Minimum Synchronous Generator Requirements in Cyprus

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Executive Summary

This report presents a comprehensive methodology for determining the Minimum Synchronous Generator Level (MSGL) required for maintaining power system stability in the Cyprus electricity network. The methodology addresses the challenges posed by increasing renewable energy integration while ensuring system stability and reliability.

Key Methodology

The approach employs a systematic five-step filtering process:

1. **Static N-1 Contingency Analysis:** Evaluates generator combinations that satisfy the N-1 criterion.
2. **Frequency Stability Assessment:** Evaluates generator combinations that meet minimum inertia requirements based on Rate of Change of Frequency (RoCoF) constraints using Mixed Integer Linear Programming (MILP).
3. **Fault Level and System Strength Requirements:** Filters combinations by validating fault levels, Short Circuit Ratio (SCR), Weighted Short Circuit Ratio (WSCR), and voltage stability factor (K_v) at HV busbars.
4. **Transient Stability Assessment:** Evaluates stability margins through time-domain simulations, ensuring adequate Critical Clearing Time (CCT) margins ($\eta \geq 0.15$) and sufficient damping ratios ($\zeta > 0.05$).
5. **Low Voltage Ride-Through (LVRT) Evaluation:** Verifies generator compliance with LVRT requirements under various fault scenarios.

Data Requirements

The implementation requires specific data from the Transmission System Operator Cyprus (TSOC):

- Inertia constants and capacities of synchronous generators
- System strength metrics (minimum WSCR, SCR, and K_v values)
- Aggregated Installed capacity of Inverter-Based Resources (IBRs) at HV substations
- Critical clearing times and stability margins
- LVRT capability requirements and credible contingencies

Modeling Requirements

A complete DIgSILENT PowerFactory model of the Cyprus transmission system is essential, including:

- Dynamic models of all synchronous generators with Automatic Voltage Regulators (AVR) and Power System Stabilizers (PSS)
- Accurate representation of IBRs where available
- Updated network topology with correct statuses of transmission elements
- DIgSILENT PowerFactory license with RMS Simulation and Small Signal stability capabilities

Significance

This methodology provides TSOC with a robust framework to determine the minimum required synchronous generation while maintaining system stability as Cyprus transitions toward higher renewable penetration. The approach balances technical constraints with operational flexibility, supporting Cyprus's renewable energy goals while ensuring power system reliability.

Contents

Abbreviations

Abbreviation	Definition
AGC	Automatic Generation Control
AVR	Automatic Voltage Regulator
BESS	Battery Energy Storage System
CCT	Critical Clearing Time
CIG	Converter-Interfaced Generation
DER	Distributed Energy Resource
DSA	Dynamic Security Assessment
EEAC	Extended Equal Area Criterion
EMS	Energy Management System
ESCR	Effective Short-Circuit Ratio
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response
HVRT	High Voltage Ride-Through
IBR	Inverter-Based Resource
LVRT	Low Voltage Ride-Through
MILP	Mixed Integer Linear Programming
MSGL	Minimum Synchronous Generator Level
NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
OFGS	Over-Frequency Generator Shedding
PLL	Phase-Locked Loop
PMU	Phasor Measurement Unit
POI	Point of Interconnection
PSS	Power System Stabilizer
PV	Photovoltaic
RES	Renewable Energy Source
RoCoF	Rate of Change of Frequency
ROCOV	Rate of Change of Voltage
SCADA	Supervisory Control and Data Acquisition
SCC	Short-Circuit Capacity
SCR	Short Circuit Ratio
SG	Synchronous Generator
STATCOM	Static Synchronous Compensator
TSM	Transient Stability Margin
TSO	Transmission System Operator
TSOC	Transmission System Operator Cyprus
UDER	Uncontrollable Distributed Energy Resources
UFLS	Under-Frequency Load Shedding
VAR	Volt-Ampere Reactive (reactive power)
VSC	Voltage-Source Converter
VSM	Virtual Synchronous Machine
WAMS	Wide-Area Measurement System
WSCR	Weighted Short-Circuit Ratio
WTG	Wind Turbine Generator

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Introduction

The transition from conventional synchronous generation to IBRs introduces complex stability challenges that necessitate careful determination of must-run synchronous units. As IBRs like wind, solar, and battery storage lack inherent inertia and fault current contribution, power systems face heightened risks of frequency and instability during disturbances [17, 8]. Synchronous generators provide critical inertia to dampen frequency deviations, enabling sufficient time for primary and secondary frequency response mechanisms[17, 12]. Voltage regulation also becomes more challenging, as IBRs often require external reactive power support to maintain steady voltage profiles, particularly during grid faults or rapid load changes [17, 1]. Additionally, the reduced fault current contribution from IBRs compromises protection system coordination, necessitating synchronous units to maintain adequate short-circuit capacity [17].

Operational complexities arise from conflicting requirements: minimizing must-run units reduces costs and emissions, but insufficient synchronous capacity jeopardizes stability. These trade-offs demand methodologies that integrate dynamic constraints-such as frequency nadir limits, voltage ride-through capabilities, and transient stability margins-with optimization models [1, 18].

1.1. Frequency Stability and RoCoF Constraints

Frequency stability is often the primary limiting factor in low-inertia systems. The behavior of the frequency response post-fault is shown in Figure 1.1, with the most important characteristics highlighted. Moreover, the frequency stability in low-inertia power systems is governed by multidimensional constraints requiring analysis beyond traditional swing equation approaches.

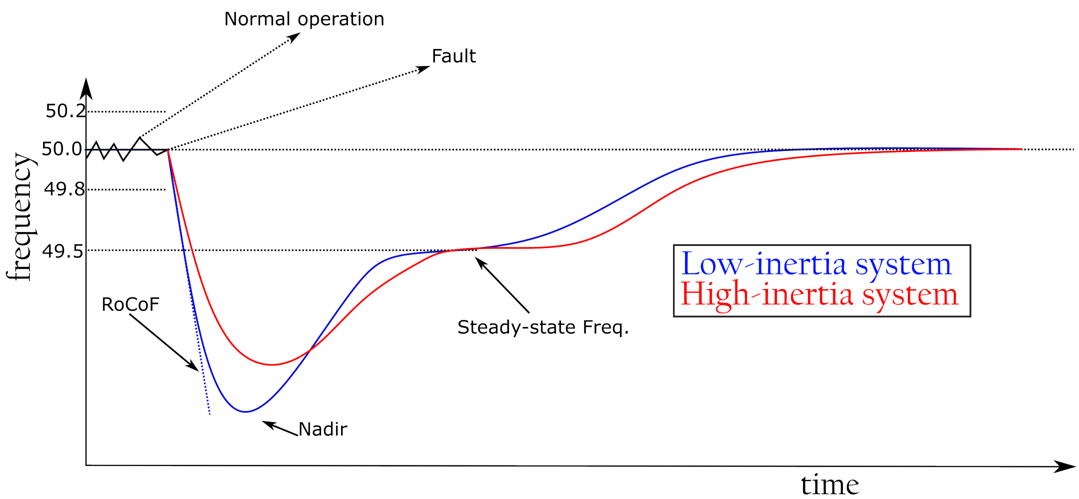

Figure 1.1: Post-fault frequency response

1.1.1. Stability Metrics

Rate of Change of Frequency (RoCoF) refers to the frequency derivative at the beginning of the event. For stability and security reasons, TSOs dictate a maximum allowed RoCoF (RoCoF$_{max}$) that can occur after an event.

The fundamental relationship between system inertia, power imbalance, and RoCoF is given by [7, 4]:

$$\text{RoCoF} = \frac{-f_N \cdot P_{loss}}{2 \cdot \sum_{g \in \mathcal{G}} (H_g \cdot S_{g,N})} \tag{1.1}$$

This can be rearranged to determine minimum required synchronous inertia [7]:

$$E_{kin}^{min} = \frac{-f_N \cdot P_{loss}}{2 \cdot \text{RoCoF}_{max}} + E_{kin}^{loss} \leq \sum_{g \in \mathcal{G}} (u_g \cdot H_g \cdot S_{g,N}) \tag{1.2}$$

where:

- f_N is the nominal frequency (50 Hz) in Hz
- P_{loss} is the largest credible contingency in MW
- H_g is each generator's inertia constant in seconds
- $S_{g,N}$ is each generator's power base in MVA
- $u_g \in \{0, 1\}$ is the commitment binary variable for generator g
- RoCoF$_{max}$ is the maximum allowable RoCoF in Hz/s
- $\mathcal{G}$ is the set of available SGs and grid-forming units
- E_{kin}^{min} is the minimum kinetic energy required to maintain a RoCoF of RoCoF$_{max}$ after a contingency of P_{loss}.
- E_{kin}^{loss} is the kinetic energy lost by the disconnection of the P_{loss}.

To get all the unit combinations that comply with this requirement, we need to solve the following MILP for every acceptable solution $\mathbf{u}^*$:

$$\begin{aligned} \min_{\mathbf{u}} \quad & 0 \\ \text{s.t.} \quad & \sum_{g \in \mathcal{G}} (u_g \cdot H_g \cdot S_{g,N}) \geq E_{kin}^{min} \\ & u_g \in \{0, 1\}, \forall g \in \mathcal{G} \end{aligned}$$

where u_g is a binary variable indicating whether generator g is committed, and $\mathcal{G}$ denotes the set of all generators.

In Cyprus, the RoCoF$_{max} = 1$ Hz/s and, in static analysis frameworks, $P_{loss} = 120$ MW is the considered value. In dynamic analysis frameworks, this value should be considered based on the predictions and market operations.

Frequency Nadir is the maximum frequency deviation post-contingency ($\Delta f^{\max}$) is equally critical as RoCoF limits. The frequency nadir occurs at the time instance t_m when $\Delta\dot{\omega}(t_m) \equiv \Delta\dot{f}(t_m) = 0$. Therefore, t_m can be derived by solving $\Delta\dot{\omega}(t_m) \equiv \Delta\dot{f}(t_m) = 0$, and then the frequency nadir can be obtained as given below [11]:

$$\Delta f^{\max} = \Delta f(t_m) = -\frac{P_{\text{loss}}}{D_{\text{sys}} + R_s} \left(1 + \sqrt{\frac{T(R_s - F_s)}{H_{\text{sys}}}} \, e^{-\zeta \omega_n t_m} \right) \leq \Delta f_{\text{lim}}^{\max} \tag{1.3}$$

where:

- H_{sys} is the aggregated level of inertia of CIG and SG units
- D_{sys} is the aggregated level of damping of CIG and SG units

- R_s is the droop support of SG units
- F_s is the turbine power fraction of SG units
- $t_m = \frac{1}{\omega_d}\tan^{-1}\left(\frac{\omega_d}{\omega_n\zeta - T^{-1}}\right)$
- $\omega_d = \omega_n\sqrt{1-\zeta^2}$
- $\phi = \sin^{-1}\left(\sqrt{1-\zeta^2}\right)$
- $\omega_n = \sqrt{\frac{D+R_s}{MT}}$
- $\zeta = \frac{M+T(D+F_s)}{2\sqrt{MT(D+R_s)}}$

However, to comply with this constraints, the FCR and FFR contributions are also necessary, which are currently dictated by market mechanisms. In Cyprus, the acceptable limits are $|\Delta f^{\max}| \leq 1$ Hz to avoid triggering the UFLS protection schemes.

Post-fault frequency steady-state: The quasi-steady-state frequency deviation can be derived from as given below:

$$\Delta f^{\text{qss}} = -\frac{P_{\text{loss}}}{D_{\textsf{sys}} + R_s} \tag{1.4}$$

This metric does not involve the inertia but only the dumping and primary regulation parameters.

It is usually required that:

$$|\Delta f^{\text{qss}}| \leq \Delta f^{\text{qss}}_{max} \tag{1.5}$$

In Cyprus the limit is $\Delta f^{\text{qss}}_{max} = 0.5$ Hz.

1.1.2. Operational Practices

System operators employ layered strategies to maintain frequency stability:

- **Inertia**: Australia's NEM mandates minimum synchronous inertia thresholds (4,500 MWs at 50 Hz) with dynamic pricing for inertia [2]. Similarly, SONI and EirGrid mandate a minimum system kinetic energy of 23,000 MWs throughout the year, along with a requirement to keep at least seven synchronous generators online at all times. In Cyprus at this moment this constraint is addressed by requiring a fixed number of specific 'must-run' SGs.
- **Frequency Containment Reserves (FCR)**: Cyprus' FCR requirements are calculated in a dynamic way, based on the load and RES predictions. This provides an R_s^{min} required to comply with (1.5).

1.1.3. Novel Provision Methods

Emerging solutions challenge traditional inertia paradigms:

- **Grid-Forming Converters** Voltage-source converters (VSCs) emulate synchronous machine dynamics through [3]:

$$\begin{cases} \frac{d\theta}{dt} = \omega_0 + K_p(\omega_{ref} - \omega)\ M_{vsc} \\ \frac{d\omega}{dt} = P_{ref} - P_{out} - D_{vsc}(\omega - \omega_0) \end{cases} \tag{1.6}$$

  where M_{vsc} is virtual inertia constant and D_{vsc} is damping factor.

  Combining physical and virtual inertia sources:

$$E^{eff}_{kin} = \sum_{g\in\mathcal{G}_{SYN}} E_{kin,g} + \sum_{g\in\mathcal{G}_{GFM}} E_{kin,g} \tag{1.7}$$

  which adds the kinetic energy of the committed SGs and GFM units.
- **Fast Frequency Response (FFR)**: Cyprus' FFR requires < 0.8 s response to frequency deviations > 0.3 Hz. This is a new mechanism that has not yet been implemented in Cyprus and mainly affects the Nadir frequency after a disturbance.

1.1.4. Implementation Challenges

Key barriers to RoCoF constraint enforcement include:

- Time-varying inertia estimation errors exceeding 15% in real-time calculations [15]
- Coupling between synthetic inertia provision and sub-synchronous oscillations
- Non-uniform frequency measurements causing protection mis-coordination
- Interactions between the market mechanisms and technical constraints of must-run units

1.2. Static N-1 Security Analysis

Static N-1 contingency analysis is a fundamental power system planning technique used to determine the minimum units that must run to maintain system reliability and stability under single component outages. The N-1 criterion ensures that the power system can withstand the loss of any single element (transmission line, transformer, generator, etc.) without violating operational limits or experiencing voltage collapse. For systems with high renewable penetration, this analysis becomes critical for identifying the SGs that must remain online to provide essential grid services.

To get all the unit combinations that comply with the N-1 security requirement, we need to solve the following MILP for every acceptable solution $\mathbf{u}^*$:

$$\min_{\mathbf{u}} \quad 0 \tag{1.8}$$

$$\text{s.t.} \quad \mathbf{g}^c(\mathbf{x}^c, \mathbf{u}) = \mathbf{0}, \quad \forall c \in \mathcal{C} \tag{1.9}$$

$$\mathbf{h}^c(\mathbf{x}^c, \mathbf{u}) \leq \mathbf{0}, \quad \forall c \in \mathcal{C} \tag{1.10}$$

where $\mathbf{g}^c$ and $\mathbf{h}^c$ are the post-contingency equality and inequality constraints for contingency c, and $\mathcal{C}$ is the set of all credible N-1 contingencies.

The equality constraints $\mathbf{g}^c$ represent the power flow equations under contingency c:

$$P_i^c = V_i^c \sum_{j=1}^{n} V_j^c (G_{ij}^c \cos\theta_{ij}^c + B_{ij}^c \sin\theta_{ij}^c) \tag{1.11}$$

$$Q_i^c = V_i^c \sum_{j=1}^{n} V_j^c (G_{ij}^c \sin\theta_{ij}^c - B_{ij}^c \cos\theta_{ij}^c) \tag{1.12}$$

where P_i^c and Q_i^c are the active and reactive power injections at bus i during contingency c, V_i^c is the voltage magnitude, θ_{ij}^c is the voltage angle difference between buses i and j, and G_{ij}^c and B_{ij}^c are the real and imaginary parts of the bus admittance matrix.

The inequality constraints $\mathbf{h}^c$ represent the security assessment criteria, described below.

1.2.1. Static Voltage Security Assessment

Voltage security represents a critical dimension of the N-1 contingency analysis. Abnormal voltages and voltage collapse pose primary threats to power system stability, security, and reliability. When performing static N-1 contingency analysis for voltage security, the following aspects require careful examination:

$$V_i^{\min} \leq V_i^c \leq V_i^{\max}, \quad \forall i \in \mathcal{N}, \forall c \in \mathcal{C} \tag{1.13}$$

where V_i^c represents the voltage magnitude at bus i for contingency c, $V_i^{\min}$ and $V_i^{\max}$ represent the minimum and maximum voltage limits, and $\mathcal{N}$ denotes the set of all buses.

The **Voltage Stability Margin (VSM)** can be quantified to determine the proximity to voltage collapse:

$$\text{VSM}^c = \frac{\lambda^c - \lambda_0}{\lambda_0} \times 100\% \tag{1.14}$$

where λ represents the current loading parameter and λ_0 represents the critical loading parameter corresponding to voltage collapse.

Excessive voltage decline can occur following severe system contingencies, potentially leading to voltage collapse through cascading events such as tripping of transmission facilities, VAR sources, or generating units due to overloading. The static voltage stability criterion serves as an essential tool in preventing severe voltage drops by identifying vulnerable nodes that could trigger system-wide instability.

1.2.2. Congestion Assessment in N-1 Analysis

Transmission congestion analysis forms another vital component of the N-1 contingency framework. Congestion occurs when the grid lacks sufficient transmission capacity to support the power flows required by market participants. This limitation directly impacts the determination of must-run units, as specific generators may need to remain operational to alleviate potential congestion under contingency scenarios.

For each contingency $c \in \mathcal{C}$, the following constraint must be satisfied:

$$|I_{ij}^c| \leq I_{ij}^{\max}, \quad \forall (i,j) \in \mathcal{L}_c, \forall c \in \mathcal{C} \tag{1.15}$$

where $\mathcal{L}_c$ represents the set of all transmission lines and transformers operating under contingency c, $|I_{ij}^c|$ is current magnitude over the line/transformer connecting buses i and j, and $I_{ij}^{\max}$ denotes the thermal limit of the line/transformer connecting buses i and j.

Constrained transmission capacity can prevent cost-effective generation from serving demand, potentially forcing system operators to dispatch more expensive or less efficient generation options. This economic inefficiency underscores the importance of identifying must-run units that can mitigate congestion under N-1 conditions.

1.2.3. Determining Must-Run Units Based on N-1 Analysis

The identification of must-run units through static N-1 contingency analysis involves a systematic assessment of system performance under all credible contingencies. The analysis **typically** follows these steps:

1. **Base Case Evaluation**: Establish a secure base case with all elements in service
2. **Contingency Selection**: Identify credible single-element outages
3. **Contingency Analysis**: For each contingency, simulate the system response and evaluate:
   - Voltage security constraints
   - Thermal loading limits
   - Power flow convergence
   - Voltage stability margins
4. **Critical Contingency Identification**: Rank contingencies based on severity indices
5. **Must-Run Determination**: Identify the minimum set of conventional units that must remain online to maintain security under all contingencies

To get **all** the unit combinations that comply with the N-1 security requirement, we need to solve the following MILP for every acceptable solution $\mathbf{u}^*$:

$$\begin{aligned}
\min_{\mathbf{u}} \quad & 0 \\
\text{s.t.} \quad & \text{Generator constraints}, \forall c \in \mathcal{C} \\
& \text{Power flow constraints}, \forall c \in \mathcal{C} \\
& \text{Security constraints}, \forall c \in \mathcal{C} \\
& u_g \in \{0,1\}, \forall g \in \mathcal{G}
\end{aligned}$$

1.3. Fault Level and System Strength Requirements

The increasing penetration of renewable energy resources, particularly IBRs such as wind and solar photovoltaic plants, is significantly affecting fault levels in power systems. Unlike SGs, IBRs do not contribute significant fault current during system disturbances, leading to reduced overall system strength. Low fault levels create numerous technical challenges for power system operation and stability.

First, the integration of IBRs into power systems significantly transforms fault current characteristics, introducing substantial challenges for conventional protection schemes. The protection schemes experience decreased detection ranges and diminished ability to identify low-level fault currents.

Second, when the fault levels decrease, the systems become weaker. In weak grids, the sensitivity of voltage magnitude and phase angle to changes in current injection increases substantially, resulting in potential control instability issues for IBRs whose control systems depend on stable voltage references. These issues can manifest as voltage oscillations, classical voltage instability, control interactions between nearby plants, phase-locked loop instability, and diminished disturbance ride-through capability. The severity of these problems increases when multiple IBRs are electrically close.

1.3.1. Short-Circuit Capacity

The Fault Levels in power systems are assessed by computing the Short-Circuit Capacity (SCC). For a fault at bus i, the SCC_i in pu is calculated as:

$$\text{SCC}_i = \frac{|V_{\text{th},i}|^2}{|Z_{\text{th},i}|}$$

where $V_{\text{th},i}$ is the Thevenin voltage and $Z_{\text{th},i}$ is the Thevenin impedance at bus i.

The SCC is significantly affected by the SGs in operation in the system:

- Their sub-transient reactance (X''_d) reduces $Z_{th,i}$, increasing SCC_i.
- Decommissioning SGs removes their contribution to fault current, raising $Z_{th,i}$ and reducing SCC_i.

Thus, must-run SGs are often retained to provide SCC, as IBRs contribute minimally to fault currents. Typical Fault Level values are given in Table 1.1.

Table 1.1: Voltage-Specific Short-Circuit Capacity and Critical Thresholds [23]

Voltage Level	**Fault Current** (kA)	**SCC** (MVA)	**Critical Thresholds** (seconds)
11 kV	?-20 kA	?-380	3s duration
22 kV	?-20 kA	?-690	3s duration
66 kV	?-25 kA	?-2850	1s duration
132 kV	?-31.5 kA	?-7200	1s duration

The upper bound of the Fault Current requirements is imposed to ensure that the withstand and breaking capability of the equipment is not exceeded. The lower bound of the Fault Current needs to be obeyed to ensure that there is adequate fault current for the existing protection devices to operate.

1.3.2. Short Circuit Ratio

To comprehensively evaluate system strength in IBR-dominated grids, operators consider both established and emerging metrics while addressing inherent limitations of conventional approaches. The Short Circuit Ratio (SCR) remains a primary indicator:

$$\text{SCR}_i = \frac{\text{SCC}_i}{\text{P}_{\text{IBR},i}}$$

where:

- SCC_i is the short-circuit capacity of the grid at the point of interconnection (in MVA), representing the grid's strength
- $\text{P}_{\text{IBR},i}$ is the nominal active power rating of the aggregated IBRs (in MW)

SCR evaluates whether the grid can maintain stable voltage levels when the IBR injects its full rated power. A higher SCR indicates a stronger grid (less sensitive to power fluctuations), while a lower SCR signals potential voltage instability.

The SCR level dictates the strength of a system. Some of the most common operation limits are:

- SCR > 3: Strong grid (stable operation)
- 1 < SCR < 3: Weak grid (requires mitigation measures)
- SCR < 1: Very weak grid (unstable without external support)

1.3.3. Extended Metrics

1. **Weighted Short-Circuit Ratio (WSCR)** is a critical metric for evaluating system strength in grids with high penetration of IBRs. It is computed as:

$$\text{WSCR} = \frac{\sum \text{SCC}_i}{\sum P_{\text{IBR},i}} \tag{1.16}$$

   Operational Significance

   - *Threshold*: ERCOT mandates WSCR ≥ 1.5 to ensure voltage stability [5].
   - *Mitigation Strategies*:
     - Synchronous condensers: Deployed to increase SCC (e.g., 950 Mvar in ERCOT's Panhandle system) [20].
     - IBR curtailment during low-SCC conditions.

   Example Calculation For a system with:

   - *POI 1*: SCC $= 6{,}500$ MVA, IBR $= 1{,}200$ MW
   - *POI 2*: SCC $= 7{,}000$ MVA, IBR $= 2{,}000$ MW

$$\text{WSCR} = \frac{6{,}500 + 7{,}000}{1{,}200 + 2{,}000} = \frac{13{,}500}{3{,}200} = 4.22$$

   Limitations

   - *Spatial Simplification*: Ignores electrical distances between POIs [5].
   - *Dynamic Behavior*: Does not account for grid-forming controls or post-fault recovery [14].

2. **Voltage Stiffness Criterion for Weak Bus Identification**

   The voltage stiffness metric quantifies a bus's ability to maintain stable voltage under reactive power variations. For weak buses in IBR-dominated grids, this is defined as:

$$K_v = \frac{\Delta Q}{\Delta V} > 3 \text{ pu} \tag{1.17}$$

   Key Aspects of Voltage Stiffness

   - **Physical Interpretation**: Represents the reactive power change required for 1 pu voltage deviation. Higher K_v indicates stiffer voltage profile.
   - **Stability Threshold**: The $K_v > 3$ pu criterion ensures:
     - Adequate margin from voltage collapse points
     - Compatibility with grid code requirements
     - Robustness against controller interactions
   - Stability margin calculation

$$\text{Stability Margin}(\%) = \frac{K_v - 3}{K_v} \cdot 100\% \tag{1.18}$$

   - K_v Strength Classification

K_v Range (pu)	Strength Classification
$K_v > 3$	Strong Grid
$2 \leq K_v \leq 3$	Weak Grid
$K_v < 2$	Very Weak Grid

Calculation methods

- Through power-flow calculations using a perturbation-based approach or employing a voltage sensitivity analysis. Many advanced power flow programs include sensitivity analysis tools that directly calculate partial derivatives of system variables, including $\frac{\partial Q_i}{\partial V_i}$.
- Analytically with the following equation:

$$K_{v,i} = \left|\frac{\partial Q_i}{\partial V_i}\right| = \frac{1}{|Z_{\text{th},i}|}\left(2V_i - \frac{V_{\text{th},i}}{V_i}\cos\theta_i\right) \tag{1.19}$$

where $Z_{\text{th},i} = R_{\text{th},i} + jX_{\text{th},i}$ and $V_{\text{th},i}$ are the Thevenin impedance and voltage at bus i, V_i the bus voltage, and θ_i the phase difference between V_i and $V_{\text{th},i}$. The term $\cos\theta_i$ accounts for the alignment of voltages [10].

Implementation Considerations

- **Comparison of Metrics**

Table 1.2: System Strength limits

Metric	Formula	Application Context
WSCR	$\frac{\sum \text{SCC}_i}{\sum P_{\text{IBR},i}}$	Multi-IBR clusters
SCR	$\frac{\text{SCC}_i}{P_{\text{IBR},i}}$	Single IBR at POI
K_v	$\frac{\Delta Q_i}{\Delta V_i} > 3$ pu	Voltage stability threshold at weak buses

- **Measurement approaches**
  - Perturbation-based estimation
  - Impedance matrix derivation
  - PMU-based real-time monitoring
- **Mitigation strategies for $K_v < 3$**
  - Synchronous condensers deployment
  - Dynamic VAR compensation
  - IBR reactive power coordination

1.3.4. Emerging Challenges

- **Non-Linear Impedance Characteristics**
  - IBR control interactions create frequency-dependent $Z_{\text{th}}(j\omega)$
  - Requires harmonic domain analysis for $> 5\%$ THD conditions
- **Protection Coordination**
  - Fault currents with $< 20\%$ SG contribution necessitate adaptive relaying
  - Recommend $I_{\text{fault}}/I_{\text{load}} > 3$ for reliable zone 2 operation
- **Multi-Timescale Stability**
  - Subcycle (< 20 ms) voltage instability from grid-forming converters
  - Coupled electromagnetic-transient (EMT) and RMS modeling is required to capture this

1.4. Transient Stability Analysis

Transient stability assessment requires simulation studies to ensure the system can maintain synchronism following severe disturbances [16, 19, 9].

1.4.1. Stability Metrics

The **Critical Clearing Time (CCT)** is a fundamental parameter in power system transient stability analysis, representing the maximum allowable duration for a fault to persist before protective devices isolate the faulted section, ensuring the system retains synchronism. Mathematically, CCT is derived from applying the equal-area criterion [9] or based on dynamic simulations.

TSOs establish a predefined critical threshold, denoted $\mathrm{CCT}_{\mathrm{critical}}$, based on dynamic simulations, protection coordination studies, and grid code requirements. This threshold accounts for circuit breaker operating times, relay coordination margins, and the system's ability to withstand transient torque imbalances. If the empirically determined CCT ($\mathrm{CCT}_{\mathrm{actual}}$) exceeds $\mathrm{CCT}_{\mathrm{critical}}$, the system's transient stability margin is compromised, potentially leading to generator pole-slipping, voltage collapse, or cascading outages. In Cyprus, $\mathrm{CCT}_{\mathrm{critical}} = 120$ ms [23].

Consequently, TSOs rigorously enforce compliance through stability-constrained analysis across credible contingency scenarios. It should be noted, that the $\mathrm{CCT}_{\mathrm{actual}}$ is impacted by the unit commitment and economic dispatch of the SGs:

- Inverse relationship between initial rotor angle δ_0 and CCT ($\frac{\partial \text{CCT}}{\partial \delta_0} < 0$). If initial rotor angle δ_0 is large, required CCT will be shorter.
- Quadratic reduction in CCT with increasing mechanical power P_m due to accelerating torque dominance. If generator mechanical power P_m is large, required CCT will be shorter.
- Linear scaling with inertia H (CCT $\propto \sqrt{H}$) until saturation effects limit rotor swing. If generator inertia constant H is larger, CCT will be longer [16].

Transient Stability Margin (TSM) isq uantified as

$$\eta = \frac{\text{CCT}_{\text{actual}} - \text{CCT}_{\text{critical}}}{\text{CCT}_{\text{critical}}}$$

Requires $\eta > 0.15$ for NERC compliance [19]

1.4.2. Common Practices

- **Dynamic Security Assessment (DSA)**: Combines time-domain simulations with pattern recognition for real-time contingency ranking [22]
- **Phasor Measurement Unit (PMU) Monitoring**: Wide-area measurement systems (WAMS) enable μs-resolution rotor angle tracking for early instability detection
- **Adaptive Contingency Screening**: Two-stage approach using extended equal area criterion (EEAC) for rapid screening followed by detailed simulations [21]

1.4.3. Novel Methodologies

- **Machine Learning Surrogates**: Deep neural networks trained on historical simulations reduce computation time from hours to milliseconds [13]
- **Hybrid Simulation-Direct Methods**: Combine time-domain analysis with Lyapunov exponents for stability boundary prediction
- **Virtual Synchronous Machines (VSMs)**: Grid-forming inverters providing synthetic inertia $M_{\text{vsm}} = k\frac{S_{\text{rated}}}{\omega_{\text{nom}}}$ where $k \in [3-5]$
- **Adaptive Protection Schemes**: Adjust relay settings based on real-time TSM estimates from PMU data

1.4.4. Minimum Synchronous Unit Requirements

The UC and ED solution need to comply with the dual constraints:

- TSM limits $\eta > 0.15$
- N-1 criterion with damping ratio $\zeta > 0.05$
- Load voltage recovery requirements (e.g., recovery above 80% required within 4 seconds, etc.)

1.5. Low-Voltage Fault Ride-Through (LVRT) Capabilities

According to most grid codes, SGs and IBRs must maintain connectivity during deep voltage dips through controlled reactive current injection. Figure 1.2 shows the capability requirements of different countries. UC and ED critically influence LVRT capabilities by shaping the system's reactive power reserves, grid strength, and dynamic response during voltage dips.

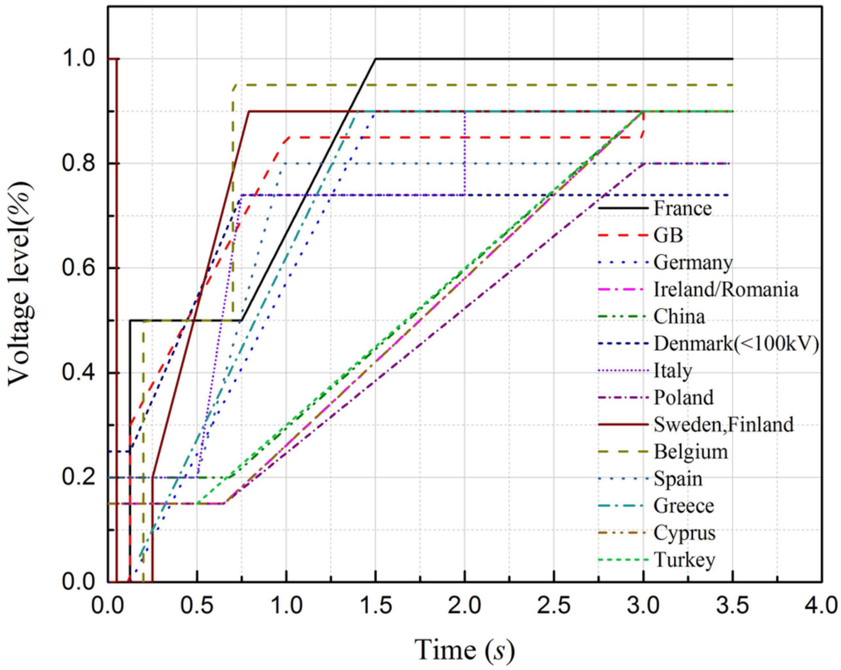

Figure 1.2: LVRT curves

1.5.1. Other related Grid Code Requirements

Modern standards specify three-phase fault requirements:

- **Reactive current injection**: Modern standards (e.g., IEEE 1547-2018) mandate reactive current injection $I_q^{\text{inj}} \geq 2.0(1 - V_{\text{pcc}})$ pu within 30ms. The UC solution must ensure sufficient online units meet this requirement, particularly in weak grids [6]
- **Active power recovery**: Restore 90% prefault active power within 1s post-fault clearance
- **Protection coordination**: LVRT capability must exceed backup protection clearing times + 30ms margin

1.5.2. Enhancement Strategies

- **Synchronous Condenser Support** Retrofit units with fast excitation systems:

$$\text{SCC}_{\text{eff}} = \text{SCC} + \sum \left(\frac{k_{\text{ce}} I_{\text{fd}}^{\max}}{X_d''} \right) \tag{1.20}$$

where k_{ce} is the ceiling voltage multiplier.

- **Advanced Inverter Controls** Grid-forming implementations using voltage-source behavior:

$$G_{\text{vsc}}(s) = \frac{\alpha s + \beta}{s^2 + 2\zeta\omega_n s + \omega_n^2} \tag{1.21}$$

  with $\zeta > 0.7$ for damped oscillation rejection during fault recovery.

- **Adaptive Voltage Compensation** Real-time adjustment of reactive current gains:

$$k_q(t) = \begin{cases} 2.0 & V_{\text{pcc}} < 0.5 \\ 2.5(1 - V_{\text{pcc}}) & V_{\text{pcc}} \geq 0.5 \end{cases} \tag{1.22}$$

1.6. Conclusion

Determining the minimum number of SGs required in low-inertia, IBR-dominated power systems necessitates a comprehensive, multi-dimensional assessment framework that integrates various technical constraints. The transition from conventional synchronous generation to inverter-based resources introduces complex stability challenges that require careful consideration of several critical factors simultaneously.

The determination of must-run synchronous units is governed by multiple technical constraints, each imposing distinct operational limits on the power system. Frequency stability constraints, particularly RoCoF and nadir limitations, establish minimum inertial requirements that directly influence the number of synchronous machines needed online. System strength requirements, quantified through metrics like SCR, WSCR, and voltage stiffness criteria, further constrain operational flexibility in low-inertia scenarios. Transient stability margins, particularly Critical Clearing Time assessments, impose additional limitations that vary with system loading and topology. Static N-1 security considerations, including voltage security and congestion management, add yet another layer of complexity to the determination process.

The dual classification of system strength into steady-state and dynamic-state domains, as proposed in recent literature, provides a valuable framework for analyzing the complex interactions between synchronous generators and IBRs. Steady-state system strength primarily addresses small-signal stability and voltage regulation capabilities, while dynamic-state strength encompasses large-disturbance responses including fault ride-through capabilities and transient recovery.

While emerging technologies offer promising pathways to reduce reliance on synchronous machines, including grid-forming converters, synthetic inertia, and fast frequency response services, these solutions are not yet fully capable of replicating all aspects of synchronous generator behavior. The challenges are particularly pronounced in areas of protection coordination, voltage recovery dynamics, and system strength provision during severe disturbances.

Therefore, robust methodologies that integrate advanced optimization techniques, real-time monitoring systems, and adaptive operational practices remain essential for system operators. By systematically addressing each stability requirement through a coordinated approach that considers the interdependencies between different constraints, operators can ensure secure grid operation while maximizing renewable energy integration as the transition to IBR-dominated power systems accelerates.

The practical implementation of these methodologies will require continued refinement of system strength metrics, improved coordination between market mechanisms and technical requirements, and enhanced modeling capabilities that capture both steady-state and dynamic behaviors of increasingly complex power systems.

2

Methodology

2.1. Overview of Methodology

A systematic approach to determine minimum synchronous generators involves:

1. **Frequency Stability and RoCoF Constraints**
    - **Input** Inertia and power data, P_{loss}, $RoCoF_{max}$, P_{load}^{min}
    - **Actions**
        - Calculate minimum inertia based on P_{loss} and $RoCoF_{max}$
        - Convert inertia requirement to specific acceptable combinations of units based on E_{kin}^{min} and P_{load}^{min}
    - **Output** Acceptable combinations of units from Step 1
2. **Eliminate Non-Feasible Solutions**
    - **Input** Acceptable combinations of units from Step 1, System Load Demand, UDER Genaration and Minimum Active Power Generation Limit of Generators P_{load}, $UDER_{gen}$, $MAPGL_g$
    - **Actions**
        - Calculate the lower value of Mimimum Syncrhonous Demand (MSD) based on P_{load}^{min} and $UDER_{gen}$
        - Calculate the Minimum Stable Generation Limit (MSGL) for each acceptable combinations of units from Step 1 based on $MAPGL_g$
        - Neglect combinations of units where MSGL > MSD
    - **Output** Acceptable combinations of units from Step 2
3. **Static Contingency N-1 Analysis**
    - **Input** Acceptable combinations of units from Step 2, generator and power data, and equipment maximum allowed loading limits, list of contingencies
    - **Actions**
        - Select Base Scenario (Operating Points)
        - Cluster Operating Points (Scenario reduction)
        - Load flow analysis considering N-1 contingency analysis
    - **Output** Acceptable combinations of units from Step 3
4. **Fault Level and System Strength Requirements**
    - **Input** Acceptable combinations of units from Step 3, dynamic DigSilent PF model with detailed fault-related data, Fault Level limits, strength limits

- **Actions**
  - For each combination from the acceptable combinations of units, ensure that the Fault Levels of all nodes are within the limits of Table 1.1.
  - For each combination from the acceptable combinations of units, ensure that the system strength metrics of all nodes are within the limits of Table 1.2.
- **Output** Acceptable combinations of units from Step 4

5. **Transient stability assessment**:
   - **Input** Acceptable combinations of units from Step 4, dynamic DigSilent PF model with detailed transient analysis related data (AVR, PSS, governor, dynamic GFM module, etc.), CCT limits, damping ratio limits, load/power recovery requirements, list of contingencies
   - **Actions**
     - Select a combination of operating points to be analyzed
     - Perform the necessary time-domain simulations in DigSilent PF
     - Ensure $\eta \geq 0.15$
     - Ensure damping ratio $\zeta > 0.05$
     - Ensure voltage/power recovery requirements
   - **Output** Acceptable combinations of units from Step 5
6. **LVRT evaluation**
   - **Input** Acceptable combinations of units from Step 5, dynamic DigSilent PF model with detailed reactive power static and dynamic reserves, LVRT curve
   - **Actions**
     - Select a combination of operating points to be analyzed
     - Perform the necessary time-domain simulations in DigSilent PF (fault analysis)
     - Ensure compliance with LVRT curve
   - **Output** Final acceptable combinations of units
   - **Comments** The LVRT filtering can be incorporated with the CCT filtering

2.2. RoCoF Constraint Calculation

As a first filter, we can find all the combinations of generators and grid-forming units that ensure the constraint:

$$E_{kin}^{min} \leq \sum_{g \in \mathcal{G}} (u_g \cdot H_g \cdot S_{g,N})$$

2.2.1. Methodology

To generate **all** combinations of generating units that comply with the minimum inertia requirements, we can solve the MILP repeatedly while adding **"no-good" cuts** to exclude previously found solutions.

Step 1: Solve the Base Model
Find an initial feasible solution of generating unit commitment (u^*).

$$\begin{aligned}
\min_{\mathbf{u}} \quad & 0 \\
\text{s.t.} \quad & \sum_{g \in \mathcal{G}} (u_g \cdot H_g \cdot S_{g,N}) \geq E_{kin}^{min} \\
& \sum_{g \in \mathcal{G}} (u_g \cdot P_g^{min}) \leq 0.9 \cdot P_{load}^{min} \\
& u_g \in \{0,1\}, \forall g \in \mathcal{G}
\end{aligned} \tag{2.1}$$

Step 2: Add Exclusion Constraints
For each new solution (u^*), save it to a list and add a cut to eliminate it:

$$\sum_{g:u_g^*=1}(1-u_g)+\sum_{g:u_g^*=0}u_g\geq 1$$

This ensures that subsequent solutions differ by at least one binary variable.

Step 3: Repeat Until Infeasibility
Terminate when the solver returns no new solutions.

2.2.2. Example with 3 generators

Problem: Find all binary solutions that comply with:

$$E_{kin}^{min}\leq\sum_{g=1}^{3}(u_g\cdot H_g\cdot S_{g,N})$$

Base Model:

$$\begin{aligned}
\min\quad & 0\\
\text{s.t.}\quad & E_{kin}^{min}\leq\sum_{g\in\mathcal{G}}(u_g\cdot H_g\cdot S_{g,N}),\\
& \sum_{g\in\mathcal{G}}(u_g\cdot P_g^{min})\leq 0.9\cdot P_{load}^{min}\\
& u_g\in\{0,1\},\quad \forall g\in\{1,2,3\}.
\end{aligned}$$

Iteration 1: Solution $(1,1,0)$.
Cut Added: $(1-u_1)+(1-u_2)+u_3\geq 1$.

Iteration 2: Solution $(1,0,1)$.
Cut Added: $(1-u_1)+u_2+(1-u_3)\geq 1$.

Continue until all solutions are found. The set **u** $\in\mathcal{U}_{s1}$ is the acceptable solutions from step 1.

2.2.3. Key Considerations

- **Computational Complexity:** Enumeration becomes intractable for large-scale problems due to exponential growth in solutions.
- **Other metrics:** Steady-state frequency response can be incorporated in this analysis. The frequency Nadir can be incorporated in the Transient Stability Calculation simulations.

This framework ensures all valid solutions are systematically generated while adhering to MILP conventions. For practical implementation, integrate solver callbacks or use decomposition techniques like Benders to streamline the process.

2.3. Eliminate Non-Feasible Solutions

Since we are investigating the **must-run units**, we can limit the acceptable combinations, that satisfy the RoCoF constraint, to ones that can cover the minimum predicted load without violation on their minimum generation limits. This can be defined mathematically as:

$$\sum_{g\in\mathcal{G}}(u_g\cdot P_g^{min})\leq P_{load}^{min}-UDER_{gen}$$

P_{load}^{min} is the minimum net load that the generators will need to feed.

u $\in\mathcal{U}_{s2}$ is the acceptable solutions from step 2.

2.4. Static N-1 Contingency Analysis

All the combinations of generators that satisfy N-1 criterion will be identified.

$$\begin{aligned} \min_{\mathbf{u}} \quad & 0 \\ \text{s.t.} \quad & \text{Power flow constraints}, \forall c \in \mathcal{C} \\ & \text{Security constraints}, \forall c \in \mathcal{C} \\ & u_g \in \{0,1\}, \forall g \in \mathcal{G} \\ & \mathbf{u} \in \mathcal{U}_{s2} \end{aligned}$$

2.4.1. Methodology

Load flow analysis will be performed for each N-1 contingency. The elements that will be outage in the analysis will be overhead transmission lines and underground cables. Optionally, the user can include in the analysis generation units and reactors outages. A clustering will be performed to reduce the number of operating points analysed.

For each solution $\mathbf{u} \in \mathcal{U}_{s2}$, the dispatch of each generation unit will be defined as follow:

- Option A: Generation dispatch will be equal to the Net Load Demand times the ratio of generator rated power to total generation units rated power.
- Option B: Generation dispath according to a **Priority List** provided by TSOC.

$\mathbf{u} \in \mathcal{U}_{s3}$ is the acceptable solutions from step 3.

2.5. Fault Level and System Strength Requirements

Need to ensure that the solutions $\mathbf{u} \in \mathcal{U}_{s3}$ comply with the requirements in Table 1.1 and 1.2.

2.5.1. Methodology

Step 1: Check Fault Levels

For each solution $\mathbf{u} \in \mathcal{U}_{s3}$, call the DigSilent PF module to provide all the node fault levels using IEC60909 standard. Compare with Table 1.1 and filter unacceptable combinations leading to the acceptable set of solutions $\mathcal{U}_{s4a} \subseteq \mathcal{U}_{s3}$.

Step 2: Check SCR

For each solution $\mathbf{u} \in \mathcal{U}_{s4a}$, call the DigSilent PF module to provide all the SCR levels using IEC60909 standard and the DERs aggregated installed capacity in each transmission substation. Compare with Table 1.2 and filter unacceptable combinations leading to the acceptable set of solutions $\mathcal{U}_{s4b} \subseteq \mathcal{U}_{s4a}$.

2.5.2. Key Considerations

- **Modeling:** The DigSilent PF model needs to have proper modeling of the fault-contribution related data (SGs and IBRs).

The set $\mathbf{u} \in \mathcal{U}_{s4}$ is the acceptable solutions from step 4.

2.6. Transient Stability Calculation

Ensure:

- $\eta = \frac{\text{CCT}_{\text{actual}} - \text{CCT}_{\text{critical}}}{\text{CCT}_{\text{critical}}} \geq 0.15$
- Damping ratio $\zeta > 0.05$
- Voltage/power recovery requirements

2.6.1. Methodology

Step 1: Identify Critical Nodes

Identify the critical areas of the power system. For the purposes of the analysis, HV busbars with the highest SCC will be considered critical.

Step 2: Define Operating Scenarios
After identifying the critical HV Busbars, the dispatch of each committed generator have to be defined. Since the actual dispatch of the committed generators will be unknown during the MSGL assessment, a sensitivity analysis will be performed. Predefined generation loadings within the range 60% to 90% will be selected. This is because, all synchronous generators must operate at least above their MSGL which usually is 50% of their nominal capacity. According to the TSOC guidelines at least 40 MW are required for spinning reserve and 25 MW for negative spinning reserve. Hence, it is considered that the committed generators will not be loaded below 60% and above 90% of their nominal capacity. Alternatively, the Methodology used for the generation dispatch for the Static N-1 contingency analysis can be used.

Step 3: Define Contingencies
A short circuit analysis will be performed at the critical busbars. For the analysis the following assumptions will be made:

- Three Phase Fault at Critical Busbars at $t = 0$ s
- Single Phase to ground Fault at Critical Busbars at $t = 0$ s
- Zero fault impedance ($Z_f = 0$)
- Fault clearing time equal to $t_{duration} = 138$ ms. This ensures that $\eta \geq 0.15$ when assuming $CCT_{critical} = 120$ ms

Multiple events, like fault at a critical Busbar and the following disconnection of a connected transmission line, must be defined explicitly.

Step 3: Perform time-domain simulations
Perform a time-domain dynamic simulation for each **u** $\in \mathcal{U}_{s4}$, and each operating point and contingency defined above.

After each simulation, the transient stability of the power system is evaluated. If the system maintains stability, then the UC scenario is considered secure. If not, then it is removed from **u**.

2.6.2. Key Considerations

- **Modeling:** The DigSilent PF model requires detailed transient analysis related data (AVR, PSS, governor, dynamic GFM module, etc.)

The set **u** $\in \mathcal{U}_{s5}$ is the acceptable solutions from step 5.

2.7. LVRT Calculation

To ensure solutions **u** $\in \mathcal{U}_{s5}$ adhere to LVRT requirements, Detailed fault simulations can be used to verify whether committed generators meet FRT criteria (e.g., voltage recovery time, reactive current injection).

2.7.1. Methodology

The dynamic simulation-based assessment will be used to ensure that UC solutions that satisfy all the above criteria (frequency stability assessment, system strength, and transient stability) adhere to LVRT requirements.

The methodology is similar with the Transient stability calculation described in subsection 2.4.1. The only difference is manifested in the simulation scenarios. Specifically, the simulated fault scenarios should result in voltages slightly lower than the LVRT requirements. For this reason, the fault resistance (R_f) will vary accordingly to result in the required voltages. After the simulation, the response of the committed generators will be compared with the LVRT requirements. If synchronised units satisfy the LVRT capabilities, then UC is considered compliant.

2.7.2. Key Considerations

- **Modeling:** The DigSilent PF model requires detailed transient analysis related data (AVR, PSS, governor, dynamic GFM module, etc.)

- **Reactive planning:** The static and dynamic reactive planning plays important role in the outcome.

The set **u** $\in \mathcal{U}_{s6}$ is the acceptable solutions from step 6 and for the whole analysis.

3

Data and Modeling requirements

3.1. Overview of Data and Modelling Requirements

For the implementation of the tool for identifying the unit commitment scenarios that satisfy minimum stability and reliability criteria for the Power System of Cyprus the following data must be provided.

3.1.1. Data Requirements

Several data must be provided by the TSOC for evaluating the must run units. Load demand scenarios should be provided by the TSOC for the implementation of the required analysis. Moreover, for the Transient Stability analysis and the LVRT evaluation, the economic dispatch is also required. If load demand and the dispatch are not available, a sensitivity analysis will be made. For each analysis the following data are required:

1. Frequency Stability Assessment:
    - Inertia Constants of synchronous generators (Hg)
    - Nominal Capacity of synchronous generators (Sg)
    - Larger Contingency Outage (MW)
    - Maximum allowable RoCoF (Hz/s)
2. System Strength and Fault Levels Evaluation:
    - Minimum SCR value for each HV Busbar (Suggested 3)
    - Installed Capacity of IBRs in each HV Substation (MW)
    - Minimum SCC values for each HV Busbar
3. Transient Stability Assessment:
    - Actual Critical Clearing Time (s)
    - Minimum Transient Stability Margin (n) (Suggested 0.15)
    - Dispatch of committed generators (percentage of nominal capacity)
4. LVRT Evaluation:
    - LVRT Capability requirements
    - Dispatch of committed generators (percentage of nominal capacity)
    - Operation of Shunt Reactors (percentage of nominal capacity)
    - Credible contingencies (generation and transmission lines outages)

3.1.2. Modeling Requirements

The complete model of the Cyprus transmission system in DIgSILENT PowerFactory must be provided. The model must include the dynamic models of all synchronous generators. It should be note that AVR and PSS models of synchronous generators have a noticeable impact on the transient stability and LVRT evaluation. Accurate representation of aggregated IBRs in each substation is preferable. However, if this is not available, IBRs will be modeled as negative load, hence their impact on the simulations will be neglected. We note that dynamic modeling of IBRs will improve significantly the accuracy of the simulation results, especially for the LVRT evaluation. The statuses (energised/deenergized) of overhead lines, underground cables and bus section CBs affect significantly the thevening impedance at the fault location. This has huge impact on the calculation of SCC and the transient stability of the power system.

The tool requires a DIgSILENT PowerFactory license with the functions of RMS Simulation and Small Signal Stability enabled.

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