Operating Power Grids during Natural Disasters

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***Abstract*—Optimal dispatch and network reconfiguration have so far been used effectively to improve power grid reliability and economic operation. This paper presents a linearized optimization formulation of best load shedding and topology control strategies under extreme events such as hurricanes. In addition, the algorithm analyzes voltage stability after each optimization cycle and iteratively tightens the constraints until a stable solution is found. The proposed method relies on the hurricane's trajectory forecast and available fragility curves for civil engineering structures to predict those power grid facilities most likely to be damaged or taken out in the next monitoring period. The developed algorithm also considers the requirements of other interdependent networks such as mobile communication and emergency services to prioritize load shedding for associated load centers.**

***Index Terms*—Extreme events, load shedding, mixed integer linear programming (MILP), resilient power grids, voltage stability.**

I. INTRODUCTION

Extreme weather events such as tornadoes, hurricanes and cyclones have serious impacts on health and economy of populations. The planet is expected to experience such extreme weather more frequently in the future [1]. The impact of such events can however be minimized with appropriate control strategies. In this paper, power grids will be considered and strategic actions will be developed to handle extreme events that may cause damage to the system elements such as generators, lines, transformers, etc. Load shedding and topology control are two strategic actions to improve resiliency of power grids. Considering the required power for maintaining communication facilities, cell towers, ambulance, rescue services and other emergency medical services, elderly homes and airports, these actions will also improve resiliency of other infrastructures and emergency services.

There are numerous studies reported in the literature for improving resiliency of power grids [2]–[12]. A number of studies are based on resilient load restoration and forming microgrids [2]–[6]. Others investigate line switching methods to address the same issues [7]–[11]. It is shown that significant improvements can be achieved when line switching is combined with optimal dispatch. These studies have been primarily focused on power market applications. Majority of these methods rely on the loose coupling between real and reactive power and solve the real power dispatch with topology control. However, voltage and reactive power that are necessary for stability analysis are commonly left out of the problem formulation. There are also studies where a solution that combines topology switching and load shedding considering worst case scenario is proposed to find the best preventive actions [12]. However, this approach may become highly conservative under changing operating conditions during an extreme event. Alternative strategy which tracks the weather conditions as well as requirements of various stake holders such as networks and services dependent on electric power and repeatedly optimizes the power grid operation has been investigated with promising preliminary results [13]. In this paper, this study is further extended by incorporating voltage and reactive power into the formulation and making it robust against voltage instability.

In many cases, an extreme event can last from hours to several days thus a better approach may be to continue adjusting control actions according to forecasted conditions during the extreme event. Moreover, impact of evacuations on needed emergency services may change, thus also changing the associated load shedding priorities. Certain locations associated with emergency services and mobile telecommunication towers typically appear as the so-called "must-serve" loads whose required demands may change at various substations during the event. Hence, the proposed approach should periodically generate a solution which will combine generation dispatch, adaptable load shedding strategy and pro-active line switching in order to maximize the resiliency of the overall power grid.

The steps of the proposed solution can be summarized as follows: first, the outage probabilities of each line and generator are acquired from an independent forecasting function during the course of the extreme event. Second, the system topology is updated if there exists a forecast on the most-likely line/generator outage. Third, the prioritized list of bus loads, load amounts, must-serve loads are received from health care, emergency and mobile communication service providers. Fourth, appropriate production costs are assigned to the so called "virtual generators". Virtual generators are defined as proxies for the amount of loads to be shed. Their costs are set very high to ensure that they are used as a last resort. Their upper limits are specified according to the difference between total load amount and must-serve load amount connected to

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the same bus. Fifth, lower voltage limits are relaxed and the optimization problem is solved using Mixed Integer Linear Programming (MILP) and optimal topology changes are determined. This step provides a new topology for the power grid indicating the breakers to be switched on or off. Such intentional line switchings can be considered as preemptive actions to further improve power grid resiliency during an active extreme event. However, those intentional line switching and load shedding actions may provoke voltage instabilities. Therefore, network's voltage stability is checked following the MILP solution. If the system is found stable, the algorithm will terminate. Otherwise, MILP solution is repeated using tightened lower bounds on corresponding bus voltages.

II. Problem Formulation

Certain generators and/or lines may be disconnected or damaged during an extreme event causing violations of current or voltage limits of remaining lines, transformers and bus voltages. The objective of this optimization problem is to determine the best generation dispatch, load shedding strategy as well as line switching without causing any voltage instabilities and yielding the minimum disruption of service to customers avoiding loss of critical loads without violating any operational limits during an extreme event. Details of the problem formulation is presented in this section.

A. Objective Function

It may not be feasible to supply power for all customers during an extreme event because of lost generators, disconnected or damaged lines and other equipment. Therefore, the objective function also considers load shedding which is modeled by using "virtual generators". Virtual generators are placed at the same bus where the load is considered to be shed. Their generation costs are set higher than those of actual generators to guarantee that load shedding will be used as a last resort.

Let P_G represent the vector of both actual and virtual generators:

$$P_G^T = \begin{bmatrix} P_{GA}^T & P_{GV}^T \end{bmatrix} \tag{1}$$

and the corresponding generation cost vector be given by:

$$C_G^T = \begin{bmatrix} C_{GA}^T & C_{GV}^T \end{bmatrix} \tag{2}$$

The objective function will thus take the form:

$$\min \; C_G^T P_G \tag{3}$$

where the costs are assigned such that:

$$min(C_{GV}) > max(C_{GA}) \tag{4}$$

Note that load shedding priorities which are dictated by the information provided by the emergency services and communication networks, are indirectly incorporated into the optimization formulation by assigning the costs of virtual generators in descending order of the given priority list. The priorities can be readjusted at each monitoring period based on updates received from interdependent networks and services.

B. Constraints

The optimization problem will have to take into account various constraints, details of which will be described next.

1) Power Balance Equations: The nodal power balance equations can be written as:

$$P_G(i) - P_D(i) = \sum_{j=1}^{n_B} P_{ij} + \sum_{j=1}^{n_B} G_{ij} V_i^2 \tag{5}$$

$$Q_G(i) - Q_D(i) = \sum_{j=1}^{n_B} Q_{ij} + \sum_{j=1}^{n_B} -B_{ij} V_i^2 \tag{6}$$

where:
P_G and Q_G: active and reactive power generation,
P_D and Q_D: active and reactive power demand,
P_{ij} and Q_{ij}: active and reactive power flows on branch (i, j),
n_B: total number of buses,
G_{ij}, B_{ij}: real and imaginary parts of ij^{th} element of the bus admittance matrix,
V_i^2: square of voltage magnitude at Bus-i.

P_{ij} and Q_{ij} can be approximated as follows [14]:

$$P_{ij} = g_{ij} \frac{V_i^2 - V_j^2}{2} - b_{ij}\theta_{ij} \tag{7}$$

$$Q_{ij} = -b_{ij} \frac{V_i^2 - V_j^2}{2} - g_{ij}\theta_{ij} \tag{8}$$

where:
g_{ij}, b_{ij} are conductance and susceptance of branch (i, j),
θ_{ij} voltage angle difference between buses i and j.

Note that the equations are linear in V^2. Substituting (7) and (8) into (5) and (6), yields the following equations:

$$P_G(i) - P_D(i) = \sum_{j=1}^{n_B} g_{ij} \frac{V_i^2 - V_j^2}{2} - b_{ij}\theta_{ij} + \sum_{j=1}^{n_B} G_{ij} V_i^2 \tag{9}$$

$$Q_G(i) - Q_D(i) = \sum_{j=1}^{n_B} -b_{ij} \frac{V_i^2 - V_j^2}{2} - g_{ij}\theta_{ij} + \sum_{j=1}^{n_B} -B_{ij} V_i^2 \tag{10}$$

2) Generator Limits:

$$0 \leq P_G \leq \overline{P} \tag{11}$$

$$\underline{Q} \leq Q_G \leq \overline{Q} \tag{12}$$

$\overline{P}$, $\overline{Q}$ and $\underline{Q}$ includes upper and lower limits for both actual and virtual generators.

$$\overline{P}^T = \begin{bmatrix} \overline{P}_{GA}^T & \overline{P}_{GV}^T \end{bmatrix} \tag{13}$$

$$\overline{Q}^T = \begin{bmatrix} \overline{Q}_{GA}^T & \overline{Q}_{GV}^T \end{bmatrix}, \quad \underline{Q}^T = \begin{bmatrix} \underline{Q}_{GA}^T & \underline{Q}_{GV}^T \end{bmatrix} \tag{14}$$

Since power must be supplied to must-serve loads, $\overline{P}_{GV}$ is limited by the difference between total load amount and must-serve load amount connected to the same bus. If no must-serve load exists, then $\overline{P}_{GV}$ of the chosen bus will be equal to the total load amount. $\overline{P}_{GA}$ is the vector of capacities for the actual generators.

3) Voltage and Angle Constraints:

$$\underline{V_i^2} \leq V_i^2 \leq \overline{V_i^2} \tag{15}$$

$$\underline{\theta} \leq \theta_{ij} \leq \overline{\theta} \tag{16}$$

Since V_i^2 will be a variable for the optimization problem, the voltage constraint is written in terms of V_i^2. In this work, angle separation between neighboring buses is limited to about 15^o in order to avoid unrealistic flows.

4) Line Switching Constraint: Apart from generation dispatch and load shedding, line switching is taken into account in the problem formulation for further minimizing the objective function. However, the number of allowed line switchings is restricted in the problem formulation by $Switch_{max}$. A binary variable vector z represents the status of lines and defined as:

$$z_{ij} = \begin{cases} 0, \text{ if line } \textit{(i,j)} \text{ is open,} \\ 1, \text{ otherwise.} \end{cases}$$

$$\sum_{\textit{(i,j)} \in \kappa} (1 - z_{ij}) \leqslant Switch_{max} \tag{17}$$

A subset of lines in the system can be specified as switchable lines, κ. Only those lines can be switched during optimization.

5) Line Flow Limits:

$$P_{ij}^2 + Q_{ij}^2 \leq S_{ij,max}^2 \tag{18}$$

Note that (18) is a circle inequality with the center at the origin and its radius being the line flow limit, $S_{ij,max}$. A polygon made up of a finite set of straight line segments, can be defined to approximate (18). In [14] a group of linear constraints are defined to limit line flows. Since line switching is considered in the optimization problem, the set of linear constraints should be written according to line status, i.e. the line flow limit should be zero if the line is open.

$$\Upsilon_1 P_{ij} + \Upsilon_2 Q_{ij} + \Upsilon_3 z \leq 0 \tag{19}$$

Note that P_{ij} and Q_{ij} can be written in terms of the squared voltage and angle as in (7) and (8). The matrices Υ_1, Υ_2 and Υ_3 will have rows and columns equal to the total number of straight line segments and total number of branches respectively.

6) Constant Power Factor:

$$\frac{P_{GV}(i)}{P_D(i)} = \frac{Q_{GV}(i)}{Q_D(i)} \tag{20}$$

Power factor is kept constant while shedding load.

C. Load Shedding by MILP

The objective function as well as the constraints related to generator limits, line flow capacity, power balance, line switching, voltage and angle limits are all described in detail in above subsections. Hence, the optimization problem (21) can now be defined in compact form as below:

$$\min_{P_G, Q_G, z, V^2, \theta} \; C_G^T P_G \tag{21}$$

subject to:
1. Nodal Power Balance Equations: (9), (10)
2. Generator Limits: (11), (12)
3. Voltage Limits: (15)
4. Angle Limits: (16)
5. Line Switching Constraint: (17)
6. Line Flow Limit: (19)
7. Constant Power Factor Constraint: (20)

D. Voltage Stability

One concern in applying strategic line switching as an optimization tool is that some switching actions may lead to voltage instability. Similar concerns exist for cases when some of the re-dispatched generators hit their reactive power limits and disrupt voltage stability. Therefore, voltage stability should be checked after the MILP solution. In [15], a method for evaluating the voltage stability strictly based on an easily calculated index, is presented. The method computes voltage stability indicators, L for all load buses using system topology, voltage magnitudes and angles. Initially, the following equation is written relating load voltages and generator currents to load currents and generator voltages:

$$\begin{bmatrix} V_L \\ I_G \end{bmatrix} = [H] \begin{bmatrix} I_L \\ V_G \end{bmatrix} = \begin{bmatrix} Z_{LL} & F_{LG} \\ K_{GL} & Y_{GG} \end{bmatrix} \begin{bmatrix} I_L \\ V_G \end{bmatrix} \tag{22}$$

V_L, I_L: Voltage and injected current vectors at load buses
V_G, I_G: Voltage and injected current vectors at generator buses
Z_{LL}, F_{LG}, K_{GL}, Y_{GG}: Partitions of H-matrix

Then, the voltage stability index L_j for a load bus j will be given by [15]:

$$L_j = \left| 1 + \frac{V_{0j}}{V_j} \right| \tag{23}$$

where:

$$V_{0j} = -\sum_{i \in G} F_{ji} V_i \tag{24}$$

It is shown in [15] that the system will lose voltage stability if L_j becomes larger than 1.

III. Implementation and Testing

The proposed optimization approach is implemented and tested using an assumed hurricane scenario on the IEEE 118-bus test system.

A. Implementation

Consider a scenario where several lines and generators will be taken out of service because of an extreme event like a flood or a hurricane. In such a scenario, forecasting tools can estimate outage probabilities of lines and generators for the next monitoring period [16], [17]. Another recent work presented in [18] derives the failure probabilities of power system components temporally and spatially under extreme weather conditions. It then evaluates power system reliability and associated reliability indices over the duration of the hurricane. Such failure probabilities of power system components can be used as inputs to the optimization problem formulated in this paper. Note that forecasting tools include both weather forecasting and prediction of failures for civil engineering structures such as transmission towers, substations, overhead lines etc. Admittedly, any errors in weather and component outage forecasts will have an impact on the final load shedding. If forecasted outage probability exceeds certain predetermined threshold, then related line and/or generator is taken out of service before solving the MILP problem. Updated probabilities are assumed to be received every 15 minutes. In addition to forecasted outage probabilities, must-serve load amounts, forecasted load amounts, switchable line data, topology data and load shedding priority list are also used in MILP problem as inputs. All inputs used by the MILP problem are illustrated in Fig. 1.

Optimization problem in MILP uses power balance equations, generator limits, voltage and angle limits, intentional line switching constraints, line flow limit and constant power factor constraints. Note that, virtual generator capacities, which indicate the maximum allowed load shedding amounts, are assigned after substracting must-serve load data from load data. In addition, load amounts are changed and updated with respect to [19] in each optimization cycle.

The solution of MILP will yield the optimal dispatch for both actual and virtual generators, P_G and Q_G; line status of each switchable line, z; squared voltage magnitudes, V^2 and angles, θ. Note that the optimization problem is linear with respect to both decision variables namely the squared voltage magnitudes and angles, hence the solution is computationally fast. Moreover, voltage stability of the result can be quickly verified using the L index, and if found unstable, optimization will be repeated with tightened voltage constraints. The flowchart of the overall implementation is shown in Fig. 2.

B. Test Results

A hurricane scenario is simulated using outage probabilities of lines and generators with respect to assumed trajectory for the eye of the storm. If the probabilities are greater than predetermined thresholds, then the lines and/or generators are taken out. The bus loads are assumed to change every 15 minutes which is typical frequency of smart meters.

The formulation is not strictly based on technical priorities dictated by the system topology and loading but it also accounts for society's health care and emergency service requirements. Therefore, the cost of virtual generators are ordered according to a load shedding priority list.

Lastly, in order to keep the scenario simple, it is assumed that only a single line can be switched in each cycle. Note that line switchings last only one cycle while outages caused by the hurricane last during the entire scenario. Fig. 3 [20] shows the hurricane path and impacted areas. Area-1, Area-2 and Area-3 have 3, 4 and 9 lines with high probability of outage respectively.

The voltage stability is checked using the L index of (23) after the first MILP solution. Since the computed indices L_j are not all less than 1 the algorithm is not terminated.

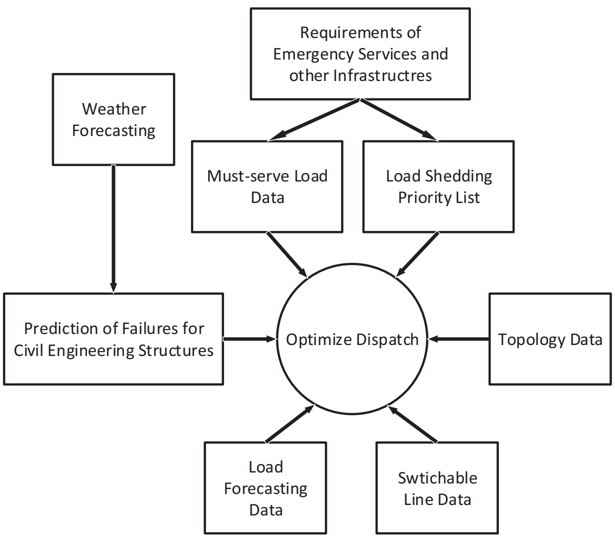

Fig. 1. Inputs of MILP

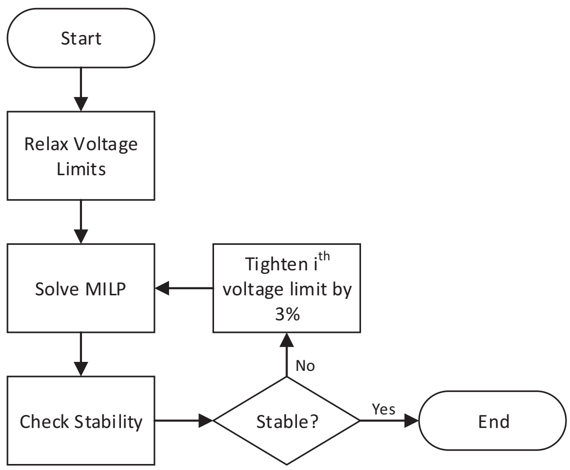

Fig. 2. Flowchart of the Algorithm

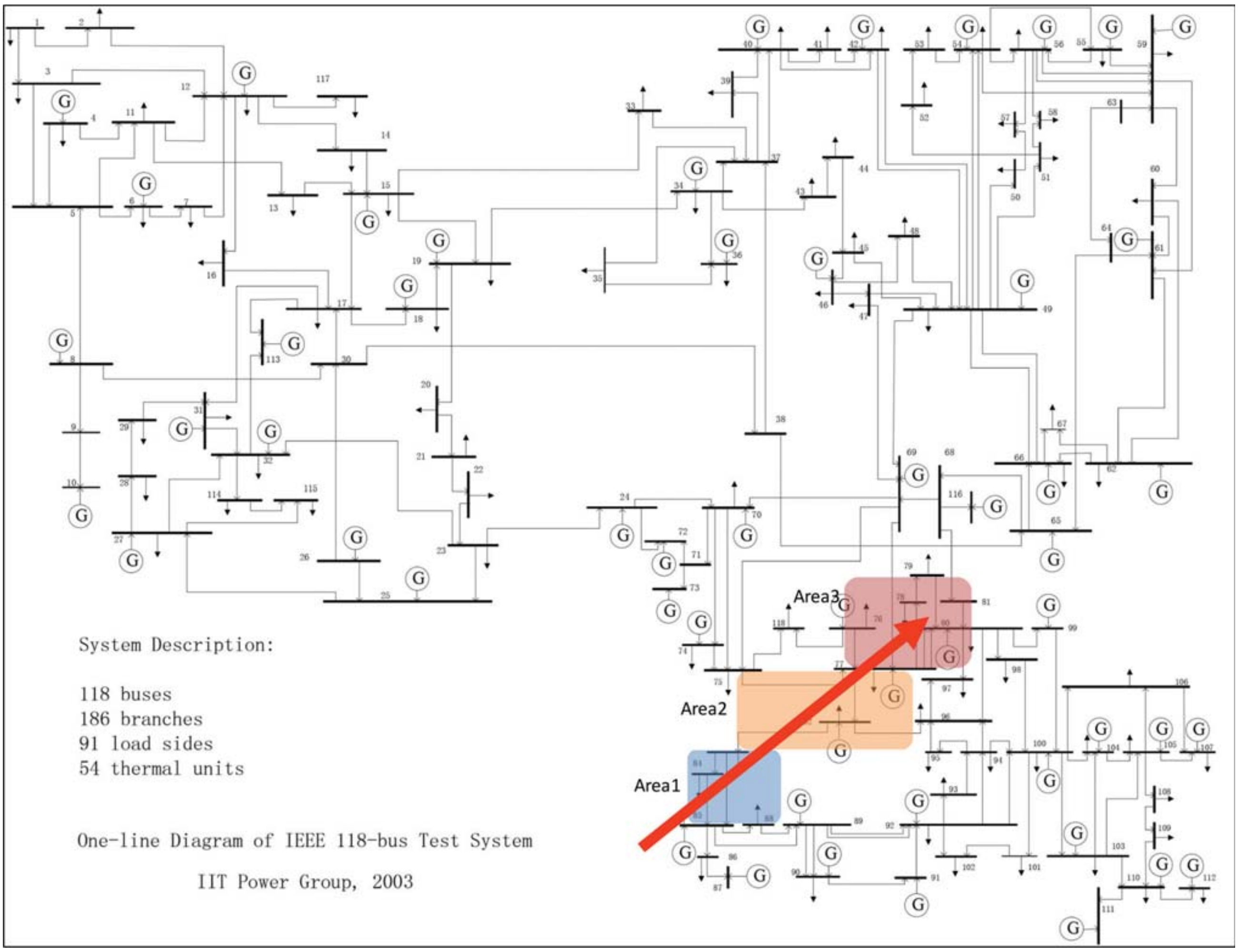

Fig. 3. Hurricane path and impacted areas in 118-Bus System

Instead the MILP solution is repeated with tightened voltage constraints. Note that H-matrix is re-calculated in each cycle because the topology may have changed by the line switching strategy.

QV Sensitivity Analysis of Power System Analysis Toolbox (PSAT) [21] is used to validate the proposed algorithm. The eigenvalues of the unstable buses after the first MILP solution are shown in Fig. 4 in red. Fig. 5 shows the eigenvalues after the final MILP solution yielding the best dispatch without instability.

Table I shows the results of simulations which represent 6 discrete 15 minute intervals designated by $t_1, t_2, \ldots, t_6$. Two sets of results are shown, with and without considering voltage stability. The bottom row presents the number of assumed line outages caused by the hurricane at different discrete time intervals. As evident from the results in rows 1-2 versus 3-4, accounting for voltage stability requires slightly higher levels of load shedding at each time interval, which is intuitively expected and a small price to pay for a robust grid operation.

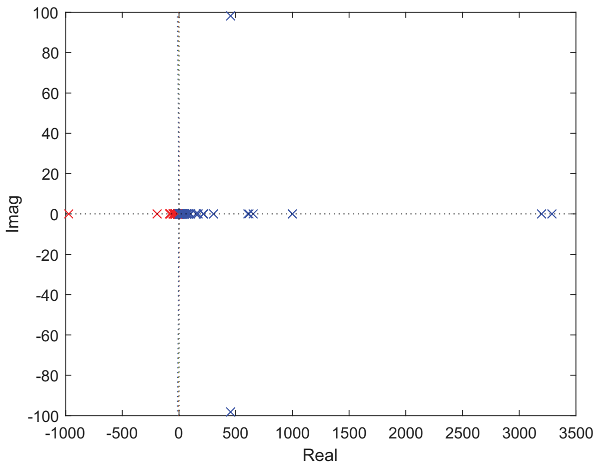

Fig. 4. Eigenvalue Analysis of First Unstable MILP Solution

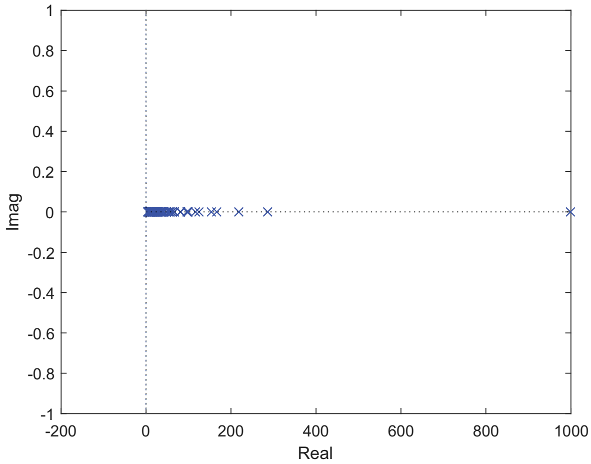

Fig. 5. Eigenvalue Analysis of Stable MILP Solution

TABLE I
LOAD SHEDDING (MW) RESULTS

	Time					
	t_1	t_2	t_3	t_4	t_5	t_6
Shed Load (Ignore L)	632	498	N/A	N/A	N/A	528
Ignored index L_{max}	1.26	1.08	N/A	N/A	N/A	1.15
Shed Load (Using L)	638	501	321	256	221	531
Used index L_{max}	0.96	0.99	0.96	0.95	0.94	0.99
No of Line Outages	1	2	2	2	2	3

IV. CONCLUSIONS

This paper presents an optimization approach for improved resiliency of power grids during extreme events such as hurricanes or cyclones. The proposed method uses the information from weather forecasts, updated failure probabilities provided by fragility curves of civil engineering structures, updates on critical loads associated with emergency services, health care and mobile communication networks in formulating constraints for constructing an optimal load shedding and line switching problem. This problem is solved repeatedly at discrete time intervals during the active period of the hurricane. A previously developed and documented voltage stability index is used to avoid solutions that will lead to voltage instabilities. Taking into account voltage stability, the best line switching and load shedding strategies are determined during the hurricane. Effectiveness of the proposed formulation could have been better evaluated if data recorded during an actual hurricane were available instead of the simulated scenario.

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