



Simulation and Analysis of Power System Performance Under Single Generator Outage Conditions

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ABSTRACT

Reliable electricity supply can be disrupted by sudden generator outages that redistribute active and reactive power flows and may reduce steady-state voltage security margins. This study evaluates a seven-bus system containing a utility grid and two synchronous generators using ETAP 19.0.1 load-flow simulation under three operating scenarios: normal operation, Generator 1 outage, and Generator 2 outage. The revised analysis distinguishes verified voltage results from generator-loading and power-balance quantities that require model revalidation. Based on the reported active and reactive outputs, the apparent-power loading of Generator 1 and Generator 2 in the normal case is approximately 89.5% and 89.8%, respectively. Under Generator 1 outage, the reported Generator 2 output of 19.5 MW and 8.7 MVAR corresponds to approximately 21.35 MVA, or 106.8% of its 20 MVA rating. Under Generator 2 outage, the reported Generator 1 output of 14.8 MW and 7.1 MVAR corresponds to approximately 16.41 MVA, or 109.4% of its 15 MVA rating. The reported voltage results show Bus-7 at 0.950 pu for Generator 1 outage and 0.941 pu for Generator 2 outage, with Bus-6 also reaching 0.947 pu in the latter case. However, the Case 2 active-power balance in the source manuscript is inconsistent: reported generation plus grid import equals 29.75 MW while the stated load is 38.5 MW before losses. Consequently, final N-1 security conclusions require rerunning all cases using one documented model and reporting complete P/Q balances and losses.

Keywords: Generator Outage; Load Flow Analysis; Steady-State Voltage Security; N-1 Contingency; Power System Reliability.

1. Introduction

The growing global demand for electrical energy, driven by rapid industrialization, population growth, and the proliferation of digital technologies, has placed unprecedented pressure on modern power systems to deliver continuous, high-quality electrical supply. According to recent projections by the International Energy Agency (IEA), world electricity demand is expected to grow by more than 3% annually through 2030, necessitating robust and resilient power network infrastructures [1]. Electrical power systems are complex networks comprising generation, transmission, and distribution subsystems, all of which must operate in coordinated harmony to sustain service quality and reliability.

Generator units form the cornerstone of any power system, serving as the primary source of active and reactive power. Synchronous generators, driven by steam turbines, gas turbines, hydro turbines, or other prime movers, are responsible for converting mechanical energy into three-phase alternating current. Their continuous and reliable operation is critical for maintaining voltage levels, frequency stability, and power flow balance across the network. Any unplanned disconnection of a generating unit, commonly

referred to as a generator outage, can trigger a cascade of adverse effects that range from voltage deviation to system instability [2].

Generator outage is classified as an N-1 contingency event, which refers to the loss of a single major system component under otherwise normal operating conditions. The N-1 criterion is a fundamental reliability standard widely adopted in power engineering practice, requiring that the power system remain operationally stable following the loss of any single component, without load shedding or violation of operational limits [3]. When a generator is unexpectedly tripped from service, the immediate consequences include a reduction in available active power, a redistribution of power flows among remaining generating units, and potential voltage drops at connected buses — particularly if the lost generator was also a significant source of reactive power support [4, 5].

The effect of a generator outage on bus-voltage magnitude is an important steady-state security concern because the loss of local reactive-power support and the redistribution of power flows can depress voltages at load buses. In this paper, the post-contingency voltage assessment is therefore described as steady-state voltage security rather

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than voltage stability, because the analysis is based on converged load-flow solutions rather than dynamic or P-V/Q-V stability calculations.

Contingency analysis, and particularly N-1 contingency evaluation, provides system planners and operators with critical information about system vulnerability and the adequacy of reserve margins. By systematically simulating the outage of individual components and assessing the resulting system state, engineers can identify weak buses, overloaded equipment, and potential stability boundaries before actual failures occur [6]. This proactive approach enables the implementation of corrective measures such as reactive power compensation, network reconfiguration, or generation redispatch to maintain system security.

The Electrical Transient Analyzer Program (ETAP) is a widely recognized power system simulation software that provides comprehensive tools for load flow analysis, short circuit analysis, stability analysis, arc flash evaluation, and contingency simulation. Its graphical user interface and built-in IEEE and IEC standard algorithms make it particularly suitable for academic research and industrial power system studies [7, 8]. ETAP version 19.0.1, utilized in this study, incorporates enhanced load flow solvers based on Newton-Raphson and Gauss-Seidel methods, providing accurate and convergent solutions for complex power system networks.

Despite substantial work on contingency analysis, fewer case studies document the simultaneous behavior of a utility interconnection and multiple embedded synchronous generators in an industrial or sub-transmission network. A useful contribution therefore requires not only voltage comparison, but also internally consistent source/load balances, generator capability-limit enforcement, and transparent documentation of how the remaining sources redispatch after each outage [9, 10].

This study addresses that practical need through an ETAP-based N-1 case assessment of a representative utility-generator system. The revised manuscript focuses on what can be verified from the reported model outputs and explicitly identifies items that require re-simulation before publication, including generator P/Q limits, PV-to-PQ switching, complete power balances, losses, and corrective-action cases.

The objectives are to: (1) document the seven-bus network and its component ratings; (2) compare bus-voltage magnitudes under normal operation and each single-generator outage; (3) calculate generator apparent-power loading consistently from reported active and reactive power; (4) audit active and reactive power balance data for each scenario; (5) evaluate the N-1 cases using explicitly defined steady-state voltage and thermal screening limits; and (6) identify the additional ETAP settings and corrective-action simulations required for a defensible final security assessment.

2. Literature review

2.1. Electrical Power System

An electrical power system is an integrated network of interconnected components designed to generate, transmit, distribute, and utilize electrical energy in a safe, efficient,

and reliable manner. The system is conventionally segmented into three primary subsystems: the generation subsystem, which converts primary energy sources into electrical energy using synchronous generators driven by thermal, nuclear, hydro, or renewable prime movers; the transmission subsystem, which transports bulk electrical energy over long distances using high-voltage overhead lines or underground cables; and the distribution subsystem, which delivers electrical energy at lower voltage levels to end consumers. Substations equipped with power transformers serve as the interface between subsystems, stepping voltages up for transmission and down for distribution [11, 12]. Modern power systems operate under complex control and protection schemes to ensure voltage and frequency are maintained within permissible limits, and to isolate faults rapidly to prevent damage and service interruption, and these schemes are typically represented and analyzed through structured mathematical and computational power system models [13].

2.2. Synchronous Generator

A synchronous generator is an electromechanical device that converts rotational mechanical energy into three-phase AC electrical energy. It operates on the principle of electromagnetic induction: a rotating magnetic field produced by a DC-excited rotor induces a balanced three-phase EMF in the stator windings at a frequency directly proportional to the rotor's rotational speed. The relationship between rotational speed (n), number of pole pairs (p), and synchronous frequency (f) is given by $f = pn/60$. Synchronous generators are characterized by their capacity to supply both active power (P) and reactive power (Q) to the network. The active power output is governed by the mechanical input torque from the prime mover, while reactive power output is controlled by the field excitation current. The fundamental power equations for a synchronous generator connected to an infinite bus are expressed as [14]:

$$P = \frac{|E||V|}{X_s} \sin(\delta) \quad (1)$$

$$Q = \frac{|E||V| \cos(\delta) - |V|^2}{X_s} \quad (2)$$

Where $|E|$ is the internal EMF, $|V|$ is the terminal voltage, δ is the power angle, and X_s is the synchronous reactance. These equations illustrate the strong coupling between generator excitation, power angle, and system voltage, which underscores the critical role of generators in maintaining voltage stability.

2.3. Generator Outage

Generator outage, also termed forced generator trip or generation loss event, refers to the sudden, unplanned disconnection of a generating unit from the power system. This condition may be caused by internal generator faults such as stator winding short circuits, rotor insulation failure, or bearing damage; by protection relay operation due to overcurrent, differential protection, or loss-of-excitation relays; by mechanical failures in the prime mover such as turbine blade damage or governor malfunction; or by external grid events that trigger generator protection systems [15]. Comparable disturbances have also been documented in nuclear power plant settings, where internal faults were

similarly found to propagate into measurable transient stability impacts on the wider connected power system [16]. The consequences of generator outage are multifaceted and system-dependent. Immediately following the trip, the active power balance in the system is disturbed, causing frequency to decline as the spinning inertia of remaining generators begins to absorb the power deficit. Automatic generation control (AGC) and primary frequency response mechanisms are then engaged to restore frequency equilibrium. Simultaneously, the loss of reactive power output from the tripped generator causes voltages at nearby buses to decrease, potentially creating reactive power deficits if no compensating devices are available [17].

2.4. Contingency Analysis

Contingency analysis is a systematic computational procedure used to evaluate the impact of potential equipment outages on power system security. In formal terms, it involves solving the load flow equations for each contingency case and comparing the resulting system state against predefined security limits [18]. The N-1 contingency criterion, which is the minimum reliability standard mandated by NERC (North American Electric Reliability Corporation) and adopted in equivalent forms by regulatory bodies worldwide [19], requires that the power system remain operable and within voltage and thermal limits following the loss of any single element — whether a generator, transmission line, transformer, or bus. N-2 contingency analysis extends this to double-element outages but is typically applied only to critical infrastructure, while N-1-1 analysis—evaluating sequential single-element outages—has also been used to assess static security margins in large interconnected power systems [20]. The results of contingency analysis are used to rank contingencies by severity, identify vulnerable system elements, and support corrective action planning. Modern energy management systems (EMS) perform online contingency analysis in near real-time to continuously monitor system security [21].

2.5. Load Flow Analysis

Load flow analysis, also referred to as power flow analysis, is a steady-state computational method used to determine the voltage magnitudes and angles at each bus, as well as the active and reactive power flows in all branches of a power network, under specified loading and generation conditions [22]. The primary parameters computed in a load flow study include: bus voltage magnitudes (per unit) and phase angles; active power (MW) and reactive power (MVAR) flows in each line and transformer; generator active and reactive power outputs; real and reactive power losses in network elements; and equipment loading percentages. The Newton-Raphson method is the most widely used iterative algorithm for load flow solution due to its excellent convergence characteristics and computational efficiency for large-scale networks. In ETAP, the load flow module implements the Newton-Raphson algorithm with automatic handling of generator reactive power limits, transformer tap adjustments, and shunt compensation [23].

2.6. Steady-State Voltage Security

Steady-state voltage security in this study refers to whether the converged post-contingency bus-voltage magnitudes remain within a predefined operating band after each generator outage

[24, 25]. This is not a dynamic voltage-stability study and does not calculate P-V curves, Q-V curves, voltage-collapse margins, or time-domain recovery [26]. Accordingly, the revised manuscript uses 0.95–1.05 pu as a study screening band for normal operation unless equipment- or utility-specific limits are supplied. Emergency limits, if different, must be explicitly documented rather than attributed generically to IEEE Std 1159.

2.7. ETAP Software

The Electrical Transient Analyzer Program (ETAP) is an electrical engineering software specifically designed to simulate, analyse, and evaluate the performance of power systems comprehensively, from the planning and design stages through to system operation [27]. In this study, ETAP version 19.0.1 serves as the primary platform for digitally modelling the seven-bus power system, which consists of a utility grid, two synchronous generators, step-up and step-down transformers, transmission-distribution lines, and aggregated loads, allowing all system components to be represented accurately according to their actual technical parameters such as capacity, impedance, and operating characteristics [28].

The main function of ETAP in this study is to perform load flow analysis using the Newton–Raphson algorithm to calculate voltage, current, and power distribution at each bus and branch of the system under various operating scenarios, namely normal conditions, Generator 1 outage, and Generator 2 outage. Through this contingency simulation capability, ETAP enables researchers to observe in detail how the system responds to the loss of a single generating unit, including changes in the voltage profile at each bus, increased loading on the remaining operating generator, and changes in the power import pattern from the utility grid [29, 30].

ETAP provides numerical and graphical reports for load-flow and contingency studies. In this work, the software is used as the calculation environment; no claim is made that ETAP results are independently 'accurate' unless they are verified against another solver, hand calculation, or field measurement. The 0.95–1.05 pu range is treated as the study's normal voltage screening band, not as a universal IEEE Std 1159 steady-state limit.

Thus, ETAP is used here as an engineering simulation platform for comparative N-1 analysis. The reliability of the conclusions depends on the consistency of the model data, limit settings, solver convergence, and power-balance results rather than on the software name alone.

3. Research Methodology

3.1. Research Method

This study employs a quantitative simulation-based research methodology. The approach is grounded in numerical power system analysis, wherein the behavior of the electrical network is characterized by mathematical models solved through iterative computational algorithms. The simulation is conducted using ETAP 19.0.1, which implements the Newton-Raphson load flow algorithm to solve the power flow equations governing bus voltages, power injections, and branch flows. Simulation-based research in power engineering is widely adopted because it enables the safe and repeatable investigation of system

behavior under contingency conditions that would be hazardous or impractical to induce in operational networks. The quantitative results obtained are analyzed comparatively across three defined operating scenarios to draw conclusions about system performance and reliability.

3.2. Research Procedure

The research was carried out in a systematic sequence of phases as described below:

1. Literature Review:

A comprehensive review of published literature on generator outage, N-1 contingency analysis, load flow methods, voltage stability, and ETAP simulation was conducted to establish theoretical foundations and identify research gaps.

2. System Modeling:

A representative power system was constructed in the ETAP 19.0.1 environment, including all relevant equipment types (utility grid, synchronous generators, transformers, transmission lines, distribution lines, buses, and loads) with parameters based on typical industrial and utility practice.

3. Normal Condition Simulation:

Load flow analysis was executed for the base case (Case 1) to establish reference values for bus voltages, power flows, and equipment loadings under normal operating conditions with all generators in service.

4. Generator Outage Simulation:

The outage of Generator 1 (Case 2) and Generator 2 (Case 3) were simulated sequentially by deactivating the respective generator in the ETAP model and re-running the load flow analysis for each contingency scenario.

5. Results Analysis:

The load flow results for all three scenarios were tabulated and compared to identify changes in bus voltage profiles, generator loading, transformer loading, and line loading.

6. Conclusions:

Conclusions were drawn based on the comparative analysis, addressing the impact of generator outage on system performance and the adequacy of the N-1 security criterion.

3.3. System Modeling

The power-system model used for all scenarios must be a single, consistent seven-bus model. The currently reported component ratings are summarized below, while parameters not present in the source manuscript—such as complete line R/X/B data, transformer tap settings and control modes, generator Q limits, stator-current limits, and capability curves—must be exported from the ETAP project for full replication.

Utility Grid (Infinite Bus): The utility grid is modeled as an infinite bus connected at the 150 kV primary transmission bus (Bus-1), with a rated short-circuit capacity of 500 MVA and a base voltage of 150 kV. The utility grid serves as the slack bus in the load flow formulation, maintaining a fixed voltage magnitude of 1.00 per unit and a reference angle of 0°.

Generator 1 (G1): rated 15 MVA, 11 kV. The source manuscript reports a normal operating point of 12.75 MW and

4.2 MVAR. These values correspond to 13.42 MVA and approximately 89.5% of the 15 MVA rating. Generator active-power, reactive-power, stator-current, and capability-curve limits must be enabled and documented in ETAP for the final rerun.

Generator 2 (G2): rated 20 MVA, 11 kV. The source manuscript reports a normal operating point of 17.0 MW and 5.8 MVAR, equivalent to 17.96 MVA and approximately 89.8% loading. The final model must also document its active-power limit, reactive-power limits, stator-current limit, capability curve, and voltage-control setpoint.

Transformers: Two main transformers are included in the model. The step-up transformer T1 (30 MVA, 11/150 kV, $\Delta 11/Yn0$ vector group, impedance 8.5%) connects the generator buses to the 150 kV transmission bus. The step-down transformer T2 (25 MVA, 150/33 kV, $Yn0/Yn0$ vector group, impedance 7.0%) connects the 150 kV bus to the 33 kV sub-transmission bus.

Transmission and Distribution Lines: the manuscript reports a 25 km, 150 kV line with ACSR Zebra 400 mm² conductor and 650 A ampacity, plus 33 kV XLPE feeders of 5–15 km. For model replication, the final revision must additionally provide each branch resistance, reactance, shunt susceptance/capacitance, conductor/cable arrangement, and thermal rating exactly as entered in ETAP.

Buses: The system comprises seven buses: Bus-1 (150 kV, slack), Bus-2 (11 kV, PV, Gen-1), Bus-3 (11 kV, PV, Gen-2), Bus-4 (150 kV, PQ), Bus-5 (33 kV, PQ), Bus-6 (33 kV, PQ), and Bus-7 (33 kV, PQ).

Loads: The system serves four aggregated load groups totaling approximately 38.5 MW at full load: Load-A (12 MW, 5.5 MVAR) at Bus-5, Load-B (10 MW, 4.8 MVAR) at Bus-6, Load-C (9 MW, 4.2 MVAR) at Bus-7, and auxiliary loads of 7.5 MW, 3.5 MVAR at Bus-4.

3.4. Generator Outage Simulation Scenarios

Three simulation scenarios were defined to evaluate the impact of generator outage on system performance. The scenarios are summarized in Table 1.

Table 1
Simulation Scenario Definitions

Scenario	Operating Condition	Description
Case 1	Normal Operation	All system components in service. Utility grid, Generator 1, and Generator 2 all operating at specified setpoints.
Case 2	Generator 1 Outage	Generator 1 (15 MVA, 12.75 MW) is disconnected from the system. Load is supplied by the utility grid and Generator 2 only.
Case 3	Generator 2 Outage	Generator 2 (20 MVA, 17 MW) is disconnected from the system. Load is supplied by the utility grid and Generator 1 only.

For each outage case, the generator is set out of service and the load flow is rerun. The remaining dispatch must be explicitly documented. If the utility grid is the slack bus, it should absorb the residual active and reactive power mismatch after the surviving generator is held at its allowed P/Q or voltage-control limits. When a surviving PV

generator reaches a reactive-power limit, ETAP should be configured to enforce that limit and switch the bus from PV to PQ as required. The final submission should report whether this switching occurs in each contingency.

3.5. Load Flow Analysis Parameters

The following parameters are observed and recorded from the ETAP load flow results for each simulation scenario:

1. Bus Voltage (kV and per unit):

The voltage magnitude at each bus is compared with the study-defined normal screening band of 0.95–1.05 pu. Any emergency voltage band used for contingency assessment must be separately stated and justified.

2. Active Power Flow (MW):

The active power delivered or absorbed at each bus and flowing through each branch.

3. Reactive Power Flow (MVAR):

Reactive power at each source and load bus is recorded so that the Q balance can be checked together with network reactive losses. Generator Q limits and any PV-to-PQ switching must also be reported.

4. Transformer Loading (%):

Equipment loading is calculated from apparent power, $S = \sqrt{P^2 + Q^2}$, divided by equipment MVA rating. A 100% continuous rating is used as the normal thermal screening threshold unless a documented emergency rating is available.

5. Line Loading (%):

The current loading of each transmission and distribution line as a percentage of its thermal rating.

3.6. Data Analysis

The revised analysis first checks numerical consistency before interpreting contingency severity. For each scenario, total active-power source injection should equal total load plus real-power losses, and total reactive-power source injection should equal load reactive demand plus reactive losses/shunt exchanges. Generator loading is calculated from apparent power rather than active power alone. Any scenario that does not close the power balance cannot support a final N-1 security conclusion until it is rerun.

3.7. State of the Research

This section presents the overall stages undertaken in this research, summarized graphically in the flowchart shown in Fig.1. The research begins with a literature review on generator outage, N-1 contingency analysis, load flow methods, voltage stability, and ETAP simulation, which establishes the theoretical foundation and identifies the research gap addressed in this study. The representative seven-bus power system is then modeled in ETAP 19.0.1, incorporating the utility grid, Generator 1 (15 MVA) and Generator 2 (20 MVA), step-up and step-down transformers, transmission and distribution lines, seven buses, and aggregated loads, as detailed in Section 3.3.

Once the system model is established, load flow analysis is executed for the normal operating condition (Case 1) using the Newton-Raphson algorithm to obtain reference values for bus voltage, power flow, and equipment loading. The

generator outage scenarios are then simulated by sequentially deactivating Generator 1 (Case 2) and Generator 2 (Case 3) in accordance with the N-1 contingency criterion, as described in Section 3.4. The resulting bus voltages, active and reactive power flows, and equipment loadings for each scenario are recorded and compared against the normal condition, with voltage deviations evaluated against the IEEE Std 1159 permissible range of 0.95–1.05 pu, as described in Sections 3.5 and 3.6. Should the N-1 criterion not be satisfied for a given contingency, corrective measures such as reactive power compensation or generation redispatch are identified prior to formulating the final conclusions and recommendations. This sequential research flow is illustrated as Fig.1.

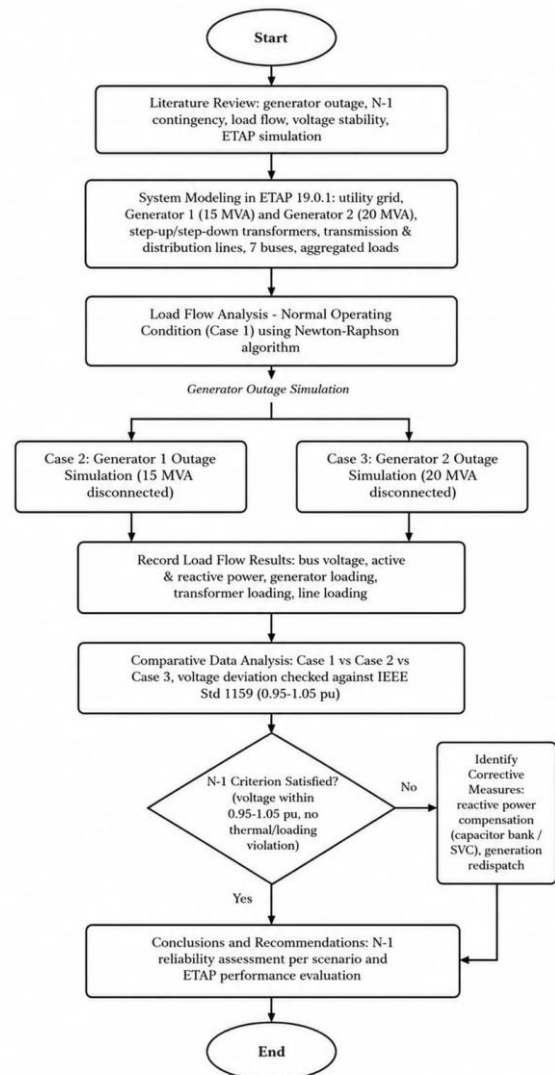


Fig. 1. Flowchart of the Research Stages.

4. Results and Discussion

4.1. Single Line Diagram of the Simulated System

The single line diagram in ETAP 19.0 software can be seen as Fig. 2

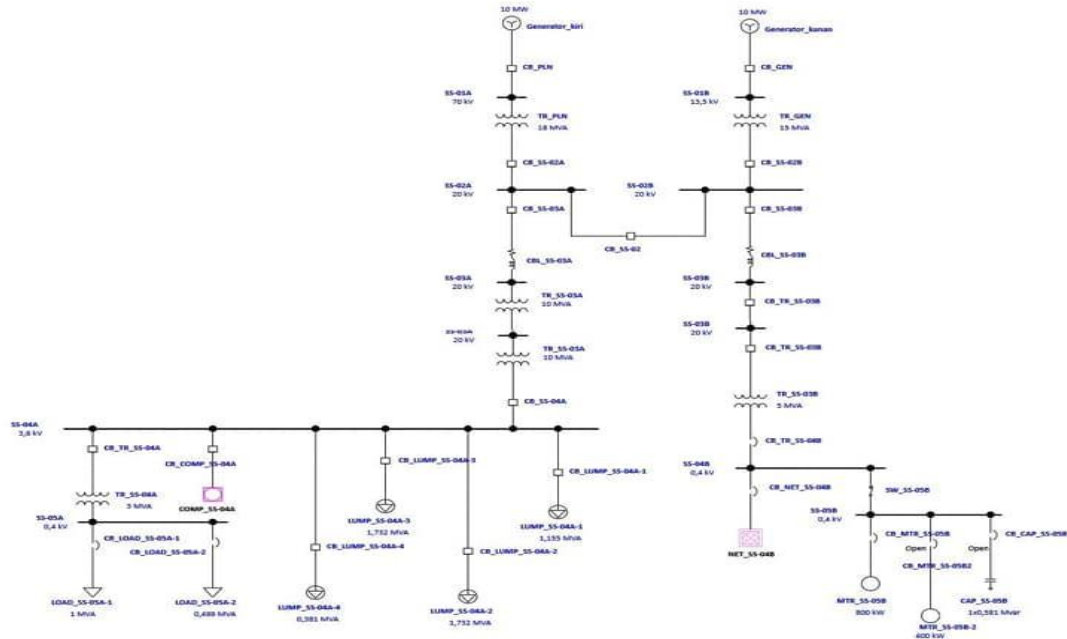


Fig. 2. Single line diagram in ETAP 19.0 software.

The single line diagram (SLD) of the simulated power system as constructed in ETAP 19.0.1 is presented conceptually in the description below. The system is a seven-bus network with a radial-mesh topology, comprising two parallel generation sources (utility grid at Bus-1 and two synchronous generators at Bus-2 and Bus-3) converging at the 150 kV transmission bus (Bus-4). Power is stepped down through transformer T2 to the 33 kV sub-transmission level at Bus-5, from which radial feeders supply load buses Bus-6 and Bus-7.

The utility grid (Slack Bus) feeds into Bus-1 at 150 kV. Bus-2 and Bus-3, at 11 kV, host Generator 1 and Generator 2 respectively, each connected to Bus-4 (150 kV) through step-up transformer T1. The 150 kV transmission line connects Bus-4 to the load region. Transformer T2 steps voltage down to 33 kV at Bus-5, with distribution feeders extending to Bus-6 and Bus-7 where the primary loads are located. The system configuration is representative of a typical industrial sub-transmission network where local generation supplements grid supply.

4.2. Normal Operating Condition (Case 1)

Under normal operation, the reported total load is 38.5 MW and 18.0 MVAR. The bus-voltage values in Table 2 lie within the 0.95–1.05 pu study screening band. However, the source manuscript does not provide a complete reactive-power balance or network-loss total, so only the reported bus-voltage and source-output values are treated as directly verifiable.

The reported normal bus voltages range from 1.000 pu at Bus-1 to 0.972 pu at Bus-7. These values satisfy the study's normal screening band. This is a steady-state voltage-security observation and is not presented as a dynamic voltage-stability margin.

Generator 1 reports 12.75 MW and 4.2 MVAR. Its apparent power is therefore $\sqrt{12.75^2 + 4.2^2} = 13.42$ MVA, corresponding to approximately 89.5% of its 15 MVA rating.

Generator 2 reports 17.0 MW and 5.8 MVAR. Its apparent power is $\sqrt{17.0^2 + 5.8^2} = 17.96$ MVA, corresponding to approximately 89.8% of its 20 MVA rating.

The reported utility active-power import is 8.75 MW. Together with Generator 1 and Generator 2 active power, this exactly equals the stated 38.5 MW load, leaving no reported allowance for real-power losses. The final ETAP rerun should therefore report source totals, load totals, and network losses explicitly rather than implying a zero-loss balance.

both well below thermal limits. Transmission line loading is 41.2%, indicating substantial available headroom. The system demonstrates healthy security margins under normal conditions, consistent with the N-1 criterion requirements.

Table 2
Bus Voltage Results — All Three Scenarios

Bus	Rated (kV)	Normal (pu)	Normal (kV)	Gen-1 Out (pu)	Gen-1 Out (kV)	Gen-2 Out (pu)	Gen-2 Out (kV)
Bus-1	150	1.000	150.00	1.000	150.00	1.000	150.00
Bus-2	11	1.020	11.22	—	—	1.015	11.17
Bus-3	11	1.018	11.20	1.010	11.11	—	—
Bus-4	150	0.998	149.70	0.983	147.45	0.975	146.25
Bus-5	33	0.985	32.51	0.965	31.85	0.956	31.55
Bus-6	33	0.978	32.27	0.956	31.55	0.947	31.25
Bus-7	33	0.972	32.08	0.950	31.35	0.941	31.05

4.3. Generator 1 outage (case 2)

When Generator 1 is out of service, the reported surviving Generator 2 output is 19.5 MW and 8.7 MVAR. These values correspond to 21.35 MVA, or approximately 106.8% of its

20 MVA rating. Thus, based on the reported P and Q values, Generator 2 is above its nameplate apparent-power rating rather than at 97.3% loading.

The reported bus voltages decrease, with Bus-7 reaching 0.950 pu, Bus-6 reaching 0.956 pu, and Bus-5 reaching 0.965 pu. These values are at or above the lower boundary of the study's normal screening band.

A major numerical inconsistency is present in the reported active-power balance for Case 2. Generator 2 contributes 19.5 MW and the manuscript reports utility import of 10.25 MW, for a total of only 29.75 MW, while the stated load remains 38.5 MW before including losses. This 8.75 MW deficit cannot represent a converged physical load-flow balance. Therefore, Case 2 must be rerun using the documented model before its N-1 security status can be finalized.

The reported transformer and line-loading percentages are retained as provisional source outputs, but they should be regenerated in the same rerun that corrects the Case 2 power balance and enforces generator capability limits.

4.4. Generator 2 Outage (Case 3)

Generator 2 outage removes the larger local generator. The source manuscript reports Generator 1 at 14.8 MW and 7.1 MVAR and utility import at 23.7 MW.

The reported voltage results show Bus-7 at 0.941 pu and Bus-6 at 0.947 pu, below the study's 0.95 pu normal screening threshold, while Bus-5 remains at 0.956 pu.

Generator 1 apparent power is $\sqrt{14.8^2 + 7.1^2} = 16.41$ MVA, equivalent to approximately 109.4% of its 15 MVA rating. Therefore, the reported operating point exceeds the generator nameplate MVA rating and must be checked against the actual capability curve, stator-current limit, and P/Q limit settings in ETAP.

The Case 3 active-power source total, $14.8 + 23.7 = 38.5$ MW, equals the stated active load exactly, again with no reported real-power losses. The voltage violations and generator overload indication make Case 3 clearly more severe in the current dataset, but a final N-1 conclusion should be based on the corrected and fully balanced rerun.

4.5. Comparison of Simulation Results

Table 3
Generator Loading Comparison Across All Scenarios

Gen	Rated (MVA)	Normal (MW)	Normal (%)	G1 Out (MW/%)	G2 Out (MW/%)
Gen-1	15	12.75	89.5%	OUT	14.8 / 109.4%
Gen-2	20	17.0	89.8%	19.5 / 106.8%	OUT
Util-Grid	500 Scc	8.75	N/A	10.25 / N/A	23.7 / N/A

Table 4
Transformer Loading Comparison Across All Scenarios

Transformer	Rating (MVA)	Normal (%)	Gen-1 Outage (%)	Gen-2 Outage (%)
T1 (Step-Up)	30	48.3%	72.1%	53.6%
T2 (Step-Down)	25	52.4%	65.8%	78.3%

Table 5
Transmission and Distribution Line Loading Comparison

Line/Feeder	Rating (A)	Normal (%)	Gen-1 Outage (%)	Gen-2 Outage (%)
TX Line (Bus-1–Bus-4)	650	41.2%	58.7%	72.5%
Feeder Bus-5–Bus-6	300	62.1%	74.3%	81.5%
Feeder Bus-5–Bus-7	300	55.8%	68.4%	76.2%

Table 6
Active-Power Balance Consistency Audit

Case	Active-Power Balance Audit
Normal	Sources = 38.50 MW; load = 38.50 MW; losses not reported.
G1 Out	Sources = 29.75 MW; load = 38.50 MW; 8.75 MW deficit - > rerun required.
G2 Out	Sources = 38.50 MW; load = 38.50 MW; losses not reported.

Table 6 shows that the reported Case 2 active-power data do not close the system balance. Reactive-power balance also cannot be verified for any case because utility-grid Q, network reactive losses, and shunt exchanges are not reported. These quantities must be exported from the rerun before final security conclusions are made.

4.6. Discussion

The revised numerical audit changes the interpretation of generator loading. Loading must be based on apparent power rather than MW alone. Using the reported P and Q values, both generators operate near 90% MVA loading in the normal case; Generator 2 reaches approximately 106.8% during Generator 1 outage, and Generator 1 reaches approximately 109.4% during Generator 2 outage. These results indicate that generator capability limits are central to the contingency assessment.

The post-outage voltage reductions are consistent with reduced local reactive-power support and increased transfer through the remaining network. The Generator 2 outage produces the lowest reported voltages, with Bus-6 at 0.947 pu and Bus-7 at 0.941 pu. Because this is a steady-state load-flow study, these results are described as steady-state voltage-security violations rather than voltage instability.

The redispatch mechanism must be represented explicitly in the final ETAP model. The utility grid/slack source should absorb residual mismatch, while the surviving generator should remain subject to its P, Q, stator-current, and capability-curve limits. If the generator reaches a Q limit, its bus should switch from PV to PQ. The current manuscript does not document whether these controls were enabled, so the reported post-outage operating points require rerun and verification.

The power-balance audit also identifies a critical inconsistency in Case 2: the reported active sources total only 29.75 MW against a stated 38.5 MW load, before losses. This means the current Case 2 dataset cannot be used to claim N-1 compliance. Case 3 source active power sums to 38.5 MW, but losses are again not reported, and the reactive balance is incomplete because utility-grid reactive power and network reactive losses are absent.

ETAP is therefore treated as the modeling environment rather than as an independently validated source of accuracy. A publication-quality final revision should report solver

tolerances/convergence, complete network data, source and load P/Q balances, losses, generator limit enforcement, and preferably an independent cross-check or hand calculation for selected buses.

5. Conclusion

This study examined three load-flow scenarios for a seven-bus utility-generator system: normal operation, Generator 1 outage, and Generator 2 outage. A detailed numerical audit shows that generator loading in the original manuscript was understated because it was not consistently calculated from apparent power. From the reported P and Q values, Generator 1 and Generator 2 are approximately 89.5% and 89.8% loaded in the normal case. Under Generator 1 outage, the reported Generator 2 operating point corresponds to approximately 106.8% of its 20 MVA rating; under Generator 2 outage, the reported Generator 1 operating point corresponds to approximately 109.4% of its 15 MVA rating. The voltage results also show that Generator 2 outage is the more severe case, with Bus-6 and Bus-7 at 0.947 pu and 0.941 pu, respectively. However, the reported Case 2 active-power balance is inconsistent by 8.75 MW, and complete reactive-power balances, losses, generator capability limits, and PV-to-PQ switching status are not documented. Consequently, the manuscript cannot yet make a definitive N-1 compliance claim for either contingency. The final conclusion should be based on a complete rerun of all three scenarios using one documented model with consistent network parameters, enforced generator limits, complete P/Q/loss balances, and clearly defined normal and emergency screening limits.

Corrective actions such as shunt capacitors, SVCs, generator redispatch, or transformer tap changes remain technically plausible options, but the original manuscript did not simulate them. The previous recommendation of a specific 2–3 MVAR compensator rating has therefore been removed. The final study should test candidate corrective actions directly in ETAP and report the resulting bus voltages, source P/Q, equipment loadings, and losses before recommending a rating or claiming restored N-1 security.

CRedit authorship contribution statement

Muh.Adam: Conceptualization, Methodology, Software, Formal analysis, Writing – original draft. **Hafidz Zikri:** Investigation, Data curation, Validation, Visualization, Writing – review & editing. **Muh. Fikry Haikal:** Writing – original draft, Formal analysis, Validation, Visualization, Writing – review & editing

Declaration of competing interest

No Conflict of interest.

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Data availability

The data supporting the findings of this study, including the ETAP 19.0.1 system model and the load flow simulation results for all three operating scenarios, are available from the corresponding author upon reasonable request.

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