Grounding grids break diagnosis with consideration of underground pipe

Cigong Yu, Zhihong Fu, Xiaorui Hu, Minghui Bao, Yongliang Ji and Shenwu Yu

***Abstract*—Grounding grid is an essential means for the safety of operators and power apparatus in substation. Many approaches including transient electromagnetic method have been applied to diagnose faults in grounding grids. This paper investigated break point diagnosis of grounding grids with consideration of underground pipe. Based on the equivalent resistivity distribution characteristics, the grounding fault can be accurately located in the grounding grids. The influence of underground pipe on the distribution of equivalent resistivity is analyzed. Factors including underground pipe made of different materials and buried in different depth are discussed in detail. The results show that the underground pipe puts a great impact on fault diagnosis of grounding grids.**

***Index Terms*—Grounding grid, transient electromagnetic method, fault diagnosis, underground pipe, substation**

I. Introduction

In China, the grounding grids are made of flat or round steel and buried about 1 m under the earth surface. Due to the years of soil erosion, lightning and short-circuit current damage, the grounding faults occur frequently. Recently, there are many research literatures focusing on fault diagnosis of grounding grids. All the diagnosis methods can be divided into four categories as method based on the theory of circuit, based on the electromagnetic theory, based on the electrochemical detection theory, and the transient electromagnetic method (TEM).

This paper is a follow-up work of fault diagnosis of grounding grids using transient electromagnetic method. In this study, we devote to investigating the effect of underground pipe on fault diagnosis of grounding grids based on transient electromagnetic method. Factors that play the role on diagnosis results including underground pipe made of different materials and buried in different depth will be discussed.

II. Key Figures

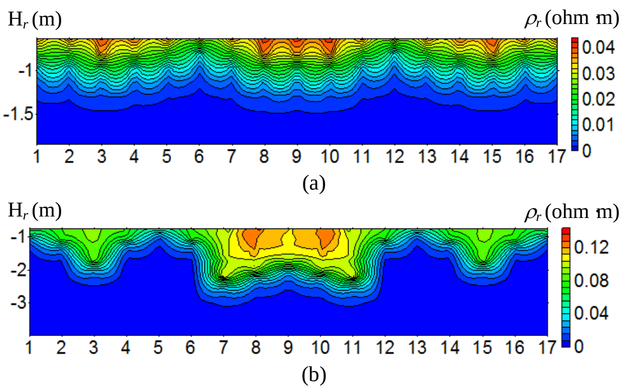

Fig. 1 Contour map of equivalent resistivity in the presence of underground pipe made of (a) steel, and (b) concrete.

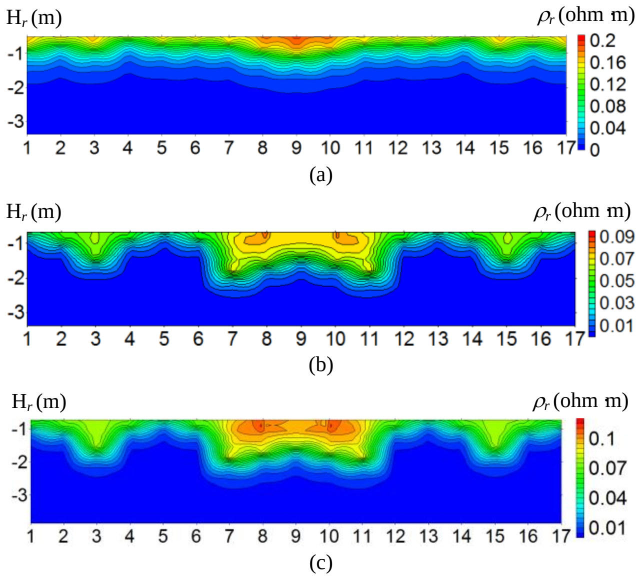

Fig. 2. Contour maps of equivalent resistivity at the situation the pipe is buried (a) 0.5m, (b) 1.15m, and (c) 1.75m beneath the earth surface. A break cut occurs at point B(4,5) (close to point 9).

III. Conclusion

In this paper, we have conducted simulation tests to investigate the influence of underground pipe on fault diagnosis of grounding grids. The contour map of equivalent resistivity displays regular distribution characteristics. When the faults occur, the equivalent resistivity calculated at locations above the broken grounding mesh increases considerably. From the typical change of equivalent resistivity distribution, the grounding fault can be accurately located.

Analyses show that the underground pipe has great impact on the fault diagnosis of grounding grids. The influence of underground pipe made of different materials and buried in different depth has been surveyed. The conclusions drawn are:

1) The pipe with high conductivity buried above the grounding girds has significant influence on the fault diagnosis of grounding grids so that the fault cannot be pinpointed, whereas that of poor conductivity has no impact on the diagnosis results.

2) The high conductivity pipe buried above the grounding grids has significant influence on fault diagnosis of grounding grids, whilst that buried under the grounding grids has no impact on diagnosis results.

A Game Theoretic Approach to Analyze the Dynamic Interactions of Multiple Residential Prosumers Considering Power Flow Constraints

Tao Chen, *Student Member, IEEE*
Hajir Pourbabak, *Student Member, IEEE*
Department of Electrical and Computer Engineering
University of Michigan-Dearborn

Wencong Su, *Member, IEEE*
Department of Electrical and Computer Engineering
University of Michigan-Dearborn
Dearborn, MI, USA

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I. Introduction

Electricity, as a flexible energy source, is still an increasingly critical infrastructure for the post-industrial, information-based world economy, even in this new century. Recently, with the high penetration of renewable energy and distributed energy resources (DERs), some electric customers with power generation capabilities can play a more active role in the reconfigurable distribution network. Smart houses or residential green buildings tend to have rooftop photovoltaic panels, wind turbines and Vehicle-to-Grid (V2G) electric vehicles to provide self-generated power. They can then sell their surplus power to others. They are not only electricity consumers, but also producers in the future electricity retail market. Thus they are called prosumers. Meanwhile, their interactions and energy utilization become increasingly complicated and should be well studied using some novel analytical tools, like game theory. And the Nikaido-Isoda function and the relaxation algorithm (NIRA) can be utilized to find the Nash Equilibrium (NE) point in the electricity market while taking price-demand elasticity into account. In this paper, a kind of economic directed method is proposed here to relieve the line pressure during the peak loading time rather than just taking into account the power loss. It also considers the line constraints in a fast effective way, such as DistFlow algorithm.

II. Key equations

$$Min\ J_i = C_i \tag{1}$$

$$Max\ J_i = (R_i - C_i) \tag{2}$$

$$C(P_i^G) = \gamma_i P_i^G \tag{3}$$

$$p_i(q_i) = \alpha_i - \beta_i q_i \tag{4}$$

$$Max\ J_i = \sum_j p_j(q_j) s_{kj} - \sum_i C(P_i^G) P_i^G \tag{5}$$

$$Z(x) = \underset{y \in X}{argmax}\ \Psi(x, y) \quad x, Z(x) \in X \tag{6}$$

$$x^{k+1} = (1-\theta_k)x^k + \theta_k Z(x^k), \quad 0 < \theta_k < 1 \tag{7}$$

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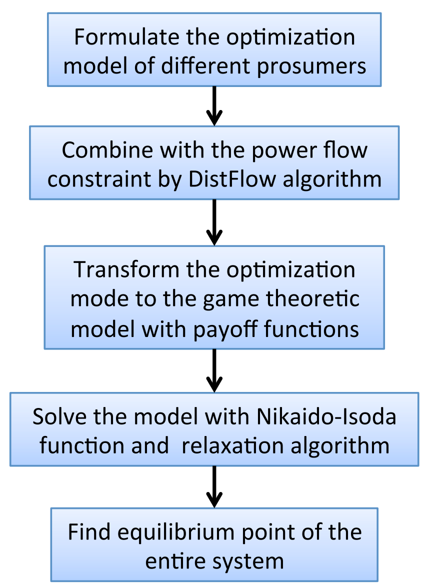

Fig. 1. The flowchart of determining the energy transaction strategies in the distribution system with multiple residential prosumers

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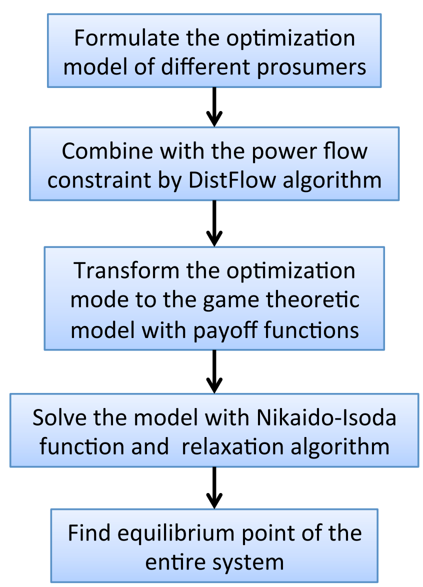

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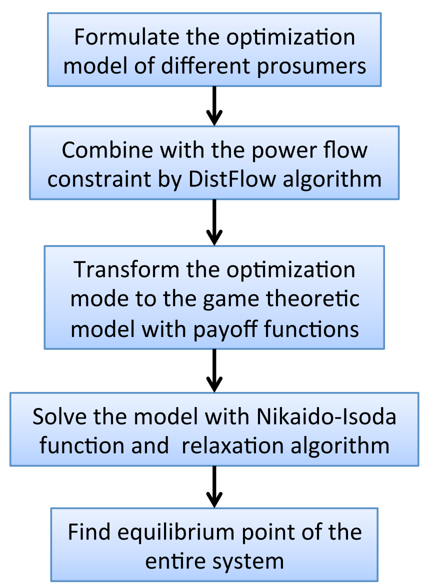

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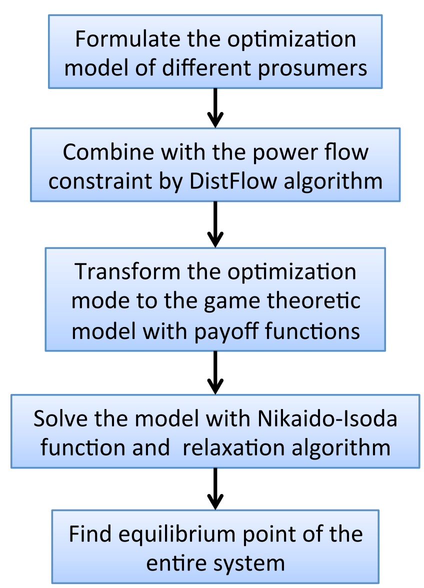

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Application of Microgrids in Addressing Distribution Network Load Ramping

Alireza Majzoobi, Amin Khodaei
Dept. of Electrical and Computer Engineering
University of Denver
Denver, CO, USA
Alireza.Majzoobi@du.edu, Amin.Khodaei@du.edu

***Abstract*—In spite of all advantages of solar energy, the deployment of this type of the renewable energy will significantly change the typical electric load profile, thus necessitating a change in traditional distribution grid management practices. In this paper, microgrids are utilized to offer a viable and local solution to this challenge while preventing costly investments from the electric utility. A microgrid optimal scheduling model is developed to ensure that the microgrid excess generation can be coordinated with the distribution grid net load to remove the associated significant variability and ramping. Numerical simulations exhibit the effectiveness of the proposed model.**

***Keywords*— Microgrid, Solar energy, duck curve, optimal scheduling, grid-connected operation.**

I. Introduction

RENEWABLE ENERGY resources have been significantly developed over the past few decades, due to significant advantages that they offer, such as reduced operation cost, air pollution reduction, and benefiting from ubiquitous source of energy. Despite these benefits, renewable energy resource challenge the traditional grid management practices, thus their likely impacts on the grid should be also considered. For instance, rapid growth of solar energy as one of the most favorable generation technologies adopted by end-use customers, has changed the typical daily demand curves. A typical daily demand curve rises in the morning and peaks in the afternoon, (especially in the summers as air conditioners are extensively used) and it hits a second highest peak in early evening. The solar energy resources, however, usually generate the highest amount of power in the afternoon and decrease toward sunset, hence they offer the capability of supplying the around-noon power demand but a marginal effect on early evening peaks. Therefore, rapid growth of solar energy has led to changing traditional afternoon peaks to afternoon valleys which followed by a steep and problematic peak in the late afternoon [1, 2].

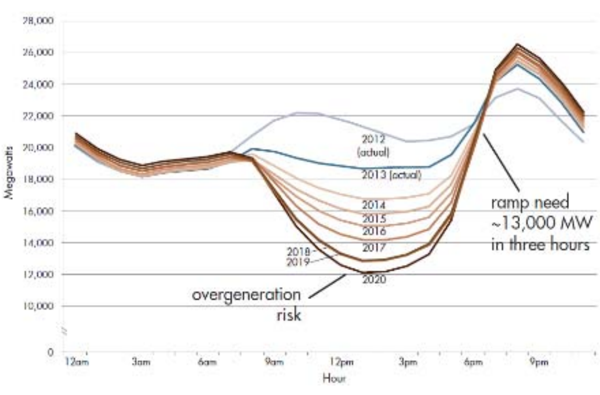

Fig1. Steep ramping in California duck curve [1].

This sever ramp-up in the new demand curve, also called "duck curve", would be a pressing issue for the utility companies as they may require additional fast response assets to respond quickly to this load ramp-up. This ramping effect becomes more severe as the solar energy penetration increases in the power grid. Fig. 1 illustrates the current and future estimates of this ramping effect in California [1, 2]. This paper proposes a new model, leveraging microgrid's ramping capability, to address this challenge.

II. Model Outline

Microgrid is considered in this paper as a viable solution for changing the demand curve and mitigating the ramping effects in distribution grids. Microgrids consist of Distributed Energy Resources (DER) and interconnected loads which can operate in both grid-connected and islanded modes [3]. In grid-connected mode, as considered here, the microgrid can export its extra generation to the grid to mitigate the sever ramping, while ensuring that the power seen by the utility has manageable ramps. To do this, two problems are modeled: first, the maximum generation ramping capability of the microgrid, defined as the microgrid generation change in two consecutive hours, is calculated, i.e., the objective (1) subject to prevailing operational constraints. Second, a model for optimal scheduling problem of microgrid in grid-connected mode is developed with the objective of minimizing the system operational cost and subject to ramping limitation constraint (2). This constraint ensures that the desirable amount of ramping, which could be managed by the utility, is achieved. The problems are modeled using mixed-integer programming and solved using CPLEX.

$$P_{Max\ ramp-up} = Max\left|P_{Mt} - P_{M(t-1)}\right| \tag{1}$$

$$\left|P_{Mt} + \sum_{j} P_{jt}\right| < \Delta_t \tag{2}$$

III. Dicsussion and Conclusion

The microgrid has been used as a solution for mitigation of net load ramping in distribution grids, which occurs due to concurrent decrease in solar generation and increase in consumers' loads. The maximum ramping of the microgrid is obtained and an optimal scheduling model is further developed for coordination of calculated maximum ramping capability with connected loads in order to alleviate the steep ramp of new demand curves.

References

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[2] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[3] S. Parhizi, H. Lotfi, A. Khodaei, S. Bahramirad, "State of the Art in Research on Microgrids: A Review", IEEE Access, Vol. 3, 2015.

Consensus-based Distributed Control for Economic Operation of Distribution Grid with Multiple Consumers and Prosumers

Hajir Pourbabak, *Student Member*, *IEEE*
Tao Chen, *Student Member*, *IEEE*
Wencong Su, *Member*, *IEEE*
Department of Electrical and Computer Engineering
University of Michigan-Dearborn
wencong@umich.edu

***Abstract*— This paper investigates the economic operation of distribution grid with multiple consumers and prosumers using consensus-based distributed control algorithms. This paper formulates the utility and cost functions of a variety of consumers and prosumers and model the interactions among multiple consumers and prosumers. The distributed control algorithms contained in this paper can apply to many other smart grid applications.**

I. Introduction

The next-generation grid is a level playing field in terms of electricity transactions, where all customers have an equal opportunity. As a result, there is a need to investigate the interactions among a number of consumers and prosumers. The existing control approaches can be divided into three categories, namely, centralized control, decentralized control, and distributed control.

The distributed control has the potential to solve the economic operation problems of multiple consumers and prosumers. The envisioned electricity market consists of multiple consumers and prosumers, as shown in Fig. 1. We will consider the mathematical models of utility and cost functions for various consumers and prosumers.

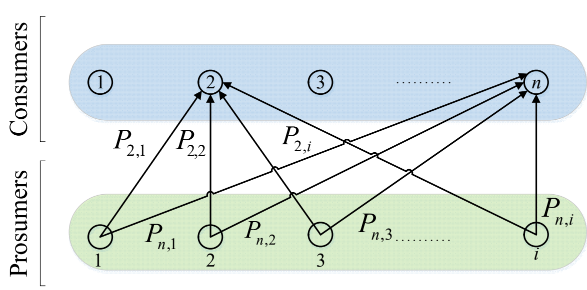


Fig. 1. The schematic model of multi consumer and prosumer

Equation (1) models the quadratic utility function $U_n(P_{n,i})$ for different consumers and Equation (2) shows the quadratic cost function for the i-th prosumer.

$$U_n(P_{n,i}) = \begin{cases} \omega_n P_{n,i} - b_n P_{n,i}^2 & P_{n,i} < \omega_n/2b_n \\ \omega_n^2/4b_n & P_{n,i} \geq \omega_n/2b_n \end{cases} \quad (1)$$

$$C_i(P_{n,i}) = \alpha_i P_{n,i}^2 + \beta_i P_{n,i} + \mathcal{X}_i \quad (2)$$

As our first case, we scale up the test system to consider four consumers and four prosumers.

The Lagrange multipliers (incremental costs) for sub-problems are shown in Fig. 2. Table II compares the proposed distributed method with the centralized method. The results of distributed method are the same as that using centralized method.

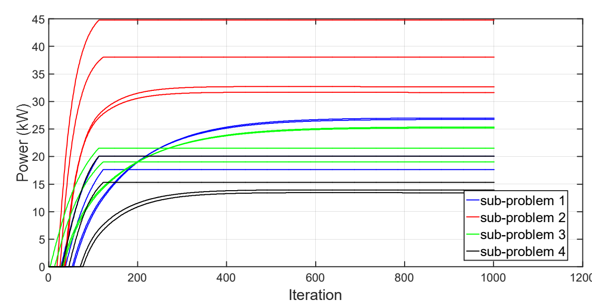


Fig. 2. Generation Output Power of Prosumers for Sub-problems in Case

Table II: Benchmarking Comparison with Distributed methods

Prosumers	Distributed Method	Centralized Method
Optimal Incremental Cost (cent/kW)		
1	9.3202	9.3247
2	9.9725	9.9785
3	8.7685	8.7684
4	8.2310	8.2312
Optimal Output Power (kW)		
1	99.4230	99.1408
2	97.4708	97.8692
3	90.0391	90.0300
4	106.4299	106.4100

Synchrophasor Reference Algorithm for PMU Calibration System

Cheng Qian, *Graduate Student Member, IEEE*, Mladen Kezunovic, *Fellow, IEEE*

Dept. of Electrical and Computer Engineering

Texas A&M University, College Station, TX

peterqiancheng@tamu.edu, kezunov@ece.tamu.edu

***Abstract*— This paper describes a reference algorithm specifically designed for PMU Calibration System. Contrary to existing DFT-based and curve fitting-based methods, which use a single signal model, the proposed algorithm applies an adaptive mechanism, and switches signal models according to specific signal input. Signals are modeled with parameters with apparent and certain physical meaning, fundamentally avoiding error magnification from derivative calculation for frequency and rate of change of frequency estimation. Levenberg-Marquardt algorithm is used for solving the signal parameters. The test results show that the proposed algorithm has a much higher accuracy than the requirements of IEEE standard C37.118.1, and hence can serve as a reference algorithm in a PMU Calibration System.**

Keywords*— *Levenberg-Marquardt algorithm, PMU calibration system, reference synchrophasor algorithm, synchrophasor estimation, power system measurements.

I. Methods and Key Equations

Levenberg-Marquardt algorithm is the key to the algorithm, as shown in (1)

$$\Delta \boldsymbol{x}^{(i)} = \left[\boldsymbol{J}^{(i)T}\boldsymbol{J}^{(i)} + \mu^{(i)}\mathrm{diag}\left(\boldsymbol{J}^{(i)T}\boldsymbol{J}^{(i)}\right)\right]^{-1}\boldsymbol{J}^{(i)T}\left[\boldsymbol{b} - f\left(\boldsymbol{t}, \boldsymbol{x}^{(i)}\right)\right] \quad (1)$$

Signal models determine the Jacobian matrix $\boldsymbol{J}$, as listed.

A. Model for Static , Step, and Frequency Ramp Signals

$$x(t) = \sqrt{2}X_{rms}\cos\left(2\pi f_0 t + 2\pi\Delta f t + \pi R_f t^2 + \varphi_0\right) \quad (2)$$

B. Model for Harmonic Distorted and Out-of-Band Signals

$$x(t) = \sqrt{2}X_{rms}\cos\left(2\pi f_0 t + 2\pi\Delta f t + \pi R_f t^2 + \varphi_0\right) + \sqrt{2}X_{rms,har}\cos\left(2\pi k f_0 t + 2\pi k \Delta f_{har} t + \varphi_{0,har}\right) \quad (3)$$

C. Model for Modulation *Signals*

$$x(t) = \sqrt{2}X_{rms}[1 + k_m\cos(2\pi f_m t)] \cos[2\pi f_0 t + 2\pi\Delta f t + k_a\cos(2\pi f_m t - \pi) + \varphi_0] \quad (4)$$

II. Key Figures

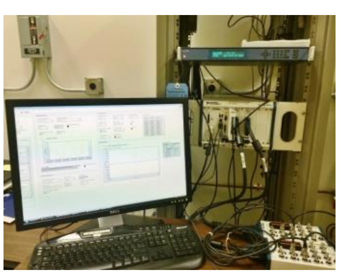


Fig. 1. Reference PMU Test System at Texas A&M University

This work was supported by the Power Systems Engineering Research Center (PSERC) Project T-57HI "Life-cycle management of mission-critical systems through certification, commissioning, in-service maintenance, remote testing, and risk assessment"

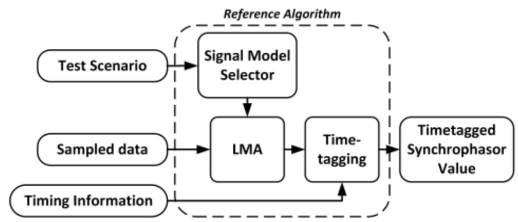


Fig. 2. Procedure of synchrophasor estimation with proposed algorithm

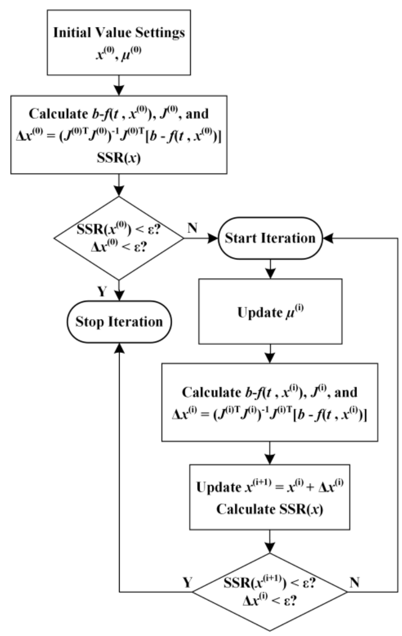


Fig. 3. Flowchart of Reference Algorithm

III. Key Results

TABLE I. Algorithm Accuracy in Implementation Tests

Test Type	TVE/IEEE (%)	Frequency/IEEE (Hz)	ROCOF/IEEE (Hz/s)
Steady-state test	0.01%/1%	0.0004/0.005	5×10^{-4}/0.1
Harmonic test	0.01%/1%	0.002/0.005	10^{-3}/0.4 (P)
OOB test	0.01%/1%	0.002/0.005	10^{-3}/0.4 (P)
Frequency ramp test	0.04%/1%	0.002/0.01	4×10^{-4}/0.2
Modulation test	0.09%/3%	0.012/0.06	0.2/2

Synchrophasor Reference Algorithm for PMU Calibration System

Cheng Qian, *Graduate Student Member, IEEE*, Mladen Kezunovic, *Fellow, IEEE*
Dept. of Electrical and Computer Engineering
Texas A&M University, College Station, TX
peterqiancheng@tamu.edu, kezunov@ece.tamu.edu

***Abstract*— This paper describes a reference algorithm specifically designed for PMU Calibration System. Contrary to existing DFT-based and curve fitting-based methods, which use a single signal model, the proposed algorithm applies an adaptive mechanism, and switches signal models according to specific signal input. Signals are modeled with parameters with apparent and certain physical meaning, fundamentally avoiding error magnification from derivative calculation for frequency and rate of change of frequency estimation. Levenberg-Marquardt algorithm is used for solving the signal parameters. The test results show that the proposed algorithm has a much higher accuracy than the requirements of IEEE standard C37.118.1, and hence can serve as a reference algorithm in a PMU Calibration System.**

Keywords*— Levenberg-Marquardt algorithm, PMU calibration system, reference synchrophasor algorithm, synchrophasor estimation, power system measurements.

I. Methods and Key Equations

Levenberg-Marquardt algorithm is the key to the algorithm, as shown in (1)

$$\Delta \boldsymbol{x}^{(i)} = \left[\boldsymbol{J}^{(i)T}\boldsymbol{J}^{(i)} + \mu^{(i)}\mathrm{diag}\left(\boldsymbol{J}^{(i)T}\boldsymbol{J}^{(i)}\right)\right]^{-1}\boldsymbol{J}^{(i)T}\left[\boldsymbol{b} - f\left(\boldsymbol{t}, \boldsymbol{x}^{(i)}\right)\right] \quad (1)$$

Signal models determine the Jacobian matrix $\boldsymbol{J}$, as listed.

A. Model for Static , Step, and Frequency Ramp Signals

$$x(t) = \sqrt{2}X_{rms}\cos\left(2\pi f_0 t + 2\pi\Delta f t + \pi R_f t^2 + \varphi_0\right) \quad (2)$$

B. Model for Harmonic Distorted and Out-of-Band Signals

$$x(t) = \sqrt{2}X_{rms}\cos\left(2\pi f_0 t + 2\pi\Delta f t + \pi R_f t^2 + \varphi_0\right) + \sqrt{2}X_{rms,har}\cos\left(2\pi k f_0 t + 2\pi k\Delta f_{har} t + \varphi_{0,har}\right) \quad (3)$$

C. Model for Modulation *Signals*

$$x(t) = \sqrt{2}X_{rms}[1 + k_m\cos(2\pi f_m t)] \cos[2\pi f_0 t + 2\pi\Delta f t + k_a\cos(2\pi f_m t - \pi) + \varphi_0] \quad (4)$$

II. Key Figures

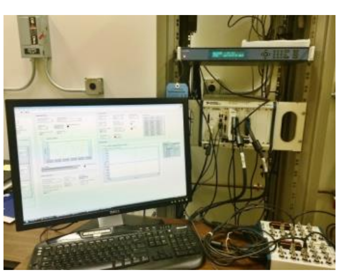


Fig. 1. Reference PMU Test System at Texas A&M University

This work was supported by the Power Systems Engineering Research Center (PSERC) Project T-57HI "Life-cycle management of mission-critical systems through certification, commissioning, in-service maintenance, remote testing, and risk assessment"

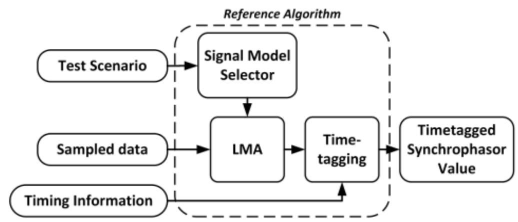


Fig. 2. Procedure of synchrophasor estimation with proposed algorithm

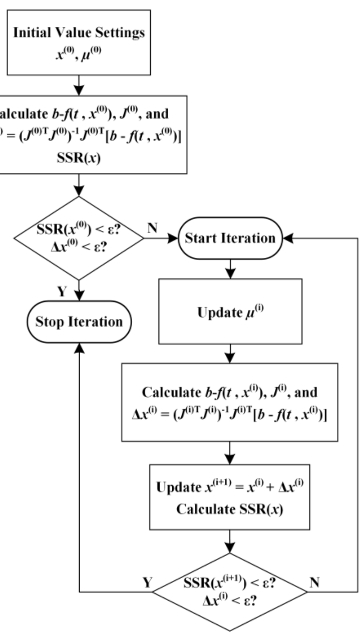


Fig. 3. Flowchart of Reference Algorithm

III. Key Results

TABLE I. Algorithm Accuracy in Implementation Tests

Test Type	TVE/IEEE (%)	Frequency/IEEE (Hz)	ROCOF/IEEE (Hz/s)
Steady-state test	0.01%/1%	0.0004/0.005	5×10^{-4}/0.1
Harmonic test	0.01%/1%	0.002/0.005	10^{-3}/0.4 (P)
OOB test	0.01%/1%	0.002/0.005	10^{-3}/0.4 (P)
Frequency ramp test	0.04%/1%	0.002/0.01	4×10^{-4}/0.2
Modulation test	0.09%/3%	0.012/0.06	0.2/2

Flexible Implementation of Power System Topology Control in Smart Electricity Grids

Payman Dehghanian, *Student Member, IEEE*, Yaping Wang, Gurunath Gurrala, *Member, IEEE*, Erick Moreno-Centeno, and Mladen Kezunovic, *Fellow, IEEE*

***Abstract*—This paper proposes a novel framework for optimal transmission switching satisfying the AC feasibility, stability and circuit breaker (CB) reliability requirements needed for practical implementation. The proposed framework can be employed as a corrective tool in day to day operation planning scenarios, in response to possible contingencies. The switching options are determined using an efficient heuristic algorithm taking into account the DC optimal power flow, resulting in a binary tree structure. Then, the AC feasibility and stability checks are conducted and the CB condition monitoring data is employed to perform a CB reliability and line availability assessment. Ultimately, the operator will be offered multiple AC feasible and stable switching options with associated benefits. The operator can use this information, other operating conditions not explicitly considered in the optimization, and his/her own experience to implement the best and most reliable switching action(s). The effectiveness of the proposed approach is validated on the IEEE-118 bus test system.**

***Index Terms*— Circuit breaker (CB); heuristic; load shed recovery (LSR); optimization; reliability; transmission switching.**

I. Introduction

THOUGH being performed for decades on a very limited scale with rather focused aims, transmission switching has recently gained further importance with the increased penetration of renewable energy resources and the growing demand for more reliable operation of power systems. It has been shown that various operating conditions can be tackled through transmission switching: voltage violations and overloading conditions as a result of possible contingencies, network losses and congestion management, security enhancement, reliability improvements, and also cost reduction for economic benefits.

The focus of this paper is to propose a corrective transmission switching framework to be used in day to day operation planning scenarios in response to system probable contingencies. It incorporates AC feasibility, stability and CB reliability requirements for practical implementation of switching actions. The proposed framework in this paper provides several switching options per contingency in a tree-like structure. At each level of the switching tree, the framework suggests the operator with a set of AC feasible and stable switching plans based on a selected optimization criterion such as minimum generation cost or maximum Load Shed Recovery, etc. This paper also proposes a decision making support tool based on a CB failure probability assessment technique using condition monitoring data. This quantifies the benefits due to each switching action in the tree. The operator can use this information, other operating conditions not explicitly considered in the optimization, and his/her own experience to select the best and most reliable switching action at each level of the switching tree for implementation. Therefore, this paper aims at bridging the gap between the theoretical advancements in transmission line switching and the day to day implementation practices.

This work was financially supported by the Advanced Research Project Agency-Energy (ARPA-E) under the Green Electricity Network Integration (GENI) project "Robust Adaptive Transmission Control".

II. Proposed Framework

The proposed framework is generally demonstrated in Fig. 1. A simple example shown in Fig. 2 is used to illustrate how a three-level Binary Switching Tree (BST) is constructed. In this figure, each box denotes a tree node (i.e. a system state); the node number and the corresponding load shed recovery (LSR) percentage (included in parentheses) are provided in each box.

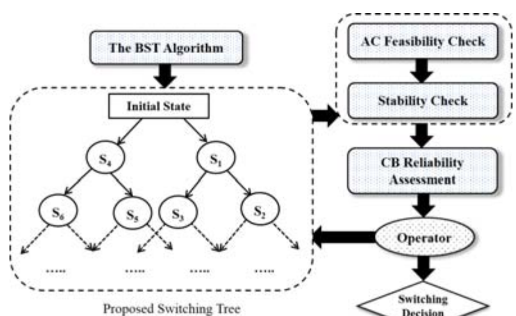


Fig. 1. The overall framework proposed for transmission line switching.

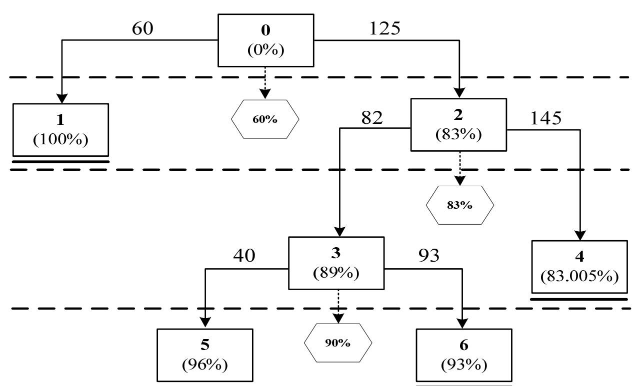


Fig. 2. Example illustrating the BST construction.

Optimal Generation Expansion Plan Under CO_2 Emission Reduction Mechanisms

Yuqian Song, and Jin Zhong
Department of Electrical and Electronic Engineering
The University of Hong Kong,Hong Kong SAR
E-mail: yqsong@eee.hku.hk

***Abstract*—Generation Expansion Planning (GEP) problem is a complex, computational consuming problem in power systems. Conventionally, several factors such as investment cost, operation and maintenances cost is taken into consideration when formulating this problem. As global-warming effect is now drawing more and more concerns, and a series of regulatory instruments of emission reduction are implemented around the world, the cost of emission abatement has now become a factor that is not to be neglected. This paper develops a model with 20-year horizon, takes account the features of different generation technologies, and investigates different CO_2 emission reduction mechanisms including carbon tax, feed-in tariff, and cap & trade mechanism. The optimal investment plans under each mechanism are obtained. By comparing the simulation result, how the regulatory instruments influence the GEP problem and the effectiveness of each mechanism is discovered.**

I. PROBLEM FORMULATION

By minimizing the cost of 20-year GEP problem, the optimal investment strategies are obtained corresponding to different emission reduction mechanisms as well as different implementing scenarios of each mechanism (slack and strict cases). The simulation result shows some interesting conclusions of the effectiveness of each mechanism.

II. KEY EQUATIONS

Objective:

$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG} F = \min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[C(P_{Gi,y}) + (w_{i,y} \times P_{INV\,i} \times LCOE_{type})\right] \tag{1}$$

$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[F + Tax \times E(P_{Gi,y})\right] \tag{2}$$

$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[F - FIT_{type}(P_{Gi,y})\right] \tag{3}$$

$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[F + (P_{ex\,y} \times \rho_{ex\,y}) - (Q_{al\,y} \times \sigma_{al\,y})\right] \tag{4}$$

III. SIMULATION RESULTS

Table I. –Investment Plan under Different Emission Reduction Mechanisms

Year	B	LT	HT	LF	MF	HF	CAP
1	0	0	2*cl	0	0	cl	2*cl
2	0	0	0	0	0	0	re
3	0	0	0	0	0	0	re
4	0	0	0	0	0	0	re
5	0	0	0	0	0	0	re
6	0	0	re	0	0	0	0
7	0	0	re	0	0	0	0
8	0	0	re	0	0	0	0
9	0	0	re	0	0	0	cl
10	0	0	0	0	0	0	re
11	0	0	0	0	0	0	2*re
12	0	0	0	0	0	0	0
13	cl+ct	2*cl	0	cl+ct	cl	0	0
14	ct	ct	0	ct	ct	ct	0
15	0	cl+ct	0	0	ct	re+ct	0
16	ct	ct	ct	ct	0	ct	0
17	ct	0	0	ct	ct	cl	ct
18	ct	ct	cl+ct	0	ct	ct	ct
19	cl	0	ct	2*cl	cl	3*re	ct
20	2*cl	ct	ct	ct	2*cl +ct	2*cl	2*cl

In the table, re, cl and ct represent for the investment decision of renewable energy unit, clean energy unit and conventional generation unit respectively. The items in table head represent for base case, low tax, high tax, low FIT, medium FIT, high FIT, and cap & trade respectively.

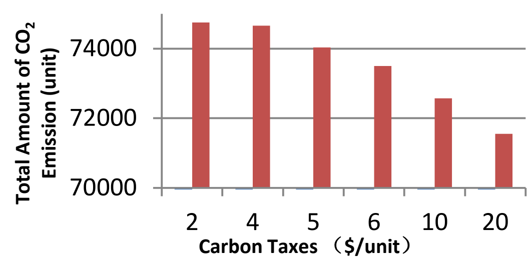


Figure I. Carbon Dioxide Emission under Different Carbon Taxes

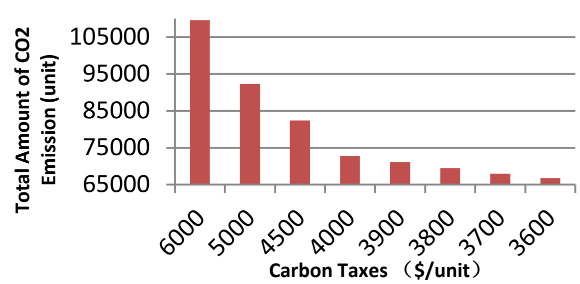


Figure II. Carbon Dioxide Emission under Different Cap

Optimal Generation Expansion Plan Under CO_2 Emission Reduction Mechanisms

Yuqian Song, and Jin Zhong
Department of Electrical and Electronic Engineering
The University of Hong Kong,Hong Kong SAR
E-mail: yqsong@eee.hku.hk

Abstract**—Generation Expansion Planning (GEP) problem is a complex, computational consuming problem in power systems. Conventionally, several factors such as investment cost, operation and maintenances cost is taken into consideration when formulating this problem. As global-warming effect is now drawing more and more concerns, and a series of regulatory instruments of emission reduction are implemented around the world, the cost of emission abatement has now become a factor that is not to be neglected. This paper develops a model with 20-year horizon, takes account the features of different generation technologies, and investigates different CO_2 emission reduction mechanisms including carbon tax, feed-in tariff, and cap & trade mechanism. The optimal investment plans under each mechanism are obtained. By comparing the simulation result, how the regulatory instruments influence the GEP problem and the effectiveness of each mechanism is discovered.**

I. Problem Formulation

By minimizing the cost of 20-year GEP problem, the optimal investment strategies are obtained corresponding to different emission reduction mechanisms as well as different implementing scenarios of each mechanism (slack and strict cases). The simulation result shows some interesting conclusions of the effectiveness of each mechanism.

II. Key Equations

Objective:

$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG} F = \min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[C(P_{Gi,y}) + (w_{i,y} \times P_{INV\,i} \times LCOE_{type})\right] \tag{1}$$

$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[F + Tax \times E(P_{Gi,y})\right] \tag{2}$$

$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[F - FIT_{type}(P_{Gi,y})\right] \tag{3}$$

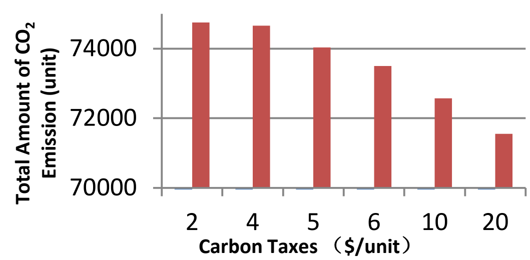
$$\min \sum_{y=1}^{20}\sum_{i=1}^{NG}\left[F + (P_{ex\,y} \times \rho_{ex\,y}) - (Q_{al\,y} \times \sigma_{al\,y})\right] \tag{4}$$

III. Simulation Results

Table I. –Investment Plan under Different Emission Reduction Mechanisms

Year	B	LT	HT	LF	MF	HF	CAP
1	0	0	2*cl	0	0	cl	2*cl
2	0	0	0	0	0	0	re
3	0	0	0	0	0	0	re
4	0	0	0	0	0	0	re
5	0	0	0	0	0	0	re
6	0	0	re	0	0	0	0
7	0	0	re	0	0	0	0
8	0	0	re	0	0	0	0
9	0	0	re	0	0	0	cl
10	0	0	0	0	0	0	re
11	0	0	0	0	0	0	2*re
12	0	0	0	0	0	0	0
13	cl+ct	2*cl	0	cl+ct	cl	0	0
14	ct	ct	0	ct	ct	ct	0
15	0	cl+ct	0	0	ct	re+ct	0
16	ct	ct	ct	ct	0	ct	0
17	ct	0	0	ct	ct	cl	ct
18	ct	ct	cl+ct	0	ct	ct	ct
19	cl	0	ct	2*cl	cl	3*re	ct
20	2*cl	ct	ct	ct	2*cl +ct	2*cl	2*cl

In the table, re, cl and ct represent for the investment decision of renewable energy unit, clean energy unit and conventional generation unit respectively. The items in table head represent for base case, low tax, high tax, low FIT, medium FIT, high FIT, and cap & trade respectively.



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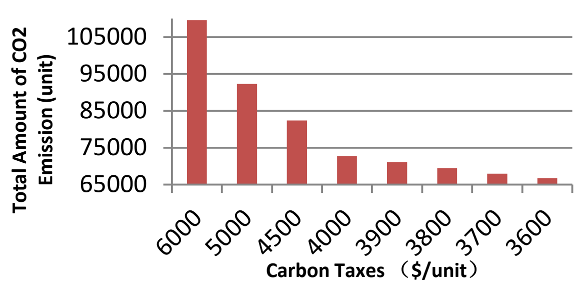

Figure II. Carbon Dioxide Emission under Different Cap

Frequency Scanning Techniques for Subsynchronous Resonance Screening Analysis

Hardik Parikh[1], *Student Member, IEEE* and Billy Yancey[2], *Member, IEEE*

***Abstract*—Subsynchronous Resonance (SSR) is a well known phenomenon that is observed in the conventional energy generation and wind farm sites. SSR is more prone to generation sites that are directly connected to the series compensated transmission lines. Series compensation is required to improve the voltage profile and reduce transmission losses of the transmission lines. The work presented here aims to highlight the potential causes, the system configurations and the methods that are used to identify SSR. The main focus of the poster is to outline frequency scan techniques that are based on the small signal perturbation method. The analysis generally employs Electro Magnetic Transient Program (EMTP). This technique provides the spectrum of frequency response to resistance and reactance. Finally, based on that we deduce the damping provided by the system, and thereby the SSR risk to the project.**

***Index Terms*—Frequency Scan; Subsynchronous Resonance (SSR); Series compensation; Grid; Contingency; Perturbations; Electro Magnetic Transient Program (EMTP)**

I. Introduction

WITH the development and implementation of Series compensation techniques improve the voltage profile, the SSR phenomenon has attracted a lot attention.

It is further classified in classical Subsynchronous Resonance (SSR), Subsynchronous Torsional Interactions (SSTI) and Subsynchronous Control Interaction (SSCI). When a series capacitor is added into a transmission line, it creates a resonant frequency. This is not a problem as long as energy is not injected at the resonant frequency. However, an interconnection which injects power at the resonant frequency can lead to severe damage to generation equipments connected to the main grid system. Following the increased events of SSR many regulatory authorities have made mandatory screening studies to identify the possibility of exposure to SSR and protection techniques to avoid any possibilities for such occurrence. In general screening analysis includes the frequency scan techniques [1], Small signal analysis, Electromagnetic transient analysis, Admittance matrix [2] methods.

[1] The University Of Texas at Arlington, Arlington, TX 76013,USA
Email: hardik.parikh@mavs.uta.edu

[2] Electric Power Engineers Inc., Austin, TX 78738, USA
Email:byancey@epeconsulting.com

II. Frequency scanning techniques for SSR

The frequency scan technique is one of the method to identify SSR susceptibility. This technique considers small signal perturbation method. Small signal current signals are injected into the system under study. The screening analysis is performed for turbine side and grid side to identify the natural frequency response. The analysis considers the resistance and reactance vs. frequency plots. The turbine side scan is shown in Figure 1 and the grid side scan is shown in Figure 2. The analysis focuses on reactance zero crossing event. The system must have sufficient resistance to damp out any oscillation that may happen at that point. If the system doesn't have sufficient resistance at that point; it may be subject to higher SSR vulnerability. Detailed EMTP type models are also developed for SSR study that considers system contingencies, faults, shunt compensation and series compensation configurations.

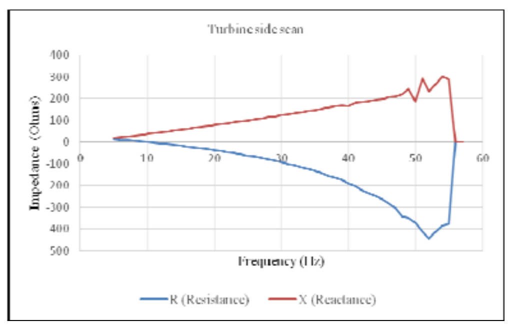

Fig. 1. Turbine side frequency scan (100% dispatch)

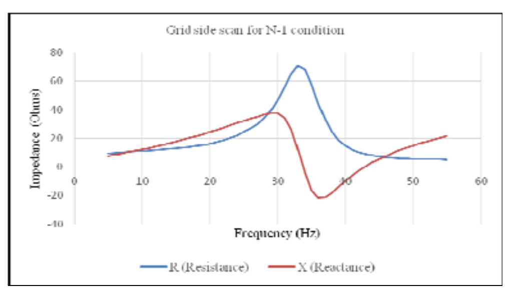

Fig. 2. Grid side frequency scan (N-1 contingency)

References

[1] Sahni, M., Muthumuni, D., Badrzadeh, B., Gole, A., & Kulkarni, A., "Advanced screening techniques for sub-synchronous interaction in wind farms," in *Transmission and Distribution Conference and Exposition (T&D), 2012 IEEE PES* (pp. 1-9).

[2] Badrzadeh, B., Sahni, M., Muthumuni, D., Zhou, Y., & Gole, A., "Sub-synchronous interaction in wind power plants—part I: Study tools and techniques," in *Power and Energy Society General Meeting, 2012 IEEE* (pp. 1-9).

Distance Relay Settings Adequacy Assessment for an Evolving Network Topology

M. Tasdighi, *Student Member, IEEE*, and M. Kezunovic, *Fellow, IEEE*

***Abstract*—A challenge raised in today's power system is assessing the system protection security and dependability after the topology has been changed due to relay operation upon occurrence of cascading faults or intentional operator switching actions. This paper proposes an automated setting calculation module which could be used to review the adequacy of the distance relay settings following network topology changes. The calculation procedure is broken down into blocks which could be processed in parallel in order to improve the computation speed. A new concept called distance-of-impact (DoI) is proposed to reduce the computational burden by conducting the calculations on a limited portion of the network affected by the topology change. The module performance is tested on synthetic IEEE 118-bus and real-life Alberta transmission operator systems. A sensitivity analysis in the form of N-2 contingency impact on the network relay settings coordination is conducted on the test systems.**

***Keywords*—Distance-of-impact (DoI), power system protection security and dependability, N-2 contingency, phase distance settings, relay ranking, topology control, vulnerability.**

I. Key Figures

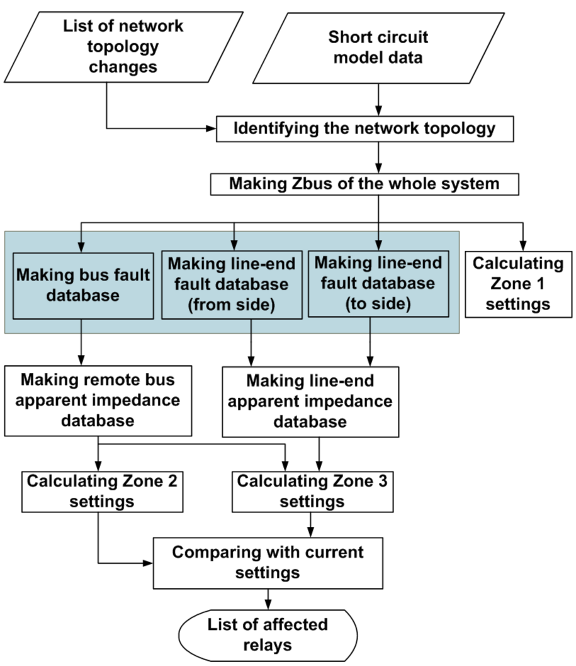

Figure 1. General flowchart of the relay setting calculation module

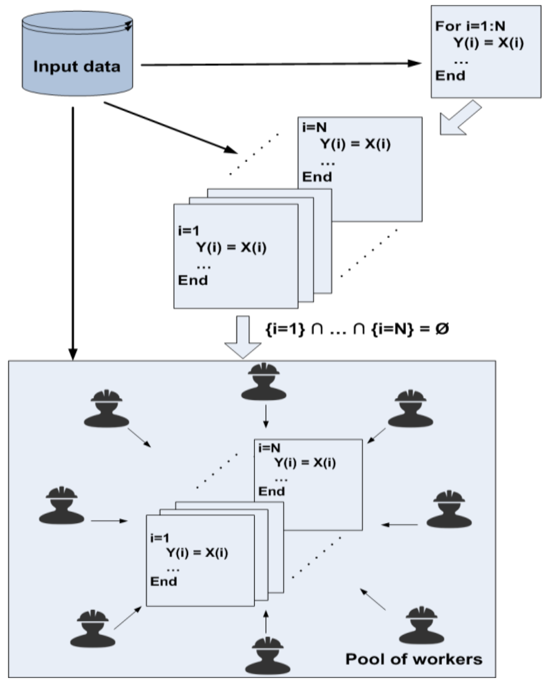

Figure 2. General implementation of parallel computation for N tasks

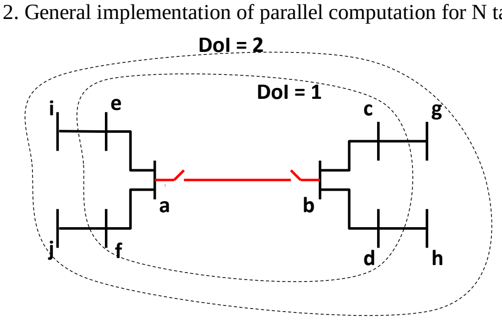

Figure 3. Illustrating the concept of DoI

II. Key Results

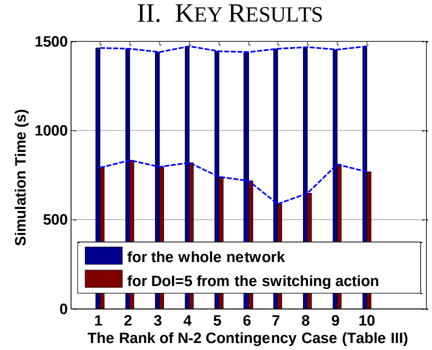

Figure 8. Simulation time comparison between with and without implementing DoI while deploying 30 processors on Alberta System

M. Tasdighi and M. Kezunovic are with Department of Electrical and Computer Engineering, Texas A&M University, Texas, USA. (E-mail: m.tasdighi@tamu.edu; kezunov@ece.tamu.edu).

The financial support for this research comes from the Advanced Research Projects Agency-Energy (ARPA-E), U.S. Department of Energy (DOE), under the Green Electricity Network Integration (GENI) project "Robust Adaptive Topology Control", ARPA-E award no. DE-AR0000220.

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[1] M. Tasdighi and M. Kezunovic, "Automated Review of Distance Relay Settings Adequacy After the Network Topology Changes," *IEEE Transactions on Power Delivery*, DOI: 0.1109/TPWRD.2016.2524654.

Optimal Power Flow-Based Generation Shedding for Dynamic Remedial Action Scheme

Arun Shrestha, *Student Member, IEEE,* Valentina Cecchi, *Member, IEEE,* and Robert W. Cox, *Member, IEEE*

***Abstract*—An optimal power flow (OPF)-based generation shedding for dynamic remedial action scheme (RAS) is proposed in this paper. A straightforward generation-shedding cost function is developed using pre-RAS and post-RAS OPF costs. The proposed method updates RAS control actions online based on the system operating conditions and cost functions. The proposed method is tested on a modified IEEE 39-Bus system. Test results demonstrate effectiveness of the proposed generation-shedding method.**

I. Introduction

In North America, the power systems are planned and operated to withstand the loss of any single or multiple elements without violating North American Electric Reliability Corporation (NERC) system performance criteria. For a contingency resulting in the loss of multiple elements (Category C), emergency transient stability controls like load shedding or generation shedding may be necessary to stabilize the power system. Emergency control is designed to sense abnormal conditions and subsequently take pre-determined remedial actions to prevent instability. Commonly known as Remedial Action Schemes (RAS), these emergency control approaches have been extensively adopted by utilities.

Previous research on generation-shedding RAS schemes are focused towards determining the minimum amount of generation to shed. In this paper, an OPF-based generation-shedding RAS is proposed. This scheme uses online stability calculations and generator cost functions to determine appropriate remedial actions. Unlike conventional RAS, which are designed using offline simulations, online stability calculations make the proposed RAS dynamic and adapting to any power system configuration and operating state. The generation-shedding cost is calculated using pre-RAS and post-RAS OPF costs. The criteria for selecting generators to trip is based on the minimum cost rather than minimum amount of generation to shed. For an unstable Category C contingency, the RAS control action that results in stable system with minimum generation-shedding cost is selected among possible candidate solutions. The RAS control actions update whenever there is a change in operating condition, system configuration, or cost functions.

II. OPF-Based Generation-Shedding Selection

The generation-shedding cost F_{GSi} is defined as:

$$F_{GSi} = f(P_{Gi,Post-RAS}) - f(P_{Gi,Pre-RAS}) \tag{1}$$

A. Shrestha, V. Cecchi, and R. Cox are with the Electrical and Computer Engineering Department and the Energy Production and Infrastructure Center (EPIC) at the University of North Carolina at Charlotte, Charlotte, NC 28223 USA (e-mail: ashrest1@uncc.edu, vcecchi@uncc.edu, robert.cox@uncc.edu).

where,

$$f(P_{Gi,Pre-RAS}) = \quad \text{Min} \sum_{i=1}^{NG} F_{Gi} \tag{2}$$

$$f(P_{Gi,Post-RAS}) = \quad \text{Min} \sum_{i=1,\ i \neq CS}^{NG} F_{Gi} \tag{3}$$

Hence, the critical generators to shed (CS) are selected such that the generation-shedding cost is minimized, the system remains stable following the contingency, and the operating constraints are not violated in the post-RAS period.

$$\text{Min} \quad F_{GSi}(i \in C) \tag{4}$$

The RAS choice, MW shed, post-RAS OPF cost, and generation-shedding cost for Test Case 2 are tabulated in Table I. Fig. 1 shows the OMIB P-δ and generator rotor angles for the G71 RAS choice. The RAS choice of G71 results in a stable system with minimum generation-shedding cost. It is noted that the MW shed during G71 generation shedding is greater than the G51. This shows that shedding minimum generation for system stability might not always be the most economical choice.

TABLE I
Generation-Shedding Cost For Test Case 2 ($/h)

RAS Choice	MW Shed	Post-RAS OPF Cost ($/h)	Gen Shed Cost($/h)	Transient Stability
G71	227.18	67,452.70	1322.10	Stable
G51	197.43	67,646.50	1515.90	Stable
G41	220.92	67,969.10	1838.50	Unstable
G71, G72	454.36	68,674.60	2544.00	Unstable
G51, G52	394.86	69,021.70	2891.10	Stable
G61	418.52	69,275.20	3144.60	Stable
G41, G42	441.84	69,695.60	3565.00	Unstable
G51, G52, G53	592.29	70,524.80	4394.20	Stable
G41, G42, G43	662.76	71,582.80	5452.20	Unstable
G61, G62	837.04	72,729.10	6598.50	Unstable

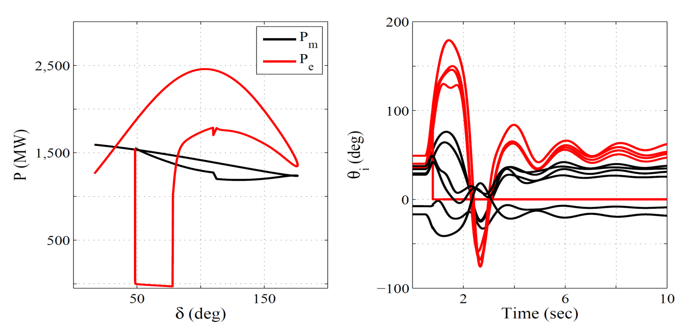


Fig. 1. OMIB P-δ curve and generator rotor angles for G71 RAS choice. Shedding generators G71 stabilizes the system.

Real Time Data Mining Techniques for Anomaly Detection in Syncrophasor Data at PDC

D.Williams, S.Warner, T.Golberg, T. McGrew, S.Thomas, Y. Wu, A. Srivastava
Washington State University, Pullman, Washington, USA

***Abstract*—Phasor Measurement Units (PMU) have become the forefront of smart grid measuring devices stemming from their high rate of data sampling and signal processing for real time monitoring of power system operation. Although important for the future of power system automation and protection, PMUs present challenges for Wide Area Monitoring System (WAMS) implementation arising from network security, signal noise and communication issues. We evaluate two techniques that allow for anomaly detection in PMU data streams to enable real time control and dynamic event detection seen during power system operation. Developed techniques also enable high data quality utilized for substation level applications and Energy Management System (EMS) applications running in control centers.**

Keywords— PMU, PDC, WAMS, Dynamic Event Analysis, Smart Grid, Data Anomaly

I. INTRODUCTION

With a need for data cleaning applications in WAMS for early stage bad data and event detection, we present two methods for anomaly detection in PMU data streams implemented in decentralized Phasor Data Concentrator (PDC) at substations. Our research aims to validate the efficiency and accuracy that can be achieved from data mining algorithms used in time series applications and provide new methods that ultimately will further our ability to detect bad data and monitor our power system in real time reliably. Developed data mining approaches implemented in OpenPDC are validated using synthetic data generated using an industrial PMU connected to simulated data anomalies generated by modeled power system test cases in Real Time Digital Simulator (RTDS).

II. METHODOLOGY

"Anytime Algorithms" provide the ability to terminate application at any given point in a data stream, allowing for analysis to be conducted at any level of completed computation. Combined with wavelet based properties, we are able to enhance the level of computational analysis to achieve the highest accuracy of anomalies flagged in the evaluated data set. This presents the ability to detect variations of different events seen in PMU data streams, ranging from incomplete data to dynamic events in power system operation. We evaluate "Haar Wavelet and K-means" which is a clustering approach and "Haar Wavelet and Chebyshev" which is a linear regression method; both give us the ability to detect data anomalies in time series applications, therefore they are optimal choices for our use for data cleaning.

This work is supported by the US Department of Energy (DOE).

III. FIGURES & KEY EQUATIONS

TABLE I. Haar and K-Means Algorithm

1.)	Read synchrophasor Data Measurement Set X
2.)	Initialization of "k". n is the number of points in data points in set X. $k \approx \sqrt{\frac{n}{2}}$
3.)	Choose random data from X as initial centroid
4.)	Compute the distance d(x) of your initial centroid and all other data points x
5.)	Determine a new centroid from the remaining centroids using the probability equation. D(x) denotes the shortest distance between a data point and closest center. $\frac{D(x)^2}{\sum x \varepsilon^{x D(x)}}$
6.)	Update d(x) as the distance between a data point and the nearest centroid
7.)	Starting at next level i, use the Euclidean Distance formula to calculate the distance between x_i And the determined centroid c_i.
8.)	Calculate mean of clusters based on data convergence towards centroids, to update cluster value.
9.)	Using final centers from previous level as new initial centers, we project centers returned by using 2^i space in the 2^{i+1} space.
10.)	Check membership changes.
11.)	Output flagged outliers determined from multi-level clustering. Move to next window.

TABLE II. Haar and Chebyshev Algorithm

1.)	Read in X data series from window.
2.)	Determine initial level one probability P_i.
3.)	For level one, solve for k using Chebyshev's inequality for upper and lower bounds. X is the data in the read in, μ is the data mean, σ is the standard deviation of the data, and k is the number of standard deviations from the mean. Upper: $P\left(\lvert X-\mu\rvert \geq k\sigma \leq \frac{1}{k^2}\right)$ Lower: $P\left(\lvert X-\mu\rvert \leq k\sigma \geq (1-\frac{1}{k^2}\right)$ k=$\frac{1}{\sqrt{p_1}}$
4.)	After determining σ and μ, solve for initial ODV (Outlier Detection Values) from the set for upper and lower bounds. ODV $1U = \mu + k + \sigma$ ODV $1L = \mu - k + \sigma$
5.)	Determine Level two probability using the multiple of stage one probability. Ex. $P_1 = .10 \rightarrow P_2 = .010$
6.)	Using the new probability value, determine bounds and solve for ODV's of level two as performed in the initial stages. Repeat 3-5 Until Desired level of stages are derived.
7.)	Flag data anomalies found outside of derived bounds. Continue to next window.

IV. FUTURE WORK

We are prepared to conduct a three stage testing sequence on our chosen methods to validate their accuracy when applied on PMU data sets. Stage one consists of offline testing, applying predefined data sets consisting of PMU anomalies and events. The final two stages will evaluate their accuracy to flag anomalies being fed "live" data streaming packets in OpenPDC. The results concluded from these tests will ultimately determine which method responds the best to anomaly detection in PMU data streaming.

Learning Scheme for Microgrid Islanding and Reconnection

Carter Lassetter*, Eduardo Cotilla-Sanchez†, Jinsub Kim‡
College of Electrical Engineering and Computer Science
Oregon State University
Corvallis, Oregon
Email: *lassettc@oregonstate.edu, †ecs@oregonstate.edu, ‡kimjinsu@oregonstate.edu

***Abstract*—The future electrical power systems tend toward smarter and greener technology. Micrograms go hand in hand with the building of this smarter grid, helping to integrate renewable resources as well as aiding in the mitigation of cascading blackouts. The main benefit of microgrids may also be their biggest detriment: A microgrid may operate in an islanded or interconnection mode; the ability to optimally and safely reconnect a microgrid is not well understood. In this poster, the use of a machine learning algorithm is demonstrated to determine timings for stable reconnection of a microgrid in real-time. With several PMU data streams, machine learning techniques can be utilized on the plethora of data created to determine safe reconnections of microgrids dynamically. Utilizing machine learning techniques for microgrids to predict the state of a reconnect will also give way to future applications of artificial intelligence on the grid. A microgrid armed with this prediction method could dynamically learn from its own predictions for future operation.**

I. Introduction

As we approach a smarter grid which implements an ever increasing amount of microgrids, it becomes important to have the ability to determine safe points in which one can reconnect an island or disconnect one from the main grid. With large variability of bus voltages and angles in the power grid, it becomes difficult to create a standard rule mathematically to depict the outcome of the disconnection or connection of a subset of the main grid; As a result, artificial intelligence techniques can be useful in creating a prediction algorithm for grid disconnects/reconnects. Support vector machines, or SVMs, have made large strides in the machine learning community and can be applied to a plethora of problems. Making use of bus voltages and angles, it is possible to create operating vectors which represent the current state of the system. With Phaser Measurement Units, one can gather data in near real time making dynamic monitoring and action schemes more reasonable.

II. Preliminary Results

The IEEE RTS-96 is a well tested case in the power system research community, thus it was selected for benchmarking this approach. The time-domain simulation is performed with Siemens PSS/E and a Python customized interface. Various operating points with different initial conditions were used as baseline cases to ensure diversity when training and testing. Using SVM, we trained a classifier which divides two classes.

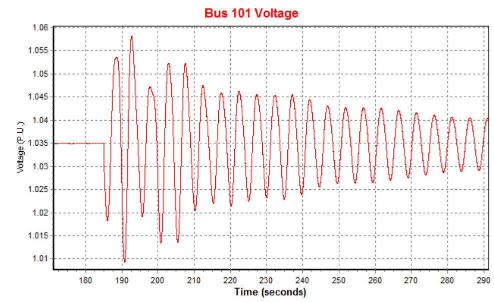


Fig. 1. A stable reconnect w.r.t. Bus 101.

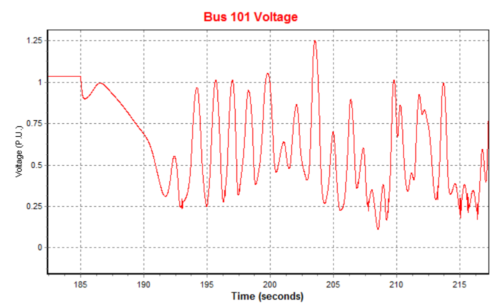


Fig. 2. An unstable reconnect w.r.t. Bus 101.

In our case, the two classes represent stable and unstable reconnections of a microgrid as shown in Figure 1 and Figure 2 respectively. It is important to note that only bus 101 is shown, all buses must abide by convergence rules to be considered stable. The operating vectors within a time-frame before reconnection of an island were used along with the outcome of the reconnect to train a classifier. After training our classifier, we could provide it with a different state of the network it hasn't seen before and obtain a prediction pertaining to the stability of the case if it were to be reconnected. The first test involved using the bus angles and voltages at the time step before reconnection. Even with limited temporal data, accuracies of the predictions averaged in the mid 80 percent range.

Multi-Area State Estimation with Synchrophasor Measurements

Xiaoyuan Fan, *Student Member, IEEE*, Dongliang Duan, *Member, IEEE*
Department of Electrical and Computer Engineering
University of Wyoming
Laramie, Wyoming, USA
Email: xfan3@uwyo.edu, dduan@uwyo.edu.

***Abstract*—Motivated by the advancements in synchronized phasor measurement units and the urgent need of a better state estimator to address the corresponding system complexity and computational burden, we focus on a potential solution for the state estimation in the control room: multi-area state estimation (MASE) with synchrophasor measurements. Two algorithms have been proposed to tackle this problem, namely synchrophasor-only linear MASE and synchrophasor-assisted hybrid MASE. Numerical simulations have been implemented in IEEE 14-bus system to evaluate and compare the performance of these two algorithms.**

I. Introduction

Power system state estimation (SE) is one of the most fundamental applications at the control center, since it helps the system operator to monitor, control and optimize the performance of the power grid. Shortly after the centralized state estimator being integrated into the control room in the late 1970s, researchers started to develop a more efficient estimator due to computational resource deficiency and communication capability limitation at that time.

To address the afore-mentioned two issues, multi-area state estimation was proposed and its core idea is to distribute the state estimation process at local control centers, which could significantly shorten the measurement collecting process and reduce the computational stress. Moreover, different areas of a huge power grid are connected and coupled by the so-called tie lines, which are originally designed to prevent the system from collapsing as a single area during emergency situations. In addition, privacy and policy issues render the reluctance of different ISOs to share the information of their operations and physical infrastructures. All these make MASE a necessity of better power system control and operations.

II. MASE with Synchrophasor Measurements

In general, there are two ways to incorporate PMU measurements (or synchrophasor measurements) into the MASE, which are the synchrophasor-assisted hybrid MASE and the synchrophasor-only linear MASE.

In the first case, PMU measurements can be processed with SCADA measurements hybridly in a single state estimator, or be processed to a separate state estimator in order to keep the traditional state estimator intact. The equivalency between these two scenarios has been proved in [1]. For the second case, the Jacobian matrix will be a constant matrix due to the linear relationship between synchrophasor voltage and current measurements, and thus the estimation result of local SE could be acquired in one iteration. Moreover, synchrophasor measurements not only have synchronization over a huge geographical area with the GPS signal, but also provide high accuracy on the magnitude and phase angle of the voltage and current.

Due to the observability issue with the current PMU placement profile, synchrophasor-assisted hybrid MASE would be more practical during this transition period, while synchrophasor-only linear MASE is more promising in the future where more PMUs are installed.

III. Key Equations

With the estimated boundary bus state, the optimization problem for the decentralized hybrid MASE is given as follows:

$$\arg\min_{\boldsymbol{x}_i} J(\boldsymbol{x}_i) = \arg\min_{\boldsymbol{x}_i}[\boldsymbol{z}_i - \boldsymbol{h}_i(\boldsymbol{x}_i)]^T \boldsymbol{C}_i^{-1}[\boldsymbol{z}_i - \boldsymbol{h}_i(\boldsymbol{x}_i)]$$
$$s.t.\ \ \boldsymbol{f}(\hat{\boldsymbol{x}}_i^b) = \hat{\boldsymbol{x}}_i^{2,b_{int}}$$

Compared with hybrid MASE, the synchrophasor-only MASE provides a linear system model due to linearity between PMU measurements and system state, the optimization problem is given as follows:

$$\arg\min_{\boldsymbol{x}_i} J(\boldsymbol{x}_i) = \arg\min_{\boldsymbol{x}_i}[\boldsymbol{z}_i - \boldsymbol{A}_i\boldsymbol{x}_i]^H \boldsymbol{C}_i^{-1}[\boldsymbol{z}_i - \boldsymbol{A}_i\boldsymbol{x}_i]$$
$$s.t.\ \ \boldsymbol{f}(\hat{\boldsymbol{x}}_i^b) = \hat{\boldsymbol{x}}_i^{b_{int}}$$

IV. Numerical Simulations

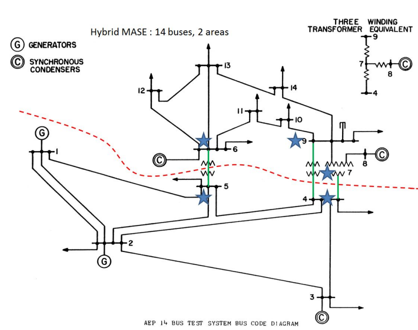


Fig. 1. Decomposing IEEE 14-bus system into two areas.

[1] M. Zhou, V. Centeno, J. Thorp, and A. Phadke, "An alternative for including phasor measurements in state estimators," *Power Systems, IEEE Transactions on*, vol. 21, no. 4, pp. 1930–1937, Nov 2006.

Risk-based stress indicators for cascading contingencies

Xian Guo, Siddhartha Khaitan, and James McCalley
Dept. of Electrical and Computer Engineering
Iowa State University
Ames, IA, USA
xianguo@iastate.edu

***Abstract*— In order to assess power systems for exposure to successive "cascading" contingencies, this poster proposes a risk-based stress indicator, which measures the system's ability to avoid cascading contingencies. The successive line outage distribution factor (LODF) is adopted to compute power flows following the *K* successive outage. The *K*th-order risk indicator provides the ability to continuously monitor the power system for cascading exposure. The IEEE 30-bus system is used to illustrate application of the risk-based indicator. Ongoing work includes implementing on a large-scale model of the Western U.S.**

***Index Terms*—Transmission, risk, stress, cascading, contingency.**

I. MOTIVATION

Stress monitoring for cascading contingencies provides the power system with the ability to guard against extreme events, recognizing possible severe events, enhancing situational awareness, and enabling early identification of corrective action when a severe event occurs. In this poster, we describe and illustrate the utilization of a risk-based cascading contingency stress indicator based on information available from a steady-state power flow solution.

II. METHODOLOGY

A. *K*th*-order system risk*

We compute K^{th}-order system risk to indicate the exposure of a particular initiating event to further propagation of up to K successive contingencies; this risk is computed as the weighted summation over the expectation of the consequences (or "severities") of all likely successive contingencies. It is calculated by applying the probability of a particular successive contingency $\Pr(.)$ and the corresponding consequences evaluated by $\mathrm{Sev}(.)$, both of which are computed as functions of power flow levels.

B. *Circuit risk*

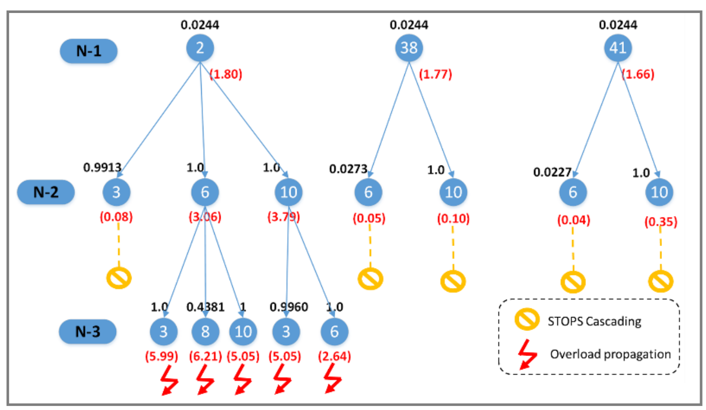
We denote i_K as the K^{th} successive contingency. Circuit risk includes conditional circuit risk and total circuit risk. Circuit risk differs from K^{th}-order system risk in that, whereas K^{th}-order system risk quantifies all likely K successive contingencies, circuit risk quantifies K successive contingencies, all of which lead to i_K. We use *conditional* circuit risk (which covers one particular K successive contingency leading to i_K), which represents the risk of an additional outage i_K following a specific successive contingency $(i_1, \ldots, i_{K-1})$, in order to evaluate the propagation of a particular cascading contingency. We also use *total* circuit risk (includes all K successive contingency leading to i_K), which is the aggregated stress exposed to a particular circuit i_K, in order to identify weak area in power system.

C. *Conditional probability*

We estimate the probability of occurrence of outaging circuit i_2 given outage of circuit i_1, $\Pr(i_2|i_1)$, to be proportional to the ratio of the increase in flow for circuit i_2 following the outage to the increase in flow for circuit i_2 necessary to trip it with certainty.

III. RESULTS

The figure shows the tree structure associated with the K^{th}-order risk for the IEEE 30 bus system under a specific operating point. The number in red indicates conditional circuit risk; the number in black shows conditional probability of a particular circuit outage.



IV. CONCLUSION

The tree structure of K^{th}-order risk identifies likely cascading events and weak areas in the system, which provides early warning information for system operators to take action in risk mitigation. The utilization of successive-LODF can realize calculation efficiency when successive cascading events are involved. We will apply this indicator in the WECC system, to verify the efficiency and efficacy of our method.

Distribution System Low-Voltage Circuit Topology Estimation using Smart Metering Data

Jouni Peppanen, Santiago Grijalva
School of Electrical and Computer Engineering
Georgia Institute of Technology
Atlanta, GA, USA

Matthew J. Reno, Robert J. Broderick
Sandia National Laboratories
Albuquerque, NM, USA

***Abstract*— Operating distribution systems with a growing number of distributed energy resources requires accurate feeder models down to the point of interconnection. Many of the new resources are located in the secondary low-voltage distribution circuits that typically are not modeled or modeled with low level of detail. This poster and the related paper present a practical and computational efficient approach for estimating the secondary circuit topologies from historical voltage and power measurement data provided by smart meters and distributed energy resource sensors. The computational infeasibility of exhaustive topology estimation is demonstrated and an efficient algorithm is presented for verifying whether two radial secondary circuits have identical topologies.**

I. Distribution Secondary Circuit Parameter and Topology Estimation Problem

The objective of the distribution secondary circuit topology and parameter estimation problem is to simultaneously identify topology and component series impedance parameters of a given secondary circuit leveraging the measurements from AMI and distributed energy sources (DER).

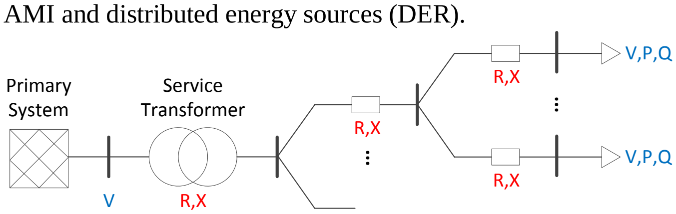


Fig. 1 Secondary circuit topology and parameter estimation problem: topology unknown, the unknown parameters in red, available measurements in blue

Theoretically, the topology of a secondary circuit can be estimated by performing an exhaustive search of all possible topologies. However, as illustrated in Table 1, to evaluate all the alternative topologies would be a computationally demanding task even with 5 to 7 meters.

TABLE I. The Number of Possible Secondary Circuit Topologies [16]

# Meters	1	2	3	4	5	6	7	8	9	10
# Topologies	1	3	22	262	4,336	91,984	2.38e6	72.8e6	2.57e9	1.03e11

II. Parameter and Topology Estimation Algorithm

Motivated by the vast number of possible topologies, we propose a computationally efficient greedy-type joint parameter and topology estimation algorithm (DSTE) that is based on linear regression and a well-known linear approximation of voltage drop magnitude. The algorithm processes each secondary circuit separately in an iterative manner. For each meter pair at each iteration, the algorithm estimates the parameters for parallel/series meters circuit subsection types with linear regression. The DSTE algorithm results in a mock circuit that includes all the meters in the original secondary circuit. The estimated topology is correct provided that at each iteration, the correct meter pair and regression model type are selected.

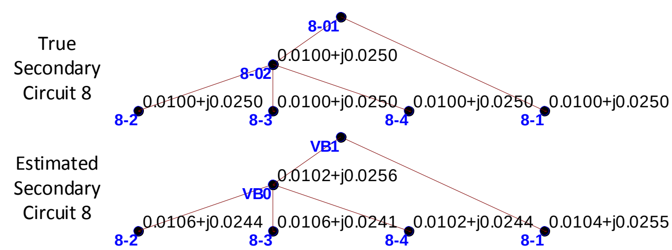


Fig. 2 True and estimated topologies for a secondary circuit

The DSTE algorithm estimates the circuit series impedance parameters with a high accuracy both without and with practical levels of measurement error.

TABLE II. The Average Relative Errors of the Estimated R and X

Meas. Error?	$R_{err,avg}$ [%]	$X_{err,avg}$ [%]	$R_{err,max}$ [%]	$X_{err,max}$ [%]
No	0.45	0.36	2.80	1.44
Yes	3.31	3.84	17.57	11.66

The DSTE algorithm is executed offline without the need of modifying any existing information systems. The algorithm is executed within seconds for each secondary circuit even if thousands of measurement samples are used to counteract the accuracy, granularity, and time synchronization issues related to AMI and DER measurements.

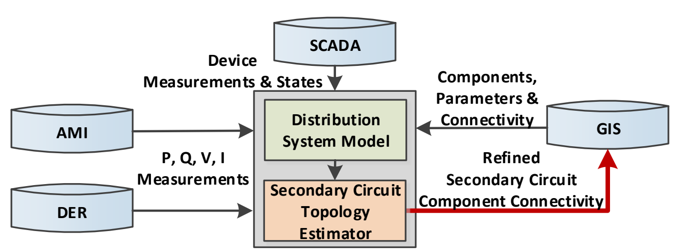


Fig. 3 Practical utility implementation of the DSTE algorithm

Q-learning Algorithm to Prevent Cascading Failure in Smart Grids: Experimental Implementation

Sina Zarrabian, *Student Member, IEEE*, Rabie Belkacemi, *Member, IEEE*
Department of Electrical and Computer Engineering
Tennessee Technological University
Cookeville, Tennessee, USA
szarrabia42@students.tntech.edu

***Abstract*—This research work proposes an adaptive learning approach based on the Q-learning algorithm to prevent cascading failure and blackout in real-time. This novel work utilizes the Q-learning algorithm to train the system for optimal action selection of power re-dispatch based on the obtained rewards. The trained system then is able to relieve the congestion of transmission lines by optimal power re-dispatch of the generators to prevent consecutive line outages and blackout after N-1 contingency condition. The proposed Q-learning control is validated by experimental results. The obtained results show the accuracy and robustness of the proposed approach in preventing blackout after contingency condition.**

Index Terms—*Blackouts, Cascading Failures, Experimental Systems, Q-learning, Real-Time, Smart Grids*

I. INTRODUCTION

The complexity of the power grid, the large number of components, and the different time scales dynamics and interactions have made modeling and analysis of cascading failure (CF) events extremely complicated. The recent methods proposed in this area involve either the use of load shedding or preventive measures that are aimed at reducing the probability of occurrence of CF.

In this paper, we utilize a novel application of the Q-learning in preventing cascading failure by estimating an optimal policy to select the best action-value (Q-value) of generated power re-dispatch by:

$$Q_{t+1}(s_t,a_t) = (1-\alpha)Q_t(s_t,a_t) + \alpha \left[\begin{matrix} r_{t+1} + \\ \gamma \max_a Q_t\,(s_{t+1},a) \end{matrix} \right]$$

II. KEY FIGURES

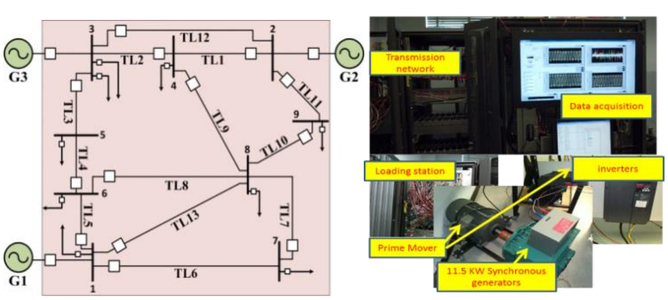


Fig. 1. Single line diagram of the testbed and experimental system

III. KEY RESULTS

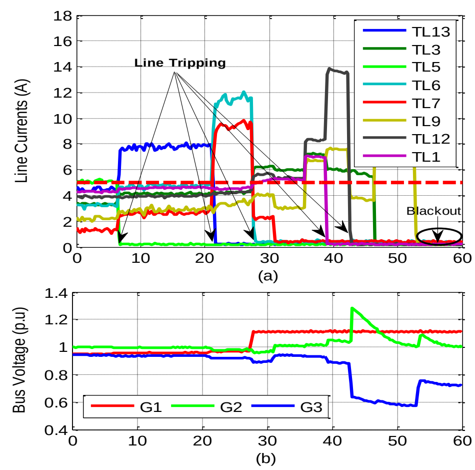


Fig. 2. Blackout without control: (a) line currents (b) bus voltages

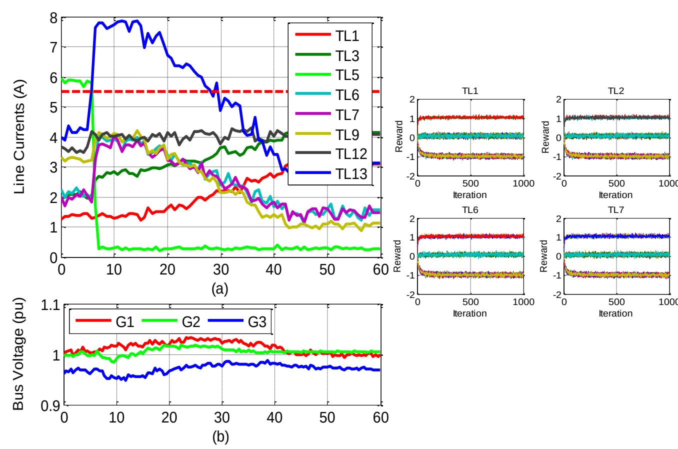


Fig. 3. N-1 with Q-learning: (a) line currents (b) bus voltages

IV. CONCLUSION

This work presents an adaptive intelligent method based on the Q-learning algorithm to prevent cascading failure and blackout after N-1 contingency. The results show the robustness and accuracy of the proposed intelligent method in providing the stability for the system after contingency while retaining the line currents, frequency and voltage values within the operation limits. Our results demonstrate that the proposed Q-learning method is accurate, fast, and promising.

Selecting and Redesigning Distribution Feeders for CVR Investment Benefits

Kaveh Rahimi, Himanshu Jain, and Abhineet Parchure
ECE Department, Virginia Tech
Virginia, USA

Tamer Rousan
ECE Department, University of Illinois at Urbana-Champaign
Illinois, USA

Robert Broadwater
Electrical Distribution Design (EDD)
Virginia, USA

***Abstract*— Conservation Voltage Reduction (CVR) is employed for peak load reduction and energy savings by electric utilities. Selecting feeders where the most benefit is realized from CVR is of interest. In the work here the theoretical CVR performance of over 1000 distribution feeders is evaluated based on circuit models and available load data. The feeders with the best CVR performance are identified, and characteristics of the good performing feeders are described. In identifying good performing feeders, load-voltage dependency factors for summer and winter are used in quasi-steady state power flow analysis. In addition, the Volt/VAR Control (VVC) scheme of a feeder with poor CVR performance is redesigned to improve its CVR performance. Results show that there can be considerable energy savings from investments in control schemes to improve CVR performance.**

***Index Terms*— Energy conservation, Conservation Voltage Reduction, Power Distribution, SCADA Systems, Volt/VAR Control**

TABLE I. CHARACTERISTICS AND SAVING OF THE SELECTED FEEDERS FOR CVR IMPLEMENTATION

Feeder Name	Type	Annual MWh (Base Case)	Annual MWh with CVR (Coordinated Control)	Percentage Improvement	Saving (MWh)	Feeder Length (Mile)	Control Category
1	Urban-Rural	23728	22609	4.72%	1119	18.4	VVC Devices
2	Urban-Rural	23885	22794	4.57%	1091	22.9	VVC Devices
3	Urban	20567	19493	5.22%	1074	13.5	Flat VP
4	Urban	18336	17350	5.38%	986	9.4	Flat VP
5	Urban	18668	17690	5.24%	977	9.4	Flat VP
6	Urban-Rural	20245	19291	4.71%	954	11.1	VVC Devices
7	Urban	17931	16979	5.31%	953	14.5	Flat VP
8	Urban-Rural	20365	19433	4.58%	932	18.7	VVC Devices
9	Urban-Rural	17402	16614	4.53%	788	15.6	Flat VP
10	Urban-Rural	14279	13615	4.65%	664	13.0	Flat VP
11	Urban-Rural	13498	12840	4.87%	658	4.1	Flat VP

Table II. CHARACTERISTICS AND SAVING OF THE MODIFIED FEEDER AFTER CVR IMPLEMENTATION

Feeder Name	Type	Annual MWh (Base Case)	Annual MWh with CVR (Coordinated Control)	Percentage Improvement	Saving (MWh)	Feeder Length (Mile)	Control Category
12	Urban-Rural	27130	26148	3.62%	983	25.2	VVC Devices

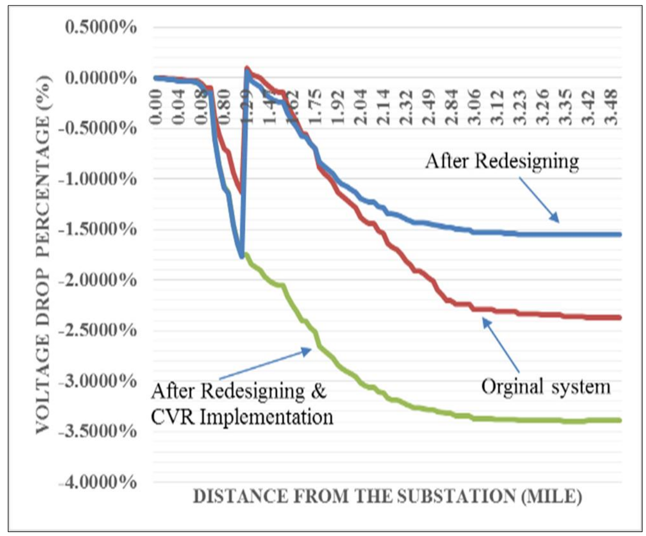


Fig. 1. Percent voltage drop before and after redesigning the VVC system for the selected poor performing feeder during summer

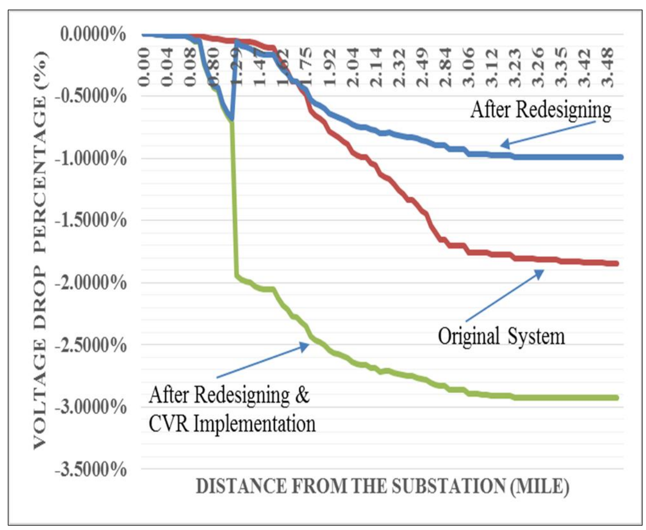


Fig. 2. Percent voltage drop before and after redesigning the VVC system for the selected poor performing feeder during winter

UCLA ENGINEERING
Henry Samueli School of
Engineering and Applied Science
Birthplace of the Internet

Mechanical and Aerospace Engineering

Optimal Energy Management for Microgrid with Stationary and Mobile Storages

Yubo Wang, Bin Wang, Tianyang Zhang, Hamidreza Nazaripouya, Chi-Cheng Chu and Rajit Gadh

Introduction and background

◆Increasing PV penetration and EV integration to smart grid in recent years

◆They add uncertainties to the microgrid Energy Management System (EMS)

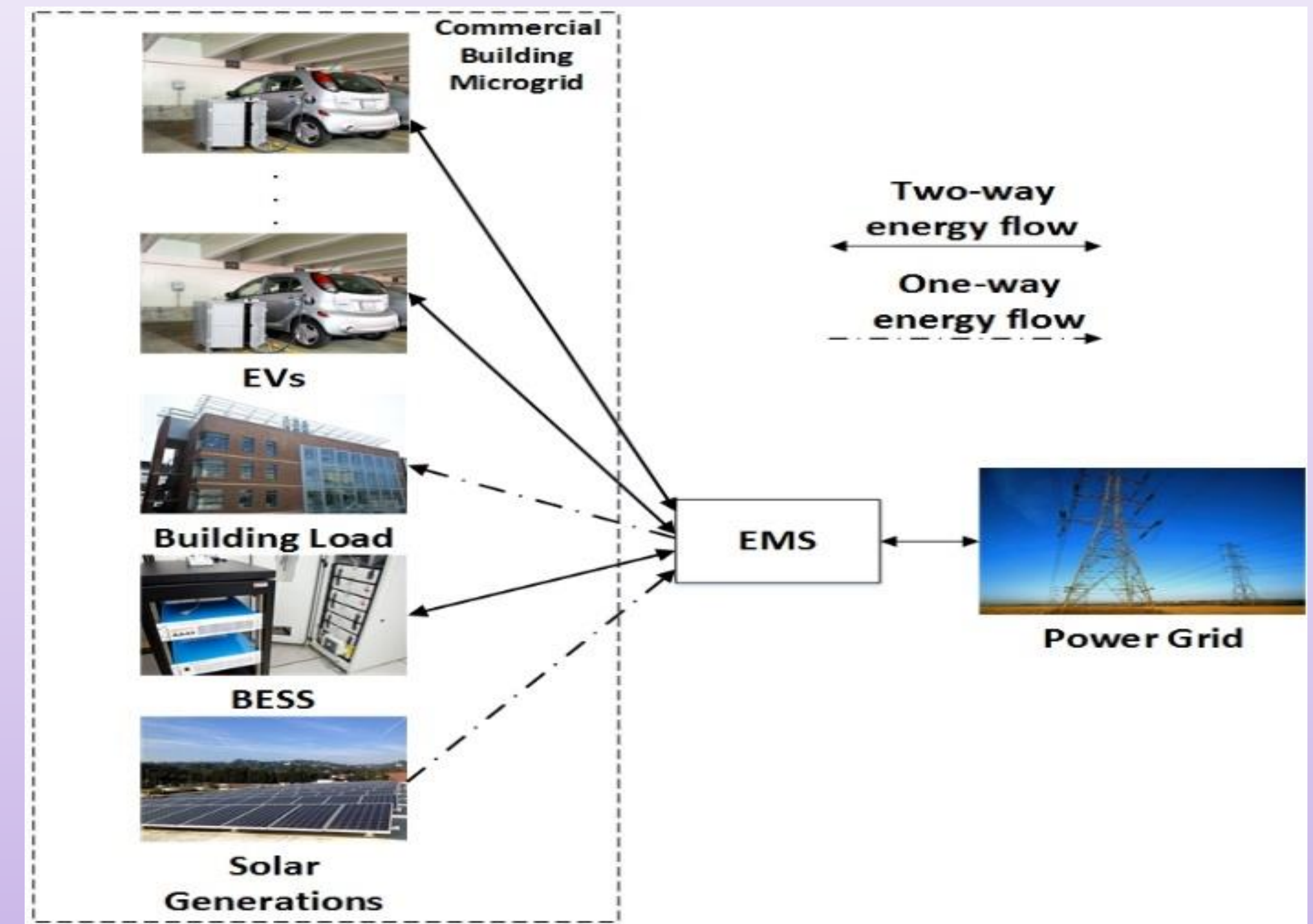
◆The state-of-art EMS either uses deterministic methods or robust methods, they either ignore the uncertainties or results in too conservative results

◆This paper models the uncertainties in EV availability, energy demands, solar generation and loads with two-stage stochastic optimization.

◆The studied grid-connected MG is a common scenario in a distribution system and we use real collected data to evaluate the performance of the proposed method

◆Extensive analysis is made on the performance of the method

The studied system



Model development

◆Two-stage stochastic optimization:

$$min\,\mathbb{E}\{(\mathbf{c}_D^T\mathbf{p}^D\tau + c_d max\{\mathbf{p}^D\} + \mathbf{c}_P^T|\mathbf{p}^P(\boldsymbol{\zeta},\boldsymbol{\nu},\boldsymbol{\xi},\boldsymbol{\delta})|)\tau\} \quad (1)$$

$$min\,(\mathbf{c}_D^T\mathbf{p}^D\tau + c_d max\{\mathbf{p}^D\} + \frac{1}{N}\sum_{s=1}^{N}(\mathbf{c}_P^T|\mathbf{p}_s^P|)\tau) \quad (2)$$

◆Grid, BESS, and EV constraints

$$\sum_{i=1}^{M}\mathbf{p}_{d,s}^{E,i} + \mathbf{p}_s^{solar} + \mathbf{p}_d^B + \mathbf{p}^D = \mathbf{p}_c^B + \sum_{i=1}^{M}\mathbf{p}_{c,s}^{E,i} + \mathbf{p}_s^{load} + \mathbf{p}_s^P\ \forall s \quad (3)$$

$$P_{min}^D\mathbf{1} \le \mathbf{p}^D \le P_{max}^D\mathbf{1} \quad (4)$$

$$-P_{step}^D \le (\mathbf{p}^D)_i - (\mathbf{p}^D)_{i+1} \le P_{step}^D,\ i = 1, ..., H-1 \quad (5)$$

$$0 \le \mathbf{p}_c^B \le P_{c,max}^B\boldsymbol{\sigma}^B \quad (6)$$

$$0 \le \mathbf{p}_d^B \le P_{d,max}^B(\mathbf{1} - \boldsymbol{\sigma}^B) \quad (7)$$

$$P_{c,lim}^B\boldsymbol{\sigma}_c^B \le \mathbf{p}_c^B \le P_{c,lim}^B(\mathbf{1} - \boldsymbol{\sigma}_c^B) + P_{c,max}^B\boldsymbol{\sigma}_c^B \quad (8)$$

$$P_{d,lim}^B\boldsymbol{\sigma}_d^B \le \mathbf{p}_d^B \le P_{d,lim}^B(\mathbf{1} - \boldsymbol{\sigma}_d^B) + P_{d,max}^B\boldsymbol{\sigma}_d^B \quad (9)$$

$$(\boldsymbol{\sigma}_c^B)_i + (\boldsymbol{\sigma}_c^B)_{i+1} \le 1,\ \ i = 1, ..., H-1 \quad (10)$$

$$(\boldsymbol{\sigma}_d^B)_i + (\boldsymbol{\sigma}_d^B)_{i+1} \le 1,\ \ i = 1, ..., H-1 \quad (11)$$

$$SoC_{min}^B\mathbf{1} \le SoC_{ini}^B\mathbf{1} + \mathbf{h}^B(\mathbf{p}_c^B\eta_c^B - \mathbf{p}_d^B/\eta_d^B) \le SoC_{max}^B\mathbf{1} \quad (12)$$

$$SoC_{fin}^B = SoC_{ini}^B + (\mathbf{h}^B)_{end}(\mathbf{p}_c^B\eta_c^B - \mathbf{p}_d^B/\eta_d^B) \quad (13)$$

$$P_{c,min}^{E,i}\boldsymbol{\sigma}_{c,s}^{E,i} \le \mathbf{p}_{c,s}^{E,i} \le P_{c,max}^{E,i}\boldsymbol{\sigma}_{c,s}^{E,i}\ \forall s\ \forall i \quad (14)$$

$$P_{d,min}^{E,i}(\mathbf{1} - \boldsymbol{\sigma}_{c,s}^{E,i}) \le \mathbf{p}_{d,s}^{E,i} \le P_{c,max}^{E,i}(\mathbf{1} - \boldsymbol{\sigma}_{c,s}^{E,i})\ \forall s\ \forall i \quad (15)$$

$$\mathbf{0} \le \boldsymbol{\sigma}_{c,s}^{EV,i} \le \boldsymbol{\sigma}_s^i\ \forall s\ \forall i \quad (16)$$

$$SoC_{min}^{E,i}\mathbf{1} \le SoC_{ini,s}^{E,i}\mathbf{1} + \mathbf{h}_s^{E,i}(\mathbf{p}_{c,s}^{E,i}\eta_c^{E,i} - \mathbf{p}_{d,s}^{E,i}/\eta_d^{E,i}) \le SoC_{max}^{E,i}\mathbf{1}\ \forall s\ \forall i \quad (17)$$

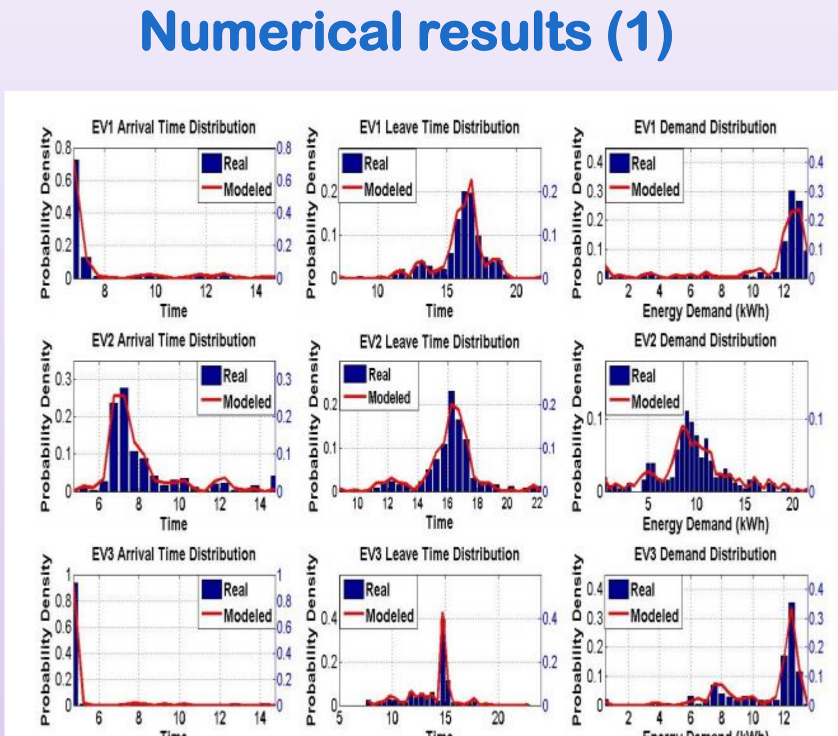
$$SoC_{fin,s}^{E,i} = SoC_{ini,s}^{E,i} + (\mathbf{h}_s^{E,i})_{end}(\mathbf{p}_{c,s}^{E,i}\eta_c^{E,i} - \mathbf{p}_{d,s}^{E,i}/\eta_d^{E,i})\ \forall s\ \forall i \quad (18)$$

◆Sample Average Approximation (SAA) Monte Carlo simulation

Algorithm 1: Algorithm for SAA Upper and Lower Bounds Estimation

```
for k = 1 to K do
    Generate N scenarios, solve (2);
        x ← first stage variables p^D, p_c^B, p_d^B, σ^B, σ_c^B, σ_d^B ;
        opt(k) ← optimum;
    Generate N' scenarios, solve (2) with fixed x;
        \overline{opt(k)} ← optimum ;
end
upper bound \overline{opt*} ← minimum of \overline{opt};
lower bound \underline{opt*} ← average of opt;
optimality gap ← (\overline{opt*} − \underline{opt*})/\underline{opt*} × 100%
```

Numerical results (1)

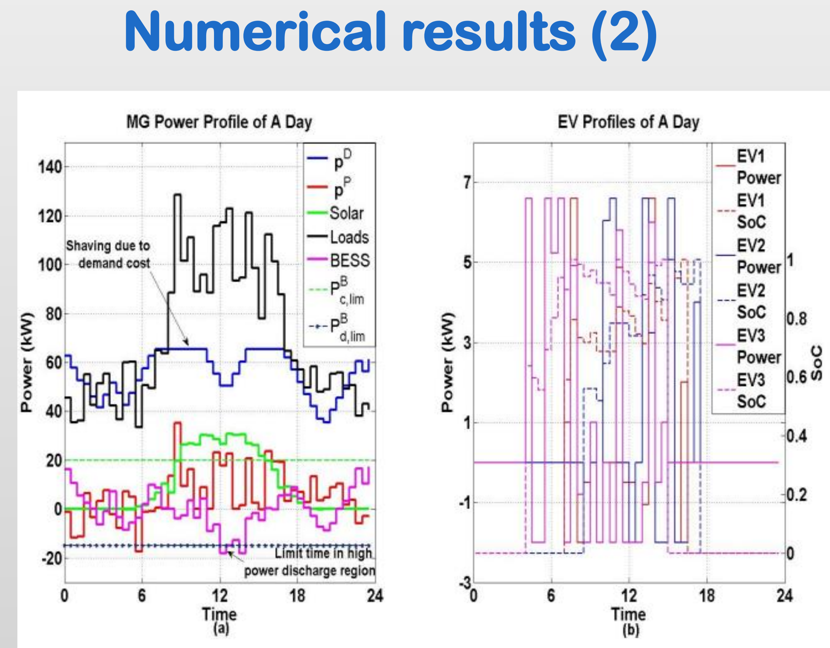


Three user behavior modeling using KDE

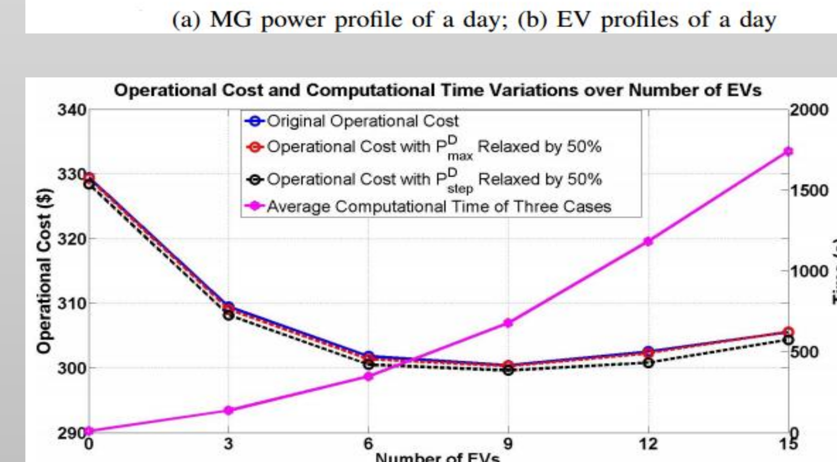
N/N'	Upper Bound	Lower Bound	Optimality Gap	Computational Time (s)
20/200	312.22	307.72	1.46%	901.1
30/200	311.37	308.75	0.85%	925.9
30/300	311.22	308.18	0.99%	1897.5
50/500	312.03	309.04	0.97%	4973.4

Upper and lower bounds estimation of SAA

Numerical results (2)



(a) MG power profile of a day; (b) EV profiles of a day



Variation on number of EVs and its impact

Conclusions and future studies

◆A comprehensive cost function is considered and the problem is formulated as a MILP problem

◆To evaluate the proposed method, we use real data for SAA Monte Carlo simulation

◆The optimum is also tightly bounded within 1 percent optimality gap

◆Two interesting observations are made:
(1) the proposed stochastic optimization method outperforms its deterministic counterpart by 5.5 percent in expectation at the cost of higher computational time;
(2) Increase of EVs in the MG helps to cut down the operation cost at first after which the cost starts to increase

◆Shed light on future EV integration to the grid. Future study will include more EV users, and stochastic modelling in EV numbers

Reserve Margin Policy for Scheduling Wind Energy and Stochastic Reserve

Mojgan Hedayati, *Student Member, IEEE*, Kory W. Hedman, *Member, IEEE, and Junshan Zhang, Fellow, IEEE*
School of Electrical, Computer, and Energy Engineering, Arizona State University, Tempe, AZ85287, USA
Email: mhedayat@asu.edu, khedman@asu.edu, Junshan.Zhang@asu.edu

***Abstract*— The rapid increase in the integration of renewable resources has given rise to challenges in power system operations. One aspect is the impact of integrating wind generation on operating reserve procurement. Due to the uncertainty and variability of renewable generation, additional reserves may be needed to maintain system reliability. Uncertainty complicates the process of economic dispatch and renders the deterministic optimization approach less effective. Existing optimization solutions for handling uncertainty, such as scenario-based stochastic programming and robust programming, are also computationally expensive, especially when there are multiple wind farms. Such approaches are less practical for large-scale systems during real-time operations. This paper investigates combining deterministic and stochastic approaches by exploiting offline stochastic calculations for training deterministic operation policies. Such deterministic policies are then added to real-time operational models. This paper focuses on deriving such policies for energy and reserve. One approach for handling the uncertainty of wind generation is to leave a reserve margin when scheduling the wind power. The extra available wind will then be accessible for providing operational reserve. This paper proposes an offline policy generation technique to provide a stochastic reserve margin to hedge against the real-time uncertainty of (multiple) wind farm generation. The proposed policy generation structure uses a forecast-based framework that accounts for wind generation and system loading conditions. A co-optimized energy and operating reserve market model is developed to embody leaving a reserve margin for wind power to obtain a more flexible energy and reserve scheduling. The proposed approach is tested on the Reliability Test System 1996 (RTS96) with consideration of wind uncertainties. The operation costs are compared to those obtained using the existing reserve rules. Wind generation data is used to analyze the effectiveness of the presented model in handling uncertainty and achieving a more secure system operation.**

I. Key Equations

$$\begin{aligned}\text{Min } &\textstyle\sum_{g,t}(c_w^e P_{wt} + c_w^r r_{wt}) + \sum_{g,t}\left(c_g^e P_{gt} + c_g^r r_{gt}\right)\\ &+ \sum_{s,t} prob_s\Big(\sum_g \left(c_{g1}^e r_{gst}\right) + \sum_w (c_{w1}^e r_{wst})\\ &+ \textstyle\sum_w\left(c_{w1}^r \Delta_{w,s,t}\right) + \sum_w\left(c_p + c_{w1}^e\right) P_{wst}^{penalty}\\ &+ \sum_n c_c^n (LS_{nt}^+ + LS_{nt}^-)\ \Big)\end{aligned}$$

Subject to:

Base case constraints:

$$\textstyle\sum_{g\in g(n)} P_{g,t} + \sum_{k\in\delta^+(n)} P_{k,t} - \sum_{k\in\delta^-(n)} P_{k,t} + \sum_{w\in w(n)} P_{w,t} = d_{n,t}, \forall n,t \tag{1}$$

$$P_g^{min} u_{g,t} \le P_{gt},\ P_{gt} + r_{gt} \le P_g^{max} u_{g,t} \forall g,t \tag{2}$$

$$\textstyle\sum_{q\in G} r_{qt} \ge P_{gt} + r_{gt} + \sum_w \xi_{wt}, \forall g,t \tag{3}$$

$$\xi_{wt} \ge P_{wt} - \left(P_{wt}^f - \alpha\sigma_{wt}\right), \forall w,t \tag{4}$$

$$P_{wt} + r_{wt} \le \alpha P_{wt}^f, \forall w,t \tag{5}$$

Second Stage constraints (for scenarios):

$$\textstyle\sum_{g\in g(n)}\left(P_{g,t} + r_{gst}\right) + \sum_{k\in\delta^+(n)} P_{k,s,t} - \sum_{k\in\delta^-(n)} P_{k,s,t} + \sum_{w\in w(n)}(P_{w,t} + r_{w,s,t}) + LS_{nt}^+ - LS_{nt}^- = d_{n,t}, \forall n,t \tag{6}$$

$$-r_{gt} \le r_{g,s,t} \le r_{gt}, \forall g,s,t \tag{7}$$

$$P_g^{min} \le P_{g,t} + r_{gst} \le P_g^{max}, \forall g,s,t \tag{8}$$

$$-r_{w,s,t} \le r_{wt} + P_{wts}^{penalty}, \forall g,s,t \tag{9}$$

References

[1] M. He, L. Yang, J. Zhang, V. Vittal, "A Spatio-Temporal Analysis Approach for Short-Term Forecast of Wind Farm Generation," *IEEE Trans. Power Syst.*, vol. 29, no. 4, July 2014.

II. Methodology

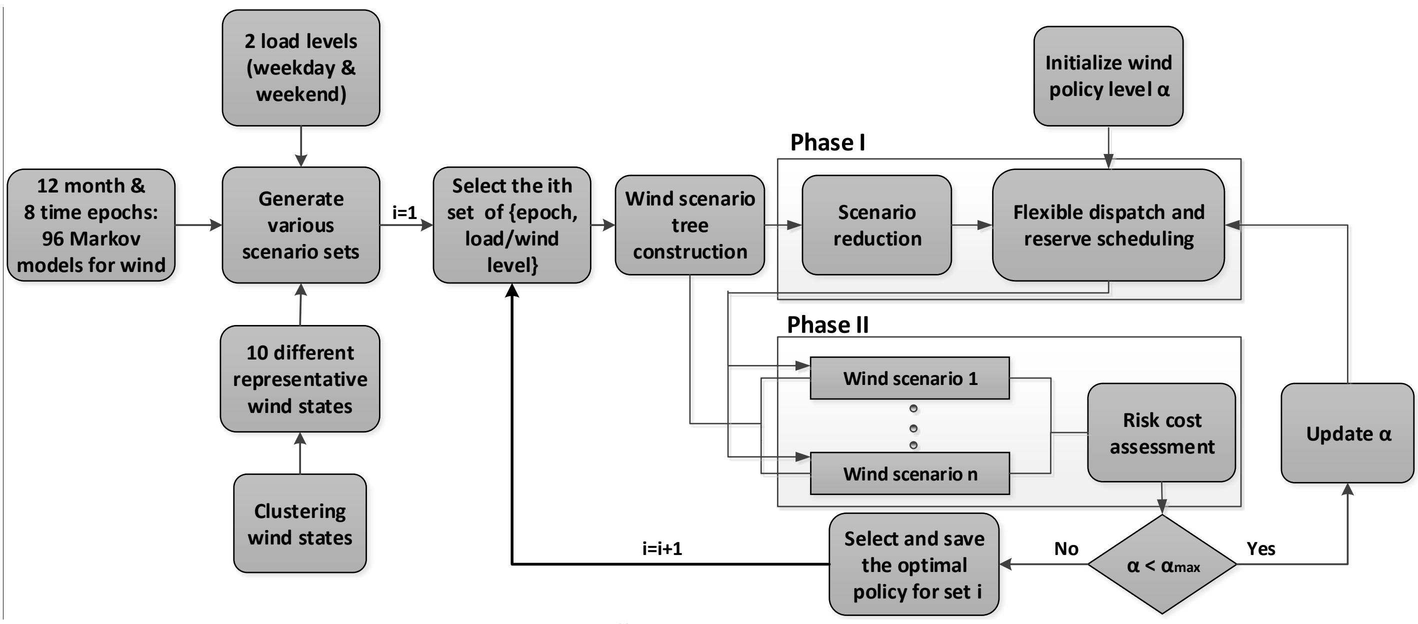


Fig. 1. Offline policy training procedure

Optimal Sizing and Placement of Battery Energy Storage in Distribution System Based on Solar Size for Voltage Regulation

H. Nazaripouya[1], Y. Wang[1], P. Chu[1], H. R. Pota[2], and R. Gadh[1] *Members, IEEE*

***Abstract*—This paper proposes a new strategy to achieve voltage regulation in distributed power systems in the presence of solar energy sources and battery storage systems. The goal is to find the minimum size of battery storage and its corresponding location in the network based on the size and place of the integrated solar generation. The proposed method formulates the problem by employing the network impedance matrix to obtain an analytical solution instead of using a recursive algorithm such as power flow. The required modifications for modeling the slack and PV buses (generator buses) are utilized to increase the accuracy of the approach. The use of reactive power control to regulate the voltage regulation is not always an optimal solution as in distribution systems *R/X* is large. In this paper the minimum size and the best place of battery storage is achieved by optimizing the amount of both active and reactive power exchanged by battery storage and its grid-tie inverter (GTI) based on the network topology and *R/X* ratios in the distribution system. Simulation results for the IEEE 14-bus system verify the effectiveness of the proposed approach.**

I. Key Equations and Figure

The mathematical relationship between location of BESS and solar and amount of exchanging power with specific node voltage developed in this paper is presented as follows:

$$V = Z_{bus}(I^0 + \Delta I) = Z_{bus}I^0 + Z_{bus}\Delta I = V^0 + \Delta V \qquad (1)$$

$$\begin{bmatrix} \Delta V_1 \\ \vdots \\ \Delta V_i \\ \vdots \\ \Delta V_n \end{bmatrix} = \begin{bmatrix} Z_{11} & \cdots & Z_{1i} & \cdots & Z_{1n} \\ \vdots & \ddots & \vdots & \ddots & \vdots \\ Z_{i1} & \cdots & Z_{ii} & \cdots & Z_{in} \\ \vdots & \ddots & \vdots & \ddots & \vdots \\ Z_{n1} & \cdots & Z_{ni} & \cdots & Z_{nn} \end{bmatrix} \times \begin{bmatrix} 0 \\ \vdots \\ I_i \\ \vdots \\ 0 \end{bmatrix} \qquad (2)$$

$$\begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \vdots \\ \Delta V_m \\ \vdots \\ \Delta V_i \\ \vdots \\ \Delta V_n \end{bmatrix} = \begin{bmatrix} Z_{11} & Z_{12} & \cdots & Z_{1m} & \cdots & Z_{1i} & \cdots & Z_{1n} \\ Z_{21} & Z_{22} & \cdots & Z_{2m} & \cdots & Z_{2i} & \cdots & Z_{2n} \\ \vdots & \vdots & \ddots & \vdots & \ddots & \vdots & \ddots & \vdots \\ Z_{m1} & Z_{m2} & \cdots & Z_{mm} & \cdots & Z_{mi} & \cdots & Z_{mn} \\ \vdots & \vdots & \ddots & \vdots & \ddots & \vdots & \ddots & \vdots \\ Z_{i1} & Z_{i2} & \cdots & Z_{im} & \cdots & Z_{ii} & \cdots & Z_{in} \\ \vdots & \vdots & \ddots & \vdots & \ddots & \vdots & \ddots & \vdots \\ Z_{n1} & Z_{n2} & \cdots & Z_{nm} & \cdots & Z_{ni} & \cdots & Z_{nn} \end{bmatrix} \times \begin{bmatrix} -\frac{Z_{1i}}{Z_{11}}I_i - \frac{Z_{12}}{Z_{11}}I_2 - \cdots - \frac{Z_{1m}}{Z_{11}}I_m \\ I_2 \\ \vdots \\ I_m \\ \vdots \\ I_i \\ \vdots \\ 0 \end{bmatrix} \qquad (3)$$

$$V_i = V_i^0 + (Z_{i2} - Z_{i1}\frac{Z_{12}}{Z_{11}})I_2 + \cdots + (Z_{im} - Z_{i1}\frac{Z_{1m}}{Z_{11}})I_m + (Z_{ii} - Z_{i1}\frac{Z_{1i}}{Z_{11}})Ii \qquad (4)$$

$$\begin{bmatrix} (Z_{21}\frac{Z_{1i}}{Z_{11}} - Z_{2i})I_i \\ (Z_{31}\frac{Z_{1i}}{Z_{11}} - Z_{3i})I_i \\ \vdots \\ (Z_{m1}\frac{Z_{1i}}{Z_{11}} - Z_{mi})I_i \end{bmatrix} = \begin{bmatrix} (Z_{22} - Z_{21}\frac{Z_{12}}{Z_{11}}) & (Z_{23} - Z_{21}\frac{Z_{13}}{Z_{11}}) & \cdots & (Z_{2m} - Z_{21}\frac{Z_{1m}}{Z_{11}}) \\ (Z_{32} - Z_{31}\frac{Z_{12}}{Z_{11}}) & (Z_{33} - Z_{31}\frac{Z_{13}}{Z_{11}}) & \cdots & (Z_{3m} - Z_{31}\frac{Z_{1m}}{Z_{11}}) \\ \vdots & \vdots & \ddots & \vdots \\ (Z_{m2} - Z_{m1}\frac{Z_{12}}{Z_{11}}) & (Z_{m2} - Z_{m1}\frac{Z_{13}}{Z_{11}}) & \cdots & (Z_{mm} - Z_{m1}\frac{Z_{1m}}{Z_{11}}) \end{bmatrix} \times \begin{bmatrix} I_2 \\ I_3 \\ \vdots \\ I_m \end{bmatrix} \qquad (5)$$

$$I_i = S^* / V_i^* = P_{pv} / V_i^* \qquad (6)$$

$$V_k = V_k^0 + Z_{eq_{ki}} I_i + Z_{eq_{kj}} I_j \qquad (7)$$

$$\left(I_j\right)_{\min}^k = -\frac{\left(\left|V_k^0 + Z_{eq_{ki}} I_i\right| - V_{\max}\right)}{Z_{eq_{kj}}} \times \frac{(V_k^0 + Z_{eq_{ki}} I_i)}{\left|V_k^0 + Z_{eq_{ki}} I_i\right|} \qquad (8)$$

$$\left(I_j\right)_{\min}^k = -\frac{\left(\left|V_k^0 + Z_{eq_{ki}} I_i\right| - V_{\min}\right)}{Z_{eq_{kj}}} \times \frac{(V_k^0 + Z_{eq_{ki}} I_i)}{\left|V_k^0 + Z_{eq_{ki}} I_i\right|} \qquad (9)$$

$$\left(I_j\right)_{\min} = \max\{real((I_j)_{\min}^k)|_{0\le k\le n}\} + j.\max\{image((I_j)_{\min}^k)|_{0\le k\le n}\} \qquad (10)$$

II. Key Results

The IEEE 14-bus benchmarks are considered as the case studies as shown in Figs. 1.

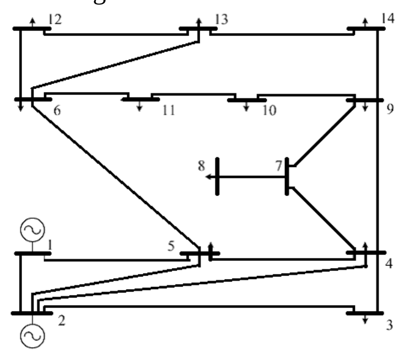


Fig. 1. 14 buses IEEE benchmark

Tables I and II demonstrate the results.

Table I. Results after BESS integration with one unit solar source

Best Location for BESS				Bus number 9		
Minimum Active power (BESS)				0.1196 pu		
Minimum Reactive Power (GTI)				0.3566 pu		
Bus #	**Voltage profile**					
	P=0pu	***P=0.2pu***	***P=0.4pu***	***P=0.6pu***	***P=0.8pu***	***P=1p.u***
1	1.0600	1.0600	1.0600	1.0600	1.0600	1.0600
2	1.0450	1.0450	1.0450	1.0450	1.0450	1.0450
3	0.9978	0.9989	0.9998	1.0007	1.0014	1.0017
4	0.9982	1.0003	1.0023	1.0041	1.0057	1.0065
5	1.0032	1.0065	1.0096	1.0127	1.0154	1.0173
6	1.0362	1.0380	1.0396	1.0413	1.0424	1.0420
7	1.0157	1.0158	1.0159	1.0160	1.0156	1.0134
8	1.0450	1.0452	1.0453	1.0454	1.0449	1.0428
9	0.9964	0.9955	0.9946	0.9937	0.9922	0.9884
10	0.9955	0.9950	0.9946	0.9941	0.9930	0.9898
11	1.0118	1.0124	1.0130	1.0135	1.0135	1.0117
12	1.0202	1.0218	1.0233	1.0248	1.0258	1.0252
13	1.0143	1.0157	1.0170	1.0183	1.0190	1.0181
14	0.9879	0.9880	0.9880	0.9881	0.9875	0.9849

Table II. Results after BESS integration with scattered solar source

Best Location for BESS	Bus number 7
Minimum Active power (BESS)	0.0845 pu
Minimum Reactive Power (GTI)	0.4338 pu

[1]Authors are with University of California, Los Angeles Smart Grid Energy Research Center (UCLA SMERC), Contact authors: hnazari@g.ucla.edu, ybwang@ucla.edu, chichengwi@gmail.com, gadh@ucla.edu.

[2] Author is with The University of NSW h.pota@adfa.edu.au

Screening Algorithms for Large-Scale Stochastic Transmission Capacity Expansion Planning with reliability Constraints

Mohammad Majidi-Qadikolai, Ross Baldick

Abstract

Increasing interest in utilizing more renewable energy resources raises the need for new transmission lines to integrate them to the gird on one hand, and increasing environmental concerns limits building new transmission lines on the other had. These issues makes transmission planning a challenging issue. To cope with environmental concerns and permitting issues, transmission expansion planning is required over a longer term that will increase uncertainties in load and generation. A large number of scenarios and candidate lines are proposed in the early stage of transmission capacity expansion planning (TCEP) to capture these uncertainties, and it makes transmission planning a very challenging task. Stochastic TCEP with reliability constraints is formulated as a two-stage mixed-integer optimization problem to capture uncertainties and network reliability. We develop a candidate line reduction algorithm, which is a heuristic method to screen candidate lines list and remove lines for which their closure will increase flow on heavily loaded lines in the network. It will reduce the number of binary variables in the optimization problem that can significantly decrease computational time. In the next step, variable contingency list algorithm is used to screen reliability constrains to further decrease the problem size.

The proposed framework is summarized as the following steps:

Step 1 : Load Input Data and data cleaning.
Load, Generation, current and candidate transmission components etc. The base case system that contains existing lines, load, buses and generators is referred to as S_o. The initial candidate lines list (CLL) in this step is referred as CLL_o.

Step 2 : Solve a relaxed version of OPF problem.
In this step, a relaxed version of OPF, in which constraints related to line capacity limits are ignored, is run.

Step 3 : Create monitored lines list (MLL).
In this step, lines with flows more than 50% of their nominal capacity will be added to Monitoring Lines List (MLL).

Step 4 : Reduce candidate lines list (RCL).
Line Closure Distribution Factor (LCDF) is calculated for candidate lines in CLL_r to evaluate the impact of closing each candidate line on the lines in MLL.

Step 5 : Solve a relaxed version of TCEP problem.
In this step, we solve a relaxed version of the original integrated TCEP, in which all constraints related to contingency analysis are ignored (for the base case S_o) with updated CLL.

Step 6 : Create variable contingency list (VCL).
Modified Line Outage Distribution Factor (LODF) matrix is calculated for single outage of all lines in S_r.

Step 7 : Solve TCEP optimization problem with updated CLL and selected contingencies.

Step 8 : Run DC-SCOPF with all contingencies for the selected plan in step 7 to check feasibility of results.

The proposed method is applied to a reduced ERCOT case study with 317 buses, 427 existing branches, 489 conventional power plants, 36 wind farms, 182 load centers, and 427 candidate lines. Two cases A and B are considered with 5 and 10 scenarios respectively. By using the RCL algorithm, the number of candidate lines is reduced to 78 and 90 for cases A and B (from 427). The VCL algorithm decreases the number of operation states to 28 and 62 for cases A and B (more than 99% problem size reduction). Sub-optimality of the proposed method for these case studies is less than 10.5% for both cases that shows the accuracy of the proposed model. The simulation run time is 5.1 and 87.4 minutes for cases A and B for the proposed method in this poster, and no answer is achieved for the original problem after 34 days.

Screening Algorithms for Constraint reduction in Large-Scale Stochastic Transmission Capacity Expansion Planning

Mohammad Majidi-Qadikolai, Ross Baldick
University of Texas at Austin

***Abstract*—In this paper, a heuristic method is proposed for solving large-scale transmission capacity expansion planning (TCEP) problem under uncertainties. The proposed method uses a modified version of candidate line reduction algorithm (CLR) to select a subset of candidate lines for expansion and the variable contingency lists algorithm (VCL) to select a subset of lines that should be considered for contingency analysis. The problem is formulated as a two-stage stochastic optimization problem, and a reduced ERCOT case study is used to demonstrate capabilities of the proposed method.**

I. Introduction

Increasing interest in utilizing more renewable energy resources raises the need for new transmission lines to integrate them to the gird on one hand, and increasing environmental concerns limits building new transmission lines on the other had. These issues makes transmission planning a challenging issue. To cope with environmental concerns and permitting issues, transmission expansion planning is required over a longer term that will increase uncertainties in load and generation. A large number of scenarios and candidate lines are proposed in the early stage of transmission capacity expansion planning (TCEP) to capture these uncertainties, and it makes transmission planning a very challenging task. Stochastic TCEP with reliability constraints is formulated as a two-stage mixed-integer optimization problem to capture uncertainties and network reliability. We develop a candidate line reduction algorithm, which is a heuristic method to screen candidate lines list and remove lines for which their closure will increase flow on heavily loaded lines in the network. It will reduce the number of binary variables in the optimization problem that can significantly decrease computational time. In the next step, variable contingency list algorithm is used to screen reliability constrains to further decrease the problem size.

II. The proposed method

The proposed framework is summarized as the following steps:

Step 1 : Load Input Data and data cleaning.
Load, Generation, current and candidate transmission components etc. The base case system that contains existing lines, load, buses and generators is referred to as S_o. The initial candidate lines list (CLL) in this step is referred as CLL_o.

Step 2 : Solve a relaxed version of OPF problem.
In this step, a relaxed version of OPF, in which constraints related to line capacity limits are ignored, is run.

Step 3 : Create monitored lines list (MLL).
In this step, lines with flows more than 50% of their nominal capacity will be added to Monitoring Lines List (MLL).

Step 4 : Reduce candidate lines list (RCL).
Line Closure Distribution Factor (LCDF) is calculated for candidate lines in CLL_r to evaluate the impact of closing each candidate line on the lines in MLL.

Step 5 : Solve a relaxed version of TCEP problem.
In this step, we solve a relaxed version of the original integrated TCEP, in which all constraints related to contingency analysis are ignored (for the base case S_o) with updated CLL.

Step 6 : Create variable contingency list (VCL).
Modified Line Outage Distribution Factor (LODF) matrix is calculated for single outage of all lines in S_r.

Step 7 : Solve TCEP optimization problem with updated CLL and selected contingencies.

Step 8 : Run DC-SCOPF with all contingencies for the selected plan in step 7 to check feasibility of results.

III. Numerical Results

The proposed method is applied to a reduced ERCOT case study with 317 buses, 427 existing branches, 489 conventional power plants, 36 wind farms, 182 load centers, and 427 candidate lines. Two cases A and B are considered with 5 and 10 scenarios respectively. By using the RCL algorithm, the number of candidate lines is reduced to 78 and 90 for cases A and B (from 427). The VCL algorithm decreases the number of operation states to 28 and 62 for cases A and B (more than 99% problem size reduction). Sub-optimality of the proposed method for these case studies is less than 10.5% for both cases that shows the accuracy of the proposed model. The simulation run time is 5.1 and 87.4 minutes for cases A and B for the proposed method in this poster, and no answer is achieved for the original problem after 34 days.

A Model for Demand Response Aggregators Participating through Demand Response Exchange

Venkat Durvasulu, *Graduate Student Member, IEEE*, Timothy M. Hansen, *Member, IEEE*

***Abstract*—With grids evolving into smart grids and communication systems deeply integrated into the grid, demand side management has gained greater significance in the operation of the electrical power system. This work presents an incentive-based demand response (DR) model for demand response aggregators (DRA) to participate in the bulk power market through a new entity Demand Response Exchange market (DRX). With the proposed model, we study the economic impact of DR on the system clearing price and the total benefit obtained. This model provides the amount each entity has to pay for the benefit they get out of the DR program. We tested the proposed model on PJM 5-bus system under various loading conditions, and compared each entities surplus before and after implementing DR.**

I. Introduction

With ever increasing demand and limited transmission capacity, the electric power system is pushed to its security limits during peak hours. To avoid such situations, the independent system operator (ISO) usually resorts to use expensive peaking generators to meet the load. With advancement in communication systems and distributed generation, the grid is evolving into smart grids allowing the ISO to implement demand side management techniques to manage peak loads. The regulatory bodies (FERC) have made necessary amendments to the existing structure to facilitate demand response (DR).

Even though the FERC orders 719 and 745 have made provisions for the ISOs in the U.S. to accept DR bids like any other resource in the market [1], the ISOs have reserved a cap on the minimum accepted bid. This cap discourages potentially small customers from participating in the DR program. Also, it is largely debated and acknowledged by FERC that the compensation for DR service is not encouraging which may lead to under investment in DR services. The proposed model aims to provide an encouraging environment for the DRA to participate as they don't directly bid into the ISO, but interact through a non-profit entity DRX who aggregates all the bids and provides the information as a service to the ISO.

II. Proposed Model

The DRA in the proposed model is an entity with a set of customers who are willing to curtail or shift their loads. The aggregator has to bid into the DRX a non-profit entity, which is organized by the ISO in a fully deregulated market [2]. During an event of market inefficiency, the ISO triggers the DRX, calling for DR bids for the day-ahead market. The DRA bid into the market with the aggregated power available from their customers who are willing to shift or curtail their loads. The most cost effective bids are cleared by the DRX and the curtailment information is sent to the ISO. Depending on the duration and the quantity of DR the aggregator chooses the most economical assets to be used for that particular event. The model also addresses the compensation to the DRA by charging the benefited entity proportional to the gain obtained by DR service.

III. Key Figures

Fig. 1 shows the flow of power, money, and bids with the aggregators in the market. Fig. 2 shows the time scale events on a typical day-ahead market with the DRX.

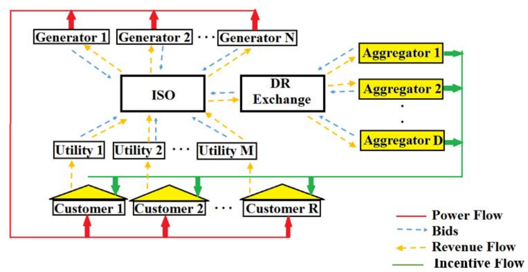


Fig. 1: Proposed Model of Demand Response Aggregator interacting with Demand Response Exchange Market

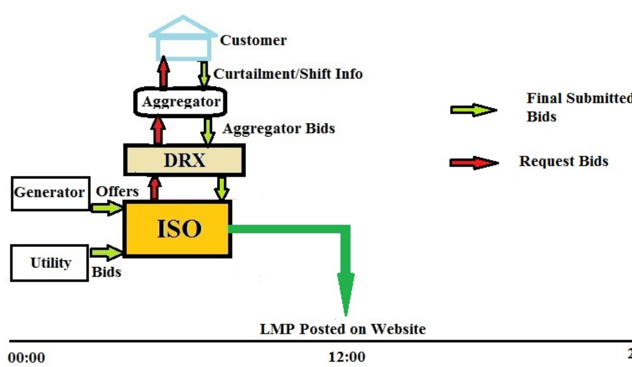


Fig. 2: Time scale events for day-ahead market with demand response exchange

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Impact of Transmission Tariff on Price Arbitrage Operation of Energy Storage System in Alberta Electricity Market

A.I. Adebayo, H. Zareipour, A.M. Knight
University of Calgary, Canada. abiola.adebayo@ucalgary.ca, andy.knight@ucalgary.ca

***Abstract*—this work investigates the impact of transmission tariff on arbitrage operational profitability of energy storage in the Alberta electricity market. While the tariff policy is under review to ascertain its applicability on energy storage facilities, we review the impact of the application of existing tariff structures to understand the potential impact on the economics of operating energy storage facilities for arbitrage.**

Keywords—tariff; arbitrage; energy storage; electricty market

I. INTRODUCTION

Increasing commercial interest in investment into energy storage system (ESS) in Alberta has made it necessary to investigate important factors that can affect the profitability of their arbitrage operation in Alberta electricity market. Factors such as capital cost, operation and maintenance cost, price variation, storage and conversion efficiency are some of the factors known to impact operational profitability of ESS. One other factor, however, which is unique to each electricity market is the transmission tariff. The current tariff structure in Alberta was not formulated with consideration of bulk energy storage facilities. However, the fact their operation modes can be regarded as either generation or load has led to suggestions that the current tariff structure for demand and supply may be suitable.

II. TRANSMISSION TARIFF IN ALBERTA

Alberta's electric system is legislated to be congestion free, requiring continuous investment in transmission facility such that there is always enough transmission capacity available for any device to connect to the grid irrespective of the location. The costs incurred by ensuring that the system always meet this legislative requirement are significant, and this cost is recovered from the participants in the electricity market through transmission tariffs. The existing tariff rates that may be applicable to ESS are[1]:

DTS Rate: This tariff is applicable to all demand and may be applied to a storage facility during charging operation, given that an ESS draws power from the grid just like any other load. The details of this tariff are given in the table 1. The most significant component of the DTS is the coincident metered demand. This charge is applied to the metered demand during the 15 minute interval of peak system demand in each month.

STS Rate: This tariff, applicable to ESS while discharging, is the product of metered energy, price and loss factor which is determined by the Independent System Operator (ISO).

Table 1: DTS tariff breakdown[1]

Volume in Settlement Period	Charge
Bulk System Charge	
(a) Coincident metered demand	$5,033.00/MW/month
(b) Metered energy	$1.68/MWh
Local System Charge	
(c) Billing capacity	$1,243.00/MW/month
(d) Metered energy	$0.70/MWh
Point of Delivery Charge	
(e) Substation fraction	$10,926.00/month
(f) First (7.5 × substation fraction) MW of billing capacity	$7,401.00/MW/month
(g) Next (9.5 × substation fraction) MW of billing capacity	$2,732.00/MW/month
(h) Next (23 × substation fraction) MW of billing capacity	$1,655.00/MW/month
(i) All remaining MW of billing capacity	$907.00/MW/month

III Operational Impact of DTS

A self–scheduling optimization model that optimizes arbitrage profit, is used to estimate operational profit, metered energy, operating hours and storage capacity utilization. The model is run with and without transmission tariff scenarios. Figure 1 shows the average power flow at a given hour of the week, for a case study evaluating operation over a 5-year period.

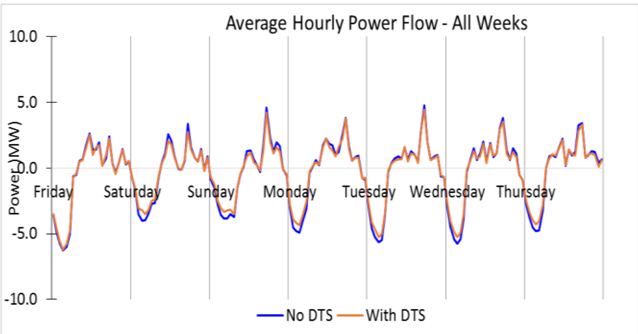

Figure 1: 5 year average hourly schedules

IV References

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Guide to Selecting Transmission Lines for Dynamic Line Rating

Leanne Dawson, Andrew M. Knight
Department of Electrical and Computer Engineering, University of Calgary

***Abstract*— With an increased focus on renewable power generation, dynamic line rating is being investigated as a way to connect the new intermittent generation to the grid without needing to build additional infrastructure.**

I. INTRODUCTION

Presently, a static thermal rating is typically used to calculate the maximum ampacity of transmission lines, based on nominal environmental conditions. Dynamic line rating is an alternative approach that takes into account changing environmental conditions to update the rating. Both the static rating and the dynamic line rating are calculated based on a set of thermal equations described in IEEE Standard 738[1]. The potential rating increase is based on line length and environmental conditions, most notably wind speed. The maximum length of line that is subject to the thermal ampacity limit is defined using the transmission line loadability curve, otherwise known as the St. Clair curve[2]. For longer lines, the transmission line loadability curve is based on the voltage drop across the line.

II. RESEARCH

Initial research to identify lines suitable for dynamic thermal rating considers the intercept between the thermal ampacity limit and the voltage quality limit. Including the nominal line resistance in the calculations of the voltage quality (VQ) curve has a significant impact on the VQ curve. The maximum length of transmission line that is thermally limited decreases significantly when resistance is included in the voltage drop equation. Fig. 1 demonstrates the effect of including a constant resistance for different voltage levels, calculating the ampacity at nominal environmental conditions.

For longer lines, the transmission line loadability curve is dependent on voltage drop and resistance. However, the resistance of a conductor is based on conductor temperature, and as demonstrated in IEEE Standard 738[1], the current rating is related to convection cooling due to wind. This research investigates the effect on resistance if the voltage drop is constant and convection cooling is considered. The resistance decreases due to convection cooling, allowing more current to flow through the line. The increase in current would subsequently increase the resistance, creating a new current rating. This process is repeated until an equilibrium point is found. Fig. 2 shows the increase in current rating due to convection cooling for longer lines, compared to the curve considering constant resistance. It demonstrates that dynamic calculation of the environmental conditions impacts both the thermal limit and the voltage quality limit.

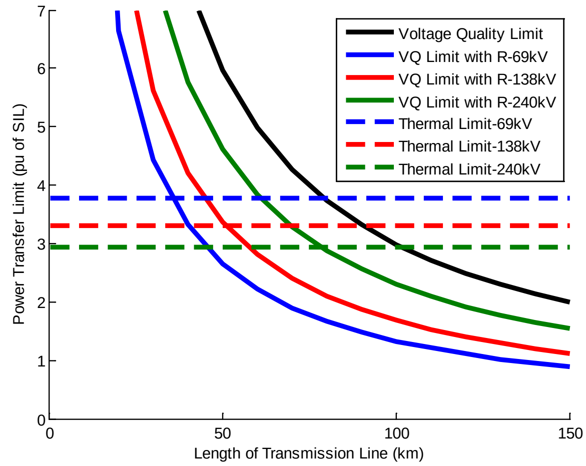

Fig. 1: Impact of Resistance of Line Loadability

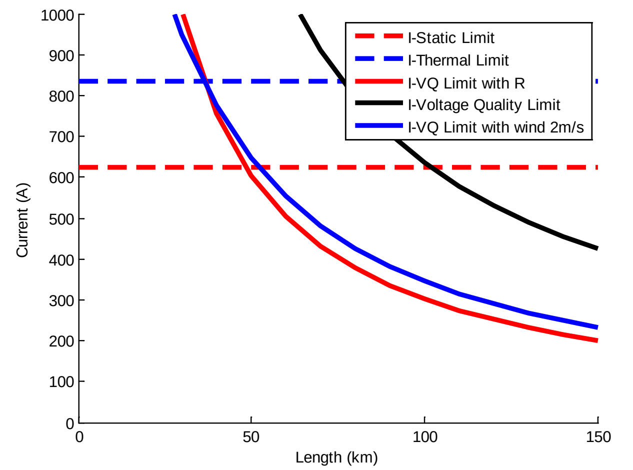

Fig. 2: Impact of Convection Cooling on Line Loadability for 138 kV

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Using Optimal Potential of Incentive and Price Base Demand Response to Reduce Costs and Price Volatility

Ailin Asadinejad Kevin Tomsovic
Department of Electrical Engineering and Computer Science
University of Tennessee
Knoxville, Tennessee
aasadine@utk.edu

***Abstract* --- There are two general categories of demand response (DR): price-based and incentive-based (IB) DR programs. Each one has its own benefits taking advantage of different aspects of flexible demand. In this paper, both categories of DR are modeled based on the demand-price elasticity concept to design an optimum scheme for achieving the maximum benefit of DR. The objective is to not only reduce costs and improve reliability but also to increase customer acceptance of a DR program by limiting price volatility. Time of use (TOU) programs are considered for a price-based scheme designed using a monthly peak and off-peak tariff. For the incentive-based DR, a novel optimization is proposed that in addition to calculation of an adequate and a reasonable amount of load change for the incentive, the best times to realize the DR is found. This optimum threshold maximizes benefit considering the comfort level of customers as a constraint. Results from a reduced model of the WECC show the proposed DR program leads to a significant benefit for both the load serving entities (LSEs) and savings in customer's electricity payment. It also reduces both the average and standard deviation of the monthly locational marginal price (LMP). The proposed DR scheme maintains simplicity for a small customer to follow and for LSEs to implement. key result**

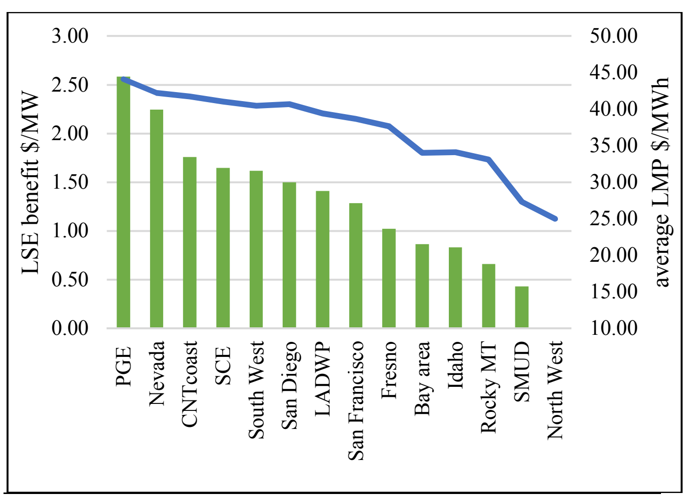

Figure 1: LSE benefit and customer saving per total load

Proposed program scheme according to Figure 1 brings comparable benefit for both customers and load aggregators that makes it fair and appropriate program for all participants. In addition, as it shown in Figure 2 this DR program has considerable effect on reducing market peak price.

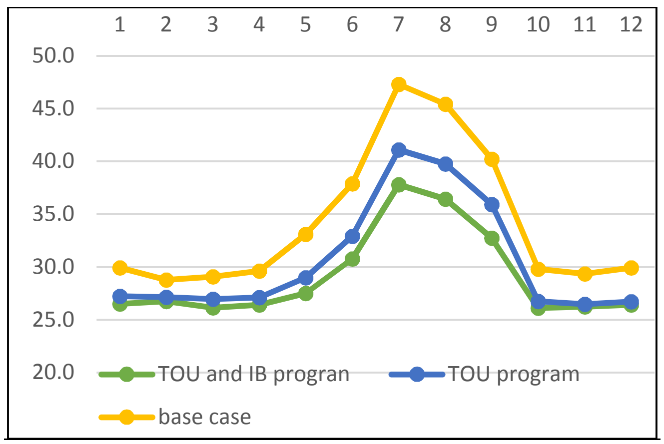

Figure 2: San Diego monthly average LMP

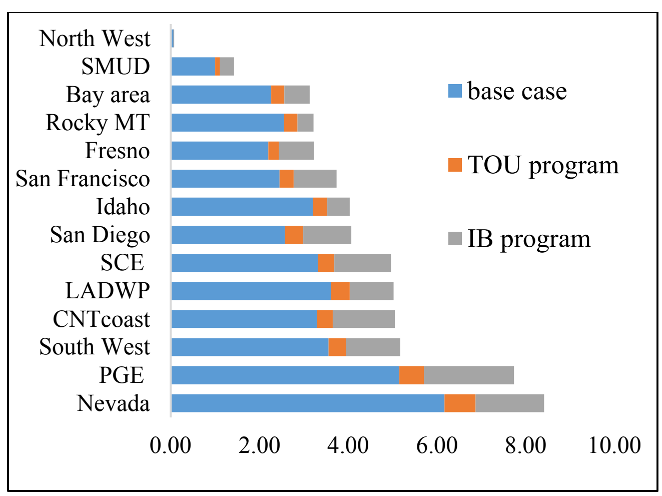

Figure 3: LSE benefit per total load

Day Ahead Solar Irradiance Forecasting using Markov Switching Model for Remote Microgrids

Ayush Shakya, Semhar Michael, and Reinaldo Tonkoski
Department of Electrical Engineering and Computer Science, South Dakota State University, Brookings, SD
Email: ayush.shakya@sdstate.edu

***Abstract*—Photovoltaic (PV) systems integration is increasingly being used to reduce fuel consumption in diesel based remote microgrids. However, low correlation of PV power availability with load and uncertainty reduces the benefits of PV integration. These challenges can be handled by introducing reserve, which causes an increment in the operational cost. Solar irradiance forecasting helps in reducing the reserve requirement. A new solar irradiance forecasting method for remote microgrids based on Markov Switching Model is presented here. This method makes use of open source, historical irradiance data to predict one day ahead solar irradiance for scheduling remote microgrids energy management systems. The model considers clear sky irradiance (CSI) and Fourier basis functions for three regimes or states: high, medium and low energy regimes for a day corresponding to sunny, mildly cloudy and extremely cloudy day, respectively. A case study for validation of the algorithm for Brookings, SD showed Root Mean Square Error (RMSE) of 50 W/m^2 for June 14, 2008. The error assessment showed that RMSE was higher during summer season and lower during winter season. This method is expected to benefit energy management system of the remote microgrids.**

***Index Terms*—Clear Sky Irradiance (CSI), Fourier Basis Expansion, Global horizontal irradiance (GHI), Markov Switching Model, Root Mean Square Error (RMSE)**

I. Key Equation

$$y_t(S_t = k) = \beta_{k,1} CSI(t) + \sum_{i=1}^{p} \beta_{k,1i}\phi_{1i}(t) + \sum_{j=1}^{q} \beta_{k,2j}\phi_{2j}(t) + \epsilon_k(t), \quad (1)$$

II. Key Figures

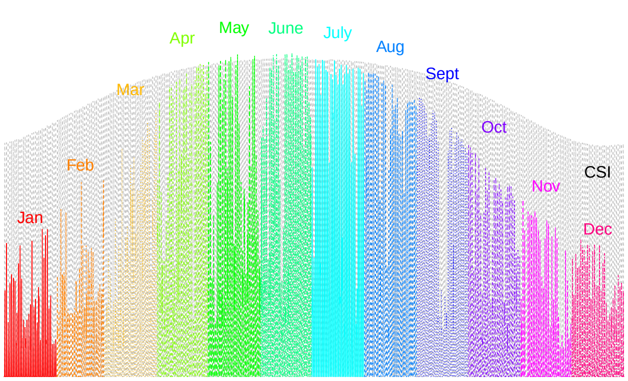

Fig. 1. CSI for a year along with actual irradiance for the year 2001.

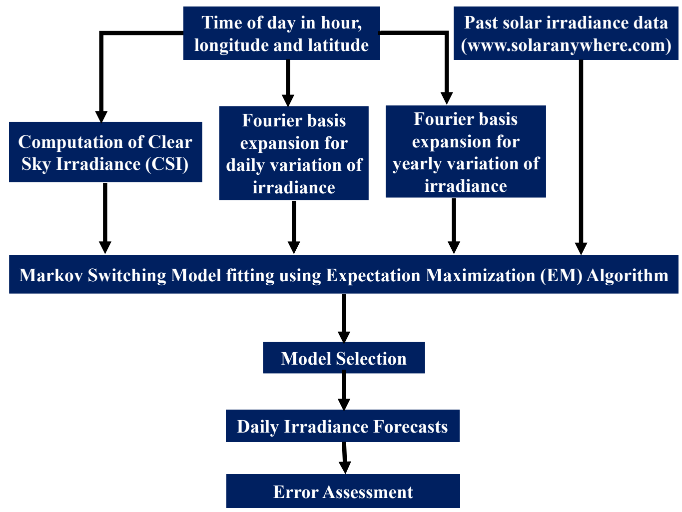

Fig. 2. Flowchart for solar irradiance forecasting using Markov Switching Model.

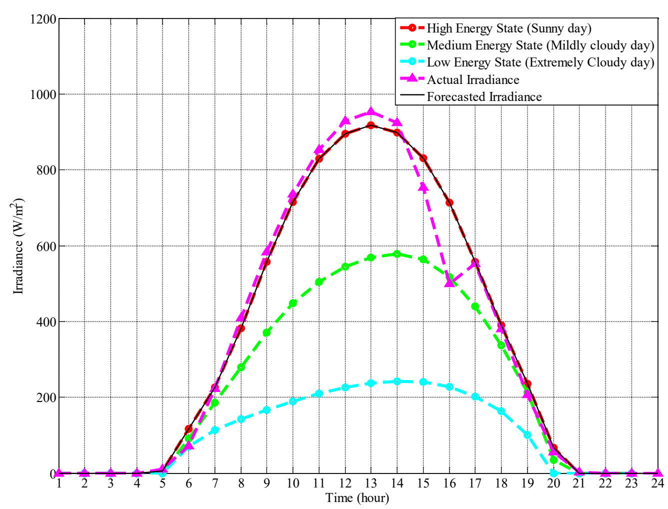

Fig. 3. Irradiance variation for June 14, 2008.

Implementation of an IDMS for Volt/VAR Optimization Testing

Paul E. Rankin, *Student Member*, *IEEE*, Jonathan A. Tribble, *Student Member,* IEEE, and Estefano Joniaux, *Student Member*, *IEEE*
Department of Electrical and Computer Engineering
University of North Carolina at Charlotte, Charlotte, NC
prankin4@uncc.edu, jtribble@uncc.edu, ejoniaux@uncc.edu

***Abstract*—An Integrated Distribution Management System (IDMS) is the next big step in grid monitoring, control, and optimization. An IDMS is able to measure and read the grid continuously in real-time in order to achieve a variety of goals. The functions of an IDMS are many; its applications include fault identification and isolation, real-time monitoring, calculation, and optimization of parameters within the grid. This research, as part of a senior design project, focused on investigating effects of load volt/var management (LVM). Through the development and testing via simulation of various LVM formulations, a business case for IDMS is proposed.**

I. Introduction

ONE way an IDMS can be used to optimize the grid is by providing Volt/Var support to various buses in the grid. An IDMS will do this by monitoring the parameters within a distribution system, such as voltage, power factor, and current, and then adjust capacitor banks, transformer taps, and line voltage regulators in order to ensure that numerous conditions are met. This support can achieve a variety of purposes from improving power factor to reduce line losses to reducing overall demand if there is concern about a possible power shortage or brownout. Even though these operations are performed separately now, they can be performed quickly and continuously when an IDMS [1] is utilized. The purpose of the project is to set up a model of a distribution system upon which one can observe the effects of an IDMS utilizing Load Volt/VAR Management (LVM) problem formulations to determine if such a system would be beneficial [2]. The analysis is performed using software provided by GE Alstom. The problem formulations developed is robust and powerful enough to realize significant changes within the distribution system. A business case based on the results is also being devised to support implementation of such a system.

II. Key Figures

A preliminary study case of Volt/VAR optimization on a model adapted from the IEEE 13 bus distribution system was performed. This was done by taking a baseline model as shown in Figure 1, adding capacitors to correct power factor as shown in Figure 2, and finally adjusting the transformer taps to reduce bus voltages for conservation voltage reduction (CVR), as seen in Figure 3.

III. Key Results

The system voltage profiles for the different cases are shown in Figure 4. It is noted how a flatter voltage profile, higher power factor (from 0.84 in the baseline to 0.94) and overall lower voltages as desired for CVR are achieved.

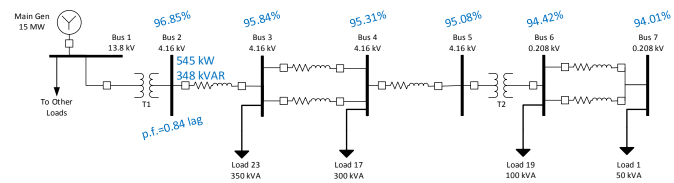

Fig. 1 Baseline Feeder for Volt/VAR Optimization

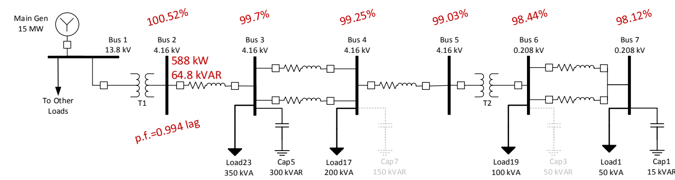

Fig. 2. Model with Capacitors for Power Factor Correction

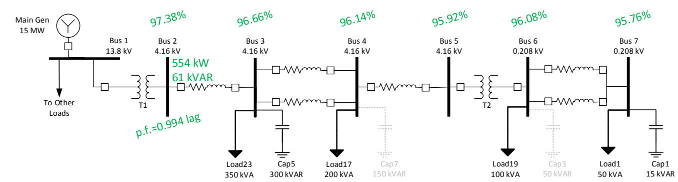

Fig. 3. Model with Adjusted Transformer Taps

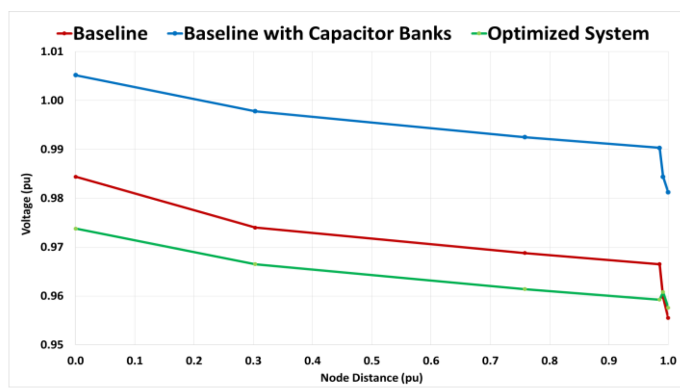

Fig. 4. Feeder Voltage Profile (Voltage [pu] vs Node Distance [pu])

IV. Conclusions

The proposed method shows that the voltage profile can be optimized in coordination with control devices resulting in better voltage profile. The algorithms developed using Alstom software also indicates that a business model can be developed.

V. References

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Microgrid Testbed for the Development of Energy Management Systems using Commercial Off-The-Shelf (COTS) Inverter/Charger

Shaili Nepal, Ayush Shakya, and Reinaldo Tonkoski
Department of Electrical Engineering and Computer Science, South Dakota State University, Brookings, SD
Email: ayush.shakya@sdstate.edu

***Abstract*—In this paper, a methodology of real time control of battery inverter/charger is implemented in OPAL-RT system. This system is a hardware based real time system. Microgrid test bed is composed of 5 kW PV, 3.5 kW natural gas generator, 6 kW inverting/charging system, 8 kWh lithium iron battery system and programmable loads upto 5 kW . The inverter/charger control algorithm is tested in the microgrid test bed. The protocol used in control of inverter/charger and battery system is Controller Area Network (CAN) protocol. This methodology is for commercial microgrids using a COTS inveter making the system economical. The laboratory scaled microgrid test bed is located in South Dakota State University, Brookings, SD.**

***Index Terms*—Battery, CAN, COTS, Hybrid Inverter/charger, Microgrid**

I. Key Figures

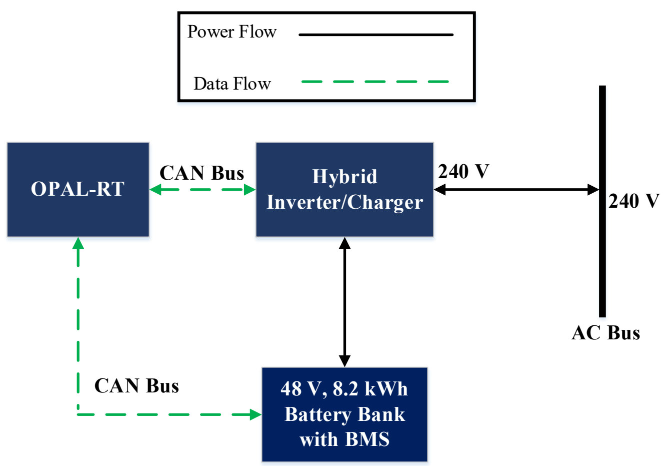


Fig. 1. Block diagram of experimental set up for real-time control of hybrid inverter/charger.

Frequency-Dependent Impedance Calculation for Electric Power Lines

Layton Hall, *Student Member, IEEE*, Hunter Damewood, *Student Member, IEEE*,
Bikash Poudel, *Student Member, IEEE*, Valentina Cecchi, *Member, IEEE*
Electrical and Computer Engineering Department
University of North Carolina at Charlotte
Charlotte, North Carolina, United States
lhall67@uncc.edu, hdamewoo@uncc.edu

***Abstract*—An approach for calculating frequency-dependent impedance of electric power lines has been the focus of this undergraduate research project, presented in this abstract. Frequency-dependent characteristics due to the effect of ground return and the skin effect are taken into account. The calculated impedances are used in frequency-dependent line models to study the propagation of non-fundamental frequency components of power systems voltages and currents. Commonly used ACSR cable types are considered. Line model frequency response from 1 to 1500 Hz is calculated and presented graphically for 25 types of 1-mile long ACSR cables. These values can be used in frequency-dependent line models or tabulated for further analysis of harmonics in the power grid.**

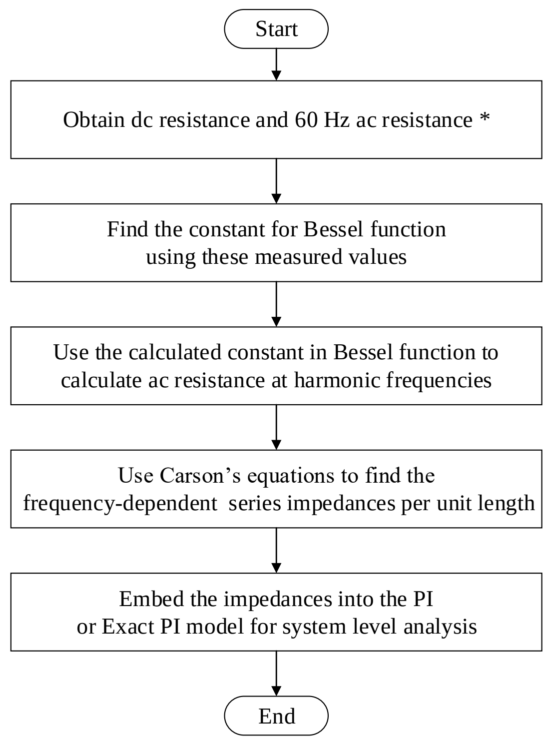
Keywords—frequency-dependent impedance, skin effect, power system, harmonics

I. Introduction

The electrical parameters of the line, i.e. series resistance, series inductance, shunt capacitance and shunt conductance are frequency dependent [1]. Frequency dependent characteristics due to the skin effect and the effect of ground return are more noticeable for series resistance and series inductance [2]. Manufacturers provide only the dc resistance and ac resistance of the cables at 60 Hz. The ac resistance calculated from the Bessel functions [3] differ from the value provided by the manufacturer. In this work, the constants used in the Bessel functions are derived based on the given/empirically determined dc resistance and 60 Hz ac resistance; the newly calculated constant is used to determine the conductor ac resistance at other harmonic frequencies. Calculations on several standard ACSR cables are performed. The work is part of an undergraduate research project in support of the development of highly accurate frequency-dependent line models to be used for harmonic power flow.

II. Calculations

The given dc resistance and 60 Hz ac resistance are utilized to find the constant applied in the Bessel functions [3]. Bessel functions are then used to calculate the ac resistance of the line at multiple frequencies. The focus of this particular work has been on single-phase lines, thus far. The ac resistance of the cable is then used in Carson's equations [4] to include the effect of ground return. The determined per unit length frequency-dependent series impedance can be used in simple PI or exact PI model structures [1], which can be easily integrated in system level analysis tools, such as Harmonic Power flow. A simplified flowchart of the proposed approach used to identify frequency-dependent line impedance is shown in Figure 1 below.



*This information is the measured value given by the manufacturer at a conductor temperature of 55^{o} Celsius.

Fig. 1. Flow Chart of the Proposed Approach Used to Determine Frequency-Dependent Line Impedance

References

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MICROGRID DEVELOPMENT IN AFRICA

Yin Mak, Alexandra Schleicher, McLean Sloughter PhD

Department of Electrical Engineering and Mathematics, Seattle University

Abstract- Energy poverty is an unfamiliar concept to many people, but can be a serious impediment to economic mobility in the areas it affects. In Muhuru Bay, Kenya, as in many areas without regular access to electricity, when the sun sets, all activities would come to a halt. In 2014 KiloWatts for Humanity (KWH) traveled to Kenya to work with local partners and installed an energy kiosk powered by solar panels and wind turbines. Portable battery kits paired with LED lights were rented out and returned for bi-weekly recharging. Using statistical analysis, our project aims to inform the development of best practices for the installation of microgrids in developing countries.

The first phase of our research involved data retrieval from KWH's Linux cloud server. A data logger installed in Muhuru Bay records and transmits data from the kiosk to the server every minute. The transmission includes information ranging from total energy accumulation and solar power to temperature. Our primary interest was to use cumulative energy consumption data to track energy usage trends at the kiosk. We utilized Matlab to format the raw data and transform it into a workable form. The first significant outcome was formed when we applied a linear regression line with the energy consumption data. The result showed that power was being consumed at a relatively constant rate over the study period, which is to say the coefficient of determination was relatively close to 1. This conflicted with our prediction of an eventual drop in usage as initial interest waned. A second significant outcome was produced when the energy consumption data was parsed by week and then by day. We discovered that all days displayed the same general behavior, despite what day of the week it was. As a result, an average day in the Muhuru Bay kiosk was computed. As shown in figure 1, we calculated the average energy consumption at each minute of the day and plotted it on a graph. This produced a load profile which is useful for predictions as well as daily comparison. Changes in energy usage habits are easily observed by referencing the load profile. We determined how power was being used throughout the day, the week and the month.

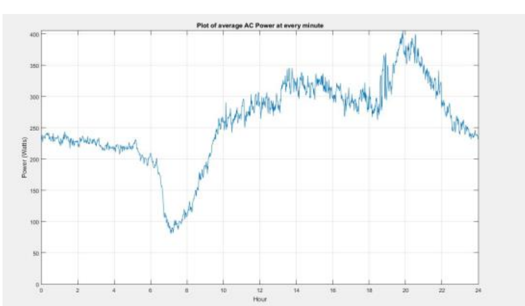


Fig 1. Average day

The second phase of our research was in preparation for another energy kiosk installation in Chalokwa, Zambia. In addition, an assessment team conducted 48 surveys and 11 detailed interviews with community members in Chalokwa. We compiled the information in Excel and used SPSS to create graphical representations of the data for easy consumption. Through analysis we were able to represent the community's current electrical situation. We found that a majority of the villagers owned cell phones and nothing else, with a small percentage also owning radios. Different households were compared to determine which type of individual had access to more electrical devices, and thus, wealth. The electrical desires of the villagers was also surveyed, and among other things it was found that the demand was highest for security lighting. The results of the surveys were presented to KWH's business team and microgrid design team to inform the plans for this new kiosk.

The third and final phase of our research was a culmination of our earlier work. At this phase the microgrid design team was determining the specifications for the electrical system in Chalokwa. As part of the team, we used the HOMER software package to determine the most efficient way to meet the predicted energy needs of the village. The primary interest was balancing the number of batteries and solar panels to purchase within the budget limitations. The survey results told us what the Chalokwa villagers wanted, and the data from Muhuru Bay provided real world context to reference. As shown below in figure 2, the energy load profile from Muhuru Bay was used as one of the baselines for predicted usage in Chalokwa. Generally speaking a higher overnight load resulted in a system requiring more batteries, whereas a higher day time load required more solar panels. The cost of each component was entered along with information about the location itself and the expected energy usage of the site. The cost to develop such a system was provided by the software. These results will be used to develop a system proposal for the new kiosk. Using this analysis KWH designed an optimal system given the total budget for the project. In June 2016 a team will travel to Chalokwa to complete the installation we have all been preparing for.

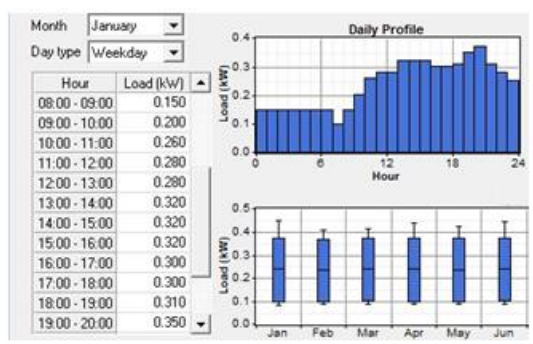


Fig 2. Load profile in HOMER

Projects such as this one are still a relatively new endeavor, and best practices are evolving or have yet to be established. Our work aims to bring information full-circle, allowing experiences from previous installations to inform the development of each new project. This work can facilitate evidence-based implementations for future projects in both our own and other organizations.

Optimal Planning of Urban Microgrids with an Energy Management System

Mike Quashie, *Student Member IEEE*
Geza Joós, *Fellow IEEE*
Department of Electrical and Computer Engineering
McGill University
Montreal, Canada. H3A 0E9
Email: mike.quashie@mail.mcgill.ca, geza.joos@mcgill.ca

***Abstract*—This paper proposes a bi-level planning strategy that optimally configures an urban microgrid to maximize its benefits. The work implores the karush- Kuhn-tucker (KKT) condition to transform the two level formulation into a single level mixed integer linear programing. The optimization strategy receives the modeled thermal and electric load as input and simultaneously size and optimize the output of the distributed energy resources through the implementation of an energy management system (EMS). It further analyzes the available investment options of the microgrid using capital budgeting techniques to determine the return on investment to a microgrid stakeholder. The approach, though applicable to all microgrids, is developed within the context of an urban microgrid. Results obtained through its application show significant savings in energy cost and related microgrid benefits to stakeholders.**

I. Key Equations

Design – Upper Level Problem:The main of objective is to minimize annualized investment cost, operation cost and cost of energy unserved.

$$\min_{x\geq 0} \gamma \sum_{y\in Y} \left\{ \varrho_y \sum_{i\in B} C_i^{inv} x_i + \sum_{t\in T} C_y(x,p,t) + \sum_{t\in T} C_y^{eus}(t) \right\} \tag{1}$$

Main Constraints:

- Budget constraint
- Maximum available capacity of DERs to be installed

EMS – Lower Level Problem: The main of objective is to hourly fuel (C_i^f) and emmission (C_i^z)cost, utility electric power $(P_g^e(t))$ and heat $(P_g^h(t))$cost .

$$\begin{aligned} C_y(x,y,t) = \\ \min_{P} \sum_{i\in D} \quad & (C_i^f + C_i^z) P_i^e(t) + C_g^e P_g^e(t) \\ & + C_g^h P_g^h(t) + \textstyle\sum_{i\in B} C_i^m x_i \end{aligned} \tag{2}$$

Main constraints:

- Electric and Thermal Power balance
- Generation limit
- Operational limit of storage resource
- Limit on energy avaialable for demand response

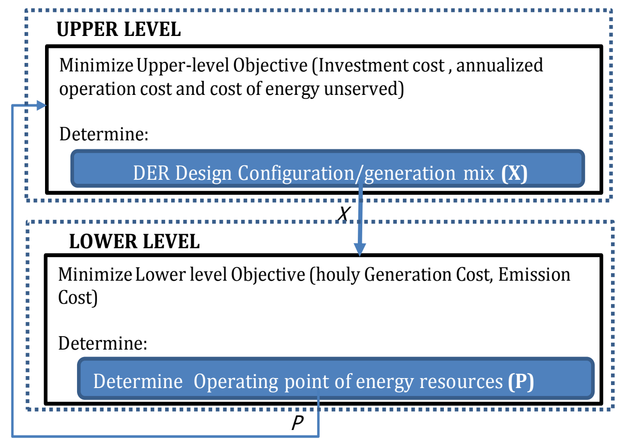


Fig. 1. Schematic diagram of the bilevel design-operating model.

II. Key Results

The base unit for cost in table I is 1000 whiles in fig. 2 the cost of energy in the base case is the base unit.

TABLE I
Optimal Microgrid Configuration

Wind (kW)	CHP (kW)	Storage (kWh)	Cost (p.u)
2900	1200	1740	1333

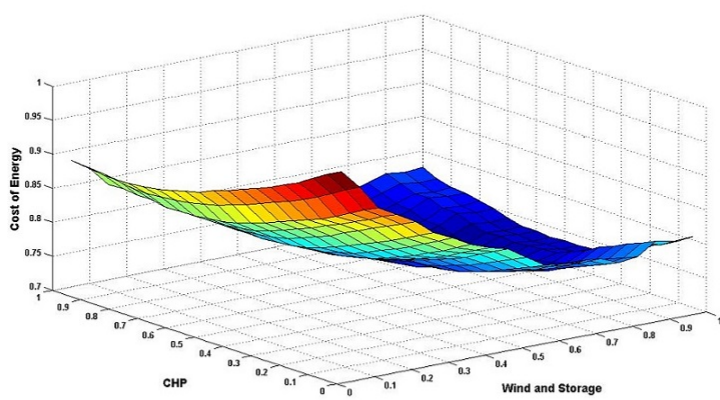


Fig. 2. Effect of penetration level of energy resources on cost of energy

PMU-based Reduced-order Modeling of Power System Dynamics via Selective Modal Analysis

Benjamin P. Wiseman, Yang Chen, Student Member, IEEE, Le Xie, Member, IEEE and P. R. Kumar, Fellow, IEEE
Department of Electrical and Computer Engineering
Texas A&M University
College Station, USA

Abstract—**This poster investigates how to perform online system identification employing synchrophasor data. Two approaches to identifying a reduced-order model are presented: a purely data-driven approach, and an approach that integrates online data-driven dynamic system identification with first principle offline selective modal analysis. With prior knowledge of the frequency range interesting to power system operators, it is shown that the second approach recovers the key modes of the original system and produces a much reduced-order model of grid-level dynamics. Even with the presence of uncertainty about the actual modes of interest, an automatic tuning scheme is devised to adaptively adjust the frequency range to improve system identification. Numerical examples with synthetic synchrophasor data demonstrate the efficacy of the proposed identification approach.**

Keywords—Phasor measurement unit (PMU), data-driven modeling, system identification, selective modal analysis (SMA).

I. Introduction

This work is motivated by the increasing complexity of power system dynamics and the need for reducing such complexity in online monitoring and control. On one hand, the grid structure is undergoing significant changes as more and more alternative resources are integrated into the system. On the other hand, new monitoring devices, such as synchrophasors, provide improved capability for online adaptive modeling and control of power system dynamics. Combined with continued advances in computing, the availability of large quantities of synchrophasor data could enhance monitoring and control for large power systems.

II. Novel Intergrated Approach

Our key contribution is the development of an integrated approach combining online data-driven dynamic system identification with first-principle-based offline selective modal analysis, described in [1].

Let a linear state-space model of a dynamic system be obtained from first-principle offline modeling:

$$\dot{\mathbf{x}} = \mathbf{A}\mathbf{x} + \mathbf{B}\mathbf{u}. \quad (1)$$

From the eigenvalues of $\mathbf{A}$, h modes can be selected according to either a frequency range or a damping ratio of interest. Then, the participation matrix $\mathbf{P}$ can be calculated, measuring the association between the state variables and the modes [2]. This matrix can be used to determine the l_G relevant states that contribute most to the h modes. SMA is then applied to obtain a low-order system G that retains the desired h modes.

If the dynamic model for G can be achieved accurately from first-principle offline modeling, then online data-driven identification targeting a specific frequency range can be directly applied to recover a mode of interest. This process assumes that the input/output data for the identification is selected from the relevant states of the mode of interest.

Since changing operating conditions in real power systems prevent offline studies from obtaining an accurate dynamic model, we have also proposed an automatic tuning scheme to adaptively adjust the frequency range of online data-driven identification to account for small errors in the offline model.

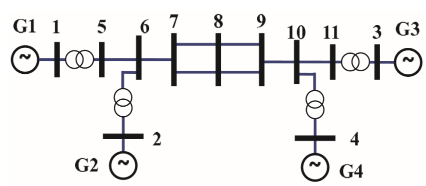


Fig. 1. Topology of simulated system [2].

This integrated approach was applied to synthetic synchrophasor data from a 4-generator, 28th-order system [2] modeled in MATLAB. A reduced-order model was obtained using SMA, and a 2nd-order system was estimated from the data. This model accurately contained the mode of interest.

III. Conclusions

This work demonstrates the significant potential to use synchrophasor data for online identification of power system dynamics. Future work will validate this approach by using real-world measurements, as well as investigating piecewise system dynamic modeling for frequency ranges of interest.

References

[1] I. J. Pérez-Arriaga, G. C. Verghese, and F. C. Schweppe, "Selective modal analysis with applications to electric power systems, part I: Heuristic introduction," Power Apparatus and Systems, IEEE Transactions on, no. 9, pp. 3117–3125, 1982.

[2] P. Kundur, N. J. Balu, and M. G. Lauby, Power system stability and control. McGraw-hill New York, 1994, vol. 7.

This material is based upon work partially supported by NSF under Contract No. CPS-1239116, ECCS-1150944, DGE-1303378, and NSF Science & Technology Center Grant CCF-0939370.

Frequency and Voltage Control of Isolated Micro-grid Using Droop Control Approach

Lekhnath Kafle, *Student Member, IEEE, Reinaldo Tonkoski, Member, IEEE* and Zhen Ni, *Member, IEEE*
Department of Electrical Engineering and Computer Science, South Dakota State University, Brookings, SD
Email: lekhnath.kafle@sdstate.edu

***Abstract*—Micro-grid can be operated in grid connected and isolated mode. In grid connected mode, frequency and voltage can be maintained by utility grid whereas in isolated mode, frequency and voltage fluctuation are major problem because of the intermittent nature of renewable resources like wind and solar. Our work focuses on frequency and voltage control of hybrid wind and Photovoltaic (PV) isolated micro-grid using battery inverter droop control technique. In droop control of inverter, active power can be controlled by regulating difference in frequency and reactive power can be regulated by regulating change in voltage magnitude of micro-grid. Droop control helps to generate reference voltage and frequency for the inverter control mechanism. The instantaneous active and reactive power can be determined by using measured micro-grid voltage and current which is then fed to low pass filter to obtain average active and reactive power. Then, reference parameters are generated using droop equations. With this, inverter outputs required power in addition to wind and solar PV to balance load and generation.**

***Index Terms*—droop control, frequency fluctuation, hybrid generation, isolated mode, micro-grid, voltage fluctuation**

I. PRINCIPLE

The proposed system module of AC micro-grid consists of wind generation, PV generation and battery storage system as shown in Fig. 1. During isolated mode, it is required to maintain balance between load and generation. This can be achieved by the help of a voltage source inverter (VSI) with droop control technique. The simplified block diagram of overall control system for VSI with droop technique is shown in fig. 2.

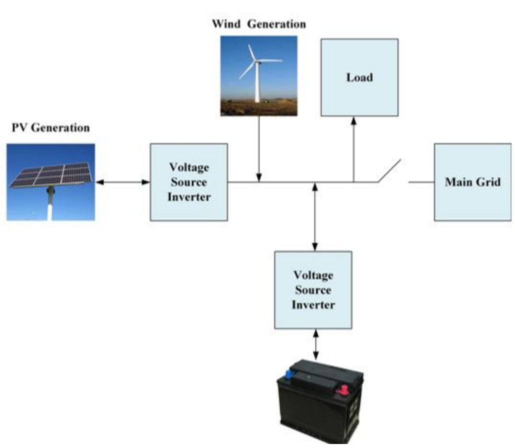


Fig. 1. A proposed system model representing micro-grid with battery storage system.

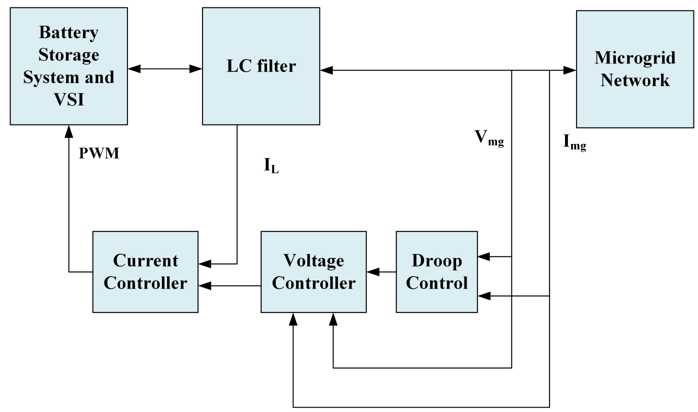


Fig. 2. Power circuit and control block diagram of inverter interfaced battery system with droop conrol

II. PRELIMINARY RESULTS

Fig. 3 shows the power balance between generation and consumption in presence of utility grid. We expect similar balance in load and generation in absence of grid with help of inverter interfaced droop controlled battery storage system.

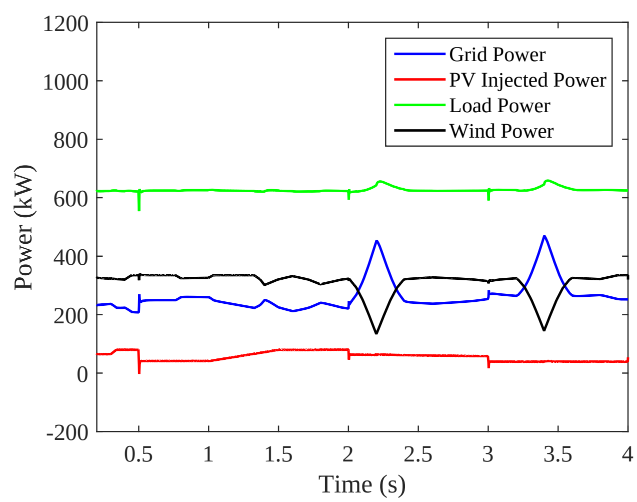


Fig. 3. Validation of total power generation and consumption in variable wind speed, variable irradiance and temperature during grid connected mode

Wide-area Control Design for Damping Inter-area Oscillations in Power Networks

May Mahmoudi and Kevin Tomsovic
Department of Electrical Engineering and Computer Science
University of Tennessee, Knoxville, Tennessee 37996-2250
Email: {mmahmoud, tomsovic}@utk.edu

***Abstract*— The next generation of the electricity grid, also known as "Smart Grid", is one of the most complex cyber-physical systems (CPS) due to its extreme dimension, geo-graphic reach, and high reliability requirements. One of the main concerns for secure and reliable operation of power systems is the small signal stability problems caused by inter-area oscillations. In the future grid, enhancing the transfer capability while maintaining system stability requires damping these oscillations. In this poster, we proposed a wide-area optimal control framework using group sparse regularization functions. The proposed control aims to optimize a standard cost criterion while penalizing the number of communication links. The group sparse regularization approach is used to induce a desired communication structure and encode prior information about the underlying system into the control design. We present two applications of the proposed algorithm for damping inter-area modes in power networks. Our results suggest that the proposed method provides flexibility in designing wide-area type controls by allowing for a pre-defined communication structure. It can also act as an alternative approach to modal analysis methods in finding effective measurement-control loops in the system. The ability to encode system constraints in the control design objective is another major advantage of the method.**

Risk Analysis of Weather Impacts on Outage Management in Distribution System

Po-Chen Chen, Tatjana Dokic, and Mladen Kezunovic
Department of Electrical and Computer Engineering
Texas A&M University
College Station, Texas, 77840, USA
pchen01@tamu.edu, tatjana.djokic@tamu.edu, kezunov@ece.tamu.edu

***Abstract*— Weather impacts are one of the main causes of distribution outages. The proposed risk analysis allows utility operators to achieve more precise outage prediction and optimize real time operation. The experiment results show that the summer rainfall amount is highly correlated with the geographical locations.**

I. Introduction

Weather impacts are the main causes of electrical outages in the US. The incidence and severity of weather conditions and major outages show a growing trend since 1992, and projections are that they will to increase in the future due to climate change. For instance, the number of outages grew by more than 12% from 2013 to 2014. Mitigating weather impacts to improve outage management is a complex task. The complexity of distribution systems may prolong the time to locate faults. The outage risk mapping techniques become critical in reducing the search range for the maintenance crew in locating faults. Without utilizing weather data or relying on manual predictions only, the outage mapping results can be unreliable.

II. Risk Analysis Framework Formulation

The risk analysis framework for improving OM may be defined as a stochastic process using

$$R = P[T] \cdot P[C|T] \cdot u(C) \qquad (1,a)$$

where R is associated risk index for each component of the system, Hazard $P[T]$ is a probability of a Threat T affecting the system; $P[C|T]$ is the vulnerability of the component or the probability that Consequences C will happen if system is under the impact of a Threat T, and $u(C)$ is the utility (cost) of the consequences. In the outage management processes, this framework is applied such that R represents the overall estimate of expected risk associated with power outages, T represents an intensity of weather impact that may cause an outage event, C represents an outage event. Hazard $P[T]$ represents a probability of a weather impact with intensity T. In this work, Hazard is represented spatially through the outage zone classifications where probability of a weather associated threat is quantified in different areas. Vulnerability $P[C|T]$ represents the probability of an outage under occurring weather conditions. Worth of Loss $u(C)$ represents the financial loss utility is experiencing due to the outage event. This study focuses on the Hazard and Vulnerability part of the risk analysis, which comprises the following part of the risk expression:

$$R = P[T] \cdot P[C|T] \qquad (1.b)$$

III. Historical Weather Data Analysis and Outage Zone Classifications

Despite the richness of global meteorological measurements, the weather data may be too sparse to provide the initial and boundary conditions for doing numerical weather predictions. Given the large amount of available weather data, the key issue is how to interpret the most relevant input data from the available data pool. Fig. 1 shows the linkage between Nino 3.4 and rainfall over Harris County of Texas in a seasonal scale. Fig. 2 shows the outage zone classifications based on the risk analysis results.

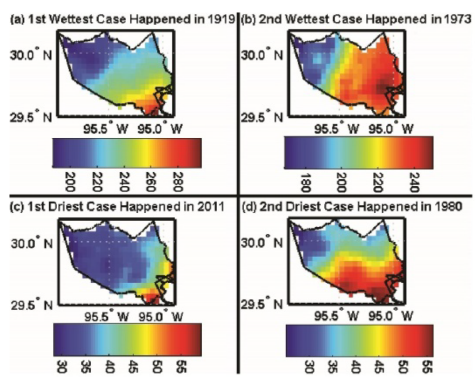


Fig. 1. The geospatial distribution of 4 extreme year summer rainfall data in each grid cell of Harris County.

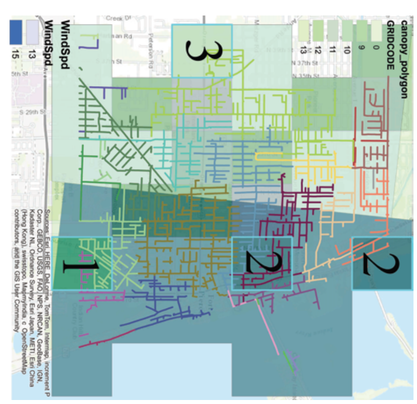


Fig. 2 Predictions of outage zone classifications.

Placement of Transmission Line Surge Arresters Based on Risk Analysis

Tatjana Dokic, Po-Chen Chen, and Mladen Kezunovic
Department of Electrical and Computer Engineering
Texas A&M University
College Station, Texas, 77840, USA
tatjana.djokic@tamu.edu, pchen01@tamu.edu, kezunov@ece.tamu.edu

***Abstract*—This study describes placement of additional line surge arresters on transmission towers in order to reduce number of lightning caused outages and associated costs. The study is based on risk analysis for insulator breakdown.**

I. Introduction

Insulator failures are the main factor contributing to line maintenance cost accounting for more than 70% of outages and 50% of cost. Due to the climate change the number of extreme and severe weather events including lightning strikes is increasing in recent years. In addition, aging infrastructure makes the network more vulnerable to these events. With risk analysis, the accumulated impact of past lightning-caused disturbances in the network can be estimated. The risk study results than can be used to determine the best placement strategy for line surge arresters that would improve overall line lightning protection scheme.

II. Risk Analysis Framework Formulation

The risk assessment framework can be defined as follows:

$$R(X,t) = P[T(X,t)] \cdot P[C(X,t)|T(X,t)] \cdot u(C(X,t)) \quad (1)$$

where R is the *State of Risk* for insulator breakdown, T is the lightning peak current, *Hazard* $P[T]$ is a probability of a lightning strike with intensity T, *Vulnerability* $P[C|T]$ is the probability of an insulation total failure, *Economic Impact*, $u(C)$ is an estimate of financial losses in case of insulation total failure, X represents the spatial parameter (longitude and latitude) and t represents the time parameter obtained using GPS.

The State of Risk value is associated with every network towers geospatially referenced as presented in Fig. 1. The map represents risk values for a selected moment in time. Each time step has a different risk map representing current state of risk value.

III. Placement of Line Surge Arresters

Based on the developed risk maps the optimal placement strategy for line surge arresters that minimizes the probability of insulator breakdown and associated economic losses with the following cost function can be made:

$$\min\left(f_i = \frac{1}{N}\sum_{j=1}^{N} P[T(i,j,t)] \cdot P[C(i,j,t)|T(i,j,t)] \cdot u\big(C(i,j,t)\big), i = 1, \ldots, K \right) \quad (2)$$

where N is a total number of insulator locations, and K is a total number of line surge arrester configurations.

IV. Study Results

The study analyzes a portion of the power network consisting of 10 substations interconnected with 12 transmission lines with 170 insulated transmission towers. The limited number of 10 line surge arresters is considered for placement in the network. The optimal location of surge arresters is presented in Fig. 2. In Fig. 3. the risk map after the surge arrester instalment is presented. Based on the study, the chosen line surge arrester configuration is expected to decrease the overall risk of insulator breakdown by 36%.

Fig. 1. Risk map.

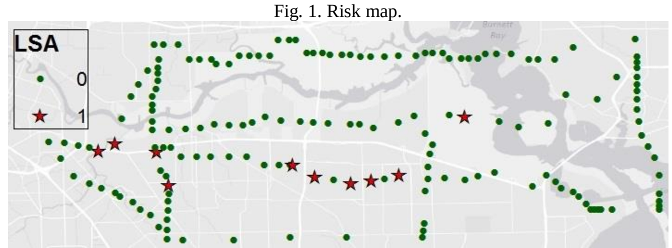


Fig. 2. Locations of surge arresters.

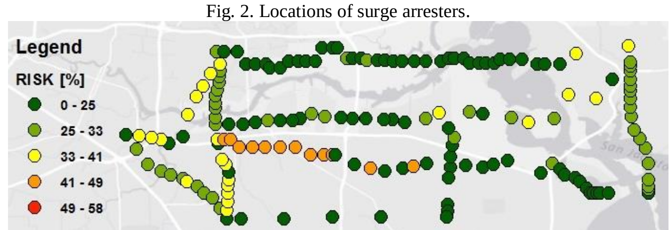


Fig. 3. Reduced risk map

Predictive Scheduling for Electric Vehicles Considering Uncertainty of Load and User Behaviors

Bin Wang, Rui Huang, Yubo Wang, Hamidreza Nazaripouya, Charlie Qiu, Chi-Cheng Chu, Rajit Gadh
Department of Mechanical and Aerospace Engineering, UCLA
{wangbin, gadh}@ucla.edu

***Abstract*— Un-coordinated Electric Vehicle (EV) charging can create unexpected load in local distribution grid, which may degrade the power quality and system reliability. The uncertainty of EV load, user behaviors and other baseload in distribution grid, is one of challenges that impedes optimal control for EV charging problem. Previous researches did not fully solve this problem due to lack of real-world EV charging data and proper stochastic model to describe these behaviors. In this paper, we propose a new predictive EV scheduling algorithm (PESA) inspired by Model Predictive Control (MPC), which includes a dynamic load estimation module and a predictive optimization module. The user-related EV load and base load are dynamically estimated based on the historical data. At each time interval, the predictive optimization program will be computed for optimal schedules given the estimated parameters. Only the first element from the algorithm outputs will be implemented according to MPC paradigm. Current-multiplexing function in each Electric Vehicle Supply Equipment (EVSE) is considered and accordingly a virtual load is modeled to handle the uncertainties of future EV energy demands. This system is validated by the real-world EV charging data collected on UCLA campus and the experimental results indicate that our proposed model not only reduces load variation up to 40% but also maintains a high level of robustness. Finally, IEC 61850 standard is utilized to standardize the data models involved, which brings significance to more reliable and large-scale implementation.**

I. System Overview

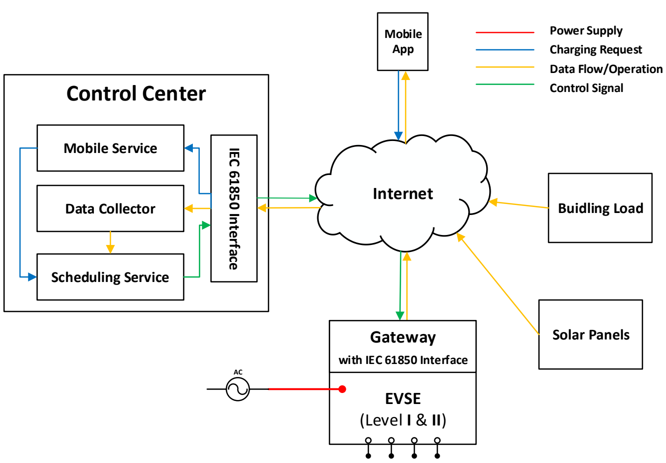


Fig. 1 System Overview

II. Problem Formulation

Key Equation:

$$\min \sum_{\tau=t}^{\tau=T} \left(P_b(\tau) + \sum_{n\in N} r_n(\tau) - \frac{1}{T-t+1}\cdot \left(P_b(\tau) + \sum_{n\in N} r_n(\tau)\right)\right)^2 \qquad (1)$$

Scheduling Algorithm:

Algorithm 1: Predictive EV Scheduling Algorithm (PESA)

Calculate average baseload by averaging historical data
Estimate EV demand for each EVSE
$t = 1$
Do
    Estimate baseload profile with error
    For each vehicle
        Estimate leave time and energy consumption
    End
    Estimate virtual load parameters
    Solve problem (1) ,subject to constraints
    For each vehicle:
        Implement new schedule
    End
    $t = t + 1$
While $t \le T$

III. Results and Conclusions

Table I Comparison of Load Variation

	With PESA	Without PESA
Load Variation	40.1413	70.7471

Table II ASER Values for Different EVSEs

EVSE ID	EVSE 1	EVSE 2	EVSE 3	EVSE 4	Overall
ASER(%)	7.4061	24.6687	1.6531	19.6281	14.9745

ASER is defined as:

$$ASER = \frac{1}{L}\cdot \sum_{n}^{L} \frac{e_n - e_{n,c}}{e_n}\cdot 100\%$$

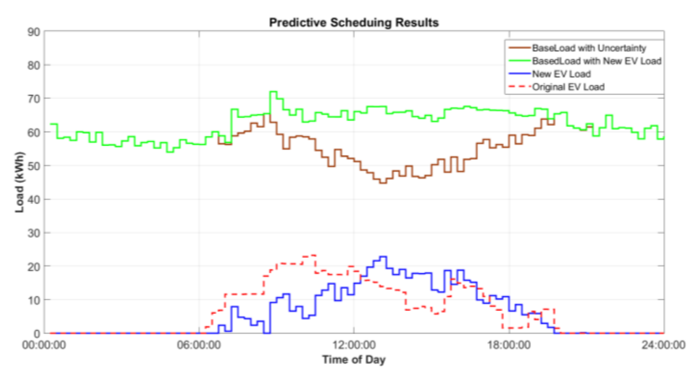
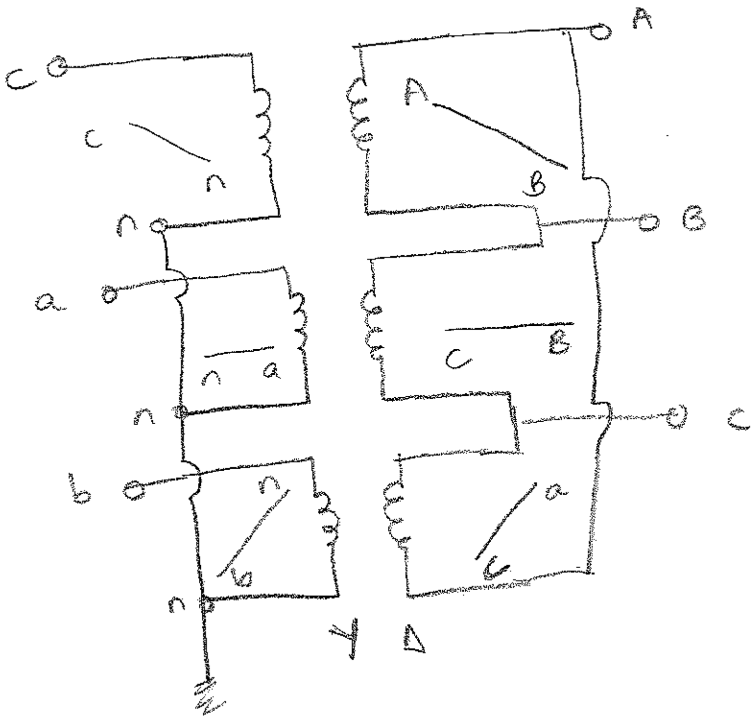
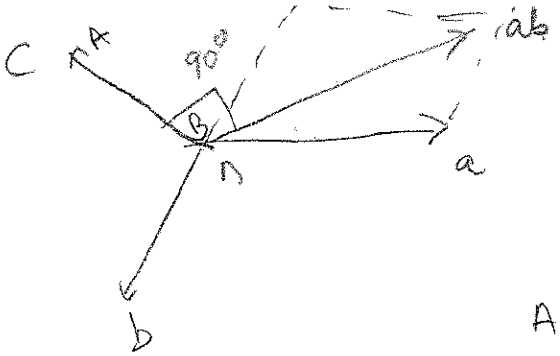
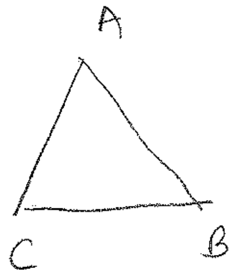


Fig. 1 Predictive Scheduling Results with PESA

(1)

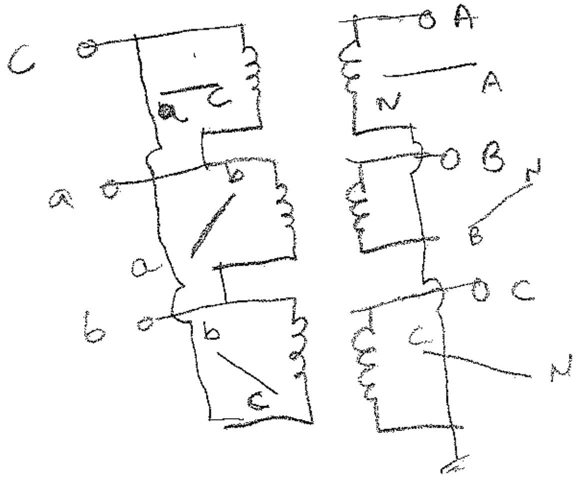


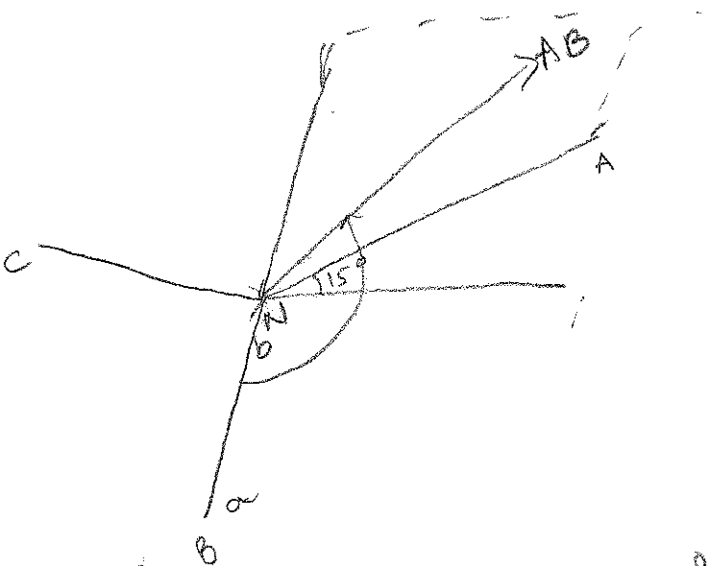


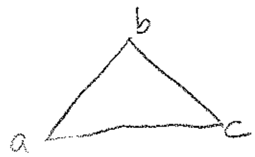


AB leads ab by 90°

(2)

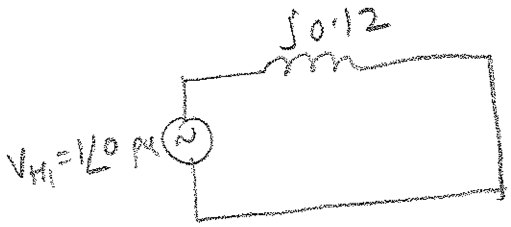






AB leads ab by 150°

3



$S_{base\,3\phi} = 30\,MVA$

$V_{base\,H} = 66.4\sqrt{3} = 115\,kV$

$I_{pu} = I_{sec\,pu} = \dfrac{1\angle 0}{j0.12} = 8.333\angle -90^\circ\ pu$

a) $I_{base\,H} = \dfrac{30}{115\sqrt{3}} = 0.1506\,kA$

$V_{base\,Low} = 12.5\sqrt{3} = 21.65\,kV$

$I_{base\,Low} = \dfrac{30}{21.65\sqrt{3}} = 0.8\,kA$

$I_{high} = 8.333 \times 0.1506 = 1.255\,kA$

$I_{low} = 8.333 \times 0.8 = 6.667\,kA$

b) $I_{base\,High} = 0.1506\,kA$, $V_{base\,Low} = 12.5\,kV$

$I_{base\,Low} = \dfrac{30}{12.5\sqrt{3}} = 1.386\,kA$

$I_{high} = 8.333 \times 0.1506 = 1.255\,kA$

$I_{low} = 8.333 \times 1.386 = 11.55\,kA$

2nd Generation (2008-2013) Forum dedicated to the discussion of 2nd generation Toyota Highlanders.

03-18-2015, 07:07 PM Thread Starter post #1 of 18

doctorman
Official TN Member

Join Date: Sep 2009
Location: usa
Posts: 189
Mentioned: 1 Post(s)
Tagged: 0 Thread(s)
Quoted: 64 Post(s)
Thanks: 72
Thanked 14 Times in 8 Posts
iTrader Score: 0 reviews
(Thread Starter)

SMARTKEY Remote FOB Programming New or Used Toyota Highlander / Prius

I saw this question all over with no solid answer so I am here to put this to rest and collect all the info in one place.

You need:

- Techstream software
- MINI VCI cable or compatible cable (Mongoose MFC)
- Compatible remote

- Used Remotes need a PASS CODE from TIS (can get it from online services or an authorized locksmith/dealer with access to TIS, or someone with the Keygen)

- Techstream software v9 (you get it with the cable or you can find it around the net)

- Cable: just search for techstream cable on ***removed source***)

- The drivers for the cable - works well on XP but for win 64bit you need to manually install x64 drivers.

-The remote with working batteries of course. needs to have the Same FCC ID and the same transmitter ID which is printed on the inside on the circuit board.
Mine for 2008 hybrid highlander with hatchback power
FCC ID HYQ14AAB
Toyota part# 8990448110
transmitter ID: 271451-0140

If your remote is virgin and has never been programmed you are good to go, if not perhaps if you bought a used one: you need to do smartkey reset via techstream and it will ask you for a passcode.
it gives you a 96 character code + vin # of the car you can get the passcode using those 2 on some website (20-30$) or from a dealer/locksmith

If the smartkey is brand new you can just use techstream and program it

turn on the car like you are going to drive it but leave it in park, this way your battery will not drain while you work, make sure your laptop is fully charged.

Install the drivers for the cable and install techstream make sure it runs
connect the cable to obdII socket and your USB and in techstream connect to the car
make sure that is your car in the menu and chose WITH SMARTKEY option.

in techstream: body electrical> smart key> utility>

New remote> key code registration and follow the prompt very easy.

Used remote> Smartkey reset with the drivers door open for the whole duration of programing and the car on fully so the battery does not die. Get the SEED code , do not close the techstream till you get the passcode , if you close it the smarkey reset code will change.

get the passcode and put it in .. wait 16 minutes .. the program is slow do not freak out if the screen disappears jus put your own timer for 16 min.
then register the remote.. using Register Key CLASSIC.. chose 3rd option " I have already reset the smart key"
program your used key first
then your original key and you are done.

FOR PEOPLE WHO NEED THE TIS PASSCODE: it goes for around 30$ online or you can buy the program for 400$ from china to generate it. the program comes on a USB dongle and only works from the dongle, I have not found the hack for that.
If you have a dealer friend or locksmith friend they should be able to hook you up.
I might be able to hook you up with SEED code for 15$ from a local locksmith friend of mine. send me a pm if you need it.

I have the Passcode calculator program but it does not work without the USB dongle if anyone can crack it and extract the algorithm or make it work without the dongle we can all get our passcodes for free

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I will update this post soon with more detail.

thanks to all who helped me in this post FYI - Keyless Remote Programming

funman1, 35Speed and -Unknown- like this.

Last edited by doctorman; 03-24-2015 at 09:38 AM.

Quote Quick Reply

The Following 4 Users Say Thank You to doctorman For This Useful Post:

-Unknown- (04-28-2015), 35Speed (03-19-2015), ***funman1*** (03-18-2015), ***sweeneyp*** (03-18-2015)

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- 40 Anyone have experience... Today 06:28 PM by sweeneyp
- 1 Speakers ? Today 06:27 PM by sweeneyp
- 3 '87 camry now what?? Today 06:18 PM by playtoy
- 32 06-08 RAV4 Oil Burners... Today 06:17 PM by rocknrobbi
- 1 Who would be able... Today 06:16 PM by sr5burgess
- 6 XLE_Philly's Build Thread Today 06:16 PM by XLE_Philly
- 14 2000 4 cyl camry will... Today 06:16 PM by Stillrunning
- 5 Need Help- No... Today 06:14 PM by MidwestGunner

03-18-2015, 07:40 PM post #2 of 18

Rolling Thunder
Official TN Member

Join Date: May 2012
Location: NJ
Posts: 254
Mentioned: 0 Post(s)
Tagged: 0 Thread(s)
Quoted: 16 Post(s)
Thanks: 3
Thanked 14 Times in 14 Posts
iTrader Score: 0 reviews

And how much of this is legal, illegal, cracked, or warez?

2012 SE FWD V6
Silver & Black

Quote Quick Reply

03-18-2015, 07:47 PM Thread Starter post #3 of 18

doctorman
Official TN Member

Join Date: Sep 2009
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Posts: 189
Mentioned: 1 Post(s)
Tagged: 0 Thread(s)
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funman1 likes this.

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03-18-2015, 07:59 PM post #4 of 18

sweeneyp
Resident Nutcase
SUPER MOD

Join Date: Apr 2010
Location: Nashville, TN
Posts: 9,351
Blog Entries: 8
Mentioned: 12 Post(s)
Tagged: 0 Thread(s)
Quoted: 552 Post(s)
Thanks: 515
Thanked 1,435 Times in 1,154 Posts
Garage
iTrader Score: 0 reviews

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FUELLY 17.0 MPG

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A production decision on the jointly developed sports car between BMW

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03-18-2015, 08:16 PM post #6 of 18

funman1
Got Pyro?
MODERATOR

Join Date: Jun 2012
Location: Roseville, CA
Posts: 3,859
Mentioned: 9 Post(s)
Tagged: 0 Thread(s)
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Thanked 352 Times in 310 Posts
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Thanks!! Glad to know it CAN be done DIY
Mine is not Smart Key so I could never test or play with this...

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doctorman (03-18-2015)

03-24-2015, 09:45 AM Thread Starter post #7 of 18

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Official TN Member

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I ended up buying the Seed code form an online source and I got 3 more Seed code credit with them ,, who ever needs them PM me.

now ordering the cut keys;
get a Torx30 screwdriver
follow this https://www.youtube.com/watch?v=TzLDWzuuAZc
get your code
you can order it online from ovnisf or maybe your local lock smith 10-20$ per key.

=========
PRIUS
the prius was more complicated since the immobilizer and the smartkey are not together in techstream like highlander,
so first erase all keys in immobilizer then register them all

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06-17-2015, 10:28 AM post #8 of 18

beachbummm
New TN User

Join Date: Jun 2015
Posts: 1
Mentioned: 0 Post(s)
Tagged: 0 Thread(s)
Quoted: 1 Post(s)
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Official TN Member

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Mentioned: 1 Post(s)
Tagged: 0 Thread(s)
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Official TN Member

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Location: usa
Posts: 189
Mentioned: 1 Post(s)
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pass code is not illegal.. it is what is needed to get the seed

Quote Quick Reply

06-17-2015, 09:20 PM **post #12 of 18**

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MODERATOR

Join Date: Jun 2012
Location: Roseville, CA
Posts: 3,859
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09-12-2015, 05:16 PM **post #13 of 18**

sugarland
New TN User

Join Date: Aug 2015
Posts: 7
Mentioned: 0 Post(s)
Tagged: 0 Thread(s)
Quoted: 2 Post(s)
Thanks: 0
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Just buy a virgin key and you wont have to worry about resetting your computer.

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New TN User

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Mentioned: 0 Post(s)
Tagged: 0 Thread(s)
Quoted: 2 Post(s)
Thanks: 0
Thanked 1 Time in 1 Post
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Doctorman... I see you like my video on how to get the key code. Thanks for reminding me what torx number it is.

Quote Quick Reply

The Following User Says Thank You to sugarland For This Useful Post:
doctorman (09-12-2015)

09-12-2015, 08:18 PM **Thread Starter** **post #15 of 18**

doctorman
Official TN Member

Join Date: Sep 2009
Location: usa
Posts: 189
Mentioned: 1 Post(s)
Tagged: 0 Thread(s)

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(Thread Starter)

I have dealt with the website that give you the seed code like 6 times so far and so far very good interactions, the first time is annoying to figure things out but now I can do the reset for any of my 3 toyota cars and for family as well save money on remote and feel good that I know how to take care of my car when I want instead of needing someone else's help.

thanks for your video .. I still did not do it lol .. got lazy as I did not really need it but I have to get it done eventually to have a backup.

I still have some seed codes left if anyone needs it.

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2nd Generation (2008-2013) Forum dedicated to the discussion of 2nd generation Toyota Highlanders.

03-18-2015, 07:07 PM Thread Starter post #1 of 18

doctorman
Official TN Member

Join Date: Sep 2009
Location: usa
Posts: 189
Mentioned: 1 Post(s)
Tagged: 0 Thread(s)
Quoted: 64 Post(s)
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SMARTKEY Remote FOB Programming New or Used Toyota Highlander / Prius

I saw this question all over with no solid answer so I am here to put this to rest and collect all the info in one place.

You need:

- Techstream software
- MINI VCI cable or compatible cable (Mongoose MFC)
- Compatible remote

- Used Remotes need a PASS CODE from TIS (can get it from online services or an authorized locksmith/dealer with access to TIS, or someone with the Keygen)

- Techstream software v9 (you get it with the cable or you can find it around the net)

- Cable: just search for techstream cable on ***removed source***)

- The drivers for the cable - works well on XP but for win 64bit you need to manually install x64 drivers.

-The remote with working batteries of course. needs to have the Same FCC ID and the same transmitter ID which is printed on the inside on the circuit board.
Mine for 2008 hybrid highlander with hatchback power
FCC ID HYQ14AAB
Toyota part# 8990448110
transmitter ID: 271451-0140

If your remote is virgin and has never been programmed you are good to go, if not perhaps if you bought a used one: you need to do smartkey reset via techstream and it will ask you for a passcode.
it gives you a 96 character code + vin # of the car you can get the passcode using those 2 on some website (20-30$) or from a dealer/locksmith

If the smartkey is brand new you can just use techstream and program it

turn on the car like you are going to drive it but leave it in park, this way your battery will not drain while you work, make sure your laptop is fully charged.

Install the drivers for the cable and install techstream make sure it runs connect the cable to obdII socket and your USB and in techstream connect to the car
make sure that is your car in the menu and chose WITH SMARTKEY option.

in techstream: body electrical> smart key> utility>

New remote> key code registration and follow the prompt very easy.

Used remote> Smartkey reset with the drivers door open for the whole duration of programing and the car on fully so the battery does not die. Get the SEED code , do not close the techstream till you get the passcode , if you close it the smarkey reset code will change.

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Wheels and Tires

Recent Discussions

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2012 SE FWD V6
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Thanked 1 Time in 1 Post
iTrader Score: 0 reviews

Doctorman... I see you like my video on how to get the key code. Thanks for reminding me what torx number it is.

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The Following User Says Thank You to sugarland For This Useful Post:

doctorman (09-12-2015)

09-12-2015, 08:18 PM Thread Starter post #15 of 18

doctorman
Official TN Member

Join Date: Sep 2009
Location: usa
Posts: 189
Mentioned: 1 Post(s)
Tagged: 0 Thread(s)

Quote:
Originally Posted by **sugarland**

> *Just buy a virgin key and you wont have to worry about resetting your computer.*

Quoted: 64 Post(s)
Thanks: 72
Thanked 14 Times in 8 Posts
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(Thread Starter)

I have dealt with the website that give you the seed code like 6 times so far and so far very good interactions, the first time is annoying to figure things out but now I can do the reset for any of my 3 toyota cars and for family as well save money on remote and feel good that I know how to take care of my car when I want instead of needing someone else's help.

thanks for your video .. I still did not do it lol .. got lazy as I did not really need it but I have to get it done eventually to have a backup.

I still have some seed codes left if anyone needs it.

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Optimal Scheduling of Integrated Microgrids with High Resolution Islanding

Guoshun Zhao, and Amin Khodaei
Dept. of Electrical and Computer Engineering
University of Denver
Denver, CO, USA
Rocky.Zhao@du.edu, Amin Khodaei@du.edu

***Abstract*—The increasing penetration of microgrids in distribution networks, as a viable option for both end-use customers and electric utilities, will result in formation of many interconnected microgrids in a not so far future. This paper considers the case in which integrated microgrids are geographically close and electrically connected, and further studies anticipated interactions between the microgrids and the utility grid, during grid-connected and islanded modes. Accordingly, a model for the optimal scheduling of integrated microgrids considering both grid-connected and islanded operation modes will be proposed. The microgrids capability in operating in the islanded mode, for multiple hours is scrutinized by a T-τ islanding criterion. Numerical simulations study test integrated microgrids for exploring merits, as well as demonstrating benefits when compared to deployment of an individual microgrid.**

***Index Terms*—Integrated microgrids, distributed energy resource, optimal scheduling, islanded operation, grid-connected operation.**

I. Introduction

MICROGRIDS, as small-scale power systems integrating distributed generators, energy storage systems, and controllable loads, are significantly deployed over the past few years and are anticipated to grow more in the near future. This growing penetration will result in emergence of networks of microgrids which not only are connected and exchange power during the grid-connected mode, but also provide support for other microgrids during the islanded mode. This integration can potentially provide considerable benefits for the system and also for individual customers, such as (1) reducing the system operation cost and customer payments, (2) reducing power losses at the distribution level and increasing energy efficiency, (3) reducing load curtailment, and (4) supporting renewable generation.

II. Model Outline

The main contribution of this paper is twofold. First, a model for the optimal scheduling problem of integrated microgrids is developed, with the objective of minimizing the system operational cost. Second, as microgrids should be controlled individually and the optimization problem cannot be solved centrally, Lagrange Relaxation is applied to decompose the integrated problem to a set of smaller and individual scheduling problems for each microgrid. Consequently, each microgrid would benefit by transfering its excess power to other microgrids and they could reliably supply its local loads, reduce power losses, and increase operational reliability.

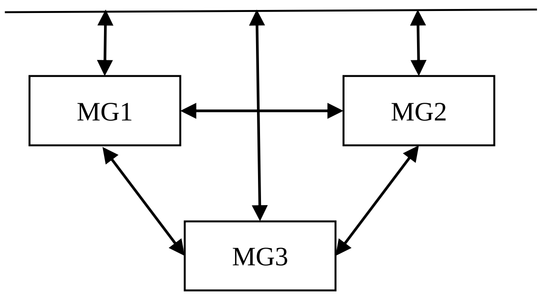

Fig 1. Integrated microgrids are connected to the same upstream substation

To achieve this, the inter-microgrids power transfer is penalized with the coefficient μ and the problem is decomposed accordingly. The equation (1) will be checked after each Lagrangian iteration until a value of zero is obtained, i.e., the problem is converged. If not zero, the associated Lagrangian multiplier (2) will be updated for revising the solution in the next iteration.

$$P_{mnt} + P_{nmt} = 0 \tag{1}$$

$$\mu^{new} = \mu^{old} + \alpha(P_{mnt} + P_{nmt}) \tag{2}$$

III. Discussion And Conclusion

The optimal scheduling model is developed for demonstrating the merits of integrated microgrids. Individual scheduling problem for each microgrid is discussed using Lagrange Relaxation as a decomposition method. Each microgrid's excess generation, beyond its load, would help other microgrids to supply local loads during islanded operation. The proposed model analyzes through numerical simulations, where it shows that integrated microgrids would reduce great amount of power losses.

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Modeling and Assessment of PV Solar Plants for Composite System Reliability Considering Radiation Variability and Component Availability

Samer Sulaeman, and Joydeep Mitra
Department of Electrical and Computer Engineering
Michigan State University
East Lansing, Michigan 48824, USA
(samersul@msu.edu and mitraj@msu.edu)

***Abstract*—This paper presents a method to model the output power of large PV systems in composite system reliability assessment. Grid level PV systems are usually constructed from a large number of power electronic components and PV panels. Modeling of these systems in power system reliability is a complex task due to the dependency of the output power on the intermittent source (solar) and the availability of a large number of system components. An analytical method to construct a capacity outage probability and frequency table (COPAFT) that captures both the intermittency of the input source and component failures is proposed to model PV systems. The intermittency of the input source and components availabilities are modeled separately and then convolved to construct a single COPAFT. The resulting COPAFT forms multi-state reliability model of the entire solar facility. The proposed method reduces the complexity of modeling and evaluating large PV systems in composite system reliability assessment. The method is demonstrated on IEEE RTS. Considering the PV farm location with a view to enhance system reliability, sensitivity study was conducted to measure the effect of the location of the PV farm on overall system reliability. The results confirm that connecting PV farms to the buses that are at high risk enhances the overall system reliability.**

***Index Terms*—PV systems, reliability of composite systems, renewable energy.**

I. Introduction

The global movement towards renewable energy resources has gained significant momentum due to environmental concerns and economic incentives of fossil fueled generating units. Despite the advantages of renewable energy resources, the reality of input uncertainty and output variability adds to the complexity of modeling these resources in planning and operation studies. One of the important aspects in the reliability evaluation of composite systems is assessment of the effect of such variable resources on the reliability of the main grid. Grid connected PV systems are usually constructed from a large number of components such as power electronic circuits and solar panels. The reliability of such components is highly dependent upon the operation and ambient conditions. Operational and environmental factors may lead to overall reduction in the output power and failure of system components [1], [2]. Modeling of these systems in power system reliability is a complex task due to the dependency of the output power on the intermittent source (solar) main input and the functionality of a large number of system components. This paper proposes an analytical method to model the output of large PV power plants in a manner that considers both the failure of system components and input dependency.

II. The Proposed Method

The purpose of this work is to construct a model that sorts the output power of PV farms into clusters considering the effect of the input variability and failures of system components. Two COPAFTs are constructed: (1) the dependency on the output on the variability of the radiation and (2) the outage due to failure of system components. These two COPAFTs are then combined to produce a single COPAFT that can be viewed as a single source with multi–states. The proposed method is depicted in figure 1.

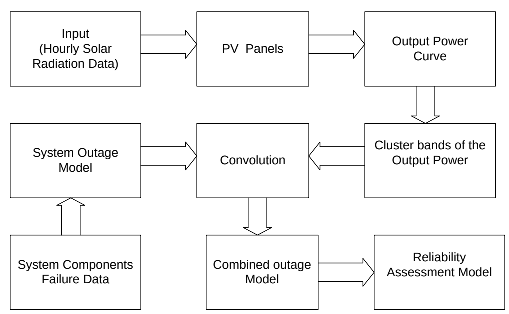

Figure 1. The Proposed Method

III. Conclusion

This paper proposes an analytical approach that comprehensively models large PV systems in power system reliability studies. The proposed method takes into account both the variability of solar radiation and failures of system components such as power electronic converters.

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Economic Analysis, Optimal Sizing and Management of Energy Storage for PV Grid Integration

Bananeh Ansari[1, 2], Di Shi[1], Ratnesh Sharma[1], and Marcelo G. Simoes[2]
[1]Energy Management Department, NEC Laboratories America, Inc., Cupertino, CA
[2]EECS Department, Colorado School of Mines, Golden, CO
Email: bansari@mymail.mines.edu; dshi@nec-labs.com

***Abstract*—This paper investigates the optimal procurement and scheduling of battery storage in distribution systems with high photovoltaic (PV) penetration. The battery under study is assumed to be owned by private entities with the objective of minimizing the electricity bill (or, interchangeably, maximizing the PV system yields). Voltage regulation is achieved by controlling the net metered real power at the point of common coupling of (PCC) of each entity. Dynamic energy conversion equation is used to model the battery with the impact of cyclic aging considered. The procurement-scheduling problem is formulated as a nonlinear programming (NLP) problem. A recursive method is proposed to determine the lifetime of the battery. The proposed methodology is validated on the IEEE 33-bus feeder system. A thorough economic analysis is conducted to quantify the financial benefits brought in by battery.**

***Index Terms*—Energy storage system (ESS), distribution network, PV generation, nonlinear programming, voltage regulation.**

I. Introduction

Traditionally, power flow in distribution system has always been unidirectional, from substation to end-users. Penetration of distributed energy resources has transformed the unidirectional distribution networks into bidirectional networks, where power can also flow in the "reverse" direction, from the downstream network toward the substation. Bidirectional power flow has introduced new operational issues to the grid, one of which is voltage rise along the feeders when power flows toward the upstream network. This is particularly significant in distribution networks with high photovoltaic (PV) penetration. The existing solution to this issue is to curtail PV generation to stop reverse power flow. However, generation curtailment causes considerable energy loss in the most productive hours of a day. The other solution is to use voltage regulation devices, i.e. on-load tap-changing transformers (OLTC), and step voltage regulators (SVR). The main drawback is that this will significantly increase the mechanical stress and maintenance cost of these devices. Reactive power control from PV inverters is another possible solution but current utility practices (IEEE 1547 and UL 1741) only allow PV to operate at unity power factor, and further, reactive power provision reduces the lifetime of PV inverters [1]

Energy storage system (ESS) has shown potentials to help mitigate the voltage rise issue in distribution networks with high PV penetration [2],[3]. Instead of curtailment, the excess energy from PV can be directed to the ESS, and, can be either self-consumed or injected back to the grid at a later time when necessary. This mechanism not only mitigates overvoltage, but also saves a considerable amount of energy, and shaves the peak.

In this paper, we propose an optimization-based framework to determine the optimal size and dispatch of end-user-owned battery storage with the objective of minimizing the end-user's energy bill taking battery degradation into account. Constraints are placed on the net power metered at PCC, so that voltage always remains within the specified limits. Moreover, the proposed approach determines the lifetime of the battery to ensure the procurement of battery is economically viable.

II. Optimal Sizing and Dispatch of ESS

A. The optimization framework

The main objective of purchasing energy storage system from an end-user's perspective is to minimize the energy costs by storing excess PV generation, self-consuming or injecting it back to the grid during peak-pricing hours. However, the battery degrades when it goes through charge/discharge cycles, and its effective capacity reduces. Degradation cost must to be taken into account when determining whether it makes economic sense to purchase the battery storage. Hence, the objective function will be

$$\sum_{t=1}^{T}\left[P_{net,t}.\pi_{net,t}+\lambda_{B}\Delta C_{B,t}\right] \qquad (1)$$

where $P_{net,t}$ is the net metered (purchased) power at the PCC in time interval t, $\pi_{net,t}$ is the time-of-use (TOU) price (hourly), λ_B is the unit cost of storage, and $\Delta C_{B,t}$ is capacity degradation.

Minimizing objective function (1) is subject to the following constraints: 1) power balance at PCC 2) battery dynamics, 3) battery charge/discharge status, 4) battery energy limits, 5) battery capacity degradation, 6) battery initial energy and capacity condition, and 7) dynamic voltage regulating limitsß on net metered power.

III. Results

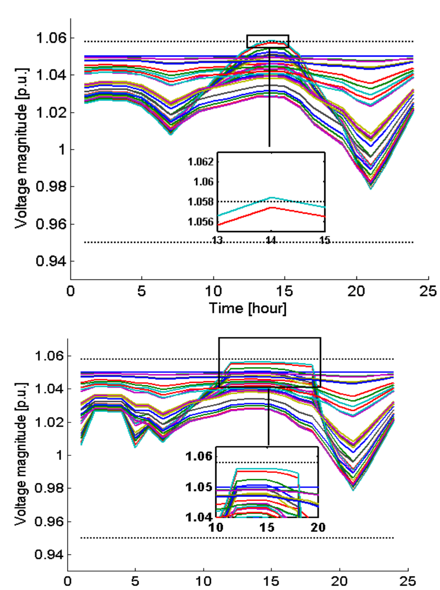

Figure 1 top: voltage profile w/o ESS, bottom: voltage profile w ESS

Resilience-Constrained Unit Commitment to Reduce the Aftermath of Hurricanes

Rozhin Eskandarpour, Amin Khodaei
Department of Electrical and Computer Engineering
University of Denver
Denver, CO 80210, USA
rozhin.eskandarpour@du.edu, amin.khodaei@du.edu

***Abstract*—Hurricanes frequently cause damage to electric power systems, leading to widespread and prolonged loss of electric services. Resilience-constrained unit commitment (RCUC) can be used to schedule available generation resources for satisfying the forecasted load in case of multiple component outages as a result of hurricanes. Accurate estimation of the duration of power outages caused by hurricanes prior to landfall is an important factor for an efficient RCUC solution. In this paper, a regression and data mining method is used to estimate and model the power grid critical components, here generation units and transmission lines, that will fail during a predicted hurricane. The model is trained on synthetic damage data from past storms and the prediction is used in the developed RCUC problem. The role of the microgrids in improving the grid response and supporting the system operator in improving grid resilience is further investigated via accurate grid-connected and islanded operation models. The RCUC problem is formulated using mixed-integer linear programming (MILP). The merits and effectiveness of the proposed models are demonstrated using the standard IEEE 118-bus system for different storm intensities and locations.**

I. INTRODUCTION

The importance of improving resilience in power systems is widely discussed in the literature [1], [2]; however, the mathematical modeling of optimal scheduling of available resources based on resilience considerations and efficient modeling of weather related incidents is limited. In particular, the power grid response to hurricanes, as one of the major extreme natural events in the U.S., requires additional discussions in the research community.

A hurricane is typically assigned a "category" of one through five based on its maximum 1-minute sustained wind speed according to the Saffir-Simpson Hurricane Scale [3]. Predicting hurricane, its impact, and strength plays a vital role in resiliency studies of power systems [4]. In this paper, kernel density estimation is applied on synthetic data to estimate the probability of failure for each unit based on the center of hurricane and the category of the hurricane. Then, a resilience-constrained unit commitment (RCUC) problem is developed which considers the probabilistic failure model of the system components, and determines the commitment and dispatch of available generation units to ensure an economic operation under normal conditions and a resilient operation under contingency cases. The proposed formulation further efficiently models the microgrid grid-connected and islanded operation modes while ensuring a practical and dynamic response to extreme events in case of upstream network outages.

II. MODEL OUTLINE AND RESULTS

Fig. 1 depicts the outline of the proposed RCUC model. The proposed RCUC problem is applied to the standard IEEE 118-bus test system [5]. In order to exhibit the effectiveness of the proposed model, two cases are studied as follows: Case 1: proposed RCUC with *N-m* criterion trained on synthetic data, and Case 2: proposed RCUC with *N-m* criterion and microgrids.

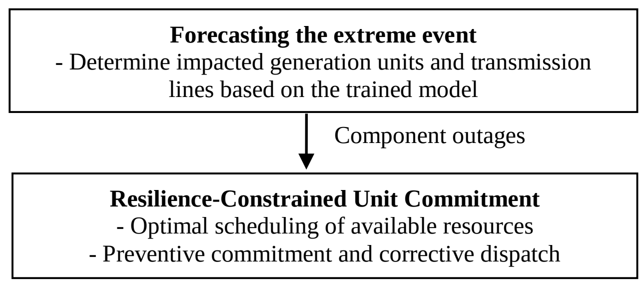

Fig. 1 Proposed RCUC model

The numerical simulations exhibit the merits and applicability of the proposed RCUC model compared to existing work on SCUC. It is shown that having proper data to train the system can improve prediction of the impact of hurricane and resiliency of the system. Numerical simulation further indicate that the microgrids have a complimentary value proposition in power system resiliency as they can efficiently lower the possibility of load shedding by utilizing local generation.

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