforcement learning (SAC-DRL) solution to simultaneously control PV inverters and battery energy storage systems for voltage regulation and peak demand reduction. The novel two-stage framework, featured with two different control agents, is applied for daytime and nighttime operations to enhance control performance. Comparison results with other control methods on a real feeder in Western Colorado demonstrate that the proposed method can provide advanced voltage regulation with modest active power curtailment and reduce peak load demand from feeder’s head.

Index Terms—Deep reinforcement learning, distribution system, voltage regulation, peak load management.

I. INTRODUCTION

This paper proposes a novel SAC-DRL solution for the coordinated control of PV inverters and BESS. The objective is to minimize the voltage violation while maintaining low PV active power curtailment and achieving an effective peak demand reduction. The contributions of this paper are:

- The proposed SAC-DRL is trained by a novel time variant reward, and the ADN can coordinate the control of a high number of PV inverters and BESS to simultaneously achieve voltage regulation and peak demand reduction.
- The proposed method requires little or no prior knowledge of ADN information. Comprehensive experiments on a real distribution feeder in Western Colorado demonstrate that the proposed solution has better performance than rule-based and other DRL-based control methods.

A. Two-Agent Control Solution

A single-agent SAC has enough capability to control a good number of PVs and BESSs during the daytime. During the training process, the agent constantly adjusts the PV active power set points in the neural network; however, setting the PV active power production at nighttime is meaningless since there is no solar. The update on the weight and bias during the nighttime will not reflect any reward change, which could mislead the update of the SAC agent. In addition, the agent seeks a balance among the active power curtailment, battery charging, and voltage violation during the daytime. When nighttime comes, the reward requires the agent to concentrate on solving the peak load demand reduction problem. The single-agent approach will be disturbed by the time-variance reward, resulting in performance degradation. Considering the generalization ability of the proposed solution to achieve 24-hour control, agents at two-stage are used to control different operating scenarios during the daytime and nighttime with different dimensions of actions. The agent applied in the daytime stage will be trained while that for the nighttime stage will be trained. The coordinated PV-BESS control based on the proposed two-agent layout is shown in Fig. 1.

II. RESULTS ON A REALISTIC DISTRIBUTION SYSTEM

<table>
<thead>
<tr>
<th>Agent</th>
<th>$N_{	ext{PVn}}$</th>
<th>Peak (kW)</th>
<th>Max Volt</th>
<th>Min Volt</th>
<th>Curt</th>
</tr>
</thead>
<tbody>
<tr>
<td>No-control</td>
<td>86</td>
<td>$2.61 \times 10^5$</td>
<td>1.059</td>
<td>0.931</td>
<td>-</td>
</tr>
<tr>
<td>VVCW+RBC</td>
<td>26</td>
<td>$2.26 \times 10^5$</td>
<td>1.053</td>
<td>0.953</td>
<td>4.6%</td>
</tr>
<tr>
<td>DDPG</td>
<td>42</td>
<td>$2.61 \times 10^5$</td>
<td>1.052</td>
<td>0.928</td>
<td>2.3%</td>
</tr>
<tr>
<td>SAC</td>
<td>2</td>
<td>$1.88 \times 10^5$</td>
<td>1.051</td>
<td>0.953</td>
<td>1.6%</td>
</tr>
<tr>
<td>Proposed</td>
<td>0</td>
<td>$1.82 \times 10^5$</td>
<td>1.049</td>
<td>0.952</td>
<td>0.6%</td>
</tr>
</tbody>
</table>

III. CONCLUSION

This paper proposes a two-stage SAC-DRL approach to achieve the coordinated control of the PV inverter and BESS to regulate the system voltage and reduce the load during the peak time. Comparative tests on a real feeder with several existing approaches demonstrate that the proposed method can address the voltage violations by curtailing modest real power and charging the BESS to store the energy for load compensation during peak hours. The new two-stage framework, featured by two different agents, is applied to deal with two different reward functions for daytime and nighttime to improve performance without system knowledge.
Abstract—Sustainable, reliable energy delivery to consumers is essential in our society. Recently, the improving economics of solar PVs have led utilities to adopt more distributed resources, including community solar farms and rooftop solar panels. This research analyzes the value of distributed solar generation for small towns in the midwestern U.S. considering infrastructure improvements. Actual data from a small farming town in Kansas is used as a case study.

I. INTRODUCTION

Large scale distributed energy resources (DERs) have become a reality in the past decade. Decreasing costs, increasing efficiency, and policy changes are paving the way for DERs as non-wire alternatives to traditional transmission upgrades [1]. Two significant renewable energy options are (i) community-scale solar farms and (ii) rooftop solar PV. This research analyzes the value of distributed solar from the perspectives of a rural midwestern transmission utility and residential customers. The following cases are analyzed using data from a small town in Western Kansas:

- **Base case**: Business as usual without solar generation. Utilities supply demand with power purchased from generators at the relevant locational marginal price (LMP). To meet regulatory reliability requirements, utility installs a new transmission line to replace aging infrastructure.
- **Case 1**: Utility installs a solar farm with battery to supply partial demand; remaining demand is supplied with power purchased at LMP.
- **Case 2**: Customers invest in rooftop solar PV. Utility purchases power produced by PVs at a fixed retail price and meets remaining demand with power purchased at LMP.

II. MODELING AND ANALYSIS

This research is based on load and LMP data from January 2015 – August 2021, obtained from a local utility. Hourly solar generation is based on production from a microgrid at Wichita State University [2]. Based on historic data, solar generation and load are modeled as a normal distribution and extrapolated to a 30-year asset lifetime. These models are used for a Monte Carlo simulation for the following cases:

- **Base case**: New line has a fixed charge rate of 14.61% [3] and capital cost of $8M based on utility data.
- **Case 1**: A 2 MW solar farm is constructed assuming capital cost of $2040/kW based on utility data, annual O&M of $100,000 [4], and renewable tax credits of 30% [5]. All panels in the solar farm are south-facing for best production.
- **Case 2**: For case 2, it was assumed that the price of residential PV generation is 10.38¢/KWh [6]. The value of solar PV is tested for three distributions of orientation:
  - 2a: 25% south, 25% west, 25% east, 25% north
  - 2b: 40% south, 30% west, 20% east, 10% north
  - 2c: 70% south, 10% west, 10% east, 10% north

III. RESULTS & DISCUSSION

The results of the simulation are summarized below. Table 1 shows economic and reliability metrics from the utility’s perspective, while Table 1 shows ROI for solar-owning customers in case 2.

<table>
<thead>
<tr>
<th>Case</th>
<th>Benefit/Cost</th>
<th>EENS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>2.5</td>
<td>25</td>
</tr>
<tr>
<td>Case 1</td>
<td>4.0</td>
<td>610</td>
</tr>
<tr>
<td>Case 2a</td>
<td>2.7</td>
<td>630</td>
</tr>
<tr>
<td>Case 2b</td>
<td>2.6</td>
<td>640</td>
</tr>
<tr>
<td>Case 2c</td>
<td>2.6</td>
<td>620</td>
</tr>
</tbody>
</table>

Table II shows the customer ROI for 30 years:

<table>
<thead>
<tr>
<th>ROI</th>
<th>South</th>
<th>West</th>
<th>East</th>
<th>North</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>25%</td>
<td>15%</td>
<td>15%</td>
<td>6%</td>
</tr>
</tbody>
</table>

Using these metrics, community and rooftop solar options will be analyzed based on a four-part value stack: energy, capacity, societal, and reliability [7]. This valuation will consider utility and customer perspectives in the system.

REFERENCES

A Data-Driven SVM-Based Method for Detection and Capacity Estimation of BTM PV Systems

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Abstract – In the past years, an increasing number of residential customers have installed rooftop solar photovoltaics (PVs). Most of these PVs are located behind-the-meter (BTM), i.e., invisible to utilities, which poses challenges to system operation and planning. Therefore, a methodology to detect and estimate the installed capacity of customer-level BTM PVs utilizing only net power curves and weather data is proposed in this paper. The methodology is based on the grouping of PV generation and pairing of native demand that feed algorithms based on support vector machine (SVM) built to detect and estimate the installed capacity of BTM PVs. The results using two datasets (real and synthetical) show that the accuracy of detection is higher than 92%, ensuring the precision of the developed method.

I. INTRODUCTION

Due to cost reduction and policies to diminish emissions of carbon dioxide, photovoltaic (PV) generation has been spreading throughout electrical systems. Most PVs installed at customers are located behind-the-meter (BTM), i.e., they are not directly monitored. Therefore, net power is the only source of information about the PVs of these customers that utilities have. On that account, this paper proposes a methodology to detect and estimate the installed capacity of customer-level BTM PVs utilizing only net power curves and weather data.

II. METHODOLOGY

The proposed methodology detects and estimates the capacity of BTM PVs in a customer using only weather data and net power curves (an overview of the steps is depicted in Fig. 1). The first step of the methodology is to group net power curves of a customer using weather data. In this process, the curves are separated based on the measured irradiance (within the same city) and only curves classified as “clear sky” or “overcast sky” are passed to the next stage of the algorithm.

The net power curves for the days selected by the previous grouping process are inputs of the native demand pairing algorithm, which matches curves based on the net power measured at night. These results feed the detection and capacity estimation algorithms based on SVM.

III. RESULTS

Both the detection and capacity estimation algorithms were tested in two datasets (synthetical and real). The assessment metrics exposed in Table I were calculated for the detection method. Despite the algorithm being more effective for the synthetical dataset, one can notice that all the assessment metrics obtained for the real dataset are higher than 0.9, which ensures the exactness of the algorithm.

Fig. 2 shows the results obtained by the capacity estimation algorithm, comparing estimated and real capacities of each customer. Also, a linear regression (red line) is applied in each data group, which can be compared to a perfect regressor (zero bias and unitary inclination), illustrated by a dashed blue line. One can notice that the synthetical dataset seems to be well distributed around a line close to the ideal one. On the other hand, the points of the real dataset follow a line that diverges more from the ideal one, and these points have low cohesiveness around this line, especially for low-capacity values, which is an expected behavior, since the average installed capacity of the customers in the real dataset is less than 0.69 kW, which makes the algorithm more susceptible to variations in native demand.

### Table I. Assessment Metrics for PV Detection.

<table>
<thead>
<tr>
<th>Type of data</th>
<th>Acc</th>
<th>P_{PV}</th>
<th>P_{NoPV}</th>
<th>Recall_{PV}</th>
<th>Recall_{NoPV}</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synthetical</td>
<td>0.95</td>
<td>0.92</td>
<td>1.00</td>
<td>1.00</td>
<td>0.91</td>
</tr>
<tr>
<td>Real</td>
<td>0.92</td>
<td>0.91</td>
<td>0.92</td>
<td>0.93</td>
<td>0.91</td>
</tr>
</tbody>
</table>

This work was supported by São Paulo Research Foundation (FAPESP) under Grants #2021/11380-5 and #2022/11692-0.
Data-Driven Estimation of Li-Ion Battery Health using a Truncated Time-based Indicator and LSTM

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Abstract—The lithium-ion battery (LIB) is widely employed in energy storage systems. Its state-of-health (SOH) is a crucial parameter for assessing battery reliability and retirement. This paper proposes a data-driven method using a simple but effective health indicator (HI) extracted from a truncated time interval (110 seconds in this paper) of the LIB’s discharge process, which is a challenge in literature since it is usually less controllable than the charge process. Unlike traditional HIs, the proposed HI can be derived from different voltage ranges, thus making it highly flexible for application. A deep learning algorithm named the long short-term memory (LSTM) is trained to learn the mapping relationship between the extracted HI and practical SOH of the LIB. The acquired test results using an open dataset show that the developed data-driven method can precisely estimate battery SOH without any additional hardware or system downtime.

Index Terms—Health indicators, lithium-ion batteries, long short-term memory, online estimation, state-of-health.

I. INTRODUCTION

The energy storage system (ESS) is extensively incorporated into electric vehicles and microgrid systems since it offers unparalleled operating flexibility. The lithium-ion battery (LIB), an energy-dense storage unit, has become an integral part of the ESS due to its long cycle life, low maintenance demand, and low self-discharge rate. However, the performance of the ESS would gradually decline due to the LIB’s innate aging process, which may result in catastrophic system failure. Therefore, only with accurate, battery state-of-health (SOH) estimation based on comprehensive aging data analytics can unexpected failures be prevented since the maintenance can be optimally scheduled; which ultimately reduces design and operating costs of the ESS.

SOH represents the degree of battery aging relative to the battery’s capacity loss or resistance increment. As SOH is not measurable, accurate estimation is key to avoiding overcharges and deep discharges. Data-driven methods, revered for being model-free and computationally cheap to apply, are growingly engaged to perform online estimations. Specifically, a machine learning (ML) algorithm is applied to map the degradation trend of the battery and estimate its SOH with reference to the information learned from historical aging data during the ML algorithm’s offline training. Such information includes the voltage, current, temperature and time variables, which are used to derive one or more battery health indicators (HIs). Online SOH estimation involves extracting the HI from real-time data measured by the ESS’s battery management system and using it as the trained ML algorithm’s input.

II. METHODOLOGY AND RESULTS

The proposed methodology of this work is summarised as follows: (i) By leveraging quantitative correlation analysis, a truncated time-based HI with strong correlation to battery SOH is extracted. This improved HI, termed as the voltage disparity in truncated time interval (VDTTI), is designed for derivation from a short segment of voltage curves. Since the segment can begin at any time spot, the VDTTI is easy to extract from LIBs operating at various voltages. (ii) In addition to constant current discharge mode, the VDTTI can be extracted in randomised discharge mode, thus enabling the employed data-driven method to obtain SOH estimates of LIBs that often switch between the two modes. (iii) Leveraging the subset of ML, the deep learning algorithm known as long short-term memory (LSTM) is used to estimate SOH with the extracted VDTTI. It is highly precise in capturing capacity regeneration trends due to the prioritised learning of capacity data from the four LIBs (RW3–6) used.

As the VDTTI is a singular and truncated feature, it does not need to be pre-processed with a filter. A shorter time interval can be used to extract the VDTTI, but at the cost of slight accuracy sacrifice. The recorded results in Table I show that the proposed method estimates SOH more accurately than three popular ML algorithms, i.e., the Gaussian process regression (GPR), support vector regression (SVR), and decision tree regression (DTR).

![Fig. 1. (a) Derivation of the VDTTI. (b) Stacked network structure of the LSTM.](image)

**TABLE I. COMPARISON OF DIFFERENT SOH ESTIMATION METHODS**

<table>
<thead>
<tr>
<th>Method</th>
<th>Root Mean Square Error (%)</th>
<th>Time (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>VDTTI+LSTM</td>
<td>0.87</td>
<td>0.73</td>
</tr>
<tr>
<td>VDTTI+GPR</td>
<td>0.98</td>
<td>0.81</td>
</tr>
<tr>
<td>VDTTI+SVR</td>
<td>1.83</td>
<td>2.09</td>
</tr>
<tr>
<td>VDTTI+DTR</td>
<td>2.03</td>
<td>2.57</td>
</tr>
</tbody>
</table>

The work in this paper is supported in part by the Economic Development Board of Singapore’s Industrial Postgraduate Programme.
I. EXTENDED ABSTRACT

As the integration of renewable energy resources (RES) in microgrids (MGs) rises and with the increasing demand for electricity, the integration of RES becomes even more critical, as it can provide a reliable and sustainable source of power that can help to meet this demand while reducing the dependence outside sources such as grid power. However, the introduction of integrating cheaper energy from RES in MGs causes other challenges such as inefficient power deliveries as it requires scheduling, control, and proper sizing. The variability and uncertainty of the electrical load would need an efficient energy management system (EMS) for a microgrid where it could cover both supply and demand side management while also providing reliable, sustainable, and economical operations. The proposed control strategy, based on model predictive control (MPC) of the incremental type, will show the effectiveness in handling the changes in loads and variability of RES power in a MG while maintaining the power dispatch to meet the demand. This will showcase its fast response in handling load disturbances and variations in a MG. Therefore, when there is a shortage of power the controller will discharge the battery to supplement the demand, and when there is surplus generation, it will be utilized to charge the battery while satisfying the battery energy storage system (BESS) and MG optimization constraints. To provide the most efficient lifetime for the battery this will include the state of charge of the battery and the upper and lower charging power limits based on the rated capacity of the BESS. These constraints will also provide controls for the battery charging to smoothen the coupled RES power.

This paper proposes an energy management system for the optimal scheduling of domestic (local) energy consumption as a control scheme for MGs, as shown in Fig. 1. An IEEE 33-bus power distribution system is considered as a baseline for RES placement configurations. The goal is to develop a test system that can represent a typical distribution system close to real networks considering a hybrid MG model. In this case, we integrate an MG to a general load bus containing an end point where a greater demand of electrical power is consumed. The combined generation of photovoltaic (PV) and wind power will charge and discharge the BESS making a hybrid EMS system minimizing the need for the main grid to supply power when required. Thus, a power balance equation between the main grid and MG must be satisfied. A variable load profile would be considered as it will provide a more realistic user ended power consumption for a hybrid integrated MG. The grid test system and MG simulations will be conducted and analysed to achieve an optimal and economical power dispatch. The optimization will be carried out and computed using MATLAB/SIMULINK quadratic optimization techniques.

REFERENCES


Distribution Systems with Smart Homes Employing PV, Electric Battery, and HVAC Energy Storage

Steven Poore, Student Member, Rosemary E. Alden, Student Member, IEEE, Evan Jones, Member, IEEE, and Dan M. Ionel, Fellow, IEEE

Abstract—Battery energy storage systems (BESS) can be used for demand response (DR) and load shifting. Large residential appliances like electric water heaters (EWH) and heating, ventilation and air-conditioning (HVAC) can be controlled to perform the same functions as batteries, reducing capital cost and decreasing energy storage capacity requirements when applied for multiple homes in a community. The CTA-2045 Standards, an industry communications protocol, is used for generalized energy storage (GES) controls and operations. A case study is conducted on the comparison of BESS discharge with HVAC equivalent energy storage controls on a distribution feeder with 350 houses, realistic load profiles, and home construction. It is demonstrated that HVAC setpoint controls for pre-cooling through “load-up” and “shed” commands may successfully reduce evening peak.

Index Terms—Genralized Energy Storage, HVAC, BESS

I. GENERALIZED ENERGY STORAGE INTRODUCTION

Large-scale use of battery energy storage systems (BESS) can reduce peak demand and energy cost. At the aggregate level BESS can be controlled to reduce battery cycling, shift loads to times of high PV generation, and lower energy costs through time-of-use (TOU) pricing. A disadvantage of BESS is high capital cost, but large residential loads such as electric water heaters (EWH) and heating ventilation and air-conditioning (HVAC) can be controlled to perform the same functions as a battery. This method minimizes cost by decreasing energy storage capacity requirements. Algorithms can be developed to control these appliances in a way that optimizes energy and cost, shifting energy use of large loads to have a significant combined effect on the distribution system, decreasing energy usage and peak demand.

II. CASE STUDY: HVAC ENERGY STORAGE AND BESS COMPARISON

A case study was conducted as an expansion of a previous study by our group. The IEEE 123 Bus node system (Fig. 1) populated realistic values was used to simulate CTA-2045 DR. When a CTA-2045 command such as "load-up" (hours 7-15) or "shed" (hours 15-22) is issued, individual indoor temperature setpoints are adjusted based upon their estimated equivalent energy capacities. During a "shed" event, operation is stopped while stored energy decreases. While in "load-up", the appliance operates and stores more energy if possible.

The use of HVAC energy storage was compared to discharge of typical residential batteries for DR and load-shifting to coordinate with distributed solar generation. For this study, residential batteries were assumed to be charged to full capacity early during off-peak hours, then discharged later in the day to decrease evening peak (4-9 PM). It was determined that while controlled HVAC energy storage decreased evening peak, the use of BESS decreased evening peak significantly more in the ideal scenario of being charged to full capacity during off-peak hours (Fig. 2). As shown in Fig. 2a, PV generation does not align with peak demand, but energy storage controls can be coordinated to shift loads to times of high PV generation, decreasing energy usage during high TOU pricing periods. With the rise of electric vehicles (EV), it is urgent that evening peak be reduced to avoid the "shark curve" due to many EV owners arriving home from work to charge their vehicles around 5 PM.

Figure 1. An IEEE 123 modified bus test feeder with residential loads and utilized for the study described in the paper (a). Multiple DERMS in a community can coordinate to respond to service requests from the grid (b). Control signals will have slight variation but must remain within a specified tolerance for optimal performance (c).

Figure 2. (a) In controlled cases, BESS and HVAC can be used to lower residential load during high TOU periods. (b) The results from the case study show both controlled HVAC and BESS can reduce evening peak. In the ideal scenario, BESS reduces the demand significantly more when compared to controlled HVAC, to as low as zero around 7 PM.

Steven Poore, Rosemary E. Alden, Evan S. Jones, and Dan M. Ionel are with SPARK Laboratory, Electrical and Computer Engineering Dept., University of Kentucky, Lexington, KY.
Abstract—A data-driven and scalable approach for real-time emulation of hydropower plants is presented using hardware-in-the-loop (HIL). The proposed setup is capable of supporting mechanical- and electrical power HIL (PHIL) and utilizes variable frequency drive and induction machines to emulate hydro-turbine and generator dynamics and can be configured for different hydropower plant designs, capacities, inertia, and grid interfaces. Some preliminary results from data-driven characterization of hardware emulation devices is performed to obtain a dynamic performance baseline. The coupling approach for emulated hydro turbine-generator will also be presented.

Index Terms—hardware-in-the-loop, real time simulation

I. INTRODUCTION

Hydropower has been a grid-scale clean generation and storage for decades. Due to adoption of renewable energy sources and increasing integration of inverter-based resources, the role of hydropower may become more critical. To meet the dynamic grid requirements, hydropower technology needs to adapt. To evaluate any modifications, control prototyping, performance validation and de-risking grid integration, a high-fidelity environment is required. In this work, we present a data-driven emulation platform for hydropower using real-time hardware-in-the-loop (HIL) approach. This approach offers advantage of allowing scalable emulation, i.e., different plant designs can be simulated in real-time and scaled dynamic response can be obtained on the hardware setup to support mechanical and electrical power HIL. The platform also supports variable speed operation through variable frequency drive (VFD) and can be used for integrated testing of variable-speed hydropower. This work aims to characterize and scale real-time model and HIL for shaft speed, torque, and power. We provide details on our approach and analysis of the dynamic experimental results.

II. PROPOSED APPROACH AND PRELIMINARY RESULT

The main objective is to faithfully represent shaft dynamics from real-time simulation to hardware emulation. To support this, the first step is to characterize the integrated VFD and IM response (wide-band) to obtain transfer functions, and then calibrate “scaling block” using physics and machine learning for desirable dynamic response (see Fig. 1). As a preliminary result the transfer function model [1] of (VFD+IM) when induction motor is set to operate at 59 Hz is found to be $\frac{-40.43s - 50.17}{s^2 + 1511s + 131}$. 

III. CONCLUSION

The data-driven approach with multi-point linearization provides a good dynamic response for VFD+IM. The work is under progress for scaling the hydropower for different inertia and capacities.

REFERENCES

Dynamic Modeling of Offshore Wind with Data-Driven Approach using Neuromancer

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Abstract—The offshore wind power industry is continuously growing and contributing to clean and green energy. However, due to the complexity and dynamics of the system, dynamic modeling is necessary to study and analyze system behavior under various operating conditions and disturbances. In this poster, we present data-driven dynamic modeling using Neuromancer (Neural Modules with Adaptive Nonlinear Constraints and Efficient Regularizations) to predict the behavior of the system under different operating condition and provides efficient regularization methods that can help to improve the accuracy and generalization of the models.

Index Terms—Offshore wind, data-driven, Neuromancer.

I. BACKGROUND

HVDC offshore wind is a highly complex and dynamic system that requires refined modeling techniques to fully understand and optimize its behavior. It is a complex system as it involves the integration of wind turbines, power converters, cables, and transformers, and its dynamic modeling is necessary for understanding the behavior of the system to see its performance and stability. For this, we can train the neural network using the Neuromancer which is a Pytorch-based framework for solving parametric constrained equations [1]. The framework can be used to develop models that predict the system's behavior under different operating conditions and environmental factors. Neural ODEs (Ordinary Differential Equations) are used for solving differential equations, which do not involve constraints whereas Neuromancer can be used to solve optimization problems subject to constraints. Neuromancer is particularly well-suited for problems with complex and nonlinear constraints and combines constraint optimization practices and control theory in one unified package.

II. PROPOSED FRAMEWORK

Fig. 1 shows the flowchart of the proposed method. First, the input-output data is collected i.e., inputs are the wind speed and pitch angle, and outputs are the active power, reactive power, and voltage at the point of coupling (POC). Other inputs are the model architecture, which is in the state space equations. The architecture consists of the input layer, hidden layer, and output layer. It is first initialized with random weight and biases. The inputs are passed to the integrator, which is a fourth-order Runge-Kutta method. The integrator is used due to the differential equations which describe the dynamics of the offshore wind system. Also, the integrator gives the discrete function which is used to predict future values. The optimization can be done by gradient descent and back-propagation which are the auto-differentiation properties of PyTorch. If the Δloss is within the limit, the loop exits; otherwise, the loop continues to run. Here the primary objective is to construct the model and learn the parameter from the observation data to provide an accurate and robust long-term output prediction. [1]

Fig. 1: Flowchart of the proposed method.

III. CONCLUSION

Overall, Neuromancer can be a valuable tool for the dynamic modeling of offshore wind farms as it can provide accurate predictions of their behavior under different operating conditions. Also, it can handle nonlinear and complex dynamics, which are common in offshore wind systems.

IV. ACKNOWLEDGEMENT

This work is supported by the U.S. Department of Energy under grant number DE-SC0020281, and National Science Foundation (NSF) grant number MRI-1726964 and OAC-1924302.

REFERENCES


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Abstract—With the proliferation of Electric Vehicle Charging Stations (EVCS), efficacious cybersecurity measures are crucial to mitigate the risk of cyber threats from nefarious adversaries who can exploit vulnerabilities in the network, ultimately undermining its confidentiality, integrity, and availability, as well as posing a threat to the power grid. Nonetheless, optimizing cybersecurity investment poses a challenge due to limited financial resources, compounded by the constantly changing tactics of attackers and the constantly transforming spectrum of security risks, rendering current solutions inadequate for practical implementation. In response, we propose a methodology that leverages Attack Defense Trees and Game Theory to optimize investment strategies for EV charging station cybersecurity. The proposed methodology utilizes Attack Defense Trees (ADTs) to scrutinize potential cyber-attack paths and devise defensive strategies to thwart such attacks. An extended CIA triad model and the MITRE ATT&CK framework work as a valuable combination in formulating these ADTs. Furthermore, the methodology adopts a Game-Theoretic approach to model attacker-defender interactions, enabling defenders to identify the most effective strategies to minimize losses against potential attack threats, thereby facilitating the protection of critical infrastructure.

Index Terms—Cybersecurity, Attack Defense Tree, Game Theory, CIA triad, MITRE ATT&CK

I. INTRODUCTION

Smart Grids are revolutionizing the current electrical grid using advanced technologies, where EVs play a paramount function. The global EV fleet has been growing at an unprecedented pace, which has led to the development and adoption of infrastructure and associated technologies to support this expansion. Consequently, there has been a significant increase in the number of EVCSs installed to meet customer demands and enhance service standards.

Although this revolution has vastly improved several aspects of our lives, its volatility and the large range of accompanying vulnerabilities have raised serious security and management issues. EVCS ecosystems are becoming extremely susceptible to cyberattacks because of the continuous monitoring and data flow between EVs and EV chargers. For instance, an adversary could exploit a vulnerability in communication protocols (ISO 15118 or OCPP) to inject a cross-site scripting payload, leading to disabling the charger, installing malware, and circumventing hard-coded authentication credentials, enabling privilege escalation.

The preceding decade witnessed numerous techniques such as Petri net, Hidden Markov Model, and Attack Graphs to enhance cybersecurity investments in different applications. While these approaches exhibited considerable proficiency in carrying out an array of security functions in recognizing weaknesses, establishing protective measures, performing risk assessments, and refining cybersecurity resources, none of them fulfilled all the prerequisites for securing the security of EVCS. Addressing this gap, our research proposes a hybrid methodology that amalgamates ADTs, created through the extended CIA triad model and the MITRE ATT&CK framework, with a game-theoretic approach. The hybrid model’s primary objective is identifying attack surfaces in the EVCS and optimizing the defender’s investment resources to safeguard the environment from cyberattacks.

II. METHODOLOGY

The proposed methodology utilizes and evaluates using a hybrid model comprising of ADT and Game Theory.

Step 1: Initially, an ADT is implemented which is a hierarchically structured tree that effectively identifies and analyzes potential attack-access points in the EVCS, providing an avenue to suggest suitable defense mechanisms. Our ADTs’ underlying basis is the extended CIA TRIAD, a comprehensive security analysis methodology that evaluates six fundamental security elements, coupled with the MITRE ATT&CK framework, aiding us in comprehending the strategies and tactics that the attacker is likely to employ.

Step 2: Post the creation of the ADT, Strategy spaces are established. Attack Strategy Space ($S_a$) = \{AP$_1$, AP$_2$, ..., AP$_n$\} comprises the entire set of available attack paths that the adversary can use to achieve their objective, while Defense Strategy Space ($S_d$) = \{DS$_1$, DS$_2$, ..., DS$_n$\} represents a collection of defender strategies that are needed to invest in defense nodes to protect all attack paths in $S_a$.

Step 3: Our methodology subsequently employs a Game Theoretic approach utilizing Nash Equilibrium and a zero-sum game formulation (where the attacker and defender’s payoff sums up to zero) which leads to optimizing the defender’s resource allocation to secure the EVCS components that the attacker can exploit.

Step 4: The final output value is the production of an Optimal Strategy ($S'_o$) for the defender, providing an exact and concise means of safeguarding the EVCS environment against potential cyber threats.
MIMO Model Predictive Control for Demand Management in Islanded Water-Energy Microgrids

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∗ Lehigh University
† University of Notre Dame
Email: sap322@lehigh.edu

Abstract—This paper proposes a multiple input multiple output (MIMO) model predictive control (MPC) strategy for demand management of an integrated water distribution system (WDS) and islanded microgrid (MG) system. The proposed closed-loop optimization framework leverages the interlinks between the water and energy supplies to provide an optimal and stable delivery of clean water and electricity to islanded communities. The results demonstrate the feasibility of the proposed interlinked water-energy MPC algorithm to provide efficient water and energy demand management, ensuring the reliability of MPC in both systems concurrently for real-time demand management.

Index Terms—Model Predictive Control, Water Distribution System, Off-grid Microgrids System, Demand Management

I. INTRODUCTION

Co-optimization of water-energy microgrids studies have shown effective energy and water conservation through optimal scheduling. However, this approach lacks feedback control and can lead to significant error margins when dealing with disturbances, which are a major challenge for water-energy microgrids. This paper proposes a novel MPC framework for integrated water-energy microgrids that incorporates the full dynamics of energy-consuming assets and considers the energy management of the microgrid assets with conceptual layout illustrated in Fig. 1(a).

II. PROPOSED METHODOLOGY

MPC formulation shown in Fig. 1(b) is developed to minimize the tracking error between the output flows of the water tanks with the water demand, as well as the power dispatch of the microgrid with the electrical demand such that demand compliance is always guaranteed. This objective is pursued while ensuring operational goals such as achieving smoothness of the actuators and limiting the power rates to protect the instruments from water-energy demand fluctuations.

III. RESULTS AND CONCLUSIONS

The results shown in Fig. 1(c), indicated the capability of the proposed combined MPC algorithm as the control strategy of the water-energy microgrid to simultaneously meet the demand and satisfying the constraints. Results of the case studies demonstrated that MPC can adapt to different operational conditions and manage the available energy sources efficiently.

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Protection of Multi-Terminal Hybrid Transmission Lines Based on Dynamic States Estimation

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Abstract—Multi-terminal hybrid transmission lines including overhead lines and cables are adopted to connect off-shore wind farms to the power grid. This paper proposes a protection method for multi-terminal hybrid lines through dynamic states estimation. The method accurately considers the shunt capacitance through the overhead line and cable. Firstly, the dynamic model of the multi-terminal hybrid line is established, where the distributed parameter lines are modeled by multiple π sections. All the physical laws are listed through differential and algebraic equations (DAEs) in matrix forms. Secondly, the principle of dynamic states estimation (DSE) is presented to quantify the consistency between the healthy line dynamic model and the available measurements at all terminals of the line, and the protection logic is designed. Numerical experiments of an example test system show the operation speed, dependability and security of the DSE based line protection.

Keywords—transmission line protection, dynamic state estimation, multi-terminal lines, hybrid lines

I. BACKGROUND

Recently, the multi-terminal hybrid transmission have been applied in power systems. The complexity of the lines make traditional protection methods less effective. Thus, the dynamic state estimation (DSE) based protection is applied to solve the protection challenges for multi-terminal hybrid lines. DSE is a powerful tool in tracking power system transients. The main idea is to identify the consistency between the available measurements and the dynamic line model via DSE, and formulate the protection logic.

II. DYNAMIC MODELS AND PROTECTION LOGIC

The modeling methodology for the three-terminal hybrid transmission line is presented in Fig.1, where each line segment is divided into multiple π sections.

![Figure 1. single phase view of three-phase multi-terminal system](image)

The physical laws of the healthy lines can finally be converted to the formula below through extract and integration:

$$z(t) = Y_{eq} x(t) - B_{eq}$$  \hspace{1cm} (1)

Where $z(t)$ includes the measurements, $x(t)$ represents states of each π section, $Y_{eq}$ and $B_{eq}$ are coefficient matrices made up of line parameters.

The protection logic is designed to quantify the consistency between the measurements and the dynamic model derived in (1). To achieve this, the residual is first defined as the difference between the estimated values and the real ones:

$$r(t) = \hat{z}(t) - z(t) = Y_{eq} \hat{x}(t) - B_{eq} - z(t)$$  \hspace{1cm} (2)

Then, the chi-square value is defined through weighted least square:

$$J(t) = r(t)^T W r(t)$$  \hspace{1cm} (3)

Obviously, the achieve of minimum of $J(t)$ gives the best estimation of $x(t)$, which is:

$$\hat{x}(t) = (Y_{eq}^T W Y_{eq})^{-1} Y_{eq}^T W (B_{eq} + z(t))$$  \hspace{1cm} (4)

III. SIMULATION RESULTS

The simulation shows the $J(t)$ of internal low impedance fault, internal high impedance fault and serious external fault respectively in Fig.2. The internal and external fault events are significantly different in chi-square value so the protection method can correctly work.

![Figure 2. chi-square values of internal low impedance fault, internal high impedance fault and serious external fault](image)

This work is sponsored by National Natural Science Foundation of China (No. 51807119) and Key Laboratory of Control of Power Transmission and Conversion (SJTU), Ministry of Education (No. 2022AB01). The support is greatly appreciated.
A Lagrange-multiplier-based Reliability Assessment for Power Systems Considering Topology and Injection Uncertainties

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Abstract—With the expansion of power grids and the growth of renewable energy generation, more uncertainties of topology (e.g., components outages) and injection (e.g., renewable energy outputs variations) need to be analyzed. As a result, analyzing a myriad of system states with optimal power flow (OPF) is challenging and this seriously restricts the efficiency of reliability assessment. To address that, this study proposes a Lagrange-multiplier-based approach to accelerate the analysis without sacrificing accuracy. The core idea is to directly obtain the optimal load shedding of topology changes and injection variations by Lagrange multiplier-based functions, rather than the time-consuming OPF algorithms. Results indicate that the proposed method can significantly reduce the computing time without compromising the calculation accuracy. 

Keywords—Lagrange multiplier, topology change, injection variation, reliability assessment

I. INTRODUCTION

Reliability assessment is crucial for evaluating the power supply ability and plays a significant role in power system planning and operation. With the expansion of power grids, the uncertainties of topology and injection lead to more serious security threats to power systems. As a result, the evaluation of an enormous number of system states considering these uncertainties impose a large computational burden for the reliability assessment.

The heavy computational burden of the state enumeration (SE) method can be attributed to two aspects: the number of system states and system state analysis. While most studies focus on reducing system states, few address the acceleration of system state analysis. Therefore, a Lagrange-multiplier-based reliability assessment (LM-T&I) method is proposed to establish the relationship among the optimal load shedding and the variables of system states, as shown in (2) and (3).

\[ f_{LS} = c_b B^{-1}(b + \Delta b) = c_b A(\text{Col})^{-1} (b + \Delta b) = w(b + \Delta b) \] (2)

where \( w \) is called the Lagrange multiplier; \( \text{Col} \) is the column number of optimal basis \( B \).

Next, the invariance criteria of Lagrange multiplier considering topology and injection states (3)-(5) are proposed to update the Lagrange multipliers, which further ensures the accuracy of the Lagrange multiplier-based linear functions.

\[ B^{-1}(b + \Delta b) \geq 0 \] (3)
\[ A(\text{Col})^{-1}(b + \Delta b) \geq 0 \] (4)
\[ c - c_b A(\text{Col})^{-1} A \geq 0 \] (5)

The (3) is used for injection states, while (4) and (5) are used for topology states. If the criteria are true, the optimal load shedding of states can be calculated by (2), otherwise, the system state must be analyzed by OPF optimizations.

III. CASE STUDY

The MCS, SE, and proposed LM-T&I methods are used to evaluate the reliability of RTS-79. The reliability assessment results are shown in Fig. 2.

The results show that the proposed LM-T&I method can remarkably improve the computing speed over 20 times without the loss of accuracy. More than 95% of system states can be directly analyzed by Lagrange-multipliers-based linear functions, rather than the time-consuming optimization algorithms. Moreover, this approach can also be conveniently integrated with the impact-increment method and the clustering technique for further efficiency enhancement.

- In the system state evaluation, the optimal power flow (OPF) is used to analyze each system state and calculate its consequences. The DC OPF model is:

\[ \min f_{LS} = c^T x \]
\[ \text{s.t. } Ax = b, \quad x \geq 0 \] (1)

where \( f_{LS} \) is the optimal load shedding. The matrices \( A \) and \( b \) vary with topology and injection respectively.

With the integration of more components, renewable generations, and loads in the power systems, it inevitably takes too much time to evaluate numerous system states. To address this, Lagrange multipliers are carried out to derive the relationship between the optimal load shedding and the variables of system states, as shown in (2) and (3).

The DC OPF model is,

\[ \sum_{i=1}^{N} a_i (x_i - x_{\text{Min}}) = 0 \] (2)

where \( a_i \) is the weight of the system state, \( x_i \) is the state of the system state, and \( x_{\text{Min}} \) is the minimum state of the system state.

![Fig. 1. The framework of the proposed LM-T&I method.](image)

![Fig. 2. Comparisons of computation efficiency.](image)
Data-driven Distribution State Estimation in Active Distribution Networks

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Abstract— The paper proposes a data-driven state estimation algorithm applied in microgrids where there is only limited number of measuring devices. Two deep neural network models are trained separately for voltage magnitudes and voltage angles. It is shown that the proposed algorithm is robust against unexpected changes compared to the conventional Weighted Least Square (WLS) method in an active distribution network. The proposed model is tested for both voltage magnitudes and angles on the 36-bus microgrid. The results show that the proposed state estimation algorithm gives more accurate results compared with the conventional WLS method.

Keywords—Deep Neural Network, Maximum Average Percentage Error, Mean Absolute Error, Microgrid, Root Mean Square Error, State Estimation.

I. INTRODUCTION

Due to the intermittent power injections by Distributed Generations (DGs), lack of direct control over them, and limited number of smart measuring devices, Active Distribution Networks (ADNs) face new challenges in terms of control and monitoring. Distribution System State Estimation (DSSE) is introduced to determine the states of the system, i.e., bus voltages and line currents in ADNs for monitoring and control purposes. State Estimation (SE) techniques are non-linear mathematical algorithms to estimate the states of a system using available raw measurements [1]. Conventional DSSE methods are mainly model-based techniques where the physical model of the system is known. One of the most common model-based SE method is Weighted Least Square (WLS) [2]. Due to high penetration of stochastic renewable energy resources and highly variable loads, conventional DSSE methods fail to address the high uncertainty and monitor every change. To overcome these issues, data-driven or model-free SE algorithms based on Artificial Intelligence (AI) and Machine Learning (ML) are introduced to reduce the computation time and increase the accuracy of the results.

The main contributions of this paper are:

1. Develop a machine-learning based SE algorithm to estimate the states of the system precisely using limited number of available measuring devices.
2. Different noises are considered to model bad data and the proposed SE model is designed to be robust against the bad data.

II. METHODOLOGY

In order to estimate both voltage magnitudes and voltage phase angles, two separate DNNs are developed and trained using the input data (available measurements). The training model has two hidden layers. The number of neurons in the first and second hidden layers are 150 and 80, respectively. The number of input layer is equal to available measurements.

III. SIMULATION RESULTS

36-nodes microgrid [3] is suitably adapted to include mix of commercial and residential loads (OpenEI) [4], and distributed PV system is utilized for evaluation purpose. One PV (DG) is placed at bus 24. We assumed that there is only one PMU located at the bus 1. Random Gaussian with $3\sigma = 1\%$ and $3\sigma = 1\%$ are selected for voltage magnitude and voltage angle, respectively. True and estimated values are shown in Figure 1 when half of all DGs and loads are available.

![Figure 1: True Voltage Magnitude, Estimated Voltage Magnitude for proposed and WLS Methods](image1.png)

The voltage magnitude of bus 24, where the DG is installed, is shown in Figure 2 for the period of two days.

![Figure 2: Voltage magnitude (Volt) of Bus 24 for two Days.](image2.png)

IV. CONCLUSION

It was shown that the proposed data-based algorithm is robust against unexpected changes compare with the conventional WLS method.

V. REFERENCES


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PM-Assisted Sub-Harmonic Synchronous Machine

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Abstract—A novel pm-assisted sub-harmonic synchronous machine is presented in this paper based on already introduced two-layer sub-harmonic synchronous machine. The aim of this work is to increase the torque-producing capability of the brushless wound rotor machines while keeping the use of rare earth magnets to a minimum. To validate the proposed model, a 2D finite element analysis has been performed and compare the performance with the reference model. The results demonstrate that the proposed machine's average torque has increased.

Keywords—Sub-harmonic Synchronous Machine, Permanent Magnet Synchronous Machine, Hybrid Excitation.

I. INTRODUCTION

Permanent magnet (PM) machines in the form of interior permanent magnet (IPM), surface permanent magnet (SPM), and brushless direct current machines have dominated the industrial markets because of their high torque density, efficiency, and less weight. However, expensive PMs bring complexity in wide speed operation. Nonetheless, brushless wound rotor synchronous machines (BL-WRSMs) are reviving to fill the void. Among modern brushless techniques, in 2015 [1], a sub-harmonic excitation technique was introduced. In 2022, using this concept, a novel 2-layer [2] and a new 3-layer [3] sub-harmonic machine was presented. Based on the 2-layer stator winding arrangement, a PM assisted sub-harmonic synchronous machine is presented in this paper, where the design is simulated and analyzed with Ansys Maxwell software.

II. PROPOSED TOPOLOGY

The proposed machine structure if shown in Fig. 1. The stator of the machine has two series connected windings: ABC and XYZ. Moreover, they are supplied from an inverter. With an identical current 8-pole ABC generate 8-pole MMF and 2-pole XYZ will generate 2-pole MMF. The rotor consists of 2-pole harmonic and 8-pole field winding. The 2-pole MMF from the XYZ induces 2-pole harmonic winding. A diode rectifier, mounted on the rotor shaft, that rectifies the AC voltage to DC and supplies to the 8-pole field winding. With this DC current, the field winding magnetically locks with the 8-pole ABC winding and starts to generate torque. Moreover, a hybrid excitation is used in the rotor, where flux generates from the windings and the PMs. Moreover, a series hybrid design is used in which the flux from the windings and the PMs flow in the same path. The volume of PMs used is less than the IPMs, and SPMs, hence the cost does not increase much. Simulation results are shown in Fig 2(a), 2(b), and Table I, where the proposed machine is compared with WRSM, SHSM, and 2L-SHSM.

![Fig. 1. Structure of the PM-2L-SHSM.](image1)

III. CONCLUSION

In this paper, a novel PM-assisted 2-layer sub-harmonic brushless wound rotor synchronous machine has been introduced. The 2D-FEA analysis ensures better average torque production compared to BL-WRSM and SHSMs. Considering all these, the proposed topology replace WRSMs and PMSMs in transportation electrification applications.

TABLE I. COMPARATIVE ANALYSIS

<table>
<thead>
<tr>
<th>Indicators (Unit)</th>
<th>WRSM</th>
<th>SHSM</th>
<th>2L-SHSM</th>
<th>PM-2L-SHSM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stator current (A)</td>
<td>4.50</td>
<td>4.50</td>
<td>4.50</td>
<td>4.50</td>
</tr>
<tr>
<td>Field current (A)</td>
<td>9.50</td>
<td>9.80</td>
<td>20.18</td>
<td>16.66</td>
</tr>
<tr>
<td>Harmonic current (A)</td>
<td>-</td>
<td>5.10</td>
<td>14.78</td>
<td>13.38</td>
</tr>
<tr>
<td>Average torque (Nm)</td>
<td>7.30</td>
<td>7.83</td>
<td>12.03</td>
<td>13.35</td>
</tr>
<tr>
<td>Efficiency (%)</td>
<td>81.53</td>
<td>79.22</td>
<td>81.10</td>
<td>85.43</td>
</tr>
</tbody>
</table>

REFERENCES

Distributed Control and Testbed Validation for Cyber-Power Distribution System Security and Resiliency

Md Fazley Rafy Student Member, IEEE, Anurag K. Srivastava Fellow, IEEE

Abstract—Rapid progression of digital automation in distribution power system enables reliable operation but also invokes the increased attack surface. Advanced detection and mitigation techniques are needed to minimize the impact of the cyber events. These techniques need to be validated using an efficient testbed emulating different control strategies and applications before industry implementation. In this paper, Mininet and OpenDSS-based co-simulated testbeds with both distributed and centralized control have been developed. Functionalities of these two different frameworks have been compared using suitable metrics for voltage control applications for three different simulated cyber events. Intrusion detection mechanism have been also developed and integrated for a thorough comparative analysis to determine most suitable algorithm for resiliency.

Index Terms—Cyber-Power Systems, DER, Co-Simulation, Test-bed, Mininet, Distributed Optimization, Cyber-attacks, Intrusion Detection.

I. INTRODUCTION

Integration of distributed energy resources (DER) with digital control into the power grids have led to reliability and sustainability but also brings variability and vulnerability. To address challenges with DERs, different controller mechanisms, such as local, centralized and distributed coordination is utilized for voltage or frequency control. Moreover, with the increasing deployment of sensors, cyber networks, control algorithms, and communication protocols the scope of cyber threats and contingencies is becoming a great concern for grid operators. Hence, the use of an efficient control strategy is essential for the security, resilience, operability, and manageability of the modern power grid. This work examines centralized and distributed controller strategies with the integration of DERs in a co-simulated testbed environment. Both IEEE-13 and IEEE-123 3Φ-phase distribution network test cases were used with different voltage control algorithms and multiple simulated cyber attacks were used to validate the performance of both the strategies.

II. VOLT-VAR & VOLT-WATT CONTROL WITH DERs

Two different kind of distributed feedback-based controller (Volt-VAR & Volt-Watt) that guarantees asymptotic convergence of voltage-related constraints have been used in this paper [1]. Our objective would be to minimize the cost of reactive power injection for Volt-VAR and active power curtailment for Volt-Watt. Given the DERs are expected to operate at their maximum power point, the associated impact on the controller model has been considered. Performance analysis of the controller is provided utilizing our testbed.

III. CENTRALIZED AND DISTRIBUTED CONTROLLER

OpenDSS and Mininet-based Cyber-Physical Systems (CPS) with DERs have been emulated in a Python-Wrapper testbed to validate the performance of different control strategies. The applications and use cases used in the analysis were generalized for both of these controllers to gain effective comparison.

IV. CYBER ATTACK SIMULATION

Three cyber-attack scenarios, namely, the Man-in-The-Middle (MiTM), Denial-of-Service (DoS), and Replay Attack, have been simulated and used with the capability of attacking multiple hosts in the communication layer. Considering the proposed distributed Volt-VAR & Volt-Watt algorithm as a use case, the impacts of the said cyber-attacks on the controller performance have been evaluated.

V. NETWORK-LEVEL DETECTION

Rule-based detection mechanisms have been developed to identify potential anomalies in the network. Snort is used with modified detection rules which trigger anomalies in the network packets and logs the packet information for further analysis.

VI. PERFORMANCE METRICS

Impact analysis of the applications on both the centralized and distributed controller are defined based on resiliency metrics, performance analysis of different architectures, and comparative analysis of the same.

VII. SUMMARY

The paper presents an end-to-end co-simulation that provides insights into the power system controller performance of the centralized and distributed controller. Comparative analysis is performed to validate the performance of both control strategies with similar metrics. The proposed IDS identifies cyber network anomalies in the network identify the grid operator of potential contingency. The future work includes incorporating mitigation tools and developing network restoration mechanisms after cyber contingency to develop a more robust and resilient Cyber Physical Distribution Power System.

REFERENCES

Abstract—Nuclear power plants are changing their traditional way of operation to a more flexible mode to support the demand for renewable energy and reduce carbon emissions. This change allows them to respond quickly to changes in energy prices and generation mix, making them more valuable in the electricity market. It is important to include flexibility as a feature in future nuclear plant deployment to keep up with the increasing need for flexible operation in the power system. Modeling nuclear plants as regular thermal plants limits their potential, and more research is needed to capture their unique operational dynamics. This study develops a comprehensive steady-state model of a small modular reactor (SMR) suitable for multi-cycle power system operation and takes into account real-time unit commitment and day-ahead forward electricity market models. The model can be used in a market simulation environment to generate electricity price signals, where the physical operational characteristics of SMR are captured.

I. INTRODUCTION

This study focuses on modeling the steady-state characteristics of a pressurized water reactor (PWR) type SMR. Control rods are used to modify the power output of a nuclear plant, with insertion reducing power output and withdrawal increasing it. The accuracy of power output control depends on the neutron absorbing capacity of the control rods. However, control rod maneuvering causes a significant change in fuel temperature, which can result in fuel cladding failure if done too quickly. Therefore, the rate at which core power can change is limited to within the design tolerance of the fuel assemblies. Ramp rates of up to 2-5.2% of rated power capacity per minute can be safely managed on a regular basis, depending on the reactor design, but reactor operators typically proceed more conservatively to limit stress on reactor components. Following changes in reactor power output, the concentration of xenon-135 ($^{135}$Xe) in the core changes over several hours. When the power output decreases, the concentration of $^{135}$Xe initially increases, reaches a maximum, and then decreases until a new equilibrium is reached. Following a decrease in power, nuclear plant operators usually keep the output steady for a certain duration, typically one or more hours, before increasing it again as illustrated in Fig. 1. In this work we have modeled these ensuing operating constraints on the timing and depth of ramp maneuvers in a multi-timescale power system simulation framework.

II. XENON-TRANSIENT CONSTRAINTS MODELING

A. Day-ahead Security Constrained Unit Commitment (DASCUC) Model

In the DASCUC model, the incorporated constraints represent the most coarse operational characteristics. The xenon poisoning impact on the nuclear operation maneuver is represented by Eq. 1, which ensures that a ramp-up event cannot occur for at least $T_H$ (hold-time) hours after a ramp-down event.

$$[\text{ramp}_{\text{up},g,t} - \text{ramp}_{\text{up},g,t-1}] \cdot T_H = \sum_{\tau=t-T_H}^{t-1} (\text{stable}_{g,\tau} + \text{ramp}_{\text{up},g,\tau}), \forall g \in G, \forall t \in T > T_H$$

B. Real-time Security Constrained Unit Commitment (RTSCUC) Model

The RTSCUC formulation for SMR characteristics is mostly focused to represent the probable transition in its ramping status. These constraints direct the SMR to retain its stable status or ramp-up or down based on its ramping status at the inception of the RTSCUC update interval while respecting any binding status carried over from the more coarse DASCUC decisions.

$$[\text{ramp}_{\text{up},g,t} - \text{ramp}_{\text{up},g,t-1}] \cdot T_H / I_{RTC} \leq \sum_{\tau=t-T_H/I_{RTC}}^{t-1} (\text{stable}_{g,\tau} + \text{ramp}_{\text{up},g,\tau}), \forall g \in G_{NPP}, \forall t \leq T - T_H / I_{RTC} + 1$$
Abstract—Low-inertia microgrids have larger frequency deviations than bulk-power systems, and energy storage systems (ESSs) can provide fast frequency support. A model predictive control (MPC)-based strategy is one of the effective control strategies to enable fast-frequency support. MPC provides the flexibility to incorporate physical constraints. However, its effectiveness relies on the accuracy of the predictive model. In this paper, a data-driven system identification (SI) based MPC is proposed for frequency support in microgrids. The results show that the SI MPC offers a better quality of service (QoS) through lower frequency deviations and rate-of-change of frequency (ROCOF).

Index Terms—Frequency support, model predictive control, system identification data-driven, log chirp

I. PROPOSED FRAMEWORK

The framework has two main parts: system identification (SI) and model predictive control (MPC) for frequency support. The SI uses a modified Cordova Benchmark model and a chirp signal to gather data and identify power system frequency dynamics as shown in Fig. 1.

Let \( N \) be defined as the length of the time horizon and \( y_k = [\Delta \omega_k \ \Delta \dot{\omega}_k] \) is output of the system (\( \Delta \omega_k, \Delta \dot{\omega}_k \) are frequency and rate-of-change of frequency), and \( \Delta u_k \) be the control input (ESS inverter power). The MPC is formulated as:

\[
\min_{x, u} J = \sum_{k=0}^{N-1} (y_k^T Q y_k + \Delta u_k^T R \Delta u_k) + y_N^T Q y_N
\]

subject to

\[
x_{k+1} = F(x_k, u_k) \quad \forall k \in \{0, 1, 2, ..., N - 1\}
\]

\[
|\Delta u_k| \leq P_{\text{max}} \quad \forall k \in \{0, 1, 2, ..., N - 1\}
\]

where \( J \) is the cost function to be minimized, and \( Q \) and \( R \) are the weighting matrix for control error and input penalty, respectively. A Kalman filter (KF) state estimator is used to estimate the system’s current state required using the frequency measurement. A schematic of the MPC-KF-based approach is shown in Fig. 2.

II. KEY RESULTS

Phase-locked loop (PLL) measures microgrid frequency, but is prone to noise. Center of Inertia (COI) provides more accurate frequency estimation and is used as a benchmark for evaluating SI performance. Fig. 3 shows the training and testing results, demonstrating that COI provides a better fit than PLL, particularly for low-frequency excitation signals. However, the fit between the PLL and COI data is low for larger frequencies. Fig. 4 shows that the MPC utilizing the SI-based has less frequency deviation and lower ROCOF.

Fig. 1: Simulation Setup for the system identification where input is the log square chirp signal \( P_{\text{inv}} \) to ESS and output is \( \Delta \omega \).

Fig. 2: Proposed MPC-KF approach for fast-frequency support.

Fig. 3: SI training and testing result.

Fig. 4: (a) Frequency, and (b) ROCOF for a step-change load in MATLAB/Simulink using simplified TF [1] and SI prediction model.

III. CONCLUSION

The paper implements system identification in MATLAB/Simulink to predict the model of a microgrid. The model was used as a predictive model for MPC and the result showed that the SI-based MPC provides a lower frequency deviation and ROCOF.

REFERENCES

Effect of Solar PV-Battery Storage Configurations in the Locational Value Assessment of DERs

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Abstract—Valuing the location of a distributed energy resource (DER) enables electric utilities to anticipate impacts to their system and compensate the resource owners accordingly. This value can be altered by changing how the DER installations are configured in the distribution side of the location. In this work, multiple cases of solar PV energy storage configurations are considered, and their value to the transmission network is calculated by capturing the changes to the system parameters.

Index Terms—Distributed Energy Resources, Rooftop Solar, Battery Storage

I. INTRODUCTION

The recent growth in solar PV coupled with battery storage has greatly reduced the reliance on the grid for customers, but also has served as a sizeable DER that releases energy back to the grid [1]. To compensate the DER owners for this additional generation, and to prepare for any impacts to the existing system, transmission utilities face the need to value DER installations. Fig. 1 shows a typical distribution network with DER presence, whose value needs to be evaluated at the location of the transmission bus it aggregates to. In [2] it was suggested that this locational value can be obtained based on the changes to three system parameters: losses, line flows and bus voltages, after the DER installation. This work applies this valuation method to analyse different solar PV-Battery storage configurations.

II. METHODOLOGY

A. Changing the DER configuration

This work utilizes data from 3.8kW Solar PV coupled with 9.8kWh battery from Microgrid at John Bardo Center [3] as a single DER system and extrapolates accordingly. Different cases of DER configurations are generated by varying the following parameters.

- Solar adoption rate of the location
- Combination of solar panel orientations
- Time at which battery is let to discharge

B. Locational value of a DER

The locational value of a DER installation with respect to any system parameter $A$ can be found by measuring the statistical shift in the parameter $A$ distribution after the addition of the DER, as given in (1).

\[
\lambda_A = \frac{X_{A,\text{DER}} - X_{A,\text{NoDER}}}{\sqrt{\frac{\sum (X_{A,\text{DER}} - \bar{X}_{A,\text{DER}})^2}{n}} + \frac{\sum (X_{A,\text{NoDER}} - \bar{X}_{A,\text{NoDER}})^2}{n}}
\]

C. Simulation

The configurations are applied to a test system developed based on Western Kansas region, US. The transmission buses evaluated for locational DER value are given in Fig. 2. The final poster will present the results and the subsequent analysis.

REFERENCES

Security-Constrained AC Unit Commitment Via Decomposition

Jorge Ramirez-Orrego, Graduate Student Member, IEEE, Antonio J. Conejo, Fellow, IEEE

Abstract—This document addresses the AC security-constrained unit commitment problem. We propose an efficient approach based on Bender decomposition. We decompose the AC security-constrained unit commitment problem into three tractable problems: a reduced-network master problem, a full-network auxiliary problem, and contingency subproblems. The reduced-network master problem provides commitment decisions to the other two problems. We use Kron’s reduction to achieve a reduced-network master problem that can be solved efficiently. The full-network auxiliary problem represents the system’s normal-operation condition and provides dispatch decisions to the subproblems. Finally, each contingency subproblem represents the operation under a single-line contingency. Subproblems provide Bender cuts to the reduced-network master problem and the full-network auxiliary problem. Similarly, the full-network auxiliary problem provides Bender cuts to the reduced-network master problem.

Index Terms—Security-constrained unit commitment, Bender decomposition, Second-order-conic relaxation, Linear AC power flow, Kron’s reduction.

I. INTRODUCTION

Voltage issues increasingly constrain the unit commitment problem, which calls for an AC power flow representation. Additionally, solving the unit commitment problem with n-1 security constraints is essential to guarantee adequate security. Therefore, we consider a security-constrained unit commitment problem with AC power flow constraints.

II. SOLUTION ALGORITHM

The proposed approach to solve the AC security-constrained unit commitment problem is described below.

We decompose the AC security-constrained unit commitment problem into three tractable problems: a reduced-network master problem, a full-network auxiliary problem, and contingency subproblems. The reduced-network master problem is a mixed-integer linear programming problem embedding a linearized AC formulation [1]. A reduced network representation based on Kron’s reduction is used [2]. This problem considers the normal-operation condition. It receives Bender cuts from the full-network auxiliary problem and the under-contingency subproblems. The solution to this problem provides commitment (binary) decisions to the extended-network auxiliary problem and the contingency subproblems.

The extended-network auxiliary problem incorporates a second-order-conic relaxation of the full AC power flow equations [3] representing the normal-operation condition. It receives commitment decisions from the reduced-network master problem and Bender cuts from the under-contingency subproblems. It provides dispatch decisions to the subproblems and the set of congested transmission lines under normal operation to the reduced-network master problem. Additionally, it produces Bender cuts pertaining to the normal operating condition to be sent to the reduced-network master problem.

Each subproblem represents the operation under a given single-line contingency. These subproblems incorporate a second-order-conic relaxation of the full AC power flow equations. Subproblems receive commitment decisions from the reduced-network master problem and dispatch decisions pertaining to the normal operation condition from the extended-network auxiliary problem. Each subproblem provides Bender cuts (pertaining to under-contingency operation) to the reduced-network master problem and the extended-network auxiliary problem.

This iterative procedure is repeated until convergence, which is guaranteed as a result of convexity assumptions.

REFERENCES

**Δ-AGC for Improved Power System Electromechanical Oscillation Damping**

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Abstract—The power variability of utility-scale solar PV plants causes reduction in the damping of the electromechanical oscillations (EMOs). A Δ-automatic generation control (Δ-AGC) is introduced in the secondary frequency control loop to compensate for the reduction in the damping of EMOs during sudden drops in PV generation. Δ-AGC temporarily changes the operating points of the synchronous generators. The operating points of synchronous generators are changed by modifying the participation factors (PFs) in the AGC using a look-up table and a fuzzy logic approach developed based on empirical studies. Typical results of conventional AGC and with Δ-AGC are compared. The Δ-AGC approach provides a practical solution to improve power system stability with large utility-scale solar PV plants.

Keywords—Automatic generation control (AGC), electromechanical oscillations (EMOs), solar PV plants, stability.

I. INTRODUCTION

Damping of the electromechanical oscillations (EMOs) in power systems is significantly affected by sudden changes in solar PV generation caused by external factors such as cloud cover [1]. The loss of solar PV generation requires conventional power plants to increase their output, leading to changes in operation conditions and poor damping of EMOs. Conventional AGC controls the power output of each power plant using fixed participation factors (PFs) based on their ratings.

![Fig. 1. Conventional AGC deployed with Δ-AGC](image1)

Advanced control techniques, such as adaptive AGC using real time situational awareness, can be utilized to compensate for the reduction in the damping of EMOs during unforeseen events in renewable energy generation [2]. The Δ-AGC connected to the conventional AGC is shown in Fig. 1. The conventional AGC’s constant PFs are modified by the Δ-AGC to be adaptive by having dynamic PFs. A selector switch selects the modes of the Δ-AGC between look-up table and the fuzzy logic approach. This study utilizes a modified two-area four machine power system with utility-scale PV plants that is simulated in the real-time digital simulator (RTDS) to demonstrate the operation of the Δ-AGC.

II. RESULTS

Fig. 2 shows the speed variation of Plant 2 for a 10 cycle fault at Plant 1 bus during high solar PV generation and after the loss of solar PV generation. The poster presents results that compare the enhanced performance of two methods, Δ-AGC with look-up table and the fuzzy logic approach in compensating for the reduction in damping, evaluated by the EMO index developed in [1].

![Fig. 2. Speed deviation of Plant 2 with 3-phase 10 cycles fault at Plant 1 Bus with high and low solar PV generation](image2)

III. CONCLUSION & FUTURE WORK

Implementation of a temporary change in the power factors (PFs) of synchronous generators through Δ-AGC has been shown to be an effective compensation method for the reduction in damping of EMOs during sudden drops in solar PV generation in power systems. An artificial intelligence-based technique can be designed to learn the system and generate optimal dispatch values that maximize system stability in the event of solar PV generation loss to enhance this approach even further.

REFERENCES


Steady-state Security Region Boundary Modification Model: A Hybrid Physical Model-Driven and Data-Driven Approach

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Abstract—The thermal security region is an important tool to analyze and evaluate the impact of random changes in power growth direction on the thermal stability of power systems. Based on the DC power flow model, the high dimensional surface of the steady-state security region boundary can be approximately replaced by a hyperplane. However, with the expansion of the system scale, the error of the analytic model will have a greater impact on the boundary of the security region. Therefore, this paper proposes a steady-state security region boundary modification model based on the hybrid physical model-driven and data-driven method. The proposed boundary modification model can retain the useful inherent information from the physical model and utilize the ability of data analysis to extract the inexplicit linear error model. It is verified on several IEEE standard test systems, and the results show that it has high accuracy.

I. FRAMEWORK OF THE METHOD PROPOSED IN THIS PAPER

The framework and process of the boundary modification method proposed in this paper are shown in the Figure 1.

![Figure 1](image)

The method mainly consists of three steps:

1) **Model-driven approach**
   Based on the DC power flow equation, a linear power flow model is built, as shown below.
   \[ P_1 = M_1 \cdot P + M_2 \] (1)
   where \( P_1 \) is branch flow, and \( P \) represents the matrix of active power injection. \( M_1 \) and \( M_2 \) are coefficient matrices of model-driven approach.

2) **Data-driven approach**
   Based on PLS regression, the linear error model is obtained as follows.
   \[ \Delta P_i = D_1 \cdot P + D_2 \] (2)
   where \( \Delta P_i \) is the error of branch flow, and \( P \) represents the matrix of active power injection. \( D_1 \) and \( D_2 \) are coefficient matrices of data-driven approach.

3) **Thermal security region boundary**
   Finally, the security boundary model is as follows:
   \[ \sum_{i=1}^{n} \alpha_{i} \cdot \Psi_i \leq 1 \] (3)
   \[ \alpha_{i} = \frac{P_{d1} \cdot D_1 \cdot P + P_{d2} \cdot D_2}{P_{d1} \cdot D_1 \cdot P + P_{d2} \cdot D_2} \] (4)

II. CASE STUDY

The accuracy calculation depends on a large number of operating points. By comparison, with the expansion of the system scale, the error gradually increases. In particular, the model-driven method is particularly affected. The proposed method can effectively solve the error of the model-driven method.

<table>
<thead>
<tr>
<th>TABLE I. ACCURACY COMPARISON</th>
</tr>
</thead>
<tbody>
<tr>
<td>system</td>
</tr>
<tr>
<td>5</td>
</tr>
<tr>
<td>30</td>
</tr>
<tr>
<td>57</td>
</tr>
<tr>
<td>118</td>
</tr>
<tr>
<td>300</td>
</tr>
</tbody>
</table>

III. CONCLUSION

This paper proposes a security region boundary modification method based on the hybrid drive method. The hybrid framework for steady-state security region boundary modification proposed, which contains the physical-equation-based linearization and the data-driven linearization of the errors of the aforementioned approximation. The proposed boundary modification model can retain the useful inherent information from the physical model and utilize the ability of data analysis to extract the inexplicit linear error model. Compared with the data-driven method, the hybrid drive model retains the line information and can be used to describe branch constraints in the optimal power flow. Compared with the physical model-drive model, the hybrid drive model makes full use of the data-driven optimization fitting ability to obtain the linear relationship between the linearization error and the node injection power. Several test system are used to validate the proposed hybrid approach and the results show a much better performance on steady-state security region boundary modification.

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Battery Bidding Strategy under Uncertainty Considering Market Practical Situations

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Abstract—Storing off-peak electricity and supplying for peak demand is advantageous in terms of energy production, social impact, and environmental preservation. The potential gain from the bidding spread for the battery owner motivates multiple methods of energy storage. Furthermore, different market conditions will result in unpredictable energy allocation based on energy production level. In this paper, we use stochastic programming to investigate optimized bidding methods under market uncertainty. From the standpoint of a battery owner, we create efficient algorithms to generate strategies for three common energy market settings. We present one-time validation for our proposed strategies in each market setting, as well as an analysis of the structural feature of each strategy that reveals the underlying logic. The numerical experiments demonstrate the empirical performance of our solutions and provide context for our findings.

Index Terms—Battery bidding, energy storage, stochastic programming.

I. INTRODUCTION

With the increasing capacity of batteries, battery energy storage systems (BESS) have been deployed as primary and secondary regulation reserves to smooth out the variation in energy supplies considering the advantages of BESS, such as the operational flexibility, fast response time, high ramp rate, and geographical independence [1], [2]. Meanwhile, battery owners can utilize the price variation in the power market to make considerable profits through energy storage arbitrage, i.e., charge the battery at off-peak hours, store the energy in the BESS, and sell the energy at higher prices. Due to complicated power market mechanisms and uncertainty, optimal bidding strategy is hard to find [3].

However, few papers on battery bidding have studied the effect of different market scenarios. In this paper, we introduce three practical market situations that a battery owner could face and generate profit maximization bidding strategies. We compare all 7 strategies and test their robustness under the energy market uncertainties.

II. KEY RESULTS

We consider three common market situations in terms of when the transaction will be executed. Since the battery capacity is relatively small, we assume the battery owners to be price-takers. Combined with three types of bidding frequency, we generate and validate 7 strategies in total.

In the case studies, we use the historical day-ahead market Locational Marginal Price (LMP) data of three buses throughout January 2020 in the market within California Independent System Operator (CAISO). Fig. 1 illustrates the average daily profit made by each strategy in each situation.

Fig. 1: One-time validation results at bus 1. Each row stands for a bidding strategy and each column stands for a market situation. The color of each tile varies based on the value of the expected daily profit from the one-time validation experiment.

Our results demonstrated the robustness of the First 24 and Random 24 methods which also outperformed the self-scheduling strategy.

REFERENCES


Quantifying the Benefits from Virtual Power Plants under Uncertainty in PJM Interconnection

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Abstract—Aggregated demand-side resources that actively participate in electricity markets, called Virtual Power Plants (VPPs), are expected to play an important role in the energy transition in the United States. We quantify the benefits of VPP in a simulation of the PJM Market in 2050 with uncertainty in net load and random generator outages.

I. MOTIVATION

A Virtual Power Plant (VPP) is an aggregation of smaller demand-side resources that is large enough to be treated as a generator by the system operator, and bids in the real-time market along with other resources. Previous studies have indicated that VPP would reduce system costs if used for energy and/or reserve. These studies have used smaller test systems, few operating days simulated, and/or omitted net load forecast error [1]–[3]. We simulate the impacts from VPP bidding into a real-time market that co-optimizes energy and reserves in a large system for a full year in the presence of uncertain net load and random outages. We quantify system benefits in terms of costs and reliability and illustrate the dynamics that lead to the cost reduction.

II. MODEL

We simulate VPP in a framework consisting of the day-ahead (DA) market, followed by the real-time unit commitment and the real-time dispatch in a rolling horizon fashion. The intermediate term security constrained economic dispatch (IT-SCED) model (two-hour lookahead, solved 30 minutes prior) is used to make real-time commitment decisions for fast-start units, while the real-time security constrained economic dispatch (RT-SCED) model (single 5-minute interval, solved 10 minutes prior) is used to make dispatch decisions. We represent uncertainty in net load using an ARIMA process to simulate forecast error and evolving forecasts through each operating day. Note that IT-SCED and RT-SCED use different forecasts because they are executed at different times. We also simulate random (forced) generator outages throughout each operating day, which are calibrated to historical outage rates in PJM. We study the impact of 500 MW of VPP available for 365 operating days in a future scenario of the generation mix in PJM with nearly 50% renewable energy penetration [4].

III. EXPERIMENT AND RESULTS

VPP reduces costs via two mechanisms. During intervals where there is no scarcity of ramp capacity, the VPP is allocated to synchronized reserves. This frees up lower cost generators (e.g., Coal, Combined-Cycle) to be able to provide energy instead of reserves (Fig. 1). In addition, fewer expensive units (e.g., Combustion Turbine) need to be started up. In intervals when there is a ramp capacity shortage, VPP provides a lower cost alternative to providing “energy” (actually curtailing demand) than other high-cost alternatives such as Combustion Turbines or calling up out-of-market units. Over 365 operating days VPP provides a 3% reduction in the average daily system bid-production cost (generation + start-up costs). In addition to cost savings, VPP improves key reliability metrics over the simulated year (Table I).

![Fig. 1. Average daily change in the generation mix when VPP is introduced.](image)

### TABLE I

<table>
<thead>
<tr>
<th>Change in System Reliability Metrics</th>
<th>Energy (MWh)</th>
<th>No. of 5-min events</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spin Reserve shortage</td>
<td>-4.90%</td>
<td>-8.71%</td>
</tr>
<tr>
<td>Unserved load</td>
<td>-13.75%</td>
<td>-14.02%</td>
</tr>
<tr>
<td>Curtailment</td>
<td>-0.43%</td>
<td>-13.01%</td>
</tr>
<tr>
<td>Out-of-market</td>
<td>-6.30%</td>
<td>-6.16%</td>
</tr>
</tbody>
</table>

REFERENCES


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HydroFlex: Maximizing the Economic and Environmental Benefits of Hydropower Generation

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Abstract—Hydropower has emerged as a prominent resource for diversifying the power generation mix, offering a clean and reliable alternative to fossil fuels and overcoming the short-term variability of solar and wind power. In this abstract, the formulation of a model to optimize the water management operation to maximize the economic and environmental benefits from the hydropower dispatch is presented. Additionally, a cloud-based web platform developed to facilitate the result visualization and analysis under multiple operation scenarios is introduced. This combined cloud-based platform and optimization engine, namely HydroFlex, was awarded with the first prize on all three phases of the hydropower operations optimization (H2Os) by the U.S. Department of Energy.

I. BACKGROUND

The impact of greenhouse gas emissions on climate change and air quality worldwide has accelerated the shift towards cleaner electricity generation resources, such as hydropower, which are environmentally friendly and can provide affordable electricity. Hydropower, in addition to its large-scale power generation capacity, has the ability to quickly adjust its power output compared to thermal generation units, provides frequency regulation capability after sudden generation-demand imbalances, offers enhanced reliability under short-term weather variability and provides inertia compared to wind and solar generation. Hydropower can be vulnerable to other climate variability affecting water inflows or increasing evaporation, e.g., extended droughts.

II. OPTIMIZATION MODELS

The optimized water discharge for hydropower generation is achieved through a two-step optimization process, as summarized in Fig. 1. The procedure takes the reservoir inflows and water demand on the water system side, along with the power demand as inputs for the problem. In the first step, the water discharge from the reservoir is obtained to maximize the economic and environmental benefits of hydropower, subject to the operational and physical constraints of the water system. The economic benefits are calculated based on the hydropower dispatch and the locational marginal price where the unit is connected. The environmental benefit is obtained as the product between the hydropower generation and the emission reduction per kW generated by the hydropower unit. This optimization ensures that the hydropower and water management constraints are met, i.e., the maximum discharge rates, the maximum capacity of reservoirs, environmental and nuisance flow constraints, and water demand. In the second step, a unit commitment problem is solved to determine the commitment status of the generation units and the electricity costs on the power system, while meeting the generation and transmission limits and the demand requirements.

III. IMPLEMENTATION

The HydroFlex platform combines several components to manage data, construct and solve optimization models for hydropower operations, and display the resulting output in a concise and easy-to-understand format. An overview of the platform is shown in Fig. 2. The online interface allows users to interact with the model by modifying constraints and parameters, or updating data for multiple scenarios. Data on the web interface is sent as an HTTP request to the cloud-based optimization engine through an API. The optimization engine solves the model coded in the Python-based open-source optimization language Pyomo. The water management optimization and the unit commitment problem are solved respectively using IPOPT and CPLEX. Finally, the results are sent back into the web interface through the API for user’s visualization. The HydroFlex platform was awarded with the first prize on all three phases of the hydropower operations optimization (H2Os) by U.S. Department of Energy.

![Fig. 1. HydroFlex optimization models](image1)

![Fig. 2. The main components of the HydroFlex implementation](image2)
Portable Power Station with Several Source of Energy for Emergencies

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Abstract—This research aims to design and build a hybrid portable power station to provide power to individuals and families affected in Puerto Rico by power outages caused by the hurricanes or power system instabilities. This power station consists of three renewable energy sources: solar, wind, and mechanical using a generator coupled to a bike. It is designed to supply approximately 6KWh/day with 24 hours of autonomy, to provide power to critical loads such as vital medical equipment, small fridge, and lightening bulbs. Deep-cycle batteries are included for storage purpose. In addition, experimental data will be collected to identify areas where the deployment of this project is feasible and required, particularly in isolated communities.

I. INTRODUCTION
Puerto Rico is located in a Hurricane-Prone area. In addition, every year many people die due to power system fragility and instability. Some vital equipment such as nebulizers were not energized, medicines that needed to be refrigerated got damaged including all food inside the fridges, and other factors that affect human life. Many persons with different conditions try use gas generator which caused many problems such as: the fuel cost increased significantly after the hurricanes, the availability of the fuel and the long lines to buy in the gas stations. Additionally environmental contamination and the dangerousness to manipulate the fuel with old generator while recharging caused many explosions and conflagration in some houses. This project will have a direct and positive impact on individuals and communities.

II. LOAD STUDY AND DAILY USE

Table I. LOAD STUDY AND DAILY USE

<table>
<thead>
<tr>
<th>Electronic Equipment</th>
<th>Quantity</th>
<th>Watts</th>
<th>Hours/Day</th>
<th>Wh/h</th>
<th>KWh/day</th>
<th>WH/Month</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lightbulb</td>
<td>5</td>
<td>10</td>
<td>6</td>
<td>300</td>
<td>0.3</td>
<td>360</td>
</tr>
<tr>
<td>Fridge</td>
<td>1</td>
<td>400</td>
<td>6</td>
<td>2400</td>
<td>2.4</td>
<td>2880</td>
</tr>
<tr>
<td>Fan</td>
<td>3</td>
<td>100</td>
<td>6</td>
<td>1800</td>
<td>1.8</td>
<td>2160</td>
</tr>
<tr>
<td>Nebulizer</td>
<td>1</td>
<td>90</td>
<td>1</td>
<td>90</td>
<td>0.09</td>
<td>108</td>
</tr>
<tr>
<td>Phone Charger</td>
<td>4</td>
<td>7.5</td>
<td>4</td>
<td>120</td>
<td>0.12</td>
<td>144</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>607.5</td>
<td></td>
<td>4710</td>
<td>4.71</td>
<td>5652</td>
</tr>
</tbody>
</table>

III. CALCULATION FOR ISOLATED PHOTOVOLTAIC SYSTEM

Average daily consumption Lnd = 4863.56 Wh/day
Battery capacity Qav = 405.29 AH
Total of solar panels N, E = 2 x 1200W or 5.5 kWPS
Inverter power Pinv = 1.2 x Pdc = 3 x 1647.5W
Wind turbine generator = 5000W at 800 rpm
Mechanical generator = 2000W at 500 rpm

IV. CIRCUIT DIAGRAM AND SKETCHUP

Figure 1 shows the proposed circuit and the 3D SketchUp. Each output is connected to the corresponding combiner box input. The outputs of the combiner box are wired to the 3 charge controllers to regulate the current and voltage that is delivered to the battery and loads. The charge controllers have an independent connection to each source of energy. In addition, the system complies with the national electric code using tab connectors, breakers, fuses, and connection to ground as protection system. The charge controllers are 12V 100A max, the main fuse is 70A, the solar panels fuses are 15 A, the wind turbine and the mechanical generator fuses are 50A and the main breaker is 70A.
Synthesizing Inertia through the Concept of Virtual Frequency

Ahmed Saad Karsani, Student Member, IEEE, Mahyar Zarghami, Senior Member, IEEE, Maryam Khanbaghi, Senior Member, IEEE

Abstract—As the share of renewable energy sources increase in the power grid, inverter-based resources have become more prevalent. Sources integrated with power-electronics differ in principle from conventional Synchronous Machines (SMs) in the sense that they lack rotational inertia and utilize a driving circuit to synthesize the frequency. To control the operation of VSCs, prior work suggested control schemes that implement Virtual Inertia (VI) using assumptions of equating DC-link dynamics to swing equation. The proposed work, based on the definition of “virtual frequency” for VI synthesis and damping, derives a mathematical relation between the swing equation and mismatch of power between the converter’s DC and AC sides, for fundamentally accurate rotor dynamics emulation.

Keywords—Virtual Frequency, Virtual Inertia, Voltage-Source Converter, Virtual Synchronous Machine.

I. INTRODUCTION

Voltage Source Converters (VSCs) have major differences in their method of operation compared to the existing Synchronous Machines (SMs) integrated with the system, particularly within the scope of their physical properties, i.e. rotational inertia. With an effective control scheme for voltage, power and frequency, it is possible to introduce Virtual Inertia (VI) using the power-electronics interface. In this work, a new definition of the concept of a “virtual frequency” for a VSC that is interfaced between a DC source/sink and the AC grid. The virtual frequency is utilized to provide improved damping and lesser frequency oscillations (better VI response) following perturbations in the grid.

II. PROPOSED SCHEME

The proposed derivation obtains an equivalent expression to swing equation representation using the VSC dynamics. Fig. 1 illustrates the proposed droop and virtual inertia scheme, built upon a base VSM scheme based on [1]. \( P_{DC} \) and \( P_{AC} \) are derived from the DC-link voltage state equation, shown in (1) and (2):

\[
P_{DC} = -i_{Rdc}v_{dc} - i_{dc}v_{dc}
\]

(1)

\[
P_{AC} = k\cos(\delta)i_{dq}v_{dc} + k\sin(\delta)i_{ag}v_{dc}
\]

(2)

III. SIMULATION RESULTS

To examine the validity of the control scheme based on the concept of virtual frequency, a hybrid microgrid (MG) model, i.e. a single-area power system with a SM and a VSC feeding a 100 kW load was modeled in MATLAB®/Simulink®. From Fig. 2, it can be observed that the proposed scheme produces dampened frequency oscillations. Compared to the base VSM scheme, it provides a smoother dynamic response (higher VI) in terms of restoring the frequency at the desired level (60 Hz) during and after the transient phase.

REFERENCES

Data-Driven Flow and Injection Estimation in PMU-Unobservable Transmission Systems

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Abstract—Fast and accurate knowledge of power flows and power injections is needed for a variety of applications in the electric grid. Phasor measurement unit (PMU) cannot directly be used to calculate power due to unobservability. This paper employs machine learning to perform fast and accurate flow and injection estimation in power systems that are sparsely observed by PMUs. We train a deep neural network (DNN) to learn the mapping function between PMU measurements and power flows/injections. The relation between power flows and injections is incorporated into the DNN by adding a linear constraint to its loss function. The results obtained using the IEEE 118-bus system indicate that the proposed approach performs more accurate flow/injection estimation in severely unobservable power systems compared to other data-driven methods.

Index Terms—Flow and Injection estimation, Machine learning (ML), Phasor measurement unit (PMU), Unobservability.

I. INTRODUCTION

This paper presents a physics-inspired machine learning (ML) approach using deep neural networks (DNNs) for high-speed estimation of power flows and injections in power systems that are sparsely observed by phasor measurement units (PMUs). The proposed ML model, called a physics-inspired constrained-DNN (PIC-DNN), incorporates the law of conservation of energy as a linear constraint. The model is trained using slow timescale historical data from supervisory control and data acquisition (SCADA) systems, while the online implementation relies on PMU data for fast estimation. The performance of the proposed PIC-DNN model is demonstrated to be superior to classical and other ML models when applied to the IEEE 118-bus system with different numbers of PMUs.

II. SOURCES OF ERROR IN POWER CALCULATED FROM STATE ESTIMATES

The traditional method of determining electrical quantities in a power system is through state estimation. However, there are issues with computing power flows and injections from linear state estimation (LSE) due to the quadratic relationship between voltage and power, and non-Gaussian noise in PMU measurements. This indirect estimation can result in lower accuracy. Additionally, a PMU-based LSE requires complete observability of the system by PMUs, which is another concern. PMUs can directly estimate power flows and injections, but solving the minimum vertex cover problem requires placing even more PMUs than needed for complete observability.

A. Implementation of PIC-DNN

The model incorporates the law of conservation of energy by appending a linear constraint to the DNN’s loss function, reducing the number of output variables and improving accuracy. The training dataset is split into multiple bins based on variations in power flows, striking a balance between homogenizing the output data and computational burden. The PIC-DNN model is then compared to other machine learning models in the IEEE 118-bus system, demonstrating its effectiveness in estimating power flows and injections.

III. RESULTS

The PIC-DNN model was applied to the IEEE 118-bus system and compared to other machine learning (ML) models, including Linear Regression (LR), Support Vector Regression (SVR), Indirect DNN, and Direct DNN. The performance of these models was evaluated using realistic load variations obtained by superimposing variations from the publicly available 2000-bus Synthetic Texas system onto the IEEE 118-bus system. Two case studies were conducted.

A. Case Study I

In this case study, the ML models used voltage and currents from PMUs placed on 11 high voltage (HV) buses in the IEEE 118-bus system. The PIC-DNN model outperformed other ML models in terms of both mean value and variation of RMSE over the 100 trials, showing at least a 15% improvement in mean and 40% in standard deviation. The results were obtained by adding a two-component Gaussian Mixture Model (GMM) noise to the voltage and current phasors, in line with the IEEE/IEC Standard for PMUs.

B. Case Study II

This case study examined how the performance of five ML models changed with an increase in the number of PMUs in the IEEE 118-bus system. The PIC-DNN model outperformed other ML models in terms of both mean value and variation of RMSE over the 100 trials, showing at least a 15% improvement in mean and 40% in standard deviation. The results were obtained by adding a two-component Gaussian Mixture Model (GMM) noise to the voltage and current phasors, in line with the IEEE/IEC Standard for PMUs.

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Estimation of Participation Factors Using the Synchrosqueezed Wavelet Transform

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Abstract—This paper proposes a data-driven approach for estimating participation factors for a power system using only simulation results on selected disturbances. The approach is purely response-based and does not need a linearized system model for eigen-analysis, which makes it applicable to systems whose detailed, complete mathematical models are not available. Considering the unavoidable nonlinearity as exhibited in the transient period of a system response, the Synchrosqueezed Wavelet Transform is applied to simulated responses for modal analysis to obtain estimated participation factors. The SSWT method was originally developed to analyze audio signals, whose modal properties can vary continuously with time.

In this paper, simulations are conducted on both the Electromagnetic Transient (EMT) model and the phasor model of Kundur’s two-area system. Estimated PFs from these two models are compared. For electromechanical oscillations, comparison results show a close resemblance of the modal properties from EMT simulations to those from phasor simulations. The PF results using SSWT are also compared with Prony analysis and Continuous Wavelet Transform (CWT) methods. SSWT can make the spectrum of CWT sharper and clearer, improve the frequency resolution, and result in more accurate detection of mode frequency than the Prony analysis and CWT methods. The paper also benchmarks the estimated PFs from the proposed approach to the PFs calculated by eigen-analysis on the linearized phasor model. The accuracy of results is confirmed. Figure 1 shows SSWT and CWT spectrum of EMT responses for G3 in Kundur’s two-area system. The SSWT and CWT of a signal are three-dimensional spectra in which the x-axis, y-axis and z-axis show respectively time, frequency, and amplitude of the signal in each moment. Two modes are observable in Figure 1, one with a frequency in the range of 1.0-1.5 Hz and the second with a frequency around 0.6 Hz.

Index Terms—Participation factor, Power system oscillation, Prony analysis, Synchrosqueezed wavelet transform, Wavelet transform

I. INTRODUCTION

Traditional model-based methods for modal properties and participation factors are based on eigen-analysis of a linearized system model. However, the detailed, complete mathematical model of a power system may not be always available especially for the Inverter-Based Resources (IBRs) and their associated controllers. For instance, manufacturers would only offer the black-box models of IBRs during the power system planning studies. These devices and control functions have only black-box models due to, e.g., confidentiality. Time-domain simulation of such components together with the rest of the system can be conducted without any issue to provide responses of the system subject to any disturbance. However, their linear, mathematical models can hardly be obtained for eigen-analysis.

II. RESPONSE-BASED PARTICIPATION FACTORS USING WAVELETS

This paper proposes a data-driven approach for estimating participation factors for a power system only from simulation results on selected disturbances. Considering possible nonlinear dynamics of a power system as exhibited in the transient period of its response under a disturbance, the Synchrosqueezed Wavelet Transform (SSWT) is applied to simulated responses for modal analysis to obtain estimated participation factors. The SSWT method was originally developed to analyze audio signals, whose modal properties can vary continuously with time.

In this paper, simulations are conducted on both the Electromagnetic Transient (EMT) model and the phasor model of Kundur’s two-area system. Estimated PFs from these two models are compared. For electromechanical oscillations, comparison results show a close resemblance of the modal properties from EMT simulations to those from phasor simulations. The PF results using SSWT are also compared with Prony analysis and Continuous Wavelet Transform (CWT) methods. SSWT can make the spectrum of CWT sharper and clearer, improve the frequency resolution, and result in more accurate detection of mode frequency than the Prony analysis and CWT methods. The paper also benchmarks the estimated PFs from the proposed approach to the PFs calculated by eigen-analysis on the linearized phasor model. The accuracy of results is confirmed. Figure 1 shows SSWT and CWT spectrum of EMT responses for G3 in Kundur’s two-area system. The SSWT and CWT of a signal are three-dimensional spectra in which the x-axis, y-axis and z-axis show respectively time, frequency, and amplitude of the signal in each moment. Two modes are observable in Figure 1, one with a frequency in the range of 1.0-1.5 Hz and the second with a frequency around 0.6 Hz.

Figure 1. SSWT and CWT spectrum of EMT response for G3

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MLE Based Nearest Neighbour Algorithm For Real-Time Transient Stability Assessment

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Abstract—Real-time monitoring of Transient Stability Assessment (TSA) is crucial in power systems to avoid sudden blackout and power failure. In this presentation, an efficient Maximal Lyapunov Exponent (MLE) algorithm is proposed for an online TSA of the Nordic 44 Test Network based on the time series data of the rotor angles of some generators and the phase angles of some generator terminal buses, respectively.

Index Terms—Maximal Lyapunov Exponent (MLE), Time Domain Simulation (TDS), Transient Stability Assessment (TSA).

I. INTRODUCTION

In power system literature, the concept of Maximal Lyapunov Exponent (MLE) for an online Transient Stability Assessment (TSA) is an emerging idea. This approach is known as MLE based model-free approach and it is based on time series data of few system variables. In [1], a comparative analysis of model based and different model-free MLE methods for TSA has been performed. In this presentation, the MLE algorithm presented in [2] is applied for an online TSA.

II. THE PROPOSED MLE APPROACH

As depicted in Fig. 1, the time series data $x(t)$ is represented as, $[x_1(t), x_2(t), \ldots, x_N(t)]$, where $t = [0, \Delta t, \ldots, N \Delta t]$, $\Delta t$ is the time step, and $N$ is the number of data points. Firstly, a phase space reconstruction (PSR) of $x$ is performed using delay coordinate embedding and reconstructed trajectory represented as matrix and each phase space vector is $X$. Then, as depicted in Fig. 2, for each reference point (R) of $X$ the algorithm locates the Nearest Neighbour (NN) which minimizes the distance to the particular R. In the Fig.2, the line shows the distance from R to every point in trajectory. Hence as shown in Fig.1, the least distance $d_{min}$ is calculated by NN algorithm and expressed as $d_{k_{min}} = \|X_{R} - X_{NN}\|$, where $k = 1, 2, \ldots, M$, $M = N - (b - 1)Y$, $b$ is embedding dimension and $Y$ is lag. Finally, MLE is calculated as the mean rate of separation of NN, i.e., $\lambda = \frac{1}{\Delta t} \langle \ln(d_{k_{min}}) \rangle$ [2].

III. NUMERICAL RESULTS

The proposed technique is applied to the Nordic 44 Test Network [3]. Simulations are carried out in SIMPOW. For the application of the proposed algorithm, the time series data of the rotor angles ($\delta$) of some generators and the phase angles ($\theta$) of some generator terminal terminal buses, respectively, are used. In Table. I, $N \Delta t$ is the sampling period after the fault clearing time ($t_c$) in (s). To validate effectiveness of this technique, TDS is performed for 40 fault cases in which stable cases are 20 with $t_{ccst} = t_{ccst} - \epsilon$ and 20 unstable cases with $t_{ccst} = t_{ccst} + \epsilon$, where $t_{ccst}$ is the critical clearing time for each case $\epsilon$ and $\epsilon$ is a small positive number. The numbers in Table. I indicate the estimated correct results out of those 20 stable (St) and 20 unstable cases (Unst), respectively. It can be concluded that the proposed method may be appropriate for an online TSA.

<table>
<thead>
<tr>
<th>$N \Delta t$</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
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<td>20/20</td>
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<tr>
<td>$\theta$</td>
<td>20/20</td>
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<td>18/20</td>
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</tbody>
</table>

TABLE I

Table of Estimated Correct Results

REFERENCES
Open Source Tool for Dynamic Simulations in Electrical Distribution Systems

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Abstract—Nowadays, electric distribution systems are rapidly transitioning toward having an increasing proportion of distributed generation (DGs) from renewable resources, such as wind and solar, and energy storage. These DGs can vary from residential-scale rooftop systems to utility-scale power plants, challenging the dynamics operation of power systems to see the impact of these numerous DGs on the traditional synchronous generators and the entire network. This paper presents a guide to using OpenDSS for dynamic simulations and lists different approaches for modeling synchronous generators and inverter-based resources based on the model complexity. The implications of coding a dynamic model, the generators’ internal structure, and dynamics study during fault scenarios are discussed to guide the user with a tool reference for studying the dynamics of the distribution network.

Index Terms—Distribution networks, Dynamic modeling, OpenDSS, Synchronous machine, Grid-forming inverters, User-written model

I. SYSTEM MODELING

Grid-forming inverters (GFMs) are represented as an ideal voltage source and are modeled in most cases as voltage-controlled voltage source converter (VC-VSC), which controls the voltage and frequency at the point of common coupling of the distributed generation unit. Adding to the VSC block, we use power control block (using Droop-control or virtual synchronous generator method, etc.) as shown in Fig. 1 to control VSC operation and system stability. During fault scenarios and network contingencies, these inverters can control their output current to balance loads and maintain voltage and frequency.

![GFM control block diagram](image)

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II. DYNAMIC MODELING IN OPENDSS

OpenDSS provides the flexibility to model GFM blocks and simulate them for large distribution unbalanced networks. Our approach provides technical procedures for defining the Generator’s internal structure and the control process of GFMs. We hard-coded the GFM model to be converted to GFM.dll file as shown in Fig. 1, which can then be called back by the OpenDSS.

![Conceptual model for compiling user-written files](image)

III. NUMERICAL RESULTS

A Kundur two-bus system used to validate the user-written approach of dynamics modeling in OpenDSS and judge their performance for the dynamics simulation. GFM is found at the low voltage side to act as power injectors for the grid network. A three-phase fault is triggered at a time of 1 sec. and lasted for 10 msec. to assess the ability of GFM to maintain system stability.

![Frequency response during fault study](image)
Real-time Economic Dispatch of IBR-penetrated Power Systems Considering Virtual Inertia Scheduling

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Abstract—This paper proposes a new concept called virtual inertia scheduling (VIS) to efficiently handle the high penetration of inverter-based resources (IBRs). First, a uniform system model is employed to quantify the frequency dynamics of the IBR-penetrated power system after disturbances. Based on the model, the s-domain and time-domain analytical responses of IBRs with inertia support capability are derived. Then, VIS-based real-time economic dispatch (VIS-RTED) is formulated to minimize generation and reserve costs, with a full consideration of dynamic frequency constraints and derived inertia support reserve constraints. The virtual inertia and damping of IBRs are formulated as decision variables. To address the non-linearity of dynamic constraints, deep learning-assisted linearization is employed to solve the optimization problem. Finally, the proposed VIS-RTED is demonstrated on a modified IEEE 39-bus system. A full-order time-domain simulation is performed to verify the scheduling results.

I. VIRTUAL INERTIA SCHEDULING IN REAL-TIME ECONOMIC DISPATCH

As shown in (17)-(23), VIS-RTED aims to minimize the total quadratic generation cost and linear reserve cost while also accounting for dynamic frequency constraints and IBR inertia support capability.

\[
\begin{align*}
\min_{P_{t},M,D} & \sum_{i=1}^{N_{g}} \left( a_{1,i}^{P} P_{i,t}^{2} + b_{1,i}^{P} P_{i,t} + c_{1,i}^{P} \right) \\
& + \sum_{i=1}^{N_{l}} \left( a_{1,i}^{P} P_{i,t}^{2} + b_{1,i}^{P} P_{i,t} + c_{1,i}^{P} \right) \\
\text{s.t.} & \sum_{i=1}^{N_{g}} P_{i,t} + \sum_{i=1}^{N_{l}} P_{i,t} + P_{t} - \sum_{i=1}^{N_{l}} L_{i,t} = 0, \ \forall t \in \{1,\cdots,T\} \quad (1)
\end{align*}
\]

\[
\begin{align*}
\sum_{i=1}^{N_{g}} GSF_{i,t}(G_{i,t} + P_{i,t} - L_{i,t}) & \leq L_{U} \\
\sum_{i=1}^{N_{l}} GSF_{i,t}(G_{i,t} + P_{i,t} - L_{i,t}) & \geq -L_{U} \\
P_{i,t}^{g} + P_{i,ru,t} & \leq P_{i,t}^{max}, \ \forall t \in \{1,\cdots,T\} \\
P_{i,t}^{g} - P_{i,ru,t} & \geq P_{i,t}^{min}, \ \forall t \in \{1,\cdots,T\} \quad (4)
\end{align*}
\]

\[\begin{align*}
P_{i,t}^{br} + P_{i,br,ru,t} + P_{i,br,peak,t} & \leq P_{i,t}^{max,b}, \ \forall t \in \{1,\cdots,T\} \\
P_{i,t}^{br} - P_{i,br,ru,t} - P_{i,br,peak,t} & \geq P_{i,t}^{min,b}, \ \forall t \in \{1,\cdots,T\} \\
M_{i}^{min,b} & \leq M_{i}^{br} \leq M_{i}^{max,b}, \ \forall i \in \{1,\cdots,N_{ibr}\} \\
D_{i}^{min,b} & \leq D_{i}^{br} \leq D_{i}^{max,b}, \ \forall i \in \{1,\cdots,N_{ibr}\} \\
-\text{RoCoF}_{\text{lim}} & \leq f_{0} \frac{\Delta P_{t}}{M_{i}^{br}} \leq \text{RoCoF}_{\text{lim}}, \ \forall t \in \{1,\cdots,T\} \\
f_{\text{min}} & \leq f_{0} + \Delta f_{\text{nadir,t}} \leq f_{\text{max}}, \ \forall t \in \{1,\cdots,T\} \quad (7)
\end{align*}\]

The total scheduling cost of IEEE 39 bus system for a one-hour VIS-RTED is $63,300. Fig. 1 shows the detailed cost results of the 12 scheduling intervals, where (a) is the total system cost constituted by generation cost and inertia support reserve cost, and (b) is the cost of each SG and IBR in each scheduling interval.

II. CONCLUSION

Although IBRs present low inertia characteristics, their controllability and flexibility allow for the design of an advanced inertia management framework for future low inertia power systems. Based on this background, this paper has proposed the concept of VIS, which targets the security-constrained and economy-oriented inertia management and power dispatch of power systems with large scale of renewable generation. VIS not only schedules the power dispatch results, but also the control modes and control parameters of system devices to provide secure and cost-effective inertia support.
Valuing Uncertainties in Wind Generation: An Agent-Based Optimization Approach

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Abstract—Increasing integration of variable renewable energy sources such as wind and solar will require new methods of managing generation uncertainty. Existing practices of uncertainty management for these resources largely focuses around modifying the energy offers of such resources in the quantity domain based around a centralized system operator consideration of these uncertainties. This paper proposes an approach to instead consider these uncertainties in the price domain, where more uncertain power is offered at a higher price instead of restricting the quantity offered. We demonstrate system-level impacts on a modified version of the RTS-GMLC system where wind generators create “risk-aware” market offers reflecting their uncertainties and compare the results with a dispatch method in which wind energy is offered at zero marginal price and restricted based on the forecast percentile.

Index Terms—risk, uncertainty management, electricity markets, wind

I. INTRODUCTION

Widespread integration of variable renewable energy (VRE) into the electrical grid is critical to reducing global carbon emissions. In contrast to conventional power plants, the capacity of VRE resources such as wind and solar power plants is subject to greater prediction uncertainties. As the proportion of VRE on the grid increases, managing these uncertainties and integrating their management into electricity markets and dispatch will become increasingly important.

In restructured electricity markets, generators are assumed to make offers that reflect their variable costs such as fuel. VRE generators have zero fuel costs, but may have a shortfall in energy delivery due to forecast uncertainty. If we assume any shortfall in day-ahead dispatch must be repurchased by the generator at the real-time price, VREs can be thought of as having an additional cost associated with uncertainty in their production forecasts. This work examines one method of pricing this uncertainty using conditional value at risk (CVaR). We describe these offer curves as “risk-aware” since they reflect the potential repurchase risks.

II. RISK-AWARE GENERATOR OFFERS

The generator seeks to create an offer curve for the day-ahead market that describes the total supply cost of as a function of MW offered. The problem is formulated as finding a quadratic coefficient \( a \) and linear coefficient \( b \) of the offer curve:

\[
\max_{a,b} \text{CVaR}_{\beta,\lambda_{i,t},\alpha_{i,t}} \left( \frac{\lambda_{i,t} - b}{2a} - \alpha_{i,t} \cdot \Delta \tilde{p} \right)
\]

s.t. \( a \geq 0 \) \hspace{1cm} (1)

Where the random variables \( \lambda_{i,t}, \alpha_{i,t}, \) and \( \tilde{p} \) represent the day-ahead price of electricity, real-time price of electricity, and the generator’s shortfall of energy in the real-time market. \( \beta \) is a term associated with CVaR describing the risk preferences of the generator.

III. CASE STUDY

We simulate the impacts of these “risk-aware” generator offers on a modified version of the RTS-GMLC system. Wind generators create market offers valuing their uncertainties over a scenario set of day-ahead production forecasts (Fig. 1). The results are compared with a dispatch method in which wind energy is offered at zero marginal price and restricted based on the forecast percentile.

![Fig. 1. Wind generator offer curves at differing times and risk preferences. Note in the top graph that as the risk preference \( \beta \) increases, the generators create steeper offer curves to reflect lower risk tolerance. In the bottom graph, the wind forecast uncertainty is lower and thus the marginal price does not change.](image-url)
Abstract—As the electricity sector moves rapidly towards carbon neutralization, demand response (DR) programs are becoming increasingly important to ensure reliable operations of the power grid, as the overall consumption of electricity increases. While numerous previous works have examined the effectiveness of various DR programs, publicly available residential demand response data is limited as it involves human-in-the-loop. This work utilizes conditional generative adversarial networks (CGAN) to learn from limited residential demand response trial data and generate new data based on exogenous factors such as electricity price and temperature.

Index Terms—Demand Response, Machine Learning

I. POSTER OVERVIEW

To understand the change in customer power consumption during the experiment, we utilized the “Similar-Day” method proposed in the original EnergyCoupon [1] for baseline prediction. For the duration outside of the experiment time, the historical weather data is first divided into weekdays/weekends and times of day, and then clustered into three clusters based on wind speed, temperature, and humidity. The average individual household power consumption for each cluster is calculated and used as the baseline.

For flexibility calculation, we first assign each day of the experiment to one of the clusters found previously, then the ratio between the current day power consumption and the baseline consumption is calculated. We use this ratio, called the flexibility score to evaluate a customer’s ability to reduce consumption during peak hours. Detail flexibility calculation is shown in Fig. 1.

Three labels are used for our CGAN model [2]: flexibility, price, and temperature. The flexibility label was determined by counting the number of flexibility scores less than one during the five-hour peak period. Customers with more than three such scores were labeled as highly flexible, those with between one and three were medium flexible, and those with zero were inflexible. Temperature and price label calculation follow similar logic, where temperature thresholds are based on its 75%, 50%, and 25% percentiles for the duration of the experiment and price threshold is set to $40/MWh.

Once the labels were generated, they were appended to the daily load profile and fed into the CGAN model. We trained separate models for active and inactive user groups, for a maximum of 10,000 epochs. The trained models were then used to generate new flexibility profiles based on the input labels. Fig. 2 shows an example of synthetic daily flexibility for one household during the summer months. It should be noted that we can produce an unlimited number of synthetic flexibility profiles by inputting the appropriate labels into the data generation process. However, due to the nature of CGAN model, it can only generate based on prior data distribution it has seen.

REFERENCES


Detection and Analysis of Oscillations Using SCADA Data

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Abstract—Recent progress in monitoring algorithms based on synchrophasor data has enabled engineers to identify oscillation problems that could have been missed previously. While an oscillation can be identified and its location can be estimated based on its waveform, the lack of enough synchrophasor data makes it hard to locate the specific generator or load that is causing it. However, SCADA provides a readily available source of data, although it has a relatively low sampling rate of 1 sample every 1 to 10 seconds. The current project from RTE focuses on using the SCADA data only to locate the source of oscillations efficiently.

I. INTRODUCTION

Forced oscillations in power systems are caused by external factors, unlike natural electromechanical modal oscillations. Identifying the source of these forced oscillations has been a challenge for the industry. Although there are many PMUs installed across the power grid, they are mainly located for monitoring transmission corridors and provide little coverage of generation facilities. This makes it difficult to locate the source of forced oscillations without exhaustive manual analysis. However, SCADA data can be used to identify the specific source of forced oscillations once they have been detected with PMU measurements. Despite the low sampling rate and non-synchronized nature of SCADA data, it can be used to monitor both real and reactive power outputs from the generators, providing broader visibility compared to PMUs.

II. PROPOSED ALGORITHMS

In this work [1], two different methods were proposed to locate the sources of forced oscillations using SCADA data. Pattern Mining Algorithm (PMA) considers the number of high-amplitude peaks in SCADA data during the time periods when oscillations were detected by the PMU engines as the key factor in ranking. The second one is called Maximal Variance Ratio Algorithm (MVRA) which ranks the SCADA signals based on the ratio of the average variances during oscillation and ambient time periods.

III. RESULTS AND FUTURE WORK

The PMA and MVRA algorithms were applied to find the source of forced oscillation location among over 2000 generators in the system and the results of two methods agree with each other. The accuracy of the findings was confirmed by consulting with the owner of the generation plant, who verified that a mechanical failure in the identified generation unit caused the forced oscillation in the system. Two other generators, 1087 and 1088, located in the same plant, also exhibited high amplitudes in response to the forced oscillation in unit 1085. Therefore, they were ranked as the second and third most likely sources of the oscillation.

Figure 1: MW outputs of the three highest ranked generators

Interarea oscillations are emerging as serious operational concerns in modern power systems because of changing intermittent generation patterns and unusual transmission power flows. In the future work, inferential statistical theory will be applied for rigorous development of new algorithms that can use widely available SCADA measurements for the detection and analysis of power system oscillations. Since the SCADA measurements are not time synchronized, the asynchronous sampling does preserve the oscillation amplitude to a great extent which can be exploited. Detection and efficient analysis of the oscillations will help the smooth integration of large numbers of renewable devices into the power grid and prevent potential damage from problematic oscillations.

ACKNOWLEDGEMENT

We would like to thank RTE for supporting the project.

REFERENCE

A Multi Criteria Based Decision Framework for Industrial Hybrid Renewable Energy System Sizing

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I. INTRODUCTION

Industrial consumers are facing increasing energy demands and costs, making it imperative to adopt sustainable and cost-effective energy solutions. Hybrid renewable energy systems have emerged as a promising solution for sustainable and cost-effective energy generation in industrial applications. However, the complexity of hybrid renewable system design and optimization often requires the use of specialized software tools. While there are many commercial software solutions available, they often fall short in capturing the unique and complex multi-criteria nature of hybrid renewable system sizing in industrial applications [1] [2]. This creates a need for a more comprehensive and specialized approach that can assist industrial consumers in selecting and sizing the optimal hybrid renewable energy system that meets their specific needs and constraints. In this work, we propose a novel multi-criteria decision making (MCDM) framework that works in conjunction with commercial software tools to provide a more comprehensive and accurate selection and sizing of hybrid renewable energy systems for industrial consumers.

II. METHODOLOGY

The proposed MCDM framework has three main steps. Firstly, a commercial software tool is used to generate a set of feasible candidate solutions for hybrid renewable energy systems of different sizes. The software generates a range of system configurations, which include various combinations of renewable energy sources such as solar, wind, and battery storage.

Secondly, a multi-criteria decision-making algorithm based on Analytic Hierarchy Process (AHP) and Technique for Order of Preference by Similarity to Ideal Solution (TOPSIS) is used to rank the feasible candidate solutions based on multiple criteria, including energy reliability, cost, and sustainability. The AHP method is used to obtain the weights of each criterion, while TOPSIS is used to generate a ranking of the candidate solutions based on the weights and performance measures of each criterion.

Finally, a technical analysis and revenue potential analysis of the highest-ranked candidate solution is performed to ensure its technical feasibility and compatibility with the industrial consumer’s specific needs and constraints.

III. CASE STUDY

A case study was conducted to demonstrate the effectiveness of the proposed framework for hybrid renewable system sizing in industrial applications. The study involved an industrial consumer that wished to expand its energy capacity by adding additional wind turbines, PV systems, and storage. The consumer had an existing hybrid system in place consisting of a grid connection and a wind turbine, with excess electricity traded to the grid.

To generate feasible solutions, the HOMER Pro software was utilized. It requires developing system design in the software based on the technical needs of the consumer’s site. The proposed MCDM framework was utilized to rank the candidate solutions based on various criteria such as energy reliability, cost, and sustainability. The highest-ranked solution was identified as the optimal sizing solution for the industrial consumer. Subsequently, a technical evaluation of the best candidate solution was conducted to verify its feasibility and practicality. The outcomes of this study highlight the potential of the proposed framework for identifying an optimal hybrid renewable energy system sizing solution in an industrial context and the economic viability of energy market participation.

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Fig. 1. Proposed MCDM Framework for Hybrid energy system sizing
Enhancing Grid Resilience Using Electric Vehicles

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Abstract—The poster depicts the utilization of trending technologies like Electric Vehicles (EV) and Renewable Energy Sources (RES) for meeting the objective of grid resiliency enhancement. It presents a novel energy management method that employs a fraction of the EV battery and UPS battery, to be made available during extreme circumstances such as natural catastrophes. The proposed approach is validated using an OPAL-RT-based real-time simulation environment.

Keywords—Electric Vehicle, Energy Management Scheme, Grid Resiliency, Natural Disasters, Renewables

I. INTRODUCTION

This work suggests a novel energy management plan for enhancing resilience beginning with a single home, which can further be expanded to an entire distribution network. In order to improve grid resiliency while operating in V2G mode, a plan to use a portion of the buffer SOC of the EV battery has been put forth. When a home needs to be powered up during a severe emergency, such as a natural disaster, this buffer SOC can be used in V2H mode [1]. The strategy aims to increase system resiliency with only minor upgrades to the currently available sources at home, which include a rooftop PV system, a UPS battery, and an EV.

II. SYSTEM DESCRIPTION

The overall system is depicted in Fig.1. It consists of a microgrid interfaced with the main grid through a bidirectional AC-DC converter. The microgrid consists of various renewable energy sources (RES) like the solar PV, wind, UPS and an EV for home application. The probable three modes of operation are also highlighted. In Fig.1.

III. NOVEL ENERGY MANAGEMENT SCHEME (EMS)

Depending upon various external conditions, the proposed EMS helps in smooth swing between the three different modes, namely: Grid-connected, Isolated (during fault) and Isolated (during natural disasters). Fig.2. depicts a flowchart for the proposed EMS.

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IV. REAL TIME SIMULATION RESULTS

The proposed three modes of operation are verified using real time OPAL-RT based simulation results.

V. CONCLUSION

The proposal is verified using real time OPAL-RT based simulation results. The saved buffer SOC provides approximately 15 KWh energy with a 8.8KWh UPS battery and 30KWh EV battery, which can serve critical loads inclusive of two 15 watts bulbs, one 18 watts mobile battery charger and one 1 KW kitchen appliance during extreme emergency for approximately 6 days.

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Long-Term Photovoltaic Power Generation Forecasting

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Abstract—Energy time-series forecasting is crucial to current and future power and energy systems. However, due to the high uncertainty of generation based on renewable energy sources, derived from their reliance on weather conditions, such as wind speed or solar intensity, the need to develop appropriate solutions to deal with such variability increases significantly. In this study, we propose two approaches, a gray-box, and a black-box method, to model and forecast solar generation based on historical data from the Competition on solar generation forecasting to predict week-ahead solar power generation. The significance of this work is that we try to forecast values for a long horizon, one week ahead in the future, which is more challenging compared to similar studies dealing with short periods, like the next few hours.

Index Terms—Time Series, Forecasting, Photovoltaic

I. DATASET AND PREPROCESSING STEPS

The dataset being explored in this study comprises three years of historical power generated by photovoltaic panels and weather data collected from a nearby station. The dataset represents raw data without any treatment. So, it contains missing data or intervals filled with fixed zero values indicating a failure in the sensing or data acquisition system. One significant challenge of this study is correctly distinguishing between actual zero values and those used to fill in the gap. We dropped those days with constant values, i.e., with zero variance, which formed 25% of the whole dataset, because they are misleading for the training process.

II. FORECASTING MODELS

We followed two approaches to forecasting week-ahead solar panel generation: I) a gray-box approach that uses physical models of solar power generation and II) a black-box approach that takes advantage of time series forecasting models only.

A. Gray-box modeling

Significant earlier research has been done on solar performance modeling and forecasting, which estimates a site’s present and future solar generation based on its location, time, weather, and various other environmental quantities. However, these models generally require deep access to the solar site and significant expertise to configure them, which are unavailable to most researchers in this field. Therefore, we used the Solar-TK tool, which requires only the site’s location and a small amount of historical data but gives comparable results with PVlib. Solar-TK employs many of the same physical models as PVlib but utilizes historical generation data to calibrate those models automatically instead of manually. Still, the location and timing of measurements were hidden in our dataset due to privacy issues, which made us borrow some ideas from sunspot and weatherman to infer the location of the site of the solar panel from the respective measurements.

B. Black-box modeling

In this approach, we do not take advantage of our prior knowledge and expertise regarding solar panel generation. Instead, we feed our dataset to one of the best long-term time series forecasting models, the Informer [5]. To deal with different sources of non-stationarity in our dataset, we trained several models for different periods of the year, assuming the local stationarity of each part.

III. EVALUATION

This study uses Root Mean Squared Error (RMSE) and Mean Absolute Error (MAE) as performance metrics.

<table>
<thead>
<tr>
<th></th>
<th>MSE</th>
<th>MAE</th>
<th>MSE</th>
<th>MAE</th>
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</thead>
<tbody>
<tr>
<td>Gray-box modeling</td>
<td>0.57</td>
<td>0.63</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Black-box modeling</td>
<td>0.46</td>
<td>0.51</td>
<td></td>
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These results show the superiority of the black-box approach over the gray-box approach for our dataset.

REFERENCES

Intelligent Controls for AC/DC Power Converters in Hybrid Power Distribution Networks

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Abstract—To ensure effective renewables integration, the power system is needed to maintain a number of attributes, such as reliable and efficient load-feeding capabilities and complete control over voltage and bi-directional power flow among the system's AC and DC sides. A controlled rectifier is used to fix voltage at the common DC bus as one objective. Another AC/DC power converter is used to control the power flow between AC and DC networks in both directions, as another objective, to ensure the power system balance. Vector decoupled control is mostly used in d-q frame for achieving these functions. Traditional PI controls have their drawbacks such as poor transient, slow response, limited bandwidth, and poor power quality. Intelligent NN-based controls are proposed here for both functions to overcome these drawbacks. Tests are done and results are validated.

Keywords—Power Converters, Intelligent Controls, AC/DC Networks, DC Microgrids.

I. PROPOSED INTELLIGENT CONTROLS

Fig. 1 depicts the hybrid AC/DC power system under study. For both AC/DC power converters, a recurrent three-layer neural networks are developed to implement the Radial Recurrent Bases Function Neural Network (RRBFN) estimators and improve the function approximation accuracy as shown in Fig. 2. Gaussian function is employed as the activation function in the hidden layer due to its differential and continuous features. Online learning algorithms are adopted [1].

Fig. 1 Hybrid AC/DC power network comprising multi-micro grids.

![Image of hybrid AC/DC power network](image1)

II. RESULTS

A laboratory-based AC/DC smart grid testbed is developed as shown in Fig. 3(a). The first controlled rectifier controls the common bus DC voltage at 300 V. Fig. 3(b) shows the $V_{dc}$ responses of both PI and the proposed controller against step change. Based on the power demand between AC and DC sides, the other power converter controls active and reactive power flow in both directions. Fig. 4 shows the $P$, $Q$ responses for both the traditional PI, in (a), and the proposed controller, in (b), to achieve the power flow in both directions as per needed.

![Image of system tests](image2)

Fig. 2 Active $P$ and Reactive $Q$ power proposed Intelligent controller.

![Image of system tests](image3)

Fig. 3 System tests; (a) H/W setup, (b) $V_{dc}$ response against step change.

![Image of system tests](image4)

Fig. 4 Active and Reactive power responses against step change; (a) PI controller, (b) Intelligent controller.

III. REFERENCES

Assessing the Resilience of an Optimal Water Pumping Strategy to Provide Frequency Regulation

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Abstract—Water distribution networks can be operated to provide services to the power grid. However, it is critical to ensure that new operational strategies maintain or improve upon the network resilience. We evaluate the resilience of power and water distribution networks to hazard events when the operation of the water pumps is optimized to minimize pump electricity costs and provide frequency regulation to the bulk transmission system. Metrics are used to quantify the network resiliency after a wind-based hazard event that causes power outages. The optimal operational strategy providing frequency regulation is compared with an optimal water flow strategy that minimizes pump electricity costs and a traditional, heuristic rule-based control strategy.

Index Terms—distribution networks, flexible loads, frequency regulation, operational resiliency, water networks

I. MOTIVATION

Recent research has demonstrated that supply pumps in the drinking water distribution network can be treated as flexible loads. Water distribution networks can be optimally operated to provide services to the power grid, such as demand response and frequency regulation [1], [2]. Currently, water utilities use heuristic rule-based controls based on the time of day or other triggers within the water network. For instance, a pump may be turned on when the water level in a tank falls below a certain level. When proposing new operational pumping strategies, it is important to ensure that the water distribution network’s resilience is maintained or improved upon.

Several papers have proposed metrics for quantifying resilience in coupled power-water systems, e.g., [3]. However, to the best of our knowledge, no work has considered the impact of optimal water pumping control strategies on the resilience of interconnected power and water networks. This work evaluates the water distribution network’s ability to respond and recover from pump power outages under three different operational strategies. We compare a rule-based strategy, an optimal pumping strategy minimizing electricity costs (OWF), and an optimal pumping strategy that also provides frequency regulation (OWF+FR). The goal is to assess how a water distribution network can safely provide services to the power grid.

II. COMPARISON OF OPERATIONAL STRATEGIES

The performance of the three operational water pump control strategies are assessed in the presence of a wind-based hazard event that causes power outages in the power distribution network (and correspondingly pump power outages in the water distribution network). We simulate 50 pump power outage scenarios caused by a wind-based hazard event by generating wooden utility pole damage states from probabilistic fragility curves. The control strategies and outage scenarios are evaluated with the hydraulic simulator WNTR [4]. We use resilience metrics to describe the performance of the water and power network under hazard events.

Overall, in our case study, we found that the network resilience of the rule-based and optimal pumping strategies to be similar. To provide an illustrative example, Fig. 1 depicts the average filled water tank volume over the contingency scenarios for the three control strategies given a hazard event. In all cases, we can observe that the tanks are depleted when there is a pump power outage (randomly starting between hours 10-15). However, the final tank level over the control strategies is similar. Additionally, the optimal pumping strategy was significantly cheaper than the rule-based (i.e., around a 35% price decrease). Full results will include an evaluation of power and water network resilience metrics over the heuristic and optimal control strategies as well as methods to incorporate resiliency metrics within the optimal pumping problem.

REFERENCES

A Risk-Averse Model for Balancing Wildfire Risks and Power Outages due to Public-Safety Power-Shutoff

Jinshun Su, Student Member, IEEE and Payman Dehghanian, Senior Member, IEEE

Abstract—Overhead power line infrastructures in electric power distribution systems (DSs) are potential sources of catastrophic wildfires. To prevent such electrically-induced wildfires, electric utilities commonly adopt the practice of public-safety power shutoffs (PSPS): strategies to intentionally and proactively de-energize power line infrastructures to prevent wildfire risks. In this work, we propose a risk-averse optimization model that generates an optimal PSPS plan, which minimizes the risk of costly wildfires while keeping the number of intentional power outages to a minimum. To achieve this objective, we strategically deploy transportable energy backup technologies in the DS, such as mobile power sources (MPSs).

Index Terms—Public-safety power-shutoff (PSPS); risk-averse; wildfire; power outages; mobile power sources (MPS).

I. INTRODUCTION

In the past decade, electrically-induced wildfires have increased in frequency and intensity, posing a threat to communities, disrupting social and organizational ecosystems, damaging natural resources, homes, and structures, and even claiming lives. Preventing wildfires is far less costly than their mitigation. To prevent wildfires, many electric utilities adopt short-term operational practices such as public-safety power shut-offs (PSPS). While selective power shutoffs have been shown to be effective in mitigating wildfire risk, they can also challenge the reliability of electric power grid operations [1]. Mobile power sources (MPSs) can be effective resources in the DS for spatiotemporal flexibility exchange during emergencies [2]. This work proposes a risk-averse framework that integrates PSPS planning and MPSs dispatching decisions to balance wildfire risks and minimize power outages.

II. PROBLEM FORMULATION

The proposed risk-averse optimization model is formulated as below:

\[
\min_{x \in X} g(x) + \min_{y \in Y} h(y),
\]

where \(x\) and \(y\) denote the variables for PSPS assignment and MPSs deployment, respectively. The notation \(X\) and \(Y\) indicate the feasible sets of PSPS assignment and MPSs deployment decisions, separately. The function \(h(y)\) represents the PSPS-caused power outage costs, including the revenue loss imposed on the electric utility, the interruption cost imposed on customers, and the operating cost of MPSs. The function \(g(x)\) denotes the costs due to wildfires, which is evaluated by the conditional value-at-risk (CVaR) measure and formulated as below:

\[
g(x) = \min_{\eta \in \mathbb{R}} \eta + \frac{1}{1 - \alpha} E [(f(x, V) - \eta)^+]
\]

where \((\cdot)^+ = \max\{\cdot, 0\}\). \(V\) is a random variable representing the magnitude (of the consequences) of wildfires. \(f(x, V)\) denote a random loss function depending on \(V\) and some controllable factors \(x\). Let \(\alpha \in (0, 1)\) be a confidence level.

III. PRELIMINARY RESULTS

Figure 1 illustrates the optimal decisions from a preliminary implementation of the proposed risk-averse model.

Fig. 1. Optimal decisions on PSPS action and MPS dispatch in the wind-exposed wildfire-prone IEEE 33-node test system.

REFERENCES


Incorporating Probabilistic Forecasting Result into Unit Commitment

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Abstract—This paper proposes the application of applying probabilistic forecasting results to unit commitment (UC) by introducing additional constraints through mixed integer linear programming (MILP) to the standard UC model. The results demonstrate that this idea is effective, as the ramp of units can cover the requirements for the secure operation of the power system, including the need to avoid involuntary load shedding, cover the trip of the generator with the highest power generation and manage the fluctuations of renewable energy. This means that the system operator can operate the system in a safer manner.

Index Terms—Probabilistic forecasting, Unit commitment, Mixed Integer Linear Programming, Prediction Intervals (PIs)

I. INTRODUCTION

The United Nations proposed the goal of achieving net zero emissions by 2050 as a way to address climate change. One of the most effective ways to achieve this goal is to replace polluting coal, gas, and oil-fired power with energy from renewable sources such as wind or solar power [1]. However, the stochastic nature of renewable energy is always a significant challenge that needs to be addressed. Since PIs can provide valuable information on not only the expected power output but also the range of possible outcomes and their probabilities, which is useful tackling the challenges. There has been a surge of published journal papers related to probabilistic forecasting with PIs in the past decade [2]–[4]. Nevertheless, limited research has been conducted on the application of forecasting results to unit commitment.

II. SIMULATION RESULTS

In the case study, we utilized five units along with our wind power probabilistic forecasting results as illustrated in Fig. 1. The results demonstrate the effectiveness of (1) and (2), which allows for the ramp of units to not only account for the tripping of a generator but also accommodate the changes of wind power generation with certain probability.

\[ DR_{su} = 0.01 \times Demand + G_{max} + Wind_{mean} - Wind_{lb} \]  
\[ P_t + R_{su} - P_{t-1} \leq Ramp_u \]

Fig. 2. Unit Commitment Result.

REFERENCES

Analytic Input Convex Neural Networks-based Model Predictive Control for Power System Transient Stability Enhancement

Tong Su, Student Member, IEEE, Junbo Zhao, Senior Member, IEEE, Xiao Chen, Xiaodong Liu

Abstract—Transient stability-constrained optimal power flow (TSC-OPF) is a non-convex optimization problem and also computationally intensive to solve. To find the global optimum and improve the convergence, this paper proposes an analytic input convex neural networks (ICNN)-based model predictive control (MPC) for transient stability enhancement. ICNN is developed to predict power system transient stability that has the particular property of ensuring its output is convex to the input. This capability allows ICNN to optimize the convex inputs, such as the active power output of generators, while keeping other values constant, such as variables that do not participate in optimization. In addition, non-convex static constraints are built by decoupled linearized power flow model to form a fully convex TSC-OPF with a global optimum. The proposed method is embedded into MPC to enhance transient stability. Numerical results show that the proposed method can greatly improve convergence, find the global optimal solution, and speed up the calculation.

Index Terms—Transient stability constrained optimal power flow, input convex neural networks, model predictive control, power system transient stability, decoupled linearized power flow.

I. INTRODUCTION

Transient stability constrained optimal power flow (TSC-OPF) is to find the optimal operating point of the power system subject to system stability constraints. Due to the non-linear and non-convex constraints, the TSC-OPF is NP-hard (Non-deterministic Polynomial-time hardness) and cannot guarantee convergence and global optimum.

For transient stability, the most accurate method is a time-domain simulation by solving the differential-algebraic equations (DAEs). In this paper, an analytic input convex neural networks (ICNN)-based model predictive control (MPC) for enhancing power system transient stability is proposed. The main contributions are as follows: (1) ICNN is introduced into the power system transient stability prediction and optimization for the first time. By using ICNN, transient stability constraint can be constructed as a convex constraint to the optimization variables, such as wind farm and synchronous generator active power outputs. (2) ICNN-based convex transient stability constraint is combined with the DLPF model to build a novel TSC-OPF and MPC model containing only linear and convex constraints, which can solve the shortcomings of poor convergence and local optimal solution of traditional optimization model and other alternatives.

This work is supported by National Science Foundation under ECCS 1917308 and Department of Energy Advanced Grid Modernization program under Contract DE-AC52-07NA27344. Email: tongsu@uconn.edu, junbo@uconn.edu.

II. NUMERICAL RESULTS

The proposed method is tested on the modified IEEE 39-bus system, where four wind farms are located on buses 2, 8, 11, and 21 with a maximum active power output of 225MW.

A. Performance of ICNN model

<table>
<thead>
<tr>
<th>Model</th>
<th>Convergent</th>
<th>Non-convergent</th>
<th>Convergence rate</th>
</tr>
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<tbody>
<tr>
<td>ICNN</td>
<td>3947</td>
<td>0</td>
<td>100%</td>
</tr>
<tr>
<td>ANN</td>
<td>2166</td>
<td>1781</td>
<td>54.8%</td>
</tr>
</tbody>
</table>

B. ICNN-based MPC

[Fig. 2. Wind farm and synchronous generator active power outputs.]
Automated Data-Driven Model Extraction and Validation of Grid-Tied Smart Inverters Dynamics with Grid Support Function

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Abstract—This work focuses on the challenges of managing distributed energy resources (DERs) in converter-dominated power systems (CDPS) due to the diverse behavior of power electronic converters (PECs). To address this challenge, the paper provides a data port for grid-tied smart PECs that allows for the collection and analysis of data from CDPS. The collected data is then used to develop data-driven models using system identification techniques, which help manage CDPS more effectively. These models are useful in improving system operation, planning for DER integration and expansion, and analyzing the impact of various factors on power system behavior. The paper highlights the potential of data-driven approaches in managing CDPS and offers insights for future research.

Index Terms—Data-driven models, data-port, grid-tied, power system, system identification.

I. INTRODUCTION

Integration of power electronic converters (PECs) in distributed energy resources (DERs) has transformed the traditional grid, leading to increased use of converter-dominated power systems (CDPS). However, managing these systems is challenging due to PECs’ diverse dynamics and behaviors, requiring vendor-specific datasets that are often unavailable. Inadequate knowledge of CDPS hinders effective planning, operation, dispatching, DER integration, and expansion. To address these issues, this study proposes a data port for grid-tied smart PECs operating at different phase systems and modes. The collected data is used to develop data-driven models, providing accurate and flexible representations of PEC behavior using system identification techniques [1].

These models can aid in managing modern power systems, improving system operation, planning for DER integration and expansion, and analyzing the impact of different factors on power system behavior, highlighting the potential of data-driven approaches for managing CDPS and providing insights for future research in this field.

II. KEY FIGURES

Fig. 1 and Fig. 2 shows the simulation setup for the data collection from the grid-tied inverter in power hardware-in-the-loop and proof-of-concept of validation of derived models.

III. FINDINGS AND CONCLUSION

The integration of PECs and DERs into the grid has led to an increase in CDPS. This presents unique challenges for managing power systems, as accurate modeling and simulation require specific vendor-specific datasets that are often not readily available. The development of data-driven models using system identification techniques and the collection of data from grid-tied smart inverters can aid in managing modern power systems and improving DER integration and expansion. This work highlights the potential of data-driven approaches for managing CDPS and provides insights for future research in this field.

REFERENCES

Inverter-Based Resources Model Verification Using Electromagnetic Transient Playback Simulation

Haoyuan Sun, Graduate Student Member, IEEE, Qiang “Frankie” Zhang, Senior Member, IEEE
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Abstract—Rapidly increasing penetration of Inverter-Based-Resources (IBRs) into modern power systems creates an urgent need for accurate modeling of IBRs in both transient and EMT domains. For Planning Coordinators (PCs), a solution that can efficiently verify these models is also needed. This work tests the EMT playback approach with both simulated and real Point-On-Wave (POW) data and proposes an IBR model verification method based on this approach.

Index Terms—Inverter-Based Resource (IBR), model verification, electromagnetic transient (EMT) simulation, PSCAD, playback.

I. INTRODUCTION

Accurate generator models play an important role in the planning and operation of modern power systems. Thus, an effective and efficient approach for generator model verification is necessary. One possible option is to use playback simulation. In short, the idea is using grid voltage (or current) measurements as input to the model and compare its current (or voltage) and power outputs with the measured ones. ISO New England implemented this approach with positive sequence models [1]. However, with rapidly increasing number of inverter-based-resources (IBRs), which exhibit faster dynamics, electromagnetic transient (EMT) models should be used for better accuracy. ERCOT briefly mentioned the use of instantaneous voltage playback as part of an EMT model verification tool in [2]. This work further tests the EMT playback approach with simulated and real data and also proposes a full EMT model verification solution including an IBR model ramp-up technique.

II. THE PLAYBACK APPROACH

This work uses PSCAD for EMT simulation. We adopt voltage playback and compare the simulated response of current and power outputs with the measured ones.

A. IBR Model Initialization/Ramp-up Technique

IBR models usually need time to ramp-up before reaching a steady state or the working state. Thus, the IBR model should be properly initialized before the playback process starts.

This work proposes a “sync check relay” initialization technique. The idea is to use another set of ideal three-phase voltage source for the ramp-up period, and switch to the playback voltage source once it reaches steady state. Voltage magnitude and phase angle are matched to ensure smooth transition at the switching time.

B. Playback of Simulated Data

To verify the playback approach and test whether the playback results can replicate the simulation results, a simple SMIB system is used to record the Point-of-Interconnection (POI) voltage and playback to the model later. A three-phase to ground fault is applied on a transmission line near the IBR facility. Three-phase instantaneous voltage at the POI bus of this IBR facility is recorded and then used as input in the playback setup. As expected and as shown in Fig. 1, the playback results exactly replicate the simulation results, thus verifying the EMT playback method and implementation.

C. Playback of Real Data

The real data used in this work is from a Digital Fault Recorder (DFR) located at the POI bus of an IBR facility. It was recorded during a voltage dip event. The data includes three-phase instantaneous voltage and current, as shown in Fig. 2. The duration of the data is 2s, with a sample rate of 8000 Hz. The voltage dip starts at 0.23s and lasts for 0.05s.

As shown in Fig. 3, the playback achieves a close match to the real data, which verifies the overall accuracy of the IBR model. The remaining differences implies minor deficiencies in the model. In order to match with the real data, a set of IBR parameters need to be set and dynamically modified throughout the playback process. These settings and modifications can help engineers understand how the IBR facility actually reacted to the voltage dip event.

III. CONCLUSION

This work proposes an IBR EMT model verification approach using field-recorded POW data playback and a ramp-up technique for initial setup of the playback process. The results show that this playback approach is efficient and effective as an IBR EMT model verification solution and also helps reveal the actual response of the subject IBR during an event.

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A Risk-Sensitive Operation and Schedule Model for Ride-Hailing Fleet in Order Grabbing Mode

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Abstract—With the advancement of mobility-on-demand and electrification technologies in transportation, electric vehicle (EV)-based ride-hailing fleets are increasingly vital to urban ground transportation systems. However, the stochastic nature of order request arrival and electricity prices creates decision-making risks for ride-hailing EVs operating in order-grabbing mode. Therefore, it is crucial to investigate their risk-aware operations and model their impact on fleet charging demand and trajectory. We propose a distributional reinforcement learning framework to model the risk-aware operations of ride-hailing EVs in order grabbing mode. We first develop a risk quantification scheme based on the dual theory of choices under risk. Then, we employ the Implicit Quantile Network, distorted quantile sampling, and distributional temporal difference learning methods to capture intrinsic uncertainties and depict risk-aware EV operation decisions. The proposed framework provides a more accurate spatial-temporal representation of charging demand and fleet management results.

Index Terms—Electric vehicle, reinforcement learning, risk management, charging scheduling, demand-side management

I. INTRODUCTION

GNERALLY, there are two types of fleet management models in ride-hailing systems, order dispatching mode and order grabbing mode respectively. In the latter, EVs choose their orders in a decentralized manner, based on options provided by the platform. The behavior patterns of EVs in this mode can significantly affect fleet management results, including order matching, reposition routing, and charging scheduling. However, the decision-making process in this mode is subject to uncertainties and diversified risk preferences among EVs, presenting significant challenges for modeling fleet trajectory and charging demand.

II. DISTRIBUTIONAL RL-BASED SOLUTION METHOD

Fig. 1. Workflow of the distributional RL-based solution method

We propose a distributional reinforcement learning scheme that combines the Implicit Quantile Network (IQN) and distributional temporal difference (TD) learning methods. This approach allows us to accurately characterize the intrinsic uncertainties in the operational environment and obtain risk-aware decision-making policies for heterogeneous EVs operating in order grabbing mode.

The risk-aware policy \( \pi^*_{g}(\tau) \) for ride-hailing fleets is shown as follows.

\[
\pi^*_{g}(\tau)(a_i, h, t | s_{i,t}) = \arg \max_{a_i, h, t \in A_{h,t}} \rho_{g}[R^\pi]
\]

\[
= \arg \max_{a_i, h, t \in A_{h,t}} \frac{1}{K} \sum_{k=1}^{K} F_{R_{i+h, t}}^{-1}(\tau_k) \hat{g}(\tau_k)
\]

where different distortion functions \( g(\tau) \) are determined by heterogeneous EV risk preferences.

III. KEY RESULTS AND DISCUSSION

We use real-world data from Haikou city to simulate the operating trajectories of EVs with different risk preferences, as shown in Fig. 2.

Fig. 2. Sampled decision-making trajectories of (a) a risk-averse EV and (b) a risk-seeking EV

It can be observed that a risk-averse EV mainly operates in areas with more orders and medium electricity price zone. Most of the orders served by this EV are short distances, which would not direct it to a remote area with fewer incoming orders. In contrast, the trajectory of a risk-seeking EV that prefers to serve long-distance orders with higher revenue. However, those decisions make it take multiple repositioning actions to return to the order-intensive area.
The Power Play: Shocking Discoveries From School to Industry

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Abstract—The power industry has had a surge of changes in the electrifying new age of alternative energy sources and complex computer systems. However, many students find themselves in a circuitous path trying to grasp the intricacies of the industry. Visiting the industry can provide students with a current of knowledge and a chance to see if what they have learned thus far could hold a charge in the real world. Industry professionals can help students generate ideas and connect lines of thought between concepts and applications, illuminating their path to success. This can give students the spark they need to power through their studies and join the industry. By exposing themselves to these types of opportunities, students can see how their knowledge of power can be integrated into practical applications, sparking new ideas and energizing their careers.

Index Terms—Engineering education, experiential learning, workplace requirements, power industry, practicum

I. INTRODUCTION
The power industry is currently undergoing a revolutionary stage with progress in different technologies such as the popularization of distributed energy resources, smart grids, electric cars, and advancements in computing chips and the possibilities they provide. To learn about the industry, five students from the university visited a power consulting company, PSC Consulting, for a spring practicum. However, they were surprised to find that there was a lot more to learn about the power industry. Many of the concepts they had learned in their classes, such as SCADA systems and HVDC, were only briefly introduced and not fully explained. This made it difficult for the students to grasp the nuances of these technologies, which are crucial in the power industry. As the power industry continues to evolve, it is crucial for aspiring engineers to have practical experience and exposure to the latest technologies. The practicum at PSC Consulting provided the students with a valuable opportunity to bridge the gap between theoretical concepts and practical applications, preparing them for their future careers in the industry.

II. MISMATCH BETWEEN CLASSROOM SKILLS AND WORKPLACE REQUIREMENTS
Engineering education faces a significant challenge in keeping pace with the rapid technological advancements that are taking place in the industry. For this reason, academic institutions prioritize critical thinking, problem-solving, and the ability to learn new skills independently in academic curriculum in universities. This focuses on creating engineers who can adapt to new technologies and situations throughout their careers, even as technological frameworks adapt and change. However, this push for adaptability can sometimes overshadow hands-on practical experience. As employers seek candidates with practical experience, there are complaints from industrial recruiters about students lacking practical skills needed for specific jobs. The gap between theoretical concepts and practical applications is particularly problematic in engineering education, as students may not have enough practical experience to apply theoretical concepts effectively in the workplace. To address this challenge, engineering education must strike a balance between theory and practice. Students should have sufficient opportunities to gain practical experience through experiential learning such as practicums or internships. Additionally, engineering curricula should be designed to give students exposure to a range of practical skills, allowing them to build a broad foundation as they begin their careers. This balance is essential to prepare students for the dynamic and ever-changing landscape of the engineering industry. Visiting PSC Consulting provides the students a unique opportunity to close the gap between classroom education and workplace requirements. Converging with subject matter experts can help students gain insights into real-world challenges and industry trends that they may not have encountered in a classroom setting. The symbiotic relationship between theory and practice is essential to the success of engineers in their careers. While theory provides a fundamental understanding of the principles behind engineering, practical experience allows engineers to apply these principles in real-world situations. This relationship between theory and practice is particularly critical in the field of engineering, where new technologies and innovations are constantly emerging. PSC Consulting played a vital role in demonstrating the importance of this relationship to the students. The students had the opportunity to converse with experienced subject matter experts who were enthusiastic about fostering new growth in the industry and sharing their knowledge with the students. Through their interactions with these experts, the students gained valuable insights into the practical applications of theoretical concepts.

III. CONCLUSION
Engineering education must focus on striking a balance between theory and practice to prepare students for the dynamic and ever-changing landscape of the engineering industry. Practical experience through internships, practicums, co-op programs, and other forms of experiential learning is critical to prepare students for the real-world challenges they will face in their careers. A strong theoretical foundation provides a framework for understanding the underlying principles that govern the behavior of systems and practical experience is important as it allows engineers to gain insights and develop the skills needed to apply theoretical knowledge effectively. Organizations such as PSC Consulting play a vital role in fostering this relationship by providing opportunities for students to gain practical experience and interact with experienced subject matter experts. Giving students the opportunity to learn from professionals in the power industry is an investment that requires significant resources and effort that needs to be diverted on behalf of the industry. Students should recognize this charity done for them and be thankful. These shared experiences look forward into the future and demonstrate a commitment to growth and development within the power industry. It is a testament to the industry’s passion and dedication and students are highly recommended to visit their local power affiliated companies and take advantage of the opportunities waiting for them.
Modeling the Commercial Activity of an Aggregator in an Electricity Market

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Abstract—In this paper the commercial activities that an intermediary agent called aggregator can offer to the system operator through an electricity market are studied. The activities offered by the aggregator are the energy supply from distributed and renewable energy sources, as well as the complementary reserve service that helps to balance the supply and demand of the power system. The aggregator coordinates sources of energy production and demand from electric vehicle (EV) users connected to electricity distribution systems (EDS). To simulate the commercial activity between the system operator and the aggregator, a multi-objective mathematical model was used. In the optimization process the system operation cost is minimized and the economic revenues that the aggregator receives for the services provided are maximized. The modeling considers the degradation of the batteries when providing the complementary backup service. The test system has a demand of 200 MW supplied by a 14-bus centralized hydrothermal system, 5 renewable energy sources provided by the aggregator, and distribution systems hosting 1000 electric vehicles. The results show that both the aggregator and the system operator obtain economic benefits from their interaction.

Keywords—Aggregator, System Operator, Electric Vehicles, Optimization.

I. INTRODUCTION

Fig. 1 shows the role of the aggregator for to model and simulate the management of an aggregator with the aim of minimizing the total cost of system operation and maximizing its revenues.

![Fig. 1. Role of the aggregator with an electrical power system.](image)

II. MATHEMATICAL FORMULATION

Equation (1) represents the revenue maximization of the aggregator for offering the voluntary disconnection service in the day-ahead market and for the sale of energy produced by the renewable units.

\[
\text{Max total incomes} = \sum_{i=1} a_{LR}^i p_{LR}^i + \sum_{i=1} a_{PV}^i p_{PV}^i \quad (1)
\]

Where \(a_{LR}^i\) and \(a_{PV}^i\) are the prices, expressed in USD/MWh, to which the aggregator offers the voluntary disconnection service, the energy from dispatchable onshore wind power plants and photovoltaic plants, respectively. \(p_{LR}^i\) and \(p_{PV}^i\) are the powers associated with the voluntary disconnection service and renewable generation for each time interval equivalent to 1 hour.

III. CASE STUDY

A. Test system

The test system is a 14-bus high-voltage, customized system supplying a demand of 200 MW. The generating fleet managed by the operator includes centralized generation sources that operate with natural gas, coal, fuel and a hydroelectric plant. The system also has 5 renewable energy sources managed by the aggregator.

B. Results

Fig. 2 shows the average marginal cost of the system for each case. In blue, the marginal costs are high when the figure of the aggregator is not considered. On the other hand, when considering the figure of the aggregator, there is a decrease in the marginal cost during peak consumption hours since the aggregator takes the high marginal cost as a market signal to disconnect the load of the EVs during those hours.

![Marginal costs](image)

The revenues of the aggregator come from the production of photovoltaic generation sources, reaching 20 kUSD per day. This happens because it is prioritized in the dispatch because it has a lower cost compared to dispatchable generation. Finally, we can observe that the income from the voluntary load disconnection service amounts to approximately 7 kUSD per day, representing 17% of the aggregator’s income.

IV. FUTURE WORK

This poster showing a modeling of the trading activities of an aggregator in an electricity market finding a common ground between the aggregator and the system operator.

For the present study the coordination strategies of EVs and the electricity market will be improved under a stochastic analysis. Also, the depth of discharge and discharge cycles will be incorporated into the battery degradation model.
Abstract—This paper proposes a time-varying inertia estimation approach for the virtual synchronous generator (VSG) control-based inverter. A Thevenin equivalent is first employed to formulate the relationship between the terminal voltage phasor and the virtual frequency inside the VSG. This allows estimating virtual frequency directly, which is further integrated into the virtual swing equation and derived measurement function of the VSG. An improved adaptive Unscented Kalman Filter (IAUKF) is proposed to estimate the time-varying inertia. Numerical results show that, under various scenarios, the proposed inertia estimator is able to converge quickly, has high estimation accuracy, and filter out measurement noise.

I. THE PROPOSED TIME-VARYING INERTIA ESTIMATOR

After a disturbance, the inertia can be tracked with the help of the improved adaptive Unscented Kalman Filter (IAUKF) estimation framework. The first step is to use the Thevenin equivalent to estimate the internal voltage $\bar{V}_s = V_s \angle \delta$. Consequently, the internal frequency of virtual synchronous generator (VSG) can be obtained as:

$$\omega = \frac{d\delta}{dt}$$

(1)

Then, the internal voltage $V_s$, virtual inertia $T_a$ and virtual damping $D_p$ of the VSG-based inverter-based resources (IBRs) are treated as unknown state variables, which are integrated into the virtual active power control:

$$\begin{aligned}
\omega_k - \omega_{k-1} &= \frac{\Delta t}{T_a,k-1} [P_{set} - \bar{P}_{c,k-1} - D_{k-1} \Delta \omega_{k-1}] + \epsilon_{k1} \\
\delta_k - \delta_{k-1} &= (\omega_{k-1} - \omega_s) \Delta t + \epsilon_{k2} \\
V_{s,k} &= V_{s,k-1} + \epsilon_{k3} \\
T_{a,k} &= T_{a,k-1} + \epsilon_{k4} \\
D_{p,k} &= D_{p,k-1} + \epsilon_{k5}
\end{aligned}$$

(2)

and,

$$\bar{P}_{c,k} = \frac{V_{s,k} V_{i,k}}{Z_k} \cos (\theta_k - \delta_k + \phi_k) - \frac{V_{i,k}^2}{Z_k} \cos (\phi_k)$$

(3)

For the measurement function, it can be written as:

$$\begin{aligned}
z_{k1} &= \frac{d\delta}{dt} = \omega_k + v_{k1} \\
z_{k2} &= \frac{V_{s,k} V_{i,k}}{Z_k} \cos (\theta_k - \delta_k + \phi_k) - \frac{V_{s,k} V_{i,k}}{Z_k} \cos (\phi_k) + v_{k2} \\
z_{k3} &= \frac{V_{s,k} V_{i,k}}{Z_k} \sin (\theta_k - \delta_k + \phi_k) - \frac{V_{s,k} V_{i,k}}{Z_k} \sin (\phi_k) + v_{k3}
\end{aligned}$$

(4)

In (2)-(4), $\Delta t$ is the time step and $\omega_s$ is the reference frequency; $P_{set}$ and $P_c$ are active power setpoint and measured active power of inverter; $\omega$ and $\delta$ are respectively the virtual frequency and angle inside the inverter; $\bar{V}_i = V_i \angle \theta$ is the measured terminal voltage of inverter; $V_s$ is the internal voltage of inverter; $\bar{Z}$ is the virtual impedance; $z_{k1}$ and $z_{k3}$ are respectively the measurement functions of $P_{c,k}$ and reactive power $Q_{c,k}$; $\epsilon_k = [\epsilon_{k1} \ \epsilon_{k2} \ \epsilon_{k3} \ \epsilon_{k4} \ \epsilon_{k5}]^T$ and $v_k = [v_{k1} \ v_{k2} \ v_{k3}]^T$ are process noise and measurement noise respectively, which are assumed to be zero-mean white Gaussian noise with covariance matrices $Q_k = \mathbb{E}[\epsilon_k \epsilon_k^T]$ and $R_k = \mathbb{E}[v_k v_k^T]$. Consequently, inertia can be tracked via (2)-(4).

II. NUMERICAL RESULTS

To verify the effectiveness of the proposed time-varying inertia estimator, extensive simulations have been conducted on the modified IEEE 39-bus power system. Specifically, 80 MW VSG control-based inverter is connected to Bus 4. A three-phase short-circuit fault is applied on Bus 3 at $t = 1s$ and cleared at $t = 1.1s$. The total simulation time is 5s.

We can find that the proposed method (IAUKF) is able to achieve excellent inertia tracking results for the time-varying inertia scenario and outperforms the existing state-of-art methods (M1 and M2).
Bidding Behavior Forecasting in Electricity Markets Based on Machine-Learning Methods

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Abstract—With the development of data technologies and policies, it is increasingly vital to forecast individual bids in day-ahead power markets in a data-driven way. This paper proposes a novel bidding forecasting framework based on machine learning methods. First, a low-rank approximation-based feature extraction algorithm is utilized to extract the critical information of bidding curves. Second, a transformer-based multi-dimension time series prediction algorithm is proposed to predict the behavior from related factors and historical bidding records. The preliminary results are shown to demonstrate the effectiveness and performance of the proposed framework.

Index Terms—power market, data-driven analysis, individual bids forecasting, machine learning.

I. INTRODUCTION
Since the restructuring of power markets worldwide, market participants’ bids have attracted increasing attention. Information about market situations and trends is usually hidden separately in numerous bids. Thus, it is essential to comprehend, model, and forecast individual bids for market organizers and market participants.

Although many studies are working on forecasting critical factors in power markets, such as load [1] and renewables [2], there have been few studies to forecast or simulate individual bids in a data-driven way until now.

II. METHODOLOGY
The overview of the proposed framework is shown in Fig. 1. First, bidding curves are decomposed by the feature extraction method (Sec. II-A) to obtain the feature values and feature matrix. Second, the transformer-based prediction model (Sec. II-B) can predict the future bidding feature values according to the historical feature values and related factors. Finally, the predicted feature values are reconstructed to bidding curves relying on the feature matrix.

A. Bidding Curve Feature Extraction
Since the bidding data are mainly in the format of price-capacity pairs, they are unstructured and cannot be directly used in machine learning models. Thus, a feature extraction method should be first applied to the initial bidding records. The non-negative matrix factorization (NMF) algorithm is utilized. It decomposes several curves $V_{n \times m}$ into two non-negative matrices, feature matrix $W_{n \times k}$ and coefficient values $H_{k \times m}$. The former contains the key characteristics of the bidding curve, and the latter uses the linear combination of the former to represent each bidding curve.

B. Bidding Feature Prediction
The feature prediction process is based on the transformer module, which is a state-of-the-art machine learning model [3]. We construct a multi-dimension time series transformer prediction model. It could predict several features according to historical features and related factors.

III. PRELIMINARY RESULTS
The preliminary results are shown in Fig. 2. It shows the models have high prediction performance on each step.

Fig. 1. Framework overview

Fig. 2. Predicted feature and curve

REFERENCES
Standards Based Data Integration for Utilities

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Monish Mukherjee
Pacific Northwest National Laboratory
Richland, WA

Abstract—This work presents a data modelling and application usage framework for utilities that utilizes the Common Information Model (CIM) to standardize and integrate data directly available from the utility enterprise database. This work describes the framework’s approach in standardizing a utility’s distribution data and storing it in a large database of high fidelity CIM models which can then be used as input to any analytical tool that can accept data in a CIM structure.

I. INTRODUCTION

Traditional distribution management systems are typically isolated from or loosely coupled with different enterprise applications such as DER management systems (DERMS), advanced metering infrastructure (AMI), outage management systems (OMS), and asset management systems (AMS). To address this challenge, CIM has emerged as a widely accepted solution for data exchange and system integration in distribution systems. Here, a data integration and application development framework is proposed that dynamically develops CIM models by standardizing interfaces of a utility’s existing enterprise systems, utilizing triple-store database technology, catalog data using SPARQL queries, and a graphical user interface (GUI) for visualization.

II. CIM BASED FRAMEWORK

The framework’s conceptual architecture is shown in Fig 1. and includes the crucial feature of standardized data abstractions and exchange. Through the utilization of GIS data, the physical infrastructure can be visualized on a GUI. It can also display the network operational states from powerflow solutions and the historical load profiles of their service customers. By using AMI data, the converted GridLAB-D model can be populated with load data to enable accurate simulation. Fig 2. illustrates the validation of the model conversion from the utility system’s feeder data to CIM simulated with GridLAB-D. The intervals of inconsistency in the AMI data correspond to the mismatched intervals of the simulation.

III. APPLICATIONS

One example application featured for utilities includes photovoltaic (PV) hosting capacity analysis. To achieve this, solar panels were virtually fitted to both industrial and residential loads, whose peak loads exceeded 10kW, with modeling conducted via GridLAB-D. The capacity of these panels was established by the supported panel area up to an integer amount of load ranging from 10kW to 250kW. Fig. 3 exhibits the outcomes from the hosting capacity analysis, illustrating the maximum per-unit voltages across all nodes in the system per penetration percentage. By employing this deterministic approach, it was determined that PV panels could support a total of 70% of qualifying loads before the system became over-voltage and exceeding the 1.05 per-unit voltage limit.

This material is based on work supported by Avista Corporation under the Micro-Grid Agreement funded through the Clean Energy Fund - II.
Coordinated Planning Strategies of Power Systems and Energy Transportation Networks for Resilience Enhancement

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Abstract—A coordinated planning method of power systems and energy transportation networks (ETNs) is proposed. The conception of ETNs is first formulated. Then a series of novel uncertainty sets are proposed to simulate the road capacity loss and renewable power variations. Modified C&CG with discretization method is developed to solve the model efficiently. Case studies have verified the significance of ETNs to power system economic operation and resilience enhancement.

I. INTRODUCTION

Strategic planning of power systems plays a fundamental role in enhancing its resilience. Power system operation greatly depends on the supply and transportation of primary energy sources which is seldom considered, making coordinated planning of power systems and ETNs necessary. Compared with transmission lines, ETNs are less vulnerable or more flexible with higher survival performance (e.g. underground pipelines and road-based transportation). Therefore, energy networks can be reinforced by replacing part transmission lines with other optional ETNs. Besides, coordinated planning could provide better operation options when encountered with extreme events.

II. ETN MODEL, UNCERTAINTY SETS AND METHODS

ETNs transport primary energy from production sites to load centers for power generation and other usages. Undirected graph \( UG = [N, A] \) is shown in Fig. 1. Primary energy exploitation and thermal units depicting conversion process are also represented as arcs to capture comprehensive effects of extreme events on energy systems.

![Fig. 1. Schematic diagram of ETNs](image)

In extreme events, ETNs could still keep in operation but with low performance, whose capacity would be decreased.

\[
A = \{DC_{\alpha} \} \bigg\{ \frac{DC_{\alpha}}{\epsilon_{\alpha, max}} \leq \Gamma_{ET}, 0 \leq DC_{\alpha} \leq \epsilon_{\alpha, max} \} \}
\]

(1)

\[
\frac{\epsilon_{\alpha, max}}{\epsilon_{\alpha}} \leq \left( \epsilon_{\alpha, max} - DC_{\alpha} \right) \frac{[\lambda]}{[\lambda]}
\]

(2)

\( DC_{\alpha} \) stands for capacity reduction of arc \( \alpha \). \( \Gamma_{ET} \) is the budget for overall capacity reduction rates. Dual variable \( \lambda \) being multiplied by \( DC_{\alpha} \) is non-linear items. Therefore, discretization method is embedded in C&CG, shown in Fig.2.

\[
z_{\alpha, min} \leq z_{\alpha, 1, max} \leq \epsilon_{\alpha}, \sum_{\alpha} z_{\alpha, 0} \leq \Gamma_{v}, \forall v, \forall \alpha
\]

(3)

Fig. 2. Discretized ETN capacity attack.

III. KEY RESULTS

<table>
<thead>
<tr>
<th>Case</th>
<th>Operation Cost</th>
<th>Expansion Cost</th>
<th>Total Cost</th>
<th>Extreme Condition</th>
</tr>
</thead>
<tbody>
<tr>
<td>II-1</td>
<td>285997.4</td>
<td>23878.1</td>
<td>309875.5</td>
<td>None / 1 TL</td>
</tr>
<tr>
<td>I-2</td>
<td>297657.2</td>
<td>17935.1</td>
<td>315592.3</td>
<td>2 TL</td>
</tr>
<tr>
<td>I-2</td>
<td>285703.8</td>
<td>24406.4</td>
<td>310110.2</td>
<td>2 TL</td>
</tr>
<tr>
<td>I-3</td>
<td>297653.5</td>
<td>18297.5</td>
<td>315951.0</td>
<td>1 GU &amp; 2 TL</td>
</tr>
<tr>
<td>II-3</td>
<td>286207.9</td>
<td>25792.6</td>
<td>312000.5</td>
<td>1 GU &amp; 2 TL</td>
</tr>
<tr>
<td>I-4</td>
<td>infeasible</td>
<td></td>
<td></td>
<td>2 GU &amp; 2 TL</td>
</tr>
<tr>
<td>II-4</td>
<td>285548.2</td>
<td>28505.2</td>
<td>314053.4</td>
<td>2 GU &amp; 2 TL</td>
</tr>
</tbody>
</table>

Group I represents decomposed planning cases while Group II are cases of coordinated planning considering ETNs.

<table>
<thead>
<tr>
<th>Case</th>
<th>Extreme Conditions</th>
<th>Distributions</th>
</tr>
</thead>
<tbody>
<tr>
<td>III-3</td>
<td>2 GU &amp; 2 TL &amp; 16.2% CL</td>
<td>8/3</td>
</tr>
<tr>
<td>III-4</td>
<td>2 GU &amp; 2 TL &amp; 16.2% CL</td>
<td>7/4</td>
</tr>
<tr>
<td>IV-1</td>
<td>2 GU &amp; 2 TL &amp; 16.2% CL</td>
<td>8/2/1</td>
</tr>
<tr>
<td>IV-2</td>
<td>2 GU &amp; 2 TL &amp; 16.2% CL</td>
<td>6/3/2</td>
</tr>
<tr>
<td>IV-3</td>
<td>2 GU &amp; 2 TL &amp; 16.2% CL</td>
<td>5/3/2/1</td>
</tr>
<tr>
<td>IV-4</td>
<td>2 GU &amp; 2 TL &amp; 14.7% CL</td>
<td>2 entire roads</td>
</tr>
</tbody>
</table>

### Table II. Attack Conditions Considering Capacity Loss

<table>
<thead>
<tr>
<th>Case</th>
<th>Operation Cost</th>
<th>Expansion Cost</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>III-3</td>
<td>285615.2</td>
<td>30027.2</td>
<td>315642.4</td>
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<td>III-4</td>
<td>293451.5</td>
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<td>322842.3</td>
</tr>
<tr>
<td>IV-4</td>
<td>infeasible</td>
<td></td>
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</table>

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Cyber-Attack Detection in AC Microgrid Based on Unsupervised Machine Learning Based Algorithm

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Abstract—Contemporary cyber-physical systems have become more advanced with the use of modern control frameworks and communication networks. These systems are capable of supporting inverter-based resources and can efficiently manage high grid dynamics. However, these systems are susceptible to disturbances from both physical anomalies and cyber attacks, which can negatively impact the grid and cause disruptions in load supply. This paper aims to develop an unsupervised learning method for identifying cyber-physical anomalies using an autoencoder-based neural network. The study uses an islanded inverter-based microgrid to evaluate the proposed anomaly detection technique, taking into account both physical and cyber implications of power system failures and false data injection that targets the communication network. The performance metric for the suggested detection method is the autoencoder error, which demonstrates the viability of the simulation results.

I. INTRODUCTION

The introduction of cognitive algorithms and communication networks has turned DG systems into cyber-physical systems, which makes them vulnerable to cyber attacks [1] [2]. These attacks occur when an attacker interferes with the microgrid’s cyber communication layer by providing misleading data or delaying bus agent communication. Physical anomalies in the microgrid’s physical layer can cause partial or complete system outages, depending on the type and location of the power system fault [3]. Cyber-physical anomalies come in various forms, including False-Data Injection (FDI) attacks and different types of faults, such as single-phase-to-ground (PG), two-phase (PP), two-phase-to-ground (PPG), and three-phase (PPP) faults. These anomalies can adversely affect the microgrid’s performance and stability, making it necessary to have an efficient detection strategy to maintain regular operation.

II. CYBER ANOMALY DETECTION BASED ON AUTOENCODER

Autoencoders are a type of artificial neural network that can be trained to recognize normal patterns in data and classify anything outside of those patterns as an anomaly. This method is particularly useful when anomalies are difficult to define using mathematical expressions. The data is compressed and then decompressed by the autoencoder from a large input stage, and any anomalies are detected by comparing the difference between the input signal and its compressed and decompressed versions, which results in an error signal. This error is small when the system is functioning normally and larger when it is under attack. The performance of the autoencoder is evaluated using Mean Average Percentage Error (MAPE).

Fig. 1. The test microgrid structure under study

Fig. 2. The performance comparison in terms of MAPE under FDI attack

Fig. 3. The performance comparison in terms of MAPE under PPG fault

REFERENCES

Operability of a Power System with Synchronous Condensers and Grid-Following Inverters

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Abstract—Growing shares of inverter-based resources generally correlate with a reduction in inertia as synchronous generators are displaced. Along the path to high shares of inverter-based resources, in particular with only conventional grid-following inverter controls, a proffered solution is the use of synchronous condensers as a source of inertia to maintain the frequency–power balance relationship. An outstanding question is whether only grid-following inverters and synchronous condensers yield a viable power system; i.e., all frequency response is derived from inverters. A validated electromagnetic transient model of the Maui system, with many nonlinear elements such as load-shedding, line tripping, and inverter ride through criteria disabled, is used to investigate the stability of such a system. Two types of perturbations were applied, a 15% generation loss and a fault event, and it was found that the system remains stable.

Index Terms—inverter-based resources, grid-following inverters, inertia, PSCAD, synchronous condensers

I. METHODS

In [1], a highly-detailed electromagnetic transient (EMT) model of the Maui Hawaiian island power system was developed and validated in PSCAD. This research utilizes the Maui EMT model with high order dynamical models of the GFLs to simulate a scenario in which only GFLs provide frequency response.

The PSCAD model of the Maui power system contains over 200 buses and nearly 200 distinct sources of generation. While the majority of real power is delivered by distributed generation, only three hybrid power plants (HPPs), plants with coupled solar photovoltaic and energy storage systems, and a single energy storage system (ESS) provide frequency response. Additionally, there are a total of six synchronous condensers (SCs) located at two buses. There are no synchronous generators online.

An open-source GFL model for use in PSCAD is provided in [2]; this model is used for all distributed generation and HPP instances in this study. Two types of perturbations are applied to assess the large signal stability of the Maui power system.

- Generation Loss: the two type 4 wind plants in the South region at bus 304 are disconnected, for a loss of generation of 21 MW (approximately, 14% of total generation).

- Fault: a three phase, zero impedance fault is applied for 5 cycles (0.083 s) in the Maalaea West region at bus 602.

II. MAIN RESULTS AND CONCLUSIONS

In [3], a 21 MW generation loss and a fault were simulated to assess the large signal stability of the system, with both simulations yielding acceptable responses, pointing to the potential viability of such an operational scenario. Fig. 1 demonstrates how frequency stabilizes after a loss in generation and highlights the benefit of synchronous condensers in stabilizing highly renewable power systems. Further analyses may be required to confirm stability of the system with these resources under a wider range of fault and operating conditions.

Fig. 1: Frequency response following a 21 MW generation loss [3].

REFERENCES

Sensitivity Analysis on Green Hydrogen as Energy Storage: A Techno-Economic Case study

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Abstract—Production of green Hydrogen is increasingly helping the world achieve its energy transition goals. Compared to conventional methods, producing Hydrogen using green energy produces fewer carbon emissions. Furthermore, green Hydrogen can be produced from several renewable sources depending on the region’s potential. Photovoltaic systems are considered in this study to estimate green hydrogen production in the United Arab Emirates. The impact of electrolyzer and hydrogen tank capital expenses on green Hydrogen production has been extensively researched in the literature. However, the impact of the varying capital cost is often overlooked. In this work, we analyze the sensitivity of renewable systems’ costs to changes in the costs of producing Hydrogen, and employing it as energy storage.

Index Terms—Hydrogen, green energy, photovoltaic systems, electrolyzer, energy storage

I. INTRODUCTION

The proposed system is for the commercial office building load demand in Abu Dhabi, UAE. The building has a variable load demand with peak hours during the middle part of the day between hours 8th to 16th. The other part of the day still has an off-peak load consumed by the security systems, elevators, and necessary equipment. The microgrid proposed is designed to satisfy the load demand with the maximum renewable fraction possible. As the central power producer, the PV system is connected to a discrete, reversible fuel cell system (RFC). This RFC will generate power during the non-PV generation hours. The Hydrogen produced during the process is stored in tanks and consumed upon RFC’s requirement. The whole system is connected to the utility company, which makes it easier for the system to import shortage power or export excess power generated. The complete system is modeled and simulated in the MATLAB software.

II. DISCUSSIONS

The Methodology can be seen in Figure 1 and sensitivity analysis of Economic results can be seen in Figure 2.

III. CONCLUSIONS

This study proposed a microgrid-based hybrid PV/RFC system for a commercial building in Abu Dhabi in the United Arab Emirates. The generated power allowed the system to meet the load demand, with excess power utilized by the electrolyzer to generate hydrogen, which was then stored in a hydrogen tank so that the fuel cell utilizes it during non-PV generation hours to meet the load demand. The system’s performance was discussed using monthly and daily average values. The initial results showed that, under current market conditions, the Levelised cost of PV energy is around 0.035 $/kWh, LCOH is around 4.339 $/kg, LCOS around 0.377 $/kWh, and LCOE around 0.1246 $/kWh. In addition, the sensitivity analysis showed how sensitive these values are to changes in the system’s overall costs. As such, the change difference was up to 20%.

Lowering the LCOH requires lowering the cost of the power utilized to produce Hydrogen along with the cost of the components utilized to produce Hydrogen. Since renewable energy sources are intermittent, on grid system reduces excess energy by exporting it, while total load demand can also be met by importing energy when the microgrids generation is not sufficient.
A Temperature-Informed Data-Driven Approach for Behind-the-Meter Solar Disaggregation

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Abstract—The lack of visibility to behind-the-meter (BTM) PVs causes many challenges to utilities. By constructing a dictionary of typical load patterns based on daily average temperatures and power consumptions, this paper proposes a temperature-informed data-driven approach for disaggregating BTM PV generation. This approach takes advantage of the high correlation between outside temperature and electricity consumption, as well as the high similarity between PV generation profiles. First, temperature-based fluctuation patterns are extracted from customer load demands without PV for each specific temperature range to build a temperature-based dictionary (TBD) in the offline stage. The dictionary is then used to disaggregate BTM PV in real-time. As a result, the proposed approach is more practical and provides a useful guideline in using temperature for operators in online mode. The proposed methodology has been verified using real smart meter data from London.

Index Terms—Behind-the-meter solar generation, dictionary learning, disaggregating BTM PV generation.

I. PROBLEM STATEMENT

This paper introduces a temperature-based data-driven approach to disaggregating BTM PV for net load. The proposed approach can be applied to households or distribution feeders. The basic idea is to create a temperature-based dictionary (TBD) based on the correlation between outside temperatures and electricity consumption, along with the similarity between PV generation profiles. There are three types of customers: C_{ON} represents customers without PVs whose native demands are visible. C_{OP} represents customers with PVs whose native demands and PV generation are visible. C_{UP} represents invisible customers with PVs whose only net-load is recorded by smart meters. This study proposes the development of a Temperature-based dictionary (TBD) through the application of a temp-based classification (TBC) technique that classifies days based on average temperature and power consumption. Using observable native demand and solar PV generation (from C_{ON} and C_{UP}) the TBD is constructed and optimized for each temperature range in an offline mode. The BTM PV disaggregation is then performed online using the TBD, improving the system’s accuracy and effectiveness.

II. PROPOSED TEMPERATURE-BASED APPROACH

The proposed approach can be divided into two phases: pre-processing phase and the main phase, as illustrated in Fig. 1. Pre-processing and the TBC are implemented either offline or online in the first phase. The pre-processing smart meter data includes cleaning data and normalizing load curves. Days are clustered by the TBC using k-means in the offline phase based on daily average temperatures and power consumption ranges. In the real-time TBC, a target day would be assigned to each cluster with high similarity. In the main phase, the TBD is constructed and then used to disaggregate invisible PV generations. To do so, in the offline stage, the k-means algorithm is applied to visible native demands from C_{ON} and C_{OP} individually for days organized by offline TBCs. Thus, the typical native demand d_{i}^{N} is the outcome of this step. In the online stage, target days are linked to the right d_{i}^{N} through online TBC and then D_{t} (TBD associated with t^{th} day) will be constructed by incorporating d_{i}^{N} with d_{i}^{PV}. The solar exemplars d_{i}^{PV} is obtained online data from C_{OP} on target day due to the significant spatial correlation in weather data. In the second stage of this phase, any off-the-shelf convex solvers can be applied to the TBD and net-load from associated C_{UP} to disaggregate their native and PV generations on the target day.

III. CONCLUSION

The approach uses TBC instead of seasonal or monthly categories to create a dictionary (here, called TBD), which improves accuracy. The proposed method performs better at the feeder level than at the customer level, with a 2% improvement over traditional dictionary learning. Case study results demonstrate the effectiveness of the proposed temperature-based dictionary.
Cost Sharing Mechanism with Statistical Learning for Peer-to-Peer Energy Trading

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Abstract—Recent results in peer-to-peer energy trading present the least core as an attractive and computationally efficient cost sharing mechanism in these cooperative markets. In the literature of statistical learning applied to cooperative games, it has been found that some approximations of the core can be efficiently learned. We bridge these two results by showing that while the exact computation of the least core for peer-to-peer energy trading has limitations as the number of participants increases, they can be overcome by leveraging asymptotic guarantees from statistical learning theory. Moreover, we show that these results can be applied to some explainable allocations, i.e. cost sharing mechanisms that can be clearly communicated to participants. We present a numerical implementation to validate our method.

Index Terms—cooperative games, least core, statistical learning, peer-to-peer trading, prosumer energy coalition

I. INTRODUCTION

Peer-to-peer (P2P) electricity trade between prosumers, i.e. the buying and selling of electricity between consumers directly, partially or entirely bypassing the utility operator can contribute to reaching decarbonization and reliability goals in power grids. One of the challenges in their implementation is the design of a cost allocation mechanism that remunerates and charges participants in a stable fashion, i.e. to make sure that no coalition (subset) of the prosumers are better off trading within themselves than trading with the whole group. A further challenge is to make sure that this mechanism is computationally scalable as the number of prosumers grows, and is explainable, i.e. is understood by the agents.

II. METHODOLOGY

In [1], Li et al. formulate a cooperative game model representing P2P energy trading and propose the computation of a least core allocation as a set of local buying and selling rates that is stable and only requires solving an LP. We build on this model by adopting their formulation and addressing a computational limitation that was not mentioned there: requiring enumeration of an exponential number of constraints in the description of the LP. To do this, we leverage results from [2], where the authors show that cost sharing mechanisms can be efficiently learned for large-scale instances, in the context of remunerating dataset owners for training machine-learning algorithms.

The method consists thus in solving the LP proposed in [1] randomly sampling only a fraction of the complete set of coalitions, instead of the entire set.

III. RESULTS

We find that it suffices to sample a small (asymptotically polynomial in \( N \)) number of coalitions \( m \) to reduce two quantities of interest: the fraction of coalitions that will be worse off within the P2P scheme than elsewhere, and the amount of money by which they would be better-off elsewhere.

These are only asymptotic guarantees, so to gauge the actual behavior, we test our method on an adaptation of the grid used in [1]. For P2P markets with different numbers of participants, we vary the fraction of total coalitions used when describing the LP. We then check the complete set of coalitions and report the fraction not satisfied by the allocation, as well as the surcharge experienced by the unsatisfied. The results (Fig. 1) validate the method proposed. In this case, as few as 5% of the total set of coalitions is enough to keep the number of dissatisfied coalitions and their surcharge under 2%. We point the interest reader to the full-length version of this conference paper for more details.

Fig. 1. Results obtained solving LP with different percentages of the total number of coalitions. Fig. 1a: Proportion of tested coalitions satisfied. Fig. 1b: Maximum excess charged to a coalition, as percentage of collective cost of that coalition. Main bars show average values over 10 repetitions. Error bars show minimum and maximum values obtained. In each figure, the smaller box shows zoomed-in detail of the larger box.

REFERENCES

Multi-Interval Real-Time Dispatch With High Renewable Penetration: Impacts on Generator Investment Incentives in PJM in 2050

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Abstract—With the increasing adoption of variable renewable resources and the retirement of dispatchable thermal plants, system operators have modified or are considering a change in their real-time market clearing model from a single-interval dispatch to a multi-interval dispatch with a look ahead window which can reduce system costs and improve system reliability. However, private asset owners make investment decisions that impact the generation mix, guided by their predictions of future prices. Changes to the distribution of electricity prices from a multi-interval dispatch has important implications for long-term investment incentives for flexible resources. We explore the impacts of a multi-interval dispatch using a rolling horizon simulation model of the PJM Real-Time Market that represents variability and forecast error in net load for a 2050 future scenario with increased renewable penetration and reduced thermal generation. We demonstrate that multi-interval dispatch improves system costs and reliability but leads to lower prices and reduced price volatility which decreases revenues to generator owners. We show the relative change across generation technology classes to generation, net revenues, and uplift, as measures of the relative incentives for investment in more flexible resources.

I. METHODOLOGY

![Fig. 1. Illustration of rolling horizon model framework with DA, IT-SCED and single-interval RT-SCED market clearing engines.](image)

We compare a single-interval to a multi-interval real-time dispatch model using a simulation of PJM with a 2050 capacity mix. In contrast to previous analyses of multi-interval dispatch, we consider a rolling horizon simulation consisting of a day-ahead (DA) model, intermediate-term security constrained economic dispatch (IT-SCED) model and real-time security constrained economic dispatch (RT-SCED) model and simulate the variability of forecast error in net load using an ARIMA model. 18 representative days were selected using k-means clustering, and each day has 20 independent realizations, giving a total of 360 simulated days.

II. RESULTS

| Table I: System Level Impacts of Multi-Interval Real-Time Dispatch |
|---|---|---|---|
| | Base | MI | Delta |
| System cost ($M) | 9,199 | 9,083 | -116 |
| Reserve shortage (MWh) | 65,277 | 44,915 | -20,361 |
| Reserve shortage (# 5-min occurrences) | 2,394 | 1,484 | -910 |
| Reserve shortage (# days) | 200 | 148 | -52 |
| Unserved energy (GWh) | 76.5 | 69.5 | -7 |
| Curtailment (GWh) | 1,991 | 1,981 | -10 |
| Out-of-market actions (GWh) | 1,788 | 1,188 | -600 |
| Mean energy price ($/MWh) | 80.3 | 43.3 | -37 |
| Standard deviation energy price ($/MWh) | 134.7 | 79.5 | -55.2 |

A multi-interval dispatch reduces system cost, improves reliability, and reduces prices and price volatility. The cost reductions are driven largely by a shift in generation from higher cost, flexible units to lower cost, less flexible units. The reduction in prices is partly a result of a lower frequency of price spikes which also leads to lower generator revenues; by pre-ramping slower units, ramp scarcity events in the Base market design are eliminated, which necessarily reduces prices.

| Table II: Impacts of Multi-Interval Real-Time Dispatch on Different Generation Types |
|---|---|---|---|---|
| | Coal ST | Gas CC | Gas CT | Others |
| Delta generation (GWh) | 1,449 | -787 | -50 | -16 |
| Delta reserves (GWh) | -100 | -116 | -101 | 1085 |
| Delta net revenue (%) | -28.1 | -28.4 | -25.2 | -23.9 |
| Delta uplift (%) | 27.2 | 9.4 | 7.3 | 11.5 |

The impact on generation owners, in contrast, do not appear to benefit from the introduction of multi-interval dispatch. The reduction in prices, and in price spikes in particular, reduces net revenues to all generation types. The greatest reductions in net revenues occur for gas combined cycle and coal units. Because of the decrease in net revenues, the required uplift for a multi-interval market increases for all generation types.
An Energy Efficient Network Reconfiguration in Active Distribution Network by Incorporating Losses from Converter-Based DGs

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Abstract—The minimization of losses is one of the key objectives behind the operation of the distribution network. To achieve this objective, a number of methods, such as distribution network reconfiguration, active/reactive power injection, etc., are employed. Nowadays, the integration of converter-based distributed generation into the distribution network is gaining popularity due to its price reduction and sustainable nature. The converters employed in such generation can also provide reactive power aid. However, the reactive power aid from the converters leads to losses inside it, which constitutes a major portion of total losses occurring in the network. As a result, this study proposes a day-ahead operation approach for an active distribution network in order to reduce overall energy losses, which include network and converter losses. The primary goal of this framework is to establish the optimal radial topology of the network and reactive power dispatch from photovoltaic sources. The proposed framework is developed as a mixed-integer second-order cone programming problem that offers a global solution and is amenable to being solved by commercial solvers. A modified IEEE 33-bus distribution network is used to test the proposed framework. The findings show that the suggested architecture minimizes the overall energy losses in the distribution network.

Index Terms—Distribution network, converter losses, network reconfiguration, reactive power support, second-order cone program.

I. KEY TABLES AND FIGURES

| Table I: Comparison of different cases |
|-----------------|-------|-------|-------|-------|-------|
| Item            | C1    | C2    | C3    | C4    | C5    |
| NEL (MWh)       | 2.5677| 1.4584| 1.6619| 1.1396| 1.3903|
| PVEL (MWh)      | 0     | 1.5213| 0.6503| 1.4620| 0.5912|
| TEL (MWh)       | 2.5677| 2.9798| 2.3122| 2.6017| 1.9816|
| Total P intake from MG (MWh) | 56.6789| 55.5710| 55.7745| 55.2521| 55.5028|
| Total Q intake from MG (MVARh) | 47.5989| 7.3578| 27.5462| 7.2858| 29.3789|
| Total Q injection from PV (MVARh) | 0 | 38.7639| 19.4455| 39.4361| 17.5104|
| Computational time (sec) | 1.23 | 13.15 | 22.78 | 6356.69 | 6938.12 |

Fig. 1. Power loss in different cases at different time intervals (a) Network power loss (b) PV power loss (c) Total power loss.

Fig. 2. (a) Active power intake from MG (b) Reactive power intake from MG (c) Total reactive power injection from all PVs.

Fig. 3. 24 hours schedule of CSWs (a) Case-4, (b) Case-5.
Developing an Equivalent Reduced Feeder Model for Power System Studies

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Abstract—The act of performing dynamic studies such as positive sequence and three-phase EMT (electromagnetic transients) simulations is time-consuming. To overcome the above obstacle without compromising performance accuracy, three-phase three-segment modeling of a detailed distribution feeder approach has been used and the same has been validated on a distribution feeder in Arizona. This work details the suitable principle of distributed energy resource (DER) aggregation compatible with time-domain simulations.

I. METHODOLOGY OF DER AGGREGATION AND LOSS MODELING

The feeder model reduction procedure proposed in [1] has been adopted. However, [1] does not consider DER integration at the distribution grid and this work considered the same for developing a reduced feeder model as shown in Fig. 1.

Based on the prior knowledge of load power ($P_L$ and $Q_L$), the aggregated load active power and reactive power at feeder section $'x'$ $P_{al}^{(x)}$ and $Q_{al}^{(x)}$ is the algebraic sum of each $P_L$ and $Q_L$ respectively. The total transformer losses are modeled based on each transformer’s loss and rating in that feeder section. The above-detailed procedure is verified on a 9 km local utility feeder during a peak insolation hour in the month of March. It is observed an active power of 2 MW is injected into the grid (Fig. 2 and Fig. 3) with a 3% voltage rise across the feeder has been observed in both detailed and reduced feeder models (Table I).

| Actual Feeder | 74.05 kW | -490.2 kVAr |
| Reduced Feeder | 74.047 kW | -489.936 kVAr |

REFERENCES

Data-Driven Approaches for Digital Twinning of a Solar Photovoltaic Plant

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Abstract—High variability in weather conditions and increasing demand for clean energy place a greater demand for stable photovoltaic (PV) generation development. However, implementing efficient PV plants into the power grid introduces a new set of complex challenges for planning, operations, and controls due to their dynamic nonlinear nature. Accurate modeling and simulation of PV power plants is a crucial step towards maximizing efficiency and understanding the characteristics of these plants at any point under changing climate conditions. Understanding the behaviors of a PV plant in forecasting and modeling contexts has been accomplished using a variety of artificial intelligence (AI) tools. This study explores AI-based data-driven approaches to the development and implementation of a PV plant digital twin (DT) model. Digital twins not only provide a platform for simulating and understanding PV plant behavior, but also lay the groundwork for future development of PV models in different locations with varying weather conditions. Thus, distributed energy resources stand to benefit from more efficient controls in complex environments.

Keywords—Artificial intelligence, digital twin, forecasting, PV plant

I. INTRODUCTION

Methods of conventional energy generation are losing their share in the energy industry due to the effects of climate change, prioritization of grid modernization and increasing development of clean renewable energy sources. Solar energy is a leading contender in renewable energy sources found in residential, commercial and industrial loads due to its distributed energy resource (DER) capability. However, the dynamic nonlinear behavior of PV plants present a major roadblock in large scale implementation and operation of PV plants. Large variations of PV generation present the possibility of an imbalance between generation and demand. Therefore, accurate modeling of PV plants will be essential for efficient and secure power system operation.

The variable and uncontrollable nature of PV power adds another layer of complexity in the electric power grid. Maintaining grid frequency has become a higher priority with the increased penetration of renewable energy sources in the power grid. For optimal management of the grid, accurate and efficient PV plant modeling is necessary [1]. This will not only assist in grid management but will also be instrumental for evaluating increasing levels of PV penetration in the grid.

Digital twins (DTs), a leading technology in modeling, are becoming a new focus in energy systems technology development. A DT is used to create high-fidelity virtual models for a physical entity or structure to closely reflect their behavior and responses by the means of evaluation, optimization and prediction [2]. Digital twins are built on the basis of real time and historical data, providing a reliable reproduction of attributes and behaviors of physical systems for applications in describing, visualizing, simulating and optimizing. Therefore, the accuracy and stability of a DT model provides knowledge and certainty in a naturally unstable PV generation source. In this study, a DT model of a 1 MW PV plant located at Clemson University, pictured in Figure 1 is developed and evaluated.

This study explores AI-based data-driven approaches to the development and implementation of a PV plant digital twin model for a 1MW PV plant at Clemson University, SC. Weather station data consisting of weather temperature, solar irradiance and PV plant output will form the data set. Various data-driven AI paradigms including recurrent neural networks and echo-state networks are explored and evaluated. DTs are compared based on accuracy, degree of foresight, and computational time.

REFERENCES


Online Model-Free Chance-Constrained Distribution System Voltage Control using DERs

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Abstract—This paper proposes an online data-driven distributed energy resource management system (DERMS) optimization method using chance-constrained formulation to address distribution system voltage regulation. This is achieved via the local sensitivity factor (LSF)-enabled reformulation of the DER control into a linear programming (LP) problem, which is easy and computationally efficient to solve. The LSF is estimated using online measurements and does not need the assumption of node load information. The latter is usually required for existing optimization-based methods but is difficult to obtain in practice. To mitigate measurement uncertainties, a scenario-based chance-constrained formulation is constructed. Compared with other control methods, the results carried out in a realistic distribution system show that the proposed method can effectively eliminate voltage violation issues.

Index Terms—Distribution system voltage control, local sensitivity factor, chance-constrained optimization, DERs

I. INTRODUCTION

The high-level penetration of DERs could cause adverse impacts on the distribution system due to the lack of enough voltage support, and oscillation control. For example, voltage violations may degrade power quality, cause distribution line congestion, etc. Typically, distribution systems are designed for unidirectional power flow in a radial structure, while PV integrations may trigger bidirectional power flow with smart inverters, especially at a high penetration level. On the other hand, implementing these smart inverters provides power grids with the opportunity for fast control.

II. PROPOSED DERMS ONLINE SOLUTION

The PV inverter control region is analyzed, and then the importance of time-varying LSF updating is emphasized and a recursive method to achieve that is presented. Finally, the chance-constrained reformulation and its solution method are proposed.

III. NUMERICAL RESULTS

According to a rough estimation based on the statistical data, day 163 is the severest day of having voltage violation issues. Fig. 3 shows the voltage profile during that day, where the highest voltage magnitudes are also displayed. The node of the highest voltage magnitudes may change over time due to the time-variant load distribution and solar irradiance. The orange line depicts the over-voltage that occurred between 6:00 and 19:00 without any action/control since the solar irradiance was maintained long in summer. The highest value of voltage magnitudes is 1.095 on one node at noon. The volt-var control (vars priority) works when the highest voltage comes across the voltage limit (1.049). The proposed DERMS control shows excellent performance with updated LSF and chance constraints. DERMS may take actions before real over-voltage happens considering the uncertainties of measurements, which can be verified in Fig. 2, where the maximum value of all risky nodes is near 1.04 before sunrise, and an error of 1% is common in measurements. In this test, 19 risky nodes are highlighted to measure over-voltage values, and half of the nodes exceeded 1.06 during the daytime, which implies an ideal selection of the risky nodes.

IV. CONCLUSION

This paper proposes an online data-driven DERMS for dealing with voltage violation issues with updated LSF and scenario-based chance constraints.
Capacity Expansion Planning for Wind Power Based on Data-Driven Approximation Approach

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Abstract—Renewable energy has been rising rapidly due to environmental and energy pressures. This paper proposes a single-level capacity planning framework in which the operating cost is properly evaluated by considering a series of hourly security-constrained unit commitment (SCUC) problems. Besides, to relieve the computational burden of long-horizon SCUC problems, a data-driven approximation method for optimal operation cost is established based on the least-squares approximation approach.

Keywords—capacity expansion planning, wind power, data-driven, security-constrained unit commitment

I. INTRODUCTION

Generally, reasonable capacity planning decisions require the accurate estimation of operating costs, therefore, short-term operating constraints shall be considered. However, when the detailed operating constraints are considered, the mathematical formulation of the planning problem is more complex, which is also the main difficulty in solving the capacity planning problem. Therefore, in this paper, a single-level model is proposed to solve the capacity expansion planning problem for wind power, in which a data-driven method is used to estimate the operating cost.

II. MODEL AND DATA-DRIVEN COST ESTIMATION

A. Capacity Expansion Planning Model

The planning cost includes investment cost, fixed operation cost, fixed maintenance cost, and operational cost. The objective function is shown in formulation (1).

\[ \min_{c^{\text{new},w}, c^{\text{pla}}} c^{\text{pla}} = c^{\text{inv,total},w} + c^{\text{om}} \]  
\[ (1) \]

Investment and operation-related constraints are directly related to the planning decisions, which are shown as (2)–(5).

\[ c^{\text{total},w} \leq \sum_{k \in \Omega} c^{\text{new},w,k} + c^{\text{inv},w} \leq C_{\text{total},w} \]  
\[ (2) \]

\[ c^{\text{new},w,k} \leq c^{\text{new},w,k} \leq \max_{k \in \Omega} \{ p_{w,k,1} \} \forall k \]  
\[ (3) \]

\[ p_{w,k,s} = \min \{ c^{\text{new},w,k} + c^{\text{inv},w,k} + p_{w,k,s} \} \forall k, s \]  
\[ (4) \]

\[ J_{t}^{\text{om}} = f \left( \sum_{k \in \Omega} p_{w,k,s} \right) \forall t, s \]  
\[ (5) \]

Constraints (2)–(4) restricts the investment ranges, the total capacity of wind power, and wind farm output. Formulation (5) represents the short-term operating cost, where \( t' \) is the index of days.

B. Data-Driven Operating Cost Estimation

For a fixed structure system (i.e., fixed installed capacity of wind farms and thermal units without considering equipment failure), formulation (5) has a specific expression. In this paper, the least-square method is used to linearly approximate formulation (5). The regression equation of the least-squares method is shown as follows.

\[ f_{\text{om}} = a_1 \sum_{k \in \Omega} p_{w,k,1} + \cdots + a_{24} \sum_{k \in \Omega} p_{w,k,24} + b \]  
\[ (6) \]

In which, \( f_{\text{om}} \) represents the estimated value of operating cost. \( a_1, a_2, \ldots, a_{24} \) and \( b \) are coefficients obtained by using the least-squares method.

The k-means++ clustering method is also adopted to merge daily wind power curves with similar output levels. Using the clustering method to preprocess data can reduce the scale of planning problems and improve estimation accuracy. The solution method is summarized as the following algorithm, for more details please refer to our previous work in [1].

Capacity Expansion Planning Algorithm:
Step.1 Use the k-means++ to cluster the historical wind power output, save the clustering results and cluster centers. For each type of data, use the least-square method to fit the equation (6).

Step.2 Input representative scenarios of wind power outputs, cluster scenarios data using the k-means++, and select the typical daily wind power output in each category to characterize the annual scenarios data.

Step.3 Calculate the distance between the typical daily wind power output and the cluster center obtained in Step.1, to confirm their category, then select the corresponding fitting function to determine the specific expression of (5).

Step.4 Solve the capacity planning problem formulated by (1)–(4) and (6), to obtain the optimal planning decisions.

III. RESULTS

A modified 118-bus system is used to verify the efficacy of the proposed method. The optimal expansion planning capacity of the wind farm is illustrated in Fig. 1.

Fig. 1. The expansion planning capacity of wind farms.

REFERENCES
Electricity Consumption Variation versus Economic Structure during COVID-19 on Metropolitan Statistical Areas in the US

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Abstract—The outbreak of novel coronavirus disease (COVID-19) has resulted in changes in productivity and daily life patterns, and as a result electricity consumption (EC) has also shifted. In this paper, we construct estimates of EC changes at the metropolitan level across the continental U.S., including total EC and residential EC during the initial two months of the pandemic. The total and residential data on the state level were broken down into the county level, and then metropolitan level EC estimates were aggregated from the counties included in each metropolitan statistical area (MSA). This work shows that the reduction in total EC is related to the shares of certain industries in an MSA, whereas regardless of the incidence level or economic structure, the residential sector shows a trend of increasing EC across the continental U.S.. Since the MSAs account for 86% of the total population and 87% of the total EC of the continental U.S, the analytical result in this paper can provide important guidelines for future social-economic crises.

Index Terms—COVID-19, electricity consumption, economic structure, metropolitan, electricity consumption modeling
Learning-Based, Safety and Stability-Certified Microgrid Control

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Abstract—A neural-Lyapunov-barrier-enabled, physics-informed-learning-based control method is devised to provide certified safe and stable hierarchical control of microgrids. The main contributions include: 1) a neural hierarchical control framework for microgrids with provable safety and stability guarantees; 2) a control Lyapunov barrier function (CLBF) considering the fast dynamics of distributed energy resources, loads, and networks in microgrids; 3) a physics-informed learning approach for CLBF-based neural hierarchical control synthesis, which learns safety and stability certificates and control policy simultaneously without a verification module. Case studies demonstrate the effectiveness of the approach in provably certifying the stability and safety of microgrids equipped with hierarchical inverter control.

This paper establishes a neural-Lyapunov-barrier-enabled control framework for microgrids. The main contributions of the paper are: 1) a novel neural hierarchical control framework for microgrids is established, which can ensure the large-signal stability and nonlinear safety requirements. 2) a control Lyapunov barrier function (CLBF) is constructed for microgrids considering the dynamics of DERs, loads, and networks to explicitly and rigorously formulate the safety and stability certificates; 3) a CLBF-based, physics-informed learning approach is established to train the safety/stability certificates and control strategies simultaneously. Consequently, the dynamic performance of microgrids with large disturbance are certified by CLBF during the training process without involving an additional verification module, which enables high efficiency for offline training and online application.

B. CLBF Certificates for Microgrids

A function $V(x) : \chi \to \mathbb{R}$ is a CLBF, if, for some safe level $c$ and $\lambda > 0$, it satisfies [10]:

$$V(x_{goal}) = 0, \quad V(x) > 0 \quad \forall x \in \chi \setminus x_{goal}$$  (1a)

$$\inf_u L_f V + L_g V u + \lambda V \leq 0 \quad \forall x \in \chi \setminus x_{goal}$$  (1b)

$$V(x) \leq c \quad \forall x \in \chi_{safe}$$  (1c)

$$V(x) > c \quad \forall x \in \chi_{unsafe}$$  (1d)

Equations (1a) and (1b) jointly define $V$ as a Lyapunov function of the microgrid with the goal point $x_{goal}$ being a stable equilibrium point, where $L_f V$ and $L_g V$ are respectively the Lie derivatives of $V$ along $f$ and $g$ (i.e., specified in (1)); $\lambda$ denotes the microgrid parameters. Equations (1c) and (1d) jointly establish the barrier function requirement.

We first introduce the CLBF-related loss function, which is used to train a CLBF certificate neural network such that the conditions in (1) are satisfied:

$$\mathcal{L}_{CLBF} = \mathcal{L}_1 + \mathcal{L}_2 + \mathcal{L}_3 + \mathcal{L}_4$$

where

$$\mathcal{L}_1 = V(x_{goal})^2$$  (2a)

$$\mathcal{L}_2 = \frac{\alpha_1}{N_{safe}} \sum_{x \in \chi_{safe}} \sigma(\epsilon + V(x) - c)$$  (2b)

$$\mathcal{L}_3 = \frac{\alpha_2}{N_{unsafe}} \sum_{x \in \chi_{unsafe}} \sigma(\epsilon + c - V(x))$$  (2c)

$$\mathcal{L}_4 = \frac{\alpha_3}{N_{train}} \sum_{x} \sigma(\epsilon + L_{f}(x) + L_{g}(x)\pi(x))$$

For future work, we will exploit the devised method in networked microgrids under more complicated system operations, such as plug-and-play.
Comparison of Accuracy of Capacity Credit Definitions for Resource Adequacy Accreditation

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Abstract—The transition towards a cleaner power system necessitates the installation of variable renewables (VREs) like wind and solar, as well as energy-limited resources such as battery energy storage (BES) and demand response (DR) programs. As the penetration of these resources grows, it becomes increasingly important to accurately quantify their contributions to system adequacy. In this paper, we compare two classic capacity credit (CC) definitions—ELCC (effective load carrying capability) and EFC (equivalent firm capacity)—with a new proposed definition EREC (equivalent reliability enhancement capability). Each values adequacy contributions of various resources based on their marginal increments. The capacity value of thermal plants is also compared with the traditional derating method (expected forced outage rate, EFOR) and Markov Chain simulated random outages. We simulate energy and capacity markets using an LP-based capacity expansion planning model. We demonstrate both numerically and mathematically that marginal EREC can accurately incentivize system-optimal investments in markets with installed capacity requirements and energy price caps. The numerical results show that marginal ELCC consistently underestimates the capacity value of various resources by up to 11%. Meanwhile, marginal EFC performs similarly to marginal EREC in systems without DR but may underestimate resource values by approximately 2% when DR is present. Furthermore, we analyze technology and system cost distortions resulting from implementing different definitions of CCs in capacity markets.

I. CAPACITY CREDIT DEFINITIONS

At present, several electricity markets in North America use ELCC-based methods to evaluate the capacity value of intermittent resources such as wind and solar. The classic definition of ELCC is based on Garver’s work \cite{1}. Variants of ELCC can be calculated using different reliability metrics (e.g., loss of load probability LOLP, loss of load hours LOLH, and expected unserved energy EUE) and benchmarks (e.g., load increase that can be met reliably, perfectly reliable capacity). Additionally, various implementations of CCs differ in whether they consider marginal, incremental, or average contributions of individual resources or entire portfolios. CCs for thermal plants typically use traditional metrics, such as nominal capacity derated by expected forced outage rates, which may overstate capacity contributions relative to other capacity credit definitions, particularly for large generating units or if outages are correlated, e.g., due to cold weather (as in Texas in Feb. 2021). As a result, use of inconsistent CC definitions for different resources might be expected to lead to biased contributions of resources to system adequacy and distortions in resource investment \cite{2-3}.

II. PROPOSED DEFINITION - EREC

A. Equivalent Reliability Enhancement Capability

In this work, we introduce a new capacity credit definition (first introduced in \cite{3}), which we call Equivalent Reliability Enhancement Capability (EREC). EREC of a resource refers to its capability of enhancing system reliability (measured by EUE or LOLP) relative to a perfectly reliable and flexible resource’s capability of enhancing system reliability. We extend its application to estimating the adequacy contributions of DR and thermal plants with random outages modeled as Markov Chains. We claim that under certain assumptions the use of marginal EREC to determine payments in installed capacity markets can lead to efficient mixes of capacity investment. We demonstrate this both numerically and mathematically for markets modeled using convex optimization.

Fig. 1 provides a comparison between the definition of EUE-based marginal EREC and marginal EFC. EREC is defined as the ratio of the change in system EUE resulting from the addition of one unit of resource $g$ to the change in system EUE resulting from the addition of one unit of a perfectly reliable and flexible resource $p$. EFC, on the other hand, is determined by the amount of capacity of the perfect resource $p$ needed to achieve the same change in EUE as adding one unit of resource $g$.

\begin{figure}[h]
\centering
\includegraphics[width=0.5\textwidth]{fig1.png}
\caption{Schematic definitions of capacity credits (EFC and EREC)}
\end{figure}

REFERENCES


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A Bilevel EV Charging Station and DC Fast Charger Planning Model for Highway Network Considering Dynamic Traffic Demand and User Equilibrium

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Abstract—This paper proposes a bilevel planning model for EV charging station (EVCS) and DC fast charger construction plans, with lower-level subproblems for traffic assignment and power distribution network operation models. The model uses statistical charging time and captures the impact of social factors and driver behavior on dynamic EV traffic demands. The case study emphasizes the importance of considering power distribution network constraints and dynamic EV adoption in planning charging facilities for more accurate traffic demand estimation and a better construction plan.

Keywords—EVCS planning, bilevel optimization, user equilibrium, social factors, dynamic traffic demand.

I. METHODOLOGY

In this paper, a bilevel electric vehicle charging station (EVCS) and DC fast charger (DCFC) planning model is proposed regarding the interaction between charging infrastructure, power distribution networks (PDNs), traffic networks, and electric vehicle (EV) drivers (see Fig. 1). The structure and variable transition of the proposed model are demonstrated in Fig. 2, taking the charging time and dynamic EV adoption as two particular concerns.

The charging time is formulated in the user equilibrium-based traffic assignment problem, calculating the charging time by dividing the statistic charging demand by the rated power of DCFCs. Such a formulation calculates the charging time from a macro perspective, considers the number of DCFCs, and avoids complex formulation.

This paper considers dynamic EV adoption, including social exposure, word-of-mouth (WOM), and EV traffic demand elasticity, to capture the social influence on EV adoption from charging facility construction plans. Social exposure captures the impact of disparities between target and real DCFC numbers on EV adoption, WOM represents regional influence on EV adoption, and EV traffic demand elasticity describes the effect of travel time on driving willingness.

![Fig. 1. The relationship among planner, PDN, traffic network, EVCS-DCFC construction plan, EV adoption, and drivers’ behaviors.](image)

![Fig. 2. The structure and variable transition of the proposed bilevel EVCS-DCFC planning model.](image)

II. CASE STUDY

Numerical case studies on an intercity traffic network show that construction plans are highly related to volumes of path flows and EV charging demands, and the number of constructed DCFCs follows the growth of traffic demands. The social factor studies reveal that: (i) the construction of charging facilities might lag behind the growth of charging demand due to social exposure, (ii) WOM can accelerate the saturation of EV adoption, and the effect depends on the number of existing EVs and potential EV customers, and (iii) the elasticity continuously decreases the driving willingness but avoids over-investment. The comparison results highlight the necessity of considering dynamic EV adoption, neglecting which would improperly estimate the EV traffic demand, leading to over- or under-investment.

<table>
<thead>
<tr>
<th>OD Year</th>
<th>Social Exposure</th>
<th>WOM</th>
<th>Elasticity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2, 7, 9</td>
<td>1, 6, 11</td>
<td></td>
</tr>
</tbody>
</table>

Table I. EV Traffic Demand Variations

<table>
<thead>
<tr>
<th>OD Year</th>
<th>Social Exposure</th>
<th>WOM</th>
<th>Elasticity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2, 7, 9</td>
<td>1, 6, 11</td>
<td></td>
</tr>
</tbody>
</table>

Table II. The Influence on DCFC Construction Plans in Certain Path Flows

<table>
<thead>
<tr>
<th>Dynamic Factors</th>
<th>Number of DCFCs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Social Exposure</td>
<td>With Factor</td>
</tr>
<tr>
<td>WOM</td>
<td>8, 4</td>
</tr>
<tr>
<td>Elasticty</td>
<td>12, 7</td>
</tr>
</tbody>
</table>

TABLE I. EV TRAFFIC DEMAND VARIATIONS

TABLE II. THE INFLUENCE ON DCFC CONSTRUCTION PLANS IN CERTAIN PATH FLOWS

Data from: [VTM]
Profit-Oriented BESS Siting and Sizing in Deregulated Distribution Systems

Xiaofei Wang, Graduate Student Member, IEEE, Fangxing Li, Fellow, IEEE, Qiwei Zhang, Graduate Student Member, IEEE, Qingxin Shi, Member, IEEE, Jinning Wang, Graduate Student Member

Abstract—Within the deregulation process of distribution systems, the distribution locational marginal price (DLMP) provides effective market signals for future unit investment. This paper proposes a two-stage stochastic bilevel programming (TS-SBP) model for investors to best allocate battery energy storage systems (BESSs). The first stage obtains the optimal sites and sizes of BESSs on a limited budget. The second stage, a bilevel BESS arbitrage model, maximizes the arbitrage revenue in the upper level and clears the distribution market in the lower level. A novel statistics-based scenario extraction algorithm is proposed to generate a series of typical operating scenarios. Then, scale reduction strategies for BESS candidate buses and inactive voltage constraints are proposed to reduce the scale of the TS-SMILP model. Finally, case studies on the IEEE 33-bus and 123-bus systems validate the effectiveness of the DLMP in incentivizing BESS planning and the efficiency of the two proposed scale reduction strategies.

Index Terms--distribution locational marginal price (DLMP), siting and sizing, scenario extraction, two-stage stochastic bilevel programming (TS-SBP), scale reduction.

I. INTRODUCTION

This paper focuses on the optimal siting and sizing of BESSs for private investors. This planning is formulated as a two-stage stochastic bilevel programming (TS-SBP) problem. The first stage determines the locations, sizes, and number of BESSs within a limited budget. The second stage maximizes investors’ arbitrage profits in the long-term operation, which is modeled as a bi-level problem with the investors in the upper level and the DSO in the lower level. The contributions are summarized as:

1) The DLMP is applied as the price signal to incentivize the BESS planning in a deregulated distribution system. 2) A TS-SBP arbitrage model is established. 3) A k-means-based scenario extraction algorithm is proposed to extract the most representative patterns of LMP and system load profiles. 4) BESS candidate buses reduction and inactive voltage constraints reduction, are proposed to reduce the computational complexity for this large-scale optimization problem.

II. PROBLEM FORMULATION

The mathematical formulation of the TS-SBP model is presented in this section. The overall framework is shown in Fig.1.

III. CASE STUDIES

The optimal sites of sizes of BESS in a modified IEEE 33-bus system in different cases are shown in TABLE I.

<table>
<thead>
<tr>
<th>Cases</th>
<th>BESS bus (#)</th>
<th>$P^{out}/E^{out}$ (kW/kWh)</th>
<th>Annual net profit ($)</th>
<th>Time (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>11, 15, 18, 31, 33</td>
<td>100/400, 149/597, 103/414, 107/426, 100/400</td>
<td>9302.22</td>
<td>7936</td>
</tr>
<tr>
<td>Case 2</td>
<td>11, 15, 18, 31, 33</td>
<td>100/400, 149/597, 103/414, 107/426, 100/400</td>
<td>9129.38</td>
<td>3442</td>
</tr>
<tr>
<td>Case 3</td>
<td>11, 15, 18, 31, 33</td>
<td>100/400, 149/597, 103/414, 107/426, 100/400</td>
<td>9129.38</td>
<td>1338</td>
</tr>
<tr>
<td>Case 4</td>
<td>11, 15, 18, 31, 33</td>
<td>100/400, 149/597, 103/414, 107/426, 100/400</td>
<td>9129.38</td>
<td>2390</td>
</tr>
<tr>
<td>Case 5</td>
<td>11, 15, 18, 31, 33</td>
<td>100/400, 149/597, 103/414, 107/426, 100/400</td>
<td>9129.38</td>
<td>1077</td>
</tr>
</tbody>
</table>

IV. CONCLUSIONS

Numerical studies on two systems demonstrate the following conclusions:

1) The DLMP can act as an effective price signal to incentivize BESS planning. This is a special attribute of the deregulated system that is quite different from traditional ones.

2) The proposed two scale-reduction strategies are verified to both significantly improve the computational efficiency and maintain the result accuracy.

3) Optimal siting and sizing are shown to be beneficial for both BESS investors and the DSO, such that it is aligned with the incentive compatibility in market operation.
Defense Against Dynamic Residential Load Demand Attack Using Robust Multi-agent Reinforcement Learning and Game Theory

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Abstract—This work introduces a model-free defense algorithm against residential load demand attacks. We propose to formulate the power suppliers and consumers as a non-cooperative game and utilize multi-agent reinforcement learning to find the optimal defense strategies. The proposed method can also adapt to changing environments by utilizing the robust reinforcement learning method.

Index Terms—Load demand attack, cybersecurity, multi-agent reinforcement learning, micro-grid.

I. INTRODUCTION

While smart home appliances are trending, cyber-attacks specifically targeted at them are also increasing due to the lack of dedicated cyber protection designs. This special vulnerability has exposed a potential loophole in the power grid operation since attacking smart home appliances is much easier than attacking power plants or transmission lines, where cyber-security specialists are often hired on-site.

As one of the most common and feasible types of consumer-side attacks, the load demand attack has raised major attention in power system security research. In an isolated micro-grid system that supplies various residential and industrial loads, if the smart home appliances in the residential area are hacked and result in abrupt changes in load demand that exceed the feasible response region, the micro-grid supply and demand balance will be challenged and further initiate protection system actions such as load shedding. As a result, there will be disturbances in frequency and voltage, leading to system instability or failure. Most of the existing defense methods against the load demand attack are model-based solutions, where a fixed model is required in advance. However, in reality, finding an accurate model for the power grid is challenging because the consumers and the environment are constantly changing. Therefore, the existing model-based approaches cannot adapt to a wide range of diverse environments and have limited tolerance to system dynamics.

II. PROPOSED METHODOLOGY

The power suppliers and consumers will be formulated into a multi-agent non-cooperative game, where Multi-agent Reinforcement Learning (MARL) will be used to design a model-free defense strategy to handle load demand attacks. Empowered by robust reinforcement learning, the developed approach provides a power grid model that is both accurate and adaptive to the environment dynamic. The robustness will be guaranteed through the Lyapunov stability analysis. The goal of the robust MARL is to first predict the optimal load-demand attacking scheme of the attackers using game theory, and then find the optimal defense scheme against the attackers.

III. EXPERIMENTS

We will test the proposed algorithm in an isolated micro-grid system. The power suppliers include a PV panel, a wind turbine, and a diesel generator. And the consumers include both industrial loads and residential houses with solar panels and electric vehicles. Both the consumers and suppliers will have a dynamic supply and consumption pattern. We will simulate two types of load demand attacks by suddenly increasing and decreasing parts of the residential loads so that load shedding will be triggered. In the first type, the attackers increase and decrease the controlled load in a fixed pattern while the suppliers use the developed robust MARL algorithm to handle the change by controlling the interruptible load, engaging the backup power source, adjusting the TOU price, and so on. The second type will allow the attackers to have a MARL-driven adaptive attack scheme. We will test the performance of the proposed algorithm and conduct comparison with traditional load-demand attack defense methods.

IV. KEY EQUATIONS

The cost function for the $i$-th defense agent:

$$V_d(u_{d,i}, u_{d,-i}, U_a) = \int_0^\infty \left[ Q^2 \| p_{su,i}(u_{d,i}, u_{d,-i}) - \tilde{p}_{de,i}(U_a) \|^2 + R^2 \| u_{d,i} \|^2 \right] dt$$

The Hamilton-Jacobi-Isaacs (HJI) equation for the defense game:

$$\min_{U_a} \max_{U_d} \left[ l(u_{d,i}, u_{d,-i}, U_a, p_{su,i}, \tilde{p}_{de,i}) + \partial_t V_d^* (u_{d,i}, u_{d,-i}, U_a) + \Delta V_d^* (u_{d,i}, u_{d,-i}, U_a) f(p_{su,i}, u_{d,i}) \right] = 0$$

REFERENCES

Reinforcement Learning Based Voltage Control Using Multiple Control Devices

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Abstract—Operators are facing challenges dealing with voltage problems with a limited solution timeframe after disturbances. This paper presents a novel reinforcement learning (RL) based method to provide voltage control that can quickly remedy voltage violations under different operating conditions. Multiple types of devices, continuous ratio control-based Adjustable Voltage Ratio (AVR) transformers and discretely controlled switched shunts, are considered as controlled devices. A modified Deep Deterministic Policy Gradient (DDPG) algorithm is adopted to combine the continuous and discrete action space of different devices. A case study conducted on the WECC 240-Bus system validated the effectiveness of the proposed method.

Index Terms—Reinforcement learning, voltage control, multi-device, DDPG, transformer, switched shunt

I. INTRODUCTION

Voltage security is critical to power system operations. The integration of renewable energy and distributed energy resources have further increased power system uncertainty, which makes real-time voltage control even more challenging.

In this paper, a data-driven control framework for multiple types of devices for voltage regulation after system disturbances is proposed to maintain the system voltage. A continuous ratio control-based transformer and discrete switched shunt control are considered as the control options. A modified Deep Deterministic Policy Gradient (DDPG) algorithm is adopted to combine the continuous and discrete action space of different devices. The well-trained agent that controls multiple devices can respond instantaneously to cope with different operating conditions and can provide operators with a quick and effective decision when voltage violations occur.

II. PROPOSED METHODOLOGY

DDPG algorithm is adopted in the control framework. The bus voltage magnitudes are considered the environment observation states. For voltage control using AVR transformers and switched shunts, the control actions are defined as a vector of the transformer ratios and the group size of the switched shunts. The reward function includes the negative absolute difference value between the observed voltage and the reference voltage, and the amount of regulation cost during the control process. Power flows, generated using PSS/E, of different operating conditions are used as the training data.

For each episode, a power flow is solved as environment initialization. A loop for a defined number of steps per episode begins with the action generated by the agent, the action then is implemented in the power system environment, which is realized by the Python API with PSS/E. The training of the episode terminates when no more voltage violations are detected or the power flow diverges, then another episode is initiated. This process repeats until the maximum number of episodes is reached.

III. KEY RESULTS AND CONCLUSION

The proposed approach is verified on a WECC 240-bus system. Figure 1 and Figure 2 show the results. During the testing, the agent takes an average of 1.536 steps to clear the violation. The voltages of 94.7% of the testing cases can be recovered to be in the defined range within one step under the combined control of transformers and switched shunt. The results show that the proposed approach can fully use the reactive power resources with different response characteristics to provide more reliable voltage support.
A Practical Urban Distribution Network Planning Method with Geographic Information System

Zhen Wang, Student Member, IEEE, Xinwei Shen, Senior Member, IEEE, Hongbin Sun, Fellow, IEEE

Abstract—Urban distribution network planning (UDNP) faces new requirements and regulations due to rapid urbanization. This paper proposes a framework for UDNP, in which the geographic information system (GIS) and a hybrid optimization model are combined to co-optimize investment and operation decisions. The integration of OSMnx, a GIS Python package, is utilized to generate the street layout graph and produce the shortest path between distribution cabinets. The proposed hybrid optimization model utilizes 1) Clark and Wright’s Savings (CWS) algorithm to produce a close-loop network topology, and 2) mixed integer linear programming (MILP) to produce the corresponding open-loop operation strategy. Case studies on an urban area in China demonstrate the effectiveness of the proposed method. The CWS algorithm improved the computation efficiency by over 1000 times compared with MILP, while introducing the shortest path for UDNP leads to a 30% increase in investment compared with that of using Euclidean or Manhattan distance.

Index Terms—Mixed integer linear programming, geographic information system, shortest path, urban distribution network planning.

I. FRAMEWORK OF UDNP BASED ON GIS

Fig. 1 illustrates the framework of the proposed UDNP method with GIS. The proposed method’s framework comprises three key components. The first part involves the integration of street layouts and distribution cabinets. The street network of the planning area is converted into a graph $G(V,E)$ using OSMnx. Additionally, GIS data is extracted from an XML file provided by DSOs to merge a new graph $G_{new}(V_{new},E_{new})$. In the second part, the distance matrix $D$ is computed based on the shortest path. Subsequently, the modified two-phase CWS algorithm is applied for the close-loop construction of UDNP, which utilizes the cost savings matrix $S$. Finally, an MILP model is formulated for open-loop operation of UDNP.

The framework has three remarkable advantages over existing methods. First, it is capable of generating UDNP results for site construction while following the “close-loop construction, open-loop operation” criteria, simply based on the IEC 61970 standard and OSM. Second, the computation efficiency of mesh construction is significantly improved through the use of the modified two-phase CWS algorithm. Third, the investment cost is reduced due to the replacement of Euclidean distance with the shortest path. These advantages make the proposed framework, combining the GIS toolbox and the hybrid optimization, a promising method for UDNP and site construction.

![Fig. 1. Framework of the proposed method for UDNP](Image)

II. CASE STUDIES

The hybrid model is significantly faster than the MILP model, over 1000 times quicker when the heuristic method converges. The optimality gap of the MILP model is provided by Gurobi which is not satisfactory despite the computation time invested. In site construction, if the sequence of feeder routing remains unchanged, the Euclidean or Manhattan distances must be replaced by the shortest path to address urban barriers. In real-world scenarios, the shortest path results in a significant drop of over 40% compared with the Euclidean distance. The actual construction cost of the shortest path also remains unchanged, while the construction cost of the Euclidean distance increases from ¥0.906M to ¥1.594M due to the actual length. Totally, the cost of the shortest path has decreased by 30.7% under the whole life cycle.

<table>
<thead>
<tr>
<th>Cases</th>
<th>MILP (Linear DistFlow Model)</th>
<th>Hybrid Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Computation Time (s)</td>
<td>16109</td>
<td>9.709</td>
</tr>
<tr>
<td>Optimality Gap (%)</td>
<td>15.9</td>
<td>-</td>
</tr>
<tr>
<td>Feeder Routing</td>
<td>S-1-2-3-4-7-6-2-27-26-30-24-19</td>
<td>S-1-2-3-4-2-2-6-39-24-25-17-19</td>
</tr>
<tr>
<td>Length (km)</td>
<td>5.730</td>
<td>5.742</td>
</tr>
<tr>
<td>Construction Cost (¥/M)</td>
<td>0.938</td>
<td>0.912</td>
</tr>
<tr>
<td>Operation Cost (¥/M)</td>
<td>1.054</td>
<td>-</td>
</tr>
<tr>
<td>Whole Life Cycle Cost (¥/M)</td>
<td>2.045</td>
<td>1.889</td>
</tr>
</tbody>
</table>

1 The actual construction lengths of cables are in bold.
2 The actual construction costs are in bold.
Voltage Stability Analysis of a Weak Power System involving DERs – A Bayesian Parameter Estimation Approach

Paul Wanjoli Student Member, IEEE, Mohamed M. Zakaria, Moustafa Member, IEEE, and Nabil H., Abbasy Member, IEEE

Abstract—Addition of distributed energy resources (DERs) in power systems (PS) coupled with uncertain loading has increased system uncertainties. The usual deterministic stability solution is no longer sufficient. While probabilistic methods (PM) have been explored before, their focus has mainly been on system events like faults or the realization of microgrids composed of DERs. Voltage stability (VS) analysis of a PS mixed with DERs has not received sufficient attention. In this work, a Bayesian parameter estimation (BPE) method is proposed. BPE works efficiently with efficient sampling techniques such as the Markov Chain Monte Carlo (MCMC) to accurately estimate uncertain parameters with good computation speed while using smaller data sample sizes. DERs and loads are represented by their respective statistical models. The models are then transformed into the Bayesian inferential framework. Using the BPE algorithm, uncertain parameters are estimated, and their corresponding power outputs are obtained. The estimated powers are injected in the continuous power flow (CPF) to determine the VS of the PS. The proposed BPE has been tested on the 14 generator, 59 bus Australian IEEE benchmark. Test results show that with a 4.33% generation increase from DERs, leads to 11% enhancement in voltage stability margin of the PS.

Index Terms—voltage stability, uncertainty, Bayesian, DERs, parameter estimation

I. INTRODUCTION

This paper demonstrates a novel method of assessing the VS limit and impact of increased penetration of DERs in PS. A solution algorithm is provided and some results showing estimates of pdf parameters using BPE, the nature of the estimated pdfs and the VS outputs compared with the MCS are given.

II. METHODOLOGY

Algorithm 1 Proposed BPE based PVSA

THE SET UP

Let \( X \), an RV, be parameters with uncertainties like DERs \( X = \{X_1, X_2, ..., X_n\} \) described by \( l(X|\theta) \)

\( l(X|\theta) \) is the likelihood function of \( X \)

\( l(X|\theta) = \prod_{i} l(X_i|\theta) \), \( X_i \) is the \( i^{th} \) component of \( X \)

If \( \theta \), the desired parameter of \( X \) has \( p(\theta) \) as its pdf

Obtain the marginal likelihood, \( g(X) \) as:

\( g(X) = \int_{\theta} p(\theta) \cdot l(X|\theta) \)

Calculate the posterior pdf thus:

\( p(\theta|X) = \frac{p(X|\theta) \cdot p(\theta)}{p(X)} \)

ESTIMATIONS

Estimate parameters of \( p(\theta|X) \) using sampling techniques

Analyze outputs using histograms, obtain MAPs, CIs etc

Use the estimates to calculate the power outputs, i.e. \( \bar{X} \)

Define the PS topology, assemble its model

Initialize \( j = 1 \)

SUBROUTINES

Draw a sample in \( S_i \), perform a DPF of the PS

Store the complex bus voltages, injected powers etc.

If \( j < N \) then \( j = j + 1 \) & repeat subroutine

else \( j > N \) & DPF converged

Invoke (9) & repeat subroutine

else, VS limit of the PS reached

END SUBROUTINES

Analyze the outputs using PV curves, etc.

\[
P_L(t) = P_L(t_0) + \beta(t)
\] (3)

III. RESULTS AND DISCUSSION

The BPE algorithm proposed in Algorithm 1 is implemented in MATLAB/Simulink R2021a on IEEE 14 Generator 59 bus system. The following Figures 1 to 3 show the outputs of the BPE process.

Fig. 1: Estimation of wind speed and solar irradiance distribution parameters using BPE.

Fig. 2: Wind speed and solar irradiance distributions

Fig. 3: Comparison of BPE & MCS Voltage stability limit estimations

IV. CONCLUSION

From figs. 1 to 3, BPE has managed to efficiently estimate DERs outputs & load uncertainty parameters, enabling efficient estimation of VS of the PS. From the obtained results, a 4.33% level of DERs penetration has translated into 11% enhancement in VS of the PS. This result shows that with good analytical tools, DERs can offer flexibility to stressed PS, proving that DERs can offer grid support services. BPE has proved capable to handle uncertainties, facilitating participation of DERs in PS.
Improved Solution Procedure for Power Quality Assessment of Nonstationary Waveforms

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Abstract—This work presents an improved solution procedure to enhance the accuracy of detecting time-varying frequency components of non-stationary voltage and current waveforms measured in the power system. The high-resolution time-frequency analysis method combined with clustering approaches are included in the solution procedure to detect dominant nonstationary frequency components of the waveforms in a holistic manner. Test results obtained by simulations and actual measurements are compared to show the accuracy and efficiency of the proposed solution procedure.

Keywords—Time-frequency analysis, nonstationary waveform, clustering method, power quality

I. INTRODUCTION

In light of the widespread deployment of power electronics-based renewable generations and a substantial increase of modern nonlinear loads in the power system, the produced nonstationary voltage and/or current waveforms present a challenge for accurate power quality assessment. Traditional methods, such as discrete Fourier transform (FT) and wavelet transform (WT), are not able to perform accurate analysis of such waveforms because the measured signal may be non-stationary in each frequency component.

In addition to S-transform, short-time Fourier transform (STFT) and continuous wavelet transform (CWT), more advanced TFA methods have been proposed to analyze nonstationary waveforms for the assessment of flicker components, harmonics, interharmonics, and sub-synchronous oscillation. These methods include wavelet-based synchrosqueezing transform (WSST), continuous wavelet transform-based multi-synchrosqueezing transform (MWSST), STFT-based synchrosqueezing transform (FSST), and multi-synchrosqueezing transform (MFSST). Some of these methods are with better anti-noise capability and maintain high resolution of time-frequency ridges (TFRs).

Table I lists the comparisons for flickers, harmonics, and inter-harmonics detection using the aforementioned advanced TFA methods, where the root mean square error (RMSE) between the actual and reconstructed waveforms is to rank performances of the compared methods. In Table I, MFSST is with better performance for detecting non-stationary frequency components. However, there is always a mismatch between the actual and reconstructed waveforms. To further improve the accuracy of the reconstructed waveform, the following addresses three main issues and proposes the improved solution procedure for [1] in Fig. 1.

<table>
<thead>
<tr>
<th>TFA Methods</th>
<th>Components in Nonstationary Waveform</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Flickers</td>
</tr>
<tr>
<td>CWT</td>
<td>Poor</td>
</tr>
<tr>
<td>STFT</td>
<td>Poor</td>
</tr>
<tr>
<td>WSST</td>
<td>Fair</td>
</tr>
<tr>
<td>FSST</td>
<td>Excellent</td>
</tr>
<tr>
<td>MWSST</td>
<td>Fair</td>
</tr>
<tr>
<td>MFSST</td>
<td>Good</td>
</tr>
</tbody>
</table>

II. PROPOSED SOLUTION PROCEDURE

A. Blurry time-frequency ridges (TFRs)

During the time-frequency transformation in TFA, the signal energy is dissipated to adjacent TF points and causes blurred TFRs which are difficult to distinguish major frequency components. The reassignment method (RM) has been proposed to obtain a high-resolution time-frequency representation. Although RM is more competitive for TFR representation, however, it does not provide a better waveform reconstruction. To tackle with such drawback, The proposed procedure is to adopt RM to obtain high-resolution TFR of each frequency component and then uses MFSST to reconstruct waveforms for further power quality assessment.

B. Accurate extraction of time-frequency ridges

The density-based clustering methods are considered as a useful tool that does not require a predetermined number of clusters to extract time-frequency ridges corresponding to dominant frequency components in the TF matrix. However, finding proper parameters used in the selected clustering algorithms for different measured signals becomes a challenge.

By applying centroid-based clustering methods combined with cluster validity indices, such as the Silhouette Coefficient and Davies-Bouldin index, to determine the suitable clustering number, one can obtain the number of dominant components.

C. Reconstruction of time-domain waveform for each dominant frequency component

After the clustering results are found, the reconstructed bandwidth of each dominant frequency component is a critical part of collecting dissipated signal energy. Given that the dissipated energy is in a small region, grid search optimization methods can provide an efficient way to obtain the results.

REFERENCES

Asymmetrically Reciprocal Effects and Congestion Management in TSO-DSO Coordination through Feasibility Regularizer

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Abstract—Transmission system operator-distribution system operator (TSO-DSO) coordination together with flexibility service pave the way for the grids to make the most of distributed energy resources while maintaining systems’ secure operations. In T-D coordination, stemming from the diversity of distribution systems including sizes and renewable levels, vulnerable distribution systems may be placed in unfavorable working conditions under the same coordination with TSO. Also, the variance of coupling points affects transmission and distribution systems differently. This work proposes to formalize such heterogeneous effects, called “asymmetric reciprocal effects” (AREs), for the first time. AREs can be characterized through flexibility services and incorporated in T-D coordination to limit improper couplings that push the weaker DSO to its feasibility boundaries associated with steady-state stability and operational constraints including voltage and thermal thresholds. An advanced flexibility region construction technique is developed by leveraging the latest feasibility certificate using Kantorovich fixed-point theorem to construct the feasibility regularizer. This work leverages the Kantorovich fixed-point theorem-based certificate [2] to construct the feasibility regions \( F_T \) with multiple coupling variables \( x_{TD} \) considering voltage limits and congestion constraints.

Case Study: Simulations on a single-TSO-multi-DSO model are presented. Two distribution systems are connected to the transmission system through PCC, with coupling variables for voltage \( V^T_{TD,k} \) and power \( p^T_{D,k} = p^D_{b,t} \), and the ARE metrics \( \gamma_{D,k}, Vol(F_{D,k}) \) propagated to the TSO, thus, the ARE constraints are:

\[
\sum_{g \in G^P} p^R_{g,t} + \sum_{b \in B^D} p^B_{D,b} \leq Vol(F_{D,k}), \quad \forall k \in K^T, t \in T \tag{2}
\]

\[
Vol(F_{D,k}) = \gamma_{D,k}(V^T_{kt} - V^D_{0}), \quad \forall k \in K^T, t \in T \tag{3}
\]

Fig. 3. Validation of 24h operational limits on 69-bus system DSO to prevent feasibility violations.

References
Deep Reinforcement Learning for Cybersecurity of Distributed Energy Resources

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Abstract—As increasing number of distributed energy resources (DERs) are deployed and connected with communication systems and devices to provide interoperability and advanced control capabilities, they are facing increasing cybersecurity risks that have traditionally been targeted at large power plants and substations. New standards, such as IEEE 1547.3, are being set up to provide guidelines to the industry to secure DERs. One main challenge is to develop adaptive and cost-effective methods to secure DERs and distribution systems in a holistic manner. Deep reinforcement learning (DRL) has shown promising results in adaptive control applications. In this work, we proposed a DRL-based software solution for securing DERs and distribution systems from cyberattacks. The preliminary results show the effectiveness of the DRL agent for controlling non-affected inverters and distribution system control devices to minimize operation loss and voltage violations.

Index Terms—Cybersecurity, Distributed Energy Resource, Deep Reinforcement Learning, IEEE 1547

I. INTRODUCTION

Distributed energy resources (DERs) are becoming an integral part of power grids. However, most DERs do not inherit cybersecurity features. The new IEEE 1547.3 standard will set forth cybersecurity guidelines for the industry to enhance cybersecurity of DERs. Yet, the industry needs adaptive and cost-effective methods to secure both the DERs and distribution systems in a holistic manner. In this work, we adapt and apply deep reinforcement learning (DRL), one of the state-of-the-art AI techniques, to introduce an extra layer of security to DERs and distribution systems, mitigating the impacts of adversarial attacks in terms of power loss and voltage violation in distribution systems.

II. METHODOLOGY

In this work, we used the IEEE 13-bus distribution feeder with four main control devices shown in Fig. 1 and performed the DRL training and test with the PowerGym environment [1]. Since the action space is discrete, the Proximal Policy Optimization (PPO) and Advantage Actor Credit (A2C) algorithms in the Stable Baselines [2] were applied to train the DRL agent with the objective of minimizing the control loss, power loss, and voltage violations. Both the PPO and A2C algorithms can train a good control agent. A2C trained the model faster than PPO and resulted in a better cumulative reward shown in Fig. 2.

III. DISCUSSION & FUTURE WORK

DRL can help coordinate and control the non-affected inverters and conventional control devices, such as capacitor banks and regulators, to mitigate the impact of cyberattacks on DERs while ensuring the voltages are within limit. In the future work, we will consider a larger distribution system including various DER models and implement the latest IEEE 1547.3 guidelines.

REFERENCES

Load Shifting for HVACR Systems Using Automated Demand Response and Interpolative Precooling

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Abstract—Commercial refrigeration systems are an enticing target for load shifting programs due to their large thermal inertia and frequent compressor on-off cycles. To demonstrate this, a test platform capable of optimally scheduling its power consumption to minimize energy cost was constructed. Peak price time periods are sent to the system using the OpenADR demand response standard. Using experimentally collected heating and cooling curves, the system calculates the length and start time of the cooling cycle needed to ensure the compressor remains off during peak price periods. To estimate the system’s monetary savings potential, mixed integer programming (MIP) was used to simulate system operation in response to historic prices. It was determined that a maximum of a 15.86% reduction in yearly energy cost is possible when compared to traditional thermostatic operation.

Keywords—automated demand response, refrigeration, load shifting, mixed integer programming, thermostatic control

I. SYSTEM TOPOLOGY AND CONTROL

The test platform adds several components which allow for intelligent operation of a thermostatically controlled refrigerator. A central computer receives temperature readings from a wi-fi thermometer and price signals sent via the OpenADR standard. The computer uses these to calculate an optimal compressor schedule to maximize savings. Control signals are sent to a microcontroller which drives two relays. During off-peak hours, the thermostat is given control authority. During the precooling and high price periods, the thermostat is disabled, and the compressor control relay determines the compressor state. During the precooling period, the compressor is constantly on; during the high price period, the compressor only turns on if the refrigerator becomes too hot. Information and electricity flow between system components is shown in green and orange arrows respectively in Fig. 1.

II. OPTIMIZATION FRAMEWORK

To estimate the maximum amount of savings the system can obtain, MIP was used to simulate a year of system operation with the goal of minimizing energy cost in response to historic DA prices while keeping temperature in safe bounds. Heating and cooling rates in this temperature range are linear but vary with load mass, requiring interpolation between high and low load rates for a given load mass. Optimal schedules are determined on a daily basis using DA prices while RT prices are used to find the resulting cost of those schedules.

\[
\min \sum_{i=1}^{36400} LMP[i] \times P[i] \times \frac{86400}{SCT} \quad (1)
\]

Subject to

\[
P[i] = 0 \Leftrightarrow T8K[i] = T[i] + 0.0004 \times SCT \quad (1a)
\]

\[
P[i] = 1 \Leftrightarrow T8K[i] = T[i] - 0.0016 \times SCT \quad (1b)
\]

\[
P[i] = 0 \Leftrightarrow T16K[i] = T[i] + 0.0002 \times SCT \quad (1c)
\]

\[
P[i] = 1 \Leftrightarrow T16K[i] = T[i] - 0.0013 \times SCT \quad (1d)
\]

\[
T[i + 1] = T8K[i] + (Lmass - 8000) \times \frac{T16K[i] - T8K[i]}{8000} \quad (1e)
\]

\[
36^\circ F \leq T[i] \leq 40^\circ F \quad (1f)
\]

\[
T[0] = 38^\circ F \quad (1g)
\]

where LMP is the DA price, Lmass is the mass of a given load in grams, SCT is the cycle length in seconds, T8K, T16K, and T are temperatures resulting from the 8000 grams, 16000 grams, and Lmass heating and cooling rates, and P is the compressor state.

III. RESULTS

Compared to thermostatically controlled operation, the system is estimated to be capable of reducing yearly energy use by 14.79% and yearly energy cost by 15.86%. Fig. 2 shows an example of an optimal daily schedule produced by the MIP.

![Figure 1: Compressor control logic during high price period](image1.png)

![Figure 2: Compressor state (blue) in response to DA prices (green)](image2.png)
Abstract—Optimal power flow (OPF) seeks to minimize the cost of electric power generation subject to physical constraints. The objective function in the OPF problem is typically defined in terms of dollars, and not in terms of environmental objectives such as plant emissions. However, the mix of generators that result in the lowest system cost does not always fully correlate with the mix of generators that result in the lowest system emissions. This can be further exacerbated under a DC OPF framework, which utilizes slack bus generators (often fast-ramping gas plants) to ensure AC feasibility. This paper analyzes the difference in emissions under different power flow models to quantify how cost-based objectives in OPF have impacts on the resulting system emissions.

I. METHODS AND RESULTS

In order to simulate a realistic loading scenario, fifteen minute demand data was taken from the California ISO (CAISO). We scale this data down linearly ensuring that the test case is able to meet demand.

Then for each time step, we ensure demand at a single load remains at a constant proportion to the total demand on the network. Likewise, the power factor remains constant at each load on the network.

Three separate methods are considered for dispatch.

1) AC Optimal Power Flow: The first method we consider is using AC optimal power flow (AC OPF). Due to the AC power flow constraints [1], this problem is non-convex in nature.

2) DC Optimal Power Flow: The second method we considered is DC optimal power flow (DC OPF) which is a commonly used first order approximation of the AC OPF problem. However DC OPF solutions do not meet AC power flow constraints [2]. In order to remedy the AC infeasibility issue, we fix the generator outputs and run an AC power flow. This implies the need for a slack bus(es) which can compensate for the difference in needed generation.

3) DC Nearest Feasible Point: In this alternative method, we consider a dispatch which first solves DC OPF and subsequently solves an AC OPF with a modified objective function that finds the nearest AC feasible point to the DC solution.

Our methods are tested using a case study of the IEEE 118 test system and generator types from [3].

REFERENCES


Learn Dynamic Hosting Capacity Based on Voltage Sensitivity Analysis

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Abstract—The extensive use of distributed energy sources (DERs) presents the substantial design, planning, and operational issues for distribution systems, thus prompting the broad adaption of methodologies for photovoltaics (PV) hosting capacity analysis (HCA). Traditional HCA methods require running power flow analysis iteratively, typically in the time-series scenario, to consider the dynamic pattern. However, the time-consuming HCA techniques fail to offer online prediction in large distribution networks because of the computational burden. To tackle the computation challenge, we first provide a deep learning-based problem formulation for HCA, which performs offline training and calculates hosting capacity in real time. The applicable learning model, long short-term memory (LSTM), uses historical time-series data to identify the underlying periodic patterns in distribution systems. However, the accuracy of HC estimation is low in the LSTM without considering system spatial information correlated with HC. To capture such spatial correlation from system measurements, we design dual forget gates in the LSTM and propose a novel Spatial-Temporal LSTM. Moreover, as voltage violations are observed to be one of the most critical constraints of HCA, we construct a voltage sensitivity gate to increase the weight on voltage variation and reduce the mismatch in HC determination.

I. DATA-DRIVEN HOSTING CAPACITY ANALYSIS VIA SPATIO-TEMPORAL LEARNING

Hosting capacity analysis determines the HC value which is defined as the maximum active power that DERs can safely inject into an existing distribution grid. Traditional HCA methods typically conduct iterative power flow analysis or solve massive optimization problems, which are time-consuming. To avoid this calculation burden, we propose a learning-based problem formulation for HCA using historical measurements in distribution systems, shown in Fig. 1.

With the historical data, we want to learn a regression model $f : X \rightarrow H$, where the input $X$ is the power flow data with respect to time $t$ and $H$ is the time-series HC values.

II. NUMERICAL RESULTS

We validate our design using an Arizona high penetration utility feeder. The training and validation/testing datasets are generated from CYME with power system data as features and hosting capacity data as labels.

A. Improve Performance by Spatial-temporal Collaboration

This paper modifies the forget gate in the LSTM to dual forget gates, creating a correlation between temporal and spatial sequences, as shown in Fig. 2.

B. Improve Performance by Voltage Sensitivity Information

This paper improves the ST-LSTM using the voltage sensitivity gate. This gate implements the outcome of voltage sensitivity analysis. Table I shows the percentage error of different models on the utility feeder.

<table>
<thead>
<tr>
<th>Test scenario</th>
<th>Without sensitivity</th>
<th>Adjacent impact</th>
<th>Overall impact</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility feeder</td>
<td>7.9%</td>
<td>7.3%</td>
<td>7.1%</td>
</tr>
</tbody>
</table>

Table I: Percentage errors of ST-LSTM without and with the voltage sensitivity gate on the utility feeder.

Fig. 1: Overview of the proposed ST-LSTM deep-learning model for hosting capacity analysis.

Fig. 2: The experiment results of three different models.
Interpretable Detection and Localization of False Data Injection Attacks Based on Causal Learning

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Abstract—False Data Injection Attack (FDIA) has become a growing concern for modern cyber-physical power systems. Existing data-driven FDIA detection methods are typically based on identifying abnormal spatiotemporal correlation patterns in measurement data, whose accuracy may degrade with the continuous drift of data distributions over the long-term application. In addition, the use of black-box models with bad interpretability may make it difficult to precisely locate manipulated measurements. This paper proposes a bi-level framework based on causal learning to detect and locate FDIAs. The lower level applies a causal inference algorithm, X-Learner, to generate causality matrices to unveil causal relationships between different measurements. The upper level then utilizes a spectral-embedded one-class support vector machine to detect FDIAs and a calibrated eigenvector centrality metric to identify attacked measurements. Compared with correlation analysis, causal learning is more robust against the variation of data distributions as it detects FDIAs based on highly abstracted physical causality. Besides, thanks to the inherent topological implication of causality matrices, causal learning also exhibits stronger potential in FDIA localization.

I. PROPOSED FRAMEWORK

A. Lower Level: Causality Matrix Construction

In the context of FDIA detection and localization, causal inference is used to evaluate how much variation in one measurement affects another. The strength of causal effects is typically measured by Average Treatment Effect (ATE), which is estimated using X-Learner + XGBoost in this work. A causality matrix is then constructed for every piece of measurements data. As shown in Fig.1, measurements with and without FDIs have distinct causal patterns.

![Fig. 1. Heat map of causality matrices under different scenarios.](image)

B. Upper Level: FDIA Detection and Localization

The task of the upper level is to recognize causal patterns from causality matrices of historical attack-free measurements and use the learned patterns to detect potential FDIAs. This work first applies the spectral embedding technique to project causality matrices onto a low-dimensional manifold. The low-dimensional features are then used to train a one-class SVM model to learn a hypersphere to delimit the contour of normal observations. Incoming observations outside the hypersphere can be regarded as FDIAs. After the SE-OCSVM model discovers the occurrence of FDIAs, the Calibrated Eigenvector Centrality (CEC) is computed. Nodes with higher CECs are likely to have more high-weight incident edges, which are a good reflection of data tampering. Thus, attacked measurements can be identified by sorting CEC scores in descending order and selecting a proper cut-off threshold.

II. CASE STUDY

This work uses PSCAD/EMTDC to conduct both transient-state and steady-state simulations on the IEEE 39-bus system. There is a total number of 3360 simulations, among which 500 include fault conditions. FDIA is launched on 10% of the total simulations.

As presented in Fig.2, the X-Learner + SE-OCSVM architecture demonstrates better performance compared with various supervised or semi-supervised models in FDIA detection. The proposed framework also proves to be sensitive to low-strength FDIs albeit with a possible increase in false alarm rate, as shown in Fig.3. Furthermore, the effectiveness of the CEC-based FDIA localization algorithm is validated for FDIs with magnitudes from 0.1% to 5%. As can be seen from the results in Table I, the anomalous numerical patterns induced by FDIs to the causality matrices can be easily detected using simple approaches.

![Fig. 2. Performance comparison of FDIA detection models](image)

![Fig. 3. Sensitivity of the proposed model for different attack magnitudes](image)

<table>
<thead>
<tr>
<th>Magnitude</th>
<th>Accuracy</th>
<th>Precision</th>
<th>Recall</th>
<th>F1 Score</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.1%</td>
<td>0.9681</td>
<td>0.4099</td>
<td>0.8142</td>
<td>0.5453</td>
</tr>
<tr>
<td>1%</td>
<td>0.9782</td>
<td>0.5043</td>
<td>0.9478</td>
<td>0.6583</td>
</tr>
<tr>
<td>3%</td>
<td>0.9792</td>
<td>0.6103</td>
<td>0.9579</td>
<td>0.7455</td>
</tr>
<tr>
<td>5%</td>
<td>0.9893</td>
<td>0.7165</td>
<td>0.9788</td>
<td>0.8274</td>
</tr>
</tbody>
</table>
Distribution Grid Line Outage Detection with Privacy Data

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Abstract—Change point detection is important for many real-world applications. While sensor readings enable line outage identification, they bring privacy concerns by allowing an adversary to divulge sensitive information such as household occupancy and economic status. In this paper, to preserve privacy, we develop a decentralized randomizing scheme to ensure no direct exposure of each user’s raw data. Brought by the randomizing scheme, the trade-off between privacy gain and degradation of change point detection performance is quantified via studying the differential privacy framework and the Kullback–Leibler divergence. Furthermore, we propose a novel statistic to mitigate the impact of randomness, making our detection procedure both privacy-preserving and have optimal performance. The results of comprehensive experiments show that our proposed framework can effectively find the outage with privacy guarantees.

I. OUTAGE DETECTION WITH PRIVACY GUARANTEE

In our outage identification procedure, the increments of voltage magnitude data are critical. However, such readings may also be used to infer the household occupancy, leading to privacy concerns. To protect raw voltage data, at each time step \( n \) when \( \Delta v[n] \) is received, we apply a randomizing scheme

\[
\Delta \tilde{v}[n] = \Delta v[n] + e[n],
\]

where \( e[n] \in \mathbb{R}^M \) is the noise vector. The noise \( e[n] \) has to be sufficiently large to hide the characteristics of the raw data while not being too large to impact the detection performance.

Fig. 1: The decentralized randomizing scheme (1) to protect privacy, where the detection procedure was performed on noisy data \( \Delta \tilde{v}[n] \).

In determining an appropriate amount of noise, we quantify the privacy gain under the differential privacy framework, and analyze how the detection performance is degraded accordingly. On one hand, we show that our proposed “encryption” scheme (1) satisfies the Gaussian differential privacy in Theorem 1. This ensures that an adversary can not easily determine if the data he observes \( (\Delta \tilde{v}[n]) \) is real user data, thus preserving privacy. Moreover, we can control the level of noise to achieve any desired level of privacy guarantee.

**Theorem 1.** The randomizing scheme (1) is \( G_{s/\sigma_e} \)-Gaussian differential private where \( s := \sup_{n,\Delta v[n],\Delta \tilde{v}[n]} \| \Delta \tilde{v}[n] - \Delta v[n] \| \) is the sensitivity of raw voltage data.

On the other hand, we show that in general, the noise added to data makes it harder to distinguish whether the data comes from distribution \( g \) or \( f \), leading to a prolonged detection delay. In Theorem 2, we show that after adding noise, distributions \( g_e \) and \( f_e \) become “closer” than \( g \) and \( f \) by evaluating the corresponding KL divergence. The “closer” the distributions are, the more difficult to distinguish them when detecting the outage. As a corollary of \( KL_\Delta \geq 0 \) in Theorem 2, the lower bound of detection delay is increased when the privacy-preserving scheme (1) is utilized, resulting in a performance degradation. Theorem 2 not only indicates a strict performance degradation but also infers the magnitude of this degradation by deriving the upper bound of \( KL_\Delta \).

**Theorem 2.** The randomizing scheme (1) reduces the KL divergence between pre- and post-outage distributions:

\[
KL_\Delta := D_{KL}(f\|g) - D_{KL}(f_e\|g_e) \geq 0,
\]

\[
KL_\Delta \leq O(\alpha^2)(\|\mu_0 - \mu_1\|^2 + (tr(\Sigma_1) - tr(\Sigma_0))^2) \over tr(\Sigma_1). \]

Lastly, integrating the analyses from Theorem 1 and Theorem 2, we propose a new statistic such that the new detection procedure is both privacy-preserving and has comparable detection performance as the optimal case.

II. NUMERICAL SIMULATIONS AND RESULTS

Fig. 2 (left) visualizes the privacy guarantee under different levels of noise variance. Fig. 2 (right) shows the noise mitigation effect when applying our new detecting procedure POD. Fig. 3 demonstrates the detection delay under different methods and systems, showing the effectiveness of our method.

![Fig. 2: Privacy guarantee and its affection on detection delay.](image)

![Fig. 3: The average detection delay in various systems.](image)

III. CONCLUSION

This paper proposes a novel approach to detect line outages in distribution grids with privacy guarantees. Our detection procedure is both privacy-preserving and has comparable performance to the optimal case.
Improved Fault Phase Selection Scheme for Lines Terminated by Inverter Based Resources

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Abstract—With more renewable energy integrated to the grid in the form of inverter based resources (IBRs), traditional current-based fault phase selector encounters limitations. The causes of this problem are the weak infeed feature and variation of source impedance of IBRs. This paper proposes an improved fault phase selection scheme to solve this problem. Firstly, the reasons for the failure of traditional fault phase selection methods are analyzed. Then, compound proportion criterion including voltages and currents is established and the corresponding improved phase selection method is proposed. The main advantages of proposed method are excellent adaptability and reliability. Numerical experiments prove the effectiveness of the proposed method.

Index Terms-- Fault phase selector, transmission line, inverter based resources (IBRs), asymmetrical faults, weak-infeed circuit

I. INTRODUCTION

Nowadays, an increasing number of renewables are integrated to the grid in the form of inverter based resources (IBRs), which present challenges to traditional protective relay systems, including fault phase selectors.

In the existing relay system, current-based phasor schemes are the most widely used fault selection method. However, the output characteristics of IBRs leads to the non-homogeneity between positive and negative sequence source impedances. The traditional phase selection methods have reliability problem in lines terminated by IBRs. In this paper, an improved scheme of fault phase selector is proposed for lines terminated by IBRs. This method is based on the phasor measurements and does not require extra data from inverter.

II. CHALLENGES OF TRADITIONAL PHASE SELECTORS

The main criteria of traditional phase selection method are
\[ \alpha = \arg(I_1/I_1) \quad \text{and} \quad \beta = \arg(\Delta I_1/I_1). \]

The integration of IBR bring the following influences on the phase selection for line in Fig.1,

![Fig. 1 Transmission line with IBR connected to local terminal](image)

1) Since the positive and negative sequence components are controlled separately, the positive and negative sequence current components and fault current components no longer have approximate phase angle, which is the basis of traditional method. The offset of angles may result in incorrect result.

2) Some control of IBRs keeps zero negative sequence output current when the asymmetric fault occurs. The result of existing criteria is unreliable due the denominator is close to 0. Thus the existing selection method cannot get stable results in asymmetric fault.

III. PROPOSED METHOD AND EXPERIMENT RESULTS

To mitigate the effects of IBRs, proposed method use compound proportion criterion \( \delta \). The flow chart of the proposed phase selection scheme is shown in Fig. 2.

![Fig. 5. Flow chart of proposed phase selection method](image)

![Fig. 6. Angle range of \( \delta \), left: PPG or SPG faults, right: PP faults](image)

<table>
<thead>
<tr>
<th>Fault type</th>
<th>( m )</th>
<th>Fault Resist.</th>
<th>( \delta )</th>
<th>Prop. method</th>
<th>Trad. method</th>
<th>Exist. method</th>
</tr>
</thead>
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<td>AG</td>
<td>10%</td>
<td>1Ω</td>
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<td>√ (ABG)</td>
<td>×(N.A.)</td>
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<td></td>
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<td>×(N.A.)</td>
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</tbody>
</table>
A Graph Attention Network Based Reinforcement Learning Method for Optimal Distributed Frequency Control of an Islanded AC Microgrid

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Abstract—This poster introduces a new deep reinforcement learning (DRL) based data-driven method for frequency control of an islanded AC microgrid (MG). This method aims to achieve the distributed secondary control in which each distributed generator (DG) adjusts its frequency based on the local measurements and neighboring information. Specifically, the proposed method embeds the graph attention network (GAT) into the policy network to decide how the neighboring features are aggregated. After sufficient offline training, the weights from GAT model can be given to controllers to realize the distributed control. Simulations are conducted in a 13-bus islanded microgrid with 6 DGs, and the results show that the proposed method displays better control performance than other existing methods.

Index Terms—Microgrid, frequency control, graph learning, distributed control, deep reinforcement learning

I. INTRODUCTION

The high penetration of intermittent renewable energy sources makes the frequency control challenging, especially for islanded MG without the support from the main grid. In this study, we propose a graph attention network based deep reinforcement learning (GAT-DRL) method for MG distributed frequency control. In contrast to prior methods using multiple DRL agents, the proposed approach employs a single agent design and drastically reduces the computational burden. The general framework of the proposed GAT-DRL method is illustrated in Fig. 1.

II. PROPOSED METHOD & RESULTS

The proposed method embeds GAT into the policy network to decide how the neighboring features are aggregated. The implementation consists of two stages: offline centralized training and online distributed application. After the training process, GAT weights, which signify the relevance of neighboring data, can be allocated to each DG. Subsequently, each DG can generate secondary control signals by consolidating data in a distributed manner according to the assigned weights.

In this study, simulations were conducted on a 13-bus islanded MG, with Fig. 1 showing the system’s electrical topology and communication links, and Fig. 2 displaying the frequency control performance of the proposed method. Table I presents a comparison of numerical results from various methods across different metrics, which validate the efficacy of the proposed method in regulating frequency with improved settling and training time and reduced overshoot.

<table>
<thead>
<tr>
<th>Method</th>
<th>Overshoot</th>
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<th>freq. dev</th>
<th>Training Time</th>
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<td>50.05Hz</td>
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</table>

Y. Xu’s work is partially supported by Project #021303-00004
Sensitivity Analysis of Climate Information on LSTM-based ERCOT Load Forecasting

Jonathan Yang, Mingjian Tuo, Student Member, IEEE, Jin Lu, Student Member, IEEE, and Xingpeng Li, Senior Member, IEEE

Abstract—Accurate load forecasting with least error is critical for efficient and reliable operations of the electric power system. Climate information is an important factor in load forecasting. This work developed a long short-term memory (LSTM) model that takes various climate information as part of the input features to predict the system load. Ablation studies were also performed to investigate and compare the impacts of different climate factors on the prediction accuracy. Actual load and historical climate data for the same region were processed and then used to train the LSTM model. Case studies demonstrated the effectiveness of the proposed LSTM-based load forecasting model.

I. INTRODUCTION

Being able to accurately predict the power demand is important for grid operators to ensure grid reliability and maintain power balance in a more cost-effective manner. Power demand is difficult to predict since it depends on various random factors including personal habits, many of which are unknown to grid operators. However, many of these factors may be influenced in part by more fundamental temporal and climate factors. We propose a machine learning method that identifies the association between time, climate, and power load using a long short-term memory (LSTM) model, which is suited to capture temporal behavior of time-series input data [1].

II. MODEL AND DATA

The data used in this work include historical Electric Reliability Council of Texas (ERCOT) load data and climate data [2]-[4]. The data for a period of 2011-2021 were used in the LSTM-based load prediction. The historical load dataset consists of hourly load data for each weather zone and the entire system. The climate dataset includes hourly data on various climate variables from 123 locations [2].

The proposed load forecasting model consists of two consecutive LSTM layers, followed by a flatten layer and several fully-connected layers. Dropout layers are also used as a regularization technique to prevent overfitting issues. Mini-batch is used as the optimization technique during training. This model is trained to predict the total ERCOT load in the next several hours for intra-day grid operations using the time, ambient measurements, and total load from preceding hours. The selected ambient features are temperature, longwave radiation (LWRAD) & shortwave radiation (SWRAD), and a combined zonal and meridional wind, each with measurements from 8 chosen stations positioned in the 8 ERCOT weather zones. The selected time features are the hour of day, the day of week, and the month. To use the data with the proposed LSTM model, consecutive ranges of 10 hours were taken, with both climate and load from the first 6 hours taken as features, and load from the next 4 hours taken as labels.

III. CASE STUDIES

After the architecture of the LSTM model was established, it is first trained with all the features mentioned above. Fig. 1 demonstrates its effectiveness in load forecasting. Then, an ablation study was conducted to perform the sensitivity analysis of different climate information. The model was evaluated against identical models trained with missing features as well as a non-LSTM fully-connected neural network (FCNN) model in which the LSTM layers are replaced by fully connected dense layers. The models are evaluated and compared in Table I using its final mean absolute percent error (MAPE) in percent, as well as accuracies with five different error thresholds.

The proposed LSTM model shows improved forecasting accuracy as compared to a traditional FCNN model. The ablation studies shows that the influence of removing individual climate features such as wind information on the load prediction is significant, even leading to accuracies less than FCNN.

IV. REFERENCES

Probabilistic Lifecycle Costing Evaluation for Configuration of Transformers in High-Speed Railway Based on Optimal KDE

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Abstract—This paper proposes the probabilistic lifecycle costing evaluation method based on optimal kernel density estimation (KDE) of different transformer configurations for supplying power to loads along high-speed railways. Based on data from operating railway systems, the precise probability density functions (PDF) of loads are obtained with optimal KDE. The economic evaluation is then analyzed with the probabilistic lifecycle costing (LCC) model to obtain the optimal transformer configuration for various loads in PTL. The applicability of the proposed method is verified in the configuration of transformers for signal transmitting stations. The proposed method is applicable for decision-making in configuration of transformers in power through line.

Keywords—High speed railway, Power through line, Configuration of Transformer, Optimal Kernel density estimation, Lifecycle costing

I. INTRODUCTION

As an important part of the railway power system, the configuration of the transformers along the railway tracks has a remarkable impact on both the operational cost and the cost for total investment. According to the load characteristic of railway system equipment, the economic evaluation based on the combination of probabilistic LCC model and optimal KDE is proposed in this paper. The optimal bandwidth for KDE applicable to relevant dataset is derived. According to the nonparametric PDF model obtained by optimal KDE, the probabilistic LCC method for economical evaluation can be constructed. Based on the data of the operating railway, the method can be applied to evaluate the comprehensive cost for different configurations of transformers in PTL. The evaluating method is applicable for optimal design of transformers in HSR-PTLs in the future.

II. PROPOSED METHOD

The method of economical evaluation based on probabilistic LCC analysis with optimal KDE is shown in Fig. 1. Based on the data collected in operating railways, the optimal kernel function will be selected. Then, the optimal bandwidth corresponding to the selected kernel function and dataset can be calculated. With the optimal KDE parameters, the power operating range and PDF of loads can be obtained to determine the capacity of related transformers, for which the construction investment can be defined. In addition, the operating cost, which consists of cost for power loss and cost for transformer interruption can be calculated according to the PDF of loads. The probabilistic LCC analysis can be then obtained by using net present value method to above investment and operational cost.

The optimal kernel function and corresponding bandwidth can be obtained by rule of thumb to improve the accuracy. The probabilistic LCC is proposed as the economic evaluation model, considering the cost for investment, operating, and scripting based on net present value:

![Fig. 1 Economical evaluation method based on probabilistic LCC analysis with optimal KDE](image)

III. RESULTS

The histogram frequency distribution diagram and the PDF curve for signal transmitting station are shown in Fig. 2.

![Fig. 2 Optimal KDE for signal transmitting station](image)

Based on the parameters and the PDF obtained above, the lifecycle costs of different transformer configurations are analyzed. The economic evaluation result is shown in Fig. 3. The configuration of 2×20kVA transformers are the optimal scheme. The lifecycle cost of the scheme is only 78% of the existing scheme, which can be used in the newly planned railways.

![Fig. 3 Economic analysis based on lifecycle costing model](image)
A Novel Searchable Encryption Scheme for Smart Grid Data Sharing

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Abstract—The traditional means for local processing and storage of the grid data is inefficient and infeasible, leading to the increasing demand for cloud storage services. However, the cloud storage service is usually provided by untrusted third parties, calling for encryption methods. In this paper, we propose a searchable encryption scheme that supports searches based on structured query language. On this basis, we derive the enhanced security assumption and propose an improved searchable encryption scheme that protects the search request privacy for the data requester by delegating the verification task to Server through a zero-knowledge membership check approach.

Index Terms—Searchable encryption, Smart grid, Relational database, Data sharing, Zero-knowledge proof, Data Security

I. BASIC MODEL

Fig. 1. Basic Model.

- **Step 1** DO encrypts the data and upload the ciphertext to S for storage.
- **Step 2** DR sends the search requests to DO.
- **Step 3** DO checks the requests and authorizes DR by sending a authenticated token to DR.
- **Step 4** DR keeps the key in the the authorization token locally and sends the search token to S.
- **Step 5** S finds the search results and sends it back to DR. Finally DR decrypts to get plaintext data.

II. PROPOSED SEARCHABLE ENCRYPTION SCHEME

In **Setup** phase, DO picks the master key $K$, then encrypts and fills the data items in $EDB$.

In **GenToken** phase, DO generates encrypted label $\overline{el}$ and associated key $\overline{K_e}$ based on the agreement, then sends them to DR.

In **Query** phase, DR sends the received $\overline{el}$ to the server. The server obtains encrypted $\overline{ev}$ and returns it to DR. Finally, DR decrypts the search result and recovers the data $\overline{v}$.

**Setup**

1. DO picks a master key $K$ for $F_\lambda$.
2. DO initializes an empty dictionary $EDX$.
3. DO performs the for loop, for each $(l, v) \in DX$:
   1) derives $el \leftarrow F_\lambda(K, 1||l)$ and $K_e \leftarrow F_\lambda(K, 2||l)$.
   2) sets $ev \leftarrow S.Enc(K_e, v)$.
   3) $EDX[el] \leftarrow ev$.
4. DO holds $K$ locally and sends $EDX$ to Server.

**GenToken**

1. DR sends a label $\overline{l}$ it wants to search to DO.
2. DO generates $\overline{el} \leftarrow F_\lambda(K, 1||\overline{l})$ and $\overline{K_e} \leftarrow F_\lambda(K, 2||\overline{l})$.
3. DO sends $tk = (\overline{el}, \overline{K_e})$ to the DR.

**Query**

1. DR holds $\overline{K_e}$ locally and only sends $\overline{el}$ to Server.
2. Server performs $\overline{ev} \leftarrow \text{Get} EDX[\overline{el}]$ and sends $\overline{ev}$ to the DR.
3. DR gets the plaintext value by $\overline{v} \leftarrow S.Dec(\overline{K_e}, \overline{ev})$.

III. ENHANCED SCHEME WITH SEARCH REQUEST PRIVACY

In our modified scheme, DO still sends the encrypted database to Cloud at first. DR sends the search quest to Server and the Server provides zero-knowledge proof to convince DO that the search request is legal. Then DO provides the authentication information to Server, Server sends the encrypted search result and encrypted key back to DR. Finally, DR decrypts to get the key, and uses the key to decrypt the search results.
DeepONet Based Uncertainty Quantification for Power System Dynamics with Stochastic Loads

Ketian Ye, Junbo Zhao, Xiaodong Liu, Christian Moya and Guang Lin

Abstract—This paper presents a DeepONet-based uncertainty quantification framework for power system dynamics with stochastic loads modeled via the Ornstein-Uhlenbeck process. We use stochastic differential and algebraic equations (SDAE) to model the stochastic power system and the proposed framework learns a surrogate for the infinite-dimensional solution operator of the SDAEs. This allows us to map the stochastic response of the loads to statistical estimates of power system dynamic trajectories, which are crucial for operators and planners. Our method is validated using the IEEE 39-bus and the WECC 179-bus systems and compared to Monte Carlo and other surrogate baselines for effectiveness and scalability.

Index Terms—Power system dynamics, stochastic load, operator learning, uncertainty quantification

I. INTRODUCTION

The impact of stochastic loads on power system dynamics requires new uncertainty quantification approaches. Stochastic differential and algebraic equations (SDAEs) can model power system transient responses under dynamic and stochastic loads. However, traditional transient analysis methods are inadequate for solving problems with stochasticity. Monte Carlo simulation (MCS) is the prevailing method for obtaining the stochastic dynamic response under uncertainty, but it is computationally expensive for large-scale systems. Surrogate methods, such as polynomial chaos expansion, trajectory sensitivity analysis, and machine learning methods, can significantly improve computational efficiency without sacrificing accuracy. However, these methods may not be suitable for stochastic systems that require temporal information of variables. Analytical methods and model-based approaches are also limited by their inability to produce post-fault trajectories needed by operators and planners.

II. PROBLEM STATEMENT

The dynamics of a power system with Ornstein-Uhlenbeck process can be described by the following differential and algebraic equations:

\[
\begin{align*}
\dot{x} &= f(x, y, u, \xi) \\
0 &= g(x, y, \xi) \\
\dot{\xi} &= \alpha(\mu - \xi) + \beta \eta
\end{align*}
\]

where \( x \) represents the dynamic state variables while \( y \) denotes the algebraic state variables, \( u \) consists of the system input, \( \xi \) consists of all uncertain variables, \( \alpha \) and \( \beta \) are parameters of Ornstein-Uhlenbeck process; \( \eta = dW/dt \) is the derivative of the Wiener process.

III. PROPOSED DEEPONET-BASED UNCERTAINTY QUANTIFICATION FRAMEWORK

To construct the surrogate model for power system dynamics, the problem is firstly reformulated into a compact form:

\[
x(t) = M(\xi, u, t)
\]

where \( M \) is the mapping relationship between stochastic loads and dynamic response. Let \( G \) denote the nonlinear solution operator of the SDAEs. \( G \) maps (i) an input function \( \xi(\cdot) \), which represents the dynamic response of stochastic loads within a given finite simulation time interval \([0, T] \subset \mathbb{R}_{\geq 0}\), to (ii) an output function \( G(\xi)(\cdot) \equiv x(\cdot) \), which represents the solution of the SDAEs within \([0, T] \). The DeepONet’s output fuses the Branch Net’s coefficients \( b_k \) and the Trunk Net’s basis functions \( p_k \) using the following dot product:

\[
G_\theta(\xi(z_1), \ldots, \xi(z_m))(t) = \sum_{k=1}^{q} b_k \cdot p_k(t) + b_0,
\]

Fig. 1. Framework of the proposed operator learning.

Fig. 2. Benchmark and estimated mean of rotor angle $\delta_{38-1}$ of the 179-bus system.
Abstract—Predicting the load of a power system is crucial for efficient energy management and decision-making. An accurate load prediction of the power system is essential for reliability improvement and economic operation. While numerous studies have predicted loads using various machine learning and deep learning techniques, it is crucial to select the most effective learning model by experimenting with different architectures and comparing their performance for specific tasks. In this study, we utilized to load data from 31 months in Jeju Island, Korea, and predicted the load one month later. This study developed ten models that predict the hourly load of the power system by combining Convolutional Neural Networks (CNNs), Long Short-Term Memory (LSTM) networks, and Gated Recurrent Units (GRUs), and compared their performances. Each model was evaluated based on maximum and mean errors to help power system operators and planners make informed decisions regarding power generation, transmission, and distribution. In addition, this study suggested the need to select a learning method suitable for the situation by presenting the maximum error and the average error through the learning of various techniques.

Keywords—deep learning, load prediction, Convolutional Neural Networks, Long Short-Term Memory, Gated Recurrent Unit

I. INTRODUCTION

Load forecasting is crucial for the efficient management of energy systems, as it enables optimal energy production, transmission, and distribution. However, accurately predicting electricity demand can be challenging due to the complex nature of energy storage systems. To solve this issue, many previous studies have applied various machine learning (ML) and deep learning (DL) techniques to load forecasting. However, the effectiveness of these learning models depends heavily on the characteristics of the data used for training. Therefore, experimenting with different learning architectures and comparing their performance for specific tasks are important.

Previous studies have compared the performance of various learning techniques for load forecasting. For example, one study examines Convolutional Neural Networks (CNN) and Long Short-Term Memory (LSTM) to predict the electrical load of the Bangladesh power system and uses LSTM and CNN-LSTM techniques to learn and predict the load and calculate errors such as MAE, RMSE, and MAP. Another study modeled Linear Regression (LR), Support Vector Regression (SVR), Convolutional Neural Networks-Recurrent Neural Networks (CNN-RNN), and other techniques to predict the next day’s load based on a week’s worth of historical data and validated the performance of each learning model by calculating MAE and MAPE based on the prediction results. Another study compared the prediction error of CNN, Gated Recurrent Unit (GRU), and GRU-CNN techniques by proposing GRU-CNN, a hybrid neural network model that combines GRU, a simple variant of the structure of LSTM, and CNN. In addition, a prediction technique called Load Tracking Feature-RReliefF-Multi-Layer Perceptron (LTF-RF-MLP) was proposed to improve the error of previous ML and DL-based learning methods, and the superiority of the proposed technique was demonstrated through 3 years of training data from the New England ISO. However, these studies only compared the performance of a few selected techniques. In contrast, this study examines the performance of 10 combinations of CNN, LSTM, and GRU to highlight the importance of selecting the best model for specific tasks through trial and error. The study analyzed load data for 31 months in Jeju Island, Korea, and predicted the load one month later using the developed models. The models’ performance was evaluated based on maximum and average errors, providing power system operators and planners with valuable insights into energy production, transmission, and distribution. By comparing the performance of different learning models, this study aims to contribute to the selecting of accurate load forecasting techniques.

II. EXPERIMENTAL DESIGN

This study selected the power system of Jeju Island in Korea as a test bed and collected load data by the hour on Jeju Island. And based on this, learning was performed through 10 models. The load data of the power system may have a daily, weekly, monthly, or seasonal pattern. Fig. 1 shows the magnitude of the load in the power system on Jeju Island, which shows a pattern of increases and decreases. A set of sequentially determined data sets collected during a specific period is called time series data. In other words, this study conducted a study to forecast the future load through time series load data of Jeju Island.

Fig. 1. Hourly load data for Jeju Island, South Korea.

ACKNOWLEDGEMENT

This work was supported by Korea Institute of Marine Science & Technology Promotion(KIMST) grant funded by the Ministry of Oceans and Fisheries(KIMST-20210629).
Design of Passive Filters for considering Voltage Stability in a Renewable Energy Integrated Network

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Abstract—This paper proposes a design of a passive filter for voltage stabilization and harmonic mitigation considering voltage sag in renewable energy sources. Inverter-based PV and wind turbine interconnected Renewable Energy Integrated Networks are evaluated. The optimal size of capacitors is determined considering the voltage sag at the PCC using PSCAD/EMTDC. Then, the capacitors are combined with R and L to function as a passive filter. The proposed process can be applied to both inverter power and nonlinear loads.

Keywords—Passive harmonic filter, Voltage sag, Inverter based resource

I. INTRODUCTION

Due to the expansion of inverter-based resource (IBR) renewable energy sources, power quality has become a critical issue. Factors for power quality include harmonics, voltage sags, instantaneous interruption, and others. Among these, harmonics directly cause problems with the lifespan and efficiency of electrical equipment. One of the methods for reducing harmonics is using filters, which can be classified into passive and active filters. Passive filters are composed of R, L, and C components that form a branch with low impedance at a specific frequency to absorb harmonic currents. Types of passive filters include single-tuned filters, high-pass filters, and C-type filters that reduce losses. This paper proposes a filter design process using an RLC passive filter to evaluate the issues caused by IBRs. The main aim of this process is to mitigate voltage sags and harmonic distortions according to the curtailment of renewable energy sources.

II. APPROACHES

When an inverter-based renewable energy source is connected to a power grid, the ripple generated by the inverter switching (PWM) in the output voltage and current is inevitable. Depending on the harmonic attenuation performance of the harmonic filter located at the output stage, the PWM ripple may not be sufficiently attenuated and may be introduced into the grid, thereby deteriorating the power quality. The generation of such harmonic voltage and current is more severe when the equivalent short-circuit impedance of the PCC is higher. The approach used in this paper requires selecting L and C based on voltage and frequency variations before designing the passive filter.

III. SIMULATION RESULTS AND CONCLUSIONS

In the case study, modelling was performed using PSCAD/EMTDC to verify the operational status and effectiveness of the filter. Assuming the curtailment of the renewable energy source in a 22.9 kV system, voltage sag simulations were performed after 3 seconds. To resolve this, a capacitor was inserted via a switch at 3.1 seconds, as shown in Figure 2, and the reactive power output was compensated. This compensated reactive power corresponded to the voltage sag at the PCC, thereby mitigating the voltage sag. Additionally, a reduction in harmonic distortion was observed, and the THD satisfied the limits specified by IEEE Std 519-2022.
Fig. 2. Voltage sag stabilization by reactive power compensation
Scalable and Lightweight Distributed Local Routing for Quantum Network-Based Microgrids

Sijia Yu, Zefan Tang, Zimin Jiang, and Yifan Zhou

Abstract—Quantum networks present a potent solution to secure microgrid communication in the quantum era. Efficient routing protocols play an important role in developing practical and resilient quantum network-based microgrids. This paper makes the following contributions: 1) lightweight-yet-holistic routing tables for scalable and low-latency quantum routing in microgrids; 2) efficient distributed local routing protocols for quantum network-enabled microgrids; and 3) integration of the devised protocols in a real-time QNetGrid testbed and their performance evaluation. Experiments validate the efficacy of the devised methods and provide insights for developing efficient quantum network routing for cyber-resilient microgrids.

Index Terms—Quantum networks, microgrid cyber-resilience, routing protocol, lightweight routing, real-time simulators.

I. MOTIVATIONS

Microgrids are undergoing an increasing deployment of information technologies and hence becoming more vulnerable to cyberattacks. Quantum key distribution (QKD) provides a powerful solution to provably secure microgrid communication even in the quantum era, since it uses fundamental quantum laws, rather than the complexity of computing, to generate and distribute secret keys for two distant parties. However, efficient routing protocols which can adapt to real-time microgrid changes significantly impact the performance and practicability of QKD.

This paper devises distributed local routing protocols for quantum network-based microgrids (QNetGrid), which provides scalable, lightweight, and distributed solutions to achieve efficient and low-latency quantum network routing and can flexibly adapt to the dynamic environment, thus greatly improving the resilience of microgrids against cyberattacks.

II. DISTRIBUTED LOCAL ROUTING FOR QNETGRID

A. Lightweight Distributed Routing Table Construction

The bottleneck for developing efficient routing algorithms in QNetGrid lies in the obstacle of predicting subsequent link situations using only local information due to resources limitation. To bridge the gap, we maintain a lightweight routing table by exploiting the hierarchy information (i.e., $h_i$ describing the shortest distance from the center to $DER_i$ as shown in Fig. 1) and local link states for each node. The benefits are twofold: 1) the hierarchy information ensures that nodes in the routing table marked with $h_i$ are all accessible from $DER_i$; 2) the routing table is more scalable and lightweight than global algorithms, because it consists of only the neighbor nodes in the upper layer.

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B. Distributed Local Routing Protocols

Based on the lightweight routing tables, we then devise four distributed local routing protocols for QNetGrid.

1) Random static hierarchy routing (RSHR): The next node is randomly selected from the routing table of the current node.

2) Attack avoidant static hierarchy routing (AASHR): If the vulnerable links mainly exist in a fixed area, the next hop node $v$ is selected as the neighboring node with the smallest possibility of failure during cyberattacks.

3) Predisposed static hierarchy routing (PSHR): If attackers choose to attack the network randomly, PSHR always tends to go in a certain direction, i.e., horizontally or vertically.

4) Dynamic hierarchy routing (DHR): When network status changes, DHR selects the next node using the dynamically-updated routing tables. In contrast, static hierarchy routing (SHR) methods only find a path using the original hierarchy.

The performances of different SHR protocols are mainly impacted by the distribution of network vulnerability points. When attacks are concentrated in a particular area of QGrid-Net, AASHR $\gg$ RSHR $\gg$ PSHR; when attacks are distributed throughout the network, PSHR $\gg$ RSHR $\gg$ AASHR (as illustrated in Fig. 2). When the network status is not stable or there are dense attacks in the network, DHR generally outperforms SHR because of the accurate real-time hierarchy (as illustrated in Fig. 2).

Fig. 1: Illustration of the hierarchical updating process with and without attack. (a) Without attack. (b) With attack.

Fig. 2: Routing performance under widely-distributed cyberattacks. (a) The attack density is 7.5%. (b) The attack density is 15%.
Invertible Neural Network for Consistent State Estimation in Distribution Grid with Unobservability

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Abstract—State estimation (SE) serves as the basis for monitoring and control, but the performance is challenged when prior knowledge and observability are limited due to increasing distribution system extension and renewable penetration. To solve the problem, machine learning (ML) approaches have been recently applied to approximate the mapping from measurements to system states. However, such direct approximation of the inverse system process lacks physical consistency with the forward system model (i.e., power flow equations), leading to inaccurate or physically infeasible solutions. Thus, we propose a two-way learning method by designing tractably invertible paths in structural neural networks, which build a perfectly matched forward-inverse system model to estimate states. For physical consistency, we fully integrate prior system knowledge to compensate for information loss against unobservability and contract feasible SE solutions in the inverse learning process. Numerical results show high accuracy, degradability of the data-driven model, and robustness to out-of-range data scenarios.

Index Terms—Distribution system edges, unobservability, state estimation, invertible NN, two-way learning, physical consistency

I. UNIFY FORWARD AND INVERSE LEARNING FOR SE

For state estimation ($y = f(x) + \epsilon$) in the distribution grids, reproducing the nonlinearity of $f(\cdot)$ is the main challenge due to unavailable grid knowledge like topology/line parameters. While model-based methods fail, historical data are available, so SE is formed as a function approximation task. Machine learning is used to learn the inverse function $x = f^{-1}(y)$ and compute states from measurements. But, one-way learning suffers from a lack of physical consistency with the power flow (PF) model and information loss due to unobservability.

To resolve the problem, we propose to unify the learning of the forward system model ($y \in \mathbb{R}^q = f_i(x|\theta_1|\theta_2)$) and the inverse mapping for SE. We design an invertible learning scheme that recovers the PF model and enforces an automatic inverse to estimate states from measurements. As Fig. 1 shows, we aim to 1) obtain a forward mapping that reveals true power system physics and 2) find a perfectly matched forward-inverse pair for consistent SE and compute feasible states in operation.

Compensate System Unobservability Limited sensors may lead to forward information loss and propagate to the inverse. We use virtual variables $y'$ to represent the power injections of unknown nodes within 1-hop distance. The virtual measurements are generated from observable $y$ and Gaussian distribution samples. The regularization imitates hidden quantities for dimensional homogeneous units in the recovered PF function.

Enforce Provable Invertibility We construct invertible transformation unit in NN: $y_1 = a_1 x_1, y_2 = a_2 x_2 + t_1(x_1)$, which is the forward function. The inverse counterpart is $x_1 = \frac{1}{a_1} (y_1'), x_2 = \frac{1}{a_2} (y_2' - t_1(x_1))$, where $y^* = [y_1', y_1']$. The nonlinear functions $t_1(\cdot)$ can be arbitrarily complex to represent the PF model without affecting the invertible property, which is guaranteed by the inverse function theorem.

Embed Physical Consistency ML model may perform poorly in out-of-range operation conditions, especially for distribution grids with DERs. Accurate SE solutions require perfect PF recovery. Thus, we embed physical features $\phi(x|\theta_1|\theta_2)$ into the invertible NN to reveal the physics of the underlying power flow function. While we find the optimal forward mapping that reveals PF physics, we naturally obtain the inverse following consistent physics for state estimation. Thus, the model is a Physical-Consistent Invertible Neural Network (PC-INN).

Fig. 2: Prediction errors (\(\sqrt{\text{MSE} \times 10^{-3}}\) p.u.) of the inverse state estimation (SE) and forward power flow recovery (PF).

Fig. 3: Validating estimated voltage magnitudes of all the nodes (from feeder head to end) in the 123-node system.

II. RESULTS AND ANALYSIS

The PC-INN is validated in various test cases, considering unavailable grid information and unobservability issues. Fig. 2 compares the prediction errors of both SE and the forward PF recovery. Our method shows a general decrease in errors compared to the direct inverse learning and the two-way learning without physical regularization. The comparison of estimated state values in Fig. 3 reveals PC-INN’s better extrapolation capability than others given out-of-range measurements.

<table>
<thead>
<tr>
<th>SE Case</th>
<th>SVR</th>
<th>VAE</th>
<th>NICE</th>
<th>PC-INN</th>
</tr>
</thead>
<tbody>
<tr>
<td>8-bus</td>
<td>0.14 ± 0.04</td>
<td>0.05 ± 0.01</td>
<td>0.05 ± 0.02</td>
<td>0.009 ± 0.00</td>
</tr>
<tr>
<td>123-bus</td>
<td>0.29 ± 0.11</td>
<td>0.25 ± 0.02</td>
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<td>0.07 ± 0.02</td>
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<tr>
<td>Utility</td>
<td>0.43 ± 0.19</td>
<td>0.31 ± 0.09</td>
<td>0.19 ± 0.06</td>
<td>0.15 ± 0.04</td>
</tr>
<tr>
<td>PF Case</td>
<td>SVR</td>
<td>VAE</td>
<td>NICE</td>
<td>PC-INN</td>
</tr>
<tr>
<td>8-bus</td>
<td>N/A</td>
<td>0.02 ± 0.01</td>
<td>0.04 ± 0.02</td>
<td>0.004 ± 0.00</td>
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<tr>
<td>123-bus</td>
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<td>0.21 ± 0.03</td>
<td>0.18 ± 0.07</td>
<td>0.06 ± 0.03</td>
</tr>
<tr>
<td>Utility</td>
<td>N/A</td>
<td>0.24 ± 0.06</td>
<td>0.22 ± 0.05</td>
<td>0.11 ± 0.05</td>
</tr>
</tbody>
</table>
Fault Location on Distribution Cables Using Traveling Waves: a Field Data Study

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Abstract—Traveling waves within the distribution network will be produced by faults. In practical distribution network, the wavefront of traveling wave is hard to be captured, as the measurement signal contains a mass of noises. The sources of noises are not only from the measurement devices, but also from traveling waves caused by other events such as load changes in the distribution systems. In addition, the wave speed of the traveling wave needs to be accurately determined to ensure fault location. This paper collects and analyzes field data from a real power distribution system. The zero sequence current signals are captured by sensors placed at each line terminal, with the high sampling rate of 50 MHz. First, the natural frequency method is adopted to derive the true velocity of the traveling wave. Second, the arrival time of the current traveling wave is captured by the tool of continuous wavelet transform (CWT). The high frequency components of CWT are utilized to avoid the frequency dependent effect of the cable line. With the arrival time and velocity of traveling waves, the accurate fault location is determined. Field data experiments show that the proposed method can accurately capture the wavefront with large background noises. The estimated fault locations are close to the actual values, proving the effectiveness of the method in practical distribution cables.

Keywords—traveling wave, fault location, continuous wavelet transform, natural frequency, distribution cables, field data

I. INTRODUCTION

Faults in real life are often caused by natural or human factors, resulting in phase to phase or phase to ground short circuits. After the occurrence of the fault, it is necessary to accurately locate the fault, to ensure the reliability of the power supply and reduce the power outage time.

II. PROPOSED METHODS

To consider situations in practical distribution systems, this paper collects data from a specific online monitoring system in a real power distribution system, and tries to accurately locate faults using traveling wave based methods. There are zero sequence instantaneous current measurements at both terminals of the cable of interest, with the sampling rate of 50 MHz and GPS synchronization. The proposed method can be seen as an extension of D-type dual ended fault locator. First, to accurately calibrate the velocity of traveling wave, the method based on natural frequency is adopted. Second, to minimize the impact of measurement noises on reliable detection of wavefronts, the tool of continuous wavelet transform (CWT) is adopted. Specifically, the coefficients calculated from CWT are normalized for each frequency, i.e., the arrival time corresponding to each frequency can be extracted. Afterwards, the accurate arrival time is determined by considering the information through the entire frequency, i.e., the peak of the coefficient summation of different frequencies corresponds to the arrival time of wavefronts. Through this procedure, the impact of measurement noise can be minimized. What’s more, to reduce the impact of frequency dependent parameters in low frequency range, the improved CWT method is proposed which uses only high frequency components. With the captured arrival time of wavefronts and the wave speed, the D-type dual ended fault locator can determine the exact fault location. Numerical experiments prove that the proposed method can accurately locate faults, the improved CWT method using high frequency range shows higher accuracy than that using low frequency range.

III. EXPERIMENT RESULTS

The comparison results of the actual fault location, the results using high wavelet frequency and the results using low wavelet frequency are shown in Fig. 2, where 6 cases are set as case number 1-6.

This work is sponsored by National Natural Science Foundation of China (No. 51807119) and Key Laboratory of Control of Power Transmission and Conversion (SJTU), Ministry of Education (No. 2022AB01). The support is greatly appreciated.
A Short-term Load Forecasting Methodology for Behind-the-Meter DERs based on Machine Learning

Aydin Zaboli, Graduate Student Member, IEEE, Junho Hong, Senior Member, IEEE, Vo-Nguyen Tuyet-Doan, Yong-Hwa Kim, Member, IEEE

Abstract—Residential locations now have the potential to generate a portion or all of their energy through on-site generation due to recent progress in the power industry. Nevertheless, utilities may find it difficult to record and monitor data due to the possibility of equipment consuming or generating energy without passing through a meter. This problem leads to a more intricate distribution system, and utilities are unable to detect events that occur within 15-minute intervals, resulting in an imprecise forecasting procedure. This paper presents a technique based on a two-layer long short-term memory (LSTM) framework to forecast the load profile of the residents regarding the different combinations of distributed energy resources (DERs). The data for training the model is considered every minute instead of conventional 15-minute intervals, so it can make a more accurate forecasting process and preserve households’ privacy better.

Index Terms—Behind-the-meter, Distributed energy resources, Energy consumption, Load forecasting, Long short-term memory.

I. METHODOLOGY

Using a stacked LSTM autoencoder (LSTM-SAE) architecture, this study looks into the load forecasting process for two houses with different PV, BESS, and EV combinations. In this research, an LSTM-based, sequence-to-sequence design is suggested for anticipating user-driven changes to electric current patterns. A higher accuracy in predictions is achievable because the training data is based on one-minute intervals. This helps utilities to promptly obtain SM data for the purpose of accurately analyzing customers’ load patterns, which might be useful for utilities and customers to check for probable anomalies in load behavior concurrently. An LSTM-SAE is presented that employs a recurrent neural network (RNN) to predict how different configurations of DERs would affect the complexity of a BTM system. The evaluation of the developed LSTM model indicates that it has good efficiency and accuracy in comparison with the conventional LSTM and RNN algorithms.

II. CONCLUSION

This paper presents a more complicated scenario of a BTM DERs system for load prediction evaluation. Also, a forecasting method based on data extraction for every minute is analyzed. Finally, an LSTM-SAE technique based on stacked decoding is suggested to accurately estimate the electric currents.

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Fig. 1. A general data transfer distribution scheme with BTM DERs.

Fig. 2. A comparison of RNN, traditional LSTM, and LSTM-SAE load forecasting results for House #1 considering BTM DERs.

<p>| Table I: A comparison of evaluation metrics. |</p>
<table>
<thead>
<tr>
<th>House#/Metrics</th>
<th>RNN</th>
<th>LSTM</th>
<th>Proposed LSTM-SAE</th>
</tr>
</thead>
<tbody>
<tr>
<td>H#1 MAE</td>
<td>2.082</td>
<td>1.730</td>
<td>1.239</td>
</tr>
<tr>
<td>RMSE</td>
<td>3.131</td>
<td>3.081</td>
<td>2.070</td>
</tr>
<tr>
<td>H#2 MAE</td>
<td>2.171</td>
<td>1.672</td>
<td>1.449</td>
</tr>
<tr>
<td>MSE</td>
<td>8.436</td>
<td>8.000</td>
<td>4.968</td>
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<tr>
<td>RMSE</td>
<td>2.904</td>
<td>2.828</td>
<td>2.229</td>
</tr>
</tbody>
</table>
Computationally efficient strategy for power systems planning in solar-dominant grids

Farzan ZareAfifi, Zabir Mahmud, Sarah Kurtz
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Abstract—Tracking energy storage for every hour of the year in a renewable-driven grid can be computationally intensive. In this study, we propose a novel temporal-resolution-reduction technique where a little loss in the accuracy of the solar-dominated modeling is observed. Using the critical times, shown to be an hour after sunrise and an hour before sunset, gives an excellent tradeoff of accuracy and computational time. The results show high accuracy in predicting both energy storage rating and power expansion of the resources for grids with more than 35% share of solar in the total operational power.

Keywords—renewable energy, computational complexity reduction, capacity expansion models, energy storage

I. INTRODUCTION

As the world is transitioning to replace fossil fuels with renewable resources, understanding how to complement wind and solar with storage to meet the demand is of prime importance. To track storage power and energy throughout a year, an hourly resolution calculation by capacity expansion modeling may be needed. Among methods available in the literature to reduce the computational time of the modeling, sampling from all the days using fixed- or variable-time-step approaches benefit from keeping the chronological order, enabling us to track storage in a 365-day horizon.

II. ANALYTICAL MODELING

In developing the fixed- and variable-time-step approaches, we can either use the exact values of the selected time points in the new profiles, the "snapshots" method, or average the values in each timeblock and use the new value in the profiles, which we call the average method. The results show that the minimum and maximum level of the storage state of charge correspond to an hour after sunrise and an hour before sunset, respectively, for most days. Averaging the values during the time steps effectively gives an integral, allowing the model to size the storage energy accurately. The power needed for wind and solar is also obtained accurately since the solar and wind generation times are differentiated.

III. RESULTS AND DISCUSSION

In Figs. 1 and 2, the results for energy storage rating and power buildouts versus the time points used by each approach are shown. As the temporal resolution decreases, the snapshot and average methods systematically overestimate and underestimate the results, respectively. However, CTS is much more accurate than the fixed-time-step approaches with similar computational times. Also, Fig. 3 shows that CTS performs well for solar ratios greater than 35%.

IV. CONCLUSIONS

We developed a novel variable time step approach that samples 365 days using only two points/day: an hour after sunrise and an hour before sunset. These two points/day are more accurate than fixed-time-step approaches with similar computational times for solar ratios > 35%.

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Integrating the Energy Flexibility of Variable Speed Heat Pump in Home Energy Management Systems

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Abstract—This paper proposes a model for energy flexibility of variable-speed heat pumps (VSHP). The proposed model ensures satisfying the customer comfort in terms of the desired temperature range, while providing energy flexibility. The proposed flexibility model is integrated in the home energy management system that maximizes the flexibility provision potential of VSHPs by queuing the indoor temperature deviation from the setpoint. The numerical results of implementing the proposed method in a house demonstrate the capability of the model in capturing the flexibility of VSHPs without violating the comfortable temperature range of residents.

I. DEMAND FLEXIBILITY MODEL AND RESULTS

Electrification of buildings is one of the most promising solutions to reduce emissions in urban areas and decrease the costs of energy use compared to mixed-fuel options [1]. Buildings that use electricity as the only source of energy for different types of energy use in the building are referred to as all-electric buildings. Among different types of loads, the heating and cooling loads are the largest users of electricity and account for about 40% of the residential energy usage in the U.S. [2]. Load shifting of heating and cooling loads as one of the largest electricity users has become increasingly important due to the growing renewable generation and grid needs. The capability to control end-uses provides benefits to buildings, the grid, and occupants.

New heating, ventilation, and air conditioning (HVAC) technology, referred to as variable-speed heat pump (VSHP), can provide continuous power according to a house’s cooling and heating needs than turning on and off to keep the temperature in setpoint. In this paper, a model is proposed to capture VSHP flexibility. The equivalent thermal model of heating and cooling systems shows that there is a time dependency on indoor temperature with regard to outdoor temperature and house thermal features [3].

Therefore, there is an opportunity to shift and queue the indoor temperature deviation from the occupant’s setpoint regarding their comfort. To satisfy occupant comfort, two constraints are considered. The delay-based constraint ensures that the cooling and heating of the house is started before the occupant’s requested delay time: Also, deadline-based constraint ensures that occupant feels the temperature setpoint at the deadline. Here, a home energy management system is developed to minimize customer bills by exploiting the flexibility of VSHPs as depicted in Fig. 1.

The results with allowed 2-hour delay time are shown in Fig. 2. With 2-hour delay comfort, the occupant can reduce the cooling cost by 33.9%. Increasing delay time increases the savings for heating and cooling. It is worth noting that the savings reach a saturation point after a certain delay time due to the thermal resistance and capacitance of the house, as well as the capacity of the VSHP.

REFERENCES

An Efficient Neural Solver for Two-Stage DC Optimal Power Flow with Guaranteed Feasibility

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Abstract—In this paper, we consider the two-stage formulation of stochastic DC optimal power flow (OPF) problem for optimal and reliable dispatch when the load is facing uncertainty. Though this problem can be approximated as a linear program using the sample average approximation method, it remains computationally challenging to solve due to the large number of scenarios needed to construct the approximation and the difficulty to guarantee network constraints for all uncertainty realizations. To address these challenges, this paper proposes a learning method to solve the two-stage problem in a more efficient way. A technique called gauge map is incorporated into the learning architecture design to guarantee the learned solutions’ feasibility to the network constraints. The simulation results on the IEEE 118-bus system show that, compared to applying the commercial solver, the proposed method not only learns solutions of good quality but also accelerates the computation by orders of magnitude.

Index Terms—Two-stage DCOPF, neural network, gauge map, feasibility guarantee

I. NEURAL SOLVER FOR TWO-STAGE DC OPTIMAL POWER FLOW

With significant penetration of renewable energy into the power grid, the fluctuation in the demand can no longer be ignored. To this end, two-stage OPF problems are solved to account for the uncertainty. In this article we consider the DC power flow model and the resulting DCOPF problem can still be challenging to solve in the stochastic programming context. The remarkable performance of neural networks (NNs) has made them popular methods to assist solving the OPF problems. This article presents an NN-based learning architecture that can solve many problem instances at fast speed and also guarantee the feasibility of learned solutions. The network architecture of our proposed algorithm is shown in Fig. 1.

II. EXPERIMENTAL RESULTS

To validate the effectiveness of the proposed learning algorithm, we consider two application contexts, namely, the risk-limiting dispatch and reserve scheduling problems on the IEEE 118-bus system. The results are shown in Table I and Table II and the average total costs of different methods are represented as the ratio compared to the average total cost obtained by applying CVXPY solver.

L. Zhang, D. Tabas, and B. Zhang are with the Department of Electrical and Computer Engineering at the University of Washington. Emails: {lzhang18,tabas,zhangbao}@uw.edu. The authors are partially supported by NSF grants ECCS-1942326 and ECCS-2023531, and the Washington Clean Energy Institute.

Application I: Risk-limiting dispatch on 118-bus system

<table>
<thead>
<tr>
<th>Methods</th>
<th>Total cost (average, %)</th>
<th>Solving Time (average, minutes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVXPY</td>
<td>100</td>
<td>0.395</td>
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<tr>
<td>Proposed</td>
<td>100.767</td>
<td>$10^{-5}$</td>
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<tr>
<td>Affine policy</td>
<td>199.413</td>
<td>0.199</td>
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</tbody>
</table>

TABLE I: Comparison of the expected total cost and solving time averaged out over 100 test instances for using different methods to solve the risk-limiting dispatch problem on the 118-bus system.

Application II: Reserve scheduling on 118-bus system

<table>
<thead>
<tr>
<th>Methods</th>
<th>Total cost (average, %)</th>
<th>Solving Time (average, minutes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVXPY</td>
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<td>3.210</td>
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<tr>
<td>Proposed</td>
<td>110</td>
<td>$10^{-4}$</td>
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<tr>
<td>Affine policy</td>
<td>1813</td>
<td>0.343</td>
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</table>

TABLE II: Comparison of the expected total cost and solving time averaged out over 100 test instances for using different methods to solve the reserve scheduling problem on the 118-bus system.

For risk-limiting dispatch, we can see from Table I that our learning method is faster than applying CVXPY solver by 4 orders of magnitude while the difference in average total cost is less than 0.8%. In comparison, using the affine policy reduces the average running time by half, however, it also performs 50% worse.

For reserve scheduling, our learning method not only learns to provide good solution quality (within 10% of the benchmark produced by CVXPY solver) but is also able to speed up the computation by 4 orders of magnitude. By contrast, using affine policy reduces the average running time at the expenses of increasing the total cost by an order of magnitude.
Scenario-based Economic Dispatch Under Conditional Wind Power Forecast Error

Qian Zhang, Graduate Student Member, IEEE, Apurv Shukla, Member, IEEE, Le Xie, Fellow, IEEE

Abstract—This paper introduces a sampling method that makes the traditional scenario approach more compatible with the empirical data in the real world. A central challenge when dealing with empirical data is that changing environments affect the distribution of random variables. In this paper, we model the uncertainty of past scenarios as the probability distribution over parameter space. In particular, we formulate the real-time economic dispatch problem under the conditional wind power forecast error. Leveraging the correlation analysis, sampling the past scenarios under similar environmental parameters results in a less conservative solution with a risk guarantee than the traditional method.

Index Terms—Chance-constrained optimization, scenario approach, economic dispatch, wind power forecast error

I. INTRODUCTION

The chance-constrained optimization providing explicit probabilistic guarantees on the feasibility of optimal solutions is helpful for power system operators making decisions under uncertainty. Over the past decade, many papers try to convert chance-constrained optimization into easily solvable form.

Data-driven methods, which are not constrained by any fixed distributions of the underlying uncertainties, but directly solve the program from history samples, received extensive attention in recent years, especially the Sample Average Approximation (SAA) and the Scenario Approach. Because of the longer solving time caused by binary variables, the SAA’s application in power systems is mainly concentrated on day-ahead unit commitment, while the easier problem-solving property makes the Scenario Approach has high potential in some real-time situations.

The biggest barrier to applying real history data in the Scenario Approach is the independent and identically distributed (i.i.d.) sample assumption, which is hard to satisfy in the real world. In this paper, we focus on the wind power forecasting error. After our environmental parameter filter process, the empirical data in the real world. A central challenge when parameter

II. PROBLEM STATEMENTS

We consider the chance-constrained DC-OPF formulation embedded with wind forecasting uncertainty, which can also be found in the existing literature. The load level is $d \in \mathbb{R}^{n_d}$, whose uncertainty is neglected, while the wind generation $w = \hat{w} + \tilde{w}$ consists of deterministic wind forecast value $\hat{w} \in \mathbb{R}^{n_w}$ and the uncertain forecast error $\tilde{w} \in \Delta$.

\[
\begin{align*}
\min & \ c(g) \\
\text{s.t.} & \ 1^T g = 1^T d - 1^T \hat{w} \\
& \ P_{\tilde{w}} \left( \frac{f}{g} \leq \frac{\tilde{w}}{g} \right) \geq 1 - \epsilon \\
& \ 1^T \eta = 1, g \leq g \leq \bar{g}
\end{align*}
\]

III. METHODS

The scenario approach randomly extracts $N$ i.i.d. scenarios to approximate the chance-constrained program. Supposing we have the random wind forecasting error scenarios set $\mathcal{N} := \{\tilde{w}_1, \tilde{w}_2, \cdots, \tilde{w}_N\}$, the inequalities (1c) can be replaced as:

\[
\frac{f}{g} \leq \frac{\tilde{w}}{g} \leq \bar{g} \quad i = 1, 2, 3, ..., N
\]

Definition (Parameter Space Behind Wind Forecasting Error): The parameter space $\mathcal{V}_N$ is defined as the set of environmental parameters which the past scenarios $\mathcal{N}$ are extracted from. For instance, the temperature between 70°F and 80°F is a temperature parameter space. And let $P_{\tilde{w}|\mathcal{V}_N}$ be a probability distribution over the parameter space.

Based on correlation analysis, the environmental difference between the now and the past can be used to filter scenarios from the empirical data.

IV. CASE STUDY

The wind forecasting data in south Texas 2022 from ERCOT is selected as the case study. We extract the empirical scenarios from a smaller parameter space than the traditional method whose scenarios are randomly generated from the past.

After setting the acceptable risk to 0.089, the results based on different sampling space in the 3-bus system is below:

<table>
<thead>
<tr>
<th>Sampling Space</th>
<th>Past Half Year</th>
<th>Past Three Months</th>
<th>Similar Environment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Violation</td>
<td>0.0006</td>
<td>0.0019</td>
<td>0.0202</td>
</tr>
<tr>
<td>Cost(10^5$)</td>
<td>4.9475</td>
<td>4.9456</td>
<td>4.9447</td>
</tr>
</tbody>
</table>

Fig. 1. The real values and the scenarios’ empirical distribution sampling from the whole past parameter space(left) and the similar parameter space(right)
Graph neural networks for risk-informed power grid operation

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Abstract—The ability of graph neural network (GNN) models to estimate the state of a power grid subject to power supply and demand uncertainty is investigated. Bus-level, branch-level and global grid states are considered as the quantities to be predicted, given the joint probability distribution (forecast) of stochastic grid variables (wind generation and load). The GNN models are surrogates for the computationally expensive optimal power flow (OPF) problem, and are trained using labeled data obtained by solving numerous OPF problems. It is shown that the GNN models are sufficiently accurate for predicting the (bus-level, branch-level and global) grid state. The GNN surrogate models are used to obtain Monte Carlo (MC) samples of the quantities of interest (operating reserve, transmission line flow) given the (hours-ahead) probabilistic wind generation and load forecast. These MC samples are used to perform system-level, zonal and branch-level reliability and risk assessment. The computational cost of GNN-based MC simulation (and risk estimation) is significantly lower than that of OPF solution-based MC simulation (and risk estimation). The proposed methodology will thus enable real-time risk assessment for the future power grid with high volatility and uncertainty due to higher participation of renewable energy resources.

Index Terms—Graph neural network, optimal power flow, system reliability, risk assessment

I. BACKGROUND

The growing penetration of renewable energy resources (RES), bulk storage, gas turbines and other flexible generation sources increases the volatility and uncertainty in the power grid. Explicit, rigorous grid reliability and risk estimation methods are needed to improve grid operators’ situational awareness and enable truly risk-informed operational decision making. The explicit risk assessment process involves: 1) MC sampling from a probabilistic forecast of supply/demand, 2) simulation of grid behavior (OPF problem solution) for each MC sample, and 3) computation of hours-ahead grid reliability/risk. Note that accurate reliability/risk quantification necessitates using numerous MC samples, since reliability/risk typically depends on the tail behavior of the quantities of interest. The second step in this explicit risk quantification process is prohibitively difficult, because it involves solution of computationally expensive security-constrained economic dispatch (SCED) problems for numerous (thousands or more) of MC samples.

II. PROPOSED SOLUTION

We train GNN surrogates for the OPF problem to alleviate computational burden of the MC simulation process. We then quantify the surrogate model error as well as reliability/risk estimation error for the GNN-based approach, by considering the corresponding OPF-based grid states as the ground truth. We demonstrate the GNN-based reliability/risk estimation using IEEE Case118 power grid. For the reliability/risk assessment we consider the following failure modes:

- **Branch-level**: transmission line power flow \( l_f \geq \epsilon \), where \( \epsilon = 95\% \) of maximum allowed capacity.
- **System-level**: operating reserve \( \Phi < \text{MRR} \) (minimum reserve requirement).

III. KEY RESULTS

<table>
<thead>
<tr>
<th>Methods</th>
<th>Prob. of ( \Phi &lt; \text{MRR} )</th>
<th>Risk of ( \Phi &lt; \text{MRR} ) ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPF</td>
<td>0.0566</td>
<td>2452.5</td>
</tr>
<tr>
<td>GNN</td>
<td>0.0566</td>
<td>2358.0</td>
</tr>
</tbody>
</table>

This study was partly funded by the Advanced Research Projects Agency-Energy (ARPA-E) Perform Award AR0001136.

Fig. 1. Branch-level reliability and risk assessment (20 branches with the highest mean flows are selected): Comparing OPF and GNN estimates.
Online correction of multi-scene load model parameters based on measured data

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Abstract—In identifying high-voltage load parameters, the identification method based on measurement data has limited application scenarios and poor identification timeliness. To solve this problem, this work takes the composite load model with distributed photovoltaic power as the research object. A dual objective function is constructed based on the load bus’s fitting degree of active and reactive power. The multi-objective particle swarm optimization algorithm is used to identify the proportional parameters of the model in the small disturbance scenario where the voltage fluctuation caused by the power change of different components of the load model is less than 5%. Combined with the identification in large disturbance scenarios, an online load parameter correction system based on load bus measurement data is proposed, which can automatically adapt to the scene. Through the validation of the EPRI-36 node system, the proposed method can realize the high-precision identification of load parameters in various scenarios and greatly improve the timeliness of load parameter correction.

I. LOAD MODEL STRUCTURE

A composite load model with distributed photovoltaic power is adopted. The structure of the load model is shown in Figure 1.

II. PROCESS OF ONLINE CORRECTION SYSTEM

The overall process of the online correction method of multi-scene load model parameters based on measured data is shown in Figure 2.

III. KEY RESULT AND CONCLUSION

It is found that the identification accuracy of MOPSO for the proportional coefficient of the load is generally higher than that of PSO, especially in the identification of small disturbance. This work proposes a high voltage level load parameter online correction system based on the measured data, which can realize the online correction of different load parameter sets under the scenarios of large disturbances and a variety of small disturbances.
Real-Time Locational Marginal Price Forecast: A Decision Transformer-Based Approach

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Abstract—This poster demonstrates a special neural network (NN) architecture named the decision transformer to forecast real-time locational marginal prices (RTLMPs) by learning temporal correlations among historical market data sequences. LMP forecasting problem is formulated as the problem of learning future actions in a model consisting of explicit locational demand data and implicit bid data, and solved by the proposed decision transformer. Case studies on Southwest Power Pool and ISO-New England datasets validate the performance of the method.

I. INTRODUCTION

To maximize profits, generators make decisions for real-time (RT) bids based on previous states (day-ahead (DA) market data) and current states (RT demand data) in the RT market. RTLMPs are dual variables deterministically solved from optimal power flow (OPF) in the RT market. Therefore, the RTLMPs are the deterministic consequences of the OPF-based optimal decision-making procedure. From the market participants’ perspective, forecasting RTLMPs requires learning the implicit sequential decision-making process represented by the OPF problems at different timestamps without any knowledge of the generator bidding strategies across the market and system operators’ OPF decision-making model. To incorporate implicit bid variation and capture the temporal correlation of market data, this paper proposes a data-driven approach to forecast RTLMPs in a sequential model using limited public market data.

II. METHODOLOGY

In this paper, the generator bidding strategies in the RT market are considered as a sequential decision-making process described by the tuple \((D_{DA}, B_{DA}, LMP_{DA}, D_{RT}, B_{RT})\). Because generators across the market decide the RT bids, which result in final RTLMPs via OPF, based on states and actions of previous \(T\) hours, the RTLMP prediction problem is formulated as a sequential decision-making problem in the RT market from market participants’ perspective.

The public electricity market data are embedded into a data sequence along with corresponding timestamp embeddings, which represent the sequential decision-making process of the RT market. The natural gas price is also embedded as a rough representation of generator bids into the RT market’s sequential decision-making process. A decision transformer NN, consisting of input encoder, multi-head self-attention (MHSA) network, and output decoder, is adopted as the predictor to solve the sequential decision-making problem and forecast RTLMPs, as shown in Fig. 1.

The inputs of the decision transformer are first processed and mapped to an embedded sequence \(\tau\) by an input encoder, including input embedding and timestamp encoding. The multi-head self-attention neural network (MHSA) network reads in the embedded input sequence from the input encoder and generates an output to the following decoder. The MHSA's output is a convex combination of the input sequence. The decoder takes the last token in the sequence \(T_{new}\) generated from MHSA, which represents the hidden state parametrized by prior states, to predict future action tokens in the sequential decision-making process.

The proposed RTLMP forecasting approach is verified using real-world public market data from SPP and ISO-NE. Fig. 2 shows the ground-truth RTLMPs and forecasted RTLMPs at Shub price node over the same testing period in SPP. Table I compares next-hour forecasting MAPEs obtained for ISO-NE using different approaches on the same testing dataset.

![Decision Transformer Architecture](image)

**Fig. 1. Decision Transformer Architecture.**

![RTLMPs at SPP in 2017](image)

**Fig. 2. Ground-truth and forecasted RTLMPs at SPP South Hub (SHub) price node.**

### TABLE I

RTLMP Forecasting Accuracy in Case 2

<table>
<thead>
<tr>
<th>Approach</th>
<th>MAPE (%) in Case 2(A)</th>
<th>MAPE (%) in Case 2(B)</th>
<th>MAPE (%) in Case 2(C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NN</td>
<td>37.2</td>
<td>34.8</td>
<td>33.1</td>
</tr>
<tr>
<td>ARMA</td>
<td>30.7</td>
<td>25.1</td>
<td>26.3</td>
</tr>
<tr>
<td>SVM</td>
<td>27.7</td>
<td>25.2</td>
<td>25.6</td>
</tr>
<tr>
<td>CLSTM-GAN</td>
<td>15.4</td>
<td>12.09</td>
<td>13.1</td>
</tr>
<tr>
<td>DT</td>
<td>12.9</td>
<td>10.8</td>
<td>10.5</td>
</tr>
</tbody>
</table>
Degradation and Thermal Runaway Prognosis Based on Real-world Battery Operation Records

Chunyang Zhao\textsuperscript{*†‡}, Billy Wu\textsuperscript{†}, Pierre Pinson\textsuperscript{‡}, Seyedmostafa Hashemi\textsuperscript{*}, Peter Bach Anderson\textsuperscript{*}, Chresten Trecholt\textsuperscript{*}, Chia-Wei Hsu\textsuperscript{‡}, Ju Li\textsuperscript{‡}, Yuan Li\textsuperscript{§}, Wei Chang\textsuperscript{§}

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\textsuperscript‡Department of Nuclear Science and Engineering, Massachusetts Institute of Technology, Cambridge, USA
\textsuperscript§Shanghai Cloudready Technology Co. Ltd, Shanghai, China

Abstract—In this work, the battery health prognosis is carried out based on the real-world operation monitoring records of electric vehicles in urban transportation. A unique battery dataset containing arbitrary usage history with non-idealistic usage profiles is presented, which contains the operation information of thousands of battery cells from hundreds of electric scooters in recent years. The monitoring history of embedded sensors, such as current, voltage, and temperature, reveals insights into battery working conditions and the deteriorated performance along the battery aging. The fragmentary operation records, real-world operation conditions, and non-idealistic charging history bring opportunities and challenges in battery health prognosis research. There are thermal-runaway batteries recorded in this dataset until their end of life, bringing the chance of modeling the failure mechanism tackling the forecasting of battery failure. Therefore, various machine-learning techniques are implemented for classification and anomaly detection for battery health states.

Index Terms—Battery health prognosis, Electric vehicle, Data-driven modeling, Real-world records, E-scooter

The prosperous development of transportation electrification prompts the application of lithium-ion batteries, while also raising concern about the safety and durability of the batteries. Besides the fundamental research on battery health based on lab experiments, the real-life recording of battery field operation gives unique insights into the battery performance and working conditions. In this work, two types of lithium-ion batteries, which are Lithium Iron Phosphate (LFP) and Nickel Manganese Cobalt (NMC), are used in similar e-scooter applications. The module-level recording includes the state of charge (SOC), voltage, current, temperature, etc., and the cell-level recording includes voltage. This unique time-series battery dataset recorded in this work shows run-to-failure use cases in the real world. With further processing, time-based and cycle-based battery operation records are acquired. Besides the statistical feature of the recorded data, expert features are extracted, for example, the incremental capacity analysis and resistance analysis during the charging process. As shown in Fig. 1 and Fig. 2, the charging process and extracted features in battery cycle life vary significantly in real-life applications. The supervised learning model and unsupervised learning are implemented, including Gaussian process regression, random forest regression, neural network, etc. Indicators like time-to-failure and cycle-to-failure are established, which are set as predictive targets for the battery health prognosis model. Arrange the training and testing datasets by different battery modules, our model gives accurate degradation and thermal runaway warnings for new use cases before it happens.

Fig. 1. Battery charging history in real-world e-bike application

Fig. 2. Battery incremental capacity analysis results over the lifetime

This work is supported by Danish Energy Technology Development and Demonstration Program (EUDP) contract no.64018-0618.
Hierarchical Deep Learning Model for Degradation Prediction per Look-Ahead Scheduled Battery Usage Profile

Cunzhi Zhao, Student Member, IEEE and Xingpeng Li, Senior Member, IEEE
University of Houston, Houston, Texas, USA.

Abstract—This paper proposed a hierarchical deep learning based battery degradation quantification (HDL-BDQ) model to quantify the battery degradation given scheduled BESS daily operations. Particularly, two sequential and cohesive deep neural networks are proposed to accurately estimate the degree of degradation using inputs of battery operational profiles and it can significantly outperform existing fixed or linear rate based degradation models as well as single-stage deep neural models. Training results show the high accuracy of the proposed system. Moreover, a learning and optimization decoupled algorithm is implemented to strategically take advantage of the proposed HDL-BDQ model in optimization-based look-ahead scheduling (LAS) problems. Case studies demonstrate the effectiveness of the proposed HDL-BDQ model in LAS of a microgrid testbed.

Index Terms—Battery degradation, Battery energy storage system, Deep learning, Energy management system, Machine learning, Microgrid generation resource scheduling, Neural network, Optimization.

I. PROPOSED MODEL AND ALGORITHM

Battery energy storage systems (BESS) are being adopted as a solution, particularly with the increasing installation of renewable energy sources such as wind and solar. The main component of BESS are lithium-ion batteries which degrade over time due to a variety of factors such as repeated charge and discharge cycles, high temperatures, and high charging or discharging rate. The repeated movement of ions within the battery can also cause physical damage to the electrodes and electrolyte, leading to a reduction in capacity and efficiency over time which is hard to quantify.

To address this challenge, a hierarchical deep learning based battery degradation quantification (HDL-BDQ) model is proposed as shown in the left part in Fig. 1. The proposed HDL-BDQ model aims to improve the training accuracy of the battery degradation by utilizing two sequential deep neural networks (DNN) which are DNN for unobtainable battery degradation features (DNN-UBDF) and DNN for battery degradation prediction (DNN-BDP). The DNN-UBDF predicts critical battery degradation features that are difficult to obtain from look-ahead scheduling (LAS), which are then used as input features for the DNN-BDP to quantify the corresponding battery degradation per scheduled usage profile.

A DNN embedded LAS problem would be hard to solve directly due to the highly non-linear and non-convex nature of the DNN models. Thus, a learning and optimization decoupled (LOD) algorithm is implemented to efficiently solve the proposed HDL-BDQ embedded LAS optimization problem. As shown in the right part of Fig. 1, the LOD algorithm iteratively solves the HDL-BDQ model embedded LAS that is decoupled to the battery degradation calculation and LAS optimization problems. In each iteration of LOD algorithm, tighter constraints will be updated on BESS operation to restrict its usage and lower the battery degradation and associated costs in the next iteration. The objective of the proposed LOD algorithm is to find the minimum total cost including battery degradation cost and microgrid operation cost.

II. MODEL PERFORMANCE

Fig. 1. HDL-BDQ and LOD algorithm [1].

Fig. 2. Training results of DNN-BDP model.

Table I LAS results for proposed and benchmark models.

<table>
<thead>
<tr>
<th>LAS</th>
<th>LOD</th>
<th>Traditional</th>
<th>Linear BDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Cost ($)</td>
<td>493.57</td>
<td>511.3</td>
<td>504.92</td>
</tr>
<tr>
<td>Operation Cost ($)</td>
<td>483.65</td>
<td>474.77</td>
<td>489.6</td>
</tr>
<tr>
<td>Degradation Cost ($)</td>
<td>9.92</td>
<td>36.53</td>
<td>15.32</td>
</tr>
<tr>
<td>Solving time (s)</td>
<td>5.76</td>
<td>0.34</td>
<td>0.42</td>
</tr>
<tr>
<td>Iteration Numbers</td>
<td>32</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

III. REFERENCES

Cost-effective Harmonic Estimation in Medium Voltage Distribution Networks

Yuqi Zhao, Student Member, IEEE, and Jovica V. Milanović, Fellow, IEEE

Abstract—Accurate estimation of harmonics in partially monitored power networks with uncertain, power electronics interfaced low carbon technologies can facilitate efficient planning and operation of future net-zero distribution networks. This study extends the general applicability of a recent methodology for estimating harmonic distortions in typical radial residential distribution networks to medium voltage distribution networks, which is typically non-radial. The proposed methodology is cost-effective since it requires limited installation of PQ monitors. The Morris screening method based harmonic variation sensitivity analysis, and the sensitivity method based on electrical distance were proposed in this study and were combined together to determine the optimal/minimum number and location of PQ monitors. Appropriate scaling factors were recommended as well. This solves the problem of sub-optimal selection of monitoring locations when harmonic distortion is not highly correlated with the voltage drop at buses in the meshed network. Different types of harmonic injections from nonlinear loads are fitted using Kernel non-parametric distribution and are estimated separately according to different load types. The approach is validated, and its accuracy and reliability were demonstrated on a highly interconnected (meshed) section of the power system.

Keywords—Harmonic estimation, meshed network, sparsely monitored system, uncertainties, power electronics, power quality, probabilistic analysis.

I. INTRODUCTION

In future net-zero distribution networks, there is expecting increasing proliferation of power electronic (PE) based technologies. These PE components will bring up the uncertainty levels and amplify the disturbance of the power system and consequently challenging the regulation of power quality (PQ) issues, especially the harmonic issues that will result in additional power loss and unexpected financial losses. The main idea of the proposed methodology is to estimate the harmonic distortions at unmonitored buses in a cost-effective way, i.e., with the information of harmonic measurements at a limited number of monitored buses.

II. METHODOLOGY

Fig. 1 summarises the required information for the proposed harmonic estimation methodology.

Unlike low voltage distribution networks, the medium voltage distribution networks are typically non-radial, thereby rendering the estimation of harmonics more challenging. In order to determine the optimal/minimum number and location of PQ monitors, a combination of the Morris screening method based harmonic variation sensitivity analysis, and the sensitivity method based on electrical distance were proposed. Different types of harmonic injections from nonlinear loads were fitted using Kernel non-parametric distribution and were estimated separately according to different load types.

III. KEY RESULTS AND CONCLUSIONS

The results of total harmonic distortion (THD) at different buses in the network are presented and compared in the form of fitted cumulative distribution function (CDF) (Fig. 2) and boxplots (Fig. 3). The proposed harmonic estimation methodology performs well and can be used to estimate the harmonic distortions at unmonitored buses in a non-radial network with multiple voltage levels with a good accuracy. An accurate estimate can be obtained at 94% of the unmonitored buses by installing PQ monitors at approximately 8% of network buses.

Fig. 2. Fitted CDFs of absolute estimation errors of THD.

Fig. 3. Boxplots of estimated and actual THD values for meshed GDN.

The approach facilitates the assessment of standard compliance, reduces the extent of monitor installations in the network, accelerates the assessment of harmonic performance and mitigation in uncertain networks, and contributes to the forecast of potential harmonic issues in future power networks.
Strategic Bidding of Hydroelectric Producer in Integrated Energy and Reserve Market

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Abstract—The increasing penetration of uncertain and variable wind and solar powers motivates the escalating demand of flexibility. The trading of flexible ramping product (FRP) has thus been integrated into modern electricity markets to incentive the participation of flexible resources. Hydroelectricity is characterized by exceptional operational flexibility, including quick start-up/shut-down and fast ramping rate. It is thus widely acknowledged as one of the most ideal energy resources to provide auxiliary services in power systems. This paper studies the strategic bidding of a hydroelectric producer in an integrated energy and reserve market. It is assumed that this hydroelectric producer’s capacity is sufficient to affect the market clearing. The impact of energy and reserve bidding of this hydroelectric producer on the market clearing is captured by a bilevel programming model. The energy bidding and reserve bidding are jointly optimized to maximize the total profit earned by selling energy and FRP. The computational results show that hydroelectric producers can stratify their bidding decisions to affect both energy and reserve prices, and thus earn more profit.

Index Terms—Thermal-hydro-wind-solar power system, day-ahead scheduling, multistage robust optimization, renewable energy generation.

I. INTRODUCTION

The major contributions of this paper are summarized as follows: 1) The conventional study on hydroelectric producer with only energy selling is extended to the case where both energy and reserve markets are taken into account. The economic and sustainability benefits of hydroelectricity’s flexibility in such an integrated market are investigated. 2) A novel integrated energy and reserve market clearing model is proposed, which simultaneously quantifies locational marginal prices for both energy and reserve. This model provides an economic justification for both prices by properly evaluating the contributions of energy and reserve supply on social welfare. 2) A bilevel programming model is proposed to describe the impact of a large hydroelectric producer’s joint energy and reserve bidding on the clearing of integrated energy and reserve market. We show that a large hydroelectric producer can strategize its bidding decisions to obtain desired energy and reserve prices maximizing its profit. 3) The insights on how to exploit hydroelectricity’s flexibility to strategize hydroelectric producer’s bidding decisions and earn profit are provided.

II. MODEL FORMULATION

Upper-level model: In the upper-level model, the hydroelectric producer jointly optimizes its bidding and operation decisions with the objective of maximizing the total profit.

\[
\begin{align*}
\max_{\pi, p} & \sum \limits_{i \in \Omega} \sum \limits_{t=1}^{T} \left( C_i(p_{i,t}) + C_i^{RU}(u_{i,t}) + C_i^{RD}(d_{i,t}) \right) \\
\text{s.t.} & \quad p \in P(q) := \{ p : \exists q \in Q(p) \}. 
\end{align*}
\]

The objective is to maximize the profit earned from both energy and reserve markets. Bidding decisions include 1) minimum and maximum generation, and 2) maximum ramping up and ramping down capacities supplied by each hydroelectric unit in every time period. They must guarantee that there exists a feasible schedule for cascaded hydroelectric system satisfying the associated bid.

Lower-level model: In the lower-level model, the ISO clears the integrated market by solving an economic dispatch problem shown as follows:

\[
\begin{align*}
\min & \sum \limits_{t=1}^{T} \left[ C_i(p_{i,t}) + C_i^{RU}(u_{i,t}) + C_i^{RD}(d_{i,t}) \right] \\
\text{s.t.} & \quad P_{i,t}^{\min} \leq p_{i,t} \leq P_{i,t}^{\max}, \quad i \in \Omega, \quad t = 1, \ldots, T, \\
& \quad -RD_{i,t} \leq \bar{p}_i - \bar{p}_{i-1} \leq RU_{i,t}, \quad i \in \Omega, \quad t = 2, \ldots, T, \\
& \quad ur_{i,t} \leq RU_{i,t}, \quad i \in \Omega, \quad t = 1, \ldots, T, \\
& \quad dr_{i,t} \leq RD_{i,t}, \quad i \in \Omega, \quad t = 1, \ldots, T, \\
& \quad p_{i,t} + ur_{i,t} \leq P_{i}^{\max} x_{i,t}, \quad i \in \Omega, \quad t = 1, \ldots, T, \\
& \quad p_{i,t} - dr_{i,t} \geq P_{i}^{\min} x_{i,t}, \quad i \in \Omega, \quad t = 1, \ldots, T, \\
& \quad \sum \limits_{i \in \Omega} p_{i,t} = ED_{t}, \quad t = 1, \ldots, T; \quad (\pi^e_t) \\
& \quad \sum \limits_{i \in \Omega} ur_{i,t} \geq RU_{D}, \quad t = 1, \ldots, T; \quad (\pi^{ur}_t) \\
& \quad \sum \limits_{i \in \Omega} dr_{i,t} \geq RDD_{t}, \quad t = 1, \ldots, T; \quad (\pi^{rd}_t)
\end{align*}
\]

where energy, ramping-up reserve, and ramping-down reserve prices are the dual variables associated with constraints (2h)-(2j). The economic interpretation of reserve price is the opportunity cost resulting from decreasing or increasing power output to supply ramping products.

III. KEY RESULTS

Figure 1 shows the impact of bidding quantity on revenue. The key conclusions include: 1) bidding decisions affect the supply-demand equilibrium and the corresponding energy and reserve prices; 2) a greater bidding quantity leads to a lower clearing price; 3) strategizing bidding decisions can optimize the profit.
Event-Driven Non-Invasive Multi-Core Cable Current Monitoring Based on Sensor Array

Qi Zhu, Graduate Student Member, IEEE, Guangchao Geng, Senior Member, IEEE, and Quanyuan Jiang, Senior Member, IEEE

Abstract—Current monitoring of multi-core cables plays an important role in various applications since cables are widely utilized in distribution and transmission systems. However, existing current sensing devices which are mostly designed for the single conductor break the cable jacket to measure conductor currents in multi-core cables. Recently various non-invasive sensing devices with reconstruction algorithms are designed for rapid access to currents in multi-core cables but don’t make full use of abundant information during current monitoring. Thus, this paper proposes an event-driven non-invasive multi-core cable current monitoring method using an array of magnetic field sensors. Real-time currents of the multi-core cable are determined by solving conductor localization and current measurement problems. Since the observed changes of the magnetic field around the cable are caused by current or position changes, conductor localization is driven by the events which are classified as electrical events and mechanical events respectively. The key idea is to improve the accuracy of conductor localization through effective electrical events. Then current monitoring is achieved by solving current measurement problems using more accurate conductor positions and the measured magnetic field. This method is utilized in the real cable current monitoring, a sustaining decrease of relative current errors is observed, which is below 1% in long-term monitoring.

Index Terms—Current monitoring, current sensor, event clustering and filtering, non-invasive current measurement, sensor array.

I. INTRODUCTION

CABLES are widely utilized in the distribution and transmission systems due to a mass of advantages compared with overhead lines, such as reliability of power supply, less space requirement, and maintenance convenience. Current measurement of cables is the foundation of power system monitoring.

This paper proposes an event-driven current monitoring method for multi-core cables based on the sensor array. When an event happens during the current monitoring, the event is recorded and classified as an electrical event or a mechanical event which are caused by the conductor currents or the conductor positions change, respectively. The effective information in the electrical events is extracted by event filtering based on multivariate Gaussian distribution. Then more precise positions of the four conductors in the multi-core cable can be identified by formulating a modified NLLS problem using effective information in electrical events, which leads to more accurate current measurement. When the mechanical event is detected, we correct the conductor positions, then collect and utilize electrical events in the new positions to improve the accuracy of the current measurement.

II. KEY FIGURES

The test bed is set up as shown in Fig. 1. A multi-core cable connects the load to a 220V three-phase voltage source. The currents of the cable are measured by the non-invasive current sensing device. The monitoring of cable currents in this experiment are shown in Fig. 2. The events generated by the hair dryer, induction cooker, and VFD are marked in Fig. 2. In the whole current monitoring, there are several obvious decreases in error, which are caused by the application of the event-driven NLLS formulation with harmonics and are the results of more effective events extracted by event filtering.

This work was supported in part by Natural Science Foundation of Zhejiang Province under Grant LGG21E070003 and the Fundamental Research Funds for the Central Universities under Grant 226-2022-00164.
Power Network Fault Location Based on Voltage Magnitude Measurements and Sparse Estimation

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Abstract—In this paper, an improved fault location method based on magnitude measurements of voltages and sparse estimation is proposed for power networks. Compared to existing sparse estimation based fault location methods, the proposed method not only retains the advantages of sparse estimation, but also avoids the complexity of PMU installation. In this paper, the influence of fault current on the bus voltages is equivalently represented by the bus injection currents at terminals of the faulted line. With only the voltage magnitude measurements, the FISTA algorithm is adjusted to match the characteristics of the sparse estimation problem and is applied to solve for fault location.

Keywords—Fault location, power network, sparse estimation, voltage magnitude measurements

I. INTRODUCTION

Compared to PMU measurements, voltage magnitude measurements are more commonly installed in practical power systems. These measurements only need to calculate phasors at the local end and output phasor magnitudes, and do not require time synchronization. Therefore, this paper proposes an improved power network fault location method based on voltage magnitude measurements and sparse estimation.

II. PROPOSED METHOD AND EXPERIMENT RESULTS

From [1], the voltage changes of buses of the entire power network caused by the fault current at the fault location can be equivalently represented by the injection current at the terminal buses of the faulted line.

In each local voltage measurement, the voltage phasor can be calculated and the phase angles at the local terminal share the same time reference (without synchronization with satellite).

As a result, the magnitude of \((\Delta V)_m\) can be measured. Then the equivalent injection current can be calculated by

\[
(\Delta V)_m = \left( Z_{bus, div} \right)_m \cdot \Delta I
\]

And the magnitude of voltage difference can be decomposed to

\[
(\Delta V)_m^2 = re\left((\Delta V)_m^2\right) + im\left((\Delta V)_m^2\right)
\]

By defining

\[
A = re\left((Z_{bus, div})_m\right) - im\left((Z_{bus, div})_m\right) \in \mathbb{R}^{3m \times 6N},
\]

\[
B = im\left((Z_{bus, div})_m\right) - re\left((Z_{bus, div})_m\right) \in \mathbb{R}^{3m \times 6N},
\]

\[
C = (\Delta V)_m^2 \in \mathbb{R}^{m \times 1}, \quad x = \left[ re(\Delta I)^T \quad im(\Delta I)^T \right]^T \in \mathbb{R}^{6N \times 1},
\]

formula (2) can be rewritten as

\[
(A \cdot x) \odot (A \cdot x) + (B \cdot x) \odot (B \cdot x) = C
\]

To obtain \(\Delta I\) is to work out the following optimization problem, and can be solved by the adjusted FISTA algorithm:

\[
x \in \arg\min_x \frac{1}{2} \left\| (A \cdot x) \odot (A \cdot x) + (B \cdot x) \odot (B \cdot x) - C \right\|_2^2 + \lambda \|x\|_1
\]

Then, the fault location can be derived by the non-zero element in \(\Delta I\) by

\[
\frac{\Delta I_i}{\Delta I} = \frac{\sinh(P \cdot (l_i - I_f))}{\sinh(P \cdot I_f)}
\]

As an example, the estimated equivalent injection current of 0.01Ω A-G fault, 225 km, line 30-38 in shown in Fig. 1. The result of numerical experiments in shown in Table I.

![Estimated real and imaginary part of the equivalent injection current, 0.01Ω A-G fault, 225 km, line 30-38](image)

Table I Fault location results, various fault resistance and types

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</table>

REFERENCES

Hardware Implementation of DC Protection Algorithms

Daniel Zintsmaster III, Undergraduate Student Member, IEEE, Munim Bin Gani, Graduate Student Member, IEEE and Sukumar Brahma, Senior Member, IEEE

Abstract—Current Fault Detection & Location algorithms require hardware implementations with high-speed data measurement, processing, and response speed to operate within the time and accuracy parameters determined by system simulation. This poster demonstrates a workflow for implementing fast fault detection and location algorithms into a hardware-in-the-loop (HIL) solution using only single-ended local measurements. The process provides a guideline for developing hardware solutions that can meet performance requirements and utilize commercially available microcontroller resources. The implemented hardware solution will then be compared to the pure software solution and assessed based on actual field measurements and response data. (Abstract)

Keywords — Hardware-in-the-loop, fault detection and location algorithms

I. Introduction

This poster discusses the challenges associated with implementing fault detection and location algorithms that operate successfully and quickly within simulations, but require high speed system state sampling, data analysis, and response time to meet the specifications set by the algorithm and confirmed in software simulations.

II. Implemented Algorithm

The algorithm that the hardware solution was developed for [1] required the system process as shown in Figure 1.

- Simultaneously sample voltage and current signals at 1MHz
- Calculate System State
  - Move to the next time instance
  - No
  - Yes
- Is our calculated distance less than the length of the line?
- Yes
- Output a trip signal

Fig. 1: System Implementation of Fault Location and Detection

The goal of the algorithm is to use single ended, time domain voltage and current measurements at a bus to calculate the distance from that bus to a fault. This algorithm is planned to be implemented in relays that can detect and locate faults with precision, speed, and without reliance on a specific type of source. The system states and appropriate response of the hardware solution are shown in Figure 2.

III. Microcontroller Selection

As the goal of the proposed solution is to create a device that can be commercially developed, optimizing for cost and size while still allowing for rapid sampling and calculation of the input data is required. For our algorithm, the Texas Instrument’s TMS320F28379D MCU [2] was used for its high clock speed and ability to implement parallel processing within its 2 CPU’s and Control Law Accelerator.

IV. Challenges of High-Speed Hardware Solutions

When instructions are executed at such a high speed, challenges arise that do not usually occur in simulation solutions, including:
- How can we display that our hardware solution is doing what it’s supposed to do? As real-time visual update at 1MHz is not an option;
- Does the act of recording the results cause any changes in the displayed results?

These questions meant that designing this solution would need to be done in cumulative steps as follows: Prove that the microcontroller can sample a signal at 1MHz; Show that the signals output from the simulated system can be recorded by the microcontroller; Confirm that the two signals (Voltage and Current) are being sampled simultaneously; Demonstrate that the fault detection loop can complete before the next set of samples are taken.


[II] TMS320F28379D C2000™ 32-bit MCU
https://www.ti.com/product/TMS320F28379D
Large-signal Stability Analysis Using Takagi-Sugeno Fuzzy Model Theory for Fractional Frequency Transmission System

Ziyue Duan, Student Member, IEEE, Yongqing Meng*, Member, IEEE, Tianyi Wang, Haitao Zhang, Member, IEEE, Yong Yang, Xiuli Wang, Senior Member, IEEE

Abstract—The rapid development of renewable energy requires transmission technology innovation. The fractional frequency transmission system (FFTS) is a promising solution for large-scale renewable energy transmission. While the stability analysis becomes urgent affairs for engineering application. Especially for the large-signal disturbance, previous methods on small-signal stability would be inapplicable. Thus, the system-level large-signal stability analysis method of FFTS is proposed considering the system parameters, control strategy of AC/AC converter and PLL in this paper. The state-space Takagi-Sugeno fuzzy model is proposed for Lyapunov function construction. Then the corresponding large-signal stability domain of attraction (LS-DOA) could be obtained. In order to overcome the qualitative and approximate problem of traditional stability analysis method, the stability strength and affine angle is introduced initially. Ultimately, considering the influence of system parameters with different-frequency interaction feature, the large-signal stability results of FFTS under different gird faults could be revealed completely. The effectiveness of proposed approach is verified by case and simulation.

Index Terms—Fractional frequency transmission system, Large-signal stability, T-S fuzzy model theory, LS-DOA, Affine transmission, Different-frequency interaction.

I. INTRODUCTION

To date, aside from the HVAC and HVDC, the fractional frequency transmission system (FFTS) is also one of the three mainstream transmission methods. Due to its excellent performance of transmission efficiency and construction-economy, FFTS provides a promising solution for integrating large-scale renewable energy into power systems especially for offshore wind power [7], [8]. Nevertheless, the problems of FFTS stability remain unfulfilled yet, which severely threatens the safety and reliability of these projects.

The lack of large-signal stability analysis on FFTS motivates the work, and the major contributions of this paper are mentioned as follows. (1) Taking the control loop dynamics and dimension disaster into account, the FFTS system-level stability analysis is completed includes the system parameters, control system of AC/AC converter modular multilevel matrix converter (M³C) and PLL initially through T-S fuzzy theory. (2) The stability strength and affine angle are proposed relied on LS-DOA for quantitative analysis. After the affine transformation, diverse LS-DOA could be projected into one same space. Compared with the traditional qualitative approach, the broad area of hypersphere is capable of describing stability strength mathematically. (3) Considering the influence of system parameters with different-frequency interaction feature, the large-signal stability results of FFTS under different gird faults has revealed completely. Ultimately, it verifies the effectiveness of proposed stability analysis method through time-domain simulations results.

II. CONCLUSION

Taking the control loop dynamics and dimension disaster into account, the system-level stability analysis method is proposed considering the system parameters, control strategy of M³C and PLL. After establishing the state-space based FFTS fuzzy model. Furthermore, considering the influence of system parameters with different-frequency interaction features, the large-signal stability results of FFTS under different gird faults could be revealed completely. It comes the conclusion that the system large-signal stability enhancement could be considered meaningfully from IF side in a certain range. And the affine angles as well as stability strength provide quantitative and mathematical methods for analysis.

Fig. 1. Topology of wind power fractional frequency transmission system.

Fig. 2. The LS-DOA of 2-D plane.
Distribution System State Estimation with Time-Delayed Measurements

Keith A. Zuckerman, Graduate Student Member, IEEE, and Karen N. Miu, Member, IEEE

Abstract—With increased automation in distribution systems, accurate state estimation is required to enable advanced control. Several types of measurement equipment now transmit data to distribution and centralized locations. Varied sampling rates and communication bandwidth and security constraints result in time-delayed, asynchronous measurements. This research implements a pre-processing step which adjusts measurements used in distribution state estimation (DSE) to account for temporal changes in the system injections. Simulation studies, on a large-scale, unbalanced system, were performed to quantify impacts of time discrepancies in measured data on DSE.

Keywords—distribution networks, smart grid, state estimation

I. INTRODUCTION

Deployment of distributed energy resources (DERs), such as photovoltaics, energy storage devices, and electric vehicles, has increased variability and uncertainty in power distribution systems. Given this uncertainty, an accurate estimate of the present system operating point is necessary to enable real-time control of the network.

Recently, the number of measurement devices in the distribution network has significantly increased. Intelligent electronic devices used for distribution supervisory control and data acquisition (DSCADA), such as feeder and capacitor switches, allow for real-time sensing and control. Additionally, advanced metering infrastructure (AMI) provides grid operators with additional data streams which can be used directly in energy management systems as well as for short-term load forecasting.

DSCADA and AMI data transmission is subject to the bandwidth and security constraints of modern communication networks. The measurements are collected and transmitted asynchronously, with potential time delays on the order of seconds to minutes for DSCADA data and minutes to hours for AMI data [1], [2].

This research utilizes an adjusted measurement model to update time-delayed measurements based on forecasted changes in injections over time [3]. The resulting adjusted measurements are input into a traditional weighted-least-squares state estimator. Simulations on a 394-bus three-phase unbalanced radial distribution network show that significant improvement can be made to the state estimate when using an adjusted measurement model, as compared to the traditional model.

II. ADJUSTED MEASUREMENT MODEL

The measurement model is given as

\[ z = h(x) + \nu \]  

where \( z \) is the measurement vector, \( h(x) \) is the nonlinear measurement function, \( x \) is the system state (node voltage phasor) vector, and \( \nu \) is the error vector. The error vector is decomposed as

\[ \nu = \nu_c + \nu_f \]  

where \( \nu_c \) is the meter and modelling error and \( \nu_f \) is the error related to changes in injections since the measurements were collected. The adjusted measurement vector is

\[ y = z - \bar{\nu}_f \]  

where \( \bar{\nu}_f = E[\nu_f] \).

III. SIMULATION SETUP AND RESULTS

Simulations were conducted on a 394-bus, three-phase radial distribution system with time-delayed measurements. The estimate error is \( \epsilon = V - \bar{V} \), where \( V \) is the complex node voltage vector from the power flow solution, and \( \bar{V} \) is the state estimate in rectangular form.

Case 1 is the reference case, in which the time-delayed measurements were not adjusted, resulting in an evaluation metric of 0.15583. In Case 2, the injection measurements were adjusted using short-term load forecasts. The resulting evaluation metric was 0.07955, a 48.952\% improvement over Case 1. In Case 3, power flows were adjusted by exploiting the radial structure of the network. The resulting evaluation metric of 0.09943 shows a 36.192\% improvement over Case 1. In Case 4, both power injections and power flows were adjusted. The evaluation metric of 0.02534 yields an improvement of 83.740\% over Case 1.

| Case | Measurement Adjustment | ||\|\epsilon||_2 | Improvement |
|------|------------------------|---|----------------|-------------|
| 1    | None                   | 0.15583 | --             |
| 2    | Injections only        | 0.07955 | 48.952\%       |
| 3    | Power flows only       | 0.09943 | 36.192\%       |
| 4    | Flows and Injections   | 0.02534 | 83.740\%       |

REFERENCES
Real-time Charging Scheduling for Electric Vehicle Aggregators in the Ancillary Service Market

Izaz Zunnurain and Yuanrui Sang
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Abstract—This paper proposes an optimal EV charging and discharging scheduling strategy for EV aggregators that will maximize its profit while minimizing EV owners’ charging costs by enabling the EVs to provide valuable ancillary service to the grid. The model was applied to the regulation, flexible ramping product and proxy demand response markets of California independent system operator (CAISO) under four case conditions with realistic data consisting of 111 EVs arriving and departing at a 22kW AC level-2 public charger located in Palo Alto, California. The results show optimally scheduled charging of the EVs yields significant increase in profit for the aggregator.

I. METHODOLOGY

This study considers EVA as a price taker, i.e., a quantity-only bids. This method allows us to develop a computationally efficient scheduling model for the electric vehicles. Figure 1 shows the concept of an EVA scheduling architecture proposed in this study.

![Illustration of EVA charging scheduling to provide CAISO ancillary services](image)

II. PROBLEM FORMULATION

In this study, an optimal EV charging scheduling model is proposed for EVA using computationally efficient linear programming (LP). Because of the space restrictions, only the objective-function of the model is shown below:

\[
\min \left( \sum_{t=1}^{T} \left[ \lambda^\text{DA,Eng} \cdot C^\text{DA,Eng} + \lambda^\text{RT,Eng} \cdot \Delta E_t \right] - \left[ \lambda^\text{DA,RegUp} \cdot C^\text{DA,RegUp} + \lambda^\text{RT,RegUp} \cdot \Delta P^\text{RegUp} \right] + \left[ \lambda^\text{DA,RegDn} \cdot C^\text{DA,RegDn} - \lambda^\text{RT,RegDn} \cdot \Delta N^\text{RegDn} \right] - \left[ \lambda^\text{DA,FRPUp} \cdot C^\text{DA,FRPUp} + \lambda^\text{RT,FRPUp} \cdot \Delta P^\text{FRPUp} \right] - \left[ \lambda^\text{DA,FRPDn} \cdot C^\text{DA,FRPDn} - \lambda^\text{RT,FRPDn} \cdot \Delta N^\text{FRPDn} \right] - \lambda^\text{RTE,Pen} \cdot C^\text{RTE,Pen} + \Delta \lambda^\text{RT,Eng} \cdot \left( \sum_{v=1}^{V} \sum_{k=1}^{K} \varepsilon^v_k \cdot \Delta \lambda^\text{RTE,Eng} \cdot \text{Disch}_k \right) \right)
\]

The objective function of this model is to minimize the overall charging cost, hence, maximize the profit in one day, as (1) shows. It includes day-ahead energy and ancillary procurement cost, penalty cost if UIE exceeds tolerance band, and battery health compensation cost due to frequent discharge.

III. SIMULATION RESULTS

The results from following four different case conditions are compared in terms of total profit of EVA, deployment of the ancillary products, and EV owners’ incentives.

- Condition (1): Bidirectional charging and discharging are allowed and optimally scheduled (proposed).
- Condition (2): Only unidirectional charging is allowed, and the charging is optimally scheduled.
- Condition (3): Bidirectional charging and discharging are allowed, and the charging immediately starts after the vehicle is plugged in until the battery is fully charged.
- Condition (4): Only unidirectional charging is allowed, and the charging immediately starts after the vehicle is plugged in until the battery is fully charged.

![Figure 2](image)

In Figure 2(a), a negative value represents that the EVA is making a profit. The EVA was able to make a profit in Conditions (1) and (3), but not in Conditions (2) and (4). The profit made in Condition (1) was 44.2% more than that in Condition (3). In Figure 2(b), allowing discharging in the model enables the EVA to provide both regulations up and down to the electricity market, and this resulted in twice as much ancillary service deployment as the case where no discharging is allowed. Figure 2(c) shows, the proposed model i.e., condition (1) has shaved off the peak spike between hours 10 to 15 and reduced the load with discharging between hours 19 to 23 in the evening when the grid usually needs more generation.

IV. CONCLUSION

In this paper, we developed a computationally efficient linear optimization model which takes advantage of the available EVs plugged into the public chargers and controls EV charging/discharging to provide ancillary service to the grid, hence, maximize the EVA’s profit.
Power Network Fault Location Based on Voltage Magnitude Measurements and Sparse Estimation

Yuxuan Zhu*, Student Member, IEEE, Yixiong Jia, Yu Liu1,2,*, Senior Member, IEEE, and Dayou Lu1
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3. Department of Electrical and Electronic Engineering, The University of Hong Kong, Hong Kong SAR, China
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\left| (\Delta V)_m \right| = \left| \left( Z_{bus \_div} \right)_m \cdot \Delta I \right| 
\]

And the magnitude of voltage difference can be decomposed to

\[
\left[ (\Delta V)_m \right]^2 = \text{re}\left[ (\Delta V)_m \right]^2 + \text{im}\left[ (\Delta V)_m \right]^2
\]

By defining

\[
A = \text{re}\left[ (Z_{bus \_div})_m \right] \in \mathbb{R}^{3m \times 6N}, \\
B = -\text{im}\left[ (Z_{bus \_div})_m \right] \in \mathbb{R}^{3m \times 6N}, \\
C = \left[ (\Delta V)_m \right]^2 \in \mathbb{R}^{3m \times 1}, \quad x = \left[ (\Delta I)^T \right] \left[ \text{re}(\Delta I)^T \right] \left[ \text{im}(\Delta I)^T \right]^T \in \mathbb{R}^{6N \times 1},
\]

formula (2) can be rewritten as

\[
(A \cdot x) \odot (A \cdot x) + (B \cdot x) \odot (B \cdot x) = C
\]

To obtain \(\Delta I\) is to work out the following optimization problem, and can be solved by the adjusted FISTA algorithm:

\[
x \in \arg\min_{x} \frac{1}{2} \left\| \left( (A \cdot x) \odot (A \cdot x) + (B \cdot x) \odot (B \cdot x) - C \right)^2 \right\|_2^2 + \lambda \left\| x \right\|_1
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Then, the fault location can be derived by the non-zero element in \(\Delta I\) by

\[
\frac{\Delta I_i}{\Delta I} = \frac{\sinh(P \cdot (l_i - l_f))}{\sinh(P \cdot l_f)}
\]

As an example, the estimated equivalent injection current of 0.01 \(\Omega\) A-G fault, 225 km, line 30-38 in shown in Fig. 1. The result of numerical experiments is shown in Table I.

![Fig. 1 Estimated real and imaginary part of the equivalent injection current, 0.01 \(\Omega\) A-G fault, 225 km, line 30-38](image)

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