Bhutan Transmission System Planning and Modelling Manual

May-2025

Power System and Market Division
Department of Energy
Ministry of Energy and Natural Resources

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Contents

Full forms of the Abbreviation and Acronym

Alternating Current	ACSR
Aluminium Conductor Steel Reinforced	ACSR
Associated Transmission System	ATS
Bhutan Power Corporation	BPC
Bhutan Power System Operator	BPSO
Central Electricity Authority, India	CEA
Department of Energy	DoE
Detailed Project Reports	DPRs
Direct Current	DC
Distributed Energy Resources	DERs
Doubly-fed Induction Generator	DFIG
Druk Green Power Corporation	DGPC
Electricity Regulatory Authority, Bhutan	ERA
Extra High Voltage	EHV
Generator Transformer	GT
Geographical Information System	GIS
High Tension Low Sag	HTLS
High Voltage	HV
Indian Standard	IS
Institute of Electrical and Electronics Engineers	IEEE
Inter Connecting Transformers	ICTs
kilo Ampere	kA
kilo volts	kV
Land Use Land Cover	LULC
Mega Volt-Ampere	MVA
Mega Volt-Ampere reactive	MVAr
Mega Watt	MW
Ministry of Energy and Natural Resources	MoENR
National Transmission Grid Master Plan, Bhutan	NTGMP
On Load Tap Changer	OLTC
Per Unit	PU
Point of Connection	PoC
Power Factor	PF
Reactive-Voltage	Q-V
Royal Government of Bhutan	RGoB
Short-Circuit	SC
Standard	Std
Temperature	Temp
Winter Power Factor	WPF

1. Preamble

The **Bhutan Transmission System Planning and Modelling Manual** aims to establish the standardized methodologies and technical frameworks essential for designing a reliable, safe, and efficient electricity transmission system. This initiative aims to support national energy security, enable the integration of emerging technologies, and promote sustainable economic growth.

This Manual serves as a comprehensive technical guide for power system planners, analysts, and engineers involved in the design and modelling of the national/cross-border transmission network. It outlines procedures, modelling standards, and key system parameters to ensure consistency, quality, reliability, and coherence in system planning, **expansion, and optimization** efforts.

Aligned with provisions of **Section 7(e) of the Electricity Act 2001**, which emphasizes the regulation of technical performance and reliability standards, the Manual provides structured procedures and guiding principles for the development of secure, integrated and forward-looking transmission systems. and integrated transmission network planning.

Key objectives of this Manual include:

1. **Regulatory Compliance** – Ensuring alignment with the Grid Code of Bhutan, National Transmission Grid Master Plan (NTGMP), and international standards such as Institute of Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), and Central Electricity Authority (CEA).
2. **Grid Reliability and Security** – Defining system performance criteria under steady-state, short-circuit, transient stability, and contingency conditions to enhance overall system robustness.
3. **Standardized System Modelling** – Promoting a Computer-aided modelling approach to ensure consistency in simulation methodologies, data interpretation, and system validation.
4. **Renewable Energy Integration** – Supporting the integration of Distributed Energy Resources (DERs) and enabling a diversified energy mix, while maintaining voltage stability margin and reactive power management.
5. **Cross-Border Power Exchange** – Facilitating regional interconnections and collaborations with neighbouring countries to enhance energy trade, system resilience, and operational coordination.

This Manual is intended for use by all relevant power sector entities, including Bhutan Power System Operator (BPSO), Bhutan Power Corporation (BPC), Electricity Regulatory Authority (ERA) and other relevant stakeholders involved in system planning and modelling activities

Recognizing the evolving nature of power systems and emerging technological advancements, the Department has developed this Manual, which is subject to regular review and updates. The revision aims to ensure the continuous improvement of transmission planning and system modelling practices, thereby reinforcing Bhutan's commitment to sustainable and secure energy development.

Adherence to this Manual will ensure grid stability, operational efficiency, and regulatory compliance, laying the foundation for a resilient and future-ready transmission network that supports the nation's long-term energy vision.

(Karma P. Dorji)

Director General

Department of Energy

2. Executive Summary

Bhutan's power transmission system is increasingly dependent on advanced modelling techniques to support effective planning, operation, and expansion in a rapidly changing energy landscape. This Manual outlines the design philosophy, simulation criteria, and modelling requirements for the Associated Transmission System (ATS), aiming to ensure grid reliability, operational efficiency, and future adaptability with the technological advancements.

The Manual provides a structured framework for ATS planning, covering key aspects such as:

- **ATS Planning Criteria**: Defines essential parameters such as data standards, network topology, generations, loads, including steady-state conditions, short-circuit levels, transient stability, voltage stability, and contingency considerations.
- **System Modelling**: Specifies intrinsic and extrinsic modelling techniques for generators, transmission lines, and loads, incorporating IEEE and CEA standards.
- **Simulation Requirements**: Establishes baseline conditions for steady-state, dynamic, and contingency simulations to validate system performance.
- **Grid Integration**: Addresses the growing role of non-hydropower renewables, emphasizing the need for reactive power management and system stability.
- **Standardization**: Ensures uniformity in power system analysis by prescribing naming conventions, bus numbering, and element classification.

These parameters shall be updated periodically based on system development and data availability.

The Manual set forth aims to harmonize Bhutan's power system studies with international best practices, enhancing the ability to maintain a secure, resilient, and future-ready grid.

3. Scope and Planning Philosophy

- The National Transmission Grid Master Plan (NTGMP) provides a comprehensive evaluation of the transmission system for ensuring the grid is resilient, safe, reliable, efficient, and capable of meeting both current and future generation resources along with new and growing projected demands.
- The NTGMP should form the basis for planning of the national grids and cross-border links.
- Transmission planning is an ongoing process of assessing the performance of a power system and its ability to efficiently deliver electricity to meet forecast load demands. The need for development of new transmission systems emanates from the addition of new generation capacity, growing demand, and the requirement for system strengthening. These developments are typically planned to connect to the nearest grid point considering overload capacity of the generation sources, and expected peak

loading of the load. In cases where grid strengthening is required, long term benefits to consumers prioritize investment decisions, ensuring a balance between cost and system reliability.

- The time horizons for transmission planning are considered three to five years in line with the NTGMP. It should be reviewed considering all possible scenarios for the next three to five years by forecasting demand and generation.
- The planning criteria should be based on the system parameters and loading of system elements within the permissible limits prescribed in Grid Code of Bhutan and amended therefore or as specified in the relevant international standards. The nomenclatures of the system element should be as specified in this document.
- Study the reliability of the power system by simulating normal and outage conditions as well as during the transient conditions due to switching operations and other disturbances, and comparing the results of these simulations to system performance requirements.
- Unpredictable power flows may arise in transmission grids during real-time operations due to deviations in the load-generation balance from the anticipated load-generation balance across different regions of the grid. These variations can lead to overloading of transmission elements, a scenario that cannot always be anticipated during the planning stage. To address such unavoidable events, it is essential to incorporate adequate margins during the planning process.
- With the increasing penetration of intermittent renewable energy (wind and solar), it is essential to maintain grid performance parameters within safe limits. To ensure system limits are not violated as a result of disturbance, an accurate model of the interconnected system analyses and assesses the impact of various scenarios.
- Study reports should be prepared to support the outlining scope of study, assumptions made, simulation results, conclusions and recommendation. The report should highlight the key finding including any limiting conditions during the study.

4. Planning Criteria:

- The new transmission network addition for system strengthening should be planned keeping a margin of 10% in the thermal loading limits of the lines and Interconnecting Transformers (ICTs). The 10% buffer is kept for the future load growth value and also to account for gradual system expansion.
- The voltage deviation limits at the planning stage should be maintained at ±0.2% of its PU at N-0 scenario.
- The tap setting of all the transformers may be kept at nominal taps and On Load Tap Changer (OLTC) may be ignored while simulating.
- Requirement of MVAr (reactive power) compensation must be assessed while designing the ATS for new generators.

- Reactive power compensation should be provided to the area of low system voltage so that the mega-Volt-Ampere reactive (MVAr) demand from the load side can be met without having to draw from the high voltage side of the system.
- Switchable bus reactors or High Voltage Controllers (HVC) should be provided at Extra High Voltage (EHV) stations for smooth controlling of voltages without resorting to turning off of the transmission lines. The bus reactors may be added to generating stations as well. The size of the reactors may be selected such that switching ON or OFF of the reactor should not introduce the voltage change of more than 5% of its bus Per Unit (PU) value.
- Static VAr compensation should be added to provide system damping if the power swings are found to cause system stability issues.
- Short-circuit level: any new substation bus should have its Short-Circuit (SC) limit not exceeding 80% of the rated SC capacity of the station. The 20% buffer is kept for growth in SC value due to gradual system expansion.
- Measures such as splitting of bus, series reactors or any devices designed to limit the SC values may be adopted in case the SC capacity of the existing substations exceeds its design limits.
- It is preferred that multiple Inter-Connecting Transformers (ICTs) be planned in such a way that any outage of the largest ICT should not overload the remaining ICTs, in critical substations.
- The wind and solar farms should maintain the Winter Power Factor (WPF) of 0.98 (lag) at their Point of Connection (PoC) if the solar bulk power is to be terminated at Transmission level.
- All the buses in the system should operate above its Knee Point of Q-V Curve under all conditions.

- Technical losses incurred due to the addition of new generators should be calculated using a suitable simulation package or CAD and it should be part of the ATS report.

5. Simulation Requirements

5.1. Minimum Simulation Requirement Considerations

5.1.1. Steady-State Simulation

In steady-state analysis, the system is assumed to be in a stable, unchanging condition. Time is irrelevant in steady-state analysis since the system is assumed to be static.

5.1.2. Short Circuit Simulation

A short-circuit condition in power system modelling refers to an abnormal electrical connection between two or more points in a circuit that are at different voltages, resulting in a low-impedance path for current flow. This condition causes a sudden and significant increase in current, which can damage equipment, disrupt power supply, and pose safety hazards.

5.1.3. Contingency Scenario Simulation and Planning

Contingency scenario simulation and planning involves analysing the power system's response to potential failures or outages of key components, such as generators, transmission lines, transformers, or substations.

5.1.4. Dynamic/Transient state simulation

In this state, the system condition is dependent on time and hence, it changes. Time is relevant in dynamic analysis since the system's behaviour evolves over time.

5.2. Criteria for Steady-state Simulation

The transmission system should be planned considering the following criteria:

5.2.1. In the Normal contingency scenario (N-0), all the elements planned are made active and available in the time horizon of study in line with NTGMP of Bhutan.

5.2.2. The introduction of disturbances within the large Grid is a highly probable case. For this, it is required that the grid maintains its system parameters like voltage, frequency, loadings and stability within the permissible normal operation as stipulated in the Grid Code Regulation of Bhutan, for a single contingency (N-1).

5.2.3. The introduction of the first single contingency may induce a second contingency (N-1-1), as the grid is still left vulnerable. In this case, some of the equipment may be loaded beyond the normal range/limits and therefore, all the system parameters like voltages, loadings, frequency should remain within the permissible emergency range/limits.

5.2.4. Necessary steps must be followed to bring back the grid from this state to a more stable state either by manually operating the required element(s) or by the use of automatic system protection mechanism.

5.3. Criteria for Short-circuit Simulation

The transmission system should be planned considering the following criteria:

5.3.1. The short-circuit shall be carried out with flat pre-fault voltage and sub-transient reactance (X''d) of the synchronous machines.

5.3.2. The vector group of the transformers shall be considered for simulating short-circuit conditions. Inter-winding reactance in case of three phase transformers shall be considered especially for conducting asymmetrical fault simulations.

5.3.3. For evaluating the short-circuit level of the generating bus, the generator and generating transformers (GTs) shall be modelled separately.

5.3.4. The three phase (symmetrical) fault shall be used to determine the maximum fault current level of the station/element/branch.

5.3.5. Adoption of SC Standards be clearly stipulated while performing short-circuit analysis

5.4. Criteria for Transient state simulation

The grid usually will face perturbation that causes transient oscillation within the main power frequency. This perturbation may be induced either by switching activities or by lightning stroke forming a travelling wave in the transmission branches. In this scenario, there are two possible states that the system can assume; it will either return to normal state after suffering a transient disturbance or will not return to its normal state. The transmission system should be planned considering the following criteria:

5.4.1. The system should survive a permanent three phase symmetrical fault on the highest voltage line close to the bus and the fault be cleared in 100ms.

5.4.2. The system should survive a permanent three phase asymmetrical fault on highest voltage line close to the bus and fault be cleared in 100ms

5.4.3. The system should survive the outage of a single largest unit or critical generator.

5.5. Criteria for Voltage Stability

The analyst should consider scenario up to N-1-1[1] and check the stability of voltage in that scenario. For Planning purposes, the voltage stability limits should be set at ±2% of rated PU Voltage. For analysis of existing power system equipment, the operational voltage limits stipulated in Grid Code of Bhutan should be adopted.

[1] Double contingency event as a direct result of N-1 event. This means there is a loss of more than one element of the grid as a result of the N-1 event.

5.6. Criteria for Contingency Planning

The contingency of the power system is considered to be an outage of a single facility of 66kV and above voltage level under N-1 condition. For N-1 Criterion, the system power flow and bus voltages above 66kV and higher is checked for abnormalities.

Contingency ranking analysis to be done based on the SC value and line criticality (bus angle separation).

5.7. Criteria for Angular Stability

If the angular difference between terminals of branches (bus-bus) is less than 20 degrees, the system is in stable condition during transient condition. If the simulated angle is more than 20 degrees, a separate transient system modelling and simulation is required to ascertain the stability of the system. The bus angular separation should not exceed 20 degree to ensure system stability.

5.8. Criteria for Fault limitation

The following are the fault current level limit during 3-phase short-circuit condition:

Voltage Level	***Rated Breaking Capacity per Second***
400kV	50kA/ 63kA
220kV	31.5kA/ 40kA
132kV	25kA / 31.5kA
66kV	20kA

5.9. Criteria for Single Contingency (N-1)

All the elements of the power system should remain within their normal thermal range of loading and voltage limits as stipulated in Grid Code of Bhutan after a perturbation/disturbance which results in the loss of any one of the following elements without undergoing load shedding and/or generation backdown/over injection:

1. Outage of a single 400kV circuit
2. Outage of a single 220kV circuit
3. Outage of a single 132kV circuit
4. Outage of a single 66kV circuit
5. Outage of single ICT
6. Outage of single generating unit

The bus angular separation should not exceed the limit as specified in topic 11. Criteria for Angular Stability.

5.10. Criteria for Double Contingency (N-1-1)

This contingency event is the direct result of the event as defined in Topic 12: Criteria for Single Contingency (N-1). During such an event, the system may be subjected to one of the following contingencies:

1. If there is a temporary fault, the system should not lose the second element after clearing of the fault and successfully survive the disturbance.
2. If the fault is permanent, the system should lose the second element as a result of fault clearing effort and the system thereafter should asymptotically reach to a new state without losing synchronism. The system parameters should remain within the emergency limits as stipulated in Topic 9: Criteria for Voltage Stability, and the thermal limits.

6. Transmission Line Length Determination

During the planning stage of the Associated Transmission System (ATS), reliance on crow-flight (straight-line) distance as a basis for estimating transmission line length should be avoided, as such a method is prone to substantial inaccuracies and may result in misleading assessments. Instead, the planner should refer to authoritative and approved documents, including but not limited to the National Transmission Grid Master Plan (NTGMP), Detailed Project Reports (DPRs), or any other official and reliable sources, to ascertain accurate transmission line data.

In the event that such documents or verified line data are not available or are incomplete, the planner should be obligated to map a preliminary route alignment of the transmission line using appropriate and verified Geographical Information System (GIS) tools, ortho-rectified satellite imagery, or equivalent geospatial datasets. This preliminary routing exercise must be cross-referenced with the existing ATS geodatabase and integrated with the relevant Land Use Land Cover (LULC) cadastral datasets to ensure geographic and regulatory coherence.

Furthermore, the planner should maintain detailed records of all data sources consulted, tools and datasets utilized, and assumptions applied in determining the indicative transmission line corridor. Such documentation should form part of the official planning dossier and may be subject to review and audit.

All existing line length should be considered as per the Power Data Book published by BPC.

7. System Modelling

7.1. Modelling Type:

There are two distinct types of modelling of power system entities. They are:

i. *Intrinsic Modelling*

In this kind of modelling approach, the Generator Transformer (GT Model) is modelled within the generator model. The PU parameters of Generating transformers are imported within the generator models.

ii. *Extrinsic Modelling*

In this kind of modelling, the GT set is modelled separately: the generator and transformer models are a separate entity within the Power system model.

7.2. Generator model Approximation

The generating unit should be modelled as per their respective capability curves. In absence of the capability curve, the reactive power limits of each individual unit should be as per the norms set forth:

i. *Hydropower Generators*

For Hydro power plant, the reactive power limits are defined using IEEE Std C50.12-2005:
In this standard if the capability curve is unavailable, it suggests assuming typical lagging power factors of 0.9 lagging and leading power factors of 0.95 to 0.98 leading, depending on system requirements

Lagging Reactive Power Limit (Over-Excitation):
Use a power factor (PF) of 0.9 lagging as a typical design benchmark for hydro generators.

$$Q_{\text{lag}} = \sqrt{S_{\text{rated}}^2 - P_{\text{rated}}^2}$$

Leading Reactive Power Limit (Under-Excitation):
For hydro generators, leading PF is typically between 0.95 and 0.98 leading.

$$Q_{\text{lead}} = -\sqrt{S_{\text{rated}}^2 - P_{\text{rated}}^2}$$

Total Reactive Power Range:

The total reactive power range will typically span between the lagging and leading values

$$Q_{\text{range}} = [Q_{\text{lead}}, Q_{\text{lag}}]$$

IS 4889-1968: Use 0.9 lagging and 0.95 leading PF as the baseline assumption unless specified otherwise

ii. Wind Power Generators

Wind turbines use different technologies (e.g., fixed-speed, doubly-fed induction generator (DFIG), full-converter-based), which influence their reactive power capabilities.
Transmission system operators define reactive power requirements at the PoC.
Reactive power limits are designed to ensure voltage stability under varying wind and load conditions.

Fixed-Speed Wind Turbines

Typically equipped with induction generators that require reactive power support.
Cannot independently control reactive power; external compensation (e.g., capacitor banks, STATCOM, or SVC) is necessary.

Doubly-Fed Induction Generators (DFIG)

Can supply and absorb reactive power using the rotor-side converter.
Commonly capable of operating within a power factor range of 0.95 lagging to 0.95 leading at rated power.

Full-Converter Wind Turbines

Utilize a full-scale converter, decoupling generator dynamics from the grid.
Offer the widest range of reactive power control, typically 0.9 lagging to 0.9 leading.

Standards to follow while modelling:

CEA Grid Standards 2020: Mandates that wind power plants maintain a power factor of 0.95 lagging to 0.95 leading at the PoC.

IEEE Std 1547-2018:
The standard specifies that Distributed Energy Resources (DERs), including wind power plants, must operate within the following power factor range:

Lagging Power Factor: Up to 0.85 lagging (absorbing reactive power).
Leading Power Factor: Up to 0.85 leading (supplying reactive power).

This range ensures the DER can provide sufficient reactive power support for grid voltage regulation and stability. This standard is applicable at distribution level.

Reactive power capability is defined in terms of the generator's apparent power (S). For a DER with rated apparent power S, the reactive power limits Qmax and Qmin are determined as follows:

$$Q_{\max} = S \cdot \sqrt{1 - \mathrm{PF}^2}$$

$$Q_{\min} = -Q_{\max}$$

Implementation of Reactive Power Limits

The limits defined in the standard are implemented based on the following:

At the PoC:

- The reactive power contribution must meet the specified limits at the PoC.

Based on Rated Apparent Power:

- Limits are calculated using the generator's rated capacity.

Considering Grid Code Requirements:

- Local transmission or distribution codes may impose additional requirements.

iii. Solar Power Generators

IEEE Std 1547-2018:

The standard specifies that DERs must operate within the following power factor range:

***Lagging Power Factor*:** Up to 0.85 lagging (absorbing reactive power).

***Leading Power Factor*:** Up to 0.85 leading (supplying reactive power).

7.3. Load modelling

The load should be modelled using the PF of 0.9 Lead/Lag for all High Voltage (HV) consumers. This is done to avoid the oversizing of the power transformers.

8. Model Validation

All developed simulation models should be subject to a formal validation process to ensure that the computed results closely reflect actual power system conditions, specifically in terms of observed MVA flows. The model's accuracy and performance should be quantitatively assessed and documented. A detailed accuracy report should be appended to each system study submitted or undertaken.

For the purpose of validation, the planner or analyst should select a representative time frame (historical or current) and import the actual load-generation dispatch data corresponding to that specific time event into the model environment. Validation should involve a comparative analysis between actual field measurements and simulated outputs for key parameters, including but not limited to: bus voltages, active power (MW), and reactive power (MVAr) flows.

9. Base Case System Settings

Modelling of the base case scenario is essential to synthesise other variable cases to fully understand the power system limitations and expansion options. For the creation of such a case, the following will be assumed.

Case with N-0 condition at Nominal setting

In this scenario, all the buses will be set to its nominal PU. All the transformer taps will be at the Nominal tap setting. And all the generators will set its bus voltage to its nominal PU setting.

For this scenario, two cases may be generated: a case of high generation/load and the case of low generation/load. These two separate models will capture the grid volatility which is dependent on seasonal variation.

For all planning purposes, the system model should follow the aforementioned setting.

10. Contingency Ranking and Analysis

In this section of analysis, a series of N-1 system contingencies are introduced at 400kV, 220kV and 132kV. Ranking of contingencies are to be done based on the SC value and angular separation introduced to the system.

This is also to identify the sequence of maintenance that can be taken up depending on the criticality of certain lines in the system. This is also to identify lines that can be lost to preserve the system parameters (voltages and PF) during abnormal system conditions.

Contingencies up to N-1-1 could be carried out on the need basis.

11. Bus and Branch Nomenclature

For the modelling of the national grid, following technical parameters are defined and fixed while starting the modelling work:

MVA Base	100 MVA
Grid System Frequency	50Hz

In order to facilitate targeted analysis and the efficient extraction of simulation outputs from the developed model, the analyst should ensure that all non-technical parameters are appropriately defined and standardized. This should include, but not be limited to, the naming and numerical designation of Area, Zone, and Owner identifiers.

Each such parameter should be uniquely assigned and systematically applied across the model database to enable effective data filtering, sorting, and categorization of simulation results. The consistent use of these attributes should support streamlined reporting, improve traceability of outputs, and allow for disaggregated or aggregated analysis as required under the scope of the study.

Failure to define and apply such parameters appropriately may be deemed non-compliant with data organization protocols and may result in the rejection or return of the study for revision.

The following naming convention should be used for naming Area Name, Zone Name and *Owner Names*

Area Name	Area Code
BHUTAN	6

Zone Name	Code
EAST_BTN	16
WEST_BTN	26

Owner Name	Code
DGPC_BTN	6001
DHPC_BTN	6002
BPC_BTN	6003
INDUS_BTN	6004
DHI_BTN	6005

Defining a bus and its number within the model is one of the most important tasks that needs to be undertaken while developing the power system model as all the other technical elements like generators, transformers and lines are suspended on them. Identifying correct bus type, bus voltages and location becomes an integral part of the modelling phase. Therefore, following codes are assigned to the buses based on their nominal rated voltage.

Voltage codes for Power system voltages of Bhutan are given as follows:

T & D Voltage		Generation Voltage	
Voltage in kV	**ID Code**	**Voltage in kV**	**ID Code**
400	400	19	019
220	220	15	015
132	132	13.8	138
66	066	11	011
33	033		
11	011		

In addition to identifying the bus voltage based on the nominal rating of the actual voltage, it is imperative to segregate buses based on the type it is used for as well. For this the buses are further classified as Load and Gen bus (which is a combination of hydro and non-hydro buses).

Load and Gen bus code:

Bus type	Code
Hydro Generator Bus	1
Non-hydro Generator Bus	2
Load Bus	3

11.1. Plant code

In order to identify the generation plants, each generation plant is assigned a unique serial number for easy identification.

The plant code comprises of two numeric values

The following section (Annexure) outlines the plant codes used in the power system database. There are no assigned region-specific codes and the allocation of plant code is merely allocated based on their expected Date of Commissioning (COD).

Note: Any new plant not in the above list is to be added to the list in ascending order of their planned date of operation

11.2. Station code

All the substations including Industrial parks/estates, special loads, pooling/switching stations, and load centres will be considered as load buses.

The numbering of major substations is assigned to identify the specific node in the power system database.

Note: Any new station not in the above list is to be added to the list in ascending order of their planned date of operation.

11.3. Bus Numbering

The selection of codes in the bus is based on several factors like assigned arbitrary load/Gen code, voltage level and plant/station code. Those individual numbers are used to assign the final codes for the buses.

The general format for numbering of buses is as given below:

X-XX-XXX

The first digit denotes the type of bus.

- **1 - Hydro-generator**
- **2 - Non-hydro-generator**
- **3 - Load**

The second and third digits represent a plant or station code.

- **E.g. 1: 322XXX would mean a load bus at station 22, which is the station code of Malbase S/S.**
- **E.g. 2: 101XXX would mean a generator bus at Plant 01, Which is the plant code of Chhukha HP.**

The last three digits represent the voltage code.

- **400 for 400 kV**
- **011 for 11 kV**
- **And so on ....**

11.4. Bus Naming Scheme

For naming purpose, following convection is adopted for easy interpretation:

(First_three_letter_of_gen) (_GEN_) (system_voltage)

Table below shows the naming convection followed for the existing generator busses in Bhutan:

Ex:

For Chhukha HEP, it would be CHH_GEN_11

For Tala HEP, it would be TAL_GEN_13

For naming of these busses, following convection is adopted for easy interpretation:

(First_three_letter_of_Load) (_LOA_) (system_voltage)

EX:

For Semtokha substation, it would be SEM_LOA_220

12. Single-Line Diagram Colour Coding

Colour code forms an essential part of visual representation within the power system model. Visualizing the power system information in a comprehensive and communicable manner is as essential as modelling a HV grid itself. Therefore, different colour codes are assigned to communicate different aspects of the grid in its Single Line Diagram (SLD) or Slider Diagram.

1. Colour Code for Bus based on its rated Nominal Voltage
   Colour codes for busses are as given in the table:

Bus Voltage (kV)	Hex Code	Colour	Colour name
11	#434C56		Luxe Blue
13.8	#434C56		Luxe Blue
400 (QUAD)	#0000FF		Teal Blue
400 (TWIN)	#1560BD		Denim
220	#66FF00		Bright Green
132	#00ED1		Turquoise
66	#000000		Black
33	#9678B6		Purple Mountain[2]

2. Colour Code for Over and Under Voltage condition
   Colour code for Over Loading condition.

Bus voltage (PU)	Hex code	Colour	Colour Name
>1.05PU	#CD5C5C		Indian Red
>1.10PU	#FF2400		Scarlet

Colour Code for Under Voltage Condition

[2] https://www.color-meanings.com/shades-of-blue-color-names-html-hex-rgb-codes/

Bus voltage (PU)	Hex code	Colour	Colour Name
<0.95PU	#9A7B4F		Tortilla
<0.90PU	#652A0E		Cinnamon

3. Colour Code for overloading condition of power system elements
   Colour Code for overloading of elements.

% Loading	Hex code	Colour	Colour Name
105%	#FFA500		Orange
110%	#FF4B33		Red orange

13. Annexures

I. Definitions:

For the purposes of this Manual, any term or expression defined in the **Electricity Act of Bhutan, 2001** should carry the meaning as prescribed therein, unless expressly stated otherwise in this Manual. The following terms and expressions should be interpreted as defined below

Act:	means the Electricity Act of Bhutan, 2001
Nodal Agency:	means Department of Energy, MoENR
Generators:	means Solar plant, Wind farm, Mega, mini and micro hydropower plants
Time horizon:	means planned time phase of ATS/generator development as per NTGMP or Energy roadmap of Bhutan.
Critical Generator:	means a generator that serves as a critical point in power system nodes and sudden outage or malfunction of it could lead to voltage instability, frequency deviations, cascading failures, or even a blackout.
Point of Connection:	means the bus where the power line is connected from the source
DERs:	means a generator which is embedded within and connected to a Distribution System
Emergency:	means a situation caused by an unforeseen event or incident that disrupts or threatens electricity supply, public safety, health, or property
Grid Code Regulation 2024:	means a document outlining the approach and responsibilities for power system planning and operation, issued by the Authority under Part 10 (Section 89) of the Act

Power Factor: means the ratio of Active Power (kW) to Apparent Power (kVA) and is expressed as the cosine of the electrical angle between the voltage and current vectors in an AC electrical circuit.

N-0 contingency condition: Normal operation of the grid with zero incidences i.e., no loss of any grid element.
In this condition, all the system parameters like voltages, loadings, frequency should remain within the permissible normal range/limits.

N-1 Contingency Condition: Refers to loss of a single active element due to disturbances induced within the grid.
In this condition, all the system parameters like voltages, loadings, frequency should remain within the permissible normal range/limits.

N-1-1 Contingency Condition: Refers to loss of second element due to the loss of first element within the grid. In this scenario, some of the grid elements will be loaded up to their emergency limits.
In this condition, all the system parameters like voltages, loadings, frequency should remain within the permissible emergency range/limits.

II. Line Loading Setting

For Loading value of all the elements, following norms should be adopted:

1. Rate 1: Surge Impedance Loading value
2. Rate 2: thermal loading at 75 deg C (35 deg ambient)
3. Rate 3: thermal loading at 85 deg C (35 deg ambient)
4. Rate 4: thermal loading at 75 deg C (40 deg ambient)
5. Rate 5: thermal loading at 85 deg C (40 deg ambient)

III. Plant Code:

Plant code	**Plant name**

Plant code	**Plant name**

Plant code	**Plant name**

01	CHHUKHA HP
02	TALA HP
03	BASO US
04	BASO LS
05	DAGACHHU
06	MANGDECHHU
07	KURICHHU
08	NIKACHHU
09	PUNA I
10	PUNA II
11	SUCHHU
12	DRUK BINDU I
13	DRUK BINDU II
14	BURGANGCHHU
15	YUNGHICHHU
16	KHORLOCHHU
17	SEPHU SOLAR
18	GAMRI-II
19	DRUK BINDU

21	BEGANA
22	GAMRI-I
23	WANGCHHU
24	SANKOSH_L
25	SANKOSH_R
26	SANKOSH REG
27	GONGRI
28	DORJILUNG
29	KURI GONGRI
30	BUNAKHA
31	NYERAMA-I
32	CHAMKHAR-II
33	JIGMECHHU
34	YURMOCHHU
35	KHOMACHHU
36	PAROCHHU
37	JONGTHANG
38	JERICHHU
39	NYERA AMA-I

41	DOROKHA
42	CHAMKHAR-I
43	SHERICHHU
44	DANGCHHU
45	LHUNTSE SOL
46	BUMTH SOL
47	SAKTENG SOL
48	BJACHO SOL
49	WOBTHA_SOL
50	JAMJI_SOLAR
51	APA_AMA_SOL
52	GOGONA_SOL
53	GAWA_WIND

20	JOMORI		40	CHAMKHAR-IV

IV. Substation Code:

S/S code	Station name	S/S code	Station name	S/S code	Station name
01	Semtokha	16	Nangkor	31	Changidaphu
02	Olakha	17	Nganglam	32	Jamjee
03	Dechencholing	18	Tintibi	33	Damji
04	Jemina	19	Gelephu	34	Sibsoo
05	Lobeysa	20	Deothang	35	Norbugang
06	Haa	21	Motanga	36	Durungri
07	Paro	22	Malbase	37	Basochhu
08	Gedu	23	Yurmo	38	Gewathang
09	Gomtu	24	Jigmeling	39	Phobjikha
10	Singhigaon	25	Pangbesa	40	Gyalsung
11	Phuntsholing	26	Dagapela	41	Lhamoizingkha
12	Watsa	27	Corlung	42	Jigmeling(India)
13	Tsirang	28	Dhamdum	43	Goling
14	Kilikhar	29	Dochula	44	Khasadrapchhu

15	Kanglung	30	Phuntshothang	45	Jamtsholing

Working Team and Approval Note:

Approval Note			Signature
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	Mr. Kinzang Rangdrel Lhendup	Deputy Executive Engineer	
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