National Electric Power Regulatory Authority
Islamic Republic of Pakistan

Registrar

NEPRA Tower, Attaturk Avenue (East), G-5/1, Islamabad
Ph: +92-51-9206500, Fax: +92-51-2600026
Web: www.nepra.org.pk, E-mail: registrar@nepra.org.pk

No. NEPRA/R/DG(LIC)/LASO-01/6696-16

March 21, 2023

Rana Abdul Jabbar Khan
Managing Director
National Transmission & Despatch Company Limited
414-WAPDA House, Lahore

Subject: **Grant of System Operator Licence No. SOL/01/2023**
Licence Application No. LASO-01
<u>National Transmission & Despatch Company Limited (NTDC)</u>

Reference: Your application submitted vide letter No. MD/NTDC/3029 dated 24.08.2022

Enclosed please find herewith System Operator Licence No. SOL/01/2023 granted by National Electric Power Regulatory Authority (NEPRA) to National Transmission & Despatch Company Limited (NTDC) pursuant to Section 23G of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997, as amended or replaced from time to time. Further, the determination of the Authority in the subject matter alongwith Grid Code 2023 are also attached.

2. Please quote above mentioned System Operator Licence No. for future correspondence.

Enclosure: <u>As Above</u>

21/03/23
(Engr. Mazhar Iqbal Ranjha)

Copy to:

1. Secretary, Power Division, Ministry of Energy, 'A' Block, Pak Secretariat, Islamabad
2. Secretary, Ministry of Planning & Development, Government of Pakistan, 'P' Block, Pak Secretariat, Islamabad
3. Secretary, Ministry of Finance, Government of Pakistan, 'Q' Block, Pak Secretariat, Islamabad
4. Secretary, Energy Department, Government of Punjab, EFU House, 8th Floor, 6-D Jail Road, Lahore
5. Secretary, Energy Department, Government of Sindh, State Life Building -3, Dr. Zia-ud-din Ahmed Road, Karachi
6. Secretary, Energy & Power Department, Government of Khyber Pakhtunkhwa, Block-A, 1st Floor, Abdul Wali Khan Multiplex, Civil Secretariat, Peshawar
7. CEO, Central Power Purchasing Agency (Guarantee) Ltd, 73 East, A.K. Fazl-ul-Haq Road, Blue Area, Islamabad
8. Managing Director, Private Power & Infrastructure Board (PPIB), Ground & 2nd Floors, Emigration Tower, Plot No. 10, Mauve Area, Sector G-8/1, Islamabad
9. Chief Executive Officer, Alternative Energy Development Board (AEDB), 2nd Floor, OPF Building, G-5/2, Islamabad

10. Chief Executive Officer
Lahore Electric Supply Company (LESCO)
22-A, Queen Road, Lahore

11. Chief Executive Officer
Gujranwala Electric Power Company (GEPCO)
565/A, Model Town, G.T Road, Gujranwala

12. Chief Executive Officer
Multan Electric Power Company (MEPCO)
NTDC Colony, Khanewal Road, Multan

13. Chief Executive Officer
Peshawar Electric Supply Company (PESCO)
NTDC House, Shami Road, Peshawar

14. Chief Executive Officer
K Electric Limited (KEL)
KE House, 39 B
Main Sunset Boulevard, DHA Phase-II,
Karachi

15. Chief Executive Officer
Quetta Electric Supply Company (QESCO)
Zarghoon Road, Quetta

16. Chief Executive Officer
Islamabad Electric Supply Company (IESCO)
IESCO Head Office Street 40
Sector G-7/4, Islamabad

17. Chief Executive Officer
Faisalabad Electric Supply Company (FESCO)
Abdullahpur, Canal Bank Road,
Faisalabad

18. Chief Executive Officer
Sukkur Electric Supply Company (SEPCO)
Old Thermal Power Station, Sukkhur

19. Chief Executive Officer
Hyderabad Electric Supply Company (HESCO)
HESCO Headquarter
WAPDA Complex, Hussainabad, Hyderabad

20. Chief Executive Officer
Tribal Areas Electricity Supply Company (TESCO)
213-NTDC House
Shami Road, Peshawar

National Electric Power Regulatory Authority
(NEPRA)

Determination of the Authority in the Matter of Application of National Transmission and Despatch Company Limited for the Grant of System Operator Licence

March 21, 2023
Case No. LASO-01

(A). Background

(i). National Transmission and Despatch Company Limited (NTDC) holds a Transmission Licence (No. TL/01/2002, dated December 31, 2002 as amended from time to time). The Transmission Licence granted to NTDC provides an exclusivity as National Grid Company (NGC) for providing transmission and system operation services in the whole country except for the area served by K-Electric Limited (KEL).

(ii). Through amendments in the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (the "Act") promulgated on May 02, 2018, various new provisions have been introduced to provide a framework for the development of a competitive electric power market in the country including, inter alia, the segregation of transmission and system operation services to be performed under different licences.

(B). Filing of Application

(i). In consideration of the above, under Sections 23G and 23H of the Act, the NTDC submitted an application (the "Application") on August 24, 2022 for the grant of System Operator (SO) Licence. NTDC also submitted a draft Grid Code along with the Application for review and approval of the Authority[1].

(ii). The Authority considered the matter and admitted the Application for further processing. Accordingly, notices were published in the press on October 06, 2022 to seek comments from the general public and other stakeholders.

[1] NTDC has also submitted an LPM for exclusion of SO services from its Licence for which separate proceedings are in process.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

Separate letters were also sent to relevant stakeholders on October 11, 2022 seeking their comments in the matter.

(C). Comments of Stakeholders

(i). In response to the above, the Authority received comments from thirteen (13) stakeholders including Lahore Electric Supply Company Limited (LESCO), Quaid-e-Azam Thermal Power (Pvt.) Limited (QATPPL), Attock Gen Limited (AGL), Independent Power Producers Advisory Council (IPPAC), Nishat Power Limited (NPL), Bahria Town Services (BTS), Matol (Pvt.) Limited (MPL), Energy and Power Department, Govt. of Khyber Pakhtunkhwa (E&PDKPK), CPPA-G, KEL, Ministry of Planning, Development & Special Initiatives (MoPD&SI), Board of Investment (BoI) and Punjab Power Development Board (PPDB).

(ii). The above stakeholders inter alia, supported the grant of SO Licence to NTDC with few observations on the submitted Application including (a). Eligibility Criteria (System Operator Licence) Rules have not been issued by the Federal Government so far; (b). Federal Government has not lifted the moratorium on Sections 23G and 23H of the Act; (c). the proposed framework under the Act requires the establishment of a new company for acquisition of licence of SO; and (d). there should be a visible and transparent mechanism for accountability of SO regarding its performance.

(iii). In addition to the said, the above stakeholders submitted various observations/comments regarding different provisions of the draft Grid Code including, inter alia, (a). Constitutional & regulatory provision/establishment of Regional Control Center (RCC) for PGCs and KEL to run the system in isolated mode; (b). the Planning Code of the Grid Code-Clashes in IGCEP and TSEPs of SO & PGCs; (c). the Planning Code also lacks harmonious planning coordination between the SO and other Licensees; (d). derogation request: due to a large number of inconsistencies in the provisions of the draft Grid Code and existing PPA, instead of seeking exemption on a case-to-case basis, the IPPs should, prima-facie, be automatically exempted; (e). Provision for inclusion of concept of regional grid company/regional SO for KEL; (f). Grid Code should provide mechanism for network islanding to avoid total system collapse; (g). the Grid Code must ensure timely evacuation of committed power on terms agreed between the

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

parties; (h). the Grid Code should provide transparent procedures for financial transaction of power sold and consumed; (i). operational interdependency of the roles of MO and SO and concept of an independent system operator combining the functions of MO and SO; (j). differences between existing Project Agreements (IAs, PPAs) and the draft Grid Code (i.e. change in frequency range, time duration of event, minimum load ceiling, definition of different terms, range of droop setting, timeline and manner of provision of schedule outages, power factor limits, and ROCOF setting etc.) and their treatment; (k). Operation Code OC 2.4.2: the mechanism under which the relevant DNO will provide the required information, requires clarification; (l). OC 3: demand control shall only be carried out in the territories/service areas of Users having generation/supply shortfall; (m). OC 9.5.3 (SCADA)-direct access to Remote Telemetry Units (RTU) of the users; (n). OC 11.7mechanism for investigation/assessment to inspect the cause of failure of the User with black start facility; (o). Scheduling and Dispatch Code-SDC 1.5.2.13: fuel stock requirement, the definition should recognize more governing documents/directives; (p). the definition of National Grid may be revised to recognize existence/interconnection of other power systems being operated by Regional Grid Companies (RGCs)/Regional System Operators (RSOs)/PGCs; (q). MC 3.8.1(b) along with DNOs, metering of BPCs engaged in redistribution should also be on low voltage side of the step-down transformer; (r). MC 3.8.2 in case of BPCs engaged in redistribution, the losses of 220/132kV transformer shall be with TNOs; (s). all SCADA system and telemetry may be revised periodically keeping in view of the technological development and enhancement and conveyed to all upcoming projects; (t). Black start capability may be installed in upcoming power plants based on the location and other grid system constraints; (u). periodic review of protection settings and testing of protection as per best international/prudent industry/utility practices; (v). the draft Grid Code is silent about eventualities where PGCs can be inter-connected as well as whether grid operation below 66 kV falls under the Distribution Code or otherwise; (w). as required under NEP-2021, the cost of transmission line must be included in the input parameters of IGCEP in PC 4 of the Grid Code; (x). PC 4.3.1 of the draft Grid Code may be suitably amended to reflect the essence of preparing TSEP, under NEP-2021, so that the transmission cost consideration can be duly included while planning future least cost power generation; (y). impact assessment of the new requirement for double contingency & N-M, is required to be made before its implementation; (z). the

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY NEPRA AUTHORITY criteria of minimum reserve, operating margin & operating reserve is required to be incorporated in planning code of the draft Grid Code and aligned with other sub codes; (z). in compliance of Section 23-G of the Act & NEP-2021, the export scenario in case of provision of excess energy/regional interconnection is required to be reflected in the draft Grid Code; (aa). mechanisms of banking and balancing of energy are required to be incorporated in the draft Grid Code; (bb). review of reactive power compensation switching limit not to exceed 3%; (cc). mismatch in frequency ranges in the Planning Code (PC) and Connection Code (CC); (dd). The LVRT & HVRT aspects to be considered in the wake of 20 MW and above projects in the Grid Code; (ee). OC-3.8: the aspect of Automatic Demand Control System (ADCS) should be mentioned; and (ff). PC4.1.3: Impact of EVs on the system should be considered.

(D). <u>Response of NTDC</u>

(i). The Authority reviewed the above comments/observations of stakeholders and considered it appropriate to seek the perspective of NTDC on the same. Accordingly, NTDC provided a detailed response to the comments/observations of the above stakeholders. The salient points of the rejoinder submitted by the NTDC are summarized in the following Paragraphs.

(ii). On the observations of stakeholders related to the application for grant of SO Licence, NTDC has submitted that the required Eligibility Criteria (System Operator Licence) Rules are still awaited from the Federal Government. However, in the absence of said rules, NTDC has submitted an undertaking stating that it shall fulfil any and all eligibility criteria laid down by the future Rules. Regarding moratorium on Sections 23G and 23H of the Act, NTDC has submitted that this issue relates to the Authority. However, it is understood that the moratorium on Sections 23G and 23H shall be automatically lifted in April 2023. NTDC has further clarified that to carry out the functions of SO, a separate company shall be incorporated in due course of time. The Strategic Business Plan provided in the SO Licence application provides the complete roadmap for the next five (05) years. On the observations regarding mechanism of accountability of the SO, NTDC submitted that the accountability of SO relates to NEPRA Performance Standards and SO Licence Regulations. However, the Grid Code addresses the highlighted issues of Merit Order (in SDC 2.2.1 (b) and SDC 2.2.2), Blackouts (in

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

OC 12.2.1(b)), Frequency variations (in OC 5.4.1, and OC 5.4.4), and Demand Forecast (in OC 2.8.3).

(iii). On the observations of the stakeholders regarding the Grid Code, NTDC submitted a detailed response including:

(a). The scope of Grid Code and SO licence includes the operation, control and planning of the National Grid i.e. the interconnected power system of Pakistan. The Authority shall provide regulatory framework for system control of isolated networks;

(b). Relevant Departments would be invited for consultation before submission of IGCEP and TSEP to avoid clashes mismatch of planning between SO and other Licensees;

(c). Provisions of PPA notwithstanding, if a generator is technically capable of conforming to the requirements of the Grid Code such as frequency limits, provision of ancillary services such as free governor response and AGC etc. it should be obligated to comply with the Grid Code. Exemption/derogation should only be allowed in cases where it is not technically possible as per manufacturer design to comply with the Grid Code (Code Management-CM 12). However, NEPRA has the authority to provide the final determination in the plea regarding general exemption to legacy PPA plants keeping in view legal and contractual issues;

(d). The Grid Code is a generic document that specifies the functional requirements of System Operator regardless of ownership of entity. That is why, instead of using actual names of organizations, functions names like TNO/DNO/SO, etc. have been used. The issue of control of KEL generators and substations, and method of conveying SO instructions to these Users is an operational matter and SO can have various operational arrangements with different entities (KEL/PGCs/DNOs, etc.) as per suitability and legal permissibility. All such foreseeable operational arrangements that the SO might have with other Users are covered in the Grid Code;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(e). OC 6.6.2.3 of the Grid Code empowers the SO to implement remedial measures to avoid system collapse including "Network Reconfiguration". Furthermore, OC 12.6 provides a detailed procedure for restoration of system from islanded mode;

(f). The purpose of TSEP, which shall be prepared in coordination with all TNO/DNOs is to ensure the timely and adequate transmission/evacuation of power. Additionally, NEPRA Open Access Regulations 2022 mandate the provision of network connection to all Grid Users. CC 2 the Grid Code provides detailed procedure for a Grid User to connect to a TNO. Also, each generator shall have a Connection Agreement with its respective Transmission Network Operator (TNO)/ Distribution Network Operator (DNO) to ensure reliable connection;

(g). Procedures for financial transaction of power and requirements for transparency are beyond the scope of the Grid Code and fall in the scope of Commercial Code;

(h). The Application for the grant of SO Licence is made by NTDC for functional separation of SO within NTDC. NTDC does not support the merger of the SO and MO. NTDC has strongly advocated for the SO and MO to remain separate entities at all forums;

(i). In OC 2, each DNO is obligated to provide information related to demand forecast to the SO as per timeline/horizon specified. In OC 2.4.2, Transmission Connected Consumers (BPCs) have been required to provide their information through the relevant TNO in whose service territory they are situated. The DNOs shall aggregate the demand in their respective service territories and provide the same to the SO in writing (or by such electronic data transmission facilities as have been agreed with the SO);

(j). According to OC 3.5.5 of the Grid Code the total amount of demand control required shall be distributed among all relevant Users considering each User's demand forecasted or in real-time and

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

System conditions on pro rata basis. The planned demand control shall be carried out on "relevant Users" only. However, as suggested by KEL, emergencies such as force majeure or in the case of legacy generators shall be dealt through OC 3.9 i.e. "Emergency Disconnection";

(k). The purpose of SCADA system is not only visibility for the SO but also control. Thus, direct access to user's RTU is required for effective system control. Remote Telemetry Units (RTUs) are used worldwide for monitoring and control of User's equipment and plant. Moreover, it has already been mentioned in the Grid Code (OC 9.5.3.9) that for Users having their own SCADA system, SCADA to SCADA communication between SO and User(s) through standard IEC protocols may be used, with the prior approval of SO, instead of direct access to the RTU(s) of the Users;

(l). The entire section OC 11.7 provides a complete mechanism for providing warning to non-compliant users as well as an opportunity to explain their position. Also, OC 11.8 provides complete procedure as to how a failed black start test shall be dealt with, including provision for re-test. The SO cannot impose any penalty on any User and all fines/penalties are the prerogative of the Authority. The purpose of OC 11.7.2 is to highlight that failure to provide black start by a generator shall not be attributable to the SO and any penalty imposed by the Authority shall lie only on the non-compliant User;

(m). Regarding fuel stock requirement, the inclusion of NEPRA Performance Standards for Generation was as per directives of NEPRA team during consultative sessions. The Authority may be approached for any proposed amendments;

(n). NTDC feeds the DNOs through auto-transformers which are owned by NTDC itself. Therefore, NTDC is responsible for their losses. Similarly, Bahria Town owns the 220kV Grid Station (and the Auto-Transformer), therefore, the metering point shall be at HV side of auto-transformer. Therefore, as per MC 3.8.1(c), Bahria Town, being

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

a BPC should bear the transformation losses of the said Auto-Transformer. Hence, the original clause MC 3.8.2 should be retained;

(o). The measures related to black start capability may be installed in upcoming power plants based on the location and other grid system constraints, have been addressed in CC 11(f) and OC 5, OC 11 and OC 13 of the Grid Code;

(p). Periodical Review of protection settings and testing of protection periodically of national grid system for protection are covered in OC-6.11 of the Grid Code;

(q). PGCs fall under the category of TNOs and they are defined as such in the Grid Code. The connection procedures for the interconnection of all the TNOs including PGCs are described in the Connection Code of the Grid Code;

(r). The scope of the Grid Code is only for transmission network (66kV and above) as defined in the Act and as explained in CM 3 of the Grid Code. Operation of the distribution network shall be as per the Distribution Code. However, OC 6 and SDC contain clauses for SO control of 11 kV feeders and embedded generators in case of emergencies;

(s). This concept of inclusion of transmission cost component in IGCEP is quite revolutionary in the development of Master Power Sector Expansion Plan. Even globally such examples and software, covering expansion and optimization of IGCEP and TSEP simultaneously are not available. However, a draft concept paper covering the high-level methodology of the inclusion of different transmission cost components has been prepared and submitted to Ministry of Energy (MoE) for review/approval. Once finalized, after consultation from the stakeholders, it will be included in the process;

(t). Regarding system impact assessment for Inclusion of N-2 and N-M contingency criteria, it is to be noted that TPCS 3.2 of the Grid Code highlights the acceptable system impact conditions in case of

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

credible and less credible contingencies. Other than N-1 contingency, all the other contingencies allow loss of load/generation in the system and they would not be applicable to the whole system. However, the provision for N-2 and N-M contingency conditions may be ensured for selected projects on a case-to-case basis keeping in view the security of the system;

(u). Regarding the criteria for minimum reserve, operating reserve & operating margin it is to be noted that these parameters are related to the operational procedures and therefore they have been addressed in the Operational Code of the Grid Code;

(v). The clauses of the Grid Code regarding Interconnectors address both import & export scenario unless otherwise stated. However, scope of the Grid Code is to provide general functional requirements. Modalities of Interconnector operation shall be detailed in the relevant Interconnection Agreement with the Interconnector as clarified throughout the Grid Code;

(w). Banking of energy is a commercial aspect and needs to be addressed in the Commercial Code. As per the approved Market Commercial Code, there is no concept of banking. Balancing Mechanism for Energy and Capacity is a commercial arrangement and lies under scope of the Commercial Code. Imbalances shall be settled on hourly basis based on Hourly Marginal Price;

(x). The frequency range mentioned in TPCS deals with the system frequency limit for planning and operational purposes of the integrated system whereas the ranges mentioned in Connection Code deal with the frequency range for design of Users Plants and apparatus for stable operation of the facility. The range mentioned in Connection Code is wide, keeping in view the exceptional circumstances the User Plant and Apparatus are required to bear for a limited time;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

(y). Special provisions for any potential future technology including EVs will be added in the Grid Code as the need arises. As of now, all the functional requirements have been added in the Grid Code; and

(z). Further, the aspects of reactive power compensation switching limit (OC-6.2.1(G); LVRT & HVRT of ≤20 MW projects (PC A4.5, CC-6.2(I), CC-6.3.6 and CC-6.4.2.1) and ADCS (OC 3.5.7. 3.5.10, PC 1.3.2 and PC 1.3.3) have been duly covered in the relevant codes of the Grid Code.

(iv). The Authority reviewed the above response of NTDC on the comments of stakeholders and found the same plausible. Accordingly, the Authority considered it appropriate to proceed further in the matter as stipulated in the NEPRA Act, Licensing Regulations and the National Electric Power Regulatory Authority Licensing (System Operator) Regulations, 2022 (the "SO Regulations").

(E). <u>Evaluation/Findings</u>

(i). The Authority has examined the entire case in detail including the Application, the Grid Code, comments of the stakeholders and rejoinder of the NTDC, provisions of the Act, the rules and regulations, the CTBCM Design, the Implementation Roadmap, and other Applicable Documents. In this regard, the observations/findings of the Authority have been bifurcated into (a). Findings/Analysis on the Application for SO Licence; and (b). Findings/Analysis on the Grid Code.

<u>Findings/Analysis on the Application for SO Licence:</u>

(ii). The Authority has observed that the NEPRA Act was amended through the Amended Act 2018 which received the assent of the President on April 27, 2018 and was notified on May 02, 2018. The Amendment Act 2018 amends the Act to provide the required regulatory framework for the introduction and development of a competitive electric power market in the country. In this regard, inter-alia, Sections 23G and 23H were introduced in the NEPRA Act which provide for the grant of the SO Licence and its duties and responsibilities.

(iii). However, Section 1(3) of the Act stipulates that Sections 23A, 23B, 23G and 23H of the Act shall come into force within a period of five (05) years of

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY NEPRA AUTHORITY coming into force of the Amendment Act 2018 or at such an earlier date as may be notified by the Federal Government. Section-1(2) of the Amendment Act 2018 states that it shall come into force at once, however, no particular date for its coming into force is given. As per Section-5 of the General Clauses Act, 1897, where no particular day for coming into force of an Act of the Parliament is provided, it shall come into force on the day it receives the assent of the President, which in the instant case as per the Gazette Notification of the Amendment Act, 2018 is April 27, 2018. Thus, Sections 23A, 23B, 23G and 23H of the Act shall come into force on April 26, 2023 (upon expiry of the five years period from the promulgation of the Amendment Act 2018) or on any earlier date as may be notified by the Federal Government.

(iv). The Authority is of the view that the legislative intent behind placing moratorium on the abovementioned sections was to provide a transition period for a smooth shift from the existing single buyer regime towards the competitive electric power market. In this regard, the Authority vide its determination dated November 12, 2020 approved the CTBCM Detailed Design along with an Implementation Roadmap. The Implementation Roadmap contained eighteen (18) group of actions to be taken by the relevant power sector entities, inter alia, including i.e. the NEPRA, MoE(PD), CPPAG, NTDC, NPCC, XW-DISCOs, KEL, AEDB and PPIB for implementation of the power market.

(v). It is pertinent to mention that in terms of Section-23G of the Act, the no person shall, unless licensed by the Authority under the Act, undertake functions as a system operator as may be specified by the Authority, including but not limited to (a). generation scheduling, commitment and dispatch; (b). transmission scheduling and generation outage coordination; (c). transmission congestion management; (d). cross border transmission coordination; (e). procurement and scheduling of ancillary services and system planning for long term capacity; and (f). such other activities as may be required for reliable and efficient system operations. Further, provisions to the Section-23G of the Act stipulate that only one such licence shall be granted at any one time. Further that the National Grid Company shall be deemed to be a System Operator for a period of two years from the commencement of the Amendment Act, 2018.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

(vi). Section 23G(2) provides that the eligibility criteria for the grant of licence as an SO shall be prescribed by the Federal Government and shall include, without limitation (a). minimum technical and human resource requirements; and (b). public service obligations of the licensee including quality of service and transparency of transactions. A person eligible to be licensed as the SO may make an application to the Authority in such form and manner and on such conditions as may be specified by the Authority. An application for SO licence shall be accompanied by a draft grid code governing the form and manner in which the SO shall undertake its licensed activities. The Authority may require an applicant for SO Licence to provide such further information as it considers necessary in relation to the application, in such form or verified in such manner as the Authority may direct.

(vii). The abovementioned Implementation Roadmap provided that the NTDC as TNO, Planner and Metering Service Provider (MSP) was required to (a). strengthen NTDC as Planner; (b). deploy the SMS Metering Project; (c). improve transparency and information sharing (Website, etc.) and IT Infrastructure; (d). prepare a revised Grid Code as per the due regulatory process and submit the same for the approval of the Authority; and (e). prepare drafts of Connection Agreements and submit for the approval by the Authority. Further, NTDC/NPCC is required to prepare and submit the application to the Authority for the grant of Licence.

(viii). In this regard, it is relevant to mention that the Authority has already notified the SO Regulations on November 21, 2022, which will come into force and effect upon lifting or expiration of the moratorium on Sections 23G and 23H, whichever is earlier, pursuant to Section-1(3) of the Act. It is also observed that although Sections 23G and 23H have not yet come into force till date and the eligibility criteria rules required for the grant of the SO Licence have not yet been prescribed by the Federal Government, the grant of the SO Licence and the approval of the Grid Code are critical to prepare the grounds for transparency in the system and commencement of the CTBCM.

(ix). Regarding the eligibility criteria rules, it is observed that NTDC being a wholly owned company of the GoP has submitted that in the Application that it

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

has the necessary human resources and technical capabilities to undertake the functions as the SO. Further, NTDC has also submitted an undertaking confirming that it shall comply with any and all requirement and conditions which are or may be notified by the Federal Government in the eligibility criteria rules and relevant regulations by the Authority for the grant of SO licence.

(x). The Authority considers that Section 22 of the General Clauses Act, 1897 provides sufficient powers for the grant of licence along with the approval of the Grid Code in the presence of moratorium on the relevant sections of the Act i.e. Sections 23G and 23H. As highlighted above, the Authority is of the considered opinion that moratorium was enacted so that the necessary preparation/steps for transition towards competitive electric power market can be undertaken during that period. This means that the readiness to achieve the competitive market operations is to be ensured before the end of moratorium period as given in the Act. However, if the grant of licence to the SO is put on hold till the lifting of moratorium in April 26, 2023, the commencement of the market might get delayed.

(xi). The Authority observed that Section 23G of the NEPRA Act, inter alia, stipulates that no person shall, unless licensed by the Authority under this Act, undertake functions as a system operator as may be specified by the Authority. In this regard, section 23(G)(2) prescribes the eligibility criteria for grant of such licence which includes (a). minimum technical and human resource requirements; and (b) public service obligations of the licensee including quality of service, and transparency of transactions. In terms of Section 2 (xxii) of the NEPRA Act, the said criteria is to be prescribed by the Federal Government through rules which are not in place at moment. It is pertinent to note that Federal Government has to bring relevant rules in conformity with section 50(2)-Proviso, however, to-date the relevant rules are not yet framed. However, as per pronouncements of the Superior Courts of Pakistan, absence of rules or inaction of the government functionaries to frame rules cannot be held to be prejudicial to the rights of the other party. Keeping in view of these settled principles, the applicant cannot be refused the license of System Operator solely on this ground. The rules are made to facilitate and not hinder the enabling legislation. In view thereof, we may seek guidance from the judgment of the Honorable Supreme Court reported as PLD 1974 SC 228 wherein the Honorable Court held as follows:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

"It is universally recognized that as regulatory statutes have to deal with a variety of situations and subject, it is not possible for the Legislature itself to make detailed regulations concerning them, and, therefore the Legislature delegates its power to specified or designated authorities to make such detailed regulations, consistent with the statute, for carrying out the purposes of the parent legislation. The power so conferred, is generally in the nature of an enabling provision, intended to further object of the statute, and not to obstruct and stultify the same. <u>As a consequence, the failure or omission of the designated authority to frame the necessary rules and regulations, in exercise of the power conferred on it by the Legislature, cannot be construed as having the effect of rendering the statute nugatory and unworkable.</u> <u>Such an eventuality could arise only if the Legislature indicates intention to this effect in clear and unmistakable terms."</u>

(xii). In another judgment, the honorable Supreme Court of Pakistan in the case reported as 2017 SCMR 206 held that:

"Absence of Rules may affect the enforceability or operation of the statute, however, for considering the constitutionality or otherwise of a statute on the touchstone of the Constitution or Fundamental Rights, framing or non-framing of the Rules under that statute could hardly be relevant."

(xiii). Further, the honorable Lahore High Court while relying on above cited Judgement and also held in its reported judgement (PLD 2018 Lhr 858) that:

"14. It is also settled law that the operation of a statute or any statutory provision is not dependent upon framing of the Rules. However, in some cases, the absence of Rules may affect the enforceability or operatability of the statute. The framing of Rules would be generally relevant for determining as to whether the power under the statute has been exercised properly or not, but the existence of Rules could neither save nor destroy the constitutional validity of the Statute.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

Reliance in this regard is placed on Shahid Pervaiz v. Ejaz Ahmad and others (2017 SCMR 206)..."

(xiv). Thus, from above judgments of the honorable Supreme Court we can deduct that a person who has filed an application for grant of license should not be penalized for any delays in framing of rules and therefore NTDC cannot be deprived of right to grant a System Operator license in absence of rules."

(xv). Further, it is also noted that MoE (PD) has initiated the process of the lifting of moratorium and circulated the draft summary dated April 12, 2022 for stakeholder's comments and the Authority has also supported the same through its letter dated April 21, 2021. In this context it is also important to observe here that as per the proviso to Section 23G of the Act, the NGC was deemed to be the SO for a period of two years from the date of commencement of the Amendment Act, 2018.

(xvi). Although Section-23G of the Act has not yet come into force, the intent of legislature appears to be clear from the first proviso to Section 23G(1) of the Act that the reference point for calculation of the period of two years (deemed SO status of NGC) for applying for SO licence is commencement of the Amendment Act, 2018, and not coming into force of Section-23G of the Act. Even otherwise, whenever the moratorium is lifted, it shall mean that the time period provided in the law to apply for the SO licence shall have already passed. Thus, it may be safe to conclude that when first proviso of Section 23G(1) of the Act is read with Section-22 of the General Clauses Act, 1897, the NTDC/SO should have approached the Authority for grant of said licence within two years of the commencement of Amendment Act 2018. In light of the same, the NTDC submitted the Application for grant of SO licence in August 24, 2022 and as explained in Para B(i) till B(ii) above, the Authority decided to process the same.

(xvii). Regarding eligibility criteria rules, the Authority observes that the NTDC being a wholly owned company of the GOP has submitted in the Application that it has the necessary human resources and technical capabilities to undertake the functions as the SO. Further, NTDC has confirmed that it shall comply with any requirement/conditions which may arise due to the finalization of the SO eligibility criteria rules by the Federal Government. It is important to highlight here that in the

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

past the Authority has also granted the licences to Provincial Grid Companies in the absence of the eligibility criteria rules considering that the applicants were companies owned by the provincial governments and submitted undertaking/certificates to comply with the eligibility criteria whenever prescribed. In view of the said, the Licensing Department considers that the SO licence can be granted in the absence of eligibility criteria rules, as has been done in the case of MO.

(xviii). Regarding the role of NTDC as NGC, the Authority observes that though necessary actions in this regard should have been taken timely by bifurcating the NTDC in two separate entities. NTDC as NPCC has now applied for grant of the SO Licence while relying on the first proviso to Section-23G (1) of the Act. Further, NTDC as NGC has also communicated an LPM to exclude the functions now falling under the purview of the SO, from its existing Transmission Licence (No.TL/01/2002, dated December 31, 2002 as amended from time to time).

(xix). The Authority considers that SO Licence can be granted to NTDC for the time being with clear directions to immediately ensure functional separation of the two roles in order to properly manage any conflict of interest and move towards legal separation of the two roles/entities in two distinct entities as per the timelines provide in Article-25 of the proposed SO Licence. The Authority is of the considered opinion that the existing Transmission Licence granted to NTDC shall be limited to its role as NGC.

Findings/Analysis on the Grid Code:

(xx). In this regard, the Authority has observed that the Grid Code is the governing document for all system operations and therefore it is imperative that the formulas, methodologies, and the processes contained therein and the IT system developed based on the same are tested and the associated risks are identified and mitigated before actual system operations can take place. This will develop the confidence of the Grid Code participants and enhance their understanding of the processes and system to be used in actual system operation and market transactions.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(xxi). The Authority has observed that the term "system operations" has been defined in Regulation-1(o) of the SO Regulations as the functions, system operations, power system planning and responsibilities to be performed and discharged by the SO in accordance with these regulations, the Grid Code, the Act, and other Applicable Documents.

(xxii). Regarding preparation and development of the Grid Code, the Authority has observed that initially NTDC submitted the draft Grid Code in late 2021, which was advertised in the local newspapers for comments of all stakeholders on December 25, 2021. The Authority reviewed the same internally and also got it reviewed from its international consultant who highlighted certain observations and suggested numerous changes in the Grid Code. Accordingly, the Authority directed NTDC to address the observations of NEPRA, its consultant and the general public in the Grid Code and submit a revised Grid Code for approval. Accordingly, NTDC submitted a revised draft of the Grid Code along with the Application for the grant of SO Licence on August 24, 2022.

(xxiii). In this regard, the Authority has observed that most of the observations of the Authority and its international consultant have been addressed. However, a few changes which were agreed upon between the NEPRA professionals and the NTDC team remained unaddressed in the revised draft of the Grid Code. Accordingly, these changes have been incorporated in the Grid Code in consultation with NTDC team.

(xxiv). In addition to the above, the Authority made the draft Grid Code public along with the Application for comments of the general public, interested/affected persons, and the stakeholders. In this regard, the Authority has considered the comments of the stakeholders as detailed in Para (C) above and observed that the comments raised by the stakeholders are more of an operational and technical nature. In this regard, the Authority considers that said comments/observations of the stakeholders have been duly responded to by the NTDC in a plausible manner as provided at Para (D) above.

(xxv). In this regard, the Authority considers that although NTDC has suitably responded to the observations of the stakeholders and that the Grid Code covers all major aspects related system operations, a few issues related to the Grid

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

Code need further deliberation/clarification of the Authority including (a). the introduction of savings clause for existing equipment/facilities; (b). the level of detail to be specified in the section dealing with Force Majeure; and (c). timelines for the submission of IGCEP and TSEP to align with the annual planning cycle laid down by the Applicable Documents.

(xxvi). In this regard, the Authority is of the view that a specific savings clause is not required to be incorporated the Grid Code. Rather, the Code Participants can approach the GCRP to initiate a request for exemption of one or more provisions of the Grid Code for plants, equipment, systems or apparatus existing prior to enforcement of the Grid Code and savings/exceptions may be provided on case to case basis. Regarding the Force Majeure clause, the Authority is of the opinion that the text proposed by NTDC is more appropriate for contracts, rather than for the Grid Code. In view of the said, the Authority has revised/modified the said clause related to Force Majeure to the extent of removal of unnecessary details/repetition from the Grid Code. Regarding, the timelines of IGCEP and TSEP, the Authority has decided that the deadline of annual submission for IGCEP and TSEP shall be April 30. The said changes have been made in the text of the Grid Code.

(xxvii). In light of the above, the Authority is of the considered opinion that the revised Grid Code submitted by the NTDC along with the SO licence Application has been thoroughly examined and is found to be based on global best practices. The same has also been reviewed and endorsed by the external consultant of the Authority. Further, as explained in the above paras, the observations of the Authority were also addressed by the NTDC and a revised draft Grid Code was submitted which was made public for stakeholders' consultation.

(F). <u>Approval of the Authority</u>

(i). In view of the above, the Authority considers that the application of NTDC for SO Licence is compliant with the relevant provisions of the Act and the SO Regulations. Further, the grant of the SO licence and approval of the Grid Code are necessary for the timely operationalization of the CTBCM and bringing transparency of transactions in the system.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(ii). Foregoing in view, the Authority hereby approves (a). the grant of System Operator Licence to NTDC to be applicable from the effective date of Sections 23G and 23H of the Act, on the terms and conditions set out in the Licence; and (b). the Grid Code (with changes) as annexed to this determination. The grant of System Operator Licence is subject to the provisions contained in the NEPRA Act, relevant rules, regulations framed thereunder and other Applicable Documents.

Authority

Maqsood Anwar Khan (Member)	
Amina Ahmad (Member)	Amina Ahmad
Rafique Ahmed Shaikh (Member)	
Mathar Niaz Rana (nsc) (Member)	
Tauseef H. Farooqi (Chairman)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

21/03/23

National Electric Power Regulatory Authority
(NEPRA)
Islamabad – Pakistan

SYSTEM OPERATOR LICENCE

No. SOL/01/2023

In exercise of the powers conferred under Section 23G of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997, as amended from time to time, the Authority hereby grants the System Operator Licence to the company having particulars as follows:

National Transmission and Despatch Company Limited

Incorporated under the Companies Ordinance, 1984
Under Certificate of Incorporation
No. L09689 of 1998-99

to act as System Operator within the territorial limits of Pakistan, where the Act is applicable subject to and in accordance with the terms & conditions of this Licence.

Given under my hand this on 21st day of March Two Thousand & Twenty Three and expires on 20th day of March Two Thousand & Forty Three.

Registrar

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

Article-1
Definitions

1.1 In this Licence, unless there is anything repugnant in the subject or context:

(a). "Act" means the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (Act No. XL of 1997) as amended or replaced from time to time;

(b). "Affiliate" means any person who owns or controls, or is owned or controlled by, or is under common ownership or control with, that person and for the purpose of this definition:

(i). "control" means the right, power, or ability to influence or determine any decision in respect of the conduct of affairs of the person under control; and

(ii). "ownership" means the ownership or the right to own the shares or other voting securities of the person owned;

(c). "Ancillary Services" means the different services, other than the production of electricity, that are required to operate and maintain power quality and a stable and reliable power system that includes reactive power support, operating reserve, frequency control and black start capability in accordance with the Grid Code;

(d). "Applicable Documents" means the rules, regulations, terms and conditions of any licence, registration, authorisation, determination, any codes, manuals, directions, guidelines, orders, notifications, agreements and documents issued or approved under the Act;

(e). "Applicable Law" means the Act and the Applicable Documents;

(f). "Associated Company" or "Associated Undertakings" shall have the same meanings as assigned to them in the Companies Act, 2017 (Act No. XIX of 2017);

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(g). "Authority" means the National Electric Power Regulatory Authority established under Section 3 of the Act;

(h). "Commercial Code" or "Market Commercial Code" means the commercial code prepared and maintained by the Market Operator pursuant to Sections 23A and 23B of the Act and approved by the Authority from time to time;

(i). "Confidential Information" means any information relating to any code participant, licensee, or registered person and shall include any other information as may be declared confidential by the Authority, or in the Grid Code or any agreement signed by the Licensee pursuant to the Applicable Documents;

(j). "CTBCM" or "Competitive Trading Bilateral Contract Market" means electric power market established in accordance with the high-level and detailed designs approved by the Authority vide its determinations dated December 05, 2019 and November 12, 2020, respectively as may be amended by the Authority from time to time;

(k). "Dispatch" means issuance of instructions, preferably automatic, by the System Operator to generation facilities and other users of the Grid Code connected directly or indirectly with the national grid, to schedule and control the operation of the generation facilities in order to make available or commence, increase, decrease or cease the delivery of electric power to achieve the operational requirements of balancing demand with generation and ancillary services that will ensure the security of the Transmission System, in accordance with the Applicable Documents including the Grid Code;

(l). "Effective Date" means the date on which Sections 23G and 23H of the Act shall come into effect;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(m). "Grid Code" means the grid code prepared and maintained by the Licensee under Section 23G of the Act, and approved by the Authority;

(n). "Indicative Generation Capacity Expansion Plan" or "IGCEP" means the rolling generation capacity expansion plan prepared by the Licensee in accordance with the Grid Code and approved by the Authority;

(o). "Licence" means this Licence granted to the Licensee under Section 23G of the Act;

(p). "Licensee" means the **National Transmission and Despatch Company Limited** or its successors or permitted assigns;

(q). "Licensed Activity" means any activity that is ordinary and necessary to perform System Operations pursuant to the Act and this Licence;

(r). "Licensing Regulations" means the National Electric Power Regulatory Authority Licensing (Application, Modification, Extension and Cancellation) Procedure Regulations, 2021 as amended or replaced from time to time;

(s). "Market Operations" means the functions, operations and responsibilities to be performed and discharged by the Market Operator in accordance with the Market Commercial Code and other applicable documents but shall not include the sale and purchase of electric power carried out through contracts between the two parties;

(t). "Market Operator" means a person licensed under Section 23A of the Act to administer Market Operations;

(u). "Market Participant" means any person who has signed a market participation agreement with the Market Operator;

(v). "Power System Planning" means the short-term, medium-term, and long-term system planning conducted by System Operator for economic operations, least cost generation and optimal transmission expansion,

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

augmentation and reinforcement to satisfy the objectives of system security, adequacy, reliability and performance, using well recognized and globally accepted tools/models and submit to the Authority, wherever applicable, for approval in accordance with the Grid Code and other Applicable Documents;

(w). "Prudent Utility Practices" means the use of equipment, practices or methods, as required, to protect the grid system, employees, agents and consumers from malfunctions occurring at the power plant, and to protect the power plant and the employees and agents at the power plant from malfunctions occurring on the grid system;

(x). "Public Information" means any information other than the Confidential Information;

(y). "Security Constrained Economic Dispatch" or "SCED" means the allocation of system demand to individual generation facilities to effect the most economical production of electricity for optimum system economy, security and reliability with due consideration to variable generation and operation costs, incremental network losses, load flow and other operational considerations as may be determined by the System Operator at the time of performing System Operations, subject to subsequent review and due diligence, if any required, by the Authority or any other party as the Authority may appoint for the said purpose;

(z). "Service Provider" means any distribution or transmission licensee and shall include any licensee or registered person who has signed a service provider agreement with the Market Operator;

(aa). "System Operations" means the functions, system operations, power system planning and responsibilities to be performed and discharged by the System Operator in accordance with provisions of the System Operator Regulations, the Grid Code, the Act, and other Applicable Documents;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(bb). "System Operator" means a person licensed under the Section 23G of the Act to administer System Operations, Dispatch and Power System Planning;

(cc). "System Operator Regulations" means National Electric Power Regulatory Authority Licensing (System Operator) Regulations, 2022, as amended or replaced from time to time;

(dd). "System Operator Rules" means the eligibility criteria rules as may be prescribed by the Federal Government under Section 23G of the Act;

(ee). "Tie-Line" means interconnection facility which connects two different transmission zones in the power system, including cross border transmission lines;

(ff). "Total System" means the interconnected generation, transmission and distribution facilities of the power system of Pakistan, including tie-lines or interconnections with territories where the Act does not extend;

(gg). "Transmission System" means one or more systems comprising electrical facilities including, without limitation, electrical lines or circuits, electrical plants, transformers, sub-stations, switches, meters, interconnection facilities, or other facilities operating at or above minimum transmission voltage constructed, owned, managed, controlled or operated by a transmission licensee and used for transmission of electric power from the generation facility to sub-stations, or to or from other generation facilities or between sub-stations or to or from any interconnection facilities or from the distribution facilities of one licensee to the distribution facilities of another licensee or from generation facility to a distribution facility or a bulk-power consumer; and

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

(hh). "Transmission System Expansion Plan" or "TSEP" means the plan for expansion of the transmission capacity prepared in accordance with the Grid Code and approved by the Authority;

1.2 The words and expressions used but not defined herein bear the meaning given thereto in the Act, the System Operator Regulations and other Applicable Documents.

1.3 Unless otherwise specified and without prejudice to any provision which restricts such variation, supplement or replacement, any reference to any agreement, licence, rule, regulation, statute, code, standard or other instrument shall include a reference to such agreement, licence, rule, regulation, statute, code, standard or other instrument as varied, supplemented, amended or replaced from time to time.

1.4 Where any obligation under this Licence is expressed to require performance within a specified time limit, that obligation shall continue to be binding and enforceable after that time limit if the Licensee fails to perform that obligation within that time limit, but without prejudice to all rights and remedies available against the Licensee by reason of its failure to perform within the specified time limit.

Article-2
Grant of Licence

The Authority hereby grants this Licence to the Licensee to perform the functions of System Operator subject to the provisions of the Act, rules and regulations made under the Act and other Applicable Documents, and the terms and conditions of this Licence contained herein.

Article-3
Functions of Licensee

3.1 The Licensee shall be performing different functions as stipulated under Section 23G of the Act, including but not limited to the following:

(a). generation scheduling, commitment and dispatch;

(b). transmission scheduling and generation outage coordination;

(c). transmission congestion management;

(d). cross-border transmission coordination;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(e). procurement and scheduling of ancillary services;

(f). integrated power system planning with regard to availability of adequate transmission and generation capacity to meet the electric power demand of the country; and

(g). such other activities as may be required for safe, secure, stable, reliable, and efficient System Operations or any other function assigned under the Act, this Licence, and other Applicable Documents.

3.2 The Licensee while performing its functions shall ensure that it complies with the relevant provisions of the Act and the Applicable Documents, including the relevant rules, regulations, the Grid Code and the Market Commercial Code without any exception.

3.3 The Licensee is not authorized to perform any other activity that may require a separate licence or registration under the Act.

3.4 The Licensee shall be an independent, not-for-profit organization and shall not have any conflict of interest in the competitive electric power market.

3.5 The Licensee shall also comply with the CTBCM as evolved through the regulatory framework from time to time.

Article-4
Effective Date and Term of the Licence

This Licence shall come into force on the Effective Date and shall be valid for a term of twenty (20) years, subject to compliance of the Licensee with the Act, rules and regulations, terms and conditions of this Licence, and other Applicable Documents, and payment of annual fee and other charges as specified in the Applicable Documents from time to time.

Article-5
Renewal of Licence

5.1 If the Licensee intends to renew the term of this Licence at expiry of the term, it shall submit to the Authority an application for renewal of its Licence ninety (90) days prior

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

to the expiry of the current term.

5.2 The application for renewal of Licence shall be accompanied with such documents, information and evidence as may be required under the Act or Applicable Documents.

5.3 In the event the Authority decides to grant an application for renewal of Licence, the Authority may renew the Licence on such revised terms and conditions as the Authority deems appropriate in accordance with the Act and Applicable Documents at the time of renewal of the Licence.

5.4 The Authority may grant or refuse an application for renewal of Licence after recording reasons in writing therefor.

Article-6
Annual Licence Fee

The Licensee shall pay to the Authority the licence fee, in the amount, time and manner specified in the National Electric Power Regulatory Authority (Fees) Regulations, 2021, as amended or replaced from time to time.

Article-7
Modification of Licence

7.1 The Licensee may, at any time during the term of the Licence, request a modification in this Licence from the Authority in accordance with the relevant provisions of the Act and the Licensing Regulations.

7.2 The Authority may at any time during the term of this License, communicate to the Licensee an Authority Proposed Modification or a Modification by Operation of Law in accordance with the relevant provisions of the Act and the Licensing Regulations.

Article-8
Transfer and Assignment of Licence

The Licensee shall not, without prior written approval of the Authority, surrender, assign or transfer its licence to any other person, as stipulated in Section

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

27 of the Act.

Article-9
General Obligations of the Licensee

9.1 The Licensee, in addition to the obligations stipulated in the Articles of this Licence, shall at all times during the term of this Licence be obligated to the following:

(a). carry out its functions in accordance with the Applicable Documents including the terms and conditions of this licence, the Grid Code, orders, directions and determinations of the Authority, and other relevant laws;

(b). administer, implement and enforce the Grid Code;

(c). promptly inform the Authority in writing;

(i). if it is unable to conduct any of the System Operations;

(ii). if the conduct of System Operations leads to breach of any of the terms and conditions in its licence, or materially affect delivery of system operation services; or

(iii). any material changes in circumstances that may adversely affect the performance of the licensed activities;

(d). maintain technical, operational, planning and financial capability, equipment and human resources, and organizational structure to effectively perform its licensed activities;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(e). exchange and maintain information in hard and electronic form about system operations including but not limited to, power system planning, SCED, maintenance outages coordination, system constraints, unplanned outages and emergencies, ancillary services, in accordance with the Grid Code and other Applicable Documents;

(f). be responsible for balancing electric power supply and demand in operational plans as well as in real time to ensure secure System Operations including maintenance of the system frequency within a predefined stability range and compliance with the amounts of reserves needed to adhere to the required reliability and quality standards, in accordance with the Grid Code and other Applicable Documents;

(g). carry out system impact studies and power system planning on future security, reliability and adequacy of supply for adequate reserves and sufficient transmission capacity in accordance with the Grid Code;

(h). not engage in buying or selling of electric power;

(i). carry out Power System Planning in accordance with the Grid Code and other Applicable Documents;

(j). ensure efficient and economic operation of the power system under the principles of SCED, duly justifying, validating, recording and properly addressing any deviation in the System Operations from these principles in subsequent power system planning;

(k). determine the system marginal price on an hourly basis as per the criteria provided in the Market Commercial Code and publish the same on a real-time basis on its website with the flexibility to view historical marginal prices at different resolutions of time;

(l). obtain and verify the variable costs of generation communicated daily by the generation companies or licensees or registered entities, as the case may be;

(m). until such time the System Operator and National Grid Company functions are separated in two distinct legal entities, any correspondence with the Authority on behalf of the Licensee is made by a suitable senior officer dealing with System Operations;

(n). ensure that its head of organization and other relevant senior officers appropriately attend any hearing or meeting of the Authority if so required by the Authority;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(o). promptly inform the Authority of any force majeure or other event that is likely to have an adverse impact on overall system operations or Licensee's compliance with the Licence terms and conditions;

(p). perform or cause to be performed necessary tests related to the verification of capacity and heat rates of generation companies to determine their dependable capacity and efficiency in accordance with the Grid Code:

Provided that such tests for legacy contracts shall be dealt with as provided in their respective power purchase agreements.

(q). ensure facilitation and support for open access; and

(r). ensure the use of appropriate, well recognized, and globally accepted tools/models for performing the functions of System Operations in accordance with the relevant provisions of the System Operator Regulations.

9.2 The Licensee shall perform all its obligations within the time period specified in the Grid Code or other Applicable Documents, and where no time limit is provided for any activity, the respective activity shall be completed within a reasonable time.

9.3 In addition to the duties and responsibilities specified in this Licence, the Licensee shall also comply with such other terms and conditions as may be provided in the relevant rules or regulations or any other Applicable Documents.

Article-10
Compliance with the Eligibility Criteria

10.1 The Licensee shall, at all times, ensure that it is in compliance with the eligibility criteria rules prescribed under Section 23G of the Act, as may be revised by the Federal Government from time to time.

10.2 The Licensee shall immediately inform the Authority in writing if circumstances exist that justify the reasonable expectation that the Licensee may not have sufficient

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

resources available to conduct its licensed business for a period of twelve (12) months.

Article-11
Obligations with Respect to CTBCM

11.1 The Licensee shall facilitate the development of liquid and efficient competitive electric power market and may submit to the Authority any proposals in furtherance of this objective.

11.2 The Licensee shall not engage in any activity that may disrupt or impede competition in the market or that may impair its function as an independent and impartial System Operator.

Article-12
Fair and Equitable Treatment

The Licensee shall, during the conduct of System Operations, provide non-discriminatory and fair treatment to all the Code Participants. Further, the Licensee shall, at all stages, avoid practices that may have any adverse impact on free and fair competition, open access rights, transparent System Operations and effective Power System Planning in accordance with the Grid Code and other Applicable Documents.

Article-13
Availability of Resources

13.1 The Licensee shall, while maintaining functional separation as required in Article 25 of this Licence, employ the required number of qualified personnel as may be prudent to ensure that System Operations are conducted effectively, efficiently, reliably, and prudently.

13.2 The Licensee shall ensure that, at all times, it possesses the relevant technical and financial capability in compliance with the relevant rules and regulations to perform its activities effectively, efficiently, reliably, and prudently.

13.3 The Licensee shall maintain the required and adequate capacity for training and professional development of its staff.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

Article-14
Provision of Information

14.1 The Licensee shall provide such information as the Authority may require from time to time in accordance with Section 44 of the Act.

14.2 The Licensee shall be subject to such penalties as may be specified in the relevant regulations made by the Authority, for failure to furnish such information as may be required from time to time by the Authority and which is or has been in the control or possession of the Licensee.

14.3 The Licensee shall publish all information that is necessary to ensure transparency of the System Operations on its website in order for it to be easily available to the users of the Grid Code and other interested parties.

14.4 The Licensee shall keep confidential information of Grid Code users, licensees and registered entities through a combination of appropriate controls, security, transparency, and consent mechanisms relating to the collection and use of their personal data.

14.5 The Licensee shall establish an information exchange system to collect, organize and process data received from the Grid Code users, Market Operator and other relevant entities.

14.6 The Licensee shall submit progress reports to the Authority on the status of activities being undertaken and, where required by the Authority and Applicable Law, publish the required reports in an appropriate manner.

14.7 The Licensee shall submit an annual report to the Authority within one (01) month of the close of the financial year in accordance with the System Operator Regulations and shall also make the same available on its website.

14.8 The Licensee shall make available its audit reports and financial statements on its website in a timely manner.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

Article-15
Compliance with the Applicable Law

15.1 The Licensee shall comply with the Act and Applicable Documents, as amended or replaced from time to time, while performing its functions as System Operator.

15.2 The Licensee shall be obligated to follow and comply with the System Operator Regulations in letter and spirit, as if all provisions of the said regulations are incorporated in the terms and conditions of this Licence.

Article-16
Compliance with HSE Standards

16.1 The Licensee shall conform to the health, safety and environmental standards as may be issued by the relevant competent authority from time to time.

16.2 The Licensee shall invariably comply with the Power Safety Code as approved and amended by the Authority.

Article-17
Corporate Social Responsibility

The Licensee shall comply with the NEPRA Social Investment Guidelines, 2021 and provide the descriptive as well as monetary disclosure of its activities pertaining to corporate social responsibility on an annual basis.

Article-18
Investigations, Fines and Penalties

18.1 Without prejudice and in addition to the powers of the Authority under the Act, and rules and regulations made thereunder, where the Authority determines that the Licensee is in violation of any Applicable Law or the terms and conditions of this Licence, the Authority may:

- **(a).** investigate the violation as per Section 27A of the Act;
- **(b).** order the Licensee to:
  - **(i).** cease a specific activity; or
  - **(ii).** direct its external auditor to report directly to the Authority;

(c). appoint and engage an external auditor to review the operations and compliance of the Licensee with Applicable Laws and this Licence;

(d). appoint an administrator to take over the System Operations for such time or until such event as the Authority may approve; or

(e). increase the reporting requirements of the Licensee on any matter related to its technical and financial performance or related to service quality.

18.2 Any contravention or non-compliance on the part of the Licensee or any of its officers with respect to this Licence, or the terms and conditions and time limits prescribed herein, shall constitute grounds for initiating penal action by the Authority.

18.3 Any instrument, document, contract or agreement, or any part thereof, may be declared void if executed in contravention or non-compliance of this Licence, the provisions of the Act, the rules and regulations made thereunder, or any other Applicable Documents.

18.4 Where it comes to the attention of the Licensee that any other person has breached its licence or registration or violated any Applicable Document, the Licensee shall report such non-compliance to the Authority.

Article-19
System Operations Fee and Revenue Requirements

19.1 The Licensee shall not levy any tariff, fee, rate or charge which has not been approved/specified by the Authority.

19.2 Within ninety (90) days of this Licence becoming effective, the Licensee shall submit to the Authority a petition for determination of its fee and revenue requirements under the Applicable Documents. The revenue requirement of the Licensee may be determined by the Authority periodically on an annual or multi-year

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

basis as deemed appropriate.

Article-20
Interpretation of the Provisions of the Licence

The Authority shall, in accordance with the provisions of the Act, shall make the interpretation of any or all of the provisions of this Licence. The decision of the Authority in this regard shall be final.

Article-21
System Operation & Central Dispatch

21.1 The Licensee shall carry out the dispatch of the following:

(a). all generation facilities that shall make their generation facilities available to the System Operator as required in the Grid Code; and

(b). available transfers on tie lines, including imports.

21.2 In carrying out the dispatch function the licensee shall pay due regard to information provided to it by the distribution and electric power supplier licensees.

21.3 The Licensee as a System Operator shall undertake operational planning:

(a). to ensure optimum generation availability, including a reserve margin to meet the forecasted demand after, *inter alia*, taking into account:

(i). non-availability of generation facilities and/or tie-line transfers;

(ii). constraints from time to time due to technical limitations on the total system or any part of it; and

(b). in accordance with the Grid Code for the release of portions of the system for maintenance, repair, extension, or reinforcement.

21.4 The Licensee as system operator shall carry out SCED for all generating units and cross border transmission in accordance with the Grid Code.

21.5 The Licensee shall furnish to the Authority any information required with

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

respect to the economic dispatch system or any aspect of its operation.

Article-22
Power System Planning

The Licensee shall be responsible for short and medium-term system operational planning (day-ahead, week-ahead, month-ahead and year-ahead), and long-term system expansion plans, including IGCEP and TSEP in accordance with the Grid Code and other Applicable Documents.

Article-23
Communication System

23.1 The Licensee shall ensure deployment of Supervisory Control and Data Acquisition (SCADA) and other necessary tools for effective and efficient System Operations within a period of one (01) year from the Effective Date.

23.2 The Licensee shall operate, maintain, expand and upgrade the SCADA system from time to time, as per the requirements arising on account of the System Operations.

Article-24
Risk Management

The Licensee shall, subject to the provisions of this Licence, promptly and diligently adhere to all reasonable risk-management and risk containment measures, and shall implement risk-mitigation measures.

Article-25
Functional and Legal Separation

25.1 The functional and legal separation of the Licensee as System Operator shall be undertaken in accordance with the provisions of this Licence, determination and directions of the Authority, as issued from time to time.

25.2 The Licensee shall, at the earliest but not later than two (02) years from the date of grant of this Licence, separate its functions, as System Operator from its existing role as a part of the National Grid Company, in two distinct legal entities and apply to the Authority for transfer of this Licence. In the event, these two functions

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

are not separated in two distinct legal entities as stated above, the same shall be treated as a persistent contravention of the terms and conditions of the Licence and the Authority may initiate legal proceedings against the Licensee accordingly, and also issue such directions as may be deemed appropriate that may include appointment of an administrator in respect of the System Operator functions of the Licensee.

25.3 Until such time the functions of the Licensee as a National Grid Company and System Operator are not separated in two distinct legal entities, the Licensee shall ensure that its business is operated in such a manner that the management responsible and resources for System Operations and Power System Planning are segregated from the National Grid Company so that the functions of System Operator are carried out independently, transparently, and impartially. This segregation of two functions of the Licensee shall be ensured at the earliest but in any event not later than three (03) months from the date of grant of this Licence.

25.4 The Licensee shall submit for the prior approval of the Authority, any changes to its management control, ownership, or nature of business. The Licensee shall inform the Authority, in writing, at least thirty (30) days prior to any change in its address and other contact details.

Article-26
Effective Coordination

26.1 The Licensee shall designate a person that will act as a primary contact with the Authority on the matters relating to this Licence. The Licensee shall inform the Authority promptly if there is any change in the primary contact.

26.2 All the communications with the Authority shall be done in writing which may include facsimile transmission or by other related electronic means of communication sources as deemed appropriate.

26.3 The Licensee shall have the ability to ensure prompt and effective coordination with the Market Operator and other relevant entities to comply with the provisions of

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

relevant rules, regulations and other Applicable Documents.

Article-27
Infrastructure for Information & Operational Technology

27.1 The Licensee shall develop automated systems and software tools relating to its various functions. All the computer programs or systems used by the Licensee shall be adequately secured as per the requirements of the Applicable Documents and relevant information technology and operational technology standards.

27.2 The Licensee shall engage in organization of a cybersecurity protection system for the energy sector with well-defined communication and reporting channels. The Licensee shall enforce security standards to measure and manage risks, as well as to define and maintain the processes. In developing an IT infrastructure, all the cybersecurity risks shall be addressed in a timely manner and managed to prevent cascading incidents.

Article-28
Preparation for Emergencies and Security Arrangements

28.1 The Licensee shall inform the relevant entities of any emergencies or security issue immediately that may arise in association with or relevant to its obligations under this Licence.

28.2 The Licensee shall take such actions as the Authority may reasonably require to plan and prepare for emergencies including taking part in necessary tests and exercises.

Article-29
Annual Report

29.1 The Licensee shall prepare and submit an annual report to the Authority within thirty (30) days of the close of financial year along with the information and documents as follows:

(a). details of its board of directors indicating change in the same, if any;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

(b). details of its senior management including their respective qualifications and experience;

(c). details about System Operations, including but not limited to, power system planning, SCED, clearly highlighting instances where economic despatch was not directed due to system constraints, i.e., network congestion, fuel constraints, unplanned outages and emergencies, measures taken to minimize deviations from SCED, etc.;

(d). details about procurement of ancillary services, etc.;

(e). details about the marginal price including daily, weekly, monthly and annual patterns and comparisons with previous years, highlighting events that led to any abnormal deviations and any measures that can be taken to reduce the overall system marginal price;

(f). details of network nodes, grids, etc. causing congestion in the system and measures required to address such congestions

(g). action taken against the generation companies for non-compliance with directions of the System Operator issued under the Grid Code, if any, including details of tests performed for verification of dependable capacity and heat rate of generation companies;

(h). actions taken to address any emergency in its operations;

(i). recommendations, if any, to reduce system constraints in the future and ensure most economical SCED, including any system impact studies or plans required for the same;

(j). status of compliance with the directions of the Authority issued during the reporting period to the Licensee, along with reasons for non-compliance, as may be necessary; and

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

(k). any other activities performed for effective and efficient system operations.

29.2 The Licensee shall also furnish to the Authority such other documents, information or explanation relating to system operations, as the Authority may, from time to time, require in writing.

Article-30
Maintenance of Confidentiality

30.1 The Licensee or its any officer, whether during the tenure of his office or thereafter, or any other person who has by any means knowledge of any confidential information in relation to the commercial affairs of any of the generation company, licensee or registered person, shall not give, divulge, reveal or otherwise disclose such information or document to any other person.

30.2 Nothing in Article 30.1 above shall entitle any person to refuse disclosure of any information or document, in cases, where: -

(a). prior written consent is given by the person to whom the information is related;

(b). the information is public;

(c). the Licensee is required or allowed to disclose the information to fulfil the terms and conditions of its licence and other Applicable Documents;

(d). it is in pursuance of any summons or notice issued by any court, tribunal or any other authority having competent jurisdiction to require the production of such information or document;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

(e). it is required in the course of an investigation into an offence or contravention of the Act;

(f). disclosure is required under any other law for the time being in force; or

(g). the information is required to be disclosed in the normal course of performing the licensed activity.

30.3 The Licensee shall undertake all necessary steps to prevent unauthorized access to the confidential information.

30.4 Any information that the Licensee shall submit to the Authority, shall be considered as public except in cases where upon specific or special request of the Licensee, the Authority decides that such information shall be treated as confidential information.

Article-31
Financial and Organizational Affairs

The Licensee or any of its Affiliate shall not, except to the extent specified in the terms and condition of this licence, stand surety, give guarantees, acquire or offer to acquire any interest in any entity without prior written approval of the Authority.

Article-32
Security of Supply

The Licensee shall take all necessary measures to ensure the security of supply in the short, medium and long-term. The Licensee shall prepare and submit to the Authority every three (03) years a report proposing any modifications or amendments in the regulatory framework that the Licensee deems necessary to ensure security of supply in the power system.

Article-33
Administration of Ancillary Services

The Licensee shall purchase or otherwise acquire ancillary services from the most economical sources available to it, keeping in view the quantity and nature of the services required, to ensure system security in accordance with the Grid Code and other Applicable Documents.

Article-34
Accounting Practices

34.1 The Licensee shall prepare its accounts in accordance with the NEPRA (Uniform System of Accounts) Regulations, 2022 as may be revised from time to time.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

Provided that the requirements with regard to maintenance of accounts specified in these regulations shall apply in addition to any other requirements as may be applicable in any other law for the time being in force.

34.2 The Licensee and each of its associated undertakings shall ensure the maintenance of accounting and financial reporting arrangements which enable separate accounts to be prepared for each separate business, showing the financial affairs of each such separate business as if it were a separate company so that the revenues, costs, assets, liabilities, capital, reserves and provisions thereof, reasonably attributable to each separate business are separately identifiable in the books of the Licensee and its associated undertakings from those of any other business, in sufficient detail for the purposes of determination of the revenue requirements of the Licensee and other purposes.

34.3 In specifying the accounting requirements, the Licensee and any of its associated undertakings will:

(a). maintain and preserve the books of accounts and accounting records in respect of each financial year for the time specified in the licence;

(b). prepare on a consistent basis from such accounting records in respect of each financial year, accounting statements comprising of a profit and loss account, a balance sheet and a statement of source and application of funds, together with notes thereto, showing separately in respect of each separate business and in appropriate detail the amounts of any revenue, costs, asset, liability, reserve, or provision which has been either (a). charged from or to any other business, whether or not a separate business, together with a description of the basis of that charge; or (b). determined by apportionment or allocation between any separate business together with a description of the basis of the apportionment or allocation.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA AUTHORITY

34.4 Without prejudice to the provisions of the Applicable Documents regarding the audit of the accounts of the Licensee, the Authority may, after giving the Licensee an opportunity to be heard in this regard, appoint independent auditors of national/international repute from amongst a panel of auditors specified in this behalf by the Authority through a notification in the official Gazette, for the audit of the accounts of the Licensee, where the Authority has reason(s) to believe that the accounts provided to the Authority by the Licensee do not provide a complete, true and fair view of the business of the Licensee, provided that such audit shall be restricted to accounting matters under question and shall not be carried out more than once in a financial year.

34.5 The costs of audit as referred to in Article 34.4 shall be borne by the Licensee.

Article-35
Performance Standards & Monitoring

35.1 The Licensee shall comply with the relevant performance standards and public service obligations in accordance with Prudent Utility Practices, and the relevant provisions of the Act and the Applicable Documents.

35.2 The Licensee shall submit to the Authority monthly, quarterly and yearly reports on its performance and compliance with System Operator Regulations, the Grid Code and other Applicable Documents including the relevant eligibility criteria rules, and the terms and conditions of this Licence.

35.3 The Authority may require the Licensee to provide any special reports on such format as may be deemed appropriate. The Authority may, if deemed necessary for reasons to be recorded in writing, order a technical and functional performance audit of the System Operator.

Article-36
Maintenance of Record

36.1 The Licensee shall keep complete and accurate record and other data in respect of all aspects of the System Operations including any contractual arrangements, agreements, and any other information in the manner and form as the Authority may require. The Licensee shall retain all the above records and data for a minimum period of ten (10) years from the date of expiry of the relevant agreement, arrangement, or transaction or for such further extended period as may be provided in the Grid Code or Commercial Code or specifically as the Authority may require.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

36.2 All records shall be kept in good order, properly indexed, and shall ensure quick search by different criteria including with respect to the respective entity, calculation of marginal price of the system, dispatch history and other related aspects.

36.3 The Authority may, upon forty-eight (48) hours prior notice, in writing, to the Licensee, enter into any of its premises where the record and data referred above is kept, for the examination or taking of copies thereof during office hours.

36.4 The records to be kept in compliance with the System Operator Regulations shall specifically include the following:

(a). a generation facility's availability and energy injected by the generation facility on hourly or such other intervals as may be provided in the Grid Code;

(b). transfers across tie-lines available or declared as available;

(c). marginal price and cost per unit of energy of every generation facility connected with the national grid;

(d). generation facility and transfers across tie-lines facilities scheduled for dispatch or dispatched;

(e). ancillary services called for by the Licensee and provided; and

(f). any other record required in the Grid Code and other Applicable Documents.

36.5 The Licensee shall establish appropriate mechanism for timely sharing of information including marginal price with the Market Operator and other relevant stakeholders.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

Article-37
Anti-Competitive Practices

37.1 The Licensee shall not engage in any form of anti-competitive activities or activities contrary to transparent, free and fair competition. Further, the Licensee shall not at any time, directly or indirectly, acquire or undertake any beneficial interest in or associate itself with any other licensee or person involved or intending to get involved in generation, transmission, distribution, supply, or trading business:

37.2 Provided that nothing in the above shall prevent the National Grid Company from performing functions of the System Operations till such time as permitted under the Applicable Documents, or prevent the Federal Government from being a shareholder of the Licensee, to keep, acquire or undertake any beneficial interest in or associate itself with the generation, transmission, distribution, electric power supply or trading business.

Article-38
Disclosure & Transparency

38.1 The Licensee shall provide complete, accurate and not misleading public information regarding the System Operations and power system planning including dispatch and marginal price discovery calculation along with monthly, quarterly and annual forecasting.

38.2 The Licensee shall calculate hourly marginal prices in a timely and efficient manner and shall publish the same on its website on real-time basis.

Article-39
Complaints & Dispute Resolution

Any dispute arising out of or in relation to this Licence or System Operations or the activities performed by the Licensee in pursuance of this Licence, or the System Operator Regulations shall be settled in accordance with relevant provisions of the System Operator Regulations.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

Article-40
Grid Code

40.1 The Grid Code developed by the Licensee shall provide detailed procedures, mechanisms and arrangements with regard to the technical requirements, guidelines and procedures to be adopted by the system operator and Grid Code users for the purpose of the following:

(a). effective and integrated power system planning;

(b). seeking new connections or modification in the existing ones;

(c). reliable and coordinated protection;

(d). precise metering at the connection points; and

(e). economic System Operation purposes for normal and abnormal system conditions.

40.2 The Authority may, if required in the public interest, direct the Licensee to amend its existing Grid Code. Provided that if the Licensee does not comply with the directions of the Authority within a period of thirty (30) days without providing cogent reason for such noncompliance to the Authority, the Grid Code of the Licensee shall be deemed to have been made or amended, as the case may be, and shall take effect accordingly.

40.3 The Licensee, Market Participants and Service Providers shall comply with the Grid Code as approved by the Authority, from time to time.

Article-41
Revocation, Suspension and Cancellation

41.1 Upon being satisfied that the Licensee is not discharging its functions in accordance with the terms and conditions of the Licence and the Applicable Documents, or otherwise fails to carry on its business in the interests of the electricity market, the Authority may initiate proceedings for suspension, revocation or cancellation of the licence under the relevant regulations or the Act and take such other action as may be necessary to safeguard the interests of all stakeholders and the power industry as

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

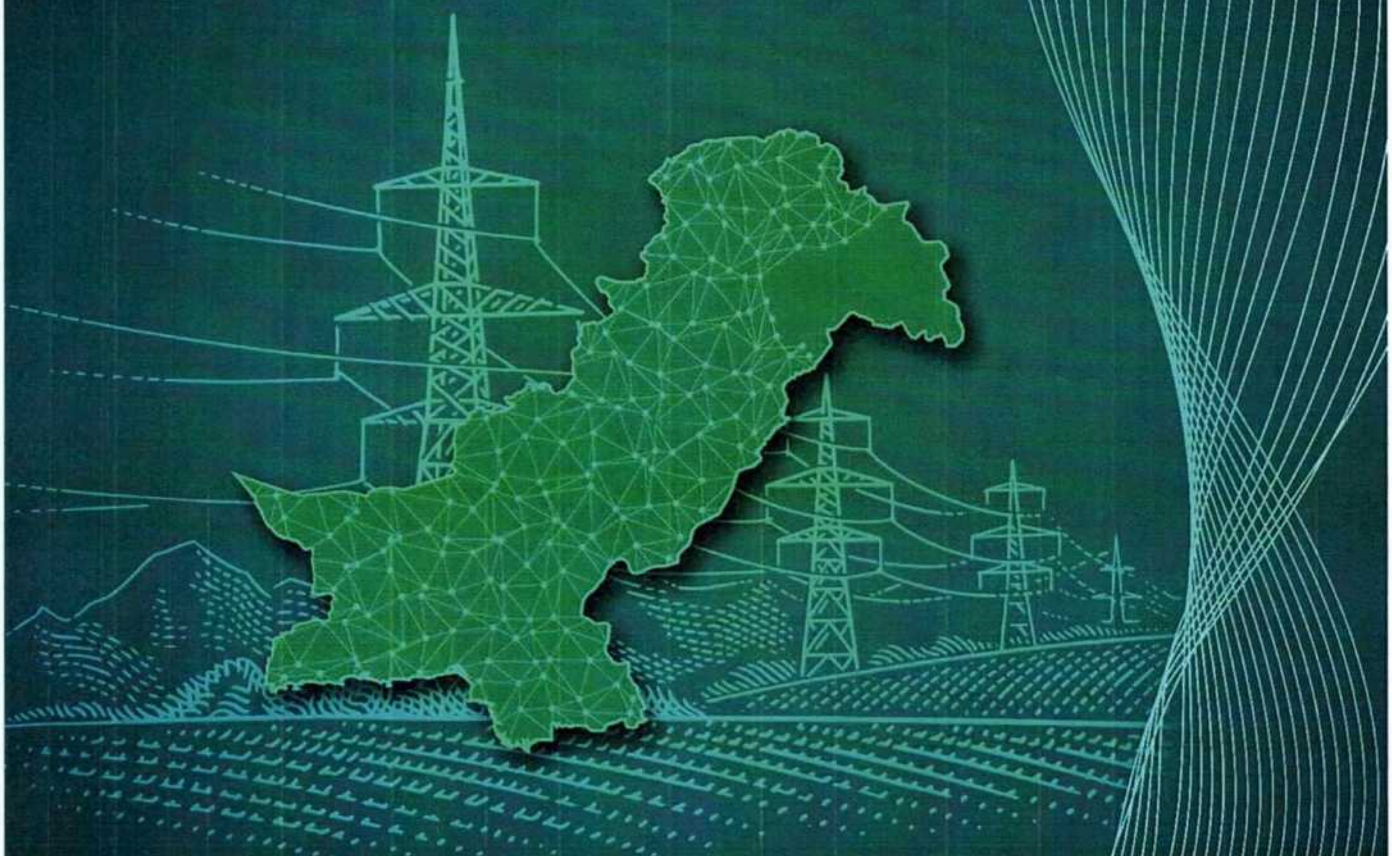
a whole.

41.2 Notwithstanding the provisions of the Article 41.1 above, the Authority shall not revoke, cancel or suspend this Licence where the Licensee demonstrates to the satisfaction of the Authority that the breach of the terms of Licence is a direct result of the failure of the Licensee to obtain consent or its renewal except where such consent is not granted or renewed because of the failure or inability of the Licensee to comply with the laws in relation to such consent or renewal and without providing an opportunity of hearing. Further, the Authority may appoint an administrator to take over the functions of the Licensee if the Licence is revoked or suspended.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA
AUTHORITY

The Grid Code 2023

Accessing the National Grid



Approved by:

National Electric Power Regulatory Authority

This page is intentionally kept blank.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

INTRODUCTION

Pursuant to the Section 23H of the NEPRA Act ("the Act"), the System Operator (SO), subject to the prior approval of the Authority, is required to prepare and keep in force a comprehensive Grid Code to enable itself to carry out its functions, operations, standards of practice and business conduct in accordance with the Act and terms and conditions of its Licence.

The Grid Code is an essential requirement of the regulation of electric network supply and delivery system. In accordance with the Act, all existing and future Users of the electric network supply and delivery system need a relevant Licence from NEPRA and register as Code Participants with the SO as per the provisions of Grid Code. One of the SO Licence's requirements is that Users of the Transmission System must comply with the provisions of the Grid Code at all times. Failure to do so may result in their Licence being suspended or revoked, or disconnection from Transmission System.

The Grid Code sets out the technical requirements, guidelines, rules and procedures to be adopted by the SO and all Code Participants for effective planning, seeking new connections or modification in the existing ones, reliable and coordinated protection of the National Grid, precise Metering at the Connection points and economic System Operation purposes for normal and abnormal Transmission System conditions.

In implementing and complying with the Grid Code, neither the Transmission Network Operators (the TNOs) nor the System Operator shall unduly discriminate in any manner between any purchasers, procurers, providers or recipients of electric power, or providers of ancillary services.

Repeal and Effectiveness

The Grid Code 2023 is approved by the Authority and shall come into force on the Effective Date. It supersedes the Grid Code 2005, which shall stand repealed on the Effective Date. The Grid Code 2023 shall enable the System Operator to carry out its functions, operations, standards of practice and business conduct in accordance with the Act and terms and conditions of its Licence.

Main Objectives of the Grid Code

1. To facilitate the planning, development, operation, and maintenance of an efficient, coordinated, safe, reliable and economical system for the transmission of electric power;
2. To facilitate open access to promote competition in the provision of Electric Power Services and efficient power market development;
3. To cover all material technical aspects including the operation of electric lines and electric plants connected to the Transmission System in so far as relevant to the Operation and Use of Transmission System; and
4. To achieve the NEPRA Performance Standards (Transmission) Rules 2005, as amended or replaced from time to time.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Sub-codes of the Grid Code 2023

A. **Code Management**

Code Management sets out general terms and conditions and procedures to be adopted by all parties in the process of administering, updating, and amending of the Grid Code.

B. **Planning Code**

The Planning Code specifies responsibilities of the Code Participants, data requirements and the integrated system planning process by which the objectives of system security, adequacy, reliability, and efficiency shall be satisfied.

C. **Connection Code**

The Connection Code sets out the minimum technical, design and operational criteria to be complied with by Users connected to or seeking connection with the Transmission System.

D. **Operation Code**

The Operation Code sets out the principles, criteria, standards, procedures, and guidelines to be followed by the SO and Users to ensure safe, adequate, secure and an efficient operation of the Transmission System, for real-time, and for managing short-term operational planning, and dealing with normal and abnormal circumstances during system operation.

E. **Scheduling and Dispatch Code**

The Scheduling and Dispatch Code sets out principles, processes and procedures to ensure Economic Dispatch, the relationship between SO and Generators, including the dispatch and balancing mechanism, and requirements for ancillary services and provisions for Frequency Control. It also places an obligation upon Users to supply certain data information to the SO in a timely manner.

F. **Protection and Control Code**

The Protection and Control Code places the protection requirements upon the Users in terms of principles, standards, design, and procedures to ensure safe, reliable, secure and effective functioning of the Transmission System.

G. **Metering Code**

The Metering Code places the Metering requirements upon the Users in terms of principles, standards, design, and procedures to ensure accurate, reliable, secure metering among the Users of Transmission System.

H. **Data Registration Code**

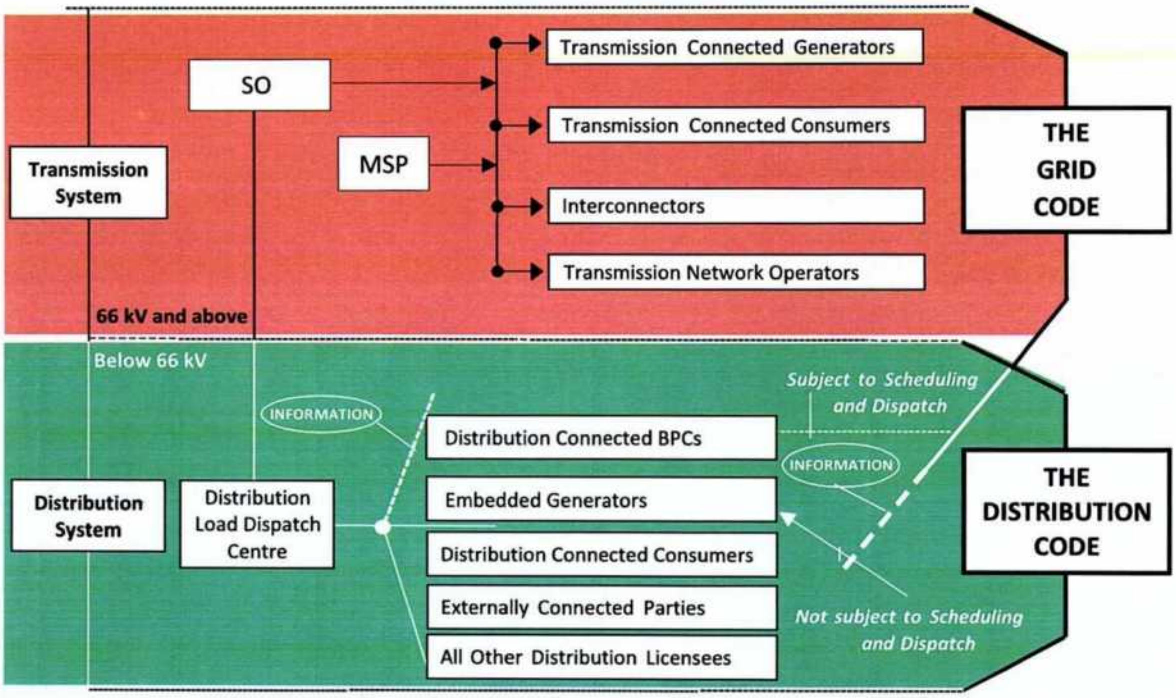
The Data Registration Code sets out a unified listing of all data required by SO from Users, and by Users from SO, from time to time under the Grid Code.

I. **Definitions and Acronyms**

The Definitions provide explanation of the special terms used in this Grid Code.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Relationship Diagram of Power System



NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

TABLE OF CONTENTS

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

CODE MANAGEMENT

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CM 1. **INTRODUCTION**

This Code Management (CM) specifies provisions which are of general application to all sub-codes of the Grid Code. Their purpose is to ensure, as much as possible, that various sub-codes work collectively and in harmony for the benefit of all Code Participants of the Transmission System.

CM 2. **OBJECTIVE**

The key objectives of the Code Management are:

(a) To specify the framework for implementing and enforcing the Grid Code;

(b) To specify the purpose, functions, and composition of the Grid Code Review Panel (GCRP);

(c) To set a structured procedure for seeking and approving any Amendments to the Grid Code or Exemptions from one or more of the Grid Code provisions;

(d) To ensure that the Grid Code has clear governance and management arrangements, including dealing with any unforeseen or unexpected events and the resolution of disputes related to the Grid Code, and that all the sub-codes are subject to the same rules and regulations; and

(e) To specify the general rules for interpreting the provisions of the Grid Code.

CM 3. **SCOPE**

This sub-code applies to the SO and:

(a) Transmission Network Operators (TNOs);

(b) Generators connected to the Transmission System;

(c) Bulk Power Consumers connected to the Transmission System;

(d) Interconnectors (AC or DC);

(e) Energy Storage Units (ESUs);

(f) Metering Service Provider (MSP);

(g) Distribution Network Operators (DNOs);

(h) Market Operator (MO);

(i) Special Purpose Agent (SPA);

(j) Embedded Generators whether represented through an Aggregator, or any other arrangement approved by NEPRA. The Embedded Generators to which this Grid Code will apply shall be determined as per the relevant Applicable Documents; and

(k) Any other person or entity with a system directly connected to the Grid administered by the SO.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CM 4. **GRID CODE REVIEW PANEL**

CM 4.1. The SO shall establish and maintain the Grid Code Review Panel (GCRP), which shall be a standing body and shall undertake the functions detailed in CM 4.4. For the first instance of the formation of the GCRP, the SO shall seek nominations and establish the GCRP within six (6) months of the Effective Date. Until the formation of the new GCRP, the existing GCRP, established under the Grid Code 2005, shall perform the functions assigned to the GCRP under this Grid Code.

CM 4.2. The GCRP shall consist of:

(a) Chairman from the SO;

(b) One (1) member appointed by National Grid Company (NGC);

(c) One (1) member from the MO;

(d) One (1) member representing Provincial Grid Companies (PGCs) and Special Purpose Transmission Licensees (SPTLs) on a 3-year rotational basis in alphabetical order;

(e) One (1) member from K-Electric;

(f) Three (3) members from different ex-WAPDA distribution companies (nominated by their respective association) on a 3-year rotational basis;

(g) One (1) member from WAPDA;

(h) One (1) member from Pakistan Atomic Energy Commission (PAEC);

(i) One (1) member from Independent Power Producers (nominated by their respective association);

(j) One (1) representative of ex-WAPDA Generation Companies;

(k) One (1) representative of public sector Generation Companies;

(l) One (1) member from Alternative and Renewable Energy Technologies (small Hydro, Solar, Wind, Bagasse, Storage Systems, etc. as defined in ARE Policy 2019) (nominated by their respective association);

(m) One (1) member from Bulk Power Consumers (directly-connected with Transmission System);

(n) One (1) member from the industry or an academic institution (on a 3-year rotation basis), nominated by Pakistan Engineering Council;

(o) one (1) member nominated by the Authority without voting rights.

CM 4.3. The detailed procedure for representation of each category shall be developed by the SO in consultation with GCRP as per CM 4.5 and approved by the Authority as part of a Code of Conduct maintained by the GCRP. This Code of Conduct shall also include, inter alia, procedures regarding meeting frequency, quorum, voting, decision, etc.

Provided that the Code of Conduct shall ensure no participation in decisions by a representative that has a conflict of interest with the decision.

CM 4.4. The GCRP shall:

(a) keep the Grid Code and its workings under regular review keeping in view the local and global developments and make recommendations to the

Authority for approval, including the deliberation on the requests for Amendment to the Grid Code received pursuant to CM 4.4(b);

(b) review all requests for Amendments to the Grid Code which the Authority, the SO, or any Code Participant files with the GCRP or the GCRP initiates at its own;

(c) make appropriate recommendations to the Authority for approval, after thorough evaluation, any request by any Code Participant seeking Exemption from any provisions of the Grid Code;

(d) incorporate and publish all the Amendments approved by the Authority on SO's website;

(e) recommend interpretation of any provisions of the Grid Code, when requested by any Code Participant;

(f) resolve dispute between the SO and any Code Participants, when requested by the parties in dispute and report the resolution of the dispute to the Authority; and

(g) consider any modifications which may be necessary to the Grid Code arising out of any unforeseen circumstances and Force Majeure, under CM 15 and CM 16 of this sub-code respectively, referred to it by the SO or Code Participants.

CM 4.5. The GCRP shall establish and comply with, at all times, its own procedures relating to the conduct of its functions as part of the Code of Conduct which shall be developed by the SO, in consultation with GCRP, within three (3) months of the GCRP's formation and approval by the Authority.

CM 5. GRID CODE AMENDMENT AND EXEMPTION PROCESS

CM 5.1. The Authority shall approve the Grid Code, its Amendments or any Exemption from its provisions. While approving any Amendment or Exemption, the Authority may consider but not be constrained, by the recommendations of the GCRP on the relevant matter.

CM 5.2. All requests for Amendment to or Exemption from the Grid Code shall be submitted to the GCRP and thereafter processed and examined by the GCRP. The GCRP after thorough evaluation shall make recommendations to Authority for its final approval.

CM 5.3. The SO shall maintain an up-to-date approved copy of the Grid Code, including all approved Amendments incorporated in the text of the document, on its website. Further, the SO shall also publish the details of every Exemption granted on its website.

CM 5.4. The Grid Code shall be thoroughly reviewed and revised after every three (3) years or earlier as and when required. The findings of this review shall be submitted to the Authority.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CM 5.5. **Grid Code Amendment**

CM 5.5.1. Any Code Participant, GCRP member, or the SO itself may propose Amendments to the Grid Code, provided that the Amendment application request includes the following information:

(a) The parts, sub-codes and conditions proposed to be amended;

(b) A clear justification of the Amendments, including on any distortion, gap or issue of concern in the existing Grid Code conditions, or any new or change in policies, legal provisions in the Act and relevant regulatory framework including the Authority approved regulations;

(c) Description on how the Amendments proposed would address the issues and conditions identified in the justification;

(d) An indicative or summary text proposed for the Amendment;

(e) Any other information and relevant supporting documents the applicant consider necessary to explain and justify the proposed amendment.

CM 5.5.2. The Amendment request shall be admitted once all the required information has been submitted. The SO may request additional information or clarifications to add to the Amendment request.

CM 5.5.3. SO shall call a GCRP meeting within a period not more than two (2) weeks after admission of the request for Amendment.

CM 5.5.4. The GCRP shall review the request for Amendment and based on the review and discussions in meetings, submit to the Authority its recommendations within one (1) month of its admission for its approval.

CM 5.5.5. The Authority shall consider the Amendment in light of the recommendations of GCRP, and may require additional information from the GCRP or carry out public or stakeholders' consultations to arrive at an informed decision.

CM 5.5.6. The Authority may return the request to the GCRP with comments and instructions to address in the Amendment. The GCRP shall review and re-submit the Amendment after addressing the comments and instructions by the Authority within fifteen (15) days of receipt of such instructions.

CM 5.5.7. After the Authority approves an Amendment, it shall be the responsibility of the GCRP to inform all the Code Participants about the same.

CM 5.5.8. If the Authority considers that an Amendment in the Grid Code is required to be made, the Authority may direct the SO to make such Amendment within thirty (30) days and submit the draft Grid Code with relevant Amendments for the approval of the Authority. Provided that the SO may convene a meeting of the GCRP to consider and submit recommendations on the Amendment to the Authority, in support or otherwise, for consideration. Provided further that if the SO does not comply with the directions of the Authority within the specified period without providing just cause, the Grid Code shall be deemed to have been amended.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

CM 5.6. **Grid Code Exemption**

CM 5.6.1. A Code Participant can seek Exemption from complying with one or more provisions of the Grid Code for Plant, Apparatus, Systems or Equipment which existed prior to the approval of this Grid Code, and which may be considered on the following grounds:

(a) to provide for existing Plant and/or Apparatus that has not been designed in accordance with the provisions of this Grid Code;

(b) to facilitate a smooth transition into this Grid Code from the existing Plant, Apparatus, Systems or Equipment;

(c) to ease one or more temporary constraints that prevent compliance and necessitate exemption; and/or

(d) to deal with any variation from this Grid Code in the Legacy Contracts.

CM 5.6.2. A Code Participant seeking Exemption from one or more provisions of the Grid Code shall make a written request to the GCRP and shall be required to justify the request in terms of both the specific circumstances and the expected duration. As a minimum, the application request must include the following information:

(a) detail of the applicant;

(b) relevant provisions of the Grid Code and the required performance;

(c) a description of the relevant Plant and/or Apparatus and/or equipment and the nature and extent of non-compliance (where applicable);

(d) a description of the proposal for restoring compliance (where applicable) including details of actions to mitigate risks and restore compliance including timelines;

(e) a description of the reasonable alternative actions that have been considered; and

(f) a statement of the expected duration of the non-compliance.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CM 5.6.3. On receipt of a request for Exemption with all the information required, the GCRP shall promptly consider such request (by seeking independent third party expert advice/opinion on the request, if necessary) and submit its recommendations to the Authority within one (1) month of the admission of the application for a final decision.

CM 5.6.4. The Authority shall consider the request in light of the recommendations of the GCRP, and shall decide on the request as appropriate. In deciding on the request, the Authority may require additional information, and/or invite the applicant or members of the GCRP to seek clarification on the request, and/or publish on its website for comments by other potentially affected Code Participants.

CM 5.6.5. The Authority determination shall be public and uploaded to the NEPRA website. It shall be considered as the final decision for the GCRP to communicate to the applicant and/or for taking further action, as may be appropriate.

CM 5.6.6. If an Exemption is granted, then the relevant Code Participant shall not be obliged to comply with the applicable provisions of the Grid Code (to the extent and for the period of the Exemption) and shall comply with any alternative provision as set forth in the Exemption.

CM 5.6.7. An Exemption from the Grid Code shall have an expiry date in order to review its continued needs and monitor performance towards compliance.

CM 5.6.8. An Exemption granted to a Code Participant shall be transferable for the approved period/term. However, in the event of transfer of ownership of Plant and Apparatus of the Code Participant, the transferee shall need to seek a concurrence of the Exemption from the Authority.

CM 5.6.9. Where a material change in circumstances has occurred, a review of any existing Exemption, and any Exemption under consideration, may be initiated by the Authority or the SO or at the request of Code Participant.

CM 6. SYSTEM CONTROL

CM 6.1. The SO shall control Code Participant's Plant and Apparatus (or part thereof) by virtue of applicability of this Grid Code.

CM 6.2. For the purposes of communication and coordination on operational matters pursuant to CM 10, the SO can (for these purposes only) treat that Code Participant's Plant and Apparatus (or any part thereof) as part of the Transmission System, but as between the SO and Code Participant it shall continue to be treated as the Code Participant's Plant and Apparatus.

CM 7. ASSISTANCE IN IMPLEMENTATION

CM 7.1. In order to fulfil its duty to implement the Grid Code, the SO may need access across boundaries, or may need services and/or facilities from Code Participants in exceptional cases wherein SO's requirements for carrying out its duty to implement the Grid Code may not be envisaged precisely or comprehensively. This may include without limitation the De-Energizing and/or Disconnecting Plant and Apparatus.

CM 7.2. In such cases, Code Participants are required to abide by the letter and spirit of the Grid Code by providing the SO with such rights of access, services and facilities as provided for in the appropriate agreements, and complying with such instructions as the SO may reasonably require in implementing the Grid Code.

CM 8. OWNERSHIP OF FACILITIES, PLANT AND APPARATUS

CM 8.1. Legal ownership of Facilities, Plant and Apparatus shall lie with Code Participant and it shall be liable for responsibilities under this Grid Code regardless of outsourcing of its Facilities, Plant and Apparatus under an agreement with third party.

CM 8.2. The Code Participant shall immediately inform the SO of any changes in Facilities, Plant and Apparatus that affects (or may affect) the operation of the Transmission System.

CM 9. DEVELOPMENT OF GRID CODE OPERATING PROCEDURES

Where the Grid Code does not specify procedures for any activity mentioned in the Grid Code or when the SO in the application of the Grid Code identifies the need to establish detailed procedures, the SO shall develop Grid Code Operating Procedures (GCOPs) to address the same, in line with all areas covered by this Grid Code, including, but not limited to, Operation, Scheduling and Dispatch, etc.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

The SO shall ensure that the GCOPs are developed in accordance with the Grid Code and other Applicable Documents, and submit for information of the Authority after approval of the GCRP. The SO shall be responsible to ensure the consistency of the GCOPs with the said documents and in case, any inconsistency is identified, the same shall accordingly be corrected.

CM 10. COMMUNICATIONS BETWEEN THE SO AND CODE PARTICIPANT

CM 10.1. All operational instructions issued by the SO to the Code Participant shall be between the SO Control Engineer based at the designated Control Centre, as advised to relevant Code Participant before Connection to the Transmission System, as may be updated from time to time, and the Code Participant's Responsible Engineer based at its Control Center, notified to the SO before Connection to the Transmission System, as may be updated from time to time.

CM 10.2. Unless otherwise specified in the Grid Code, all operational communications shall be through Control Telephony (dedicated telephone networks).

CM 10.3. All non-operational communications (data information and notices) between the SO and Code Participant shall be in writing or by such electronic interface as have been agreed with the SO, and issued to the appropriate staff of the SO and the Code Participant.

CM 10.4. If for any reason, the SO or Code Participant relocates its Control Centre, the SO or Code Participant must inform the other party in writing of the move and any changes to its Control Telephony.

CM 10.5. All instructions and communications given by Control Telephony are to be recorded by whatever means available, kept for at least five (5) years, and shall be acceptable by the SO and Code Participants as evidence of those instructions or communications.

CM 10.6. Any test required under this Grid Code shall be coordinated between the SO and the applicable User, and dates agreed as soon as possible. Where the Grid Code requires that the test is witnessed by other NEPRA Licensees or the SO, the SO and/or the relevant Licensee or Generation Company, as applicable, shall designate the witness within a period not greater than ten (10) working days. If at the agreed date and time of the required test, one or more of the designated witnesses is absent, it shall be understood that the SO or the relevant NEPRA Licensee or the generation company declines the requirement to be a witness and the tests will proceed, provided that the User shall provide the report and documentation to demonstrate the results of the tests.

CM 11. INFORMATION DISSEMINATION

CM 11.1. The SO shall establish, operate and maintain a website, providing necessary information about the Transmission System status, marginal price discovery, congestion, operating procedures, and other relevant information and data. Including all above the SO shall include daily demand and generation status at website. Any general information regarding the operation of the system and aggregated data of Code Participants, as well as information regarding historical data and statistics, are not considered confidential.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CM 11.2. The SO and Code Participant shall sign a Non-Disclosure Agreement (NDA) between them and with the external/third parties before disclosing confidential information. The issuance, disclosure and/or publication of any data by the SO on its website or otherwise shall be subject to prior classification of data/information on the basis of sensitivity, i.e. public, limited/authorized access, etc.

CM 11.3. The Grid Code and its GCOPs are public documents that shall be easily accessible to all on the SO website.

CM 11.4. The SO shall publish on its website together with the Grid Code any interpretation resulting from the application of the provisions of this Grid Code.

CM 12. CONTRACTS PRIOR TO ENACTMENT OF GRID CODE

If certain provisions in this Grid Code are different from those in the Legacy Contract of a Code Participant, the Grid Code shall prevail for the Code Participant who is technically capable of complying with the requirements of the Grid Code. Where the Code Participant is technically capable of complying with the said provisions of the Grid Code but the relevant Legacy Contract does not specify any compensation mechanism, the SO may call a meeting of the GCRP, which shall consider the matter and submit its recommendations to the Authority for the determination of compensation for the Code Participant. A Code Participant not technically capable of complying with the provisions of Grid Code shall seek Exemption in accordance with CM 5.6.

CM 13. HIERARCHY

CM 13.1. In the event of any inconsistency or discrepancy between the provisions of the Grid Code and any contract, agreement, or arrangement between the SO and a Code Participant or between Code Participants, the provisions of the Grid Code shall prevail unless the Grid Code expressly provides otherwise.

CM 13.2. In the event of any inconsistency between the provisions of the Grid Code and any regulations specified by the Authority, the provisions in Authority regulations shall prevail to the extent of the inconsistency.

CM 13.3. In the event of any inconsistency between the provisions of the Grid Code and conditions in the Licence of a Code Participant, the conditions in the Licence shall prevail to the extent of the inconsistency.

CM 13.4. In the event of any inconsistency between the Grid Code and any other Authority approved Code, the Grid Code shall prevail in all technical and operational matters and governance provisions related to the SO and Code Participants.

CM 14. INDEMNITY TO THE SO

Each Code Participant shall keep the SO indemnified at all times against any claim, action, damage, loss, liability, expenses or outstanding liability which the SO pays, suffers, incurs or is liable for in respect of any breach by such Code Participant or any of its officer, agent or employee.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

CM 15. UNFORESEEN CIRCUMSTANCES

CM 15.1. If unforeseen circumstances arise which are not included in the Grid Code, the SO shall promptly consult with all affected Code Participants in an effort to reach an agreement on what needs to be done under such circumstances.

CM 15.2. If an agreement between the SO and Code Participants as to what needs to be done cannot be reached in the time available, the SO shall determine what should be done. In any event, the SO shall act reasonably and in accordance with Prudent Utility Practice in all circumstances.

CM 15.3. Code Participants shall fully comply with all instructions given to it by the SO following such a determination, provided the instructions are consistent with the then current technical parameters of the Code Participant's Plant and Apparatus as notified under the Grid Code.

CM 15.4. The SO shall promptly refer all such unforeseen circumstances, and any such determination, to the GCRP as appropriate for consideration in accordance with CM 4.4.

CM 15.5. For sake of clarity, it is highlighted that unforeseen circumstances do not include Force Majeure Events as detailed below.

CM 16. FORCE MAJEURE

CM 16.1. Force Majeure shall mean any event or circumstance or combination of events or circumstances (including the effects thereof) that is beyond the reasonable control of the SO or any Code Participant and that on or after the Effective Date, materially and adversely affects the performance by such affected party of its obligations under or pursuant to the Grid Code, provided, however, that such material and adverse effect could not have been prevented, overcome or remedied in whole or in part by the affected party through the exercise of diligence and reasonable care, it being understood and agreed that reasonable care includes acts and activities to protect the Power System from a casualty or other event, that are reasonable in light of the probability of the occurrence of such event, the probable effect of such event if it should occur, and the likely efficacy of the protection measures.

CM 16.2. The SO or a Code Participant (as the case may be) shall not be considered to be in default of its obligation to comply with one or more provisions of the Grid Code if it is prevented from such compliance by Force Majeure. The defaulting party, the SO or the Code Participant (as the case may be), shall give prompt notice and the full particulars of such Force Majeure event to NEPRA and other concerned parties in writing or by telephone as soon as reasonably possible after the occurrence of the Force Majeure. Telephone notices given shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Code Participants affected shall, however, exercise due diligence and all necessary efforts to remove such disability and fulfil their obligations under the Grid Code.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CM 17. PARTIAL INVALIDITY AND SEVERABILITY

CM 17.1. If any provision of the Grid Code or part or section thereof is ruled to be illegal or partially invalid by any court of law for any reason whatsoever, all the remaining provisions or part or section of the Grid Code, as applicable, shall remain legally valid.

CM 17.2. In case any term or provision in Grid Code is found to be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions shall not in any way be affected or impaired thereby and such term or provision shall be ineffective only to the extent of such validity, illegality or unenforceability.

CM 18. GRID CODE IMPLEMENTATION, ENFORCEMENT, INTERPRETATION AND NON-COMPLIANCE

CM 18.1. The SO shall be responsible for implementing and enforcing the Grid Code, ensuring transparency and non-discrimination. All other Code Participants shall support the SO in this function, by properly and timely complying with their obligations as defined in the Grid Code during normal operation of the National Grid as well as providing support to the SO in effectively dealing with any unexpected and contingent conditions on the System.

CM 18.2. Any Code Participant that has evidence that any other Code Participant has violated or is violating provisions of the Grid Code, may file a complaint with the SO, with the information that justifies and validates the complaint. The SO shall inform the Authority and initiate an enforcement process, or may request the GCRP to initiate the enforcement process. Additionally, the Authority may instruct the SO or GCRP to initiate the enforcement process, even if no complaint has been filed by a Code Participant with the SO, if the Authority identifies or receives information on possible violations to the Grid Code by a Code Participant or the SO.

CM 18.3. The enforcement process by the relevant entity, the SO or the GCRP as applicable, for an alleged violation by a Code Participant shall be in accordance with the following steps:

(a) The relevant entity shall send a written notice to the Code Participant describing the alleged violation and the recommended measures or actions to correct the alleged violation;

(b) The Code Participant shall respond in writing, within twenty (20) working days from receipt of the notice, with its response to the alleged violation and whether or not it shall comply with the measures or actions in the notice;

(c) If the relevant entity is satisfied with the response of the Code Participant, it shall prepare and send to NEPRA a report, including when justified the recommended measures or actions, for the Authority to make the final decision on the matter; or

(d) If the relevant entity is not satisfied with the response, it shall prepare a report documenting the alleged violation charges against the Code Participant and submit to NEPRA, including the recommended measures or actions, for the Authority to make the final decision.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

CM 18.4. The enforcement process for an alleged violation by the SO shall be in accordance with the following steps:

(a) The Authority shall send notice to the SO of the identified potential violations to the GC, including the description and/or documentation, with copy the GCRP. The notice will require the SO to respond within a specified deadline, and for the GCRP to submit a GC violation assessment report within the same deadline.

(b) The GCRP shall designate a group of its members, excluding representatives of the SO and any other representative of the same company as the SO, to collect information and assess the complaint on alleged violation by the SO. The designated group shall submit to the Authority the GC alleged violation report within the specified deadline.

(c) The SO shall respond in writing, within the deadline specified by the Authority, to the alleged violation presenting its case and including as necessary document that supports its case, and as applicable corrective actions or measures to avoid future cases of non- compliance.

(d) NEPRA shall review the submitted reports and documentation, and may require additional information or meetings, to decide whether the SO was in violation of its obligations and procedures under the Grid Code.

CM 18.5. Non-compliance of any of the provisions of this Grid Code by the SO or any of the Code Participants shall be treated as a violation and shall be subject to penalties. The Authority may impose fines or other sanctions as specified in the Applicable Documents in case of non-compliance with any provision of this Grid Code.

CM 18.6. In case a Code Participant is not clear about any particular provisions of the Grid Code, that Code Participant may seek interpretation on that provisions from the SO. If the Code Participant is not satisfied by the SO's interpretation, the Code Participant can file a request with the GCRP seeking its guidance. The GCRP shall consider the Code Participant's request in its next scheduled meeting, but not later than two (2) months and provide the GCRP's interpretation to the requesting Code Participant. In case the Code Participant is still not satisfied with the interpretation provided by the GCRP, the Code Participant can seek guidance from the Authority. If the interpretation of the GCRP differs from the SO, the SO can seek guidance from the Authority. The interpretation by the Authority on that particular provisions shall be final and binding on the SO and all Code Participants (including the Code Participant making the request). The interpretation shall be published by the SO on its website.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
* NEPRA *

CM 18.7. The GCRP may refer to the Authority any matters requiring interpretation of the Grid Code provisions.

CM 18.8. Should a dispute arise between the SO and any Code Participant on any matter pertaining to the implementation of the Grid Code, the SO and Code Participant shall try to resolve it amicably between them. If they are unable to resolve it between them within one (1) month from notice of such dispute, then any of them can seek resolution of the dispute by referring the same to the GCRP. The GCRP shall try to mediate between the SO and the Code Participant to resolve it to the satisfaction of both the SO and the Code Participant within two (2) months from the date of receipt of such request for resolution. If the matter is still not resolved, either party can seek resolution of the dispute by filing a complaint with the Authority.

CM 18.9. The cost of the dispute resolution process, if any shall be shared in one of the following ways:

(a) If the dispute is resolved, part of the resolution shall include an allocation of the cost of the process;

(b) If the dispute is not resolved (e.g. the dispute is dropped or becomes a legal action), each party to the Dispute shall bear its own costs incurred for the dispute resolution process;

(c) If the decision is referred to the Authority, the final decision of Authority related to cost shall prevail and becomes binding on the Code Participants.

CM 19. MISCELLANEOUS

CM 19.1. Subject to CM 12, the provisions of the Grid Code shall apply from the date of its coming into effect and shall be mandatory for Code Participants seeking new or modification of their existing Connection with the Transmission System. Plant and Apparatus of existing Code Participants may not have been designed in accordance with the provisions of this Grid Code. Such Code Participant shall seek Exemption by the Authority (through the GCRP) for relevant provisions of the Grid Code by following the process described in CM 5.6. The GCRP will recommend and the Authority shall decide on such requests based on the merit of the case and the evidence provided by the relevant Code Participant for this purpose.

CM 19.2. All laws, regulations, standards, procedures, Applicable Documents referred to in the Grid Code shall include their latest revision that are amended or replaced from time to time.

CM 19.3. The titles, headings, charts and figures included in this Grid Code are provided purely to ease understanding of various provisions of the Grid Code. As such, these shall be ignored for the Grid Code interpretation, compliance, and enforcement.

CM 20. DATA AND NOTICES

CM 20.1. References in the Grid Code to 'in writing', shall include typewriting, printing, lithography and other modes of reproducing words in a legible and non-transitory form such as electronic communications.

CM 20.2. Where applicable all data items shall refer to Nominal Voltage and Frequency.

CM 21. DEFINITIONS

CM 21.1. When a word or phrase that is defined specifically and in a detailed manner in the Definitions section is more particularly defined in another sub-code, the particular definition in that sub-code shall prevail if there is any discrepancy. Such discrepancies, when noticed, shall be brought to the notice of the GCRP and shall be removed.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

CM 21.2. **Mandatory Provisions**

The word "shall" refers to a rule, procedure, requirement, or any other provision of the Grid Code that requires mandatory compliance.

CM 21.3. **Interpretation**

In interpreting any provision of the Grid Code:

(a) the singular shall include the plural and vice versa, unless otherwise specified; and

(b) one gender shall include all genders.

CM 21.4. **Person or Entity**

Person shall include an association of persons, concern, company, firm or undertaking, authority, or body corporate set up or controlled by the Federal Government or, as the case may be, the Provincial Government.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PLANNING CODE

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PC 1. **INTRODUCTION**

The Planning Code specifies responsibilities of the Code Participants, data requirements and the integrated system planning (ISP) process by which the objectives of system security, adequacy, reliability, and efficiency shall be satisfied.

PC 1.1. **Objective**

The key objectives of the Planning Code are:

(a) to specify the responsibilities of the SO and TNOs in the planning and development of the National Grid;

(b) to specify the planning data requirements from the Users seeking new Connection or a modification in their existing Connection to the Transmission System; and

(c) to specify the planning standards, procedures and technical studies that shall ensure the safety, security, reliability, and stability of the National Grid.

PC 1.2. **SCOPE**

This sub-code applies to the SO and:

(a) Transmission Network Operators;

(b) Generators connected to the Transmission System;

(c) Energy Storage Units;

(d) Bulk Power Consumers connected to the Transmission System; and

(e) Interconnectors.

PC 2. **PLANNING RESPONSIBILITIES**

PC 2.1. **Responsibilities of the SO**

The SO shall be responsible for the following activities:

(a) Preparation of Global Demand Forecast for different growth rates scenarios (low, medium and high);

(b) Consolidation of the Spatial Demand Forecasts submitted by the DNOs;

(c) Annual preparation of, at least, 10 years "Indicative Generation Capacity Expansion Plan" (IGCEP) that shall be developed following the least-cost generation planning methodologies with due consideration of the Applicable Documents, as well as adhering to the stipulated system reliability criteria;

(d) Review and validate the "Transmission System Expansion Plan" (TSEP) submitted by the National Grid Company and ascertain its adequacy and completeness;

(e) Annual submission of IGCEP and TSEP together as "Integrated System Plan" by 30th April each year to the Authority for approval;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(f) Perform or cause to perform the required connection studies for the applications of any User Development submitted by the potential or existing Generators;

(g) Verify the results of required connection studies submitted by TNOs for the applications of any User Development submitted by the potential or existing Demand Users; and

(h) Preparation of an Annual System Reliability Assessment and Improvement Report (ASRAIR) for submission to the Authority by 15th February each year. The ASRAIR shall identify and evaluate Transmission System Congestion problems that cause or may potentially cause restrictions in the economic dispatch and/or may cause load curtailment or raise the cost of service significantly and shall propose recommendations to the relevant network licensees. The ASRAIR shall be developed in consultation with the relevant TNOs, which may propose remedial measures in their jurisdictions.

PC 2.2. Responsibilities of TNOs

TNOs shall be responsible for the following activities:

(a) TNOs shall be responsible for proposing transmission network expansion plans for the networks they own or operate;

(b) In addition to the obligation indicated in PC 2.2 (a), the NGC shall liaise with other TNOs to coordinate and/or consolidate the proposals issued by each TNO for the annual preparation of 10-year centralized TSEP and submission to the SO for review;

(c) Perform or cause to perform the required connection studies for the applications of any User Development submitted by the potential or existing Demand Users;

(d) Conduct Facility Assessment Studies for all applications for any User Development submitted by potential or existing Users;

(e) Annual preparation of at least 5 years "Transmission Investment Plans" (TIP) based on the approved TSEP for their respective territories and submit to the Authority for the approval;

(f) Preparation of the project feasibility study reports, justifying the proposed connection projects along with the detailed cost estimate of the recommended transmission facilities.

PC 3. SYSTEM PLANNING DATA

The SO and TNOs will require different types of data/information from the Users in order to develop system models, conduct the required system studies and develop reinforcement/expansion plans for the National Grid to adequately meet the desired objectives of cost-effectiveness and reliable system operation. This data shall be termed as "System Planning Data" and it is broadly classified into two categories, i.e. "Standard Planning Data" and "Project Planning Data".

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PC 3.1. **Standard Planning Data**

PC 3.1.1. The data required from the existing Users at regular intervals (annually) relating to their respective Connection Sites, as stated in the Appendix Part-1 of the Planning Code, shall be termed as Standard Planning Data. This data shall be submitted, to the SO/NGC, by 30th November each year and shall cover ten (10) succeeding years.

PC 3.1.2. Where from the date of one submission to the subsequent date of submission there is no change in the data to be submitted for any given year, instead of resubmitting the data, a User may submit a written statement that there has been no change from the data submitted previously, pertaining to the particular year specified.

PC 3.1.3. Standard Planning Data, together with other data relating to the Transmission System, will provide the basis on which new applications by Users shall be considered and from which planning of the National Grid shall be undertaken. Accordingly, Standard Planning Data will be used for:

(a) Preparation of the Spatial Demand Forecast;

(b) Preparation of Indicative Generation Capacity Expansion Plan;

(c) Preparation of Transmission System Expansion Plan.

PC 3.2. **Project Planning Data**

A new or existing User, applying for any User Development, shall provide data to the involved TNO, as stated in Appendix Part-2 of the Planning Code, for the evaluation of its Connection application. Such data/information shall be termed as the Project Planning Data.

The data related to the User Development of Generators shall be shared by the involved TNO to the SO, whereas, data related to the User Development of Demand Users shall be processed by the involved TNO. Project Planning Data shall be used by SO/TNO to perform the Connection Studies. Project Planning Data is further classified into the following three sub-categories:

PC 3.2.1. **Preliminary Data**

At the time the User applies for a Connection (Intention Application), but before such an offer is made, the data relating to the proposed User Development will be considered as Preliminary Data. This data shall be treated as confidential within the scope of the policy on confidentiality as per DRC.

PC 3.2.2. **Committed Data**

Once the "Offer to Connect" has been formally accepted by the prospective User, the data relating to the User Development, already submitted as Preliminary Data, and any subsequent data required and submitted by the User as stated in the Appendix Part-2 of the Planning Code, shall become Committed Data. This data, together with other data relating to the Transmission System, shall provide the basis on which new applications by any User shall be considered and from which planning of the Transmission System and analysis of the Power System shall be undertaken. Accordingly, Committed Data shall not be treated as confidential to the extent that the SO (or any other relevant entity) is obliged to use or disclose these to discharge its contractual or regulatory obligations.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

PC 3.2.3. **Registered Data**

The Planning Code requires that, as soon as is practical, and not later than a date which is the earlier of 18 months prior to the firm Connection Date or six months after the signing of the Connection Agreement, unless otherwise directed by the Authority, all data requirements as stated in the Appendix Part-2 of the Planning Code, not previously required by the SO or TNOs and/or supplied by the User, shall be submitted by the User to the relevant TNO, which shall submit it to the SO. This shall include confirming any estimated values/parameters assumed for planning purposes or, where practical, replacing them with validated actual values/parameters and by updating the Forecast Data items such as Demand. Data provided at this stage of the project shall become Registered Data.

PC 3.3. **Data Verification and Validation**

PC 3.3.1. Where a User submits data, which in the opinion of the SO or the TNO, as applicable, is incorrect or insufficient then the SO or the TNO, as applicable, shall require that the User provides such additional information as the SO or the TNO, as applicable, deems necessary to verify the accuracy of the data. If SO or the TNO, as applicable, considers that the additional information is still insufficient to verify the accuracy of the original data, then the SO or the TNO, as applicable, may request that the User carry out specific Tests to verify the data or validate it from reliable third party the costs of which shall be borne by the User (irrespective of the test results). Where such Tests or Validations are requested, they shall be subject to the provisions of OC 11.

PC 3.3.2. In the event that any of the data items submitted by the User are found to be incorrect or inaccurate, and (i) such inaccuracy materially affects the results obtained by the SO or the TNO, as applicable, in its studies, and (ii) the result of the studies is relevant to take some decisions, then the User shall also bear the additional costs of the studies which the SO shall perform using the data values as ascertained by the Tests. However, in the case where test results validate the data provided by the User the additional cost of the studies shall not be borne by the User.

PC 4. **INTEGRATED SYSTEM PLANNING**

The SO in coordination with the TNOs shall prepare and develop, on an annual basis, an Integrated System Plan based on the System Planning Data outlined in PC 3. The Integrated System Plan shall include both, the IGCEP and TSEP, and shall be submitted by the SO to the Authority by 30th April each year for approval. Standard planning activities and their corresponding processes are described below.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

The SO shall develop, within six (6) months of the approval of this Grid Code, a detailed GCOP for Planning, consistent with the procedure outlined below, clearly indicating the information that shall be submitted by each User, their deadlines and the processes that shall follow such submission. The SO shall periodically review the indicated process and keep the GCOP for Planning permanently updated.

PC 4.1. **Demand Forecasting**

PC 4.1.1. The DNOs shall produce, and send to the SO, a Spatial Demand Forecast for the facilities or territory they control or operate covering a horizon of, at least, 10 years.

The SO shall prepare, and include in the GCOP for Planning, templates indicating how this information shall be provided.

PC 4.1.2. The Spatial Demand Forecast shall be based on the most recent available information, and shall have geographical or Voltage level discrimination, as considered appropriate by the SO for the required planning purposes. PC A2.5. details the information that should be submitted.

PC 4.1.3. In preparation of Spatial Demand Forecasts for the respective areas they control, the DNOs shall take into consideration any other potential aspect that may affect the overall Demand growth, which may include, inter alia:

(a) Impact of net-metering and embedded generation;

(b) Energy efficiency programs or measures;

(c) Development of any new technology e.g. Electric Vehicles (EVs), etc.;

(d) Impacts produced by the development of the competitive market under CTBCM.

PC 4.1.4. The SO shall review and consolidate the information provided by the Users and produce an aggregated Spatial Demand Forecast, covering a period of at least, 10 years.

PC 4.1.5. Spatial Demand Forecast shall be used for preparing, inter alia:

(a) Transmission System Expansion Plan;

(b) Transmission Investment Plans;

(c) Distribution Investment Plan by DNOs; and

(d) Power Acquisition Plan by electric power suppliers.

PC 4.1.6. The SO shall liaise with all DNOs which have submitted information, sharing with them the draft aggregated Spatial Demand Forecast it has produced. In case a DNO, or group of DNOs, consider that the review and consolidation process has not properly represented the demand forecast in the territory or facilities they own or operate, they shall submit such observations to the SO, including the necessary supporting documentation.

PC 4.1.7. The SO shall evaluate all the observations submitted and shall decide whether to dismiss them or to take them into account. In the latter case, it will produce a final version of the Spatial Demand Forecast.

PC 4.1.8. The SO shall also produce a Global Demand Forecast for three growth levels (Low, Medium, High) based on the econometric modelling approach. This forecast shall be prepared every year for a horizon of at least 20 years. The econometric model shall take into account (as required):

(a) The economic activity of the country;

(b) Population Trends;

(c) Industrialization;

(d) Impact of net-metering and embedded generation;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(e) Demand Side Management; and

(f) Any other potential variable that may affect the Demand growth.

PC 4.1.9. The SO shall strive to minimize the difference between the outputs of Global Demand Forecast and aggregated Spatial Demand Forecast.

PC 4.2. Indicative Generation Expansion Plan

PC 4.2.1. The SO shall prepare annually an "Indicative Generation Capacity Expansion Plan" for a horizon of at least ten (10) years based on the least-cost principle to meet the Global Demand Forecast.

PC 4.2.2. The IGCEP shall identify any new capacity requirements by type, capacity, location and year-by-year projects development sequence along with their commissioning dates by taking into account the capacity retirements, annual outage periods, and Transmission System aspects.

PC 4.2.3. The IGCEP shall satisfy Loss of Load Probability (LOLP) which should not exceed 1% per year. If the SO considers it appropriate, it may develop and submit to the Authority for approval, alternative reliability metrics and/or changes of the LOLP criteria, which would be better suited to the evolution and characteristics of the Transmission System. The SO shall use the approved changes in the reliability criteria in the next iteration of IGCEP after receiving the approval by the Authority. The changes in the reliability criteria shall be published on the SO website.

PC 4.2.4. As indicated in PC 4, the SO shall develop, and submit to the GCRP for approval, a GCOP for Planning, which shall include details about the process and procedures the SO will use in developing the IGCEP. It shall contain, at least:

(a) A timeline for the preparation of the Global Demand Forecast;

(b) A clear calendar for the Users or potential Users who are considering developing Generation projects in Pakistan, to submit information regarding their potential projects, they wish to be considered in the IGCEP developing process. The information submitted in these cases shall be as indicated in PC A2.6;

(c) The dates at which Users or Potential Users which are developing generation projects in Pakistan, shall provide information regarding the development of their projects;

(d) The procedures for receiving, evaluating and using of the information submitted by the potential developers;

(e) The minimum requirements for considering a development as project in progress, and, therefore, it shall be considered as committed in the determination of the least cost plan;

(f) The sources for the information which will be used to develop the IGCEP; and

(g) The minimum set of studies and analysis that shall be performed for the elaboration of the IGCEP.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

PC 4.2.5. The SO shall share the results of IGCEP with the NGC and other TNOs by 31st December each year to enable them in the timely preparation of TSEP.

PC 4.3. Transmission System Expansion Plan

PC 4.3.1. Each TNO shall develop proposals for the transmission network expansion for the networks it owns or operates. Following aspects shall be duly considered by the TNOs while developing its proposals:

(a) Expansions or reinforcements which are considered priority to comply with its Licence obligations;

(b) Expansions aimed to eliminate Congestion and/or to reduce losses;

(c) Transmission expansions to allow connection of additional generation capacity being commissioned in its territory under the IGCEP;

(d) Any recommendations of the SO in the ASRAIR.

PC 4.3.2. The NGC shall liaise and coordinate with other TNOs in order to consolidate their proposals and/or proposing alternative solutions which it may consider more appropriate from a technical and economic point of view.

PC 4.3.3. The NGC shall submit this consolidated proposal to the SO as a centralized TSEP not later than 31st March each year. This submission should cover a period of ten (10) years, or more if it considers more appropriate. The NGC submission shall clearly indicate a list of the TNOs that fully adhere to the solution proposed by the NGC and those which do not agree with the solution. In such case, a techno-economic analysis shall be included in the proposal, to support the solution proposed.

PC 4.3.4. Any TNO which does not agree with the proposal submitted by NGC or it considers that an alternative solution should be considered, shall submit such proposal to the SO, along with its techno-economic analysis and appropriate justifications.

PC 4.3.5. The SO shall review the TSEP, incorporating any improvements required based on its observations and analyses submitted by the TNOs, and submit it to the Authority for approval along with the IGCEP, as part of the Integrated System Plan, not later than 30th April each year.

PC 4.3.6. The TSEP shall recommend specific transmission system reinforcements, upgradation, and expansion projects and evaluate the corresponding investment requirements, which are calculated based on the preliminary/feasibility cost estimates. The proposed transmission system projects may entail new transmission lines, new grid stations, new transformer installations, extension/augmentation of transformers and substations including bus expansions, reactive power compensation equipment (shunt and/or series compensation), power quality compensation equipment and upgradation of switchgear, etc. The identified transmission system requirements shall be proposed based on the stipulated technical criteria indicated in the "Transmission Planning Criteria & Standards" document.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

PC 4.4. Transmission Investment Plans

PC 4.4.1. Each TNO shall prepare a Transmission Investment Plan in conformance with the centralized TSEP, approved by the Authority, for its respective territory on an annual basis for a horizon of at least five (5) years. These plans shall specify project-wise, year-by-year investment requirements for developing the required transmission facilities along with their commissioning dates. Each TNO shall submit its TIP to the Authority for approval in accordance with the Applicable Documents, but no later than three (03) months from the date of approval of the TSEP.

PC 4.4.2.

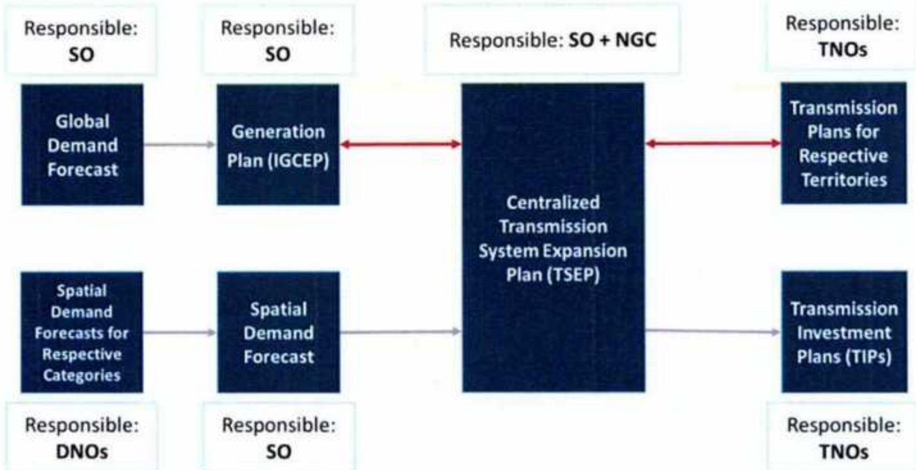


Figure PC 1 Integrated System Planning

PC 4.5. Connection Studies

PC 4.5.1. During the evaluation of any User's application for the new Connection or modification to its existing Connection, three level of studies may be performed at two different stages of User's Development application as outlined in CC 2, i.e.:

(a) At the "Intention Application" stage, "Feasibility Study" shall be performed whereas;

(b) At the "Formal Application" stage, "System Impact Assessment Studies" (SIAS) and "Facility Assessment Study" shall be performed.

PC 4.5.2. The scope of "Feasibility Study" shall include evaluation of the possible connection options and availability of transmission capacity, based on the load flow analysis, as well as providing budgetary cost estimates. The outcome of the Feasibility Study shall establish most feasible connection option as input to SIAS.

PC 4.5.3. The scope of SIAS shall include the evaluation and recommendation of the most appropriate transmission interconnection, system reinforcement and expansion requirements after the incorporation of the User's project development without compromising security and stability of the integrated Power System. This evaluation shall be based on at least load flow, short circuit and transient stability studies. If deemed necessary, any other advance level studies, as outlined in TPCS 2.3, may be performed by the responsible entity.

PC 4.5.4. Based on the results of SIAS, "Facility Assessment Study" shall be performed to quantify the changes/modifications as well as the reinforcement facilities that maybe required to implement in the transmission network after incorporation of the User's project. Preparation of a detailed cost estimate to the User for the proposed transmission interconnection and reinforcement facilities also falls under the scope of this study.

PC 4.5.5. For Generators, applying for any User Development, SO shall perform or cause to perform the "Feasibility Study" and/or the "System Impact Assessment Studies". SO shall share the results of these studies to the relevant TNO to perform the "Facility Assessment Study". TNO shall submit the results of the "Facility Assessment Study" to the SO for concurrence. Consequently, SO shall allow the TNO to issue "Offer to Connect" to the User.

PC 4.5.6. For Demand Users, applying for any User Development, respective TNOs shall perform or cause to perform the required Connection Studies and submit them to the SO for concurrence. Consequently, SO shall allow the TNO to issue "Offer to Connect" to the User.

PC 4.5.7. The SO or the relevant TNO (as the case maybe) may conduct the required studies in-house or may ask the User to engage any eligible consultant to perform these studies in compliance with the standards defined in the "Transmission Planning Criteria & Standards" document.

PC 4.5.8. User's projects connecting at the distribution Voltage shall be reviewed and approved by the involved DNOs.

PC 5. PLANNING CRITERIA AND STANDARDS

The Transmission Planning Criteria and Standards document defines all the criteria and standards according to which planning activities shall be performed, established in the Annex Transmission Planning Criteria & Standards.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Appendices

The appendices specify the data to be submitted to the SO by Users or prospective Users of the Transmission System. The requirement to provide data is governed by the Planning Code PC 3.

The specific data requirements depend on whether the User is a Bulk Power Consumer/Demand User or a Generator or Interconnector/HVDC or an External Party in general or more than one combined. Appendices have following two parts:

Part-1 Standard Planning Data

PC A1. Applies to all Users

PC A2. Applies to all Users

Part-2 Project Planning Data

PC A3. Applies to Generators

PC A4. Applies to Controllable Solar, Wind and ESPP

PC A5. Applies to Interconnector/HVDC

Any material changes to the data specified in PC A3., PC A4. And PC A5. must be notified to the SO as soon as practicable.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Appendix Part-1 **STANDARD PLANNING DATA**

PC A1. **GENERAL INFORMATION**

All Users connected directly through existing Connection Points to the Transmission System or seeking a direct Connection shall provide to the SO or the relevant TNO (as the case may be) the data on their Systems, which relates to the Connection Site which may have an effect on the performance of the Transmission System.

PC A1.1 Full name of the User

PC A1.2 Address of the User

PC A1.3 Contact Person

PC A1.4 Telephone Number

PC A1.5 Telefax Number

PC A1.6 Email Address

PC A2. **USER'S SYSTEM DATA**

PC A2.1. **Map and Diagrams**

Provide a 1:50,000 survey map, with the location of the facility clearly marked with an "X". In addition, please specify the survey grid coordinates of the electrical connection point, which is assumed to be at the HV bushings of the grid connected transformer.

Provide a plan of the site (1:200 or 1:500) of the proposed facility, indicating the proposed location for a transmission station compound, location of the connection point, generators, transformers, converter stations, site buildings etc. The plan is to be submitted in hard and soft copy format. A digitized format may be required and should also be provided if available.

PC A2.2. **Licensing and Authorization (For Generation and other applications requested by the SO)**

PC A2.2.1. **Licensee**

Details of any Generator or Interconnector/HVDC Licence held by the applicant, or of any application for a Generator or Interconnector/HVDC Licence.

PC A2.2.2. **Authorization**

Details of any authorization or application for authorization to construct or reconstruct the Generation station, Interconnector/HVDC or other applications requested by the SO for which the connection is being sought.

PC A2.3. **User's System Layout**

PC A2.3.1. Each User shall provide a Single Line Diagram, depicting both its existing and proposed arrangements of load current carrying apparatus relating to both existing and proposed Connection Points.

PC A2.3.2. The Single Line Diagram shall include all parts of the User System operating at transmission Voltage at any User's Site. In addition, the Single Line Diagram must include all parts of the User's sub-transmission system.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

If the SO or the relevant TNO requires, the Single Line Diagram shall also contain additional details of the User's sub-transmission System not already included above, and also details of the transformers connecting the User's sub-transmission system to a lower Voltage.

PC A2.3.3. The Single Line Diagram shall also include:

(a) Electrical circuitry identifying overhead lines, underground cables, power transformers reactive compensation equipment and similar equipment etc.

(b) Name of the substation with operating Voltages.

(c) Circuit breakers isolators, current transformers, potential transformers, protection data.

PC A2.3.4. For each circuit shown on the Single Line Diagram, the User shall provide the following circuit parameters details relating to that part of its system:

Circuit Parameters

(a) Rated Voltage (kV)

(c) Line Length (km)

(d) Conductor Name & number of bundles.

(e) Type of Tower

(f) Positive phase sequence reactance

(g) Positive phase sequence resistance

(h) Positive phase sequence susceptance

(i) Zero phase sequence reactance

(j) Zero phase sequence resistance

(k) Zero phase sequence susceptance

(l) Thermal Limits/Surge Impedance Loading of conductor.

PC A2.3.5. For each transformer shown on the Single Line Diagram, the User shall provide the following details:

(a) Rated MVA

(b) Voltage Ratio

(c) Winding arrangement

(d) Percentage Impedance

(e) Positive sequence reactance for all windings

(f) Positive sequence resistance for all windings

(g) Zero sequence reactance for all windings

(h) Vector Group

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PC A2.3.6. In addition, for all interconnecting transformers of the Users connected to the Transmission System shall supply the following information:

(a) Earthing system details i.e. direct, resistance or reactance impedance (if not directly earthed).

(b) Tap changer range

(c) Tap change step size

(d) Tap changer type

PC A2.3.7. The User shall supply the following information about the User's equipment installed at a Connection Site, which is owned, operated or managed by TNO:

(a) Switchgear: User shall provide the following parameters for the circuit breakers.

(i) Rated Voltage (kV)

(ii) Operating Voltage (kV)

(iii) Rated 3-phase rms short-circuit breaking current, (kA)

(iv) Rated 1-phase rms short-circuit breaking current, (kA)

(v) Rated 3-phase peak short-circuit making current, (kA)

(vi) Rated 1-phase peak short-circuit making current, (kA)

(vii) Rated rms continuous current (A)

(viii) DC time constant applied at testing of asymmetrical breaking abilities ("seconds" or "s".)

(b) Substation Infrastructure: User shall provide the following parameters for the installed electrical equipment.

(i) Rated 3-phase rms short-circuit withstand current, (kA)

(ii) Rated 1-phase rms short circuit withstand current, (kA)

(iii) Rated 3-phase short-circuit peak withstand current, (kA)

(iv) Rated 1-phase short-circuit peak withstand current, (kA)

(v) Rated duration of short circuit withstand (sec)

(vi) Rated rms continuous current (A)

(c) Detailed short circuit data for single-point or multi-point connection sites.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PC A2.3.8. **Lumped System Susceptance**

For all parts of the User's Sub-Transmission System, which are not included in the Single Line Diagram provided under PC A.2.1.1., each User shall provide the equivalent lumped shunt susceptance at Nominal Frequency.

PC A2.3.9. **Reactive Compensation Equipment**

For all independently switched reactive power compensation equipment, including that shown on the Single Line Diagram, not owned by TNO and connected to the

User's System at 66 kV and above, other than power factor correction equipment associated directly with User's Plant and Apparatus, the User shall supply the following information.

(a) Type of equipment (e.g. fixed or switched or variable);

(b) Capacitance and/or inductive rating or its operating range in MVAR;

(c) Details of any automatic control logic to enable operating characteristics to be determined;

(d) The Connection Point to the User's system in terms of electrical location and system Voltage; and

(e) Voltage assessment studies of the User system if it is a generator of weak reactive power capability or if it is a load of high reactive demand causing Power Quality issues e.g. arc furnace, etc. (with and without reactive compensation equipment).

PC A2.3.10. **Short Circuit Contribution to the Transmission System**

General

(a) To allow the SO or the relevant TNO to calculate fault currents, each User is required to provide data and short circuit analysis of its system; calculated in accordance with IEC 60909, as set out in the following paragraphs;

(b) The data should be provided for the User's system with all Generating Units synchronized to the User's System. The User must ensure that the pre-fault network conditions reflect a credible system operating arrangement;

(c) The list of data items required, in whole or part, under the following provisions. Each of the relevant following provisions identifies which data items in the list are required for the situation with which that provision deals;

(d) The SO or the relevant TNO may at any time, in writing, specifically request for data to be provided for any alternative system condition, for example minimum plant, and the User shall provide the information as soon as reasonably practicable following the request.

The fault current in sub-paragraphs (a) and (b) of the data list should be based on an AC load flow that takes into account any pre-fault current flow across the Connection Point being considered. Measurements made under appropriate system conditions may be used by the User to obtain the relevant data.

Generator's Data for Short Circuit Calculations

For each Generating Unit with one or more associated Station Transformers, the Generator is required to provide values for the contribution of the Generator auxiliaries (including auxiliary gas turbines or auxiliary diesel engines) to the fault current flowing through the Station Transformers.

(a) Root mean square of the symmetrical three-phase short circuit current in feed at the instant of fault;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(b) Root mean square of the symmetrical three-phase short circuit after the sub-transient fault current contribution has substantially decayed;

(c) If the associated generating unit step-up transformer can supply zero phase sequence current from the generating unit side to the Transmission System;

(d) If the value is not 1.0 pu as per IEC 60909;

(e) Root mean square of the pre-fault Voltage at which the maximum fault currents were calculated.

If the Generator has separate Station Transformers, data should be provided for the fault current contribution from each transformer at its high Voltage terminals, assuming a fault at that location, as follows:-

Data for the fault in feeds through both step-up Transformers and Stations Transformers shall be provided for the normal running arrangement when the maximum number of Generating Units in the Power Station are synchronized to the System.

Data Items

The following is the list of data utilized in this part of the Planning Code:

(a) Root mean square of the symmetrical three-phase short circuit current in feed at the instant of fault;

(b) Root mean square of the symmetrical three-phase short circuit after the sub-transient fault current contribution has substantially decayed;

(c) The zero sequence source resistance and reactance values of the User's System as seen from the node on the Single Line Diagram provided;

(d) Root mean square of the pre-fault Voltage at which the maximum fault currents were calculated;

(e) The positive sequence X/R ratio at the instant of fault; and

(f) The negative sequence resistance and reactance values of the User's System seen from the node on the Single Line Diagram.

PC A2.4. **Data Required for Demand Forecasting**

1. Data required by the SO for the preparation of the Spatial Demand Forecast includes (but not limited to) the following;

a. Data required from the TNOs (as applicable)

i. Annual recorded and computed peak demand with month, date and time

ii. Annual electricity consumption (GWh) by category;

iii. Annual distribution losses;

iv. Annual secondary transmission losses (132 kV);

v. Future loss reduction plan;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

b. **Substation level data**

   i. Substation wise peak demand with substation name and unique identifier

   ii. Coincidence factor

   iii. Relevant data of proposed substations

c. **11 kV Feeder level data**

   i. Feeder code, name and category

   ii. Category-wise planned load

   iii. Category-wise pending load

   iv. Captive load (kW and kWh)

   v. Net metering/roof top solar data

2. Data required by the SO for the preparation of the Global Demand Forecast includes (but not limited to) the following:

   a. Annual energy generation (GWh)

   b. Category-wise energy consumption (GWh)

   c. Recorded and computed peak demand (MW)

   d. Hourly load data

   e. Yearly system losses

      i. Primary and secondary transmission losses

      ii. Distribution system losses

   f. Electricity average price (PKR/kWh) by category

   g. Historical and projected sector-wise gross domestic product (GDP)

   h. Load shedding/Load management data

   i. Demand side management targets by NEECA

   j. Category-wise number of consumers

   k. Historical and projected population of country

   l. Any other potential variable that may affect the Demand growth

   Based on the above data, Active Power (MW) and Active Energy requirements (MWh) of the system shall be calculated.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PC A2.5. **Data Required for Indicative Generation Capacity Expansion Plan**

Table PC A-1: Data Requirement of Bagasse/Co-generation/Waste to Energy/Solid Waste Management-based Generator for IGCEP

Data Pro forma for Bagasse/Co-generation/Waste to Energy/Solid Waste Management-based Power Plant		
Sr. No.	**Particulars**	**Details**
1	Project Executing Agency Name	
2	Name of Project Representative	
3	Designation of Representative	
4	Contact number	
5	Email Address	
6	Name of Project	
7	Nature of Project (Public, Private, G2G, Strategic, Others)	
8	Other Project Nature (if any)	
9	Installed Capacity (MW)	
10	De-Rated/Dependable Capacity (MW)	
11	Auxiliary Capacity (MW)	
12	Other Project Type (If any)	
13	Current Status of the Project (Existing, FS, LOI (Issued)/PC-2 Approved (for Public Sector Projects only),LOS Issued, Financial Close (Achieved)/PC-1 Approved (for Public Sector Projects only, Feasibility Study Approved by POE)	
14	Date of Approval of Feasibility Study (dd-mm-yy)	
15	Financial Close Date (for Private Sector plants only)	
16	Is Financing Secured? (for Public Sector Plants only)	
17	Source of Financing	
18	PC-1/LOS Approval Date (dd-mm-yy)	
19	Date of Licensing or Registration with NEPRA (dd-mm-yy)	
20	Location and site coordinates of project	
21	Interconnection Voltage level (kV)	
22	Dispatching Arrangement	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

23	Region of Project (Gilgit, AJK, KE, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO, GEPCO, TESCO, PESCO)	
24	Interconnection Study Conducted (Yes/No)	
25	Distance to Nearest Grid (km)	
26	Dispatching Arrangement (NPCC, DISCO)	
27	Construction start date (dd-mm-yy)	
28	Percentage of construction work completed (%)	
29	Expected Commissioning date of all unit (dd-mm-yy)	
30	Total Construction period (months)	
31	Economic Life of Plant (years)	
32	De-commissioning date (dd-mm-yy)	
33	Power Purchase Agreement expiry date (dd-mm-yy)	
34	Fuel Type	
35	Unit of Fuel Rate ($/GJ, $/Metric Ton)	
36	Fuel Rate	
37	Financial Year of cost Calculation for Fuel Rate (Year)	
38	Dollar Conversion Rate for fuel rate (1$=PKR)	
39	Unit of Heating Value (kCal/kg)	
40	Heating Value of Fuel	
41	Capacity of each Unit (MW)	
42	Total Number of Units	
43	Annual Capacity Factor for Export to grid (%)	
44	Schedule Maintenance Time Annual (days)	
45	Estimated forced outage rate annual (%)	
46	Estimated mean time to repair during forced outage (Hours)	
47	Variable O&M (USD/MWh)	
48	Financial Year of Cost Calculation for Variable O&M (Year)	
49	Dollar Conversion Rate for Variable O&M (1$=PKR)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

50	Fixed O&M (USD/kW-year)	
51	Financial Year of Cost Calculation for Fixed O&M (Year)	
52	Dollar Conversion Rate for Fixed O&M (1$=PKR)	
53	Capital Cost with IDC – Local Component (million USD)	
54	Capital Cost with IDC –Foreign Component (million USD)	
55	Capital Cost with IDC -Total (million USD)	
56	Capital Cost without IDC – Local Component (million USD)	
57	Capital Cost without IDC -Foreign Component (million USD)	
58	Capital Cost without IDC -Total (million USD)	
59	Financial Year of Cost Calculations (Year)	
60	Dollar Conversion Rate (1$=PKR)	
61	Spur Cost of Transmission	
62	Financial Year of Cost Calculation for Spur Cost (Year)	
63	Dollar Conversion Rate for Spur Cost (1$=PKR)	
64	Monthly Total Energy (GWh)	
65	Monthly Peak Capability (MW)	
66	Any other information	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Table PC A-2: Data Requirement of Batteries for IGCEP

Data Pro forma for Batteries		
Sr. No.	**Particulars**	**Details**
1	Project Executing Agency Name	
2	Name of Project Representative	
3	Designation of Representative	
4	Contact number	
5	Email Address	
6	Name of Project	
7	Nature of Project (Public, Private, G2G, Strategic, Others)	
8	Other Project Nature (if any)	
9	Installed Capacity (MW)	
10	Storage Capacity (MWh)	
11	Current Status of the Project (Existing, FS, LOI (Issued)/PC-2 Approved (for Public Sector Projects only),LOS Issued, Financial Close (Achieved)/PC-1 Approved (for Public Sector Projects only, Feasibility Study Approved by POE)	
12	Date of Approval of Feasibility Study (dd-mm-yy)	
13	Financial Close Date (for Private Sector plants only)	
14	Is Financing Secured? (for Public Sector Plants only)	
15	Source of Financing	
16	PC-1/LOS Approval Date (dd-mm-yy)	
17	Date of Licensing or Registration with NEPRA (dd-mm-yy)	
18	Location and site coordinates of project	
19	Interconnection Voltage level (kV)	
20	Dispatching Arrangement	
21	Region of Project (Gilgit, AJK, KE, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO, GEPCO, TESCO, PESCO)	
22	Interconnection Study Conducted (Yes/No)	
23	Distance to Nearest Grid (km)	
24	Dispatching Arrangement (NPCC, DISCO)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

25	Construction start date (dd-mm-yy)	
26	Percentage of construction work completed (%)	
27	Expected Commissioning date of all unit (dd-mm-yy)	
28	Total Construction period (months)	
29	Economic Life of Plant (years)	
30	De-commissioning date (dd-mm-yy)	
31	Capacity of each Unit (MW)	
32	Total Number of Units	
33	Max Power Export to Grid (MW)	
34	Charge Efficiency (%)	
35	Discharge Efficiency (%)	
36	Ramp Up Rate (MW/min)	
37	Ramp Down Rate (MW/min)	
38	Maximum State of Charge (SoC) (%)	
39	Depth of Discharge (%)	
40	Per cycle power (MW) Degradation Factor (%)	
41	Per Cycle capacity (MWh) Degradation factor (%)	
42	Maximum Cycles	
43	Variable O&M (USD/MWh)	
44	Financial Year of Cost Calculation for Variable O&M (Year)	
45	Dollar Conversion Rate for Variable O&M (1$=PKR)	
46	Fixed O&M (USD/kW-year)	
47	Financial Year of Cost Calculation for Fixed O&M (Year)	
48	Dollar Conversion Rate for Fixed O&M (1$=PKR)	
49	Capital Cost with IDC (Local Component) million USD	
50	Capital Cost with IDC (Foreign Component) million USD	
51	Capital Cost with IDC (Total) million USD	
52	Capital Cost without IDC (Local Component) million USD	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

53	Capital Cost without IDC (Foreign Component) million USD	
54	Capital Cost without IDC (Total) million USD	
55	Financial Year of Cost Calculations (Year)	
56	Dollar Conversion Rate (1$=PKR)	
57	Spur Cost of Transmission	
58	Financial Year of Cost Calculation for Spur Cost (Year)	
59	Dollar Conversion Rate for Spur Cost (1$=PKR)	
60	Any other information	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Table PC A-3: Data Requirement of Hydro Generator for IGCEP

Data Pro forma for Hydropower Plant		
Sr. No.	**Particulars**	**Details**
1	Project Executing Agency Name	
2	Name of Project Representative	
3	Designation of Representative	
4	Contact number	
5	Email Address	
6	Name of Project	
7	Nature of Project (Public, Private, G2G, Strategic, Others)	
8	Other Project Nature (if any)	
9	Installed Capacity (MW)	
10	Auxiliary Consumption (MW)	
11	Type of project (Run of River, Reservoir)	
12	Current Status of the Project (Existing, FS, LOI (Issued)/PC-2 Approved (for Public Sector Projects only), LOS Issued, Financial Close (Achieved)/PC-1 Approved (for Public Sector Projects only, Feasibility Study Approved by POE)	
13	Date of Approval of Feasibility Study (dd-mm-yy)	
14	Financial Close Date (for Private Sector plants only)	
15	Is Financing Secured? (for Public Sector Plants only)	
16	Source of Financing	
17	PC-1/LOS Approval Date (dd-mm-yy)	
18	Date of Licensing or Registration with NEPRA (dd-mm-yy)	
19	Location and site coordinates of project	
20	Interconnection Voltage level (kV)	
21	Dispatching Arrangement	
22	Region of Project (Gilgit, AJK, KE, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO, GEPCO, TESCO, PESCO)	
23	Interconnection Study Conducted (Yes/No)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

24	Distance to Nearest Grid (km)	
25	Dispatching Arrangement (NPCC, DISCO)	
26	Construction start date (dd-mm-yy)	
27	Percentage of construction work completed (%)	
28	Expected Commissioning date of all unit (dd-mm-yy)	
29	Total Construction period (months)	
30	Economic Life of Plant (years)	
31	De-commissioning date (dd-mm-yy)	
32	Capacity of each Unit (MW)	
33	Total Number of Units	
34	Ramp Up Rate (For Whole Complex)(MW/min)	
35	Ramp Down Rate (For Whole Complex) (MW/min)	
36	Annual Schedule Maintenance Time (Per Unit)(days)	
37	Expected forced outage rate annual (Per Unit) (%)	
38	Expected mean time to repair during forced outage (Hours)	
39	Variable O&M (USD/MWh)	
40	Financial Year of Cost Calculation for Variable O&M (Year)	
41	Dollar Conversion Rate for Variable O&M (1$=PKR)	
42	Fixed O&M (USD/kW-year)	
43	Financial Year of Cost Calculation for Fixed O&M (Year)	
44	Dollar Conversion Rate for Fixed O&M (1$=PKR)	
45	Storage Capacity (GWh)	
46	Storage Capacity (GWh)	
47	Water Head of Storage (Meters)	
48	Volume of Reservoir (Cubic meters)	
49	Efficiency of Reservoir (%)	
50	Capital Cost with IDC (Local Component) million USD	
51	Capital Cost with IDC (Foreign Component) million USD	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

52	Capital Cost with IDC (Total) million USD	
53	Capital Cost without IDC (Local Component) million USD	
54	Capital Cost without IDC (Foreign Component) million USD	
55	Capital Cost without IDC (Total) million USD	
56	Financial Year of Cost Calculations (Year)	
57	Dollar Conversion Rate (1$=PKR)	
58	Spur Cost of Transmission	
59	Financial Year of Cost Calculation for Spur Cost (Year)	
60	Dollar Conversion Rate for Spur Cost (1$=PKR)	
61	Monthly Total Energy (GWh) (Average Season)	
62	Monthly Minimum/Base Energy (GWh) (Average Season)	
63	Monthly Maximum Capability (MW) (Average Season)	
64	Monthly Total Energy (GWh) (Wet Season)	
65	Monthly Minimum/Base Energy (GWh) (Wet Season)	
66	Monthly Maximum Capability (MW) (Wet Season)	
67	Monthly Total Energy (GWh) (Dry Season)	
68	Monthly Minimum/Base Energy (GWh) (Dry Season)	
69	Monthly Maximum Capability (MW) (Dry Season)	
70	Any other information	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Table PC A-4: Data Requirement of Solar Generator for IGCEP

Data Pro forma for Solar PV Power Plant		
Sr. No.	**Particular**	**Details**
1	Project Executing Agency Name	
2	Name of Project Representative	
3	Designation of Representative	
4	Contact number	
5	Email Address	
6	Name of Project	
7	Nature of Project (Public, Private, G2G, Strategic, Others)	
8	Other Project Nature (if any)	
9	Installed Capacity (MW)	
10	Auxiliary Consumption (MW)	
11	Current Status of the Project (Existing, FS, LOI (Issued)/PC-2 Approved (for Public Sector Projects only),LOS Issued, Financial Close (Achieved)/PC-1 Approved (for Public Sector Projects only, Feasibility Study Approved by POE)	
12	Date of Approval of Feasibility Study (dd-mm-yy)	
13	Financial Close Date (for Private Sector plants only)	
14	Is Financing Secured? (for Public Sector Plants only)	
15	Source of Financing	
16	PC-1/LOS Approval Date (dd-mm-yy)	
17	Date of Licensing or Registration with NEPRA (dd-mm-yy)	
18	Location and site coordinates of project	
19	Interconnection Voltage level (kV)	
20	Dispatching Arrangement	
21	Region of Project (Gilgit, AJK, KE, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO, GEPCO, TESCO, PESCO)	
22	Interconnection Study Conducted (Yes/No)	
23	Distance to Nearest Grid (km)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

24	Dispatching Arrangement (NPCC, DISCO)	
25	Construction start date (dd-mm-yy)	
26	Percentage of construction work completed (%)	
27	Expected Commissioning date of all unit (dd-mm-yy)	
28	Total Construction period (months)	
29	Economic Life of Plant (years)	
30	De-commissioning date (dd-mm-yy)	
31	Capacity of each Unit (MW)	
32	Total Number of Units	
33	Annual Capacity Factor for export to grid (%)	
34	Variable O&M (USD/MWh)	
35	Financial Year of Cost Calculation for Variable O&M (Year)	
36	Dollar Conversion Rate for Variable O&M (1$=PKR)	
37	Fixed O&M (USD/kW-year)	
38	Financial Year of Cost Calculation for Fixed O&M (Year)	
39	Dollar Conversion Rate for Fixed O&M (1$=PKR)	
40	Capital Cost with IDC (Local Component) million USD	
41	Capital Cost with IDC (Foreign Component) million USD	
42	Capital Cost with IDC (Total) million USD	
43	Capital Cost without IDC (Local Component) million USD	
44	Capital Cost without IDC (Foreign Component) million USD	
45	Capital Cost without IDC (Total) million USD	
46	Financial Year of Cost Calculations (Year)	
47	Dollar Conversion Rate (1$=PKR)	
48	Spur Cost of Transmission	
49	Financial Year of Cost Calculation for Spur Cost (Year)	
50	Dollar Conversion Rate for Spur Cost (1$=PKR)	
51	Battery (or other energy storage) connected (Yes/No)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

52	Type of Batteries	
53	Installed Capacity of Project (MW)	
54	Storage Capacity of Project (MWh)	
55	Expected COD of BESS	
56	Charge Efficiency (%)	
57	Discharge Efficiency (%)	
58	Ramp Up Rate (MW/min)	
59	Ramp Down Rate (MW/min)	
60	Maximum State of Charge (SoC) (%)	
61	Depth of Discharge (%)	
62	Per cycle power (MW) Degradation Factor (%)	
63	Per Cycle capacity (MWh) Degradation factor (%)	
64	Maximum Cycles	
65	Technical Life (Years)	
66	Fixed O&M Cost $/kW-year	
67	Capital Cost with IDC (Local Component) million USD	
68	Capital Cost with IDC (Foreign Component) million USD	
69	Cost with IDC (Total) million USD	
70	Capital Cost without IDC (Local Component) million USD	
71	Capital Cost without IDC (Foreign Component) million USD	
72	Capital Cost without IDC (Total) million USD	
73	Financial Year of Cost Calculations (Year)	
74	Dollar Conversion Rate (1$=PKR)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Table PC A-5: Data Requirement of Wind Generator for IGCEP

Data Pro forma for Wind Power Plants		
Sr. No.	**Particulars**	**Details**
1	Project Executing Agency Name	
2	Name of Project Representative	
3	Designation of Representative	
4	Contact number	
5	Email Address	
6	Name of Project	
7	Nature of Project (Public, Private, G2G, Strategic, Others)	
8	Other Project Nature (if any)	
9	Installed Capacity (MW)	
10	Auxiliary Consumption (MW)	
11	Current Status of the Project (Existing, FS, LOI (Issued)/PC-2 Approved (for Public Sector Projects only), LOS Issued, Financial Close (Achieved)/PC-1 Approved (for Public Sector Projects only, Feasibility Study Approved by POE)	
12	Date of Approval of Feasibility Study (dd-mm-yy)	
13	Financial Close Date (for Private Sector plants only)	
14	Is Financing Secured? (for Public Sector Plants only)	
15	Source of Financing	
16	PC-1/LOS Approval Date (dd-mm-yy)	
17	Date of Licensing or Registration with NEPRA (dd-mm-yy)	
18	Location and site coordinates of project	
19	Interconnection Voltage level (kV)	
20	Dispatching Arrangement	
21	Region of Project (Gilgit, AJK, KE, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO, GEPCO, TESCO, PESCO)	
22	Interconnection Study Conducted (Yes/No)	
23	Distance to Nearest Grid (km)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

24	Dispatching Arrangement (NPCC, DISCO)	
25	Construction start date (dd-mm-yy)	
26	Percentage of construction work completed (%)	
27	Expected Commissioning date of all unit (dd-mm-yy)	
28	Total Construction period (months)	
29	Economic Life of Plant (years)	
30	De-commissioning date (dd-mm-yy)	
31	Capacity of each Unit (MW)	
32	Total Number of Units	
33	Annual Capacity Factor for export to grid (%)	
34	Number of Turbines (#)	
35	Capacity of each Turbine (MW)	
36	Variable O&M (USD/MWh)	
37	Financial Year of Cost Calculation for Variable O&M (Year)	
38	Dollar Conversion Rate for Variable O&M (1$=PKR)	
39	Fixed O&M (USD/kW-year)	
40	Financial Year of Cost Calculation for Fixed O&M (Year)	
41	Dollar Conversion Rate for Fixed O&M (1$=PKR)	
42	Capital Cost with IDC (Local Component) million USD	
43	Capital Cost with IDC (Foreign Component) million USD	
44	Capital Cost with IDC (Total) million USD	
45	Capital Cost without IDC (Local Component) million USD	
46	Capital Cost without IDC (Foreign Component) million USD	
47	Capital Cost without IDC (Total) million USD	
48	Financial Year of Cost Calculations (Year)	
49	Dollar Conversion Rate (1$=PKR)	
50	Spur Cost of Transmission	
51	Financial Year of Cost Calculation for Spur Cost (Year)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

52	Dollar Conversion Rate for Spur Cost (1$=PKR)	
53	Battery (or other energy storage) connected (Yes/No)	
54	Type of Batteries	
55	Installed Capacity of Project (MW)	
56	Storage Capacity of Project (MWh)	
57	Expected COD of BESS	
58	Charge Efficiency (%)	
59	Discharge Efficiency (%)	
60	Ramp Up Rate (MW/min)	
61	Ramp Down Rate (MW/min)	
62	Maximum State of Charge (SoC) (%)	
63	Depth of Discharge (%)	
64	Per cycle power (MW) Degradation Factor (%)	
65	Per Cycle capacity (MWh) Degradation factor (%	
66	Maximum Cycles	
67	Technical Life (Years)	
68	Fixed O&M Cost $/kW-year	
69	Capital Cost with IDC (Local Component) million USD	
70	Capital Cost with IDC (Foreign Component) million USD	
71	Cost with IDC (Total) million USD	
72	Capital Cost without IDC (Local Component) million USD	
73	Capital Cost without IDC (Foreign Component) million USD	
74	Capital Cost without IDC (Total) million USD	
75	Financial Year of Cost Calculations (Year)	
76	Dollar Conversion Rate (1$=PKR)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
NEPRA

Table PC A-6: Data Requirement of Thermal Generator for IGCEP

Data Pro forma for Thermal Power Plant		
Sr. No.	**Particulars**	**Details**
1	Project Executing Agency Name	
2	Name of Project Representative	
3	Designation of Representative	
4	Contact number	
5	Email Address	
6	Name of Project	
7	Nature of Project (Public, Private, G2G, Strategic, Others)	
8	Other Project Nature (if any)	
9	Installed Capacity (MW)	
10	De-Rated/Dependable Capacity (MW)	
11	Auxiliary Capacity (MW)	
12	Type of project (CCGT, OCGT, Gas ST, Nuclear ST, Coal ST, DG, FO ST, Others	
13	Other Project Type (If any)	
14	Current Status of the Project (Existing, FS, LOI (Issued)/PC-2 Approved (for Public Sector Projects only), LOS Issued, Financial Close (Achieved)/PC-1 Approved (for Public Sector Projects only, Feasibility Study Approved by POE)	
15	Date of Approval of Feasibility Study (dd-mm-yy)	
16	Financial Close Date (for Private Sector plants only)	
17	Is Financing Secured? (for Public Sector Plants only)	
18	Source of Financing	
19	PC-1/LOS Approval Date (dd-mm-yy)	
20	Date of Licensing or Registration with NEPRA (dd-mm-yy)	
21	Location and site coordinates of project	
22	Interconnection Voltage level (kV)	
23	Dispatching Arrangement	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

24	Region of Project (Gilgit, AJK, KE, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO, GEPCO, TESCO, PESCO)	
25	Interconnection Study Conducted (Yes/No)	
26	Distance to Nearest Grid (km)	
27	Dispatching Arrangement (NPCC, DISCO)	
28	Construction start date (dd-mm-yy)	
29	Percentage of construction work completed (%)	
30	Expected Commissioning date of all unit (dd-mm-yy)	
31	Total Construction period (months)	
32	Economic Life of Plant (years)	
33	De-commissioning date (dd-mm-yy)	
34	Power Purchase Agreement expiry date (dd-mm-yy)	
35	Fuel Type (Nuclear, Gas, RLNG, RFO, Imported Coal, Local Coal, Other)	
36	Other Fuel Type (If any)	
37	Unit of Fuel Rate ($/GJ, $/Metric Ton)	
38	Fuel Rate	
39	Financial Year of cost Calculation for Fuel Rate (Year)	
40	Dollar Conversion Rate for fuel rate (1$=PKR)	
41	Unit of Heating Value (kCal/kg)	
42	Heating Value of Fuel	
43	Fuel Price Escalation/De-escalation (%)	
44	Take or Pay contract (%) (if any)	
45	Take or Pay contract expiry date/Period (dd/mm/yyyy)	
46	Reduced Fuel price if Take or Pay Contract cannot be met ($/Metric Ton, $/GJ)	
47	Annual Take or Pay Contract Quantity (TJ)	
48	Capacity of each Unit (MW)	
49	Technology of each unit (GT, ST, DG, GE)	
50	Total number of units	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

51	Minimum Stable Level (Whole Complex) (MW)	
52	CCGT configuration	
53	Ramp Up Rate (Whole Complex) (MW/min)	
54	Ramp Down Rate (Whole Complex) (MW/min)	
55	Minimum Up Time (hours)	
56	Minimum Down Time (hours)	
57	Efficiency at Minimum Stable Level (%)	
58	Efficiency at Full Load (%)	
59	Heat Rate at 25% Load (BTU/kWh)	
60	Heat Rate at 40% Load (BTU/kWh)	
61	Heat Rate at 50% Load (BTU/kWh)	
62	Heat Rate at 60% Load (BTU/kWh)	
63	Heat Rate at 70% Load (BTU/kWh)	
64	Heat Rate at 80% Load (BTU/kWh)	
65	Heat Rate at 90% Load (BTU/kWh)	
66	Heat Rate at 100% Load (BTU/kWh)	
67	Schedule Maintenance Time Annual (days)	
68	Expected forced outage rate annual (%)	
69	Expected mean time to repair during forced outage (Hours)	
70	Emission production rate (gCO_2/MWh)	
71	Variable O&M (USD/MWh)	
72	Financial Year of Cost Calculation for Variable O&M (Year)	
73	Dollar Conversion Rate for Variable O&M (1$=PKR)	
74	Fixed O&M (USD/kW-year)	
75	Financial Year of Cost Calculation for Fixed O&M (Year)	
76	Dollar Conversion Rate for Fixed O&M (1$=PKR)	
77	Capital Cost with IDC (Local Component) million USD	
78	Capital Cost with IDC (Foreign Component) million USD	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

79	Capital Cost with IDC (Total) million USD	
80	Capital Cost without IDC (Local Component) million USD	
81	Capital Cost without IDC (Foreign Component) million USD	
82	Capital Cost without IDC (Total) million USD	
83	Financial Year of Cost Calculations (Year)	
84	Dollar Conversion Rate (1$=PKR)	
85	Spur Cost of Transmission	
86	Financial Year of Cost Calculation for Spur Cost (Year)	
87	Dollar Conversion Rate for Spur Cost (1$=PKR)	
89	Any other information	

Appendix Part-2 **PROJECT PLANNING DATA**

PC A3. **GENERATOR DATA**

PC A3.1. **Generator Unit Details**

Each Generator shall submit to the SO detailed information as required to plan, design, construct and operate the Transmission System.

Table PC A-7: Data Requirement of Generators for IGCEP

Generator Data		
Sr. No.	**Descriptions**	**Data**
1	Expected COD	
2	Coordinates of the Project	
3	Fuel Type	
Generator Basic Data		
4	Generation Voltage Level (kV)	
5	No. of generating units	
6	Power factor (Lagging/Leading) of generating unit	
7	Rated Apparent Power of each generating unit (MVA)	
8	Gross Output of each unit (MW)	
9	Maximum Output in Summer and Winter (Peak and Off-Peak)	
10	Total Auxiliary Load (MW)/Auxiliary Load with each unit	
11	Net Output of each generating unit (MW)	
12	Power factor for Auxiliary Load	
13	RPM of the machine	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

14	Total Inertia Constant H for entire rotating mass (MW-s/MVA) – (Generator + Turbine + Rotating Exciter)		
15	Short circuit ratio of each generating unit		
Reactances for Generator (pu)			
16	Direct Axis Sub-Transient Reactance (X_d'') (unsaturated)		
17	Direct Axis Sub-Transient Reactance (X_d'') (saturated)		
18	Quadrature Axis Sub-Transient Reactance (X_q'') (Unsaturated)		
19	Quadrature Axis Sub-Transient Reactance (X_q'') (saturated)		
20	Direct Axis Transient Reactance (X_d') (unsaturated)		
21	Direct Axis Transient Reactance (X_d')(saturated)		
22	Quadrature Axis Transient Reactance (X_q') (unsaturated)		
23	Quadrature Axis Transient Reactance (X_q') (saturated)		
24	Direct Axis Synchronous Reactance X_d		
25	Quadrature Axis Synchronous Reactance X_q		
26	Leakage Reactance Xl (unsaturated)		
27	Leakage Reactance Xl (saturated)		
28	Negative sequence Reactance X2 (unsaturated)		
29	Negative sequence Reactance X2 (saturated)		
30	Zero-Phase Sequence Reactance X0 (unsaturated)		
31	Zero-Phase Sequence Reactance X0 (saturated)		
Time Constants for Generator (s)			
32	Transient Direct-Axis Open-Circuit Time Constant T_{do}'		
33	Transient Quadrature-Axis Open-Circuit Time Constant T_{qo}'		
34	Transient Direct-Axis Short-Circuit Time Constant T_d'		
35	Transient Quadrature-Axis Short-Circuit Time Constant T_q'		
36	Sub-Transient Direct-Axis Open-Circuit Time Constant T_{do}''		
37	Sub-Transient Quadrature-Axis Open-Circuit Time Constant T_{qo}''		
38	Sub-Transient Direct-Axis Short-Circuit Time Constant T_d''		
39	Sub-Transient Quadrature-Axis Short-Circuit Time Constant T_q''		
Other Factors			
40	Saturation Factors of Generator	S (1.0)	
41		S (1.2)	
42	Characteristic Curves (Saturation, PQ, V-Curve)		
Generator Step-Up (GSU) Transformers			
43	Voltage Rating of GSU transformer (kV)		
44	Vector Group		
45	No. of transformers and generators connected to each transformer		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

46	Transformer Rated Power (MVA)	
47	Type	
48	Percentage Impedance, (R, X) in % at rated MVA base	
49	Total Number of Taps	
50	Principal Tap Number	
Earthing Specifications		
51	Type of Earthing for Generator (Direct, impedance, transformer)	
52	MVA Rating of transformer	
53	Voltage Ratio of transformer	
54	Transformer Impedance Grounding (R, X) (ohm/pu)	

PC A3.2. Excitation System Parameters

Provide parameters and supply a Laplace-domain control block diagram (or as otherwise agreed with the SO) completely specifying all time constants and gains to fully explain the transfer function from the compensator or generator terminal Voltage and field current to generator field Voltage. These parameters may include but are not limited to:

Table PC A-8: Data Requirement of Exciters for GIS

Exciter Data		
Sr. No.	**Description**	**Data**
1	Excitation system type (AC or DC)	
2	Excitation feeding arrangement (solid or shunt)	
3	Excitation system Filter time constant – Tr	
4	Excitation system Lead time constant - Tc	
5	Excitation system Lag time constant - Tb	
6	Excitation system Controller gain - Ka	
7	Excitation system controller lag time constant - Ta	
8	Excitation system Maximum controller output - Vmax	
9	Excitation system minimum controller output - Vmin	
10	Excitation system regulation factor - Kc	
11	Excitation system rate feedback gain - Kf	
12	Excitation system rate feedback time constant - Tf	

For Simulation purpose, the model of the exciter would also be required in IEEE or PTI's PSS/E format.

PC A3.3. Speed Governor System

Supply a Laplace-domain control block diagram and associated parameters of prime mover models for thermal and hydro units (or as otherwise agreed with the **SO**)

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

completely specifying all time constants, gains, droop settings etc. to fully explain the transfer function for the Governor Control System.

For Simulation purpose, the model of the speed governor system would also be required in IEEE or PTI's PSS/E format.

PC A3.4. Power System Stabilizers

Supply a Laplace-domain control diagram and associated parameters for any outstanding control devices including Power System Stabilizer in the generating unit. Some of the critical parameters that are required are:

- Type of inputs;
- Gain for each input;
- Lead Time constants for each input;
- Lag Time constants for each input;
- Power System Stabilizer Model (in IEEE or PTI's PSS/E format).

PC A4. CONTROLLABLE SOLAR, WIND AND ESPP (SWE) DATA REQUIREMENTS

All information for Controllable SWE connection applications shall include details of the Transmission System Connection Point. This shall include details listed in PC A2.1. and PC A2.2. for the Connection Point. The minimum technical, design and operational criteria to be met by Controllable SWE are specified in the Connection Code.

PC A4.1. SWE Generators Parameters

The User shall provide electrical parameters related to the performance of the Controllable SWE. This may include but is not limited to parameters of electrical generator, power electronic converters, and electrical control and/or protection systems. For WTG, State whether turbines are Fixed Speed or Variable Speed. Also provide the Type of WTG i.e. Type-1, Type-2 (Single Fed Induction Generators), Type-3 (Doubly Fed Induction Generator), Type-4 (Full Converter) or else.

Laplace diagrams and associated parameters shall be provided to the SO where appropriate. For Simulation purpose, the Electrical model of the SWE Connection shall also be required in IEEE or PTI's PSS/E format. A sample data sheet for the basic parameters related to wind turbine generators and solar generators are provided below:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Table PC A-9: Data Requirement of WTG for GIS

	Wind Turbine Generator (WTG) Data	
Sr. No.	**Description**	**Data**
1	Expected COD of Generator	
2	Generation Type	
3	No. of WTGs	
4	Manufacturer/Model	
5	Gross Capacity of each WTG (MW)	
6	Type of WTG	
7	Generation Voltage (kV)	
8	Power Factor (Lagging/Leading)	
9	Ramp Up/Down Rate (MW/Min) or (%/Min)	
WTG Arrangement in Wind Farm		
10	No. of Collector Groups	
11	No. of WTGs in one collector group	
12	Length of each collector group within the switchyard (km)	
Total Wind Farm Capacity		
13	Total Gross Capacity (MW)	
14	EBOP Losses (MW)	
15	Auxiliary Consumption (MW)	
16	Total Net Output Capacity that will flow to the grid (MW)	
Generator Step Up Transformer Data		
17	No. of step up transformers	
18	Voltage Ratio (kV)	
19	MVA Rating	
20	Percentage Impedance %	
21	Vector Group	
Proposed Switchyard of Wind Power Project		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

22	High Level (HV) Voltage	
23	Medium Level (MV) Voltage	
24	Proposed Bus Bar Scheme	
25	Proposed Bus Bar Capacity (Ampere)	
26	Proposed Circuit Breaker Capacity at HV Level (kA)	
Power Transformer from HV to MV Level		
27	No. of transformers	
28	Voltage Ratio (kV)	
29	MVA Rating	
30	Percentage Impedance %	
31	Vector Group	
Proposed Reactive Power Compensation		
32	Proposed size of Reactive Power Compensation Equipment (MVAR) installed at MV or HV	
Miscellaneous		
33	Proposed reactance for each collector group X_d'' (pu)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Table PC A-10: Data Requirement of Solar Generator for GIS

Solar Generator Data		
Sr. No.	**Particulars**	**Data**
1	Expected COD	
2	Generation Type	
3	Generation Voltage Level (kV)	
4	Medium Voltage Level (kV)	
5	High Voltage Level (kV)	
6	No. of inverter units	
7	No. of Clusters made for Inverters	
8	AC Cable Lengths (km)	
9	Power factor	
10	DC power Connected to each unit (MW)	
11	AC power output of each unit (MW)	
12	Rated Apparent Power of each inverter unit (MVA)	
13	Total Installed DC Capacity of Plant (MW)	
14	Gross AC Output of the Plant (MW)	
15	Reactive Power Compensation Requirement (MVAR) SVC/Switched shunt Capacitor Bank, installed at MV or HV	
16	Ramp Up/Down Rate (MW/Min) or (%/Min)	
GSU Transformers		
17	No. of GSU transformers (MV/LV kV)	
18	Transformer Rated Power (MVA)	
19	Vector Group	
20	Percentage Impedance	
Step-up Power Transformer for Grid End		
21	No. of GSU transformers (HV/MV kV)	
22	Transformer Rated Power (MVA)	
23	Vector Group	
24	Percentage Impedance	

Note: Most of the initial planning studies of WTGs are carried out using the generic models in PSS/E format. Therefore, WTGs shall submit their Users' specific controller models in PSS/E format of proposed WTGs once the manufactures provide this data to such Users. If Users' specific data is significantly different from the generic model, then the studies shall be carried out again and charges of studies shall be borne by these Users.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

PC A4.2. **Mechanical parameters**

For SWE Connections, the mechanical parameters related to the performance of the plant are required. For WTG, this may include but is not limited to the drive train characteristics of the WTG, the stiffness of the shaft of the WTG, Total Inertia constant "H" and/or a multi-mass model of the WTG components. Laplace diagrams and associated parameters shall be provided to the SO where appropriate.

For Simulation purpose, the Mechanical model of the SWE Connection shall also be required in IEEE or PTI's PSS/E format.

PC A4.3. **Aerodynamic performance**

Provide details on the aerodynamic performance of the Wind Turbine Generator. This may include but is not limited to variation of power co-efficient with tip speed ratio and WTG blade pitch angle, aerodynamic disturbance from WTG tower, WTG blade pitch control and high and low wind speed performance of the WTG. Laplace diagrams and associated parameters shall be provided to the SO where appropriate.

For Simulation purpose, the Pitch model of the SWE Connection shall also be required in IEEE or PTI's PSS/E format.

PC A4.4. **Reactive Power Compensation**

Provide details of any additional reactive power compensation devices and control systems employed by the Controllable SWE. This shall include MVAR capability, the number of stages in the device and the MVAR capability switched in each stage and any control or protection systems that influence the performance of the Controllable SWE at the Connection Point. Laplace diagrams and associated parameters shall be provided to the SO where appropriate. Detailed model, if it is a compensator e.g. Static VAR Compensator (SVC) or Static VAR Generator (SVG) or STATCOM or else. For Simulation purpose, the model of the reactive power compensation device shall also be required in IEEE or PTI's PSS/E format.

PC A4.5. **Control and Protection systems**

Provide details of any control or protection systems that affect the performance of the Controllable SWE at the Connection Point. This shall include any systems or modes of operation that activate during system Voltage or Frequency excursions including Low Voltage Ride Through (LVRT), High Voltage Ride Through (HVRT), Low Frequency Response and High Frequency Response. The transition between Controllable SWE control modes shall also be specified. Laplace diagrams and associated parameters shall also be provided to the SO where appropriate.

PC A4.6. **Internal network of Controllable SWE**

Provide details of the Controllable SWE's internal network structure (Collector Network) and lay out (by means of a single-line diagram or other description of connections). This shall include but is not limited to a breakdown of how the individual WTGs are connected together as well as how they are connected back to the Controllable SWE substation. It is required to specify different cables or overhead line types and the individual length of each section of the circuit.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Table PC A-11: Data Requirement for the Internal Network of Controllable SWE

Type1	Type2	Type3	
Total length (m)			**Extend Table as appropriate**
Conductor cross section area per core (mm)			
Conductor type (Al, Cu, etc.)			
Type of insulation			
Charging capacitance (μF/km)			
Charging current (Ampere/km)			
Positive sequence resistance(R1 ohm/km)			
Positive sequence reactance (X1 ohm/km)			

PC A4.7. **Flicker and Harmonics**

Provide details of emission of harmonic or flicker contribution from the Controllable SWE at the Connection Point that may affect the performance of the Grid. This may include harmonic current injections and phase angles associated with the Controllable SWE. Details of any additional AC filter devices shall also be provided by the Controllable SWE to the SO. The flicker and harmonic levels must comply the relevant international standards (IEC and/or IEEE).

PC A4.8. **Short Circuit Contribution and Power Quality**

Provide details of the single-phase to ground, phase-phase and three-phase to ground short circuit contribution from the Controllable SWE at the Connection Point. The Controllable SWE shall provide the SO with the single-phase and three-phase short circuit contribution for rated conditions, i.e. maximum output from the Controllable SWE with all WTGs and any additional devices in the Controllable SWE contributing to the short circuit current. The Controllable SWE shall also provide the single-phase to ground, phase-phase and three-phase to ground short circuit contribution from an individual WTG. Signature plots of the short circuit contribution from an individual WTG shall also be supplied by the Controllable SWE. Minimum short circuit levels at the Connection Point would also be provided with the Voltage-Unbalance, Voltage-Dip and Flicker calculated at minimum Short Circuit level.

PC A5. **INTERCONNECTOR/HVDC DATA REQUIREMENTS**

Notwithstanding the Interconnectors Technical Code, all information for Interconnector connection applications shall include details of the Transmission System Connection Point and external Transmission System Connection Point. This shall include details listed in PC A2.1. and PC A2.2. for each Connection Point. The minimum technical, design and operational criteria to be met by Interconnectors are specified in the Connection Conditions.

Interconnector Operating Characteristics and Registered Data

Interconnector Registered Capacity

i. Interconnector Registered Import Capacity for import from the Transmission System (MW);

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

ii. Interconnector Registered Export Capacity for export to the Transmission System (MW).

Interconnector Registered Capacity shall include transmission power losses for the Interconnector and be considered Registered Data.

(a) **General Details**

i. single line diagram for each converter station

ii. proposed Transmission connection point

iii. Control Facility location

iv. Interconnector Operator details

(b) **Technology details where applicable**

i. Interconnector technology type (i.e. if AC or DC-Line or Back-to Back DC and, if applicable, current or Voltage source technology)

ii. AC/DC network cable or overhead line type & characteristics i.e. length, resistance (R), reactance (X), susceptance (B)

iii. AC/DC rated DC Network Voltage/Pole (kV)

iv. number of Poles and Pole arrangement

v. Earthing/return path arrangement

vi. short circuit contribution (three phase to ground, single line to ground, phase to phase)

vii. Interconnector losses (MW/MVAR)

- converter station
- line circuits
- house load demand
- losses on de-block at minimum transfer for DC Interconnector
- total losses at max import/export

viii. overload capability including details of any limitations, i.e. time, temperature.

(c) **AC filter reactive compensation equipment parameters**

i. total number of AC filter banks

ii. type of equipment (e.g. fixed or variable)

iii. single line diagram of filter arrangement and connections

iv. Reactive Power rating for each AC filter bank, capacitor bank, or operating range of each item or reactive compensation equipment (SVC or else), at rated Voltage

v. performance chart (PQ), showing Reactive Power capability of the Interconnector, as a function of Interconnector Registered Capacity transfer

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

vi. harmonic and/or flicker contribution from the Interconnector that may affect the performance of the Interconnector at the Connection Point

vii. Effective Short Circuit Ration (ESR) at the Transmission System Connection Point, compliant to international standards (IEC and/or IEEE)

(d) **Interconnector power electronic converter and control systems**

i. parameters related to the power electronic converters. Interconnector converter characteristics to be represented may include but is not limited by the following: converter firing angle, modulation index, Valve winding Voltage, DC Voltage, DC Current as the output variables

ii. transfer function block diagram representation including parameters of the Interconnector transformer tap changer control systems, including time delays

iii. transfer function block diagram representation including parameters of AC filter and reactive compensation equipment control systems, including any time delays

iv. transfer function block diagram representation including parameters of any Frequency, Voltage and/or load control systems

v. transfer function block diagram representation including parameters of any small signal modulation controls such as power oscillation damping controls or sub-synchronous oscillation damping controls, which have not been submitted as part of the above control system data

vi. transfer block diagram representation including parameters of the Active Power control, DC Voltage Control, AC Voltage Control and Reactive Power control at converter ends for a Voltage source converter for both the rectifier and inverter modes including Voltage set points that would trigger commutation failure, blocking and unblocking of a Pole

vii. transfer block diagram representation including parameters of any control modes that affect the performance of the Interconnector at the Connection Point which have not been submitted as part of the above control system data. Features to be represented shall include but are not limited to the following; start-up sequence, shutdown sequence, Normal operating mode, Voltage Source Converters (VSC) control mode, Island mode and Emergency Power control

viii. Dynamic model of complete DC Interconnector either from the available model library of PSS/E or a user defined model (.dll file) with complete documentation of inputs, outputs and control features, ensuring successful simulation runs in PSS/E

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(e) **Interconnector Transformer**

Table PC A-12: Interconnector Transformer data requirements

Sr. No	Description	Data
1	Number of windings	
2	Vector Group	
3	Rated current of each winding (Ampere)	
4	Transformer rating (MVA)	
5	Transformer nominal LV Voltage (kV)	
6	Transformer nominal HV Voltage (kV)	
7	Tapped winding	
8	Transformer ratio at all transformer taps	
9	Transformer impedance (Commutation Reactance) at all taps (% on rating MVA)	
10	Transformer zero sequence impedance at nominal tap (ohm)	
11	Earthing arrangement including neutral Earthing resistance & reactance	
12	Core construction (number of limbs, shell or core type)	
13	Open circuit characteristic	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PC Annex-1 TRANSMISSION PLANNING CRITERIA & STANDARDS (TPCS)

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

TPCS 1. **INTRODUCTION**

The purpose of this annex is to provide specific guidelines, criteria and performance standards for developing a cost-effective transmission system with adequate capacity and redundancy. These transmission assets should enable efficient and reliable system operation while providing open access to Users. Major considerations involve the application of technical reliability criteria, investment requirements, and seamless integration with generation and distribution facilities, strategic developments, adoption of new technologies and complying with environmental guidelines.

This Transmission Planning Criteria & Standards describes,

(a) Planning studies and their respective horizons for developing a reliable National Grid;

(b) Normal and contingency conditions to consider; and

(c) Planning performance standards and criteria.

TPCS 2. **PLANNING STUDIES**

TPCS 2.1. **Horizons**

Table TPCS 1: Main Planning Activities and their Horizons

Sr. No.	Planning Activity	Horizon
1.	Global Demand Forecast	20 years
2.	Spatial Demand Forecast	10 years
3.	Indicative Generation Capacity Expansion Plan	10 years
4.	Transmission System Expansion Plan	10 years
5.	Transmission Investment Plan	5 years

TPCS 2.2. **Base Cases**

The following four dispatch scenarios shall be employed, in principle, to prepare load flow base cases and perform a Grid Impact Study for incorporating a new connection or modification to an existing connection with the Transmission System.

(a) Summer peak and Summer off-peak (High water conditions)

(b) Winter peak and Winter off-peak (Low water conditions)

Depending on the evolution of the system, the SO may propose additional, more demanding, scenarios to be considered also in the Grid Impact Study.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

TPCS 2.3. **Connection Studies**

The SO or the relevant TNO at which the connection is requested shall employ or cause to employ various analytical techniques to evaluate the impact on system due to the incorporation of a new connection or modification to an existing connection of a User. The purpose is to ensure compliance with the applicable planning and operation standards for different types of connection studies. Accordingly, a scope of work shall be mutually agreed between the SO and the TNO at which the connection is requested, and communicated to the User before embarking on a specific system study. The scope of a typical System Impact Assessment Study entails but not limited to the following analyses:

(a) Load flow analysis

(b) Short circuit analysis

(c) Transient stability analysis

In addition, the SO, in coordination with the relevant TNO may conduct or cause to conduct further assessments of a new connection or modification to an existing connection, whenever deemed necessary as per the prudent international practices to ensure security and stability of the National Grid is not compromised. These additional studies may include but not limited to the following:

(a) Voltage Stability Studies

(b) Electromagnetic Transient Studies (including temporary over voltage (TOV)/dynamic over voltage (DOV), switching surges, LC resonance, Ferro resonance etc.)

(c) Small Signal Stability Analysis

(d) Sub Synchronous Resonance (SSR) Analysis/Sub Synchronous Torsional Interaction (SSTI) Analysis

(e) Power Quality Studies (for interconnection of RE Plants or loads causing Power Quality issues e.g. harmonics, flicker, Voltage dips, and Voltage unbalances, etc.)

(f) Converter Instability Analysis

(g) Resonance Instability Analysis

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

TPCS 3. NORMAL AND CONTINGENCY CONDITIONS

TPCS 3.1. Normal Condition

TPCS 3.1.1. The normal condition corresponds to the integrated Power System with all elements in service and operating within their allowable limits. This is also referred to as (N-0) condition

TPCS 3.1.2. In normal condition, the system must be able to supply all firm demand and firm transfers to other interconnected areas. All equipment must operate within applicable limits as mentioned in TPCS 4 "System Performance Requirements" of this Annex, and the system must be stable.

TPCS 3.2. Contingency Conditions

The contingency conditions are categorized as: 1) Credible/More Probable Contingencies and 2) Less Probable/less credible Contingencies

TPCS 3.2.1. **Credible Contingencies**

Credible contingencies include:

(a) Single Contingency (N-1)

(b) Non-Simultaneous Contingencies (N-1-1)

TPCS 3.2.2. **Single Contingency (N-1)**

Single contingency involves the loss of:

(a) Single transmission element (One Pole of HVDC, a transformer, a cable, OHL circuit, a reactor) with or without fault (three-phase to ground fault with Normal Clearing or single-phase to ground fault with Delayed Clearing); or

(b) Largest Operating Generating Unit.

The acceptable system impact is summarized as follows:

(a) All equipment must operate within contingency limits following the single contingency outage. Automatic system adjustments would respond to achieve contingency limits including, but not limited to governor action of generators, fast response of other controllers e.g. SVC, PSS, WAMS, transformer tap changing and switching of shunt equipment;

(b) No loss of load allowed, except for radial loads connected in the secondary transmission network.

The system should be transiently and dynamically stable under single-contingency events. Normal Clearing means clearing of a fault in 5 cycles and Delayed Clearing means clearing of fault in 12.5 cycles owing to a stuck-breaker condition.

Exception for N-1 may be given at the Connection Point where a generator of 50 MW or below is to be connected with the existing radial transmission line (up to 132 kV Voltage level), in case of transmission corridor limitations and/or long-distance transmission lines.

TPCS 3.2.3. **Non-Simultaneous Contingencies (N-1-1)**

Non-simultaneous contingencies are referred to as (N-1-1) event. It includes an outage condition involving single contingency (N-1) either forced or scheduled), followed by system adjustments to operate similar to (N-0) operating conditions, and followed by another single forced contingency. The acceptable system impact under (N-1-1) is as follows:

(a) The system should perform within contingency limits following either outage. Automatic system adjustments would respond to achieve contingency limits including, but not limited to governor action of generators, fast response of other controllers e.g. SVC, PSS, WAMPAC, transformer tap changing, switching of shunts equipment

(b) Loss of load and loss of generation may be allowed

(c) The system should be transiently and dynamically stable

TPCS 3.2.4. **Less-credible Contingencies**

Less-credible contingencies shall include:

(a) Double Contingency (N-2)

(b) Extreme Contingencies (N-M)

(c) Less Probable but High Impact Contingencies

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

In the System Impact Assessment studies for connection, the SO, in coordination with the relevant TNO, shall only consider less credible contingencies if the system, without the new connection (or amended connection) can perform with the reliability criteria defined.

While planning the transmission expansion, if the National Grid, in the existing situation, cannot deliver the reliability performance, the SO shall prepare the Transmission Expansion Plan with a path for gradual improvements, to achieve at the end of a specified period the reliability performance stated in this Grid Code.

TPCS 3.2.5. **Double Contingency (N-2)**

Double Contingency involves the loss of a double circuit overhead line (with or without fault) or double circuit towers. Normal Clearing of a double-phase to ground fault shall be assumed for transient stability assessments. The acceptable system impact under (N -2) event is similar to (N–1) event except that loss of load and/or generation is allowed.

TPCS 3.2.6. **Extreme Contingencies (N-M)**

Extreme Contingencies shall be considered by the SO only for the design and scope of special remedial actions schemes, or under special circumstances that require additional reliability in the system performance, adequately justified and informed.

Extreme contingencies may result in instability followed by widespread loss of load and/or generation. Extreme contingency tests should be run or studied to evaluate risks and their associated consequences and to verify that system integrity can be maintained and that it would be possible to attain a new stable state via coordinated load shedding and remedial action schemes (RAS) or special protection schemes (SPS) including islanding. Extreme Contingencies could include:

(a) Outage of critical transmission interfaces with bulk power flows across the regions which may result in extreme situations, i.e. System splitting, System Islanding, and plant tripping, etc.

(b) Outage of multiple units at a Generator

(c) Other severe events involving delayed fault clearing such as stuck breaker scenario i.e. A single-phase fault followed by circuit breaker failure leading to tripping of multiple elements

The acceptable system impact allowed is:

(a) Loss of load and loss of generation allowed

(b) The intact system or islanded system should be transiently and dynamically stable

However, no Voltage collapse, or overloads exceeding the half hour emergency rating of the transmission equipment is to be permitted.

TPCS 3.2.7. **Less Probable but High Impact Contingencies**

Less probable contingencies involve bus section faults leading to the loss of two or more elements including loss of a substation. The acceptable system impact is as follows:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(a) Loss of load and/or loss of generation allowed;

(b) The intact system or islanded system should be transiently and dynamically stable;

(c) No Voltage collapse, or overloads exceeding the half hour emergency rating of the transmission equipment.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Table TPCS 2: Normal and Contingency Conditions

<table>
<tr><th>Test Conditions</th><th>Elements out of Service</th><th>Analysis</th><th>Acceptable System Conditions</th></tr>
<tr><td>Base Case</td><td>All Elements in Service
(N-0 Conditions)</td><td>Steady State Load Flow</td><td>• System within normal operating limits
No loss of load allowed</td></tr>
<tr><td rowspan="2">Single Contingencies (N-1)</td><td rowspan="2">Any one of the following:
• Largest Operating Unit
• Transformer
• OHL Circuit
• Reactor
• Cable
• HVDC Monopole</td><td>Steady State Load Flow</td><td>• System within Contingency operating limits immediately after outage.
• No loss of load allowed except for the radial loads connected to secondary transmission network</td></tr>
<tr><td>Stability Analysis</td><td>Transiently and dynamically stable</td></tr>
<tr><td rowspan="2">Double Contingencies (N-2)</td><td rowspan="2">• Double circuit tower collapse (in hilly areas or plain areas).
• Outage of parallel circuits connected to sensitive/strategic Generator like nuclear or a large hydel plant.</td><td>Steady State Load Flow</td><td>• System within contingency operating limits.
• Loss of load allowed.</td></tr>
<tr><td>Stability Analysis</td><td>Transiently and dynamically stable</td></tr>
<tr><td rowspan="2">Non-Simultaneous Contingencies (N-1-1)</td><td rowspan="2">Single contingency (forced or scheduled) followed by system adjustments and another single forced contingency.</td><td>Steady State Load Flow</td><td>• System within contingency operating limits
• Loss of load allowed</td></tr>
<tr><td>Stability Analysis</td><td>Transiently and dynamically stable</td></tr>
<tr><td>Extreme Contingencies (N-M)</td><td>• Outage of multiple generating units
• System Splitting/Islanding
• Loss of Load/Generation.
• Delayed fault clearance.</td><td>Stability Analysis</td><td>Avoidance of wide spread loss of load, uncontrolled cascading and system blackouts.</td></tr>
<tr><td rowspan="2">Less Probable High Impact Contingencies</td><td rowspan="2">• Bus section
• Loss of two or more elements, including loss of substation</td><td>Steady State Load Flow</td><td>• Loss of load and generation allowed
• No Voltage collapse, or overloads exceeding the half hour emergency rating of the transmission equipment</td></tr>
<tr><td>Stability Analysis</td><td>The intact system or islanded system should be transiently and dynamically stable</td></tr>
</table>

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

TPCS 4. **SYSTEM PERFORMANCE REQUIREMENTS**

The Users shall ensure that any of their Apparatus, Equipment, or Plant connected to the Transmission System, shall not cause Power Quality issues such as flicker, harmonics, Voltage dips, or Voltage unbalance beyond the permissible limits stated in the relevant International Standards (IEC and/or IEEE). Where such limits are exceeded at the Connection Point, the Users shall install appropriate and specific compensation and/or power quality mitigation equipment within their premises/networks. This may include, but not limited to installation of harmonics filter, Static VAR Compensator (SVC) or STATCOM.

System performance assessment studies shall be based on evaluation of system parameters against their stipulated criteria listed in the subsections below. The studies shall be deemed acceptable if these do not result in any violation of the limits defined in this section for Normal and Contingency conditions.

TPCS 4.1. **Equipment Loading**

TPCS 4.1.1. The following loading criteria shall be observed for load flow studies.

(a) All transmission lines and transformers shall be loaded below their Normal Continuous Maximum Ratings under normal operating conditions (N-0 condition);

(b) All transmission lines and transformers shall be loaded below their Contingency Ratings under contingency conditions (N-1).

TPCS 4.1.2. Dynamic ratings for loading limits may be evaluated and applied for specific geographical regions. For instance, loading limits of transmission lines and transformers in the wind corridors or low temperature northern hilly areas may be increased up to 10%. All loading limits shall be determined in accordance with applicable IEC Standards and updated from time to time as new and revised standards become available. In the event that an IEC Standard with necessary scope does not exist, then other applicable standards such as ANSI C57.92, IEEE 738-2012, IEC-287 or other standards of internationally recognized institutions may be used. In the event of a dispute as to which planning and design Standards are to be used, GCRP shall have the final decision.

TPCS 4.1.3. Transmission circuit loading limits shall be based on the following conditions:

(a) Thermal loading limits of the conductors

(b) Maximum ambient temperature, i.e. 40 degrees Centigrade

(c) Maximum conductor temperature, i.e. 90 degrees Centigrade

(d) Minimum clearance to ground at mid-span under maximum load

(e) Allowable overload for 20 minutes

(f) Transient stability and Voltage stability limits

(g) Wind velocity

(h) Aging Factor

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

TPCS 4.1.4. Transformer loading limits shall be based on following conditions:

(a) Maximum loading capacity with forced cooling

(b) Maximum ambient temperature

(c) Allowable overloading for two hours

(d) Summer (April – October) loading and winter (November- March) loading

Table TPCS 3: Equipment Loading

Sr. No.	Equipment	Loading in N-0 Conditions	Loading in Contingency Conditions
1.	Transformers	80% of the rated capacity	110% of rated capacity
2.	Transmission Lines	80% of the rated capacity	100% of rated capacity

TPCS 4.1.5. **Substation Transformer Capacity Adequacy**

TPCS 4.1.5.1. The SO shall submit and present an "Annual System Reliability Assessment and Improvement Report" (ASRAIR) in close coordination with all TNOs to the Authority on or before 15th February of each year for the next year, listing the Total Installed Transformer Capacity in MVA, Firm Transformer Installed Capacity, and Estimated Load Demand for the next year for each UHV and EHV substation. For each substation, the ratio of Estimated Peak Substation Demand to Firm Transformer Capacity shall be calculated and reported. If the ratio of Estimated Peak Substation Demand to Firm Substation Capacity is 80% (Single Transformer substation) or 100% (more than one Transformer substation) then the SO shall identify inadequacies in the transformation capacities and transmission lines that may affect system reliability. Accordingly, the relevant TNOs, in consultations with SO, shall devise corrective measures and provide descriptions of their plans, together with cost and in-service date, to either add additional transformer capacity or to shift load from/to other substations or reconfigure/build transmission lines. If load is shifted to another substation, then the amount of the shifted load will be added to the estimated peak demand for the substation to which the load has been shifted to and shall be used to calculate the ratio. The SO shall incorporate the information and plans informed by each TNO to the ASRAIR submitted to the Authority.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

Table TPCS 4: ASRAIR Format

SUBSTATION TRANSFORMER CAPACITY ADEQUACY					
Substation Name	**Number of Transformers & total name plate Ratings (MVA)**	**Transformer Voltage Ratio kV/kV**	**Firm Substation Capacity (MVA)**	**Estimated Peak Substation Demand (MVA)**	**Ratio of Peak Substation Demand to Firm Transformer Capacity %**

TPCS 4.1.5.2. Firm Substation Capacity (MVA) is the Total Installed Transformer Capacity less the largest transformer based on its Nameplate MVA rating.

TPCS 4.1.5.3. Transformer MVA loading based on Manufacturer's Nameplate Rating, and IEC standard 60354 Ed 2.0, 1991, Loading Guide for Oil-Immersed Power Transformers.

TPCS 4.1.5.4. In the case of single transformer substation, the Firm Capacity of the substation is 80% of Transformer's Nameplate Rating.

TPCS 4.2. Voltage Limits

TPCS 4.2.1. **Terminal Voltage Limits for HVDC System**

HVDC system should be capable to maintain AC Voltage at its terminals within the limits mentioned in TPCS 4.2.2 and TPCS 4.2.3. Design of Valves should have enough margins for Voltage excursions to avoid Commutation Failure.

TPCS 4.2.2. **Voltage Limits for UHVAC System of 800 kV class (Nominal 735-765 kV)**

The upper limit of the Voltage is 800 kV and lower limit of the Voltage should not fall below 5% of the nominal Voltage under normal and N-1 contingency conditions.

TPCS 4.2.3. **Voltage Limits for HVAC System of 500 kV and below**

Voltage should remain within ± 5% of nominal Voltage under normal conditions and ± 10% under N-1 contingency conditions. However, Voltages at some Generators and/or substations maybe allowed up to +8% of the nominal Voltage under normal operating conditions as per network configuration and/or system requirements.

TPCS 4.3. Voltage Step

For normal system operation, i.e. with all transmission elements in service, the Voltage step resulting from reactive power compensation switching shall not exceed ±3.0% of pre-switching Voltage.

TPCS 4.4. Frequency Ranges

The integrated Power System shall be so planned and operated that the System Frequency remains within the following limits.

(a)	Normal operating range	49.8 Hz to 50.2 Hz
(b)	Contingency Operating Range	49.3 Hz to 50.5 Hz

TPCS 4.5. Short Circuit Levels

Maximum and Minimum Short Circuit current calculation studies should be carried out for three phase and single phase to ground faults. The assumptions for such studies should be based on the IEC 60909 standard, which are given as follows:

(a) For Maximum Short Circuit current calculations, pre-fault Voltage should be 1.1 pu

(b) For Minimum Short Circuit current calculations, pre-fault Voltage should be 0.9 pu

(c) Planned make and break short circuit currents shall not be greater than the rating of the equipment.

(d) All generating units and transmission elements should be kept in service for maximum short circuit current calculations, whereas minimum generation dispatch should be assumed for minimum short circuit current calculations.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

TPCS 4.6. **Dynamic Testing**

TPCS 4.6.1. **Transient stability**

The strength of the system shall be such as to maintain stability of the system for at least for the following conditions:

(a) Three phase faults cleared in 5 cycles followed by outage of the associated component

(b) Single phase fault cleared in 12.5 cycles (stuck breaker condition) followed by outage of the associated component

(c) In case auto-reclosing scheme is implemented, then system should be tested for unsuccessful auto-reclosing (with a Deadband of 300 ms to 400 ms) followed by single phase fault only

It shall be assumed that the fault is correctly cleared by primary protection and that automatic line reclosing is in operation where appropriate. System Stability must be maintained and adequately damped without sustained oscillations after the transient period.

TPCS 4.6.2. **Frequency Stability**

From the perspective of Frequency stability, the system shall be able to maintain stability for the:

(a) Loss of largest operating unit or largest power in feed/loss of importing interconnectors, allowing automatic load shedding;

(b) Loss of large load or out feed/loss of exporting interconnectors.

TPCS 4.6.3. **Voltage Recovery Criterion**

After clearance of fault, the Voltage recovery profile should meet the following criterion in order to avoid Voltage collapse:

(a) Bus Voltages should recover to 0.7 pu or should not overshoot to above 1.3 pu;

(b) Bus Voltages should reach and stay above 0.8 pu within 1 second of fault inception;

(c) Bus Voltages should reach and stay above 0.9 pu within 2 seconds of fault inception; and

(d) Bus Voltages should recover at or below 1.1 pu within 2 seconds of fault inception.

TPCS 4.7. **Power Factor**

All demand customers connected with Transmission System, shall ensure a power factor of 0.95 or higher at the connection point.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CONNECTION CODE

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC 1. INTRODUCTION

The Connection Code (CC) specifies the general terms and conditions, principles, standards, and requirements for connecting to and using the Transmission System. First, it describes the procedure for seeking new, or modification of an existing, Connection to the Transmission System. Second, relevant to the new or modified requested connection, it specifies the performance standards to which the Transmission System is to be maintained and operated by the SO and the TNOs. Third, it specifies the minimum technical design and performance requirements of the User Plant and Apparatus Connected with the Transmission System.

In addition to those specified in this CC, the SO may indicate additional requirements to a specific Connection of the corresponding particular User in relevant agreement for the SO to comply with its Licence conditions and system operation standards and obligations, defining in greater detail and in more specific terms, the mutual obligations of the SO and the User.

Any reference to a User shall include the Users already Connected with the Transmission System, as well as those, who are seeking a new, or modification of an existing, Connection.

CC 1.1. Objectives

The key objectives of the Connection Code are:

(a) to provide a set of fair and non-discriminatory open access basic rules and standards for accessing and using the Transmission System;

(b) to provide the minimum performance standards according to which the SO and TNOs will operate the Transmission System under normal and contingency operating conditions, which the connection must not negatively impact; and

(c) to provide minimum design and performance requirements for Users Plant and Apparatus when Connected with the Transmission System.

CC 1.2. Scope

This sub-code applies to the SO and the following Users:

(a) Transmission Network Operators;

(b) Generators connected to the Transmission System;

(c) Bulk Power Consumers connected to the Transmission System; and

(d) Interconnectors.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

For avoidance of doubt, the above categories of User shall become bound by the Planning Code prior to actually generating, transmitting, distributing or consuming electricity, as the case may be, and references to the various categories (or to the general category) of Users should, therefore, be taken as referring both to a prospective User in that role or to Users actually connected.

CC 2. CONNECTION PROCESS

Users will be able to assess opportunities for connecting to, and using, the Transmission System that are most suited to a new, or modification of an existing, Connection through the IGCEP and TSEP by the SO or directly request a connection application solicitation to the involved TNO.

CC 2.1. Principles for Connection

The provisions specified under this Connection Code are based on, among others, the following principles and conditions:

(a) All Users shall have a fair and equal opportunity to get a new, or modification of an existing, Connection with the Transmission System and benefit from the services provided by the TNOs and the SO; and

(b) The SO and the TNOs shall provide a fair and non-discriminatory treatment to all Users when setting the terms and conditions for new, or modification of an existing, Connection with the Transmission System.

CC 2.2. Intention Application for Connection/Modification

For the purpose of User Development, the User shall file an application to the involved TNOs along with the requisite documents, by paying the admissible application processing fees, and providing the Project Planning Data as per requirement specified in the Planning Code, and the following information:

(a) The type of facilities it intends to establish (generation, distribution, loads, etc.);

(b) Magnitude of generation capability and/or Load demand/profile for the facility;

(c) Proposed locations of the Connection Points; and

(d) Tentative date by which the connection is sought.

CC 2.2.1. The involved TNO shall check the completeness of the submitted application package and notify the User within ten (10) working days whether the User application is acceptable for further processing or not. If the application is found to be incomplete or unacceptable, the TNO in its notification shall clearly state the reasons for its decision, also identifying the deficiencies which after rectification shall make the application acceptable.

CC 2.2.2. Once all the deficiencies in the application have been resolved by the User, the involved TNO shall inform the SO about the application received and its characteristics.

CC 2.2.3. Based on the connection required and the information provided by the User, the Intention Application of Demand User shall be evaluated by the involved TNOs whereas Intention Application of Generator shall be evaluated by the SO. The scope of this evaluation shall be as per PC 4.5.

CC 2.2.4. Based on the evaluation results, the involved TNOs shall inform the applicant about the availability of transmission capacity, most feasible Connection option and budgetary cost estimates.

CC 2.3. **Formal Application for a New, or Modification of an Existing, Connection**

On the basis of the Intention Application evaluation results, User may decide to continue with the Connection application process and shall submit the Formal Application to the involved TNO.

CC 2.3.1. The Formal Application package shall include the following:

(a) Project Planning Data as per requirement of the Planning Code;

(b) Preliminary design of the User Facility that the applicant intends to install;

(c) Expected Connection date;

(d) Information required as per the CC appendices of this Connection Code;

(e) Any other information/data as deemed necessary by the SO and/or the TNO for the purpose of evaluation; and

(f) Application processing fees, if any.

CC 2.3.2. The TNO shall check the completeness and notify the User regarding the timelines for the assessment of the Formal Application.

CC 2.3.3. The Formal Application of Demand User shall be evaluated by the involved TNOs whereas Formal Application of Generator shall be jointly evaluated by the SO and involved TNO. The scope of this evaluation shall be as per PC 4.5.

CC 2.3.4. The involved TNO shall issue "Offer to Connect" to the User on the basis of the evaluation results and shall include the following:

(a) Detailed Connection configuration

(b) Firm Connection Date

(c) Proposed transmission interconnection

(d) Detailed cost estimate for item (c) directly above

CC 2.3.5. On receipt of an "Offer to Connect" to the Transmission System, the User shall bear the costs related to development of all facilities from User Site up to and at the identified Connection Point.

CC 2.3.6. The User shall inform the involved TNO, within three (3) months of receiving the "Offer to Connect", of its acceptance along with proof of payment of the costs specified in the Offer. In case the User fails to inform the TNO of its acceptance along with payment proof within the stipulated period, the "Offer to Connect" shall lapse automatically.

CC 2.3.7. If the User considers the Offer to Connect does not comply with this Grid Code or the Applicable Documents, the User will submit the complaint to Authority for its resolution and decision.

CC 2.4. **Connection Agreements**

The following minimum information shall be supplied by the User to the TNO prior to signing of the Connection Agreement and shall form the basis for setting the terms and condition of the Connection Agreement provided that, for data that had

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

been previously already been submitted, the User would only need to reiterate and confirm the previous data continues to be valid:

(a) Compliance to the terms and conditions mentioned in "Offer to Connect";

(b) Registered Planning Data as specified in the Planning Code and Data Registration Code with estimated values being confirmed or replaced with validated actual values and updated Forecast Data such as Load Demand pursuant to the Planning Code;

(c) Details of the technical design of switchyard, protection, metering and telecommunication facilities at the Connection Point;

(d) Copies of all safety guidelines and local safety instructions applicable at the User's Sites;

(e) Information regarding Site Responsibility Schedules;

(f) Operation diagram for all HV apparatus at interface Voltage on the User side of the Connection Point;

(g) Unique proposed name of the User Site;

(h) Written confirmation that the Safety Coordinators acting on behalf of the User are authorized and competent pursuant to the requirements of OC 13, and relevant sections of this CC;

(i) List of managers who have been duly authorized to sign Site Responsibility Schedules on behalf of the User;

(j) Site common drawings; and

(k) List of the telephone numbers for the User's facsimile machines and other recordable communication media acceptable both to the TNO and the SO.

Upon receipt of these documents and information, the involved TNO shall provide copies of the same to the SO.

CC 2.4.1. The User shall be responsible for complying with any other applicable law or regulation of any other entity such as those of the Environmental Protection Agency.

CC 2.4.2. Acceptance of the "Offer to Connect" shall be followed by execution of the Connection Agreement or an amended Connection Agreement, as the case may be, among the Users, which will render the respective User Facility as Committed User Facility and shall be binding between the parties in accordance with the relevant terms and conditions.

CC 2.4.3. The User shall be bound to comply with all the provisions of the Grid Code (as amended from time to time) as well as the Connection Agreement before Connection and also after Connection for the entire validity period of the Connection. Failure to comply with any substantial provisions laid down in the Grid Code or the Connection Agreement shall be a sufficient cause for disconnecting User Facility from the Transmission System as per OC 6 and subject to the Applicable Documents.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

CC 2.5. **Maintenance and Replacement of Interconnecting Facilities due to Aging/Damage**

The User, who owns the assets at the Connection Site, shall be liable for maintenance of the equipment. All the costs incurred in this respect shall be borne by the owner of the assets. The SO shall approve the Outage Plan for the maintenance to be performed in line with OC. The replacement of equipment owned by the User due to aging shall be the responsibility of the Users.

CC 3. NETWORK BOUNDARIES

The network bifurcation point between Users shall be clearly defined in the Connection Agreement else it would be tee-clamp of dropper from gantry span to switchyard equipment.

CC 4. TECHNICAL STANDARDS AND SPECIFICATIONS

CC 4.1. All User's Plant and Apparatus at the Connection Point shall comply with technical standards and specification mentioned in this code and:

(a) The Authority's standards and specifications pursuant to Section 35 of the Act; or

(b) NGC standards and specifications as a bare minimum in the absence of standards and specifications pursuant to item (a) above; or

(c) Standards and specifications developed by the involved TNO provided it meets the minimum requirements of item (a) and (b) above.

CC 4.2. Where:

a) the SO determines that supplemental standards and specifications are required to be applied for a User's Plant and Apparatus in order to ensure safe and coordinated operation with the Transmission System; or

b) A TNO determines that changes to the existing standards and specifications are required to be applied for a User's Plant and Apparatus to improve system reliability,

the SO or the TNO shall notify such situation to the NGC. After receiving such notification, or in the case NGC considers, by itself, that a change on existing standards or specifications require adaptations, the NGC shall:

a) communicate the situation to the GCRP, the TNOs and, eventually, the relevant Users; and

b) propose wording for the new required standards or the changes to be produced to the existing ones.

The proposed changes/additions shall be processed by the GCRP, using the same procedure and process as if it were a modification to the Grid Code.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC 5. **SYSTEM PERFORMANCE PARAMETERS**

The SO shall ensure that the Transmission System complies with the technical, design and operational criteria, standards, and limits specified in this Grid Code.

The Users shall ensure that their facilities are designed and operated within the limits and according to the performance standards specified in this Grid Code and their respective Connection Agreements.

CC 5.1. **Transmission System Voltages**

CC 5.1.1. Under normal and N-1 contingency conditions, Transmission System Voltage shall be maintained within the bandwidth as mentioned below.

Table CC 1: Transmission System Voltages

Nominal Voltage Level (kV)	Normal Condition (%)	N-1 Condition (%)
765	+4.58/-4.84	+4.58/-4.84
500	±5	±10
220	±5	±10
132	±5	±10
66	±5	±10

Note: However, Voltages at some Generators and/or substations may be allowed up to +8% of the nominal Voltage under normal operating conditions as per network configurations and/or system requirements.

CC 5.1.2. Some Transmission System disturbances (e.g. earth faults, lightning strikes) may result in short-term Voltage deviations outside the above ranges.

CC 5.1.3. The negative phase-sequence component of Transmission System Voltage shall not exceed 1% under normal operating conditions.

CC 5.1.4. The Transmission System shall be designed and operated to maintain the Short-Circuit Current as identified by the SO at different points in the System through periodic studies.

CC 5.2. **Frequency Withstand Capabilities**

The Power System Frequency is nominally 50 Hz but could rise to 53.0 Hz or fall to 47.0 Hz in exceptional circumstances. Design of User Plant and Apparatus shall ensure stable operation of their facility within that range in accordance with the following:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Table CC 2: System Frequency Limits

	Frequency	Requirement
Below Nominal	47.0 Hz - 47.5 Hz	Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5 Hz
	47.5 Hz – 48.0 Hz	Operation for a period of at least 15 minutes is required each time the Frequency is within the range 47.5 - 48.0 Hz
	48.0 Hz - 49.0 Hz	Operation for a period of at least 90 minutes is required each time the Frequency is within the range 48.0 - 49.0 Hz
Nominal	49.0 Hz – 51.0 Hz	Continuous operation
Above Nominal	51.0 Hz - 51.5 Hz	Operation for a period of at least 90 minutes is required each time the Frequency is within the range 51.0 – 51.5 Hz
	51.5 Hz – 52 Hz	Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5 Hz
	52.0 Hz – 53.0 Hz	Operation for a period of at least 20 Seconds is required each time the Frequency is above 52.0 Hz

For the avoidance of doubt, disconnection, by Frequency or speed-based relays is not permitted within the Frequency range 47.0 Hz to 53.0 Hz before lapse of time period given in Table CC 2 unless otherwise as specified by the SO.

CC 6. SPECIFIC TECHNICAL PARAMETERS

To facilitate secure and stable operation of the Transmission System for the benefit of all Users, it is necessary that User Plant and Apparatus is designed to be capable of sustained operation within a range of Transmission System conditions.

CC 6.1. All Users

CC 6.1.1. **Earthing**

CC 6.1.1.1. The Earthing of all User Plant and Apparatus and provision of an Earthing system shall as a minimum requirement be in accordance with the recommendations contained in the "Guide for Safety in Alternating Substations Grounding", ANSI/IEEE No. 80.

CC 6.1.1.2. For Connections to the Grid at all nominal system Voltages, the Grid is solidly earthed with Earth Fault Factor below 1.4.

CC 6.1.1.3. Each User's earth disconnects must be earthed directly to the main station earth grid.

CC 6.1.1.4. Each User's Earthing system shall be bonded to the Transmission Station earth grid so that both the Earthing systems are effectively integrated.

CC 6.1.2. **Lightning Protection**

Each User shall adopt best industry practices for lightning protection of their Plant and Apparatus.

CC 6.1.3. **Design**

User Plant and Apparatus shall be designed with the following minimum capabilities (at the applicable Voltage levels), as specified in Table CC 3. In case some parameters are not available in this table, values/standards recommended by the Authority shall be followed:

Table CC 3: Reference minimum withstand Voltages AC

Parameter (Minimum) (kV)	66 kV	132 kV	220 kV	500 kV	765 kV
Insulation level Lightning impulse Switching impulse Power Frequency (1 min)	 325 140	 650 - 275	 1050 - 460	 1550 1300 620	 2100 1550 830

CC 6.1.4. User Plant and Apparatus at the Connection Point shall be designed taking account of the short circuit current levels identified in System Impact Assessment Studies, and applicable standards as mentioned in CC 4. The SO shall determine, what safety margins, if any, to apply when selecting the User's Plant and Apparatus.

CC 6.1.5. Transformers

CC 6.1.5.1. All transformers, except the Generator Transformer, connected with the Transmission System shall be equipped with an on-load tap-changer (OLTC) facility having ±10% Voltage regulation range. The requirement for an OLTC on Generator Transformer shall be established through Connection Studies. The OLTC mechanism shall possess automatic, manual and blocking functions.

CC 6.1.5.2. Generator Transformer's windings shall be connected in star-delta (Y-d) configuration. The star or neutral point of the star configuration shall be brought out for system grounding.

CC 6.1.5.3. All transformers, except the Generator Transformer, may be connected either:

(a) In delta-star (D-y) configuration. The star or neutral point of the star configuration shall be brought out for system grounding; or

(b) In star-star (Y-y) configuration with a tertiary winding in delta configuration.

CC 6.1.6. Synchronizing Facility

All Users shall provide Synchronization facility and associated controls at circuit breakers as required by the SO.

CC 6.1.7. Metering System

Provision of Primary Metering System and Back-up Metering System shall be in accordance with the provisions of the Metering Code.

CC 6.2. Conventional Generators

CC 6.2.1. Each Generator shall, as a minimum, have the following capabilities;

(a) Deliver Active Power at the Connection Point according to its registered Capability Curve as provided in the relevant Connection Agreement and submitted to the SO;

(b) Deliver Reactive Power at the Connection Point according to its registered Capability Curve as provided in the relevant Connection Agreement. The maximum and minimum Reactive Power limits shall be, at least, between 0.8 Power Factor lagging and 0.90 Power Factor leading at the Generating Unit's terminals;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

(c) Remain Synchronized with the Transmission System during rate of change of Frequency (ROCOF) in the system. The detailed settings of ROCOF are elaborated in the PCC 3.4. For the avoidance of doubt, this requirement relates to the capabilities of Generating Units only and does not impose the need for ROCOF protection nor does it impose a specific setting for any anti-islanding or loss-of-mains protection relays;

(d) Remain Synchronized during and following any Fault disturbance anywhere in the Transmission System;

(e) Remain Synchronized with the Transmission System during a negative phase sequence load unbalance of 5% of positive sequence component in accordance with IEC 60034-1;

(f) The Short Circuit Ratio (SCR) of each Generating Unit shall be in line with the System Impact Assessment Studies as follows:

   (i) Short Circuit Ratio of each Steam Turbine Generating Unit (e.g. coal, gas, biomass, nuclear), Gas Turbine Units etc. shall be more than 0.5; and

   (ii) Short Circuit Ratio for Hydroelectric Generators shall be more than 1.1;

(g) Generator Terminal Voltage variation shall be maintained within ±5% at rated power output (MW) with power factor range of 0.8 lagging to 0.9 leading or otherwise as specified in the System Impact Assessment Studies on a case-to-case basis;

(h) Minimum Load, Ramp up/down capability of Generating unit shall be as per Table CC 4 below:

Table CC 4: Minimum Load ceiling and Ramp rate for Thermal Generators

Sr. No.	Thermal Generation Technologies	Minimum Load ceiling (% of Registered Capacity)	Ramp rate (% of Registered Capacity/min)
1.	CFPP	≤40%	2-4%
2.	CCGT	≤20%	3-4%
3.	OCGT	≤20%	8-12%
4.	ICE	≤20% per unit	50%
5.	ST (RFO/HSD/Gas)	≤20%	2-5%

Any specific requirements for plants established as a result of the Connection Studies, as it corresponds, shall supersede above reference values and shall be specified in relevant agreement.

(i) Notice required to synchronize generating unit will depend on the state of the generating unit i.e. Hot, Warm & Cold. The synchronization time shall not exceed as mentioned in below table:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Table CC 5. Reference Synchronization times for Thermal Generators.

Sr. No.	Thermal Generation Technologies	Hot (Min)	Warm (Min)	Cold (Min)
1.	CFPP	≤ 130	≤ 280	≤ 400
2.	Gas Turbine	≤ 20	≤ 20	≤ 25
3.	Steam Turbine (Gas)	≤ 40	≤ 80	≤ 120
4.	Steam Turbine (RFO)	≤ 90	≤ 120	≤ 270

Note: (1) The coal & FO based STs shall be considered in Hot, Warm & Cold standby mode when the shutdown period is less than 10 hours, less than 150 hours and more than 150 hours respectively from the time of desynchronization.

(j) The ramp rates for hot startup shall be more than the warm startup and ramp rates for warm startups shall be more than cold startups. Minimum ramp rate in cold startup should be more than 1 percent of gross capacity;

(k) Time to de-load generating unit shall not be more than the time as per hot ramp rate except any holding times agreed by the system operator in relevant agreements;

(l) Generating Units with Registered Capacity greater than or equal to 50 MW for thermal Generators and 20 MW for reservoir/pond based hydro Generator shall have AGC provision at all loads between AGC minimum load and AGC maximum load. The values of AGC maximum and minimum load shall be established by the SO in a case-by-case basis, based on the results of the System Impact Assessment Studies, which shall be reflected in the Connection Agreement;

(i) Remain Synchronized with the Transmission System and continue to operate stably during and following any Fault disturbance anywhere on the Transmission System which could result in Voltage Dips at the Connection Point. The voltage-against-time profile specifies the required capability as a function of Voltage and Fault Ride-Through time at the Connection Point before, during and after the Fault disturbance. That capability shall be, at least, in accordance with the voltage-against-time profile as specified in the shaded region in the Figure CC 1 and Table CC 6:

Figure CC 1: FRT for conventional generators

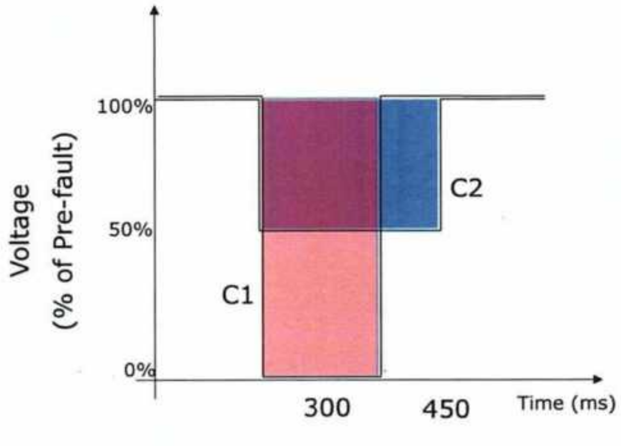


Table CC 6: FRT duration for conventional generators

Voltage Magnitude	Fault Ride Through duration			
	132 kV	220 kV	500 kV	765 kV
0% retained	300 ms	300 ms	300 ms	300 ms
50% retained	450 ms	450 ms	450 ms	450 ms

(m) Capable of disconnecting automatically from the Transmission System in order to help preserve system security or to prevent damage to the Generating Unit. The SO shall approve the criteria for detecting loss of angular stability or loss of control and angular stability under fault conditions;

(n) The maximum admissible Active Power reduction from Registered Capacity with falling Frequency shall be no greater than:

(i) Steady State domain: 2% of the Registered Capacity, per 1 Hz Frequency drop, below 49.5 Hz to 49 Hz;

(ii) Transient domain: 2% of the Registered Capacity, per 1 Hz Frequency drop, below 49 Hz and subject to the ambient condition correction curves as provided by each individual Generating Unit as well as other relevant technical factors as agreed between the SO and the Generator; and

(iii) For Generating Units using gas as a fuel source at the time of the low Frequency Event, the standard ambient conditions for the measurement of admissible Active Power reduction shall be 25°C, 70% relative humidity and 1013 hPa.

(o) For all Generating Units with Secondary Fuel provision, the Generating Unit must be capable of starting up on Secondary Fuel. The Generating Unit must be capable of carrying out an online fuel changeover from Primary Fuel to Secondary Fuel at Primary Fuel Switchover Output in minimum time as agreed with the SO. When operating on Secondary Fuel, the Generating Unit must be capable of operating on Secondary Fuel nearest as possible to Primary Fuel Registered Capacity. The Generating Unit must also be capable of carrying out an online fuel changeover from Secondary Fuel to Primary Fuel at Secondary Fuel Switchover Output;

(p) The Generating Unit must have storage capability (for stock able fuel) for Primary Fuel equivalent to thirty (30) days continuous operation at Primary Fuel Registered Capacity and Secondary Fuel (if applicable) equivalent to seven (07) days continuous operation at Primary Fuel Registered Capacity;

(q) Users shall install Generating Unit governors that comply with OC 5. Users shall not change Frequency or load related control settings of Unit governors without prior approval of SO. Generating Units shall be capable of setting droop between 2% and 12%. The default droop setting shall be 4%.

CC 6.2.2. Generating Units shall be designed to have the capability, when supply from the Transmission System is lost, to reduce output to match house load and sustain operation (i.e. tripping to Auxiliaries) for two (02) hours following tripping to house-load. Also, Generating Units shall be designed to trip to house load from any operating point in its Reactive Power Capability Curve.

CC 6.2.3. Control Synchronizing shall be provided by Generators at all circuit breakers or as identified by the SO, depending on the Plant configuration under the following conditions:

(a) Transmission System Frequency within the limits as specified in CC 5.3; and

(b) Transmission System Voltage within the limits as specified in CC 5.3.

CC 6.2.4. Each Generating Unit shall be designed, where practicable, to mitigate the risk of common mode failure with other Generating Units. Auxiliary supplies provided shall be in accordance with good industry practice and shall be approved by the SO.

CC 6.2.5. Reactive Power capability

Each Generating Unit shall have the Reactive Power capability measured at Connection Point with the Transmission System as per the requirements established in CC 6.2.1 (b) & (g).

The Generating Unit shall be able to operate at any point within its Generator Capability Curve in appropriate timescale to target values.

CC 6.2.6. Generator Control Systems

CC 6.2.6.1. Generating Unit shall be capable of contributing to Primary Frequency Control, and Secondary Frequency Control where applicable (AGC and LFC).

CC 6.2.6.2. Generating Unit shall be capable of regulating Voltage within the specified range at the Connection Point.

CC 6.2.6.3. Generating Unit shall be capable of providing adequate damping to the power oscillations for maintaining the steady-state and dynamic stability of the National Grid.

CC 6.2.7. Turbine Control System

CC 6.2.7.1. Generating Unit shall be fitted with a fast-acting Turbine Controller. The turbine speed control principle shall be in such a way that the Generating Unit output shall vary with rotational speed according to a proportional droop characteristic (Primary Control) and the Frequency of Generating Unit.

CC 6.2.7.2. Superimposed Load Control loops shall have no negative impact on the steady state and transient performance of the Turbine Speed Control.

CC 6.2.7.3. The turbine shall be capable of operating at speeds corresponding to the Frequency ranges mentioned in Table CC 2.

CC 6.2.7.4. Turbine Controller shall provide sufficient damping for both isolated and interconnected operation modes. The damping coefficient of the Turbine Speed Control shall be above 0.25 for speed droop settings between 2 and 12%, under all operation conditions.

CC 6.2.7.5. Turbine Controller shall have no negative damping on generator oscillations for frequencies below two (2) Hz.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC 6.2.7.6. The Turbine Speed Controller and any other superimposed control loop (Load Control, gas turbine temperature limiting control, etc.) shall not compromise the Primary Control response requirements.

CC 6.2.7.7. The normalized primary response characteristic as defined by the primary response performance Index shall be maintained under all operating conditions. Consequently, in the event that a Generating Unit becomes isolated from the system but is still supplying Demand, the Generating Unit must be able to provide Primary Control according to the Primary Response Performance Index.

CC 6.2.8. Automatic Voltage Regulator

CC 6.2.8.1. A continuous Automatic Voltage Regulator (AVR) acting on the excitation system is required to provide constant terminal Voltage of the Generating Unit without instability over the entire operating range of the Generating Unit. Control performance of the Voltage Control loop shall be such that under isolated operating conditions the damping coefficient shall be above 0.25 for the entire operating range. The Automatic Voltage Regulator (AVR) shall have no negative impact on generator oscillation damping.

CC 6.2.8.2. The specific requirements for automatic excitation control facilities, including Power System Stabilizers (PSS) where these are necessary for system reasons, shall be specified in the Connection Agreement. Operation of such control facilities shall be in accordance with the Operation Code and Scheduling and Dispatch Code.

CC 6.3. Requirements for Solar-Wind- ESPP (SWE) Projects

CC 6.3.1. Reactive Power and Voltage Control

A SWE must be able to operate in power factor, reactive power or Voltage Control modes given as follows:

CC 6.3.2. Power Factor:

A SWE shall manage at the Connection Point the reactive power control to maintain the power factor within the range of 0.90 lagging to 0.95 leading, over the full range of operation, as per dispatch instructions and/or Voltage adjustments/ requirements within the above range of power factor.

CC 6.3.3. Generator Control System

An SWE shall be equipped with a control system able to operate, at least, in the following control modes:

(a) Free Energy Production (no Energy control): The Generation Plant operates producing its maximum Energy depending with the availability of the primary resource.

(b) Energy Constraint: The Generation Plant operates producing Energy equal to a value specified by the SO, provided the availability of the primary resource is equal or higher than the prescribed value, or producing the maximum possible Energy in case the primary resource availability is lower than the prescribed set-point;

(c) Delta Production Constraint: The Generation Plant operates producing Energy in a pre-determined proportion of its maximum capability

POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY NATIONAL ELECTRIC * NEPRA * depending on the availability of the primary resource, used to establish Frequency Response, as established in OC 5.

(d) Instructed set point: Additionally, for ESPP and Solar or Wind Generation Plants equipped with Energy Storage Systems, the Generation Plant shall be capable to operate at a set point instructed by the SO, within its storage and technical capabilities.

The SWE control system shall comply with OC 5, to provide Frequency Response as instructed by the SO. The SO shall indicate the adjustments of such control settings.

CC 6.3.4. Reactive Power:

A SWE shall manage at the Connection Point the Reactive Power control within the set points of Qmin and Qmax as per unit of full output of Plant as shown in Figure CC 2 and Figure CC 3. The set points of Qmin and Qmax shall be, at least, as follows:

(a) Qmin = -0.33 pu of full Output

(b) Qmax = +0.5 pu of full Output

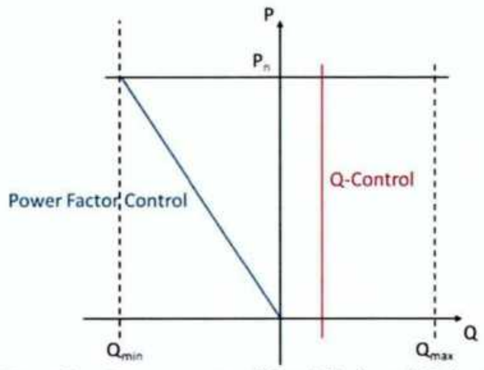


Figure CC 2: Reactive Power control for Wind and Solar Generators

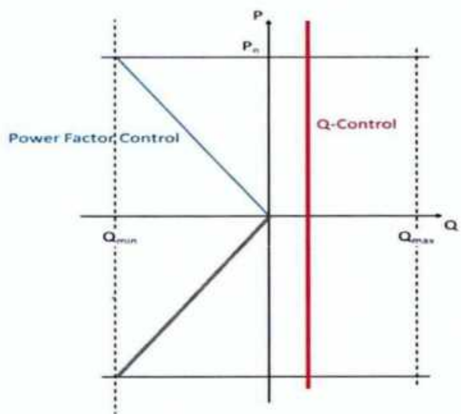


Figure CC 3: Reactive Power control for BESS

CC 6.3.5. Voltage Control

A SWE must control Voltage at Connection Point along a Voltage vs. reactive power characteristic as shown in Figure CC 4. The following parameters are set as:

(a) Voltage offset: ± 5 % under normal operating conditions and ± 10 % during contingency conditions.

(b) Reactive power offset: +0.5 to ± 0.33 pu of full Output of Plant

(c) Droop (5 % of Nominal Voltage at max. Reactive Power)

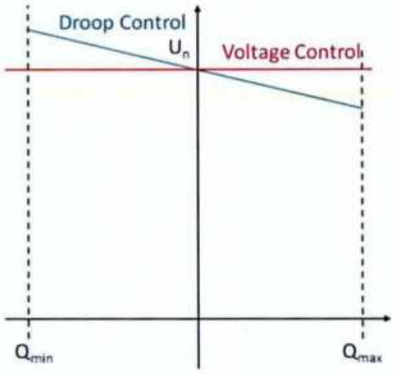


Figure CC 4: Voltage Control Mode

CC 6.3.6. LVRT and HVRT Requirements:

CC 6.3.6.1. An SWE must stay connected for transient short duration low Voltage dips with slow recovery i.e. called Low Voltage Ride through (LVRT), and short duration high Voltage swells i.e. called High Voltage Ride Through (HVRT).

CC 6.3.6.2. An SWE must have the LVRT/HVRT capability as indicated Figure CC 5. It is required to stay connected in the Voltage envelope below the HVRT curve and above the LVRT curve.

CC 6.3.6.3. For LVRT, a controllable SWE must stay connected for:

(a) Zero Voltage i.e. Zero Voltage Ride Through (ZVRT) for the initial duration of 300 ms;

(b) Recovered/Retained Voltage of 30% for the next duration till 500 ms;

(c) Slow Voltage recovery up to 0.9 pu in 3 seconds after occurrence of fault;

(d) It may disconnect if the Voltage dips below these limits for longer durations as specified in the envelope.

CC 6.3.6.4. For HVRT, a controllable SWE must stay connected for:

(a) Voltage swells up to 1.2 pu for the duration of 3 seconds;

(b) Voltage recovers to 1.1 pu in 3 seconds after occurrence of fault;

(c) It may disconnect if the Voltage swells higher than this limit or for longer duration as specified in the envelope.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

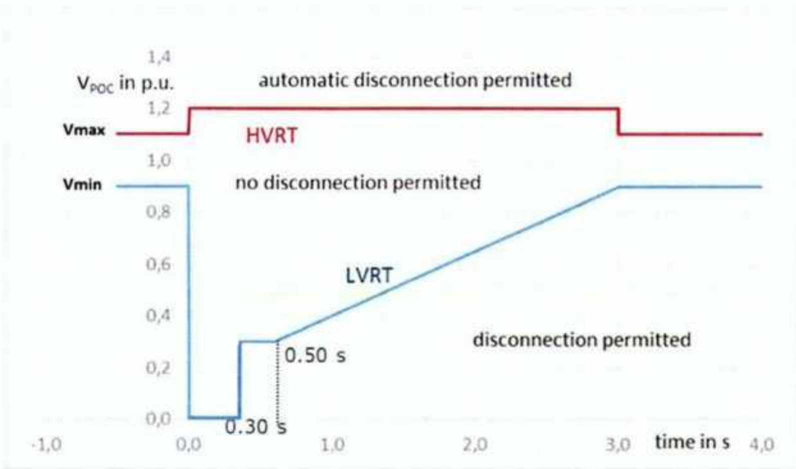


Figure CC 5 HVRT/LVRT Requirements for SWE Projects

CC 6.3.6.5. In order to actively support Voltage during low Voltage situations (LVRT-situations), an SWE must inject additional reactive current into the grid. Likewise, in order to actively reduce the Voltage and help keep the Voltage within reasonable limits during high Voltage conditions, an SWE must absorb reactive current.

(a) During Transmission System Voltage Dips, the SWE shall provide Active Power in proportion to retained Voltage and provide reactive current to the Transmission System, as set out in Figure CC 6;

(b) The provision of reactive current shall continue until the Transmission System Voltage recovers to within the normal operational ranges of Voltages and frequencies of the Transmission System as specified in the Grid Code or for at least 500 ms, whichever is sooner;

(c) The SWE may use all or any available reactive sources, including installed STATCOMS or SVCs, when providing reactive support during Transmission System Fault Disturbances resulting in Voltage Dips.

CC 6.3.6.6. The SWE shall provide at least 90% of its maximum Available Active Power or Active Power Set-point, whichever is lesser, as quickly as the technology allows and in any event within 500 ms of the Transmission System Voltage recovering to 90% of nominal Voltage, for Fault Disturbances cleared within 140 ms. For longer duration Fault Disturbances, but less than 300 ms, the SWE shall provide at least 90% of its maximum Available Active Power or Active Power Set-point, whichever is lesser, within 1 second of the Transmission System Voltage recovering to 90% of the nominal Voltage.

CC 6.3.6.7. During and after faults, priority shall always be given to the Active Power response as defined in (c). The reactive current response of the SWE shall attempt to control the Voltage back towards the nominal Voltage and should be at least proportional to the Voltage Dip. The reactive current response shall be supplied within the rating of the SWE, with a Rise Time no greater than 100 ms and a Settling Time no greater than 300 ms. For the avoidance of doubt, the SWE may provide this reactive response directly from individual Generation Units, or other additional dynamic

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

reactive devices on the site, or a combination of both. The characteristics of reactive current support are indicated in Figure CC 6.

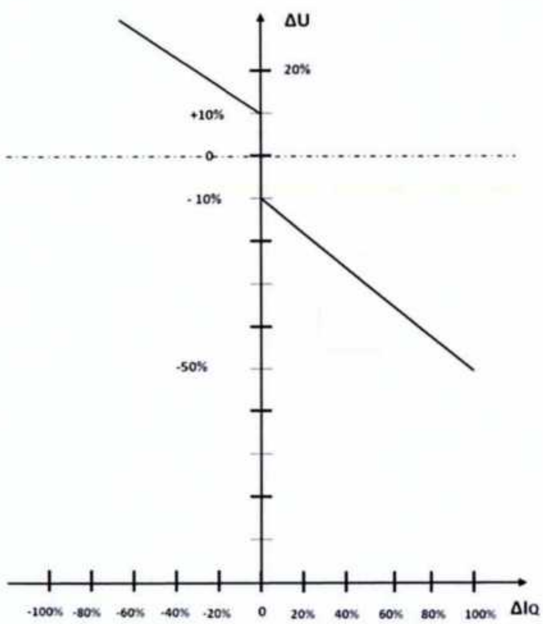


Figure CC 6 Reactive Current Support Requirements

CC 6.3.6.8. According to this figure, an SWE will inject an additional reactive current (ΔI_Q in addition to the pre-fault reactive current) into the grid if the difference between post-disturbance and pre-disturbance Voltage (ΔU) goes below -10%.

CC 6.3.6.9. In the case that ΔU goes above 10%, a high Voltage condition is identified, and ΔI will be absorbed in order to stabilize the Voltage.

CC 6.3.6.10. It is further recommended that ΔI is defined as being in proportion to ΔU (the factor of proportionality is then named "K").

CC 6.3.6.11. Besides this, the definition of reactive current support shall include the following:

(a) It applies to both, symmetrical and asymmetrical

(b) Voltage and Current means, deviation of positive sequence Voltage and current's post-fault from pre-fault values

(c) The support is required at the generator terminals

(d) The value of K is settable to $0 \leq K \leq 10$

(e) Dynamic performance requirement for this support is 60 ms, well below minimum fault clearing times

(f) The accuracy of reactive current injection within the tolerance band of +/- 20% of the given value

(g) The limitation of this current would be absolute current value to rated current

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(h) The minimum Voltage threshold for the applicability of the reactive current support would be 10%, meaning that below a retained Voltage of 10%, reactive current injection is not required

CC 6.3.6.12. The SWE shall manage active power restoration, after the Voltage recovery, at a rate of at least 20% of nominal output power per second, subject to availability of adequate wind speed at site. However active power recovery must not be faster than a rate of 50% of nominal power per second. The active power has to be ramped up to pre-fault level (or maximum available power), or at least to 90% of pre-fault level.

CC 6.3.6.13. The SWE must manage reactive power restoration, after Voltage recovery, such that post-fault reactive power must not be below pre-fault reactive power with a minimum tolerance of 10% and maximum delay time of 200 ms after fault clearance.

CC 6.3.6.14. The SWE shall be capable of providing its transient reactive response irrespective of the reactive control mode in which it was operating at the time of the Transmission System Voltage Dip.

CC 6.3.6.15. The SWE shall revert to its pre-fault reactive control mode and set point within 500 ms of the Transmission System Voltage recovering to its normal operating range as specified in CC 4 of this document

CC 6.3.6.16. Additionally, an SWE shall have the following capabilities:

(a) Remain Synchronized with the Transmission System during rate of change of Frequency (ROCOF) in the system. The detailed settings of ROCOF are elaborated in the PCC3.4. For the avoidance of doubt, this requirement relates to the capabilities of the SWE only and does not impose the need for ROCOF protection nor does it impose a specific setting for any anti-islanding or loss-of-mains protection relays;

(b) Remain Synchronized with the Transmission System during a negative phase sequence load unbalance of 5% of positive sequence component in accordance with IEC 60034-1;

(c) Minimum Load, Ramp up/down capability of Generating unit shall be as per Table CC 7 below:

Table CC 7: Minimum Load ceiling and Ramp rate for Renewable Generators

Sr. No.	Generation Technologies	Minimum Load ceiling (% of Registered Capacity Subject to availability)	Ramp rate (% of Registered Capacity/min Subject to availability)
1.	PV & CSP	0-100%	10%
2.	Wind	0-100%	10%

APPROVED BY THE AUTHORITY
NATIONAL ELECTRIC POWER REGULATORY AUTHORITY ★ NEPRA ★

(d) All SWEs shall, through appropriate necessary equipment, be capable of quick and smooth Synchronization and de-Synchronization, without causing jerks on the Transmission System, as per the requirement of the SO.

CC 6.3.6.17. Control Synchronizing shall be provided by SWE at all circuit breakers or as identified by the SO, depending on the Plant configuration under the following conditions:

(a) Transmission System Frequency within the limits as specified in CC 5.3; and

(b) Transmission System Voltage within the limits as specified in CC 5.3.

CC 6.4. HVDC System and Convertor Station

CC 6.4.1. High-Voltage Direct Current (HVDC) systems and convertors which includes embedded HVDC, Interconnector, back-to-back, isolated/linked Power Park modules when connected with Transmission System shall be provided with the following minimum capabilities in addition to other applicable sections of CC and standards; These requirements, which shall further be detailed in the relevant agreements as otherwise applicable, includes Line Commutated Convertors and Voltage Source Convertor HVDC.

CC 6.4.2. Reactive Power Capabilities

Adequate reactive power compensation equipment (filters) needs to be installed at the HVDC converter stations to ensure efficient and stable operation of the interconnected Transmission System.

CC 6.4.3. SCR Value

An SCR value of greater than three (3) is recommended at the Connection Point of an HVDC and an AC grid or a hybrid AC/DC grid. Employment of appropriate reactive power devices (synchronous condensers, FACT devices, etc.) shall be considered for planning an HVDC to an AC connection.

CC 6.4.4. HVDC Configurations

HVDC system includes following configurations:

(a) Bipolar with ground return or dedicated metallic return

(b) Mono-polar with ground return, metallic return on other pole conductor or dedicated metallic return

(c) Symmetric monopole

(d) Rigid bipole

(e) Operation with one or more converters out of service in a pole (for multi-terminal HVDC system)

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CC 6.4.5. Control Modes

This section includes HVDC control modes.

CC 6.4.6. Bipole Power Control Mode

In a bipolar system, the most usual mode of control is bipole power control. In this mode the power order is divided between the two poles in inverse proportion to the DC operating Voltage of the pole.

CC 6.4.7. Pole Power Control Mode

CC 6.4.8. A bipolar HVDC system shall be capable of operation with one or both poles in individual power control mode. The Power Order shall be settable in each of the two poles independently.

CC 6.4.9. In a multi-terminal HVDC with two inverters and one rectifier, operating in Pole power control, the most common control method would be to operate one of the inverters in Voltage Control and other inverter in current control. The rectifier will control the total pole power, measured at the DC bus of the rectifier, by adjusting its current until the Pole Power Order is achieved. The pole power, minus the DC line losses would be divided between the two inverters as follows:

(a) the inverter operating in current control (I_i) will have a DC side power of $I_i * V_{dci}$

(b) the inverter operating in Voltage Control (I_v) will have a DC side power of $I_v * V_{dci}$

where,

V_{dci} - is the DC Voltage at the inverter

I_i - is the current of the inverter operating in current control

I_v - is the current of the inverter operating in Voltage Control ($I_v = I_r - I_i$))

I_r - is the current of the rectifier

Thus, the inverter operating in Voltage Control transmits any power not transmitted by the inverter operating in current control.

CC 6.4.10. Pole Individual Current Control Mode

A bipolar HVDC system shall be capable of operation with one or both poles in constant current control. The current shall be settable in each of the two poles independently.

CC 6.4.11. Pole Reduced Voltage Mode

Each pole of the HVDC system shall be capable of operation with full or reduced Voltage at the reduced Voltage levels specified for the project. The reduced Voltage mode shall be initiated or reset in each pole separately and the operating DC Voltage in each pole shall be independently settable. Reduced Voltage mode is a sub-mode and shall be available in any of the other operating modes described in this section.

CC 6.4.12. Round Power Mode

If specified by the SO, a bipolar HVDC system shall be capable of operation with different power direction in each of the two poles independently. In a multi-terminal system, the power direction and the power order of each converter shall be independently settable.

CC 6.4.13. Reactive Power Control Mode

HVDC converter station shall be capable of operating in one or more of the following three control modes:

CC 6.4.13.1. Voltage Control Mode (U-control)

Each HVDC converter station shall be capable of contributing to Voltage Control at the connection point utilizing its capabilities, in accordance with the following control characteristics:

APPROVED BY THE AUTHORITY
NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
NEPRA

(a) A set-point Voltage at the connection point shall be specified to cover a specific operation range, either continuously or in steps.

(b) The Voltage Control may be operated with or without a Deadband around the set-point selectable in a range from zero to +/– 5 % of reference 1 pu network Voltage.

(c) Voltage Control mode shall include the capability to change reactive power output based on a combination of a modified set-point Voltage and an additional instructed reactive power component. The slope shall be specified by a range and step as approved by the SO.

CC 6.4.13.2. Reactive power exchange mode (Q-control)

SO shall specify in relevant agreement a reactive power range, Deadband and reference value of Q control in MVAR or in % of maximum reactive power, as well as its associated accuracy at the connection point.

CC 6.4.13.3. Power factor control mode

HVDC converter station shall be capable of controlling the power factor to a target value mention in CC 8.1 at the connection point.

CC 6.4.14. Rate-of-change-of-Frequency (ROCOF)

HVDC system shall remain connected to the Transmission System during rate of change of Frequency (ROCOF) in the System up to and including 2.5 Hz per second (ROCOF averaged over the previous 1 second).

CC 6.4.15. Frequency Control

HVDC system shall be equipped with an independent control mode to modulate the active power output of the HVDC converter station to maintain stable system frequencies. Operating principle, the associated performance parameters and the activation criteria of the Frequency Control shall be as specified by the SO.

CC 6.4.16. Frequency Sensitive Mode (FSM, LFSM-O and LFSM-U)

Frequency sensitive mode shall be operable within specified ranges with two modes, i.e. limited Frequency sensitive mode over frequency and limited Frequency sensitive mode under Frequency.

CC 6.4.17. Active Power Controllability (Control Range and Ramp Rate)

HVDC system shall be capable of and equipped to:

(a) adjust the transmitted active power up to its maximum HVDC active power transmission capacity in each direction;

(b) modify the transmitted active power infeed in case of disturbances into one or more of the AC networks to which it is connected; and

(c) control functions enabling the SO to modify the transmitted active power for the purpose of balancing;

(d) ramp rate or active power transfer increase and decrease shall be adjustable within the technical capabilities of the HVDC system in from a

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

minimum of 1 MW per minute to 1000 MW per minute with a setting granularity of 1 MW per min.

CC 6.4.18. Maximum Loss of Active Power

CC 6.4.18.1. HVDC system shall be configured in such a way that its reduction of active power injection in a synchronous area shall be limited to a value specified by the SO for their respective load Frequency Control area, based on the HVDC system's impact on the Power System, where applicable.

CC 6.4.18.2. Where an HVDC system connects two or more control areas, the SO shall consult with other control area SO in order to set a coordinated value of the maximum loss of active power injection as referred above, taking into account common mode failures.

CC 6.4.18.3. The AC filter design, reactive power supply and absorption design, automatic filter switching and reactive power control design of the HVDC System Owner are subject to the approval of the System Operator.

CC 6.4.19. Withstand Capability

The HVDC facilities shall be capable to remain connected to the Grid for a minimum duration of 1000 ms without damage in response to external fault.

CC 6.4.20. Capable of Riding Through Fault

The HVDC converter station shall be capable of staying connected to the network and continuing stable operation after the Power System has recovered following fault clearance. The SO shall consider the pre-fault and post-fault conditions regarding:

(a) pre-fault minimum short circuit capacity at each connection point expressed in MVA;

(b) pre-fault operating point of the HVDC converter station expressed as active power output and reactive power output at the connection point and Voltage at the connection point; and

(c) post-fault minimum short circuit capacity at each connection point expressed in MVA;

(d) alternatively, generic values for the above conditions derived from typical cases.

CC 6.4.21. Fault Conditions Specified as A Voltage-Time Profile

(a) The HVDC converter station shall be capable of staying connected to the network and continue stable operation when the actual course of the phase-to-phase Voltages on the network Voltage level at the connection point during a symmetrical fault, given the pre-fault and post-fault conditions provided for in, remain above the lower limit set out in CC. Appendix-2, unless the protection scheme for internal faults requires the disconnection of the HVDC converter station from the network. The protection schemes and settings for internal faults shall be designed not to jeopardize fault-ride-through performance.

(b) The SO may specify Voltages (U_{block}) at the connection points under specific network conditions whereby the HVDC system is allowed to block. Blocking means remaining connected to the network with no active and reactive power contribution for a time frame that shall be as short as technically feasible and which shall be agreed between the SO and the User.

(c) The SO shall specify fault-ride-through capabilities in case of asymmetrical faults.

CC 6.4.22. Post Fault Active Power Recovery

The SO shall specify the magnitude and time profile of active power recovery that the HVDC system shall be capable of providing, in accordance with CC 6.4.4.

CC 6.4.23. Fast Recovery from DC Faults

HVDC systems, including DC overhead lines, shall be capable of fast recovery from transient faults within the HVDC system. Details of this capability shall be subject to coordination and agreements on protection schemes and settings.

CC 6.4.24. Requirements for Control

CC 6.4.24.1. Converter Synchronization/De- synchronization

Unless otherwise instructed by the SO, during the energization or synchronization of an HVDC converter station to the AC network or during the connection of an energized HVDC converter station to an HVDC system, the HVDC converter station shall have the capability to limit any Voltage changes to a steady-state level specified by SO. The level specified shall not exceed 5 percent (5%) of the pre-synchronization Voltage. The SO, shall specify the maximum magnitude, duration and measurement window of the Voltage transients.

CC 6.4.24.2. Interaction between HVDC systems or other Plants and Apparatus

The SO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity equipment and that of grid users in a manner consistent with grid code.

CC 6.4.24.3. Power Oscillation Damping Capability

The HVDC system shall be capable of contributing to the damping of power oscillations in connected AC networks. The control system of the HVDC system shall not reduce the damping of power oscillations. The SO shall specify a Frequency range of oscillations that the control scheme shall positively damp and the network conditions when this occurs on the basis of dynamic stability assessment studies.

CC 6.4.24.4. Sub Synchronous Torsional Interaction Damping Capability

With regard to sub synchronous torsional interaction (SSTI) damping control, the HVDC system shall be capable of contributing to electrical damping of torsional frequencies.

CC 6.4.25. Network Characteristics

The pre-fault and post-fault conditions for the calculation of at least the minimum and maximum range of short circuit power and other network characteristics at the connection points for stable HVDC system operation shall be declared by User in intention application.

CC 6.5. **HVDC Supplementary Controls**

HVDC systems shall be equipped with the following supplementary control functions and the necessary input hardware and interface points so that the functions can be readily implemented at any time:

(a) Runback and Run-up controls

(b) Fast power transfer between poles at single pole block and during single pole dc line faults and fault clearing

(c) Frequency Limiter Control

(d) Frequency Control of the AC system at any one converter station if the other converter stations of the HVDC system are within a different asynchronous area

(e) Power oscillation damping controls

(f) Sub-synchronous oscillation damping controls

CC 7. **PROTECTION AND CONTROL SYSTEM**

CC 7.1. Every User shall design protection and control system of its facility ensuring minimal disturbance to the Transmission System operation in accordance with the Protection and Control Code.

CC 7.2. Protection and control system of the User facility may include but not limited to the following:

(a) Over current protection

(b) Distance protection

(c) Differential protection

(d) Impedance protection

(e) Load unbalance (negative sequence) protection

(f) Out of step protection

(g) Loss of excitation protection

(h) Over/under-voltage protection

(i) Over/under-frequency protection

(j) High speed automatic reclosing (HSAR)

(k) Breaker failure protection

(l) Any special protection scheme (SPS) or remedial action schemes (RAS)

(m) Reverse power protection

CC 7.3. User shall devise and execute adequate protection system for its equipment against internal and external electrical faults. In addition, User shall implement special

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

protection schemes against any system disturbances as required by the System Operator.

CC 7.4. User shall provide the required information and signals to the SO and other relevant Users for monitoring and interface coordination, respectively.

CC 8. POWER QUALITY

User shall comply with Power Quality requirements of Power Factor, Harmonic Distortion, Voltage Unbalance, Voltage Fluctuation, Flicker Severity and Rapid Voltage Changes at 132 kV Voltage level and below, as well as HVDC interface point with the AC transmission network. SO shall ensure compliance of Power Quality parameters as specified below.

CC 8.1. Power Factor

CC 8.1.1. User drawing load shall maintain Power Factor on Connection Points within the range of 0.95 lagging to unity in any half-hour period.

CC 8.1.2. The aggregate power factor for a User shall be calculated in accordance with the following formula:

$$APF = \frac{\Sigma P}{\sqrt{(\Sigma P)^2 + (\Sigma Q)^2}}$$

Where:

(a) APF is the aggregate Power Factor for the User

(b) Sum of Active Energy (Σ P) exchanged by the user at the Connection Point for any half-hour period; and

(c) Sum of Reactive Energy (Σ Q) exchanged by the user at the Connection Point for the same half-hour period.

CC 8.2. Harmonic Distortion

CC 8.2.1. User Plant and Apparatus shall not inject Voltage harmonics on the Transmission System that exceed the limits mentioned below at the relevant Connection Point:

Table CC 8: Harmonic Distortion

Voltage Level	Total Harmonic Distortion	Individual Harmonic Distortion
For Voltage ≤132	2.5%	1.5%
For Voltage >132	1.5%	1%

CC 8.2.2. User Plant and Apparatus shall not induce current harmonics on the Transmission System that exceed the limits specified in the IEEE Standard 519 (as amended from time to time), titled, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

CC 8.3. Voltage Imbalance

User Plant and Apparatus shall not cause the phase-to-phase Voltage unbalance of the Transmission System to exceed by more than one percent (1%) at the Connection Point, as measured with no load and with balanced three-phase load.

CC 8.4. **Voltage Fluctuation and Flicker Severity**

CC 8.4.1. The Voltage fluctuation at any Connection Point with a fluctuating Demand shall not exceed one percent (1%) of the nominal Voltage level for step changes, which may occur repetitively. Any large Voltage excursions other than step changes may be allowed up to a level of three percent (3%) provided that this does not pose a risk to the Transmission System or to the system of any other User.

CC 8.4.2. The Flicker Severity at any Connection Point in the Transmission System shall not exceed the limits of P_{st} =0.8 and P_{lt} =0.6, both 95th percentile values measured over a period of one week.

CC 8.5. **Rapid Voltage Changes**

User Plant and Apparatus shall not produce disturbance levels that promote Rapid Voltage Changes exceeding those specified in the table below.

Table CC 8: Rapid Voltage Change Parameters

Type of Rapid Voltage Change	$\frac{\Delta U}{U_N}$ Limit (%)	Timeframe
Temporary Voltage Depression	5	Must recover to nominal Voltage in 3 seconds
Step Change	3	One cycle

CC 9. **SCADA AND COMMUNICATION SYSTEM**

CC 9.1. User shall install, modify, upgrade and integrate SCADA and the associated communication system within its facility and up to the designated Control Centers to comply with monitoring, control and cyber security requirements for ensuring secure system operation.

CC 9.2. User shall provide SCADA integration readiness certificate to SO for consent/approval before energizing its facility.

CC 9.3. User shall ensure SCADA data retention period, resolution, accuracy as per SO requirement.

CC 9.4. User shall install high resolution devices to monitor and record normal system operation and system disturbance events with following parameters but not limited to:

(a) Voltage

(b) Current

(c) Active Power

(d) Reactive Power

(e) Frequency

(f) Power angles

(g) Phase angle

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

The detailed operational requirements of the communication facilities, signals and data to be provided by Users to the SO are specified in CC Appendix-1 and OC 9.

CC 10. PLANT AND APPARATUS NOMENCLATURE

CC 10.1. User shall submit nomenclature of its new Plant and Apparatus or its modification in accordance with the specified template designed by the SO for review and approval of the SO before Testing and Commissioning of the User Facility.

CC 10.2. User shall implement clear and unambiguous labeling of its Plant and Apparatus as per the approved nomenclature by the SO and shall ensure its maintenance.

CC 10.3. User shall not alter/modify the approved nomenclature of its Plant and Apparatus without prior permission of the SO.

CC 11. ANCILLARY SERVICES

User shall install such Plant and Apparatus in its Facility to provide ancillary services as per system operational requirement, as determined by SO:

(a) Voltage/Reactive Power support;

(b) Primary Frequency Control

(c) Frequency response from ESU

(d) Synthetic Inertia

(e) Demand Response

(f) Black Start Capability

(g) Hot Standby

(h) Secondary Frequency Response normally taken through Automatic Generation Control (AGC), Load/Frequency Control (LFC), etc.

(i) Reactive Power support from Synchronous Condenser or FACTS devices or switched shunt capacitors

Compensation mechanism for the above ancillary services shall be administered according to the Market Commercial Code.

CC 12. TESTING & COMMISSIONING

CC 12.1. User shall perform Testing and Commissioning in accordance with technical standards and provisions of the Grid Code and/or relevant Agreements, witnessed jointly by SO, NGC and relevant TNO.

CC 12.2. User shall request SO for dispatch requirements during commissioning tests, as applicable, which shall be discussed and agreed before commencement and shall be subjected to SDC and OC 11.

CC 12.3. User shall demonstrate to the SO that it has complied with all requirements by successfully completing the Operational Notification Procedure for Connection.

CC 12.4. User shall maintain complete and accurate records of all performance inspection, testing and monitoring that it conducts in fulfillment of its obligations under this Code for at least five (5) years that shall be made readily available to SO and relevant TNO.

CC 12.5. Operational Notification Procedure

The Operational Notification Procedure for connection of each User requires completion of following three-step sequential processes:

(a) Energization Operational Notification (EON)

(b) Interim Operational Notification (ION)

(c) Final Operational Notification (FON)

CC 12.5.1. Energization Operational Notification

The SO shall issue an EON to the User, subject to completion and verification of the EON checklist by SO, NGC and relevant TNO. Upon issuance of the EON, a User may energize its internal network and auxiliaries for the associated Plant and Apparatus by using the grid connection that is specified for the Connection Point as instructed by the SO.

CC 12.5.2. Interim Operational Notification Procedure

The SO shall issue an ION to the User, subject to completion of the ION checklist by SO, NGC and relevant TNO. Upon receipt of the ION, a User may operate the associated Plant and Apparatus for a limited period of time, by using the grid connection that is specified for the Connection Point. The limited period of time shall be agreed with the SO and shall not be longer than six (6) months. An extension to this period of time may be granted if the User can demonstrate sufficient progress towards full compliance and outstanding issues are clearly identified. FON shall not be issued during ION period.

CC 12.5.3. Final Operational Notification

CC 12.5.3.1. The SO shall issue a FON to the User, subject to completion of the FON checklist by SO, NGC and relevant TNO. Upon receipt of the FON, a User may operate the associated Plant and Apparatus by using the grid connection that is specified for the Connection Point.

CC 12.5.3.2. If the SO identifies a reason not to issue a FON, the User may seek relaxation.

CC 12.5.3.3. Where a request for relaxation is rejected, the SO shall have the right to refuse to allow the operation of the User until the User and the SO resolve the incompatibility and the SO considers that the User Plant and Apparatus is compliant with Grid Code. If the SO and the User do not resolve the incompatibility within a reasonable time frame, but in any case, not later than six (6) months after the notification of the rejection of the request for a relaxation, each party may initiate a Dispute Resolution process, according with the provisions of this Grid Code.

CC 12.5.3.4. A User issued with a FON shall inform the SO immediately in the following circumstances:

(a) The Plant and Apparatus is temporarily subject to either significant modification or loss of capability affecting its performance; or

(b) Equipment failure leading to non-compliance with some relevant requirements.

CC 12.6. **Limited Operational Notification (LON)**

CC 12.6.1. A User shall apply to the SO for a Limited Operational Notification (LON), if User reasonably expects the circumstances described in CC 12.6 to persist for more than three (3) months.

CC 12.6.2. The SO shall then issue a LON containing the following information:

(a) Unresolved issues justifying the granting of the LON;

(b) Responsibilities and timelines for the expected solution; and

(c) Maximum period of validity which shall not exceed twelve (12) months.

The initial period granted may be shorter with the possibility of an extension if evidence is submitted to the satisfaction of the SO demonstrating that substantial progress has been made towards achieving full compliance.

CC 12.6.3. The FON shall be suspended during the period of validity of the LON with regard to the items for which the LON has been issued.

CC 12.6.4. A further extension of the period of validity of the LON may be granted upon a request for a relaxation made to the SO before the expiry of that period.

CC 12.6.5. The SO shall have the right to refuse to allow the operation of the User Plant and Apparatus, once the LON is no longer valid. In such cases, the FON shall automatically become invalid.

CC 12.6.6. If the SO does not grant an extension of the period of validity of the LON and/or if it refuses to allow the operation of the User Plant and Apparatus once the LON is no longer valid in accordance with CC 12.7, the User may initiate a Dispute Resolution process, according with the provisions of this Grid Code, within six (6) months after the notification of the decision by the SO.

CC 12.7. No new Plant and Apparatus of any User shall be energized or commissioned/connected prior to fulfillment of the following conditions in addition to conditions mentioned in this Connection Code or any other sub-code of the Grid Code:

(a) Data sharing with TNO, SO and relevant Users has been completed for Connection of its Plant and Apparatus on approved formats.

(b) Required communication links for voice, data, SCADA have been established by the User up to SO and TNO designated sites.

(c) Operational drawing of User Plant and Apparatus or amendments in drawings of existing User Facilities have been approved by the SO in coordination with involved Users.

(d) All necessary agreements, schedules, registrations etc. have been finalized and signed by all relevant parties/departments/utilities etc.

Facilities already Energized/Connected/Commissioned that have not fulfilled all the conditions mentioned above shall comply with the requirement.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

CC 13. POWER SUPPLIES

User shall provide 400/230 V AC power supply at its Plant and Apparatus through:

(a) an auxiliary; and

(b) a standby Plant and Apparatus (diesel generator or any alternative means) capable of supplying for minimum ten (10) hours.

CC 14. SAFETY

CC 14.1. User shall ensure safety of personnel and equipment during construction, Testing and Commissioning of Plant and Apparatus as per Prudent Utility Practices and NEPRA Power Safety Code (amended to date).

CC 14.2. User shall detail the demarcation of responsibility for safety of persons carrying out work or testing at the connection Site and on circuits.

CC 14.3. Detailed information on procedures and responsibilities involved in safety procedures is set out in OC 13.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CC Appendix – 1

SCADA SIGNALS TO BE PROVIDED BY USERS

CC A1.1. **Status Indication Signals**

Circuit Breakers, Isolators & Disconnecting/Earth Switches positions pertinent to the status of Transformers, Transmission Lines, Generators, Bus bars, Shunt Reactors, Capacitors, SVCs, Filters, Battery Energy Storage Systems and/or any other equipment as specified by SO, through a set of two potential free auxiliary contacts (one contact normally open and one contact normally closed when circuit breaker is open) for each circuit breaker, isolator & disconnecting switch individually.

CC A1.2. **Measurement Signals**

(a) ± Active Power, ± Reactive Power, Ampere, Voltage kV, Power Factor, Control Angles, State of Charge, Energy measurements pertinent to Transformers, Transmission Lines, Generators, Bus Bars, Shunt Reactors, Capacitors, SVCs, Filters, Battery Energy Storage Systems and/or any other equipment as specified by SO (acting reasonably);

(b) Bus Bar Frequency (in Hz) measurement at least up to 3 decimal places;

(c) For generators, MW, MVAR & Power Factor shall be required at alternator terminals of each Generating Unit (Gross Output);

(d) Transformers Tap Position (including generator transformers & grid connected transformers);

(e) For Transformers, Voltage kV measurement signal shall be required from LV side except for generator transformer where Voltage kV Signal shall be required from HV side;

(f) Real Time meteorological data e.g. Wind Speed, Wind Direction, Solar Radiation, Ambient Temperature, Atmospheric pressure, Humidity, etc.;

(g) Real Time Hydrological Data e.g. inflow, outflow, discharge, reservoir or pond level, tail race level, etc.

CC A1.3. **Control Signals**

(a) Remote Command signals from SO to Open/Close Circuit Breakers, Raise Lower Transformer Tap position and interrupt regulation process at Users facilities;

(b) Remote Command signals from SO, including both Digital Output (Raise/Lower) and Analog Output (Set point), to regulate active and reactive power output and ramp rate of generating unit/interconnector/SVCs manually and/or through AGC;

(c) Remote Command Signals from SO (set point) to curtail output of Wind and Solar Plants;

(d) Remote Command Signals from SO, to change or select mode and control of operation of HVDC, Wind or Solar & BESS plants, etc.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC A1.4. **Protection Signals**

Signals pertinent to Circuit Breakers, Transformers, Transmission Lines, Generators, Bus bars, Shunt Reactors, Capacitors, SVCs, telecommunication devices, GPS Clocks, HVDC System, BESS and/or any other equipment as specified by SO for fault indications. To avoid any doubt, these signals shall be provided on individual protection basis.

CC A1.5. **Other Signals**

Other Signals may include:

(a) Status indication signals of remote control permit switches;

(b) Status indications of PSS, AVRs, SCS, PMUs, WAMS, or any other system stability related devices;

(c) Signals related to Synchro-check/Tele-couplers;

(d) Type of fuel in use (for generators);

(e) Feedback Set point Signals (Echo MW, Echo MVAR, Echo Ramp rate, etc.);

(f) Other process or event related signals;

(g) Any other signals required by SO to monitor and control the performance of the User equipment.

CC A1.6. Generators, in addition to above mentioned relevant Signals shall also provide:

(a) Measured or derived MW output on each fuel, from Generating Units that can continuously fire on more than one fuel simultaneously;

(b) Where it is agreed between the SO and the Generator that MW & MVAR signals are not available on the HV terminals (Net output), measurements shall be provided at the Grid Connected Transformer low Voltage terminals;

(c) Remaining Secondary Fuel capability (where applicable) in MWh equivalent when running at Registered Capacity;

(d) With regard to real-time monitoring of Frequency Sensitive Mode, as described in OC 5, the Generator, Interconnector and embedded HVDC shall be equipped to transfer in real time and in a secured manner, at least the following signals:

i. status signal of Frequency Sensitive Mode (on/off);

ii. actual parameter settings for Active Power Frequency response;

iii. Governor Droop;

iv. Governor/Frequency Response Deadband;

v. Frequency Limiter Control and other such Control Functions of HVDC; and

vi. The SO shall specify additional signals to be provided by the User in order to verify the performance of the Active Power Frequency response provision of participating Generating Units.

CC A1.7. AC & HVDC Interconnectors shall provide:

(a) For AC Interconnectors: Relevant Signals as mentioned above and any other signals required by SO;

(b) For HVDC Interconnectors: Status Indications, Measurements, Commands Protection & Other Signals related to AC & DC Switchyard, Filters, Reactors etc., as specified by SO;

(c) Where signals and indications required to be provided by the User under CC 10.1 become unavailable or do not comply with applicable standards due to failure of the Users' technical equipment or any other reason under the control of the User, the User shall, acting in accordance with Good Industry Practice, restore or correct the signals and/or indications as soon as possible;

(d) Where, the SO, determines that because of a modification to the Transmission System or otherwise to meet a Transmission System requirement, additional signals and/or indications in relation to a User's Plant and Apparatus are required, the SO shall notify that requirement to the User. On receipt of such a notification the User shall promptly, and in accordance with Good Industry Practice, ensure that such signals and/or indications are made available at the relevant marshalling rack.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CC **Appendix – 2**

VOLTAGE-AGAINST-TIME PROFILE

Fault-ride-through profile of the DC converter stations

The diagram represents the lower limit of a voltage-against-time profile at the connection point, expressed by the ratio of its actual value and its reference value (in per unit) before, during and after a fault.

U_{ret} is the retained Voltage at the connection point during a fault

t_{clear} is the instant when the fault has been cleared

U_{rec1} and t_{rec1} specify a point of lower limits of Voltage recovery following fault clearance.

U_{block} is the blocking Voltage at the Connection Point under specific network conditions whereby the DC Facilities is allowed to block. Blocking means remaining connected to the network with no active and reactive power contribution for a timeframe that shall be as short as technically feasible, and which shall be eventually agreed between the relevant TNO and SO.

The time values referred to are measured from fault.

Figure CC A2-1: Voltage-against-Time profile referred to section

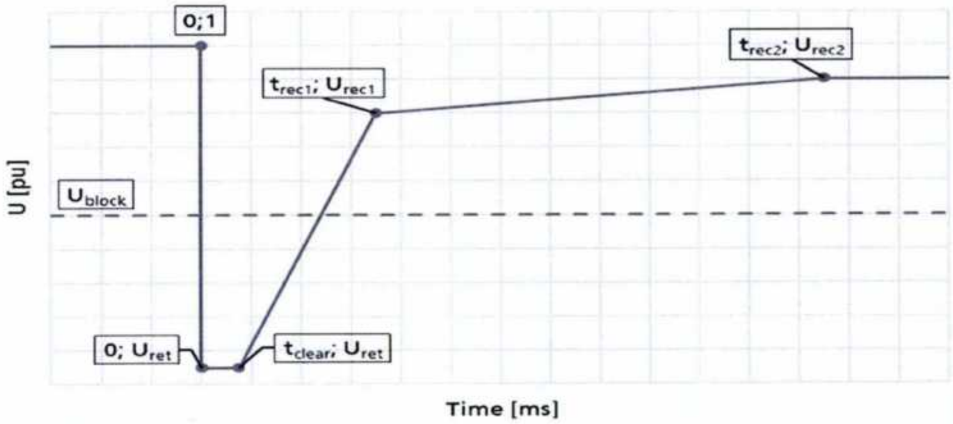


Table CC A2-1: Parameters for Figure CC A2-1 for the fault-ride-through capability of an HVDC converter station (Source: CASA Technical Code)

Voltage Parameters (pu)		Time Parameters (seconds)	
U ret	0.00-0.30	t clear	0.14-0.25
U rec1	0.25-0.85	t rec1	1.5-2.5
U rec2	0.85-0.90	t rec2	t rec1-10.0

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 3

CONFIGURATIONS FOR USERS CONNECTION

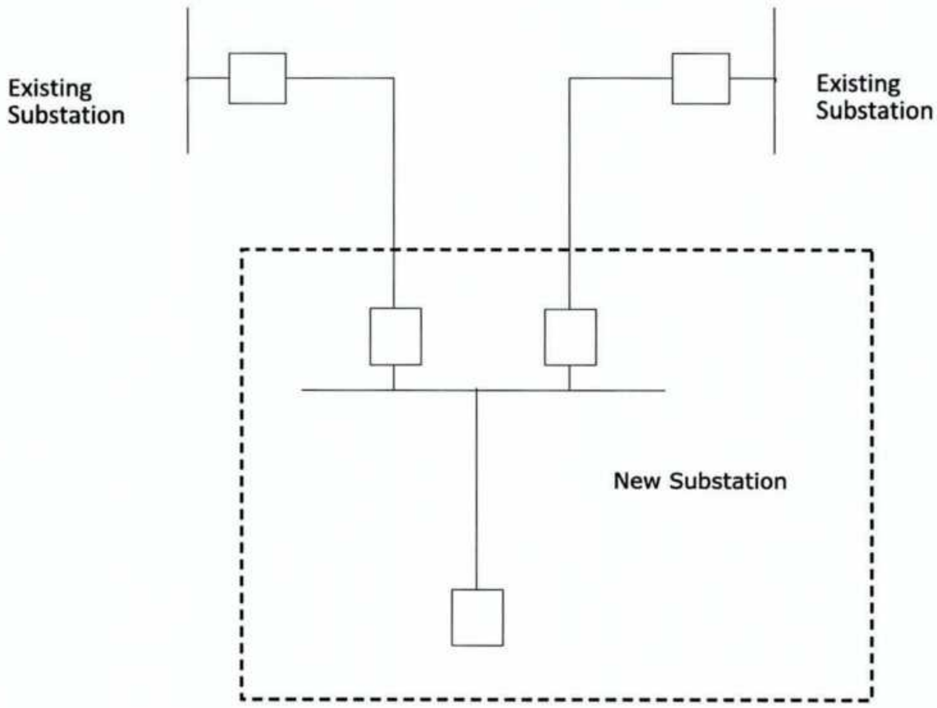
For connection of User Substation, following three connection configurations have been indicated which may be adopted according to the system conditions.

Consumer 132 kV and below	Consumer 220 kV and above	Generator connecting at Transmission System
Scheme 1, 2 or 3	Scheme 1 or 2	Scheme 1 or 2

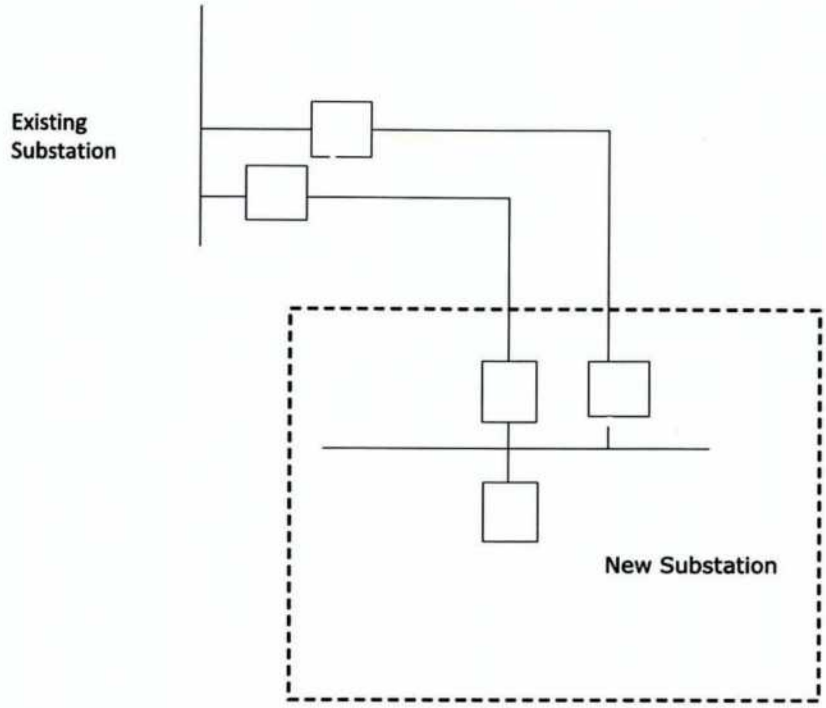
The User shall opt for one of the following connection configurations, subject to the SO's approval based on System Impact Assessment Studies.

Note: Bus bar and breaker configuration (single, double, one and half or ring) shall be as per System Impact Assessment Studies.

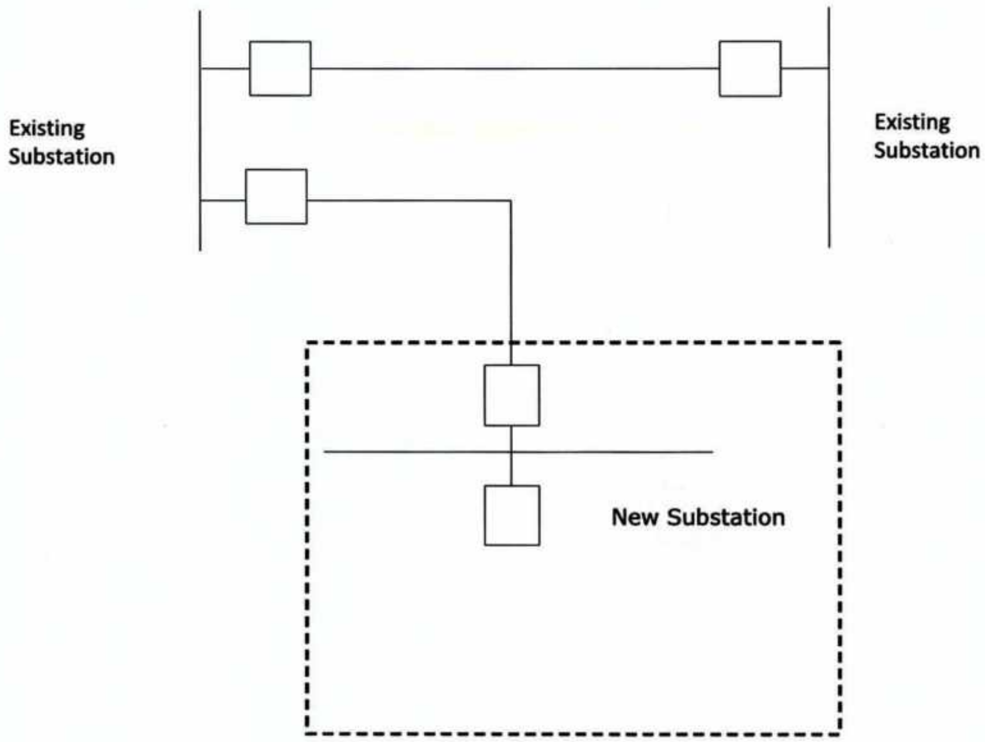
Scheme 1: CONNECTION CONFIGURATIONS WITH IN-OUT ARRANGEMENT



Scheme 2: **CONNECTION CONFIGURATIONS (radial with N-1)**



Scheme 3: **CONNECTION CONFIGURATIONS (radial)**

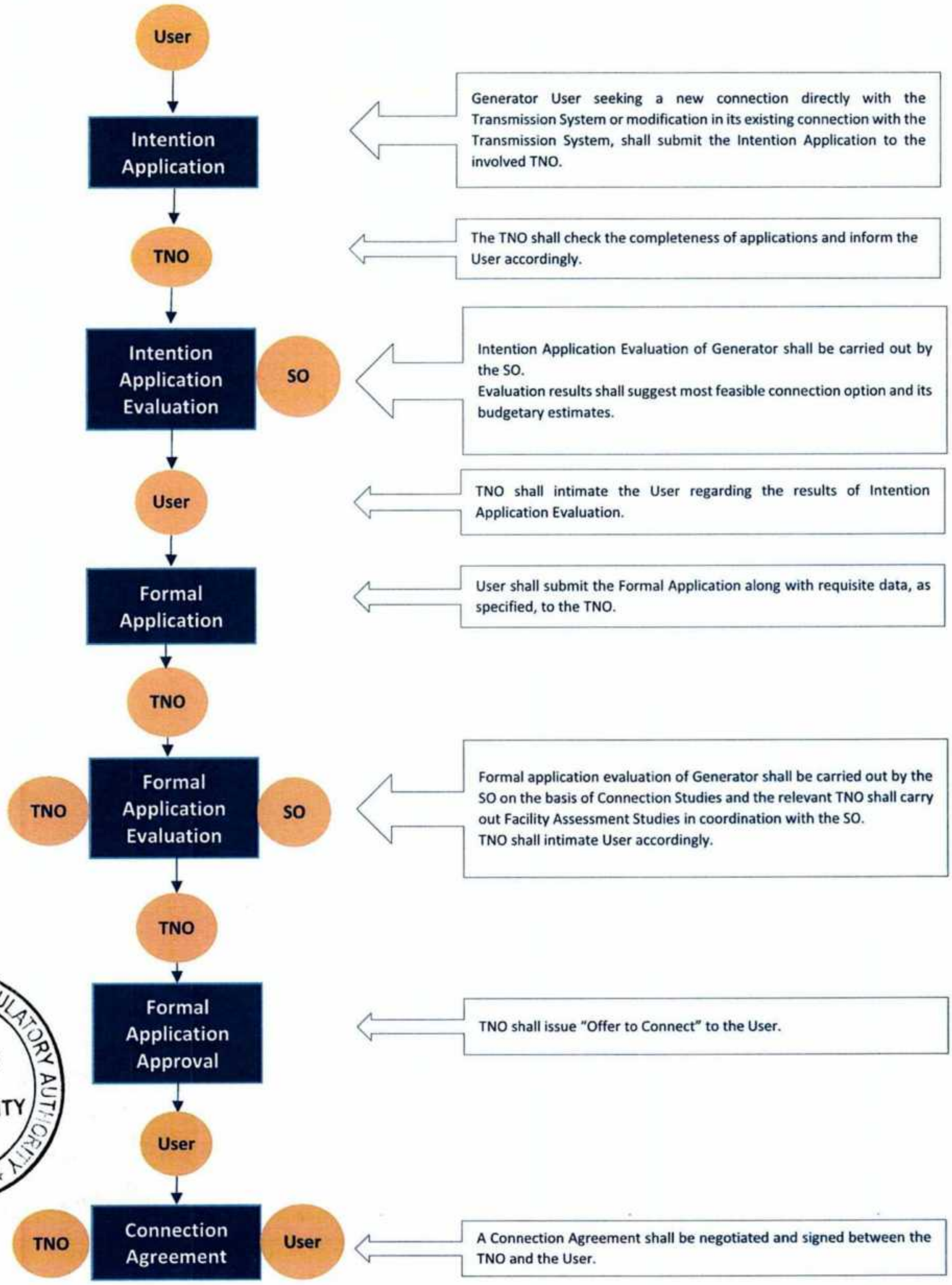


NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

CC Appendix – 4

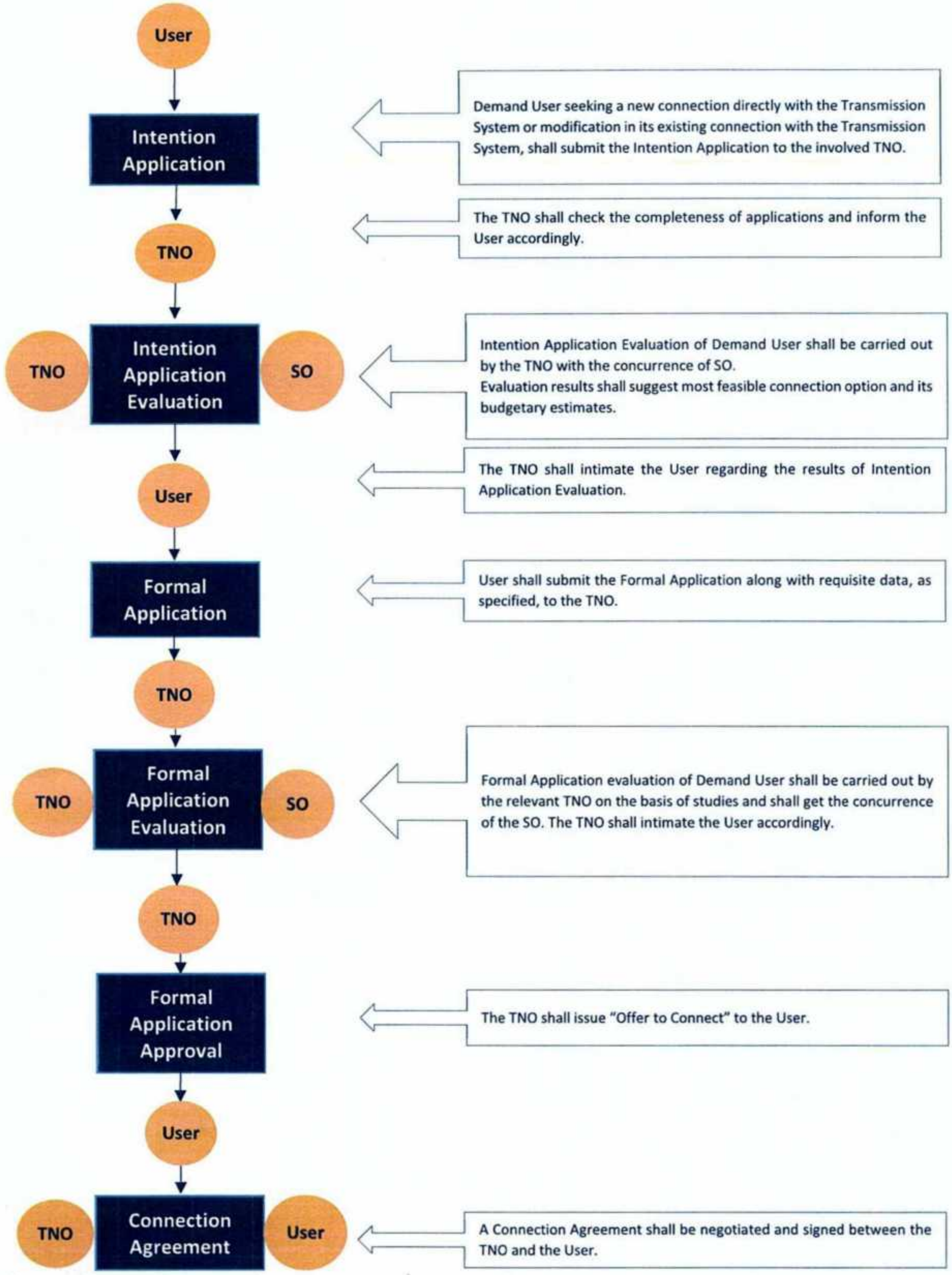
CONNECTION PROCESS

For Generator



NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

For Demand



NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PRO FORMA FOR SITE RESPONSIBILITY SCHEDULE (SRS)

This pro forma should at least contain the following:

1. Number of Schedule, Issue, Number and Date.
2. Name of Complex and Connection Site.
3. Identification of Apparatus.
4. Name of the Owner of the Apparatus.
5. Name of the Person in charge of the Work Site (Authorized Person)
6. Item of Plant Apparatus.
7. Name of the Safety coordinator.
8. Details of the Operations carried out on each Apparatus.
9. Safety Guidelines and Precautions.
10. Operational Procedures.
11. Party Responsible for Undertaking Inspections, Fault Investigation and Maintenance.
12. Remarks

<u>PRO FORMA FOR SITE RESPONSIBILITY SCHEDULE</u>

CC A5.1. Principles
Principles which form the basis of developing SRS

CC A5.2. Types of Schedules

a. Construction	b. Commissioning
c. Control	d. Operation
e. Maintenance	f. Testing

CC A5.3. New connection sites

CC A5.4. Sub-division of connection site, if any

CC A5.5. Description of each item of plant and apparatus at the connection site.

CC A5.6. Additional detail of plant and apparatus, if any.

CC A5.7. Lines and cables emanating from connection sites.

CC A5.8. Issuance of draft SRS

CC A5.9. Accuracy confirmation by concerned parties

CC A5.10. Site responsibility schedule

CC A5.11. Distribution of SRS

CC A5.12. Availability of site responsibility schedules (SRS)

CC A5.13. Alterations/revisions to existing site responsibility schedules, if any

CC A5.14. Revised site responsibility schedules

CC A5.15. Finalization of site responsibility schedules

CC A5.16. Urgent changes

CC A5.17. Names and designation of authorized person and safety coordinators

CC A5.18. De-commissioning of connection sites

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

CC Appendix – 5

PRINCIPLES AND PROCEDURES RELATING TO OPERATION DIAGRAMS

(The Operation Diagram shall include all HV Apparatus and the Connections to all external circuits including Numbering, Nomenclature, and Labelling).

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

CC Appendix – 6

PRINCIPLES AND PROCEDURES RELATING TO GAS ZONE DIAGRAMS

(Areas of the Connection Sites where gas-insulated metal enclosed switchgear and/or gas-insulated HV apparatus is installed shall be depicted by a chain dotted line which intersects the Gas Zone boundaries. A Gas Zone Diagram is to be prepared for each Connection Site where a gas-insulated switchgear/apparatus has been used. These Diagrams shall conform to the Operation Diagrams in terms of Graphical symbols and Nomenclature)

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
* NEPRA *

CC Appendix – 7

APPARATUS TO BE SHOWN ON THE OPERATION AND GAS ZONE DIAGRAMS

List of all apparatus to be shown on the Operation and Gas Zone Diagrams that is installed at the Connection Sites including its present status as it pertains to the System Operation.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 8

MINIMUM FREQUENCY RESPONSE REQUIREMENTS SCOPE

CC A8.1. Scope

CC A8.2. Plant Operating Range

a. Minimum Frequency Response Capability Profile in the graphical form;
b. Interpretation of Initial and Secondary Response Values by the Connecting Party in the graphical form

CC A8.3. Testing of Minimum Frequency Response Capability

CC A8.4. Repeatability of Response

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
* NEPRA *

CC Appendix – 9

TECHNICAL REQUIREMENTS FOR LOW FREQUENCY RELAYS

CC A9.1. Low Frequency Relays

(Technical Specifications and Setting as per Connection Agreement)

CC A9.2. Low Frequency Relay Voltage Supplies

(Secured Voltage supply arrangement for the low frequency relay)

CC A9.3. Scheme Requirements

a. Minimum dependability functional requirements at each Connection Site.

b. Outage requirements with respect to load shedding specified by the System Operator.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

CC Appendix – 10

List of Minimum Requirements for Power System and Apparatus Connected To the Transmission Systems

Generator Information

S. No	Description of Required Information	(Data To Be Filled According To Description)
1	Name of Generator	
2	Location of Generator (Complete Address)	
3	Name of Owner of Generator (e.g. WAPDA, PEDO KPK, AJK, Mr.------ IPP) And Its Address	
4	Type of Generator Hydel (Small, Medium, Large/Run of River, Storage/Low, Medium, High Head), Thermal (Steam, Gas Turbine-Open Cycle, Close Cycle, Diesel Engine), Nuclear, Wind, Solar	
5	Fuel (Water, Coal, RLNG, Gas, FO, LSFO, HSD, Wind, Solar Radiation)	
6	Type of Agreement (e.g. BOO, BOOT, BOT)	
7	PPA Signing Date	
8	Expected Commercial Operation Date (COD)	
9	Agreement Period	
10	Year of Retirement	
11	Installed Capacity (MW)	
12	Derated Capacity (MW)	
13	Available Capacity	
14	Number of Generating Units And Capacity	
15	Type of Generators (Synchronous, Induction)	
16	Total Number of Unit Transformers	
17	Total Number of Auxiliary/Station Transformers	
18	Total No of Power Transformers	
19	Type of Bus Bar Scheme (Breaker And A Half, Single, Ring, Transfer)	
20	Total No of Bays/Dias	
21	Total No of Connected Circuits	
22	Total No of Circuit Breakers	
23	Estimated Power (MW) Required For Auxiliaries	
24	Estimated Auxiliary Consumption (kWh)	
25	Availability of Black Start Facility (Yes/No)	
26	Generating Set Capacity For Black Start Facility	
27	Fuel Requirement Per Hour, Day On Full Load	
28	Fuel Requirement Per Hour, Day On Minimum Load (e.g. Water, Coal, FO, Gas, Wind, Solar Radiation)	
29	Fuel Storage Capacity	
30	Fuel Stock To Be Maintained As Per Applicable Documents	
31	Heat Rate At: • Full Installed Capacity • 80% of Installed Capacity	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

S. No	Description of Required Information	(Data To Be Filled According To Description)
	• 50% of Installed Capacity • Minimum Load	
32	Scheduled Outage Period	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 11

Grid Station Information

S. No	Description of Required Information	(Data To Be Filled According To Description)
1	Name of Grid Station	
2	Location of Grid Station (Complete Address)	
3	Name of Owner of Grid Station (e.g. WAPDA, DNO, PEDO KPK, AJK, Mr.------ IPP) And Its Address	
	Type of Grid Station (i.e. AIS or GIS)	
4	Voltage Levels of Grid Station (e.g. 500/220/132/11 kV)	
5	Type of Bus Bar Scheme (Breaker And A Half, Single, Ring, Transfer)	
6	Total No of Bays/Dias	
7	Total No of Power Transformers	
8	Total No of Transmission Lines Connected Circuits	
9	Total No of Circuit Breakers	
10	Types of Circuit Breakers	
11	No of Auxiliary Transformers	
12	Estimated Power (MW) Required For Auxiliaries	
13	Estimated Auxiliary Consumption (kWh)	
14	No of Reactors	
15	Capacitor Bank Units And Capacity	
16	Land Availability For Future Extension (How Much and For How Many Bays For Transformer/Transmission Lines/Capacitor Banks/Reactors, etc.)	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CC Appendix – 12

DC Converter Station

NAME OF CONVERTER STATION: ____________CONVERTER STATION LOCATION: ________________

S. No	Description	Measurement Units	
1	Name of Converter Station	Name	
2	Rated MW Per Pole For Transfer In Each Direction	MW	
3	DC Converter Type (i.e. Current or Voltage Source)	Name	
4	Number of Poles And Pole Arrangement	Number	
5	Rated DC Voltage/Pole	kV	
6	Return Path Arrangement (Earth, Conductor, etc.)	Description	
7	Rated DC Current Per Pole	Name	
8	Nominal And Maximum (Emergency) Loading Rate With DC Converter In Rectifier Mode	Ampere	
9	Nominal And Maximum (Emergency) Loading Rate With DC Converter In Invertor Mode	Breaker Code	
10	Maximum Recovery Time, To 90% of Pre-Fault Loading, Following The Ac System Fault/Transient DC Network Fault or Severe Voltage Depression	Time In Minutes	
11	Single Line Diagram of Complete DC Network	Attached/Not Attached	
12	Detail of The Complete DC Network Including Resistance, Inductance And Capacitance of All DC Cables and/or DC Lines	Attached/Not Attached	
13	Detail of Any DC Reactors (Including DC Reactor Resistance)	Attached/Not Attached	
14	Detail of DC Capacitor and/or DC-Side Filters That Form Part of DC Network	Attached/Not Attached	
15	Detail of AC Filter Reactive Compensation Equipment Parameters	Attached/Not Attached	
16	DC Converter Control System Model	Model	
17	Detail of Harmonic Assessment Information	Attached/Not Attached	
18	**Any Other Information Required By The SO**		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 13

Power Generators Unit Data

NAME OF GENERATOR: ________________ GENERATOR LOCATION: ____________________

S. No.	Description	Measurement Units	Unit Number (Separate Column For Each Unit)
A	**Generator Identification**		
1	Generator Type	Synchronous/Induction	
2	Manufacturer	Name	
3	Generator Serial Number		
B	**Generator Rating Capabilities**		
1	MVA Rating (Nameplate) (S)	MVA	
2	Hydrogen Pressure (psig)		
3	Winding Connection	Type	
4	Generator Speed	RPM	
5	Angular Velocity of Generator (Ω)	rad/sec	
6	Rated Generation Voltage (Phase To Phase)	kV	
7	Rated Current	Ampere	
8	Power Factor (PF) Lagging (Over Excited)	%age or Value	
9	Power Factor (PF) Leading (Under Excited)	%age or Value	
10	Active (Real) Power (P) Base	MW	
11	Active (Real) Power (P) Maximum	MW	
12	Active (Real) Power (P) Minimum	MW	
13	Reactive (Imaginary) Power (Q) Maximum	MVAR	
14	Reactive (Imaginary) Power (Q) Minimum	MVAR	
15	Continuous Operation Frequency Ranges	Hz	
16	Short Time Frequency Range	Hz	
17	Continuous Operation, Operating Voltage Limits	pu	
18	Short Time Operating Voltage Limits	pu	
19	Field Current At Rated Load	Ampere	
20	Field Current At Full Load, Rated Voltage And Rated Power Factor Overexcited	Ampere	
21	Field Current At Generator Rated Voltage, No Load	Ampere	
22	Field Voltage At Rated Load	V	
23	Nominal Exciter Ceiling Voltage (+ve Polarity)	V or pu	
24	Nominal Exciter Ceiling Voltage (-ve Polarity)	V or pu	
25	Air Gap Field Voltage With Generator At Rated Voltage	V	
26	Field Winding Resistance At Operating Temperature of _______°C	ohm	
27	Short Circuit Ratio (SCR)		
28	Damping (D)		
29	Damping Torque Coefficient (Kd)	pu MW/pu Frequency	
C	**Inertia**		
1	Wr^2 For Generator	kg-m^2 Or lb-ft^2	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

S. No.	Description	Measurement Units	Unit Number (Separate Column For Each Unit)
2	Wr^2 For Exciter (If Applicable)	kg-m^2 Or lb-ft^2	
3	Wr^2 For Turbine	kg-m^2 Or lb-ft^2	
4	"Turbine + Generating Unit" Inertia Constant (H)	MW-sec/MVA	
D	**Losses And Efficiency**		
1	Open Circuit Core Losses	kW	
2	Windage Losses	kW	
3	Seals And Exciter Friction Loss	kW	
4	Stator I2r Loss At _______°C	kW	
5	Rotor I2r Loss At _______°C	kW	
6	Stray Load Loss	kW	
7	Excitation Loss	kW	
E	**Generator Impedances/Reactances/Resistances**		
-	Apparent Power Base	MVA	
-	Voltage Base	kV	
1	Direct Axis Synchronous Reactance (X_d) Unsaturated At Own Base	%age or pu	
2	Quadrature Axis Synchronous Reactance (X_q) Unsaturated At Own Base	%age or pu	
3	Direct Axis Transient Reactance ($X_{d'}$) Unsaturated At Own Base	%age or pu	
4	Direct Axis Transient Reactance (X_{ds}') Saturated At Own Base	%age or pu	
5	Quadrature Axis Transient Reactance (X_q') Unsaturated At Own Base	%age or pu	
6	Quadrature Axis Transient Reactance (X_{qs}') Saturated At Own Base	%age or pu	
7	Direct Axis Sub Transient Reactance (X_d") Unsaturated At Own Base	%age or pu	
8	Direct Axis Sub Transient Reactance (X_{ds}") Saturated At Own Base	%age or pu	
9	Quadrature Axis Sub Transient Reactance (X_q") Unsaturated At Own Base	%age or pu	
10	Quadrature Axis Sub Transient Reactance (X_{qs}") Saturated At Own Base	%age or pu	
11	Negative Phase Sequence Reactance (X2) At Rated Voltage (Unsaturated)	%age or pu	
12	Negative Phase Sequence Reactance (X2s) At Rated Voltage (Saturated)	%age or pu	
13	Zero Phase Sequence Reactance (X0) Unsaturated	%age or pu	
14	Zero Phase Sequence Reactance (X0s) Saturated	%age or pu	
15	Positive Sequence Armature Resistance (R1) At 100°C	%age or pu	
16	Negative Sequence Armature Resistance (R2) At 100°C	%age or pu	
17	Direct Current Armature Resistance (R_{dc}) At	%age or pu	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

S. No.	Description	Measurement Units	Unit Number (Separate Column For Each Unit)
	100°C		
18	Stator (Armature) Resistance (Rs)	%age or pu	
19	Direct Axis Stator Inductance (Lsd)	%age or pu	
20	Quadrature Axis Stator Inductance (Lsq)	%age or pu	
21	Direct Axis Damper Winding Leakage Inductance (L1dλ)	%age or pu	
22	Quadrature Axis Damper Winding 1 Leakage Inductance (L1qλ)	%age or pu	
23	Quadrature Axis Damper Winding 2 Leakage Inductance (L2qλ)	%age or pu	
24	Stator Leakage Inductance (Lsλ)	%age or pu	
25	Field Resistance (Rfd)	%age or pu	
26	Direct Axis Damper Winding Resistance (R1d)	%age or pu	
27	Quadrature Axis Damper Winding 1 Resistance (R1q)	%age or pu	
28	Quadrature Axis Damper Winding 2 Resistance (R2q)	%age or pu	
29	Potier Reactance (Xp)	%age or pu	
30	Armature Leakage Reactance (Xl)	%age or pu	
F	**Generator Time Constants**		
1	Direct Axis Open Circuit Time Constant Transient (T_{do}')	seconds	
2	Direct Axis Open Circuit Time Constant Sub Transient (T_{do}'')	seconds	
3	Quadrature Axis Open Circuit Time Constant Transient (T_{qo}')	seconds	
4	Quadrature Axis Open Circuit Time Constant Sub Transient (T_{qo}'')	seconds	
5	Direct Axis Short Circuit Time Constant Transient (Td')	seconds	
6	Direct Axis Short Circuit Time Constant Sub Transient (Td'')	seconds	
7	Quadrature Axis Short Circuit Time Constant Sub Transient (T_q'')	seconds	
8	Armature Winding Short Circuit Time Constant(Ta)	seconds	
G	**Generator Characteristic Curves**		
1	Generator Reactive Capability Curves	Attached/Not Attached	
2	Generator Voltage - Frequency Capability Curve	Attached/Not Attached	
3	Generator Excitation "V" Curves	Attached/Not Attached	
4	Generator Saturation And Synchronous Impedance Curves Full Load And No Load	Attached/Not Attached	
5	Generator Efficiency - Load Curve	Attached/Not Attached	
6	Generator Output - Air Inlet Temperature Curves At Various PF	Attached/Not Attached	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

S. No.	Description	Measurement Units	Unit Number (Separate Column For Each Unit)
7	Open Circuit And Short Circuit Characteristic Curves	Attached/Not Attached	
8	Permissible Duration of Negative Sequence Current Curve	Attached/Not Attached	
9	Generator Fuel Cost Curve	Attached/Not Attached	
10	Generator Heat Rate Curve	Attached/Not Attached	
11	Generator Input-Output Curve	Attached/Not Attached	
12	Generator Incremental Cost Curve	Attached/Not Attached	
H	**Other Data**		
1	Upward Ramp Rate	MW/min	
2	Downward Ramp Rate	MW/min	
3	Fast (Emergency) Ramp Rate	MW/min	
4	Step Change In Dispatched Load	%/min	
5	Dispatch Levels	Multiple (or) Any Other (One, Two, etc.)	
6	Basic Cost Coefficient "A"		
7	Basic Cost Coefficient "B"		
8	Basic Cost Coefficient "C"		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 14

Generator (Unit) Transformer

NAME OF GENERATOR: _____________ GENERATOR LOCATION: ___________________

S. No	Description	Measurement Units	Unit Number (Separate Column For Each Unit)
1	Transformer Serial No	Digits	
2	Manufacturer Name	Name of Company	
3	Rated Capacity	MVA	
4	Rated Voltage Primary	kV	
5	Rated Voltage Secondary	kV	
6	Rated Voltage Tertiary	kV	
7	Nominal Voltage Ratio, Primary/Secondary	Digits	
8	No of Taps	Number	
9	Tap Side	HV/LV	
10	Maximum Tap Voltage	kV	
11	Minimum Tap Voltage	kV	
12	Voltage Base	kV	
13	Power Base	MVA	
14	Positive Sequence Impedance At Own Base And Maximum Tap	%age	
15	Positive Sequence Impedance At Own Base And Minimum Tap	%age	
16	Positive Sequence Impedance At Own Base And Nominal (Principal)Tap	%age	
17	Zero Phase Sequence Impedance	%age	
18	Tap Changer Range	+% to -%	
19	Tap Changer Step Size	%	
20	Tap Changer Type	On Load/Off Load	
21	Earthing Primary	ohm	
22	Earthing Secondary	ohm	
23	Vector Group		
24	Magnetizing Curve	Attached/Not Attached	
25	Total Iron Losses/Core Losses/No Load Losses (Three Phase)	Watt	
26	Total Copper Losses/Winding Losses/Load Losses (Three Phase)	Watt	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

CC Appendix – 15

Excitation System (AVR and Exciter Parameters)

NAME OF GENERATOR: __________________ GENERATOR LOCATION: __________________

S. No	Description	Measurement Units	Unit Number (Separate Column For Each Unit)
1	Type of Exciter	Rotating (AC or DC Generator) or Static (Thyristor)	
2	Manufacturer	Name	
3	Base Voltage	volts	
4	Regulator Reference Voltage Setting (V_{ref})	volts (or) pu	
5	Regulator Input Voltage (V_i)	volts (or) pu	
6	Voltage Regulator Input Voltage Maximum Or Maximum Integral Control Action Voltage (V_{imax})	volts (or) pu	
7	Voltage Regulator Input Voltage Minimum Or Minimum Integral Control Action Voltage(V_{imin})	volts (or) pu	
8	Regulator Output Voltage (V_r)	volts (or) pu	
9	Voltage Regulator Output Voltage Maximum Limit "Or" Power Convertor Positive Ceiling Voltage (V_{rmax})	volts (or) pu	
10	Voltage Regulator Output Voltage Minimum Limit "Or" Power Convertor Negative Ceiling Voltage(V_{rmin})	volts (or) pu	
11	Maximum Proportional Control Action Voltage (V_{pmax})	volts (or) pu	
12	Minimum Proportional Control Action Voltage (V_{pmin})	volts (or) pu	
13	Auxiliary Signal (V_s)	volts (or) pu	
14	Exciter Voltage At Which Exciter Saturation Is Defined	volts (or) pu	
15	Maximum Exciter Field Current Feed Back Signal (V_{hmax})	volts (or) pu	
16	Exciter Field Current Limit Reference (V_{felim})	volts (or) pu	
17	Voltage Regulator Time Constant (Ta)	seconds	
18	Voltage Regulator Lag Time Constant (Tb)	seconds	
19	Voltage Regulator Lead Time Constant (Tc)	seconds	
20	Derivative Filter Time Constant (Td) or Regulator Derivative Block Time Constant (Tdr)	seconds	
21	Exciter Time Constant Or Rotating Exciter Time Constant (Te)	seconds	
22	Excitation Control System Stabilizer Time Constant (Tf) or Rate Feedback Excitation System Stabilizer Time Constant (Tf)	seconds	
23	Exciter Field Current Limiter Time Constant (Th)	seconds	
24	Resetting Time (Tr) or Regulated Output Filter Time Constant or Regulator Input Filter Time Constant	seconds	
25	Rheostat Time Constant (Trh)	seconds	
27	Voltage Regulator Gain (Ka)	pu	
28	Rectifier Loading Factor Proportional To Commutating Reactance (Kc)	pu	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

S. No	Description	Measurement Units	Unit Number (Separate Column For Each Unit)
29	Demagnetization Factor or Derivative Gain (Kd) or Regulator Derivative Gain (Kdr)	pu	
30	Exciter Constant Related To Self-excited Field or Rotating Exciter Gain (Ke)	pu	
31	Excitation Control System Stabilizer Gain (Kf)	pu	
32	Exciter Field Current Limiter Gain (Kh)	pu	
33	Current Circuit Gain or Avr Integral Gain (Ki) or Regulator Integral Gain (Kir)	pu	
34	Voltage Regulator Integral Gain (Kia)	pu	
34	Potential Circuit Gain or AVR Proportional Gain (Kp) or Regulator Proportional Gain (Kpr)	pu	
35	Voltage Regulator Proportional Gain (Kpa)		
36	Terminal Voltage Transducer Time Constant (Tr)	pu	
37	Exciter Saturation Function (Se)	-	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

CC Appendix – 16

Generating Units Stabilizer Data

NAME OF GENERATOR: ____________________ GENERATOR LOCATION: __________________

S. No	Description	Measurement Units	Unit Number (List Information In Separate Column For Each Unit)
1	Type of Stabilizer		
2	Stabilizer Model		
3	Gain Block Data		
4	PSS Gain (List All K_s)		
5	Wash Out Circuit Data (High Pass Filter)		
6	Wash-Out Time Constant (Mention All Time Constants Separately)		
7	Phase Compensation Block Data		
8	Limiter Data		
9	PSS Output Limiter (Max) V_{stmax}		
10	PSS Output Limiter (Min) V_{stmin}		
11	Lead/Lag Time Constant		
12	Lead Time Constant (Mention All Time Constants)		
13	Integral Time Constant (T8)		
14	Ramp-Tracking Time Constant (T9)		
15	Filter Time Constant (T10)		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 17

Governor Data

NAME OF GENERATOR: ____________ GENERATOR LOCATION: ____________________

S. No	Description	Measurement Units	Unit Number
A	**Hydel Turbine**		
1	Permanent Speed Droop "R" (i.e. Reciprocal of Proportional Gain Kp)		
2	Temporary Droop (R)		
3	Governor Time Constant (Tr)		
4	Filter Time Constant (Tf)		
5	Servo Time Constant (Tg)		
6	Gate Velocity Limit (Velm)		
7	Maximum Gate Limit (G_{max})		
8	Minimum Gate Limit (G_{min})		
9	Water Time Constant (Tw)		
10	Turbine Gain (At)		
11	Turbine Damping (D_{turb})		
12	No Load Flow (Qni)		
B	**Gas Turbine**		
1	Permanent Speed Droop "R" (i.e. Reciprocal of Proportional Gain Kp)		
2	Governor Time Constant (T1)		
3	Combustion Chamber Time Constant (T2)		
4	Load Limit Time Constant (Exhaust Gas Measurement Time)- (T3)		
5	Load Limit Feed Back Gain (Kt)		
6	Speed Damping Coefficient of Gas Turbine Rotor (D_{turb})		
7	Operational Control High Limit On Fuel Valve Opening (V Max)		
8	Low Output Control Limit On Fuel Valve Opening (V Min)		
9	Ambient Temperature Load Limit (At)		
C	**Steam Turbine**		
1	Permanent Speed Droop "R" (i.e. Reciprocal of Proportional Gain Kp)		
2	Governor Time Constant (T1)		
3	Combustion Chamber Time Constant (T2)		
4	Load Limit Time Constant (Exhaust Gas Measurement Time)- (T3)		
5	Load Limit Feed Back Gain (Kt)		
6	Speed Damping Coefficient of Gas Turbine Rotor (D_{turb})		
7	Operational Control High Limit On Fuel Valve Opening (V Max)		
8	Low Output Control Limit On Fuel Valve Opening (V Min)		
9	Ambient Temperature Load Limit (At)		

S. No	Description	Measurement Units	Unit Number
D	**Reciprocating Engine**		
1			
2			
E	**Any Other Data**		
1			
2			

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

CC Appendix – 18

Prime Mover Data

NAME OF GENERATOR: _______________ GENERATOR LOCATION: __________________

S. No	Description	Measurement Units	Unit Number
	Hydel Turbine		
1	Rated Capacity	MW	
2	Water Time Constant	seconds	
3	Inertia Constant (H)	seconds	
4	Rated Speed	RPM	
5	Maximum Speed	RPM	
6	Minimum Speed	RPM	
	Steam Turbine		
1	Rated Capacity	MW	
2	Power Fraction For High Pressure (Hp), (Intermediate Pressure (Ip) And Low Pressure (Lp) Turbine		
3	Functional Description And Black Diagram Showing Transfer Function of Individual Element of Governor, Turbine And Boiler	Attached/Not Attached	
4	Hp Steam Extraction Range (Expressed In Terms of The Boiler Rated Output)		
5	Detail of HP Steam Extraction Valves	Attached/Not Attached	
6	General Boiler Control Strategy	Attached/Not Attached	
7	Test Data/Reports Load Rejection Data Load Step Response Tests Frequency Response Test	Tests Conducted/Data Attached	
8	Control And Intercept Valve Curves Position vs Signal Valve Opening Vs Signal Closing/Opening Speed Tests	Attached/Not Attached	
9	Rated Speed	RPM	
10	Maximum Speed	RPM	
11	Minimum Speed	RPM	
	Gas Turbine Open Cycle And Combined Cycle		
1	Rated Capacity	MW	
2	Performance Data/Curves Power vs Fuel Consumption Exhaust Temperature vs Fuel Consumption Power vs Ambient Temperature Power vs Speed Inlet Guide Van Effect	Attached/Not Attached	
3	Functional Description And Black Diagram of Gas Turbine Units Showing Transfer Function of Individual Element Including Effect of Ambient Temperature	Attached/Not Attached	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

S. No	Description	Measurement Units	Unit Number
4	Test Data/Reports Load Rejection Data Load Step Response Tests Frequency Response Test	Tests Conducted/Data Attached	
5	Rated Speed	RPM	
6	Maximum Speed	RPM	
7	Minimum Speed	RPM	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 19

Wind Turbine Generator

NAME OF GENERATOR: ____________________ GENERATOR LOCATION: ______________________

S. No	Description	Measurement Units	Unit Number
1	Rated Capacity	MW	
2	Generator Type: Cage Rotor, Doubly Fed Induction Generator Or Synchronous, Constant Speed Or Variable Speed		
3	Inertia Constant (H)	seconds	
4	Power Converter Rating Where Applicable		
5	Frequency Tolerances (i) Frequency Range Within Which Continuous Operation Is Guaranteed (ii) Time Based Capabilities For Frequencies Lower And Above The Limits Where Continuous Operation Is Guaranteed	Hz	
6	Voltage Tolerances (i) Continuous Operation (ii) Time Based Capabilities For Voltages Lower And Above The Limits Where Continuous Operation Is Guaranteed	kV	
7	Low Voltage Ride Through (LVRT/FRT) -- Curve Showing The Tolerable Drop In Voltage, Setting Time To Resume Normal Output	kV-min	
8	Unbalance Loading: ----Negative Phase Sequence Withstand	MW	
9	Active Power Regulation: ----Ramp Rate (% of Rated Output Per Minute)	MW/min	
10	Frequency Control: ----Frequency Response (Regulate The Output Above A Certain Defined Frequency, Say 50.2)	Hz	
11	Reactive Power Capability: ----Limits On Lagging And Leading Power Factor Within Which The Rated Output Can Be Guaranteed	MVAR	
12	Reactive Power Capability: ----P-Q Capability Curve	Attached/Not Attached	
13	Minimum Wind Speed Limit Required For Operation	M/Second	
14	Maximum Wind Speed Limit Required For Operation	M/Second	
15	Flicker Limitation		
16	Harmonics With Standing Level		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 20

Transmission Lines Data

NAME OF TRANSMISSION LINE: ________________ OWNER OF TRANMSISSION LINE: ___________

S. No	Description	Measurement Units	Transmission Line Number
1	Name of Transmission Line	Name	
2	Station 1	Name	
3	Station 2	Name	
4	Voltage	kV	
5	Circuit No	Number	
6	Length of Line	km	
7	Conductor Name	Name	
8	No of Conductors Per Phase (No of Bundle Conductors)	Number	
9	Controlling Breakers At Station-1	Breaker Code	
10	Manufacturer Name of Controlling Breakers At Station-1	Name	
11	CT Ratio of Breakers At Station-1 For Protection	Amp Ratio	
12	CT Ratio of Breakers At Station-1 For Metering	Amp Ratio	
13	Controlling Breakers At Station-2	Breaker Code	
14	Manufacturer Name of Controlling Breakers At Station-2	Name	
15	CT Ratio of Breakers At Station-2 For Protection	Amp Ratio	
16	CT Ratio of Breakers At Station-2 For Metering	Amp Ratio	
17	Thermal Loading Capacity of Transmission Line	Amp/MW	
18	Surge Impedance Loading (SIL)	MW	
19	SIL Factor (St. Clair Curve)	Number	
20	Loading Limit Fixed By Field Formation	Amp/MW	
21	Positive Sequence Parameters Base MVA	Value of Base MVA	
22	Positive Sequence Resistance (R1)	ohm	
23	Positive Sequence Resistance (R1) On Base MVA	Percentage/pu	
24	Positive Sequence Reactance (X1)	ohm	
25	Positive Sequence Reactance On (X1) Base MVA	Percentage/pu	
26	Positive Sequence Susceptance (B1)	Mohs	
27	Positive Sequence Susceptance (B1) On Base MVA	Percentage/pu	
28	Zero Sequence Resistance (R0)	ohm	
29	Zero Sequence Resistance (R0) On Base MVA	Percentage/pu	
30	Zero Sequence Reactance (X0)	ohm	
31	Zero Sequence Reactance On (X0) Base MVA	Percentage/pu	
32	Zero Sequence Susceptance (B0)	Mohs	
33	Zero Sequence Susceptance (B0) On Base MVA	Percentage/pu	
34	Number of Towers of Transmission Line	Numbers	
35	Type of Towers	Types	
36	Single Circuit Towers or Double Circuit	Single/Double	
37	If Double Circuit Towers Installed, Then Double Circuit Exist or Not Exist	Exist/Not Exist	
38	If Double Circuit Exist, Then Name of Double Circuit Transmission Line	Name	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 21

Power Transformer Data

NAME OF GENERATOR SWITCHYARD/GRID STATION: ______________________________

LOCATION OF GENERATOR SWITCHYARD/GRID STATION: ___________________________

S. No	Description	Measurement Units	Transformer Number
1	Transformer Serial No	Digits	
2	Manufacturer Name	Name of Company	
3	Commissioning Date	Date	
4	Type of Transformer	Two Winding/Three Winding/Auto Transformer/Auto Transformer With Tertiary	
5	No of Units (i.e. One Three Phase Unit Or Three Single Phase Units)	One-3p Unit or Three-Sp Units	
6	Rated Capacity	MVA	
7	Vector Group (e.g. Dy11, Dd10, etc.)	Name of Group	
8	Year of Manufacturing	Year	
9	Year of Commissioning	Year	
10	Standard/Class	Specification	
11	Type of Cooling	AN, AF, ON, OF, ANOF, AFOF, AFON, ONWF	
12	Max Rated Capacity At Ultimate Cooling Method	MVA at (Cooling Method)	
13	Rated Voltage Primary	kV	
14	Rated Voltage Secondary	kV	
15	Rated Voltage Tertiary	kV	
16	Nominal Voltage Ratio, Primary/Secondary	Digits	
17	Rated Current Primary	Amp	
18	Rated Current Secondary	Amp	
19	Rated Current Tertiary	Amp	
20	Max Rated Current At Ultimate Cooling Method	Amp at (Cooling Method)	
21	No Load Excitation Current	Amp	
22	No of Taps	Number	
23	Tap Side	HV/LV	
24	Tap Changer Type	On Load/Off Load	
25	Tap Changer Range	+% To -%	
26	Tap Changer Step Size	% or pu	
27	Nominal Tap Position	No	
28	Maximum Tap Position	No	
29	Minimum Tap Position	No	
30	Maximum Tap Voltage	kV	
31	Minimum Tap Voltage	kV	
32	Voltage Base	kV	
33	Power Base	MVA	
34	Positive Sequence Impedance At Own Base	%age	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

S. No	Description	Measurement Units	Transformer Number
	And Maximum Tap		
35	Positive Sequence Impedance At Own Base And Minimum Tap	%age	
36	Positive Sequence Impedance At Own Base And Nominal (Principal)Tap	%age	
37	Zero Phase Sequence Impedance	%age	
38	Total Iron Losses/Core Losses/No Load Losses (Three Phase)	Watt	
39	Total Copper Losses/Winding Losses/Load Losses (Three Phase)	Watt	
40	Reactance Between Primary And Secondary Winding (Z1-2) In Three Winding Transformer	ohm	
41	Base MVA For Primary And Secondary Winding For Three In Three Winding Transformer	MVA 1-2	
42	%age or Pu Reactance Between Primary And Secondary Winding (Z1-2) In Three Winding Transformer	% or pu	
43	Reactance Between Primary And Tertiary Winding (Z1-3) In Three Winding Transformer	ohm	
44	Base MVA For Primary And Tertiary Winding For Three In Three Winding Transformer	MVA 1-3	
45	%age or pu Reactance Between Primary And Tertiary Winding (Z1-3) In Three Winding Transformer	% or pu	
46	Reactance Between Secondary And Tertiary Winding (Z2-3) In Three Winding Transformer	ohm	
47	Base MVA For Secondary And Tertiary Winding For Three In Three Winding Transformer	MVA 2-3	
48	%age or pu Reactance Between Secondary And Tertiary Winding (Z2-3) In Three Winding Transformer	% or pu	
49	Winding Contact Type Primary	Delta/Star	
50	Grounding Resistance	ohm	
51	Grounding Reactance Primary	ohm	
52	Grounding Type Primary	Resistance/Inductance, etc.	
53	No of Primary Transformer	Units	
54	Winding Contact Type Secondary	Delta/Star	
55	Grounding Resistance Secondary	ohm	
56	Grounding Reactance Secondary	ohm	
57	Grounding Type Secondary	Resistance/Inductance, etc.	
58	No of Secondary Transformer	Units	
59	Winding Contact Type Tertiary	Delta/Star	
60	Grounding Resistance Tertiary	ohm	
61	Grounding Reactance Tertiary	ohm	
62	Grounding Type Tertiary	Resistance/Inductance, etc.	
63	No of Tertiary Transformer	Units	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

S. No	Description	Measurement Units	Transformer Number
64	Earthing Primary	ohm	
65	Earthing Secondary	ohm	
66	CT Used For Current Measurement	Ampere	
67	Magnetizing Curve	Attached/Not Attached	
68	Table of Current And Voltage With Respect To Tap Position	Attached/Not Attached	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 22

Bus Bar Data

NAME OF GENERATOR SWITCHYARD/GRID STATION: ______________________________

LOCATION OF GENERATOR SWITCHYARD/GRID STATION: ___________________________

S. No	Description	Measurement Units	Bus Bar Number
	Ac Sub Stations		
1	Bus Bar Scheme Used For Bus Bar (i.e. Double Bus Bar Breaker And Half, Transfer Bus, Single Bus Bar Single Breaker, etc.)	Name	
2	Bus Bar Type	Solid Bars/Hollow Tube, Rectangular, Round, etc.	
3	Conductor/Tube Name For Bus Bar	Name	
4	Material of Conductor (i.e. Copper, Aluminum, Alloy, etc.) Used For Bus Bar	Name	
5	Ampere Capacity of Bus Bar	Ampere	
	HVDC Convertor Station		
6			
7			

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 23

Circuit Breaker Data

NAME OF GENERATOR SWITCHYARD/GRID STATION: ______________________________

LOCATION OF GENERATOR SWITCHYARD/GRID STATION: ___________________________

S. No	Description	Measurement Units	Breaker Number
1	**Voltage Level**		
2	Circuit Breaker Code	Code	
3	Breaker Manufacturer Name	Name	
4	Interrupting Media Used For CB	SF6, Air Pressurized, Oil, Vacuum, etc.	
5	Operating Mechanism Used For CB	Hydraulic. Pneumatic, Motor, Spring, etc.	
6	No of Interrupter Per Pole of CB	Numbers	
7	CB Commissioning Date	Date	
8	Asymmetrical Fault Rating	Ampere	
9	Symmetrical Fault Rating	Ampere	
10	Rated Impulse Standing Voltage	kV	
11	Rated Normal Current Rating	Ampere	
12	CT Ratio Used For Protection	Ratio of Amps	
13	CT Ratio Used For Metering	Ratio of Amps	
14	CT Type Used For 765 kV Breaker	Double Core, Multicore With Ratio ____/____/____/____	
15	**___ kV DC Breaker**		
16	___ kV Circuit Breaker Code	Code	
17	___ kV Breaker Manufacturer Name	Name	
18	Interrupting Media Used For ___ kV CB	SF6, Air Pressurized, Oil, Vacuum, etc.	
19	Operating Mechanism Used For ___ kV CB	Hydraulic, Pneumatic, Motor, Spring, etc.	
20	No of Interrupter Per Pole of ___ kV CB	Numbers	
21	___ kV CB Commissioning Date	Date	
22	___ kV CB Asymmetrical Fault Rating	Ampere	
23	___ kV CB Symmetrical Fault Rating	Ampere	
24	___ kV CB Rated Impulse Standing Voltage	kV	
25	___ kV CB Rated Normal Current Rating	Ampere	
26	___ kV CB CT Ratio Used For Protection	Ratio of Amps	
27	___ kV CB CT Ratio Used For Metering	Ratio of Amps	

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

S. No	Description	Measurement Units	Breaker Number
28	Current Measuring Device Type Used For ___ kV Breaker		
29	Any Other Information Required By The TNO or The SO		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 24

Isolators Data

NAME OF GENERATOR SWITCHYARD/GRID STATION: ______________________________

LOCATION OF GENERATOR SWITCHYARD/GRID STATION: ____________________________

S. No	Description	Measurement Units	Isolator Number
1	**AC Voltage Level**		
2	Isolator Code	Code	
3	Isolator Manufacturer Name	Name	
4	Interrupting Media	SF6, Air Pressurized, Oil, Vacuum, etc.	
5	Operating Mechanism	Hydraulic, Pneumatic, Motor, etc.	
6	Type of Isolator (Vertical, Horizontal Pentograph, etc.)	Name	
7	Commissioning Date	Date	
8	Ampere Capacity	Ampere	
	___ kV DC		
1	___ kV Isolator Code	Code	
2	___ kV Isolator Manufacturer Name	Name	
3	Interrupting Media Used For ___ kV Isolator	SF6, Air Pressurized, Oil, Vacuum, etc.	
4	Operating Mechanism Used For ___ kV Isolator	Hydraulic, Pneumatic, Motor, etc.	
5	Type of ___ kV Isolator (Vertical, Horizontal Pentograph, etc.)	Name	
6	___ kV Isolator Commissioning Date	Date	
7	___ kV Isolator Ampere Capacity	Ampere	
8	Any Other Information Required By The TNO or SO		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CC Appendix – 25

Shunt Reactors Data

NAME OF GENERATOR SWITCHYARD/GRID STATION: ____________________

LOCATION OF GENERATOR SWITCHYARD/GRID STATION: ____________________

S. No	Description	Measurement Units	Reactor -1
1	Shunt Reactor Code	Code No	
2	Shunt Reactor Type	Name	
3	Manufacturer Name		
4	Voltage	kV	
5	Capacity of Reactor	MVAR	
4	Inductance of Reactor	Henry	
5	Reactance of Reactor	ohm	
6	Base of Reactor	MVAR	
7	%age Reactance of Reactor on Own Base	% or pu	
8	Line Name With Which Reactor Installed	Name	
9	Reactor Control (CB or Isolator)	Name	
10	Reactor Controlling Breaker/Isolator ID	Code No	
11	Any Other Info Required By The TNO or SO		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OPERATION CODE

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 1. OPERATING OBJECTIVES AND PRINCIPLES

OC 1.1. Introduction

The Operation Code (OC) specifies the technical and operating criteria, and procedures to be followed by the SO and Code Participants in the operation of the National Grid. The SO shall be responsible for the Safe, Secure and Reliable operation of the National Grid. The Code Participants shall follow the technical design and operating criteria and procedures as specified in the Grid Code.

The functions and responsibilities of the SO are subject to the conditions as specified in the SO Licence, and include Operation, Control and discipline of the Transmission System.

The Operation Code is comprised of 13 sub-codes as mentioned below:

(a) OC 1: Operating Objectives and Principles

(b) OC 2: Operational Demand Forecasts

(c) OC 3: Demand Control

(d) OC 4: Operational Planning

(e) OC 5: System Services

(f) OC 6: Network Control

(g) OC 7: HVDC Operation and Performance

(h) OC 8: Operational Liaison

(i) OC 9: Operational Communication and Data Retention

(j) OC 10: Operational Testing

(k) OC 11: Monitoring, Testing and Investigation

(l) OC 12: System Recovery

(m) OC 13: Work Safety

OC 1.2. Operating Principles

The SO shall prepare an operating plan prior to bringing scheduled generation on-bar for the next day to meet the forecasted load demand. Procedures for implementation of the plan are described in the Scheduling and Dispatch Code.

The operating plan shall take into consideration the following operating principles:

(a) Adequate capability for Voltage regulation and Frequency Control must be ensured in the System at all times under Normal operating conditions;

(b) Proper Outage coordination and assessment of System Security impacts should be carried out prior to real-time Operations;

(c) Transmission congestion management and contingency event management must be provided in accordance with the Operating Criteria and principles laid down in the operation sub-code Network Control (OC 6) of this sub-code;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(d) Adequate reactive reserve management and Voltage regulation must be carried to meet the operating standards stated in OC 5 of this Code;

(e) Adequate Ancillary Services must be ensured prior to real-time operations;

(f) Provision of adequate protection and control based on the requirements laid down in Protection and Control Code must be provided by the Users;

(g) Functioning of dual communication systems during System Operation and Dispatch must be ensured by the SO and Code Participants using devices as described in OC 9 of this code;

(h) Provision of pre-operational plans regarding Black Start Facilities and pre-tested system restoration plan under Black Out conditions must be ensured by the System Operator, via restoration plan revisions as given in OC 12;

(i) The SO must ensure in the operating plan that all the thermal loadings, system Voltages, System Frequency, system stability (both steady-state and transient) are well within established limits as provided in the OC 5 and 6, of this sub-code;

(j) The HVAC system shall at all times be operated in harmony with HVDC in such a way as to achieve the best possible overall performance of the integrated HVAC and HVDC Transmission System;

(k) The SO shall periodically carry out necessary Transmission System studies, simulations and tests (e.g. fast fault current injection, fault ride through capability, power oscillations damping control etc.) for expected system event scenarios (e.g. major outages of equipment, HVDC pole failure etc.) that could lead to transient instability (unsatisfactory system dynamic performance and loss of power angle stability), voltage instability, small signal instability, and/or lack of power system oscillation damping;

(l) The SO shall maintain and be able and ready to implement, when required, standard operating procedures and Defense Plans (including manual control actions, cross-trip schemes, Stability Control Systems, Remedial Action Schemes) designed to mitigate the extent of disturbance resulting from a system event/contingency as established in this Grid Code.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 2.	**OPERATIONAL DEMAND FORECASTS**
OC 2.1.	**Introduction**

OC 2.1.1. This Operational Demand Forecast sub-code (OC 2) specifies the process and information requirements for preparing Operational Demand Forecasts by the SO for different Operational Planning Horizons to match supply with demand on the Transmission System. The Demand Forecast shall include forecast for Active and Reactive Power.

OC 2.1.2. Demand Forecasts and reporting shall be conducted on four (4) Operational Planning Horizons:

(a) Pre-Operational Phase (Year 1 and Year 2);

(b) Operational Phase, (3-Month ahead of the Schedule Day);

(c) Control Phase, (day ahead of the Schedule Day and real-time operation); and

(d) Post Control Phase (the day following the Schedule Day).

OC 2.1.3. OC 2 also deals with the provision of data on Demand Control by the Users in the four (4) Operational Planning Horizons as listed in (OC 2.1.2) above.

OC 2.1.4. The SO shall develop demand forecasts by taking into account the information/forecasts supplied by the Users and by considering any other external factors as described in OC 2.6.1.

OC 2.1.5. In this OC 2, Year 0 means the current calendar year, Year 1 means the next calendar year, and Year 2 means the calendar year following Year 1 and so on.

OC 2.1.6. References in OC 2 to data being supplied on an hourly basis refer to these being supplied for each period of 60 minutes ending on the hour (or any sub-hourly period that may be specified by the SO).

OC 2.1.7. Reactive Power Demand shall be determined at the Connection Point and shall include the reactive losses of the User's System but exclude any network susceptance and any reactive compensation connected at the Voltage levels equal to or above 66 kV. The SO shall obtain the lumped network susceptance values and details of the reactive compensation from the data supplied by the User pursuant to the Planning Code.

OC 2.1.8. The timelines and data resolutions specified in this OC 2 may be modified by the SO from time to time subject to notifying in advance to the Users.

OC 2.2. Objectives

OC 2.2.1. The objectives of OC 2 are to:

(a) Ensure the provision of data to the SO by Users for all Operational Planning Horizons by the specified time and in the requisite format; and

(b) Describe the factors that the SO will take into account when preparing Demand Forecasts.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

OC 2.3. **Scope**

OC 2 applies to the SO and:

(a) Transmission Network Operators;

(b) Distribution Network Operators;

(c) Energy Storage Units;

(d) Electric Power Suppliers;

(e) Transmission Connected Consumers;

(f) Interconnectors; and

(g) Energy Storage Units in respect of their demand (energy planned to be taken from the network).

OC 2.4. **Data Required by the SO in the Pre-Operational Phase**

OC 2.4.1. No later than 1st of March each Year, the SO shall notify to each User in writing (or by publishing on its website) the following (for Year 1 and Year 2):

(a) the date and time of the SO's expected annual peak Demand at annual maximum Demand conditions; and

(b) the date and time of the SO's expected annual minimum Demand at average conditions.

OC 2.4.2. For Pre-Operational Phase, the Users shall provide to the SO the following data in writing (or by such electronic data transmission facilities as have been agreed with the SO), by end-March of Year 0:

(a) profiles of the User's anticipated hourly Demand summed over all its Connection Points and for each Connection Point (or as otherwise specified by the SO e.g. district wise), for defined categories of day types as mentioned in OC 2.4.1;

(b) profiles of the User's anticipated hourly Demand summed over all Connection Points and for each Connection Point (or as otherwise specified by the SO e.g. district wise), for the day of that User expects its own maximum/minimum Demand;

(c) annual Active Energy requirements for Average Conditions segregated when applicable and practical into different usage categories such as, residential, commercial, industrial, agriculture, etc., (summed over all Connection Points);

(d) For Year 1, profiles of the anticipated Energy and Peak Demand on monthly basis, summed over all Connection Points and for each Connection Point (or any other basis specified by the SO, e.g. district wise);

(e) Users shall supply MW profiles of the amount and duration of anticipated demand management which may result in a Demand change of 10 MW or more on hourly and Connection Point basis;

(f) For DNOs, typical MW profiles for the operation, or Availability as appropriate, of Embedded Generation within their respective systems,

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

where the total Registered Capacity of these Generating units on a single Site exceeds ten (10) MW for defined categories of the day type as determined by the SO (and for all other profiles as well). The method for submitting MW schedules and/or Availability shall be agreed between the SO and the DNOs, such agreement not to be unreasonably withheld;

(g) For Transmission Connected Consumers the required information shall be provided by its relevant TNO (or by its relevant Supplier if agreed and notified with the SO), provided that the obligation of the submission remains with the Transmission Connected Consumer;

(h) Notwithstanding OC 2.4.2 (f), if the SO considers the Site to be critical for System Operation, it may request the Users MW profiles for the operation, or Availability as appropriate, of Embedded Generation where the total Registered Capacity of Generating units on a single Site exceeds five (5) MW, for defined categories of day type as determined by the SO. The method for submitting MW schedules and/or Availability shall be agreed between the SO and the Users, such agreement not to be unreasonably withheld;

(i) While consolidating the demand forecasts provided by individual Users, the SO will also take into account estimated Transmission System losses, based on historical and other relevant factors.

OC 2.5. Data Required by the SO for the Operational Phase

OC 2.5.1. Three (3) months ahead of the real-time, the Users shall provide to the SO the following information in writing by 1000 hours on first working day of each month (the three (3) month period being a rolling period):

(a) profiles of the anticipated daily Energy and Peak Demand, summed over all Connection Points and for each Connection Point (or any other basis specified by the SO e.g. district wise).

(b) MW profiles of the amount and duration of their proposed daily demand management which may result in a Demand change of ten (10) MW or more on any Connection Point.

(c) Daily MW average of the Embedded Generators within their system, with Registered Capacity of ten (10) MW or more. (Or less than ten (10) MW in case of critical Sites as determined by the SO).

OC 2.5.2. By 1000 hours each Wednesday, the Users shall provide to the SO the following information for the next seven (7) days ahead of the Schedule Day:

(a) Profiles of the anticipated Energy and Peak Demand on hourly basis, summed over all Connection Points and for each Connection Point basis (or any other basis specified by the SO e.g. district wise).

(b) MW profiles of the amount and duration of their proposed hourly demand management which may result in a Demand change of ten (10) MW or more, on any Connection Point.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(c) Hourly MW profile of the Embedded Generators within their system, with Registered Capacity of ten (10) MW or more. (Or less than ten (10) MW in case of critical Sites as determined by SO).

OC 2.6. Development of Operational Demand Forecast by SO

OC 2.6.1. The SO shall develop demand forecast consolidating the information/forecasts provided by Users pursuant to OC 2.5, and by also considering the following additional factors, if necessary:

(a) Historical Demand data;

(b) Weather forecasts and the current and historical weather conditions;

(c) The incidence of major events or activities which are known to the SO in advance;

(d) Transmission System losses and auxiliary consumption;

(e) Embedded Generation;

(f) Any other relevant Socioeconomic development in the country;

(g) Demand management of ten (10) MW or proposed to be exercised by the User and of which the SO has been informed; and

(h) Any other information required by the SO from the Users.

OC 2.6.2. The SO shall develop Demand Forecast using appropriate forecast methodologies and tools, by incorporating the demand forecast provided by Users and further taking into account factors specified in OC2.6.1.

OC 2.6.3. For all Operational Planning Horizons, the Users shall inform the SO of any changes to the information provided as soon as this information is available. This information shall be provided in writing, or as otherwise agreed between the Users and the SO, such agreement not to be unreasonably withheld.

OC 2.6.4. The forecasts developed under OC 2.6 shall be used during Operational Planning, Scheduling and Dispatch and system studies/simulations.

OC 2.7. Post Control Phase

The Users shall provide the following data to the SO in writing (or by such electronic data transmission facilities as have been agreed with the SO) by 0200 hours each day in respect of Active Power data and Reactive Power data for the previous Schedule Day:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(a) MW profiles of the amount and duration of Demand Control produced or instructed by the SO on hourly and Connection Point basis or any other demand management carried out by the User; and

(b) details of hourly Active Power output and Reactive Power produced or absorbed by Embedded Generation, with a single Site with Registered Capacity in excess of ten (10) MW.

OC 2.8. Accuracy of Demand Forecasts provided by Users to the SO

OC 2.8.1. The SO shall assess the accuracy of Users' demand forecasts against actual demand over the relevant Planning Horizon.

OC 2.8.2. The performance of the forecasts provided shall be assessed based on the mean absolute percentage error (MAPE) indicators and values provided for different Planning Horizons in Table OC 1. A similar assessment shall be done for demand forecasts by the SO.

Table OC 1: Performance Requirements for Demand Forecasts

Horizon	Resolution	Evaluation Metric	Evaluation Metric Range	Probability Metric and Measurement horizon	Remarks
Day Ahead	Hourly	Daily MAPE	3%	P95 at hourly Basis	Daily MAPE to be less than 3% at least 95% of the hours in a day
Week Ahead (OC 2.5.2)	Hourly	Daily MAPE	3%	P95 at monthly basis	Daily MAPE to be less than 3% at least 95% of the days in a month
Year Ahead (OC 2.4.2 (d))	Monthly	Annual MAPE of the monthly energy values	3%	-	Error between the forecasted and actual energy consumption averaged over 12 months be within 3% range

OC 2.8.3. The SO shall publish in its website the demand forecast performance of each User and of the SO, to assist as feedback to improve forecast tools and methodologies used. The SO shall inform NEPRA when a User's monthly forecasts repeatedly fail to meet the MAPE targets specified in Table OC 1 at least three (3) times during a six (6) month period, for NEPRA evaluation and applicable measures or regulations.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 3. **DEMAND CONTROL**

OC 3.1. **Introduction**

OC 3.1.1. The Demand Control sub-code (OC 3) of the Operation Code specifies the provisions that are to be used by the SO to maintain demand-generation balance through managing demand on the Transmission System using Demand Control provided by DNOs due to:

(a) available Generation and imports from Interconnectors being insufficient to meet Demand;

(b) insufficient Operating Reserve; or

(c) breakdown, contingencies or operating problems resulting in System Frequency excursions, Voltage variations or Thermal Overloading on any part of the Transmission System.

OC 3.1.2. Demand Control may be achieved by any of the following:

(a) Demand Control instructed by the SO;

(b) Demand restoration instructed by the SO;

(c) Automatic Low Frequency Demand Disconnection;

(d) Automatic Low Voltage Demand Disconnection;

(e) Automatic Frequency Restoration; or

(f) Emergency Manual Disconnection by the SO.

OC 3.2. **Objective**

OC 3.2.1. The objective of OC 3 is to provide principles, criteria and procedures to enable the SO to achieve Demand Control that will relieve planned and unforeseen operating problems on the National Grid that could impact on system balance and reliability.

OC 3.3. **Scope**

OC 3 applies to the SO and:

(a) Distribution Network Operators;

(b) Transmission Network Operators;

(c) Energy Storage Units;

(d) Electric Power Suppliers;

(e) Transmission Connected Consumers; and

(f) Interconnectors with respect to their demand.

OC 3.4. **Explanation**

OC 3.4.1. Demand Control is exercised in contingency and emergency situations whereby the SO can instruct any User to reduce its Demand.

OC 3.4.2. In addition, the SO can also manually disconnect supply to the User Facility or part thereof from any disconnection point, without prior notice, in extreme emergencies.

OC 3.4.3. The procedures set out in the sub-code System Recovery (OC 12) of this Operation Code includes a system of Alerts, issued to Users, to give advance notice of Demand Control that may be required by the SO under this OC 3.

OC 3.4.4. Demand Control shall not, so far as possible, be exercised in respect of Priority Customers.

OC 3.4.5. Demand Control shall be exercised fairly and equitably in respect of all Users affected by Demand Control, on best effort basis.

OC 3.4.6. Demand Control is exercised through operation of the Distribution System or the Transmission System. Demand Control relates to the physical organization of the total System, and not to any contractual arrangements that may exist. Where Demand Control is needed in a particular area, the SO would not know which Supplier to contact and (even if it was to) the resulting Demand Control implemented, because of the diversity of contracts, may not produce the required result.

OC 3.4.7. Therefore, in most instances, Demand Control instructed by the SO shall be exercisable by the network licensee, either the DNO or the TNO as applicable. Suppliers should note therefore, that although implementation of Demand Control in respect of their Customers may not be exercisable by them, their Customers may be affected by Demand Control of the SO. Suppliers/BPCs shall coordinate with their respective DNO or TNO, as applicable, to prepare Demand Control plans. In all and any case, each DNO and TNO shall ensure the implementation of Demand Control within its Service Territory as instructed by SO.

OC 3.5. Procedure for the Implementation of Planned Demand Control on the Instructions of the System Operator

OC 3.5.1. Where due to a shortage of generation capacity or constraints in network capacity or any other reason related to reliability, security and system balance, when exercising of Demand Control becomes imminent, the SO will alert the Users in accordance with OC 12.

OC 3.5.2. The System Operator shall provide as much advance warning as practicable of any unforeseen circumstances which are likely to result in Demand Control procedures being implemented, trying to ensure that all the Users shall be in a state of readiness to implement their planned Demand Control procedures.

OC 3.5.3. All the Users are required to be able to respond at a short notice to the System Operator's instructions to implement Demand Control.

OC 3.5.4. The SO shall initiate the Demand Control if the Transmission System is in shortage to cover the demand or shortage seems imminent. The total amount of Demand Control required shall be distributed among all relevant Users considering each User's demand forecasted or in real-time and System conditions on pro rata basis. The instruction for Demand Control could be given in any suitable form, including:

(a) fixed quantum of load to be shed; or

(b) quota allocation for power drawn from System; or

(c) maintaining load on a network equipment below specified limit; or

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY * NEPRA * APPROVED BY THE AUTHORITY

(d) maintaining Voltage on a specified node above a certain threshold.

OC 3.5.5. Where reasonable notice time for Demand Control is available, the SO shall instruct the relevant DNO and/or TNOs to implement Demand Control within their respective Service Territories, and Demand Management schedules (prepared by coordination among DNO/TNOs and Suppliers/BPCs) shall be implemented. The SO and Users shall cooperate with each other to enable the implementation of Demand Control as per instructions of the SO. The SO may also, if possible, specify the expected duration of Demand Control required, as indicative information.

OC 3.5.6. Where the requirement for Demand Control arises at a short notice, it may be necessary for practical reasons to implement Demand Control immediately, outside the planned Demand Management schedule. All Users shall adhere to the specified procedures (and will cooperate in forming such procedures) so that Demand Control can be exercised rapidly when required, in accordance with the SO's instructions.

OC 3.5.7. In the event that Demand Control exercised under OC 3.5.7 is expected to be sustained, then the relevant DNO and TNO will arrange to gradually shift towards planned Demand Control schedule, as soon as it is practicable.

OC 3.5.8. The planned Demand Control schedule provides for disconnection and reconnection of defined blocks of demand as per predefined time schedules. The Users shall comply with the instructions issued by the SO and shall not lift Demand Control without the SO's instructions.

OC 3.5.9. Users shall provide full details of their Demand Control plans to the System Operator on an annual basis in advance (if required by SO). The SO may instruct certain modifications of the Demand Control plans proposed by a User.

OC 3.5.10. After restoration of the National Grid to normal condition, each User shall supply information to the System Operator, including the magnitude, date and time, location, cause and the relevant details of the Demand Control methods employed by the User.

OC 3.5.11. Users shall also provide online facilities to SO for monitoring Demand Control implementation in real-time, as further detailed in sub-code OC 9.

OC 3.6. Automatic Low Frequency Demand Disconnection

OC 3.6.1. All disconnection points (11 kV and above) or otherwise as identified by the SO shall be provided with Low Frequency Disconnection facilities. This is necessary to ensure that in the event of a large Generating Unit failure or other significant large contingency, there is a staged and phased Demand disconnection to ensure System Stability.

OC 3.6.2. Low Frequency Disconnection scheme should, as far as practical, ensure that supply of any Embedded Generation is not affected.

OC 3.6.3. Demand of Generating Units which is required to enable the start-up of Generating Units, as far as possible, should not be subject to Automatic Low Frequency Disconnection.

OC 3.6.4. Once an Automatic Low Frequency Demand Disconnection has taken place, a User shall not reconnect its Demand until instructed to do so by the SO, or otherwise in accordance with agreed procedures.

OC 3.6.5. The Users which are subject to Automatic Low Frequency Disconnection shall be split into discrete MW blocks. The number, location, size and the associated Low Frequency settings of these blocks, shall be as specified by the SO by week 28 in each calendar year or as and when required by SO following discussion with the Users. The distribution of the blocks shall be such as to exercise Demand Control as uniformly as may be practicable across all Connection Points.

OC 3.6.6. User equipment shall be capable of Automatic Low Frequency Disconnection of demand between 47 – 50 Hz.

OC 3.6.7. The Automatic Low Frequency Disconnection scheme for a User shall be capable of disconnecting Demand in Phases for a range of operational frequencies. The specific performance requirements of the scheme shall be specified by the SO.

OC 3.6.8. The Automatic Low Frequency Disconnection scheme shall allow for operation from a nominal AC input to be specified by the SO, and shall meet the following functional capabilities:

(a) Frequency range: at least between 47 – 50 Hz, adjustable in steps of 0.05 Hz;

(b) Operating time: no more than 200 ms after triggering the Frequency set point;

(c) Voltage lock-out: blocking of the functional capability shall be possible when the Voltage is within a range of 20 to 90 % of the nominal Voltage;

(d) Provide the direction of active power flow at the point of disconnection;

(e) Rate of Change of Frequency shall be adjustable anywhere within in the range of 0.1 Hz/sec to 2.5 Hz/sec.

The AC Voltage supply used in providing these Automatic Low Frequency Disconnection functional capabilities, shall be measured at the Connection Point.

OC 3.7. Restoration after Automatic Low Frequency Demand Disconnection

OC 3.7.1. Once the System Frequency has recovered, the Users shall abide by the instructions of the SO with regard to reconnection, and/or shall implement agreed procedures for Demand reconnection, without undue delay.

OC 3.7.2. Where conditions following Automatic Low Frequency Demand Disconnection do not permit restoration of a large proportion of the total Demand disconnected within a reasonable time period, the SO may instruct the Users to implement additional Demand Control manually, and restore an equivalent amount of the Demand that had been disconnected automatically. The purpose of such action is to ensure that a subsequent fall in Frequency shall again be contained by the operation of Automatic Low Frequency Demand Disconnection. If the requirement for Demand Control is expected to continue for a sustained period of time, then the SO shall initiate the implementation of the planned Demand Control schedule in accordance with OC 3.5.

OC 3.7.3.	The SO may require Users to make necessary arrangements to enable automatic Frequency restoration of Demand that is subject to Automatic Low Frequency Demand Disconnection. The SO shall specify the Frequency settings on these blocks of Demand.
OC 3.8.	**Voltage Demand Disconnection**
OC 3.8.1.	The SO may from time to time determine the requirement for Automatic Low Voltage Disconnection of Demand, in order to limit the consequences of the loss of a Generating Unit, or any other event on the System, which otherwise would result in part of the total System Voltages to become outside the levels specified in OC 5.5.7.
OC 3.8.2.	The SO may exercise the required Automatic Low Voltage Demand Disconnection (ALVDD) at the level of the Transmission System. However, depending on the extent of ALVDD required, and in order not to disconnect more Demand than reasonably required in response to a specific Incident or set of circumstances, it may be preferable that ALVDD is carried out at the lower Voltage levels.
OC 3.8.3.	As and when required by the SO, the Users shall cooperate with the SO in the design, placement and implementation of ALVDD, where the requirement is indicated, in accordance with OC 3.8.2. The SO shall retain full control over the enabling/disabling of the ALVDD, and the Voltage settings at which ALVDD shall be initiated in each circumstance.
OC 3.8.4.	In general, the settings shall be specified by the SO by week 28 every three calendar years following discussion with the Users, but the specification of settings may be altered by the SO at other times to address specific circumstances pertaining at that time. The Users shall respond to any change in specification by altering the settings without undue delay.
OC 3.8.5.	The SO shall specify the functional capabilities for low Voltage demand disconnection, in coordination with Users, on a site-specific basis. It shall include as a minimum: monitoring Voltage at all three phases, and blocking of the relay's operation based on direction of either Active Power or Reactive Power flow.
OC 3.8.6.	Low Voltage demand disconnection shall be implemented automatically or manually.
OC 3.8.7.	The SO may specify the requirement for on-load tap changer blocking. Users shall be advised as necessary, on a case-by-case basis, taking into consideration the site-specific requirements.
OC 3.9.	**Emergency Disconnection**
OC 3.9.1.	In the event of a System Emergency, irrespective of the Frequency, the System Operator shall have the right of disconnection (manually or automatically) of any Facility of any User when it determines that the Transmission System might or could become incapable of operating within the permissible operating ranges as defined in this Grid Code. Users shall provide appropriate facilities to the SO for fast disconnection of load as per System requirements.
OC 3.9.2.	Quantum and location of Demand reduction shall be at the discretion of the System Operator depending on the conditions prevailing at that time. This action may be

necessary to protect life, limit plant damage and to maintain power supply to the majority of Consumers. However, the System Operator shall endeavor to carry out Demand Control fairly.

OC 3.9.3. Users shall comply with the System Operator instructions when restoring supplies in their respective systems.

OC 3.9.4. Each User shall provide the System Operator in writing, (or by such electronic data transmission facilities as have been agreed with the SO), by week 28 of each calendar year, the information contained in Appendix-A of this sub-code in respect of the next following calendar year, on each Transmission Connection Point basis. However, SO, if necessary, shall advise modifications in the provided information to make it practicable as per prevailing system conditions and requirements.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 3. **Appendix**

EMERGENCY MANUAL DEMAND REDUCTION/DISCONNECTION SUMMARY SHEET

Name of Company/Code Participant/Transmission Connected Consumer:

Peak Demand [Year] MW

(132 & 66 kV Radial Lines, 132/11 kV & 66/11 kV Transformers)

Transmission Connection Point	**Peak (MW)**	**% of Load Demand Reduction or Disconnection _with respect to Peak MW at the Transmission Connection_ Point (%)**

Note: Data to be provided annually by week 28 to cover the following calendar year.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 4. OPERATIONAL PLANNING

OC 4.1. Introduction

In order to enable the SO to fulfill its obligations for reliable operation of the Transmission System, the Generation and Transmission facilities must be kept in perfect working conditions by carrying out their necessary upkeep and maintenance in a timely, coordinated, and orderly fashion. This requires proper planning and coordination of maintenance activities among the Transmission Network Operators, Generators, DNOs, BPCs and Interconnectors. The mechanisms by which this is to be achieved are formalized in this Operational Planning sub-code (OC 4) of the Operation Code.

OC 4.2. Objective

OC 4.2.1. The primary objective of OC 4 is to ensure the development and implementation of a coordinated Generation and Transmission Outage Program (G&TOP) that is consistent with the requirements for the secure and economic operation of the Transmission System and also duly considers the maintenance requirements of relevant Users.

OC 4.2.2. In order to achieve this objective, the OC 4 defines:

(a) the procedure for formal notification of proposed Outages by relevant Users to the SO;

(b) the process the SO will use to review and develop the long, medium and short term Outage Programs, in consultation with the relevant Users;

(c) the procedure for formal notification by Users of:

(i) a decision to cancel a major Outage of a Generating Unit/equipment;

(ii) the findings during or following a major Outage of a Generating Unit/equipment;

(iii) an unexpected and unplanned failure of a Generating Unit/equipment.

OC 4.2.3. In respect of Generators/Interconnectors, the OC 4 shall apply to all proposed Outages that may affect the ability of a Generator/Interconnector to achieve either its full Registered Capacity appropriate to each Registered Fuel, or Interconnector Registered Capacity, as the case maybe, in accordance with its Registered Operating Characteristics.

OC 4.2.4. Generators/Interconnectors are also mandated to inform the SO of any other proposed maintenance of their Units or any associated Plant or Apparatus, where such maintenance will affect the availability of their obligation or capability to provide System Services.

OC 4.2.5. In this OC 4, a reference to Year 0 shall mean the current calendar year, Year 1 shall mean the next calendar year, Year 2 shall mean the calendar year after Year 1, and so forth.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 4.3. Scope

The scope of this sub-code applies to the SO and:

(a) Generators;

(b) Transmission Network Operators;

(c) Distribution Network Operators;

(d) Energy Storage Units;

(e) Transmission Connected Consumers;

(f) Interconnectors; and

(g) Embedded Generators whether represented through some Aggregators or any other arrangement (if required by SO). The Aggregators or arrangements and Embedded Generators to which this Grid Code will apply shall be determined as per NEPRA applicable regulations

OC 4.4. Planning of Generation/Interconnector Outages

OC 4.4.1. The Outage planning process in respect of a Generating Unit/Interconnector shall commence not later than three (3) years prior to the scheduled Operational Date. The process shall culminate in development of the following three Programs scheduled over the time scales indicated as below:

(a) Committed Generation/Interconnector Outage Program, covering real time up to end of Year 1;

(b) Provisional Generation/Interconnector Outage Program, covering Year 2; and

(c) Indicative Generation/Interconnector Outage Program, covering Year 3.

OC 4.4.2. The closer the Generation/Interconnector Outage Program is to real-time operations, the more accurate it must be to ensure that there is adequate generation to match demand. As real-time approaches, there shall be regular exchange of information between each Generator/Interconnector and the System Operator, to update when and as necessary the Generation/Interconnector Outage Program with the latest availabilities.

OC 4.5. Procedure

OC 4.5.1. By the end of March Year 0, Generators/Interconnectors shall provide to the SO (in the forms notified by the SO from time to time), for each of their Generating Units, the following details of proposed Outages and estimates of probabilities of Forced Outages[1] for Years 1 to 3, for inclusion in the Committed, Provisional, and Indicative Generation/Interconnector Outage Programs, as defined in (OC 4.4.1) above:

(a) identity of the Generating Units concerned;

(b) MW unavailable (and MW that will still be available, if any, notwithstanding the Outage);

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

[1] Force outage probability of existing Generators shall normally be based on historical data for each Generating Unit regarding faulted events and time-to-repair as further elaborated in the relevant operating procedures.

(c) expected duration of the Outage;

(d) preferred start date and start time or range of start dates and start times;

(e) any other information required by the SO (such as Generator Work Units, etc.).

OC 4.5.2. In rolling over the Generation/Interconnector Outage Program from one year to the next, for every year, the procedure set out below is to be followed:

(a) submissions by the Generator/Interconnector for Year 2 should reflect the current Indicative Generation Outage Program; and

(b) submissions by the Generator/Interconnector for Year 1 should reflect the current Provisional Generation Outage Program.

(Except, in any such case, to the extent that the Generator is reasonably responding to changed circumstances and changes which, in the context of the Generation/Interconnector Outage Program, are necessary but expected to have minimal effect on the operation of the National Grid).

OC 4.5.3. By 1st September Year 0, VRE Generators shall provide to the SO (or revise any such information previously given) the forecast of estimated net output of the Wind/Solar PV/CSP Power Plant in MWh which it is likely to generate for each Month of Years 1, 2 and 3.

OC 4.5.4. By the end of September Year 0, the SO shall conduct Reliability analysis of the Transmission System for the operational planning horizon in light of the proposed Outages, and calculate the monthly peak Generation Capacity required from Generating Units for the various planning periods (Year 0, 1, 2, etc.) by considering the following factors:

(a) Forecasted Demand;

(b) User Demand Control;

(c) Operating Reserve as set by the SO;

(d) Estimated hydrology (reservoir levels, water flows etc.);

(e) Ancillary Services requirements;

(f) Transmission System and Distribution System constraints;

(g) Transmission System and Distribution System Outages to ensure that, in general, these have the least restraint on Generating Unit Outages; and

(h) Any other relevant factor.

OC 4.5.5. During this period the SO may, as appropriate, contact any User which has supplied information to seek clarification on its information received or any other relevant information as is reasonable. The SO shall also notify to Generators/Interconnectors any concerns for their submitted Programs and try to settle these through mutual discussion. If these cannot be resolved mutually, the Generator/Interconnector must provide the SO with such evidence as the SO may reasonably require to substantiate that the proposed Outages cannot be modified. If the Generator/Interconnector fails to establish to the reasonable satisfaction of the SO

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

that the proposed Outage is inflexible, the SO shall modify the Outage as per its requirements. All communication shall be recorded for future reference.

OC 4.5.6. The process of consultation and preparation of the Generation/Interconnector Outage Program shall be concluded by October 31st of each year and published on the SO website.

OC 4.5.7. In proposing Outages, and in relation to all other matters under OC 4, the Generators/Interconnectors must act reasonably and in good faith. Without limitation to such obligation, each Generator/Interconnector shall act in accordance with Prudent Industry Practice in planning their Outages, so as to avoid a situation arising in which a Generator/Interconnector is obliged to schedule an Outage at short notice by reason of obligations imposed on it by statute, as a consequence of the Generator/Interconnector not having planned in accordance with Prudent Industry Practice, for example, by not having planned sufficiently in advance its Outages for any statutory time limit.

OC 4.6. Changes to the Committed Outage Program within the Implementation Year (Year 0)

OC 4.6.1. A request for a change to an Outage included in the Committed Generation Outage Program may be initiated either by the SO or by a Generator/Interconnector at any time.

OC 4.6.2. Request initiated by the SO

(a) The SO may at any time request a Generator/Interconnector to change the timing or duration of any Outage in the Committed Generation Outage Program where, in the SO's opinion (were such Outage not to be deferred):

(i) the statutory or regulatory obligations could not be met; or

(ii) there would be insufficient Generation Capacity to meet Forecasted Demand and the Operating Reserve.

(b) The SO may require the Generator/Interconnector to continue to defer such Outages for as long as the above situation persists. If a Generator/Interconnector responds by agreeing to the request, the Committed Generation Outage Program shall be deemed to have been amended accordingly.

(c) If a Generator/Interconnector declines the request of the SO, then the SO may discuss with the Generator/Interconnector to resolve the issue. If a mutual resolution is not reached, the Generator must provide the SO with such evidence as the SO may reasonably require to substantiate that Outage cannot be modified. If the Generator/Interconnector fails to establish to the reasonable satisfaction of the SO that the proposed modification is not possible, the Outage shall stand modified as per SO requirements.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

OC 4.6.3. Outage Change Initiated by a Generator/Interconnector

(a) Generators/Interconnector may at any time request the SO for a change in the timing or duration of its Outage in the Committed Generation/Interconnector Outage Program. Such requests should normally be initiated by giving not less than seven (7) days prior notice before the earliest start date of the Outage.

(b) Such a request must also include a valid reason for the proposed change in the Outage schedule.

(c) The SO shall evaluate whether the change is likely to have a detrimental effect on Capacity Adequacy or on the secure operation of the Transmission System. This shall be done within a reasonable time frame, taking into consideration the extent of the change and the timing of the Outage.

(d) Where the request is not likely to have a detrimental effect on Capacity Adequacy or the secure operation of the Transmission System then the SO shall amend the Committed Generation/Interconnector Outage Program accordingly. The Generator/Interconnector shall be advised by the SO that the change has been accepted.

(e) Where the Outage change is likely to have a detrimental effect on Capacity Adequacy or requirements for the secure operation of the Transmission System, then the SO shall not amend the Committed Generation/Interconnector Outage Program. The Generator/Interconnector and the SO may discuss and agree on a modification which may meet the requirements of the Generator/Interconnector, and not have an unacceptable effect on Capacity Adequacy or requirements for secure operation of the Transmission System. In the event that the Generator/Interconnector wishes to avail of an agreed modification, it shall re-submit a change request accordingly.

(f) Where the Generator/Interconnector has been notified that the change to the Committed Generation/Interconnector Outage Program has not been accepted, but the Generator/Interconnector still avails the Outage, it shall be considered as non-compliance as per OC 11.

OC 4.7. Short Term Planned Maintenance (STPM) Outage

OC 4.7.1. A Generator/Interconnector may request the SO at any time during Year 0, by giving not less than seven (7) days prior notice before the earliest start date, for a Short Term Planned Maintenance (STPM) Outage. The request must contain the following information:

(a) identity of the Generating Units/Interconnectors concerned;

(b) MW on Outage (and MW which would still be available, if any, notwithstanding the Outage);

(c) required duration of the Outage (which must not exceed seventy-two (72) hours); and

(d) preferred start date and start time or range of start dates and start times.

OC 4.7.2. On receipt of such a request, the SO shall consider the request and shall, after discussing the position with the Generator/Interconnector, reply normally within three (3) working days in writing indicating:

(a) acceptance of the request, confirming the requested start time and duration of the STPM Outage;

(b) proposals for the advancement or deferment of the requested STPM Outage, indicating alternative start time and duration; or

(c) rejection of the request.

OC 4.7.3. If the SO accepts the request, the STPM Outage, if taken, must be taken by the Generator/Interconnector in accordance with the approved request. If the SO has indicated an alternative start time and/or duration, the SO and the Generator/Interconnector must discuss the alternative and any other options which may arise during the discussion. If agreement is reached, then the Outage, if taken, must be taken by the Generator/Interconnector in accordance with the agreement. If the request is refused by the SO based on grounds established in OC 4.6.2 (a) or if agreement is not reached, then the Generator/Interconnector shall not take the Outage.

OC 4.7.4. Where an STPM Outage is scheduled pursuant to OC 4.7, the SO shall confirm the details, normally within one (1) working day after the approval of the STPM Outage by the SO. Such notice shall contain the following information:

(a) the identity of the Generating Units/Interconnectors concerned;

(b) MW on Outage (and MW which would still be available, if any, notwithstanding the Outage);

(c) duration of the Outage; and

(d) the start date and start time of the Outage.

OC 4.8. Release of Generating Units/Interconnectors for Outages

OC 4.8.1. The Generators/Interconnectors shall only undertake Planned Outages with the SO agreement pursuant to the provisions of this OC 4.

OC 4.8.2. In real time operation, Generating Units must not be withdrawn for an Outage without express formal permission of the SO for such release according to the procedures set out in OC 4.5, OC 4.6 and OC 4.7.

OC 4.8.3. The SO's express formal permission shall specify:

(a) the identity of the Generating Unit and MW on Outage (and MW which would still be Available, if any, notwithstanding the Outage);

(b) the duration of the Outage; and

(c) the start date and start time of the Outage.

OC 4.8.4. The SO may withhold its permission for the release of a Generating Unit for a Planned Outage under Committed Generation Outage Plan or STPM, in accordance with OC 4.6.2.

OC 4.8.5. Notified Unplanned Outage

OC 4.8.5.1. If Generator/Interconnector must require an Unplanned Outage which cannot reasonably be requested to the SO as per OC 4.7, it must provide notice to the SO as early as possible. Such notice must include an identification of the Generating

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Unit, the expected start date and start time and duration of the Unplanned Outage, and the nature of the Outage together with the MW on Outage (that is, MW which will not be available as a result of the Outage and that which will still be available, if any). The SO shall acknowledge such notice as soon as reasonably possible after the notice is received by the SO.

OC 4.8.5.2. The SO may request the Generator/Interconnector to advance or defer the Outage. If the Generator agrees to such a request, the Generator/Interconnector shall send the SO a written notice confirming this agreement. The SO shall acknowledge this notice. The Generator/Interconnector must then take the Outage in accordance with this agreement.

OC 4.8.5.3. A Generator/Interconnector shall use all reasonable endeavors to ensure that, following an Unplanned Outage, the Generating Unit/Interconnector is repaired and restored to its full level of Availability as soon as possible and in accordance with Prudent Industry Practice.

OC 4.8.5.4. However, the SO shall have the right to Investigate, in accordance with the provisions of OC 11, whether the Outage was unavoidable or could not have been planned in time.

OC 4.9. Forced Outages

OC 4.9.1. In the event that a Generator/Interconnector suffers a Forced Outage, the Generator/Interconnector shall inform the SO immediately.

OC 4.9.2. As soon as possible after the commencement of the Outage, the Generator/Interconnector shall also inform the SO of the cause of the Outage and the Generator/Interconnector's best estimate of the date and time by which the Generating Unit is likely to be repaired and restored to its full level of Availability. If the Generator is unable for any reason to provide this information, the Generator/Interconnector shall not later than twenty-four (24) hours after the commencement of the Forced Outage, provide the SO such information as is then known to the Generator/Interconnector regarding the date and time of return from such Outage and shall provide such updates thereafter as the SO may reasonably require.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 4.9.3. In such an event, the SO shall have the right to inspect the Generating Unit and all relevant records on any working day and at a reasonable time. The Generator shall fully cooperate with the SO during any such inspection.

OC 4.9.4. A Generator shall use all reasonable endeavors to ensure that, following a Forced Outage, the Generating Unit is repaired and restored to its full level of Availability as soon as possible and in accordance with Good Industry Practice.

OC 4.10. Return to Service and Overruns

OC 4.10.1. For a Planned Outage, as far in advance as reasonably possible before the expiry of the Outage period, the Generator/Interconnector must notify the SO either that it is returning to service earlier than expected, or at the time and date expected, or later than expected and if, upon return, it is expected to be fully available.

OC 4.10.2. Where a Generating Unit is not expected to be fully available upon its return to service, the Generator shall state the MW level at which the Generating Unit is expected to be available. In the case of a Generating Unit which is capable of firing on multiple fuels, the Availability must be stated for each fuel.

OC 4.10.3. In the case of a return from a Planned Outage later than expected, the notice of return to service shall state the reasons for the delay in the return of the Generator/Interconnector to service and a best estimate of the date and time at which it shall return to service.

OC 4.10.4. A Generator/Interconnector must use all reasonable endeavors to ensure that, in respect of each Planned Outage, the Outage schedule as included in the Committed Generation Outage Program (or as moved in accordance with the provisions of this section) is followed.

OC 4.10.5. Before returning from any Outage other than a Planned Outage, a Generator/Interconnector must inform the SO, as far in advance as reasonably possible that it is returning to service. The Generator/Interconnector must, in addition, give an Availability Notice in accordance with the provisions of the SDC 1 on the day prior to the Schedule Day on which the Generator/Interconnector is to return to service.

OC 4.10.6. If at any time during an Outage, the Generator/Interconnector becomes aware that it will not have been maintained, repaired or restored to be available by the expiry of the period specified for the duration of the Outage in the Committed Generation Outage Program or as otherwise notified in the case of Outages other than Planned Outages, the Generator/Interconnector shall notify the SO immediately in writing stating the reasons for the delay and a best estimate of the date and time by which the Generating/Interconnector will actually have been maintained, repaired, or restored to be available in accordance with the provisions of the SDC 1.

OC 4.11. Planning of Transmission Outages

OC 4.11.1. The System Operator, in coordination with the Transmission Network Operators, shall prepare the Transmission Outage Program annually for the next three (3) years. The process shall culminate in development of the following three Programs scheduled over the time scales as indicated below:

(a) Committed Transmission Outage Program, covering real time up to end of Year 1;

(b) Provisional Transmission Outage Program, covering Year 2; and

(c) Indicative Transmission Outage Program, covering Year 3.

OC 4.11.2. The closer the outage program is to real-time operations, the more accurate it must be to ensure the Stability and Reliability of National Grid. As real-time approaches, there shall be regular exchange of information between each TNO and the System Operator, to update the Transmission Outage Program with the latest availabilities.

OC 4.11.3. The SO shall plan Transmission System Outages required in Years 2 and 3 as a result of construction or refurbishment works taking due account of the known requirements. The planning of Transmission System Outages required in Years 0 and 1 ahead will, in addition, take into account Transmission System Outages required as a result of maintenance.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

OC 4.11.4. The SO shall coordinate the Transmission System Outages and Generating Unit Outages in such a way that the overall Generation and Transmission Outage Program (G&TOP) has minimized impact on Users and total System cost. However, the SO shall have the discretion to determine the precedence of Generation or Transmission Outage over the other, on the basis of reasons relating to the proper operation of the National Grid.

OC 4.12. Procedure

OC 4.12.1. By the end of March Year 0, each TNO shall provide to the SO (in the forms notified by the SO from time to time), the following details of proposed Outages for inclusion in the Committed, Provisional, and Indicative Transmission Outage Programs, as defined in (OC 4.11.1) above:

(a) Identification of the equipment and the MW capacity involved;

(b) Reasons for the maintenance;

(c) Expected duration of Outage (including time required for switching operations); and

(d) preferred start date and start time or range of start dates and start times.

OC 4.12.2. In rolling over the Transmission Outage Program from one year to the next, for every year, the procedure set out below is to be followed:

(a) submissions by the TNOs for Year 2 should reflect the current Indicative Transmission Outage Program; and

(b) submissions by the TNOs for Year 1 should reflect the current Provisional Transmission Outage Program.

(Except, in any such case, to the extent that a TNO is reasonably responding to changed circumstances and changes which, in the context of the Outage Program, are minimal in their effect on the operation of the National Grid)

OC 4.12.3. By the end of September Year 0, the SO shall conduct Reliability analysis of the Transmission System for the operational planning horizon in light of the proposed Outages, for the various planning periods (Year 0, 1, 2, etc.) by considering the following factors:

(a) The forecasted Demand and its geographical distribution;

(b) Network equipment loading and Voltage profile;

(c) The requests by Users for changes in their Outage schedules;

(d) The maintenance requirements of the Transmission System;

(e) Generator/Interconnector Outages;

(f) The need to minimize the total impact of such Outage in respect of System Security and Reliability and/or Demand Control; and

(g) Any other relevant factor.

OC 4.12.4. For each proposed Outage, the SO shall determine the Users which will be operationally affected by the Outage and the approximate amount of Demand

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Control, if required. In case of possible Demand Control, the TNOs shall coordinate with the relevant Users and provide formal consent of the Users to the SO.

OC 4.12.5. The SO shall also indicate where a need exists to use inter-tripping, emergency switching, or other measures including restrictions on the Scheduling and Dispatch of Generating Units to allow the Security of the Transmission System to be maintained within allowable limits.

OC 4.12.6. During this period the SO may, as appropriate, contact any User which has supplied information to seek clarification on its information received or any other relevant information as is reasonable. The SO shall also notify to each TNO any concerns for their submitted Transmission Outage Programs and try to settle these through mutual discussion. If these cannot be resolved mutually, the TNO must provide the SO with such evidence as the SO may reasonably require to substantiate that the proposed Outages cannot be modified. If the TNO fails to establish to the reasonable satisfaction of the SO that the proposed Outage is inflexible, the SO can modify the Outage as per its requirements. All communication shall be recorded for future reference.

OC 4.12.7. The process of consultation and preparation of the Transmission Outage Program shall be concluded by October 31st of each year and published on the SO website.

OC 4.12.8. In proposing Outages, and in relation to all other matters under OC 4, the TNOs must act reasonably and in good faith. Without limitation to such obligation, each TNO shall act in accordance with Prudent Industry Practice in planning their Outages, so as to avoid a situation arising in which a TNO is obliged to schedule an Outage at short notice by reason of obligations imposed on it by statute, as a consequence of the TNO not having planned in accordance with Prudent Industry Practice, for example, by not having planned sufficiently in advance its Outages for any statutory time limit.

OC 4.13. Changes to the Committed Transmission Outage Program within the Implementation Year (Year 0)

OC 4.13.1. A request for a change to an Outage included in the Committed Transmission Outage Program may be initiated either by the SO or by a TNO at any time.

OC 4.13.2. Request initiated by the SO:

(a) The SO may at any time request a TNO to change the timing or duration of any Outage in the Committed Transmission Outage Program where, in the SO's reasonable opinion (were such Outage not to be deferred):

(i) the statutory or regulatory obligations could not be met; or

(ii) System Security, Reliability or Stability would be at risk.

(b) The SO may require the TNO to continue to defer such Outage for as long as the above situation persists. If a TNO responds by agreeing to the request, the Committed Transmission Outage Program shall be deemed to be amended accordingly.

(c) If a TNO declines the SO's request, then the SO may negotiate with the TNO to reach a resolution. If a mutual resolution is not reached, then the TNO must provide the SO with such evidence as the SO may reasonably require

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

to substantiate that Outage cannot be modified. If the TNO fails to establish to the reasonable satisfaction of the SO that the proposed modification is not possible, the Outage shall stand modified as per the SO requirements.

OC 4.13.3. Outage Change Initiated by a TNO

(a) A TNO may at any time request the SO for a change in the timing or duration of any Outage in the Committed Transmission Outage Program. Such requests should normally be initiated by giving not less than seven (7) days prior notice before the earliest start date of the Outage.

(b) Such a request must also include a valid reason for the proposed change in the Outage schedule.

(c) The SO shall evaluate whether the change is likely to have a detrimental effect on the secure operation of the Transmission System. This shall be done within a reasonable time frame, taking into consideration the extent of the change and the timing of the Outage.

(d) Where the request is not likely to have a detrimental effect on the secure operation of the Transmission System then the SO shall amend the Committed Transmission Outage Program accordingly. The TNO shall be advised by the SO that the change has been accepted.

(e) Where the Outage change is likely to have a detrimental effect on requirements for the secure operation of the Transmission System, then the SO shall not amend the Committed Transmission Outage Program. At the TNO's request, the SO may enter into discussions with the TNO to facilitate an alternative modification which may meet the requirements of the TNO, while not having an unacceptable effect on secure operation of the Transmission System. In the event that the TNO agrees with the proposed alternate, it shall re-submit a change request accordingly.

(f) Where the TNO has been notified that the change to the Committed Transmission Outage Program has not been accepted, the TNO shall not carry out any switching operations, otherwise it shall be considered a non-compliance as per OC 11.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 4.14. Short Term Planned Maintenance (STPM) Outage

OC 4.14.1. A TNO may request the SO at any time during Year 0, by giving not less than seven (7) days prior notice before the earliest start date, for a Short Term Planned Maintenance (STPM) Outage. The request notice must contain the following information:

(a) identity of the equipment concerned;

(b) required duration of the Outage (which must not exceed six (6) hours); and

(c) preferred start date and start time or range of start dates and start times.

OC 4.14.2. On receipt of such a request, the SO shall consider the request and shall, after discussing the position with the TNO, reply indicating:

(a) acceptance of the request, confirming the requested start time and duration of the STPM Outage;

(b) proposals for the advancement or deferment of the requested STPM Outage, indicating alternative start time and duration; or

(c) rejection of the request.

OC 4.14.3. If the SO accepts the request, the STPM Outage, if taken, must be taken by the TNO in accordance with the request. If the SO has indicated an alternative start time and/or duration, the SO and the TNO may discuss the alternative and any other options which may arise during the discussion. If agreement is reached, then the Outage, if taken, must be taken by the TNO in accordance with the agreement. If the request is refused by the SO or if agreement is not reached, then the TNO will not take the Outage.

OC 4.14.4. For the proposed STPM outage, the SO shall determine the Users which will be operationally affected by the Outage and the approximate amount of Demand Control, if required. In case of possible Demand Control, the TNO shall coordinate with the relevant Users and provide formal consent of the Users to the SO.

OC 4.14.5. In the event that an STPM Outage is scheduled pursuant to OC 4.14, the SO shall confirm the details of the approval of the STPM Outage. Such notice shall contain the following information:

(a) the identity of the equipment concerned;

(b) duration of the Outage; and

(c) the start date and start time of the Outage.

OC 4.15. De-energization of Transmission Equipment

OC 4.15.1. A TNO shall only undertake Planned Outages with the SO agreement in accordance with the Outage Program produced pursuant to the provisions of this OC 4.

OC 4.15.2. In real time operation, no equipment shall be de energized for an Outage without express formal permission of the SO according to the procedures set out in OC 4.12, OC 4.13 and OC 4.14.

OC 4.15.3. The SO's express formal permission shall specify:

(a) the identity of the equipment on Outage;

(b) the duration of the Outage; and

(c) the start date and start time of the Outage.

OC 4.15.4. The SO may withhold its permission for the Planned Outage where such Outage has previously been planned in accordance with OC 4.13.2.

OC 4.16. Notified Unplanned Outage

OC 4.16.1. If a TNO requires an Unplanned Outage which cannot reasonably be requested to the SO as per OC 4.14, it must provide notice to the SO as early as possible. Such notice must include an identification of the equipment, the expected start date and start time and duration of the Unplanned Outage and the nature of the Outage together. The SO will acknowledge such notice as soon as reasonably possible after the notice is received by the SO.

OC 4.16.2. The SO may request the TNO to advance or defer the Outage. If the TNO agrees to such a request, the TNO shall send the SO a notice confirming this agreement. The SO will acknowledge this notice. The TNO must then take the Outage in accordance with this agreement.

OC 4.16.3. A TNO shall use all reasonable endeavors to ensure that, following an Unplanned Outage, the equipment is repaired and restored as soon as possible and in accordance with Prudent Industry Practice.

OC 4.16.4. However, the SO reserves the right to Investigate, in accordance with the provisions of OC 11, whether the Outage was unavoidable or could not have been planned in time.

OC 4.17. Return to Service and Overruns

OC 4.17.1. If at any time during an Outage, the TNO becomes aware that the equipment will not have been maintained, repaired or restored to be available by the expiry of the period specified for the duration of the Outage in the Committed Transmission Outage Program or as otherwise notified in the case of Outages other than Planned Outages, the TNO shall notify the SO immediately, stating the reasons for the delay and a best estimate of the date and time by which the equipment will actually have been maintained, repaired, or restored to be available.

OC 4.17.2. A TNO must use all reasonable endeavors to ensure that, in respect of each Planned Outage, the Outage schedule as included in the Committed Transmission Outage Program (or as moved in accordance with the provisions of this section) is followed.

OC 4.18. Annual Production Plan (APP)

OC 4.18.1. Based on the Committed G&TOP, the System Operator shall prepare an indicative Annual Production Plan indicating:

(a) estimated monthly capacity and energy requirements to support the forecasted peak Demand along with adequate Operating Reserve;

(b) estimated peak and average production from each Generator; and

(c) any periods of inadequate Operating Reserve and Demand Control required.

OC 4.18.2. For the avoidance of doubt, the Annual Production Plan (APP) prepared and published by SO is indicative and is only intended to provide an outlook of the National Grid operations.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 4. Appendix – A

COMMITTED GENERATION OUTAGE PROGRAM TIMETABLE

This appendix should be completed by the System Operator in consultation with the Generators and other relevant stakeholders.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
* NEPRA *

OC 4. Appendix – B

PROVISIONAL GENERATION OUTAGE PROGRAM TIMETABLE

This appendix should be completed by the System Operator in consultation with the Generators and other relevant stakeholders.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 4. Appendix – C

INDICATIVE GENERATION OUTAGE PROGRAMTIMETABLE

This appendix should be completed by System Operator in consultation with the Generators and other relevant stakeholders.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

OC 4. Appendix – D, E, F

TRANSMISSION OUTAGES

Primary or bulk and secondary transmission outages

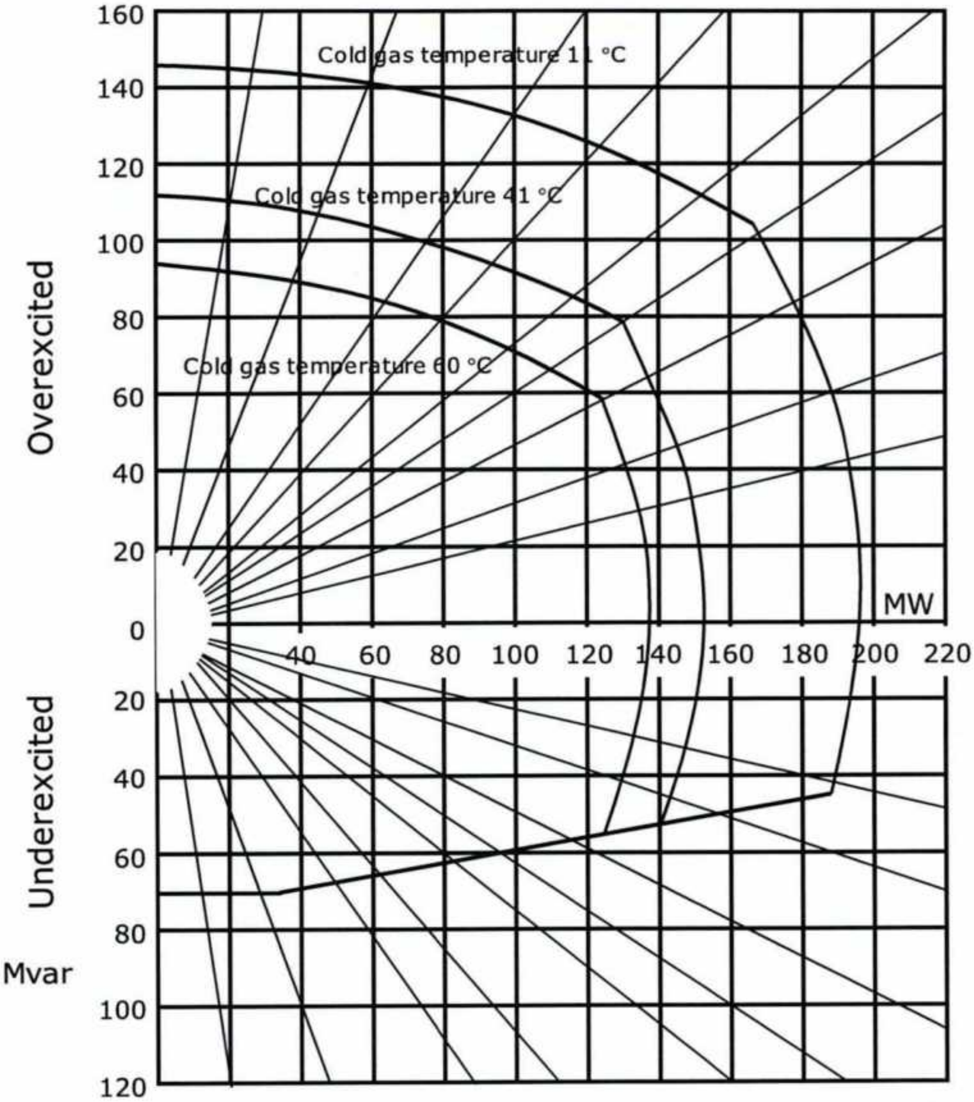
This appendix should be completed by System Operator in consultation with the generators and other relevant stakeholders.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 4. Appendix – G

Generator Performance Chart, Example

Rated Apparent Power	S_N MVA	Rated Frequency	$f_N = 50$ Hz
Rated Active Power	P_N MW	Power Factor	PF = 0.95
Rated Armature Voltage	V_N kV	Speed	$n_N = 50\ s^{01}$
Rated Armature Current	I_N kA	Cold Air Temperature	$T_K = 41$ °C



NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

OC 4. Appendix – H

GENERATION PLANNING PARAMETERS

The following parameters are required in respect of each Genset.

Regime Unavailability

Where applicable the following information must be recorded for each Genset.

a) Earliest synchronizing time; and

b) Latest de-synchronizing time.

Synchronizing Intervals

The Synchronizing intervals between Gensets.

De-Synchronizing Interval

A fixed value de-synchronizing interval between Gensets.

Synchronizing Generation

The amount of MW produced at the moment of Synchronizing.

Minimum on Time

The minimum period on-load between synchronizing and De-synchronizing.

Run-Up Rates

A run-up characteristic consisting of different stages from Synchronizing Generation to Output Usable.

Run-Down Rates

A run down characteristic consisting of different stages from Output to Desynchronizing.

Notice to Synchronize (NTS)

The period of time required to Synchronize a Genset.

Minimum Shutdown Time

The minimum interval between De-synchronizing and Synchronizing a Genset.

Maximum Shifting Limit

The maximum number of times that a Genset may De-synchronize per **Operational Day.**

Gas Turbine Units Loading Parameters

a) Loading rate for fast starting

b) Loading rate for slow starting

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

OC 4. Appendix – I

TECHNICAL PARAMETERS - VRES/BESS

This appendix should be completed by the System Operator in consultation with the VREs and BESS Plants and other relevant stakeholders.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 4. Appendix – J

TECHNICAL PARAMETERS - INTERCONNECTORS

This appendix should be completed by the System Operator in consultation with the Interconnectors and other relevant stakeholders.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

OC 5. SYSTEM SERVICES

OC 5.1. Introduction

OC 5.1.1. This sub-code OC 5 of the Operation Code deals with System Services which are essential to the proper functioning of the National Grid including:

(a) Frequency Control

(b) Operating Reserves

(c) Voltage/Reactive Power Control

(d) Black Start

OC 5.1.2. In order to ensure secure operation, the SO shall have control over all System Services, i.e. the SO shall specify what System Services are to be provided when, where and by whom.

OC 5.1.3. System Services mentioned in OC 5.1.1 (a) to (d) above are Ancillary Services and its provision, as per the requirements of the SO, shall be considered mandatory for all Users, except for the Black Start service, within the limits established in this OC and, if applicable, the corresponding Connection Agreement.

OC 5.1.4. Nothing contained in this OC 5 shall restrict a User from providing System Services that are better than the requirements established in this OC 5.

OC 5.2. Objectives

OC 5.2.1. The objectives of this OC 5 are:

(a) to establish a policy to ensure Frequency Control capability in the National Grid for operational control by the SO, and to set out appropriate procedures to enable the SO to control the National Grid Frequency and (insofar as practicable) maintain it within the limits specified in this OC;

(b) to set out the types and amounts of Reserve, as provided in a number of time scales, which make up the Operating Reserve that the SO may make use of under certain operating conditions for Frequency Control;

(c) to set out the control strategies to be used by the SO, in conjunction with Users where appropriate, for controlling the Transmission System Voltages and Reactive Power;

(d) to describe the various time scales for which Operating Reserves are required, the policy which will govern the Dispatch of the Operating Reserves, and the procedures for monitoring the performance of Generating Units and other Operating Reserve providers; and

(e) to set out requirements relating to Black Start Stations for the Users, to enable the SO to manage the recovery of the National Grid back to normal, from a Partial or Total Shutdown.

OC 5.3. Scope

OC 5 applies to the SO and:

(a) Generators;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

(b) Energy Storage Units;

(c) Distribution Network Operators;

(d) Transmission Network Operators;

(e) Interconnectors; and

(f) Transmission connected Consumers.

OC 5.4. Frequency Control

OC 5.4.1. To maintain the security and integrity of the National Grid, it is necessary that the SO operates the Transmission System and Dispatches supply and demand resources in such a manner as to provide adequate Frequency Control in the Transmission System to achieve its operation within the applicable Frequency limits at all times.

OC 5.4.2. In order to cater for normal Frequency fluctuations, Demand/VRE forecast variations and to cover against a sudden loss of generation or a major in-feed from the Transmission System, it is necessary that sufficient Operating Reserve is maintained through the Control Phase.

OC 5.4.3. Operating Reserve is the additional output from Generating Units (or available injection/withdrawal capacity of ESUs), either connected or ready to connect to the Transmission System, which is realizable in real time to aid in containing and correcting System Frequency from falling beyond an acceptable level due to loss of Generation or a mismatch between Supply and Demand. It will include Primary Operating Reserve, Secondary Operating Reserve and Tertiary Operating Reserve. Any support or reserves provided by an Interconnector shall be governed by the conditions in the Interconnection Agreement.

OC 5.4.4. Operating Frequency Limits

OC 5.4.4.1. The SO shall coordinate with all the Users connected to Transmission System in order to maintain the System Frequency at 50 Hz with the following allowance excursions:

(a) Target System Frequency shall be 50 Hz ± 0.05 Hz.

(b) Frequency Sensitive Band shall be 49.8 Hz - 50.2 Hz. Such band is permissible to allow Frequency variations while ramping up generation and load pick-up.

(c) Tolerance Frequency Band shall be in the range of 49.5 Hz - 50.5 Hz, which are protected periods of operation of the system.

(d) Contingency Frequency Band shall be 49.3 Hz - 50.5 Hz, which is the maximum expected absolute value of the instantaneous Frequency after the occurrence of an imbalance, beyond which SO shall deploy emergency measures such as Demand Control or Automatic Low Frequency Demand Disconnection.

(e) A Significant Frequency Disturbance Event is deemed to have occurred if the Frequency falls below 49.3 Hz or rises above 50.5 Hz.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

OC 5.4.4.2. Instantaneous Frequency excursions are to be handled in the following manner:

(a) In the event of a single contingency, the Power System Frequency must be maintained within "Tolerance Frequency Band" within 5 minutes of the excursion, and to within the "Frequency Sensitive Band" within 10 minutes of the contingency.

(b) Instantaneous Frequency excursions outside the "Contingency Frequency Band" shall be handled in such a manner that:

(i) System Frequency returns to "Contingency Frequency Band" within 60 seconds.

(ii) System Frequency returns to "Tolerance Frequency Band" within 5 minutes, and within the "Frequency Sensitive Band" within 30 minutes.

(c) For avoidance of doubt, the operating ranges mentioned above are the limits for System Frequency which are to be maintained by the SO (insofar as practicable) to comply with NERPA Performance Standards to ensure Power Quality in Normal State. The Frequency limits provided in CC 5.2 are withstand capabilities for User equipment within which the User shall remain Connected with the Transmission System.

Table OC 2: Operating Frequency Limits

Sr. No.	Description	Frequency Limits
1	Target Frequency	50 ± 0.05 Hz
2	Frequency Sensitive Band	49.8 Hz to 50.2 Hz
3	Tolerance Frequency Band	49.5 Hz to 50.5 Hz
4	Contingency Frequency Band	49.3 Hz to 50.5 Hz

OC 5.4.5. Description of Frequency Control

OC 5.4.5.1. Frequency Control occurs in three interlinked stages, namely:

(a) Primary Frequency Control

(b) Secondary Frequency Control

(c) Tertiary Frequency Control

OC 5.4.6. Primary Frequency Control

OC 5.4.6.1. Primary Frequency Control takes place in a time scale immediately following a change in Frequency and reaches its maximum value within 10 seconds which is sustainable up to 30 seconds, and is achieved by automatic corrective responses to Frequency deviations occurring on the Transmission System. This automatic correction arises from:

(a) System inertia of rotating synchronous generators;

(b) Natural Frequency demand relief of motor load;

(c) Automatic MW output adjustment of Synchronous Generating Units/Interconnectors (if such possibility is included in the Interconnection Agreement) initiated by Free Governor Response or other responses including peaking of Combustion Turbine Units, condensate stop;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

(d) Automatic MW output adjustment of Non-Synchronous Generating Units when it is technically possible;

(e) Automatic Frequency modulation by embedded HVDC systems.

OC 5.4.7. Primary Frequency Control of Synchronous Generators

OC 5.4.7.1. Primary Frequency Control maintains the balance between the Load and Generation using turbine speed governors. It is an automatic decentralized function of the turbine governor to adjust the generator output of a unit as a consequence of a Frequency deviation. The need for the Governor Control mode lies in the fact that the Generating Units should be able to correct their own Frequency when a disturbance occurs in the system, considering the difference of the speed of the Generating Units depending on the type of technology. Generating Plants shall not depend on any order or instruction, issued by the SO either manually or electronically, to modify the amount of Energy injected into the Transmission System (MW) to correct their Frequency.

OC 5.4.7.2. All Generating Units when Synchronized to the Transmission System shall be able to provide:

(a) Free Governor Control Action (FGC) through a Governor Control System, to maintain System Frequency within the prescribed limits provided in this OC;

(b) The Active Power Frequency Response shall be capable of having a Governor Droop between 2% and 12%. The default Governor Droop setting, unless something different is required by the SO and reflected in the Connection Agreement, shall be 4%;

(c) No time delays other than those necessarily inherent in the design of the Governor Control System shall be introduced;

(d) A Frequency Deadband of no greater than +/- 0.05 Hz may be applied to the operation of the Governor Control System. The design, implementation and operation of the Frequency Deadband shall be agreed with the SO prior to commissioning of the Generating Unit/Station.

OC 5.4.7.3. The amount of Frequency Response in MW that the synchronized Generators can provide cumulatively under Free Governor Control is known as "Primary Operating Reserve". For Low Frequency Events, each Generator, subject to operational and resource constraints of VRE and small hydro, shall be capable of providing:

(a) minimum Primary Operating Reserve of 5% Registered Capacity while operating at MW Output of 95% of Registered Capacity;

(b) While operating at MW Output in the range from 50% to 95% Registered Capacity, the amount of Frequency Response shall not be less than that indicated by a straight line with unity rise from 50% of Registered Capacity at 50% MW output to 5% at 95% MW output;

(c) While operating at MW Output in the range of 95% to 100% Registered Capacity the amount of Frequency Response shall not be less than that indicated by a straight line with unity decay from 5% of Registered Capacity at 95% output to 0 at 100% output;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(d) For High Frequency Events, the minimum amount of Frequency Response shall be vice versa with 50% of Registered Capacity at 100% MW Output and 0 at 50% MW Output.

OC 5.4.7.4. The Generator may only restrict governor response action where:

(a) the action is essential for the safety of personnel and/or to avoid damage to Plant, in which case the Generator shall inform the SO of the restriction without delay; or

(b) in order to (acting in accordance with Good Industry Practice) secure the reliability of the Generating Unit; or

(c) the restriction is agreed between the SO and the Generator in advance, subject to the SO informing all the agreements with Generators on governor response; or

(d) the restriction is in accordance with a Dispatch Instruction given by the SO.

Provided that the Generator shall justify their actions by reporting to the SO about their event.

OC 5.4.7.5. In the event that the SO either agrees to a restriction on governor action or instructs such a restriction, the SO shall record the nature of the restriction, the reasons, and the time of occurrence and duration of the restriction in the operation or dispatch reports.

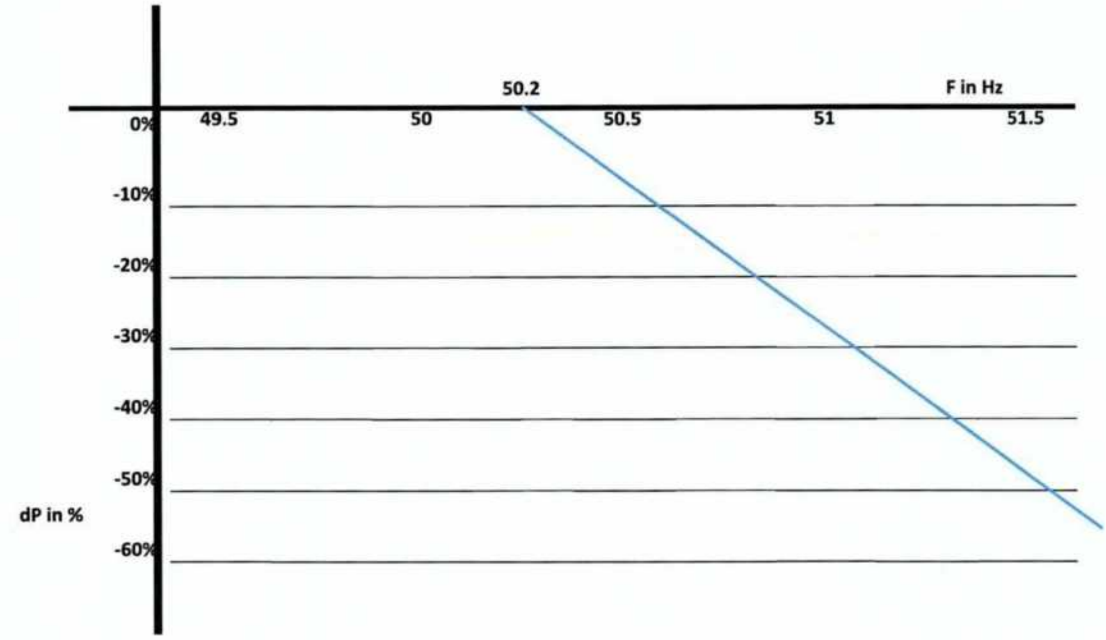
OC 5.4.8. Primary Frequency Control of Non-Synchronous Generators

OC 5.4.8.1. Unless specifically instructed by the SO, Wind and Solar PV/CSP Power Plants without Energy Storage Units, will operate in Free Energy Production mode, and they will be exempted from the responsibility of Frequency Regulation and Control while Frequency is within the "Frequency Sensitive Band".

OC 5.4.8.2. When Frequency is greater than 50.2 Hz, entering the "Tolerance Frequency Band", with upper range defined as 50.5 Hz, all Wind and Solar PV/CSP Power Plants shall contribute to Frequency stabilization by reducing active power (as per SO instructions) as described in Figure OC 1 below:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Figure OC 1: Active Power and Frequency Control of VRE Plants



OC 5.4.8.3. The SO may instruct to Wind and Solar PV/CSP Power Plants without Energy Storage Units to operate in a different production mode, as indicated in CC 6.3.3, when it considers necessary to maintain the security or reliability of the National Grid. This mode of operation may include the operation under control of the Frequency Regulation system (Delta Production Constraint) mode.

OC 5.4.8.4. ESPP and other Non-Synchronous Generators, equipped with Energy Storage Units, when connected to the Transmission System shall operate at all times under the control of a Frequency Regulation system, unless otherwise instructed by the SO or permitted exceptional circumstances as laid down in OC 5.4.8.6 below. When operating under this control system:

(a) No time delays other than those necessarily inherent in the design of the Frequency Control shall be introduced;

(b) Frequency sensitivity shall be activated for any Frequency deviations exceeding ± 0.05 Hz, except for those Non-Synchronous Generators for which Frequency Regulation service is not activated on instructions of the SO.

OC 5.4.8.5. ESPPs and other Non-Synchronous Generators, equipped with Energy Storage Units may only restrict the Frequency Control Action in exceptional circumstances, to be agreed with the SO in advance, when essential for any of the following situations:

(a) for the Safety of personnel and/or to avoid damage to the Plant;

(b) to secure the Reliability of the Non-Synchronous Generators;

(c) other restrictions agreed between the SO and the ESPP in advance;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(d) The restriction is in accordance with a Dispatch Instruction issued by the SO.

Provided that the Generator shall justify their actions by reporting to the SO about their event.

Such actions shall be brought to the notice of the SO immediately, and the SO shall record them properly.

OC 5.4.9. Frequency Control of Interconnectors

OC 5.4.9.1. Interconnectors, when energized, shall operate at all times in Frequency Control mode, unless otherwise specified by the SO, with characteristics within the appropriate ranges as specified in Connection Code.

OC 5.4.9.2. The Interconnector Frequency Droop shall normally be 4% and shall be settable between 2% and 12%.

OC 5.4.9.3. No intentional time delays other than those agreed with the SO shall be introduced into the frequency response system.

OC 5.4.9.4. The Frequency Deadband shall normally be zero. Any non-zero Deadband must be agreed in advance with the SO and shall not exceed ±0.05 Hz.

OC 5.4.9.5. Interconnectors shall not act to control the frequency in another System unless agreed in advance with the SO and the Interconnector.

OC 5.4.9.6. For Low Frequency Events, each Interconnector shall be capable of providing:

(e) minimum Primary Operating Reserve of 5% Registered Capacity while operating at MW Output of 95% of Registered Capacity;

(f) While operating at MW Output in the range from 50% to 95% Registered Capacity, the amount of Frequency Response shall not be less than that indicated by a straight line with unity rise from 50% of Registered Capacity at 50% MW output to 5% at 95% MW output;

(g) While operating at MW Output in the range of 95% to 100% Registered Capacity the amount of Frequency Response shall not be less than that indicated by a straight line with unity decay from 5% of Registered Capacity at 95% output to 0 at 100% output; and

(h) For High Frequency Events, the minimum amount of Frequency Response shall be vice versa with 50% of Registered Capacity at 100% MW Output and 0 at 50% MW Output.

OC 5.4.9.7. The Interconnector may only restrict the action of the Frequency Control mode in such as a manner as to contravene the terms of OC 5.4.9.1 where:

(i) The action is essential for the safety of personnel and/or to avoid damage to Plant, in which case the Interconnector shall inform the SO of the restriction without undue delay; or

(j) in order to (acting in accordance with Good Industry Practice) secure the reliability of the Interconnector, in which case the Interconnector shall inform the SO of the restriction without undue delay; or

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

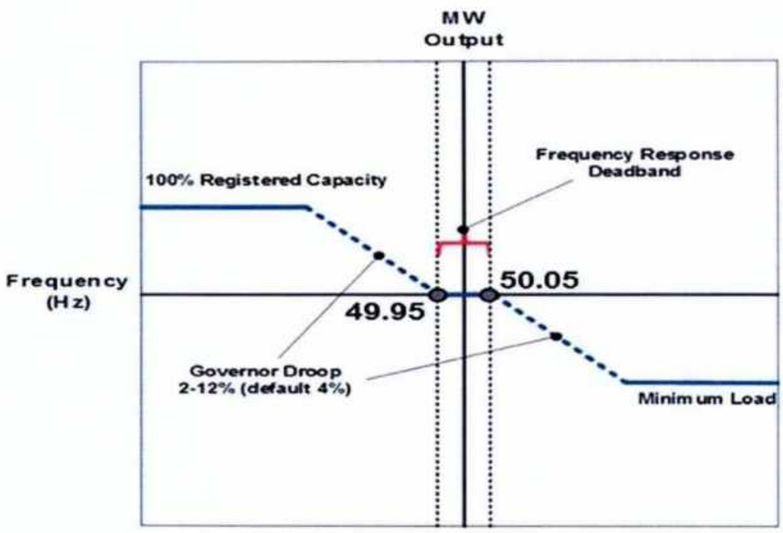
(k) the restriction is agreed between the SO and the Interconnector in advance; or

(l) the restriction is in accordance with a Dispatch Instruction given by the SO.

Provided that the Interconnector shall justify their actions by reporting to the SO about their event.

OC 5.4.9.8. In the event that the SO in accordance with OC 5.4.9.7 either agrees to a restriction on the control action or instructs such a restriction, the SO shall record the nature of the restriction, the reasons, and the time of occurrence and duration of the restriction.

Figure OC 2: Primary Frequency Control



OC 5.4.10. Primary Frequency Control of embedded HVDC

For the purpose of Primary Frequency Control:

(a) Embedded HVDC systems shall be equipped with an independent control mode to modulate the Active Power output of the HVDC converter station depending on the frequencies at all Connection Points of the HVDC system in order to maintain stable system frequencies.

(b) The SO shall specify the operating principle, the associated performance parameters and the activation criteria of the Frequency Control of the HVDC referred to point (a) above, as per relevant Agreements.

OC 5.4.11. Secondary Frequency Control

OC 5.4.11.1. Frequency deviations, outside the levels specified in OC 5.4.4.1 (b) such as those that may occur on the loss of Generating Units, Interconnectors, Demand or other MW input into the Transmission System or the Distribution System are corrected through the use of Secondary Frequency Control.

OC 5.4.11.2. Secondary Frequency Control takes place in the time scale from 5 seconds following the change in Frequency and achieves its maximum value within 30 seconds which is sustainable up to 30 minutes.

OC 5.4.11.3. Secondary Frequency Control acts directly on the MW Outputs of participating Generating Units. This automatic action facilitates more frequent MW output adjustments than is practicable by means of Dispatch Instructions and manual set point adjustment, thus allowing more frequent and rapid Frequency correction.

OC 5.4.11.4. The Secondary Frequency Control operational on the Transmission System is carried out through "Automatic Generator Control" (AGC), except when AGC is not available or the SO considers necessary to disconnect it when the Secondary Frequency Control may be assigned to a single Generator or Generating Unit and further actions from other Generators shall be coordinated according to instructions issued by the SO to obtain the required Frequency response[2].

OC 5.4.11.5. Generating Units with a Registered Capacity in accordance with CC 6.2.1 (l) shall be capable to provide Secondary Frequency Control as instructed by SO, within the limits stated in the Connection Agreement.

OC 5.4.11.6. SO shall maintain appropriate reserve (headroom) in the participating Generators to allow them to vary their MW Output under Automatic Generation Control.

OC 5.4.11.7. The amount of Frequency Response in terms of MW available from all Generators participating in Secondary Frequency Control is known as "Secondary Operating Reserve".

OC 5.4.11.8. SO shall determine which Generators shall participate in AGC for Secondary Frequency Control, based on the results obtained in the Security Constrained Economic Dispatch, as per SDC 1.7, and real time conditions. All Generating Units participating in AGC shall operate under the control of AGC when within their AGC Control Range.

OC 5.4.11.9. For Low Frequency Events, each Generator shall be capable of providing:

(a) minimum Operating Reserve of 10% Registered Capacity while operating at MW Output of 90% of Registered Capacity;

(b) While operating at MW Output in the range from 50% to 90% Registered Capacity, the amount of Frequency Response shall not be less than that indicated by a straight line with unity rise from 50% of Registered Capacity at 50% MW output, to 10% at 90% MW output;

(c) While operating at MW Output in the range of 90% to 100% Registered Capacity the amount of Frequency Response shall not be less than that indicated by a straight line with unity decay from 10% of Registered Capacity at 90% output to 0 at 100% output;

(d) For High Frequency Events, the minimum amount of Frequency Response shall be vice versa with 50% of Registered Capacity at 100% MW Output and 0 at 50% MW Output.

---

[2] In case AGC is not available in the system due to any reason, the Secondary Operating Reserves shall be operated manually for frequency regulation. In such case, the response time mentioned in OC 5.4.10.2 is impracticable, and the SO shall use its best efforts to manually operate the Reserve as fast as practicable. However, it is clarified that during this emergency, System Reliability and Power Quality would be at risk and all possible endeavours must be made by all Users to restore AGC in the system.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 5.4.11.10. Secondary Frequency Control shall not impair the action of the Primary Frequency Control. These actions of Secondary Frequency Control will take place simultaneously and continually, both in response to small deviations (which will inevitably occur in the course of normal operation) and in response to a major discrepancy between generation and Demand (associated e.g. with the tripping of a generating unit or network).

OC 5.4.11.11. In the event that the Generator (acting in accordance with Good Industry Practice) considers that it is necessary to secure the reliability of a Generating Unit, or for the safety of personnel and/or Plant, to prevent a Generating Unit from operating under AGC, then the Generator shall inform the SO of this without delay, requesting its authorization for this change its operating mode. Generators shall inform the SO of the justification for not operating the Generating Unit under AGC/Secondary Frequency Control, including as necessary the required documentation, and the course of action being taken to rectify the problem forthwith. The SO shall decide if the control actions could be maintained manually, or, alternatively, it will disconnect such Generating Unit from the AGC or from providing Secondary Frequency Control, replacing it, if it is deemed appropriate, by other Generating Units. When the problem has been rectified, the Generator shall contact the SO to arrange for the Generating Unit to return to operation under the control of AGC/Secondary Frequency Control as applicable. The Generator shall justify its actions by reporting to the SO about their event.

OC 5.4.11.12. The SO may issue a Dispatch Instruction to a Generator to prevent a Generating Unit (equipped with AGC) from operating under AGC, in accordance with SDC 2.

OC 5.4.11.13. Generating Units not operating under AGC/Secondary Frequency Control for reasons set out in OC 5.4.10.11 and OC 5.4.10.12 shall nevertheless continue to follow MW Dispatch Instructions as required by SO.

OC 5.4.12. Tertiary Frequency Control

The goal of Tertiary Frequency Control is to restore the reserves that were used during Primary and Secondary Frequency Control. Reserves may be restored using re-dispatch, commitment of resources, or establishing new Interconnector schedules. Restoring these reserves completes the repositioning of the National Grid so that it is prepared to respond to a future loss-of-generation event. Tertiary Frequency Control is utilized using Replacement Reserve and Contingency Reserve as established in this sub-code.

OC 5.4.12.1. Replacement Reserve

Replacement Reserve is the additional MW output required compared to the pre-Incident output which is fully available and sustainable over the period from 20 minutes to 4 hours following an Event. Each Generator/Interconnector shall be capable of providing Replacement Reserve as per the requirement of the SO, provided these requirements are within the Technical Parameters registered under this Grid Code, the relevant Connection Agreement, and the Availability Notices issued under SDC 1, not less than 10% Registered Capacity, at a minimum, at MW Outputs in the range from 50% to 90% Registered Capacity, with provision in the range of 90% to 100% Registered Capacity to be not less than that indicated by a

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

straight line with unity decay from 10% of Registered Capacity at 90% output to 0 at 100% output.

OC 5.4.12.2. Contingency Reserve

Contingency Reserve is the margin of available Generation Capacity over Forecast Demand, which is required in the period from twenty-four (24) hours ahead down to real time, to cover against uncertainties in the availability of Generation Capacity and also against weather forecast and Demand Forecast uncertainties. Contingency Reserve is provided by Generating Plants which are not required to be Synchronized, but must be available to Synchronize with the System within a time scale as specified by the SO while preparing Indicative Operation Schedule (IOS) as per SDC 1.

OC 5.4.13. Operating Reserve Policy

OC 5.4.13.1. The SO shall determine any reserve requirements, including the amount of Primary Operating Reserve, Secondary Operating Reserve and Tertiary Operating Reserve to ensure system security. For such reason, within twelve (12) months of the approval of this Grid Code, the SO shall establish, and maintain permanently updated, GCOP for Operating Reserve Requirements, detailing the methodology to be used to determine the amounts of different types of reserve required by the Transmission System in different operational conditions. The GCOP shall take due consideration, inter alia, the following factors:

(a) the relevant SO operating policy in existence at that time;

(b) the magnitude and number of the largest generation infeed to the Transmission System, including infeed over Interconnectors, and also over single transmission feeders within the Transmission System, and the amount of Generation that could be lost following a single Contingency;

(c) the extent to which Demand Control allowed under the relevant standard have already occurred within the then relevant period;

(d) the elapsed time since the last Demand Control Incident;

(e) particular events of national or widespread significance, which may justify provision of additional Operating Reserve;

(f) the cost of providing Operating Reserve at any point in time;

(g) Expected demand/VRE generation forecast variability;

(h) ambient weather conditions, insofar as they may affect (directly or indirectly) Generating Unit and/or Transmission System reliability;

(i) the predicted Frequency drop on loss of the largest infeed as may be determined through simulation using a dynamic model of the National Grid;

(j) constraints imposed by agreements in place with Externally Interconnected Parties;

(k) uncertainty in future Generation output.

OC 5.4.13.2. The SO shall submit the GCOP, and its amendments, to NEPRA for review of consistency with the approved Grid Code. The SO shall publish the GCOP, including its updates, on its website, keep records of each modification to the Operating Reserve policy so determined under OC 5.4.12.

OC 5.4.13.3. **Contingency Reserve Quantity**

The SO shall determine the amount of Contingency Reserve required for each time scale up to 24 hours ahead, taking due consideration of relevant factors, including but not limited to the following:

(a) historical Availability Factor and reliability performance of individual Generating Units;

(b) notified risk to the reliability of individual Generating Units;

(c) Demand/VRE forecasting uncertainties;

(d) status and availability of DNOs; and

(e) status and availability of Interconnectors.

Table OC 3: Primary, Secondary & Tertiary Frequency Control Summary

Name	Timescale	Description	Type of Operating Reserve	Participants	Quantum
Primary Frequency Control	0 - 10 sec and sustainable up to 30 sec	Free Governor Control/Non-Synchronous Frequency Control	Primary Frequency Reserve	Fitted on all Generators and ESUs, including Embedded Generators and always activated.	As per the GCOP for Operating Reserve Requirements. Until such GCOP is developed, as per Generators on-bar
Secondary Frequency Control	5 sec - 30 sec and sustainable up to 30 min	Automatic Generation Control (AGC) or secondary Frequency Control	Secondary Frequency Reserve	Fitted on all applicable Generators and activated on SO instructions or AGC	As per the GCOP for Operating Reserve Requirements. Until such GCOP is developed, equal to the largest synchronized Generating Unit
Tertiary Frequency Control	20 min - 4 hours	Re-dispatch/Synchronization	Replacement Reserve	Re-dispatch/Synchronization of Generators to restore Primary and Secondary Reserves	As per the GCOP for Operating Reserve Requirements. Until such GCOP is developed, equal to the largest Generating Unit
	24 hour ahead to real time		Contingency Reserve		

OC 5.4.14. **Responsibilities of the SO in Respect of Operating Reserve**

OC 5.4.14.1. The SO shall, in accordance with Prudent Utility Practice, make reasonable endeavors to Dispatch generation and operate the system in compliance with the

SO's determinations as per GCOP for Operating Reserve Requirements updated from time to time.

OC 5.4.14.2. The SO shall, acting in accordance with Prudent Utility Practice, Dispatch Generating Units which are available as per the provisions of SDC 1 and SDC 2. In any case, having met its obligations under the preceding provisions of OC 5.4, the SO is entitled to modify such Dispatch and levels and assign Operating Reserves, issuing the necessary Dispatch Instructions, if it deems necessary to maintain the Transmission System security and reliability. The SO shall record and justify such decisions.

OC 5.4.14.3. The SO shall Monitor the Frequency Response provided by Users for compliance. In evaluating the adequacy of the performance of a Generator/Interconnector, the SO shall compare the actual performance as measured, with the expected performance for that Generating Unit or Interconnector. The expected performance from the Generating Unit/Interconnector shall be calculated based on the Frequency deviation from the pre-incident Frequency, and the values of Response expected from the Generating Unit or Interconnector.

OC 5.4.14.4. In the event of a Generating Unit not providing Frequency Response, unless instructed by SO, the SO may impose restrictions on the operation of the Generating Unit in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Generator to De-Energize, or not energize/synchronize the Generating Unit.

OC 5.4.14.5. In the event of an Interconnector not providing Frequency Response, the SO may impose restrictions on the operation of the Interconnector in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Interconnector to De-Energize, or not connect/synchronize the Interconnector. Following the occurrence of a Significant Frequency Disturbance, the SO shall analyze the adequacy of the provision of Operating Reserve and may re-evaluate the amount of Reserve to be maintained in the System, updating, if necessary the GCOP for Operating Reserve Requirements.

OC 5.4.14.6. If the System Operator foresees that there will be insufficient Operating Reserve, it shall discuss this problem with the Users, and seek to change the generation plant mix forcing generation dispatched to ensure that there shall be sufficient Operating Reserve in the System.

OC 5.4.14.7. Action required by Generators/ESU in response to Low Frequency Events:

(a) If System Frequency falls to below 49.95 Hz, each Generator shall be required to check that each of its CDGUs is achieving the required level of response including that required from the Governor Control System, where applicable, in order to contribute to containing and correcting the low System Frequency.

(b) Generators/ESUs shall be capable of providing a power increase up to Registered Capacity. ESUs shall be capable of disconnecting their load in response to low Frequency. This requirement does not extend to auxiliary supplies.

(c) Where the required level of response is not being achieved, appropriate action should be taken by the Generators/ESUs without delay as per OC 5.4.11.11.

OC 5.4.14.8. Action required by Generators/ESUs in response to High Frequency Events:

If System Frequency rises to or above 50.05 Hz, each Generator will be required to ensure that its CDGUs have responded in order to contribute to containing and correcting the high System Frequency by automatically:

(a) reducing MW Output without delay and without receipt of instruction from the SO to achieve the required levels of response, provided the Generator's local security and safety conditions permit.

(b) Generators shall be capable of providing a power decrease down to Minimum Load. ESUs shall be capable of decreasing supply/increasing load as per Technical Parameters.

(c) Stable operation shall be ensured.

(d) Generating Units shall be capable of continuous stable operation when MW Output is reduced to Minimum Load. This response will prevail over any other Active Power control mode.

(e) Where the required level of response is not being achieved, appropriate action should be taken by the Generators without delay as per OC 5.4.10.11.

OC 5.4.14.9. Action required by Interconnectors in response to low Frequency:

(a) If System Frequency falls to below 49.95 Hz, each Interconnector will be required to ensure that it has responded in order to contribute to containing and correcting the low System Frequency by automatic increasing the Active Power input to the Transmission System or decreasing the Active Power import from the Transmission System without delay as per OC 5.4.10.11.

(b) Any such action shall be in accordance with the relevant Agreements between the Interconnector and the SO. Actions required by an Interconnector shall be governed by the corresponding Interconnection Agreement.

OC 5.4.14.10. Action required by Interconnectors in response to high Frequency:

(a) If System Frequency rises above 50.05 Hz, each Interconnector will be required to ensure that it has responded in order to contribute to containing and correction of the high System Frequency by automatic decreasing the Active Power input to the Transmission System or increasing the Active Power import from the Transmission System without delay and without receipt of instruction from the SO to achieve the required levels of response, provided the Interconnector's local security and safety conditions permit.

NATIONAL ELECTRIC POWER REGULATORY APPROVED BY THE AUTHORITY * NEPRA

(b) Any such action shall be in accordance with the relevant Agreements between the Interconnector and the SO.

OC 5.4.14.11. Action required by Interconnector in response to External System Frequency Events

Automatic MW set point changes of Interconnectors triggered by Frequency Events on the External System shall be agreed between the Interconnector and the SO, in accordance with the relevant Agreements.

OC 5.5. Voltage/Reactive Power Control

OC 5.5.1. In order to maintain security and integrity of the Transmission System, to avoid damage to the Transmission System and to User facilities, and to maintain Voltages in the Transmission System within the limits specified in the OC 5.5.7, the SO is required to control Transmission System Voltages.

OC 5.5.2. Voltage Control of power systems requires that MVAR demand is met and sufficient dynamic Voltage Control capability is available on the Transmission System to cover changes in the MVAR demand such as result from Demand variations, to facilitate controlled Voltage adjustment and to limit the duration and extent of Voltage fluctuations under fault/contingency conditions. The SO shall endeavor to maintain sufficient availability of dynamic and static reactive power in order to maintain Transmission System Voltages at Connection Points within the limits specified in OC 5.5.7, at all times.

OC 5.5.3. This OC 5.5 sets out the procedures for the utilization of User Plant or facilities by the SO for the purposes of Transmission System Voltage Control, where appropriate. Some procedures for implementation of Voltage Control strategies (e.g. Generating Unit MVAR Dispatch, Interconnector MVAR Dispatch, etc.) are addressed under the provisions of SDC 2, and therefore this OC 5.5 shall be read in conjunction with those provisions.

OC 5.5.4. Factors that influence the required MVAR capacity include:

(a) charging capacitance of the Transmission System;

(b) User MVAR Demand;

(c) Transmission System MVAR losses;

(d) Generating Unit MVAR production or absorption;

(e) Interconnector MVAR production or absorption; and

(f) Voltage Control facilities, such as capacitor banks, reactors or synchronous condensers, etc.

OC 5.5.5. The effects of Transmission System capacitance can be controlled by variation of the Transmission System Voltage. Thus, at times of high MVAR Demand (normally times of high MW Demand), the Transmission System Voltage may be operated towards the upper portion of the allowable control range, and at times of low MVAR Demand (normally times of low MW Demand), the Transmission System Voltage may be operated towards the lower portion of the allowable control range. This daily variation is typically required for operation of the Transmission System.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

OC 5.5.6. Due to the electrical characteristics of the Transmission System, the Voltage (for Plant operated at the same nominal Voltage) will not be the same at all points on the Transmission System and may vary within the operating Voltage limits defined in OC 5.5.7.

OC 5.5.7. Operating Voltage Limits

The SO shall maintain the operating Voltage of the System within Target Voltage Levels specified in Table OC 4. The system operating Voltage shall be maintained within these limits both for Normal Operating Conditions and Contingency Conditions excluding transient and abnormal System conditions.

(a) Under (N-0) Normal Operating Conditions: The bus Voltages shall be within the bandwidth of +4.58/-4.84% of the Nominal System Voltage for 765 kV Voltage level, and +8% and -5% of Nominal System Voltage for 500 kV, 220 kV, 132 kV and 66 kV Voltage levels.

(b) Under (N-1) Contingency Operating Conditions: The bus Voltages shall be within the bandwidth of +4.58/-6.8% of the Nominal System Voltage for 765 kV Voltage level while ±10% of the Nominal System Voltage for 500 kV, 220 kV, 132 kV and 66 kV Voltage level.

Table OC 4: System Operating Voltage Limits

Voltage Level (kV)	Normal Condition		N-1 Condition	
	Max kV	Min kV	Max kV	Min kV
765	800	728	800	713
500	540	475	550	450
220	238	209	245	198
132	142	125	145	119
66	70	63	72	59

These limits of System Operating Voltages are provided strictly for Voltage regulation purposes. These limits are not to be construed by Users as National Grid operating Voltages at the Connection Points which shall be maintained as per instructions of the SO.

OC 5.5.8. Description of Voltage Control

OC 5.5.8.1. The SO shall control system Voltage in order to maximize security of the Transmission System, while trying to reduce system losses and cost of use of Ancillary Services. The SO shall determine and modify as appropriate, general procedures for its use in controlling Voltage on the Transmission System. The procedures shall be formulated having due regard to relevant economics of Transmission System operation and reliability. In particular, the Voltage Control shall take cognizance of daily, weekly and seasonal factors.

OC 5.5.8.2. The SO shall determine:

(a) suitable target Voltages in order to limit/control the effect of transmission capacitance;

(b) best utilization of dedicated Voltage Control facilities; and

(c) MVAR dynamic reserve requirements.

OC 5.5.8.3. Transmission System Voltages shall be continuously monitored by the SO. Appropriate Voltage operating points shall be determined by the SO, taking account of OC 5.5.8.1 and in particular of System conditions pertaining at the time of operation.

OC 5.5.8.4. The SO shall adjust System Voltages, using control facilities that are available so as to achieve the MVAR capacity necessary in order to operate Transmission System Voltages within the limits specified in Operation Code and retain a dynamic MVAR capability to deal with changing System conditions which result from changes in Demand or changes in transmission or generation configuration, whether as a result of control actions or faults.

OC 5.5.8.5. DNOs and Transmission Connected Consumers/BPCs shall be responsible for the maintenance of power factor at 132 kV buses above 0.95 during steady-state operating conditions by installing appropriate power factor correction facilities within their Service Territories. DNOs and Transmission Connected Consumers/BPCs shall not offer leading power factor to the Transmission System in any case.

OC 5.5.8.6. To avoid any doubt, there shall be no export of Reactive Power (MVAR) to the Transmission System from DNOs or Transmission Connected Consumers/BPCs at 132 kV Connection Points or otherwise permitted by SO.

OC 5.5.9. Methods of Voltage Control

OC 5.5.9.1. The SO can use the following Voltage Control methods:

(a) User MVAR Demand/power factor correction;

(b) transformer tap-changing, cable switching, reactor and capacitor switching;

(c) dynamic Voltage support including control modes of HVDC/ESUs (e.g. Voltage Control, reactive power control, power factor control modes, FACTS devices, etc.);

(d) utilization of Generating Unit Reactive Power capability, both by means of AVR control and also MVAR Dispatch Instructions issued by the SO to Generators;

(e) if allowed under the Interconnector Agreement, utilization of Interconnector Reactive Power capability by means of suitably acting AVR/RPC control and/or MVAR Dispatch Instructions issued by the SO to Interconnector;

(f) tap-changing on Generator Transformers;

(g) In case the methods listed above would not be sufficient, switching out of transmission HV cables (and occasionally transmission lines) in order to reduce the capacitive contribution of the Transmission System.

OC 5.5.9.2. The excitation system of each Synchronous Generating Unit shall normally be operated under the control of a continuously acting AVR, which shall be set so as to maintain a constant terminal Voltage, as per instructions issued by the SO. The Generator may not disable or restrict the operation of the AVR except in accordance

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

with OC 5.5.9.6, in which event the Synchronous Generator shall notify the SO without delay.

OC 5.5.9.3. Each Non-Synchronous Generating Unit shall control the Voltage at the Connection Point by means of a suitable continuously acting Reactive Power Controller (RPC) system. The Voltage Control mode and relevant settings shall be instructed by the SO. The Non-Synchronous Generating Unit may not change the control mode or restrict the operating of the RPC except in accordance with OC 5.5.9.6, in which event the Synchronous Generating Unit shall notify the SO without undue delay

OC 5.5.9.4. Each Interconnector shall control the Voltage at the Grid Connection Point by means of a suitable continuously acting RPC. The Voltage Control mode shall be as per relevant Interconnection Agreements. Subject to such agreement, the Interconnector may not disable or restrict the operating of the RPC except in accordance with OC 5.5.9.6, in which event the Interconnector shall notify the SO without undue delay.

OC 5.5.9.5. The Generator, or when applicable an Interconnector, may only disable or restrict AVR action where:

(a) the action is essential for the safety of personnel and/or Plant; or

(b) in order to (acting in accordance with Prudent Utility Practice), secure the reliability of the Generating Unit or Interconnector; or

(c) the restriction is agreed between the SO and the Generator or Interconnector in advance.

OC 5.5.9.6. In case the SO either agrees to a restriction in AVR action or instructs such a restriction, the SO shall record the nature of the restriction, as well as the reasons, time of occurrence, and the duration of the restriction.

OC 5.5.9.7. In the event of a Generating Unit declared not operating under AVR, unless instructed by SO, the SO may impose restrictions on the operation of the Generating Unit in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Generator to De-Energize, or not Energize/Synchronize the Generating Unit. Such situation shall be communicated by the SO to the Authority.

OC 5.5.9.8. In the event of an Interconnector not operating under AVR, in case such type of control is established in the Interconnection Agreement, the SO may impose restrictions on the operation of the Interconnector in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Interconnector to De-Energize, or not connect/synchronize the Interconnector.

OC 5.5.9.9. The SO shall, by means of Dispatch Instructions (as provided in SDC), instruct Generators and, when applicable subject to the Interconnection Agreement, Interconnectors to adjust the Voltage set points and/or Reactive Power output of Generating Units and Interconnectors, and the relevant provisions of SDC shall apply.

OC 5.5.9.10. On some occasions it shall be necessary for the SO to reschedule Generating Units or Interconnectors away from their desired output in order to achieve Transmission System Voltages within the limits specified in OC 5.5.7. However, the SO will resort to such rescheduling only to deal with emergencies or contingencies that threaten the Stability and Security of the Transmission System.

OC 5.5.10. Emergency or Exceptional Voltage Control

OC 5.5.10.1. Additional Voltage Control mechanisms may be utilized by the SO in the event of System emergency conditions. These shall include the following:

(a) Generators may be requested to operate Generating Units at MVAR production or absorption levels outside their currently declared Technical Parameters. This will be done by agreement between the Generator/Interconnector and the SO. In such situation the SO and Generator/Interconnector shall not be considered as non-compliant, and shall not be subject to payment of any damages, fines, penalties etc. to anyone whomsoever; and

(b) the SO may also effect changes in System Voltage by instructing, as a form of Dispatch Instruction, the Generators to carry out a tap-change on the main Generator transformer of several Generating Units simultaneously; and

(c) Demand Control may be used to prevent Voltage from contravening low Voltage limits.

OC 5.6. Black Start

OC 5.6.1. In order to recover the Transmission System from a Partial or Total Shutdown, it is necessary to have designated Generating Stations/HVDC Stations (Black Start Stations) available which have the ability for at least one of their Generating Units/Converter Stations to Start-Up from Shutdown and to Energize a part of the System, Synchronize with the System, and Energize dead bus, upon instruction from the SO, without an external electrical Power supply.

OC 5.6.2. In order to maintain Security on the Transmission System at all times, Black Start Stations are required to comply with the provisions of this OC 5.6.

OC 5.6.3. The Generating Units/HVDC Stations with Black Start capability must provide Frequency and Voltage within the prescribed limits during line Energization and remote load pick up.

OC 5.6.4. The SO shall verify the actual performance of Black Start capability when actual system Blackout conditions occur, or may request Tests from time to time to verify readiness and adequacy of response.

OC 5.6.5. Generators/HVDC Stations providing Black Start capability will also be required to provide voice and other communication facilities linked with the SO and capable of operating without an external AC Power supply for the period as specified by the SO in the relevant agreement.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 5.6.6. Requirements of Black Start Stations

OC 5.6.6.1. During a Black Start situation, instructions relating to Black Start Stations will be in the format required for instructions to Generating Units/HVDC Stations in the Scheduling and Dispatch Code, and will recognize any differing Black Start operational capabilities (however termed) set out in the relevant declared Technical Parameters and the Connection Agreement. For the purposes of these instructions, the Black Start will be an emergency circumstance. For Generating Units/HVDC Stations which are not Black Start Units, Dispatch Instructions will recognize each Unit's Declared operational capability as registered pursuant to the CC/PC.

OC 5.6.6.2. The Generator or HVDC shall report to the SO all the required operational procedures to operate the Black Start Unit.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 6. NETWORK CONTROL

OC 6.1. Introduction

OC 6.1.1. In routine operation of the National Grid, in implementing the Transmission Outage Program, and in responding to Emergency and Fault situations on the Transmission System, the SO needs to carry out Control Actions which may from time to time affect the operations of Users or Security of supply to Users.

OC 6.1.2. The purpose of this sub-code Network Control OC 6 of the Operation Code is to set out the actions which may be taken by the SO in controlling the National Grid, to set out the procedures whereby the SO shall inform Users, where practicable, as to network Control Actions which will or may be likely to significantly affect User's operations, and to identify when the SO shall, insofar as reasonably practicable, consult with Users and take into consideration Users' reasonable requirements.

OC 6.1.3. All Transmission connected facilities/Apparatus shall be under the operational control of the SO. Any switching operation or Control Action carried out by any User on Transmission System without prior instructions/authorization of SO shall be deemed as non-compliance and reported by the SO to NEPRA for action under applicable regulations of Authority. In case a switching operation or Control Action is carried out by a User in Emergency, the action must be justified to the satisfaction of the SO, to not be considered as non-compliance.

OC 6.1.4. Each User shall also make their facilities/Apparatus connected below Transmission Voltage levels available to the SO for control when required. Instructions given by the SO regarding facilities/Apparatus connected below Transmission Voltage levels shall be binding on the Users and non-compliance shall be notified by the SO to NEPRA for action under applicable regulations of the Authority.

OC 6.2. Objective

The objective of OC 6 is to:

(a) identify the Control Actions that may be taken by the SO and relevant Code Participants, so that the SO may carry out the operation of the Transmission System and respond to Transmission System faults/contingencies and emergencies.

(b) to establish procedures whereby the SO will:

(i) where practicable, inform Users who will be or are likely to be significantly affected by network Control Actions, of relevant details of intended Control Actions and the expected effect of those Control Actions;

(ii) consult with Users as appropriate in order to find out and take into consideration reasonable objections raised by Users so affected.

APPROVED BY THE AUTHORITY
NATIONAL ELECTRIC POWER REGULATORY AUTHORITY * NEPRA *

OC 6.3. Scope

The scope of this OC 6 applies to SO and:

(a) Transmission Network Operators;

(b) Generators connected to the Transmission System;

(c) Distribution Network Operators;

(d) Transmission Connected Consumers;

(e) Interconnectors; and

(f) Embedded Generators whether represented through some Aggregators or any other arrangement approved by NEPRA (if required by SO). The Embedded Generators to which this Grid Code will apply shall be determined as per the relevant applicable regulations of NEPRA.

OC 6.4. Network Control Actions

OC 6.4.1. The SO needs to carry out Control Actions for a number of purposes, which include, but not limited to, the following:

(a) Outages of network component and Apparatus for the purposes of maintenance, User Development, System Tests, protection testing and work by Users;

(b) Outages of Transmission System Plant and Apparatus due to suspected or potential faults and emergency repairs;

(c) Voltage Control;

(d) Managing network configuration to maintain power flows on the Transmission System within the levels consistent with the capabilities of the Transmission System Plant and Apparatus for System Security;

(e) Demand Control;

(f) Change of Control Modes, adjustment of Control Mode parameters and setting associated set points, flow variations of HVDC in the Transmission System.

OC 6.4.2. Additionally, network switching may occur automatically and without advance warning due to operation of protection equipment in isolating or clearing faults on the National Grid.

OC 6.4.3. Automatic switching sequences may also be established to limit power flows or Voltage or Frequency deviations in the event of faults elsewhere on the System.

OC 6.4.4. This OC 6 also applies to third party entities contracted by Users for the purpose of operation and maintenance, etc.

OC 6.5. Transmission System Operating States

OC 6.5.1. Normal State

The Transmission System shall be considered to be in the Normal State when:

(a) The Single Outage Contingency (N-1) Criterion is met;

(b) The Operating Reserves are in accordance with the values established as given in OC 5;

(c) The System Frequency is within the limits as specified in OC 5.4.4.1(c);

(d) The Voltages at all transmission nodes are within the limits as specified in OC 5.5.7;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(e) The loading levels of all transmission lines and substation equipment are within normal operating limits defined in OC 6.7;

(f) The Transmission System configuration is such that any potential fault current can be interrupted and the faulted equipment can be isolated from the Transmission System.

OC 6.5.1.1. Single Outage Contingency (N-1) Condition

The N-1 Condition consists of one of the following contingencies:

(a) Loss of a single-circuit transmission line, except those radial circuits which connect Loads using a single line or cable;

(b) Loss of one circuit of a double-circuit transmission line including the point-to-point connection of a Generator to the Transmission System;

(c) Loss of a single Transformer, except those which connect Loads using a single radial Transformer;

(d) Loss of a single pole of a bipole HVDC;

(e) Loss of a Generating Unit; and

(f) Loss of compensating devices, i.e. Capacitor/Reactor/SVC, etc.

OC 6.5.1.2. Single Outage Contingency (N-1) Criterion

The Single Outage Contingency (N-1) Criterion is satisfied if, after a single Outage in the system specified in OC 6.5.1.1 occurs, the following rules are observed:

(a) There is no breach of the limiting values for operation Voltage, as given in OC 5.5.7 and Frequency, as given in OC 5 that may endanger the Security of the Power System;

(b) No equipment/transmission line loading has exceeded normal operating limits defined in OC 6.7;

(c) Interruptions of electric power supply to end-users are avoided, except for automatic load shedding by Frequency Control mechanisms in case of loss of Generating Unit as per OC 6.5.1.1 (e);

(d) Cascading Outage is avoided;

(e) There is no need to change generation dispatch except in case of loss of Generating Unit;

(f) The loss of Generating Unit stability is avoided.

OC 6.5.2. Contingency State

The Transmission System shall be considered to be in the Contingency State when any one of the following conditions exists:

(a) The Single Outage Contingency (N-1) Criterion is not met;

(b) The Operating Reserves are less than the values required to stabilize Frequency within the limits of OC 5;

(c) The Voltages at the Connection Points are outside the limits as established in OC 5.5.7;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

(d) No equipment/transmission line loading is above contingency operating limits (as described in Transmission Planning Criteria and Standards of the Planning Code);

(e) A severe weather condition has occurred; or

(f) A law and order problem exists, which may pose a threat to Transmission System operations.

OC 6.5.3. Emergency, Extreme Emergency and Restorative States

OC 6.5.3.1. The Transmission System shall be considered to be in the "Emergency State" when either a Single Outage Contingency or a Multiple Outage Contingency (as described in Transmission Planning Criteria and Standard Standards of the Planning Code) has occurred without resulting in Total System Blackout, but any one of the following conditions exists:

(a) There is generation deficiency to maintain demand-generation balance or Operating Reserve is zero;

(b) The Transmission System Voltage is outside the limits established in OC 5.5.7 for N-1 conditions; or

(c) The loading level of any transmission line or substation equipment is outside contingency operating limits.

OC 6.5.3.2. The Transmission System shall be considered to be in the "Extreme Emergency State" when the corrective measures undertaken by the System Operator during an Emergency State failed to maintain System Security and resulted in Partial or Total Shutdown, Cascading Outages, Islanding, and/or National Grid Voltage collapse.

OC 6.5.3.3. The Transmission System shall be considered to be in Restorative State when, under the instructions of the SO, Generating Units, transmission lines, substation equipment, and Loads are being Energized and Synchronized to restore the Stability of the Power System.

OC 6.6. Transmission System Operating Cases

OC 6.6.1. Base Operating Case

The System Operator shall make its best efforts to operate the National Grid in the Normal State. Each day the System Operator shall establish a generation schedule for the next day and shall dispatch generating units and transmission resources on an hour by hour basis as per the provisions in the Scheduling and Dispatch Code. The Dispatch Schedule shall provide adequate generation capacity to meet expected load, total operating reserves as per OC 5 and ancillary services requirements.

The operation of the Transmission System shall:

(a) not result in transmission congestion or Voltage violations during the Normal State;

(b) not violate contingency Voltage limits or contingency loading limits on transmission lines or transformers or manifest stability problems during Normal and N-1 contingencies; and

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(c) be based on the principles of SCED and Optimal Power Flow while maintaining stability and reliability.

OC 6.6.2. Corrective Actions for Contingency, Emergency, Extreme Emergency and Restorative Operating States

OC 6.6.2.1. The System Operator shall have available and shall implement when required, generation re-dispatch plans and schedules for credible (N-1) contingency events (as described in Transmission Planning Criteria and Standards in the PC) so that, if the system moves to a credible (N-1) contingency state, the System Operator can follow the re-dispatch decided in short period, returning the system to a Normal State.

OC 6.6.2.2. The System Operator shall make available and implement Emergency operating procedures to deal with system emergencies.

OC 6.6.2.3. The System Operator shall have available and shall implement Remedial Actions able to neutralize or mitigate the consequences of Contingencies. Against each Contingency, the SO shall study the most effective countermeasures that could be applied (manually or automatically) in real-time to prevent the Transmission System from being operated beyond contingency operating limits, and/or to avoid Cascading Outages resulting in a Partial/Total Shutdown, in case of incredible and extreme emergencies. These may include:

(a) Generating Unit Re-Dispatching and reassigning reserves

(b) Usage of Voltage and/or power flow control on regulation Transformers

(c) Network re-configuration

(d) Demand Control

(e) Generating Unit Tripping

OC 6.6.2.4. The System Operator shall have available at all times and be in a position to implement, system restoration plans for the situation in which the system moves to an Islanded state or suffers Cascading Outages resulting in a Partial or Total Shutdown.

OC 6.6.2.5. TNOs and DNOs must be engaged to cope with the conditions of all credible and incredible contingencies.

OC 6.7. Transmission System Loading Criteria

OC 6.7.1. Transmission Lines Loading Criteria

OC 6.7.1.1. The TNOs shall establish loading limits for each transmission line which it operates. Loading limits shall be established according to Normal state (N-0) and (N-1) contingency states, as well as for Summer and Winter seasons, while keeping in view:

(a) Thermal loading limits of the conductors

(b) Maximum conductor temperature

(c) Minimum clearance to ground at mid-span under maximum load

(d) Allowable overload for 15 minutes (to cater for SO reaction time)

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(e) Transient (power angle) stability and Voltage stability limits

(f) Maximum allowable conductor temperature

(g) Wind velocity

(h) Aging Factor

OC 6.7.1.2. The loading limits established by Users must be consistent with applicable IEC, ANSI/IEEE standards such as:

(a) IEC-60287 for Underground cables

(b) IEEE Std. 738™-2012, IEC 60826 for Overhead conductors

OC 6.7.1.3. For reference, the following table summarizes overhead conductor's ambient conditions to calculate loading criteria of overhead lines.

Table OC 5: Ambient Conditions for Overhead Conductors[3]

Parameter	Summer Rating Bases	Winter Rating Bases
Maximum Conductor Temp.	90°C	90°C
Outdoor Ambient Temp. (avg.)	40°C	(see footnote)
Conductor Temp. Rise	(see footnote)	(see footnote)
Max. Emergency Conductor Temp.	None Allowed	None Allowed
Wind Velocity	0.61 m/s	0.61 m/s

OC 6.7.2. Transformer Loading Criteria

Power transformers including three-phase and single-phase banks shall be loaded under normal and contingency conditions according to applicable IEC, ANSI/IEEE standards (such as IEC 60076-7:2005) or as specified by the respective manufacturers. Also, pre-load conditions shall be taken into account to determine loading limits in real time.

[3]Conductor Temperature Rise shall be calculated based on the Outdoor Ambient Temperature (average used for each respective Province). Lower or higher Outdoor Ambient Temperature (average) within a Province different from the values stated in above table may be considered if the variation in such temperature is significant, depending upon the location.

Notes on Table OC 5:

(a) Summer Months = April through October

(b) Winter Months = November through March

(c) Emergency ratings are limited to (8) hours of continuous operation. Conductors shall not be operated above 100° C conductor temperature for more than 960 cumulative hours.

(d) The following average temperature of Winter shall be used for the respective provinces:

(i)	Lahore (Punjab)	9.3° C
(ii)	Peshawar (Khyber Pakhtunkhwa)	5.3° C
(iii)	Quetta (Baluchistan)	-1.7° C
(iv)	Karachi (Sindh)	13° C

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

OC 6.7.3. **Transmission System Components Loading Criteria**

Transmission System components listed below, shall be loaded under Normal and Contingency conditions according to applicable IEC, ANSI/IEEE standards or as specified by the respective manufacturers.

(a) Circuit breakers

(b) Current Transformers

(c) Circuit switchers

(d) Potential transformers

(e) Capacitors

(f) Wave traps

(g) Shunt reactors

(h) Substation power buses

(i) Disconnect switches

(j) Substation power cables

OC 6.8. **Notification to Users of Network Control**

OC 6.8.1. All network Control Actions carried out on the Transmission System have the potential in a given set of circumstances to affect Users. It is not practicable to attempt to inform all Users of every Control Action and in most cases, the information will not be of any material value to the User as the User will not invoke any specific action as a result of receipt of the information.

OC 6.8.2. Where a specific Control Action has an Operational Effect on a User and if the SO considers that there is merit in notifying the User in advance of the Control Action, then the SO will notify the User of the Control Action (if planned and where time permits), in accordance with OC 8.

OC 6.8.3. Typical examples of Actions notified in accordance with OC 6.8 may include instructions to the Users of a significant reduction in supply security to a Connection Point (such as the Outage of one of two transmission connections), where the Users may arrange standby feeding arrangements at lower Voltages and/or activate embedded Generating units and/or connect Reactive Compensation equipment and/or run in-house Generating Units.

OC 6.8.4. Where it is necessary to carry out urgent switching or other network Control Actions resulting from a System condition or fault, it may not be possible for the SO to inform Users in advance of the switching or other Control Actions. The SO shall endeavor to inform Users where time permits, but this shall not delay timely implementation of Control Actions as required. Where the SO is unable to inform Users prior to the Control Actions, then the provisions of OC 6.9 shall apply.

OC 6.9. **Control Under Fault or Emergency Conditions**

OC 6.9.1. In the event of a System fault/contingency or protection operation or other automatic operation, it will not be possible to invoke standing procedures in accordance with OC 6.8 prior to the occurrence of the Control Action.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 6.9.2.	In the circumstances referred to in OC 6.9.1 or in the event that the SO needs to implement Control Actions urgently and without informing Users, then unless the situation is of a temporary nature and has been rectified to normal, the SO shall inform Users of the occurrence of the actions.
OC 6.9.3.	The SO shall also inform Users as to the likely duration of the condition and shall update this prognosis as appropriate. The SO shall additionally inform Users when the condition has ended.
OC 6.9.4.	Emergency Assistance to and from Interconnectors will be detailed in the relevant Interconnection Agreements. In accordance to such agreement, an Interconnector may request that the SO take any available action to increase the Active Power transferred into its External System, or reduce the Active Power transferred into the Transmission System. Such request will be met by the SO only if this does not require a reduction of Demand on the Transmission System, or lead to a reduction in security of the Transmission System.
OC 6.10.	**Termination (disconnection and reconnection) of User Facility, Plant and Apparatus**
	Disconnection of a User's Plant and Apparatus may be effected at any time and from time to time, if and to the extent that the SO considers it necessary for safe and secure operation of the Transmission System within prescribed standards. The principles and procedure described in this OC shall be followed to disconnect and re-connect it with the Transmission System.
OC 6.10.1.	**Voluntary disconnection**
OC 6.10.1.1.	Any User intending to de-rate, close, retire or withdraw from service or otherwise cease to maintain any Generating Units or VRE plants or ESUs or any Apparatus shall give the SO at least thirty-six (36) calendar months' notice of such action, subject to prior approval of Authority.
OC 6.10.1.2.	However, it should be ensured that disconnection and reconnection procedures are made an integral part of the Connection Agreement.
OC 6.10.1.3.	Before taking any decision for disconnection of the equipment of the Facility of the User, the SO shall ensure that such disconnection/de-rating will not have any adverse impact on the Transmission System Stability, Reliability, or Quality of Supply.
OC 6.10.1.4.	All the costs incurred by any User for the de-rating/disconnection of equipment or Facility from Transmission System will be borne by the User seeking the de-rating/disconnection as per the Market Commercial Code/Connection Agreement/Authority decision.
OC 6.10.2.	**Involuntary disconnection**
	The SO may disconnect (through any action) Apparatus or the Facility of a User without any compensation to the relevant User, if:
	(a) the User is not operating its Facility in accordance with the Connection Agreement or in accordance with the recommended requirements of the Grid Code or relevant Licence, and other Applicable Documents;

(b) during emergencies, the User's Facility must be disconnected in an orderly manner or as indicated in the Connection Agreement, such that the security and integrity of the System is not jeopardized;

(c) there is risk to the safety of personnel;

(d) there is risk to the Transmission System or any User's Plant or Apparatus;

(e) there is risk of Transmission System elements to become loaded beyond their emergency limits;

(f) voltage excursions on the Transmission System outside the ranges specified in OC 5.5.7;

(g) there is need for Demand Control as described in OC 3;

(h) the User exhibits behavior causing sustained operation outside the normal Transmission System operating Frequency range;

(i) there is any action or inaction which places the SO in breach of any legal or statutory or regulatory obligation; or

(j) Any disconnection of a User from Transmission System has been requested by the relevant TNO (to be dealt in accordance with Connection Agreement).

OC 6.10.3. Reconnection of equipment or Facility

The System Operator shall permit the reconnection of the User's Facility, equipment, and apparatus after confirming that the User has rectified all such circumstances that were the cause of disconnection, and the SO has agreed and is satisfied with the corrected status of the Users Facility. All the costs for reconnection of the User's Facility which was disconnected shall be borne by the relevant User. The facilities, which were disconnected due to emergencies, must be reconnected as soon as the causes of emergencies were rectified and the Transmission System has returned to normal state.

OC 6.11. Power System Stability and Security Coordination

OC 6.11.1. The System Operator shall periodically carry out necessary Transmission System studies, simulations and tests (e.g. fast fault current injection, fault ride through capability, power oscillations damping control, etc.) for expected system event scenarios (e.g. major outages of equipment, HVDC pole failure, etc.) that could lead to transient instability (unsatisfactory system dynamic performance and loss of angular stability), Voltage instability, converter instability, small signal instability and/or lack of power system oscillation damping.

OC 6.11.2. The System Operator shall maintain and be able and ready to implement, when required, standard operating procedures and Defense Plans (including manual control actions, cross-trip schemes, Stability Control System strategy, Remedial Action Schemes), designed in coordination with Users, to mitigate the extent of disturbance resulting from a system event, including the following:

(a) Permanent three-phase fault on any Transmission Apparatus

(b) Bus bar section fault

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

(c) Permanent line fault with automatic reclosing to the fault

(d) Double circuit fault on both branches of a double circuit line

(e) Generator trip

(f) Interconnector trip

(g) HVDC pole trip/block

OC 6.11.3. The studies may include (as the situation or case may demand) load flow studies, short-circuit studies, transient Stability studies, steady state Stability studies, dynamic performance studies, Voltage Stability studies, electromagnetic transient studies, and Reliability studies, etc.

OC 6.11.4. The SO shall also prepare plan for tuning of Power System Stabilizers (PSS) and Automatic Voltage Regulator (AVR) of Generators which shall be implemented by respective Generators. PSS and AVR tuning shall be carried out as per the plan developed by SO and should have good local as well as system-level damping performance.

OC 6.11.5. The SO with the help of studies may identify the requirement of Black Start Facility and designate a User to provide Black Start Facility for system recovery. For avoidance of doubt, the provisions of OC 6.11.5 are applicable to User, irrespective of the Voltage level.

OC 6.11.6. All the Users shall be responsible to provide accurate and consistent technical data and simulation models to the SO, as when required, in order to enable the SO to carry out above mentioned studies.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 7. HVDC CONTROL AND PERFORMANCE

OC 7.1. Introduction

OC 7.1.1. Requirements related to design, performance, operational planning, communications, dispatch and operation of HVDC systems are already covered throughout the Grid Code as Transmission Network Operator (embedded HVDC), Special Purpose Transmission Licensee and/or Interconnector. However, for avoidance of doubt, details of operation and performance of HVDC systems are further elaborated in this sub-code HVDC Operation and Performance OC 7 of the Operation Code.

OC 7.1.2. User-specific details regarding connection, design, operation, performance and communication with HVDC systems shall be as per relevant Agreements and Standard Operating Procedures, agreed with the SO.

OC 7.1.3. All DC yard main circuit equipment, converter transformer, converter valve, AC filter yard main circuit equipment, AC yard main circuit equipment of all Voltage level, shall be under the exclusive control of SO, except auxiliary service equipment at 11 kV or below.

OC 7.1.4. For avoidance of doubt, OC 6.1.3 and OC 6.1.4 also apply on all Control Actions carried out under OC 7.

OC 7.2. Objectives

The objective of OC 7 is to:

(a) further elaborate operation of HVDC systems;

(b) identify the Control Actions that may be taken by the SO, so that the SO may carry out operation of the HVDC Transmission System and respond to HVDC Transmission System's faults and emergencies;

(c) to establish requirements, and roles and responsibilities for operation of HVDC systems;

(d) establish procedures on non-compliance by a User.

OC 7.3. Scope

The scope of this OC 7 applies to SO and

(a) Transmission Network Operators (for HVDC Systems); and

(b) HVDC Interconnectors.

OC 7.4. HVDC Control Actions

OC 7.4.1. The SO needs to carry out operational Control Actions on HVDC Systems for a number of purposes, which include:

(a) Start/deblock, and stop/block operation of HVDC pole;

(b) Change operation mode of HVDC Poles (Pole Current Control/Pole Power Control/Bipole Power Control);

(c) Change of HVDC equipment status (Connect/Isolate Pole, Metallic return/Ground return switching);

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

(d) Change of DC power flow direction;

(e) Change of DC pole bus Voltage (Normal, Reduced);

(f) Start or stop operation of reactive power equipment at all voltage levels;

(g) Start or stop operation of transmission line connected with Converter Stations;

(h) Change of Master Station and Slave Station;

(i) Change of Bipole Power Order, DC pole power order or DC pole current order;

(j) Control mode of reactive HVDC power;

(k) Open line test (OLT);

(l) Change of AC filters equipment status;

(m) Shift of control location between Converter Stations and SO; and

(n) Black Start operation (VSC based HVDC), where available.

OC 7.4.2. Additionally, network switching may occur automatically and without advance warning due to operation of protection equipment in isolating or clearing faults on the National Grid.

OC 7.4.3. Automatic switching sequences may also be established to limit power flows or Voltage or Frequency deviations in the event of faults elsewhere on the System.

OC 7.4.4. This OC 7 also applies on third party entities contracted by Users for the purpose of operation and maintenance etc.

OC 7.5. HVDC Transmission System Operation

OC 7.5.1. The HVDC system shall at all times be operated in harmony with in such a way as to achieve the best overall performance of the integrated AC and HVDC Transmission System.

OC 7.5.2. The SO shall, to the best of its abilities, seek to prevent any disturbances from the AC system outside Converter Stations interfacing with the HVDC System that may result in fluctuations in the power transmitted through HVDC. The consequences of such disturbances shall be dealt with in accordance with the relevant Connection or Interconnection Agreements.

OC 7.5.3. The SO will make its best endeavors to operate the Transmission System in a way that provides the necessary conditions, such as enough short circuit ratio/level, to ensure the smooth operation of the HVDC Transmission System in accordance with Technical Parameters and relevant Connection or Interconnection Agreements.

OC 7.5.4. All Active overload capability and Reactive capability and other inherent capabilities of the HVDC system shall at all times be available to support the AC Transmission System in the event of AC system contingency as per the Technical Parameters of the HVDC system.

OC 7.5.5. The HVDC system shall meet or exceed the withstand capability and ride-through requirements for off-Frequency and off-voltage operation as specified in this Grid Code and/or relevant Connection or Interconnection Agreements.

OC 7.5.6. Where an HVDC system is required to have the capability to provide fast fault current at a Connection Point in case of symmetrical (3-phase) faults, the SO, in coordination with the relevant User, shall specify the following:

(a) when a Voltage deviation is to be determined as well as the end of the Voltage deviation;

(b) the characteristics of the fast fault current and the timing and accuracy of the fast fault current, which may include several stages;

(c) a requirement for asymmetrical current injection in the case of asymmetrical (1-phase or 2-phase) faults.

All these aspects shall be properly reflected in the corresponding Connection (or Interconnection) Agreements.

OC 7.5.7. The HVDC protections shall include protections for AC system protection from over and under voltage as well as over and under Frequency, in the event that AC and/or HVDC systems are unable to restore the system to within operational limits of the withstand characteristic.

OC 7.5.8. The HVDC system shall be capable of finding stable operation points with a minimum change in active power flow and Voltage level, during and after a planned or unplanned change in the HVDC system or AC network to which it is connected. Any information on the resilience of the HVDC system to AC system disturbances shall not be withheld.

OC 7.5.9. Fast Generator and/or load tripping (SCS) strategies shall be developed and provided as necessary, to avoid angular instability for mono/bipole blocking.

OC 7.5.10. However, necessary sufficient overload capability shall be provided in the second pole of a bipole to avoid generator/load tripping for a monopolar block, as far as possible.

OC 7.5.11. The protection of the HVDC system shall be coordinated with the protection systems of the AC system components so that the HVDC can continue to operate and shall not trip before other AC system protection events including:

(a) Generator over-voltage and under-voltage trips;

(b) Generator over-frequency and under-frequency trips;

(c) AC line breaker failure trips;

(d) Impedance protection Zone 2 tripping without communications;

(e) AC line trip and reclose (including single pole trip and reclose).

OC 7.5.12. A strategy shall be developed by the SO in coordination with Users to attempt to clear the DC line faults in symmetric monopole and restart the pole as early as possible.

OC 7.5.13. The HVDC control system shall be resistant to repetitive commutation failure and shall recover promptly in case of such faults.

OC 7.5.14. The HVDC controls shall not cause negative damping of sub-synchronous oscillations of Generators or inter-area oscillations. HVDC Transmission System shall also not interact with Non-Synchronous Generators to cause Sub-Synchronous Control Interaction (SSCI).

OC 7.5.15. As long as the HVDC Transmission System is operating in monopole mode or bipole mode, the maintenance of any main circuit equipment or secondary circuit equipment of the bipolar neutral bus is prohibited. A complete shutdown of both poles of the HVDC system is needed to perform maintenance of a Bipole Neutral bus.

OC 7.5.16. The SO can take/release the remote control of HVDC system anytime with prior intimation to the User, and the User shall follow the instructions of SO.

OC 7.5.17. Exchange of Reactive Power under U-control, Q-Control or Power Factor Control modes shall be at discretion of SO as per System conditions or as per relevant Connection or Interconnection Agreements.

OC 7.5.18. The Reactive Power variation caused by the Reactive Power Control mode of the HVDC Converter Station, shall not result in a Voltage step exceeding the allowed value at the Connection Point.

OC 7.5.19. Similarly, exchange of Active Power under different control modes and supplementary control functions shall be at discretion of SO as per System conditions or as per relevant Connection or Interconnection Agreements.

OC 7.5.20. The relevant parameters and set-points for operation of HVDC system, including ramp rates, deadbands, auto/manual mode etc. shall be adjusted by SO as per System conditions, Technical Parameters and/or relevant Connection or Interconnection Agreements.

OC 7.6. Compliance of SO Instructions

OC 7.6.1. Users shall follow the instructions from SO without compromise. The procedure for non-compliance shall be as described in OC 11.

OC 7.6.2. Users shall immediately inform about the possible implication of the instructions issued by SO that may lead to:

(a) possibility of posing hazards or threat to staff or personnel of operation and maintenance;

(b) possibility of overloading or damage to equipment at Converter Stations/HVDC Transmission Line;

(c) possibility of causing disturbance in Transmission System.

OC 7.6.3. In case a User does not follow any SO Instructions due to any of the reasons expressed in OC 7.6.2 above, the User shall immediately inform and clarify to SO at the earliest regarding the non-conformity.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 8. **OPERATIONAL LIAISON**

OC 8.1. **Introduction**

This sub-code Operational Liaison OC 8 of the Operation Code sets out the requirements for the exchange of information relating to Operations, Events and Significant Incidents on the Transmission System that may have, or have had, an Operational Effect on the Transmission System or systems of other Users.

OC 8.2. **Objectives**

OC 8.2.1. The objectives of OC 8 are to:

(a) provide a coordination mechanism between Code Participants to ensure that communication of Operations, Events, and Significant Incidents is timely and effective, to assess their potential consequences and take appropriate actions to minimize their adverse impacts on the Transmission System;

(b) to specify the procedure for investigation and reporting of Significant Incidents on the Transmission System that materially affected the quality of service.

OC 8.3. **Scope**

OC 8 applies to the SO and:

(a) Generators (CDGUs or Embedded);

(b) Energy Storage Units;

(c) Interconnectors;

(d) Transmission Network Operators;

(e) Distribution Network Operators; and

(f) Transmission Connected Consumers.

OC 8.4. **Notification of Operations and Events**

OC 8.4.1. The SO will notify the User (except as provided in OC 8.4.3) of Operations/Events on the Transmission system, which will have (or may have), in the reasonable opinion of the SO, an Operational Effect on the User.

OC 8.4.2. The User shall notify the SO of any Operations/Events on the User's System which will have (or may have) an Operational Effect on the Transmission System. The SO may use this information to notify any other Users on whose Systems the Operation/Event will have, or may have, in the opinion of the SO, an Operational Effect, in accordance with this OC 8.

OC 8.4.3. In circumstances where it is not possible to invoke standing procedures prior to the occurrence of an Operation or in the event that the SO needs to implement Operations urgently and without informing the User then, unless the situation is of a temporary nature, the SO shall inform the User of the occurrence of the Operations without undue delay. The SO shall also inform the User as to the likely duration of the condition and shall update this prognosis as appropriate. The SO shall additionally inform the User as soon as possible when the condition has ended.

OC 8.4.4. Notwithstanding the general requirements to notify set out in this OC 8, the SO and Users shall agree to review from time to time which Operations and Events are required to be notified.

OC 8.4.5. Form of Notification of an Operation/Event

OC 8.4.5.1. A notification (and any response to any questions asked under OC 8), of an Operation/Event shall be of sufficient detail to describe the Operation/Event and to enable the recipient of the notification reasonably to consider and assess the implications and risks arising.

OC 8.4.5.2. A notification will include the name and job title of the individual reporting the Operation/Event on behalf of the SO or the User, as the case may be.

OC 8.4.5.3. The recipient of the notification may ask questions to clarify the notification and the issuer of the notification will, insofar as the person is able, answer any questions raised.

OC 8.4.5.4. The notification shall be given in writing or in electronic form, whenever possible, before carrying out an Operation. If there is insufficient time before the Operation is scheduled to take place for notification to be given in writing, then the notification shall be given verbally and if either the User or the SO requests, it shall be submitted in writing. Verbal notifications shall be recorded by the SO and may be recorded by the User.

OC 8.4.5.5. A notification (via an acceptable medium) under this section shall be given as far in advance as practicable to allow the recipient to consider and assess the implications and risks arising.

OC 8.4.5.6. A System Alert, further defined in OC 12, may be issued by the SO (subsequently to be confirmed in writing) to Users who may be affected when the SO realizes that there is a risk of widespread and serious disturbance to the whole, or a part of, the Transmission System.

OC 8.5. Significant Incidents

Where a User notifies the SO pursuant to this section of an Event which the SO considers has had or may have had a significant effect on the Transmission System, the SO shall require the User to report that Event in writing in accordance with the provisions of this section. Such Event will be termed as "Significant Incident" and may include, but not limited to, the following cases:

(a) The SO is aware of an Event which has had or may have had a significant effect on the Transmission System; and/or

(b) a User notifies the SO pursuant to this section of an Event which the SO considers has had or may have had a significant effect on the Transmission System.

the Event so will be termed as "Significant Incident". In such a case, if the Event has been notified by a User, the SO may require the User to report that Event in writing in accordance with the provisions of this section. A Significant Incident may include, but not limited to, the following events:

(a) Voltage outside operational limits

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

(b) System Frequency outside statutory limits

(c) Load Disconnection

(d) islanding conditions

(e) System instability

(f) Malfunction of equipment

OC 8.6. Significant Incident Reporting Procedure

OC 8.6.1. A Significant Incident Notice shall be issued by the SO or a User, as the case may be, immediately after its occurrence but in no case later than 24 hours after the occurrence of the Significant Incident, and shall identify the following, if possible:

(a) date, time, and location of the Incident

(b) brief description of the Incident

(c) expected impact

(d) expected time to restore

(e) the cause

OC 8.6.2. The SO shall investigate any Significant Incident that materially affected the Transmission System or the system of any another User. A preliminary Significant Incident Report shall be available within fifteen (15) working days and shall include the following:

(a) factual description of the Event/Incident root causes

(b) the pre-incident conditions

(c) the operational conditions of the Transmission System at the time of Incident

(d) the corrective and mitigating actions implemented after the Event/Incident

OC 8.6.3. A final Significant Incident Report shall be available within two (2) months of the Incident which shall include:

(a) root causes of the Incident

(b) estimated energy not served

(c) proposal for corrective measures/mitigation actions to increase the System reliability

OC 8.6.4. The SO shall initiate and coordinate such an investigation, arrange for the writing of the report, and involve all Affected Users through a cross-functional team having members of relevant stakeholders or third party as deemed appropriate. The Users shall make all relevant information, such as User's own investigative report, disturbance recorder/event logger details, pre- and post-event operational data, restoration sequence details, relay indications for all elements affected, Remedial Action plan, and/or any non-compliance of Grid Code observed during the Incident available to the SO and participate in the investigation where reasonably required.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

OC 8.6.5. The final Significant Incident Report shall include recommendations on future actions to be taken, including proposing modifications to this Grid Code or GCOPs, aiming to avoid the occurrence of similar Significant Incidents in the future.

OC 8.6.6. Both the preliminary and final Significant Incident Report shall be published on the SO website and submitted to the Authority for evaluation.

OC 8.7. Monthly and Annual Events Reports

OC 8.7.1. The Users shall prepare and submit, to the SO, monthly Reports on Grid Events by the 5th of every month. These reports shall include an evaluation of the Operations, Events, Significant Incidents, and any other problems that occurred on the Users' Facilities during the previous month, the measures undertaken by the Users to address them, and the recommendations to prevent their recurrence in the future. The reports shall be consolidated and reviewed by the SO and published on the SO website.

OC 8.7.2. Based on the User reports provided above, the SO shall prepare and submit to the Authority quarterly and annual Grid Event Reports. These reports shall include the Operations, Events, and Significant Incidents that had a Material Effect on the Transmission System or the System of any User (as the case may be) during the past months or the year. The reports shall be published on the SO website.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 8. Appendix

Report of a Significant Incident on System

Information (where relevant) to be given

1. Time and date of Significant Incident on System
2. Location
3. Plant/Apparatus involved
4. Description of the Significant Incident
5. Demand/Generation lost
6. Generating Unit Frequency
7. Generating Unit MVAR performance
8. Estimated duration of non-availability of Power Plant or that of Demand interruption.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 9. OPERATIONAL COMMUNICATION AND DATA RETENTION

OC 9.1. Introduction

To ensure proper monitoring, operation and control of the National Grid, standard, reliable and adequate communication facilities and procedures between SO and the Users are essential. This sub-code Operational Communication and Data Retention OC 9 of the Operation Code specifies the details of the communication facilities required between the SO and Users and also establishes the procedures to be used by the SO and Users to ensure timely exchange of information to enable the SO to discharge its obligations regarding the operation of the National Grid.

OC 9.2. Objective

OC 9.2.1. The objectives of this OC 9 is:

(a) to establish proper contact locations for the SO and other Users;

(b) to detail real time monitoring, control and communication facilities which are required to be installed and maintained between the SO and the Users;

(c) to establish the general procedures (notwithstanding any specific procedures which may be established in other sections of this Grid Code and/or relevant Agreements) for exchange of operational information between the SO and the Users;

(d) to establish the general procedures (notwithstanding any specific procedures which may be established in other sections of this Grid Code and/or relevant Agreements) for the authorization of the SO and the User personnel to act on behalf of their respective entities in the communication of operational information between the SO and the User; and

(e) to establish the general procedures (notwithstanding any specific procedures which may be established in other sections of this Grid Code) for the retention of data.

OC 9.2.2. This OC 9 covers the general procedures for all forms of communication of operational information between the SO and Users, other than the pre-connection communication that is dealt with in the Connection Code. Data relating to commercial (Energy) metering is specifically not covered by this OC 9.

OC 9.3. Scope

The provisions of OC 9 shall apply to the SO and:

(a) Generators in respect of their generating units and Transmission Facilities;

(b) Transmission Network Operators (in respect of their transmission stations and communication services);

(c) Distribution Network Operators (in respect of their substations and communication services);

(d) Transmission Connected Consumers;

(e) Interconnectors;

(f) Energy Storage Units; and

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(g) Embedded generators whether represented through Aggregator or otherwise. The Embedded Generators to which this Grid Code will apply shall be determined as per the relevant Applicable Documents.

OC 9.4. Contact Locations and their Adequacy

OC 9.4.1. The System Operator Contact Locations

OC 9.4.1.1. Other than where specifically provided for under OC 9.4.1.2 or in other sections of the Grid Code, the contact location within the SO for communication on matters pertaining to the real time operation of the National Grid shall be the designated Control Centers of System Operator (e.g. Main Control Centre (MCC), Backup Control Centre (BCC), Emergency Control Centre (ECC), etc.).

OC 9.4.1.2. The SO will, from time to time, notify to Users the relevant points of contact in the SO (and their contact details) and any changes to such points of contact and/or details for the purposes of each section of this Grid Code (including, where appropriate, for specific purposes under each section), and the User shall, as required, contact the relevant notified points of contact.

OC 9.4.1.3. The SO shall from time to time distribute to each User an organizational chart and list of personnel and contact numbers (consistent with the notification given under OC 9.4.1.2) in order to assist the User in communicating with the SO.

OC 9.4.2. The Users Contact Locations

OC 9.4.2.1. The User contact locations and personnel (including their electronic mailing addresses, if any) referred to in this OC 9.4.2 shall be notified by the User to the SO prior to connection and thereafter updated as appropriate.

OC 9.4.2.2. Each User is required to establish a Control Facility at each of its substations in the Transmission System. In case of TNOs, in addition to the Control Facilities at individual substations, a central liaison office shall also be established at any appropriate location for information collection, consolidation, reporting and/or relaying of Dispatch Instructions/Control Actions (in special circumstances) as per SO requirements. In case of DNOs and Generator Aggregators, a single Control Facility is required for each. In case of Suppliers, only a contact person is required.

OC 9.4.2.3. The Users shall ensure acting in accordance with Good Industry Practice that the Control Facility/liaison office is operational round the clock and is staffed at appropriate qualified and trained level at all times.

OC 9.4.2.4. The Control Facility of all Users shall be staffed by a Responsible Operator who shall respond to communications from the SO without undue delay, except where otherwise provided for by agreement between the User and the SO (such agreement not to be unreasonably withheld). All the communications (other than relating to the submission of data and notices) between the SO and the User shall take place between the SO and Responsible Operator of the User. The Responsible Operator shall be of suitable experience and training and is authorized to perform the following functions on behalf of the User:

(a) to accept and execute Dispatch Instructions;

(b) to receive and acknowledge receipt of instructions from SO, for amongst other matters, operation outside the Declared values of Availability, Ancillary Service capability, or Operating Characteristics of the User Plant and Apparatus during System Emergency Conditions.

OC 9.4.2.5. At any point in time, a single person shall be designated by the User and notified to the SO as the Responsible Manager. The Responsible Manager shall be responsible for dealing with the SO on matters other than as provided for in OC 9.4.2.4. In the event that the Responsible Manager is not a person on duty at the Control Facility, then the Responsible Manager must be capable of being contacted from the Control Facility at all times, and in the event that the SO issues an instruction to the Control Facility requiring the Responsible Manager to contact the System Operator, the Responsible Manager shall comply with the request without undue delay and in any case within 10 minutes of the instruction.

OC 9.4.2.6. The Responsible Manager shall be authorized by the User to perform, at least, the following functions on behalf of the User:

(a) to make estimates in accordance with Good Industry Practice as to the Availability, Ancillary Service capability and Operating Characteristics of the User Facility;

(b) to submit and revise an Availability Notice and other data related to the User Facility as under SDC 1;

(c) to communicate with respect to issues regarding Outages of User Plant and Apparatus as under OC 4.

OC 9.4.2.7. The User may, from time to time, notify a replacement contact location and personnel which meets the foregoing requirements.

OC 9.5. Communication Facilities

OC 9.5.1. The minimum communications facilities which are to be installed and maintained between the SO and the Users are defined in this OC 9.5.

OC 9.5.2. All equipment to be provided by Users under this OC 9.5 shall comply with the applicable International Telecommunications Union (ITU) and International Electro-Technical Commission (IEC) standards for SCADA and communications equipment and shall meet such standards as notified by the SO and, when applicable, the TNO or DNO.

OC 9.5.3. Supervisory Control and Data Acquisition System (SCADA)

OC 9.5.3.1. The SCADA System will be used by the SO for real time monitoring and control of the National Grid during normal, contingency, emergency, extreme emergency and restorative conditions.

OC 9.5.3.2. All Users shall install remote telemetry equipment and associated auxiliary components, at their respective facilities for exchanging real time data and control signals with the SO's SCADA System through standard IEC protocols. The cost of integration of Users telemetry equipment (Remote Telemetry Units RTUs, SAS/PCS/DCS Gateways etc.) with the SO's SCADA System, both at Main and Backup Control Centers, will be borne by the relevant Users.

OC 9.5.3.3. Remote telemetry equipment, which may include RTU, PCS/DCS/SAS Gateways, IEDs or any other such equipment/Facility (to be installed with prior approval of the

SO), shall be capable of exchanging real time data and control signals with the SO's SCADA System through standard IEC data communication protocols.

OC 9.5.3.4. The remote telemetry equipment of Users shall be compatible with the SO SCADA master station protocol requirements and must provide redundant and standard IEC interfaces for data connectivity with Main and Backup Control Centers of SO. It shall also be capable of time stamping of signals and events on minimum resolution of 1 millisecond or finer resolution as specified by the SO.

OC 9.5.3.5. All Users shall maintain the remote telemetry, networking and communication equipment at their respective sites and shall be responsible to expand and upgrade the equipment as and when required by the SO. All such equipment shall have at least 50% spare capacity for future expansion. The cost of such expansion and upgradation of User's remote telemetry system along with its auxiliary components and its integration with SO SCADA System will be borne by the relevant Users.

OC 9.5.3.6. SCADA Signals Interface Cabinets/Cubicles (SIC) shall be installed in the User's Control Centre/Control Facility, for the transmission of signals and indications to and from the SO. The provision and maintenance of the wiring and signaling from the User's Plant and equipment to the interface cabinets shall be the responsibility of the User.

OC 9.5.3.7. The signals and indications which must be provided by Users for transmission by remote telemetry equipment to the SO are the signals and indications referred to under CC 9. Appendix-1 together with such other information as the SO may require from time to time by notice to Users.

OC 9.5.3.8. In case of Generators, signals and indications must be provided to the SO on individual Generating Unit basis.

OC 9.5.3.9. In cases where the Users are equipped with or intending to develop their own SCADA System or any other telemetry system such as Automatic Meter Reading (AMR), Smart/Secured Metering System (SMS), Web portals based telemetry, Awareness System, etc., covering all or part of its Transmission/Distribution System or Plant/equipment and the SO considers necessary to exchange the information collected into such system, data communication/exchange through standard IEC protocols between the SO's and User's SCADA or other such system, as the case may be, shall be established. In general, sharing of such data/information/telemetry/Control Facility under OC 9.5.3.9 shall not be withheld by the Users.

OC 9.5.3.10. If any change occurs in the User's Plant and equipment, User shall be responsible to incorporate all such changes in the remote telemetry equipment.

OC 9.5.3.11. The SO shall have the capability to deactivate and reactivate the scanning of a given RTU, as well as the capability of monitoring the availability of all RTUs from a central location.

OC 9.5.3.12. In the absence of any such remote telemetry system or during development phase of such remote telemetry facilities, Users shall provide the real time data/information related to its plant and equipment to SO through interim alternate arrangements with prior approval of SO.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 9.5.4. Communication System

OC 9.5.4.1. The TNOs/DNOs shall provide at least dual, high-speed, network-wide, secure and dedicated communication facilities installed on its system, to provide for the communication between SO's designated Control Centers and the User Site. The communication systems shall provide redundant channels for direct telephone, facsimile and data links between the SO (Main and Backup Control Centers) and User Facility.

OC 9.5.4.2. The TNOs/DNOs shall provide the communication system for the network in its Service Territory and extend the facility to the Connection Point of the User.

OC 9.5.4.3. The TNOs/DNOs shall also install, operate and maintain a redundant communication interface, compatible with the SO's SCADA System, at the SO designated Control Centers (Main and Backup Control Centers).

OC 9.5.4.4. TNOs/DNOs shall provide its network for all communication services (e.g. voice, facsimile, data, etc.) between Users and SO (Main and Backup) Control Centers.

OC 9.5.4.5. The SO, TNOs/DNOs and other Users shall operate, maintain, expand and upgrade from time to time, their respective SCADA Systems, with dedicated supporting communication system and remote telemetry equipment, as required.

OC 9.5.4.6. The SO shall provide any standards and specifications for remote telemetry equipment, communication system requirements and protocols, and technical assistance required to connect Users' facilities with the SO's SCADA system. The standards and specifications shall be as per international best practices and globally adopted standards and specifications. The SO shall inform the Authority of these standards and specifications. The Authority may review such standards and specifications, if required.

OC 9.5.4.7. A User will be responsible for installation, upgrade and maintenance of their respective remote telemetry equipment and associated communication equipment up to the Connection Point.

OC 9.5.4.8. TNOs/DNOs may establish communication interlinks between their networks to provide connectivity between Users facilities and SO's designated Control Centers.

OC 9.5.4.9. The TNOs/DNOs communication facility may also be used for communicating with TNOs/DNOs work crews and substation personnel.

OC 9.5.4.10. An electronic recording devices shall be provided at the SO control centers to record all dispatch transactions and communication with the User's Control Centers/Control Facilities. Such records shall be kept until at least five (5) years and will be used to deal with any dispute should such disputes arise during implementation.

OC 9.5.4.11. All Users shall provide the SO approved dedicated voice communication service (e.g. telephone hotlines based on IP/PLCC/Satellite, etc.) to provide both primary and alternate communication links between the SO and the operator controlling the User Facility.

OC 9.5.4.12. The remote telemetry and communication equipment shall also provide signals and indications for faults.

OC 9.5.5. **Computer Equipment**

Each User shall comply with the SO requirements and provide dedicated and appropriate computer and data networking equipment, at the cost of User, to allow data exchange such as electronic mail, dispatch instructions, etc. between the SO and the User. The equipment shall only be used by the User for operational communications with the SO.

OC 9.5.6. **Telephone and Facsimile**

OC 9.5.6.1. Each User shall be responsible for the provision and maintenance (at the cost of the User) of telephone and facsimile equipment as required by this OC 9.5.6.

OC 9.5.6.2. The SO shall provide at least two or more dedicated Public Switched Telephone Network (PSTN) circuits/extensions and/or cellular connections at designated Control Centers. This facility shall be reserved for operational purposes only, and shall be continuously attended by a person meeting the requirements of OC 9.4.2.4 and answered without undue delay.

OC 9.5.6.3. Users shall provide at least two dedicated Public Switched Telephone Network (PSTN) circuits/extensions and/or cellular connections at the Control Facility.

OC 9.5.6.4. Users shall also provide at least one dedicated facsimile unit, connected to a dedicated Public Switched Telephone Network (PSTN) circuit at the Control Facility.

OC 9.6. **Other Requirements**

OC 9.6.1. **Access and Security**

All SCADA, remote telemetry equipment, computer and communication equipment that interfaces with the SO and the information carried by it must be secure from unauthorized access. Procedures governing security and access shall be agreed by the SO with the Users. Such procedures shall allow for adequate access to the equipment and information by the SO or its representatives for the purposes of maintenance, repair, testing and recording of readings.

OC 9.6.2. **Time Standards**

All the relevant SCADA System, remote telemetry and tele-communication equipment will be synchronized with Global Positioning System (GPS) to maintain time coherence. Pakistan Standard Time (PST) (GMT+5) will be used as the time standard. Daylight Saving Time (DST) provision, if any, will be considered while synchronizing time with GPS.

OC 9.6.3. **Cyber Security**

OC 9.6.3.1. The SO, TNOs/DNOs and Users must ensure Cyber Security of all the remote telemetry and communication equipment at their respective ends. In this regard, firewalls and Intrusion Prevention Systems (IPS) must be used by all the Code Participants. All remote telemetry and communication facilities (including SCADA) shall not be connected to the utility communication network through insecure connection.

OC 9.6.3.2. Additionally, all Users shall also ensure Cyber Security of ICT infrastructure, control systems and other Cyber Assets at their ends as per guidelines and/or standards issued under the Applicable Documents.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 9.6.4. Uninterrupted Power Supplies

All SCADA, remote telemetry equipment, computers, networking and communication equipment must be provided with redundant Uninterrupted Power Supplies (UPS) at SO, TNOs/DNOs and User Sites, at the cost of respective Code Participant. The UPS arrangement shall have adequate capacity to support all the essential services at SO, TNOs/DNOs and User Sites during any emergency condition on National Grid to allow for communication between the SO and Users Facility. The power supplies shall have at least 50% spare capacity for future expansion.

OC 9.7. Communications

OC 9.7.1. Other than where specifically provided for in other sections of the Grid Code, communication between the SO and Users on matters pertaining to the real time operation of the National Grid shall take place between the SO's and the User's Control Facility.

OC 9.7.2. If the SO or the User Control Centre/Facility is moved to another location, the SO shall notify the Users or the relevant User shall notify the SO (as the case may be) without delay of the new location and any changes to the communication facilities necessitated by such a move.

OC 9.7.3. Unless otherwise specified in the Grid Code, all instructions given by SO and communications between SO and the User's Control Facility shall be given by means of the facilities described in OC 9.5.

OC 9.7.4. Any automatic recording (by whatever means) of communications given by means of telephony, electronic means, facsimile transfer or telex will be accepted by the SO and Users as evidence of those instructions or communications.

OC 9.8. Communication with Cross-Border SO

OC 9.8.1. In order to discharge its responsibilities in respect of the safe, secure and reliable operation of the Interconnected Transmission System, the SO will need to carry out communication with the cross-border System Operators/Load Dispatch Centers. The communication flow and operating procedures between the SO and Cross-Border SO/LDC shall be governed by the relevant Agreements.

OC 9.9. Data and Notices

OC 9.9.1. Data and notices to be submitted to the SO or to Users under the Grid Code (other than data and notices which are the subject of a specific requirement of the Grid Code as to the manner of their delivery) shall be in writing and shall be delivered by hand or sent by pre-paid post, by telex, receipted email or facsimile transfer.

OC 9.9.2. Data and notices to be submitted to the SO under the Grid Code shall be addressed to the person, and at the address, notified by the SO to Users for such purpose.

OC 9.9.3. Data and notices to be submitted to Users under the Grid Code shall be addressed to the User's nominated representative at the address notified by the User to the SO for such purpose or, failing such notification to the principal office of the addressee, to such other person or address as the User may notify to the SO from time to time.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 9.9.4. All data items, where applicable, will be referenced to nominal Voltage and Frequency unless otherwise stated.

OC 9.9.5. All Operational Data is to be supplied in accordance with the timetables set out in the Grid Code.

OC 9.10. Data Retention

OC 9.10.1. Operational Data is all data required to be supplied by either the SO or Users under the Grid Code and any other data expressly provided to be Operational Data under the Grid Code. Operational Data to be supplied by the User must be submitted to the department or address as the SO may from time to time advise.

OC 9.10.2. The SO shall maintain a complete and accurate record of all Operational Data supplied or maintained under the Grid Code. The format for the retention of records shall be as the SO may reasonably determine (provided such format shall not prejudice its accessibility and comprehension by the Users under OC 9.10.3). All Operational Data shall be maintained for a period of not less than ten (10) years commencing from the date the Operational Data was first supplied (or first created, if earlier).

OC 9.10.3. The SO shall afford Users access to its records (and copies thereof) of Operational Data and/or data required to be maintained under OC 9.10.2 on reasonable notice.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 10. **OPERATIONAL TESTING**

OC 10.1. **Introduction**

OC 10.1.1. The sub-code OC 10 of the Operation Code deals with the responsibilities and procedures for arranging and carrying out Operational Tests which may have an effect on the Transmission System or the system of any User.

OC 10.1.2. By their nature, Operational Tests may impact either or both of:

(a) the SO's responsibilities in respect of the operation of the National Grid; and

(b) the operations of Users and the quality and continuity of supply of electricity to them.

OC 10.1.3. To minimize disruption to the operation of the National Grid, it is necessary that tests which affect the operation of the National Grid as under OC 10.1.2 are subject to central coordination and control.

OC 10.1.4. To achieve the primary objective as outlined in OC 10.2.1, OC 10 sets out the procedures for conducting and reporting Operational Tests on the National Grid.

OC 10.2. **Objective**

OC 10.2.1. The primary objective of OC 10 is to establish a structured procedure for central coordination and control of an Operational Test required by the SO or a User, where such test will or may:

(a) affect the secure operation of the Transmission System;

(b) have a significant effect on the operation of the Transmission System or a User System;

(c) affect the economic operation of the Transmission System or User System; or

(d) affect the quality or continuity of supply of electricity to Users.

OC 10.2.2. By way of example, tests that will be typically covered by OC 10 are listed in OC 10.4 and OC 10.5. This list is not exhaustive and other tests may also fall within the scope of Operational Tests and shall be covered under this OC 10.

OC 10.2.3. OC 10 does not cover tests which the SO may conduct to assess compliance of Users with their design, operational and performance requirements as specified in the Grid Code and in relevant Agreements, or to assess that Generators or Interconnectors are in compliance with their Registered Data as notified by Declarations, where appropriate, or to determine that Generators or Interconnectors are in compliance with Dispatch Instructions, or to assess Generating Unit efficiency for Dispatching purposes, or Commissioning or re-Commissioning Tests. These issues are covered under OC 11 (Monitoring, Testing and Investigation).

OC 10.2.4. A system test proposed by a User that shall have no effect on the Transmission System or the System of any other User is not subject to this sub-code. A system test proposed by the System Operator shall always to subject to this sub-code.

OC 10.3. Scope

OC 10 applies to the SO and:

(a) Generators with units having a Registered Capacity greater than 10 MW and Aggregators;

(b) Energy Storage Units;

(c) Interconnectors;

(d) Transmission Network Operators; and

(e) Distribution Network Operators.

OC 10.4. Tests Required by the SO

OC 10.4.1. The SO may need to carry out Operational Tests on the Transmission System in order to train staff, and to acquire information in respect of National Grid behavior under abnormal operating conditions. The SO will endeavor to limit the frequency of Operational Tests only to those that are absolutely necessary and shall always follow Prudent Utility Practices when conducting these Tests.

OC 10.4.2. Operational Tests required by the SO from time to time shall include, but not limited, to the following:

(a) Tests involving the controlled application of Frequency and/or Voltage variations aimed at gathering information on National Grid behavior;

(b) National Grid restoration Tests;

(c) Testing of standing procedures for System Emergency Conditions and Alert conditions; and

(d) Testing or monitoring of Power Quality under various National Grid conditions and configurations.

OC 10.4.3. Where the SO intends to carry out an Operational Test pursuant to OC 10.4 and, in the SO's reasonable opinion, such Test will or may have an Operational Effect on a User's System, the SO shall, in accordance with OC 8 provide such notice to the User of the scheduled time and effect of the Operational Test as is reasonable in all the circumstances and shall keep the User informed as to any changes to the scheduled time and nature of the Operational Test.

OC 10.4.4. A User, having been informed about an Operational Test under OC 10.4.3 may, acting reasonably, contact the SO to request additional time to consider the impact of the proposed Test on the User system. The SO shall cooperate with the User to assess the risks. The test shall not proceed until all the Users with potential adverse impacts are satisfied except where, in the SO's view, a User is acting unreasonably.

OC 10.4.5. Operational Tests shall be witnessed by the SO and any other User that will or may be affected by the Test, unless the User may decide not to participate.

OC 10.4.6. The provisions of OC 10.6, OC 10.7 and OC 10.8 shall not apply to Operational Tests required by the SO under this OC 10.4.

OC 10.5. Tests Required by the Users

OC 10.5.1. Operation of User's Plant and equipment may also require Operational Testing in order to maintain and develop operational procedures, test and measure performance, comply with statutory or other regulatory obligations and to train their staff.

OC 10.5.2. In accordance with Good Industry Practice, each User shall endeavor to limit the frequency of such Operational Tests and to limit the effects of such Tests on the Transmission System or the systems of other Users.

OC 10.6. Procedure for Requesting Operational Tests

OC 10.6.1. The User shall submit its proposal to the SO for an Operational Test in a timely fashion in accordance with OC 8 and OC 9 or alternative procedures agreed with the SO.

OC 10.6.2. As part of the proposal, the User, when requesting an Operational Test, shall supply sufficient detail to the SO to allow the SO to adequately asses any operational consequences of the proposed Test. This shall include the following information:

(a) the reason for the proposed Test indicating whether the Operational Test is a Test required by statute, required for compliance with Licence conditions, regulations, or safety codes, which may require that execution of the Operational Test be expedited and given priority over other Operational Tests;

(b) The preferred time or times for the test;

(c) The milestones for individual stages of the Operational Test (if any) which can be completed separately, and/or do not require to be repeated if the Operational Test is interrupted by the SO after completion of each stage;

(d) Whether there may be an adverse material impact on the relevant User if the Operational Test is cancelled at short notice or delayed (reasonable detail being given by the User to the SO of the impact);

(e) The Dispatch or Dispatches required by the User for completion of the test, if any, including the duration of the required Dispatch shall be supplied to the SO as part of the proposal;

(f) Where the User may not know the entire Dispatches required for completion of the test until part of the test is completed then the User, when proposing the test, shall:

(i) divide the test into sections as appropriate;

(ii) indicate and discuss with the SO which sections of the test can be completed in stages and which cannot; and

(iii) indicate possible variations of the test for the sections that can be completed in stages.

Additionally, the factors that influence the completion of the stages should be outlined to the SO, namely, if the procedure to be followed for a certain stage depends on the outcome of a previous stage.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

OC 10.6.3. A request by the User for an Operational Test requiring a Generating Unit, Interconnector or DNO to be Dispatched to a particular MW Output or operating condition shall not be considered a Re-declaration of Availability, Ancillary Service capability or Operating Characteristics.

OC 10.6.4. The SO may also initiate an Operational Test if it determines necessary to ensure the safety, stability, security, and reliability of the Transmission System.

OC 10.7. Evaluation of Proposed Operational Tests

OC 10.7.1. The SO shall, on receipt of an Operational Test request from the User, assess the impact of the proposed test on the operation of the Transmission System. The SO may request additional information from the User required to evaluate the impact of the test.

OC 10.7.2. The Test Proposer shall provide sufficient time for the SO to evaluate/plan the proposed test. The SO shall determine the time required for each type of the test. However, the associated costs shall be borne by the User requesting the tests.

OC 10.7.3. The SO will evaluate the impact (in terms of continuity and quality of supply only) of the Operational Test with significant potential effects on other Users. The SO shall determine and notify other Users, other than the Test Proposer, that may be affected by the proposed Operational Test. For the purpose of this OC, such Users shall be collectively referred to as Affected Users.

OC 10.8. Approval for Operational Testing

OC 10.8.1. Within one (1) month after the acceptance of a Test Request, the SO shall notify the Test Proposer, and the Affected Users of the proposed test. The notice shall contain the following:

(a) the purpose and nature of the proposed test, the extent and condition of the equipment involved, the identity of the Test Proposer, and the Affected Users;

(b) an invitation to nominate representatives for a Test Group to be established to coordinate the proposed test; and

(c) if the test involves work or testing on (E)HV equipment, the responsible persons for Safety assurance shall be informed by the User requesting the test and the Safety procedures specified in OC 13 shall be followed.

OC 10.8.2. The Test Proposer and the Affected Users shall nominate their representatives to the Test Group within one (1) week of receiving the notice from the SO.

OC 10.8.3. If an Affected User fails to nominate its representative within the period stipulated in OC 10.8.2, the SO will issue a reminder to that User to nominate the representative immediately. If the User still does not nominate its representative, the SO may decide to proceed with the proposed test and may appoint an independent expert to the Test Group to represent the interests of that Affected User.

OC 10.8.4. The SO shall establish the Test Group and appoint a Test Coordinator, who shall act as lead of the Test Group. The Test Coordinator may come from the SO or the Test Proposer.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 10.8.5. The members of the Test Group shall meet within two (2) weeks after the Test Group is established. The Test Coordinator shall convene the Test Group as often as necessary.

OC 10.8.6. The agenda for the meeting of the Test Group shall include the following: (i) the details of the purpose and nature of the proposed Test and other matters included in the Test Request; (ii) evaluation of the Test Procedure, including sequence of operations and dispatch, as submitted by the Test Proposer and making necessary modifications to come up with the final Test Procedure; (iii) the possibility of scheduling the proposed test simultaneously with any other tests or with equipment maintenance which may arise pursuant to the Maintenance Program requirements of the SO or the Users, to minimize their adverse impacts on the Transmission System or other Users; and (iv) the economic, operational, and risk implications of the proposed test on the Transmission System or the systems of other Users, and the Scheduling and Dispatch of the Generating Unit/Station.

OC 10.8.6.1. The Test Proposer and the Affected Users (including those which are not represented in the Test Group) shall provide the Test Group, upon request, with such details as the Test Group reasonably requires for carrying out the proposed Operational Test.

OC 10.8.7. Within two (2) months after the first meeting and at least one (1) month prior to the date of the proposed Operational Test, the Test Group shall submit to the SO, the Test Proposer, and the Affected Users a proposed Test Program which shall contain the following:

(a) a plan for carrying out the test;

(b) the procedure to be followed for the test, including the manner in which the test is to be monitored;

(c) list of responsible persons, including those responsible for coordinating on Safety, when necessary, and who will be involved in carrying out the test;

(d) allocation of costs; and

(e) such other matters as the Test Group may deem appropriate and necessary and are approved by the management of the Affected Users.

OC 10.8.8. The Test Group shall use reasonable endeavors to prioritize Operational Tests where the Test Proposer has notified the SO that Operational Tests are required in accordance with Licence conditions, statutory regulations or safety codes or a delay in the execution of the tests may have an adverse material impact on a User.

OC 10.8.9. The Test Group shall prepare a Test Program. If the proposed Test Program is acceptable to the SO, the Test Proposer and the Affected Users, the final Test Program shall be prepared and notified to all concerned, and the test shall proceed accordingly. Otherwise, the Test Group shall revise the Test Program to make it acceptable.

OC 10.8.10. If the Test Group is unable to develop a Test Program or reach a consensus in implementing the Test Program, the SO shall determine whether it is necessary to proceed with the test to ensure the Security of the Transmission system.

OC 10.8.11. If the Test Proposer or Affected Users are not satisfied with the Test Program, they shall inform the SO of their concerns. The SO shall not cancel the Test Program unless these objections are reasonable. If the Test Proposer or Affected Users are still not satisfied with the Test Program being approved, then they may appeal the decision using the Dispute Resolution process established in CM.

OC 10.9. Scheduling and Dispatch of Operational Tests

OC 10.9.1. Operational Tests will usually, but not necessarily, be scheduled by the SO in accordance with SDC 1.

OC 10.9.2. Where an Operational Test is requested by a User, the User shall submit, if it corresponds, an Availability Notice consistent with planned Operational Tests in accordance with SDC 1. The User shall also submit all other data as required under the SDC 1.

OC 10.9.3. Dispatch Instructions for Operational Tests shall be issued by the SO in the normal manner for issuing Dispatch Instructions in accordance with SDC 2.

OC 10.9.4. The SO shall use reasonable endeavors to ensure that scheduled Operational Tests are conducted in accordance with the agreed Dispatch procedures.

OC 10.9.5. Where the SO foresees a requirement or likely requirement to cancel, postpone or otherwise significantly alter an agreed Dispatch procedure and schedule, then the SO shall inform the Test Group as soon as is reasonably possible. In this case, the provisions of OC 10.9.6 and OC 10.9.7 shall apply.

OC 10.9.6. Where the SO assesses that the impact of an Operational Test on Transmission System security or on the continuity and quality of supply or operation of a User, may or is likely to be significantly greater than originally estimated, the SO may contact the Test Group to discuss a revised test procedure or schedule.

OC 10.9.7. The SO may, where it considers necessary, cancel, interrupt or postpone an Operational Test at any time, but shall where possible utilize the procedures outlined under OC 10.9.6 prior to taking such action where the cancellation, interruption or postponement is for other than technical reasons.

OC 10.9.8. If the Test Proposer wishes to cancel/postpone an Operational Test either before commencement of the Test or during the Test, the SO and the Test Group must be notified by the Test Proposer, in accordance with OC 8 and OC 9.

OC 10.10. Test Reporting

OC 10.10.1. Upon conclusion of the scheduled time for an Operational Test, the Test Proposer shall notify the SO, the Test Group and Affected Users as to whether the Test has been completed, or sections of the Test, if divided into sections under OC 10.6.2 (c), have been completed.

OC 10.10.2. At the conclusion of the Operational Test, the Test Proposer shall be responsible for preparing a written report on the Operational Test (the "Final Report") which shall be available within three (3) months of the conclusion of the Operational Test to the SO, the Test Group, Affected Users and the Authority.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

OC 10.10.3. The Final Report shall include a description of the Plant and/or Apparatus tested and a description of the System Test carried out together with the results, conclusions and recommendations as they relate to the SO and Affected Users.

OC 10.10.4. The Final Report shall not be submitted to any person who is not a representative of the SO or the Test Group unless the SO and the Test Proponent having reasonably considered the confidentiality issues arising, shall have unanimously approved such submission.

OC 10.10.5. After the submission of the final Test Report, the Test Group shall stand dissolved.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 11. MONITORING, TESTING AND INVESTIGATION

OC 11.1. Introduction

OC 11.1.1. To ensure safe, secure and economic operation of the Transmission System and in respect of Dispatch of Generators, Interconnectors, TNOs/DNOs and ESUs, the SO will need to carry out certain Monitoring, Testing and Investigation in respect of the performance of Users' Plant and Apparatus.

OC 11.1.2. This sub-code OC 11 of the Operation Code details the procedures, the System Operator will follow to monitor and assess the fulfillment of the committed performance of any Generator, Interconnector, ESU, DNO or TNOs. The System Operator will also monitor and assess the fulfillment of the committed Ancillary Services of Users as and when required.

OC 11.1.3. OC 11 does not apply, however, to Operational Tests, which may be required by the SO or by Users. The procedures by which Operational Tests are notified, approved, executed and reported are covered under Operational Testing OC 10.

OC 11.1.4. Monitoring is required by the SO to periodically verify the Users' compliance with the Grid Code provisions.

OC 11.1.5. Testing is required by the SO to validate and verify performance of the Users in routine and/or if suspected of deterioration.

OC 11.1.6. Where necessary, the System Operator will also conduct Black Start Tests to ensure satisfactory operation of the relevant Generators in the event of an Emergency.

OC 11.2. Objective

OC 11.2.1. The primary objectives of OC 11 are to establish procedures for verifying that Users are operating within their design, operating and connection requirements, as specified in the Grid Code, Connection Agreements, or Interconnection Agreements.

OC 11.2.2. In order to achieve the primary objective, set out in OC 11.2.1, OC 11 establishes procedures for Monitoring, Testing and Investigation. In particular, to facilitate adequate assessment of each but not limited to the following:

(a) Whether Centrally Dispatched Generating Units (CDGUs), Interconnectors and TNOs/DNOs comply with Dispatch Instructions;

(b) Whether Generators, Interconnectors, DNOs, TNOs and Generator Aggregators are in compliance with their Declarations of Availability, Ancillary Services capabilities, Technical Parameters and any other data required to be registered by those Generators, Interconnectors, ESUs, DNOs, TNOs and Generator Aggregators under the Grid Code;

(c) Whether the Power Quality at User's Connection Points conforms with CC 8;

(d) Whether Users are in compliance with protection requirements and protection settings under the Grid Code, Connection Agreements, Ancillary Service Agreements;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

(e) Whether the Generators designed to operate on multiple fuels have the ability to generate on Primary Fuel and Secondary Fuel and have the ability to carry out an on-line fuel changeover;

(f) Whether Generators referred in (e) above have the required Fuel stock levels at the Generator Site and Off-Site Storage Location; and

(g) Assess adequacy of the Generating Units Variable cost, submitted by the Generators as per SDC 1.

OC 11.3. Scope

OC 11.3.1. OC 11 applies to the System Operator and:

(a) Generators, which, for the purposes of OC 11, include all Generators with Generating Units subject to Central Dispatch or with Generating Units that have a total Registered Capacity greater than 10 MW on a single Site;

(b) Interconnectors;

(c) Energy Storage Units;

(d) Transmission Connected Consumers;

(e) Transmission Network Operators; and

(f) Distribution Network Operators.

OC 11.4. Monitoring

OC 11.4.1. Monitoring will be normally continuous or continuous for periods of time, and shall be carried out by the SO by monitoring, data recording and analysis or by such other methods as the SO considers appropriate in the prevailing circumstances. It may not require advance notification from the SO to the Users in every case.

OC 11.4.2. Monitoring may be carried out by the SO at any time and may result, without the application of further Testing, in the evaluation of the User's non-compliance. Where the User disputes a finding of non-compliance, the SO shall provide the User, on request, any data collected during Monitoring over the period of alleged non-compliance and such other documentation as is reasonably necessary to show evidence of non-compliance.

OC 11.4.3. Procedures and systems used for assessment of compliance will be either generic procedures (which will be provided by the SO) or otherwise agreed between the SO and the User, such agreement not to be unreasonably withheld.

OC 11.4.4. Performance parameters that the SO monitors shall include, but are not limited to, the following:

(a) Compliance with Dispatch Instructions;

(b) Compliance with Declarations including, without limitation, in respect of:

(i) Primary, Secondary and Tertiary Operating Reserve provided by relevant Users, following a Low Frequency Event on the Transmission System;

(ii) Frequency Regulation provided by relevant Users (to confirm that it is consistent with the Declared Governor Droop);

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

(c) Compliance of the User with Power Quality requirements and standards (such as IEEE Std. 519-1992: IEEE Recommended practices and requirements for Harmonic control in Electric Power Systems; IEEE standard 141-1993: IEEE Recommended practice for electric power distribution for industrial plants; IEEE standard 1159-1995: IEEE recommended practice for monitoring electrical power quality; IEC 61000: Electromagnetic Compatibility (EMC)).

(d) Defense Plan implementation (ALFDD/ALVDD/SPS, etc.) and healthiness, compliance for protection system healthiness, compliance for substation physical healthiness, PSS tuning, Black Start Facility during restoration;

(e) Provision of static and dynamic Reactive Power; and

(f) Monitoring of Primary Fuel and Secondary Fuel capability, on-line changeover capability and fuel storage levels.

OC 11.4.5. If there is any persistent non-compliance by a User, the System Operator shall notify the User in writing, requiring an explanation of the non-compliance and the User shall have the opportunity to present its case and as applicable propose measures/actions to ensure compliance with its obligations.

OC 11.4.6. The SO and the User shall discuss the proposed action to make its facilities compliant with the committed performance and endeavor to reach an agreement on the proposed action. If agreement cannot be reached within ten (10) working days of notification of the failure by the System Operator to the User, the SO or the User shall be entitled to require a test as detailed in OC 11.5.

OC 11.5. Testing

OC 11.5.1. The SO may, from time to time, carry out Tests to achieve the objectives described in OC 11.2. The SO may:

(a) from time to time and for the purposes of Testing, issue a Dispatch Instruction under SDC 2 or by such alternative procedure as is required or permitted by this OC 11;

(b) induce controlled Power System Frequency or Voltage conditions or variations for the purpose of determining that a User Facility's response is in accordance with its Declared Availability, Ancillary Service provision and Registered Parameters and Operating Characteristics;

(c) verify by Testing in accordance with the Test procedures specified in OC 11.5.7, that the User is in compliance with its Declared values/Technical Parameters or communicated values as per SDC 1 (such as Annual Capacity Test, Heat Rate Test, etc.);

(d) instruct Start-Up on Secondary Fuel, or on-line changeover at Primary Fuel switchover output from Primary Fuel to Secondary Fuel or from Secondary Fuel to Primary Fuel at Secondary Fuel switchover output;

(e) On short notice, send a representative to the Generator's Site to verify the Fuel stock levels, at the onsite Fuel storage location and, if required, at the Off-Site Storage Location;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

(f) any other Tests SO may consider necessary for fulfillment of its licensed obligations and Grid Code requirements;

(g) All costs associated with the Tests shall be borne by the respective Users unless otherwise stated in the Applicable Documents.

OC 11.5.2. Testing may involve attendance by the SO or its representative at User Sites in order to carry out Tests in accordance with the testing procedures set out in OC 11.5.7.

OC 11.5.3. A Test may require the User to carry out specific actions in response to a Dispatch Instruction.

OC 11.5.4. The results of a Test may be derived from the Monitoring of performance during the Test.

OC 11.5.5. The results of the Test of the performance of the User's Facility shall be recorded at the SO facility using SCADA or any other means provided to the SO by the User.

OC 11.5.6. If the results are recorded on Site, representatives appointed and authorized by the SO shall witness the test.

OC 11.5.7. Test Procedures

OC 11.5.7.1. The SO shall prepare User-specific and/or Test-specific procedures in coordination with all relevant Users.

OC 11.5.7.2. The proposed procedure for a Test will be notified to the User by the SO in advance of the Test. For an existing procedure, three (3) working days' notice shall be given.

OC 11.5.7.3. For a new procedure, the SO will give a prior notice of seven (7) days to the User. On receipt of such a notification, the User, acting in good faith may, by giving the SO five (5) days' notice, can reasonably object to the proposed procedure on the grounds that there will be a material risk to the safety of the User's Plant or personnel, or that the proposed procedure is technically infeasible or inappropriate to the purpose (in accordance with Good Industry Practice), giving full details of its concerns. In the event that the User so objects, the SO may, as it considers necessary, modify the procedure and re-notify the User.

OC 11.5.7.4. The SO shall treat information collected from Users during monitoring and testing as confidential.

OC 11.5.8. Heat Rate Testing

OC 11.5.8.1. Heat Rate Testing shall be carried out by the SO, or by specialized companies contracted by the SO, for each Generating Unit of a Thermal Generator, at least, every three (3) years.

OC 11.5.8.2. The SO shall prepare a detailed GCOP detailing the procedures for carrying out the Tests as well as the required coordination with the involved Generators.

OC 11.5.8.3. The SO shall establish, every year, a comprehensive calendar for conducting these Tests. The SO will send the Test calendar to NEPRA, whose representatives will be entitled to observe the Tests.

OC 11.5.8.4. The SO shall produce a Heat Rate Test Report, for each Test it has carried out or instructed. Such report shall contain, at least, all the results obtained at each loading level, as well as any observation related with the conditions at which the

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Tests have been developed. In case that the results of the Tests show significant differences with the registered Technical Parameters (in case such parameters have been registered) and/or the values notified as per SDC 1, the Test Report shall clearly indicate such situation.

OC 11.5.8.5. The results of the Test shall be made public and published on the SO website.

OC 11.5.9. Black Start Testing

OC 11.5.9.1. The SO may require a User with a Black Start Station to carry out a test (a "Black Start Test") on a CDGU/Facility in a Black Start Station either while the Black Start Station remains connected to an external alternating current electrical supply (a "Black Start Unit Test") or while the Black Start Station is disconnected from all external alternating current electrical supplies (a "Black Start Station Test"), in order to demonstrate that a Black Start Station actually has the Black Start Capability.

OC 11.5.9.2. Where the SO requires a User with a Black Start Station to carry out a Black Start Unit Test, the SO shall not require the Black Start Test to be carried out on more than one CDGU/Facility at that Black Start Station at the same time, and would not, in the absence of exceptional circumstances, expect any other CDGU/Facility at the Black Start Station to be directly affected by the Black Start Unit Test.

OC 11.5.9.3. The SO may require a User with a Black Start Station to carry out a Black Start Unit Test at any time (but not more than once in each Calendar Year in respect of any particular CDGU/Facility unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test, and will not require a Black Start Station Test to be carried out more than once in every two Calendar Years in respect of any particular CDGU unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test.

OC 11.5.9.4. When the SO wishes a User with a Black Start Station to carry out a Black Start Test, it shall notify the relevant User at least seven (7) working days prior to the time of the Black Start Test with details of the proposed Test.

OC 11.5.9.5. All Black Start Tests shall be carried out at the time specified by the SO in the notice given under OC 11.5.9.4 and shall be undertaken in the presence of the authorized representatives of the SO, who shall be given access to all information relevant to the Black Start Test.

OC 11.5.10. Procedure for a Black Start (BS) Test

OC 11.5.10.1. Black Start Unit Test

OC 11.5.10.1.1. The relevant Generating Unit shall be synchronized and loaded.

OC 11.5.10.1.2. All auxiliary supply sources in the Black Start Station where the Generating Unit is located shall be shut down.

OC 11.5.10.1.3. The Generating unit shall be de-Loaded and de-synchronized, and all alternating current supplies to its auxiliaries shall be disconnected.

OC 11.5.10.1.4. The auxiliary supplies shall be re-started and energize the unit board of the relevant Generating Unit, thereby enabling the Generating Unit to return to synchronous speed.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 11.5.10.1.5.	The relevant Generating Unit shall be synchronized to the system but not loaded unless instructed to do so by the SO.
OC 11.5.10.2.	**Black Start Station Test**
OC 11.5.10.2.1.	All Generating Units at the Black Start Station other than the Generating Unit on which the Black Start Test is to be undertaken, and all auxiliary supplies to the Back Start Station shall be shut down.
OC 11.5.10.2.2.	The relevant Generating Unit shall be synchronized and loaded
OC 11.5.10.2.3.	The relevant Generating Unit shall be de-loaded and desynchronized.
OC 11.5.10.2.4.	All external alternating current electrical supplies to the unit board of the relevant Generating Unit and to the station board of the relevant Black Start Station shall be disconnected.
OC 11.5.10.2.5.	The auxiliary supply generator at the Black Start Station shall be started and shall re-energize either directly or via the station board, the unit board of the relevant Generating Unit.
OC 11.5.10.2.6.	The relevant Generating Unit shall be synchronized to the System but not loaded unless instructed to do so by the System Operator.
OC 11.5.10.3.	**Black Start HVDC systems**
OC 11.5.10.3.1.	The HVDC link shall be de-loaded.
OC 11.5.10.3.2.	All external alternating current electrical supplies to HVDC Converter stations shall be disconnected.
OC 11.5.10.3.3.	The auxiliary supply generator at the Black Start HVDC Converter station shall be started at the delivering end and shall re-energize HVDC control system.
OC 11.5.10.3.4.	The HVDC Converter station at the rectifying end is started, energizing the DC transmission line.
OC 11.5.10.3.5.	The inverter end of the HVDC link is started, energizing the dead AC bus bar.
OC 11.6.	**Inquiries and Probes/Investigation**
OC 11.6.1.	The SO may, if it suspects non-compliance by a User, carry out detailed inquiries and probes (referred to for the purpose of this Grid Code investigation (or to investigate) to acquire or verify information relevant to User's Plant and Apparatus design, operation, procedures or other requirements under the Grid Code, or the relevant Connection Agreement.
OC 11.6.2.	Investigation by the SO usually applies to information not collected on a regular basis by means of monitoring and testing. The SO may, having given reasonable notice, send a representative or sub-contractor to investigate any equipment or operational procedure or register in the Control Facility on or applicable to the User Site insofar as the condition of that equipment or operational procedure or register information is relevant to compliance with the Grid Code and Connection Agreement.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 11.7. **Consequences of Monitoring, Testing and Investigation**

OC 11.7.1. As a result of Monitoring, Testing and Investigation, the SO may determine that a User is in non-compliance due to any of the following reasons:

(a) Non-compliance with a Dispatch Instruction issued by the SO;

(b) Non-compliance by a Generator or Interconnector with Declared Operating Reserve;

(c) Non-compliance by a User with an Availability Notice;

(d) Non-compliance by a User with Declared Ancillary Services or declared Technical Parameters;

(e) Failure to pass the routine testing of the Black Start Facility by a User, and/or in case a User, designated to provide Black Start Facility, fails or underperforms during an emergency situation of System Restoration. The SO shall inform about these aspects to the Authority, for appropriate decision-making and further action;

(f) any other case of non-compliance by a User to the Grid Code.

OC 11.7.2. When the SO considers that a User is not in compliance, then the SO shall notify the User, identifying the relevant CDGU, Interconnector or TNO/DNO or any other equipment or procedure, and the type and time of non-compliance as determined by the SO. This shall be known as a "Warning for non-compliance" notice. The Warning for non-compliance shall contain appropriate corrective actions instructions by the SO to make the User compliant with its obligations. The occurrence of the Warning shall be logged by the SO and by the User.

OC 11.7.3. On receipt of a Warning for non-compliance, the User must as soon as possible, within a reasonable period of time with respect to the nature of non-compliance and in any case within fifteen (15) minutes of the receipt of the Warning:

(a) Commence to comply with the instructions included with the Warning; or

(b) Reply to the SO, disputing in good faith the validity of the Warning, detailing the grounds on which the validity is being disputed; or

(c) Reply to the SO, disputing in good faith the validity of the assessment of non-compliance. In this case, the User must as soon as be practicable, inform the SO in detail of the grounds on which the assessment of non-compliance is being disputed; or

(d) Reply to the SO, giving a reason for non-compliance, and making a revised Declaration in respect of the Availability, Ancillary Service capabilities or Technical Parameters, as appropriate.

OC 11.7.4. If the User complies in accordance with OC 11.7.3 (a), no further action shall arise.

OC 11.7.5. In the event of the User making a revised Declaration under OC 11.7.3 (d), the SO shall then issue a new Dispatch Instruction (if applicable), consistent with the revised Declaration. The revised Declaration will be backdated to the time of issue of the relevant Dispatch Instruction. Notwithstanding the backdating of the revised

Declaration, the User will still be deemed to have been non-compliant under OC 11.7.1.

OC 11.7.6. In the event of OC 11.7.3 (b) or OC 11.7.3 (c), the SO shall consider the substance of the User's disputation. The SO shall, where the SO considers appropriate, communicate with the User to clarify aspects relating to the issue and receiving of the User's actions. The SO shall determine the validity of the User's disputation, and shall inform the User as to its decision. The SO shall record both its decision, and also all the pertinent information relating to the alleged non-compliance, including the User's disputation and such information shall be deemed to be Operational Data.

OC 11.7.7. Where the SO is of the view that a disputation given by a User is not valid or not wholly valid or if the User has not replied in accordance with OC 11.7.3, the SO shall inform the User that it is overriding, by means of a Post Event Notice, the User's Availability Notice or declared Operating Reserve or declared Ancillary Service or declared Technical Parameter or Registered Operating Characteristics (as the case may be). The Post Event Notice shall govern until such times as the User submits a revised Availability/Declaration Notice.

OC 11.7.8. Where the SO gives a Post Event Notice under OC 11.7.7, the Post Event Notice shall be backdated to the time for which there exists compelling evidence that the User was acting in non-compliance, as determined by the SO. The Post Event Notice shall set the level of Declared Availability, Declared Ancillary Service capability or declared Technical Parameter/Operating Characteristics, as the case may be, at such level as the Monitoring, Testing or Investigation indicates the User actually achieved.

OC 11.7.9. Notwithstanding the backdating of the Post Event Notice, the User will still be deemed to have been non-compliant under OC 11.7.1.

OC 11.7.10. Following the Post Event Notice, the SO shall make available to the User within reasonable time, the relevant data that the User may reasonably require to substantiate the assessment of non-compliance.

OC 11.7.11. The SO shall follow the enforcement procedures established in the CM, and notify NEPRA, submitting all required information and documentation.

OC 11.7.12. In case of OC 11.7.1. (e), the terms of this OC 11.7 shall be without prejudice to the rights of the SO to De-Energize the User Facility in accordance with the terms of OC 6.

OC 11.7.13. In the event that a TNO or DNO is deemed by the SO in accordance with the provisions of this OC 11 to be in non-compliance with its Dispatch Instructions, that is the TNO or DNO failed to comply with three (3) Dispatch Instructions in one calendar month period, then the SO shall notify the TNO or DNO of the continued non-compliance. The TNO or DNO shall take immediate action to remedy such non-compliance. The terms of this OC 11.7.13 shall be without prejudice to the rights of the SO to inform NEPRA that the TNO or DNO is in breach of the Grid Code and Applicable Documents, for NEPRA to review.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 11.8. Failure of a Black Start Test

OC 11.8.1. A Black Start Station shall be considered as failing a Black Start Test if the Black Start Test shows that it does not have the Black Start Capability (i.e. if the relevant Generating Unit fails to be Synchronized to the System within two hours of the Auxiliary Gas Turbines or Auxiliary Diesel Engines being required to start).

OC 11.8.2. If a Black Start Station fails to pass a Black Start Test the Generator or Interconnector must provide the SO with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the Generator or Interconnector after due and careful enquiry. This report must be provided within five (5) working days of the test. If a dispute arises relating to the failure, the SO and the relevant Generator or Interconnector shall seek to resolve the dispute by amicable discussion. If they fail to reach agreement, the Generator or Interconnector may require the SO to repeat the Black Start Test on forty-eight (48) hours' notice which shall be carried out following the agreed procedure, as the case may be, as if the SO had issued an instruction at the time of notice from the Generator or Interconnector.

OC 11.8.3. If the Black Start Station concerned fails to pass the re-test and a dispute arises on that re-test, either party may use the Disputes Resolution Procedure for a ruling in relation to the dispute, which ruling shall be binding.

OC 11.8.4. If following the procedure in OC 11.8.2 and OC 11.8.3 it is established that the Black Start Station has indeed failed the Black Start Test (or a re-test), within fourteen (14) days, or such longer period as the SO may agree, following such failure, the relevant Generator or Interconnector shall submit to the SO in writing for approval, the date and time by which that Generator or Interconnector shall have brought that Black Start Station to a condition where it has a Black Start Capability and would pass the Black Start Test. The SO will not unreasonably withhold or delay its approval of the Generator's or Interconnector's proposed date and time submitted. Should the SO not approve the Generator's or Interconnector's proposed date and time (or any revised proposal) the Generator or Interconnector shall revise such proposal having regard to any comments the SO may have made and resubmit it for approval.

OC 11.8.5. Once the Generator or Interconnector has indicated to the SO that the Generator or Interconnector has again Black Start Capability, the SO shall either accept this information or require the Generator or Interconnector to demonstrate that the relevant Black Start Station has its Black Start Capability restored, by means of a repetition of the Black Start Test referred to in OC 11.5.9.4 following the same procedure as for the initial Black Start Test. The provisions of this OC 11.5.9 will apply to such Test.

OC 11.8.6. In the event that the Generator or Interconnector fails to meet the test criteria specified by SO, the Generator or Interconnector is required to provide the System Operator with a written explanation of the reasons for failure. If the System Operator and the Generator or Interconnector are unable to agree, the System Operator may require the Generator or Interconnector to perform a re-test.

OC 11.8.7. If in the opinion of the System Operator the Generator or Interconnector again fails the re-Test, every effort should be made to resolve the matter. In the event that a dispute arises between the Generator or Interconnector and the System Operator, the dispute resolution procedure in the CM shall apply and decision shall be binding on both entities.

OC 11.9. Disputing Assessment of Non-Compliance by a User

OC 11.9.1. In the event that a User has received notification from the SO of an assessment of non-compliance and/or application of a Post Event Notice under OC 11.7, then the User may reply to the SO disputing in good faith the validity of either the assessment of non-compliance and/or the content of the Post Event Notice, detailing the grounds on which the validity is being disputed. Any dispute should be submitted within twelve (12) hours although additional information in support of the dispute may follow within two (2) working days.

OC 11.9.2. If the User submits a dispute to the SO under OC 11.9.1, then the SO shall consider the substance of the User's dispute. The SO may, where the SO considers appropriate, communicate with the User to clarify aspects of the assessment of non-compliance or the User's dispute.

OC 11.9.3. The SO shall determine the validity of the User's dispute, and shall inform the User within five (5) working days as to its decision. The SO shall alter or revise any assessment of non-compliance and/or Post Event Notices as appropriate.

OC 11.9.4. In the event that there is still disagreement as to the outcome, if requested by either the SO or the User, the dispute resolution procedure in the CM shall apply.

OC 11.10. Failure of Test/Re-Test

OC 11.10.1. If after the procedure described in OC 11.7, it is accepted that a User has failed the Test or re-test, the User shall within ten (10) working days submit to the SO a date with a proposal by which the User shall be able to comply with the relevant requirements and its obligations. If the SO does not approve the date and time submitted by the User, the User shall amend such proposal having regard to any comments given by the SO and re-submit it for the SO's approval.

OC 11.10.2. If a User fails the Test, the User shall submit revised limits and other data as may be relevant as per Revised Technical Parameter Notice for the period of time until the User can achieve the Parameters previously registered under the CC or the PC or demonstrated under SDC.

OC 11.10.3. When the User informs the System Operator that it is able to achieve the Technical Parameters, the System Operator shall either accept this information or require the User to re-Test the User to confirm the stated capability. The System Operator shall give forty-eight (48) hours' notice to the User for a re-Test. The Test shall be conducted in accordance with OC 11.5.7, and the provisions of OC 11.9 and OC 11.10 shall apply to this further test.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 12. SYSTEM RECOVERY

OC 12.1. Introduction

OC 12.1.1. Despite best intentions and efforts, the Transmission System can occasionally come under severe stress and impacted by some unforeseen operating conditions or unusual weather events such as major thunderstorm, heavy rains, flooding, dense fog, etc.).

OC 12.1.2. Electricity systems can suffer Partial Shutdown or Total Shutdown under fault and abnormal operating conditions. These collapses can result from a number of causes but most typically due to a high number of Plant failures (generation and/or transmission) resulting from severe weather conditions and/or mal-operation of protection systems.

OC 12.1.3. The Grid Code provides a proper mechanism in the Grid Code to deal with a Partial Shutdown or Total Shutdown of the Transmission System, to ensure that the necessary procedures and facilities are in place to support as fast as possible recovery of the Shutdown parts and restore supply to Customers.

OC 12.1.4. A Partial Shutdown or Total Shutdown represents one of the most serious fault situations liable to occur on the Transmission System, having a major effect on both Users of the Transmission System and electricity Customers. High significance of such Incidents and urgency in restoring supply to all Customers, makes it imperative that all Users should maintain a high level of awareness and training for National Grid restoration after a Partial or Total Shutdowns.

OC 12.1.5. This sub-code System Recovery OC 12 of the Operation Code establishes the procedures for the restoration of power supplies following a Total Shutdown or a Partial Shutdown of the System and the re-synchronization of specific parts of the System that have been Islanded. Where the need for a procedure is identified for the first time for any type of Shutdown or Islanding, and there is no agreement already in place, the System Operator and relevant Users shall coordinate the course of action to be adopted.

OC 12.1.6. This OC 12 requires that effective channels of communications must be established and maintained between the System Operator, the Transmission Network Operators, Generators, DNOs, Consumers connected to the Transmission System, and Interconnectors, in addition to channels used for day-to-day operations of the Transmission System and User facilities.

OC 12.1.7. In order to mitigate the effects of any national-level emergency, the System Operator and Users shall take quick actions to safeguard the System and facilities connected with it. Such actions may necessitate use of principles and procedures contrary to those laid down in the Grid Code, and as such, during restoration the appropriate sections of the Grid Code shall stand suspended till the System is restored to Normal State.

OC 12.2. Objective

OC 12.2.1. The objective of OC 12 is to ensure that in the event of a Partial Shutdown or Total Shutdown of the Transmission System, normal supply is restored to all Customers

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

as quickly and as safely as practicable in accordance with Prudent Utility Practice. This objective can be subdivided:

(a) To outline the general restoration strategy which will be adopted by the SO in the event of a Partial Shutdown or Total Shutdown of the Transmission System;

(b) To establish the responsibility of the SO to produce and maintain a comprehensive National Grid Restoration Plan, covering both Partial Shutdowns and Total Shutdowns;

(c) To establish the responsibility of the Users to cooperate with the SO in the formulation and execution of the National Grid Restoration Plan;

(d) To ensure that the SO and User personnel who will potentially be involved with the implementation of the National Grid Restoration Plan, are adequately trained and fully familiar with the relevant details of this Plan.

OC 12.3. Scope

OC 12 applies to the SO and to:

(a) Generators;

(b) Interconnectors;

(c) Energy Storage Units;

(d) Transmission Network Operators;

(e) Distribution Network Operators; and

(f) Transmission Connected Consumers.

OC 12.4. System Alerts

OC 12.4.1. In the event of a System emergency condition or imminent shortfall of MW capacity, the SO may issue any of several Alerts to the Generators/Interconnectors, key Transmission Stations and DNOs. These Alerts may include a Yellow Alert, Blue Alert or Black Alert or Red Alert, or other Alerts as may be agreed from time to time.

OC 12.4.2. Alerts will normally be transmitted to the User via the Electronic Alert System (except in the case of a failure of the Electronic Alert System when it will be given verbally). The Alert shall cause an alarm in the receiving location, which must be acknowledged by the User in accordance with their Alert procedures.

OC 12.4.3. Standing procedures to be activated in response to an Alert will be developed by the SO, in consultation with Users, and notified to each User as appropriate. These standing procedures will not impose obligations on the User which are not already provided in the Grid Code.

OC 12.4.4. Each User shall be responsible for development of internal procedures, in consultation with the SO, that may be necessary to execute the standing procedures.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 12.4.5. **Yellow Alerts**

A Yellow Alert may be issued when a single Event would give rise to a reasonable possibility of failure to meet the National Grid Demand, or of Frequency or Voltage departing significantly from normal, as per OC 5.4.4 and OC 5.5.7, or if multiple Events are probable due to prevailing system or weather conditions i.e. System is under Contingency State.

OC 12.4.6. **Blue Alerts**

A Blue Alert may be issued when, other than as provided for in OC 10, the Frequency or Voltage in the Transmission System has deviated significantly from normal, or when the Contingency Reserve in the System becomes zero, or a Generation deficiency exists, or there is a Critical Loading or imminent overloading of the Transmission lines or equipment, or User's Demand has been disconnected i.e. System is under Emergency State.

OC 12.4.7. **Black Alert**

The issuing of a Black Alert other than as provided for in OC 12.5.5, by the SO signifies that either a Partial Shutdown or a Total Shutdown of the National Grid has taken place i.e. System is under Extreme Emergency State.

OC 12.4.8. **Red Alert**

The issuing of Red Alert signifies that the System is in Restorative State.

OC 12.5. **Power System Restoration**

OC 12.5.1. A Total Shutdown of the System is a situation when there is no internal generation online and operating, and also there is no power supply available from external connections. The restoration of power supply from such a situation is a Black Start Recovery. A Partial Shutdown is a situation when there is no on-line and operating generation or external connection to a part of the System that is under Shutdown, and it may be necessary for the System Operator to instruct Black Start Recovery procedures to restore supplies to that part of the System and Synchronize it back to the healthy part of the Transmission System.

OC 12.5.2. The National Grid Restoration Plan will be developed and maintained by the SO in coordination with relevant Users in accordance with Prudent Utility Practice and relevant Agreements. It shall clearly define the responsibilities of Users during Total or Partial Shutdown.

OC 12.5.3. The procedure for National Grid Restoration shall be notified by the SO to the User at the time of a Partial Shutdown or Total Shutdown. Each User shall abide by the SO's instructions during the restoration process, subject to safety of personnel and the System's and the User's Plant and Apparatus.

OC 12.5.4. The User shall ensure that their personnel who are expected to be involved in the National Grid Restoration process are fully familiar with, and are also adequately trained and experienced in executing their standing instructions and discharging their obligations so as to be able to implement the procedures and comply with any procedures notified by the SO under OC 12.5.3.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 12.5.5. To test the procedures, the SO shall, in consultation with each User, and at least once each year, issue a Black Alert to the Users for the purposes of Testing the Restoration Plan and the preparedness and training of the relevant staff. The content of the drills shall be notified in advance to the Users, and a date and time for execution of the drills shall be agreed and notified. The User must, acting in accordance with Good Industry Practice, cooperate with the SO in successfully carrying out of any such drills.

OC 12.5.6. Following a Total Shutdown of the System, designated power plants that have the ability to Start Up without any external connection to the System shall be instructed to commence Black Start Recovery procedures. These procedures, which are to be agreed in advance between SO and participating Users, may include the restoration of blocks of local loads that can be restored in coordination with the involved DNO. DNO procedures may include the restoration of power supplies via Embedded Generators, which shall be clearly established in the Distribution Code. The System Operator shall be responsible for the re-energization of the Transmission System, and the re-synchronization of the various islanded blocks.

OC 12.5.7. The complexities and uncertainties relating to the restoration of power supplies following a Total Shutdown or Partial Shutdown of the System dictate that any internal procedure and any local procedure agreed between the System Operator and Users allows for a flexible approach to be adopted in the light of actual circumstance rather than a rigid and inflexible procedure involving prescribed actions.

OC 12.5.8. During the restoration of Load, the System Operator may issue instructions that conflict with a local procedure for the restoration of power supplies. In such an event, the System Operator's instructions shall override any previously agreed procedure.

OC 12.5.9. During restoration process of the Transmission System, the normal standards of Voltage and Frequency under OC 5.4.4 and OC 5.5.7, and Performance Standards, shall not apply.

OC 12.5.10. Procedures for the restoration of power supplies may include the requirement for the Generators to communicate directly with the relevant DNO or TNO, as applicable, on the SO's instructions, so that the restoration of blocks of local power supplies can be managed in a controlled manner to ensure the Generator's stability and safety.

OC 12.5.11. Frequency sensitive automatic load disconnection schemes may be taken out of service during the restoration of load to prevent unwanted disconnection of load.

OC 12.5.12. Generators/Interconnectors shall not be permitted to reconnect to the Transmission System or install automatic reconnection systems unless instructed by the SO.

OC 12.5.13. The System Operator shall instruct the interconnection of islanded networks to form progressively larger and resilient sub-systems until the complete System has been reconnected properly. This shall be facilitated by using appropriate synchronization facilities (e.g. digital synchro-check relays etc.). Users are

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

responsible to maintain such facilities at all strategic points as identified by the SO, or in accordance with CC 6.1.6.

OC 12.5.14. During the restoration of supplies, the System Operator shall agree the reconnection of the System to any Interconnector as per the relevant Interconnection Agreements.

OC 12.5.15. In case of Total Shutdown, Solar PV Power Plants shall be required to be disconnected from the System. The PV inverter shall have anti-islanding protection built in and shall inject small pulses that are slightly out of phase with the AC electrical system in order to cancel any stray resonances that may be present when the System shuts down.

OC 12.6. Islanded Network

OC 12.6.1. If a part of the System gets disconnected from the complete System, but there has been no resultant Total Shutdown or Partial Shutdown of the System, the System Operator shall instruct the regulation of Generation and/or Demand, in both parts of the Transmission System to enable the disconnected part to be re-synchronized back to the complete System

OC 12.6.2. In order to achieve requisite conditions to permit the re-synchronization of the islanded network, the System Operator may adopt one of the following approaches:

(a) The System Operator and the Users in the islanded network may exchange information to enable the System Operator to issue emergency instructions until the islanded network has been successfully re-synchronized. Transfer of Load Demand between interconnection and un-synchronized parts of the System will be at the discretion of the SO.

(b) The System Operator shall issue an emergency instruction to the operators of power plants in the islanded network to float local Load to maintain Target System Frequency until the islanded network has been re-synchronized. During this period, the Distribution Company is required to inform the System Operator of any anticipated changes in load.

(c) If the supply to a part of the System gets de-synchronized, then that particular part may be shut down and power supplies restored for the Synchronized part of the System, and the remaining system shall maintain power supplies in balance with the relevant demand.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 13. WORK SAFETY

OC 13.1. Introduction

OC 13.1.1. Notwithstanding the standard safety procedure for employees working within Service Territory of Code Participants, this sub-code OC 13 of the Operation Code focuses on the coordination on Safety matters when repair or maintenance work is to be performed at or near the Transmission System (66 kV and above).

OC 13.1.2. At times, the TNOs and the Users may need to work on, or in close proximity to the Transmission System. It is imperative that the TNOs and Users operate strictly in accordance with the safety guidelines and procedures as laid down in the approved NEPRA Safety Code and other Applicable Documents, to ensure the Safety of life, network, and equipment in such situations.

OC 13.1.3. It will also be necessary to facilitate work by third parties in close proximity to Transmission System and Apparatus.

OC 13.1.4. In the event of a conflict between OC 13 and any other section of the Grid Code, the OC 13 shall take precedence.

OC 13.1.5. To ensure safe conditions for each and every foreseeable situation during system operation, it is essential that the Transmission Network Operator and the Users operate in accordance with safety guidelines and procedures as laid down in the approved NEPRA Safety Code, and other Applicable Documents. The Transmission Network Operators and Code Participants shall have their own comprehensive power safety procedures in place and available at all times, which shall also cover work on live Transmission System Plant and Apparatus.

OC 13.1.6. OC 13 does not impose a particular set of safety guidelines on the Transmission Network Operators or Users, and does not replace the safety guidelines of any Users already in place.

OC 13.2. Objective

OC 13.2.1. The objective of OC 13 is to ensure that the Users and their respective sub-contractors operate in accordance with the approved NEPRA Safety Code, which ensure the safety of personnel working on or in close proximity to Transmission System, Plant and Apparatus, or personnel who may have to work at or use the equipment at the interface between the Transmission System and the User's System.

OC 13.2.2. This will normally involve making electrical equipment dead and suitably isolating/disconnecting (from all sources of Energy) and Earthing of that equipment such that it cannot be made live.

OC 13.3. Scope

OC 13 applies to the SO and:

(a) Generators;

(b) Interconnectors;

(c) Transmission Network Operators;

(d) Distribution Network Operators;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

(e) Transmission Connected Consumers; and

(f) Third parties contracted by any User.

OC 13.4. Safety Procedures

OC 13.4.1. The Safety of personnel working on or in close proximity to Transmission System Plant and Apparatus shall be governed by the approved NEPRA Safety Code, safety procedure of Users, and other Applicable Documents.

OC 13.4.2. In the event of any conflict with this OC 13, the provisions of the approved NEPRA Safety Code, safety procedure of Users, and other Applicable Documents shall take precedence.

OC 13.4.3. Where clarification is required regarding the correct interpretation of any provision within the User Safety procedure, the User shall issue the interpretation following consultation with the relevant parties.

OC 13.4.4. In this document, the following terms have the following meanings:

(a) HV Apparatus means High Voltage electrical circuits forming part of a System, on which "Safety from the System" is required or on which Safety Precautions are required to allow work to be carried out on the System.

OC 13.4.5. The words mentioned in OC 13.4.4., for the purpose of this OC 13, are defined as follows:

(a) "Safety from the System" means that condition which safeguards the persons, when work is being carried out at or near a System, from the dangers which are inherent to the System.

(b) "System" means any User System and/or the Transmission System, as the case may be.

(c) "Safety Precautions" means Isolation and/or Earthing.

(d) "Isolation" means the disconnection of apparatus from the remainder of the live System in which that apparatus has been connected. The integrity of the Isolation being achieved and maintained by the use of an approved isolation device, on which all of the procedures to maintain Safety from the System have been carried out. The means of Isolation shall be maintained in accordance with the rules of the owner of the Isolation Apparatus.

(e) "Earthing" means the application of a connection between the isolated system and the general mass of earth, by an approved means that is adequate for the purpose, and is required to be in place in a secure condition in accordance with the rules of the owner of the Isolation.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

OC 13.5. Procedure for Safety at the Interface

OC 13.5.1. There shall be a designated Safety Coordinator for each User Site. Operating Instructions for each User Site shall, following consultation with the relevant User, be issued by the SO to the User and will include:

(a) Detailed switching sequences for voluntary, fault and emergency switching;

(b) Control and operational procedures;

(c) Identity of the authorized operator of the SO and the Users;

(d) Other matters agreed between the SO and User.

OC 13.5.2. Demarcation of responsibility for safety of persons carrying out work or testing at the User Site and on circuits which cross the User's Site at any point, shall be in accordance with Connection Code or relevant Connection Agreement.

OC 13.5.3. The SO and each User shall cooperate in developing procedures and agreement on any matter that may be relevant for ensuring overall Site Safety and, in particular, the overall safety of equipment at the interface between the Transmission System and the User System.

OC 13.5.4. In the event of a modification or a change in operational practices, which may have an Operational Effect on a User, the User shall inform the SO without any delay.

OC 13.5.5. Adequate means of Isolation/disconnection (from all sources of Energy) and Earthing shall be provided at the work site to allow work to be carried out safely at, or either side of this point, by each User.

OC 13.5.6. On completion of work, the designated Safety Coordinators at each relevant Site shall agree to the cancellation of the Safety documentation and shall ensure all requests and subsequent confirmations have been recorded in their log books. These Logs shall be retained for at least five (5) years.

OC 13.5.7. It is the responsibility of the designated Safety Coordinator to ensure that all Safety Precautions are maintained in place until completion of work and the Safety documentation is cancelled on completion of work.

OC 13.5.8. Users shall be aware of clearance limits and shall perform work only within their approved clearance limits. Any work at the boundary of the Connection Point shall not be performed without the supervision of a TNO representative.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 13. Appendix – A

(A) INTER-SYSTEM SAFETY RECORD OF INTER-SAFETY PRECAUTIONS (RISSP - R)

(For Requesting Safety Coordinator's Record)

RISSP No.___________

Name and location of the Control Centre:____

Name of Control Centre Operator:____

Name and Location of Grid Station/Work Station: _________

PART 1

1.1 (a)Identification of HV Apparatus where isolation and safety from the system is to be achieved.

____

____

(b) Details of work to be done:____

(c) Any other instructions or safety measures to be taken:________________________

____

1.2 Identification and Safety Precautions Established

(Whether on the implementing safety coordinator's system or any other Users system connected to implementing safety coordinator system) Tick mark √ in the relevant box.

Identification of HV Apparatus	Location	Isolation	Earthing	Confirm Notices Displayed	Locking Arrangements Provided
(i)	_________	☐	☐	☐	☐
(ii)	_________	☐	☐	☐	☐
(iii)	_________	☐	☐	☐	☐

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

1.3 Confirmation and Issues

Mr.____________________________ implementing Safety Coordinator at location ______________________________ has confirmed that the safety precautions identified in Para 1.2 have been established and will not be removed until this RISSP is cancelled

Signature: ____________________

Dated: ____________________ Name: _______________________

Time:_____________________ (Requesting Safety Coordinator)

Date and Time of Commencement of Work ____

Date and Time of Completion of the Work ____

____

Name & Signature of

In charge of work

(Authorized Person)

PART 2

CANCELLATION

I have confirmed to Mr. ________ implementing Safety Coordinator at location ___________ that all men working on the HV apparatus as identified in Para 1.2 have been withdrawn, and the safety precautions set out in Para 1.2 are no longer required and hence the RISSP is cancelled.

Signature: _________________

Name: ____________________

(Requesting Safety Coordinator)

Dated: ______________________________

Time:_______________________________

Date and Time of Re-energizing of Apparatus ______________________________________

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

OC 13. Appendix – B

(B)INTER-SYSTEM SAFETYRECORD OF INTER-SAFETY PRECAUTIONS (RISSP - R)

(For Requesting Safety Coordinator's Record)

RISSP No.___________

Name and location of the Control Centre: ____

Name of Control Centre Operator: ____

Name and Location of Grid Station/Work Station: __________

PART 1

1.1 (a) Identification of HV Apparatus where isolation and safety from the system is to be achieved.

____

____

(b) Details of work to be done: ____

(c) Any other instructions or safety measures to be taken: _________________________

____

1.2 Identification and Safety Precautions Established

(Whether on the implementing safety coordinator's system or any other Users system connected to implementing safety coordinator system) Tick mark √ in the relevant box.

Identification of HV Apparatus	Location	Isolation	Earthing	Confirm Notices Displayed	Locking Arrangements Provided
(i)	_________	□	□	□	□
(ii)	_________	□	□	□	□
(iii)	_________	□	□	□	□

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

1.3 Confirmation and Issues

I, ______________________________implementing Safety Coordinator at location ___________________ has confirmed that the safety precautions identified in Para 1.2 have been established and will not be removed until this RISSP is cancelled

Signature: _________________

Name: _____________

(Implementing Safety Coordinator)

Dated: ______________________________

Time:______________________________

PART 2

CANCELLATION

Mr. __________________ requesting Safety Coordinator at location ____________________ has confirmed that the safety precautions set out in Para 1.2 are no longer required and hence the RISSP is cancelled.

Signature: _________________

Name: ____________________

(Implementing Safety Coordinator)

Date: ______________________________

Time:______________________________

Date and Time of Re-energizing of Apparatus ____

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SCHEDULING AND DISPATCH CODE

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1. INDICATIVE OPERATIONS SCHEDULING

SDC 1.1. **Introduction**

This Scheduling and Dispatch Code No. 1 ("SDC 1") defines the roles and responsibilities of the SO and other Code Participants in the Scheduling of available resources (Generation, Demand Control, and Interconnector transfers) to serve electricity Demand on the Transmission System at least-cost while ensuring Adequacy, Security and Quality of electricity supply in the Transmission System.

SDC 1.2. **Objective**

The objective of SDC 1 is to enable the SO to prepare the day ahead "Indicative Operations Schedule" to be used subsequently in the Dispatch process (described in SDC 2) during the real time Operation of the National Grid and thereby:

(a) maintain sufficient Scheduled Generation capacity to meet total Demand on the System at all times together with adequate Operating Reserves;

(b) ensure the Security and Quality of Supply in National Grid;

(c) minimize system operating cost on principles of Optimal Power Flow;

(d) publish the Indicative Operations Schedule as provided for in this SDC 1;

(e) comply with the applicable environmental regulations; and

(f) keep a set of potential Special Actions, to deal with any credible contingency on the Transmission System.

The SO will utilize an appropriate Scheduling software program and tools using principles of Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) to fulfil the objectives of this SDC 1.

SDC 1.3. **Scope**

SDC 1.3.1. SDC 1 applies to the SO, and the following Users:

(a) Centrally-Dispatched Generating Units:

(i) Conventional Generator (thermal, hydro, nuclear, bagasse, and concentrated solar power Generators, etc.) directly connected to the Transmission System;

(ii) VRE Generator (run-of-the-river hydro, solar, and wind, etc.) directly connected to the Transmission System; and

(b) Conventional or VRE Generation, not directly connected to the Transmission System, which the SO considers, due to its particular characteristics or network Connection Point, shall be under its centralized dispatch and/or direct control. The SO shall publish on its website a list of such Generating Units along with the reasons which justify considering them CDGU;

(c) Energy Storage Units with respect to their supply to or demand on the Transmission System (as may be the case at a specified time, including Battery Energy Storage Systems, Pumped Storage Hydro, etc.);

(d) Market Operator;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(e) Transmission Network Operators;

(f) Interconnectors;

(g) Distribution Network Operators;

(h) Bulk Power Consumers connected to the Transmission System;

(i) Embedded Generators whether represented through some Aggregators or any other arrangement approved by NEPRA (if required by SO). The Embedded Generators to which this Grid Code will apply shall be determined as per the relevant Applicable Documents; and

(j) The Special Purpose Agent.

SDC 1.3.2. Responsibilities of the System Operator

SDC 1.3.2.1. The SO shall be responsible for developing a daily Forecast of System Demand (in accordance with OC 2) of the National Grid for the next Schedule Day (initially for each hour of the Schedule Day, but for a finer time resolution, if required by SO in the future).

SDC 1.3.2.2. The SO shall develop or procure a state-of-the-art wind and solar forecasting tool/software/service whose forecast accuracy shall be, at least, as specified in Table OC 1. The SO will use the forecast from this tool in the Scheduling process and, if necessary, to validate the Availability and expected energy production declared by VRE Generators.

SDC 1.3.2.3. The SO shall use these forecasts (SDC 1.3.2.1 and SDC 1.3.2.2) for performing the Scheduling of the available resources for the next Schedule Day to match Supply with Demand, maintaining the requisite levels of Operating Reserve, Minimum Demand Regulation capability, System Stability requirements, and other System Services requirements.

SDC 1.3.3. Responsibilities of the Transmission Network Operators (TNOs)

The TNO shall be responsible for providing to the SO on the Availability and operating status of its Transmission System facilities and equipment, and in particular, any situation which lead or may lead to a reduction in their operational characteristics, if different from those registered as established in the Planning Code, for the next operational day.

SDC 1.3.4. Responsibilities of Generators and Interconnectors

The Generators shall be responsible for providing to the SO the Variable Operating Costs and Start-Up Costs of all CDGUs and Interconnectors (if applicable) in accordance with SDC 1.6, for using these in preparation of Indicative Operations Schedule and actual Dispatch based on a SCUC and SCED process, following the procedures and mechanisms established in SDC 1.4 and SDC 1.7.

SDC 1.4. Scheduling Process

SDC 1.4.1. The SO shall develop an Indicative Operations Schedule (IOS) a day-ahead of the following Schedule Day using the process described in this SDC 1.4. This process will be phased and iterative to allow, if needed, appropriate interactions of the SO with Generators and other TNOs/Users to match Supply with Demand in the System.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

SDC 1.4.2. The Schedule Day shall begin at 00:00 hours on the Schedule Day and shall last for 24 hours until 00:00 hours on the next Schedule Day.

SDC 1.4.3. The Users must submit the requisite data and information to the SO as detailed in this SDC to allow it to prepare the IOS. Since the SO is required to match Generation, Interconnector transfers, and Demand in the System on an instant-by-instant basis, the SO may require some additional information from Users to accomplish this objective. Details of any such additional information requirements shall be notified by the SO to the relevant Users, as per the need. If the SO considers this additional data and information necessary and asks a User for it, the User shall provide this data and information without any undue delay.

SDC 1.4.4. Data and information submissions to the SO shall normally be made electronically in accordance with the provisions of OC 9. In the event of failure of the Electronic Interface for submitting data and information to the SO, submissions may be made by telephone, fax or any other means of communication acceptable to the SO.

SDC 1.4.5. If any changes occur after a User has supplied data and information to the SO pursuant to SDC 1.5, the User shall inform the SO, without any delay, of all such changes.

SDC 1.4.6. Based on the data and information supplied by the Users (as described in this SDC 1), the SO shall develop Indicative Operation Schedule (IOS) for the following Schedule Day and shall publish this Schedule according to the provisions of Market Commercial Code and this Grid Code.

SDC 1.4.7. Only those Generators that are active Market Participants enrolled with the Market Operator as per the provisions of Market Commercial Code (unless an exemption is granted in the Market Commercial Code or other Applicable Documents) shall be considered in the Scheduling and Dispatch process.

SDC 1.5. Availability Notices

SDC 1.5.1. Requirements

SDC 1.5.1.1. By 1000 hours each day, each User shall notify the SO by means of an Availability Notice (in the forms as set out in Appendix B or such other form as the SO may notify to Users from time to time and publish on its website) its Availability or Available Transfer Capability (as the case may be) for each of its:

(a) CDGUs;

(b) Energy Storage Units (for their generation or demand);

(c) Interconnectors; or

(d) Embedded Generators whether represented through an Aggregator or some other arrangement (if required by the SO).

SDC 1.5.1.2. The Availability Notice shall state the MW Availability (at levels of MW at the Connection Point) of the relevant User for the next Schedule Day.

SDC 1.5.1.3. For Generators, the MW figure stated in the Availability Notice shall be consistent with the resolution of Capacity Certificates in accordance with the Market Commercial Code.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1.5.2. Contents

SDC 1.5.2.1. Generating Units which are affected by ambient conditions shall state in the Availability Notice, their best estimate of the ambient conditions and the resulting Availability for each interval of the Schedule Day to which the Availability Notice relates.

SDC 1.5.2.2. When the Availability of a CDGU is zero and Availability Notice is given increasing the Availability of the CDGU with effect from a specified time, such Notice shall be taken to mean that the CDGU is capable of being synchronized with the Transmission System at that specified time. A dispatch instruction issued by the SO to synchronize CDGU to the Transmission System, at or after the specified time shall be a valid dispatch instruction (regardless of the minimum time to synchronize specified in the relevant Technical Parameters).

SDC 1.5.2.3. When a CDGU is synchronized with the Transmission System, and the Generator issues an Availability Notice to increase the level of Availability of the CDGU from a specified time, such notice shall be taken to mean that the CDGU is capable of ramping up to this new increased generation level at that specified time from the previously declared level of Availability (without violating its registered Technical Parameters).

SDC 1.5.2.4. When a CDGU is synchronized with the System, and the Generator issues an Availability Notice to decrease the level of Availability of the CDGU from a specified time, such Notice shall be taken to mean that the CDGU is capable of maintaining its output till the specified time as per its previous declared Availability level and will ramp down to the new decreased generation level strictly in accordance with its registered Technical Parameters.

SDC 1.5.2.5. Where a Generating Unit is capable of firing on multiple fuels, the Generator shall submit an Availability Notice in respect of each designated fuel for its Generating Units, marked clearly to indicate to which particular designated fuel the Availability Notice relates to.

SDC 1.5.2.6. In case of hydro Generators, the Availability Notice shall state the capability of each of its Unit in MW adjusted with respect to the inflow and head of its pond or reservoir (if applicable). The Availability Notice shall also state the parameters related to its reservoir/pond and inflow forecast, in the form as set out in Appendix-B (or such other form as the SO may notify from time to time and publish on SO website).

SDC 1.5.2.7. In respect of Interconnectors, the Availability Notice shall state the Available Transfer Capability of the Interconnector and shall take account of any further restrictions placed by any relevant Interconnection Agreements or by the System Operator or dispatch center of foreign system connected to the National Grid.

SDC 1.5.2.8. If an Interconnector issues an Availability Notice changing its Available Transfer Capability from any previous level beginning from a specified time, such Notice shall be taken to be effective exactly at that specified time.

SDC 1.5.2.9. By 1200 hours each day, each VRE Generator shall provide a forecast of the expected Generation of its plant to the SO on hourly resolution (or a finer resolution if so notified by the SO), for the next Schedule Day. This forecast must be carried

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

out through a state-of-the-art model with minimum forecast accuracy as indicated in Appendix-E. In addition, not later than four (4) hours before the start of each hour, the VRE Generator must provide a forecast of expected Generation for the said hour, provided, the VRE Generator may revise, only once, the forecast for the said hour no later than three (3) hours prior to the commencement of the hour for which the forecast is revised.

SDC 1.5.2.10. If a VRE Generator issues an Availability Notice changing its Availability from any previous level beginning from a specified time, such Notice shall be taken to be effective exactly at that specified time.

SDC 1.5.2.11. Notwithstanding that a Generating Unit has been declared unavailable, the Generator shall still submit all data and information that it would have submitted to the SO under this SDC 1 had its Generating Unit been declared Available.

SDC 1.5.2.12. Generators shall ensure that their Generating Units are maintained, repaired, operated, and fueled using Prudent Industry Practices and are always compliant with any legal or regulatory requirements to ensure the provision of the power delivery, System Services as applicable, Declared Available Capacity, and the Technical Parameters.

SDC 1.5.2.13. Generators shall maintain a fuel stock (for storable fuels) equivalent to at least thirty (30) days of continuous operation at full load on Primary Fuel, and seven (07) days continuous operation at full load on Secondary Fuel (where applicable), unless a different requirement has been established in the NEPRA Performance Standards and other Applicable Documents.

SDC 1.5.2.14. In the case of an Aggregator, the Availability Notice shall state the Availability of each individual Generating Unit individually, as well as the aggregated availability as a whole.

SDC 1.5.2.15. If a Generator (or Interconnector) submits a Maintenance Outage Notice under (OC 4) or SO submits a Post Event Notice under (OC 11) in relation to any part of the period covered by the Availability Notice at any time after submission of the Availability Notice, the Generator shall be deemed to have submitted a revised Availability Notice consistent with such Outage Notice or Post Event Notice, as the case may be. The Generator shall revise its Availability Notice as such.

SDC 1.5.2.16. If a User has submitted a proposal for conducting a Test on its Facility to the SO and the SO has approved the proposal, the User shall submit Test MW Output profile for the unit under Test for the time periods during which their units are under Test. The User shall ensure that the hourly MW profile submitted in respect of a unit under Test aligns with the approved Test start time and Test end time.

SDC 1.5.2.17. Users shall employ all reasonable endeavors to ensure that they do not, at any time, declare by issuing, or allowing to remain effective, an Availability Notice, declare the Availability or Technical Parameters of their facilities at levels or values which are different from those that their relevant facilities could achieve at the relevant time except under unavoidable circumstances and only with prior consent of the SO. The SO can reject declarations to the extent that they do not meet these requirements.

SDC 1.5.2.18. Nothing contained in this SDC 1 shall restrict a User from declaring levels or values for their Generating Units or other resources that are better than their Capacity and Technical Parameters.

SDC 1.5.3. Additional Requirements

The following items are required to be submitted by each User by no later than 1000 hours each day. The requirements in SDC 1.5.2 in relation to data apply to this SDC 1.5.3 as if repeated here.

SDC 1.5.3.1. **CCGT Availability**

CCGT Installations shall also submit the following:

(a) The Availability of each CCGT Unit within each CCGT Complex;

(b) The CCGT Installation Matrix submitted by the Generator in the form as set out in Appendix A (or such other form as the SO may notify to Users from time to time and publish on its website) is used and relied upon by the SO as a 'look up table' to determine the number of CCGT Units within a CCGT Installation which will be synchronized to achieve the MW Output specified in a Dispatch Instruction. When using a CCGT Installation Matrix for Scheduling purposes, the SO will take account of any updated information on the individual Availability of each CCGT Unit contained in an Availability Notice submitted by a Generator pursuant to this SDC 1;

(c) In cases where some change in MW Output in response to Dispatch Instructions issued by the SO is inevitable, there may be a transitional variance to the conditions reflected in the CCGT Installation Matrix. Each Generator shall notify the SO as soon as practicable after the event of any such variance.

In achieving a Dispatch Instruction, the range or number of CCGT Units envisaged in moving from one MW Output level to the other shall not be departed from.

SDC 1.5.4. Revisions

SDC 1.5.4.1. **Revised Availability Notice**

SDC 1.5.4.1.1. User shall submit to the SO, any revisions to its previously submitted data and information at any time between 1000 hours each day and the expiry of the following Schedule Day.

SDC 1.5.4.1.2. If the revised data and information is received by the SO before 1200 hours on the day prior to the relevant Schedule Day, the SO shall take into account the revised Availability Notice in preparing the Indicative Operations Schedule (IOS).

SDC 1.5.4.1.3. If the revised data and information is received by the SO after 1200 hours but before the end of the following Schedule Day, the SO shall, if it re-Schedules the available resources, take into account the revised Availability Notice in that re-Scheduling.

SDC 1.5.4.1.4. The provisions of SDC 1.5.1, 1.5.2 and 1.5.3, shall apply to revision to data submitted under SDC 1.5.4.1.

SDC 1.5.4.2. **Revised Technical Parameters**

SDC 1.5.4.2.1. Any revisions to the registered Technical Parameters (submitted as Registered Data in the Planning Code and Connection Code of this Grid Code or as per Appendices in SDC) must be well documented and agreed to with the SO including the nature and quantification of the revision, duration of such revision, reasons for the revision, and anticipated time when the User will restore the Technical Parameters to their registered values.

SDC 1.5.4.2.2. For such temporary revisions in the Technical Parameters, notification must be made by the User by submitting a Technical Parameters Revision Notice (Appendix C). In accordance with the Generator's obligations under SDC 1.5.2.17, such characteristics may only be amended (with the SO's prior consent) in the event of a defect in or failure of a CDGU or any associated Generator equipment. Such amendment shall only take place so long as it takes place in accordance with Prudent Industry Practices, and such repair must reinstate the parameters to the level stated in the Technical Parameters, taking into account the provisions of SDC 1.5.2.17, and the Generator must then submit a Technical Parameters Revision Notice re-declaring its reinstated Technical Parameters accordingly. The Generator must specify to the SO the nature of any such defect or its failure, and of the Generator's best estimate, acting as a reasonable and prudent Generator, of the time it shall take to complete the repair and restore the Technical Parameters to their former registered levels.

SDC 1.5.4.3. The SO shall re-optimize the Schedules when, in its reasonable judgment, a compelling need arises. As it may be the case that no notice will be given prior to this re-optimization, it is important that Users always keep the SO informed of any changes of Availability and Technical Parameters relating to their facilities immediately as they occur.

SDC 1.5.4.4. For any permanent revision in Technical Parameters in special circumstances, the User shall get the revision approved from the Authority, based on the impact analysis carried out by SO.

SDC 1.5.5. Default Availability

SDC 1.5.5.1. If an Availability Notice is not received, in total or in part, by the SO in accordance with SDC 1.5.1 to 1.5.3, then the SO will make reasonable efforts to establish contact with the User in question to check whether a complete Availability Notice for a Schedule Day was sent and not received by the SO. For such a case, the Availability Notice for a Schedule Day shall be resubmitted by the relevant User without delay in accordance with the provisions of this section. If no Declaration (or, as the case may be, the data and information necessary to complete the Declaration for a Schedule Day) is received by 1200 hours despite the above reminder, then the SO will use the information provided in the Declaration for the previous Schedule Day to the extent necessary to provide the SO with a complete Declaration. A User which fails to submit a reasonably accurate Declaration or does not submit the Declaration in time shall be considered in non-compliance with the GC. The SO will communicate immediately to NEPRA, with a copy to the Market Operator, any non-compliance with the availability information requirements.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1.5.5.2. If any data submitted or deemed to have been submitted on any particular day in any Availability Notice, or any revision, is inconsistent with any other data in any other such notice, then the most recently submitted data which, if substituted for the inconsistent data, would make the data in such notices consistent, shall apply for the next following Schedule Day or any other values that the SO may reasonably deem appropriate.

SDC 1.6. Generating Units Variable cost

SDC 1.6.1. Requirements

SDC 1.6.1.1. Every two weeks, or any other shorter period to be established by the SO, the Thermal Generators shall submit to the SO a Variable Cost Notice, containing the Variable Operation Costs, as well as the start-up costs of each Generation Unit it operates. Provided that:

(a) For Generators with Legacy Contracts, the obligation of submitting the Variable Cost Notice applies to the SPA. In order to determine the Variable Operating Costs, the SPA shall:

(i) estimate the future price of the fuel or fuels used by each relevant Generating Unit;

(ii) apply the correction formulas which are contained in the Legacy Contracts; and

(iii) add the variable O&M cost, as per relevant NEPRA tariff determinations.

(b) For Generators represented by an Aggregator the obligation of submitting the Variable Cost Notice is assigned to the involved Aggregator.

Until the SO develops the necessary IT tools, capable to receive the Variable Cost Notices with the Variable Operation Costs and startup costs submitted by the Generators, SPA or Aggregators, as the case may be, the requested information shall be uploaded to the Market Operator's IT system and the Market Operator will transfer this information to the SO. The SO will inform on its website when it has the IT systems ready to receive directly these Variable Cost Notice from Generators and the SPA.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

SDC 1.6.1.2. The SO will develop a calendar, detailing the days and time at which the Variable Operation Costs and/or Fuel Costs shall be communicated, in the forms as set out in SDC 1 Appendix-F or such other form as the SO may notify to Users from time to time and publish on its website.

SDC 1.6.1.3. Every two (2) weeks, or any other shorter period to be established by the SO, the Interconnectors shall submit to the SO a Variable Cost Notice, containing the costs associated with the energy imported, for each Interconnection it operates. In case the Interconnector is represented by a Trader, this obligation will apply to the Trader.

SDC 1.6.1.4. Provided that until the SO develops the necessary IT tools, capable to receive the costs associated with the energy imported, by each Interconnector, the requested information shall be uploaded to the Market Operator's IT system and the Market Operator will transfer the information to the SO. The SO will inform in its website when it has the IT systems ready to receive directly the Variable Cost Notice of Interconnectors.

SDC 1.6.1.5. Generators that fall in the category of Co-generation or Captive Generation, may be allowed to declare their Variable Operating Cost equal to zero if the specific process associated with such plant requires it to be dispatched irrespective of its true Variable Operation Cost.

SDC 1.6.2. Contents

SDC 1.6.2.1. Where a Generating Unit is capable of firing on multiple fuels, the Generator, SPA or Aggregator, as the case may be, shall submit a Variable Cost Notice in respect of each designated fuel for its Generating Units, identifying clearly to which particular designated fuel the Variable Cost Notice relates to.

SDC 1.6.2.2. Generators, Aggregators, the SPA and Interconnectors shall employ all reasonable endeavors to ensure that they do not, at any time, submit or allow to remain effective, a Variable Cost Notice declaring costs which are different from those that their relevant facilities have.

SDC 1.6.2.3. The SO will review and assess consistency of the Variable Cost Notices submitted before utilizing them in the development of the IOS. In case the SO has reasonable concerns about the accuracy or correctness of the received information, it will contact the relevant Generator/Aggregator/Interconnector/SPA requesting correction or clarification and confirmation of the submitted data. The relevant Generator/Interconnector/SPA shall correct or confirm the submitted data without delay, providing additional clarification as necessary. For the avoidance of doubt:

(a) The SO shall utilize, for the development of the IOS, in all cases the values in the Variable Cost Notices submitted, even if it has concerns on their adequacy; and

(b) In case the SO has concerns on the validity of the submitted information, the SO shall inform NEPRA regarding the Variable Cost Notice and potential concerns, with copy to the Market Operator.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

SDC 1.6.2.4. CCGT Installations shall also submit in their Variable Cost Notices:

(a) The Variable Operational Cost of each CCGT Unit within each CCGT Complex;

(b) The Variable Operational Cost of each possible combination of gas and steam turbines; and

(c) The Variable Operational Cost of the GGCT Generating Unit as a whole.

SDC 1.6.3. Revisions

SDC 1.6.3.1. If any change arises to the variable costs declared in the notice, Generators, SPA, Aggregators and Interconnectors shall submit to the SO, any revisions to its previously submitted Variable Cost Notice at any time before the submission of the next scheduled Variable Cost Notice.

SDC 1.6.3.2. Based on revisions received, the SO will re-optimize the Schedules when, in its reasonable judgment, a compelling need arises. As it may be the case that no notice will be given prior to this re-optimization, it is important that

Generator/Aggregators/Interconnector/SPA always keep the SO informed of any changes of Variable Cost Notice relating to their facilities immediately as they occur.

SDC 1.6.3.3. If the revised data and information is received by the SO before 1200 hours on the day prior to the relevant Schedule Day, the SO shall take into account the revised Variable Cost Notice in preparing the Indicative Operations Schedule (IOS) for the next day. Otherwise, it will be taken into account in the following IOS.

SDC 1.6.3.4. If the revised data and information is received by the SO after 1200 hours, the SO shall take into account the revised Variable Cost Notice only if it considers relevant to re-Schedules the available resources.

SDC 1.6.4. Non-submission of Variable Operational Cost

SDC 1.6.4.1. If a Variable Cost Notice is not received, in total or in part, by the SO in accordance with SDC 1.6.1 and 1.6.2, then the SO will make reasonable efforts to establish contact with the corresponding Generator/Aggregator/Interconnector/SPA in question to check whether a complete Variable Cost Notice for a Schedule Day was sent and not received by the SO. For such a case, the Variable Cost Notice for a Schedule Day shall be resubmitted by the relevant Generator/Aggregators/Interconnector/SPA without delay in accordance with the provisions of this section. If no information (or, as the case may be, the data and information necessary to complete the Variable Cost Notice for a Schedule Day) is received by 1200 hours of the date stated in the calendar for submission, then the SO will use the information provided in the Variable Cost Notice for the previous period to the extent necessary to permit the SO to develop the IOS. Failure by a Generator/Aggregators/Interconnector/SPA to submit a reasonably accurate Variable Cost Notice or to submit the Variable Cost Notice in time shall be considered non-compliance to the Grid Code. The SO shall notify these non-compliances to NEPRA, with copy to the Market Operator, for evaluation and decision making by the Authority.

SDC 1.7. Preparation of Indicative Operations Schedule

SDC 1.7.1. Each day by 1700 hours, the SO shall develop, by following the process described in this SDC 1, a day ahead IOS on hourly resolution (or a finer time resolution, if considered necessary and notified by the SO in future) for the next Schedule Day using the last valid set of Technical Parameters for the Users as applicable.

SDC 1.7.2. The IOS prepared by the SO shall be developed using state-of-the-art Security Constrained Economic Dispatch Model (the SCED_M) which jointly optimizes the overall costs of the dispatch plus the necessary reserves for the following day, taking into account the security and reliability constraints of the National Grid.

SDC 1.7.3. The SCED_M shall be capable to properly represent, at least:

(a) Forecasted Demand and its geographical distribution;

(b) Declared MW capabilities of Generators under SDC 1.5;

(c) Variable Cost and Start-up Cost of each Generating Unit, as per SCD 1.6;

(d) The availability and cost of energy transfers across any Interconnector;

(e) The Energy limits for Hydro Units/Plants;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

(f) Fuel stocks and fuel constraints of Thermal CDGUs;

(g) In respect of CDGUs, the values of their Technical Parameters registered under this Grid Code and other information submitted under SDC 1.5;

(h) Transmission System and/or Generating Unit/Station Outages;

(i) Transmission network capability and reliability constraints, as per the data registered in PC 3 and other power system studies carried out by the SO;

(j) The minimum Operating Reserve, of different reserve categories, as specified in OC 5;

(k) The inability of any CDGU to meet its full Operating Reserve capability;

(l) Transmission System losses;

(m) If required, Monitoring, Testing and/or Investigations to be carried out, or being carried out, under OC 11; testing to be carried out, or being carried out, at the request of a TNO/User under OC 10 and/or commissioning/acceptance testing prior to connection or re-connection or commissioning under the Connection Code.

SDC 1.7.4. In addition of the parameters listed in SDC 1.7.3, the SO shall incorporate into the SCED_M, the following restrictions:

(a) Compliance with any take-or-pay contractual obligation, provided such obligation is stated in a legacy PPA; and

(b) Compliance with any contractual obligation, explicitly stated in a legacy PPA, approved by the Authority, for which the purchaser is obliged to execute a Dispatch which may be different from the SCED.

The SO shall make its best endeavors to properly represent the obligations incorporated into the Legacy Contracts as dispatch restrictions in the SCED_M and, in the case this wouldn't be possible, through modifications to the IOS as per SDC.

SDC 1.7.5. The restrictions indicated in SDC 1.7.4 shall be formally submitted to the SO by the SPA in a report Dispatch Constraints for Legacy Contracts, with copy to NEPRA. The report shall describe for each Legacy Contract the applicable take-or-pay conditions, if any, and any constraint imposed to the dispatch of the contracted power plant. Should there be any change, the SPA will, as soon as practical, notify the SO and submit an updated report.

SDC 1.7.6. The SO will compile and review the information submitted in the Dispatch Constraints for legacy PPAs and require authorization by the Authority for incorporating these constraints the SCED_M and/or in the IOS.

SDC 1.7.7. The SO will run the SCED_M in two different scenarios:

(a) The valid one, in which all the restrictions indicated in SDC 1.7.3 are adequately represented (this scenario will be used to develop the final IOS); and

(b) A simulation in which the network restrictions, as indicated in 1.7.3 (i) are eliminated. The results of such scenario will be used only for reporting purposes.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

SDC 1.7.8. The SO shall closely evaluate the results provided by the SCED_M and it will be entitled to introduce justified changes in the results of the model, to take into consideration relevant aspects of the National Grid, which it considers are not adequately represented by the mathematical model. These may include among others:

(a) Compliance with applicable environmental standards;

(b) Requirements of reactive power and/or Voltage Control which could not be properly represented in the model;

(c) Compliance with N-1 requirements, as stated in OC 6;

(d) Requirement of primary, secondary or tertiary reserves, which could not be properly represented in the SCED_M; and

(e) Other matters to enable the SO to meet its Licence conditions

SDC 1.7.9. In publishing the Indicative Operation Schedule (IOS), including reserves, for the next day, the SO shall properly document any change introduced to the SCED_M results, clearly indicating the reasons and justification of the required changes produced.

SDC 1.7.10. Publication of Indicative Operations Schedules

SDC 1.7.10.1. The SO shall publish the IOS by 1700 hours each day for the following Schedule Day on its website, including the results provided by the SCED_M and the changes introduced by the SO as per SDC 1.7.8. However, if during the period in which the Indicative Operations Schedule (IOS) is being prepared, Incidents on the System occur which require a substantial amendment to the data being used in preparing the IOS, the SO may extend the timescale for publication of the IOS to the extent necessary as a result of such Incidents. Such Incidents may include, inter alia, the following:

(a) Changes to System conditions that would impose increased risk to the National Grid and, therefore, would require extra Operating Reserve and flexibility;

(b) Unpredicted Transmission System Outages connecting Generating Units;

(c) Unpredicted Outage of a Generating Unit/equipment which imposes increased risk to the National Grid;

(d) Severe weather conditions imposing high risk to the total System Demand;

(e) A Total or Partial Shutdown exists in the System.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

SDC 1.7.10.2. The IOS is intended to provide a guide to the expected output requirements, including reserves from Users and shall not be construed as Dispatch Instructions or orders by itself.

SDC 1.7.10.3. The SO may inform Generating Units before the issuance of the IOS for the Schedule Day to which the Instruction relates, if the length of Notice to Synchronize requires the Dispatch Instruction to be given at that time. When the length of the time required for Notice to Synchronize is such that the Generating Unit will not be able to meet the indicative Synchronizing time in the IOS or a subsequent Dispatch Instruction, the Generator must inform the SO without delay.

SDC 1.7.10.4. The SO shall also maintain a log of the SCED model as well as all input parameters used.

SDC 1.7.11. Content of Indicative Operations Schedules

The information contained in the IOS will indicate, where appropriate, on an individual Generator, Energy Storage Unit, Demand Side Unit, and/or Interconnector basis, the period and MW output (at the Connection Point/Delivery Point) for which it is Scheduled. In the case of a CDGU which is capable of firing on multiple fuels, it will also indicate the fuel for which it is scheduled. If no fuel is contained in the IOS, then the most economical fuel available shall be treated as having been indicated.

SDC 1.7.12. Minimum Demand Regulation (MDR)

For the reliable, secure, and safe operation of the Transmission System, it is imperative that all Synchronized CDGUs and/or Controllable Solar, Wind & ESUs shall at all times be capable of reducing their MW Output to allow a sufficient regulating margin for adequate Frequency Control. The SO will monitor the MW Output data of the IOS against forecast of System Demand to see whether the level of regulation for any period is sufficient, and may take any shortfall into account in Scheduling and Dispatch process.

SDC 1.7.13. Notice of Inadequate Operating Margin (NIOM)

SDC 1.7.13.1. The SO will monitor the output data of the IOS against forecast Demand to see whether the anticipated level of the Operating Reserve for any period is insufficient.

SDC 1.7.13.2. Where this level for any period is anticipated to be insufficient, the SO will indicate through a Notification of Inadequate Operating Margin (NIOM) published on its website (the form of which will be determined by the SO). The NIOM will indicate the nature and extent of the insufficiency and the period for which the insufficiency is anticipated. The SO will make its best efforts to address the situation, and take measures to restore adequate reserve margins, including modifying the IOS.

SDC 1.7.13.3. The monitoring of the Operating Reserves by the SO shall be regular and revised NIOMs may be sent out from time to time. These shall reflect any changes in the declared Availability which have been notified to the SO and shall reflect any Demand Control which has also been notified. They shall also reflect generally any changes in the forecast Demand and the relevant Operating Reserve.

SDC 1.7.14. Special Actions

SDC 1.7.14.1. The IOS may be followed by a list of Special Actions (either pre-Fault or post-Fault) that the SO may request a User to take in respect of a procedure to be followed by a User in order to maintain the integrity and quality of the Transmission System in accordance with the SO operational GCOPs.

SDC 1.7.14.2. For a Generator, such Special Actions may involve a load change or a change of required Notice to Synchronize, in a specific timescale on individual or group of Generating Units basis.

SDC 1.7.14.3. For a DNO, these Special Actions may involve load transfers between the Connection Points or arrangements for Demand Control by manual or automatic means.

SDC 1.7.15. Data Requirements

SDC 1.7.15.1. SDC 1 Appendix-A lists, the Technical Parameters for which values are to be supplied by a User in respect of each of its CDGUs, ESUs, Demand Side Units and/or Aggregated Generating Units (if required by the SO) either under the standard planning data under PC, or CC or this SDC 1. Additional information may be required by the SO when necessary.

SDC 1.7.15.2. SDC 1 Appendix-B sets out the form for declaration of Availability.

SDC 1.7.15.3. SDC 1 Appendix-C sets out the form for revision in Availability.

SDC 1.7.15.4. SDC 1 Appendix-D sets out the form for revision in Technical Parameters.

SDC 1.7.15.5. SDC 1 Appendix-E provides VRE forecast performance criteria.

SDC 1.7.15.6. SDC 1 Appendix-F sets out the form for declaration of the Variable Costs.

SDC 1.7.15.7. SDC 1 Appendix-G sets out the declaration of the legacy PPAs dispatch restrictions.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

SDC 1. Appendix – A

TECHNICAL PARAMETERS

Where more than one parameter applies, this is indicated by adding a number at the end of the parameter. E.g. De-loading Rate 1, De-loading Rate 2, etc.

Technical Parameter	CDGU			ESU		Inter-connectors	TNOs	Aggr. Gen.
	Thermal	Hydro	VRE Gen.	Gen.	Demand			
Block Load Cold	✓	✓	✓	✓				✓
Block Load Hot	✓							✓
Block Load Warm	✓							✓
Charging Capacity				✓	✓			
Cycle Efficiency				✓				
Demand Side Unit MW Availability								
Demand Side Unit MW Response Time								
Demand Side Unit Notice Time								
De-load Break Point	✓	✓	✓	✓				
De-Loading Rate	✓	✓	✓	✓				
Dwell Time Up	✓	✓	✓	✓				
Dwell Time Down	✓	✓	✓	✓				
Dwell Time Up Trigger Point	✓	✓	✓	✓				
Dwell Time Down Trigger Point	✓	✓	✓	✓				
End Point of Start Up Period	✓	✓	✓	✓				
Energy Limit		✓		✓				
Forecast Minimum Output Profile			✓	✓	✓			
Forecast Minimum Generation Profile	✓	✓	✓	✓				
Load Up Break Point Cold	✓	✓	✓	✓				
Load Up Break Point Hot	✓							
Load Up Break Point Warm	✓							

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Loading Rate Cold	✓	✓	✓	✓				
Loading Rate Hot	✓							
Loading Rate Warm	✓							
Max Ramp Down Rate	✓	✓	✓	✓		✓		
Max Ramp Up Rate	✓	✓	✓	✓		✓		
Maximum Down Time	✓	✓	✓	✓		✓		✓
Minimum Down Time	✓	✓	✓	✓		✓		✓
Maximum Generation/Registered Capacity	✓	✓	✓	✓		✓		✓
Maximum On Time	✓	✓	✓	✓		✓		✓
Minimum On Time	✓	✓	✓	✓		✓		✓
Minimum Off Time	✓	✓	✓	✓		✓		✓
Maximum Storage/Charge Capacity				✓	✓			
Minimum Storage/Charge Capacity				✓	✓			
Minimum Generation	✓	✓	✓	✓		✓		✓
Off to Generating Time				✓	✓			
Off to Spin Pump Time				✓	✓			
(Other relevant technical parameters)	✓	✓	✓	✓	✓	✓	✓	✓
Pumping capacity				✓	✓			
Ramp Down Break Point	✓	✓	✓	✓		✓		✓
Ramp Down Rate	✓	✓	✓	✓		✓		✓
Ramp Up Break Point	✓	✓	✓	✓		✓		✓
Ramp Up Rate	✓	✓	✓	✓		✓		✓
Short Term Maximization Capability	✓	✓	✓	✓		✓		✓
Short Term Maximization Time	✓	✓	✓	✓		✓		✓
Soak Time Cold	✓	✓	✓	✓				
Soak Time Hot	✓							
Soak Time Warm	✓							
Soak Time Trigger Point Cold	✓	✓	✓	✓				

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Soak Time Trigger Point Hot	✓							
Soak Time Trigger Point Warm	✓							
Spin Pump to Pumping Energy Time					✓			
Synchronizing Time Cold	✓	✓	✓	✓				✓
Synchronizing Time Hot	✓							✓
Synchronizing Time Warm	✓							✓
Target Charge Level Percentage				✓	✓			
Start of Restricted Range (Forbidden Zone)	✓	✓	✓	✓				✓
End of Restricted Range (Forbidden Zone)	✓	✓	✓	✓				✓

A. For each CDGU:

1. in the case of steam turbine CDGUs, synchronizing times for the various levels of warmth; (Hot, Warm and Cold)
2. in the case of gas turbine CDGUs, the time from initiation of a start to achieving dispatched load.
3. Basic data:
    a. Governor Droop (%);
    b. Sustained Response Capability.
4. Available reactive power generation both leading and lagging, in MVAR;
5. The MW and MVAR capability limits within which the CDGU is able to operate as shown in the relevant Generator Performance Chart;
6. Maximum number of changes to the dispatched fuel per 24-hour period;
7. Maximum quantity of oil in "ready-use tanks" and associated pipe work;
8. Maximum number of changes to the designated fuel per 24-hour period;
9. Minimum notice to change the designated fuel;
10. Fuel transition time/changeover for each CDGU;
11. Maximum number of on load cycles per 24-hour period, together with the maximum load increases involved;
12. Settings of the Unit Load Controller for each CDGU;
13. In the case of gas turbine CDGUs only, the declared peak capacity;
14. In the case of a Gas Turbine Unit, only the data applicable to Gas Turbine Units should be supplied;
15. Ambient temperature curves.

B. For the Generator of which the CDGU forms part:

1. Time between synchronizing different CDGUs in a Generator taking account of actual off-load periods for the various levels of warmth; and

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

2. Time between de-synchronizing different CDGUs in a Generator.

C. Additional Data items required:

1. Heat Rate Curves, Turbine Efficiency, Power curves for VRE
2. GT to ST Ratios
3. Hydrology Tables (Volume vs Level, Head vs. Capability, etc.)
4. Declared Primary Operating Reserve
5. Declared Secondary Operating Reserve
6. Declared Tertiary Operating Reserve
7. Minimum MW for Primary Operating Reserve
8. Minimum MW for Secondary Operating Reserve
9. Minimum MW for Tertiary Operating Reserve
10. Primary Operating Reserve Decrement Rate
11. Secondary Operating Reserve Decrement Rate
12. Tertiary Operating Reserve Decrement Rate
13. Black Start Capability (Yes/No)
14. Declared Reactive Power Consumption
15. Declared Reactive Power Production
16. Any other Data and Information required by SO for preparing IOS

D. CCGT Installation Matrix

This matrix is a look up table determining which CCGT Unit will be operating at any given MW Dispatch level. This information will be applied for planning purposes and for scheduling, Dispatch and control purposes as covered in the SDC unless by prior agreement with the SO.

As an example of how the matrix might be filled out, consider a sample unit with a total capacity of 400 MW made up of two 150 MW combustion turbines and one 100 MW steam turbine. In this case, the following ranges might be specified:

0 MW to 50 MW	GT1
50 MW to 170 MW	GT1 and ST
170 MW to 400 MW	GT1 and GT2 and ST

For Example:

Please insert MW ranges and tick the boxes to indicate which units are synchronized to deliver each MW range at the following atmospheric conditions: Temperature 10°C, Pressure 1.01 bar and 70% Humidity.

CCGT Installation	CCGT Unit Available					
Output Usable	1st GT	2nd GT	3rd GT	1st ST	2nd ST	3rd ST
	Output Usable					
Unit MW Capacity→	e.g. 150	150	-	100	-	-
Total MW Output Range↓						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1. Appendix – B

AVAILABILITY NOTICE

Daily Declaration of Available Capacity
From: __for example: Thermal Plant___
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ________________ Dated: ________________

For the Day ____________ (DD/MM/YYYY)

		Available Capacity on Fuel 1 MW			Available Capacity on Fuel 2 ... MW		
Hour	**Estd. Temp: C°**	**Unit 1**	**Unit 2**	**Unit 3 ...**	**Unit 1**	**Unit 2**	**Unit 3 ...**
00-01							
01-02							
02-03							
03-04							
04-05							
05-06							
06-07							
07-08							
08-09							
09-10							
10-11							
11-12							
12-13							
13-14							
14-15							
15-16							
16-17							
17-18							
18-19							
19-20							
20-21							
21-22							
22-23							
23-24							

Signature____________________________Name____
Position: Commercial Engineer/Control Engineer (delete as applicable)
Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

AVAILABILITY NOTICE

Daily Declaration of Available Capacity
From: for example: HVDC
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ________________ Dated: ________________

For the Day ____________ (DD/MM/YYYY)

Hour	Estd. Temp: C°	Available Capacity, MW	Comments/Notes
00-01			
01-02			
02-03			
03-04			
04-05			
05-06			
06-07			
07-08			
08-09			
09-10			
10-11			
11-12			
12-13			
13-14			
14-15			
15-16			
16-17			
17-18			
18-19			
19-20			
20-21			
21-22			
22-23			
23-24			

Signature____________________________Name____

Position: Commercial Engineer/Control Engineer (delete as applicable)

Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

AVAILABILITY NOTICE

Daily Declaration of Available Capacity
From: for example: Hydro Plants
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ________________ Dated: ________________

For the Day _____________ (DD/MM/YYYY)

				Declared Available Capacity, MW				
Hour	**Head m**	**Inflow Cusecs or Cumecs**	**Water Indent Cusecs or Cumecs**	**Unit-1**	**Unit-2**	**Unit-3**	**Unit-4**	**Unit-5...**
00-01								
01-02								
02-03								
03-04								
04-05								
05-06								
06-07								
07-08								
08-09								
09-10								
10-11								
11-12								
12-13								
13-14								
14-15								
15-16								
16-17								
17-18								
18-19								
19-20								
20-21								
21-22								
22-23								
23-24								

Signature_____________________________Name____

Position: Commercial Engineer/Control Engineer (delete as applicable)

Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1. Appendix – C

NOTIFICATION OF REVISED AVAILABILITY NOTICE

Declaration of Revised Available Capacity
From: _for example: Thermal Plants
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ____________________ Dated: __________________

For the Day _____________ (DD/MM/YYYY)

				Revised Declared Available Capacity, MW			Comments/Notes
Hour	**Estd. Temp: °C**	**Declared Available Capacity**	**Estd. Temp: °C**	**Revision-1**	**Revision - 2**	**Revision - 3…**	
00-01	-	-					
01-02							
02-03							
03-04							
04-05							
05-06							
06-07							
07-08							
08-09							
09-10							
10-11							
11-12							
12-13							
13-14							
14-15							
15-16							
16-17							
17-18							
18-19							
19-20							
20-21							
21-22							
22-23							
23-24							

Signature____________________________Name_____________________________________

Position: Commercial Engineer/Control Engineer (delete as applicable)

Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Declaration of Revised Available Capacity
From: for example: Hydro Plants
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ____________________ Dated: __________________

For the Day _____________ (DD/MM/YYYY)

				Revised Declared Available Capacity, MW			Comments/Notes
Hour	**Declared Head m**	**Declared Inflow**	**Water Indent**	**Revision-1**	**Revision - 2**	**Revision - 3...**	
00-01	-	-					
01-02							
02-03							
03-04							
04-05							
05-06							
06-07							
07-08							
08-09							
09-10							
10-11							
11-12							
12-13							
13-14							
14-15							
15-16							
16-17							
17-18							
18-19							
19-20							
20-21							
21-22							
22-23							
23-24							

Signature____________________________Name____
Position: Commercial Engineer/Control Engineer (delete as applicable)
Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Declaration of Revised Available Capacity – Temperature/Hydrology Adjustments
From: for example: HVDC or Thermal Plants
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ____________________ Date: ________________

For the Day _____________ (DD/MM/YYYY)

				Revised Declared Available Capacity (MW)	Comments/Notes
Hour	**Declared Estimated Temp. °C/Head/Inflow/Indent**	**Declared or Revised Declared Available Capacity (MW)**	**Revised Temp. °C/Head/Inflow/Indent**	**Adjusted Declared Available Capacity (MW)**	
00-01	-	-			
01-02					
02-03					
03-04					
04-05					
05-06					
06-07					
07-08					
08-09					
09-10					
10-11					
11-12					
12-13					
13-14					
14-15					
15-16					
16-17					
17-18					
18-19					
19-20					
20-21					
21-22					
22-23					
23-24					

Signature______________________________Name____

Position: Commercial Engineer/Control Engineer (delete as applicable)

Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Notes

1. All Availabilities shall be expressed in MW.
2. For each CDGU, an Availability figure must be entered for the first settlement period. Where the CDGU is completely unavailable, a zero shall be entered. Thereafter, an Availability figure shall only be entered where the Availability for the CDGU is changed from the previously expressed value.

3. This Availability Notice shall include all planned Outages agreed with SO and all Unplanned/Forced Outages already notified to SO. It shall not include Unplanned/Forced Outages not yet notified to SO unless the appropriate Outage Notice is attached.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

SDC 1. Appendix – D

TECHNICAL PARAMETERS REVISION NOTICE

[USERNAME] declares that the under mentioned CDGUs/Demand Sites are presently unable to perform to the characteristics stated in Connection/Planning Code and that the affected characteristics are mentioned below with revised values that should be used for the purposes of Scheduling and Dispatch.

				Time		
Unit ID	**Technical Parameter Affected**	**Registered Value**	**Revised Value**	**From**	**To**	**Reason**

Examples

1	Governor Droop	4%	4.5%	0000	2400
2	Loading Rate after Hot Start 300+ MW	6.0	2.5	1800	2200

This notice is applicable to schedule day: ______________________________

Signature: ______________________________

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1. Appendix – E

VRE Forecast Errors

For hour-ahead intraday generation forecasts, the desired forecast accuracy, measured in terms of P95 of the absolute percentage error is 10%.
For day-ahead generation forecasts, the desired forecast accuracy is P95 of 15%.

Minimum Metric for Forecasting Error Calculation:

P95 Error Computation

Step 1:

$$APE_t = \left| \frac{(A_t + X_t) - F_t}{C_t} * 100 \right|$$

where APE_t is the absolute percentage error,
A_t is Actual net generation in MW,
X_t is curtailment in MW due to transmission congestion or other reasons,
F_t is forecast in MW,
C_t is the available capacity in MW, and
t is a time block.

Step 2:

- Daily P95 - Create a daily time series of {$APEt$, t=1 to 24}, and compute the daily P95 using this time series
- Monthly P95 - Create a monthly time series of {$APEt$, t=1 to 24$*n$}, where n is the number of days in the month. The monthly P95 is computed using this time series.
- Annual P95 - Create the yearly time series of {$APEt$, t=1 to 24*365}. The annual P95 is computed using this time series.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1. Appendix – F

VARIABLE COST NOTICE

For the weeks starting at [DD/MM/YYYY] and ending at [DD/mm/YYYY]

[To be used by Generators which do not have registered their Heat Rate information as per PC 3]

Valid only for Generators connected to the Transmission System before the approval date of this Grid Code [xxxx]

Bi Weekly Declaration of Variable Operational Cost
From: _[Thermal Plant xxxx] – [Generating Unit yyy]
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ________________ Dated: ______________

Estimated Fuel Prices	Rs/kWh
Fuel 1	
Fuel 2	

Load Level	Operational Cost (Fuel 1)	Operational Cost (Fuel 2)	Variable O&M Cost	Total Variable Cost [Rs/kWh]	
	Rs/kWh	Rs/kWh	Rs/kWh	Fuel 1	Fuel 2
Minimum Generation (Load Point 1)					
Load Point 2 . . .					
Load Point n					
100 % of Max. Capacity					

Startup Costs	Fuel 1	Fuel 2
	Rs	Rs
Cold Start		
Warm Start		
Hot Start		

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Notes: The Fuel Costs shall be estimated by the Generator/SPA, as it corresponds.

The Operational Costs shall be determined based on the formulas contained in the relevant PPA/determination of the Authority, as applicable.

The variable O&M Costs shall be those approved by the Authority in its latest tariff determination for the relevant Generator.

The startup costs shall be those contained in the relevant PPA/determination of the Authority, as applicable, duly corrected by the estimated price of fuel.

Signature____________________________Name____

Position: Commercial Engineer/Control Engineer (delete as applicable)

Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

VARIABLE COST NOTICE

For the weeks starting at [DD/MM/YYYY] and ending at [DD/mm/YYYY]

[To be used by Generators which have registered their Heat Rate information as per PC 3]

Generators connected to the Transmission System after [xxxx]

Bi Weekly Declaration of Variable Operational Cost
From: [Thermal Plant xxxx] – [Generating Unit yyy]
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ________________ Dated: ______________

	Estimated Fuel Prices [Rs/kWh]	VO&M Variable Costs [Rs/kWh]
Fuel 1		
Fuel 2		

Startup Costs	Fuel 1	Fuel 2
	Rs	Rs
Cold Start		
Warm Start		
Hot Start		

Notes: The Fuel Costs shall be estimated by the Generator
The Variable Operational Costs shall be calculated by the SO, based on the fuel costs submitted and the Heat Rate registered in the SO Database

The startup costs shall be determined by the Generator.

Signature______________________________Name____
Position: Commercial Engineer/Control Engineer (delete as applicable)
Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

VARIABLE COST NOTICE

For the weeks starting at [DD/MM/YYYY] and ending at [DD/mm/YYYY]

[To be used by Interconnectors (in case such a format is not provided in the relevant Interconnection Agreements]

Biweekly Declaration of Variable Operational Cost

From: [Interconnector xxxx]
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ________________ Dated: ______________

	Variable Operational Cost [Rs/kWh]
From [xxx1] to [yyy1] MW	
From [xxx2] to [yyy2] MW	
From [xxx3] to [yyy3] MW	
Above [yyy3] MW	

Signature____________________________Name____
Position: Commercial Engineer/Control Engineer (delete as applicable)
Date/Time of issue:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 1. Appendix – G

For the period starting at [DD/MM/YYYY] and ending at [DD/mm/YYYY]

[To be used by Generators contracted or by the SPA for Legacy PPAs]

We here by inform you that the Power Purchase Agreement indicated below, contain clauses which may either:

a) Limit the liberty of the System Operator in developing a Security Constrained Economic Dispatch, and/or
b) May have significant influence in the amount of money to be paid by the Purchaser, if certain dispatching conditions are not fulfilled.

Identification of the Power Purchase Agreement and the conditions agreed are stated below:

Identification of the PPA	
Name of the Seller	
Name of the Purchasers	
Date of signature	
Date of approval by the Authority	
Date of Commercial Operation	
Duration of the contract	

Conditions which restrict, or may restrict, the dispatch performed by the SO

Type of restriction	Description	Economic Implication
a) Take of pay conditions	*[clearly describe the take-or-pay conditions, indicating maximum values, minimum values and the periods over such maximum and minimum values will be calculated]*	*[Indicate the additional cost or penalties the Purchaser shall afford if the requirement is not accomplished]*
b) Clauses which may restrict the liberty of the SO to decide the dispatches.	*[clearly describe the any condition which may restrict the possibility of the SO to develop yearly, weekly, or daily dispatches it considers more economical. I.e. clauses which require agreements before implementing the dispatch, requirements of dispatch communications larger than one day, minimum dispatch times, etc.]*	*[Indicate the additional cost or penalties the Purchaser shall afford if the requirement is not accomplished]*
c) Any other clause which may be known by the SO before deciding about the most economical dispatch.		*[Indicate the additional cost or penalties the Purchaser shall afford if the requirement is not accomplished]*

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Signature____________________________

Name______________________________

Seller/Purchaser ____________________

Position: __________________________

Date/Time of issuing: ________________

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

SDC 2. DISPATCH AND CONTROL

SDC 2.1. Introduction

In real time operation, the SO shall Dispatch and Control the available Supply and Demand resources to serve the power and energy demand on the National Grid. This Scheduling and Dispatch Code (SDC 2) defines the roles and responsibilities of the SO and other relevant Code Participants in this respect and also sets out the procedure that the SO will follow to issue Dispatch Instructions to different TNOs/Users pursuant to the "Indicative Operations Schedule" developed in SDC 1.

SDC 2.2. Objectives

SDC 2.2.1. The objectives of SDC 2 are to establish the process, guidelines and procedures:

(a) to issue Dispatch Instructions by the SO to Generators, ESUs in respect of their supply or demand, TNO/DNOs, and/or Interconnector; and

(b) to enable (as far as practicable), the SO to match Supply and Demand in real time at the minimum achievable variable cost, while maintaining adequate Operating Reserves to ensure the Reliability, Security, and Safety of the Transmission System.

SDC 2.2.2. The SO will use SCED principles to achieve the objectives of this SDC 2.

SDC 2.3. Scope

SDC 2 applies to the SO, and:

(a) Centrally-Dispatched Generating Units:

(i) Conventional Generator (thermal, hydro, nuclear, bagasse, and concentrated solar power Generators, etc.) directly connected to the Transmission System;

(ii) VRE Generator (run-of-the-river hydro, solar, and wind, etc.) directly connected to the Transmission System; and

(b) Conventional or VRE Generators, not directly connected to the Transmission System, which the SO considers, due to its particular characteristics or network Connection Point, to be under its control. The SO shall publish on its website a list of such Generating Units along with the relevant justifications;

(c) Energy Storage Units with respect to their supply to or demand on the Transmission System;

(d) Transmission Network Operators;

(e) Interconnectors;

(f) Distribution Network Operators;

(g) Transmission Connected Consumers; and

(h) Embedded generators whether represented through some Aggregators or any other arrangement (if required by SO). The Aggregators to which this Grid Code will apply shall be determined as per Applicable Documents.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

SDC 2.4. **Procedure**

SDC 2.4.1. **Information to be Used**

SDC 2.4.1.1. The SO shall assess as to which User to Dispatch, based on the real time System conditions and factors as listed in SDC 1.7.3, SDC 1.7.4 and SDC 1.7.8.

SDC 2.4.1.2. Except as provided below, the SO shall Dispatch the Scheduled resources strictly in accordance with those specified in the IOS developed under SDC 1.

SDC 2.4.1.3. Additional factors which the SO shall also take into consideration when issuing Dispatch Instructions are the effect of those Users which have not partially or fully complied with the Dispatch Instructions of the SO, deviations of VRE Generation from the forecasts, or Special Actions (including Demand Control) pursuant to SDC 2.5.9, Testing or Investigations carried out under OC 11, unforeseen outages, and variation between forecast and actual Demand on the System.

SDC 2.5. **Dispatch Instructions**

SDC 2.5.1. **Introduction**

SDC 2.5.1.1. Dispatch Instructions relating to a Schedule Day will normally be issued at any time during the period beginning immediately after publication of the IOS. The SO may, however, at its discretion, issue Dispatch Instructions to a User prior to the publication of the IOS, if considered necessary.

SDC 2.5.1.2. A Dispatch Instruction may be subsequently cancelled or changed as per real time System conditions.

SDC 2.5.1.3. Dispatch Instructions to Users will always be issued to the relevant Control Facility.

SDC 2.5.1.4. The SO will issue Dispatch Instructions directly to a:

(a) Generator for the Dispatch of its Generating Units;

(b) Aggregator in case of Embedded Generators;

(c) TNO/DNO in respect of Demand Control (as applicable);

(d) ESUs in respect of their supply to or demand on the Transmission System; and/or

(e) Interconnector for the Dispatch of its Interconnector transfers.

SDC 2.5.1.5. The SO may issue Dispatch Instructions for any Facility of the User which has been declared Available in an Availability Notice even if that Facility was not included in the IOS.

SDC 2.5.1.6. Some examples of forms of and terms to be used by the SO in issuing Instructions are set out in the Appendix of this SDC 2.

SDC 2.5.2. **Dispatch Instruction to Generators/Interconnectors**

Generator and Interconnectors, subject to Interconnection Agreement as applicable, shall adhere to the following:

(a) Dispatch Instruction to a Conventional Generator for a specific Generating Unit and/or Interconnector may involve a change in the Active Power output, a change in the Reactive Power output, Synchronizing and De-

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

synchronizing time (if appropriate), a change of the mode of operation or fuel, or to provide one or more of the System Services.

(b) Dispatch Instruction to VRE Generators may involve a curtailment/decrease or increase (subject to their primary resource availability) in the Active Power output, or to provide one or more of the System Services. In case of run-of-the-river hydro plants, the SO will use the results of the SCED Model as well as real-time conditions to determine whether the plant shall be operated on constant-level mode or whether the pondage will be used for peaking/Frequency Control. However, the applicable limits of pond operation and environmental/irrigation obligations shall be fulfilled by the SO in its dispatch instructions.

(c) Dispatch Instruction to an Interconnector may involve, where applicable, a change in the Active Power flow (quantum and direction), a change in the Reactive Power exchange, Synchronizing and De-synchronizing time, a change of mode of operation, a change of the control mode, adjustment of control mode parameters and associated set points, and/or to provide one or more of the System Services while considering the relevant Agreements.

(d) As Demand and Availability of resources varies during real-time operation, the SO will adjust Generating Unit/Interconnector MW level by using an economic loading order (as applicable) by following the principles of SCED, taking into account, in the case of Interconnectors, the provisions in the relevant Interconnection Agreements.

(e) Dispatch Instruction issued shall always be in accordance with Technical Parameters but shall take into account any temporary changes to these Parameters notified to the SO under SDC 1.5.4.2.

(f) A Dispatch Instruction issued by the SO to a Generator/Interconnector may be issued through Electronic Interface, verbally by phone, or by fax in accordance with the procedures detailed in OC 9.

(g) A Dispatch Instruction must be formally acknowledged immediately by the Generator in respect of its Generating Units or by the Interconnector by using the Electronic Interface, or in its absence, by telephone or fax, or a reason given to the SO immediately for non-acceptance or partial acceptance. The reason for non-acceptance may only be on Safety grounds (relating to personnel or Plant) or if the Dispatch Instruction is not considered valid by the Generator/Interconnector as further detailed in (h) below.

(h) For a Dispatch Instruction to be valid, it must observe the limits of Availability, Ancillary Services capability and Technical Parameters, as properly Declared to the SO in accordance with the provisions of this SDC relevant to the time and period to which the Dispatch Instruction relates, subject to System Emergency Condition as laid down in SDC 2.5.2.5.

(i) In the event that two or more CDGUs/Interconnectors have the same "Variable Operating Cost" and the SO is unable to differentiate on the basis of the factors identified in SDC 1.7.3, SDC 1.7.4 and SDC 1.7.8, the SO shall

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

select for Dispatch first the Generator/Interconnector which in the SO's judgement is the most appropriate under the circumstances and prevailing conditions of the Schedule Day.

(j) When the identical CDGUs mentioned in (i) above are at the same Site, the Generator may notify the SO as to the preferred Unit to Dispatch.

(k) When complying with Dispatch Instructions for a CCGT station, a Generator will operate its CCGT Units in accordance with the applicable CCGT Installation Matrix.

(l) In the event that in carrying out the Dispatch Instruction, an unforeseen problem arises, caused on Safety grounds (relating to personnel, property, or Plant), the Generator/Interconnector will notify the SO by telephone without delay.

SDC 2.5.2.1. **Synchronizing and De-Synchronizing Instructions**

SDC 2.5.2.1.1. Except in an emergency or by prior agreement, Synchronization or De-synchronization of a CDGU/Interconnector with or from the System shall only be carried out as a result of a Dispatch Instruction issued by the SO. Provided that all instructions by the SO to Interconnectors shall be in accordance with the relevant Interconnection Agreement, if and as applicable.

SDC 2.5.2.1.2. The SO shall determine the required Synchronizing and De-Synchronizing times for the CDGUs/Interconnector in accordance with the times Declared in their Technical Parameters and will issue Dispatch Instructions to Generators/Interconnectors accordingly. With the prior mutual consent of the SO and the Generator/Interconnector, the specified Synchronizing or De-synchronizing time in a Dispatch Instruction may vary from the Declared Technical Parameters, if it is practicable for the CDGU/Interconnector and acceptable to the SO.

SDC 2.5.2.1.3. If a Dispatch Instruction to a specific CDGU/Interconnector does not contain a MW level to be achieved, then it shall be assumed that the Dispatch Instructions is to set the MW level (following Synchronization) up to the Minimum Stable Level of the CDGU/Interconnector (as applicable).

SDC 2.5.2.1.4. Where the SO issues a Synchronizing time to a Generator/Interconnector for a specific Generating Unit/Interconnector, and the Generator/Interconnector finds that the Generating Unit/Interconnector will not be able to Synchronize within (±10) ten minutes of the instructed Synchronizing time, the Generator/Interconnector will immediately inform the SO of the situation and provide a new estimate of the Synchronizing time.

SDC 2.5.2.1.5. When a CDGU/Interconnector fails to Synchronize or trips before reaching Minimum Stable Level at the time mentioned in the Dispatch Instruction to Synchronize (where applicable), then the CDGU/Interconnector will not Synchronize with the System until a new Dispatch Instruction is issued by the SO for this purpose.

SDC 2.5.2.1.6. In the case of a CDGU capable of firing on different fuels, the Dispatch Instruction will also specify the fuel to be used by the Generator, subject to fuel availability. The Generator will only be permitted to change Fuels with the SO's prior consent.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

SDC 2.5.2.1.7. For a CCGT, an instruction may specify the Cycle Operating Mode and/or an Instruction to Dispatch one or more of the CCGT Units in Open Cycle Mode. The Generator must then ensure that its CCGT Station achieves the new operating mode, without undue delay and in accordance with that CCGT's declared Availability and Technical Parameters.

SDC 2.5.2.1.8. The instruction to synchronize a CDGU with the System, unless otherwise specified by the SO at the time of giving the Dispatch Instructions, shall be deemed to include an automatic instruction of Operating Reserve, the level of which is to be provided in accordance with the applicable provisions of OC 5.4.

SDC 2.5.2.2. **Dispatch of Active Power**

SDC 2.5.2.2.1. Based on the IOS, on System conditions, and on other factors as may arise from time to time, the SO will issue Dispatch Instructions to a Generator in relation to a specific CDGU or to an Interconnector, which is synchronized with the System, to adjust its Active Power output at a Target Frequency.

SDC 2.5.2.2.2. The SO shall determine the required times for achieving the Instructed MW levels of the CDGUs/Interconnectors in accordance with their declared Technical Parameters and will issue Dispatch Instructions to Generators/Interconnectors accordingly.

SDC 2.5.2.2.3. On receiving a Dispatch Instruction to change the level of Active Power, the Generating Unit/Interconnector must, without any delay, adjust the MW level of the CDGU/Interconnector to achieve the new target within that Generating Unit's/Interconnector's Declared Technical Parameters.

SDC 2.5.2.2.4. A Generating Unit/Interconnector shall be deemed to have complied with a Dispatch Instruction when it achieves a MW level within the allowable tolerance (as per its Declared Technical Parameters) of the Instructed MW level and within the time calculated for the change as per its Declared Technical Parameters.

SDC 2.5.2.2.5. The adjustment of Active Power level of a CDGU/Interconnector operating in a Frequency Sensitive Mode for System Frequency other than an average of 50 Hz, shall be made in accordance with the current declared value of the droop setting of the Governor Droop for Conventional Generating Units/HVAC Interconnectors, or Active Power Frequency Regulation for VRE Generating Units, or Frequency Limit Control for HVDC Interconnectors.

SDC 2.5.2.2.6. The Dispatch Instructions for Active Power at the Connection/Delivery Point will be made with due regard to any resulting change in Reactive Power capability and may include instruction for reduction in Active Power generation to enable an increase in Reactive Power capability.

SDC 2.5.2.2.7. In addition to instructions relating to the Dispatch of Active Power, Dispatch Instructions (unless otherwise specified by the SO at the time of giving the Dispatch Instructions) shall be deemed to have included an automatic instruction of Primary Operating Reserve, and Voltage/reactive support, the level of which is to be provided in accordance with OC 5 and system stability control facilities (such as Power System Stabilizer, Power Oscillation Damper etc.) as specified in Connection Code.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

SDC 2.5.2.3. **Dispatch of Reactive Power**

SDC 2.5.2.3.1. To ensure that a satisfactory Voltage profile is maintained in the System and that sufficient Reactive Power reserves are maintained, the SO may issue Dispatch Instructions in relation to Reactive Power (with due regard to the Technical Parameters).

SDC 2.5.2.3.2. MVAR output: Where a Generating Unit/Interconnector is instructed to achieve a specific output (at instructed MW level), the Generator/Interconnector shall achieve that output within a tolerance of (±2%) two percent or one (±1) MVAR (or such other figure as may be agreed with the SO) by:

(a) tap changing on the Generating Unit step-up transformer;

(b) adjusting the set point of the Generating Unit's Automatic Reactive Power Regulator or Automatic Voltage Regulator;

(c) operation of any other reactive compensation equipment available on Generation Site/Interconnector; or

(d) Q-Control mode of HVDC Interconnector (manual or automatic).

SDC 2.5.2.3.3. Once this has been achieved, the Generator/Interconnector will not tap change or adjust the set point of the Generating Unit's Automatic Voltage Regulator or change Q-Control parameters (as applicable) without prior consent of the SO, on the basis that MVAR output will be allowed to vary with System conditions.

SDC 2.5.2.3.4. Where a Generating Unit/Interconnector is instructed to a specific target Voltage (at target MW level), the Generator/Interconnector shall achieve that target within a tolerance of one (±1) kV (or such other figure as may be agreed with the SO) by:

(a) tap changing on the Generating Unit step-up transformer;

(b) adjusting the set point of the Generating Unit's Automatic Voltage Regulator;

(c) operation of any other reactive compensation equipment available on Generation/Interconnector Site; or

(d) U-Control mode of HVDC Interconnector (manual or automatic).

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

SDC 2.5.2.3.5. Under normal operating conditions, once this target Voltage level has been achieved, the Generators/Interconnectors will not tap change or adjust terminal Voltage or change U-Control parameters (as applicable) again without the prior consent of the SO.

SDC 2.5.2.3.6. Maximum MVAR production ("maximum Excitation" for Synchronous Generating Units): Under certain conditions, such as low System Voltage, an instruction to maximum MVAR output (or "maximum Excitation" for Synchronous Generating Units) at instructed MW output may be given, and a Generator/Interconnector shall take the required actions to maximize MVAR output, provided its registered Technical Parameters are not exceeded.

SDC 2.5.2.3.7. Maximum MVAR absorption ("minimum Excitation" for Synchronous Generating Units): Under certain conditions, such as high System Voltage, an instruction to maximum MVAR absorption at instructed MW output (or "minimum Excitation" for

Conventional Generating Units) may be given, and a Generator/Interconnector shall take the required actions to maximize MVAR absorption, provided its registered Technical Parameters are not exceeded.

SDC 2.5.2.3.8. The Automatic Reactive Power or Automatic Voltage Regulator of Generators shall be operated only in its constant terminal Voltage mode of operation with "VAR limiters" in service, with any constant Reactive Power output control mode or constant Power Factor output control mode always disabled, unless expressly agreed otherwise with the SO. In the event of any change in System Voltage, Generators shall not take any action to override automatic MVAR response which is produced as a result of constant terminal Voltage mode of operation unless instructed otherwise by the SO or unless immediate action is necessary to maintain the stability limits.

SDC 2.5.2.3.9. In the event of a sudden change in System Voltage, a Generator/Interconnector must not take any action to override automatic MVAR response unless instructed otherwise by the SO or unless immediate action is necessary to maintain the stability limits or to avoid an imminent risk of injury/damage to persons, property, or Plant/equipment.

SDC 2.5.2.3.10. A Dispatch Instruction relating to Reactive Power will be implemented without any delay and will be achieved not later than two (2) minutes after the instructed time, or such longer period as the SO may instruct. Non-compliance with any such instruction shall be dealt in accordance with provisions of OC 11.

SDC 2.5.2.3.11. On receiving a new Active Power Dispatch Instruction, no tap changing, or Generator terminal Voltage adjustment shall be carried out to change the MVAR unless there is a new Dispatch Instruction.

SDC 2.5.2.3.12. Where an instruction to synchronize a CDGU is given, or where a Generating Unit is Synchronized and a MW Dispatch Instruction is given, a MVAR Dispatch Instruction consistent with the Generating Unit's relevant parameters will also be given. In the absence of a MVAR Dispatch Instruction with an instruction to Synchronize, the MVAR output should be zero (0) MVAR.

SDC 2.5.2.3.13. Where a Dispatch Instruction to De-synchronize a CDGU is given, a MVAR Dispatch Instruction, compatible with Shutdown, may also be given prior to De-Synchronization being achieved. In the absence of a separate MVAR Dispatch Instruction, it is implicit in the Dispatch Instruction to De-Synchronize that MVAR output should at the point of synchronism be zero (0) MVAR at De-Synchronization.

SDC 2.5.2.4. **Additional Dispatch Instructions**

SDC 2.5.2.4.1. **Reserve:** Details of the reserve to be provided by each Generating Unit/Interconnector including specification of the timescale in which that reserve may be transferable into increased Generating Unit/Station output.

SDC 2.5.2.4.2. **System (Ancillary) Services:** An instruction for a User to provide some specific System (Ancillary) Services and the limits for such provision.

SDC 2.5.2.4.3. **Testing or Monitoring:** To carry out Testing, Monitoring or Investigations as required under OC 11, or Testing at the request of a TNO/User under OC 10, or

Commissioning Tests under the CC, or to carry out a System Test as required under OC 10.

SDC 2.5.2.4.4. **Fuel:** Fuel to be used by the Generator in operating the CDGUs.

SDC 2.5.2.4.5. Dispatch Instruction could also be issued:

(a) to switch into or out of service a Special Protection Scheme or other Inter-tripping Scheme or Stability Control System (SCS) strategy;

(b) for a Generating Unit to operate in Synchronous Condenser mode if the Generating Unit has this capability, as indicated in its registered Technical Parameters (where is considered necessary by the SO).

SDC 2.5.2.4.6. **Energy Storage Unit:** mode changes for ESU, in relation to ESU Generation/injection or Demand.

SDC 2.5.2.5. **Dispatch Instructions under Emergency Conditions**

SDC 2.5.2.5.1. In order to maintain Transmission System integrity under System Emergency Conditions, the SO may issue Dispatch Instructions to Generators/Interconnectors to operate outside the limits specified in their registered Technical Parameters or Availability Notice for short periods of time. When issuing such a Dispatch Instruction, the SO shall inform the Generator/Interconnector that the Dispatch Instruction is being issued under System Emergency Conditions.

SDC 2.5.2.5.2. Where the SO has issued a Dispatch Instruction in accordance with the provisions for System Emergency Conditions requiring operation of a CDGU/Interconnector outside the limits specified in their registered Technical Parameters or Availability Notice, then the Generator/Interconnector shall comply with the Dispatch Instructions, provided its equipment is capable to implement such Dispatch Instruction.

SDC 2.5.2.5.3. The De-Synchronization of a CDGU/Interconnector following the operation of a Special Protection Scheme/Stability Control System strategy selected by the SO shall be deemed to have happened as a result of a Dispatch Instruction issued by the SO.

SDC 2.5.2.6. **Changes to Technical Parameters**

SDC 2.5.2.6.1. Each Generator/Interconnector shall notify to the SO without delay by telephone of any change or loss (temporary due to a defect) to the operational capability including any changes to the Technical Parameters of each CDGU/Interconnector.

SDC 2.5.2.6.2. If, for any reason, including a change of Availability or Technical Parameters made by the Generator/Interconnector, the prevailing Dispatch Instruction in respect of any CDGU/Interconnector is no longer within the applicable Availability or Technical Parameters then the Generator/Interconnector shall communicate it to the SO. The SO shall issue a revised Dispatch Instruction such that the new Dispatch Instruction is within the new applicable Availability and/or Technical Parameters.

SDC 2.5.2.6.3. If the SO fails to issue such new Dispatch Instruction in accordance with SDC 2.5.2.6.2 within a reasonable time, then the relevant Generator/Interconnector shall be entitled to change the operation of its such CDGU/Interconnector to bring its operation within the applicable Availability and/or Technical Parameters until

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

the SO issues a new Dispatch Instruction within the applicable Availability and/or Technical Parameters. Prior to making such a change in operation, the Generator/Interconnector will use reasonable endeavors to inform the SO (by electronic mode, or by telephone and then confirming it by fax) of its intended action and the timing of the intended action.

SDC 2.5.2.7. **Target Frequency**

SDC 2.5.2.7.1. Dispatch Instructions to Generators/Interconnectors will generally indicate the target MW (at Target Frequency) to be provided at the Connection/Delivery Point to be achieved in accordance with the Technical Parameters.

SDC 2.5.2.8. Subject only to SDC 2.5.2.10 and SDC 2.5.2.11, Dispatch Instructions will not be inconsistent with the Availability Notice and/or Technical Parameters and/or other relevant data notified to the SO under SDC 1 (and any revisions under SDC 1 to that data).

SDC 2.5.2.9. The SO may issue a Dispatch Instruction (including an instruction for a cancelled start) at any time.

SDC 2.5.2.10. Dispatch Instructions may, however, be inconsistent with the Availability and/or Parameters for the purposes of carrying out a Test or System Test at the request of the relevant Generator under OC 10, to the extent that such Dispatch Instructions are consistent with the procedure agreed (or otherwise determined) for conducting the Test or System Test (as the case may be).

SDC 2.5.2.11. For the avoidance of doubt, any Dispatch Instructions issued by the SO for the purpose of carrying out a Test or System Test at the request of the relevant Generator/Interconnector under OC 10 shall not be considered a Dispatch Instruction given pursuant to this SDC 2.

SDC 2.5.2.12. To preserve System integrity under emergency circumstances where, for example, the SO cannot meet its Licence condition, the SO may issue a Dispatch Instruction to change Generating Unit output or Interconnector transfers even when this is outside the parameters registered or amended, provided that the Generator, Interconnector is capable to provide such response. The Dispatch Instruction will clearly state that it is being issued by the SO pursuant to emergency circumstances under SDC 2.5.2.5.

SDC 2.5.2.13. If a Generator/Interconnector is unable to comply with any Dispatch Instruction due to some compelling reasons, the Generator/Interconnector must immediately inform the SO of such reasons and provide justifications for being unable to comply.

SDC 2.5.3. **Dispatch Instructions for Frequency Control**

SDC 2.5.3.1. When the SO determines it is necessary, by having monitored the System Frequency, it may, as part of the procedure set out in OC 5, issue a Dispatch Instruction (including Target Frequency where applicable) in order to seek to regulate Frequency to meet the requirements for Primary Frequency Control. The SO shall give, where applicable, 15 minutes notice to each relevant User of variation in Target Frequency.

SDC 2.5.3.2. Target System Frequency changes shall normally only be 49.95, 50.00, 50.05 Hz (at an interval of 0.05 Hz).

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

SDC 2.5.3.3. When the System Operator determines it is necessary, by having monitored the System Frequency, it shall, as a part of the procedure set out in SDC 2, issue Dispatch Instructions including the instructions for Secondary Operating Reserve, in order to regulate the System Frequency to meet the requirements for Frequency Control as contained in the OC 5. The CDGUs to be selected by the System Operator for Secondary Frequency Control shall be instructed by the System Operator to operate at the Target System Frequency, which shall be 50.00 Hz.

SDC 2.5.3.4. The Dispatch Instruction for Secondary Frequency Control shall include the range (AGC/secondary reserve Maximum and AGC/secondary reserve Minimum), being a registered Technical Parameter.

SDC 2.5.3.5. All variations in MW Output of Generators/Interconnectors in response to Frequency Control shall be deemed as Dispatch Instructions.

SDC 2.5.3.6. The System Operator may allocate a part of the requirements for Operating Reserve to Gas Turbine CDGUs with the capability of Low Frequency Relay initiated response (if applicable) for start-up to a pre-determined output level which have not been Scheduled for Dispatch in accordance with SDC 1, although the System Operator may, in the event, decide to issue a Dispatch instruction in respect of any of such CDGU in accordance with SDC 2. Alternatively, Gas Turbine CDGUs of this type may be scheduled for Dispatch by the System Operator in accordance with SDC 1.

SDC 2.5.3.7. For Generators with Low Frequency Relay capability, the System Operator shall periodically specify, within the range established in Technical Parameters, Low Frequency Relay settings to be applied to the CDGUs pursuant to SDC 2.5.3.6 and shall instruct the Low Frequency Relay initiated response to be placed in and out of service.

SDC 2.5.3.8. Upon the synchronization of a Generator under an agreed Low Frequency Relay start-up, the target MW (at Target Frequency) to be provided at the Connection Point may be as previously specified by the SO, in accordance with the Technical Parameters and/or parameters as revised by the SO in its Dispatch Instruction.

SDC 2.5.3.9. All applicable Generators with Low Frequency Relay capability shall comply with System Operator's instructions issued under SDC 2.5.3.7 for Low Frequency Relay settings. The Generators shall not alter such low frequency relay settings or take low frequency initiated response out-of-service without the System Operator authorization, except where necessary, in the Generator's reasonable opinion, to avoid an imminent risk of injury to persons or material damage to property (including the CDGU) with the prior notice for authorization of the System Operator.

SDC 2.5.3.10. The System Operator shall endeavor (in so far as it is able to) control electric clock time to within plus or minus 10 seconds of Standard Time by specifying changes to target the System Frequency, and by Dispatch taking into account Variable Operating Cost and forecast Generator/load demand margins. Errors greater than plus or minus 10 seconds may be temporarily accepted at the System Operator's reasonable discretion. The System Operator shall give 15 minutes notice to each Generator of variation in Target System Frequency.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

SDC 2.5.4. Dispatch Instruction to TNOs/DNOs

SDC 2.5.4.1. Dispatch Instructions to TNOs/DNOs relating to the Schedule Day will normally be issued at any time during the period beginning immediately after the publication of the IOS as a list of Special Actions in respect of that Schedule Day.

SDC 2.5.4.2. The SO will issue Dispatch Instructions to the relevant TNO/DNO at its designated Control Centre in relation to Special Actions and/or Demand Control.

SDC 2.5.4.3. Dispatch Instructions may include:

(a) a requirement for Demand reduction, Disconnection, or restoration;

(b) an instruction for load transfer between some Connection Points; and

(c) an instruction to switch in the load-shedding scheme.

SDC 2.5.4.4. The TNO or DNO, as it corresponds, shall comply without delay with all the Dispatch Instructions received by it. In the event that in carrying out the Dispatch Instructions, an unforeseen problem arises, the TNO or DNO, as it corresponds, will notify the SO by telephone without delay.

SDC 2.5.4.5. The Dispatch Instruction delivered verbally (by phone) shall be followed by a written confirmation afterwards.

SDC 2.5.5. Standing Instructions

SDC 2.5.5.1. The SO may notify a User that in certain circumstances it requires the User to operate in accordance with a Standing Instruction, which shall be deemed to be given when the circumstances arise. These Standing Instructions may include, for example, how to operate if the System Operator loses the ability to direct the operation and control of the Transmission System temporarily, in the circumstances envisaged under OC 9 where the System Operator is unable for any reason, pending the transfer of system operations to a temporary Control Centre.

SDC 2.5.5.2. The SO shall not, by means of a Standing Instruction, require any of the Users to be dispatched in a manner in which the SO would not have access or be able to exercise option to require such facilities to be dispatched by means of a Dispatch Instruction issued in accordance with this SDC 2.

SDC 2.5.6. Action required by Users

SDC 2.5.6.1. Each User shall comply in accordance with SDC 2.5.6 with all Dispatch Instructions issued by the SO, except where the User has contested the SO under the provisions of SDC 2.5.2 (g) for the invalidity of the Dispatch Instructions.

SDC 2.5.6.2. A CDGU shall not, however, be in default in complying with the Dispatch Instructions, if, subsequent to the issuance of the Dispatch Instruction, the CDGU and the System Operator agree on an early or late synchronization, and the CDGU synchronizes the relevant Unit in accordance with the agreed synchronization time.

SDC 2.5.7. Implementation of Dispatch Instructions by Users

SDC 2.5.7.1. A User shall take the required action on Dispatch Instructions issued by the SO, immediately and without any undue delay, including the Instructions issued pursuant to SDC 2.5.2.5.

SDC 2.5.7.2. Except as specified in SDC 2.5.7.4 below, Generators/Interconnectors shall Synchronize or de-Synchronize their CDGUs/Interconnectors on the Dispatch Instructions of the SO only or when Synchronization or de-Synchronization (as the case may be) occurs automatically as a result of activation of a Special Protection Scheme or an Under-Frequency Relay.

SDC 2.5.7.3. Except as specified below in SDC 2.5.7.5, DNOs will reduce or increase their Demand Control only to the Dispatch Instructions of the SO or when it occurs automatically as a result of activation of a Special Protection Schemes or Under- Frequency Relay operations.

SDC 2.5.7.4. De-Synchronization may be permitted without Instruction by SO only if it is to avoid, in the Generator's/Interconnector's reasonable opinion, an imminent risk of injury or damage to persons, or property, or Plant.

SDC 2.5.7.5. A TNO or DNO, as the case may be, may be excused from fully complying with a Dispatch Instruction by the SO for a Demand Control commitment only if it is to avoid, in that DNO's reasonable opinion, an imminent risk of injury/damage to persons, property, or Plant.

SDC 2.5.7.6. If any exceptions occur, pursuant to SDC 2.5.7.4 or SDC 2.5.7.5, then the relevant User will inform the SO immediately about the exception, explaining the circumstances which led to the situation. The SO may require the relevant User to support its claim with acceptable evidence for the stated exception.

SDC 2.5.7.7. When necessary, the SO shall issue dispatch instructions for a Black Start activation pursuant to OC 5.

SDC 2.5.8. Minimum Demand Regulation (MDR)

Synchronized CDGUs must, at all times, be capable of reducing their output up to the level indicated in its registered Technical Parameters, if so instructed by the SO, to allow adequate Operating Reserve for Frequency Control in the Transmission System. The SO shall monitor the output of the Synchronized Generating Units against the demand being experienced on the System to ascertain whether the level of MDR in the System is sufficient, and may take any shortfall into account in altering the Dispatch.

SDC 2.5.9. Special Actions

SDC 2.5.9.1. The SO may, as part of a Dispatch instructions, issue instructions for Special Actions (either pre- or post-fault) to a User in respect of any of its facilities, in the event that the SO believes that such instructions are necessary to maintain the Integrity, Security, or Stability of the Transmission System.

SDC 2.5.9.2. For a Generator, such Special Actions may involve a load change or a change of required Notice to Synchronize, in a specific timescale on individual or group of Generating Units basis.

SDC 2.5.9.3. For a DNO, these Special Actions may involve load transfers between the Connection Points or arrangements for Demand Control by manual or automatic means.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

SDC 2.6. **Dispatch against IOS**

Based on the factors mentioned in SDC 2.4, actual Dispatch carried out by SO in real-time may differ from the IOS published for the Schedule Day. The SO shall maintain regular comparison logs for differences between IOS and actual Dispatch.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

SDC 2. Appendix

Dispatch Instructions for CDGUs

General

This Appendix to SDC 2 provides further information on the form of a Dispatch Instruction as well as an example of a Dispatch Instruction for CDGUs.

Form of Dispatch Instruction

All Loading/De-Loading Rates shall be assumed to be in accordance with Technical Parameters. Each Dispatch Instruction shall, wherever possible, be kept simple, drawing as necessary from the following forms and SDC 2.5.2.

The Dispatch Instruction given by Electronic Interface, telephone, or facsimile transmission shall normally follow the form:

a. where appropriate, the specific CDGU Plant to which the instruction applies;
b.
    i. the MW Output to which it is instructed; or
    ii. the MW Output to which it is instructed until, a specified time, in which case the instructed MW Output shall be followed until a further Dispatch Instruction is issued;
c. if the start time is different from the time the instruction is issued, the start time shall be included;
d. where specific Loading/De-Loading Rates are concerned, a specific target time;
e. the issue time of the instruction;
f. the designated fuel and/or declared fuel; and
g. in the case of a CCGT Installation, the operating mode to which it is instructed.

The dispatch instruction given by the SO shall normally follow the form:

a. The specific CDGU to which the instruction applies, if the Instruction is on a unit basis or the group of CDGUs to which the instruction applies;
b. The MW Output to which it is instructed.

Any dispatch instruction relating to the designated fuel and/or declared fuel, (or fuel) as the case may be, shall be given by telephone, electronically or by facsimile transmission.

Dispatching a Synchronized CDGU to increase or decrease MW Output

If the time of the Dispatch Instruction is 1400 hours, the Unit is Unit 1 and the MW Output to be achieved is 205 MW, the relevant part of the instruction would be, for example:

"Time 1400 hours. Unit 1 to 205 MW until further notice" Or,

"Time 1400 hours. Unit 1 to 205 MW effective until 1500 hours"

If the start time is 1415 hours, it would be, for example:

"Time 1400 hours. Unit 1 to 205 MW until further notice, start at 1415 hours" Or

"Time 1400 hours. Unit 1 to 205 MW effective until 1500 hours, start at 1415 hours"

Loading and De-Loading Rates are assumed to be in accordance with Technical Parameters. If different Loading or De-Loading Rates are required, the time to be achieved shall be stated, for example:

"Time 1400 hours. Unit 1 to 205 MW by 1420 hours"

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Dispatching a CDGU to Synchronize/de-Synchronize

CDGU Synchronizing

In this instance, for CDGUs, the Dispatch Instruction issue time shall always have due regard for the synchronizing Start-Up Time (for cold, hot, warm states) declared to the SO by the Generator as a Technical Parameters.

The instruction shall follow the form, for example:

"Time 1300 hours. Unit 1, Synchronize at 1600 hours"

In relation to an instruction to Synchronize, the Synchronizing time shall be deemed to be the time at which synchronization is to take place.

Unless a loading program is also given at the same time it shall be assumed that the CDGUs are to be brought to Minimum Generation and on the Generator reporting that the unit has synchronized, a further Dispatch Instruction shall be issued.

When a Dispatch Instruction for a CDGU to Synchronize is cancelled (i.e. a Cancelled Start) before the unit is Synchronized, the instruction shall follow the form, for example:

"Time 1400 hours. Unit 1, cancel Synchronizing instruction"

CDGUs De-Synchronizing

The Dispatch Instruction shall normally follow the form, for example:

"Time 1300 hours. Unit 1, Shutdown"

If the instruction start time is for 1400 hours the form shall be, for example:

"Time 1300 hours. Unit 1, Shutdown, start at 1400 hours"

Both the above assume De-Loading Rate at declared Technical Parameters. Otherwise, the message shall conclude with, for example:

"... and De-Synchronize at 1500 hours"

Dispatch Instructions to HVDC.

The Dispatch Instruction to HVDC shall normally follow the form, for example:

"Start/de-block operation of HVDC pole in Q-Mode, Bipole Power Mode with Ground Return with Normal Voltage Mode" or

"Increase Bipole Dispatch to 1500 MW at the rate 100 MW/min" or

"Stop/block operation of HVDC pole" or

"Change of DC power flow direction from Station A to Station B" etc.

Frequency Control

All the above Dispatch Instructions shall be deemed to be at the instructed Target Frequency, i.e. where a CDGU is in the Frequency Sensitive Mode instructions refer to target MW Output at Target Frequency. Target Frequency changes shall always be given to the Generator by telephone or Electronic Interface and shall normally only be 49.95, 50.00, 50.05Hz.

The adjustment of MW Output of a CDGU for System Frequency other than an average of 50 Hz, shall be made in accordance with the current declared value of Governor Droop for the CDGU.

CDGUs required to be Frequency insensitive shall be specifically instructed as such. The Dispatch Instruction shall be of the form for example:

"Time 2100 hours. Unit 1, to Frequency insensitive mode"

Frequency Control instructions may be issued in conjunction with, or separate from, a Dispatch Instruction relating to MW Output.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

Emergency Load Drop

The Dispatch Instruction shall be in a pre-arranged format and normally follow the form, for example:

"Time 2000 hours. Emergency Load drop of "X"MW in "Y" minutes"

Voltage Control Instruction

In order that adequate System Voltage limits as specified in OC 5.5.7 are maintained under Normal and (N-1) conditions, a range of Voltage Control instructions shall be utilized from time to time, for example:

i. Operate to Nominal System Voltages;
ii. Operate to target Voltage of 132 kV;
iii. Maximum production or absorption of Reactive Power (at current instructed MW Output);
iv. Increase reactive output by 10 MVAR (at current instructed MW Output);
v. Change Reactive Power to 100 MVAR production or absorption;
vi. Increase CDGU Generator step-up transformer tap position by [one] tap or go to tap position [x];
vii. For a Simultaneous Tap Change, change CDGU Generator step-up transformer tap position by one [two] taps to raise or lower (as relevant) System Voltage, to be executed at time of telegraph (or other) Dispatch Instruction.
viii. Achieve a target Voltage of 210 kV and then allow to vary with System conditions;
ix. Maintain a target Voltage of 210 kV until otherwise instructed. Tap change as necessary.

It should be noted that the excitation control system constant Reactive Power level control mode or constant Power Factor output control mode shall always be disabled, unless agreed otherwise with the SO.

Instruction to change fuel

When the SO wishes to instruct a Generator to change the fuel being burned in the operation of one of its CDGUs from one Dispatched Fuel (or fuel) to another (for example from Gas to HSD), the Dispatch Instruction shall follow the form, for example:

"Time 1500 hours. Unit 2 change to HSD fuel at 1700 hours".

Instruction to change fuel for a dual firing CDGU

When the SO wishes to instruct a Generator to change the fuel being burned in the operation of one of its CDGUs which is capable of firing on two different fuels (for example, coal or oil), from one designated fuel (or fuel) to another (for example, from coal to oil), the instruction shall follow the form, for example:

"Time 1500 hours. Unit 1 generate using oil at 1800 hours".

Maximization/Peak Instruction to CDGUs

When the SO wishes to instruct a Generator to operate a CDGU at a level in excess of its Availability, the instruction shall follow the form, for example:

"Peak Instruction. Time 1800 hours. Unit GT2 to 58 MW."

Emergency Instruction

If a Dispatch Instruction is an Emergency Instruction the Dispatch Instruction shall be prefixed with the words. This is an Emergency Instruction. It may be in a pre- arranged format and normally follow the form, for example:

"This is an Emergency Instruction. Reduce MW Output to "X"MW in "Y" minutes,
Dispatch Instruction timed at 2000 hours.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

Dispatch Instructions to a DNO

When the SO wishes to instruct a DNO to commence Demand Control, the form of instruction may be for example:

"Time 1400 hours. Start Demand Control of 20MW until further notice, start at 1410 hours" Or

"Time 1400 hours. Start Demand Control of 20MW until 1500 hours, start at 1410 hours. Or

"Time 1400 hours. Limit consumption to maximum 100 MW until further notice, start at 1410 hours" etc.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PROTECTION AND CONTROL CODE

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

PCC 1. INTRODUCTION

The Protection and Control Code specifies the requirements that are to be complied with by the Users to ensure System's Security, Reliability, and Stability of the National Grid by using necessary and appropriate protection schemes at their facilities, especially at the Connection Point.

Users shall be liable to meet minimum technical, design and operational criteria from protection perspective in order to protect the Transmission System and their Plant and Apparatus directly connected with it, and to maintain stable and secure operation of the Transmission System.

PCC 1.1. Objectives

The key objectives of the Protection & Control Code are:

(a) To specify the minimum technical and performance requirements for the Protection Systems of User Facilities which include design and coordination of associated devices and equipment.

(b) To specify the protection requirement in selecting the protection scheme that will ensure the Reliability and Security of the Transmission System.

PCC 1.2. Scope

This sub-code applies to the SO and:

(a) Transmission Network Operators;

(b) Generators connected to the Transmission System;

(c) Bulk Power Consumers connected to the Transmission System; and

(d) Interconnectors.

PCC 1.3. Technical Standards and Specifications

PCC 1.3.1. All User's Plant and Apparatus shall comply with the technical standards and specifications as specified in CC 4.

PCC 1.3.2. NGC, in close coordination with the SO, shall develop a document, (the "Transmission System Protection" document) containing, at least:

(a) General guidelines for designing the protection schemes of the connected equipment to ensure System Integrity;

(b) The coordination requirements among the protections installed at different parts of the Transmission System.

All Users shall comply with the guidelines mentioned in the document for designing and adjusting their Protection System in addition to the technical standards and specifications as mentioned in PCC 1.3.1.

PCC 1.3.3. Where the SO or NGC, determines that, in order to ensure safe and coordinated operation of a User's Plant and Apparatus with the Transmission System, there is a requirement for some supplemental specifications and/or more stringent standards to apply to the User's Protection System, the SO or NGC, as it corresponds, shall notify the User of such requirements and the User shall comply with these supplemental/additional requirements to the protection schemes without undue delay.

PCC 2. PROTECTION OF POWER SYSTEM EQUIPMENT

PCC 2.1. Introduction

The Users shall provide necessary Protection of their Plant and Apparatus and equipment which shall include but not limited to the following:

(a) Bus Bars

(b) Transmission lines

(c) Transformers

(d) Generators

(e) Shunt Reactor

(f) Circuit Breakers

(g) Grid Station auxiliary systems

(h) Interconnectors

PCC 2.2. Types of Protection

The requirements laid down hereunder stipulate the minimum requirement for the Protection System to be provided by Users for their Facilities. More detailed and specific requirement for a particular User, if required, shall be determined and specified in the relevant Connection Agreement.

The type of Protection can be segregated into Primary and Back-up Protections. The protective relaying schemes, which include but not limited to, shall be provided for the following (wherever applicable):

(a) 220 kV, 500 kV and higher Voltage levels substation bus bars

(i) Bus Differential Protection (High Impedance/Low Impedance) with built-in End Zone Fault detection and clearing feature

(ii) Bus Coupler Protection

(iii) Lightning Protection

(b) 220 kV, 500 kV and higher Voltage Transmission Lines

(i) Distance Protection SET-I, alternatively Differential Protection SET-I

(ii) Distance Protection SET-II, alternatively Differential Protection SET-II

(iii) Transfer Trip including communication schemes

(iv) Over Current & Earth Fault Protection

(v) Line Current Differential Protection with built-in Multi Zone Distance Protection SET-I (if applicable)

(vi) Line Current Differential Protection with built-in Multi Zone Distance Protection Set II (if applicable)

(vii) Line Over Voltage Protection (Low Set, Inverse Set and High Set).

(viii) Line Open Circuit Fault (Broken Conductor) Protection

(ix) Auto-Recloser with built-in Synchronism Check feature

(x) Tele Protection Scheme

(xi) Provision for Implementation of Cross-Trip/Special Protection Scheme

(xii) Lightning/Surge Arrestor for protection against surges

Multi-channel telecommunication system shall be provided between the Users' substations/switchyards for bi-directional telecommunication of Protection signals, in order to limit the effects of Power System disturbances/abnormalities, and clearance of system faults, with the required discrimination and speed.

Tele-protection schemes implemented at both ends should be compatible with each other and able to exchange tele protection signals without any issue.

The telecommunication infrastructure shall also be capable of sending and receiving any inter-trip signals required for Cross-Trip schemes to be implemented at Users' substations/switchyards as per the standards and specifications mentioned in PCC 1.3, other sections of the Grid Code, and in the relevant Connection Agreements.

(c) 765/500 kV, 500/220 kV and 220/132 kV Transformers

(i) Transformer Differential Protection

(ii) Impedance Protection

(iii) Under/Over Voltage Protection

(iv) Over Current & Earth Fault Protection (HV, LV, Tertiary)

(v) Neutral Over Current Protection

(vi) Over Flux Protection

(vii) Over Load Protection

(viii) Restricted Earth Fault (REF) Protection

(ix) High Impedance Restricted Earth Fault (REF) Protection

(x) Percentage Biased Transformer Differential Protection SET-I

(xi) Percentage Biased Transformer Differential Protection SET-II

(xii) Sudden Pressure Protection

(xiii) Buchholz Protection

(xiv) Oil Temperature Protection

(xv) Winding Temperature Protection

(xvi) Pressure Relief Devices/Valves

(xvii) OLTC Protection

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(xviii) AVR Control Scheme

(xix) Provision for Implementation of Cross-Trip/Special Protection Scheme

(xx) Transformer Explosion and Fire Protection System & Equipment

(d) Generators

(i) Generator Differential Protection

(ii) Overall Differential Protection for Generator and Transformer

(iii) Generator Impedance/Distance Protection

(iv) Over Current & Earth Fault Protection

(v) Voltage-controlled Over Current Protection

(vi) Over/Under Voltage Protection

(vii) Loss of Excitation Protection

(viii) Over/Under Frequency Protection

(ix) Overload Protection

(x) Rate of Change of Frequency (ROCOF) Protection

(xi) Loss of Load (Load Rejection) Protection Scheme for step-wise isolation of generators

(xii) Reverse Power Protection

(xiii) AVR Control Scheme

(xiv) Provision for Implementation of Cross-Trip/Special Protection Scheme

(xv) Neutral displacement Voltage detection for Generating Unit transformer

(xvi) Loss-of-Mains Protection (rate of change of Frequency or vector shift)

(xvii) Pole Slip Protection and/or out of step and/or power swing

(e) Shunt Reactors

(i) Differential Protection

(ii) Impedance Protection

(iii) High Impedance Restricted Earth Fault (REF) Protection

(iv) Over Current & Earth Fault Protection

(v) Switch Synchronization/Point on Wave Switching Protection

(vi) Sudden Pressure Protection

(vii) Buchholz Protection

(viii) Oil temperature protection

(ix) Winding Temperature Protection

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY

(f) Circuit Breakers

(i) Breaker-Fail Protection

(ii) Pole Discrepancy Protection

(iii) Trip Circuit Supervision Protection

(iv) Anti-pumping Protection

(v) Low Pressure Alarm & Lockout Protection

(vi) Over Current Protection for Bus Coupler Breaker

(g) Users Below 220 kV level

(i) Bus Differential Protection

(ii) Transformer Differential Protection

(iii) Line Distance Protection

(iv) Over Current & Earth Fault Protection

(v) Over/Under Voltage Protection

(vi) Breaker Failure Protection

(vii) Transfer Trip Protection Schemes

(viii) Over/Under Frequency Protection

(ix) Auto-Recloser with built-in Synchronism Check feature

(x) Bus Coupler Protection

(xi) Line Open Circuit Fault (Broken Conductor) Protection

(xii) Backup Over Current & Earth fault Protection on 132 kV Transmission Lines

(xiii) Provision for Implementation of Cross-Trip/Special Protection Scheme

(h) Interconnectors (DC Protections)

(i) Converter Protection

a. Voltage Stress Protection

b. Valve Short-circuit Protection

c. Commutation Failure Protection

d. Backup Terminal DC Voltage Supervision Protection

e. DC Overcurrent Protection

f. Valve Misfire Protection

(ii) Pole Protection

a. DC Differential Protection

b. DC Line Ground Fault Protection

c. DC Harmonic Protection

d. DC Abnormal Voltage Protection

e. DC Filter Overload Protection

f. Electrode Line Open-circuit Protection

(iii) DC Switchyard Protection

a. Bipole Neutral Differential Protection

b. Metallic Return Conductor Ground Fault Protection

c. Transfer Breaker Protection

d. Station Ground Over-Current Protection

e. Electrode Cable Longitudinal Differential Protection

f. Electrode Line Unbalance Supervision

g. Electrode Line Impedance Supervision

(iv) DC Line Protection

a. Travelling Wave Front Protection

b. Under Voltage Sensing Protection

c. Under Voltage Operation Protection

d. DC Line Differential Protection

e. Remote Station Fault Detection or AC-DC Conductor Contact Protection

f. Electrode Line Protection

(v) DC Filter Bank Protection

a. Capacitor Differential Overcurrent Protection

b. Capacitor Unbalance Supervision

c. Inverse Overcurrent Time Protection

d. DC Filter Differential Protection

(vi) Miscellaneous DC Protection

a. Bridge Differential Protection

b. Sub-Synchronous Resonance Protection

c. Open Converter or DC Overvoltage Protection

d. Excessive Delay Angle Protection

(i) Interconnectors (AC) Protections

(i) AC Bus and Converter Transformer Protections

a. Differential Protection

b. Over-current & Earth fault Protection

c. AC Bus Over-Voltage Protection

d. Thermal Overload Protection

e. Transformer Winding Differential Protection

f. Transformer Zero Sequence Current Protection

g. Transformer Neutral Shift Protection

h. Transformer Over-excitation Protection

i. Transformer Saturation Protection

j. Transformer Restricted Earth Fault Protection

(ii) Last Breaker Protection AC Filter/Shunt Bank Protections

a. Differential and Over-current Protection

b. Filter Over-voltage Protection

c. Capacitor Unbalance Protection

d. Zero Sequence Current Protection

e. Filter Detuning Supervision

f. Resistor/Reactor Harmonic Overload Protection

g. Low Voltage Capacitor Protection

h. Start Breaker Failure Protection

PCC 2.3. Instrument Transformers

PCC 2.3.1. Instrument Transformers for the Protection Systems shall meet the technical standards and specifications as specified in CC 4.

PCC 2.3.2. Instrument Transformers used for protective relaying shall not be shared with any Revenue Metering equipment. Likewise, Instrument Transformers for Revenue Metering shall not be shared with protective relaying equipment.

PCC 2.4. Shunt Reactor Protection

PCC 2.4.1. The use of circuit breaker for the shunt reactor shall be mandatory for all Users.

PCC 2.4.2. In special cases, only if allowed by the relevant TNO to temporarily install shunt reactors without circuit breakers, protective relaying on shunt reactors shall be used to trip associated line circuit breakers. Isolation-switches shall be provided to allow the isolation of shunt reactors and circuit breakers for maintenance.

PCC 2.5. DC Supply of User's Substation/Switchyard

PCC 2.5.1. DC back-up power supply shall be provided in the User's substation/switchyard. The User substation/switchyard shall be equipped with two (2) independent DC battery banks to provide independently protected and monitored DC sources for reliable Protection Systems.

PCC 2.5.2. Independent DC back-up power supply shall also be provided in the User's substation/switchyard for communication equipment including PLCC, OPGW, etc.

PCC 2.5.3. Two separate floating cum boost battery charging Facilities shall be available for each DC Voltage level. One should always be in service while the other shall be in hot standby mode through DC distribution box (DB) and should immediately respond in case of failure of primary supply.

PCC 2.5.4. Users shall ensure testing and periodic checks to verify the readiness and adequacy of DC systems and Facilities in their substations/switchyards, i.e. battery, charger, and distribution switchboard including DC system supervision relay. Testing/checking shall be carried out as per NGC practices/guidelines.

PCC 2.6. Switching Procedures

PCC 2.6.1. All switching activities at the Connection Point shall be performed under the direction of the SO. All other switching activities in the User's system shall be coordinated with the SO. Proper communication and tagging procedure shall be observed to prevent accidents and damage to equipment involved in the switching operation.

PCC 2.6.2. The details regarding the switching procedures shall be as per OC.

PCC 3. GENERATING UNIT PROTECTION

PCC 3.1. Connection between a Generating Unit and the Transmission System must be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the Connection Point. User Plant and Apparatus at the Connection Point shall be designed taking account of the short circuit current levels identified in System Impact Assessment Studies, and applicable standards as mentioned in CC 4. The SO shall determine, what safety margins, if any, to apply when selecting the User's Plant and Apparatus.

PCC 3.2. Protection Design

The Generating Unit shall include protections, not limited to the following:

(a) Protection System shall be designed to provide adequate protection of the Generating Unit and its substation/switchyard Apparatus.

(b) Differential protection (Main-I and Main-II) on the Generator Transformer. The connections between the Connection Point's circuit breaker and the HV terminals of the Generator Transformer shall be included in the protected zone of this differential protection.

(c) Short-circuit and earth fault protection of primary conductors from the current transformer at the line side of the circuit breaker to the Connection Point shall be provided.

(d) Circuit breaker fail protection shall be provided at the Generating Unit. A back-up trip signal shall be provided in the event of a main circuit breaker failure to trip all the electrically adjacent breakers to clear the fault within the time limits provided under the NGC standards in the "Transmission System Protection" document.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

(e) Protection shall be provided to initiate a Generating Unit trip when loss of excitation is detected.

(f) Pole slipping protection shall be provided with the synchronous generating units.

(g) The Protection System of Generating Unit shall ensure that fault in Generating Unit facility must be cleared by its Protection System and there will be no adverse effect on the Transmission System.

PCC 3.3. Requirements at the Connection Point

Protection of Generating Units and their connections to the Transmission System must meet the minimum requirements (relay settings shall be reviewed by involved TNO with the concurrence of the SO, from time to time) which shall include but are not limited to the following:

(a) For faults on the Generating unit's equipment directly connected to the Transmission System and for faults on the Transmission System directly connected to the Generating unit's equipment, fault clearance period from fault inception to circuit breaker arc extinction shall be as per SO requirements.

(b) In the event where the fault clearance times are not met as a result of failure to operate the Primary or Main Protection System, a Back-up or Secondary Protection System shall operate. Back-up Protection along with the specified fault clearance time shall be coordinated with the Users so as to provide adequate discrimination.

(c) On the Generating Unit connected to the Transmission System where Primary or Main Protection is provided to clear fault on the high Voltage Generating Unit connections within the required fault clearance time, the Back-up or Secondary Protection in the Generating Unit, shall operate to give a total fault clearance within the limits as per the SO requirements.

(d) Generating Unit's Back-up Protection or Secondary Protection relays shall be required to withstand, without tripping, the loading incurred during clearance of a fault by a breaker fail protection on the Transmission System. Back-up Protection in the Generating Unit and Transmission System shall be coordinated to provide adequate discrimination.

(e) Circuit breakers installed at the Connection Point between the Generating Unit and the Transmission System shall be provided with breaker failure protection. In the event the breaker fails to operate, the breaker failure protection shall initiate tripping of all the electrically adjacent circuit breakers within the time limits provided by the NGC as per the SO requirements.

(f) The target performance for the System Fault Dependability Index shall not be less than 99%. This is a measure of the ability of the Protection System to initiate successful tripping of circuit breakers that are associated with the fault in the system.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

(g) The TNO, at which the Generating Unit is connected shall review and approve schemes/settings with concurrence of the SO necessary to protect the Transmission System, which shall be in accordance to PCC 1.3. Taking into account the characteristics of the Generating Units and to preserve system stability, the SO or NGC can propose protection schemes/settings which would be different from those in the "Transmission System Protection" document, in order not to jeopardize the performance of a Generating Unit or the Transmission System. Such modifications shall be reflected in the Connection Agreement.

(h) Electrical protection of the Generating Units shall take precedence over operational controls, taking into account the security of the System and the health and safety of staff and of the public, as well as mitigating any damage to the Generating Units.

PCC 3.4. Requirements for Rate of Change of Frequency (ROCOF)

The operation of the ROCOF relay may be based either only on the rate of change (rise/fall) of Frequency (± df/dt) or both on a set Frequency value and the rate of Frequency recovery/decline [(f> and +df/dt) OR (f< and -df/dt)]. ROCOF detection shall not be instantaneous, rather it shall be calculated over 500 milliseconds span after Frequency is filtered properly, i.e. sample shall be taken every 5 milliseconds and calculated over 500 milliseconds span for operation of ROCOF relay. It is further added that at any ROCOF, whether ramping up or down, between the range of 48.5 Hz to 51 Hz, the relay shall not activate and the Generating Unit itself shall remain stable at any ROCOF between this Frequency range. Recommended settings based on Generator/Interconnector capability are as under:

PCC 3.4.1. For Gas Turbine Generators:

(a) Rate of Change of Frequency setting based on generator capability in case Frequency ramping up, i.e. f > 51.0 Hz and +df/dt ≥ 1.5 Hz/Sec with time delay of 500 milliseconds (minimum).

(b) Rate of Change of Frequency setting based on generator capability in case Frequency ramping down, i.e. f < 48.5 Hz and -df/dt ≥ 1.5 Hz/second with time delay of 500 milliseconds (minimum).

PCC 3.4.2. For Steam Turbine Generators (e.g. coal, natural gas, biomass, nuclear), Wind Farms, Hydro-electric Turbine Generators, etc.:

(a) Rate of Change of Frequency setting based on generator capability in case Frequency ramping up, i.e. f > 51.0 Hz and +df/dt ≥ 2.0 Hz/Sec with time delay of 500 milliseconds (minimum).

(b) Rate of Change of Frequency setting based on generator capability in case Frequency ramping down, i.e. f < 48.5 Hz and -df/dt ≥ 2.0 Hz/Sec with time delay of 500 milliseconds (minimum).

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PCC 3.4.3. For the HVDC, the capability to remain connected to the Grid and being operable if the network Frequency changes at a rate between -2.5 and +2.5 Hz/s (measured in the AC part of the Converter Stations as an average of the rate of change of Frequency for the previous one (1) second).

PCC 4. USERS SUBSTATION/SWITCHYARD PROTECTION FOR CONNECTION WITH TRANSMISSION SYSTEM

PCC 4.1. Users' substations/switchyards for the Connection Point shall be designed taking account of the short circuit current levels identified in System Impact Assessment Studies, and applicable standards as mentioned in CC 4 as well as the provisions contained in the "Transmission System Protection" document. The SO shall determine, what safety margins, if any, to apply when selecting the User's substation/switchyard.

PCC 4.1.1. For faults on the User's substation/switchyard equipment connected to the Transmission System and for faults on the Transmission System connected to the User's substation/switchyard equipment, fault clearance period from fault inception to circuit breaker arc extinction shall be as per the "Transmission System Protection" document requirements or, in case it is deemed necessary, as proposed by the SO.

PCC 4.1.2. In special circumstances, the SO may specify longer fault clearing times in view protection and design criteria of the TNO and the capability of the Transmission System to resist such longer clearing times.

PCC 4.1.3. Where the fault clearance times are not met as a result of failure to operate the Primary or Main Protection System, a Back-up or Secondary Protection System shall operate. Back-up Protection shall be coordinated with the Primary Protection, as per the "Transmission System Protection" document, so as to provide adequate discrimination.

PCC 4.1.4. Users' substations/switchyards connected to the Transmission System where Primary or Main Protection is provided to clear faults on the Connection Point within the required fault clearance times, the Secondary or Back-up Protection shall operate to give a total fault clearance within the limits as per the criteria mentioned in the "Transmission System Protection" document or, if so indicated, as per the SO requirements.

PCC 4.1.5. Users' substation/switchyard Back-up Protection or Secondary relays will be required to withstand, without tripping, the loading incurred during clearance of a fault by a breaker fail protection on the Transmission System. Back-up Protections in the substation/switchyard and Transmission System shall be coordinated to provide adequate discrimination.

PCC 4.1.6. Circuit breakers installed at the substation/switchyard of the Connection Point shall be provided with breaker-fail protection. In the event the breaker fails to operate at User's substation/switchyard, the breaker-fail protection will initiate the tripping to all the electrically adjacent circuit breakers within the time limits mentioned in "Transmission Protection System" document or, if so indicated, as per the SO requirements.

PCC 4.1.7. The target performance for the system Fault Dependability Index shall not be less than 99%. This is a measure of the ability of the Protection System to initiate successful tripping of circuit breakers that are associated with the fault on the System.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

PCC 4.1.8. The Back-up Protection relays of the User's system also need to be coordinated with the Back-up protection of the other User facility (as the case may be) and the Transmission System. The coordination times specified in the "Transmission System Protection document", shall be followed by all Users. In case of the particularities of the Transmission System at the Connection Point, the SO or NGC will be entitled to request different coordination times.

PCC 4.1.9. For Facilities interconnection between new User and existing User, if any addition/change/modification in Protection & Control Equipment is required at existing User's grid stations to complete the scheme, the same shall be procured, installed, commissioned & tested by the new User at existing User grid stations at his own cost & expense. The operation & maintenance (O&M) of such Protection and Control Equipment along-with all other allied material, installed at existing User Grid Stations shall be the responsibility of existing User. However, if the equipment/technology is new and require training for O&M, the same shall be arranged by the new User at his own expenses. Further, the User shall also transfer this asset to the existing User with ownership & warranty claims, etc.

PCC 5. PROTECTION COORDINATION

PCC 5.1. General

PCC 5.1.1. Users' Plant and Apparatus shall be protected from faults and overloads at the Connection Point. Both Primary and Back-up Protections are to be provided to enhance System Reliability.

PCC 5.1.2. The User shall submit proposed relay settings of their Facilities, for the review and approval of involved TNO with the concurrence of the SO as per the provisions of PCC 1.3. The involved TNO shall provide Transmission System data to the User for relay settings calculations, if requested.

PCC 5.1.3. Protection settings of Users shall be coordinated with the transmission line and substation/switchyard protection to prevent inadvertent and unwanted operations.

PCC 5.1.4. Design and relay settings of Protection System shall be coordinated among the Users, which shall be reviewed periodically to maintain consistency with operation, planning and protection design standards.

PCC 5.1.5. All protection, control, monitoring and recording equipment/devices/systems shall be in accordance with relevant technical specifications as mentioned in PCC 1.3 and Good Industry Practice.

PCC 5.2. Fault Clearance Times

PCC 5.2.1. Faults on Users' Plant and Apparatus connected to the Transmission System shall comply with the following requirements for Fault Clearance Times (from fault inception to Circuit Breaker's arc extension) by Primary Protection not exceeding:

(a) 120 milliseconds for the 132 kV system and below;

(b) 100 milliseconds for the 220 kV system; and

(c) 80 milliseconds for the 500 kV system and above.

PCC 5.2.2. The maximum allowed times for fault clearance specified in PCC 5.2.1 shall be considered as reference, unless some other clearance times are required by the SO.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

PCC 5.2.3. The clearance times specified in PCC 5.2.1 are for Primary Protection Systems only. Without limiting this obligation, prior to connection with the Transmission System, the User shall as a minimum, install and maintain the Protection Equipment as per requirements of the SO and involved TNO in accordance with PCC 1.3 and Good Industry Practice.

PCC 5.2.4. For the avoidance of doubt, the User is solely responsible to determine the adequacy of Protection System installed by the User for protecting its Plant and Apparatus against electrical disturbances. Standards and specifications mentioned in PCC 1.3, are primarily intended to protect the User Facility and Transmission System to ensure System Stability and Reliability, which shall serve as bare minimum level of Protection System for the Users.

PCC 5.3. Relay Coordination

PCC 5.3.1. Protective relays in the various sub-systems of the Transmission System must be coordinated to prevent unwanted tripping. Proper coordination of Protection Systems of the various sub-systems will enhance the security and safe operation of the system.

PCC 5.3.2. Relay coordination shall be checked and updated each time the system characteristics are substantially changed/modified, but in any case, at least after every three (3) years by the involved TNO with the concurrence of the SO, using state-of-the-art relay-coordination software.

PCC 5.3.3. The NGC and SO shall maintain the Transmission System protection database, tripping database, relay and protection performance database and shall be share with relevant participants in case of requirement this database should be shared with all participants to ensure proper data exchange for coordination activity.

PCC 5.3.4. Users shall exchange Primary and Back-up Protection relay setting times and other necessary parameters to facilitate the coordination of the interfaces between Users' facilities, and shall fully cooperate with the NGC and/or the involved TNOs to implement protection settings/schemes for their respective Protection and Control Equipment to meet the SO requirements.

PCC 5.3.5. Prior to energization of a User's Facility, the User shall submit the relay settings to the involved TNO for review and approval with the concurrence of the SO, which the User proposes to apply to its Facility's Protection and Control equipment. If requested, the User shall provide data/parameters of its Facility/system to other Users, required for calculation and coordination of the relay settings.

PCC 5.3.6. The involved TNO shall, within the specified time of receiving the User's submission of relay settings, notify to the User that it approves the proposed settings, or if the involved TNO or NGC determines that the settings proposed by the User are not in accordance with the applicable "Transmission System Protection" document, disapproves these relay settings along with comments/recommendations to be incorporated. The User, after addressing the TNO or NGC's concerns, shall submit the revised settings to the relevant TNO.

PCC 5.3.7. The relevant TNO shall submit all the information to the SO related to the User relays and protection settings.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

PCC 5.3.8. If any change or modification is envisaged by the Users in relay settings/protection schemes prior to energization of the User's facility due to any untoward situation, the Users shall notify to the involved TNO and the SO without delay along with intimation to NGC. Such change/modification shall be implemented by the Users after approval of the involved TNO or NGC, as it corresponds.

PCC 5.3.9. If any change/modification is required, the User requesting Connection with the Transmission System, shall be liable to revise the relay settings of already connected Users which got affected by this User's Facility, in consultation/approval of the involved TNO. Any cost incurred shall be borne by the User requesting the change, in such cases.

PCC 5.3.10. Protection coordination studies including Cross-Trip schemes, Remedial Action Schemes, etc., shall be performed after every five (5) years by engaging independent consultants, based on which Stability, Security and Reliability of the National Grid shall be evaluated and validated jointly by the SO and NGC.

PCC 5.3.11. The SO and involved TNO shall maintain the Transmission System protection database, tripping database, relay and protection performance database and shall be shared with relevant participants. In case of requirement by the User, this database shall be shared with all participants to ensure proper data exchange for coordination activity.

PCC 5.4. Tripping & Reclosing Schemes

PCC 5.4.1. The Protection System for the 220 kV, 500 kV and higher Voltage levels shall be capable of both single pole and three pole tripping and associated reclosing arrangement. The configuration of the tripping scheme shall be finalized jointly by the SO and the involved TNO, which will be adopted by the User.

PCC 5.4.2. The line relaying system shall be arranged to allow for Single Pole Tripping of selected 220 kV, 500 kV and higher Voltage transmission lines, in case of single phase to earth fault. One-shot reclosing of the tripped line shall be allowed according to studies designed to establish the best reclosing time. If the tripped phase fails to reclose, all three phases will be tripped accordingly.

PCC 5.4.3. Three pole tripping shall also be associated with delayed Auto-Recloser scheme with successful synchronism-check feature. The reclosing scheme, relevant time-delay and allied parameters shall be as per PCC 1.3.

PCC 6. CONTROL AND AUTOMATION

PCC 6.1. General

PCC 6.1.1. The control and automation shall be as per the requirements laid down in PCC 1.3. All the technical data including device and equipment ratings shall be submitted by the User to the involved TNO for its review and approval with the concurrence of the SO.

PCC 6.1.2. For the purpose of Connection and Disconnection of Generator and User's substation/switchyard to/from the Transmission System, the necessary equipment shall be provided which includes but not limited to the following:

PCC 6.1.2.1. Circuit breakers shall be provided at the Connection Point between the Users and the Transmission System. The circuit breaker shall have the proper Voltage ratings, short circuit current rating, continuous current rating, etc.

PCC 6.1.2.2. Control panels for circuit breakers, disconnecting switches and other equipment (wherever applicable) shall be provided at the Connection Point.

PCC 6.1.2.3. Disconnecting switches shall be provided for isolation of circuit breaker. Disconnecting switches shall be no-load break type and have the same Voltage and continuous current rating as of the circuit breaker.

PCC 6.1.2.4. Disconnecting switches shall be provided for isolation of transformer in the substation/switchyard. Disconnecting switches shall have wipers to prevent arcing during energization of the transformer. Disconnecting switches shall be of no-load break type and shall have the same Voltage and continuous current as of the circuit breaker.

PCC 6.1.2.5. Disconnecting switches shall be provided for the bus bars for safety and maintenance purpose. The grounding feature can be provided as per standards and specifications mentioned in PCC 1.3.

PCC 6.1.2.6. Disconnecting switches with grounding feature shall be provided for the Transmission lines for safety and maintenance purpose.

PCC 6.1.2.7. Disconnecting and Earthing switches shall be motor-operated to facilitate remote operation. Control and electrical interlocks for Disconnecting and Earthing switches shall be provided in the control panel that shall have interface with SCADA for remote control and monitoring.

PCC 7. SCADA

PCC 7.1.1. Users shall install and integrate SCADA system of their network/Facilities with SO's designated control centers and shall be fully compatible with the SO's SCADA system. The telecommunication system shall be fully compatible with the SO and, if required, with the TNO communication system.

PCC 7.1.2. The telecommunication equipment for remote SCADA interface (e.g. RTUs, gateways, etc.) used for Substation Automation System (SAS) shall comply with the standards and specifications as mentioned in PCC 1.3.

PCC 7.1.3. In case substation/switchyard or generating station has implemented Parallel Redundancy Protocol (PRP) based Substation Control/Automation, the equipment, Apparatus, and all accessories shall comply with the standards and specifications as mentioned in PCC 1.3

PCC 7.1.3.1. SCADA connections for monitoring and control of circuit breakers, disconnecting switches, Earthing switches and other Protection Equipment shall be provided for the SO's designated control centers.

PCC 7.1.4. The detailed requirement of communication Facilities to be provided by Users shall be covered in the Connection Code, Operating Code, and respective Connection Agreements with a specific User.

PCC 7.2. **Time Clock Synchronization**

PCC 7.2.1. Time clock in Protection Equipment, recording equipment and SCADA shall have Facilities for synchronizing time with Global Positioning System (GPS). The User shall provide at the Connection Point the required signal receiving and signal distribution equipment.

PCC 7.2.2. Time clock synchronization source for the Protection, event recording, fault recording and SCADA applications shall be Precision Time Protocol (PTP) compliant and shall be in-line with the requirements laid down in PCC 1.3.

PCC 7.3. **Fault & Event Recording Requirements**

PCC 7.3.1. Equipment for recording fault conditions and sequence of events shall be provided by the User at the Connection Point. The recording equipment shall record a snapshot of the Voltages and current during the fault, and sequence of events for subsequent investigation and evaluation of the fault to determine its causes. The fault recording equipment shall have Facilities for the information provision via SCADA to SO's designated control centers.

PCC 7.3.2. Fault recording equipment design shall be as per standards and specifications as mentioned in PCC 1.3. It shall be an independent/standalone equipment for substation/switchyard.

PCC 8. **INSPECTION AND TESTING**

PCC 8.1. **General**

PCC 8.1.1. The inspection and testing including site acceptance tests (SAT) of the User Facility shall follow the procedures as mentioned in CC 12.

PCC 8.1.2. The facility shall be witnessed and inspected jointly by the SO, NGC and TNO. The User shall be responsible for providing necessary equipment with valid calibration certificate and qualified personnel, who will complete all the required/necessary tests.

PCC 8.1.3. The relevant User shall be liable for arranging type tests, Factory Acceptance Tests (FAT) and Site Acceptance Test (SAT), where applicable, for all protection equipment of its Plant and Apparatus, to be witnessed by authorized representatives of the NGC and TNO, as it corresponds. Test results shall demonstrate the design performance, functionality, and safety of individual protection equipment as well as the entire User system, up to the satisfaction of NGC and TNO.

PCC 8.1.4. The Users which connect to the NGC Transmission System shall pre-commission and on successful pre-commissioning user must notify the SO, NGC and TNO prior to performing the required tests for final commissioning. Approved drawings must be provided to the SO, NGC and TNO at least seven (7) business days before performing the testing.

PCC 8.1.5. Once SO, NGC and TNO determines that the installations are suitable to operate in connection with the Transmission System, the User, SO, NGC and TNO representatives (whichever applicable) must sign and date the "Approval for operation of the facility" certificate. After receiving the "Approval for operation of the facility" certificate, the User will be authorized to operate its facility in parallel with the Transmission System.

PCC 8.1.6. User shall provide the final version of updated drawings (As-Built) in all aspects in an agreed format to the SO, NGC and TNO for the record.

PCC 8.2. Periodic Testing, Calibration and Maintenance of Protection Systems

PCC 8.2.1. Periodic testing of all Protection Systems including relays, control and switching equipment and allied system shall be carried out by the relevant User to ensure that entire Protection System is in good operating condition. Protection Equipment found defective during the test must be repaired or replaced, accordingly. Circuit breakers and control circuits shall also be tested periodically, and if parts are found defective or deficient, they should be repaired or replaced. Testing and maintenance shall be coordinated among the User, SO, NGC and TNO (whichever applicable). Tests, calibration, repair and replacement of equipment shall be recorded and disseminated to all concerned parties.

PCC 8.2.2. Users shall perform testing of their protective relay under supervision of the NGC, or may request NGC to perform testing of their relays after payment of service charges.

PCC 8.2.3. Users shall perform routine testing of their protective relay and submit the test report both to the involved TNO and to NGC as per the prescribed format under testing procedure developed by NGC.

PCC 8.2.4. All testing and maintenance performed on the Protection and Control Equipment of the User shall be recorded, and copies submitted to SO, NGC and TNO for record and archiving. The User shall keep records for a period of at least ten (10) years.

PCC 8.2.5. User shall carry out a thorough periodical review, testing, calibration and maintenance of its entire Protection System at the Connection Point as well as for its complete network/Facility.

PCC 8.2.6. Users shall provide annual testing schedule of their Protection Systems in its/their substation/switchyard. The TNO, SO and NGC shall have the right to require additional testing as well as the recalibration of the testing equipment. The User shall arrange such testing equipment so as to meet the quality standards as mentioned in PCC 1.3 for performing these tests.

PCC 8.2.7. User shall ensure verification of the protection settings/schemes at the Connection Point along with healthiness of associated Protection System, to be witnessed by the NGC and involved TNO on annual basis.

PCC 8.2.8. **Right to Inspect**

The SO shall have the right to inspect (as and when required) substations/switchyards and transmission lines that are connected to the Transmission System on compliance with protection and control requirements. The NGC and relevant TNO (as and when required) shall also have the same right to inspect on compliance with protection and control requirements by the transmission lines/generating stations/substations connected to their systems at the Connection Point.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

METERING CODE

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

MC 1. INTRODUCTION

The Metering Code specifies the general terms and conditions, responsibilities, standards and requirements for commissioning, operation, maintenance and management of Revenue Metering for the purpose of electricity trading.

MC 1.1. Objectives

The key objectives of the Metering Code are:

(a) To specify the responsibilities, and obligations of the Code Participants;

(b) To support the efficient settlement of electricity transactions by verification, communication of secure and accurate Metering Data;

(c) To provide minimum technical requirements for Metering Systems.

MC 2. SCOPE

This sub-code applies to the Metering Service Provider and:

(a) Transmission Network Operators;

(b) Generators connected to the Transmission System;

(c) Bulk Power Consumers connected to the Transmission System; and

(d) Interconnectors.

MC 3. METERING SYSTEM

MC 3.1. Metering System shall consist of the following equipment at Connection Site:

(a) Energy meters along with meter communication devices;

(b) Instrument Transformers; and

(c) Secondary circuits of Instrument Transformers including interconnecting cables, wires, metering cabinets and associated devices.

MC 3.2. Metering System configuration shall be as follows:

(a) Primary and Back-up Metering System comprising of energy meters (along with communication devices), dedicated separate sets of Instrument Transformers and their secondary circuit equipment;

(b) Backup Metering System comprising of backup energy meters (along with communication devices), Instrument Transformers (CT and VT) and their secondary circuit equipment to be used for backup metering purposes.

MC 3.3. MSP shall approve the following technical data to be submitted by the User:

(a) Engineering design for revenue metering;

(b) Detailed data for all components of Metering System; and

(c) Proposed location of Metering System with installation drawings and design.

MC 3.4. The MSP shall provide the Primary and Back-up Meters along with the associated communication equipment at the User's cost. The MSP can allow the User to arrange approved Primary and Back-up Meters along with the associated communication equipment.

MC 3.5. The User shall be responsible for installation of complete Metering System at Connection Site.

MC 3.6. The MSP shall be responsible for the commissioning, operation and maintenance of the Primary and Back-up Meters along with associated communication equipment.

MC 3.7. The User shall be responsible for provision, commissioning, operation and maintenance of Primary and Back-up Instrument Transformers along with their allied secondary circuit equipment.

MC 3.8. Location of Metering Point

MC 3.8.1. The location of the Metering Point at the Connection Site shall be as follows:

(a) At high Voltage side of generator step-up transformer, in case of Generators;

(b) At low Voltage side of the step-down transformer, in case of Transmission Facility connected to DNO;

(c) At the high Voltage side of the step-down transformer, in case of Transmission connected BPCs;

(d) At the interface between the networks of two parties in any other case, in accordance with MC 3.8.2.

MC 3.8.2. Notwithstanding the above, the location of the Metering Point will be such that transformation and transmission lines losses shall always be assigned to the User that owns the transformer or transmission line, respectively.

MC 3.8.3. Where there are practical constraints, Metering System can be installed at a physically different location other than the actual Metering Point as stated above. In such cases, the MSP shall determine the parameters for accounting of losses, which shall be submitted to the Authority for approval.

MC 3.9. Metering Point Documentation

MSP shall maintain the following minimum documentation for each Metering System:

(a) Unique identification and name of the Metering Point and User site;

(b) Unique identification and name of the relevant User;

(c) Metering single line drawing showing the actual electrical location of all the meters and Instrument Transformers within the Metering System;

(d) Unit of measurement used to measure energy and power flowing through the Metering System;

(e) Unique internal meter identifier, the passwords, the online secure communication address for the Metering System;

(f) Site-specific loss adjustment and measurement error correction factors to be applied, including the sign of the loss adjustment;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(g) Burdens connected to each Instrument Transformer contained within the metering system;

(h) Instrument Transformer detailed data and operational configuration;

(i) Contact details for purpose of communication between the MSP and the relevant User; and

(j) Any other integration remarks, required by the MSP.

MC 4. METERING SYSTEM PERFORMANCE REQUIREMENTS

MC 4.1. Applicable Standards and Specifications

The components of Metering Systems must comply with the latest applicable standards (international and national) including but not limited to the following:

(a) The Authority's standards and specifications pursuant to the Section 35 of the Act; or

(b) NGC standards and specifications as a bare minimum in the absence of standards and specifications pursuant to item (a) above; or

(c) Standards and specifications developed by the involved TNO (having registered MSP function) provided it meets the minimum requirements of item (a) and (b) above.

MC 4.2. In addition to compliance with the relevant standards as mentioned in MC 4.1, the Primary and Back-up Meters shall have the following minimum characteristics:

(a) Bidirectional, 4-Quadrant electronic, digital, with 3-Phase 4-wire meter connection configuration with accuracy class as defined in MC 4.6;

(b) Meter shall be rated for

  (i) Reference Voltage (phase-phase) = 100-110 V;

  (ii) Reference Frequency = 50 Hz;

  (iii) Nominal current (In) = 1.2 times In (secondary) with selectable option for 1 A or 5 A;

  (iv) Short-time over-current shall be 20 times I_{max} for 0.5s;

  (v) Impulse Voltage withstand level = 8 kV;

  (vi) Power Frequency withstand level = 4 kV;

(c) Meters shall be capable of measuring and recording time stamped Load Profile. The Load Profile must support multiple channels (minimum 16 channels) with configurable logging interval and the minimum memory capacity as follows:

  (i) Incremental and cumulative energy (active and reactive) every thirty (30) minutes interval, with a storable capacity of at least seventy (70) days.

(d) The meter must have the capability of recording active and reactive power, and energy for defined billing period. The meter-billing period may be

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

programmable and shall automatically store the accumulated registers and increment the reset counter for the next billing period;

(e) Meter shall store all Energy and Maximum Demand registers for at least fifteen (15) previous billing intervals;

(f) Multiplier corresponding to the combination of CT and VT ratios may be programmable in the meter and any manual meter multiplying factor shall be avoided;

(g) Meters shall have internal time clock for time and date stamping of Metering Data. Time clock must be capable of synchronization to Meter Data Management (MDM) server that will be according to the Pakistan Standard Time;

(h) Meters shall support Maximum Demand measurement over programmable fixed intervals;

(i) Meters should have capability for remote meter reading by Advanced Metering Infrastructure (AMI) and/or by SCADA and communication/integration with the central Meter Data Management (MDM) Server of MSP. Data communication ports as per requirement of MSP shall be provided along with optical communication;

(j) Meter should have self-diagnostic capability, maintain complete event log, and include an alarm to indicate failure and/or tampering.

MC 4.3. In addition to compliance with the relevant standards as mentioned in MC 4.1, the Primary and Back-up Instrument Transformers shall have the following minimum characteristics:

(a) Primary Instrument Transformers and cables used for Revenue Metering purposes shall not be shared with any other system;

(b) Back-up Instrument Transformers and cables used for Revenue Metering purposes shall not be shared with any other system;

(c) Instrument Transformers shall be operated within the rated burden limits. Prior approval of MSP shall be required for any change/modification in the connected burden of the Instrument Transformers;

(d) Instrument Transformers shall have a locking termination compartment that can be sealed;

(e) The Primary and Back-up current transformers shall have a rated secondary current of 1A, and burden of minimum 10 VA;

(f) The short circuit withstand capability for Instrument Transformers shall be as per the Connection Studies, performed or approved by the SO and/or the involved TNO, as it corresponds.

MC 4.3.1. In case of BPCs (up to 30 MW) connected through GIS, separate metering cores of Instrument Transformers can be utilized for Primary Metering System with the approval of MSP as mentioned in MC 3.3.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

MC 4.3.2. In case of non-generation facilities, if separate dedicated Back-up metering Instrument Transformers are not available, the Back-up Meters can be connected with the separate metering core of existing Instrument Transformers, with the approval of MSP as mentioned in MC 3.3.

MC 4.4. The secondary circuits of Instrument Transformers shall include interconnecting cables, wires, metering cabinets and associated devices like test blocks, VT fuses/VT MCBs (Miniature Circuit Breakers), contactors etc. and shall conform to the following minimum requirements:

(a) Terminal blocks shall be provided for Primary and Back-up Meters to facilitate on site tests. These terminal blocks shall be in close proximity to the Meters;

(b) Metering cabinets for Primary and Back-up Metering Systems shall be installed in the switchyard near the Metering Point in separate metering room;

(c) Separate fuses shall be installed for all burdens connected to VT;

(d) A glass window shall be provided on the door to permit visual and optical port reading of the meter.

MC 4.5. Separate communication modems for Primary & Back-up Meters shall be made available to ensure online availability and redundancy of Metering Data to Meter Data Management (MDM) Server of MSP and then onwards communication. MSP shall develop the necessary detailed Standard Operating Procedures.

MC 4.6. The communication between meters, communication modules, routers and MDM Server shall be securely isolated via use of VPNs, firewall to ensure network security and prevent unauthorized access of Metering Data.

MC 4.7. Metering System accuracy class selection shall be as per Table MC 1.

Table MC 1: Meters and Instruments Accuracy Class

Equipment		Equipment Accuracy Class Selection
Current Transformers		0.2s
Voltage Transformers		0.2
Meters	Active Energy	0.2s
	Reactive Energy	2

Error limits in accuracy for measurement of active & reactive energy of energy meter and Instrument Transformers shall be as per relevant IEC standards.

MC 4.8. Security and Sealing

MC 4.8.1. All components of Metering Systems (energy meters, meter communication devices, instrument transformers and their secondary circuits) shall be installed in such a manner that they cannot be tampered with.

MC 4.8.2. The MSP shall make arrangement to seal and secure all Primary & Back-up Metering Systems with unique serial number seals.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

MC 4.8.3. The MSP shall be responsible for record-keeping and supervision of sealing/de-sealing activities of Metering System. The authorized representatives of the relevant User and MSP shall be present during the said sealing/de-sealing activities.

MC 4.8.4. All wiring between Instrument Transformers outside the metering compartment shall be installed in rigid galvanized steel conduits.

MC 4.8.5. Primary and Back-up metering rooms shall be locked and sealed under supervision and control of authorized representative nominated by MSP.

MC 4.8.6. To prevent unauthorized access to the data in the Metering System, a security scheme, as described below, shall be incorporated for both direct local and remote electronic access:

(a) Level 1 security, with or without password for read-only access of the Metering Data including meter time, data registers and Load Profile.

(b) Level 2 security with password for programming of CT and VT ratios, and other parameters including Load Profile configuration, display sequences, Maximum Demand period, MDI reset.

(c) Level 3 security with password for corrections to the time and date

MC 4.8.7. In case of tampering with Metering System, MSP shall perform audit/enquiry of User's Metering System to ascertain if the tampering is deliberate or inadvertent and the duration of such tampering. If the tampering of Metering System is proven to be deliberate, a complaint will be lodged by MSP with the Authority and the appropriate law enforcement agency for investigation and/or punitive actions as per law of the country, if any.

If the MSP detects any anomaly, including maintenance defects, inappropriate equipment, or evidence of tampering, thereof, it shall prepare a Metering Incident Report, informing this situation to the Market Operator as per the provisions of the Market Commercial Code.

MC 5. ADVANCED METERING INFRASTRUCTURE (AMI)

MC 5.1. MSP shall establish Advanced Metering Infrastructure (AMI) system to facilitate measurement, recording and communication of Metering Data. The minimum parameters of this Metering Data shall include following:

(a) Active energy import and export registers

(b) Reactive energy import and export registers

(c) Active import and export billing maximum demand registers (with date-time)

(d) Reactive import and export billing maximum demand registers (with date-time)

(e) 30 minutes (or less-than) timestamped Load Profile data for channels including:

(i) Active energy import

(ii) Active energy export

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

(iii) Reactive energy import

(iv) Reactive energy export

(v) Power-factor each phase

(vi) Voltage each phase

(vii) Current each phase

(f) Meter local time

(g) Maximum Demand reset counter

(h) Meter event log

MC 5.2. MSP shall maintain MDM server with database of all metering devices installed at Metering Points to store the Metering Data along with meter information, metering constants, Instrument Transformer ratios, etc. required for billing and settlement in accordance with the Market Commercial Code.

MC 5.3. MSP shall formulate operating procedures for operation and maintenance of the AMI System to achieve uninterrupted and complete Metering Data retrieval which shall cover the following:

(a) Metering Data Reading remotely by MDM/by locally attached device/by hand-held data collection device as required. In the event of failure of communications facilities, Metering Data shall be read locally from the meter and transferred to the Meter Data Management (MDM) Server.

(b) Metering Data Validation, Estimation & Editing (VEE), as per the requirements of the MCC and/or any other applicable regulation.

(c) Time synchronization of meters

(d) Meter display parameters

(e) Sign conventions

MC 5.4. Data Communications

MC 5.4.1. Meters shall be equipped with standard communications ports/modules for local and remote downloading of Load Profile and other Metering Data.

MC 5.4.2. Both the Primary and Back-up Energy meters shall be integrated in the AMI System of MSP. The relevant User shall be provided with read-only indirect access of Metering Data for its Primary and Back-up Meters.

MC 5.4.3. The communication protocol for transmitting Metering Data shall be in accordance with IEC 61107, IEC 62056 (DLMS/COSEM/UDIL specifications), or IEC 61850.

MC 5.4.4. Provided energy meter shall be capable of integration with the MDM Server of MSP. All the necessary communication modules required for this integration shall be provided by User.

MC 5.4.5. Remote communication option shall be provided by means of suitable communication medium as deemed appropriate by MSP while adhering to security guidelines as set out in MC 4.6.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

MC 5.5. Metering Data Storage

MC 5.5.1. MSP shall maintain record of Metering Data in MDM server for at least five (5) years. Metering Data shall be maintained with a back-up arrangement.

MC 5.5.2. The stored Metering Data values shall be in kilowatt (kW) and kilowatt-hour (kWh) for power and energy respectively.

MC 5.5.3. In the event of a power supply failure, the meters shall protect all data stored up to the time of the failure and maintain the time accuracy. To cater for continuous supply failures, the clock, calendar and all data shall be retained in meters for a period of at least twenty-four (24) months without an external supply connected.

MC 5.5.4. Uninterrupted auxiliary supply should be provided to meters and communication devices for metering and continuous transmission of data.

MC 5.5.5. A "read" action shall not delete or alter any stored Metering Data in the meter and MDM.

MC 5.6. Meter Time Synchronization

MC 5.6.1. Time of Metering System shall be kept synchronized as per Pakistan Standard Time (PST).

MC 5.6.2. Time synchronization of meters shall be performed as per MSP operating procedures and consequently, appropriate measures shall be taken to ensure the accuracy of the time-stamped Metering Data.

MC 5.7. Sharing of Metering Data

MC 5.7.1. The MSP shall share relevant Metering Data with the following:

(a) The MO for performing billing and settlement activities;

(b) The SO, required for operational monitoring;

(c) The involved User, to fulfil their own obligations.

MC 5.7.2. MSP shall keep the Metering Data confidential to avoid unauthorized access by any entity.

MC 5.8. Metering Data Validation, Estimation, and Editing (VEE)

The Metering Data – that will be transferred to the MO – shall be complete, correct and its type, format and Frequency shall be in accordance with the Market Commercial Code. For such purpose, the MSP shall follow the provisions of the Market Commercial Code and its associated CCOPs.

MC 5.9. Technical Disputes in Metering Data

MC 5.9.1. MSP shall resolve errors/omissions in Metering Data (as a result of metering system error or malfunction), if any, in collaboration with the relevant Users and the adjusted/corrected Metering Data shall be reported to the MO and the relevant Users.

MC 5.9.2. In case MSP and the relevant Users do not reach an agreement, the Dispute Resolution Procedure provided in the Market Commercial Code shall be followed.

MC 6.	**METERING SYSTEM TESTING**
MC 6.1.	The Metering System shall be subject to all special, type and factory acceptance tests as required in applicable standards and specifications in MC 4.1.
MC 6.2.	MSP shall be responsible for testing of Metering System as per the applicable IEC standards.
MC 6.3.	MSP shall maintain relevant record including but not limited to dates, readings, test results and adjustments for the life of metering equipment.
MC 6.4.	Equipment used for testing of Metering System shall conform to the applicable IEC standards and shall have a valid calibration certificate from an authorized entity and/or the relevant accreditation authority.
MC 6.5.	**Commissioning Tests**
MC 6.5.1.	Metering System shall be subject to Site Acceptance Tests (SAT) to ensure compliance of applicable standards and specifications mentioned in MC 4.1.
MC 6.5.2.	MSP shall conduct commissioning tests of the Primary and Back-up Meters in the presence of authorized representatives of the relevant Users.
MC 6.5.3.	User shall be responsible for conducting commissioning tests of the Instrument Transformers in the presence of authorized representatives of the relevant Users.
MC 6.5.4.	After successful commissioning tests, the MSP shall issue a certificate to the relevant User certifying the completeness of the Metering System.
MC 7.	**ROUTINE AND OFF-SCHEDULE TESTING**
MC 7.1.1.	MSP shall conduct Meter testing periodically at least once in every two (2) years in the presence of authorized representatives of the relevant Users.
MC 7.1.2.	User shall be responsible for conducting routine and accuracy testing of Instrument Transformers at least once in every five (5) years in the presence of authorized representatives of the relevant Users.
MC 7.1.3.	The MSP shall take appropriate corrective measures if difference between the Primary and Back-up Metering Data is more than ±0.5% for active energy or ±4% for reactive energy.
MC 7.1.4.	User can request for an off-schedule testing at its own cost.
MC 7.1.5.	Inaccurate or faulty equipment shall be replaced by the respective User who owns the assets.
MC 8.	**ACCESS TO USER PREMISES**
MC 8.1.	MSP shall have the right to enter premises of the relevant User for the purpose of installing, checking, testing and maintaining of Metering System. The User shall cooperate with the MSP in this regard and shall not prevent the MSP from making unscheduled inspections on reasonable prior notice.
MC 8.2.	The right of access provided for under this sub-code includes the right to bring on to the User's property such vehicles, test equipment, and maintenance/communication equipment or other materials as may be necessary for the purpose of testing and troubleshooting of Metering System faults.

DATA REGISTRATION CODE

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

DRC 1. **INTRODUCTION**

DRC 1.1. The Data Registration Code (DRC) presents a unified listing of all data required by the SO from Users and vice versa, from time to time under the Grid Code. The data is specified in each sub-code of the Grid Code and gathered here in the DRC. Where there is any inconsistency/conflict in the provisions and/or data requirements under DRC with another sub-code, the provisions of the respective sub-code of the Grid Code shall prevail.

DRC 1.2. The specific procedures and timelines for the submission of DRC data, for routine updating, and recording temporary or permanent changes to the data, are specified in the respective sub-codes under which any item of the data is required.

DRC 1.3. The SO reserves the right to ask for any other data not listed in the DRC or in any sub-code of the Grid Code as per its requirement.

DRC 2. **SCOPE**

This sub-code is applicable to the SO and:

(a) Transmission Network Operators;

(b) Transmission connected Generators;

(c) Transmission connected Consumers;

(d) Interconnectors;

(e) Energy Storage Units;

(f) Demand Side Units;

(g) Metering Service Provider;

(h) Distribution Network Operators;

(i) Market Operator;

(j) Small/Embedded generators whether represented through some Aggregators or any other arrangement (if required by SO); and

(k) Third parties contracted by any User.

DRC 3. **DATA CATEGORIES FOR REGISTRATION**

DRC 3.1. Each data item is allocated to five categories and annexed with the respective sub-code:

(a) Planning Code (PC) Data list mentioned in Schedule I

(b) Connection Code (CC) Data list mentioned in Schedule II

(c) Operation Code (OC) Data list mentioned in Schedule III

(d) Scheduling and Dispatch Code (SDC) Data list mentioned in Schedule IV

(e) Metering Code (MC) Data list mentioned in Schedule V

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

DRC 4. PROCEDURES AND RESPONSIBILITIES

DRC 4.1. Responsibility for Submission of Data

User shall submit data as summarised in DRC in accordance with the provisions of the various sub-codes of the Grid Code.

DRC 4.2. Methods of submitting Data

DRC 4.2.1. The data requirements annexed with the sub-codes are structured to serve as standard templates for the data submission in written format to the SO.

DRC 4.2.2. Data shall be submitted to the SO, or to any other entity (TNO, MSP, NGC, etc.) as advised by the SO. The name of the person submitting the schedule of data on the behalf of the User shall be included.

DRC 4.2.3. Subject to SO's prior written consent, where a computer or electronic data exchange link exists between a User and SO, the data can be submitted via this link.

DRC 4.3. Changes to User's Data

The User must notify SO whenever the User becomes aware of change to any item of the data which is registered with the SO.

DRC 4.4. Data not supplied

DRC 4.4.1. User and SO are responsible to submit data as set out in the sub-codes of the Grid Code and mentioned in the DRC.

DRC 4.4.2. If User fails to submit the data as per DRC requirements even after the SO's reminder notice, SO shall make an estimation (typical values) of such data, if and when, in the SO's view, it is necessary to do so.

DRC 4.4.3. If SO fails to provide the data as per requirements of any sub-code of the Grid Code, the User to whom that data ought to have been provided, shall estimate (typical values) of such data, if and when, in that User's view it is necessary to do so.

DRC 4.4.4. Such estimates shall, in each case, be based upon data supplied previously for the same Plant and Apparatus or upon such other information as SO or that User, as the case may be, deems appropriate.

DRC 4.4.5. In the event of data not being provided, SO shall inform the User in writing of any estimated data it intends to use pursuant to DRC 4.4.2.

DRC 4.4.6. In the event of data not being provided, the User shall inform SO in writing of any estimated data it intends to use pursuant to DRC 4.4.3.

DRC 4.4.7. In the event the required data is consistently not submitted, or is incomplete or inaccurate, by the User, the SO shall refer the matter to the "Grid Code Review Panel", which shall issue necessary instructions to the defaulting party in writing.

DRC 4.4.8. In the event the required data is consistently not submitted, or is incomplete or inaccurate, by the SO, the User shall refer the matter to the "Grid Code Review Panel", which shall issue necessary instructions to the defaulting party in writing.

DRC 4.4.9. Failure to obtain the required data within the specified timeframes from the defaulting party, NEPRA shall consider the matter as a violation of the Grid Code

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

provisions. Suitable measures as specified in CM 15 regarding Grid Code non-compliance shall be used.

DRC 4.5. Confidentiality Obligations

Users shall use their best efforts to stop the disclosure of any of the confidential information which comes into the possession or control of that User or of which the User becomes aware of. The User:

(a) must not disclose confidential information to any person except as permitted by the Grid Code;

(b) must only use or reproduce confidential information for the purpose for which it was disclosed, or another purpose contemplated by the Grid Code;

(c) must not permit unauthorized persons to have access to confidential information;

(d) to prevent unauthorized access to confidential information which is in the possession or control of that User; and

(e) to ensure that any person to whom it rightfully discloses confidential information observes the provisions of Grid Code.

DRC 5. DATA TO BE REGISTERED

DRC 5.1. Schedules I to V cover the following data areas:

DRC 5.1.1. SCHEDULE I - Planning Code Data

Standard Planning schedules comprising of data including General Information, User System Data (Maps and Diagrams), Licensing and Authorization, User System Layout (Single Line Diagrams, Circuit Parameters, Lumped System, Susceptance, Reactive Compensation Equipment and Short-Circuit Contribution to TNO/DISCO Transmission System), Data Required for Load Forecasting and Data Requirement for Generation Capacity Expansion Plans.

Project Planning schedules comprising of data including Generator Data (Generator Unit Details, Excitation System Parameters, Speed Governor System, Power System Stabilizers), Controllable Solar, Wind and ESPP (SWE) Data Requirements (SWE Generators Parameters, Mechanical parameters, Aerodynamic performance, Reactive Power Compensation, Control and Protection systems, Internal network of Controllable SWE, Flicker and Harmonics and Short Circuit Contribution and Power Quality) and Interconnector Data Requirements (Interconnector Operating Characteristics and Registered Data).

DRC 5.1.2. SCHEDULE II – Connection Code Data

Connection Code schedules comprises of data including list of minimum requirements for Power System And Apparatus Connected to the Transmission Systems, Grid Station Information, DC Convertor Station, Power Generators Unit Data, Generator (Unit) Transformer, Excitation System (AVR and Exciter Parameters), Generating Unit Stabilizer Data, Governor Data, Prime Mover Data, Wind Turbine Generator, Transmission Lines Data, Power Transformer Data, Bus bar Data, Circuit Beaker Data, Isolator Data, Shunt Reactor Data, Pro forma for Site Responsibility Schedule (SRS), Principles and Procedures Relating to Operation

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY * NEPRA *

Diagrams, Appendix Principles and Procedures Relating to Gas Zone Diagrams, Apparatus to be Shown on the Operation and Gas Zone Diagrams, Minimum Frequency Response Requirements Scope, Technical Requirements for Low Frequency Relays for the Automatic Load Shedding, SCADA Signals to be Provided by Users (Status Indication Signals, Measurement Signals, Control Signals, Protection Signals, Other Signals, Signals related to Generators, Signal related to Demand Side Units and Signals related to AC and HVDC Interconnectors), Voltage against Time Profile.

DRC 5.1.3. **SCHEDULE III – Operation Code Data**

Operation Code schedules comprises of data including Emergency Manual Demand Reduction/Disconnection, Short Term Planning Timetable for Generation Outages, Medium Term Planning Timetable for Generation Outages, Long Term Planning Timetable for Generation Outages, Transmission Outages, Generator Performance Chart, Generation Planning Parameters, Technical Parameters - RES/BESS, Technical Parameters – Interconnectors, Response data for Frequency Changes, Primary Response to Frequency Fall, Secondary Response to Frequency Fall, High Response to Frequency Rise, Generator, Governor and Droop Characteristics, Unit Control Options, Control of Load Demand, Significant System Incident, System Warnings, Inter-System Safety record of Inter-Safety Precautions (RISSP - R), Inter-System Safety record of Inter-Safety Precautions (RISSP - R).

DRC 5.1.4. **SCHEDULE IV – Schedule and Dispatch Code Data**

Schedule and Dispatch Code schedules comprises of data including Technical Parameters, Availability Notice, Notification of Revised Availability Notice, Technical Parameters Revision Notice and Dispatch Instructions for CDGUs and Demand Side Units.

DRC 5.1.5. **SCHEDULE V – Metering Code Data**

Metering Code schedules comprises of data including Technical Parameters for Metering Voltage Transformer and Metering Current Transformer.

DRC 5.2. If at any time, SO considers that the Schedules do not reflect the operative provisions relating to the submission of data, the SO may, by notice in writing to all affected User amend the Schedules to this DRC.

DRC 5.3. No changes may be made in DRC schedules which would affect the substantive obligations of the Users. Changes of this nature can only be achieved by means of the usual procedure for Grid Code changes and will require the approval of NEPRA.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

DEFINITIONS AND ACRONYMS

Acronym	Meaning
AC	Alternating Current
ADMS	Automatic Demand Management System
AGC	Automatic Generation Control
AJK	Azad Jammu and Kashmir
ALFDD	Automatic Low Frequency Demand Disconnection
ALVDD	Automatic Low Voltage Demand Disconnection
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
APP	Annual Production Plan
ARE	Alternative and Renewable Energy
ASRAIR	Annual System Reliability Assessment And Improvement Report
AVR	Automatic Voltage Regulator
BCC	Back-up Control Center
BESS	Battery Energy Storage System
BOO	Build Own Operate
BOOT	Build Own Operate Transfer
BOT	Build Operate Transfer
BPC	Bulk Power Consumer
CC	Connection Code
CCGT	Combined Cycle Gas Turbine
CCOP	Commercial Code Operating Procedure
CDGU	Centrally Dispatched Generating Unit
CFPP	Coal Fired Power Plant
CM	Code Management
COD	Commercial Operation Date
COSEM	Companion Specification for Energy Metering
CSP (Solar)	Concentrated Solar Power
CT	Current Transformer
CTBCM	Competitive Trading Bilateral Contracts Market

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

CVT	Capacitive Voltage Transformer
DB	Distribution Box
DC	Direct Current
DCS	Distributed Control System
DISCOS	Ex-WAPDA Distribution Companies
DLMS	Device Language Message Specification
DNO	Distribution Network Operator
DRC	Data Registration Code
DST	Daylight Saving Time
ECC	Emergency Control Center
EMC	Electromagnetic Compatibility
EON	Energization Operational Notification
EPA	Energy Purchase Agreement
ESU	Energy Storage Unit
EV	Electric Vehicles
FACT	Flexible AC Transmission
FAT	Factory Acceptance Test
FESCO	Faisalabad Electric Supply Company
FGC	Free Governor Control Action
FON	Final Operational Notification
FRT	Fault Ride Through
G&TOP	Generation and Transmission Outage Program
GB	Gilgit-Baltistan
GCOP	Grid Code Operating Procedure
GCRP	Grid Code Review Panel
GEPCO	Gujranwala Electric Power Company
GIS	Grid Impact System
GIS	Gas Insulated Substation
GPS	Global Positioning System
GSM	Global System for Mobile Communication
HESCO	Hyderabad Electric Supply Company
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

HVRT	High Voltage Ride Through
ICE	Internal Combustion Engine
ICT	Information and Computer Technology
IEC	International Electro-Technical Commission
IEEE	Institute of Electrical and Electronics Engineers
IESCO	Islamabad Electric Supply Company
IGCEP	Integrated Generation Capacity Expansion Plan
ION	Interim Operational Notification
IOS	Indicatable Operations Schedule
IPS	Intrusion Prevention System
ISP	Integrated System Plan
ITU	International Telecommunications Union
KE	K-Electric
LDC	Load Dispatch Center
LESCO	Lahore Electric Supply Company
LFC	Load/Frequency Control
LOLP	Loss of Load Probability
LON	Limited Operational Notification
LVRT	Low Voltage Ride Through
MAPE	Mean Absolute Percentage Error
MC	Metering Code
MCB	Miniature Circuit Breaker
MCC	Main Control Center
MDI	Maximum Demand Indicator
MDM	Meter Data Management
MDR	Minimum Demand Regulation
MEPCO	Multan Electric Power Company
MO	Market Operator
MS	Milliseconds
MSP	Metering Service Provide
MVAR	Megavolt-Amperes Reactive
NDA	Non-Disclosure Agreement
NEPRA	National Electric Power Regulatory Authority

NGC	National Grid Company
NIOM	Notice of Inadequate Operating Margin
NTDC	National Transmission and Despatch Company
NTS	Notice to Synchronize
O&M	Operation and Maintenance
OC	Operation Code
OCGT	Open Cycle Gas Turbine
OHL	Overhead Line
OLT	Open Line Test
OLTC	On Load Tap Changer
OP	Operation Code
OPGW	Optical Ground Wire
PF	Power Factor
PU	Per Unit
PC	Planning Code
PCC	Protection And Control Code
PCS	Plant Control System
PESCO	Peshawar Electric Supply Company
PGC	Provincial Grid Company
PLCC	Power Line Carrier Communication
PMS	Power Market Survey
PPA	Power Purchase Agreement
PRP	Parallel Redundancy Protocol
PSS	Power System Stabilizer
PSS	Power System Stabilizers
PST	Pakistan Standard Time
PSTN	Public Switched Telephone Network
PT	Potential Transformer
PTP	Precision Time Protocol
PV (SOLAR)	Photovoltaic
QESCO	Quetta Electric Supply Company
REF	Restricted Earth Fault
RIV	Radio Influence Voltage

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

RM	Reserve Margin
ROCOF	Rate of Change of Frequency
RPC	Reactive Power Controller
RTU	Remote Telemetry Unit
SAS	Substation Automation System
SAT	Site Acceptance Test
SCADA	Supervisory Control and Data Acquisition
SCED	Security Constrained Economic Dispatch
SCR	Short Circuit Ratio
SCS	Stability Control System
SCUC	Security Constrained Unit Commitment
SDC	Scheduling and Dispatch Code
SEPCO	Sukkur Electric Power Company
SIAS	System Impact Assessment Studies
SIC	Signals Interface Cabinets/Cubicles
SMS	Smart/Secured Metering System
SO	System Operator
SOP	Standard Operating Procedure
SPA	Special Purpose Agent
SPS	Special Purpose Scheme
SPTL	Special Purpose Transmission Licensee
SRS	Site Responsibility Schedule
SSCI	Sub-synchronous Control Interaction
SSTI	Sub synchronous torsional interaction
ST	Steam Turbine
STATCOM	Static Synchronous Compensator
STPM	Short Term Planned Maintenance
SVC	Static VAR Compensator
SWE	Solar, Wind And Energy Storage Generators
TESCO	Tribal Areas Electric Supply Company
TNO	Transmission Network Operator
TPCS	Transmission Planning Criteria and Standards
TSEP	Transmission System Expansion Plan

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

UPS	Uninterrupted Power Supply
VEE	Validation Estimation and Editing
VPN	Virtual Private Network
VRE	Variable Renewable Energy
VSAT	Very Small Aperture Terminal
VSC	Voltage Source Converter
VT	Voltage Transformer
WAMPAC	Wide Area Monitoring, Protection and Control
WAMS	Wide Area Management/Monitoring System
WAPDA	Water and Power Development Authority
WTG	Wind Turbine Generator
ZVRT	Zero Voltage Ride Through

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Definitions

Term	Definition
Act	The Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (XL of 1997), as amended from time to time.
Active Energy	The electrical energy produced, flowing or supplied by an electrical circuit during a time interval, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof.
Active Power	The product of Voltage and the in-phase component of alternating current measured in units of watt and standard multiples thereof.
Advanced Metering Infrastructure or (AMI) or Secured Metering System (SMS)	The system, including hardware, software and communication channels, which records and retrieves information from the Metering System and transfers it electronically at specified times.
Affected User	A User, affected by any Operation, Event or Significant Incident, which provides evidence in the matter to the satisfaction of the SO.
AGC Control Range	The range of loads over which AGC may be applied.
AGC Maximum	The upper limit of the AGC Control Range.
AGC Minimum	The lower limit of the AGC Control Range.
Aggregated Generating Unit	A group of Embedded Generators Units represented by an Aggregator.

Term	Definition
Aggregators	It may represent more than one Embedded Generator.
Alert	Warning issued pursuant to OC 12.4.
Amendment	A change or modification in any provisions of the Grid Code, but not the Grid Code in its entirety, recommended by the Grid Code Review Panel and approved by the Authority.
Ancillary Services	The different services, other than the production of electricity, that are required to operate and maintain power quality and a stable and reliable Power System that includes Reactive Power, Operating Reserve, Frequency Control and Black Start Capability. The financial compensation of an ancillary service, when applicable, is established through provisions in the Market Commercial Code.
Apparatus	The electrical apparatus, including all apparatus, machines, and fittings in which conductors are used, or of which they form a part.
Apparent Power	The product of Voltage and of alternating current measured in units of Volt-Amperes and standard multiples thereof, and for AC systems consists of a real component (Active Power) and an imaginary component (Reactive Power).
Applicable Documents	The rules, regulations, terms and conditions of any licence, registration, authorisation, determination, any codes, manuals, directions, guidelines, orders, notifications, agreements and documents issued or approved under the Act.
Authority	The National Electric Power Regulatory Authority established under Section 3 of the Act.
Automatic Generation Control (AGC)	A control system installed at Generators whereby Active Power (MW) can be adjusted remotely by the SO to reflect the Dispatch Instruction and Frequency Control.
Automatic Low Frequency Demand Disconnection	The automatic disconnection of Load when the Frequency is lower or the rate of change of Frequency is greater than permissible limits in accordance with this Grid Code.
Automatic Low Voltage Demand Disconnection (ALVDD)	The automatic disconnection of Load when the Voltage has dropped below permissible limits in accordance with this Grid Code.
Automatic Meter Reading (AMR)	A technology of automatically collecting consumption, diagnostic, and status data from energy metering devices and transferring that data to a central database for billing, troubleshooting, and analyzing.
Automatic Reactive Power Regulator	Automatic control system which acts to control continuously the reactive power exchange with the Power System in accordance with instructed modes and set points.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Term	Definition
Automatic Voltage Regulator (AVR)	A continuously acting automatic excitation control system to control the Voltage of a Generator at the Generator terminals within a reference set point value.
Auxiliaries	The supplementary equipment or apparatus other than Generating Units, required for the operation of Generation Facility. "Auxiliary" shall be construed accordingly.
Availability	At any given time: the measure of Active Power (MW) a Generating Units is capable of delivering at the Connection Point; The measure of Active Power (MW) a ESU is capable of delivering/consuming at the Connection Point; the measure of Active Power an Interconnector is capable of importing to or exporting from the Connection Point; the capability of a transmission line, or any other system component or facility, to provide service when energized, irrespective of whether or not it is actually in service. The term "Availabilities" and "Available" shall be construed accordingly.
Availability Factor	The ratio of the Energy that could have been produced during a specified period of time by a Generating Unit operating in accordance with its Availability, and the Energy that could have been produced during the same period by that Generating Unit operating at its Registered Capacity.
Availability Notice	A notice to be submitted to the SO pursuant to SDC 1.
Available Transfer Capability	The effective power that can be imported from or exported to an Interconnector for load dispatch or energy exchange between Power Systems.
Average Conditions	The combination of elements within a period of time which is the average of the observed values of those elements during equivalent periods over many years.
Back-up Control Center	The stand-by Control Center of the SO to be used as an alternative if it's Main Control Center fails or is rendered un-operational.
Back-up Meter	A backup metering device used to record electrical quantities such as energy, MDI, etc. for verification or substitution purposes.
Back-up Metering System	A backup metering system, established according to the requirements of the Grid Code, to measure and record the Energy injected into or withdrawn from the Transmission System by relevant Code Participant.

Term	Definition
Back-up Protection/Secondary Protection	A Protection System which will operate when a system fault is not cleared by Primary Protection/Main Protection.
Base Case	The Power System's software model for a particular project under study.
Black Start	The procedure necessary for a recovery of Power System from a Total Shutdown or Partial Shutdown.
Black Start Capability	The ability of a Generator to start up at least one of its Generating Units from Shutdown; and to energize a part of the National Grid and/or be synchronized to the National Grid without any external electrical power supply; or The ability of an HVDC System to start-up from Shutdown and to energize a part of the National Grid and be synchronized to the National Grid without any external electrical power supply.
Black Start Station	The designated Generators/HVDC System with Black Start Capability, with an emergency auxiliary (station service) supply, such as auxiliary diesel-electric generator capable of supplying auxiliary power.
Black Start Test	A test carried out by a Generator/HVDC System to demonstrate that the designated Black Start Station has a Black Start Capability.
Block Load	The level of output that a Generating Unit/Interconnector immediately produces following Synchronization. The term "Block Loading" shall be construed accordingly.
Block Load Cold	Block Load during a Cold Start.
Block Load Hot	Block Load during a Hot Start.
Block Load Warm	Block Load during a Warm Start.
Bulk Power Consumer (BPC)	Shall have the meaning assigned to the term in the Act.
Transmission System Expansion Plan (TSEP)	A transmission expansion plan as elaborated in PC 4.3.
Cancelled Start	A response by a Generator to an instruction from the SO cancelling a previous instruction to Synchronize to the Transmission System.
Capability Curve	The curve of equipment that defines the boundaries within which it can deliver Active Power and Reactive Power continuously without overheating.
Capacity	The rated continuous load-carrying ability, expressed in Megawatts (MW) or Megavolt-Amperes (MVA) of generation, transmission, or other electrical equipment.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Term	Definition
Capacity Adequacy	A condition when there is sufficient Generation Capacity to meet the Demand and Operating Reserve requirements.
Cascading Outage	The uncontrolled successive loss of system components triggered by an Incident at any location.
CCGT Installation Matrix	The matrix which must be submitted by a CCGT installation which is used by the SO for Scheduling and Dispatch purposes under the SDC as a "look up" table determining which CCGT Units will be operating at any given MW Dispatch level subject to any updated Availability information submitted by a Generator to a SO under SDC 1.
CCGT Installation/Complex	A collection of Generating Units comprising one or more Combustion Turbine Units and one or more Steam Units where, in normal operation, the waste heat from the Combustion Turbine Units is passed to the water/steam system of the associated Steam Unit or Steam Units and where the component Generating Units within the CCGT Installation are directly connected by steam or hot gas lines which enable those Units to contribute to the efficiency of the combined cycle operation of the CCGT Installation/Complex.
CCGT Unit	A Generating Unit within a CCGT Installation
Central Dispatch	The process of Scheduling and issuing Dispatch Instructions directly to a Control Facility by the SO pursuant to the Grid Code.
Centrally Dispatched Generating Unit	A Generating Unit within a Generator subject to Central Dispatch. Further elaborated in SDC 1
Charging Capacity	The maximum amount of Energy consumed by Energy Storage Unit when acting as a Demand.
Code Participant	Any person being the participant of the Grid Code, as described in CM 3.
Cold Start	Any Synchronization of a Generating Unit that has previously not been Synchronized for a period of time longer than its submitted Warm Cooling time.
Combustion Turbine Units	The Generating Unit which compresses the inlet air and feeds fuel to the combustion chamber. The fuel and air burn to form hot gases which in turn forces these hot gases into the turbine, causing it to spin. The turbine can be fueled by natural gas, by distillate or by other such fuels as technology may allow.
Commercial Code or Market Commercial Code	The Commercial Code or Market Commercial Code prepared and maintained by the Market Operator pursuant to sections 23A and 23B of the Act and approved by the Authority that may be amended or replaced from time to time.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
Commissioning	The activities involved in undertaking the Commissioning Test or implementing the Commissioning Instructions pursuant to the terms of the Connection Agreements or as the context requires the testing of any item of relevant Code Participant equipment required pursuant to this Grid Code prior for the SO to authorize the connection or re-connection in order to determine that it meets all requirements and standards for connection to the Transmission System.
Commissioning Instructions	A step-by-step test procedure for a Commissioning Test.
Commissioning Test	The testing of a User or an item of User's Equipment required pursuant to the Connection Conditions prior to connection or re-connection in order to determine whether or not it is suitable for connection to the Power System and also to determine the new values of parameters to apply to it following a material alteration or modification of a User or of an item of User's Equipment and the term "Commissioning Testing" shall be construed accordingly.
Committed Data	Shall have the meaning as described in PC 3.2.2.
Committed Outage Program	The Outage Program that the SO shall prepare for the period up to end of Year 1.
Congestion	A constraint that would result or is resulting from overloading of Equipment which could jeopardize the System Security and System Integrity.
Connection Agreement	Shall have the meaning as described in CC 2.4.
Connection	The installation of electrical Equipment used to connect a User's System to the Transmission System in such a way that, subject to energization, the User may exchange electricity to or from the Transmission System at the Connection Point. The term "Connected" shall be construed accordingly.
Connection Date/Operational Date	The date on which the Commissioning Instructions have been properly implemented in respect of every part of the User's Equipment to the satisfaction of SO, following which the SO shall, as soon as reasonably practicable notify the User to that effect, specifying the date of completion of such implementation.
Connection Point	A physical point at which a User's Plant and Apparatus connects to the Transmission System.
Connection Site	A site containing a Connection Point.
Consumer/Customer/End User	"Consumer" shall have the same meaning as the term defined in the Act and reproduced hereunder:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Term	Definition
	"Consumer" means a person or his successor-in-interest who purchases or receives electric power for consumption and not for delivery or re-sale to others, including a person who owns or occupies a premises where electric power is supplied. "Customer" and "End User" shall be construed accordingly.
Contingency	The unexpected failure or Outage of a system component, such as a Generating Unit, transmission line, circuit breaker, switch, or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages.
Control Action	The process of managing the System Operator Transmission System or a Distribution System or a User System in "real time" by means of instructions issued verbally using the control telephony or by means of SCADA systems. Control includes monitoring as well as operating the networks.
Control Area	A coherent part of the Power System operated by a single System Operator with physical loads and controllable Generating Units connected within it.
Control Centre	The SO location used for the purpose of Monitoring, control and operation of the National Grid and for issuing Dispatch Instructions/Control Actions by the SO via Electronic Interface or any other such agreed means and approved by the Authority.
Control Facility	A User's location used for the purpose of Monitoring, control and operation of the User 's Plant and Apparatus and for accepting Dispatch Instructions via Electronic Interface.
Control Phase	The Control Phase follows on from the Operational Phase and covers the period from Day Ahead down to the real time.
Control Synchronizing	The coupling (by manual or automatic closing of the circuit breaker) of two asynchronous Systems by means of synchroscope.
Controllable Solar, Wind & ESPP/ESU (SWE)	Generation Facility based on Solar or Wind, as well as ESPP/ESU, the output of which can be remotely changed according to the minimum technical requirements.
Critical Loading	The condition where the loading of transmission lines or substation Equipment is between 90 percent and 100 percent of the continuous rating.
Cyber Asset	Any programmable electronic device, including hardware, software, information, or any of the foregoing, which are components of such devices or enable such devices to function.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

Term	Definition
Cyber Security	The application of technologies, processes and controls to protect systems, operations, networks, programs, devices and data from cyber-attacks.
Cycle Efficiency of ESU, BESS	The energy efficiency of an ESU over a complete cycle of charging and discharging.
Cycle Operating Mode	The Open Cycle Mode or combine cycle Operating Mode of a CCGT Installation which may need to be specified pursuant to a Dispatch Instruction under SDC 2.
Day Ahead	Pertaining to the next Scheduled Day
Daylight Saving Time	The practice of advancing clocks during different months so that darkness falls at a later clock time.
Deadband	A band of input values in a control system or signal processing system where there is no response.
Declaration	A notice prepared by the User submitted to the SO setting out the values (and times applicable to those values) of Availability, Ancillary Services capabilities, Operating Characteristics, and "Declared" shall be construed accordingly.
Declared Available Capacity	The Availability Declared under SDC.
De-Energize/Disconnect	Disconnect from the Transmission System utilizing circuit switches etc. to isolate the Plant and/or Apparatus, and "De-Energized" and "De-energizing" shall be construed accordingly.
Defense Plan	The set of manual or automatic control actions, defined in sequence by each system operator aimed at mitigating the consequences of exceptional contingencies.
Delivery Point	A Connection Point at which electric energy flows from an HVDC system into the Transmission System.
Deload Break Point	The point at which due to technical reason a Generating Unit may need to pause during its MW output reduction process.
Deloading Rate	The rate at which a Generating Unit reduces MW Output from Minimum Generation to zero when it is instructed to cease output.
Demand	The amount of electrical power consumed by the Power System comprising of both Active and Reactive Power, unless otherwise stated.
Demand Control	The reduction in Demand when the Grid is in an Emergency State. This includes Automatic Load Dropping, Manual Load Dropping and Demand reduction upon instruction by the System Operator.

Term	Definition
Load Forecast	The projections of Power and Active Energy requirements relating to a Connection Point, or group of Connection Points, in the Transmission System. The term "Forecasted Load" shall be construed accordingly.
Designated Control Center	The central location approved in writing by the SO as its Control Centers.
Designated Control Facility	The central location communicated in writing by the User to the SO as its Control Facility.
Designated Safety Operator	The operators approved in writing by the relevant User as competent to carry out the Safety procedure given in OC 13.
De-Synchronize	The act of taking a Generating Unit/Interconnector which is Synchronized to the Transmission System off the Transmission System to which it has been Synchronized and the term "De-Synchronized", "De-Synchronization" and other like terms, shall be construed accordingly.
Dispatch	The process of apportioning the total Demand of the System through the issuance of Dispatch Instructions to relevant Code Participant in order to achieve the operational requirements of balancing Demand with Generation and Ancillary services that will ensure the quality, reliability and Security of the Transmission System.
Dispatch Instruction	An instruction given by the SO under SDC for Dispatch. "Instruct" and "Instructed" shall be construed accordingly.
Dispute Resolution Procedure	A process or procedure to resolve disputes related to the implementation of the Grid Code among the Code Participants.
Distribution	Shall have the meaning assigned to the term in the Act and reproduced hereunder: "Distribution" means the ownership, operation, management or control of distribution facilities for the movement or delivery to consumers of electric power but shall not include the ownership, operation, management and control of distribution facilities located on private property and used solely to move or deliver electric power to the person owning, operating, managing and controlling those facilities or to tenants thereof.
Distribution Code	The code, approved by the Authority that defines the technical and operational aspects of the relationship between a Distribution Company acting as DNO and all those entities connected to the Distribution System of that DNO.
Distribution Facility	Shall have the meaning assigned to the term in the Act and reproduced hereunder:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
	"Distribution Facilities" means electrical facilities operating at the distribution Voltage and used for the movement or delivery of electric power.
Distribution Network Operator (DNO)	Shall have the same meaning as the term "distribution company" as defined in the Act and reproduced hereunder: "distribution company" means a person engaged in the distribution of electric power.
Dwell Time Down	The duration for which the Generating Unit must remain at the Dwell Time Down Trigger Point during a change in its MW Output while ramping down between instructed MW output and Minimum Generation.
Dwell Time Down Trigger Point	A constant MW level at which a Generating Unit must remain while ramping down between instructed MW output and Minimum Generation.
Dwell Time Up	The duration for which the Generating Unit must remain at the Dwell Time Up Trigger Point during a change in its MW output while ramping up between Minimum Generation and instructed MW output.
Dwell Time Up Trigger Point	A constant MW level at which a Generating Unit must remain while ramping up between Minimum Generation and instructed MW output.
Earth Fault Factor	The ratio of the highest power-frequency phase to earth Voltage on a healthy phase during an earth fault to the power frequency phase to earth Voltage in absence of the fault at the same location in the system
Earthing	A way of providing a connection between conductors and earth by an Earthing Device.
Earthing Device	A means of providing a connection between a conductor and earth being of adequate strength and capability for the intended purpose.
Economic Dispatch	The allocation of demand to individual generation plants or units to effect the most economical production of electricity for optimum system economy, security, and reliability with due consideration of incremental generation costs, incremental power purchase costs, incremental transmission and distribution losses, load flow considerations and other operational considerations as determined solely by the system operator.
Effective Date	The date on which sections 23G and 23H of the Act shall come into effect.
Electric Power Supplier	Shall have the same meaning as the term defined in the Act and reproduced hereunder:

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
	"Electric Power Supplier" means a person who has been granted a Licence under this Act to undertake supply of electricity.
Electronic Alert System	An Electronic Interface for issuing/receiving Alerts.
Electronic Interface	A system, in accordance with the requirements of the SO's data system, at the Control Center, providing an electronic interface between the SO and a User, for issuing and receiving instructions, including Dispatch Instructions as provided for in the Grid Code and established pursuant to an agreement between the SO and the User.
Embedded Generator	Generating Units within a Power Station which are directly connected to a Distribution System or the system of any other User and has no direct Connection to the Transmission System.
Embedded HVDC	HVDC system connected within a Control Area.
Emergency	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the safety and security of the Transmission System.
Emergency Assistance	The actions taken with respect to an Interconnector in case of Emergency in External System.
End Point of Startup Period	The time after which the rate of change of the Generating Unit output is not dependent upon the initial warmth of the Generating Unit.
Energize	The movement of any isolator, breaker or switch so as to enable active power and reactive power to be transferred to and from the Facility through the Generator's Plant and Apparatus and "Energized" and "Energizing", "Energization" shall be construed accordingly.
Energy	Electrical energy produced by Generating Units, flowing through or supplied by Transmission Facilities or Distribution Facilities, measured in units of kilo watt hours (kWh) or multiples thereof.
Energy Limit	The forecasted maximum amount of Energy that can be generated by an Energy Limited Generating Unit within a Schedule Day.
Energy Limited Generating Unit	A Generating Unit with a limit on the Energy it can deliver in a specified time period.
Energy Storage Generator (ESPP)	A site containing at least one ESU that can automatically act upon a remote signal to change its Active Power output.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
Energy Storage Unit (ESU)	Generating Units using generic storage devices to generate and consume electricity such as BESS and Pumped Storage Hydro Plants.
Event	An occurrence on, or relating to either the Transmission System or a User's System, including faults, Incidents and breakdowns. These include, *inter alia*: (a) Operations that form part of a planned outage which has been arranged in accordance with OC 4. (b) Events which cause plant or apparatus to operate beyond its rated design capability, and present a hazard to personnel. (c) Adverse weather conditions being experienced. (d) Failures of protection, control or communication equipment. (e) Risk of trip on apparatus or plant.
Excitation System	The Equipment providing the field current of Generating Unit, including all regulating and control elements, as well as field discharge or suppression Equipment and protective devices. The term "Excitation" shall be construed accordingly.
Extra High Voltage (EHV)	Voltages of 220 kV and 500 kV in Pakistan's Power Sector.
Exemption	"Exemption" is an exception to the ordinary operation of Grid Code obligation as an excuse from performance of a legal duty, obligation, liability or responsibility.
External Supply	An electrical supply source (diesel engine or any other) used to provide emergency electric power for Black Start capability in absence of supply from National Grid.
External System	A Power System that is connected to National Grid via an Interconnector.
Facility	Means Generation Facility or Transmission Facility or Distribution Facility.
Fault	Any abnormal condition of the Power System that involves the electrical failure of the equipment, such as transformers, generators, switchgear and bus bars, etc.
Fault Ride-Through Capability	The ability to stay Synchronized/connected to the Power System during and following a Fault.
Firm Capacity Certificate	Shall have the meaning as defined in the Market Commercial Code.
Flicker Severity (Short Term)	A measure of the visual severity of flicker derived from the time series output of flicker meter over a ten minute period and as such provides an indication of the risk of the User complaints.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Term	Definition
Flicker Severity (Long Term)	A value derived from 12 successive measurements of Flicker Severity (Short Term) (over a two-hour period) and a calculation of the cube root of the mean sum of cubes of 12 individual measurements.
Forbidden Zone	A MW range within which a Generator or Interconnector cannot operate in a stable manner due to an inherent technical limitation of the machine.
Force Majeure	Shall have the meaning ascribed thereto in CM 16.
Forced Outage	An Outage of a Generating Unit or a Transmission Facility due to a Fault or other reasons which has not been planned, also it results from emergency conditions directly associated with a component, requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed.
Forecast Minimum Generation Profile	The User's forecast of the average level of Minimum Generation, in MW, for the User's Plant for each Schedule Day
Forecast Minimum Output Profile	The User's forecast of the average level of minimum MW output, in MW, for each Schedule Day
Forecast Minimum Output Profile	The User's forecast of the average level of minimum MW output, in MW, for each Schedule Day
Formal Application	The process of application to be followed by User in accordance with CC 2.3.
Free Governor Response	The automatic adjustment of Active Power output by a Generating Unit, initiated by free governor action in response to continuous minor fluctuations of Frequency on the Power System.
Frequency Control	The retention of the Frequency on the Transmission System within acceptable limits.
Frequency Limit Control	Operating mode of HVDC facilities in which Active Power output changes in response to change in System Frequency, in such a way that it assists with the recovery to the Target Frequency.
Frequency Regulation	The mechanism through which the System's Frequency is maintained within the allowable limits as specified in the Grid Code (OC 5) and NEPRA Performance Standards (Transmission) Rules 2005 (as amended or replaced from time to time).
Frequency Response	The automatic adjustment of Active Power output from a Generator or Interconnector in response to Frequency changes.
Gas Turbine Unit	A Generating Unit driven by a gas turbine.

Term	Definition
Generating Unit	One of the units of a Generator in a generating plant/station producing electric power and energy.
Generation	Shall have the meaning assigned to the term in the Act and reproduced hereunder: "Generation" means the ownership, operation, management or control of generation facilities for delivery or sale of electric power and not solely for consumption by the person owning, operating, managing, and controlling those facilities.
Generation and Transmission Outage Program (G&TOP)	The combined Indicative Outage Program, the Provisional Outage Program and the Committed Outage Program of Generation and Transmission System, as per OC 4.
Generation Capacity	The amount of Generation Supply available in the system.
Generation Company	Shall have the meaning assigned to the term in the Act and reproduced hereunder: "Generation Company" means a person engaged in the generation of electric power.
Generation Facility	Shall have the meaning assigned to the term in the Act and reproduced hereunder: "Generation Facility' means the electrical facility used for the production of electric power.
Generation Outage Program	Any or all of the Indicative Outage Program, the Provisional Outage Program and the Committed Outage Program of Generators.
Generator	Generation Facility or Generation Company as defined in the Act.
Generator Performance Chart	A diagram which shows the MW and MVAR capability limits within which a Generator is expected to operate under steady-state conditions in the format set out in the Grid Code.
Generator Terminal Voltage	The Voltage at stator terminals of a Generating Unit.
Generator Transformer	The main step-up transformer for a Generator through which power flows from the Generating Unit to the Transmission System.
Generator Work Unit	Auxiliary consumption of an individual Generating Unit of a Generator during maintenance/Outage.
Global Demand Forecast	Econometric model-based system-level Load Forecast which is prepared by the SO and is used for the preparation of IGCEP.
Good Industry Practice	The exercise of that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced operator engaged in the same type of undertaking under the same or similar circumstances.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
Governor	A mechanical device used to automatically regulate the speed of a turbine of electric generator.
Governor Control System	A system which will result in Active Power output of a Generating Unit changing, in response to a change in System Frequency, in a direction which assists in the recovery to Target Frequency.
Governor Droop	In relation to the operation of the governor of a Generating Unit, the percentage droop in System Frequency which would cause the Generating Unit under free governor action to change its output from zero to full load.
Grid Code	This code prepared by the SO pursuant to Section 23G of the Act, and approved by the Authority, as revised, amended, supplemented or replaced from time to time with the approval of the Authority.
Harmonic Distortion	The departure of a waveform from sinusoidal shape, that is caused by the addition of one or more harmonics to the fundamental, and is the square root of the sum of the squares of all harmonics expressed as a percentage of the magnitude of the fundamental.
Heat Rate Tests	A test required by a Generator or the SO aimed to determine the efficiency of a Generating Unit at different loading levels.
High Voltage Ride Through Capability	The ability of an SWE Plant to stay connected to the system during the allowable over-voltage conditions.
Hot Cooling Time	The period of time, following De-Synchronization of a Generating Unit after which the Warmth State transfers from being hot to being warm.
Hot Standby	A condition of readiness to be able to synchronize and attain an instructed output in a specified time period that must be maintained by Generator.
Hot Start	Any Synchronization of a Generating Unit that has previously not been Synchronized for a period of time shorter than or equal to its submitted Hot Cooling Time.
HVDC Converter	Any Apparatus used to convert alternating current electricity to direct current electricity, or vice versa. An HVDC Converter is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, reactors, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion.
HVDC Converter Station	The part of an HVDC System which consists of one or more HVDC Converters installed in a single location together with

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
	buildings, reactors, filters reactive power devices, control, monitoring, protective, measuring and auxiliary equipment.
HVDC System	An electrical power system which transfers energy in the form of high Voltage direct current between two or more alternating current (AC) buses and comprises at least two HVDC Converter Stations with DC transmission lines or cables between the HVDC Converter Stations.
Hydro Unit/Plant	A Generating Unit which generates electric power from the flowing of water to spin a turbine which turns a shaft that's connected to an electric generator, excluding Pumped Storage Generation.
Imminent Overloading	The condition when the loading of transmission lines or substation Equipment is between 100 percent and 110 percent of the continuous rating.
Incidents	An event of external or internal origin, affecting equipment or the supply system, and which disturbs the normal operation of the System.
Independent Power Producer (IPP)	A private power generating company not owned/controlled by any public sector organization but subject to Central Dispatch.
Indicative Generation Capacity Expansion Plan (IGCEP)	The least-cost generation capacity expansion plan as elaborated in PC 4.2.
Indicative Outage Program	The Outage Program that the SO shall prepare for Year 3.
Instrument Transformer	A transformer intended to transmit an information signal to measuring instruments, meters and protective or control devices. The term "instrument transformer" encompasses both current transformer and Voltage transformers.
Integrated System Plan (ISP)	A plan that provides integrated road map based on generation cost and incremental transmission cost for the efficient development of the National Grid, this includes the IGCEP and TSEP as approved by the Authority.
Intention Application	The process of application to be followed by User in accordance with CC 2.2.
Inter tripping Scheme	The tripping of circuit-breakers by signals initiated from protection at a remote location independent of the state of the local protection.
Interconnector	An entity connected to another Power System.
Interconnector Ramp Rate	The maximum rate of increase or decrease of the power transferred, in either flow direction, by an Interconnector.
Interconnector Ramp-down Capability	The rate of decrease of an Interconnector. Ramp-down Capabilities apply over the bi-directional range from its

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Term	Definition
	Interconnector Registered Import Capacity to its Interconnector Registered Export Capacity.
Interconnector Ramp-up Capability	The rate of increase of an Interconnector. Ramp-up Capabilities apply over the bi-directional range from its Interconnector Registered Export Capacity to its Interconnector Registered Import Capacity.
Interconnector Registered Capacity	The maximum Capacity, in either flow direction, expressed in whole MW, that an Interconnector can deliver on a sustained basis, without accelerated loss of equipment life, at the Connection Point. This figure shall include transmission power losses for the Interconnector.
Interconnector Registered Export Capacity	The maximum Capacity, expressed in whole MW that an Interconnector may export (transfer energy from the Power System to a remote network) on a sustained basis, without accelerated loss of equipment life, as registered.
Interconnector Registered Import Capacity	The maximum Capacity, expressed in whole MW that an Interconnector may import (transfer energy from a remote network into the Power System) on a sustained basis, without accelerated loss of equipment life, as registered.
Interconnector Transformer	A transformer whose principal function is to provide the interconnection between the Interconnector and the Network and to transform the Interconnector Voltage to the Network Voltage.
Investigation	Investigation carried out by the SO under OC 11, and "Investigate" shall be construed accordingly.
Island/Islanding	A Generating Plant or a group of Generating Plants and its associated Demand, which is isolated from the rest of the Transmission System but is capable of generating and maintaining a stable Supply of power to the Customers within the isolated area.
Legacy Contract	A PPA or EPA which was signed or administered by the SPA before the Effective Date.
Licensee	The holder of a Licence.
Licence	A licence issued under the Act.
Load	The Active, Reactive or Apparent Power as the context requires, generated, transmitted or distributed and all like terms shall be construed accordingly.
Load Curve	The curve that represents the behavior of the MW load during a particular study period.
Load Curves of Daily Peaks	The graphical representation of daily peak MWs of electric power over a given study period.

Term	Definition
Load Dispatch Center	The Control Center of the SO.
Load Factor	The ratio between average Load over a given period to the peak Load occurring in that period.
Load Profile	Means configurable interval multi-channel data as specified time stamped stored in energy meter.
Load Up Break Point Cold	The break point which defines the shared MW boundary between the two Loading Rates Cold.
Load Up Break Point Hot	The break point which defines the shared MW boundary between the two Loading Rates Hot.
Load Up Break Point Warm	The break point which defines the shared MW boundary between the two Loading Rates Warm.
Loading Rate	The Loading Rate Cold, Loading Rate Hot or Loading Rate Warm as the case may be.
Loading Rate Cold	The rate at which a Generating Unit increases Output from Block Load to Minimum Generation when it is instructed to Cold Start.
Loading Rate Hot	The rate at which a Generating Unit Increases Output from Block Load to Minimum Generation when it is instructed to Hot Start.
Loading Rate Warm	The rate at which a Generating Unit Increases Output from Block Load to Minimum Generation when it is instructed to Warm Start.
Loss of load probability (LOLP)	Loss of Load Probability, the percentage of time that the system capacity is inadequate to meet load demand.
Low Frequency Disconnection	The process, a part of load reduction or management, of load disconnection (manually or automatic) under low Frequency system conditions.
Low Frequency Event	An event where the Transmission System Frequency deviates to a value below acceptable values.
Low Frequency Relay	An electrical measuring relay intended to operate when its characteristic quantity (Frequency) reaches the relay settings by decrease in Frequency.
Low Voltage Ride Through Capability	The ability of an SWE Plant to stay connected to the system during the allowable under-voltage conditions.
Maintenance Program	A set of schedules specifying planned maintenance for Equipment in the Transmission System or in any User System.
Maximum Charge Capacity	The maximum amount of Energy that can be produced from the storage of an Energy Storage Unit for a Schedule Day, e.g. BESS.

Term	Definition
Maximum Continuous Rating (MCR)	The normal Full Load MW Capacity of a Generator, which can be sustained on a continuous basis under specified conditions.
Maximum Demand	Maximum electrical power (MW and MVAR) used and registered in a time period specified by the Authority.
Maximum Down Time	In the case of a Demand Side Unit, the maximum period of time during which Demand Side Unit MW Response can be greater than zero.
Maximum On Time	The maximum time that a Generating Unit/Interconnector can run following Start Up.
Maximum Ramp Down Rate	The maximum Ramp Down Rate of a User. Mostly in MW per Minute.
Maximum Ramp Up Rate	The maximum Ramp Up Rate of a User. Mostly in MW per Minute.
Maximum Storage Capacity	The maximum amount of Energy that can be produced from the reservoir of a Pumped Storage Hydro for a Schedule Day.
Metering Data	Information on measured electrical quantities recorded in the meter register, such as energy, demand and power factor, including time and date.
Metering Point	The physical location of Metering System at Connection Site.
Metering Service Provider or MSP	An entity responsible for the organization, administration and maintenance of the Metering System and serves as the central aggregator of Metering Data; additionally performs the functions of meter reading and validation at Metering Points and transferring those values to the Market Operator.
Metering SOPs	The Standard Procedures (SOPs) developed by MSP for Meter Data Reading, Meter Data VEE, and for operation and maintenance of the Metering System and MDM server.
Metering System	The system, established according to the requirements of the Grid Code, to measure and record the Energy injected into or withdrawn from the Transmission System by a User.
Minimum Charge Capacity	The minimum amount of Energy that must be produced from the storage of an Energy Storage Unit for a Schedule Day, e.g. BESS.
Minimum Demand Regulation or MDR	The minimum level of Active Power of a Generator, which is sufficient to provide an adequate regulating margin for necessary Frequency Control.
Minimum Down Time	In the case of Demand Side Units, the minimum period of time during which Demand Side Unit MW Response at a Demand Side Unit can be greater than zero.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Term	Definition
Minimum Generation/Minimum Stable Level/Minimum Load	The minimum MW output, which a Generator can generate continuously, registered as a Technical Parameter.
Minimum Off Time	The minimum time that must elapse from the time of a Generating Unit De-synchronizes before it can be instructed to Start-up.
Minimum On Time	The minimum time that must elapse from the time of a Generating Unit Start-up before it can be instructed to Shut down.
Minimum Storage Capacity	The minimum amount of Energy that must be produced from Energy Storage Unit for a Schedule Day, e.g. Pumped Storage Hydro.
Minimum Transmission Voltage	Sixty-six (66) kilovolts or such other Voltage that the Authority may determine to be the minimum Voltage at which electrical facilities are operated when used to deliver electric power in bulk.
Monitoring	The monitoring carried out by the SO under OC 11, and "Monitor" shall be construed accordingly.
Multiple Outage Contingency	An Event caused by the failure of two or more Components of the Grid
National Grid	The Power System of the Islamic Republic of Pakistan
National Grid Company (NGC)	Shall have the same meaning as assigned to the term in the Act and reproduced hereunder: "National Grid Company" means the person engaged in the transmission of electric power and granted a Licence under Section 17.
NEPRA	The National Electric Power Regulatory Authority (NEPRA) established under Section 3 of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997.
NEPRA (Fees) Regulations 2021 and NEPRA (Fines) Regulations 2021	The regulations specified by the Authority in respect of the payment of fees by the licensees and the procedure for imposition and payment of fines levied by the Authority, as amended or replaced from time to time.
NEPRA Power Safety Code for Licensees 2021	The Power safety code for licensees specified and approved by the Authority (as amended or replaced from time to time)
Nominal or Nameplate Power	The rated power output specified by the manufacturer of a given electrical equipment.
Nominal System Voltage	Shall have the same meaning as defined in NEPRA Performance Standards (Distribution) Rules, 2005 (as amended from time to time) or other Applicable Documents.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
Nominal Voltage	The value of the Voltage by which the electrical installation or part of the electrical installation is designated and identified.
Non-Disclosure Agreement	A non-disclosure agreement is a legally binding contract that establishes a confidential relationship. An NDA may also be referred to as a confidentiality agreement.
Non-Synchronous Generators	Power Electronics-based Generators that are not Synchronous.
Notice to Synchronize	The amount of time (expressed in minutes) that is declared by a Generator in relation to a CDGU or Interconnector to enable it to be synchronized following the receipt of an Instruction from the SO to synchronize with the System.
Notification	The daily submission Notice of Availability by Users to the System Operator for dispatch purposes.
Off-Site Storage Location	The site in close vicinity to the Generator Site where (pursuant to a lease, Licence or other agreement) the User stores stocks of Primary Fuel and/or Secondary Fuel. A dedicated pipeline with a dedicated pump must be in place on this site between the dedicated fuel tank off-site and the Generating Plant.
Open Access	The non-discriminatory access to a transmission or distribution network licensee's system or its associated facilities for movement and delivery of electric power, subject to the terms and conditions as provided in the Act and use of system agreement as specified by the Authority to an electric power supplier or generator for delivery of the electric power from generation facility to the destination of its use.
Open Cycle Mode	The mode of operation of a CCGT Installation where only the Gas Turbine Unit is operational (i.e. without operation of any associated Steam Turbine Units).
Operating Characteristics/Technical Parameters	The technical capabilities, flexibilities and limitations for the operation of a User as registered or declared in accordance with the provisions of the Grid Code.
Operating Criteria	The criteria of Operation explained in OC 6.
Operating Reserve	The sum of Primary, Secondary and Tertiary Operating Reserves as explained in OC 5.
Operation	A scheduled or planned action relating to the Operation of a System.
Operational Data	The data required under the Operating Codes and/or Scheduling and Dispatch Codes.
Operational Date	Commissioning Date
Operational Effect	Any effect on the operation of the relevant other system that causes the Transmission System or the User's System to

Term	Definition
	operate (or be at a materially increased risk of operating) differently to the way in which they would or may have normally operated in the absence of that effect. Operationally Effected shall be construed accordingly.
Operational Phase	The Operational Phase follows on from the Pre-Operational Phase and covers the period of three (3) months ahead of Schedule Day.
Operational Planning	The procedure established in OC 4 of the Operation Code.
Operational Planning Horizons	Pre-Operational, Operational, Control and Post Control Phases as established in the Operation Code.
Operational Tests	The tests carried out by the SO in order to maintain and develop operational procedures, to train staff and to acquire information in respect of Transmission System behavior under abnormal System conditions, and also tests carried out by other Users for similar purposes in respect of their Plant.
Operational Thermal Limit Capacity	The maximum loading capacity of Transmission facilities in Normal conditions.
Operations Report	An annual Report summarizing the occurrences of operation on the User or Transmission System.
Optimal Power Flow (OPF)	The best operating levels for electric Generators in order to meet demands given throughout a Transmission System, usually with the objective of minimizing Operating cost.
Other System	The External System
Outage	The state of a system, User or component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of service to customers, depending on system configuration.
Outage Notice	A Notice submitted by a User under OC 4 notifying the SO of an Outage.
Output	The actual output at the main terminals of a Generating Unit (in MW) derived from data measured pursuant to this Grid Code.
Partial Shutdown/Collapse	The situation existing when all generation has ceased in a particular part of the System and there is no electricity supply from Interconnectors or other parts of the System to that particular part of the Total System and, therefore, that particular part of the Total System is shutdown, with the result that it is not possible for that particular part of the Total System to begin to function again without directions relating to a Black Start or re-energization from healthy part.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

Term	Definition
Peak Demand	Maximum Demand
Peak Instruction	In the case of a Gas Turbine CDGU, an instruction requiring it to generate at a level in excess of its Availability but not exceeding its temperature adjusted peak capability
Person	Shall include an association of persons, concern, company, firm or undertaking, authority, or body corporate set up or controlled by the Federal Government or, as the case may be, the Provincial Government.
Planned Outage	An Outage of Equipment that is requested, negotiated, scheduled and confirmed a reasonable amount of time ahead of the maintenance or repairs taking place, as given in OC 4.
Plant and Apparatus	Fixed and movable equipment used in the generation and transmission of electricity.
Plant Factor	The ratio of the actual electrical energy produced to the possible maximum electrical energy that could be produced in any defined period.
Post Control Phase	The day following the Schedule Day.
Post Event Notice	A notice issued by the SO to a User in accordance with OC 1
Power Factor	The ratio of Active Power to Apparent Power.
Power Line Carrier (PLC)	Communications system of radio frequency generally under 600 kHz, which transmits information using high Voltage transmission lines.
Power Oscillation Damper	A supplementary control system that can be applied to existing devices like HVDC, STATCOM and Generators (in the form of PSS) to improve the damping of oscillations in the system which may initiate due to any reason.
Power Quality	Electric power quality is the degree to which the Voltage, Frequency, and waveform of a power supply system conform to established specifications.
Power System	An interconnected electricity system consisting of generation, transmission and distribution systems with an independent system operation and control.
Power System Planning	The short-term, medium-term, and long-term system planning conducted by system operator for economic operations, least cost generation and optimal transmission expansion, augmentation and reinforcement to satisfy the objectives of system security, adequacy, reliability and performance, using well recognized and globally accepted tools/models and submit to the Authority, wherever applicable, for approval in accordance with this Grid Code and other Applicable Documents.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED
BY
THE AUTHORITY
★ NEPRA ★

Term	Definition
Power System Restoration Plan	An Operational Plan developed under OC 12 for restoration of System after Partial or Total Shutdown.
Power System Stabilizer (PSS)	The Equipment controlling the exciter output via the Voltage regulator in such a way that power oscillations of the synchronous machines are dampened. Input variables may be speed, Frequency or power (or a combination of these).
Preliminary Data	Shall have the meaning as described in PC 3.2.1.
Pre-Operational phase	Pre-Operational phase covers Year 1 and Year 2.
Preventive Maintenance	The periodic maintenance performed on the equipment to avoid the occurrence of possible unplanned failure or outages.
Primary Control	Primary Frequency Control
Primary Frequency Control	Primary Frequency Control enables a Frequency response to maintain grid stability. This PFC Frequency response algorithm replaces the tuning of regular droop speed controls, which are standard on any turbine: Maintains correct Frequency for turbine/generator by adjusting the total MW output. This shall be taken as Fast Frequency Control for invertor based generators.
Primary Fuel	The fuel or fuels registered in accordance with the Grid Code as the principal fuels authorized for Energy production by the Generating Unit
Primary Fuel Registered Capacity	The Registered Capacity of Generating Unit running of Primary Fuel.
Primary Fuel Switchover Output	The MW output, not lower than Minimum Load at which a Generating Unit can achieve a switch over from Primary Fuel to Secondary Fuel.
Primary Meter	A device used to record electrical quantities such as energy, MDI etc. consumed by a USER along with time stamped events used for billing purpose.
Primary Metering System	A complete metering system installed at the Metering Point such as metering CT, VT, Meter, communication equipment and secondary circuits of Instrument Transformers including interconnecting cables, wires, metering cabinets and associated devices used for billing purpose.
Primary Protection/Main Protection	A Protection System which has priority above other Protection Systems in initiating either a fault clearance or an action to terminate an abnormal condition in a Power System.
Priority Customers	Customers who are either: exempt from load shedding; or

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
	exempt from load shedding under the technical under-frequency load shedding scheme; or prioritized for supply under the technical under-frequency load shedding scheme.
Project Planning Data	Shall have the meaning as described in PC 3.2.
Protection Equipment/Protection and Control Equipment	A group of one or more protection relays/devices and/or logic elements designated to perform a specified protection function.
Protection System	The provisions for detecting abnormal conditions on a Power System and initiating fault clearance or actuating signals or indications.
Provincial Grid Company (PGC)	Shall have the same meaning as assigned to the term in the Act and reproduced hereunder: "Provincial Grid Company" means the person engaged in the transmission of electric power and licensed under Section 18A.
Provisional Outage Program	The Outage Program that the SO shall prepare for the period up to end of Year 2.
Prudent Utility Practice/Prudent Industry Practice/Good Industry Practice	Those standards, practices, methods and procedures conforming to safety and legal requirements which are attained by exercising that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from skilled and experienced operatives engaged in the same type of undertaking under the same or similar circumstances.
Q Control	A facility providing the means to automatically adjust the Reactive Power output of an HVDC System within a specified range.
Ramp Down Break Point	The MW level at which the Ramp Down Rate changes
Ramp Down Rate	The maximum rate of decrease in a Generating Unit's Output.
Ramp-up Rate	The maximum rate of increase in a Generating Unit's Output.
Rapid Voltage Change	A quick transition in root means square (rms) Voltage occurring between two steady-state conditions, and during which the rms Voltage does not exceed the dip/swell thresholds.
Reactive Compensation Equipment	An Equipment for production or absorption of Reactive Power to maintain Transmission System Voltage within the specified limits.
Reactive Energy	Means the product of Voltage, current, the sine of the phase angle between them and time, measured in units of VARh and standard multiples thereof.

Term	Definition
Reactive Power	The product of Voltage and current and the sine of the phase angle between them measured in units of VAR and standard multiples thereof.
Reactive Reserve	The MVAR reserve on the on-line Generators (difference between MVAR capability at the output MW level at a given time and actual MVAR produced).
Registered Capacity	The rated continuous load-carrying ability, expressed in Megawatts (MW) or Megavolt-Amperes (MVA) of generation, transmission, or other electrical equipment.
Registered Data	Shall have the meaning as described in PC 3.2.3
Registered Operating Characteristic	The values of Technical Parameters.
Remedial Actions	Those actions described in SDC 2, which the Operator undertakes in case of emergency.
Remote Terminal Unit (RTU)	A part of the SCADA system. It is a set of electronic devices that collects and transmits data to, and receives and executes the commands from the master unit.
Renewable Electricity	Means electricity derived from (a) a wind, solar, renewable, biomass, ocean (including tidal, wave, current and thermal), geothermal or hydroelectric source; or (b) hydrogen derived from renewable biomass or water using an energy source described in clause (c); or (c) any other resource as amended or defined through relevant government power policies and/or regulatory frameworks.
Reserve	Operating Reserve
Reserve Margins	Excess generation which is available to meet the system demand if in service generation is lost or demand exceeds the forecast.
Responsible Manager	A manager who has been duly authorized by a User or the SO to sign Site Responsibility Schedules on behalf of that User or the SO.
Responsible Operator	A person nominated by a User to be responsible for System control for its System.
Revenue Metering	The Metering System established to measure Energy and Load of the Code Participant at the Metering Point for billing and invoice purposes.
Revision	A comprehensive revision, which replaces and supersedes, in its entirety, the existing Grid Code based on changes in power sector reforms, policies and technological changes

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
	recommended by Grid Code Review Panel and approved by NEPRA.
Safety	Safety from the hazards arising from the live Equipment, Plant, or other facilities of the Transmission System (or User System).
Safety Codes	The rules that seek to safeguard personnel working on the Grid (or User System) from the hazards arising from the Equipment or the Transmission System (or User System).
Safety Coordinator	A Person or Persons nominated by SO and each User to be responsible for the coordination of Safety when work (which includes testing) is to be carried out on a System which necessitates the provision of Safety Precautions. "Coordination" to be construed accordingly.
Schedule Day	The period from 0000 hours in the Schedule Day until 0000 hours on the next following Day.
Scheduling	A process to determine which Unit or Equipment will be in operation and at what loading level and the term "Scheduled" and like terms shall be construed accordingly.
Secondary Fuel	The fuel or fuels registered in accordance with the Grid Code as the secondary or back-up fuels authorized for Energy production by the Generating Unit.
Secondary Fuel Switchover Output	The MW output, not lower than the Minimum Load at which a Generating Unit can achieve a switch over from Secondary Fuel to Primary Fuel.
Secondary Response	The Frequency Response as a result of Secondary Frequency Control.
Security Constrained Economic Dispatch (SCED)	The allocation of System Demand to individual Generation Facility to effect the most economical production of electricity for optimum system economy, security and reliability with due consideration to Variable Operation Costs, incremental network losses, load flow considerations and other operational considerations in accordance with the approved Grid Code by the Authority.
Service Territory	The geographical area specified in a Licence within which the licensee is authorized to conduct its business.
Shaving Mode	The Synchronized operation of Generating Units to the Distribution System at an Individual Demand Site of a Demand Side Unit where the Generating Units supply part of the DNO Demand Customer's Load.
Short Circuit Ratio	The ratio of field current required to produce rated armature Voltage at open circuit to the field current required to produce the rated armature current at short circuit.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Term	Definition
Short Term Maximization Capability	The capability of a Generating Unit to deliver, for a limited duration of time, MW Output greater than its Registered Capacity.
Short Term Maximization Capability	The capability of a Generating Unit to deliver, for a limited duration of time, MW Output greater than its Registered Capacity.
Short Term Maximization Time	The time that the Short-Term Maximization Capability could be maintained.
Short Term Planned Maintenance Outage or STPM Outage	An Outage designated as an STPM Outage, the duration of which shall not, unless SO in its absolute discretion agrees, exceed 72 hours but not including any overrun of such Outage.
Short-Circuit Current	The current flowing through electrical system during the occurrence of short circuit.
Significant Incident	An Event on the Transmission System, a Distribution System, or the System of any User that has a serious or widespread effect on the Grid, the Distribution System, and/or the User System.
Significant Incident Report	A report prepared after the occurrence of a Significant Incident pursuant to OC 8.
Single Line Diagram	Schematic representations of a three-phase network in which the three phases are represented by single lines. The diagram shall include (but not necessarily be limited to) bus bars, overhead lines, underground. Cables, power transformers, and reactive compensation equipment. It shall also show where Generating Plant is connected, and the points at which Demand is supplied.
Site Common Drawings	Drawings prepared for each Connection Site which incorporate Connection Site layout drawings, electrical layout drawings, common protection/control drawings and common service drawings.
Small Generator	A Generator with aggregated capacity at a site below 10 MW.
Soak Time Cold	The duration of time for which the Generating Unit must remain at the Soak Time Trigger Point Cold during a Cold Start.
Soak Time Hot	The duration of time for which the Generating Unit must remain at the Soak Time Trigger Point Hot during a Hot Start.
Soak Time Trigger Point Cold	A constant MW level at which a Generating Unit must remain while loading up between Block Load and Minimum Generation after a Cold Start.
Soak Time Trigger Point Hot	A constant MW level at which a Generating Unit must remain while loading up between Block Load and Minimum Generation after a Hot Start.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
Soak Time Trigger Point Warm	A constant MW level at which a Generating Unit must remain while loading up between Block Load and Minimum Generation after a Warm Start.
Soak Time Warm	The duration of time for which the Generating Unit must remain at the Soak Time Trigger Point Warm during a Warm Start.
Spatial Demand Forecast	The load forecast prepared by DNOs, in accordance with the Distribution Code and other Applicable Documents, as elaborated in PC 4.1.
Special Actions	The actions, as defined in Scheduling and Dispatch Code, that the SO may require a User to take in order to maintain the integrity of the System.
Special Protection Scheme	A control or protection scheme to facilitate System operation by the inter-tripping of circuit breakers or other Control Actions.
Special Purpose Agent (SPA)	Shall have the meaning as described in the Market Commercial Code.
Special Purpose Transmission Licensee (SPTL)	A company licensed under Section 19 of Act to engage in the construction, ownership, maintenance and operation of specified transmission facilities as per the terms and conditions approved by the Authority.
Standard Planning Data	Shall have the meaning as described in PC 3.1.
Standing Instruction	An Instruction for a specified action notified to a User in advance by SO whereby, when the specified circumstances arise, the User will take the specified action as though a valid Instruction had been issued by SO.
Start of Restricted Range (Forbidden Zone)	The start point in MW of a Forbidden Zone.
Start-Up	The action of bringing a Generator from shutdown to synchronous speed.
Start-up Cost	That element of the generation prices for a CDGU which relates to the start-up of the CDGU.
Station Transformer	A transformer supplying electrical power to the auxiliaries of a Generator, is not directly connected to the Generator terminals.
Steam Turbine	A Generating Unit whose prime mover converts the heat-energy in steam to mechanical energy.
Supply	The sale of electric power to consumers; also, the amount of electric energy delivered, usually expressed in Megawatt-hours (MWh).

Term	Definition
Synchronize	The condition where an incoming Generating Unit or system/Interconnector is connected to another System so that the frequencies and phase relationships of that Generating Unit or System, as the case may be, and the System to which it is connected are identical and the terms "Synchronize", "Synchronizing", "Synchronized", and "Synchronization" shall be construed accordingly.
Synchronizing Time	The time taken to bring a Generating Unit to a Synchronized state from a De-Synchronized state.
Synchronizing Time Cold	The time taken to bring a Generating Unit to a Synchronized state from a Cold (De-Synchronized) state.
Synchronizing Time Hot	The time taken to bring a Generating Unit to a Synchronized state from a Hot (De-Synchronized) state.
Synchronizing Time Warm	The time taken to bring a Generating Unit to a Synchronized state from a Warm (De-Synchronized) state.
Synchronous Generating Unit	A Generating Unit composed of a synchronous alternators coupled to a turbine and synchronously-connected to the Transmission System
Synchronous Compensation/Condenser	The operation of rotating synchronous Apparatus for the specific purpose of either the production or absorption of Reactive Power.
Synthetic Inertia	The controlled contribution of electrical torque from a unit that is proportional to the ROCOF at the terminals of the unit.
System Adequacy	The ability of the system at any instant to balance Power supply and demand
System Emergency Condition	A Partial Shutdown or Total Shutdown or any other physical or operational condition and/or occurrence on the Power System which, in the SO's opinion, is imminently likely to endanger or is endangering life or property; or is imminently likely to impair or is impairing: (a) the SO's ability to discharge any statutory, regulatory or other legal obligation and/or (b) the safety and/or reliability of the Power System.
System Fault Dependability Index (DP)	A measure of the ability of Protection to initiate successful tripping of circuit breakers, which are associated with a faulty item of Apparatus. It is calculated using the formula: $DP = 1 - F1/A$ Where: A = Total number of system faults

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
	F1 = Number of system faults where there was a failure to trip a circuit breaker.
System Frequency/Frequency	The number of alternating current cycles per second (expressed in Hertz) at which a Power System is running.
System Integrity	Status of a Power System operating as a unique interconnected system.
System Operating Voltage	Operating Voltage limits as defined in OC 5.
System Operations	The functions, system operations, power system planning and responsibilities to be performed and discharged by the system operator in accordance with this Grid Code, the Act, and other Applicable Documents
System Operator or the SO	A person licensed under the section 23G of the Act to administer system operations, dispatch and power system planning.
System Planning Data	Shall have the meaning as described in PC 3.
System Reliability	The ability of the system to fulfill Adequacy and Security
System Security	The ability of the system to withstand contingencies/changes and remain in its secure state or operate within its acceptable limits.
System Stability	The ability of the dynamic components of the Power System to return to a normal or stable operating point after being subjected to some form of change or disturbance.
System Test	The tests which involve simulating conditions, or the controlled application of irregular, unusual or extreme conditions, on the system, or any part of the system, but which do not include Commissioning or recommissioning tests or any other tests of a minor nature.
Target Charge Level	The Target Charge Level for BESS.
Target Frequency	The Frequency determined by the SO, as the desired operating Frequency of the Power System.
Technical Parameters	The technical capabilities, flexibilities and limitations for the operation of a User as registered or declared in accordance with the provisions of the Grid Code.
Telemetering	A process in which measurements are made at some remote location and the results are transmitted through telecommunication facilities. The transmission of the values of measured variables using telecommunication techniques is also called telemetering.
Test Coordinator	The coordinator appointed by the SO pursuant to the provisions of the OC 10.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY APPROVED BY THE AUTHORITY ★ NEPRA ★

Term	Definition
Test Proposer	The User submitting proposal for a test under OC 10.
Testing	The Testing carried out by the SO or User pursuant to OC 10, OC 11 and/or CC and the term "Test" shall be construed accordingly.
Testing and Commissioning	The Testing involved during the process of Commissioning.
Thermal Generator	The Generating Units that transform thermal energy into electricity
Thermal Overload	A Thermal Overload occurs when the designed thermal rating of a transmission line or cable is exceeded. The thermal rating of a transmission line is dictated by its physical construction and varies with the ambient weather conditions, while the thermal rating of a transmission cable is dependent solely on its physical construction.
Total Harmonic Distortion	The departure of a waveform from sinusoidal shape, that is caused by the addition of one or more harmonics to the fundamental, and is the square root of the sum of the squares of all harmonics expressed as a percentage of the magnitude of the fundamental.
Total Shutdown/Blackout/Collapse	The situation existing when all generation of the system has ceased resulting in the shutdown of the Power System, and it is not possible for the power system to begin to function again without SO directions relating to a Black Start.
Transformer	A device that transfers electric energy from one alternating-current circuit to one or more other circuits, either increasing (stepping up) or reducing (stepping down) the Voltage.
Transmission	Shall have the same meaning as defined in the Act and reproduced hereunder: "Transmission" means the ownership, operation, management or control of transmission facilities.
Transmission Connected Consumer	Any Consumer directly connected to the Transmission System, other than the Generator or Interconnector or DNO.
Transmission Constraint	A limitation on the use of Transmission System due to lack of transmission capacity.
Transmission Facilities	"Transmission Facilities" means electrical transmission facilities including electrical circuits, transformers and sub-stations operating at or above the minimum transmission Voltage but shall not include electrical circuits forming the immediate connection between generation facilities and the transmission grid to the extent that those circuits are owned by a generation company and are directly associated with that company's generation facilities.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★

Term	Definition
	"Transmission Facility" shall be construed accordingly.
Transmission Network Operator (TNO)	An entity, licensed by the Authority pursuant to the Act, which owns, operates and maintains Transmission Facilities. For the avoidance of doubt, companies holding a Distribution Licence which are entitled, through such Licence, to own and/or operate Transmission Facilities shall be considered in this Grid Code as Transmission Network Operators.
Transmission Outage Program	Any or all of the Indicative Outage Program, the Provisional Outage Program and the Committed Outage Program of Transmission System.
Transmission System	An electrical system comprising of Transmission Facilities owned or operated by licensees for transmission of electric power including, without limitation, electric lines, circuits, meters, transformers, substations, interconnection facilities or other facilities determined by the Authority as forming part of the transmission system, operating at or above the Minimum Transmission Voltage (66 kV and above).
Turbine Controller	A turbine controller consists of a number of computers which continuously monitor the conditions and collect statistics on its operation. As the name implies, the controller also controls a large number of switches, hydraulic pumps, valves, and motors within the turbine
Turbine Speed Control	A turbine speed control is a response that regulates rotational speed in response to changing load conditions.
U Control	A facility providing the means to automatically adjust the Reactive Power output of an HVDC System in response to changes in Voltage at AC Bus bar.
Ultra-High Voltage (UHV)	Voltage above 500 kV in Pakistan's Power Sector.
Under frequency protection/relay	System protection that disconnects User or Equipment when the Frequency drops below a percentage of the nominal operating Frequency.
Unit Load Controller	A device which regulates the generation level when the Generator is operating in Frequency Sensitive Mode to ensure (as far as possible) that it does not exceed or fall short of acceptable limits as set in the Grid Code OC 5 and NEPRA Performance Standards (Transmission) Rules, 2005 (as amended or replaced from time to time).
Unplanned Outage	Any Outage that cannot reasonably by the SO as a Short-Term Planned Management Outage.
User	A specific Code Participant or Person to whom the relevant sub-code of this Grid Code applies as listed in the scope of each sub-code.

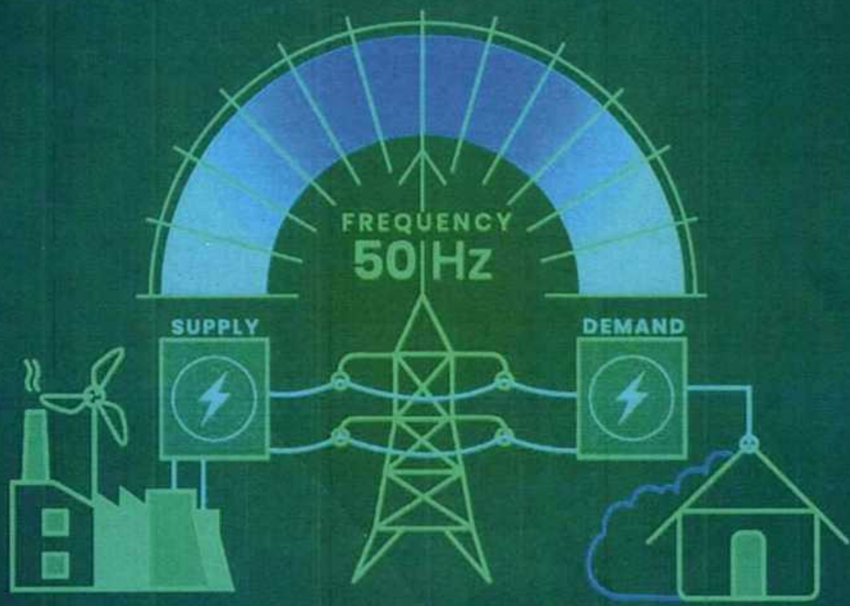
NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
NEPRA

Term	Definition
User Development	A new Connection or modification in the existing Connection sought by a User.
User Facility	Fixed and movable equipment of User used in the generation and transmission of electricity.
User Site	A site owned (or occupied pursuant to a lease, Licence or other agreement) by a User in which there is a Connection Point.
User System	Any system owned or operated by a User comprising: (i) Generator; or (ii) Electrical systems consisting (wholly or mainly) of electric facilities used for the transmission or distribution of electricity from Connection Points onwards. The User system includes any sub-transmission assets operated by such User or other Person, and any plant and/or apparatus and meters owned or operated by the User or other Person in connection with the transmission, distribution and delivery of electric power but does not include any part of the bulk power transmission system.
Variable Operating Cost	The variable cost of operation of a Generator or Interconnector.
Voltage	Voltage of a relevant section of Transmission System - nominally 765 kV, 500 kV, 220 kV, 132 kV, and 66 kV.
Voltage Control	The strategy used by the SO and Users to maintain the Voltage of the system, or the User System within the limits prescribed in the Grid Code.
Voltage Dip	A short-duration reduction in Voltage on any or all phases due to a Fault Disturbance or other Significant Incident, resulting in Transmission System Voltages outside the ranges as specified in this Grid Code.
Voltage Unbalance	The ratio of the negative or zero sequence component to the positive sequence component. In simple terms, it is a Voltage variation in a power system in which the Voltage magnitudes or the phase angle differences between them are not equal
Warm Cooling Time	The period of time, which must be greater than that defined by the Hot Cooling Time, post De-Synchronization of a Generating Unit after which the Generating Unit's Warmth State transfers from being warm to cold.
Warm Start	Any Synchronization of a Generating Unit that has previously not been Synchronized for a period of time longer than its submitted Hot Cooling Time and shorter than or equal to its submitted Warm Cooling Time.
Warmth	The temperature related condition of a CDGU which changes according to the length of time since the CDGU was last De-

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
* NEPRA *

Term	Definition
	Synchronized, expressed as various levels of warmth (dependent upon the design of the CDGU).
Warmth State	Either cold, warm or hot, as defined under the timeframes since last De-Synchronizations for Cold Start, Warm Start or Hot Start respectively.
Week Ahead	A week prior to the Schedule Day.
Wind Farms	A group of wind turbines in the same location used to produce electricity.
Year Ahead	A year prior to the Year for which the data is being provided.
Zero Voltage Ride Through Capability	Ability of an SWE Plant to stay connected to the system during zero Voltage condition.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
APPROVED BY THE AUTHORITY
★ NEPRA ★



THE AUTHORITY
NEPRA