Dynamic Islanding in Power Systems Based on Real-Time Operating Conditions

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***Abstract*—During cascading failure in a power system, intentional controlled islanding is deemed as the last resort that prevents complete power system collapse. However, there exist two major challenges in the process of partitioning a power system: (a) optimal coordination of circuit breakers to trip candidate transmission lines, and (b) ensuring large steady state and transient stability margins to prevent further outages in smaller islands. This paper addresses the challenge of creating stable partitions. Contrary to the traditional methods, the developed islanding method is considered to be dynamic, i.e. the lines to be disconnected during an island are not pre-determined, rather, depend on real-time system conditions. Highly stable partitions alleviate frequency problems in the smaller islands, minimize load loss, and reduce dependency on large black-start units. Simulations are performed on synthetic Illinois 200-Bus system considering different number of islands and loading conditions.**

***Index Terms*—coherency, dynamic islanding, load-generation imbalance, mixed integer linear programming**

I. Introduction

Intentional controlled islanding is used as a last resort to prevent widespread failures when power system is evolving through a cascading propagation phase. The failure propagation phase, shown in Fig. 1, often initiates after multiple contingencies occur on a healthy power system. Such failures are more common when contingencies occur under heavy power transfers across long distances. System operators continuously monitor major interfaces, transmission lines, transformers, loads and generators, and perform both online and offline dynamic stability studies to identify scenarios that may potentially evolve into a cascade.

Major disturbances due to sudden loss of large generators, load clusters or critical tie-lines introduce large oscillations in a power system often leading to generation separation. Under such conditions, protective relays trip generators to prevent physical damage. To prevent transient instability or voltage collapse, event-based remedial action schemes (RAS) such as load shedding or generation rejection are immediately triggered. These automatic schemes are based on extensive offline simulations or prior operator experience. If voltage or thermal violations still persist, parameter-based RAS are used as the next optimal mitigation technique. These schemes are based on offline lookup tables and include generator

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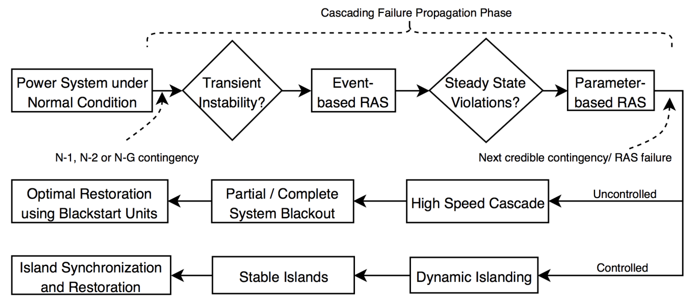

Fig. 1: Cascading propagation, RAS and islanding in power systems

rejection or rescheduling, MVAr dispatch, line switching or load shedding. However, all such RAS have been shown to cause additional outages if their operations are not coordinated properly [1]. In the event of RAS failure or critical contingencies, the probability of high speed uncontrolled cascading failure increases, which may evolve into partial or complete blackout without prompt corrective actions.

Following major faults, timely taken controlled islanding decisions have shown to stabilize the power system by damping large oscillations and separating the system into smaller islands that can be restored rapidly [2]–[5]. However, two major challenges remain: (1) optimally coordinating multiple circuit breakers to trip the selected lines, and (2) ensuring large steady state and transient stability margins in smaller islands. This paper addresses the second challenge by introducing a methodology that enables creating balanced partitions of a given power system under any loading scenario. While traditional islanding methods disconnect a pre-determined set of lines, the developed method identifies candidate lines based on real-time system conditions, hence the islanding method is considered to be dynamic. This results in stable islands with minimum load-generation imbalance, eliminates frequency problems, minimizes subsequent load loss, and reduces dependency on large black-start units.

The rest of the paper is organized as follows: Different techniques for controlled islanding in the literature are presented in Section II. This is followed by a discussion on the proposed method, islanding constraints and generator coherency in Section III. Simulation results are presented in Section IV and concluding statements in Section V.

II. Controlled Islanding Techniques

Controlled islanding in general is a NP-hard graph partition problem. In this section, a survey of approaches proposed over the last two decades to deal with the complexity of the problem are presented. Sun et. al [2] proposed a splitting strategy based on ordered binary decision diagram (OBDD). As the splitting problem is a typical satisfiability checking problem, a three-phase method was introduced to reduce the computational complexity. The power network was simplified using node removal and merging, node combination on same voltage level and edge cut off. An exhaustive search was performed to find feasible solutions. You et. al [3] recommended a rate-of-frequency decline based load-shedding scheme for controlled islanding. Coherent generators were identified using two time-scale method and weak interconnections between areas. An exhaustive search was used to find the optimal cut set that minimized load-generation imbalance in each island. This work was extended in [4] where a data-structure containing bus, line and generator configuration information was used to find optimal islands. Improving on [3], [4], Xu et. al [5] proposed slow coherency based islanding using a graph partition library. Radial buses and step-up transformers were removed, parallel lines were substituted by their equivalence, coherent generator groups were collapsed into single nodes and smaller islands were merged with bigger adjacent islands. To quickly identify coherent generators, Ali et. al [6] recommended a hierarchical clustering algorithm on generator bus angle changes obtained from the real-time PMU measurements while Stadler et. al [7] used inter-area modes and electrical proximity. Yang et. al [8] proposed a multi-level recursive bisection method for controlled islanding. Radial nodes were removed and the shortest path connecting coherent generators in an area was collapsed into one multi-mode. Vittal and Heydt in [9] proposed a Pareto optimization to tackle multiple objectives that ensured large stability in each island while retaining inter-ties between critical sale and purchase nodes in the power market. Tortós et. al [10] proposed a splitting strategy where candidate lines were opened that led to minimum power exchange between areas. Provisions were made to include black-start units to compensate for high load-generation imbalance in islands. Trodden et. al [11] formulated a MILP that split the power system network at the busbar-switch level. Ding et. al [12] modelled a MILP that considered multiple optimal islanding solutions with minimum number of lines to be switched using a recursive process. Demetriou et. al [13] proposed an exact MILP to find cut-sets resulting in minimum power-flow disruption. This was extended by Kyriacou et. al [14] where a recursive linearization method was proposed that minimized power flow disruption when transmission lines were switched.

III. Dynamic Islanding

A. Motivation

A drawback of the formulation in [14] is that the resulting islands have large load-generation imbalances. When a power system is partitioned, large imbalances translate into significant frequency problems in smaller individual islands. This can trigger under-frequency load shedding or over-frequency generator protection relays. Building upon the methodology introduced in [14], this paper proposes a dynamic islanding formulation that alleviates frequency problems in the newly formed islands by minimizing load-generation imbalance. At a cost of a slight increase in the number of lines disconnected, the developed method results in highly stable islands. The rest of the section discusses the proposed method, associated constraints, generator coherency and application of the proposed dynamic islanding method.

B. Dynamic Islanding Formulation

Here, the power system is represented as a graph $G \in \{V, E\}$ with V nodes and E edges. Let $x_{i,h}$ be a binary variable that indicates if node x is in area h, $z_{i,j}$ be a binary variable that indicates whether the edge (i, j) belongs to two different areas, $u_{i,h}$ indicate a source generator node i in area h and $f_{i,j,h}$ denote a connectivity flow variable between nodes (i, j) in area h. The flow variable $f_{i,j,h}$ ensures connectivity within each individual islands by introducing a continuous flow from source $u_{i,h}$ to all other nodes in the island. Bus injection measurements are assigned as node weights, denoted by t_i. Weights are negative for loads and positive for generations. For a n bus system, the following objective function is proposed for dynamic islanding,

$$\text{minimize} \quad \sum_{h=1}^{k} \left| \sum_{i=1}^{n} t_i x_{i,h} \right| \tag{1}$$

In each area $h = \{1, ..., k\}$, the objective function adds the weights t_i associated with each node's binary variable $x_{i,h}$. The inclusion of absolute value ensures that each individual island has minimum imbalance while the objective function minimizes the overall imbalance across all islands. When absolute values are not used, there are chances that the optimization problem finds sub-optimal solutions. For example, mismatches of $+200$ MW and -200 MW in two islands ensures minimum overall imbalance but defeats the purpose of creating stable islands. However, the inclusion of absolute value in the objective function introduces non-linearity which cannot be solved by common solvers, hence the problem is re-written by introducing slack variables.

Let the slack variable S_h denote the mismatch in each island h and be defined as $S_h = |\sum_{i=1}^{n} t_i x_{i,h}|$. The objective function can then be reformulated as,

$$\text{minimize} \quad \sum_{h=1}^{k} S_h \tag{2}$$

The slack variable S_h is relaxed using the following two constraints to accommodate the absolute values,

$$\begin{aligned} \sum_{i=1}^{n} t_i x_{i,h} &\geq -S_h \\ \sum_{i=1}^{n} t_i x_{i,h} &\leq S_h \end{aligned} \tag{3}$$

Under all power system conditions, the objective function in (2) results in h areas with minimum load-generation imbalance. The details of the partitioning and connectivity constraints presented in [14], are briefly described next.

C. Partition and Connectivity Constraints

The binary variable $z_{i,j}$ is relaxed using auxiliary variables $w_{i,j,h}$ as,

$$\begin{aligned} z_{i,j} &= \sum_{h \in K} w_{i,j,h}, \qquad (i,j) \in E \\ z_{i,j} &= z_{j,i}, \qquad (i,j),(j,i) \in E \end{aligned} \tag{4}$$

The auxiliary variables $w_{i,j,h}$ are related to $x_{i,h}$ as,

$$\begin{aligned} w_{i,j,h} &\le x_{i,h} \quad (i,j) \in E, h \in K \\ w_{i,j,h} &\le x_{j,h} \quad (i,j) \in E, h \in K \end{aligned} \tag{5}$$

The constraints restricting a node in a single area and ensuring that at least M nodes are in a given area are,

$$\begin{aligned} &\sum_{h \in K} x_{i,h} = 1, \quad i \in V \\ &\sum_{i \in V} x_{i,h} \ge M, \quad h \in K \end{aligned} \tag{6}$$

For each area, a generator node $u_{j,h}$ is selected as a source node from $V_s \subset V$ which is denoted as,

$$u_{j,h} = 1, \quad j \in V_s, h \in K \tag{7}$$

To ensure each area is connected, a continuous flow variable $f_{i,j,h}$ is introduced,

$$0 \le f_{i,j,h} \le |V| z_{i,j}, \quad (i,j) \in E, h \in K \tag{8}$$

The network flow constrained for $h \in K$ is thus given as,

$$u_{j,h} \sum_{i \in V} x_{i,h} - x_{j,h} + \sum_{\substack{i,j \in V, \\ (i,j) \in E}} f_{i,j,h} = \sum_{\substack{i,j \in V, \\ (j,i) \in E}} f_{j,i,h} \tag{9}$$

To reduce the search space of the candidate transmission lines to be disconnected, another constraint is introduced,

$$z_{i,j} = 1, \quad (i,j) \in E_l \tag{10}$$

where lines $E_l \subset E$ are the set of lines that belong to the Steiner tree connecting all coherent generators in an island. Note the authors in [14] only pre-assigned Steiner nodes. The above partitioning constraints and connectivity constraints (4)-(10) together ensure an optimal islanding formulation resulting in h connected islands with at least M nodes in each partition.

D. Identifying Coherent Generators

Typically after a severe disturbance, there exist two kinds of motions: generators close to the fault point have fast non-coherent motions while those further away exhibit slow coherent motions. The theory of slow coherency partitions n states of a system into $(n-r)$ fast states and r slow states [15]. The number of slow states r correspond roughly to the number of generator clusters that exhibit slow oscillations (coherency) w.r.t other clusters in their neighborhood, independent of disturbance size. These inter-area clusters are connected through long distance transmission lines and have weak electrical connections between them.

The oscillations after a large disturbance generally exhibit three different frequency components or modes: dominant, inter-area and local. Dominant modes exhibit very low frequency of around 0.38 Hz. Inter-area modes and local modes exhibit oscillations of frequency around 0.7 Hz and 1.3 Hz respectively [16]. In general, inter-area modes and weak connections together can be used to identify coherent groups [7]. During controlled islanding, such coherent generator groups are clustered together.

To identify the coherent generators, the following steps are performed [15]: (1) linearize the non-linear electro-mechanical model of the system, $\ddot{x} = M^{-1}Kx = Ax$, where M, K, A are the inertia, connection and system matrix respectively; (2) compute the eigenvectors and eigenvalues $[V, D] = eig(A)$; (3) find the largest eigen-gap r which approximately defines the number of coherent areas in the system; (4) compute the basis matrix V for r slowest modes, (5) perform Gaussian elimination on V and assign the elements of the first r rows as the reference generators; (5) assign the rest of the generators to the reference generators. The following constraint is added to ensure coherent generators are connected in each area [14],

$$x_{i,h} = 1, \quad i \in V_{gen}, V_{gen} \subset V, h \in K \tag{11}$$

Thus, the complete formulation can now be written as[1],

$$\begin{aligned} \text{minimize} \quad & \sum_{h=1}^{k} S_h \\ \text{subject to} \quad & \sum_{i=1}^{n} t_i x_{i,h} \ge -S_h \\ & \sum_{i=1}^{n} t_i x_{i,h} \le S_h \\ & z_{i,j} = 1, (i,j) \in E_l \\ & (4) - (9), (11) \\ & w_{i,j,h} \in [0,1], z_{i,j} \in [0,1] \\ & x_{i,h} \in [0,1] \end{aligned} \tag{12}$$

The objective function in eq (12) can be combined with that of [14] to minimize both load-generation imbalance and the total number of lines disconnected,

$$\text{minimize} \quad \sum_{h=1}^{k} S_h + \sum_{(i,j) \in E} \frac{1}{2}(1 - z_{i,j}) d_{i,j} \tag{13}$$

E. Application

Dynamic islanding aims to prevent total system collapse during a cascading failure, which can evolve due to different contingencies [17]: (a) loss of a generator, followed by re-dispatch and loss of another generator, line or transformer, (b) fault plus stuck breaker that result in loss of multiple elements, (c) non-redundant protection relay failure, (d) loss of any two adjacent circuit that share a common structure, (e) loss of tower with three or more lines or all transmission lines on a common structure, (f) loss of an entire substation, (g) loss of all generators or loads at a node and (h) failure of RAS. Few examples of situations that necessitated controlled islanding

[1] Source code: https://github.com/sagnikbm/dynamicIslanding

TABLE I: Area Load-Generation in 200 Bus System: Basecase

Area	Name	Generation (MW)	Load (MW)	Imabalnce (MW)
2	Peoria	386.82	536.81	-149.99
3	Springfield	94.3	159.22	-64.92
4	Rural SW	70.32	270.06	-199.74
5	Champaign	5.64	275.16	-269.52
6	Rural NE	94.66	81.31	13.35
7	Blooming	1120.87	427.44	693.43

TABLE II: Small Signal Stability: Three Modes in 200 Bus System

State	Type	Mode	Freq(Hz)	Damp(%)	Real	Imag
189	Dominant	38/38	0.10	71.48	-0.69	0.68
153	Inter-Area	11/38	1.03	11.05	-0.72	6.52
71	Local	2/38	1.20	19.01	-1.46	7.55

include (a) triple line outage and critical double line outage of 500-kV California Oregon inter-tie lines carrying more than 4000 MW power [3], [5], [18], (b) 3-ϕ bus fault with delayed clearing leading to generator separation [10], [19], (c) multiple line outages under heavy loaded conditions [4], (d) consecutive line tripping of most probable cascading failure patterns [20], (e) opening of both ends of a line [11], [13] and (f) fourteen sequential tie-line outages due to Hurricane Isaac [21].

IV. Simulation Results

In this section, the dynamic islanding method is tested on the Illinois 200-Bus system. The 200-Bus system is a synthetic test bed of a central part of Illinois with 245 transmission lines (both 230 kV and 115 kV), 49 generators and six areas [22]. Two different cases are considered: (a) **Case 1:** base case with 1750 MW load, (b) **Case 2:** 1.6 times the base load. All simulations are performed using Gurobi and DSATools on an Intel(R) i5-4460, 3.20GHz 16 GB RAM. As seen from Table I, Rural NE and Blooming are generation rich while Champaign and Rural SW are load rich. Large power transfers occurs (a) from Blooming to Champaign and Rural SW directly, (b) from Blooming to Champaign through Rural NE and (c) from Blooming to Rural SW through Peoria. Springfield is a radially connected area which is supplied through Rural SW only.

The major tie-lines that transfer large power are shown in Fig. 2. Interestingly, the set of all tie-lines {55-81, 81-178, 178-121, 121-14, 14-149} connect 230 kV buses and form a continuous backbone of the system. A contingency on any of these major interfaces re-routes large power flows between different areas. For example, loss of line 55-81 increases flow

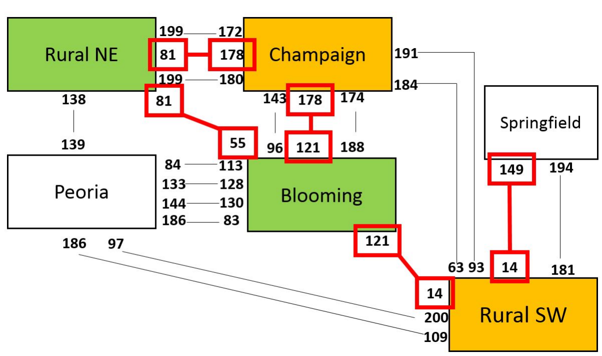

Fig. 2: 200 Bus system with major tie-lines between six zones

TABLE III: Coherent Generator Groups in 200 Bus

Groups	Generator ID
Group 1	49,50,51,52,53,65,164,165,166,167,168,169,170
Group 2	67,68,69,70,71,72,73,94,151,152,153,154,155,161,182,183
Group 3	104,105,114,115,147
Group 4	76,77,78,79,125,126,127,135,136,196,197

from Blooming to Champaign and Peoria and decreases flow from Rural NE to Champaign and Peoria.

To simulate dynamic islanding, a stuck breaker scenario is considered when a three phase fault occurs on bus 55. Bus 55 forms a major part of the tie-line between Blooming and Rural NE. Around 101 MVA flows through line 55-102 and 88 MVA flows through line 55-81. The fault is applied at 50 cycles and delayed clearing occurs after 15 cycles. Without appropriate corrective action, the speed of generator 105 exceeds its set point and the system becomes transient unstable, as shown in Fig 3(a). To prevent system collapse, the proposed dynamic controlled islanding technique is applied next.

The first step is to identify the group of generators that have a tendency to swing together after a fault. From small signal stability analysis, the three different modes of the system are identified and shown in Table II. The inter-area mode gives an approximation of coherent generator groups. These groups were further confirmed using hierarchical clustering on generator angle time series data obtained under various faults. The coherent generators are shown in Table III.

The coherency information is used in the dynamic islanding problem in eq (12) to obtain the optimal cut set. The following 28 candidate transmission lines were obtained: {7-86, 45-187, 102-45, 61-46, 48-74, 55-112, 55-128, 55-102, 56-103, 57-159, 159-62, 81-178, 86-193, 95-58, 98-123, 7-101, 110-101, 117-116, 122-46, 128-133, 130-106, 101-141, 145-176, 163-111, 163-179, 180-191, 134-186, 44-200}, which were opened

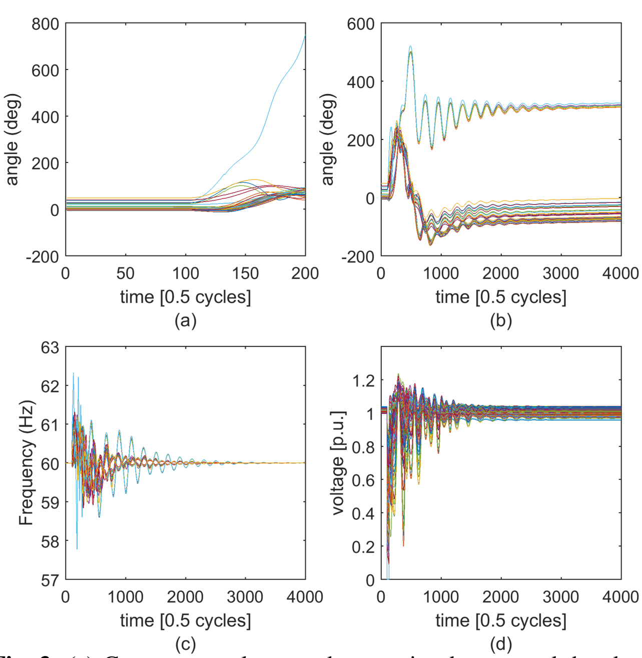

Fig. 3: (a) Generator angle exceeds set point due to stuck breaker, (b) dynamic islanding partitions the system into 4 islands, (c) island frequency is restored to 60 Hz, (d) voltage stabilizes.

TABLE IV: MW Load-Generation Mismatch for Case 1: 4 Islands

Method	Area 1	Area 2	Area 3	Area 4	Lines Out	Total MW Imbalance
Proposed	**12.34**	**8.22**	**13.63**	**1.66**	**28**	35.85
Kyriacou. et al [1]	63.94	31.31	108.75	65.01	20	269.01
Proposed + [1]	**12.34**	**15.26**	**7.27**	**0.98**	**24**	35.85

TABLE V: MW Load-Generation Mismatch for Case 2: 4 Islands

Method	Area 1	Area 2	Area 3	Area 4	Lines Out	Total MW Imbalance
Proposed	**60.89**	**6.75**	**29.08**	**47.06**	**25**	143.78
Kyriacou. et al [1]	143.98	291.23	96.01	29.25	20	560.47
Proposed + [1]	**60.89**	**58.54**	**10.78**	**13.57**	**21**	143.78

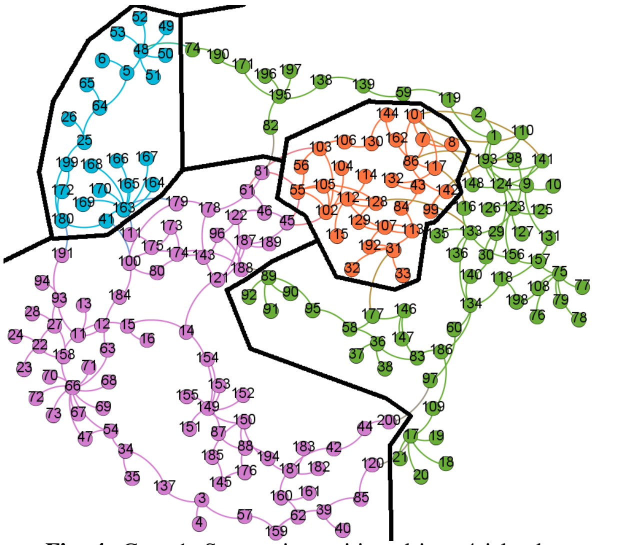

Fig. 4: Case 1: System is partitioned into 4 islands

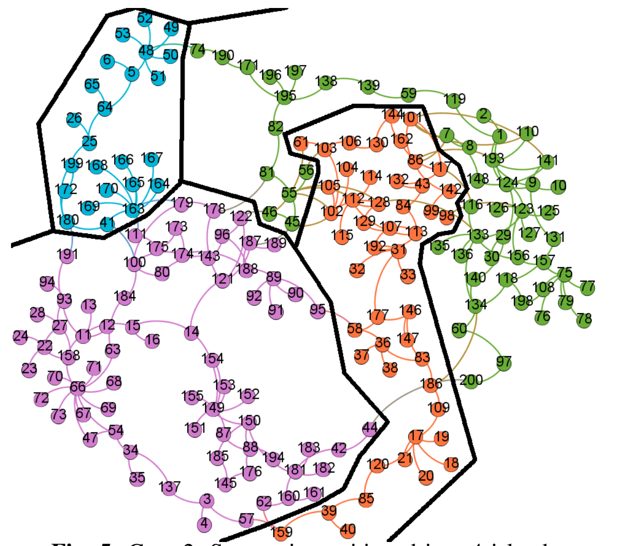

Fig. 5: Case 2: System is partitioned into 4 islands

at 66 cycles. From Fig. 3(b), it is seen that the power system partitions into four islands, each demonstrating relative rotor angle stability. For each island, frequency is restored to 60 Hz shown in Fig. 3(c) while bus voltages return within tolerable range of 0.95 p.u. - 1.10 p.u., shown in From Fig. 3(d). Optimality of the solution is demonstrated through 0 MIP gap.

For **Case 1**, the results of dynamic islanding are shown in Fig. 4. The corresponding areas and their imbalances are summarized in Table IV. The system splits into four islands when 28 lines are disconnected with a maximum imbalance of 13.63 MW in island 3. Under similar conditions, [14] results in maximum imbalance of 108.75 MW with 20 lines disconnected. These results clearly demonstrate that the developed method creates more stable islands at the cost of slight increase in the number of lines disconnected. When both objective functions are combined, similar mismatches and slight improvement in number of disconnected lines are seen.

For **Case 2**, the partitions are shown in Fig. 5 and area imbalances are recorded in Table V. Similar improvements in load-generation mismatch are observed when compared to [14]. Notice how the partitions dynamically change in Fig. 4 and Fig. 5. While part of Rural NE remains in the same island for both cases, a major re-organization in the newly formed islands is observed in Blooming and Rural SW. This demonstrates that the developed method adapts to new loading and generation patterns to create stable partitions.

Next, the system is partitioned into two islands that correspond to the natural partition of the system (as observed through inter-area modes). Similar observations were recorded using the proposed method. For both the cases, the partitions are shown in Fig. 6 and Fig. 7. The area imbalances are summarized in Table VI and Table VII. Compared to [14], it is seen that our method improves island imbalances up to 98.5%. This not only ensures increased stability but also reduces the need for dependence on large black-start units post islanding.

While the dynamic islanding method results in very stable partitions of the system, two challenges have been identified. The first challenge is to ensure synchronization of circuit breakers in pre-islanding conditions. With dynamic islanding, candidate lines to be opened vary with the real-time system loading conditions, hence islanding status signal need to be sent to the correct set of circuit breakers. The second challenge is to establish complete observability to obtain a correct state estimation solution in the newly formed islands. Partitions obtained through dynamic islanding are often independent of utility jurisdictions. From the simulations on the 200-bus system, it was observed that parts of Blooming and Rural SW fall under different islands when system conditions vary. A partially observable system with incorrect state estimates can risk further outages and lead to incorrect island re-synchronization. Alleviating these problems would require measurement redundancy among utilities and additional communication between different reliability coordinators supported by extensive use of real-time phasor measurement units.

V. Conclusion

In this paper, an improved power system dynamic islanding methodology was developed. The objective was to minimize the absolute value of the load-generation imbalance in each smaller island while minimizing the overall imbalance over all islands. To tackle with the non-linearity of the absolute value, the objective function was reformulated using slack variables. In contrary to the existing islanding practices where pre-determined transmission lines are disconnected, the developed

TABLE VI: MW Load-Generation Mismatch for Case 1: 2 Islands

Method	Area 1	Area 2	Lines Out	Total MW Imbalance
Proposed	**8.59**	**2.58**	**20**	11.17
Kyriacou. et al [1]	49.68	38.16	16	87.84
Proposed + [1]	**4.87**	**6.30**	**14**	11.17

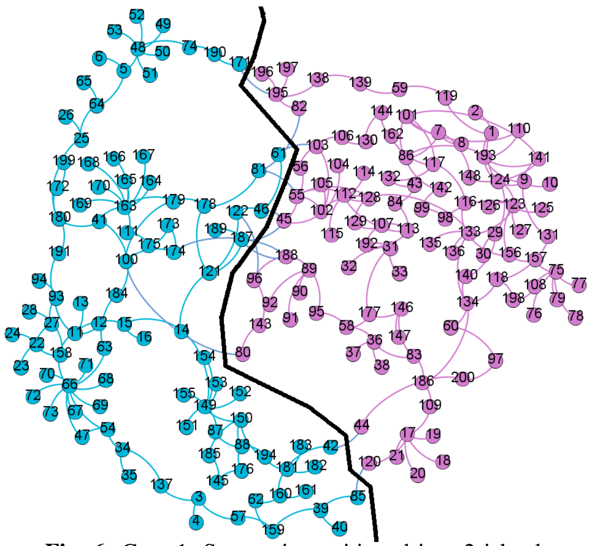

Fig. 6: Case 1: System is partitioned into 2 islands

TABLE VII: MW Load-Generation Mismatch for Case 2: 2 Islands

Method	Area 1	Area 2	Lines Out	Total MW Imbalance
Proposed	**4.23**	**17.77**	**26**	21.99
Kyriacou. et al [1]	278.15	256.05	15	534.20
Proposed + [1]	**2.42**	**19.57**	**20**	21.99

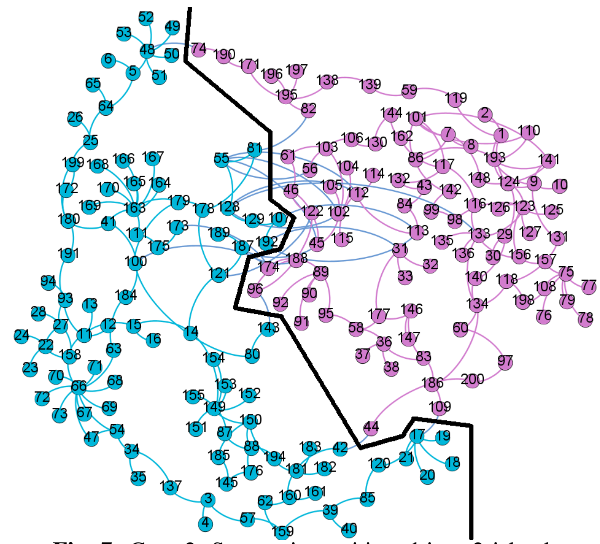

Fig. 7: Case 2: System is partitioned into 2 islands

method partitions the system based on the real-time loading conditions. The chief advantage of this method is that highly stable islands are obtained, over- and under-frequency problems in smaller islands are eliminated, load loss is minimized, and post-islanding dependency on black start units is reduced. In future, the problem of ensuring complete observability of smaller islands that overlap different utility jurisdictions and synchronization of circuit breakers shall be investigated.

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