Power Flow and Contingency Analysis of a Modified IEEE 14-Bus with Siemens PSS®E

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1 Introduction

Ontario's electricity demand continues to rise. In 2024, Ontario used a record high 139.4 terawatt-hours of electrical energy, increasing 1.7% from 2023 [1]. With an increasing population and growing emphasis on electric vehicles, demand is projected to increase 75% by the year 2050 [2]. In order to ensure Ontario's electricity grid can reliably meet this growing demand, planning for potential contingencies during the planning phase is essential.

This study was undertaken independently by a third-year Electrical Engineering student to gain practical experience with the Siemens PSS®E platform. While learning the technical operation of the software, a deeper understanding of how power systems are modeled and tested for reliability will be developed. In the context of the IEEE 14-bus system, a well-known system model will be analyzed in the steady state using Siemens PSS®E, and will then be tested for resiliency using cases involving losses of transmission lines and generation units. This study supports preparation for a career in power systems engineering.

2 Historical Significance

On August 14, 2003, more than 50 million people in Ontario and the northeastern United States experienced a widespread failure of the Eastern Interconnection [3]. This event became known as the Northeast Blackout of 2003, and had an estimated economic impact of $10 billion [4]. The Northeast Blackout of 2003 was caused by the combined effect of three cascading faults in the Midwest Independent System Operator (MISO)'s grid.

Preceding the outage, several transmission lines surrounding MISO's reliability area had tripped offline. However, problems in the state estimator tool used by MISO led to these outages not being taken into account when performing a Real-Time Contingency Analysis (RTCA). As such, the state estimator could not converge on a model for the current grid state [4]. Staff at MISO could no longer see how further outages would affect the grid due to the loss of RTCA.

High air conditioner usage due to warm weather placed a high demand for reactive power on MISO's grid. Four capacitor banks used for power factor correction were offline the day of the outage [4], which caused the voltage and current on MISO's lines to shift out of phase. The #5 generator at Eastlake Power Plant was overexcited as an attempt to compensate for the extra power needed; however, protective relays opened to avoid damage to the generator [4].

Transmission lines in Ohio began experiencing heat sag from carrying excessive current, and contact with poorly managed vegetation caused several phase-to-ground faults, opening protective relays [3]. A power surge of 2,000-4,000 megawatts traveled around Lake Ontario, overloading transmission lines and tripping protective relays in Ontario, New York, and Michigan [3]. Figure 1 shows the drop in available power on Ontario's grid as the blackout progressed.

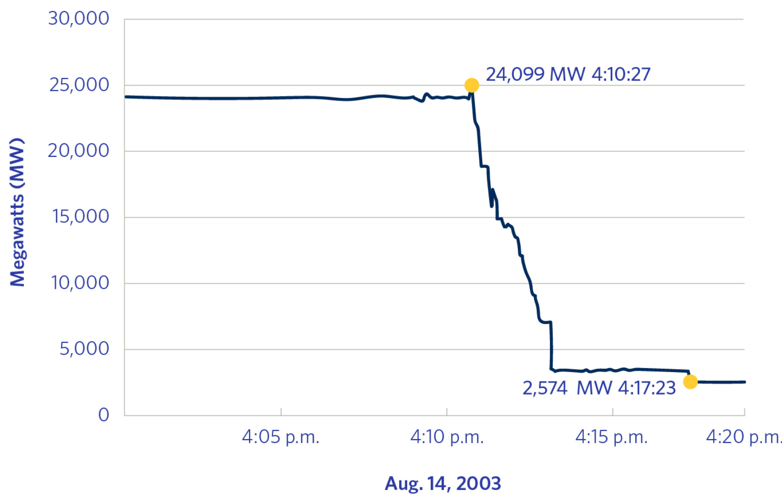

Figure 1: The drop in available power during the blackout. Adapted from [3].

As the Northeast Blackout of 2003 ultimately resulted in a widespread loss of power, it shows how devastating the loss of contingency analysis software can be on the power grid. Had MISO's state estimator been able to run RTCA, better information about the current vulnerability of the power grid could have been conveyed. The value of predictive tools such as Siemens PSS®E can show these vulnerabilities during the planning phase, ensuring grids do not have to reach a critical state for their vulnerabilities to be identified and corrected.

3 System Overview

The model power grid used in this study is the IEEE 14-bus. The IEEE 14-bus system has 14 buses, 11 loads, 5 generators, 17 transmission lines, 3 two-winding transformers, and 1 fixed shunt capacitor [5]. The IEEE 14-bus was chosen for this project as it is a well-documented model with data files available online, and meets the size constraints of the PSS®E Xplore license used for this study.

The role of a bus in an electric grid is similar to that of a node used in circuit analysis: it is a point in the circuit where the voltage is known, or can be solved for. In grid modeling, a bus can be one of three types [6]:

- PQ bus: The real power P and reactive power Q are known, and the power flow solution finds the voltage $|V|$ and phase δ. Used for load buses.
- PV bus: The real power P and voltage $|V|$ are known, and the power flow solution finds the reactive power Q and phase δ. Used for generator buses.
- Slack (Vδ) bus: The voltage $|V|$ is known and the phase δ is set to $0°$. The power flow solution finds the real power P and reactive power Q.

A raw data (.raw) file provided by the University of Illinois Center for a Smarter Electric Grid contains all case data needed to model the buses, generating machines, loads, transformers, and transmission lines [5]. The voltage values are expressed on a per-unit (p.u.) scale, and the transmission line and generating machine capacities are expressed on a individual rated MVA scale. The base voltage for all buses is initially set to 138 kV; however, the presence of two-winding transformers allows for a step up or down in operating voltages between buses 5 & 6, buses 4 & 7, and buses 4 & 9.

Figure 2 shows a single-line diagram of the IEEE 14-bus.

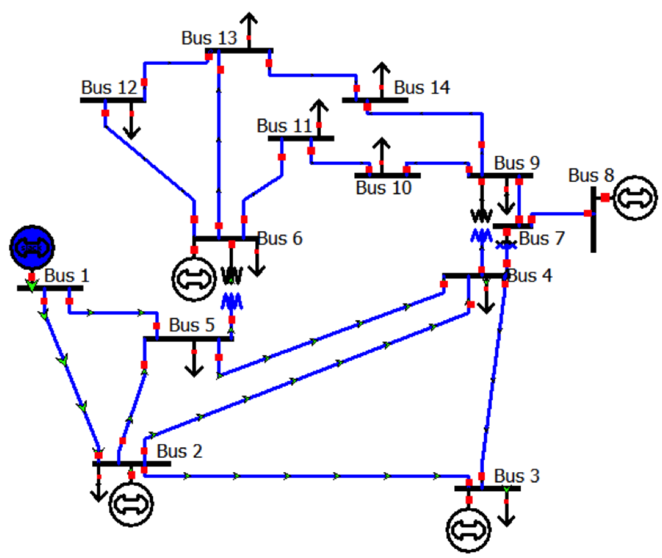

Figure 2: Single-line diagram of the IEEE 14-bus system. Adapted from [5].

In the above diagram, Bus 1 is selected as the slack bus. Buses 2, 3, 6, and 8 are PV buses, while all others are PQ buses.

The generators on buses 3, 6, and 8 are initially operating as synchronous condensers: they provide no real power, but compensate for the reactive power demands. Synchronous condensers are generators whose prime mover is disconnected, and can balance reactive power demands while providing rotational inertia for grid stability [7]. Synchronous condensers are an alternative to using shunt capacitors and reactors for reactive power balancing.

Note that the original case data does not impose capacity ratings on transmission lines, which will cause issues when performing power flow analysis as there is no quantitative definition of a propertly loaded or overloaded line. As such, they will be defined here in accordance with a Southwire® 138 kV cable with an 850 A ampacity at 90°C [8].

Equation 1 shows how Rate A (steady state power capacity) is calculated. Note the factor of $\sqrt{3}$ is to reflect the three-phase capacity, not single-line capacity.

$$Rate_A = \sqrt{3} V_{Base} I_{Rated} = \sqrt{3}(138 \text{ kV})(850 \text{ A}) \approx 200 \text{ MVA} \tag{1}$$

PSS®E defines the emergency ratings Rate B and Rate C as the long-term and short-term emergency line ratings. They are greater than Rate A but cannot be sustained in normal operation and are only used for contingency analysis purposes. In this study, Rate B and Rate C are assumed to be, respectively, 10% and 20% greater than Rate A. The calculations of Rate B and Rate C are shown in Equations 2 and 3.

$$Rate_B = 1.1 Rate_A = 1.1(200 \text{ MVA}) = 220 \text{ MVA} \tag{2}$$

$$Rate_C = 1.2 Rate_A = 1.2(200 \text{ MVA}) = 240 \text{ MVA} \tag{3}$$

With the line ratings assigned in the PSS®E save case, the model is complete.

4 Power Flow Analysis

To perform power flow analysis on the IEEE 14-bus under the normal operating state, Siemens PSS®E uses numerical methods to find the power flow solution. For this study, the Newton-Raphson method is used due to its ability to converge efficiently on large power system models with numerous buses [9]. The goal of a power flow analysis is to find:

- The magnitude $|V|$ and phase angle δ of the voltage signal at each bus.
- The real and reactive components P and Q of power at each bus.

The base results of the power flow analysis for all generation buses (PV or slack) are shown in Table 1. Recall that $V_{\text{base}} = 138$ kV for all buses.

Table 1: Generator voltages and power data.

Bus	$\lvert V \rvert$ [p.u.]	δ [°]	P_{Gen} [MW]	Q_{Gen} [MVAR]
1	1.0600	0.00	232.39	-16.55
2	1.0450	-4.98	40.00	43.56
3	1.0100	-12.73	0.00	25.08
6	1.0700	-14.22	0.00	12.73
8	1.0900	-13.36	0.00	17.62

The generation data in Table 1 shows the generators at buses 3, 6, and 8 are generating no real power, confirming their operation as synchronous condensers.

Synchronous condenser distribution around the grid creates a shorter distance from each bus to a source of reactive power, reducing the current load on distant transmission lines. The slack generator at Bus 1 also has relaxed power limits to produce as much P or Q as needed to account for any power imbalances.

The voltage and power data for buses connected to loads is shown in Table 2. Positive power means power is delivered to the load from the bus. Note that a generator bus from Table 1 may also appear in Table 2 if connected to a load.

Table 2: Load bus voltages and power data.

Bus	$\|V\|$ [p.u.]	δ [°]	P_{Load} [MW]	Q_{Load} [MVAR]
2	1.0450	-4.98	21.70	12.70
3	1.0100	-12.73	94.20	19.00
4	1.0177	-10.31	47.80	-3.90
5	1.0195	-8.77	7.60	1.60
6	1.0700	-14.22	11.20	7.50
9	1.0559	-14.94	29.50	16.60
10	1.0510	-15.10	9.00	5.80
11	1.0569	-14.79	3.50	1.80
12	1.0552	-15.08	6.10	1.60
13	1.0504	-15.16	13.50	5.80
14	1.0355	-16.03	14.90	5.00

In the case data file, normal bus voltages are defined as 0.90 p.u. to 1.10 p.u., with any values outside this range indicating an emergency. Table 1 and Table 2 shows all bus voltages within this range, indicating normal operation. However, buses 1, 6, and 8 are all operating at or above 1.06 p.u., which is acceptable in this case as these voltage values match their respective $V_{scheduled}$ in the case data file, but may hit the 1.10 p.u. mark and open protective circuitry if these generators' $V_{scheduled}$ rises. No bus is operating below 1.0 p.u., showing strong reactive power support and no low voltage regions.

Each generator in the model has a rating for the magnitude of apparent power it can generate, measured in MVA. The magnitude of complex power, S, can be expressed as $S = \sqrt{P^2 + Q^2}$. Table 3 shows the loading of all generators.

Table 3: Generator loading data.

Bus	S_{Gen} [MVA]	Rated MVA	% Loading
1	232.98	615.00	38
2	59.14	60.00	99
3	25.08	60.00	42
6	12.73	25.00	51
8	17.62	25.00	70

Table 3 shows a generation issue. The Bus 2 generator is running at 99% of its rated MVA in normal operation. Should demand on this generator increase, as if another generator is taken offline or grid demand increases, the generator will hit its rated MVA. For this reason, running a real generator at 99% leaves a small margin for load fluctuations and should be avoided.

Table 4 shows the powers flowing along all transmission lines. Note, for example, that the complex power flowing from bus 1 to 2 need not equal that flowing from Bus 2 to 1. This is because transmission lines have resistances and reactances, causing a difference in both real power and reactive power.

Table 4: Transmission line power flow data.

Direction	P [MW]	Q [MVAR]	**Direction**	P [MW]	Q [MVAR]
1 to 2	156.88	-20.40	2 to 1	-152.59	27.68
1 to 5	75.51	3.86	5 to 1	-72.75	2.23
2 to 3	73.24	3.56	3 to 2	-70.91	1.60
2 to 4	56.13	-1.55	4 to 2	-54.45	3.02
2 to 5	41.52	1.17	5 to 2	-40.61	-2.10
3 to 4	-23.29	4.47	4 to 3	23.66	-4.84
4 to 5	-61.16	15.82	5 to 4	61.67	-14.20
4 to 7	28.07	-9.68	7 to 4	-28.07	11.38
4 to 9	16.08	-0.43	9 to 4	-16.08	1.73
5 to 6	44.09	12.47	6 to 5	-44.09	-8.05
6 to 11	7.35	3.56	11 to 6	-7.30	-3.44
6 to 12	7.79	2.50	12 to 6	-7.71	-2.35
6 to 13	17.75	7.22	13 to 6	-17.54	-6.80
7 to 8	0.00	-17.16	8 to 7	0.00	17.62
7 to 9	28.07	5.78	9 to 7	-28.07	-4.98
9 to 10	5.23	4.22	10 to 9	-5.21	-4.18
9 to 14	9.43	3.61	14 to 9	-9.31	-3.36
10 to 11	-3.79	-1.62	11 to 10	3.80	1.64
12 to 13	1.61	0.75	13 to 12	-1.61	-0.75
13 to 14	5.64	1.75	14 to 13	-5.59	-1.64

Table 4 shows that the distribution of power flow is uneven. Significant power flow corridors in terms of line loadings (above 30%) are the lines between:

- Bus 1 and 2 (operating at 79% of $Rate_A$)
- Bus 1 and 5 (operating at 38% of $Rate_A$)
- Bus 2 and 3 (operating at 37% of $Rate_A$)
- Bus 4 and 5 (operating at 32% of $Rate_A$)

A loss in any of these lines will cause a large power flow redistribution and will be taken into account when performing the contingency analysis. In contrast, the transmission line between Bus 7 and 8 carries no real power, and is only used for balancing the system's Q through its inductive reactance.

The resistance and reactances of the transmission lines in the model result in system losses. A power flow analysis finds these dissipations in each transmission line to identify areas with high losses. Table 5 shows the power dissipated by each transmission line, found using Equation 4.

$$S_{Line} = \sqrt{(P_{a \to b} + P_{b \to a})^2 + (Q_{a \to b} + Q_{b \to a})^2} \quad (4)$$

Table 5: Transmission line power dissipation.

Line #	**Direction**	P_{Line} [MW]	Q_{Line} [MVAR]	S_{Line} [MVA]
1	1 to 2	4.29	7.28	8.45
2	1 to 5	2.76	6.09	6.69
3	2 to 3	2.33	5.16	5.66
4	2 to 4	1.68	1.47	2.23
5	2 to 5	0.91	-0.93	1.30
6	3 to 4	0.37	-0.37	0.52
7	4 to 5	0.51	1.62	1.70
8	4 to 7	0.00	1.70	1.70
9	4 to 9	0.00	1.30	1.30
10	5 to 6	0.00	4.42	4.42
11	6 to 11	0.05	0.12	0.13
12	6 to 12	0.08	0.15	0.17
13	6 to 13	0.21	0.42	0.47
14	7 to 8	0.00	0.46	0.46
15	7 to 9	0.00	0.80	0.80
16	9 to 10	0.02	0.04	0.04
17	9 to 14	0.12	0.25	0.28
18	10 to 11	0.01	0.02	0.02
19	12 to 13	0.00	0.00	0.00
20	13 to 14	0.05	0.11	0.12

Transmission lines 1, 2, 3, and 10 dissipate the most apparent power from the system, accounting for 69% of the total power loss in the transmission network. To decrease system losses, the shunt capacitor found on Bus 9 cancels inductive reactances and supplies of reactive power. Table 6 shows the power of the shunt capacitor.

Table 6: Shunt capacitor voltage and power data.

Bus	$\lvert V \rvert$ [p.u.]	δ [°]	P_{Shunt} [MW]	Q_{Shunt} [MVAR]
9	1.0559	-14.94	0.00	-21.18

With all power flow data included, a power system balance can be performed. The intention is to show that the power generated equals the power consumed by loads and system losses. Recall, the system's slack bus at Bus 1 is to provide the ability to balance power lost, so the net complex power generated should equal 0. Table 7 shows a power system summary.

Table 7: Power system operation summary.

Quantity	P [MW]	Q [MVAR]
Total Generation	272.39	82.44
Total Load Demand	259	73.5
Shunt Q Injection	0.00	21.18
Total System Losses	13.39	30.12
Net Balance	0.00	0.00

This concludes the power flow analysis of the IEEE 14-bus system. Although the model is valid, several key issues as identified in this chapter should be addressed to improve its stability under normal operating conditions.

5 System Improvements

The results from the Power Flow Analysis indicate several improvements that can be made to improve system resiliency. The save case file will be modified using the included Python file, using several functions from the psspy library. In this section, the following modifications will be made to the IEEE 14-Bus system to decrease generator loading and increase distributed generation:

- Add shunt capacitors to buses 2 and 13 to alleviate high local reactive power demand on generating units and inject local Q.
- Re-dispatch all non-slack generating machines to meet a smoother voltage and power profile, increasing distributed power generation.

The addition of shunts on buses 2 and 13 is motivated by the lack of locally-supplied reactive power sources and on buses with relatively high Q_{Load} values. With extra shunts distributed around the grid, it is expected that the total Q_{Gen} decreases, decreasing loading on generators and current flow along transmission lines [10]. The original plan for consistency was for all added shunts to have a susceptance of 19.00 MVAR; however, this resulted in the Bus 6 generator hitting its lower Q limit. As such, the Bus 2 shunt will have a susceptance of 19.00 MVAR, and the shunt on Bus 13 will have a susceptance of 10.00 MVAR.

Another issue with the current IEEE 14-bus system is the reliance on centralized generation, with only Bus 1 and Bus 2 contributing to the generation of real power. With this current setup, no real power is generated in the upper half of the grid and must take an unnecessarily long path through 2-winding transformers and transmission lines to reach its load. Additionally, if either generating unit trips offline, the system relies on one generating unit for real power, degrading system resiliency. To remedy this, the generator dispatch profile has been updated to the one in Table 8, including a decreased $|V|$ for the Bus 8 generator to bring the bus away from the 1.10 p.u. upper voltage limit. Recall that a non-slack generator dispatch specifies only each generator's $|V|$ and P, and all other values in Table 8 are found by the power flow solution.

Table 8: Updated generator voltages and power data.

Bus	$|V|$ [p.u.]	δ [°]	P_{Gen} [MW]	Q_{Gen} [MVAR]
1	1.0600	0.00	155.43	-2.34
2	1.0450	-3.18	40.00	7.13
3	1.0100	-7.88	40.00	8.06
6	1.0700	-9.73	15.00	0.67
8	1.0700	-7.48	15.00	9.10

Table 9 shows the loading of each generator (as a percent of rated MVA) becoming more uniform across units, decreasing reliance on centralized generation.

Table 9: Updated generator loading data.

Bus	S_{Gen} [MVA]	Rated MVA	% Loading (New)	% Loading (Old)
1	155.45	615.00	25	38
2	40.63	60.00	68	99
3	40.80	60.00	68	42
6	15.02	25.00	60	51
8	17.54	25.00	70	70

The decrease in reactive power demand is attributed to the addition of two new shunts. Table 10 shows the power of the three total shunts in the grid.

Table 10: Shunt capacitor voltage and power data.

Bus	$|V|$ [p.u.]	δ [°]	P_{Shunt} [MW]	Q_{Shunt} [MVAR]
2	1.0450	-3.18	0.00	-20.75
9	1.0532	-10.58	0.00	-21.07
13	1.0593	-10.95	0.00	-11.22

The total power of the shunts is now 53.04 MVAR. This is more than double the original model, with shunts supplying only 21.18 MVAR. This allows loads at Bus 2 and Bus 13 to get Q directly from the local shunt, without loading a transmission line or generating unit. Figure 3 shows an example of how a new shunt is placed directly at Bus 2 from the single-line diagram, generating Q.

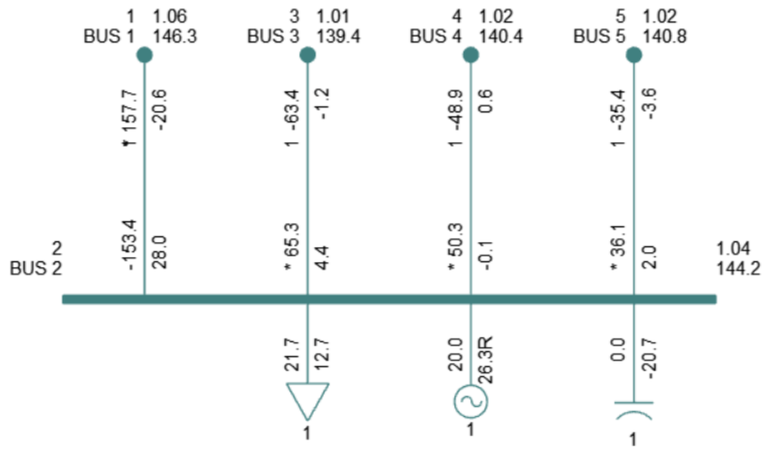

Figure 3: Bus 2 single-line diagram, showing the directly connected shunt.

Another motivation for system improvements is to reduce reliance on the major flow corridors. The significant corridors for real power flow are the lines between buses $1-2$, $1-5$, $2-3$, and $5-4$. Table 11 shows how the improved model reduces reliance on major power flow corridors, with no line loaded above 51%.

Table 11: Updated major corridor power flow data.

Direction	P_{New} [MW]	Q_{New} [MVAR]	S_{New} [MVA]	% Loading
$1-2$	102.72	-6.85	102.95	51
$1-5$	52.71	4.50	52.91	26
$2-3$	45.85	6.99	46.38	23
$5-4$	44.51	-7.02	45.06	23

Table 12 shows the updated system generation and loading balance summary. Note the decrease in system losses and increase in shunt Q injection, which are attributed to the new model using distributed generation, producing power closer to each load and relying less on transmission lines with impedances. Real power losses have decreased about 52% from the original case.

Table 12: Updated power system operation summary.

Quantity	P [MW]	Q [MVAR]
Total Generation	265.43	22.62
Total Load Demand	259	73.5
Shunt Q Injection	0.00	53.04
Total System Losses	6.43	2.16
Net Balance	0.00	0.00

6 Contingency Analysis

In power systems engineering, a grid's resilience to faults is written in the form $N - n$, where n specifies how many outages of generators, transmission lines, or transformers can occur before components reach a critical state. The standard contingency rating is $N - 1$, meaning the grid can operate with a single component offline [11]. In this section, various outages are introduced to the modified IEEE 14-bus system, starting with various $N - 1$, then continuing to $N - 2$ by pairing the most detrimental $N - 1$ contingencies.

A $N-1$ contingency analysis first requires identifying the contingency set, or the list of all elements that will be taken out of service. For a small model such as the IEEE 14-bus, each of the 5 generators, 17 transmission lines, 3 transformers, and 3 shunts can be individually disabled, making a 28 item contingency set.

Starting with generator outages, each of the 5 generators are individually taken offline. The small number of generators makes automation unnecessary for this test as all outages can be manually triggered in the respective case data file. The Bus 2 generator will be defined as slack when taking the Bus 1 slack generator offline to ensure power balance and case convergence. Table 13 shows the case summary for each generator outage.

Table 13: Contingency data for generator outages.

Generator Outage	**Max. Generator Loading** [% MBASE]	**Max. Line Loading** [% RATEA]	**Max. Bus Voltage** [p.u.]	**Min. Bus Voltage** [p.u.]
1	323%	25%	1.0700	1.0100
2	72%	69%	1.0700	1.0100
3	88%	68%	1.0700	0.9843
6	73%	57%	1.0700	1.0100
8	71%	57%	1.0700	1.0100

The contingency data on rotating generator outages show the grid is able to operate effectively with the loss of any generator unit except for the Bus 1 slack generator. This is because the slack generator is, by a wide margin, the largest generator in the grid in terms of rated MVA. Under normal operations, the slack generator is solely responsible for 59% of the system's total generation, and the outage of this generator pushes this demand onto other units with smaller rated MVAs, quickly overloading their power balancing limits. To remedy this, it is suggested that the capacity of the Bus 2 generator (as that is the only one that is overloaded with the Bus 1 generator offline), be increased. Under none of these generator outages did a transmission line overload or a bus voltage go out of range, showing strong grid resiliency.

The next case considered for an $N-1$ contingency is the individual losses of the shunt capacitors at buses 2, 9, and 13. Recall the purpose of the shunt capacitors in the grid is to provide a separate and local source of Q, to decrease demand on generators and long-distance transmission lines. Table 14 shows a summary of contingency data for each shunt outage.

Table 14: Contingency data for shunt outages.

Shunt Outage	**Max. Generator Loading** [% MBASE]	**Max. Line Loading** [% RATEA]	**Max. Bus Voltage** [p.u.]	**Min. Bus Voltage** [p.u.]
2	81%	51%	1.0700	1.0100
9	87%	52%	1.0700	1.0100
13	75%	51%	1.0700	1.0100

Shunt outage data shows that the modified IEEE 14-bus is capable of withstanding the outage of any single shunt capacitor without violating generation, transmission line, or bus voltage limits. Notably, when a shunt was switched offline, the generating unit electrically nearest to the outage saw a large increase in demand for Q, as the generator compensates for the offline shunt's reactive generation. For example, the Bus 9 shunt offline caused the Bus 8 generator to reach 87% of its MVA rating, up from 70% in normal operation. These results highlight the role of shunts in supporting local Q generation, but also show that the IEEE 14-bus is able to withstand the loss of any single shunt.

The last $N-1$ case to consider is the outage of a single transmission line. As the IEEE 14-bus has 17 branches and 3 two-winding transformers, manually disabling each line in a new .sav file is inefficient. Instead, a psspy script was created that disables a single branch, runs the power flow solution, and then saves the case data to its own .sav file. The script repeats this process for the two-winding transformer branches and saves a brief summary of each case to a .txt file, making the contingency analysis of case straightforward and efficient.

For a transmission line contingency to pass the $N-1$ test unconditionally, the case must both converge and not violate any line or generator loading, power generation, or bus voltage limits. If a case fails due to violating a limit but still converges, the power flow solution will still run but the output .sav files must be individually analyzed to determine the constraint that was violated. If a case does not converge, a power flow solution cannot be run, but the cause of the blown case will be identified. Out of the contingency set of 20 transmission lines, 12 cases passed, 7 converged but failed, and 1 outright diverged.

Table 15 shows all transmission outage cases that passed unconditionally. The data is obtained from the .txt file output by the psspy script, as a full analysis of the case .sav file is not necessary for a successful case.

Table 15: Successful transmission line outages contingency data.

Branch Offline	**Max. Generator Loading** [% MBASE]	**Max. Line Loading** [% RATEA]	**Max. Bus Voltage** [p.u.]	**Min. Bus Voltage** [p.u.]
Bus 1 – 2	91%	83%	1.0700	1.0100
Bus 1 – 5	82%	80%	1.0700	1.0100
Bus 2 – 3	91%	48%	1.0700	1.0100
Bus 2 – 4	76%	46%	1.0700	1.0100
Bus 2 – 5	73%	46%	1.0700	1.0100
Bus 4 – 9	72%	51%	1.0700	1.0100
Bus 6 – 12	71%	52%	1.0700	1.0100
Bus 6 – 13	73%	52%	1.0700	1.0100
Bus 7 – 9	68%	51%	1.0700	1.0100
Bus 9 – 10	68%	51%	1.0700	1.0100
Bus 9 – 14	68%	51%	1.0700	1.0100
Bus 12 – 13	70%	51%	1.0700	1.0100

Most of the cases that converged but failed have the same cause: the Q_{Min} limit on the Bus 6 generator is reached. At a generator's Q_{Min} limit, the machine is operating at a leading power factor and absorbing the most reactive power it can. At this level, the amount of real power it can generate decreases sharply [12]. This relationship is illustrated in the generator capability curve, Figure 4.

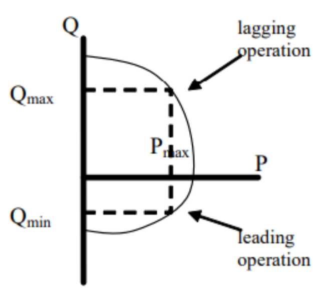

Figure 4: A typical generator capability curve. Adapted from [12].

As the Bus 6 generator's Q_{Min} of 0.00 MVAR is too high for the machine to operate with a transmission line offline, it may be advisable that the Bus 6 machine's model be modified to support a lower Q_{Min}, such as that of the Bus 2 generator, which can absorb up to 40.00 MVAR of reactive power. Alternatively, a shunt reactor can be placed on Bus 6 to assist with reactive power absorption.

The exception to this is when the Bus $5-6$ two-winding transformer is offline. This case failed due to an overload (106% of rated MVA) of the Bus 6 generator. With the transformer offline, the Bus 6 generator supplies 21.67 MVAR of Q, while with the transformer online, it only supplies 0.67 MVAR. This increase in reactive power demand is what overloaded the Bus 6 machine, and is caused by the Bus 6/11/12/13 cluster being more electrically distant from the slack generator. This increases the demand on the Bus 6 generator to balance the cluster's reactive power demand to ensure the power balance.

The cases that outright diverged was when the Bus $7-8$ transmission line was switched offline. The psspy script was not able to generate a summary, so the individual .sav file was analyzed for the cause of the divergence. The transmission line between buses 7 and 8 being offline creates a condition known as an islanded generator. This is caused by a generating unit (which imposes a voltage and P injection to a bus by definition) being isolated from the rest of the grid, and if there is no load in the generator island, there is nothing to dissipate the generated power. Figure 5 shows the islanded Bus 8 generator.

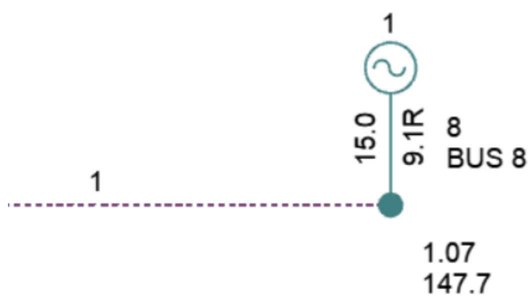

Figure 5: The islanded Bus 8 generator.

The generator producing real power that is not dissipated at a load or lost to a transmission line creates a power mismatch of 15 MW, which will never be within the 0.1 MW required for convergence. As such, this case can not converge. To correct this, upon loss of the transmission line, the Bus 8 generator can be either tripped offline or set its $P_{Gen} = 0.00$ MW so the mismatch is never greater than the convergence tolerance. If resources permit, a second transmission line between Bus 8 and the rest of the model will eliminate the issue and add resiliency to the grid, so even if the first transmission line trips offline, the Bus 8 generator can continue supporting the grid's demand.

With all cases in the $N-1$ contingency set analyzed, the study can move to the $N-2$ contingency analysis. In the $N-2$ case, the system is analyzed with two separate, concurrent outages. The $N-2$ contingency set for the modified IEEE 14-bus has $\binom{28}{2} = 378$ outage cases, which is substantially larger than the $N-1$ contingency set. As such, this section focuses on four combinations of heavily-loaded generators or the slack generator and major power flow corridors, rather than performing a comprehensive $N-2$ contingency analysis. This section's purpose is to show an understanding of N-2 contingencies, acknowledging that multiple simultaneous outages can occur and must be considered in reliability planning for real power systems.

The first $N-2$ case considers the outage of the Bus 2 generator and the transmission line connecting Bus 1 to Bus 2. This case is significant because the Bus 2 generator is responsible for a substantial 41 MVA of generation, which would be redistributed to other units. The outage of the Bus $1-2$ transmission line eliminates the heaviest-loaded line and leaves only one link between the grid and the Bus 1 slack generator, making a line overload a serious reliability concern. Table 16 shows the loading and voltage summary for this case.

Table 16: $N-2$ contingency data for Generator 2 and Branch 1-2 offline.

N-2 Contingency Case	**Max. Generator Loading** [% MBASE]	**Max. Line Loading** [% RATEA]	**Max. Bus Voltage** [p.u.]	**Min. Bus Voltage** [p.u.]
1	128%	110%	1.0700	0.9756

This case highlights a vulnerability in the grid. Two generators (Bus 6 and 8) and the Bus $1-5$ transmission line are overloaded. Additionally, the Bus 3 generator has hit Q_{Max}, meaning it can not supply any more reactive power to the grid. The concurrent outages degrade grid conditions as they force a substantial amount of power to be rerouted through limited paths with less capacity, stressing these elements and creating grid instability.

The next $N-2$ case is more severe, it combines the outages of the Bus 1 slack generator and the Bus $2-3$ transmission line. The Bus 1 slack generator has the highest MVA generation of any in the model, and its outage is likely to overload other machines. This outage is paired with another heavily loaded transmission line outage to attempt to overload other lines. The Bus 2 generator is defined as slack for this case. Table 17 shows the loading and voltage summary.

Table 17: $N-2$ contingency data for Generator 1 and Branch 2-3 offline.

N-2 Contingency Case	**Max. Generator Loading** [% MBASE]	**Max. Line Loading** [% RATEA]	**Max. Bus Voltage** [p.u.]	**Min. Bus Voltage** [p.u.]
2	332%	38%	1.0700	1.0100

Aside from severely overloading the Bus 2 generator, this case did not create any other faults in the grid. All bus voltages, transmission line loadings, and individual generation limits are in range (aside from that of Bus 2). Had the

Bus 2 generator had more generation capacity to act as a slack generator, the system would likely be able to survive this $N-2$ contingency case.

The third $N-2$ considers the combined losses of the Bus 1 and Bus 3 generators. In normal operation, these two generators produce the majority of power, accounting for nearly 74% of the total P generation. Bus 2 remains as the slack generator for this case to ensure the power balance is satisfied. Table 18 shows the loading and voltage summary for this case.

Table 18: $N-2$ contingency data for Generator 1 and Generator 3 offline.

N-2 Contingency Case	**Max. Generator Loading** [% MBASE]	**Max. Line Loading** [% RATEA]	**Max. Bus Voltage** [p.u.]	**Min. Bus Voltage** [p.u.]
3	395%	38%	1.0700	0.9828

Similarly, this case reveals the same issue: the Bus 2 generator is critically overloaded. All other bus voltages, transmission line loadings, and individual generation limits are satisfied. Modifying the Bus 2 generator's model would likely make the system resilient against this $N-2$ contingency case.

The last $N-2$ case that is considered attempts to recreate the islanding condition. In this case, the two-winding transformers connecting Bus $4-7$ and Bus $5-6$ will be taken offline. This requires all power that flows between the upper and lower subsystems to take the Bus $9-7-4$ route, potentially overloading the transformer connecting Bus 4 to 7. Table 19 shows the loading and voltage summary for this case.

Table 19: $N-2$ contingency data for Branch $4-7$ and Branch $5-6$ offline.

N-2 Contingency Case	**Max. Generator Loading** [% MBASE]	**Max. Line Loading** [% RATEA]	**Max. Bus Voltage** [p.u.]	**Min. Bus Voltage** [p.u.]
4	107%	53%	1.0700	1.0100

This case overloaded the Bus 6 generator. The power flow solution report shows the overload caused by a high demand for Q of 22.08 MVAR, up from 0.67 MVAR in normal operation. In addition to the 15.00 MW of real power it is dispatched to generate, the Bus 6 generator surpasses its rated MVA. As Bus 6 is electrically closest to the two branches switched offline, the generator attempts to compensate for Q flowing into the upper subsystem from the slack generator and Bus 2 shunt. Increasing the Bus 6 generator's rated MVA in the model, or adding additional reactive support to Bus 6 in the form of a shunt or synchronous condenser, will allow the model to pass this contingency scenario.

With testing of contingency scenarios completed, the modified IEEE 14-bus is moderately resilient against $N-1$ and $N-2$ contingencies. The grid was able to function under most $N-1$ contingencies, but most $N-2$ contingencies overloaded a generator, and usually its rated MVA instead of a P_{Gen} or Q_{Gen} limit. With changes identified in this section made to the IEEE 14-bus model, such as adding stronger reactive generation capacity to Bus 6, the model can pass all contingencies tested, improving the grid's reliability.

7 Conclusion

This study used the IEEE 14-Bus system as a test case to demonstrate the importance of contingency planning when designing resilient electrical grids. This project began with a historical analysis of the 2003 Blackout, then a IEEE 14-Bus model was created. A power flow solution was performed, and then model improvements were made to reduce generator loading and bus voltages, add reactive support, and better reflect a grid structured around distributed generation. A contingency analysis showed the modified model is decently resilient against all $N-1$ outages, and a test set of four $N-2$ contingencies chosen to maximize impact, which provides useful data to inform future improvements.

Through the completion of this project, practical experience with Siemens PSS®E was gained. These skills include creating and working with .sav and .sld files, running a power flow solution, and using Python's psspy library to automate large, tedious test cases. This ability to use PSS®E to model large grids, coupled with an understanding of the importance of contingency planning, reinforces foundational knowledge necessary to succeed in power systems engineering.

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