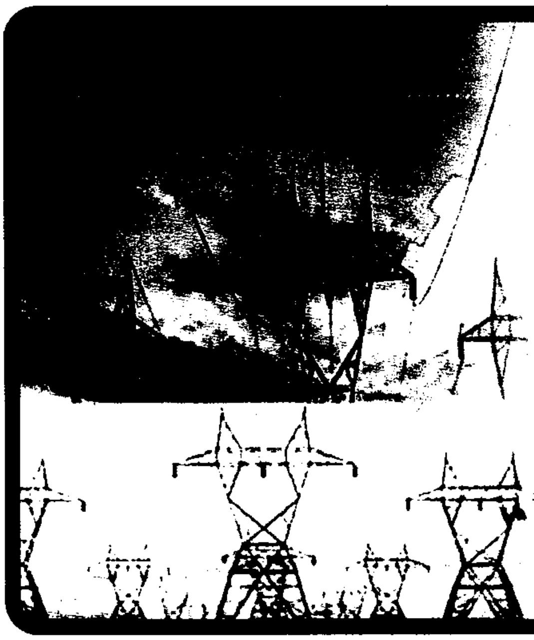

NATIONAL
TRANSMISSION &
DESPATCH COMPANY
LIMITED

Licensing Application for System Operator by National Transmission and Dispatch Company Limited under applicable provisions of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 as amended up to date.

Dated:24 August 2022

NATIONAL TRANSMISSION & DESPTACH COMPANY LTD

PABX: 042-99202211/Ext:2060
Tel: 042-99202229
Fax: 042-99202053

Office of the
Managing Director (NTDC)
414-Wapda House, Lahore.

No. MD/NTDC/ 3029 /

Date: 24 / 08 /2022

The Registrar
National Electric Power Regulatory Authority

Subject: **Application for Grant of License of System Operator by NTDC.**

I, **Rana Abdul Jabbar Khan**, being the duly authorized representative of National Transmission and Despatch Company Limited (NTDCL) by virtue of BOARD RESOLUTION No. NTDC/CS/1514-18 dated 23-08-2022, hereby apply to the National Electric Power Regulatory Authority for the grant of a System Operator License to NTDC pursuant to Section 23-G of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997, as amended upto date.

I hereby certify that the documents-in-support attached with this application are prepared and submitted in conformity with the provisions of the National Electric Power Regulatory Authority Licensing (Application, Modification, Extension and Cancellation) Procedure Regulations, 2021, and undertake to abide by the terms and provisions of the above-said regulations. I further undertake and confirm that the information provided in the attached documents-in-support is true and correct to the best of my knowledge and no material omission has been made.

A BANK DRAFT / PAY ORDER bearing No. 17514955 in the sum of PKR. 1141585 (Pakistani Rupees: One Million One Hundred and Forty One Thousand Five Hundred and Eighty Five Only) being the license application fee calculated in accordance with Schedule II to the National Electric Power Regulatory Authority Licensing (Application, Modification, Extension and Cancellation) Procedure Regulations, 2021, is also attached herewith.

Rana Abdul Jabbar Khan
Managing Director (NTDC)
34101-4940598-9
Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

NATIONAL TRANSMISSION & DESPATCH CO. LTD

Company Secretary

No. NTDC/CS/ 1514 -18 **Dated:** 23 **-08-2022**

NOTIFICATION

Approval for

i) Submission of the System Operator license application to NEPRA for functional separation of System Operator within NTDC

ii) Strategic Business Plan for submission to NEPRA as part of NTDC's application for System Operator's License

The Board of Directors of National Transmission & Despatch Company Limited (NTDC) through resolution by circulation No.452 has resolved and approved by majority the following: -

1) Submission of System Operator license application and its particulars to NEPRA for functional separation of the System Operator within NTDC
2) Authorization of the Managing Director to file the System Operator license application in NEPRA.
3) Strategic Business Plan to be submitted to NEPRA as part of the SO application.

Azhar Saleem
Company Secretary

Copy to: -

1) Managing Director NTDC.
2) DMDs (AD&M, P&E & (SO)) NTDC.
3) Chief Financial Officer NTDC.

407 WAPDA House, Lahore,| TEL:+92 42-99201330, Fax: +92 42-9920 4236|cs@ntdc.com.pk, www.ntdc.com.pk

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- Section 130 Companies Act compliance report/Annual return statement
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Recitals

1. Profile of the Company

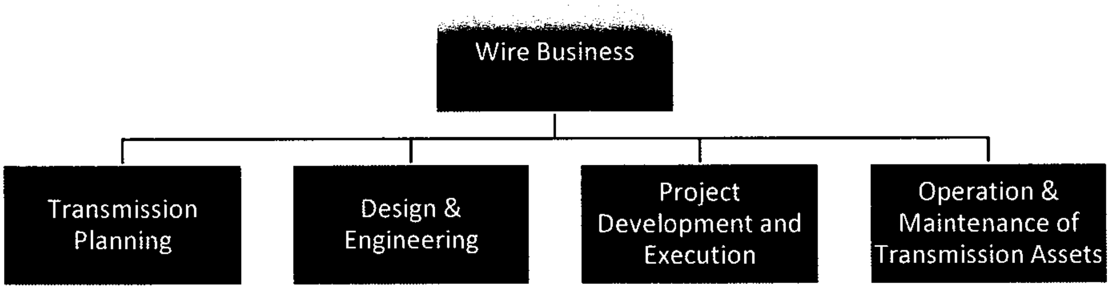
National Transmission and Despatch Company Limited ("**NTDCL**") is a Public Limited Company incorporated on 6th November, 1998 under the Companies Ordinance 1984 (now Companies Act 2017) which started its commercial operations on 1st March, 1999. NTDCL has Corporate Universal Identification No. L09689 of 1998-99 with its Registered Office at WAPDA House, Lahore.

NTDCL is currently operating under the terms and conditions of its Transmission License TL/01/2002 granted on 31st December 2002 (the "**Existing License**") valid until 30th December 2032, to engage in the exclusive transmission and system operation business, for a term of thirty (30) years.

Pursuant to the mandate given in the Existing License, NTDCL links Power Generation Units with Load Centers spread all over the country (including Karachi) and thus establishes and governs one of the largest interconnected Networks. NTDCL is responsible for evacuation of Power from the Hydroelectric Power Plants (mainly in the North), the Thermal Units of Public (GENCOs) and Private Sectors (IPPs) (mainly in the South) to the Power Distribution Companies through primary (EHV) Network. The following functions are performed by NTDCL under its Existing License:

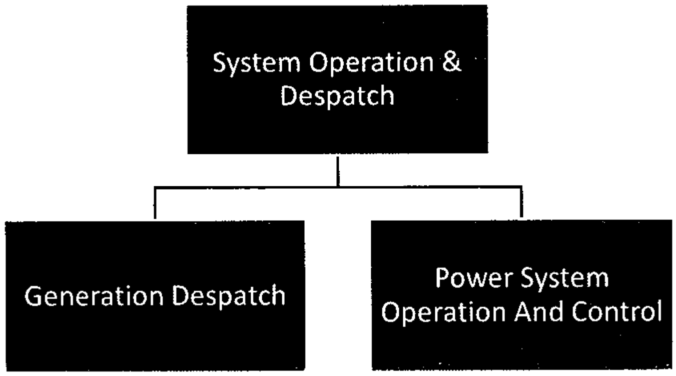
A. Transmission Network Operator (TNO)

Operation and Maintenance of 500/220kV Network Planning, Design and Construction of the new 500/220kV System and strengthening/ up gradation of the existing one.



B. System Operator (SO)

Arranging Non-Discriminatory, Non-Preferential Economic Despatch ensuring Safe, Secure and Reliable Supply.



In November, 2020, National Electric Power Regulatory Authority ("NEPRA") as Authority approved a Competitive Trading Bilateral Contract Market (CTBCM) model that provided a roadmap for opening the wholesale electricity market of Pakistan, aiming to provide choice to the bulk power consumers (with 1MW or above load) to purchase electric power from the DISCOs or a competitive supplier of their choice. As per Authority approved CTBCM detailed design, restructuring of System Operator (SO) is required to be carried out under Item No. 9 of Authority approved CTBCM Implementation Roadmap which stated as under:

"The successful implementation of the CTBCM will depend on the efficient and transparent functioning of the SO and it is, therefore, considered vital that the SO develops its capacity and improves its ability to perform its activities in an effective, transparent, and non-discriminatory manner. The Authority considers that it is need of the hour that NPCC is restructured and equipped with adequate human, technical, financial, and IT resources to turn it into a state-of-the-art SO."

Accordingly, NTDCL has been in the process of developing functions and competencies including revenure requirements to deliver as per approved CTBCM roadmap as detailed herein.

2. Regulation of Generation, Transmission and Distribution of Electric Power Act 1997 as amended up to date (the "Amended NEPRA Act")

Through the Regulation of Generation, Transmission and Distribution of Electric Power (Amendment) Act, 2018 as amended on 23rd April 2018, various legislative provisions were added or modified in the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 which amongst others included requirement to seek separate license to carry out the System Operators function as a licensed activity under Section 23G of the Amended NEPRA Act. Moreover, the Act stipulated that National Grid shall perform the function of a system operator and only one such license shall be granted at any one time. This meant that NTDCL carrying out the functions of System Operator (SO) is required to apply for separate license, hence this License application by NTDCL to comply with requirements of the Amended NEPRA Act.

3. Directions of the Authority and Federal Government

As stated above, the National Electric Power Regulatory Authority (the **"NEPRA and/or Authority"**) in its determination dated 12th November 2020 has already approved the detailed design and implementation roadmap of the Competitive Trading Bilateral Contract Market (CTBCM) which requires separate license for system operation. Group Actions for implementation as approved by Federal Government requires submission of separate application for the license of System Operator. Further, NTDCL is also required to submit the revised draft Grid Code to the Authority for approval.

The Federal Government has endorsed the decision of the Authority and accordingly in the CTBCM implementation plan, directed NTDCL to submit the SO License Application to the Authority which is being filed pursuant to section 23G of the Amended NEPRA Act, and which shall come into force immediately upon the relevant section i.e. section 23G coming into effect upon lifting of the moratorium mentioned in Section1(3) of the Amended NEPRA Act upon either i) the competion of the period of five years of coming into force of the Regulation of Generation, Transmission and Distribution of Electric Power (Amendment) Act, 2018, or ii) on such earlier date as the Federal Government may, by notification in the official Gazette, appoint, which shall enable NTDCL to deliver as per legislative and regulatory framework.

4. Requirements for submission of License Application

As per criteria stipulated in Section 23G of the Amended NEPRA Act, following are the requirements for the submission of the SO License Application:

i. A person shall have to be licensed under the Amended NEPRA Act to undertake functions of a System Operator.

ii. Under Section 23H of the Amended NEPRA Act, the Legislature required that: -

"...a system operator shall from time to time and subject to approval of the Authority, make <u>such grid management code as may be required by the Authority to enable it to carry out its functions as a system operator</u>...".

Hence this License Application is accompanied by a draft Grid Code duly approved by competent authority within NTDCL governing the form and manner in which SO shall undertake the licensed activity.

5. Grounds for SO License Application

In view of the above, the table below shows the list of grounds and their respective status which forms the basis as pre-requisite for submission and consideration of the SO Application by NTDCL

Sr. #	Grounds for submission	Remarks
1	As per Section 23G of the Amended NEPRA Act, any person shall apply for the SO license application.	NTDCL is currently operating as an exclusive system operator for nearly two decades and has the requisite organizational structure, knowledge and expertise pursuant to the Amended NEPRA Act, its i) Transmission License TL/01/2002 dated 31st December 2002 (Annexure – I), ii) SECP certified Certificate of Incorporation dated 6th November 1998 (Annexure – I-A), iii) Certificate for Commencement of Business dated 6th November 1998 (Annexure – II-A), iv) Memorandum of Association (Annexure – III-A), iv) Articles of Association (Annexure – IV-A), iv) Duly submitted Form A (Annexure – V-A) are enclosed herewith.
2	As per Section 23H of the Amended NEPRA Act, the license application shall be accompanied with draft Grid Code.	The duly approved draft Grid Code along with NTDCL Board Resolution is enclosed as Annexure-II.
3	Solvency Requirements	1. Section 130 Companies Act compliance report/Annual return statement including authorized paid up capital of NTDCL and shareholding patters etc. is attached as Annexure-III. 2. Copies of last 3 years audited financial statements of NTDCL are enclosed as Annexure-III-A. Please note that the paid-up/share capital of the company is Rs. 52.7 Billion (5.27 Billion ordinary shares of Rs. 10 each). GoP owns 88% shares whereas employee owns 12%.
4	Technical Requirements & readiness	Competencies and Readiness Report along with CVs is attached as Annexure-IV.

5	System Operator's Five Year Strategic Business Plan	The duly approved Stratgic Business Plan for SO along with Board Resolution is enclosed herewith as Annexure – V.
6	Process and Procedures (Satisfactory system and controls for system operator and compliance with Grid Code)	Please refer to Item (4) above.
8	Undertaking and Statement of Compliance by MD NTDCL	Attached as Annexure -VI.
9	Conflict of Interest Declarations	Attached as Annexure-VII.

As demonstrated in the table above, all the requirements and pre-requisites for submission of application to the Authority for License of System Operator under Section 23G of the Act are hereby complied with. Accordingly, this application for the System Operator License is filed by NTDCL in its capacity of existing System Operator and in accordance with applicable law before the Authority in accordance with the current and envisages institutional arrangement for SO as specified as the following section.

6. Existing and Envisaged Institutional Framework/Arrangement for SO

The transition towards wholesale market demands restructuring of several power sector entities as their roles have been modified. System Operator and Market Operators re-structuring and reforms are most important as they form technical and commercial aspects of the wholesale market governance. This section describes the current and future institutional arrangement in relation to pre CTBCM and post CTBCM regime with respect to SO.

6.1. Existing Institutional Framework

The roles and responsibilities of System Operator, as mentioned in the Amended NEPRA Act and other applicable rules and regulations, are being carried out under the terms of the NTDCL Existing License read in conjunction with relevant rules and regulations.

The Authority in its determination dated 8th December 2019 has approved the high level conceptual design of the CTBCM and subsequently through its determination dated 12th November 2020 has approved the detailed design and Implementation Roadmap of CTBCM which also envisages bifurcation of the NTDCL's transmission/wire business from the System Operator function as a separate licensed activity.

Consequently an institutional rearrangement is required to comply with the above direction in pursuance of legal requirement to be in place before the commencement of competitive market operations which is discussed in this application. The company has strived hard to ensure that SO as a separate function achieves readiness in-terms of people, resources, processes and technology before the commencement of wholesale electricity market.

6.2. Envisaged Institutional Framework

From global experience with respect to central economic dispatch markets, the preferred institutional arrangement is to combine the System Operator and the Market Operator into one single independent entity. This institutional model is termed as independent System Operator (ISO). Since, in such coupled markets, the System Operator and the Market Operator are technical and commercial pillars of the wholesale market and are interdependent functions even at routine operational level, therefore, it is imperative that these interdependent roles are performed by an independent, corporatized, and credible institution to demonstrate credibility and ensure confidence and trust among market players to achieve the competitive wholesale market objectives.

This proposition is under deliberation at the level of policy makers and as such, the Ministry of Energy (Power Division) may, at its discretion, move a summary in consultation of relevant stakeholders before Federal Government for creation of a new entity having similar institutional structure; however, this has yet to take place. The final decision will be taken by the Federal Government. The term "new company" has been used in this document to describe the independent company that may be established pursuant to Federal Government decision at a later date.

Meanwhile, NTDCL has endeavored to ensure that SO as a separate function achieves readiness in-terms of people, resources, processes and technology before the commencement of wholesale electricity market. Eventually, the SO function of NTDCL may be transferred to the new company through a Business Transfer Agreement (BTA), once incorporated in accordance with the final decision of the Federal Government.

Subsequent to the incorporation of new company, and pursuant to the decision of the Federal Cabinet, application(s) under section 33 read with section 27 and 23G of the Act may be filed to seek approval for re-organization and bifurcation of NTDCL to Independent System Operator, and for grant /assignment of the System Operator license to the newly established company.

7. Transfer of System Operations from NTDCL to new Company

A Business Transfer Agreement (BTA will be signed between this Applicant and new Company to be established pursuant to the decision of the Federal Government once notified.

Through the BTA, the following functions may be transferred to the new company:

i) The function under (a) System Operator performed under the Grid Code; (b) All functions relating to System Operations including economic dispatch etc. under Amended NEPRA Act.

ii) All functions which are ancillary or incidental to the above functions.

For the avoidance of doubt, it is hereby clarified that all functions and projects related to the Wire Business and Transmission shall continue to be performed by NTDCL in its current role under the Existing Exclusive License and will neither be affected nor any right will be transferred to the new company, whenever formed.

8. Submission

NTDCL submits that pursuant to the applicable laws of Pakistan including the Amended NEPRA Act and in lieu of the above explanation, NTDCL is submitting this Application for the grant of System Operator License as a sperate function within NTDCL before the Authority along with Grid Code duly approved by its Board of Directors to ensure that the SO License is available upon Section 23G of Amended NEPRA Act coming into force.

This Application for SO Licence is submitted in triplicate, and is accompanied with the required SO Licensing fee through a non-refundable Draft No. 17514955 in the amount of PKR 1,141,585/- (Pakistani Rupees One Million One Hundred and Forty One Thousand, Five Hundred and Eighty Five Hundred only) dated 19-08-2022 drawn in favour of the Authority.

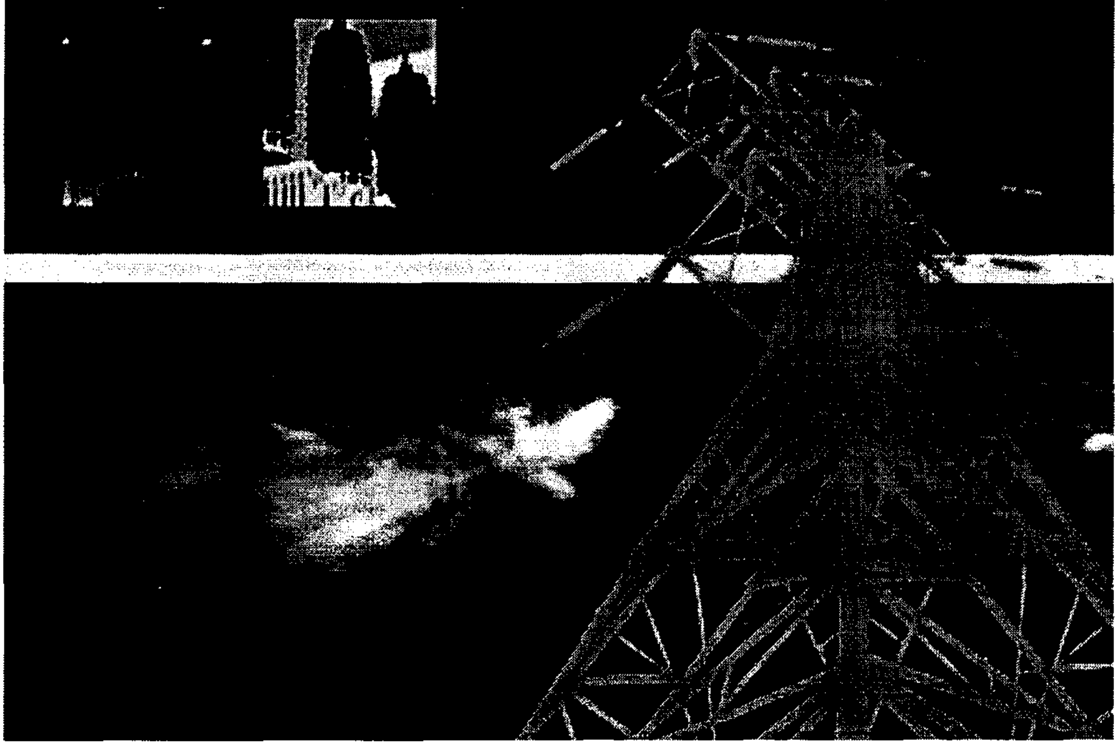
Signature: ____________

Rana Abdul Jabbar Khan
Managing Director NTDC
34101-4940598-9

Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

NATIONAL TRANSMISSION & DESPATCH COMPANY LIMITED

NTDCL Transmission License



National Electric Power Regulatory Authority
(NEPRA)
Islamabad - Pakistan

TRANSMISSION LICENCE

No TL/01/2002

In exercise of the Powers conferred on the National Electric Power Regulatory Authority (NEPRA) under Section 17 of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (XL of 1997), and subject to the provisions of Section 7(4) thereof, the Authority hereby grants a Transmission Licence to

NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED

Incorporated under the Companies Ordinance, 1984

Under Certificate of Incorporation

No. L09689 of 1998-99

to engage in the transmission of electric power in the Territory subject to and in accordance with the terms and conditions of this Licence.

Issued under my hand this 31st, day of December, Two Thousand & Two, and expires on 30th day of December, Two Thousand & Thirty Two.

31.12.02

Registrar

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY REGISTRAR (NEPRA)

31/12/02

31.12.02

31/12/2002

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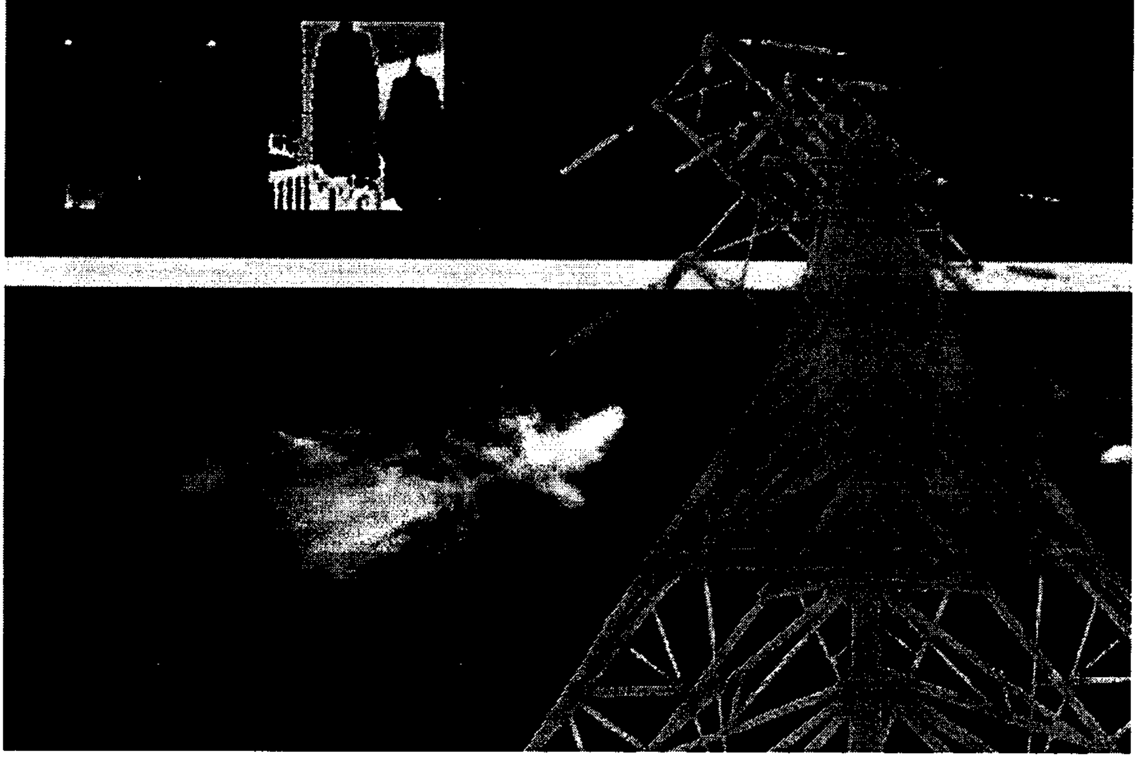
NATIONAL TRANSMISSION
& DESPATCH COMPANY LIMITED

SECP Certificate of Incorporation



16

GOVERNMENT OF PAKISTAN

CERTIFICATE OF INCORPORATION

(Under section 32 of the Companies Ordinance, 1984 (XLVII of 1984)

Company Registration No. L 09689 of 1998-99

I hereby certify that "NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED" // // //

is this day incorporated under the Companies Ordinance, 1984 (XLVII of 1984) and that the company is limited by Shares.

Given under my hand at Lahore.

this 6th day of November

one thousand nine hundred and Ninety eight.

Fee Rs. =5,000,200/-.

CERTIFIED TO BE TRUE COPY

ADDITIONAL REGISTRAR OF COMPANIES
COMPANY REGISTRATION OFFICE
LAHORE.

(AKBAR SHAH)
JOINT REGISTRAR
OF COMPANIES

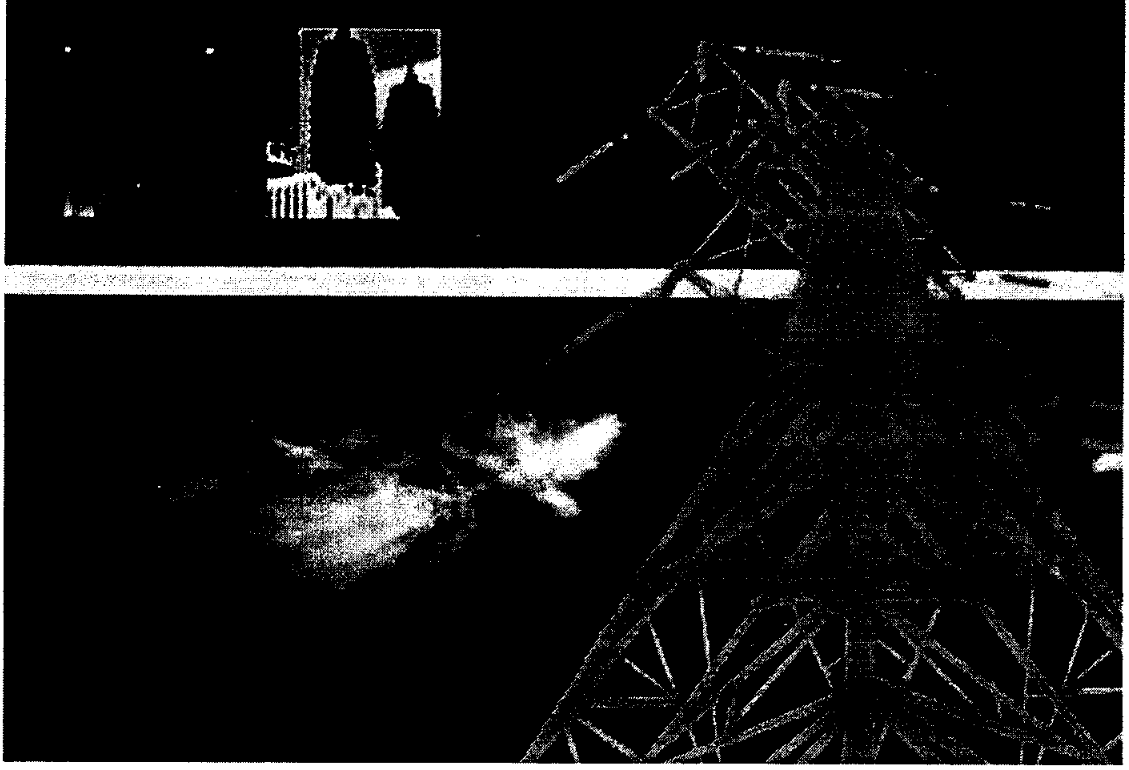
CRO-1

No. JRL/3312 dt 7/11/98

PCPPK

NATIONAL TRANSMISSION
& DESPATCH COMPANY LIMITED

Certificate of Commencement of Business



GOVERNMENT OF PAKISTAN

CERTIFICATE FOR COMMENCEMENT OF BUSINESS

[Under section 146 (2) of the Companies Ordinance, 1984 (XLVII of 1984)]

Company Registration Office Lahore
Securities and Exchange Commission of Pakistan

I hereby certify that the NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED which was incorporated under the Companies Ordinance, 1984 (XLVII of 1984), on the 6th day of November 19 98 and which has filed a duly verified declaration in the prescribed form that the conditions of clauses (a) to (e) of sub-section (1) of Section 146 of the said Ordinance have been complied with, is entitled to commence business.

Given under my hand at Lahore

this 24th day of December

one thousand nine hundred and Ninety eight.

CERTIFIED TO BE TRUE COPY

ADDITIONAL REGISTRAR OF COMPANIES
COMPANY REGISTRATION OFFICE
LAHORE.

Fee Rs. 200/-

Seal of the Company Registration Office
LAHORE
Government of Pakistan

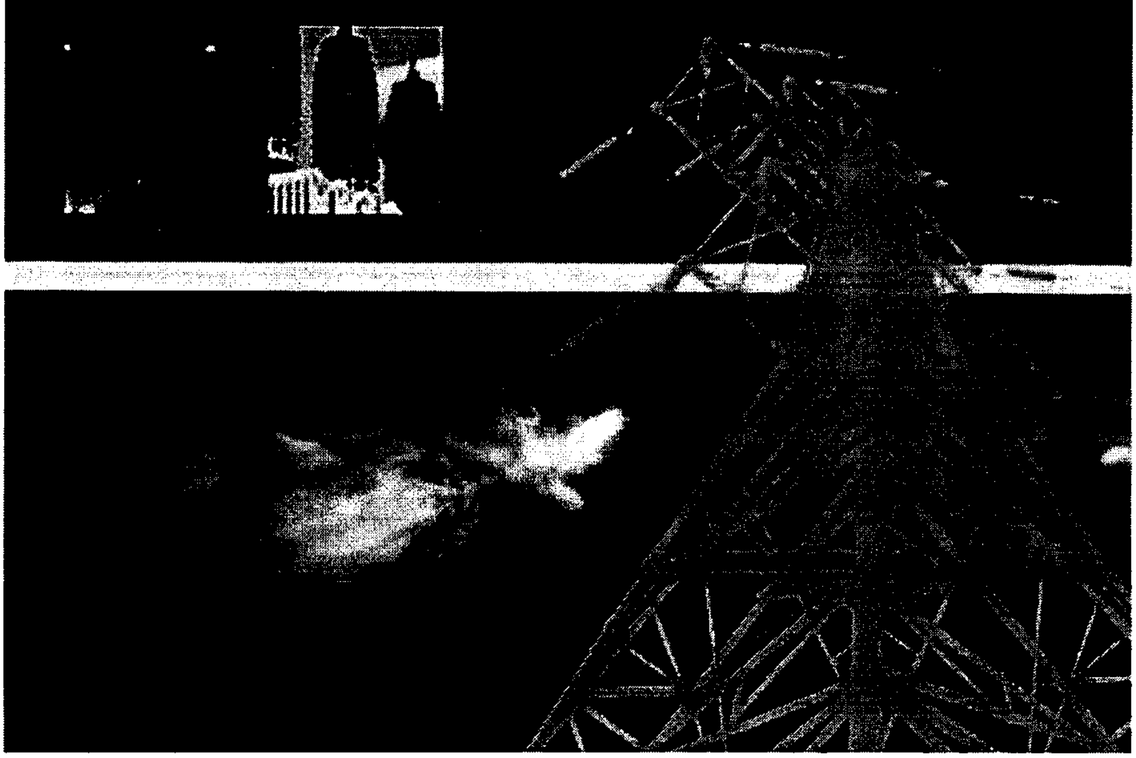
C.R.O.-4

(AKBAR SHAH)
Joint Registrar of Companies

/4309 # 26/12/98

NATIONAL TRANSMISSION
& DESPATCH COMPANY LIMITED

NTDCL Memorandum of Association



THE COMPANIES ORDINANCE, 1984

PUBLIC COMPANY LIMITED BY SHARES

MEMORANDUM OF ASSOCIATION

-OF-

NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED

I The name of the Company is NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED

II The registered office of the Company will be situated in Lahore, Province of Punjab, Pakistan.

III The objects for which the Company is established are to undertake any or all of the following businesses:

1. To acquire or take over those properties, rights and liabilities of the Pakistan Water and Power Development Authority comprising of that administrative division formerly engaged in the transmission and despatch of electrical power from power generation units for supply to the distribution subsector and to carry on, expand and extend the businesses and activities required for ensuring the effective and economical transmission of electric power from power generating units to the distribution subsector.

2. To acquire or take over those properties, rights and liabilities of the Pakistan Water and Power Development Authority consisting of the National Power Control Centre located at Islamabad, 220KV and above grid stations and transmission lines, the telecommunication systems (including but not limited to the Supervisory Control and Data Acquisition System, also known as "SCADA"), mimic boards, and all other assets, properties, rights and liabilities related thereto.

3 To carry on all or any of the businesses of purchasing, importing, transforming, converting, supplying, exporting and dealing in electricity and all other forms of energy and products or services associated therewith and of promoting the conservation and efficient use of electricity and all other forms of energy, and all other powers necessary or incidental to the business of electricity transmission, despatch and supply.

4 Monitoring/Upgrading - To do anything which a public transmitter, despatcher and electricity supplier is empowered or required to do under or by virtue of or under a license or other authorization granted according to law and its implementing rules and regulations or any statutory instrument made thereunder or any statutory modification or re-enactment thereof, to prepare and regularly monitor and evaluate the country's power development program and to operate, maintain and continuously upgrade the aforementioned 220KV and above grid stations and transmission lines.

5. Dealer in Electrical Equipment. - To carry on all or any of the businesses of wholesalers, retailers, traders, importers, exporters, suppliers, designers developers, manufacturers, installers, fitters, testers, repairers, maintainers contractors, constructors, operators, users, inspectors, reconditioners, servicers improvers, alterers, protectors, removers, hirers, replacers, importers and exporters of, and dealers in, electrical appliances systems products and services used for energy conservation, domestic, commercial, agricultural, industrial, household and general equipment, furniture, fixtures, fittings and devices, and all other kinds of goods, equipment, machinery, materials and installations, including but not limited to cables, wires, meters, pylons, tracks, rails, pipelines and any other plant, apparatus, equipment, systems and things incidental to the efficient transmission, despatch and supply of electricity.

6. Facilities and Installations. - To locate, establish, construct, equip, operate, use, manage and maintain power grid stations, transforming, switching, conversion, and transmission facilities, grid stations, cables, overhead lines, substations, switching stations, tunnels, cable bridges, link boxes, telecommunications stations, masts, aerials and dishes, fiber optic circuits, satellites and satellite microwave connections, heat pumps, plant and equipment for combined heat and power schemes, offices, computer centers, shops, dispensing machines for pre-payment cards and other devices, showrooms, depots, factories, workshops, plants, printing facilities, warehouses and other storage facilities (including but not limited to facilities for storage and disposal of products and waste), training, education and display centers, stands and show-houses, testing premises, laboratories, research stations, compressor stations, vehicle parks, terminals, transport facilities, roads, and other electrical installations and structures it may deem beneficial.

7. Acquisition and Conveyance of Assets. - To acquire, own, hold, either by purchase, lease, concession, grant, hire or otherwise, establish, develop, exploit, operate and maintain real or personal properties including but not limited to land, any estates in land, claims, licenses, concessions, easements, exploration and production rights, and rights or interests of all descriptions in or relating to the same, which may seem to the Company capable or possibly capable of affording or facilitating the purchase, transformation, conversion, supply, distribution, and development of electricity or any other form of energy, and for the accomplishment of all the purposes of the Company herein stated.

8. Site Development. - To build, construct, maintain, alter, enlarge, pull down, and remove or replace structures, factories, offices, works, wharves, roads, railways, tramways, machinery, engines, walls, fences, banks, dams, sluices or water courses and to clear sites for the same and to work, manage and control the same and to carry on any other business which may seem to the Company capable of being conveniently carried on in connection with the above or calculated directly or indirectly to enhance the value of or render more profitable the Companys properties, but not to engage in the business of a real estate developer.

9. Intellectual Property Rights. - To apply for and take out, purchase or otherwise acquire any patents, patent rights, inventions, secret processes, designs, copyrights, trademarks, service marks, commercial names and designations technological know-how, formulae, licenses, concessions and the like (and any interest in any of them), and exclusive or non-exclusive or limited rights to use any secret or other information as to any invention or secret process of any kind

and to use, exercise, develop, and grant licenses in respect of, and otherwise turn to account and deal with, the property, rights and information so acquired.

10. Metering. - For the purposes of electricity supply and communication to install in, on, above or under any premises or place and to operate, use, inspect, maintain, repair, replace and remove cables, lines, ducts, transformers, switchgear (remotely controlled and otherwise, and including time switches), fuses, circuit breakers, electricity service equipment, meters and other devices for measuring or controlling the quantity or quality of electricity supplied, prepayment and debt payment devices, items provided to afford access to, support, encase, insulate, and protect from damage or tampering, the above-mentioned gadgets, or to protect people and property from injury or damage, or to comply with any legal obligation and for other purposes associated with the supply of electricity and to install all such things and apparatus and items for the purposes of supplying, measuring and controlling light, heat, steam, hot water, air-conditioning and refrigeration, and for associated purposes, including payment for these facilities.

11. Transportation. - To acquire, (whether by purchase, lease, concession, grant, hire or otherwise), charter, lease, take or let on hire, operate, use, employ or turn to account, build, equip, service, repair, maintain, and supply motor vehicles, railway locomotives, wagons, trucks, vessels, and craft of any description, engineering plants and machinery, and parts and accessories of all kinds, and to carry on the businesses of storage contractors, freight contractors, carriers by land, water and air of freight and passengers, forwarding agents, shipping agents and agents of any other kind, in so far as such activities are incidental to or necessary for the transmission, despatch and supply of electricity.

12. Audio-Visual System. - To carry on as principal, agent, contractor or sub-contractor all or any of the businesses of running, operating, managing, supplying and dealing in systems for the conveyance by any means of sound, visual images, signals, and services, facilities and equipment ancillary to or for use in connection with such systems.

13. Management Information System. - To carry on all or any of the businesses of running, operating, managing, supplying and dealing in data processing and information retrieval systems, computers, computer programmes and software, computer bureau and data bases, meter reading and credit checking and to provide services, facilities and equipment ancillary to or for use in connection with the same.

14 Research and Development. - To carry on business as inventors, researchers and developers, to conduct, promote and commission research and development in connection with the businesses and activities of the Company and its subsidiaries, to establish and maintain research stations, laboratories, workshops, testing and proving grounds and sites, facilities and establishments and installations, and to exploit and turn to account the results of any research and development carried out by or for it.

15. Labour Contracting. - To carry on all or any of the businesses of consultants, advisers and suppliers of management, personnel and training services, whether generally or in respect of one or more of the types of business or activity which the Company has power to carry on, and to provide training and educational courses, instruction and materials, of every description for workers of the Company and for other persons.

16. Contracts. - To enter into agreement with any individual, firm, cooperative or other society, company, corporate body, Government or local authority or other legal entity necessary or expedient for the purpose of carrying on any business of the Company.

17. Engineering Services. - To carry on all or any of the businesses of and provide services associated with, engineers (including without limitation electrical, mechanical, heating, ventilation, civil, chemical, sanitation, telecommunications and gas engineers), mechanics, technicians, draftsmen, designers, surveyors, architects, builders, decorators, caterers, kitchen installers, and shopfitters.

18. Advertisement. - To adopt such means of making known the products of the Company as may seem expedient and, in particular, by advertising in the press, by circulars, by purchase and exhibition of works of art or interests, by publication of books and periodicals, and by granting prizes, rewards and donations.

19. Other Businesses. - To carry on all or any of the businesses of manufacturers, wholesalers, retailers, and traders, whether generally or in relation to particular goods or commodities, and to carry on all or any of the businesses of factors, debt collectors, and developers of and dealers in property, so far as incidental to or necessary for the transmission, despatch and supply of electricity.

20. Borrowing. - To borrow or raise money or secure or discharge any debt or obligation (whether of the Company or any other person) in such manner as the Company thinks fit and in particular (but without prejudice to the generality of the foregoing) by the creation or issue, upon such terms as to priority or otherwise as the Company thinks fit, of securities of any kind or mortgages or discharges founded or based upon all or any part of the undertaking, property, assets and rights (present and future) of the Company, or, without any such security, and advance payments with or without allowance of mark-up thereon.

21. Bank Accounts. - To open, operate, transfer, and close banking accounts of the Company with any bank or banks and to draw, make, accept, endorse, discount, execute, and issue promissory notes, bills of exchange, bills of lading, warrants, debentures, and other negotiable/non-negotiable or transferable/non-transferable instruments, but not to act as a finance or banking company.

22. Guaranty and Suretyship. - To enter into any guarantee, contract of indemnity or suretyship and, in particular (without prejudice to the generality of the foregoing), to guarantee, support or secure, with or without consideration, whether by personal obligation or by mortgaging or charging all or any part of the undertaking, property and assets (present and future), and unsubscribed capital of the Company or by both such methods or in any other manner, the performance of any contract, obligation or commitment of, and the repayment or payment of the principal amounts of and any premiums, interest, dividends, and other moneys

Declaration. It is hereby declared that

(a) the word company in this Memorandum of Association, except where used in reference to this Company, shall be deemed to include any partnership or other body of persons, whether corporate or unincorporated, and whether domiciled in Pakistan or elsewhere;

(b) the objects specified in each of the paragraphs of this clause shall be regarded as independent objects and, accordingly, shall in no way be limited or restricted (except where otherwise expressed in such paragraphs) by reference to or inference from the terms of any other paragraph or the name of the Company, but may be carried out in as full and ample a manner and construed in as wide a sense as if each of the said paragraphs defined the objects of a separate and distinct company;

(c) the headings used in each of the paragraphs of this clause are for convenience only and are not intended to affect the construction thereof in any way; and,

(d) notwithstanding anything contained in the foregoing object clauses of this Memorandum of Association, nothing shall be construed as empowering the Company to undertake or indulge in the business of managing agency, banking or financing, leasing, investment, or real estate brokerage or insurance, directly or indirectly, as restricted by law or in any unlawful operations;

IV The liability of the members is limited.

V The authorized capital of the company is Rupees 60,000,000,000 divided into 6,000,000,000 ordinary shares of Rupees 10 each. The Company shall have powers to increase or reduce the Capital to divide the shares in the capital for the time being into several classes and to attach thereto respectively such preferential, deferred, qualified or special rights, privileges or conditions as may be determined by or in accordance with the regulations of the Company and to vary, modify or abrogate any such rights, privileges or conditions in such manner as may for the time being be provided by the regulations of the Company and to consolidate or sub-divide the shares and issue shares of higher or lower denomination".

Company may think necessary or proper in connection with any of the matters aforesaid

14. Charitable Contributions. - To subscribe or contribute (in cash or in kind) surplus properties to, and to promote or sponsor, any charitable, eleemosynary, scientific, educational, benevolent or useful object of a public character or any object which may in the opinion of the Company be likely, directly or indirectly, to further the interests of the Company, its employees and workers or its members, and to receive donations and grants, in cash or in kind, whether absolutely gratuitous or otherwise, which it may deem beneficial to its business, employees or shareholders.

35. Dissolution and Winding Up. - To cease carrying on or wind up any business or activity of the Company and to cancel any registration of and to wind up or procure the dissolution of the Company in any state or territory.

36. Equity Conversion. - To issue, allot and grant options over securities of the Company towards the satisfaction of any liability or obligation undertaken or agreed to be undertaken by or for the benefit of the Company or in consideration of any obligation or for any other similar purpose.

37. International Operations. - To procure the Company to be registered or recognized in any part of the world and to do all or any of the above things in any part of the world, either as principal, agent, trustee, contractor or otherwise, alone or in collaboration with another, and either by or through agents, trustees, sub-contractors, subsidiaries or otherwise.

38. Disposal of Assets and Declaration of Dividends. - To dispose by any means of the whole or any part of the assets of the Company or of any interest therein and to distribute in specie or otherwise by way of dividends or bonus or reduction of capital all or any of the property or assets of the Company among its members, and particularly, but without prejudice to the generality of the foregoing, securities of any other company formed to take over the whole or any part of the assets or liabilities of the Company or any proceeds of sale or other disposal of any property or assets of the Company.

39. Insurance. - To insure the property, assets, and employees of the Company in any manner deemed fit by the Company, and to create any reserve fund, sinking fund, insurance fund or any other special fund whether for depreciation or for repairing, insuring, improving, extending or maintaining any of the properties of the Company or for any other purpose conducive to the interests of the Company, but not to act as an insurance company.

40. Regulations. - To make rules or regulations not inconsistent with this Memorandum and to provide for all matters for which provision is necessary or expedient for the purpose of giving effect to the provisions of this Memorandum and the efficient conduct of the affairs of the Company.

41. General Power. - To carry on any other businesses or activities which the Directors consider capable of being carried on directly or indirectly for the benefit of the Company and to do all such other things as may be deemed incidental or conducive to the attainment of the above objects or any of them.

Government Permissions. - To apply for and obtain necessary consents, permissions and licenses from any Government, Provincial, Local, Foreign, Multilateral or other authorities or entities for enabling the Company to carry any of its objects into affect or for extending any of the powers of the Company or for effecting any modification of the constitution of the Company or for any other purpose which may seem expedient, and to enter into arrangements with any Government or authorities, foreign, federal, provincial, municipal, local or otherwise, public or quasi-public bodies, or with any other persons, in any place where the Company may have interests that may seem conducive to the objects of the Company or any of them and to obtain from any such Government, authorities or persons any rights, privileges and concessions which the Company may think fit to obtain, and to carry out, exercise and comply therewith.

30. Dispute Resolution. - To resolve disputes by negotiation, conciliation, mediation, arbitration, litigation or other means, judicial or extra-judicial, and to enter into compromise agreement with creditors, members and any other persons in respect of any difference or dispute with them and to exercise the power to sue and be sued and to initiate or oppose all actions, steps, proceedings or applications which may seem calculated directly or indirectly to benefit or prejudice, as the case may be, the interests of the Company or of its members.

31. Employees Funds. - To establish and maintain or procure the establishment and maintenance of any contributory or non-contributory pension or superannuation funds for the benefit of, and give or procure the giving of donations, gratuities, pensions, allowances or emoluments to such persons who are or were at any time in the employ or service of the Company, or of any company which is a holding company or a subsidiary of the Company or is allied to or associated with the Company or with any such subsidiary or affiliate company, or who are or were at any time directors or officers of the Company or of any such other company as aforesaid, and the wives, widows, families and qualified dependents of any such persons, and also to establish, subsidize and subscribe to institutions, associations, clubs or funds calculated to be for the benefit of or to advance the interests and well-being of the Company or of any such other company as aforesaid, and make payments to or towards the insurance of any such person as aforesaid and do any of the matters aforesaid, either alone or in conjunction with any such other company as aforesaid.

32. Remuneration. - To enter into contracts with its salaried employees, including a chief executive who, prior to his appointment as such, was not a director of the Company or of its subsidiary or holding Company, and to provide for such other financial assistance to said employees or workers under personnel rules and regulations that the Company may subsequently adopt.

33. Commissions. - To pay and discharge all or any expenses, costs and disbursements, and to pay commissions and to remunerate any person for services rendered or to be rendered in connection with the formation, registration, promotion and floatation of the Company and any company formed, sponsored, registered, and promoted by the Company or incidental to any negotiations between promoters preliminary to the formation of the Company, and the underwriting, placing or issue at any time of securities of the Company or of any other person plus all costs and expenses incurred in the acquisition of any property or assets, including the accomplishment of all or any formalities which the

payable on or in respect of any securities or liabilities of, any person, including (without prejudice to the generality of the foregoing) any company which is a subsidiary, an affiliate or a holding company of the Company or otherwise associated with the Company, whether or not any valuable consideration or advantage is received by the Company.

23. Partnerships. - To enter into partnership, joint venture or cooperation arrangements with any person or company or other legal entity, local or foreign, carrying on or engaged in any business or transaction which the Company is authorized to carry on or engage in, or otherwise seek assistance from or assist any such person, company or legal entity.

24. Related Businesses - To acquire by any means the whole or any part of the assets, and to undertake the whole or any part of the liabilities, of any person, natural or juridical, carrying on or proposing to carry on any business which the Company is authorized to carry on or which can be carried on in connection therewith, to acquire an interest in, amalgamate or enter into partnership or into any arrangement for sharing profits, cooperation, or mutual assistance, with any such person, to promote, form and sponsor any company or companies in furtherance of the objects herein stated, and to give or accept, for any of the acts or things aforesaid or property acquired, such consideration as the Company thinks fit, including without limitation, any shares, debentures, or other securities or rights.

25. Equity Investment. - To invest the surplus moneys of the Company not immediately required in any manner to subscribe for, purchase or otherwise acquire, and to hold, and deal with, any shares, debentures, bonds, and other securities, obligations and investments of any nature whatsoever, including any options or rights in respect of them, and otherwise to invest and deal with the money and assets of the Company, but not to act as an investment company.

26. Lending. - To advance money or give credit to such persons or companies and on such terms as may seem expedient and, in particular, to customers and others having dealings with the Company, to guarantee the performance of any contract or obligation and the payment of money by the Company, and to accept securities of any person or any property or interest therein of whatever nature in payment or partial payment for any services rendered or for any sale or supply made to, or debt owing from, any such person, but not to act as a finance or banking company.

27. Trusts. - To vest any real or personal property, rights or interests acquired by or belonging to the Company in any person or company on behalf of or for the benefit of the Company, with or without any declared trust in favour of the Company, and to undertake and execute any trust the undertaking whereof may seem desirable, either gratuitously or otherwise.

28. Portfolio Investments. - Subject to such terms and conditions as may be thought advantageous, to trade its shares and to undertake markup and currency swaps, options (including traded options), swap, option contracts, forward exchange contracts, futures contracts or other financial instruments allowed by law, including hedging agreements of any kind, all or any of which may be on a fixed and/or floating rate basis and/or in respect of local or foreign currency or commodities of any kind, but not to engage in the business of a stockbroker.

We, the several persons whose names and addresses are subscribed below are desirous of being formed into a company in pursuance of this Memorandum of Association and we respectively agree to take the number of shares in the capital of the Company set opposite our respective names.

Name and surname (present and former) in full (in Block Letters)	Father's/ Husband's Name in Full	Nationality	Occupation	Residential Address in Full	Number of Shares taken by each Subscriber	Signature
Syed Tanzim Hussain Naqvi	Syed Taslim Hussain Naqvi	Pakistani	Wapda Service	House No. 56-B, Wapda Officers Colony, Upper Mall, Lahore.	1	
Mr. Muhammad Aslam Javed	Muhammad Yousaf	Pakistani	Wapda Service	49-Wapda Colony, Lahore.	1	
Mr. Riaz Ahsan Baig	Abdul Latief Baig	Pakistani	Wapda Service	House No. 88/E/2, Arif Jan Road, Lahore Cantt.	1	
Mr. Noor Elahi Baig	M. Fazal Elahi Baig	Pakistani	Wapda Service	B-2, Shalamar Grid Station, Wapda Colony, Lahore.	1	
Mr. Javed Nizam	Muhammad Islam	Pakistani	Wapda Service	263-Tariq Block, New Garden Town, Lahore.	1	
Brig. Saeed Ahmad Rafi	Muhammad Ajaib	Pakistani	Wapda Service	B-33, Upper Mall, Wapda Colony, Lahore.	1	
Mr. Muhammad Rafique	Abdul Ghani	Pakistani	Wapda Service	927-Ravi Block, Allama Iqbal Town, Lahore	1	

Total number of shares taken 7 (Seven)

Dated the 2 day of November 1998

Witness to the above signatures

Signature

(Full Name, Father's/Husband's Name)

(in Block Letters) TARIQ MAHMOOD S/. M.M. BABAR

Occupation

Full Address

CERTIFIED TO BE TRUE COPY

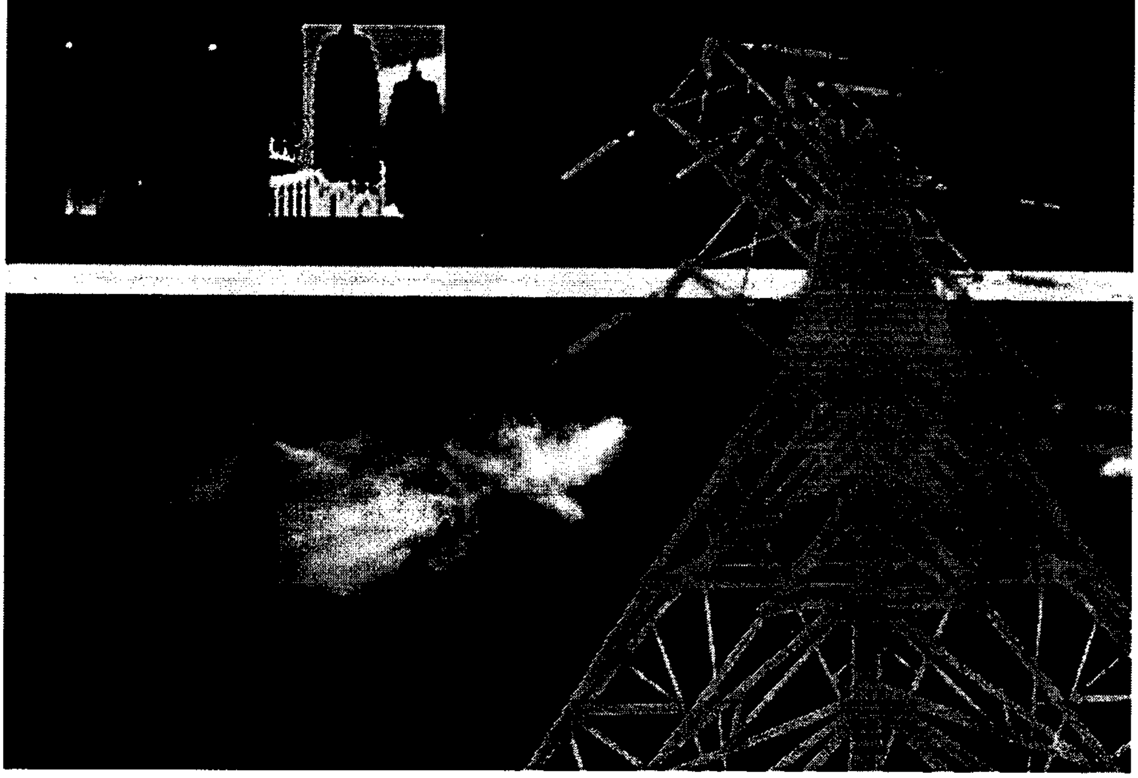
Z. Haider 29-7-22

ADDITIONAL REGISTRAR OF COMPANIES
COMPANY REGISTRATION OFFICE
LAHORE

Company Registration Office Lahore
Securities and Exchange Commission of Pakistan
SECP

NATIONAL TRANSMISSION & DESPATCH COMPANY LIMITED

NTDCL Articles of Association



THE COMPANIES ORDINANCE, 1984

PUBLIC COMPANY LIMITED BY SHARES

ARTICLES OF ASSOCIATION

-OF-

NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED

I. PRELIMINARY

1. TABLE A Not to Apply

The regulations in Table A in the First Schedule to the Companies Ordinance, 1984 shall not apply to the Company except as reproduced herein.

2. Definitions

Unless the context otherwise requires, capitalized terms used in these Articles shall have the meanings set out below:-

(a) Articles mean these Articles as originally framed or as from time to time altered in accordance with law.

(b) Board means the group of Directors in a meeting duly called and constituted or, as the case may be, the Directors assembled at a board.

(c) Company means the National Transmission and Despatch Company Limited.

(d) Directors means the Directors for the time being of the Company as named in Article 49 and, subsequently, such members duly elected and appointed pursuant to Sections 178 and 205, respectively.

(e) Month means calendar month according to the Gregorian calendar.

(f) Office means the registered office for the time being of the Company.

(g) Ordinance means the Companies Ordinance, 1984, or any modification or re-enactment thereof for the time being in force.

(h) Ordinary Resolution means a resolution passed at a general meeting of the Company when the votes cast (whether viva voce, by show of hands or by poll) in favour of a resolution by members who, being entitled to vote in person or by proxy, do so vote, exceed the number of votes, if any, cast against the resolution by members so entitled and voting.

(i) Register means, unless the context otherwise requires, the register of members to be kept pursuant to Section 147 of the Ordinance.

(j) Seal means the common or official seal of the Company.

(k) Section means a Section of the Ordinance.

(l) Special Resolution means the special resolution of the Company as defined in Section 2(1)(36) of the Ordinance.

3. Interpretation

In these Articles, unless the context otherwise requires:-

(a) provisions bearing on transfer or transmission of shares, meetings, voting in person or by proxy, management, and the appointment, powers and removal of Directors and employees of the Company shall be read subject to the provisions of Section 183 relating to the power of control by holding company over its subsidiary;
the headings are for convenience only and do not constitute part of these Articles and shall not be used in construing these Articles;

(b) the singular includes the plural and vice versa and words denoting any gender shall include all genders;

(c) references to any Act, Ordinance, legislation, Rules or Regulations or any provision of the same shall be a reference to that Act, Ordinance, legislation, Rules or Regulations or provision, as amended, re-promulgated or superseded from time to time;

(d) the terms include or including shall mean include or including without limitation;

(e) expressions referring to writing shall, unless the contrary intention appears, be construed as including references to printing, lithography, photography, and other modes of representing or reproducing words in a visible form;

(f) words importing persons shall include bodies corporate; and

(g) words and expressions contained in these Articles shall bear the same meaning as in the Ordinance.

II. BUSINESS

4. Public Company

The Directors shall have regard to the restrictions on the commencement of business imposed by Section 146 if, and so far as, those restrictions are binding upon the Company.

III. SHARES

A. General

5. Shares Under Directors Control

Subject to Section 183 and these Articles, the shares of the Company shall be under the control of the Directors who may allot or otherwise dispose of the same to such persons, on such terms and conditions as the Directors think prudent.

6. Amount Payable on Application

No shares shall be offered to the public for subscription except upon the term that the amount payable on application shall not be less than the full amount of the nominal amount of the share.

7. Allotment of Shares

No share shall be issued at a discount except in accordance with the provisions of the Ordinance. The Directors shall, as regards any allotment of shares, duly comply with such of the provisions of Sections 68 to 73, as may be applicable to the Company. The minimum subscription upon which the Company may proceed to allot the shares shall be Rs. 500,000.

8. Share Certificates

Every person whose name is entered as a member in the Register shall, free of charge, be entitled to receive within ninety (90) days after allotment or within forty-five (45) days of the application for registration of transfer, a certificate under Seal specifying the share or shares held by him and the amount paid-up thereon, including in particular and without limitation, such legends as the Company shall be obliged to affix to certain classes of share certificates as provided by law or as the Company shall have agreed to affix pursuant to any contractual arrangement in this respect; Provided, that, in respect of share or shares held jointly by several persons, the Company shall not be bound to issue more than one certificate, and delivery of a certificate for a share to one of several joint holders shall be sufficient delivery to all.

9. Certificate under Seal

The certificate of title to shares may be issued under the authority of a Director or of a committee of Directors duly authorized thereto by the Board in such manner and form as the Directors may from time to time prescribe. The Seal shall be duly affixed to every share certificate issued by the Company.

10. Issuance of Replacement Certificate

If a share certificate is defaced, lost or destroyed, it may be renewed on payment by the requesting shareholder or his representative of such fee and stamp taxes, if any, and compliance with such terms prescribed by the Directors as to evidence and indemnity and payment of expenses incurred by the Company in investigating title.

11. Joint Holders

The Company shall not be bound to register more than four persons as joint holders of any share.

12. Trusts Not Recognized

Except as required by law, no person shall be recognized by the Company as holding any share/s upon any trust, and the Company shall not be bound by or be compelled in any way to recognize (even when having notice thereof) any equitable, contingent, future or partial interest in any share or any interest in any fractional part of a share or (except only as by these Articles or by law otherwise provided) any other rights in respect of any share except an absolute right to the entirety thereof in the registered holder.

13. Payment of Commission

The Company may at any time pay a commission to any person for subscribing or agreeing to subscribe (whether absolutely or conditionally) for any shares, debentures or debenture stock in the Company or procuring or agreeing to procure subscriptions (whether absolutely or conditionally) for any shares, debentures or debenture stock in the Company; Provided, that, if the commission in respect of shares shall be paid or payable out of capital, the statutory requirements and conditions shall be observed and complied with, and the amount or rate of commission shall not exceed such percentage on the shares, debentures or debenture stock in each case subscribed or to be subscribed, as may be determined by the Board subject to any limits required by law. The commission may be paid or satisfied, either wholly or partly, in cash or in shares, debentures or debenture stock. The Company may also on any issue of shares pay such brokerage fees as may be lawful; Provided that such brokerage fees shall not exceed such percentage of the shares, debentures or debenture stock paid-up as may be determined by the Board, subject to any limits required by law.

14. Bar on Use of Company Funds

Except to the extent and in the manner allowed by Section 95, no part of the funds of the Company shall be employed in the purchase of, or in loans upon the security of, the Companys shares.

B. TRANSFER OF SHARES

15. Transfer

The instrument of transfer of any share in the Company shall be executed both by the transferor and transferee, and the transferor shall be deemed to remain the holder of the share until the name of the transferee is entered in the Register in respect thereof.

16. Form of Transfer

Shares in the Company shall be transferred in the following form, or in any usual or common form which the Directors shall approve:-

18

National Transmission and Despatch Company Limited.

I/We, ____________, of ____________, in consideration of the sum of Rupees ____________ paid to me by ____________, of ________, (hereinafter called the Transferee/s, for brevity), do hereby transfer to the Transferee/s the Ordinary/Preferred Share(s) numbered __________ to ___________,inclusive, standing in my/our name in the books of the National Transmission and Despatch Company Limited, to hold unto the said Transferee, his/her/their executors, administrators and assigns, subject to the several conditions on which I/We held the same at the time of the execution hereof, and I/We, the Transferee/s, do hereby agree to take the said share (s) subject to the conditions aforesaid.

Witness our hands this __________ day of __________.

Transferor   Transferee

Signature_______________   Signature_______________

Signed by the above-named Transferor/s and Transferee/s in the presence of:

Witnesses____________________ Full Name, Fathers/ ________________

Husband's Name____________________

(1)   Nationality______________________

Signature____________________

Full Address:______________________ Occupation ________________

Full Address of ___________________

Transferee: _______________________

(2)

Signature____________________

Full Address:__________________ Occupation _____________

Company Registration Office Lahore Securities and Exchange Commission of Pakistan SECP

17. Non- Refusal of Transfer of Shares

The Directors shall not refuse to transfer any fully paid shares unless the transfer deed is defective or invalid. The Director may decline to recognize any instrument of transfer, unless-

(a) a fee not exceeding two rupees as may be determined by the Directors and the appropriate stamp tax is paid to the Company in respect thereof; and

(b) the duly stamped instrument of transfer is accompanied by the certificate of the shares to which it relates, and such other evidence as the Directors may reasonably require to show the right of the transferor to make the transfer.

If the Directors refuse to register a transfer of shares, they shall within one month after the date of which the transfer deed was lodged with the Company send to the transferee and the transferor notice of the refusal indicating the defect, invalidity or any ground for objection to the transferee, who shall, after removal of such defect or invalidity be entitled to re-lodge the transfer deed with the Company.

18. Closure of Register

On giving seven days prior notice in the manner provided by the Ordinance, the Register may be closed for such period or periods not exceeding forty-five (45) days in any one year as the Directors may from time to time determine; however, the Register shall not be closed for a period longer than thirty (30) days at any given time.

C. TRANSMISSION OF SHARES

19. Transmission

The executors, administrators, heirs or nominees, as the case may be, of a deceased sole holder of a share shall be the only persons recognized by the Company as having any title to the share. In the case of a share registered in the names of two or more holders, the survivor or survivors shall upon proof of his right of succession be the only person or persons recognized by the Company as having any title to the share.

20. Election to Register or Transfer

Any person becoming entitled to a share in consequence of the death or insolvency of a member shall, upon such evidence being produced as may from time to time be required by the Directors, have the right, either to be registered as a member in respect of the share or, instead of being registered himself, to make such transfer of the share as the deceased or insolvent person could have made. The Directors shall, in either case, have the same right to decline or suspend registration as they would have had in the case of a transfer of the share by the deceased or insolvent person before the death or insolvency.

21. Rights of Person Entitled by Transmission

A person becoming entitled to a share by reason of the death or insolvency of the holder shall be entitled to the same dividends and other advantages to which he would have been entitled if he were the registered holder of the share, except that he shall not, before being registered as a member in respect of the share, be entitled in respect of it to exercise any right conferred by membership in relation to meetings of the Company.

D. ALTERATION OF CAPITAL

22. Power to Increase Capital

The Company may, from time to time, by ordinary resolution, increase the share capital by such sum to be divided into shares of such amount as the resolution shall prescribe.

23. Further Issue of Capital

All further issue of share capital shall be subject to the applicable provisions of Section 86. Thereafter, the Directors may dispose of the same in such manner as they think most beneficial to the Company.

24. Provisions Applicable to New Shares

The new share capital shall be subject to the same provisions with reference to transfer and transmission as the original share capital.

25. Consolidation and Subdivision

The Company may, by ordinary resolution:-

(a) consolidate and divide its share capital into shares of larger amount than its existing shares;

(b) subdivide its existing shares or any of them into shares of smaller amount than that fixed by the Company Memorandum of Association, subject to the provisos to Section 92, sub-section (1), clause (d); or

(c) cancel any shares which, at the date of the passing of the resolution, have not been taken or agreed to be taken by any person.

26. Reduction of Share Capital

The Company may, by Special Resolution, reduce its share capital in any manner with and subject to any incident authorized and consent required by law.

Company Registration Office Lahore
SECP
Securities and Exchange Commission of Pakistan

IV. MEETINGS AND PROCEEDINGS

A. GENERAL MEETINGS

27. Statutory Meeting

The statutory meeting of the Company shall be held within the period required by Section 157.

28. Annual General Meeting

The annual general meeting shall be held in accordance with the provisions of Section 158, within eighteen (18) months from the date of incorporation of the Company and, thereafter, once at least in every year within a period of six months following the close of its financial year and not later than fifteen months after the holding of its last preceding annual general meeting, as may be determined by the Directors.

29. Other Meetings

All general meetings of the Company other than the statutory meeting or an annual general meeting shall be called extraordinary general meetings.

30. Extraordinary General Meetings

The Directors may whenever they think necessary, call an extraordinary general meeting. Extraordinary general meetings may also be called on such requisition, or in default, may be called by such requisition, as provided under Section 159. If at any time there are not within Pakistan sufficient Directors capable of acting to form a quorum, any Director of the Company may call an extraordinary general meeting in the same manner as nearly as possible as that in which meetings may be called by the Directors.

B. Notice and Proceedings

31. Notice of Meetings

Twenty-one days notice at the least (exclusive of the day on which the notice is served or deemed to be served, but inclusive of the day for which notice is given) specifying the place, the date and the hour of meeting and, in case of special business, the general nature of that business, shall be given in the manner provided by the Ordinance for the general meeting to such persons as are, under the Ordinance or the regulations of the Company, entitled to receive such notice from the Company.

32. Special Business

All business shall be deemed special that is transacted in an extraordinary general meeting and those transacted in an annual general meeting, with the exception of declaration dividends, the consideration of the accounts, balance sheet and the reports of the Directors and auditors, the election of Directors, and the appointment and fixing of the remuneration of auditors.

33. Quorum

No business shall be transacted at any general meeting unless a quorum of members is present at that time when the meeting proceeds to business. Three members present personally who represent not less than twenty-five percent of the total voting power either on their own account or as proxies shall be a quorum.

34. Effect of Quorum Not Being Present

If within half an hour from the time appointed for the meeting a quorum is not present, the meeting, if called upon the requisition of members, shall be dissolved; In any other case, it shall stand adjourned to the same day in the next week at the same time and place, and, if at the adjourned meeting a quorum is not present within half an hour from the time appointed for the meeting, the members present, being not less than three, shall be a quorum.

35. Chairman of Meeting

The Chairman of the Board of Directors, if any, shall preside as chairman at every general meeting of the Company, but if there is no such Chairman, or if at any meeting he is not present within fifteen minutes after the time appointed for the meeting, or is unwilling to act as chairman, any one of the Directors present may be elected to be the chairman, and if none of the Directors is present, or willing to act as chairman, the members present shall choose one of their number to be the chairman.

36. Adjournment

The Chairman may, with the consent of any meeting at which a quorum is present (and shall if so directed by the majority of members present), adjourn the meeting from time to time but no business shall be transacted at any adjourned meeting other than the business left unfinished at the meeting from which the adjournment took place. When a meeting is adjourned for ten days or more, notice of the adjourned meeting shall be given as in the case of an original meeting. Save as aforesaid, it shall not be necessary to give any notice of an adjournment or of the business to be transacted at an adjourned meeting.

37. Voting

A resolution put to the vote in any general meeting shall be decided on a show of hands unless a poll is (before or on the declaration of the result of the show of hands) demanded. Unless a poll is so demanded, a declaration by the Chairman that a resolution has, on a show of hands, been carried, or carried unanimously, or by a particular majority, or lost, and an entry to that effect in the minutes of proceedings of the Company shall be conclusive evidence of the fact without proof of the number or proportion of the votes recorded in favor of, or against, that resolution.

Company Registration Office Lahore Securities & Exchange Commission of Pakistan

38. Demand for a Poll

A poll may be demanded only in accordance with the provisions of Section 167.

39. Manner of Taking a Poll

If a poll is duly demanded, it shall be taken in accordance with the manner laid down in Section 168 and the result of the poll shall be deemed to be the resolution of the meeting at which the poll was demanded.

40. Time of Taking a Poll

A poll demanded on the election of Chairman or on a question of adjournment shall be taken at once.

41. Casting Vote

In the case of an equality of votes, whether on a show of hands or on a poll, the chairman of the meeting at which the show of hands takes place, or at which the poll is demanded, shall have and exercise a second or casting vote.

C. Votes of Members

42. Right to Vote

Subject to any rights or restrictions for the time being attached to any class or classes of shares, on a show of hands every member present in person shall have one vote except for election of Directors in which case the provisions of Section 178 shall apply. On a poll, every member shall have voting rights as laid down in Section 160.

43. Voting By Joint Holders

In case of joint-holders, the vote of the senior who tenders a vote, whether in person or by proxy, shall be accepted to the exclusion of the votes of the other joint-holders. For this purpose, seniority shall be determined by the order in which the names stand in the Register.

44. Voting; Corporation Representatives

On a poll, votes may be given either personally or by proxy; Provided, that, no body corporate shall vote by proxy as long as a resolution of its directors in accordance with the provisions of Section 162 of the Ordinance is in force.

45. Proxy to be in Writing

The instrument appointing a proxy shall be in writing under the hand of the principal to his attorney duly authorized in writing. A proxy must be a member of the Company.

46. Instrument Appointing Proxy to be Deposited

The instrument appointing a proxy and the power-of-attorney or other authority (if any) under which it is signed, or a notarially certified copy of that power of authority, shall be deposited at the Office of the Company not less than forty-eight (48) hours before the time for holding the meeting at which the person named in the instrument proposes to vote and in default the instrument of proxy shall not be treated as valid.

47. Form of Proxy

An instrument appointing a proxy may be in the following form, or a form as near thereto as may be:

NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED

I,________________, of ______________, in the District of ____________________, being a member of National Transmission and Despatch Company Limited, hereby appoint ______________________________of ___________, as my proxy to vote for me and on my behalf at the (annual/extraordinary as the case may be) general meeting of the Company to be held on the ______________day of __________ 19 ___ and at any adjournment thereof.

48. Revocation of Authority

A vote given in accordance with the terms of an instrument of proxy shall be valid notwithstanding the previous death or insanity of the principal or revocation of the proxy or of the authority under which the proxy was executed, or the transfer of the share in respect of which the proxy is given; Provided, that, no intimation in writing of such death, insanity, revocation or transfer as aforesaid shall have been received by the Company at its Office before the commencement of the meeting or adjourned meeting at which the proxy is used.

V. MANAGEMENT AND ADMINISTRATION

A. BOARD OF DIRECTORS

49. Number of Directors

The number of Directors shall not be less than seven. The first Directors, to hold office until the first annual general meeting, shall be:-

(1) Syed Tanzim Hussain Naqvi
(2) Mr. Muhammad Aslam Javed
(3) Mr. Riaz Ahsan Baig
(4) Mr. Noor Elahi Baig
(5) Mr. Javed Nizam
(6) Brig. Saeed Ahmad Rafi
(7) Mr. Muhammad Rafique

50. Qualification of Directors

Save as provided in Section 187, no person shall be appointed as a Director unless he is a member of the Company.

51. Chairman of the Board

The Directors may elect one of their number as the Chairman of the Board and vest in him such powers and functions as they may deem fit in relation to the management and administration of the affairs of the Company subject to their general supervision and control.

52. Chief Executive

The Directors may elect one of their number to be the Chief Executive of the Company in accordance with the provisions of Sections 198 and 199 and vest in him such powers and functions as they deem fit in relation to the management and administration of the affairs of the Company subject to their general supervision and control. The Chief Executive of the Company shall be the ex-officio Vice-Chairman of the Board. The provisions of the Ordinance shall be observed regarding other matters relating to the Chief Executive.

53. Remuneration

Subject to any approval or limits required by law, the terms and conditions and remuneration of:-

(a) Director for performing extra services, including the holding of the office of Chairman:

(b) the Chief Executive; and

(c) any Director for attending the meetings of the Directors or a Committee of Directors shall be determined by the Board of Directors.

54. Alternate Director

A Director may, with the approval of the Board, appoint any person (including another Director) to be his alternate Director and such an alternate Director shall be entitled to notice of meetings of the Directors and to attend and vote thereat accordingly and, generally, to exercise all the rights of such absent Director subject to any limitations in the instrument appointing him. For the purposes of the proceedings at such meetings, the provisions of these Articles shall apply as if any alternate Director (instead of his appointer) were a Director. An alternate Director shall not require any share qualification and he shall ipso facto vacate office as and when his appointer (a) vacates office as a Director; (b) removes the appointee from office; or (c) returns to Pakistan; Provided, that, upon each occasion upon which the appointer thereafter leaves Pakistan again, and unless the appointer shall have informed the Company to the contrary, he shall be deemed to have re-appointed the appointee as his alternate Director and no further approval of the Board shall be required unless the appointer desires to approve another person not previously approved by the Board as his alternate. If an alternate Director shall be himself a Director, his voting rights shall be cumulative but he shall not be counted as more than one for quorum purposes. Any appointment or removal under this Article shall be reflected by notice in writing under the hand of the Director making the same.

B. POWERS AND DUTIES OF DIRECTORS

55. General Management Powers

The business of the Company shall be managed by the Directors, who may exercise all such powers of the Company as are not by the Ordinance or by the these regulations, required to be exercised by the Company in general meeting, subject nevertheless to the provisions of the Ordinance or to any of these Articles, and such regulations being not inconsistent with the aforesaid provisions, as may be prescribed by the Company in a general meeting; but no regulation made by the Company in general meeting shall invalidate any prior act of the Directors which would have been valid if that regulation had not been made.

56. Borrowing Powers

The Directors may exercise all the powers of the Company to raise money otherwise than by issue of shares and to mortgage, charge, pledge, hypothecate or otherwise create an encumbrance on its undertaking or any part thereof and to issue debentures and other securities whether outright or as security for any obligation, liability or debt of the Company or of any third party. In exercising the aforesaid powers of the Company the Directors may, from time to time and on such terms and conditions as they think fit, raise money from banks and financial institutions and from other persons under any permitted system of financing, whether providing for payment of interest or some other form of return, and in particular the Directors may raise money on the basis of mark-up price, musharika, modaraba or any other permitted mode of financing, and without prejudice to the generality of the foregoing, the Directors may exercise all or any of the powers of the Company under Section 196(2) of the Ordinance. In particular, the Directors may issue any security as defined in Section 2(1)(34) of the Ordnance or may issue any instrument or certificate representing redeemable capital as defined in 2(1)(30A) of the Ordinance or participatory redeemable capital as defined in Section 2(1)(25) of the Ordinance.

57. Duties of Directors

The Directors shall duly comply with the provisions of the Ordinance.

58. Minute Books

The Directors shall cause minutes to be made in books provided for the purpose of:-

(a) all appointments of officers made by the Directors;

(b) the names of the Directors present at each meeting of the Directors and of any committee of the Directors; and

(c) all resolutions and proceedings at all meetings of the Company and of the Directors and of committees of Directors; and every Director present at any meeting of Directors or committee of Directors shall sign his name in a book to be kept for that purpose.

C. DISQUALIFICATION OF DIRECTORS

59. Disqualification of Directors

No person shall become a Director of the Company if he suffers from any of the disabilities or disqualifications mentioned in Section 187 of the Ordinance and, if already a Director, shall cease to hold such office from the date he so becomes disqualified or disabled or:-

(a) if removed by general or special order of the holding company;

(b) if removed by a resolution of members as hereinafter provided; or

(c) if by notice in writing given to the Company he resigns his office;

Provided, however, that no Director shall vacate his office by reason only of his being a member of any company which has entered into contracts with, or done any work for, the Company but such Director shall not vote in respect of any such contract or work, and if he does so vote, his vote shall not be counted.

D. PROCEEDINGS OF DIRECTORS.

60. Meetings of Directors

(a) The Directors may meet together for the dispatch of business, adjourn and otherwise regulate their meetings, as they deem proper. Questions arising at any meeting shall be decided by a majority of votes. In case of an equality of votes, the Chairman shall have and exercise a second or casting vote. A Director may, and the secretary on the requisition of a Director shall, at any time, summon a meeting of Directors. Seven (7) days notice at the least, exclusive of the day on which the notice is served or deemed to be served, but inclusive of the day for which notice is given, shall be given for a meeting of Directors; Provided, that, if all the Directors entitled to attend and vote at any such meeting so agree, in writing, a meeting may be held of which less than seven (7) days notice has been given.

(b) The quorum for the meeting of Directors shall not be less than one third of their number or four, whichever is greater.

(c) A meeting of the Directors may consist of a conference between Directors, some or all of whom are in different places; Provided, that, each Director who participates is able to hear each of the other participating Directors addressing the meeting and, if he so wishes, to address each of the other participating Directors simultaneously, whether directly, by conference telephone or by any other form of communications equipment (whether in use when this Article 60(c) is adopted or developed subsequently) or by a combination of methods. A quorum shall be deemed to be present if those conditions are satisfied in respect of the minimum number and designation of Directors required to form a quorum. A meeting held in this way shall be deemed to take place at the place where the largest group of Directors is assembled or, if no such group is readily identifiable, at the place from where the Chairman participates. Any Director may, by prior notice to the Secretary, indicate that he wishes to participate in the meeting in such manner, in which event, the Directors shall procure that an appropriate conference facility is arranged.

61. Chairman of Directors Meetings

The Chairman of the Board shall preside at all meetings of the Board but, if at any meeting the Chairman is not present within ten minutes after the time appointed for holding the same or is unwilling to act as Chairman, the Directors present may choose one of their number to be chairman of the meeting.

62. Committees

The Directors may delegate any of their powers not required to be exercised in their meeting to committees consisting of such member or members of their body as they think fit. Any committee so formed shall, in the exercise of the powers so delegated, conform to any restrictions that may be imposed on it by the Directors.

Company Registration Office Lahore
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SECP

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63. Chairman of Committee Meetings

A committee may elect a chairman of its meetings but, if no such chairman is elected, or if at any meeting the chairman is not present within ten minutes after the time appointed for holding the same or is unwilling to act as chairman, the members present may choose one of their number to be chairman of the meeting.

64. Proceedings of Committee Meetings

A committee may meet and adjourn as it thinks fit. Questions arising at any meeting shall be determined by a majority of votes of the members present. In case of an equality of votes, the chairman shall have and exercise a second or casting vote.

65. Validity of Directors' Acts

All acts done in any meeting of the Directors or of a committee of Directors shall, notwithstanding that it be afterwards discovered that there was some defect in the appointment of such Directors or that they or any of them were disqualified, be as valid as if every such person had been duly appointed and was qualified to be a Director unless the said act or acts is ultra vires in itself.

66. Resolution in Writing

A resolution in writing circulated to all the Directors and signed by a majority of the total number of Directors or affirmed by them through fax, telex or telegram shall be as valid and effectual as if it had been passed at a meeting of the Directors duly convened and held.

E. ELECTION AND REMOVAL OF DIRECTORS

67. Rotation of Directors

At the first annual general meeting of the Company, all the Directors shall retire from office, and Directors shall be elected in their place in accordance with Section 178 for a term of three years.

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SECP

68. Eligibility for Re-election

A retiring Director shall be eligible for re-election.

69. Election in Accordance with the Ordinance

The Directors shall comply with the provisions of Sections 174 to 178 and Sections 180 and 184 relating to the election of Directors and matters ancillary thereto.

70. Filling of Casual Vacancy

Any casual vacancy occurring in the Board of Directors may be filled by the Directors, but the person so chosen shall be subject to retirement at the same time as if he had become a Director on the day on which the Director in whose place he is chosen was last elected as Director.

71. Removal of Director

The Company may remove a Director but only in accordance with the provisions of the Ordinance.

VI. THE SEAL

72. Common Seal

The Directors shall provide a common seal of the Company which shall not be affixed to any instrument except by the authority of a resolution of the Board or by a committee of Directors authorized in that behalf by the Board. Two (2) Directors or one Director and the secretary of the Company shall sign every instrument to which the common seal is affixed.

73. Official Seal

The Directors may provide for the use in any territory, district or place not situated in Pakistan, of an official seal which shall be a facsimile of the common seal of the Company, with the addition on its face of the name of every territory, district or place where it is to be used. The provisions of Section 213 shall apply to the use of the official seal.

VII. DIVIDENDS AND RESERVE

74. Declaration of Dividends

The Company in general meeting may declare dividends but no dividend shall exceed the amount recommended by the Board.

75. Interim Dividends

The Board may from time to time direct payment to the members or to the holding company such interim dividends as appear to be justified by the distributable profits of the Company.

76. Dividends Payable Out of Profits

No dividends shall be paid otherwise than out of distributable profits of the year or any other undistributed profits. No unpaid dividend shall bear interest against the Company.

77. Dividends Payable on Amount Paid on Shares

All dividends shall be declared and paid according to the amounts paid on the shares.

78. Reserve Fund

The Directors may, before recommending any dividend, set aside out of the profits available for distribution of the Company such sums as they think proper as a reserve or reserves which shall, at the discretion of the Directors, be applicable for meeting contingencies, or for equalizing dividends, or for any other purpose to which the profits of the Company may be properly applied, and pending such application may either be employed in the business of the Company or be invested in such investments (other than shares of the Company) as the Directors may, subject to the provisions of the Ordinance, from time to time think fit.

79. Profit Carried Forward

The Directors may carry forward any profits which they may think prudent not to distribute, without setting them aside as a reserve.

80. Payment of Dividends Specie

With the sanction of a resolution in a general meeting, any dividend may be paid wholly or in part by the distribution of specific assets and in particular of paid-up shares or debentures of any other company or in any one or more of such ways. The Directors may fix the value for distribution of such specific assets or any part thereof and may determine that cash payments shall be made to any members upon the footing of the value so fixed, in order to adjust the rights of all members, and may vest any such specific assets in trust for the members entitled to the dividend as may seem expedient to the Directors.

81. Dividends to Joint Holders

If several persons are registered as joint holders of any share, any one of them may give effectual receipt for any dividend payable on the share.

82. Notice of dividend

Notice of any dividend that may have been declared shall be given in the manner hereinafter mentioned to the persons entitled thereto. The Company may give such notice by publication in a newspaper of general circulation in the Province where the Office is situated.

83. Period for Payment of Dividends

Dividends shall be paid within the period specified in Section 251.

VIII. ACCOUNTS

84. Books of Account

The Directors shall cause to be kept proper books of account as required under Section 230.

85. Place Where Accounts Kept

The books of account shall be kept at the Office or at such other place as the Directors shall think fit and shall be open to inspection by the Directors during business hours.

86. Inspection by Members

The Directors, or their representatives, shall from time to time determine whether and to what extent and at what time and place/s and under what conditions or regulations the accounts and books or papers of the Company or any of them shall be open to the inspection of members not being Directors. No member (not being a Director) shall have any right of inspecting of any account and book or papers of the Company, except as conferred by law or authorized by the Directors or by the Company in general meeting.

87. Annual Accounts

The Directors shall as required by Sections 233 and 236 cause to be prepared and to be laid before the Company in general meeting such profit and loss accounts and balance sheets duly audited and reports as are referred to in those sections.

88. Balance Sheet and Profit and Loss Account

A balance sheet, profit and loss account, and other reports referred to in the preceding Article shall be made out every year and laid before the Company in the annual general meeting made up to a date not earlier than six months before such meeting. The balance sheet and profit and loss account shall be accompanied by a report of the auditors of the Company and the report of Directors.

89. Copy of Accounts to be Sent to Members

A copy of the balance sheet and profit and loss account and reports of Directors and auditors shall, at least twenty-one days preceding the meeting, be sent to the persons entitled to receive notices of general meetings in the manner in which notices are to be given as hereinafter provided.

90. Compliance with the Ordinance

The Directors shall in all respects comply with the provisions of Sections 230 to 236.

91. Capitalization of Profits

The Company in general meeting may, upon the recommendation of the Directors, resolve that it is desirable to capitalize any part of the amount for the time being standing to the credit of any of the Companys reserve accounts or to the credit of the profit and loss accounts or otherwise available for distribution. The Company may then set free such sum for distribution among the members who would have been entitled thereto if distributed by way of dividend and in the same proportions, on condition that the same be not paid in cash but be applied in or towards paying up in full un-issued shares or debenture of the Company to be allotted and distributed, credited as fully paid up to and amongst such members in the proportion aforesaid. The Board of Directors shall give effect to such distribution by resolution.

92. Audit

Auditors shall be appointed and their duties regulated in accordance with Sections 252 to 255 of the Ordinance.

IX. NOTICES

93. Notice to Members, etc.

Notice shall be given by the Company to members and auditors of the Company and other persons entitled to receive notice in accordance with law.

X. CONFIDENTIALITY

94. Confidentiality Undertaking

Every director, manager, adviser, auditor, trustee, member of a committee, officer, agent, accountant, or other employees of the Company shall, if so required by the Directors, before entering upon his duties, sign a confidentiality undertaking in relation to all transactions of the Company with its customers and the state of accounts with individuals and in matters relating thereto, and shall undertake not to reveal any of the matters which may come to his knowledge in the discharge of his duties, except when required to do so by the Directors or by any general meeting or by any a court of law of competent jurisdiction and except so far as may be necessary in order to comply with any of the provisions in these presents.

95. Members Access to Company Premises

No member or other person (not being a Director) shall be entitled to enter upon the property of the Company or examine the Companys premises or properties without the permission of a Director, subject to Article 94, to require discovery of or any information respecting any detail of the Companys trading or any matter which is or may be in the nature of a trade secret, mystery of trade, or secret process or of any matter whatsoever which may relate to the conduct of the business of the Company and which in the opinion of the Directors [illegible] inexpedient, in the interest of the Company and its members, to communicate.

XI. RECONSTRUCTION

96. Reconstruction

On any sale of the undertakings of the Company, the Directors or the liquidators on a winding up may, if authorized by a Special Resolution, accept fully paid shares, debentures or securities of any other company, either then existing or to be formed for the purchase in whole or in part of the property of the Company. The Directors (if the profits of the Company permit), or the liquidators (in a winding up), may distribute such shares or securities, or any other properties of the Company amongst the members without realization, or vest the same in trustees for them. A Special Resolution may provide for the distribution or appropriation of the cash, shares or other securities, benefits or property, and for the valuation of any such securities or property at such price and in such manner as the meeting may approve. All shareholders shall be bound by any valuation or distribution so authorized, and waive all rights in relation thereto save only such statutory rights (if any) as are, in case the Company is proposed to be or is in the course of being wound up, incapable of being varied or excluded by these Articles.

XII. WINDING UP

97. Division and distribution of Assets Upon Dissolution

If the Company is wound up, the liquidator may, with the sanction of a Special Resolution of the Company and any other sanction required by law, divide amongst the members in specie or kind the whole or any part of the assets of the Company (whether they shall consist of property of same kind or not) and may, for such purpose, set such value as he deems fair upon any property to be divided as aforesaid and may determine how such division shall be carried out as between the members or different classes of members. The liquidator may, with like sanction, vest the whole or any part of such assets in trustees upon such trust for the benefit of the contributors, as the liquidator with like sanction, shall think fit; Provided, that, no member shall be compelled to accept any shares or other securities whereon there is any liability.

XIII. INDEMNITY

98. Indemnification

Every officer or agent of the Company may be indemnified out of the assets of the Company for any liability incurred by him in defending any proceedings, whether civil or criminal, arising out of his dealings in relation to the affairs of the Company, except those brought by the Company against him, in which judgement is given in his favour or in which he is acquitted, or in connection with any application under Section 488 in which relief is granted to him by a court of competent jurisdiction.

XIV. ARBITRATION

99. Differences to be Referred to Arbitrator

Every intra-corporate dispute shall, as a condition precedent to any other action at law be referred, in conformity with the Arbitration Act, 1940, as amended, and its implementing rules, to the decision of an arbitrator to be appointed by the parties in dispute or, if they cannot agree upon a single arbitrator, to the decision of two arbitrators of whom one shall be appointed by each of the parties in dispute, or, in the event of the two arbitrators not agreeing, then of an umpire to be appointed by the two arbitrators, in writing, before proceeding on the reference. Such decision and arbitral award shall be final and binding on the parties. Intra-corporate disputes shall include any dispute that may arise between the Company on the one hand and any of the members, their executors, administrators or assigns on the other hand, or between members, their executors, administrators or assigns, relating to these Articles or the statutes, or anything then or thereafter done, executed, omitted or suffered in pursuance of these Articles or of the statutes or any breach or alleged breach, or otherwise relating to these Articles or to any statute affecting the Company or to any of the affairs of the Company.

We, the several persons whose names and addresses are subscribed below, are desirous of being formed into a company in pursuance of these Articles of Association and we respectively agree to take the number of shares in the capital of the Company set opposite our respective names.

Name and surname (Present and former) in full (in Block Letters)	Father's/ Husband's Name in Full	Nationality	Occupation	Residential Address in Full	Number of Shares taken by each Subscriber	Signature
1. Syed Tanzim Hussain Naqvi	Syed Taslim Hussain Naqvi	Pakistani	Wapda Service	House No. 56-B, Wapda Officers Colony, Upper Mall, Lahore.	1	
2. Mr. Muhammad Aslam Javed	Muhammad Yousaf	Pakistani	Wapda Service	49-Wapda Colony, Lahore.	1	
3. Mr. Riaz Ahsan Baig	Abdul Latief Baig	Pakistani	Wapda Service	House No. 83/E/2, Arif Jan Road, Lahore Cantt.	1	
4. Mr. Noor Elahi Baig	M. Fazal Elahi Baig	Pakistani	Wapda Service	B-2, Shalamar Grid Station, Wapda Colony, Lahore.	1	
5. Mr. Javed Nizam	Muhammad Islam	Pakistani	Wapda Service	263-Tariq Block, New Garden Town, Lahore.	1	
6. Brig. Saeed Ahmad Rafi	Muhammad Ajaib	Pakistani	Wapda Service	B-33, Upper Mall, Wapda Colony, Lahore.	1	
7. Mr. Muhammad Rafique	Abdul Ghani	Pakistani	Wapda Service	927-Ravi Block, Allama Iqbal Town, Lahore.	1	

Total number of shares taken 7 (Seven)

Dated the 2 day of November 1998

Witness to the above signatures

(Full Name, Father's/Husband's Name)

(in Block Letters) TARIQ MAHMOOD S/o M M BAGAR

Signature

Occupation SERVICE

Full Address 3-Mall Mansion 30-Shahrah-e-Quaid-e-Azam LAHORE

CERTIFIED TO BE TRUE COPY

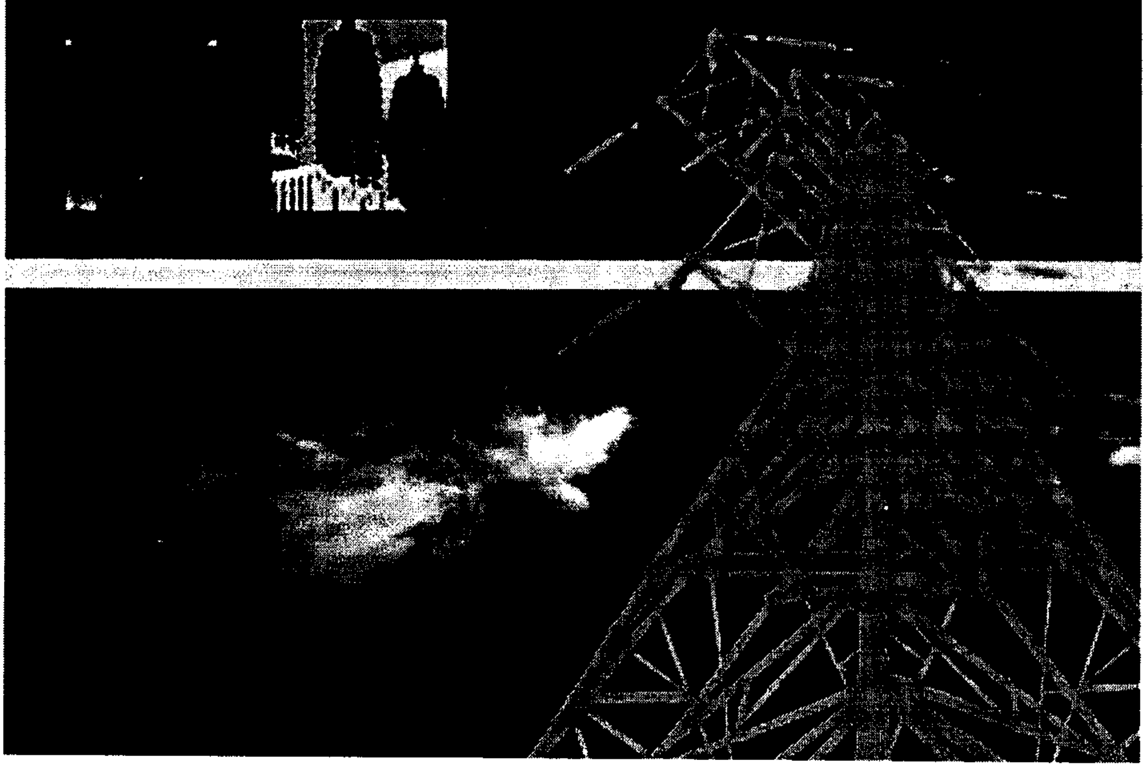
Z. Haider 29-7-22

ADDITIONAL REGISTRAR OF COMPANIES COMPANY REGISTRATION OFFICE LAHORE.

Securities and Exchange Commission of Pakistan * Company Registration Office Lahore * SECP

NATIONAL TRANSMISSION
& DESPATCH COMPANY LIMITED

Form-A submitted to SECP



Form A

THE COMPANIES ACT, 2017
THE COMPANIES (GENERAL PROVISIONS AND FORMS) REGULATIONS, 2018
[Section 130(1) and Regulation 4]

ANNUAL RETURN OF COMPANY HAVING SHARE CAPITAL

1499371
23/06/2022

PART-I

(Please complete in typescript or in bold block capitals.)

1.1 CUIN (Registration Number) | 0 | 0 | 3 | 9 | 6 | 1 | 1 |

1.2 Name of the Company: NATIONAL TRANSMISSION & DESPATCH COMPANY LIMITED

1.3 Fee Payment Details 1.3.1 Challan No: M-2022-422122 1.3.2 Amount: Rs.1200/-

	dd	mm	yyyy
1.4 Form A made up to	1 6	0 6	2 0 2 2
1.5 Date of AGM	1 6	0 6	2 0 2 2

Company Registration Office * Securities and Exchange Commission of Pakistan

PART-II

Section-A

2.1 Registered office address: 414-WAPDA HOUSE, LAHORE

2.2 Email Address: MD@NTDC.COM.PK

2.3 Office Tel. No.: 042-99202229

2.4 Office Fax No.: 042-99202053

2.5 Principal line of business: POWER GENERATION – ALLIED (OTHERS)

2.6 Mobile No. of Authorized officer (Chief Executive/ Director/ Company Secretary/Chief Financial Officer): 0335-7402132

2.7 Authorized Share Capital

Classes and kinds of Shares	No. of Shares	Amount	Face Value
Ordinary Shares	6,000,000,000	Rs.60,000,000,000.00	Rs.10/-

2.8 Paid up Share Capital

Classes and kinds of Shares	No. of Shares	Amount	Face Value
Ordinary Shares	5,270,038,100	Rs.52,700,381,000	Rs.10/-

2.9 **Particulars of the holding /subsidiary company, if any**

Name of company	Holding/Subsidiary	% of shares held

2.10 **Chief Executive Officer**

Name	
Address	
NIC No	

2.11 **Chief Financial Officer**

Name	KHAWAJA ASIF KALEEM												
Address	Defence Housing Authority H - No Z-57, Lahore Cantt.												
NIC No	3	5	2	0	1	5	6	8	6	3	0	1	3

2.12 **Secretary**

Name	AZHAR SALEEM												
Address	House No. 95-D, Madina Street, New Shalimar Town Gulshan-e-Ravi Lahore.												
NIC No	3	5	2	0	2	2	6	2	7	7	7	4	3

2.13 **Legal Advisor**

Name	AKHTAR ALI MONGA												
Address	G-23, Hajveri Complex, 2-Mozang Road, Lahore												
NIC No													

2.14 **Particulars of Auditor(s)**

Name	Address
Grant Thornton Anjum Rahman & Co (Chartered Accountants)	01 - Inter Floor, Eden Center, 43 - Jail Road, Lahore, Pakistan

2.15 **Particulars of Share Registrar (if applicable)**

Name	
Address	
e-mail	

Section-B

2.16 List of Directors as on the date annual return is made

S#	Name	Residential Address	Nationality	NIC No. (Passport No. if foreigner)	Date of appointment or election
1	Ahmed Naveed Ismail	House No. 9, Street 26, F-6/2, Islamabad	Pakistani	61101-7965020-5	28.01.2021
2	Nauman Kramat Dar	60/II, Khayaban-e-Hafiz, DHA Phase-V, Karachi	Pakistani	61101-4909597-5	28.01.2021
3	Almas Hyder	9/94 K Sarwar Road , Lahore	Pakistani	35202-2420438-3	28.01.2021
4	Haroon Jan Baryalay	H. No. 352-B, Street 68, M.P.C.H.S. E-11/3, Islamabad.	Pakistani	35201-2357705-5	28.01.2021
5	Shakeel Qadir Khan	Defence Officer Colony, House # 10, Street # 12, Peshawar.	Pakistani	17301-0892252-5	18.05.2022
6	Waqas Bin Najib	House # 155, Street # 22, F-10/2, Islamabad	Pakistani	42501-2990620-3	28.01.2021
7	Ahmed Taimoor Nasir	House # 49-B, Askari II, Chaklala-3, Rawalpindi	Pakistani	37405-0341695-3	28.01.2021
8	Shah Jahan Mirza	House #199, Street 60, E-11/3, Islamabad	Pakistani	37405-6204389-9	28.01.2021

9	Rihan Akhtar	House # 155-A-1, WAPDA Town Extension, Lahore.	Pakistani	33100-1888395-3	01.04.2022

Use separate sheet, if necessary

2.17 List of members & debenture holders on the date upto which this Form is made

S#	Folio #	Name	Address	Nationality	No. of shares held / Debenture	NIC No. (Passport No. if foreigner)
Members						
1	42	President of Islamic Republic of Pakistan	Islamabad	Pakistani	4637633520	
2	66	NTDCL Employees Empowerment Trust, BESOS	440-Wapda House, Lahore	Pakistani	632404571	
3	92	Ahmed Naveed Ismail	House No. 9, Street 26, F-6/2, Islamabad	Pakistani	1	61101-7965020-5
4	94	Nauman Kramat Dar	60/II, Khayaban-e-Hafiz, DHA Phase-V, Karachi	Pakistani	1	61101-4909597-5
5	95	Almas Hyder	9/94 K Sarwar Road , Lahore	Pakistani	1	35202-2420438-3
6	96	Haroon Jan Baryalay	H. No. 352-B, Street 68, M.P.C.H.S. E-11/3, Islamabad.	Pakistani	1	35201-2357705-5
7	102	Shakeel Qadir Khan	Defence Officer Colony, House # 10, Street # 12, Peshawar.	Pakistani	1	17301-0892252-5
8	97	Waqas Bin Najib	House # 155, Street # 22, F-10/2, Islamabad	Pakistani	1	42501-2990620-3
9	90	Ahmed Taimoor Nasir	House # 49-B, Askari II, Chaklala-3, Rawalpindi	Pakistani	1	37405-0341695-3
10	67	Shah Jahan Mirza	House #199, Street 60, E-11/3, Islamabad	Pakistani	1	37405-6204389-9
11	101	Rihan Akhtar	House # 155-A-1, WAPDA Town Extension, Lahore.	Pakistani	1	33100-1888395-3
Debenture holders						

Use separate sheet, if necessary

2.18	Transfer of shares (debentures) since last Form A was made			
S#	Name of Transferor	Name of Transferee	Number of shares transferred	Date of registration of transfer
	Members			
1	Khawaja Riffat Hassan	President of Islamic Republic of Pakistan	1	20.05.2021
2	Muhammad Ayub	--do--	1	04.08.2021
3	Azaz Ahmad	--do--	1	03.11.2021
4	Waseem Mukhtar	--do--	1	01.04.2022
5	Ali Zain Banatwala	--do--	1	14.05.2022

6	Manzoor Ahmed	--do--	1	14.05.2022
7	Musaddiq Ahmed Khan Tahirkheli	--do--	1	18.05.2022
8	President of Islamic Republic of Pakistan	Muhammad Ayub	1	20.05.2021
9	--do--	Azaz Ahmad	1	04.08.2021
10	--do--	Manzoor Ahmed	1	15.11.2021
11	--do--	Rihan Akhtar		01.04.2022
12	--do--	Shakeel Qadir Khan	1	18.05.2022
	Debenture holders			

Use separate sheet, if necessary

PART-III

3.1 Declaration:

I do hereby solemnly, and sincerely declare that the information provided in the form is:

(i) true and correct to the best of my knowledge, in consonance with the record as maintained by the Company and nothing has been concealed; and

(ii) hereby reported after complying with and fulfilling all requirements under the relevant provisions of law, rules, regulations, directives, circulars and notifications whichever is applicable.

3.2 Name of Authorized Officer with designation/ Authorized Intermediary	AZHAR SALEEM	Company Secretary
3.3 Signatures		
3.4 Registration No of Authorized Intermediary, if applicable		

3.5 Date

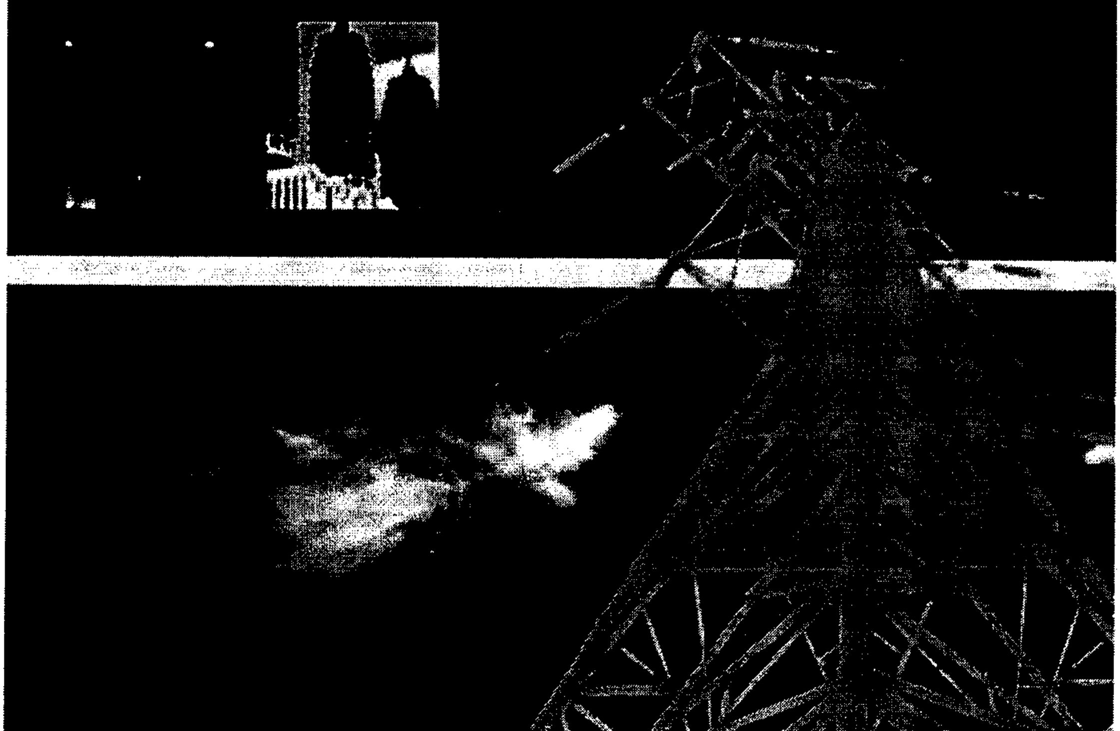
Day		Month		Year			
1	6	0	6	2	0	2	2

INSTRUCTIONS FOR FILLING FORM-A

1. The Form shall be made upto the date of last AGM of the Company or the last date of the calendar year where no AGM is held during the year.
2. Under S. No.2.17 above, the aggregate number of shares held by each member should be stated.
3. When the shares are of different classes the columns should be subdivided so that the number of each class held, is shown separately against S. Nos. 2.7, 2.8 and 2.17
4. If the space provided in the Form is insufficient, the required information should be listed in a separate statement attached to this return which should be similarly signed.
5. In case a body corporate is a member, registration number may be mentioned instead of NIC number.
6. In case of foreign nationals, indicate "passport number" in the space provided for "NIC No." Pakistani nationals will only indicate "NIC No."
7. This form is to be filed within 30 days of the date indicated in S.No.1.4.

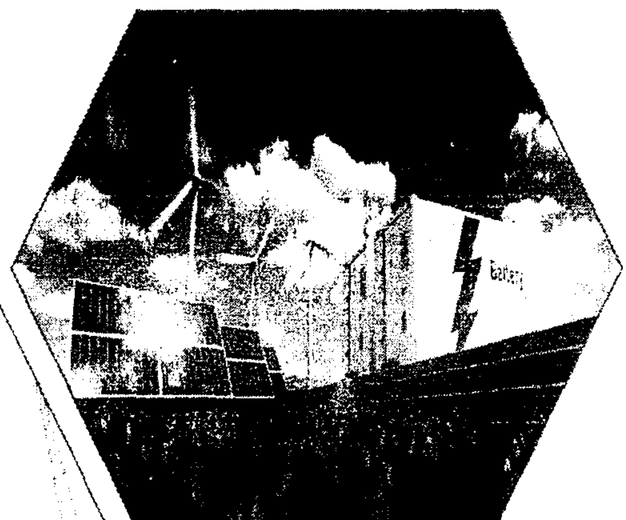
NATIONAL TRANSMISSION & DESPATCH COMPANY LIMITED

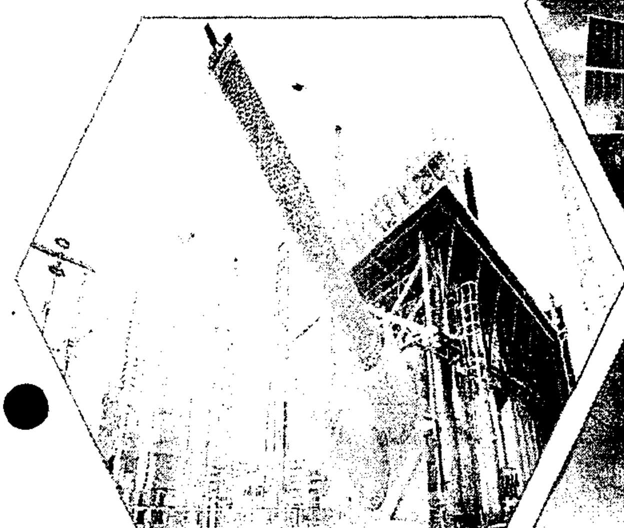
Draft Grid Code

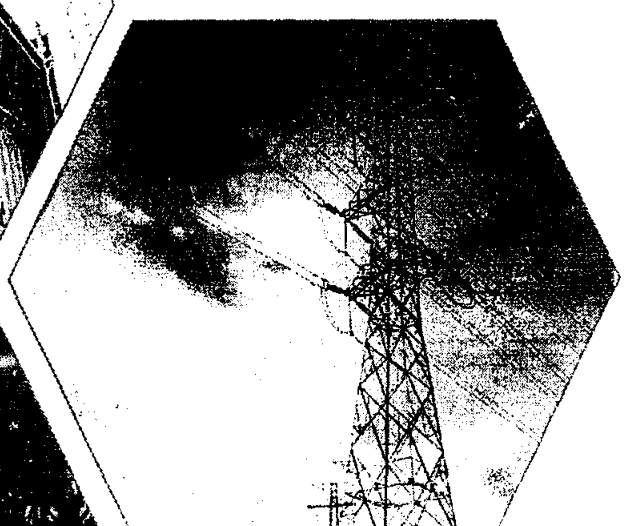


National Transmission and Despatch Company Limited (NTDC)

GRID CODE - 2022







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INTRODUCTION

Pursuant to the Section 23H of the NEPRA Act (referred to as "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 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 Operator(s) (the TNO(s)) 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.

The Main Objectives of the Grid Code are:

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;

This Grid Code includes the following sub-codes:

A. Code Management

B. Planning Code

C. Connection Code

D. Operation Code

E. Scheduling and Dispatch Code

F. Protection and Control Code

G. Metering Code

H. Data Registration Code

I. Definitions and Acronyms

Relationship Diagram

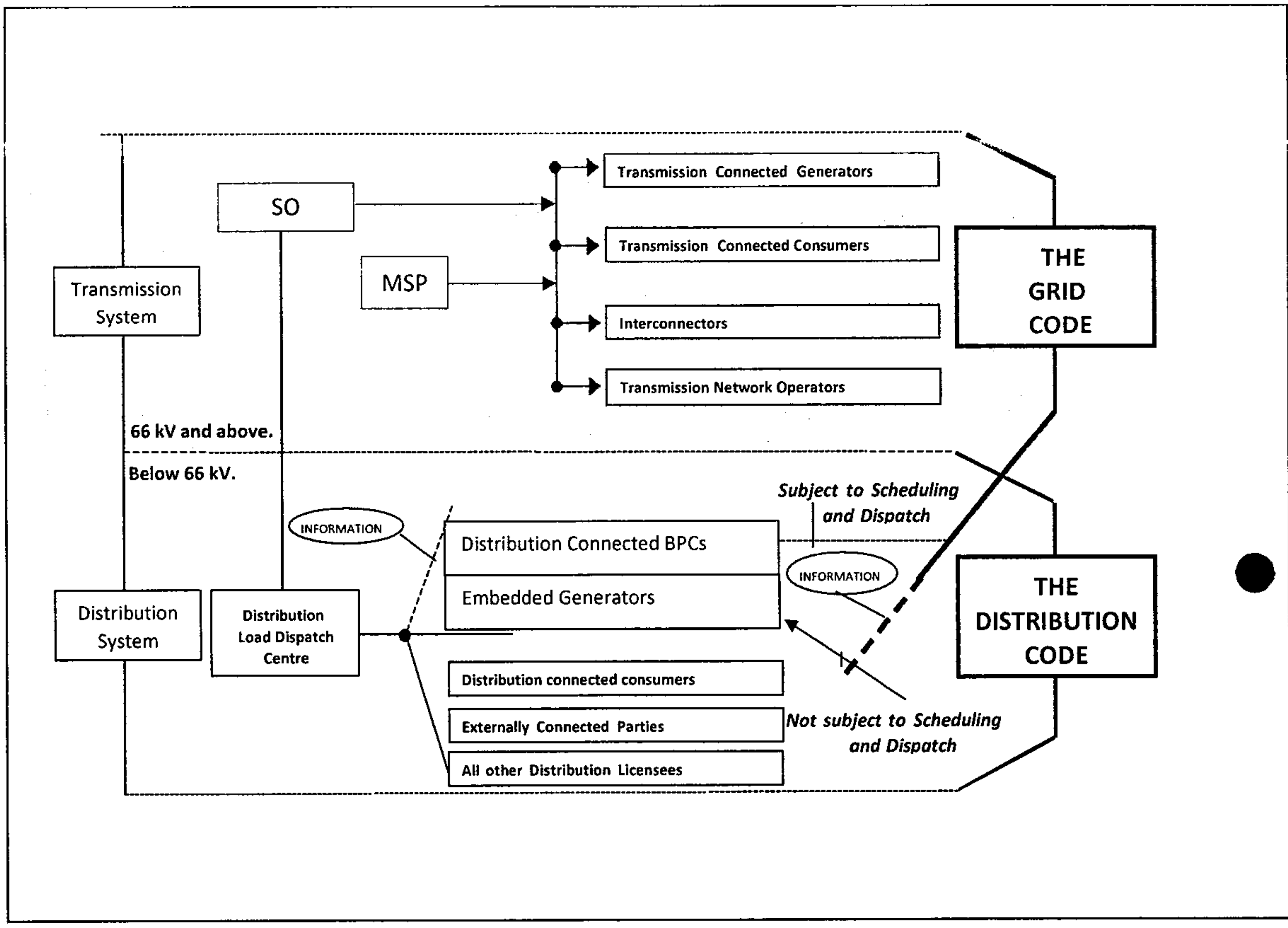


TABLE OF CONTENTS

CODE MANAGEMENT

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 the following Users:

(a) Transmission Network Operator(s);

(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;

(f) Metering Service Provider (MSP);

(g) Distribution Network Operators (DNOs);

(h) Market Operator (MO);

(i) Special Purpose Trader (SPT);

(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 Authority regulations; and

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

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.

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 ex-WAPDA distribution companies (nominated by their respective association);

(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 Authority without voting rights;

CM 4.3 The detailed rules 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;

Provided that the GCRP shall have maintained Code of Conduct rules or procedures to ensure no participation in decisions by a representative that have 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 CM4.4(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 for Exemption from any provision(s) of the Grid Code;

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

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

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

(g) consider any modification(s) 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 rules and procedures relating to the "Conduct of its Functions", 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 will 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 Every Amendment approved or Exemption granted will be entered on a register maintained by Authority for this purpose 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.

CM 5.5 Grid Code Amendment

CM 5.5.1 Any Code Participant, GCRP member, the SO, or the Authority itself may propose Amendment(s) 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 Amendment(s), 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 Amendment(s) 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 GCRP meeting within a period not more than two (2) months after admission of the request for Amendment by a Code Participant.

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 recommendation(s) within two (2) months of its admission for its approval.

CM 5.5.5 The Authority shall consider the request for Amendment in light of the recommendation(s) of GCRP, and may require additional information from the GCRP or carry out public or stakeholder's consultations to arrive at a 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, the GCRP will inform all to Code Participants.

CM 5.5.8 If the Amendment is proposed by the Authority, it may direct the GCRP to make such Amendment within thirty (30) days and submit the draft Grid Code relevant Amendments for the approval of the Authority.

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; and/or

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

CM 5.6.2 A Code Participant seeking Exemption from one or more provision(s) 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 provision(s) 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.

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 recommendation(s) to the Authority within two (2) months of receipt of the application for a final decision.

CM 5.6.4 The Authority shall consider the request in light of the recommendation(s) 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 member(s) of the GCRP to seek clarification on the request, and/or publish in its website for comments by other potentially affected Code Participants.

CM 5.6.5 The Authority determination shall be public and uploaded at NEPRA website to be considered as final decision and the GCRP to communicate same for information 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 will not be obliged to comply with the applicable provision(s) 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 will 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 but the transfer of ownership of Plant and Apparatus of Code Participant, shall be subject to the prior concurrence of the SO and the Authority by the transferee.

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 will 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**

In case 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, Grid Code Operating Procedures (GCOPs) shall be developed by the SO. The SO shall share the GCOPs for information to the Authority.

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 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.

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 in the SO website. Additionally, the approved Grid Code may be made available on the Authority's 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**

For the agreements that were executed prior to this Grid Code coming into force, conditions contained in this Grid Code that are different to provisions in the agreement shall be applicable to such Code Participants which are technically capable, in accordance with the provisions of the Grid Code, to comply with the requirements of the Grid Code. A Code Participant not technically capable of complying with the provisions of Grid Code shall seek Exemption in accordance with CM 5.6 and if such Exemption results in non-compliance of relevant provisions of Grid Code and applicable performance standards by the SO or any other Code Participant, then such implementation of such Exemption shall be considered waived to the extent of SO or such other Code Participant and they shall be held harmless and indemnified against such non-compliance to the extent of that Exemption.

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 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 license of a Code Participant. the conditions in the license 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**

The SO shall be 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 i.e., both acts and omissions by any Code Participant.

Without prejudice to the Act, SO licence and other applicable documents of the Authority, the SO shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements or damages of a Code Participant whatsoever, howsoever arising and whether as claims in contract, claims in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the SO in the exercise or performance or the intended exercise or performance of any power or obligation under this Grid Code or any other document derived from this Grid Code.

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 Participant(s) 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 will 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 any Code Participant and that on or after the effective date of the Grid Code, 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. Force Majeure events here under shall include each of the following events and circumstances (including the effects thereof), but only to the extent that each satisfies the above requirements:

(a) The following political events that occur inside or directly involve Pakistan:

(i) Any act of war (whether declared or undeclared), invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, civil commotion, or act or campaign of terrorism or political sabotage; or

(ii) Any lapse of consent that shall have existed as required; or

(iii) Any strike, work-to-rule, go-slow, or analogous labor action that is politically motivated and is nationwide; or

(b) Any Change in Law; or

(c) Other events beyond the reasonable control of the affected Party (each an "Other Force Majeure Event"), including, but not limited to:

(i) Lightning, fire, earthquake, tsunami, flood, storm, cyclone, typhoon, or tornado; or

(ii) Any lapse of consent that shall have existed as required; or

(iii) Any strike, work-to-rule, go-slow, or analogous labor action that is not politically motivated and is not nationwide; or

(iv) Fire, explosion, chemical contamination, radioactive contamination, or ionizing radiation (except to the extent any of the foregoing events or circumstances results directly from a Pakistan Political Event, in which case such event or circumstance shall constitute a Pakistan Political Event);

(v) Non-availability of fuel due to a force majeure event;

(vi) Non-availability of water due to a force majeure event;

(d) Force Majeure Events shall expressly not include the following events or circumstances:

(i) Late delivery or interruption in the delivery of machinery, equipment materials, spare parts or consumables (other than as permitted under Sections 16.1(C)(vi) and (vii);

(ii) Delay or default in the performance of any third party;

(iii) Breakdown in machinery or equipment excluding normal wear and tear; or

(iv) Normal wear and tear or random flaws in all kinds of materials, machinery, equipment or assets:

(v) Epidemic, pandemic or plague;

(vi) Insufficiency of funds or failure to make payments due and/ or financial hardship;

(vii) Any event which a diligent Code Participant has been expected to avoid as per prudent industry practice and as per industry bench marks; and

(viii) Acts (including omissions) of negligence or wrongdoings.

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 the other concerned party (or 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.

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 Power System.

CM 18.2 The Code Participants shall comply with the Grid Code, at all times, as applicable and the SO shall monitor such compliance. Non-compliance of any of the provisions of this Grid Code by a Code Participant shall be treated according to CM 18.4.

CM 18.3 Any Code Participant which has evidence that another Code Participant has violated or is violating the provisions of the Grid Code, shall inform the SO immediately along with all supporting documents.

CM 18.4 A non-compliance of the provisions of this Grid Code solely determined by the SO or informed to the SO by a Code Participant for its determination, shall be reported to the Authority within 28 days after such determination for proceeding against such non-compliance and penalty/fine shall be imposed thereon by the Authority under applicable law, rules & regulations. If such non-compliance results in violation of relevant provisions of Grid Code and applicable performance standards by the SO or relevant TNO, then SO or relevant TNO shall be indemnified against such violation.

CM 18.5 Additionally, the Authority, on suo-moto basis, may proceed against any non-compliance, even if no complaint has been reported by a Code Participant or determined the SO.

CM 18.6 In case a Code Participant is not clear about any particular provision(s) of the Grid Code, that Code Participant may seek interpretation on that provision(s) 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 will 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 provision(s) will be final and binding on the SO and all Code Participants (including the Code Participant making the request. The interpretation will be published by the SO on its website together with the Grid Code.

CM 18.7 The GCRP or the SO 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 will 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 will 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 through the dispute resolution process prescribed by NEPRA.

CM 18.9 The Authority may impose fines or other sanctions as specified in regulations in case of non-compliance with any provision of the Grid Code.

CM 19 MISCELLANEOUS

CM 19.1 Subject to CM 12, the provisions of the Grid Code will 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 will 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 will 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 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, will be brought to the notice of the GCRP and will be removed.

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.

PLANNING CODE

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 the following Users:

(a) Transmission Network Operators (TNO)s;

(b) Generators connected to the Transmission System;

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

(d) Interconnectors.

PC 2. **PLANNING RESPONSIBILITIES**

PC 2.1. **Responsibilities of the SO**

The SO shall be responsible for the following activities:

(a) Preparation of Spatial Demand Forecast by consolidating the PMS based area forecasts;

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

(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/processes as well as adhering to the stipulated system reliability criteria;

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

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

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

(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;

(h) Preparation of an Annual System Reliability Assessment and Improvement Report (ASRAIR) for submission to the Authority. 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. The ASRAIR will 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) Preparation of transmission expansion plans for their respective territories;

(b) Annual preparation of 10-year centralized TSEP by the NGC in coordination with other TNOs 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) for their respective territories and submit to the Authority for the approval;

(f) Preparation of the project feasibility study reports, justifying the proposed connection project(s) 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".

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 Site(s), 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 User(s) will be considered and from which planning of the National Grid will 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 (IGCEP);

(c) Preparation of Transmission System Expansion Plan (TSEP).

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, 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 will 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 this Code, will become Committed Data. This data, together with other data relating to the Transmission System, will provide the basis on which new applications by any User will be considered and from which planning of the Transmission System and power system analysis will 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.

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, will be submitted by the User to the relevant TNO, which shall submit it to the SO. This will 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 Validation and Verification**

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 Test(s) 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 will 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 Test(s). 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 develop, on 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 to the Authority by 30th June each year for approval. Standard planning activities and their corresponding processes are described below.

PC 4.1. Demand Forecasting

Two types of Demand forecasts shall be prepared for the Users of National Grid;

PC 4.1.1. The TNOs shall produce, and send to the SO, a Demand Forecast for the facilities or area they control or operate covering a horizon of, at least, 10 years. The SO will prepare templates indicating how this information shall be provided.

PC 4.1.2. The Demand Forecast shall be based on the Power Market Survey (PMS) and shall have geographical or voltage level discrimination, as required by the SO. Appendix PC A2.5 details the information that should be submitted by each User.

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

(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) Development of the competitive electric power suppliers and traders demand in the power market. The SO shall review and consolidate the information provided by the Users and produce an aggregated Area

Demand Forecast, covering a period of at least, 10 years. This aggregated country level Area Demand Forecast shall be called Spatial Demand Forecast. The geographical discrimination of the forecast will be as the SO considers appropriate for the required planning purposes.

PC 4.1.4. Spatial Demand Forecast shall be used by the TNOs for preparing;

(a) Transmission System Expansion Plan (TSEP);

(b) Transmission Investment Plans (TIPs);

(c) Distribution Integrated Investment Plan (DIIP); and

(d) Power Acquisition Plan (PAP) by DNOs for network reinforcement/ expansion.

PC 4.1.5. In addition to the Spatial Demand Forecast, the SO shall 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) Spatial Demand Forecast;

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

(f) Demand Side Management; and

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

PC 4.2. Indicative Generation Expansion Plan (IGCEP)*

PC 4.2.1. The SO shall prepare annually an "Indicative Generation Capacity Expansion Plan" (IGCEP) 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 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 as public information on the SO website.

PC 4.2.3. The IGCEP shall identify any new capacity requirements by type, size, location and year-by-year development sequence along with their commissioning dates by taking into account the capacity retirements, annual outage periods, generation capacity upgrades, plants whose PPAs are expiring and plan to retire, and Transmission System aspects.

*In case if any User fails to submit the requisite data by 30th November, the SO shall prepare IGCEP using the latest available data and shall share results with the NGC by the end of February each year to enable it for the timely preparation of TSEP. The SO/NGC shall not be responsible for any inaccuracy caused by the late or non-submission of data by Users.

PC 4.2.4. The SO shall develop "Grid Code Operating Procedures" (GCOP) to encapsulate a complete framework for generation planning including but not limited to data acquisition and verification, assumptions, analytical tools, studies and analyses, stakeholder consultations, internal and external approval processes.

PC 4.2.5. Generators below 20MW shall not be considered in the IGCEP.

PC 4.2.6. The SO shall share the results of IGCEP with the NGC by 28th February each year to enable it in the timely preparation of TSEP.

PC 4.3. Transmission System Expansion Plan (TSEP)

PC 4.3.1. Each TNO shall prepare transmission expansion plans for their respective territories. The NGC, in coordination with other TNOs shall consolidate these plans to prepare a centralized Transmission System Expansion Plan (TSEP) on annual basis for a horizon of ten (10) years in conformance with the results of IGCEP. NGC shall submit TSEP to the SO not later than 31st May each year. The SO shall review the TSEP and submit it to the Authority for approval along with the IGCEP not later than 30th June each year.

PC 4.3.2. 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 sub-stations 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" (TPCS) document.

PC 4.4. Transmission Investment Plans (TIPs)

PC 4.4.1. Each TNO shall prepare Transmission Investment Plan (TIP) in conformance with the centralized TSEP for its respective territory on annual basis for a horizon of at least 5 years. These plans shall specify 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.

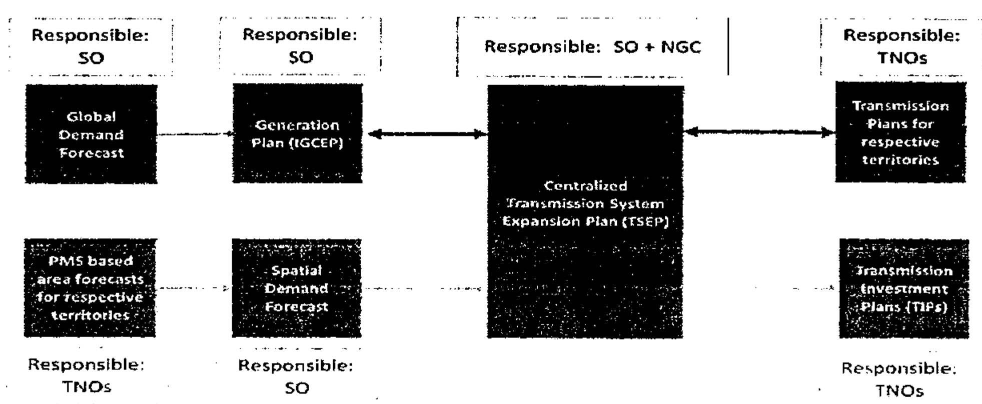


Figure 1 Integrated System Planning

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 option(s) and availability of transmission capacity (based on the load flow analysis) as well as providing budgetary cost estimates. The outcome of the Feasibility Study will 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 TNO(s) shall perform or cause to perform the required Connection Study (ies) 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" (TPCS) 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 (TPCS) document defines all the criteria and standards according to which planning activities shall be performed, established in the Annex TRANSMISSION PLANNING CRITERIA & STANDARDS.

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, PC. A5 must be notified to the **SO** as soon as practicable.

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. A 1.1 Full name of the User(s)

PC. A 1.2 Address of the User(s)

PC. A 1.3 Contact Person

PC. A 1.4 Telephone Number

PC. A 1.5 Telefax Number

PC. A 1.6 Email Address

PC. A2 USER'S SYSTEM DATA

PC. A 2.1 **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 co-ordinates of the electrical connection point, which is assumed to be at the HV bushings of the grid connected transformer.

PC. A 2.2 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. A 2.3 Licensing and Authorization (For Generation and other applications requested by the SO)

PC. A 2.3.1 **Licensee**

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

PC. A 2.3.2 **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. A 2.4 **User's System Layout**

PC. A 2.4.1 Each User shall provide a Single Line Diagram, depicting both its existing and proposed arrangement(s) of load current carrying apparatus relating to both existing and proposed Connection Points.

PC. A 2.4.2 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.

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. A 2.4.3 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 sub-station with operating voltages.

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

PC. A 2.4.4 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 & no. 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. A 2.4.5 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

PC. A 2.4.6 In addition, for all interconnecting transformers of the User(s) 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. A 2.4.7 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 (Secs)

(vi) Rated rms continuous current (A)

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

PC. A 2.4.8 **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. A 2.4.9 **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. A 2.4.10 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.

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.

(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 will provide the information as soon as reasonably practicable following the request.

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 Transformer(s).

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

(b) Root means 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 p.u. 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

(a) The following is the list of data utilized in this part of the Planning Code.

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

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

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

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

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

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

PC. A2.5 **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;

b. **Substation level data;**

   i. Sub-station wise peak demand with substation name and unique identifier;

   ii. Coincidence factor;

   iii. Relevant data of proposed sub-stations;

c. **11kV 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 (Rs. /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. and any other potential variable that may affect the Demand growth

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

PC. A2.6 Data Required for Indicative Generation Capacity Expansion Plan (IGCEP)

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

Data Proforma for Bagasse / Co-generation / Waste to Energy / Solid Waste Management based Power Plant	
Particulars	**Details**
Project Executing Agency Name	
Name of Project Representative	
Designation of Representative	
Contact number	
Email Address	
Name of Project	
Nature of Project (Public, Private, G2G, Strategic, Others)	
Other Project Nature (if any) – Public or Private	
Installed Capacity (MW)	
De-Rated/Dependable Capacity (MW)	
Auxiliary Capacity (MW)	
Other Project Type (If any)	
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)	
Date of Approval of Feasibility Study (dd-mm-yy)	
Financial Close Date (for Private Sector plants only)	
Is Financing Secured? (for Public Sector Plants only)	
Source of Financing	
PC-1 / LOS Approval Date (dd-mm-yy)	
Date of Licensing or Registration with NEPRA (dd-mm-yy)	
Location and site coordinates of project	
Interconnection Voltage level (kV)	

Dispatching Arrangement	
Region of Project (Gilgit, AJK, K.E, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO,TESCO, PESCO)	
Interconnection Study Conducted (Yes/No)	
Distance to Nearest Grid (km)	
Dispatching Arrangement (NPCC, DISCO)	
Construction start date (dd-mm-yy)	
Percentage of construction work completed (%)	
Expected Commissioning date of all unit (dd-mm-yy)	
Total Construction period (months)	
Economic Life of Plant (years)	
De-commissioning date (dd-mm-yy)	
Power Purchase Agreement expiry date (dd-mm-yy)	
Fuel Type	
Unit of Fuel Rate (\$/GJ, \$/Metric Ton)	
Fuel Rate	
Financial Year of cost Calculation for Fuel Rate (Year)	
Dollar Conversion Rate for fuel rate (1\$=PKR)	
Unit of Heating Value (kCal/kg)	
Heating Value of Fuel	
Capacity of each Unit (MW)	
Total Number of Units	
Annual Capacity Factor for Export to grid (%)	
Schedule Maintenance Time Annual (days)	
Estimated forced outage rate annual (%)	
Estimated mean time to repair during forced outage (Hours)	
Variable O&M (USD/MWh)	
Financial Year of Cost Calculation for Variable O&M (Year)	

Dollar Conversion Rate for Variable O&M (1$=PKR)	
Fixed O&M (USD/kW-year)	
Financial Year of Cost Calculation for Fixed O&M (Year)	
Dollar Conversion Rate for Fixed O&M (1$=PKR)	
Capital Cost with IDC – Local Component (million USD)	
Capital Cost with IDC –Foreign Component (million USD)	
Capital Cost with IDC -Total (million USD)	
Capital Cost without IDC – Local Component (million USD)	
Capital Cost without IDC -Foreign Component (million USD)	
Capital Cost without IDC -Total (million USD)	
Finacial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	
Spur Cost of Transmission	
Financial Year of Cost Calculation for Spur Cost (Year)	
Dollar Conversion Rate for Spur Cost (1$=PKR)	
Monthly Total Energy (GWh)	
Monthly Peak Capability (MW)	
Any other information	

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

Data Proforma for Batteries	
Particulars	**Details**
Project Executing Agency Name	
Name of Project Representative	
Designation of Representative	
Contact number	
Email Address	
Name of Project	
Nature of Project (Public, Private, G2G, Strategic, Others)	
Other Project Nature (if any) – Public or Private	
Installed Capacity (MW)	
Storage Capacity (MWh)	
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)	
Date of Approval of Feasibility Study (dd-mm-yy)	
Financial Close Date (for Private Sector plants only)	
Is Financing Secured? (for Public Sector Plants only)	
Source of Financing	
PC-1 / LOS Approval Date (dd-mm-yy)	
Date of Licensing or Registration with NEPRA (dd-mm-yy)	
Location and site coordinates of project	
Interconnection Voltage level (kV)	
Dispatching Arrangement	
Region of Project (Gilgit, AJK, K.E, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO,TESCO, PESCO)	
Interconnection Study Conducted (Yes/No)	
Distance to Nearest Grid (km)	

Dispatching Arrangement (NPCC, DISCO)	
Construction start date (dd-mm-yy)	
Percentage of construction work completed (%)	
Expected Commissioning date of all unit (dd-mm-yy)	
Total Construction period (months)	
Economic Life of Plant (years)	
De-commissioning date (dd-mm-yy)	
Capacity of each Unit (MW)	
Total Number of Units	
Max Power Export to Grid (MW)	
Charge Efficiency (%)	
Discharge Efficiency (%)	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Maximum State of Charge (SoC) (%)	
Depth of Discharge (%)	
Per cycle power (MW) Degradation Factor (%)	
Per Cycle capacity (MWh) Degradation factor (%)	
Maximum Cycles	
Variable O&M (USD/MWh)	
Financial Year of Cost Calculation for Variable O&M (Year)	
Dollar Conversion Rate for Variable O&M (1$=PKR)	
Fixed O&M (USD/kW-year)	
Financial Year of Cost Calculation for Fixed O&M (Year)	
Dollar Conversion Rate for Fixed O&M (1$=PKR)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	

Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Financial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	
Spur Cost of Transmission	
Financial Year of Cost Calculation for Spur Cost (Year)	
Dollar Conversion Rate for Spur Cost (1$=PKR)	
Any other information	

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

Data Proforma for Hydro Power Plant	
Particulars	**Details**
Project Executing Agency Name	
Name of Project Representative	
Designation of Representative	
Contact number	
Email Address	
Name of Project	
Nature of Project (Public, Private, G2G, Strategic, Others)	
Other Project Nature (if any) – Public or Private	
Installed Capacity (MW)	
Auxiliary Consumption (MW)	
Type of project (Run of River, Reservoir)	
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)	
Date of Approval of Feasibility Study (dd-mm-yy)	
Financial Close Date (for Private Sector plants only)	
Is Financing Secured? (for Public Sector Plants only)	
Source of Financing	
PC-1 / LOS Approval Date (dd-mm-yy)	
Date of Licensing or Registration with NEPRA (dd-mm-yy)	
Location and site coordinates of project	
Interconnection Voltage level (kV)	
Dispatching Arrangement	
Region of Project (Gilgit, AJK, K.E, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO,TESCO, PESCO)	

Interconnection Study Conducted (Yes/No)	
Distance to Nearest Grid (km)	
Dispatching Arrangement (NPCC, DISCO)	
Construction start date (dd-mm-yy)	
Percentage of construction work completed (%)	
Expected Commissioning date of all unit (dd-mm-yy)	
Total Construction period (months)	
Economic Life of Plant (years)	
De-commissioning date (dd-mm-yy)	
Capacity of each Unit (MW)	
Total Number of Units	
Ramp Up Rate (For Whole Complex)(MW/min)	
Ramp Down Rate (For Whole Complex) (MW/min)	
Annual Schedule Maintenance Time (Per Unit)(days)	
Expected forced outage rate annual (Per Unit) (%)	
Expected mean time to repair during forced outage (Hours)	
Variable O&M (USD/MWh)	
Financial Year of Cost Calculation for Variable O&M (Year)	
Dollar Conversion Rate for Variable O&M (1$=PKR)	
Fixed O&M (USD/kW-year)	
Financial Year of Cost Calculation for Fixed O&M (Year)	
Dollar Conversion Rate for Fixed O&M (1$=PKR)	
Storage Capacity (GWh)	
Storage Capacity (GWh)	
Water Head of Storage (Meters)	
Volume of Reservoir (Cubic meters)	
Efficiency of Reservoir (%)	
Capital Cost with IDC (Local Component) million USD	

Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Finacial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	
Spur Cost of Transmission	
Financial Year of Cost Calculation for Spur Cost (Year)	
Dollar Conversion Rate for Spur Cost (1$=PKR)	
Monthly Total Energy (GWh) (Average Season)	
Monthly Minimum/Base Energy (GWh) (Average Season)	
Monthly Maximum Capability (MW) (Average Season)	
Monthly Total Energy (GWh) (Wet Season)	
Monthly Minimum/Base Energy (GWh) (Wet Season)	
Monthly Maximum Capability (MW) (Wet Season)	
Monthly Total Energy (GWh) (Dry Season)	
Monthly Minimum/Base Energy (GWh) (Dry Season)	
Monthly Maximum Capability (MW) (Dry Season)	
Any other information	

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

Particular	Details
Project Executing Agency Name	
Name of Project Representative	
Designation of Representative	
Contact number	
Email Address	
Name of Project	
Nature of Project (Public, Private, G2G, Strategic, Others)	
Other Project Nature (if any) – Public or Private	
Installed Capacity (MW)	
Auxiliary Consumption (MW)	
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)	
Date of Approval of Feasibility Study (dd-mm-yy)	
Financial Close Date (for Private Sector plants only)	
Is Financing Secured? (for Public Sector Plants only)	
Source of Financing	
PC-1 / LOS Approval Date (dd-mm-yy)	
Date of Licensing or Registration with NEPRA (dd-mm-yy)	
Location and site coordinates of project	
Interconnection Voltage level (kV)	
Dispatching Arrangement	
Region of Project (Gilgit, AJK, K.E, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO,TESCO, PESCO)	
Interconnection Study Conducted (Yes/No)	
Distance to Nearest Grid (km)	
Dispatching Arrangement (NPCC, DISCO)	

Construction start date (dd-mm-yy)	
Percentage of construction work completed (%)	
Expected Commissioning date of all unit (dd-mm-yy)	
Total Construction period (months)	
Economic Life of Plant (years)	
De-commissioning date (dd-mm-yy)	
Capacity of each Unit (MW)	
Total Number of Units	
Annual Capacity Factor for export to grid (%)	
Variable O&M (USD/MWh)	
Financial Year of Cost Calculation for Variable O&M (Year)	
Dollar Conversion Rate for Variable O&M (1$=PKR)	
Fixed O&M (USD/kW-year)	
Financial Year of Cost Calculation for Fixed O&M (Year)	
Dollar Conversion Rate for Fixed O&M (1$=PKR)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Financial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	
Spur Cost of Transmission	
Financial Year of Cost Calculation for Spur Cost (Year)	
Dollar Conversion Rate for Spur Cost (1$=PKR)	
Battery (or other energy storage) connected (Yes/No)	
Type of Batteries	

Installed Capacity of Project (MW)	
Storage Capacity of Project (MWh)	
Expected COD of BESS	
Charge Efficiency (%)	
Discharge Efficiency (%)	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Maximum State of Charge (SoC) (%)	
Depth of Discharge (%)	
Per cycle power (MW) Degradation Factor (%)	
Per Cycle capacity (MWh) Degradation factor (%)	
Maximum Cycles	
Technical Life (Years)	
Fixed O&M Cost $/kW-year	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Financial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	

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

Data Proforma for Wind Power Plants	
Particulars	**Details**
Project Executing Agency Name	
Name of Project Representative	
Designation of Representative	
Contact number	
Email Address	
Name of Project	
Nature of Project (Public, Private, G2G, Strategic, Others)	
Other Project Nature (if any) – Public or Private	
Installed Capacity (MW)	
Auxiliary Consumption (MW)	
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)	
Date of Approval of Feasibility Study (dd-mm-yy)	
Financial Close Date (for Private Sector plants only)	
Is Financing Secured? (for Public Sector Plants only)	
Source of Financing	
PC-1 / LOS Approval Date (dd-mm-yy)	
Date of Licensing or Registration with NEPRA (dd-mm-yy)	
Location and site coordinates of project	
Interconnection Voltage level (kV)	
Dispatching Arrangement	
Region of Project (Gilgit, AJK, K.E, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO,TESCO, PESCO)	
Interconnection Study Conducted (Yes/No)	
Distance to Nearest Grid (km)	

Dispatching Arrangement (NPCC, DISCO)	
Construction start date (dd-mm-yy)	
Percentage of construction work completed (%)	
Expected Commissioning date of all unit (dd-mm-yy)	
Total Construction period (months)	
Economic Life of Plant (years)	
De-commissioning date (dd-mm-yy)	
Capacity of each Unit (MW)	
Total Number of Units	
Annual Capacity Factor for export to grid (%)	
Number of Turbines (#)	
Capacity of each Turbine (MW)	
Variable O&M (USD/MWh)	
Financial Year of Cost Calculation for Variable O&M (Year)	
Dollar Conversion Rate for Variable O&M (1$=PKR)	
Fixed O&M (USD/kW-year)	
Financial Year of Cost Calculation for Fixed O&M (Year)	
Dollar Conversion Rate for Fixed O&M (1$=PKR)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Financial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	
Spur Cost of Transmission	
Financial Year of Cost Calculation for Spur Cost (Year)	

Dollar Conversion Rate for Spur Cost (1$=PKR)	
Battery (or other energy storage) connected (Yes/No)	
Type of Batteries	
Installed Capacity of Project (MW)	
Storage Capacity of Project (MWh)	
Expected COD of BESS	
Charge Efficiency (%)	
Discharge Efficiency (%)	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Maximum State of Charge (SoC) (%)	
Depth of Discharge (%)	
Per cycle power (MW) Degradation Factor (%)	
Per Cycle capacity (MWh) Degradation factor (%	
Maximum Cycles	
Technical Life (Years)	
Fixed O&M Cost $/kW-year	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Financial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	

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

Data Proforma for Thermal Power Plant	
Particulars	**Details**
Project Executing Agency Name	
Name of Project Representative	
Designation of Representative	
Contact number	
Email Address	
Name of Project	
Nature of Project (Public, Private, G2G, Strategic, Others)	
Other Project Nature (if any) – Public or Private	
Installed Capacity (MW)	
De-Rated/Dependable Capacity (MW)	
Auxiliary Capacity (MW)	
Type of project (CCGT, OCGT, Gas ST, Nuclear ST, Coal ST, DG, FO ST, Others	
Other Project Type (If any)	
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)	
Date of Approval of Feasibility Study (dd-mm-yy)	
Financial Close Date (for Private Sector plants only)	
Is Financing Secured? (for Public Sector Plants only)	
Source of Financing	
PC-1 / LOS Approval Date (dd-mm-yy)	
Date of Licensing or Registration with NEPRA (dd-mm-yy)	
Location and site coordinates of project	
Interconnection Voltage level (kV)	
Dispatching Arrangement	

Region of Project (Gilgit, AJK, K.E, HESCO, SEPCO, QESCO, MEPCO, FESCO, LESCO, IESCO,TESCO, PESCO)	
Interconnection Study Conducted (Yes/No)	
Distance to Nearest Grid (km)	
Dispatching Arrangement (NPCC, DISCO)	
Construction start date (dd-mm-yy)	
Percentage of construction work completed (%)	
Expected Commissioning date of all unit (dd-mm-yy)	
Total Construction period (months)	
Economic Life of Plant (years)	
De-commissioning date (dd-mm-yy)	
Power Purchase Agreement expiry date (dd-mm-yy)	
Fuel Type (Nuclear, Gas, RLNG, RFO, Imported Coal, Local Coal, Other)	
Other Fuel Type (If any)	
Unit of Fuel Rate ($/GJ, $/Metric Ton)	
Fuel Rate	
Financial Year of cost Calculation for Fuel Rate (Year)	
Dollar Conversion Rate for fuel rate (1$=PKR)	
Unit of Heating Value (kCal/kg)	
Heating Value of Fuel	
Fuel Price Escalation/De-escalation (%)	
Take or Pay contract (%) (if any)	
Take or Pay contract expiry date/Period (dd/mm/yyyy)	
Reduced Fuel price if Take or Pay Contract cannot be met ($/Metric Ton, $/GJ)	
Annual Take or Pay Contract Quantity (TJ)	
Capacity of each Unit (MW)	
Technology of each unit (GT, ST, DG, GE)	
Total number of units	

Minimum Stable Level (Whole Complex) (MW)	
CCGT configuration	
Ramp Up Rate (Whole Complex) (MW/min)	
Ramp Down Rate (Whole Complex) (MW/min)	
Minimum Up Time (hours)	
Minimum Down Time (hours)	
Efficiency at Minimum Stable Level (%)	
Efficiency at Full Load (%)	
Heat Rate at 25% Load (BTU/kWh)	
Heat Rate at 40% Load (BTU/kWh)	
Heat Rate at 50% Load (BTU/kWh)	
Heat Rate at 60% Load (BTU/kWh)	
Heat Rate at 70% Load (BTU/kWh)	
Heat Rate at 80% Load (BTU/kWh)	
Heat Rate at 90% Load (BTU/kWh)	
Heat Rate at 100% Load (BTU/kWh)	
Schedule Maintenance Time Annual (days)	
Expected forced outage rate annual (%)	
Expected mean time to repair during forced outage (Hours)	
Emission production rate (gCO2/MWh)	
Variable O&M (USD/MWh)	
Financial Year of Cost Calculation for Variable O&M (Year)	
Dollar Conversion Rate for Variable O&M (1$=PKR)	
Fixed O&M (USD/kW-year)	
Financial Year of Cost Calculation for Fixed O&M (Year)	
Dollar Conversion Rate for Fixed O&M (1$=PKR)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	

Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Financial Year of Cost Calculations (Year)	
Dollar Conversion Rate (1$=PKR)	
Spur Cost of Transmission	
Financial Year of Cost Calculation for Spur Cost (Year)	
Dollar Conversion Rate for Spur Cost (1$=PKR)	
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. #	**Descriptions**	**Data**
	Expected COD	
	Coordinates of the Project	
	Fuel Type	
	Generator Basic Data	
	Generation Voltage Level (kV)	
	No. of generating units	
	Power factor (Lagging/Leading) of generating unit	
	Rated Apparent Power of each generating unit (MVA)	
	Gross Output of each unit (MW)	
	Maximum Output in Summer and Winter (Peak and Off-Peak)	
	Total Auxiliary Load (MW) / Auxiliary Load with each unit	
	Net Output of each generating unit (MW)	
	Power factor for Auxiliary Load	
	RPM of the machine	

	Total Inertia Constant H for entire rotating mass (MW-s/MVA) – (Generator + Turbine + Rotating Exciter)		
	Short circuit ratio of each generating unit		
Reactance's for Generator (pu)			
	Direct Axis Sub-Transient Reactance (X"d) (unsaturated)		
	Direct Axis Sub-Transient Reactance (X"d) (saturated)		
	Quadrature Axis Sub-Transient Reactance (X"q) (Unsaturated)		
	Quadrature Axis Sub-Transient Reactance (X"q) (saturated)		
	Direct Axis Transient Reactance (X'd) (unsaturated)		
	Direct Axis Transient Reactance (X'd)(saturated)		
	Quadrature Axis Transient Reactance (X'q) (unsaturated)		
	Quadrature Axis Transient Reactance (X'q) (saturated)		
	Direct Axis Synchronous Reactance Xd		
	Quadrature Axis Synchronous Reactance Xq		
	Leakage Reactance Xl(unsaturated)		
	Leakage Reactance Xl(saturated)		
	Negative sequence Reactance X2 (unsaturated)		
	Negative sequence Reactance X2 (saturated)		
	Zero-Phase Sequence Reactance X0 (unsaturated) X0		
	Zero-Phase Sequence Reactance X0 (saturated) X0		
	Time Constants for Generator (s)		
	Transient Direct-Axis Open-Circuit Time Constant T'do		
	Transient Quadrature-Axis Open-Circuit Time Constant T'qo		
	Transient Direct-Axis Short-Circuit Time Constant T'd		
	Transient Quadrature-Axis Short-Circuit Time Constant T'q		
	Sub-Transient Direct-Axis Open-Circuit Time Constant T"do		
	Sub-Transient Quadrature-Axis Open-Circuit Time Constant T"qo		
	Sub-Transient Direct-Axis Short-Circuit Time Constant T"d		
	Sub-Transient Quadrature-Axis Short-Circuit Time Constant T"q		
	Other Factors		
	Saturation Factors of Generator	S (1.0)	
		S (1.2)	
	Characteristic Curves (Saturation, PQ, V-Curve)		
	Generator Step-Up (GSU) Transformers		
	Voltage Rating of GSU transformer (kV)		
	Vector Group		
	No. of transformers and generators connected to each transformer		

	Transformer Rated Power (MVA)	
	Type	
	Percentage Impedance, (R, X) in % at rated MVA base	
	Total Number of Taps	
	Principal Tap Number	
	Earthing Specifications	
	Type of Earthing for Generator (Direct, impedance, transformer)	
	MVA Rating of transformer	
	Voltage Ratio of transformer	
	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

(a) Description	(b) Data
Excitation system type (AC or DC)	
Excitation feeding arrangement (solid or shunt)	
Excitation system Filter time constant – Tr	
Excitation system Lead time constant - Tc	
Excitation system Lag time constant - Tb	
Excitation system Controller gain - Ka	
Excitation system controller lag time constant - Ta	
Excitation system Maximum controller output - Vmax	
Excitation system minimum controller output - Vmin	
Excitation system regulation factor - Kc	
Excitation system rate feedback gain - Kf	
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**) 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 input(s);
- Gain for each input;
- Lead Time constant(s) for each input;
- Lag Time constant(s) for each input;
- Power System Stabilizer Model (in IEEE or PTI's PSS/E format)

PC. A 4 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. A 2.1, PC. A 2.2** for the **Connection Point**. The minimum technical, design and operational criteria to be met by **Controllable SWE** are specified in the **Connection Code**.

PC. A 4.1 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:

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

Sr. #	Wind Turbine Generator (WTG) Data	
	Expected COD of Generator	
	Generation Type	
	No. of WTGs	
	Manufacturer/Model	
	Gross Capacity of each WTG (MW)	

	Type of WTG	
	Generation Voltage (kV)	
	Power Factor (Lagging/Leading)	
	Ramp Up/Down Rate (MW/Min) or (% /Min)	
WTG Arrangement in Wind Farm		
	No. of Collector Groups	
	No. of WTGs in one collector group	
	Length of each collector group within the switchyard (km)	
Total Wind Farm Capacity		
	Total Gross Capacity (MW)	
	EBOP Losses (MW)	
	Auxiliary Consumption (MW)	
	Total Net Output Capacity that will flow to the grid (MW)	
Generator Step Up Transformer Data		
	No. of step up transformers	
	Voltage Ratio (kV)	
	MVA Rating	
	Percentage Impedance %	
	Vector Group	
Proposed Switchyard of Wind Power Project		
	High Level (HV) Voltage	
	Medium Level (MV) Voltage	
	Proposed Bus Bar Scheme	
	Proposed Bus Bar Capacity (Amp)	
	Proposed Circuit Breaker Capacity at HV Level (kA)	
Power Transformer from HV to MV Level		
	No. of transformers	
	Voltage Ratio (kV)	
	MVA Rating	
	Percentage Impedance %	
	Vector Group	

Proposed Reactive Power Compensation		
	Proposed size of Reactive Power Compensation Equipment (MVAR) installed at MV or HV	
Miscellaneous		
	Proposed reactance for each collector group X"d (pu)	

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

Sr. #	Solar Generator Data	
	Expected COD	
	Generation Type	
	Generation Voltage Level (kV)	
	Medium Voltage Level (kV)	
	High Voltage Level (kV)	
	No. of inverter units	
	No. of Clusters made for Inverters	
	AC Cable Lengths (km)	
	Power factor	
	DC power Connected to each unit (MW)	
	AC power output of each unit (MW)	
	Rated Apparent Power of each inverter unit (MVA)	
	Total Installed DC Capacity of Plant, (MW)	
	Gross AC Output of the Plant, (MW)	
	Reactive Power Compensation Requirement (MVAR) SVC/Switched shunt Capacitor Bank, installed at MV or HV	
	Ramp Up/Down Rate (MW/Min) or (% /Min)	
GSU Transformers		
	No. of GSU transformers (MV/LV kV)	
	Transformer Rated Power, MVA	
	Vector Group	
	Percentage Impedance	
Step-up Power Transformer for Grid End		
	No. of GSU transformers (HV/MV kV)	
	Transformer Rated Power, MVA	
	Vector Group	
	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.

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. A 4.4 **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.A 4.5 **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. A 4.6 **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 ndividual length of each section of the circuit.

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

Type1	Type2	Type3	Extend Table as appropriate
Total length (m)			
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. A 4.8 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. A5.0 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, 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);

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**

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

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

vii. AC/DC rated DC Network Voltage/Pole(kV);

viii. number of Poles and Pole arrangement;

ix. Earthing / return path arrangement;

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

xi. 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.

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

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

xiii. total number of AC filter banks;

xiv. type of equipment (e.g., fixed or variable);

xv. single line diagram of filter arrangement and connections;

xvi. 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;

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

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

xix. 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**

xx. 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;

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

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

xxiii. transfer function block diagram representation including parameters of any Frequency, voltage and/or load control systems;

xxiv. 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;

xxv. 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

xxvi. 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.

xxvii. 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

(e) **Interconnector Transformer**

Table PC.A-12 Interconnector Transformer data requirements

Description	Data
Number of windings	
Vector Group	
Rated current of each winding (Amps)	
Transformer rating (MVA)	
Transformer nominal LV voltage (kV)	
Transformer nominal HV voltage (kV)	
Tapped winding	
Transformer ratio at all transformer taps	
Transformer impedance (Commutation Reactance) at all taps (% on rating MVA)	
Transformer zero sequence impedance at nominal tap (ohm)	
Earthing arrangement including neutral Earthing resistance & reactance	
Core construction (number of limbs, shell or core type)	
Open circuit characteristic	

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

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 (TPCS) describes;

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

(b) Normal and contingency conditions to consider

(c) Planning performance standards and criteria

TPCS 2. **PLANNING STUDIES**

TPCS 2.1. **Horizons**

Table 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.

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.

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 Section 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-cyles owing to a stuck-breaker condition.

Exception for N-1 may be given at the Connection Point where a generator of 50MW or below is to be connected with the existing radial transmission line (up to 132kV 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

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 will 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:

(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.

TPCS 4. SYSTEM PERFORMANCE REQUIREMENTS

The Users will 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., 40degrees 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

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 (November- March) loading

Table 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 April 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 sub-station) or 100% (more than one Transformer sub-station) 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 will be used to calculate the ratio. The SO will incorporate the information and plans informed by each TNO to the ASRAIR submitted to the Authority.

Table 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; and
TPCS 4.1.5.4.	In the case of single transformer sub-station, the Firm Capacity of the sub-station 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 800kV class (Nominal 735-765kV)

The upper limit of the voltage is 800kV 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 500kV 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 50.2Hz
(b)	Contingency Operating Range	49.3 Hz to 50.5Hz

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 p.u.

(b) For Minimum Short Circuit current calculations, pre-fault voltage should be 0.9 p.u.

(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.

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; and

(c) In case auto reclosing scheme is implemented, then system should be tested for unsuccessful auto reclosing (with a dead band 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 0.7pu or should not over shoot to above 1.3pu;

(b) Bus voltages should reach and stay above 0.8 p.u within 1 second from the fault inception;

(c) Bus voltages should reach and stay above 0.9 p.u within 2 second from the fault inception; and

(d) Bus voltages should recover at or below 1.1 p.u within 2 second from the 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.

CONNECTION CODE

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 license 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 (TNOs);

(b) Generators connected to the Transmission System;

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

(d) Interconnectors.

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(s) 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 TNO(s) and the SO; and

(b) The SO 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 TNO(s) 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 location(s) of the Connection Point(s); 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 will 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 TNO(s) 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 TNO(s) 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 TNO(s) 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 and reinforcement facilities, if any; and

(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. In addition, Generators and Transmission-Connected BPCs shall bear the additional costs related to the reinforcement of the Transmission System beyond the identified Connection Point only if and on pro rata basis, as calculated by SO/relevant TNO as applicable in Authority regulations and/or TNO license conditions.

CC 2.3.6. If a new Generator/ Transmission-Connected BPC is utilizing an ongoing/already completed reinforcement whose cost has already been apportioned among other Users, the new User shall also bear the pro rata cost of such reinforcement.

CC 2.3.7. 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 2.3.8. If the User considers the Offer to Connect does not comply with this Grid Code or an applicable NEPRA regulation, 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 will form the basis for setting the terms and condition of the Connection Agreement provided that, for data that had 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 rules 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(s) 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 reception of these documents and information, the involved TNO shall provide copies of them 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 (EPA).

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 provision(s) 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 applicable NEPRA regulations.

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 switch yard 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 clause 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 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, the SO shall notify such additional requirement(s) to the relevant User for compliance.

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 T-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 will 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:

Table CC T-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

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 breaker(s) as required by the SO.

CC 6.1.7. Metering System

All Users shall provide Primary Metering System and Back-up Metering System 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;

(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 T-4 below;

Table CC T-4: Minimum Load ceiling and Ramp rate for Thermal Generators

Sr. #	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 plant(s) 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:

Table CC T-5. Reference Synchronization times for Thermal Generators.

Sr. #	Thermal Generation Technologies	Hot (Mints)	Warm (Mints)	Cold (Mints)
1.	CFPP	≤ 130	≤ 280	≤ 400
2.	Gas Turbine	≤ 20	≤ 20	≤ 25
3	Steam Turbine (Gas)	≤ 40	≤ 80	≤ 120
4	Steam Turbine (RFO)	≤ 90	≤ 20	≤ 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 F-1 and Table CC T-6:

Figure CC F-2: FRT for conventional generators

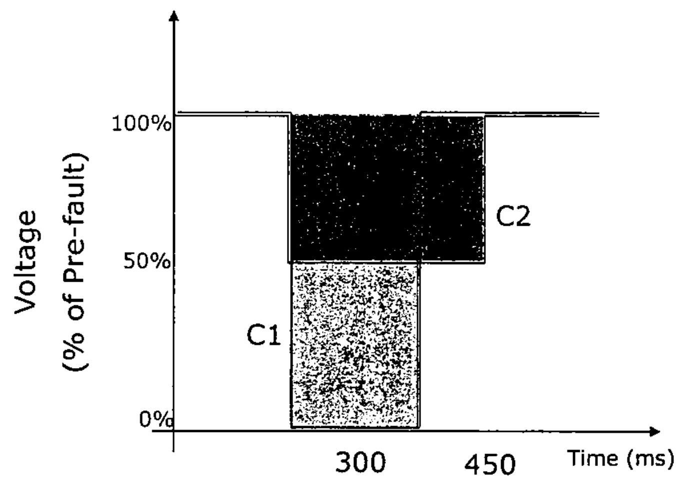


Table CC T-6: FRT duration for conventional generators

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; and

(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.

(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 will 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 6.3.1 (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 T-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.

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 its maximum capability 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 will 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 F-2 and Figure CC F-3. The set points of Qmin and Qmax shall be, at least, as follows:

(a) Qmin = -0.33 P.U. of full Output

(b) Qmax = + 0.5 P.U. of full Output

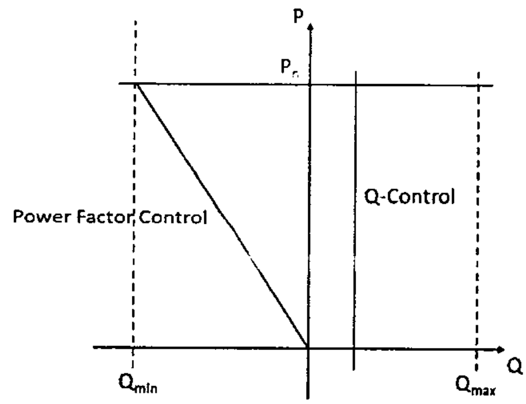


Figure CC F-2 Reactive Power control for Wind and Solar Generators

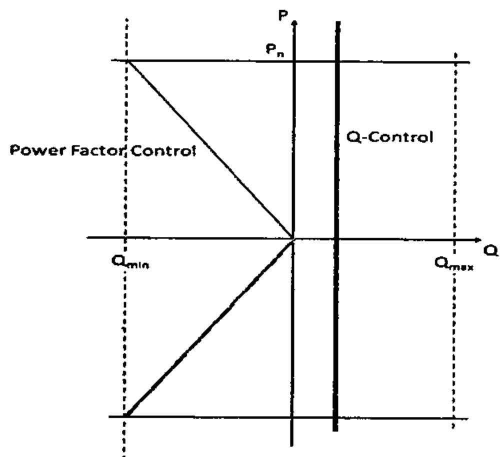


Figure CC F-3 Reactive Power control for BESS

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 F-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 P.U. of full Output of Plant

(c) Droop (5 % of Nominal Voltage at max. Reactive Power)

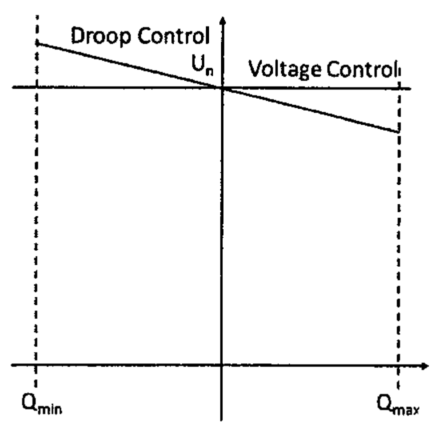


Figure CC F-4 Voltage Control Mode

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 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 500ms.

(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.

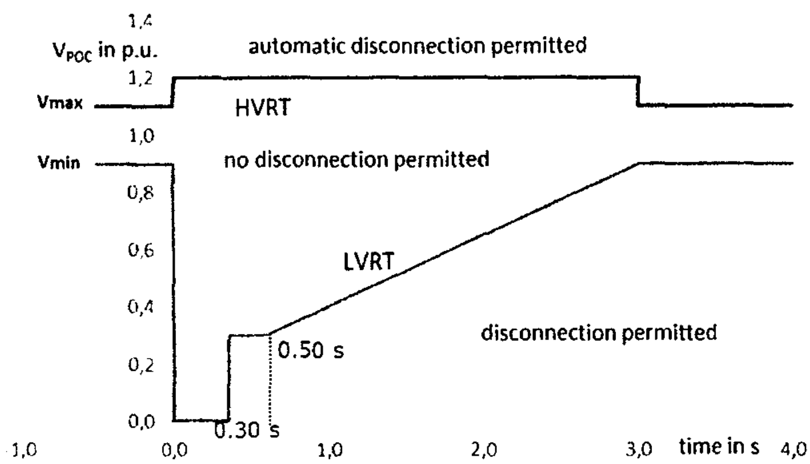


Figure CC F-5 HVRT/LVRT Requirements for SWE Projects

CC 6.3.6.5. In order to actively support voltage during low voltage situations (LVRT-situations), a 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, a 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 F-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 500ms, 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 500ms of the Transmission System Voltage recovering to 90% of nominal Voltage, for Fault Disturbances cleared within 140ms. For longer duration Fault Disturbances, but less than 300ms, 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 100ms and a Settling Time no greater than 300ms. For the avoidance of doubt, the SWE may provide this reactive response directly from individual Generation Units, or other additional dynamic reactive devices on the site, or a combination of both. The characteristics of reactive current support are indicated in Figure CC F-6.

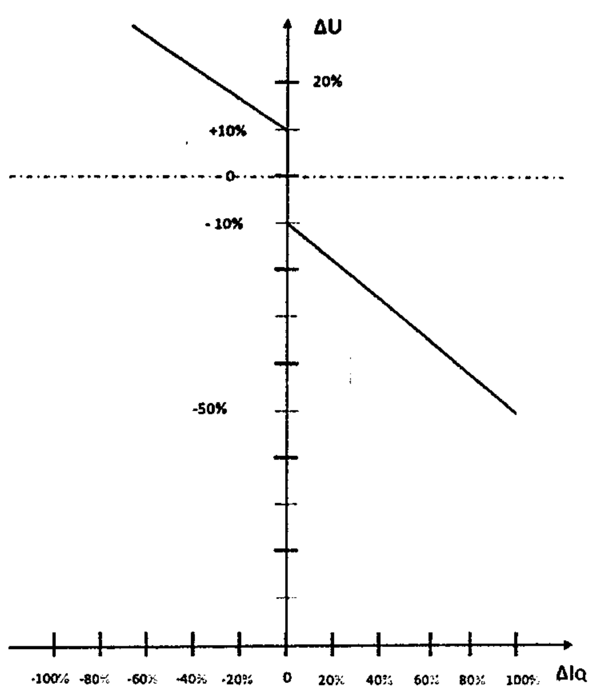


Figure CC F-6 Reactive Current Support Requirements

CC 6.3.6.8. According to this figure, a SWE will inject an additional reactive current (DIQ in addition to the pre-fault reactive current) into the grid if the difference between post-disturbance and pre-disturbance voltage (DU) goes below -10%.

CC 6.3.6.9. In the case that DU goes above 10%, a high voltage condition is identified, and DI will be absorbed in order to stabilize the voltage.

CC 6.3.6.10. It is further recommended that DI is defined as being in proportion to DU (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 60ms, 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

(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 200ms 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 500ms of the Transmission System Voltage recovering to its normal operating range as specified in Section 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 T-7 below;

Table CC T-7: Minimum Load ceiling and Ramp rate for Renewable Generators.

Sr. #	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%

(d) In case of disconnection of the SWE from the Transmission System, the SWE shall be capable of quick re-Synchronization as per 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 bi-pole

(e) Operation with one or more converters out of service in a pole (for multi-terminal HVDC system)

CC 6.4.5. Control Modes

This section includes HVDC control modes;

CC 6.4.6. Bi-pole Power Control Mode

In a bipolar system, the most usual mode of control is bi-pole 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 multiterminal 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:

(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 minimum of 1 MW per minute to 1000MW 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 millisecond 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 (Ublock) 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 section 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 per cent (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 station(s) 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); and

(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 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 User(s) for monitoring and interface co-ordination, 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 132kV 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 T-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 Unbalance**

User Plant and Apparatus shall not cause the phase-to-phase voltage unbalance of the Transmission System to exceed by more than one (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 (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 (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 T-8: Rapid Voltage Change Parameters

Type of Rapid Voltage Change	$\frac{\Delta U}{UN}$ 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 center(s) 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; and

(g) Phase angle.

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(s) 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 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 Agreement(s), 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 OC11.

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); and

(c) Final Operational Notification (FON).

CC 12.5.1. Energization Operational Notification

The SO will 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 will 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 will 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 will 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 User(s) 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 User(s).

(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.

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.

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, Busbars, Shunt Reactors, Capacitors, SVCs, Filters, Battery Energy Storage Systems (BESS) 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, Busbars, Shunt Reactors, Capacitors, SVCs, Filters, Battery Energy Storage Systems (BESS) and/or any other equipment as specified by SO (acting reasonably);

(b) Busbar Frequency Hz measurement at least up to 3 decimal places

(c) For generators, MW, MVAR & Power Factor will 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 will be required from LV side except for generator transformer where Voltage kV Signal will 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, out flow, discharge, reservoir or pond level, tail race level etc.

CC.A1-3. **Control Signals**

(h) Remote Command signals from SO to Open/ Close Circuit Breakers, Raise Lower Transformer Tap position and interrupt regulation process at Users facilities

(i) 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.

(j) Remote Command Signals from SO (set point) to curtail output of Wind and Solar Plants.

(k) Remote Command Signals from SO, to change or select mode and control of operation of HVDC, Wind or Solar & BESS plants etc.

CC.A1-4. **Protection Signals**

Signals pertinent to Circuit Breakers, Transformers, Transmission Lines, Generators, Busbars, 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 shall 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; and

(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; and

iv. Governor/Frequency Response Dead band.

v. Frequency Limiter Control and other such Control Functions of HVDC

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.

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 one (1) pu value in per unit before, during and after a fault. Uret is the retained voltage at the connection point during a fault, tclear is the instant when the fault has been cleared, Urec1 and trec1 specify a point of lower limits of voltage recovery following fault clearance. Ublock 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 time frame 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.

Table: Parameters for above Figure for the fault-ride-through capability of an HVDC converter station

Voltage-against-time-profile referred to section

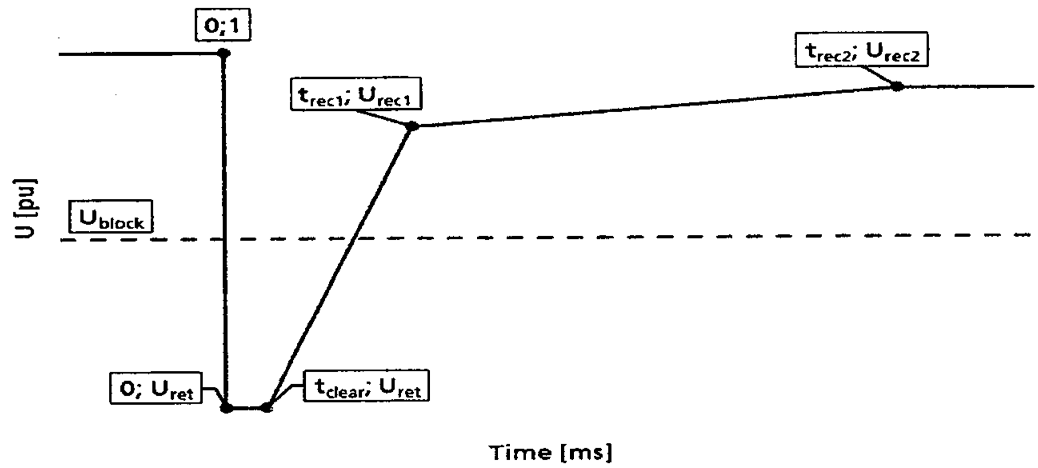


Table: Parameters for above Figure for the fault-ride-through capability of an HVDC converter station (Source: CASA Technical Code)

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

CC. Appendix -3

CONFIGURATIONS FOR USERS CONNECTION

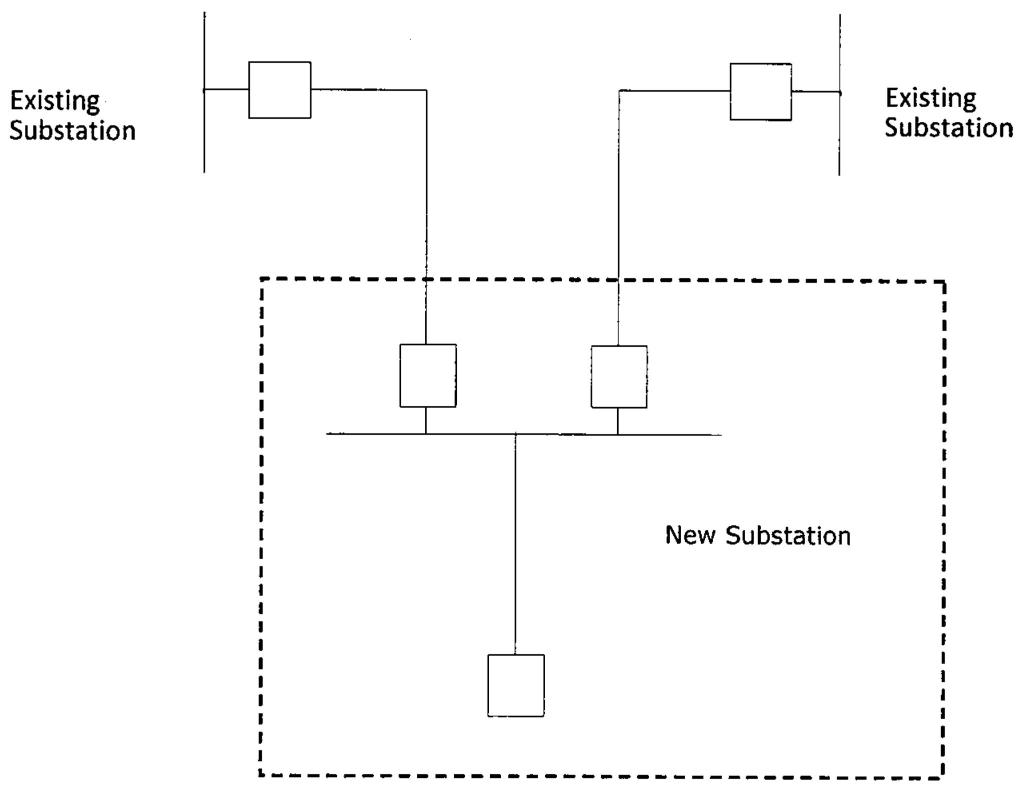
For connection of User Substation, following three configurations have been indicated which may be adopted according to the system conditions.

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

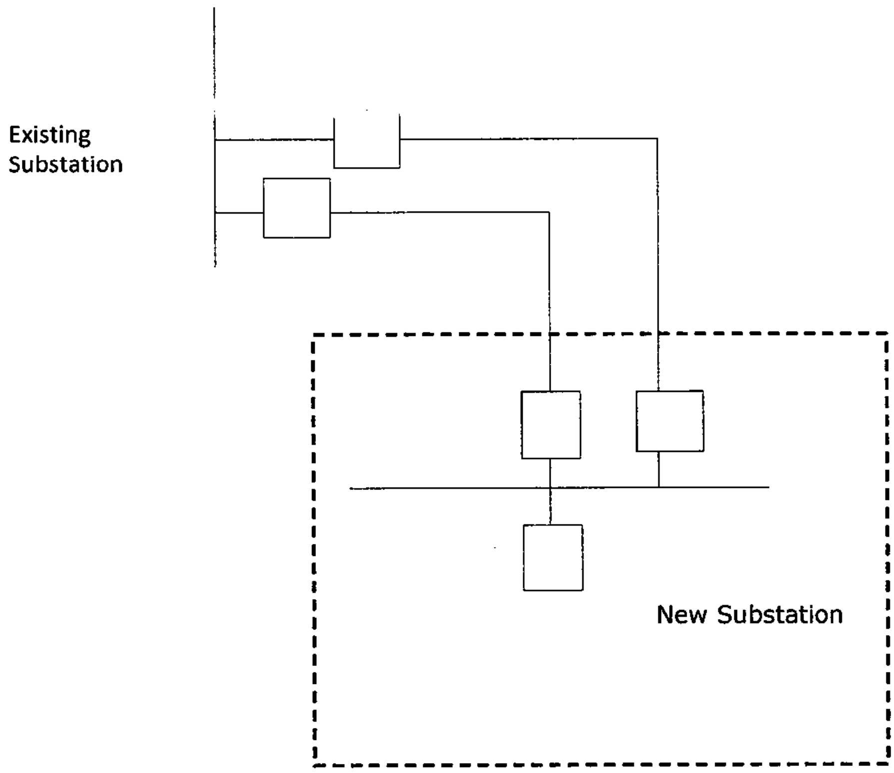
The User(s) shall opt one of the following configuration subject to the SO's approval based on System Impact Assessment Studies.

Busbar and breaker configuration (single, double, one and half or ring) shall be as per System Impact Assessment Studies.

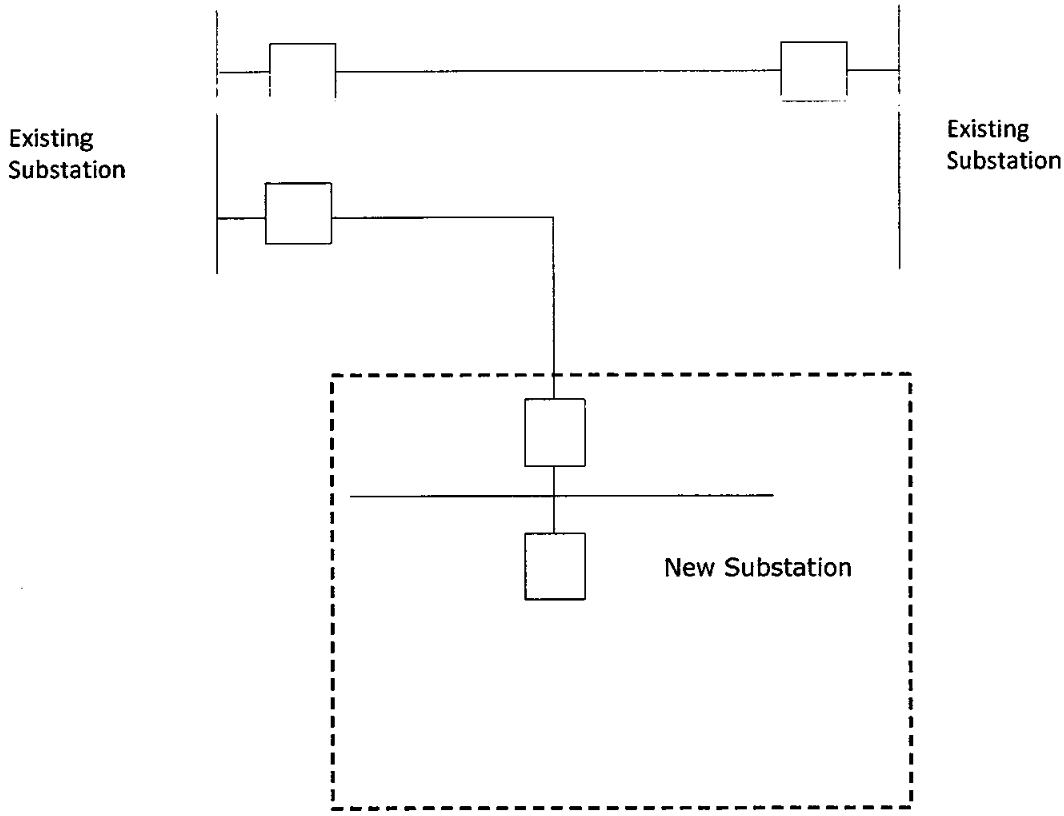
Scheme 1: **CONNECTION CONFIGURATIONS WITH IN-OUT ARRANGEMENT**



Scheme 2: CONNECTION CONFIGURATIONS (radial with N-1)

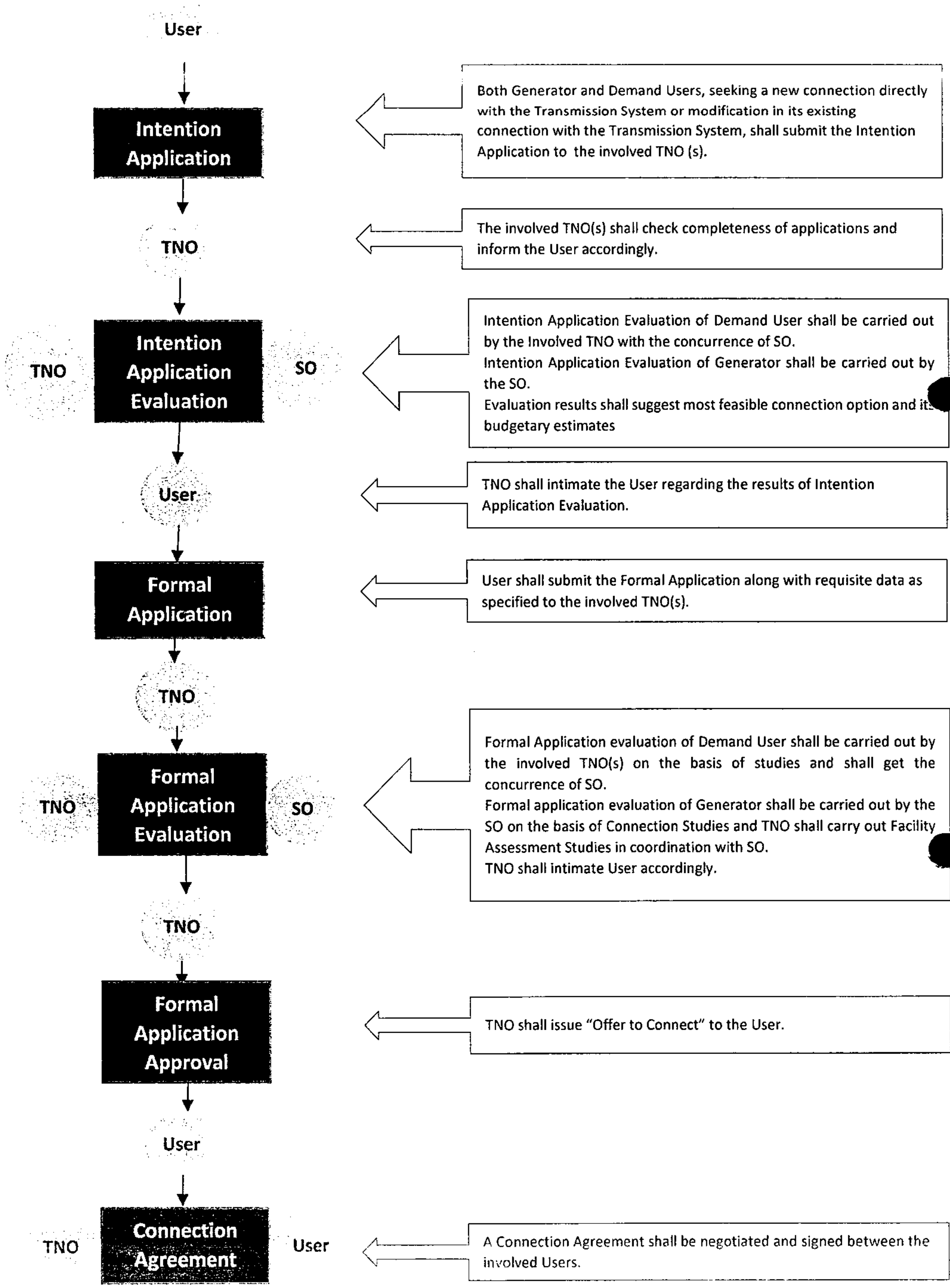


Scheme 3: CONNECTION CONFIGURATIONS (radial)



CC. Appendix -4

CONNECTION PROCESS



PROFORMA FOR SITE RESPONSIBILITY SCHEDULE (SRS)

This proforma 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 Rules and Precautions.
10. Operational Procedures.
11. Party Responsible for Undertaking Inspections, Fault Investigation and Maintenance.
12. Remarks

PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

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 sites; 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

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).

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)

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.

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

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.

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 THEIER 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 BUSBAR 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 RADIATTION)	
29	FUEL STORAGE CAPACITY	
30	FUEL STOCK TO BE MAINTAINED AS PER applicable regulations or commitments	
31	HEAT RATE at:	

S. No	DESCRIPTION OF REQUIRED INFORMATION	(DATA TO BE FILLED ACCORDING TO DESCRIPTION)
	• Full Installed Capacity • 80% of Installed Capacity • 50% of Installed Capacity • Minimum Load	
33	SCHEDULED OUTAGE PERIOD	

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)	
5	TYPE OF BUSBAR 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 bay for transformer/ transmission lines/ capacitor banks/ reactors etc)	

DC CONVERTOR STATION

NAME OF CONVERTER STATION: ____________CONVERTER STATION LOCATION: ______________

S. No	DESCRIPTION	MEASUREMENT UNITS	
1	NAME OF CONVERTOR STATION	NAME	
2	RATED MW PER POLE FOR TRANSFER IN EACH DIRECTION	MW	
3	DC CONVERTOR 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 CONVERTOR CONTROL SYSTEM MODEL	MODEL	
17	DETAIL OF HARMONIC ASSESSMENT INFORMATION	ATTACHED/ NOT ATTACHED	
18	**ANY OTHER INFORMATION REQUIRED BY THE SO**		

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 (NAME PLATE) (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 (P.F) LAGGING (OVER EXCITED)	%AGE OR VALUE	
9	POWER FACTOR (P.F) 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 EXCITOR CEILING VOLTAGE (+VE POLARITY)	V OR PU	
24	NOMINAL EXCITOR 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	OHMS	
27	SHORT CIRCUIT RATIO (SCR)		

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
28	DAMPING (D)		
29	DAMPING TORQUE COEFFICIENT (KD)	P.U MW/PU FREQ	
C	**INERTIA**		
1	WR^2 FOR GENERATOR	$KG\text{-}M^2$ OR $LB\text{-}FT^2$	
2	WR^2 FOR EXCITOR (IF APPLICABLE)	$KG\text{-}M^2$ OR $LB\text{-}FT^2$	
3	WR^2 FOR TURBINE	$KG\text{-}M^2$ OR $LB\text{-}FT^2$	
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	MVA	
-	VOLTAGE BASE	KV	
1	DIRECT AXIS SYNCHRONOUS REACTANCE (X_d) UNSATURATED AT OWN BASE	% AGE or P.U	
2	QUADRATURE AXIS SYNCHRONOUS REACTANCE (X_q) UNSATURATED AT OWN BASE	% AGE or P.U	
3	DIRECT AXIS TRANSIENT REACTANCE (Xd') UNSATURATED AT OWN BASE	%AGE or P.U	
4	DIRECT AXIS TRANSIENT REACTANCE (X_{ds}') SATURATED AT OWN BASE	%AGE or P.U	
5	QUADRATURE AXIS TRANSIENT REACTANCE (X_q') UNSATURATED AT OWN BASE	%AGE or P.U	
6	QUADRATURE AXIS TRANSIENT REACTANCE (X_{qs}') SATURATED AT OWN BASE	%AGE or P.U	
7	DIRECT AXIS SUB TRANSIENT REACTANCE (Xd") UNSATURATED AT OWN BASE	%AGE or P.U	
8	DIRECT AXIS SUB TRANSIENT REACTANCE (X_{ds}") SATURATED AT OWN BASE	%AGE or P.U	
9	QUADRATURE AXIS SUB TRANSIENT REACTANCE (Xq") UNSATURATED AT OWN BASE	%AGE or P.U	
10	QUADRATURE AXIS SUB TRANSIENT REACTANCE (X_{qs}") SATURATED AT OWN BASE	%AGE or P.U	
11	NEGATIVE PHASE SEQUENCE REACTANCE (X2) AT RATED VOLTAGE (UNSATURATED)	%AGE or P.U	
12	NEGATIVE PHASE SEQUENCE REACTANCE (X2s) AT RATED VOLTAGE (SATURATED)	%AGE or P.U	
13	ZERO PHASE SEQUENCE REACTANCE (X0) UNSATURATED	%AGE or P.U	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
14	ZERO PHASE SEQUENCE REACTANCE (X0s) SATURATED	%AGE or P.U	
15	POSITIVE SEQUENCE ARMATURE RESISTANCE (R1) AT 100°C	%AGE or P.U	
16	NEGATIVE SEQUENCE ARMATURE RESISTANCE (R2) AT 100°C	%AGE or P.U	
17	DIRECT CURRENT ARMATURE RESISTANCE (R_{dc}) AT 100°C	%AGE or P.U	
18	STATOR (ARMATURE) RESISTANCE (RS)	%AGE or P.U	
19	DIRECT AXIS STATOR INDUCTANCE (LSD)	%AGE or P.U	
20	QUADRATURE AXIS STATOR INDUCTANCE (LSQ)	%AGE or P.U	
21	DIRECT AXIS DAMPER WINDING LEAKAGE INDUCTANCE (L1Dλ)	%AGE or P.U	
22	QUADRATURE AXIS DAMPER WINDING 1 LEAKAGE INDUCTANCE (L1Qλ)	%AGE or P.U	
23	QUADRATURE AXIS DAMPER WINDING 2 LEAKAGE INDUCTANCE (L2Qλ)	%AGE or P.U	
24	STATOR LEAKAGE INDUCTANCE (LSλ)	%AGE or P.U	
25	FIELD RESISTANCE (RFD)	%AGE or P.U	
26	DIRECT AXIS DAMPER WINDING RESISTANCE (R1D)	%AGE or P.U	
27	QUADRATURE AXIS DAMPER WINDING 1 RESISTANCE (R1Q)	%AGE or P.U	
28	QUADRATURE AXIS DAMPER WINDING 2 RESISTANCE (R2Q)	%AGE or P.U	
29	POTIER REACTANCE (Xp)	%AGE or P.U	
30	ARMATURE LEAKAGE REACTANCE (XL)	%AGE or P.U	
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	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
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	
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 DESPATCHED LOAD	%/MINUTE	
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"		

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	BASE VOLTAGE	KV	
13	BASE MVA	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	

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 EXCITOR	ROTATING (AC OR DC GENERATOR) OR STATIC (THYRISTOR)	
2	MANUFACTURER	NAME	
3	BASE VOLTAGE	VOLT	
4	REGULATOR REFERENCE VOLTAGE SETTING (V_{REF})	VOLT (or) PU	
5	REGULATOR INPUT VOLTAGE (V_I)	VOLT (or) PU	
6	VOLTAGE REGULATOR INPUT VOLTAGE MAXIMUM or MAXIMUM INTEGRAL CONTROL ACTION VOLTAGE (V_{IMAX})	VOLT (or) PU	
7	VOLTAGE REGULATOR INPUT VOLTAGE MINIMUM or MINIMUM INTEGRAL CONTROL ACTION VOLTAGE(V_{IMIN})	VOLT (or) PU	
8	REGULATOR OUTPUT VOLTAGE (V_R)	VOLT (or) PU	
9	VOLTAGE REGULATOR OUTPUT VOLTAGE MAXIMUM LIMIT "or" POWER CONVERTOR POSITIVE CEILING VOLTAGE (V_{RMAX})	VOLT (or) PU	
10	VOLTAGE REGULATOR OUTPUT VOLTAGE MINIMUM LIMIT "or" POWER CONVERTOR NEGATIVE CEILING VOLTAGE(V_{RMIN})	VOLT (or) PU	
11	MAXIMUM PROPORTIONAL CONTROL ACTION VOLTAGE (VPMAX)	VOLT (or) PU	
12	MINIMUM PROPORTIONAL CONTROL ACTION VOLTAGE (VPMIN)	VOLT (or) PU	
13	AUXILIARY SIGNAL (VS)	VOLT (or) PU	
14	EXCITER VOLTAGE AT WHICH EXCITER SATURATION IS DEFINED	VOLT (or) PU	
15	MAXIMUM EXCITER FIELD CURRENT FEED BACK SIGNAL (VHMAX)	VOLT (or) PU	
16	EXCITER FIELD CURRENT LIMIT REFERENCE (VFELIM)	VOLT (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	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
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	
29	DEMAGNETIZATION FACTOR "or" DERIVATIV 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)		
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)	-	

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" VSTMAX		
10	PSS output limiter "min" VSTMIN		
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)		

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 (GMAX)		
8	MINIMUM GATE LIMIT (GMIN)		
9	WATER TIME CONSTANT (TW)		
10	TURBINE GAIN (At)		
11	TURBINE DAMPING (Dturb)		
12	NO LOAD FLOW (qNl)		
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 (Dturb)		
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 (Dturb)		
7	OPERATIONAL CONTROL HIGH LIMIT ON FUEL VALVE OPENING (V MAX)		
8	LOW OUTPUT CONTROL LIMIT ON FUEL VALVE OPENING		

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER
	(V MIN)		
9	AMBIENT TEMPERATURE LOAD LIMIT (AT)		
D	RECIPROCATING ENGINE		
1			
2			
E	**ANY OTHER DATA**		
1			
2			

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	SECOND	
3	INERTIA CONSTANT (H)	SECOND	
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	ATTACHED / NOT ATTACHED	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER
	AMBIENT TEMPERATURE		
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	

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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)	SECOND	
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 LAGING 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		

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	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 BREAKER (S) AT STATION -1	BREAKER CODE	
10	MANUFACTURER NAME OF CONTROLLING BREAKER (S) AT STATION -1	NAME	
11	CT RATIO OF BREAKER(S) AT STATION -1 FOR PROTECTION	AMP RATIO	
12	CT RATIO OF BREAKER(S) AT STATION -1 FOR METERING	AMP RATIO	
13	CONTROLLING BREAKER (S) AT STATION -2	BREAKER CODE	
14	MANUFACTURER NAME OF CONTROLLING BREAKER (S) AT STATION -2	NAME	
15	CT RATIO OF BREAKER(S) AT STATION -2 FOR PROTECTION	AMP RATIO	
16	CT RATIO OF BREAKER(S) 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 MAVA	VALUE OF BASE MAVA	
22	POSITIVE SEQUENCE RESISTANCE (R1)	OHM	
23	POSITIVE SEQUENCE RESISTANCE (R1) ON BASE MAVA	PERCENTAGE / P.U	
24	POSITIVE SEQUENCE REACTANCE (X1)	OHM	
25	POSITIVE SEQUENCE REACTANCE ON (X1) BASE MAVA	PERCENTAGE / P.U	
26	POSITIVE SEQUENCE SUSCEPTANCE (B1)	MOHS	
27	POSITIVE SEQUENCE SUSCEPTANCE (B1) ON BASE MVA	PERCENTAGE / P.U	
28	ZERO SEQUENCE RESISTANCE (R0)	OHM	
29	ZERO SEQUENCE RESISTANCE (R0) ON BASE MAVA	PERCENTAGE / P.U	
30	ZERO SEQUENCE REACTANCE (X0)	OHM	
31	ZERO SEQUENCE REACTANCE ON (X0) BASE MAVA	PERCENTAGE / P.U	
32	ZERO SEQUENCE SUSCEPTANCE (B0)	MOHS	

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSMISSION LINE NUMBER
33	ZERO SEQUENCE SUSCEPTANCE (B0) ON BASE MVA	PERCENTAGE / P.U	
34	NUMBER OF TOWERS OF TRANSMISSION LINE	NUMBERS	
35	TYPE OF TOWERS	TYPE (S)	
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	

CC. Appendix -21

POWER TRANSFORMER DATA

NAME OF GENERATOR SWITCH YARD / GRID STATION: ______________________________

LOCATION OF GENERATOR-SWITCH YARD / 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	BASE VOLTAGE	KV	

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSFORMER NUMBER
33	BASE MVA	MVA	
34	POSITIVE SEQUENCE IMPEDANCE AT OWN BASE AND MAXIMUM TAP	%AGE	
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	MVA1-2	
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	MVA1-3	
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	MVA2-3	
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	

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSFORMER NUMBER
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	
64	EARTHING PRIMARY	OHM	
65	EARTHING SECONDARY	OHM	
66	CT USED FOR CURRENT MEASUREMENT	AMP	
67	MAGNETIZING CURVE	ATTACHED / NOT ATTACHED	
68	TABLE OF CURRENT AND VOLTAGE WITH RESPECT TO TAP POSITION	ATTACHED / NOT ATTACHED	

CC. Appendix -22

BUSBAR DATA

NAME OF GENERATOR SWITCH YARD / GRID STATION: ______________________________

LOCATION OF GENERATOR-SWITCH YARD / GRID STATION: ___________________________

S. No	DESCRIPTION	MEASUREMENT UNITS	BUSBAR NUMBER
	AC SUB STATIONS		
1	BUS BAR SCHEME USED FOR BUSBAR (i.e., DOUBLE BUS BAR BREAKER AND HALF, TRANSFER BUS, SINGLE BUSBAR SINGLE BREAKER ETC)	NAME	
2	BUSBAR TYPE	SOLID BARS / HOLLOW TUBE, RECTANGULAR, ROUND, ETC	
3	CONDUCTOR / TUBE NAME FOR BUSBAR	NAME	
4	MATERIAL OF CONDUCTOR (i.e., COPPER, ALUMINIUM, ALLOY ETC) USED FOR BUSBAR	NAME	
5	AMPERE CAPACITY OF BUS BAR BUSBAR	AMP	
6			
	HVDC CONVERTOR STATION		
7			
8			

CC. Appendix -23

CIRCUIT BREAKER DATA

NAME OF GENERATOR SWITCH YARD / GRID STATION: ______________________________

LOCATION OF GENERATOR-SWITCH YARD / 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 C. B	SF6, AIR PRESSURIZED, OIL, VACCUM ETC	
5	OPERATING MECHANISM USED FOR C. B	HYDRAULIC. PNUMETIC, MOTOR, SPRING ETC	
6	NO OF INTERRUPTURE PER POLE OF C. B	NUMBERS	
7	C.B 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 C. B	SF6, AIR PRESSURIZED, OIL, VACUUM ETC	
19	OPERATING MECHANISM USED FOR ___ KV C. B	HYDRAULIC. PNEUMATIC, MOTOR, SPRING ETC	
20	NO OF INTERRUPTURE PER POLE OF ___ KV C. B	NUMBERS	
21	___ KV C.B COMMISSIONING DATE	DATE	
22	___ KV C.B ASYMMETRICAL FAULT RATING	AMPERE	
23	___ KV C.B SYMMETRICAL FAULT RATING	AMPERE	
24	___ KV C.B RATED IMPULSE STANDING VOLTAGE	KV	
25	___ KV C.B RATED NORMAL CURRENT RATING	AMPERE	
26	___ KV C.B CT RATIO USED FOR PROTECTION	RATIO OF AMPS	
27	___ KV C.B CT RATIO USED FOR METERING	RATIO OF AMPS	

S. No	DESCRIPTION	MEASUREMENT UNITS	BREAKER NUMBER
28	CURRENT MEASURING DEVICE TYPE USED FOR ___ KV BREAKER		
29			
30	ANY OTHER INFORMATION REQUIRED BY THE TNO OR the SO.		
31			

CC. Appendix -24

ISOLATORS DATA

NAME OF GENERATOR SWITCH YARD / GRID STATION: ______________________________

LOCATION OF GENERATOR-SWITCH YARD / 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, VACCUM ETC	
5	OPERATING MECHANISM	HYDRAULIC. PNUMETIC, MOTOR, ETC	
	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, VACCUM ETC	
4	OPERATING MECHANISM USED FOR ___ KV ISOLATOR	HYDRAULIC. PNUMETIC, MOTOR, ETC	
5	TYPE OF ___ KV ISOLATOR (VERTICAL, HORIZONTAL PENTOGRAPH, etc.,)	NAME	
6	___ KV ISOLATOR COMMISSIONING DATE	DATE	
7	___ KV ISOLATOR AMPERE CAPACITY	AMPERE	
	ANY OTHER INFORMATION REQUIRED BY THE TNO OR SO.		

CC. Appendix -25

SHUNT REACTORS DATA

NAME OF GENERATOR SWITCH YARD / GRID STATION: ______________________________

LOCATION OF GENERATOR-SWITCH YARD / 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	HENERY	
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 (C.B "or" ISOLATOR)	NAME	
10	REACTOR CONTROLLING BREAKER / ISOLATOR ID	CODE NO	
11	ANY OTHER INFO REQUIRED BY THE TNO OR SO.		

OPERATION CODE

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 System Operator (SO) and Code Participants in the operation of the National Grid. The System Operator 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 System Operator are subject to the conditions as specified in the System Operator license, 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 System Operator 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 co-ordination 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;

(d) Adequate reactive reserve management and voltage regulation must be carried to meet the operating standards stated in OC 5 of the operation sub code System Services 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 System Operator and Code Participants using devices as described in the operation sub code Operational Communication and Data Retention OC 9;

(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 the operation sub code System Recovery OC 12;

(i) The System Operator 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 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(s) 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 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 Systems, Remedial Action Schemes) designed to mitigate the extent of disturbance resulting from a system event / contingency as established in this Grid Code.

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. Demand Forecast will include forecast for Active and Reactive Power.

OC 2.1.2. Demand Forecasts and reporting will 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 will 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 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.

OC 2.3. **Scope**

OC 2 applies to the SO and:

(a) TNOs;

(b) DNOs;

(c) Suppliers;

(d) Transmission Connected Consumers;

(e) Interconnectors; and

(f) Energy Storage Units in respect of their demand (energy planned to take 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 web site) 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 OC2.4.1;

(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 10MW 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, 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 DNO (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 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.

(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 OC2.5, 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 will 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 will 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 will 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:

(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 will 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 will be assessed based on the mean absolute percentage error (MAPE) indicators and values provided for different

Planning Horizons in Table OC 2-1. A similar assessment will be done for demand forecasts by the SO.

Table: OC 2-1: 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 will 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 2-1 at least three (3) times during a six (6) month, for NEPRA evaluation and applicable measures or regulations.

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) DNOs;

(b) TNOs;

(c) Suppliers;

(d) Transmission Connected Consumers; and

(e) 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. During Demand Control, Economic Generation Dispatch shall cease and shall not be re-implemented until the SO has determined that it is safe to do so.

OC 3.5.3. 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 3.5.4. 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 3.5.5. 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

(d) maintaining voltage on a specified node above a certain threshold.

OC 3.5.6. Where reasonable notice time for Demand Control is available, the SO will 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) will be implemented. The SO and Users shall co-operate 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 3.5.7. 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. The Users will each adhere to the specified procedures (and will co-operate in forming such procedures) to provide that Demand Control can be exercised rapidly when required, in accordance with the SO's instructions.

OC 3.5.8. In the event that Demand Control exercised under OC 3.5.7 is expected to be sustained, then the relevant DNO(s) and TNO(s) will arrange to gradually shift towards planned Demand Control schedule, as soon as it is practicable.

OC 3.5.9. 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 reconnect Demand without the SO's instructions.

OC 3.5.10. 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 3.5.11. 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 3.5.12. 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 (11kV 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 practicable, 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 will be split into discrete MW blocks. The number, location, size and the associated low Frequency settings of these blocks, will 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 will 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; and

(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 will 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 will 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 will 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 blocks of Demand subject to automatic Frequency restoration.

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(s), 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 of the Users.

OC 3.8.3. As and when required by the SO, the Users will cooperate with the SO in the design and implementation of ALVDD at locations on the Users, where the requirement is indicated, in accordance with OC 3.8.2. The SO will retain full control over the enabling/disabling of the ALVDD, and the Voltage settings at which ALVDD will be initiated in each circumstance.

OC 3.8.4. In general, the settings will be specified by the SO by week 28 in every three calendar years (but not limited to) 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 will specify the functional capabilities for low voltage demand disconnection, in co-ordination with Users, on a site-specific basis. It will 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 will 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 involuntarily disconnection (manually or automatically) of any Facility of any User when it determines that the Transmission System might or could become incapable of providing the required services as mandated in its license. Users shall provide appropriate facilities to the SO for fast disconnection of load as per System requirements such as Automatic Demand Control System (ADCS).

OC 3.9.2. Quantum of Demand and specific 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 in 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.

OC.3 APPENDIX-A

EMERGENCY MANUAL DEMAND REDUCTION/DISCONNECTION SUMMARY SHEET

Name of Company/ Code Participant/ Transmission Connected Consumer:

Peak Demand [Year] MW

(132 & 66kV Radial Lines, 132/11kV & 66/11kV 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.

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.

OC 4.3. **Scope**

The scope of this sub code applies to the SO and:

(a) Generators;

(b) Transmission Network Operators;

(c) DNOs;

(d) Transmission Connected Consumers;

(e) Interconnectors; and

(f) 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 GC 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 Unit(s) concerned;

(b) MW unavailable (and MW that will still be available, if any, notwithstanding the Outage);

(c) expected duration of the Outage;

[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.

(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 in their 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 that the proposed Outage is inflexible, the SO will 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.

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 Unit(s)/Interconnector(s) 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 will 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 Unit(s)/Interconnector(s) 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 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 will 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 will 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.

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 reason(s) for the delay in the return of the Generator/Interconnector to service and a best estimate of the date and time at which it will 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 reason(s) 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.

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 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 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.

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 reason(s) 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.

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.

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.

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.

OC.4 Appendix - D, E, F

TRANSMISSION OUTAGES

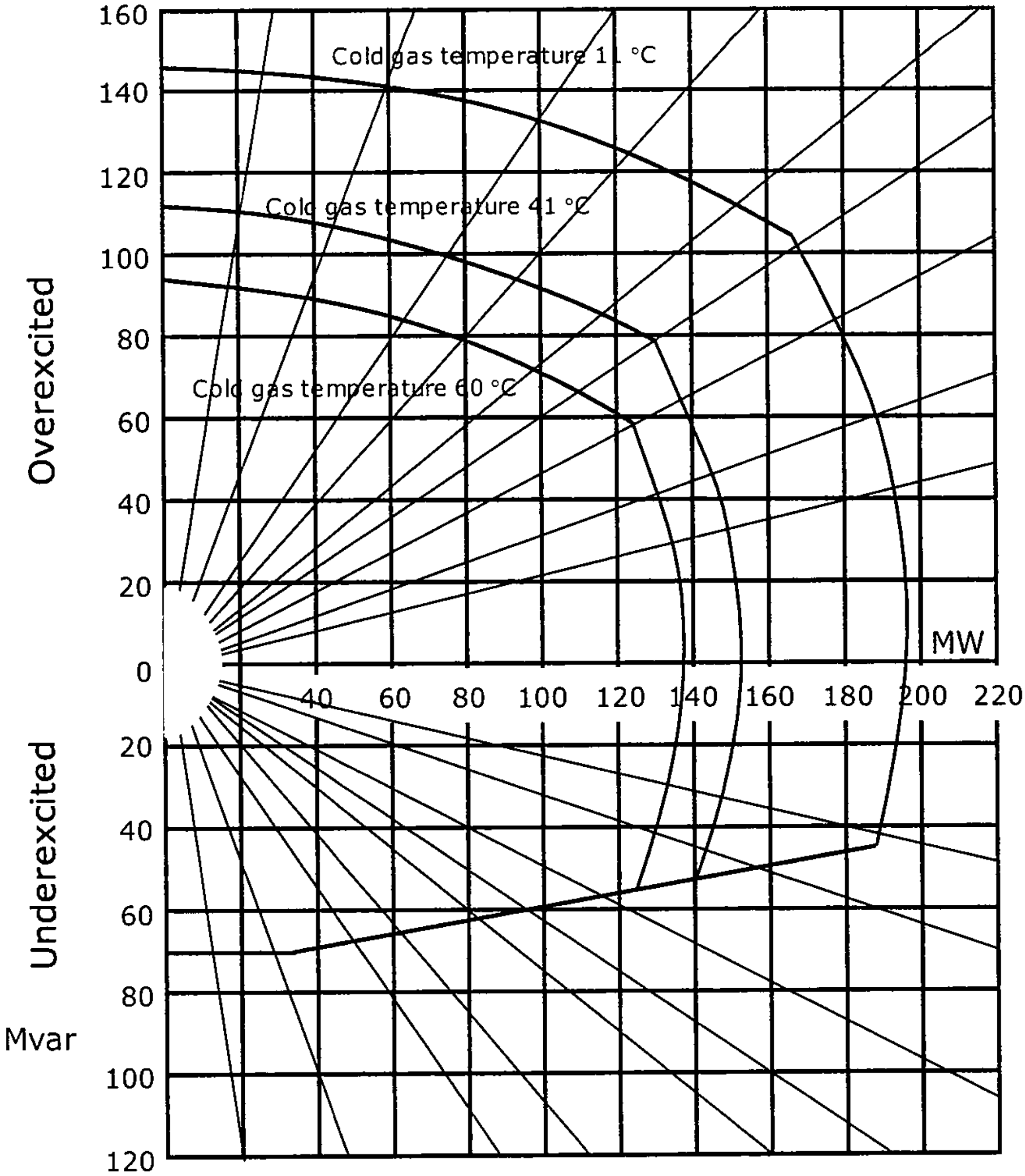
Primary or bulk and secondary transmission outages

This appendix should be completed by System Operator in consultation with the generators and other relevant stakeholders.

Appendix – G

Generator Performance Chart, Example

Rated Apparent Power	S_NMVA	Rated Frequency	f_N = 50 Hz
Rated Active Power	P_N MW	Power Factor	P.F. = 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



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

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.

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.

OC 5. SYSTEM SERVICES

OC 5.1. Introduction

OC 5.1.1. This sub code 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; and

(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 to the following Users:

(a) Generators;

(b) Energy Storage Units;

(c) DNOs;

(d) Transmission Network Operators;

(e) Interconnectors;

(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 System Operator shall co-ordinate with all the Users connected to Transmission System in order to maintain the declared system frequency at 50 Hz (Cycles/sec) with the following allowance excursions:

(a) Declared or Target System Frequency shall be 50Hz ± 0.05Hz.

(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 means the maximum expected absolute value of an instantaneous frequency deviation 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 49.30 Hz or rises above 50.5 Hz.

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.5-1: 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; and

(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 initiated by Free Governor Response or other responses including peaking of Combustion Turbine Units, condensate stop;

(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.

(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.

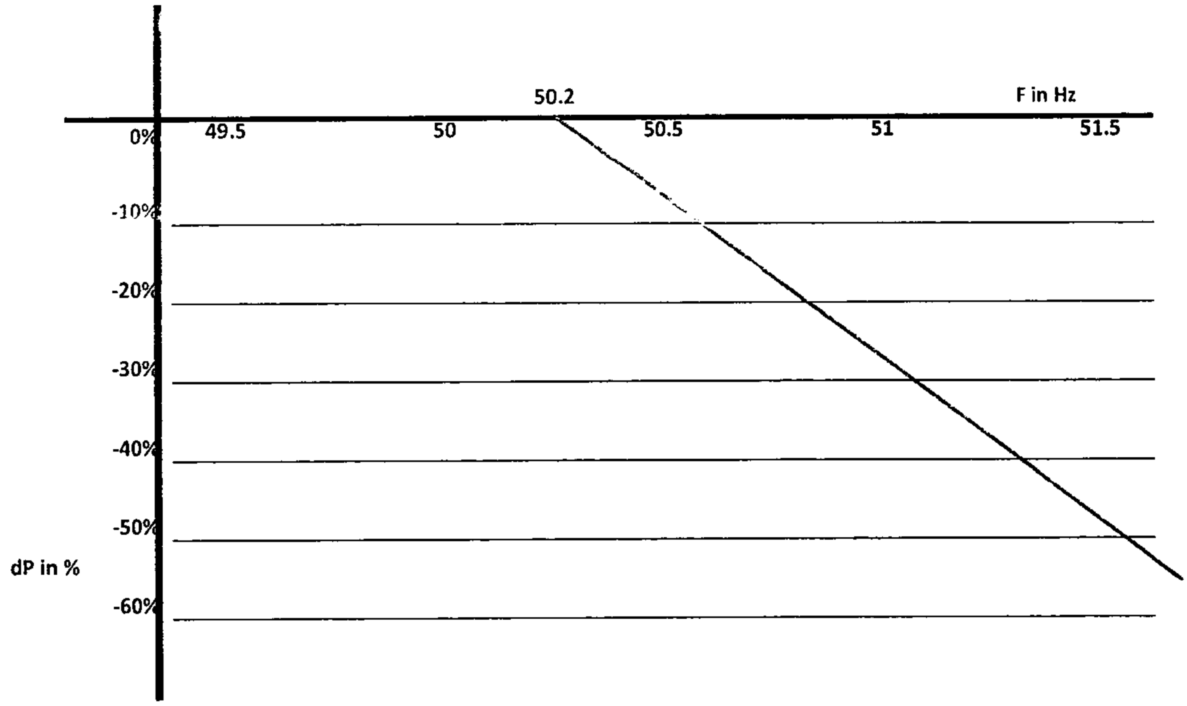
OC 5.4.7.5. In the event that the SO either agrees to a restriction on governor action or instructs such a restriction, the SO shall record the nature of the restriction, the reasons, and the time of occurrence and duration of the restriction in the operation or dispatch reports.

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. 5-1 below:

Figure OC.5-1: 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 5.4.8.5 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. ESUs 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 Non-Synchronous Generators in advance;

(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. Primary 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 +/- 0.05Hz.

OC 5.4.9.5. Interconnectors shall not act to control the frequency in an Other 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:

(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; and

(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 5.4.9.7. 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:

(a) 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

(b) in order to (acting in accordance with Good Industry Practice) secure the reliability of the Interconnector, in which case the Interconnector shall inform the Reference SO of the restriction without undue delay; or

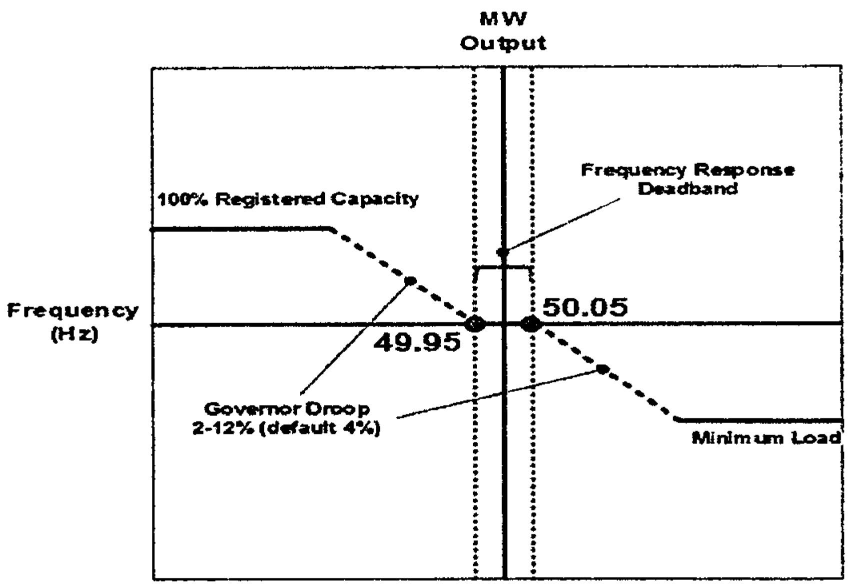
(c) the restriction is agreed between the Reference SO and the Interconnector in advance; or

(d) the restriction is in accordance with a Dispatch Instruction given by the Reference 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.5-2. Primary Frequency Control



OC 5.4.9.9. 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 Agreement(s).

OC 5.4.10. Secondary Frequency Control

OC 5.4.10.1. Frequency deviations, outside the levels specified in OC 5.4.4.1 (b) such as those that may occur on the loss of Generating Unit(s), Interconnectors, Demand or other MW input into the Transmission System or the Distribution System are corrected through the use of Secondary Frequency Control.

OC 5.4.10.2. 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.

(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 5.4.10.10. 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 5.4.10.11. In the event that the Generator or Interconnector (acting in accordance with Good Industry Practice) considers that it is necessary to secure the reliability of a Generating Unit or Interconnector, or for the safety of personnel and/or Plant, to prevent a Generating Unit or Interconnector from operating under AGC, then the Generator or Interconnector shall inform the SO of this without delay, requesting its authorization for this change its operating mode. Generators and Interconnector shall inform the SO of the justification for not operating the Generating Unit or Interconnector 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 Unit(s). When the problem has been rectified, the Generator or Interconnector shall contact the SO to arrange for the Generating Unit or Interconnector 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 5.4.10.12. The SO may issue a Dispatch Instruction to a Generator or Interconnector to prevent a Generating Unit or Interconnector (equipped with AGC) from operating under AGC, in accordance with SDC 2.

OC 5.4.10.13. Generating Units or Interconnectors 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 5.4.11. 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 5.4.11.1. 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 GC, 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 straight line with unity decay from 10% of Registered Capacity at 90% output to 0 at 100% output

OC 5.4.11.2. 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 which must be available to Synchronize with the System within a time scale as specified by the SO while preparing Indicative Dispatch Schedule (IOS) as per SDC 1.

OC 5.4.12. Operating Reserve Policy

OC 5.4.12.1. 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 GC, the SO shall establish, and maintain permanently updated, an SOP (The "Operating Reserve Requirements" SOP) 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 SOP 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 5.4.12.2. The SO shall submit the SOP, and its amendments, to NEPRA for review of consistency with the approved GC. The SO shall publish the SOP, including its updates, in its website, keep records of each modification to the Operating Reserve policy so determined under OC 5.4.12.

OC 5.4.12.3. 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.5-2: 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 "Operating Reserve Requirements" SOP. Until such SOP 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 "Operating Reserve Requirements" SOP. Until such SOP is developed, equal to the largest Generating Unit

Name	Timescale	Description	Type of Operating Reserve	Participants	Quantum
Tertiary Frequency Control	20 min-4 hrs	Re-dispatch/ Synchronization	Replacement Reserve	Re-dispatch/Synchronization of Generators to restore Primary and Secondary Reserves	As per the "Operating Reserve Requirements" SOP. Until such SOP is developed, equal to the largest Generating Unit
	24 hr ahead to real time		Contingency Reserve		

OC 5.4.13. Responsibilities of the SO in Respect of Operating Reserve

OC 5.4.13.1. 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 "Operating Reserve Requirements" SOP updated from time to time.

OC 5.4.13.2. 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 assignations of 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 5.4.13.3. 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 5.4.13.4. 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 5.4.13.5. 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 "Operating Reserve Requirements" SOP.

OC 5.4.13.6. 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 5.4.13.7. Action required by Generators/ESU in response to Low Frequency Events:

(a) If System Frequency falls to below 49.95Hz, 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 5.4.10.11.

OC 5.4.13.8. 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 5.4.13.9. 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 Agreement(s) between the Interconnector and the SO. Actions required by an Interconnector shall be governed by the corresponding Interconnection Agreement.

OC 5.4.13.10. 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.

(b) Any such action shall be in accordance with the relevant Agreement(s) between the Interconnector and the SO.

OC 5.4.13.11. 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 Agreement(s).

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 controlled 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.

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. 5-3. 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.5-3: 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) from bulk Transmission System to 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 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 Agreement(s). 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 reason(s), 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 Station(s) 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 subsection 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.

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.

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, not to 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 review and applicable regulations by 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.

OC 6.3. Scope

The scope of this OC 6 applies to SO and:

(a) TNOs;

(b) Generators connected to the Transmission System;

(c) DNOs;

(d) Transmission Connected Consumers;

(e) Interconnectors;

(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 GC 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;

(d) The voltages at all transmission nodes are within the limits as specified in OC 5.5.7;

(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(s) 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 bi-pole 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 of -5 to +8% of Nominal System Voltage during N-0 conditions but within the limits of ±10% of the Nominal Value;

(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 of ±10% of the Nominal Value; 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 subject to 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 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 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

(c) be operated on the principles of SCED and Optimal Power Flow while maintaining stability and reliability.

(d) be operated to minimize system operating costs (including generation, transmission costs) while maintain 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 have available and shall 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 countermeasure(s) 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; or

(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 Users shall establish loading limits for each transmission line. 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)

(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.6-1 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	0.61m/s	0.61m/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

[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.6-1:

(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

manufacturers. Also, pre-load conditions shall be taken into account to determine loading limits in real time.

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.

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 Agreement(s). 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 Unit(s) or VRE plants or ESUs or any Apparatus shall give the SO at least thirty-six (36) calendar months' notice of such action, a 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 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 license, 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) A 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.

(j) Any disconnection of a User from Transmission System requested by relevant TNO will 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(s) 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) Busbar section fault

(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(s) 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(s) to provide Black Start Facility for system recovery. For avoidance of doubt, the provisions of OC 6.11.5 are applicable to User(s), 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.

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 Line 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 Agreement(s) 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 11kV 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)

(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).

(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.

(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, with its best endeavor, avoid any disturbances from the AC system outside Converter Stations which interfacing with the HVDC System may result in fluctuation of the HVDC transmission power, consequences of such disturbance shall be dealt with in accordance with relevant Connection or Interconnection Agreement(s).

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 Agreement(s).

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 Agreement(s).

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) specify 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 User(s) 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 Agreement(s).

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 Agreement(s).

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 Agreement(s).

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.

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 to:

(a) Generators (CDGUs or Embedded);

(b) ESUs;

(c) Interconnectors;

(d) TNOs;

(e) DNOs; 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 User(s) on whose System(s) 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 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 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;

(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, as soon as possible but not 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; and

(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.

OC 8.6.5. The final Significant Incident Report shall include recommendations on future actions to be taken, including proposing modifications to this GC or SOPs, aiming to avoid that similar Significant Incidents may occur in the future.

OC 8.6.6. Both the preliminary and final Significant Incident Report shall be published in 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 5th of every month. These reports shall include an evaluation of the Operations, Events, Significant Incidents, and any other problems that occurred on the Transmission System 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 in 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 month(s) or the year. The reports shall be published in the SO website.

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.

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 Agreement(s)) 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 Agreement(s)) 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.

(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 (DNOs) (in respect of their substations and communication services);

(d) Transmission Connected Consumers;

(e) Interconnectors;

(f) ESUs;

(g) Embedded generators whether represented through Aggregator or otherwise. The Embedded Generators to which this GC will apply shall be determined as per the relevant applicable NEPRA regulations.

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 Section 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 Centre(s) 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 Section 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 Section 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(s) 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(s) of the User. The Responsible Operator(s) shall be of suitable experience and training and are 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 Section OC 9.5.

OC 9.5.2. All equipment to be provided by Users under this Section 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 Centre(s), will be borne by the relevant User(s).

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 Centre(s) 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 User(s).

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 Connection Code 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 (temporary) 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.

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 Center(s) and the Users sites. The communication systems shall provide redundant channels for direct telephone, facsimile and data links between the SO (Main and Back Up Control Centers) and User facilities.

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 Back up 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 it corresponds to.

OC 9.5.4.6. Specifications for remote telemetry equipment, communication system requirements and protocols, and technical assistance required to connect Users' facilities with the SO SCADA system shall be as per applicable Authority's standards and specifications pursuant to Clauses 34 and 35 of the Act.

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 Centre(s).

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 device(s) shall be provided at the SO control centers to record all dispatch transactions and communication with the Users 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 disputed 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 fault(s).

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 Section 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 Centre(s). 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

Time will be set by a standard determined by the SO. 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. Any Day Light 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 by SO from time to time.

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 Users 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's 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 Operator(s)/ Load Dispatch Centre(s). The communication flow and operating procedures between the SO and Cross-Border SO/LDC shall be governed by the relevant (Interconnection) Agreement(s).

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 tele 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.

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 so 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.

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 impinge on either or both of:

(a) the SO's responsibilities in respect of the Transmission System, including Dispatch of Generation, Interconnectors and DNO MW Availability; 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 Transmission System and the Systems of other Users, it is necessary that tests which affect the operation of the Transmission System or Users' Systems as under OC 10.1.2 are subject to central co-ordination 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 co-ordination 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; or

(b) have a significant effect on the operation of the Transmission System or a User System; or

(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, operating and performance requirements as specified in the Grid Code and in relevant Agreement(s), 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 to:

(a) Generators with units with Registered Capacity greater than 10 MW and Generator Aggregators;

(b) Energy Storage Units (ESUs);

(c) Interconnectors;

(d) Transmission Network Operators; and

(e) Distribution Network Operators (DNOs).

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 co-operate 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 Users' 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(s) 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 licensee 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.

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 or impacts of the test.

OC 10.7.2. The Test Proponent 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 test(s).

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 Proponent, 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 Proponent, 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 Proponent, and the Affected Users;

(b) an invitation to nominate representative(s) for the 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 person(s) 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 Proponent and the Affected Users shall nominate their representative(s) to the Test Group within one (1) week after 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 asking the time. If the User still does not nominate its representative, the SO may decide to proceed with the proposed test and may appoint another "independent third party expert" to the Test Group to represent the interests of that Affected User.

OC 10.8.4. The SO shall establish a 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 Proponent.

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 Proponent and making necessary modifications to come up with the final Test Procedure; (iii) the possibility of scheduling the proposed test simultaneously with any other test(s) and 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 Proponent 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 Proponent, 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 Proponent has notified the SO that Operational Tests are required in accordance with licensee 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. If the proposed Test Program is acceptable to the SO, the Test Proponent and the Affected Users, the final Test Program shall be prepared and notified to the SO, the Test Proponent, and the Affected Users, 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 Proponent 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 Proponent 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 Proponent 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 Proponent, 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 Proponent 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 Proponent shall be responsible for preparing a written report on the Operational Test (the "Final Report") which shall be available within three months of the conclusion of the Operational Test to the SO, the Test Group, Affected Users and the 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.

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/Interconnectors 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, Users' Connection Agreements, Ancillary Service Agreements;

(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 to:

(a) Generators, which, for the purposes of OC 11, include all Generators with Generating Unit(s) subject to Central Dispatch or with Generating Unit(s) that have a total Registered Capacity greater than 10 MW on a single Site;

(b) Interconnectors;

(c) Energy Storage Units (ESUs);

(d) Transmission Connected Consumers;

(e) Transmission Network Operators;

(f) Distribution Network Operators (DNOs).

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 Monitor 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)

(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 both at the onsite Fuel storage location and if required at the Off-Site Storage Location;

(f) any other Test(s) SO may consider necessary for fulfillment of its licensed obligations and Grid Code requirements;

(g) All costs associated with the Test(s) shall be borne by the respective User(s) unless stated in NEPRA Regulations otherwise.

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 performance of the User's Facility under test 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 SOP 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

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 in 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 representative(s) 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 Plant 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.

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 and shall re-energize HVDC control system.

OC 11.5.10.3.4. The HVDC Converter station at the rectifying end is started and energizing the DC transmission line.

OC 11.5.10.3.5. The inverter end of the HVDC link is started and energizing a 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 GC 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, Connection Agreement.

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) Non-compliance by a User with Connection Code;

(f) any other case of non-compliance by a User to the GC;

(g) Failure to follow the routine testing of the Black Start Facility by a User will be considered as non-compliance and the User shall be penalized by the Authority;

(h) In addition to routine testing of Black Start Facility, if a User, designated with Black Start Facility, fails to supply the system during emergency situation of System Restoration, the respective User shall be penalized by the Authority without any attribution to the SO.

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 con-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, 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 the 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 DNO failed to comply with three (3) Dispatch Instructions in one calendar month period, then the SO shall notify the DNO of the continued non-compliance. The 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 DNO is in breach of the Grid Code, for NEPRA to review and applicable NEPRA regulations.

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 Turbine(s) or Auxiliary Diesel Engine(s) 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.

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 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 co-operate 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 (TNOs);

(e) Distribution Network Operators (DNOs);

(f) Suppliers and BPCs directly connected to transmission DNO; and

(g) 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.

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 Agreement(s). 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.

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, co-operate 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 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 Agreement(s).

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 (islanded), 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 Operator (s) 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.

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 (66kV 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 approved Safety Rules and procedures 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 rules and procedures as laid down in the NEPRA approved Safety Codes, 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 Rules on the Transmission Network Operator(s) or Users, and does not replace the safety rules 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 approved safety rules, 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 to the following Users:

(a) Generators;

(b) Interconnectors;

(c) Transmission Network Operators;

(d) Distribution Network Operators;

(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 NEPRA approved 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 NEPRA approved Safety Codes, 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 above 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 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.

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 User(s)

(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 co-operate 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 cancellation of all safety documentation.

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.

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)	________	☐	☐	☐	☐

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 _______________________________________

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)	_________	☐	☐	☐	☐

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 _______________________________________

SCHEDULING AND DISPATCH CODE

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 System Operator (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 Integrity, 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 (CDGUs):

(i) Conventional Generator (thermal, hydro, nuclear, bagasse, and concentrated-solar Generators (CSP), etc.) directly connected to the Transmission System; and

(ii) VRE Generator (run-of-the-river hydro, solar, and wind, etc.) directly connected to the Transmission System

(iii) 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 in its web page a list of such Generating Units along with the reasons which justify considering them CDGU.

(b) 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.);

(c) Market Operator (MO);

(d) Transmission Network Operators;

(e) Interconnectors;

(f) Distribution Network Operators and Transmission Connected BPCs); and

(g) Embedded Generators whether represented through some Aggregators or any other arrangement approved by NEPRA (if required by SO). The Embedded Generators to which this GC will apply shall be determined as per the relevant applicable NEPRA regulations

(h) The Special Purpose Trader (SPT).

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. 2-1. The SO will use this forecast 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 will 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, with requisite levels of Operating Reserve, Minimum Demand Regulation capability, System Stability requirements, and other System (Ancillary) 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.

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 will 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 will 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 as well as any agreement between the SO and a particular User. 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 change(s) 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 will develop Indicative Operation Schedule (IOS) for the following Schedule Day and shall publish this Schedule according to the provisions of Commercial Code and this Grid Code.

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 may be the case) 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 Commercial Code.

SDC 1.5.2. Contents

SDC 1.5.2.1. Generating Unit(s) 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 Unit(s), 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 Agreement(s) 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 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 SDC1 had its Generating Unit been declared Available.

SDC 1.5.2.12. Generators shall ensure that their Generating Unit(s) are maintained, repaired, operated, and fueled using Prudent Industry Practices and are always compliant with any legal or regulatory requirements with a view to providing the power delivery, System (Ancillary) Services as applicable, Declared Available Capacity, and the Technical Parameters.

SDC 1.5.2.13. Generators shall maintain a fuel stock (for stock able 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 Regulations for Generation.

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.

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 Unit(s) 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:

(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 SDC1.

(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.

(d) 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 GC 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, reason(s) 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 of 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 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 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 the Authority, with copy to the Market Operator, any non-compliance with the availability information requirements.

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 the 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 SPT. In order to determine the Variable Operating Costs, the SPT 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.

(c) 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, SPT or Aggregators, as the case may be, the requested information shall be uploaded in the Market Operator's IT system and the Market Operator will transfer this information to the SO. The SO will inform in its website when it has the IT systems ready to receive directly these Variable Cost Notice from Generators and the SPT.

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 Appendix E 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 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 in 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 1.6.2. **Contents**

SDC 1.6.2.1. Where a Generating Unit is capable of firing on multiple fuels, the Generator, SPT or Aggregator, as the case may be, shall submit a Variable Cost Notice in respect of each designated fuel for its Generating Unit(s), identifying clearly to which particular designated fuel the Variable Cost Notice relates to.

SDC 1.6.2.2. Generators, Aggregators, the SPT 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/Aggregators/Interconnector/SPT requesting correction or clarification and confirmation of the submitted data. The relevant Generator/Interconnector/SPT 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 the Variable Cost Notice and potential concerns, with copy to the Market Operator. The Authority will review the information provided by the SO and may require additional information from the relevant Generator/Aggregators/Interconnector/SPT to evaluate and decision making on the appropriate actions.

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. **Default Variable Operational Cost**

SDC 1.6.3.1. 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/Aggregators/Interconnector/SPT 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/SPT 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/SPT 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 NEPRA evaluation and decision making by the Authority. In accordance to applicable regulations and license conditions, the Authority may require additional information from the Generator/Aggregators/Interconnector/SPT and/or inspect the generation facilities.

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 SDC1, 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;

(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 OC10 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 PPAs 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 SPT in a report Dispatch Constraints for legacy PPAs, with copy to NEPRA. The report shall describe for each legacy PPA 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 SPT 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.

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 License 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.

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 issue 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 will be regular and revised NIOMs may be sent out from time to time. These will reflect any changes in the declared Availability which have been notified to the SO and will reflect any Demand Control which has also been notified. They will 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 SOPs.

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 requested 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.

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	✓							

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	✓	✓	✓	✓				

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 tank(s)" 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; and
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
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						

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:

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:

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:

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:

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:

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:

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: ___________________________________

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.

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:

$$APE_t = \left| \frac{(At + Xt) - Ft}{C_t} * 100 \right|$$

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.
C_t is the difference between contracted capacity and capacity under maintenance in time block t.

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.

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.Capaciity					

Start up Costs	Fuel 1	Fuel 2
	Rs	Rs
Cold Start		
Warm Start		
Hot Start		

Notes: The Fuel Costs shall be estimated by the Generator / SPT, as it corresponds
The Operational Costs shall be determined based on the formulas contained in the relevant PPA

The variable O&M Costs shall be those approved by the Authority in its latest tariff determination for the relevant Generator

The start up costs shall be those contained in the relevant PPA, duly corrected by the estimated price of fuel.

Signature____________________

_______Name________________

Position: Commercial Engineer/ Control Engineer (delete as applicable)

Date/Time of issue:

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		

Start up 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 start up costs shall be determined by the Generator.

Signature______________________
________Name__________________
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

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 Interonnection Agreement(s)]

BiWeekly Declaration of Variable Operational Cost

From: _[Interconnector xxxx]
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ______________ Dated: ____________

	Variable Operationl 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:

For the period starting at [DD/MM/YYYY] and ending at [DD/mm/YYYY]

[To be used by Generators contracted or by the SPT of 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 Purchaser(s)	
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	*[clearly describe the any*	*[Indicate the additional cost*

which may restrict the liberty of the SO to decide the dispatches.	*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.]*	*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]*

Signature____

Name____________________________

Seller / Purchaser ____________________

Position: ___________________________

Date/Time of issuing: ________________

SDC 2. DISPATCH AND CONTROL

SDC 2.1. Introduction

In real time operation, the System Operator (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 the following TNOs/Users:

(a) Centrally-Dispatched Generating Units (CDGUs):

(i) Conventional Generator (thermal, hydro, nuclear, bagasse, and concentrated-solar power Generators (CSP), etc.) directly connected to the Transmission System; 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 control. The SO shall publish in its web page a list of such Generating Units along with the reasons which justify to consider them CDGU. Energy Storage Units with respect to their supply to or demand on the Transmission System;

(c) Transmission Network Operators;

(d) Interconnectors;

(e) Distribution Network Operators and Transmission Connected Consumers; and

(f) Embedded generators whether represented through some Aggregators or any other arrangement (if required by SO). The Aggregators to which this GC will apply shall be determined as per applicable NEPRA regulations.

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 User(s) 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 Unit(s);

(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. To add clarity, some examples of forms of and terms to be used by the SO in issuing Instructions are set out in the Appendix-A 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-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 (HVAC/HVDC) 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 Agreement(s).

(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 Agreement(s).

(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 Unit(s) 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 select for Dispatch first the Generator/Interconnector which in 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. The SO shall however, select the Unit for Dispatch, taking into account its obligations in operating the Transmission System.

(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 to 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.

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 2.5.2.1.9. A VRE Generator shall, through appropriate necessary equipment, be capable of smooth Synchronization and de-Synchronization, without causing jerk(s) on the Transmission System.

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. With mutual consent of the SO and the Generator/Interconnector, the specified time to achieve the target output in a Dispatch Instruction may vary from the Declared Technical Parameters, if practicable for the CDGU/Interconnector.

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 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.

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).

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 action(s) 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 action(s) 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 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/Interconnector 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. A new Dispatch Instruction may be subsequently given (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 Instruction(s) 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 License 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 will 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, 50.05Hz (at an interval of 0.05 Hz).

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 operation of an agreed Low Frequency Relay, the target MW (at Target Frequency) to be provided at the Connection Point may be either at maximum MW Output or at some lower MW Output (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.

SDC 2.5.4. Dispatch Instruction to TNOs/DNOs

SDC 2.5.4.1. Dispatch Instructions to 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 a 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.

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.

SDC.2 Appendix

Dispatch Instructions for CDGUs

General

This Appendix A 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 User's 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.
h.

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 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 unless otherwise stated. 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"

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 CDGU(s) 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 (Interconnector/Embedded) shall normally follow the form, for example:
"Start/ de-block operation of HVDC pole in Q-Mode, Bi-pole Power Mode with Ground Return with Normal Voltage Mode" or

"Increase Bi-pole 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.

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.

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.

PROTECTION AND CONTROL CODE

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 the following Users:

(a) Transmission Network Operators (TNOs);

(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; and

All Users shall comply to 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 sub-station 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' substation(s)/switchyard(s) 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' substation(s)/switchyard(s) as per the standards and specifications mentioned in PCC 1.3, other sections of the Grid Code, and in the relevant Connection Agreement(s).

(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

(xviii) AVR Control Scheme

(xix) Provision for Implementation of Cross-Trip/Special Protection Scheme

(xx) Fire Fighting Equipment System

(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

(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) Below 220 kV level Users

(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 Transformer for the Protection Systems shall meet the technical standards and specifications as specified in CC 4.

PCC 2.3.2. Instrument Transformer 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 SO relevant TNO to temporarily install shunt reactors without circuit breakers, then 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 independent two (2) Nos. DC battery banks to provide independently protected and monitored DC sources for reliable Protection System(s).

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 substation(s)/switchyard(s), 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.

(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.

(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 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 (ROCOF) 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 (ROCOF) 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 (ROCOF) 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 (ROCOF) 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).

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' substation(s)/switchyard(s) 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(s)/switchyard(s).

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' substation(s)/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.

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 station(s) to complete the scheme, the same shall be procured, installed, commissioned & tested by the new User at existing User grid station(s) 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 Station(s) 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.

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 co-ordination of the interfaces between Users' facility; and shall fully co-operate 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.

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 User(s) 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 consultant(s), 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 Agreement(s) 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 cause(s). 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 Accepance 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. User(s) 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) substation(s)/switchyard(s) 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.

METERING CODE

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 Metering Service Provider (MSP) and the following Users:

(a) Transmission Network Operators (TNOs);

(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 Primary and Back-up Meters along with the associated communication equipment at 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 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.

MC 3.8.2. Notwithstanding the above, the cost of transformation and transmission lines losses shall always be with 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;

(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 clause 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) = 100-110V;

(ii) Reference frequency = 50Hz;

(iii) Nominal current (In) 1.2 In (secondary) with selectable option for 1A or 5A;

(iv) Short-time over-current shall be 20 times Imax for 0.5s;

(v) Impulse voltage withstand level = 8kV;

(vi) Power frequency withstand level = 4kV;

(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 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 10VA.

(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 30MW) 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.

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 necessary detailed 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 T-1.

Table MC T-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.

MC 4.8.3. The MSP shall be responsible for record-keeping and supervision of sealing / de-sealing activities of Metering System.

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.

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

(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 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.

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 kilo-watt (kW) and kilo-watt-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 Commercial Code. For such purpose, the MSP shall follow the provisions of the 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 User(s) and the adjusted/corrected Metering Data shall be reported to MO.

MC 5.9.2. In case MSP and the relevant User(s) do not reach an agreement, the Dispute Resolution Procedure provided in the 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 7. ROUTINE AND OFF-SCHEDULE TESTING

MC 7.1.1. MSP shall conduct Meter testing periodically at least once in every two 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 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 co-operate 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

DRC 1. **INTRODUCTION**

DRC 1.1. The Data Registration Code (DRC) presents a unified listing of all data required by the System Operator (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 following Users:

(a) System Operator;

(b) Transmission Network Operators (NGC, PGCs, RGCs, SPTLs, DISCOs, etc.);

(c) Transmission-connected Generators;

(d) Transmission-connected Consumers;

(e) Interconnectors (both AC & HVDC);

(f) Energy Storage Units;

(g) Demand Side Units (DISCOs, Suppliers, BPCs);

(h) Meter Service Provider (MSP);

(i) Distribution Network Operators (DNO)

(j) Market Operator (MO);

(k) Small/Embedded generators whether represented through some Aggregators or any other arrangement (if required by SO); and

(l) 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

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 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, Busbar Data, Circuit Beaker Data, Isolator Data, Shunt Reactor Data, Proforma for Site Responsibility Schedule (SRS), Principles and Procedures Relating to Operation

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.

DEFINITIONS AND ACRONYMS

Acronym	Meaning
AC	Alternating Current
ADMS	Automatic Demand Management System
AGC	Automatic Generation Control
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

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	Environmental Protection Agency
EPA	Energy Purchase Agreement
ESU	Energy Storage Unit
EV	Electric Vehicles
FACT	Flexible AC Transmission
FAT	Factory Acceptance Test
FGC	Free Governor Control Action
FON	Final Operational Notification
FRT	Fault Ride Through
G&TOP	Generation and Transmission Outage Program
GCOP	Grid Code Operating Procedure
GCRP	Grid Code Review Panel
GIS	Grid Impact System
GIS	Gas Insulated Substation
GPS	Global Positioning System
GSM	Global System for Mobile Communication
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
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
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
LDC	Load Dispatch Center
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
MO	Market Operator
MS	Milliseconds
MSP	Metering Service Provide
MVAR	Mega Volt-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 Desptach 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
P.F	Power Factor
P.U.	Per Unit
PC	Planning Code
PCC	Protection And Control Code
PCS	Plant Control System
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
REF	Restricted Earth Fault
RIV	Radio Influence Voltage
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 Despatch
SCR	Short Circuit Ratio
SCS	Stability Control System
SCUC	Security Constrained Unit Commitment
SDC	Scheduling and Dispatch Code
SIAS	System Impact Assessment Studies
SIC	Signals Interface Cabinets/Cubicles
SMS	Smart/Secured Metering System
SO	System Operator
SOP	Standard Operating Procedure
SPS	Special Purpose Scheme
SPT	Special Purpose Trader
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
TNO	Transmission Network Operator
TPCS	Transmission Planning Criteria and Standards
TSEP	Transmission System Expansion Plan
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

WAMS	Wide Area Management/Monitoring System
WAPDA	Water and Power Development Authority
WTG	Wind Turbine Generator
ZVRT	Zero Voltage Ride Through

Definition

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 watts 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.
Aggregators	It may represent more than one Embedded Generator.
Alert	Warning issued pursuant to OC 12.4.
Amendment	A change or modification in any provision(s) 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

Term	Definition
	Capability. The financial compensation of an ancillary service, when applicable, is established through provisions in the market Commercial Code.
Apparatus	means electrical apparatus, and includes 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).
Area Load Forecast	The load forecast prepared by the Users for their respective territories.
Authority	The National Electric Power Regulatory Authority established under section 3 of the Act.
Automatic Generation Control (AGC)	A control system installed at Generator(s) 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.
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 Unit(s) is capable of delivering at the Connection Point;

Term	Definition
	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 SDC1.
Available Transfer Capability	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.
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	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

Term	Definition
	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.
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 SDC1.

Term	Definition
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 the Code Management Scope 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	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.
Commissioning	Activities involved in undertaking the Commissioning Test or implementing the Commissioning Instructions pursuant to the terms of the Connection Agreement(s) 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	Testing of a User or an item of User's Equipment required pursuant to the Connection Conditions prior to connection or

Term	Definition
	re-connection in order to determine whether or not it is suitable for connection to the 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	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	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: "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.

Term	Definition
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)	Solar, Wind and ESPP/ESU which output can remotely be changed according to the minimum technical requirements.
Critical Loading	This refers to 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.
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 SDC2.
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.

Term	Definition
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, Demand reduction upon instruction by the System Operator.
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 Center(s).
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-

Term	Definition
	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. Comment: this expression is not used in the draft. The expression and meaning is modified to be consistent with the draft GC
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: "Distribution Facilities" means electrical facilities operating at the distribution voltage and used for the movement or delivery of electric power.
Distribution Network Operator (DNO)	Def. #2: 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

Term	Definition
	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;
Electric Power Supplier	Shall have the same meaning as the term defined in the Act and reproduced hereunder: "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.

Term	Definition
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 Unit(s), 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 can automatically act upon a remote signal to change its Active Power output.
Energy Storage Unit (ESU)	Generating Unit(s) 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: (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.

Term	Definition
	(c) Adverse weather conditions being experienced. (d) Failures of protection, control or communication equipment. (e) Risk of trip on apparatus or plant. This list is not exhaustive.
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)	Voltage of 220kV and 500kV 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 busbars, etc.
Fault Ride-Through Capability	The ability to stay Synchronized/ connected to the Power System during and following a Fault.
Firm Capacity Certificate	As defined in 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.
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.
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

Term	Definition
	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.
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 OC4.

Term	Definition
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	means Generation Facility or Generation Company as meaning assigned to the terms 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	Econometrics 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.
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.

Term	Definition
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	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	Part of an HVDC System which consists of one or more HVDC Converters installed in a single location together with 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.

Term	Definition
Imminent Overloading	The condition when the loading of transmission lines or substation Equipment is above 100 percent up to 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-breaker(s) 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 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.

Term	Definition
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 OC11, 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.
Licensee	A holder of a Licence.
Licence	means 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.
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.

Term	Definition
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	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.
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.

Term	Definition
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	means the physical location of Metering System at Connection Site
Metering Service Provider or MSP	means an entity as defined by NEPRA 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	Means 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.
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

Term	Definition
Minimum transmission voltage	Sixty-six kilovolts or such other voltage that the Authority may determine to be the minimum voltage al which electrical facilities are operated when used to deliver electric power in bulk.
Monitoring	Monitoring carried out by the SO under OC11, 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 to exclusively regulate the provision of electric power services and it extends to whole of Pakistan.
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	As defined in NEPRA Performance Standards (Distribution) Rules, 2005 (as amended from time to time) or other NEPRA applicable documents.,
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.

Term	Definition
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, license 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 provision for the use of transmission lines and/or distribution system and associated facilities with such lines or system by any licensee or consumer or a person engaged in generation subject to the payment of transmission and/or distribution as specified by the Authority.
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	Criteria of Operation explained in OC 6.
Operating Reserve	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	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 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 3 months ahead of Schedule Day.
Operational Planning	The procedure established in the sub-code OC4 of the Operation Code.
Operational Planning Horizons	Pre-Operational, Operational, Control and Post Control Phases as established in the Operation Code.

Term	Definition
Operational Tests	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 OC4 notifying 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.
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.

Term	Definition
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 OC1
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 electricity interconnected system consisting of generation, transmission and distribution systems with an independent system operation and control.
Power System Restoration Plan	An Operational Plan developed under OC 12 for restoration of System after Partial or Total Shutdown.
Power System Stabilizer (PSS)	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	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

Term	Definition
	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 fuel(s) 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 which are either: exempt from load shedding or 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	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.

Term	Definition
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 (r.m.s.) voltage occurring between two steady-state conditions, and during which the r.m.s. 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.
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	Meaning as described in PC 3.2.3
Registered Operating Characteristic	The values of Technical Parameters.
Remedial Actions	Those actions described in SDC2, which the Operator undertakes in case of emergency.

Term	Definition
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); 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	means the Metering System established to measure Energy and Load of the Code Participant at Metering Point for billing and invoice purposes.
Revision	means a comprehensive revision of, and replaces and supersedes, in its entirety, the existing Grid Code based on changes in power sector reforms, policies and technological changes recommended by Grid Code Review Panel and approved by the 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 co-ordination 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.

Term	Definition
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 fuel(s) authorized for Energy production by the Generating Unit.
Secondary Fuel Switchover Output	The MW output, not lower than 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 license within which the licensee is authorized to conduct its business.
Shaving Mode	The Synchronized operation of Generating Unit (s) to the Distribution System at an Individual Demand Site of a Demand Side Unit where the Generating Unit (s) supplies part of the DNO Demand Customer's Load.
Short Circuit Ratio	It is 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
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.

Term	Definition
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.
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 aggregated area load forecast, that the SO shall develop, after consolidating the area load forecasts provided by Users as elaborated in PC 4.1.
Special Action(s)	The action(s), 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.

Term	Definition
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 Trader (SPT)	Shall have the same meaning as described in the Commercial Code.
Special Purpose Transmission Licensee (SPTL)	A company licensed under Section 19 of NEPRA 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	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 mega-watthours (MWh).
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.

Term	Definition
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 alternator(s) 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	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 F 1 = 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 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 Operator or the SO	Shall have the same meaning as the term defined in the Act and reproduced hereunder:

Term	Definition
	"System Operator" means a person licensed under this Act to administer system operation and dispatch.
System Planning Data	Meaning as described in PC 3.
System Reliability	Ability of the system to fulfill Adequacy and Security
System Security	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	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	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.
Test Proposer	The User submitting proposal for a test under OC10.
Testing	Testing carried out by the SO or User pursuant to OC 10,11 and/or CC and the term "Test" shall be construed accordingly.
Testing and Commissioning	Testing involved during the process of Commissioning.
Thermal Generator	A 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

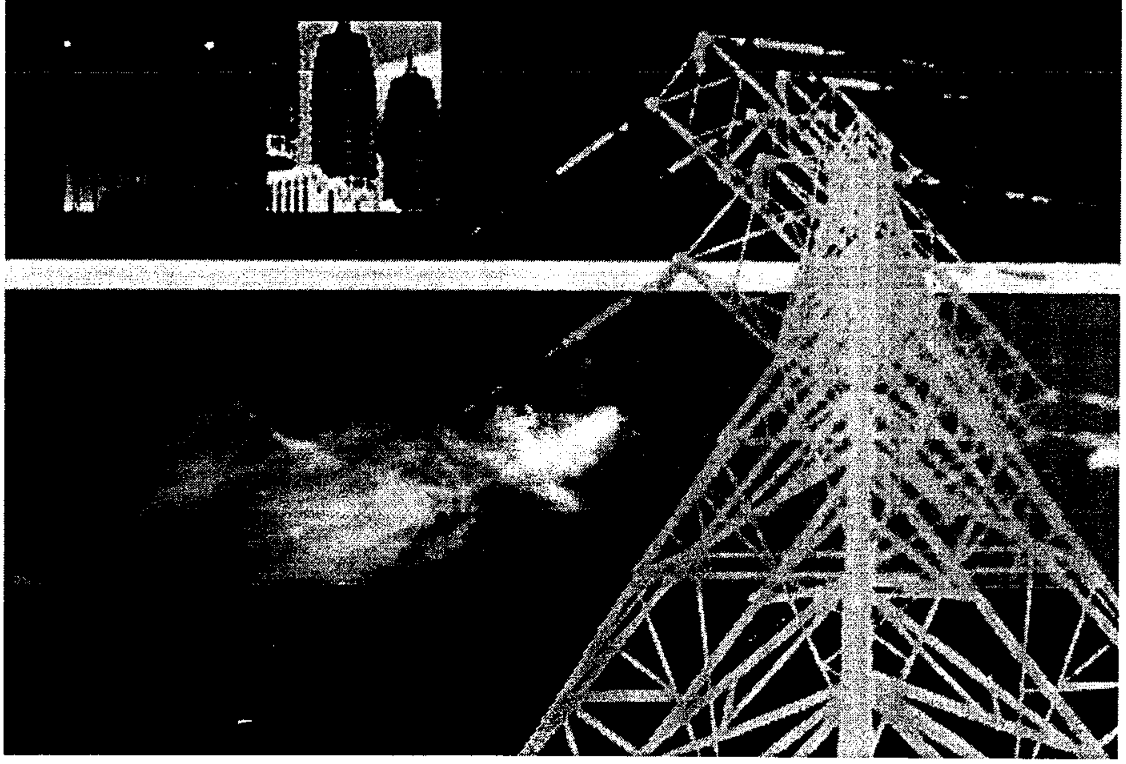
Term	Definition
	thermal rating of a transmission cable is dependent solely on its physical construction.
Total Harmonic Distortion	The departure of a waveform from sinusoidal shape, that is caused by the addition of one or more harmonics to the fundamental, and is the square root of the sum of the squares 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, that 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 the term 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. "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 license, 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 licencees for transmission of electric

Term	Definition
	power including, without limitation, electric lines, circuits, meters, transformers, sub-stations, interconnection facilities or other facilities determined by the Authority as forming part of the transmission system, operating at or above the minimum transmission voltage (66kV 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 Busbar.
Ultra-High Voltage (UHV)	Voltage above 500kV 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 be SO as a STPM.
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.
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, license 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

Term	Definition
	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 relevant section of Transmission System - nominally 500kV, 220kV, 132kV, 66kV.
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-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 TRANSMISSION
& DESPATCH COMPANY LIMITED

System Operator – Competencies and Readiness Report with CVs



COMPETENCIES AND READINESS

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SECTION 1

ORGANIZATIONAL READINESS

The roles and responsibilities of System Operator, as mentioned in NEPRA Act and other relevant documents, are already being implemented by NTDCL under its existing License. These include long-term planning, operational planning (from one year ahead to real time), maintenance coordination (both generation and transmission), real-time operation and control, calculation of Marginal Prices, reporting to NEPRA, the CPPA-G and, to the Ministry of Energy (Power Division). The hierarchy of NTDC Authority with respect to System Operations is as follows:

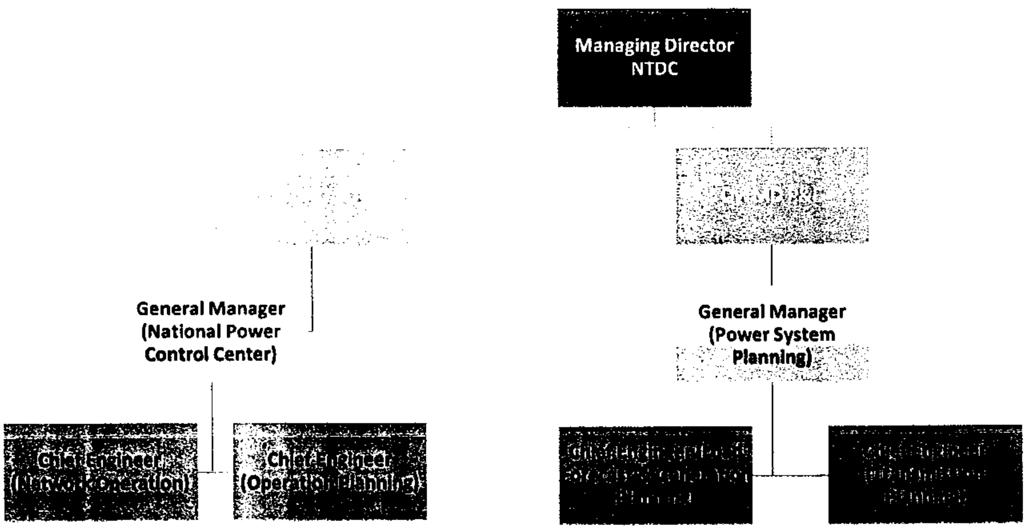


Figure-1: Hierarchy of NTDC Authority with respect to System Operations

Historically, these functions were being carried out manually because of the absence of sufficient IT infrastructure and applications to automate those processes. For the successful operation of a competitive market in the country, NTDC has embarked upon an ambitious journey to make improvements in these functions, aligning them with international best practices, and ensuring accuracy and transparency through clearly defined process flows and SOPs. Active coordination among all stakeholders, trained manpower, and state of the art tools augmented by IT infrastructure is underway to ensure a liquid market functioning.

This section of the License Application deals with competencies that exist or have been developed to date to undertake the operations as separate SO function in terms of organizational human resource, processes development, technical and technological capabilities and financial resources. The details in eh following sections of this Annexure focus exclusively on the competencies and capabilities of System Operations component of NTDCL operations.

Section 2 of this Annexure deal with Network operation including overview of real-time Control Room operations, transmission outage management and allied technical offices. Section 3 provides a summary of Operational Planning sections including generation and transmission operational planning, generation outage coordination, VRE forecast and PPA (Power Purchase Agreement) & LDs (Liquidated Damages) settlement department. Section 4 deals with Long Term Expansion Planning which covers preparation of IGCEP (Indicative Generation Capacity Expansion Plan), TSEP (Transmission System Expansion and long-term demand forecast. Section 5 provides the brief summary of the need for revised Grid Code and what it covers. Section provides summary of IT Strategy and implementation tools, and Section 8 provides brief description of Human Resource available to SO with detailed CV annexed separately.

SECTION 2

A brief summary of the different departments working under NTDC w.r.t System Operation is as follows:

NETWORK OPERATION

This is the core of the system operator, where the control rooms and the real time activities take place. National Power Control Centre under NTDC has 03 No. Control Rooms that are carrying out generation and transmission operational control of the National Grid round the clock (24x7) i.e.

- National Control Center, Islamabad
- Regional Control Center (North), Islamabad
- Regional Control Center (South), Jamshoro

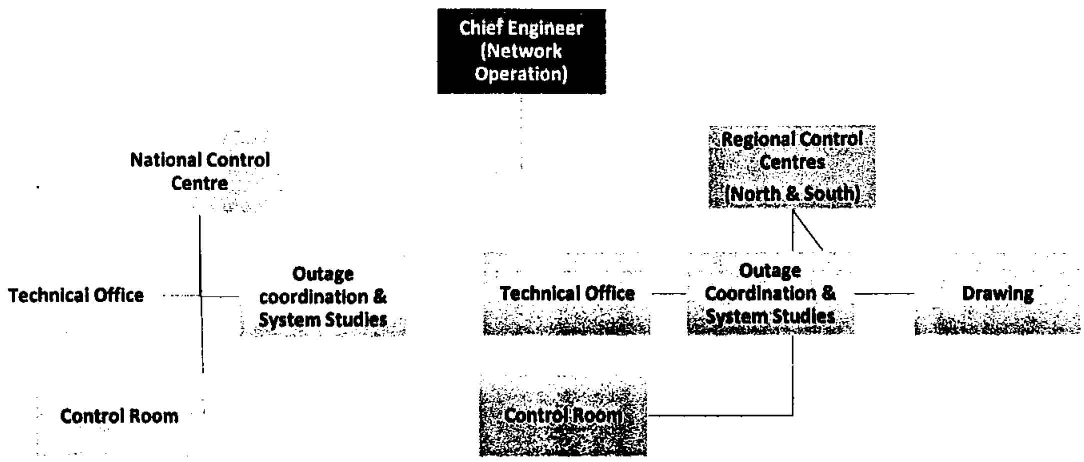


Figure-2: Hierarchy of Network Operation Department

The Control Rooms have been designed to provide mission-critical environment where active system monitoring, issuance of dispatch instructions in a seamless manner, rapid emergency response and situation management is carried out by a team of experienced shift engineers in coordination with specialized technical offices such as Power Control and Outage Coordination departments, which are also available round the clock for Control Room support. The Control Rooms are equipped with redundant power supplies including dual power supply from the grid as well as back-up generator, emergency lighting, firefighting equipment, explosion-proof entry doors and ergonomic amenities. Redundant communication channels for instant communication with power plants and grid stations are also available including dedicated hotlines, power line carriers, landlines, fax, email & mobile phones, while hardcopy phonebooks are also available for emergencies. A brief detail of these Control Rooms and the facilities available are as follows:

2.1 National Control Centre (NCC)

National Control Centre, situated in NPCC Islamabad, is the main Control Room for scheduling, commitment and dispatch of all generation facilities connected on transmission voltages (66kV & above) as well as operation and monitoring of primary transmission network (including 500,220 kV NTDC network, KE power interconnection and HVDC line). The purpose of NCC Control Room is:

- Balancing the National Grid frequency in real-time as per NEPRA Performance Standards for Transmission Rules (PSTR) 2005
- Monitoring and Control of primary transmission network
- Outage Coordination of primary transmission network and generators
- System restoration and situation management in emergencies
- Issuance of dispatch and switching instructions in real-time as per PPAs

Since system operations is a critical task, and safety and security are at stake, a high level of priority is given to the Control Room related activities and staff as there is no option of downtime or delay. For visualization of the system, high-performance displays designed for 24x7 operation are available in NCC to enhance situational awareness of Control Room engineers, including a VTRON Multi-Screen Processor Digicom Ark 1221 (1200 Series). Each shift is supervised by a Deputy Manager level Shift Engineer who is not only responsible for coordination and collaboration among the 03 Control Rooms under NPCC, but also for implementation of PPAs and liaison and reporting to NTDC Authority. Control Room operations are implemented through 04 No. dedicated desks i.e. Generation Control (Conventional and VRE), Transmission Control and HVDC Control. Previously, all communication with power plants was carried out through telephone and dispatch instruction were passed on through faxed hard copies, as per PPAs. However, for effective implementation of PPAs, improved reporting and time management, state-of-the-art SO Data Exchange Portal (SDXP) has been established to enhance the efficiency of Control Room operations. The Information and Communication Technology (ICT) available with NCC Control Room as detailed below:

2.1.1 SDXP

An interactive and secure web portal has established to disseminate and receive the data and information within NPCC departments and external stakeholders like Power Producers, DISCOs, CPPA-G, Market Operator etc. Following are the few cases:

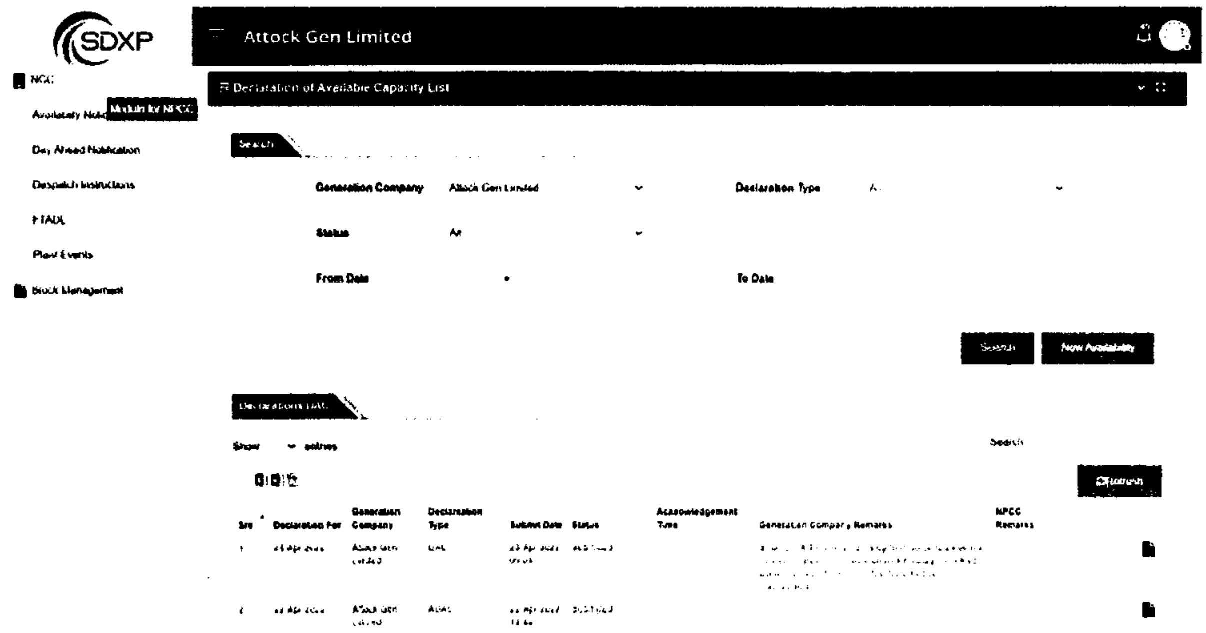
- Power Plants submitting their availability's to NPCC.
- Day Ahead Notification to Power Plants.
- Dispatch Instructions to Power Plants.
- Power Plants events.
- Integration with SMS Metering system for real-time power generation data.
- Integration with Wind Forecast.

A brief overview of these modules is as follows:

Power plants declared their power availability for next day as per their respective PPAs.

- Power plant shares Available Capacity 12/24 hours before the start of the day as per contract (PPA/ EPA)
- Power plant may provide revisions (Revised Declare availability (RDAC) / Adjusted Declare availability (ADAC)) after declaration of availabilities.
    - Downward Revision Based on Revised Declared Available Capacity.
    - Upward revisions to the Declared Available Capacity after the Declaration Deadline.
    - Power Plants notifies change in available capacity based on Ambient Temperature.
- Time constraints are implemented in SDXP as per PPA / EPA as follows:
    - Power Plants has to communicate revision based on Ambient Temperature 45 min prior to Relevant Hour.
    - Upward RDAC is notified at least 4 hours prior to the start of the relevant hour.
    - For Power plants running on Gas fuel, time for upward revision is 2 hours as per PPA / EPA

ii. Screenshot



b. NPCC Day Ahead Notification

NPCC shares indicative day ahead demand with power plant based upon availability and requirements within given time limit.

i. Process

- NPCC shares day ahead demand with Power Plant based upon availability and requirements within given time limit i.e. before 5 pm.
- Generation Company receives day ahead demand notification prior to the beginning of an Operating Day

ii. Screenshot

Day Ahead Demand

Show All entries | Search

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Sr#	Demand For	Generation Company	Generation Company Site	Block/Complex	Fuel	Policy	Declaration Type	Intimation Time	Status	NPCC Remarks	Generation Company Remarks	Acknowledgement Time
1	20-May-2022	The Hub Power Company Limited	Islamabad - THE HUBCO COMPANY LIMITED Islamic Chamber Building Block-9.Clifton Karachi	ComplexUnit-I	RFO	1994	DAD	19-May-2022 15:39	Submitted	System Generated Entry		
2	20-May-2022	TPS Guddu (Genco-2)	TPS Guddu - Guddu Thermal Power Plant	ComplexUnit-VII	GAS	1994	DAD	19-May-2022 15:39	Submitted	System Generated Entry		
3	20-May-2022	TPS Jamshoro (Genco-1)	TPS Jamshoro - Jamshoro Power Company Limited	ComplexUnit-I	RFO	1994	DAD	19-May-2022 15:39	Submitted	System Generated Entry		
4	20-May-2022	Liberty Power Tech Limited	Islamabad - LIBERTY POWER TECH LTD A 51-A S.I.T.E. Karachi	ComplexUnit-I	RFO	2002	DAD	19-May-2022 15:39	Submitted	System Generated Entry		
5	20-May-	CCPP	CCPP Nandipur -	ComplexUnit-I	RLNG	1994	DAD	19-May-	Acknowledged	System		19-May-2022 15:39

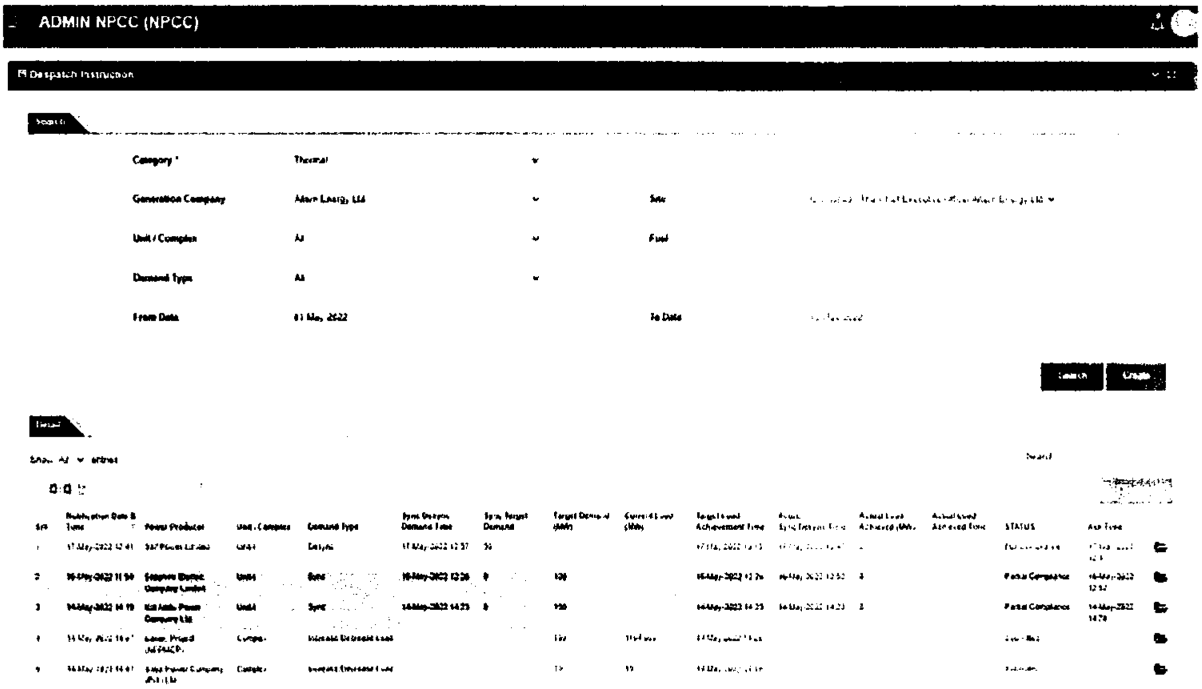
[illegible]

NPCC gives despatch instruction as per system requirement and technical limits of the plant in real-time.

- Process

- NPCC gives despatch instruction as per system requirement and technical limits of the plant.
- Generation Company receives Despatch Instructions.
- Generation Company acknowledges Despatch Instructions.
- Generation Company complies with despatch instruction.
- Generation Company notifies about compliance achieved.
- NPCC acknowledge the achievement.
- In case of failure of achieving despatch level NPCC will issue a FATDL.

- SCREENSHOT



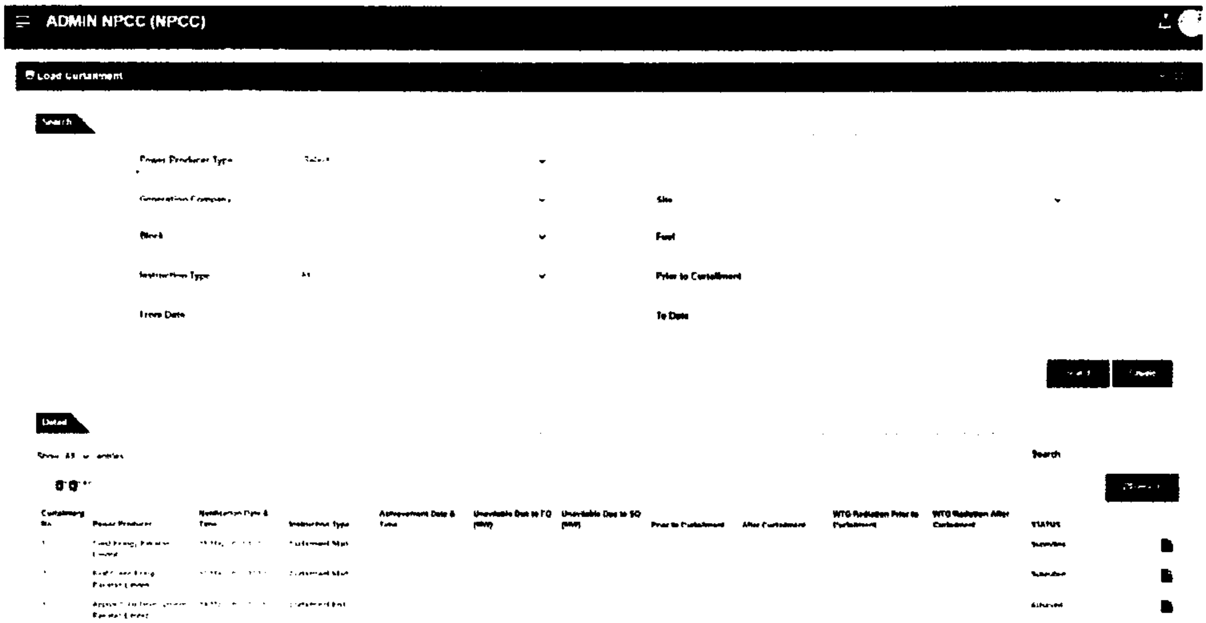
d. LOAD CURTAILMENT

NPCC gives Load Curtailment instructions to Wind and Solar power plants in case of system emergency.

i. PROCESS

- NPCC gives Load Curtailment instructions.
- Generation Company receives and acknowledges instructions.
- Generation Company complies with Load Curtailment instruction and inform NPCC.
- NPCC acknowledges the compliance.

ii. SCREENSHOT



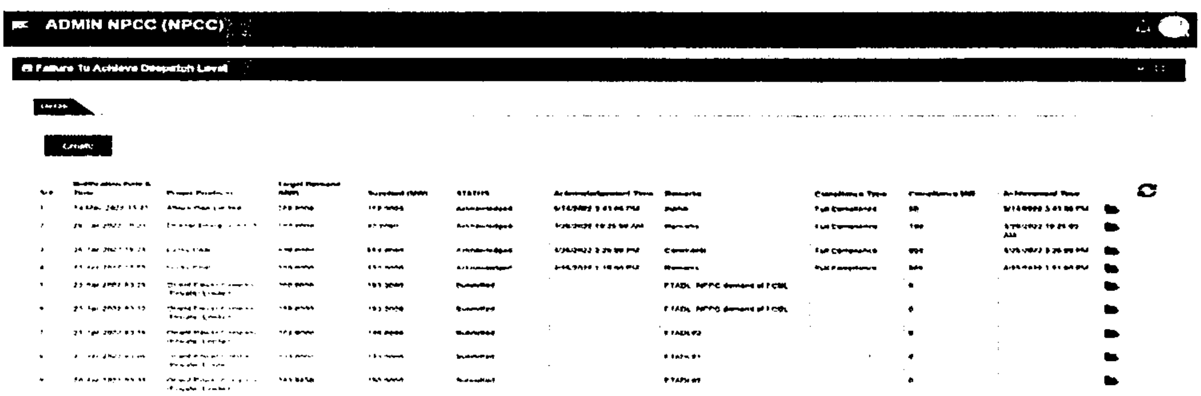
TO ACHIEVE DESPATCH LEVEL)

NPCC sends Failure to Achieve Despatch Level notification to power plants in case of failing to achieve dispatch level as instructed.

i. PROCESS

- NPCC sends first Failure to Achieve Despatch Level notification.
- Generation Company receives FTADL notification.
- Generation Company acknowledges the notification and does the compliance.

ii. SCREENSHOT



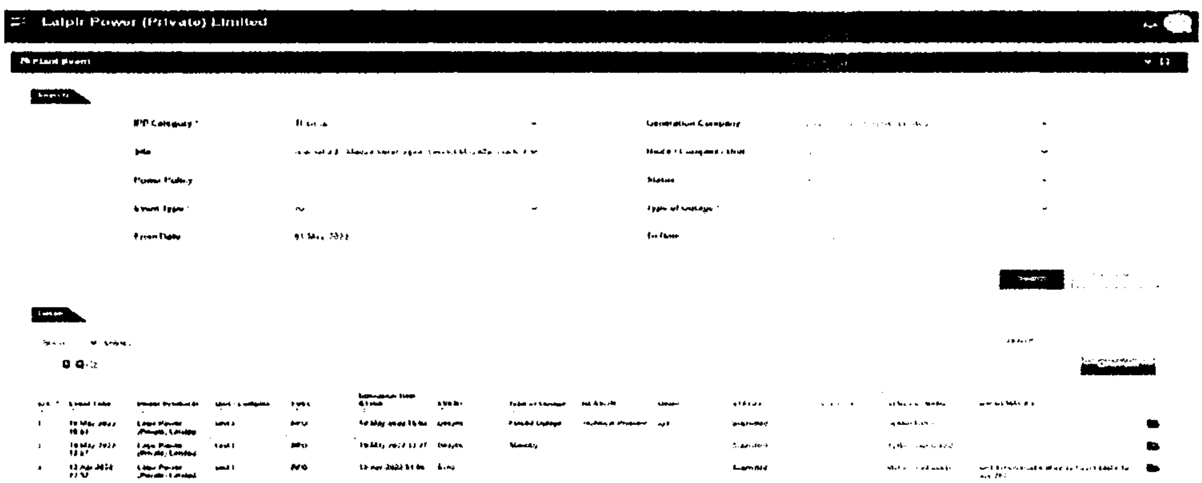
f. PLANT EVENTS

Generation Company notifies NCC about each event including time of occurrence, nature of event (e.g. Forced Outage, Grid Supply Failure, Synchronization with Grid etc.).

i. PROCESS

- Generation Company notifies about Event.
- NPCC Responds and Acknowledges Event.
- Generation Company receives NPCC response.

ii. SCREENSHOT

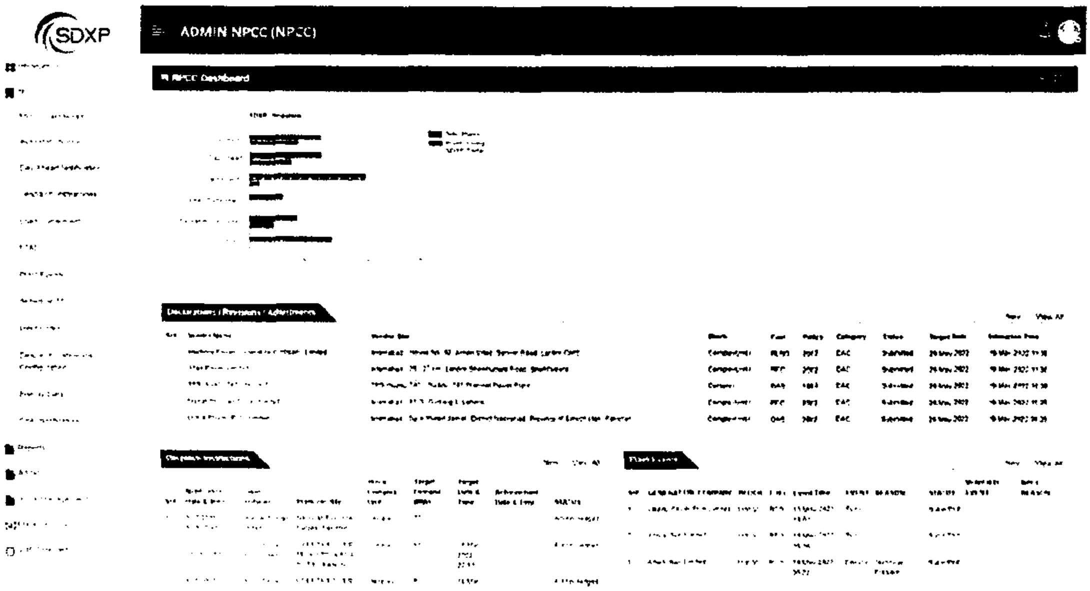


g. REPORTS /DASHBOARD

Following reports/ Dashboard are available in SDXP:

- Plant Event Report
- Plant Major Event Report
- Plant Wise Availability Report
- Despatch Instruction Report
- Load Curtailment Report
- Demand Despatch Report
- Ancillary Services Report
- Force & Schedule Report
- Stock Report

Sample Screenshot is given below:

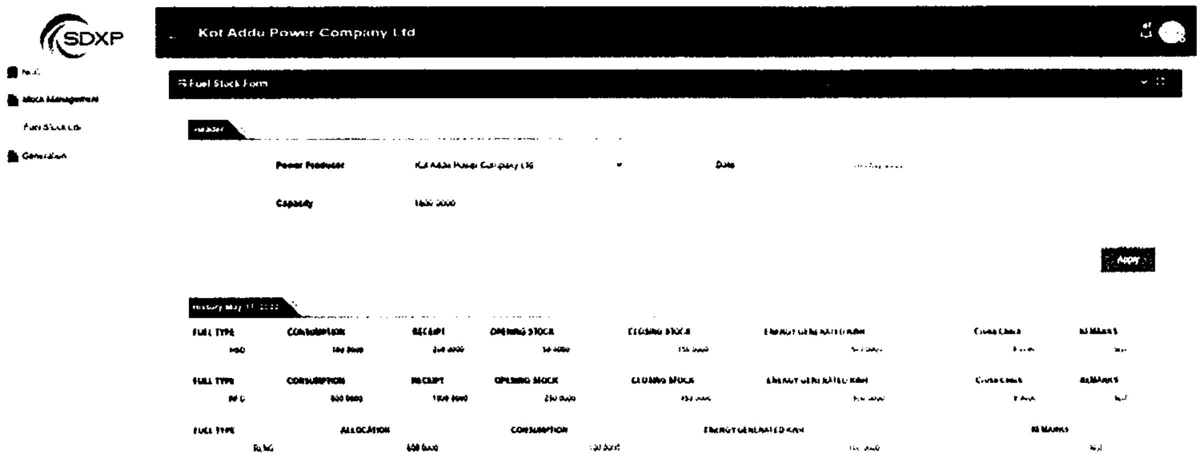


Fuel Stock Management Portal is used for the inventory record of fuel maintained by Power Plants in their stock after operating day. This information of fuels that are recorded in SDXP portal are Coal, HSD, RFO, RLNG, & Gas (detailed below) as well as the energy generated on these fuels. Power plants enter the fuel stock position after the end of operating day.

i. PROCESS

- Power Plant enters the fuel information i.e.
  - Gas and RLNG: Allocation and consumption
  - Coal, RFO, HSD: values entered will be Closing Stock Consumption and Receipt.
  - Crosscheck: the values will be cross checked through this formula i.e. Opening stock + receipt-consumption-closing stock must be equal to zero.
- After submission, plant is unable to edit the fuel stock until its get rejected by the NPCC.
- NPCC can also update the submitted fuel stock and both versions will be maintained in System.

ii. SCREENSHOT



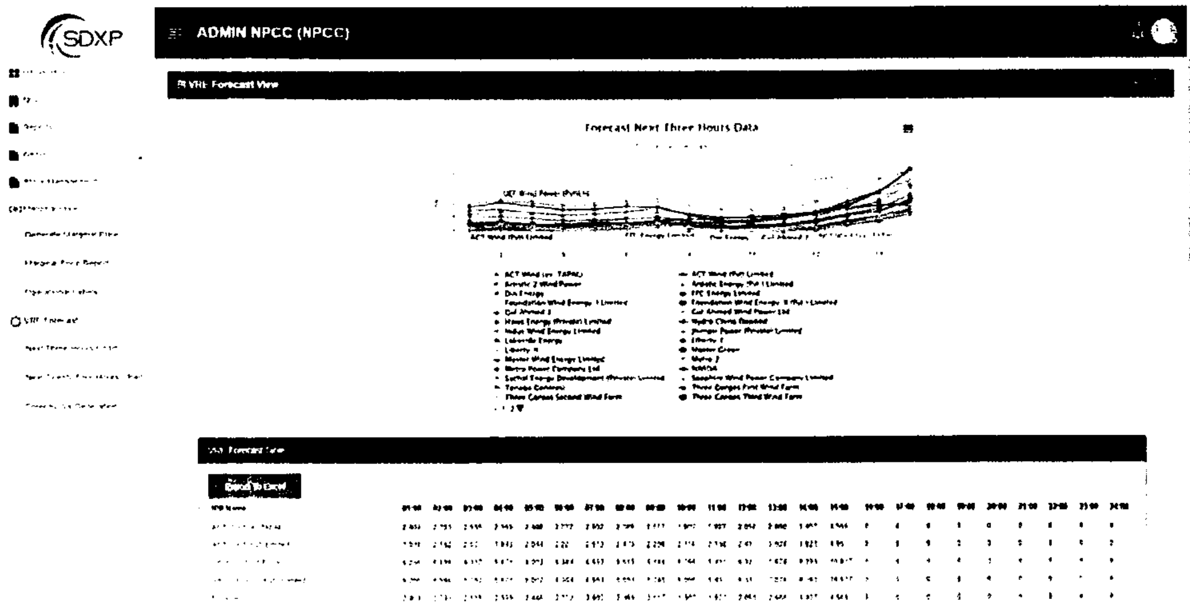
5. VRE FORECAST

NPCC has acquired the services of Meteologica (based in Spain) to forecast wind generation (further elaborated in Operation Planning section). All data exchange with Meteologica (including wind forecast for all horizons as well as actual wind generation provided to Meteologica for feedback) is carried out through APIs and has been integrated in SDXP.

Dashboards have been developed to visualize wind generation forecasts as follows:

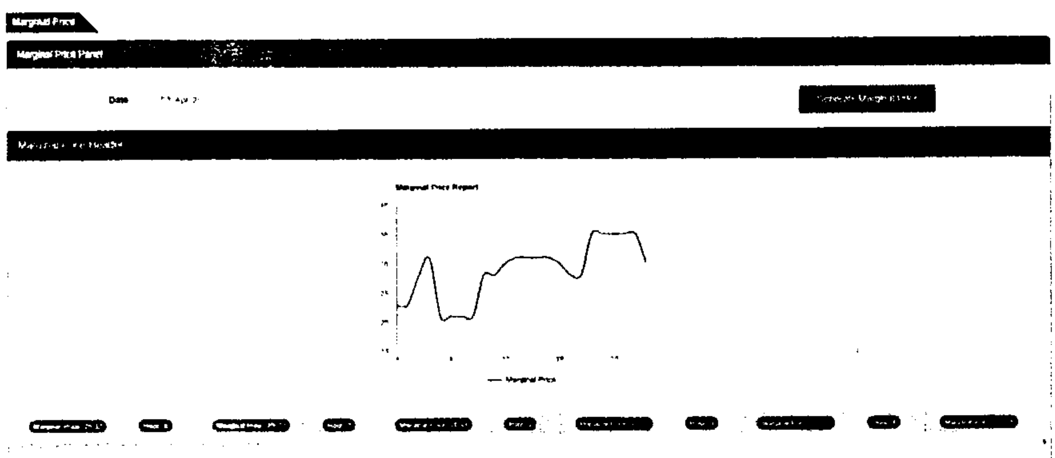
- **Forecast of Next Three Hours:** Gives forecast of the Wind Power Plants for the next three hours, displayed in graph and grid form.
- **Forecast of Next Twenty-Four Hours:** Gives forecast of the Wind Power Plants for the next Twenty-Four Hours, displayed in graph and grid form.
- **Forecast Vs Actual Generation:** the forecasted wind generation and actual generation entered by power plant are added and displayed in graph and grid form.

A sample screenshot is given below:



[illegible] CALCULATION

As per the new approved Commercial Code, System Operator shall calculate System Marginal Price on daily basis on hourly resolution. The complete procedure for calculation of Marginal Prices as given in the Commercial Code has been automated in SDXP. The actual generation recorded through SMS is compared with the availability declared by the Generators as per PPAs and Operational Labels, as given in Commercial Code, are assigned. The hourly Marginal Price is calculated automatically and can be visualized through tables and graphs. Also, the forms for data exchange between SDXP and MMS through API, e.g. Ancillary Services, Transmission Must-Run Generation etc. have also been prepared and finalized with CPPA-G. A sample screenshot is given below:



2.1.2 SCADA SYSTEM

INTRODUCTION

Supervisory Control and Data Acquisition (SCADA) is a system of hardware and software components used by industrial organizations e.g. power generation, transmission and grid companies, electrical utilities etc. for online monitoring, control and data acquisition. SCADA system offers the following features:

- Collecting, monitoring and processing real time data from field e.g. substations and power plants
- Control industrial process remotely e.g. switching operations, power generation, voltage control and transformers tap regulation etc
- Interacting with devices/ applications through Human Machine Interfaces
- Recording and archiving real time data for future analysis

SCADA applications can support power dispatchers, operators, engineers, managers, etc. with tools to predict, control, visualize, optimize, and automate the Electric Power System.

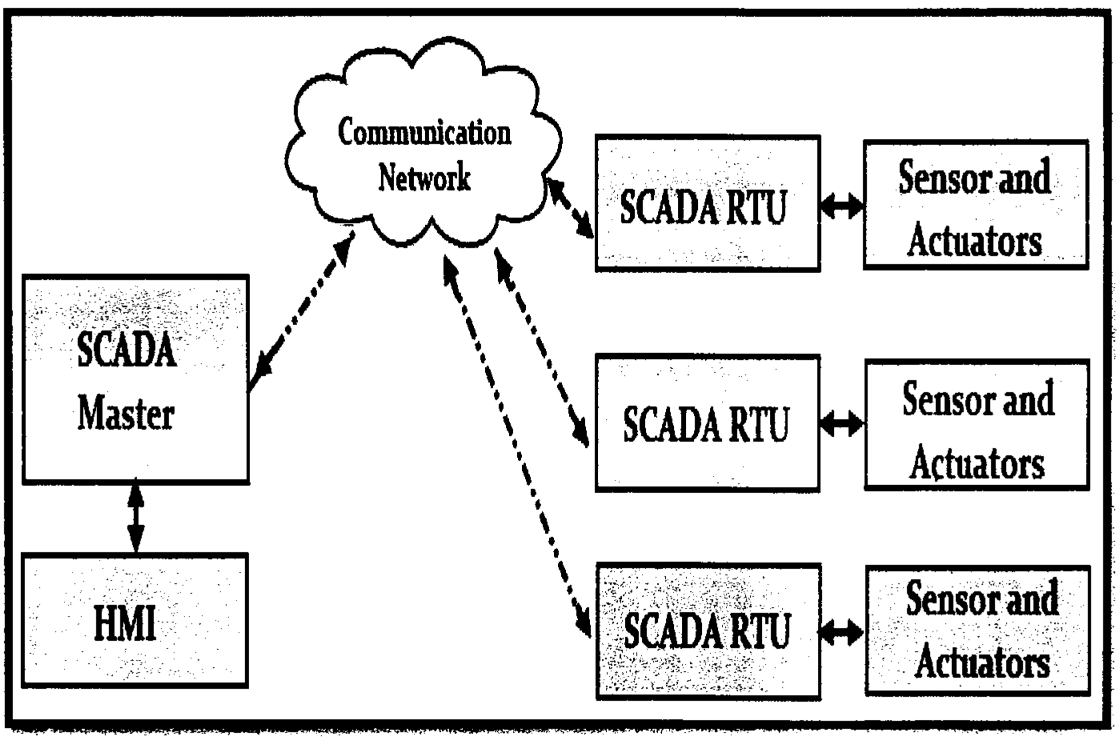


Figure 4: SCADA System Block Diagram

2.2.2 SCADA SYSTEM IN NPCC – SCADA-I

In order to perform system operations efficiently, SCADA System was introduced in NPCC Islamabad in January 1990, about 30 years ago, which remained effectively operational till year 2009. The Vendor of the said system was ASEA Brown Boveri (ABB) Switzerland and Energy Management System was called SINDAC-5. The said system was based on proprietary communication protocols and Operating Systems by ABB and inter-operability with other Remote Telemetry Units (RTUs) was not possible. Hence up gradation of this system was indispensable due to the following reasons:

- Rapid technological development in the field of Computers, SCADA and telecommunication systems
- Global Standardization of SCADA System
- Expansion in NTDC/WAPDA power Network and addition of IPPs
- To provide advanced and improved tools to meet the Dispatching, Control and Monitoring requirements of NPCC

LOAD DESPATCH SYSTEM UP-GRADATION (PHASE –II) PROJECT SUMMARY

Keeping in view the technical constraints of SCADA system and Telecommunication infrastructure in Phase - I, rapid network expansion, technological advancement and global standardization of SCADA systems, an upgradation project was initiated in early 2000. However, the said project was delayed due to law and order situation in the country and finally awarded to M/s ALSTOM in 2010. This project is known as LDSUP-II.

WORK OF LDSUP-II

- Latest and standard hardware and software for Supervisory Control & Data Acquisition (SCADA) / Energy Management System (EMS) at NPCC and Remote Terminal Units (RTUs) at 220 kV & 500 kV Grid Stations and Power Plants (Total 49 New RTUs).
- Supply and installation of Optical Fibre Ground Wire (OPGW) on 606 km of existing EHV (500/220/132 kV) Transmission Lines by replacing existing ground wire under live line conditions.

- Telecommunication Subsystem comprising; terminal equipment for various types of media (Optical Fibre and Power Line Carrier PLC) and Integrated Telephone System.
- Interfacing of 1994 policy IPPs (14 no.) with SCADA system of NPCC using protocol converters.

PROJECT LOCATION

- SCADA Servers & Work stations installed at NPCC Islamabad.
- RTUs /Telecom equipment installed at various Power Houses and NTDC Grid-stations throughout Pakistan.
- Optical Fibre Ground Wire (OPGW) installed on existing 500/220/132 kV transmission lines.

SALIENT FEATURES OF NEW SCADA SYSTEM HARDWARE

- User Friendly MS Windows based Operating System.
- Redundant LAN based environment.
- State of the art LED Type Rear Projection Video Wall Display 9.59 x 3.08m to display any type of power system displays / geographical picture.
- Paper less Chart Recorder with high time resolution.

FACILITIES OF SCADA SYSTEM SOFTWARE

- Monitoring and control of 500/220/132 kV Sub Stations and Power Plants.
- Recording and review of Historical Information data using HIS (Historical Information System).
- Weather Conditions (8 Locations)

LAYOUT OF SCADA II

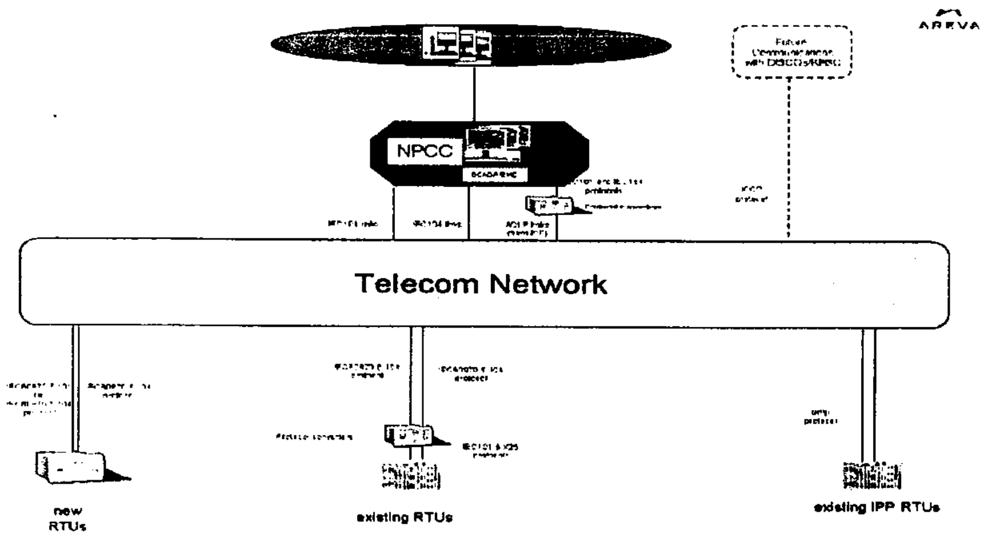
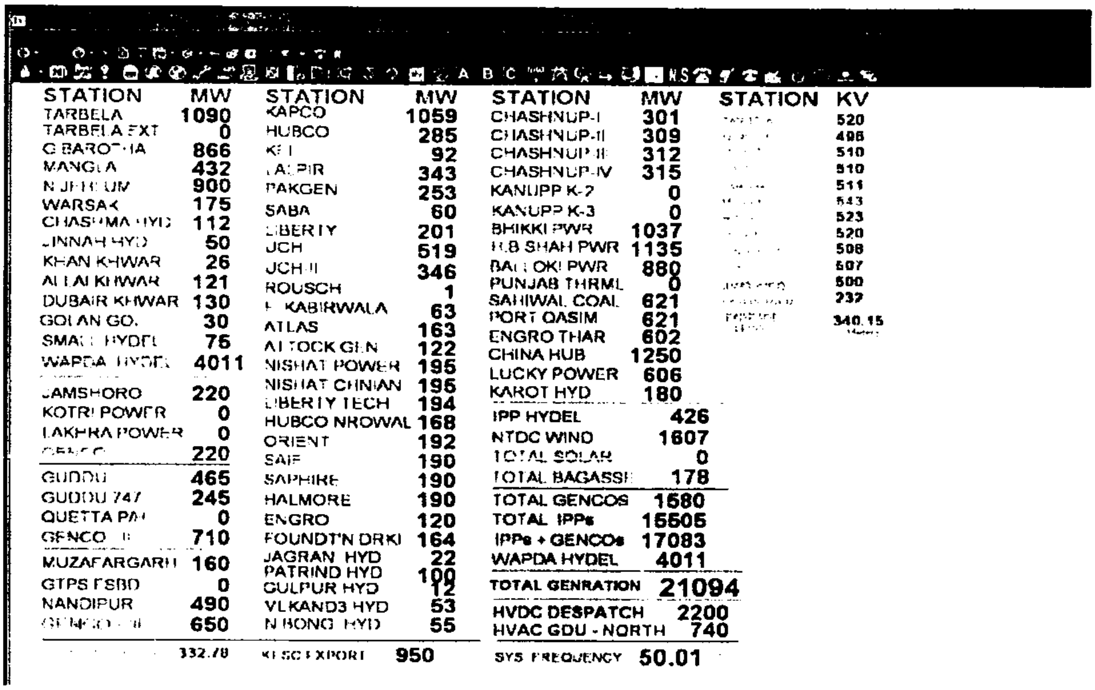


Figure 5: Overall Layout of SCADA – II



STATION	MW	STATION	MW	STATION	MW	STATION	KV
TARBELA	1090	KAPCO	1059	CHASHNUP-I	301		520
TARBELA EXT	0	HUBCO	285	CHASHNUP-II	309		496
G BAROTHA	866	KEL	92	CHASHNUP-III	312		510
MANGLA	432	LALPIR	343	CHASHNUP-IV	315		510
N JHELUM	900	PAKGEN	253	KANUPP K-2	0		511
WARSAK	175	SABA	60	KANUPP K-3	0		543
CHASHMA HYD	112	LIBERTY	201	BHIKKI PWR	1037		523
JINNAH HYD	50	UCH	519	H.B SHAH PWR	1135		520
KHAN KHWAR	26	UCH II	346	BALLOKI PWR	880		508
ALLAI KHWAR	121	ROUSCH	1	PUNJAB THRML	0		507
DUBAIR KHWAR	130	F KABIRWALA	63	SAHIWAL COAL	621		500
GOLAN GO.	30	ATLAS	163	PORT QASIM	621		232
SMALL HYDEL	75	ATTOCK GEN	122	ENGRO THAR	602		340.15
WAPDA HYDEL	4011	NISHAT POWER	195	CHINA HUB	1250		
JAMSHORO	220	NISHAT CHINIAN	195	LUCKY POWER	606		
KOTRI POWER	0	LIBERTY TECH	194	KAROT HYD	180		
LAKHRA POWER	0	HUBCO NROWAL	168	IPP HYDEL	426		
GENCO	220	ORIENT	192	NTDC WIND	1607		
GUDDU	465	SAIF	190	TOTAL SOLAR	0		
GUDDU 747	245	SAPHIRE	190	TOTAL BAGASSE	178		
QUETTA PM	0	HALMORE	190	TOTAL GENCOS	1580		
GENCO II	710	ENGRO	120	TOTAL IPPs	15505		
MUZAFARGARH	160	FOUNDT'N DRKI	164	IPPs + GENCOs	17083		
GTPS FSBD	0	JAGRAN HYD	22	WAPDA HYDEL	4011		
NANDIPUR	490	PATRIND HYD	100	TOTAL GENRATION	21094		
GENCO - III	650	GULPUR HYD	12	HVDC DESPATCH	2200		
	332.78	VLKAND3 HYD	53	HVAC GDU - NORTH	740		
		N BONG HYD	55	SYS FREQUENCY	50.01		
		KESC EXPORT	950				

Figure 6: HMI - Network Generation Summary

SCADA – III PROJECT

Preliminary working on SCADA – III project was initiated in year 2016 and the contract is awarded to M/s CMEC – Hitachi Energy Consortium in year 2021. Following are the components of SCADA – III project:

BRIEF DESCRIPTION OF THE PROJECT

The project's main objective is to improve, upgrade, and extend the existing Load Despatch facilities at NPCC Islamabad and NTDC telecommunication infrastructure to meet the essential requirements of effective monitoring and control of expanding power networks. The project also includes the expansion of the revenue metering system.

SCOPE OF WORK OF SCADA – III

- Addition and up-gradation of existing SCADA system (Hardware and Software) to perform system operation at NPCC Islamabad & establishing backup control centre at Jamshoro.
- Interfacing of missing signals of SCADA - II.
- Interfacing and integration of new Stations (RTU/SAS/DCS) in SCADA system.
- Installation of EMS / RMS System at NPCC Islamabad with backup @ BCC Jamshoro.
- Interfacing and Integration of SMS meters installed in the Network (700 meters covering 220 sites approx.)
- Revamping of Telecom Network.

PROJECT FEATURES

- Tender ADB-202R-2019 is of type 'Single Stage Two Envelope'
- Foreign Component is Financed under ADB Loan No. 3577- PAK under MFF Second Power Transmission Enhancement Investment Program-Tranche 2.
- Local Component is financed under Public Sector

[illegible]	[illegible]	Details
1.	Location	All over the country
2.	Funding Agency	ADB under Multi-Tranche Financing Facility-II (MTFF-II)
3.	Total PC-1 cost/ Escalated PC-I Cost	PKR 11,638M / PKR 15168M PKR
4.	Contract Award Cost	PKR 17,097M PKR (Equivalent) $110 M

5.	Contract Award	• Notification of Award issued on 20-01-2021 • Contract agreement signed on 27-03-2021 • Contract Effectiveness declared on 25-06-2021 • **Tentative Completion Date: 24-06-2024 (1095 days)**
6.	Name of Contractor	M/s Consortium: CMEC China, ABB Power Grids Switzerland Ltd, ABB PowerGrid AB Sweden
7.	Name of Consultant	M/s JV: SAGE Automation Australia, Barqaab Consultancy Services Ltd Pakistan

SALIENT FEATURES OF SCADA / EMS SYSTEM

SCADA FUNCTIONS

- Acquisition of network data
- Processing of status indication signals, alarms and measurements
- Visualization of process information and logging (Human-Machine-Interface - HMI)
- Processing of commands and set-point values
- Storage and retrieval of archive data, including disturbance data processing
- Topology calculation and dynamic network colouring
- Equipment statistics
- Automatic Load shedding
- Check before execute function

EMS FUNCTIONS

- Short-term load forecast (STLF).
- Interchange transaction scheduling (ITS),
- Transaction evaluation (TE),
- Generation scheduling (GS),
- Unit Commitment (UC),

REAL-TIME DISPATCHING FUNCTIONS

- Interchange transaction monitoring (ITM)
- Reserve Monitoring (RM)
- Automatic generation control (AGC)

- Energy Accounting (EA)
- Energy/Load Forecasting
- Integration and load forecasting for Renewable Energy

NETWORK APPLICATION FUNCTIONS

- Network Model Builder (NMB)
- State estimation (SE)
- Bus Load Forecast (BLF)
- Despatcher power flow (DPF)
- Optimal power flow (OPF)
- Contingency analysis (CA)
- Equipment Outage scheduler (OS)

➢ Powerful and expandable database to manage the historical and future data

➢ Clearly defined data exchange with other systems of NTDC e.g., offline application software

➢ Provided SCADA/EMS/RMS Software should be upgradeable.

➢ Hardware facilities including; Tele-control Interface, Data Entry and Maintenance Servers and Workstation; SCADA servers; Redundant LAN; Operator workstations; Printing devices and weather stations

➢ Extensive Training

➢ Safe connection between the NTDC corporate LAN, the SCADA/EMS & RMS LAN and CPPA-G LAN

➢ Furniture and fixtures for NPCC and BCC

➢ Environment Control System for both main and backup control centre.

LAYOUT OF SCADA - III

MAIN CONTROL CENTER - NPCC ISLAMABAD

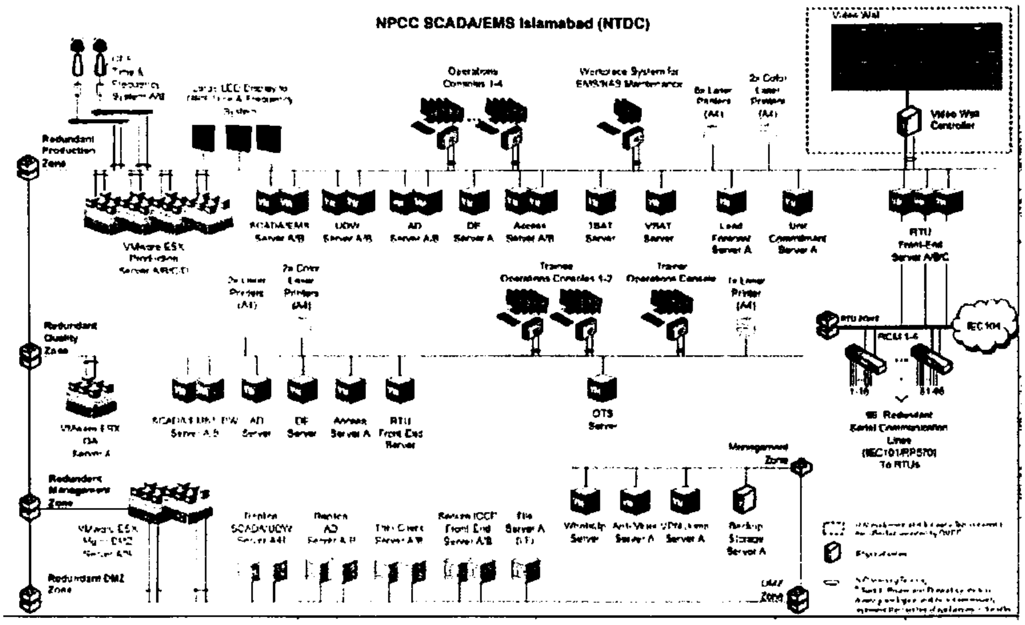


Figure 7: SCADA - III Layout

BACKUP CONTROL CENTER - BCC JAMSHORO

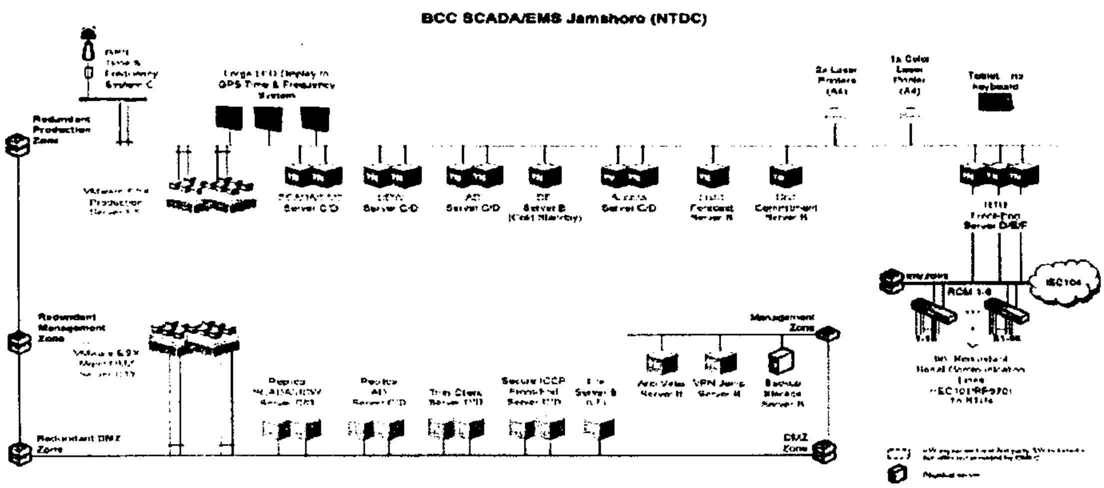


Figure 8: BCC Layout

USE OF APPLICATIONS IN SCADA SYSTEM

Although, basic utility of SCADA System is to provide a monitoring and control facility but modern SCADA System is not limited to monitor physical parameters and control circuit breakers. In fact, modern SCADA is a suite of Monitoring, Control, Data

Recording, Information Storage and Advisory Applications which equip an Engineer with complete control over power system and process industry. SCADA Applications are basically software utilities included in SCADA package which make use of offline Models in collaboration with tele-metered data to provide best possible results which help the user in taking decisions. Some of these applications are as follows:

1. Load Forecast
2. Automatic Generation Control
3. Contingency Analysis
4. Optimum Power Flow
5. Unit Commitment
6. Economic Despatch
7. Dispatcher Training Simulator
8. Automatic Load Shedding

LOAD FORECAST

Load forecast is an essential feature of SCADA system. It makes use of historical and daily generation/ load along with weather parameters like temperature, humidity, wind speed, wind direction and solar radiation and forecasts short term (next half an hour) upto next 10 years. This forecasted load helps the dispatcher in timely scheduling the generation to ensure optimum and most economic despatch.

AUTOMATIC GENERATION CONTROL - AGC

Controlling hundreds of generators manually over telephone to control system frequency is a hectic job. SCADA applications have solved this problem for control engineers both in central control centre and power houses. AGC application ensures that all the generators with AGC facility to follow a certain set point frequency and automatically raises and lowers the generation level. In this way it automatically and effectively controls generation and keep the system in safe frequency limits. In this way it reduces burden over despatchers and the engineers can focus on other major areas of power system stability.

CONTINGENCY ANALYSIS

Power system stability is the ultimate goal of SCADA System. Everyday scheduled and emergency outages can be tested in study mode using Contingency Analysis to check for all possible contingencies. This application helps the dispatcher to check any outage in study mode before actual event takes place. For this purpose, an offline power system model is developed and real time tele-metered data is used on this model to get the desired results. This study could avoid system disturbance by taking precautionary measures.

OPTIMUM POWER FLOW

The Optimal Power Flow (OPF) application represents the problem of determining the best operating levels (Both MW & MVAR) for electric power plants in order to meet demands given throughout a transmission network, usually with the objective of minimizing operating cost and losses.

UNIT COMMITMENT

Unit Commitment (UC) is an optimization problem used to determine the operation schedule of the generating units at every hour interval with varying loads and generations under different generational, environmental and technical constraints. It is a multivariable problem which is impossible to cater for by a human brain. Unit commitment application of SCADA System helps in this regard and come up with a generation plan on hourly or half hourly basis for best power system operation.

ECONOMIC DESPATCH

Economic dispatch is the short-term determination of the optimal output of a number of electricity generation facilities, to meet the system load, at the lowest possible cost, subject to transmission and operational constraints. The Economic Dispatch Problem is solved by specialized SCADA Application which satisfy the operational and system constraints of the available resources and corresponding transmission capabilities.

DISPATCHER TRAINING SIMULATOR

A dispatcher training simulator (DTS) is a computer-based training system for operators of electrical power grids. It performs this role by simulating the behaviour of the electrical network forming the power system under various operating conditions, and its response to actions by the dispatchers. Student dispatchers may therefore develop their skills from exposure not only to routine operations but also to adverse operational situations without compromising the security of supply on a real transmission system.

AUTOMATIC LOAD SHEDDING

SCADA System takes care of power system equipment over loading and demand supply unbalance by carrying out automatic load shedding sequence which improves system stability.

2.2 REGIONAL CONTROL CENTRES

The Regional Control Centers under NTDC are one-of-a-kind control rooms for central control of secondary transmission network (132&66kV) as well as for central liaison with DISCOs. The purpose of the RCCs is:

- Monitoring and Control of secondary transmission network
- System restoration and situation management in emergencies
- Managing the radial configuration of 132&66kV network to maintain load flow on primary transmission network
- Outage coordination and restoration of tripping/ underfrequency disconnection
- Coordination with DISCO Power Distribution Centers (PDCs)
- Frequency Control through Demand Control in extreme emergencies

Since secondary transmission network is immense and switching operations on radial 132kV network are complex and frequent, its operational control has been split region-wise into two Control Rooms. RCC (North) controls secondary network up to Multan region whereas RCC(South) control the network of HESCO, SEPCO, QESCO and partial MEPCO. In the absence of SCADA system on secondary transmission network, visual appraisal of the network is done through an ingenious solution of Mosaic Mimic Panel with removable mosaic tiles to display the primary/secondary network Single Line Diagram along with equipment codes engraved on the panel. In real-time, magnetic beads are used to display breaker openings, Busbar topologies, equipment faults, line disconnections and active Permit to Works (PTW). The mosaic tiles are mounted on a modular steel structure for easy and quick network updation.

For DISCO monitoring, a dedicated screen wall is available with AMR based data of DISCO demand and consumption which is available on both aggregate level as well as category-wise feeder level detail. During periods of emergencies, generation shortfall or special circumstances such as Ramadan, the system is used to allocate power consumption quotas to DISCOs as well as to monitor their power consumption in real-time. With the advent of SMS meters on CDPs, the Control Room also has access to monitoring power factor on the CDPs which is extremely crucial for congestion and voltage management.

Additionally, the RCCs are also responsible for switching operations of generators connected on 132kV network. As a part of network control as well as congestion management, the three Control Rooms of NPCC coordinate closely among each other for system monitoring, congestion management, frequency control and system restoration. Especially, with the mushroom growth of wind generation in southern region, RCC (South) is playing a critical role of management of highly wind generation intensive 132kV network of Jhimpir region and information logging of wind plant tripping and curtailment events which are used for NPMV (Non-Project Missed Volume) calculations. Moreover, during summer peak season, since the network in load centers in highly stressed, NCC and RCC manage the network very minutely by controlling generation connected at 132 kV as well as by managing configuration of radially operated secondary network to alleviate congestion and avoid load management.

[illegible] OFFICES

The function of technical offices is to provide support to the working of Control Rooms and provide a single point of contact for queries, reporting and policy enforcement. The main functions of technical offices of NCC/RCC are:

- Ensure the adequacy of resources (both financial and human resource) for the performance of Control Room activities
- Review and assure quality of services delivered by shift and support teams to ensure compliance with established policies and procedures;
- Liaise with counterparts in power stations, regional control centers, DISCOs, CPPA-G and interconnected authorities such as KESC for power production, interchange and system operational issues;
- Supervise preparation of reports and ensure accuracy and completeness of information to be shared with internal and external stakeholders;

- Ensure effective management of schedule outages of generation units and emergent shutdowns of power plant for stability and security of system;
- Exercise oversight of the operations of control room to ensure smooth functioning;

Additionally, the technical offices of RCCs also have dedicated Drawing sections. These departments are responsible for preparation of operational Single Line Diagram (SLD) of all substations and power stations at 66kV and above level. Each substation is issued an SLD with unique operational code for each equipment. For uniformity, there is a set standard for assigning codes to different types of equipment on different voltage levels. These codes are communicated to the relevant control rooms of the substations where they are engraved on control panels and yards. For safety purposes, all switching operations are carried out by NPCC using these operational codes. No transmission facility is energized with the National Grid unless the operational Single Line Diagram has been approved by NPCC. The Drawing section has draftsmen and AutoCAD experts who prepare SLDs and allocate operational codes.

2.4 OUTAGE COORDINATION

Dedicated sections under each Control Room technical offices have been set up for outage coordination of Transmission equipment installed at 500kV, 220kV, 132kV & 66kV and generator switchyards throughout the network. All relevant formations such as NTDC Asset Management & Project Delivery, DISCOs, KE (for interconnection), Generators and HVDC operators apply all required maintenance outages to NPCC outage coordination offices. NPCC carries out studies to entertain the outage on daily basis, to facilitate the equipment outage requests, which are carried out to perform the maintenance or upgradation of network equipment. These studies involve analysis of National Grid after the outage of network equipment throughout the network, to calculate the schedule and quantum of load management or generation increment/curtailment (if required) to operate the system in stable and reliable manner.

2.5 HVDC OPERATIONS

To promote development of coal and electricity base at south of Pakistan, the HVDC project was developed and put into operation after the successful commissioning of

±660kV Pak-Matiari-Lahore Transmission Company Project with a capacity of 4000MW. The project is the first HVDC Project in Pakistan. It was constructed by State Grid of China on BOOT basis and has a commercial operation period of 25 years. Moreover, CASA-1000 project has also been conceived wherein the National Grid will be connected to Central Asian states via HVDC line for power exchange. Given the unique technical and contractual nature of HVDC line, a specialized section has been established in NPCC to oversee the operational matters of HVDC. The working responsibilities of this section are as follows:

- Data verification for Transmission services payment invoice as per Transmission Services Agreement (TSA), which includes verification of:
    - Operational notifications and operational information with the procedures finalized in Standard Operating Procedures and as per TSA between HVDC Converter stations operators and the national control center regarding operations of AC & DC facilities in relation to commencement of interconnected operations and termination of interconnected operations, including instructions related to the delivery of power.
    - Declared Transmission Capability on hourly basis.
    - Revised(upward/downward) Declared Transmission Capability.
    - Forced & Partial Forced outage of AC/DC HVDC equipment (Pole, Filters etc.).
    - Maintenance outage of AC/DC equipment.
    - In case of despatch variations, NPCC target time, and actual despatch level achievement time verification from real time operator workstations.
    - Outages due to Force Majeure Events
- Preparation of data regarding Liquidated Damages due to
    - Excessive Actual Transmission Unavailability
    - Revisions on the Declared Available Transmission Capability
    - Due to failure in delivering the Declared Available Transmission Capability
    - Due to Excessive Actual Transmission Losses
    - Due to reduction in Contracted Capacity
- Outages management and operational planning of HVDC

- Preparation of Yearly, Monthly, and Weekly energy requirement of the ±660kV Pak-Matiari-Lahore Transmission Company Project as per SOP.
- Preparation of ±660kV Pak-Matiari-Lahore Transmission Company Project associated circuits tripping and maintenance outages month wise.
- Preparation of the Southern tripping and maintenance outages of Power plants in south for its impact on ±660kV Pak-Matiari-Lahore Transmission Company Project.
- Preparation of the despatch on HVAC & HVDC corridor on daily basis, by incorporating the generation of Power plants in south, and AMR data.
- Supporting power despatch engineers during low system load and abnormal weather conditions (fog, storm etc.).
- Manage overall HVDC Control functions and their configurations including supplementary function of HVDC (Frequency Limiter control, Run back etc.).
- Monitor Stability Control System (SCS) keeping special attention to HVAC and HVAC hybrid power flow for system security and stability.
- Participate in studies involved during interconnection of upcoming coal power plants in south region of network as interim as well as permanent basis.
- Coordinate with internal and external stakeholders for all activities.
- Active participation during arranged meetings among NPCC, CET, HATCH and other NTDC departments for Stability Control System (SCS), Dynamic performance study (DPS) and other technical functionalities of HVDC.
- Participating and assisting in the studies for the installation of SCS for upcoming Southern Coal Power Plants (TEL, Lucky, Thal Nova, SECL) in the 2nd phase of SCS installation, as in the 1st first SCS panels were installed for the Port Qasim, Hub China, and Engro Thar, and generator trip priority was set by NPCC.
- Coordination with other NPCC departments, for outage planning and commissioning support to HVDC.
- Preparation of Technical Code of CASA 1000.
- Preparation of Standard Operating Procedures of CASA 1000 Project.
- Operational Readiness Activities of CASA 1000 Project.

The team has received training in China, UAE and Pakistan on technical aspects of HVDC and is also involved with international consultants such as HATCH and CESI whose experts are carrying out practical capacity building of the team.

SECTION 03

OPERATIONAL PLANNING

The functions performed by Operation Planning branch include:

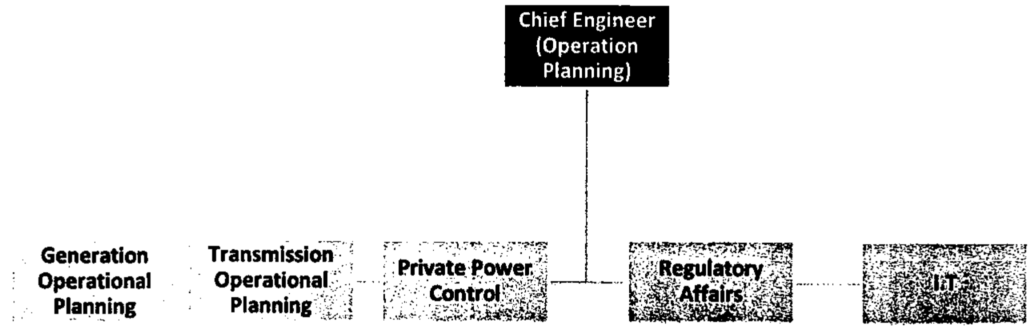


FIGURE-9: HIERARCHY OF OPERATION PLANNING DEPARTMENT

The different activities carried out by the Operation Planning branch are summarized below:

OPERATIONAL PLANNING

3.1.1 YEAR AHEAD GENERATION OPERATIONAL PLANNING

Year ahead planning at the operational stages is among the initial steps for optimization of available resources, fuel planning and assessing power balance. Currently, NPCC's mandate is indicative operational planning of generators for next calendar year for following purposes:

- Year Ahead notification to power plants as per PPA requirements
- Planning of fuel requirements for plants
- Determining demand and capacity balance

After implementation of CTBCM, this Year Ahead Plan (Annual Production Plan) will also be important for Market Participants to foresee the trend of marginal prices throughout the year as well as the expected plant factors of each generator.

Since 2018, NPCC is using Stochastic Dual Dynamic Programming (SDDP) for medium to long term generation operational planning. SDDP is a hydrothermal dispatch model with representation of the transmission network and used for medium term operation studies. The model calculates the least-cost stochastic operating policy of a hydrothermal system, taking into account the following aspects:

- Operational details of hydro plants (water balance, limits on storage and turbine outflow, spillage, filtration etc.);
- Detailed thermal plant modelling (unit commitment, generation constraints due to "take or pay" fuel contracts, concave and convex efficiency curves, fuel consumption constraints, multi-fuel plants etc.);
- Detailed transmission network: Kirchhoff laws, power flow limit in each circuit, losses, security constraints, export and import limits for each electrical area etc.;
- Load variation per load level and per bus, with monthly or weekly stages (medium or long term studies);

SDDP has been used in studies for valuation of companies, international interconnections and analysis of new hydroelectric and thermal projects in more than 30 countries, including:

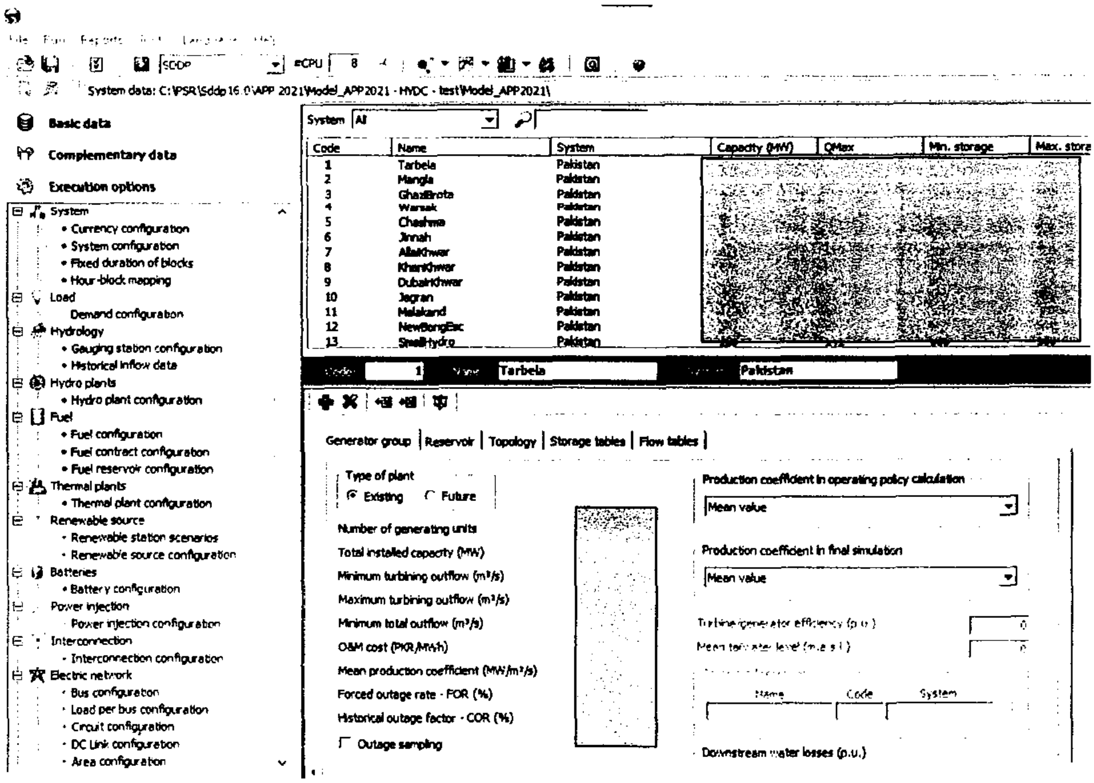
- all countries in South and Central America;
- USA and Canada;
- Austria, Spain, Norway, the Balkan region (10 countries) and Turkey;
- New Zealand, South China and Shanghai province.

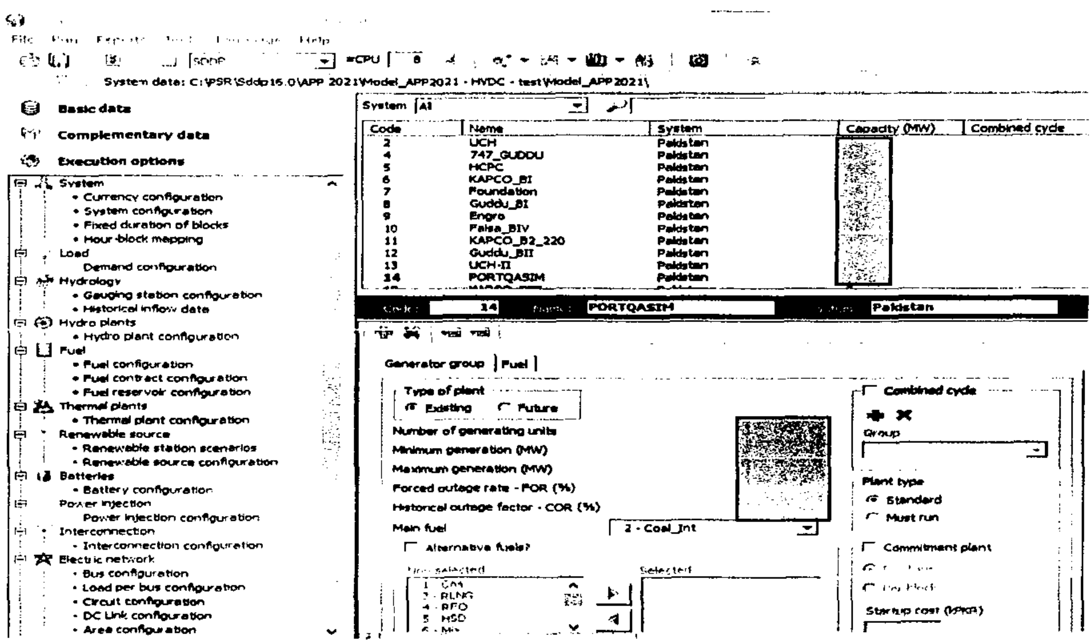
The model has also been used in the dispatch centres of Bolivia, Colombia, Chile, Guatemala, El Salvador, Ecuador, Panama and Venezuela.

The major parameters modelled for Year Ahead Plan are:

- Year Ahead Demand Forecast
- Hydrological Forecast
- Variable Renewable Energy Forecast
- Commercial Operation Date of new generators
- Expected Transmission Expansion
- Expected demand per bus (Load participation factors per bus)
- Fuel Contracts and Fuel Availability
- Merit Order

Sample screenshots are included below to demonstrate the parameters modelled in the software:





In future, it is necessary for sake of transparency in the market that this information be available to all market participants, along with the underlying factors that shaped this plan, such as transmission constraints, fuel contracts, must run generation etc. This will help the participants to formulate their own market strategy in an informed manner.

For the sake of uniformity and reliability, it is required that all underlying assumptions/parameter estimates etc. be formalized. In the new Grid Code, sub-code Operating Code (OC-4) has been completely overhauled to formalize the process of operational planning. Also, with support of MRC Consultant, Standard Operating Plan to formalize the process flow of operational planning has been prepared.

3.1.2 GENERATION OUTAGE COORDINATION

- NTDC has a dedicated department setup at NPCC for coordination of outages of generators. The different tasks carried out by the department is as follows:
- Designation of Maintenance, Non-Maintenance and Demonstration months to all IPPs.
- Allocation of Weighing factors to all IPPs as per respective PPAs.
- Year Ahead, Quarter Ahead, Month Ahead notifications to all plants that include energy targets in accordance with PPAs.
- Approval of Scheduled Outages of all Hydel, GENCOs and IPPs for the next year.
- Preparation of Power Position showing expected peak generation, peak demand. and power balance for the present year up to December.
- Correspondence with all Hydel, GENCOs & IPPS regarding Scheduled Outages and any modifications to the outage plan in extreme circumstances if required.

3.1.3 SECURITY CONSTRAINED ECONOMIC DISPATCH (SCED)

Unit commitment and economic dispatch (Day ahead planning) are the areas which offers maximum potential for optimization of operating cost in the power system. The dispatch of generation facilities to produce demanded energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities and other parameters require sophisticated mathematical tools. NPCC has acquired a state-of-the-art NCP (Nuevo Corto Plazo) tool to perform this exercise. NCP determines the operation of a transmission-constrained hydrothermal system in order to minimize costs or to maximize revenues of energy sales to the market. Costs include fuel usage (variable production and startup costs), deficit costs, and penalties for the violation of operational constraints, among others.

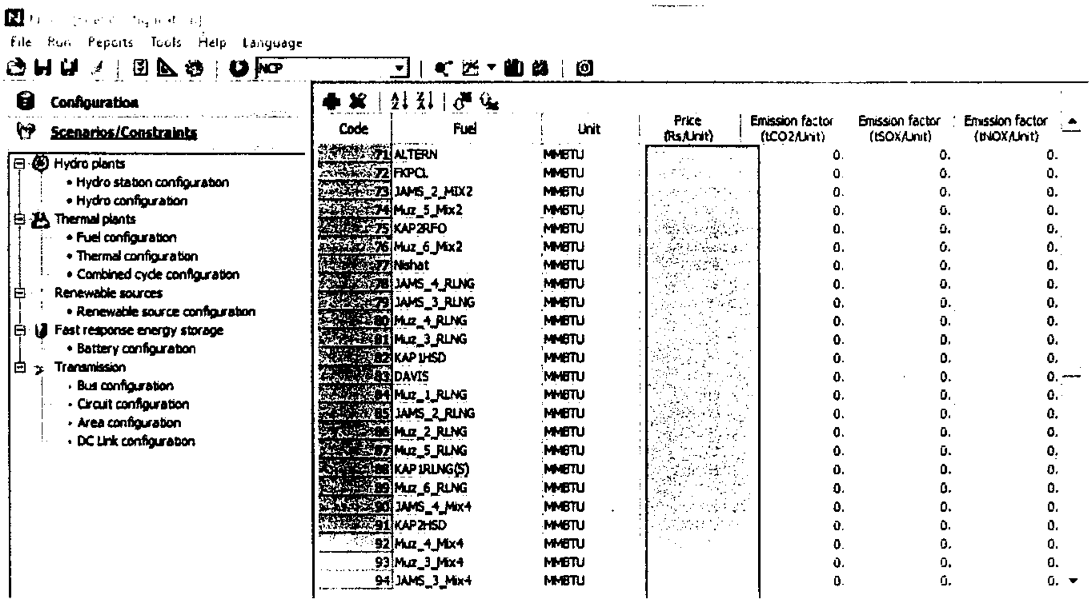
Utilities using NCP worldwide include:

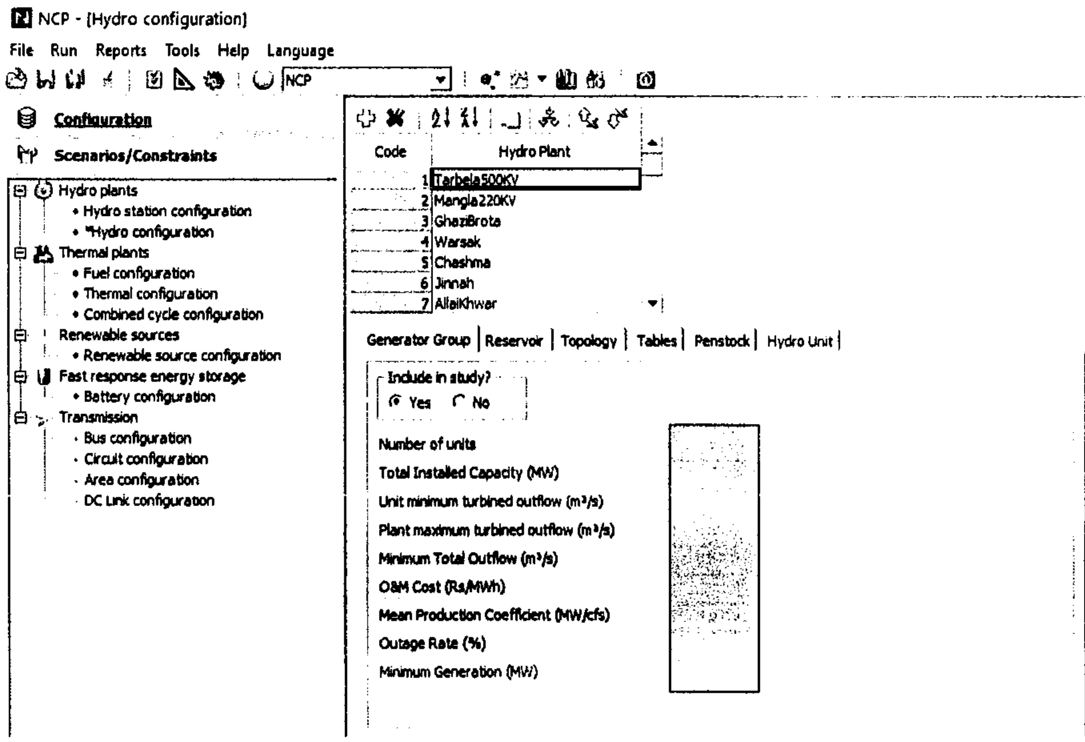
- National load dispatch centers of Bolivia, Ecuador, Guatemala, El Salvador and Peru (the daily and weekly scheduling)
- Largest generating companies of Turkey, with more than 30,000 MW
- Various institutions in the Balkans region in activities related to the Southeast European Electrical System Technical Support (SEETEC) project
- Agder Energi (Norway) for maximizing revenues in the Nord Pool market
- Evaluation for determining the scheduling of the Brazilian power system (~5800 circuits, 3900 buses and more than 100 hydro power plants)

The features modelled in NCP include:

- Load balance for each bus of the transmission network
- Linear power flow model, including circuit flow capacity constraints
- Water availability for hydro plants in river cascades considering the water travel time
- Minimum and maximum power levels for each power plant, including unit commitment decisions
- Reservoir minimum, alertness and flood control storage volumes
- Minimum and maximum downstream water outflows and constraints for the rate of change of these outflows
- Thermal plant constraints: minimum up-time and down-time, power ramping rates, fuel availability and number of start-ups
- System security constraints (primary and secondary reserves, sum of circuit flow constraints, general generation constraints, etc.)

The solution is achieved using advanced Mixed Integer Programming (MIP) techniques. A few screenshots are included below to demonstrate the parameters modelled in the software:





The factors such as Merit Order, Transmission constraints, unit start-up costs and number of start-ups allowed, fuel availability as well as fuel contracts, operating margins, system stability considerations etc. are taken into account in the "Final Generation Schedule" prepared by NPCC. The plan is used as a guideline for Control Room Operators who adjust it as per actual system requirements for real-time frequency control.

As envisaged in the approved CTBCM model, the Day Ahead generation plan is to be published on System Operator's website. For this, it is necessary that all underlying input factors that informed this plan be also transparently provided so that the actual system marginal cost could be justified, and market participants develop confidence in the decisions of System Operator. In the revised Grid Code attached with this License Application, Scheduling & Dispatch Code (SDC) has been reviewed keeping in view best world practices of software-based day ahead planning.

In order to prepare a robust Day Ahead Generation Schedule, besides other parameters, demand forecast and VRE generation forecast are the most critical inputs as they are themselves continuously varying in time. As such, there is a need to develop such models that can forecast these time varying parameters with a certain accuracy.

NPCC is already working in these two areas and the progress is explained in the next sections.

Long term and short term forecast of variable renewable energy (solar/wind) is a basic input parameter for generation scheduling. Forecast of VREs is not only important for demand-supply management, but to also maintain appropriate reserve margin to cater the high intermittency, especially for wind generation.

Since Oct 2020, NTDC is utilizing services of wind generation forecast service Meteologica. At present, Meteologica is providing services to over 80 countries and providing forecasting services to wind generation farms of 600 GW installed capacity. A centralized portal has been established in SDXP wherein all wind generation forecasts, provided by Meteologica as well as by individual WPPs bound by their PPAs, is consolidated.

The forecast services provided by Meteologica includes following horizons:

Service Content	(i)	Hourly forecast: Hour-ahead forecast of net delivered energy for a period of 24 hours in the future with a granularity of 15 minutes, update once an hour. • Forecasting update: Once an hour • Forecasting range: 24 hours • Delivery time: one hour ahead of the forecasted hour • Time resolution: 15mins
	(ii)	Day ahead forecast: Day-ahead forecast of net delivered energy for day 1 will be delivered by 10AM of day 0 with an hourly granularity every day with a forecasting range of seven (7) days. • Forecasting update: Once a day • Forecasting range: 7 days • Delivery time: Every day at 9:50am Pakistan local time • Time resolution: 1 hour
	(iii)	Month forecast: Month-ahead forecast of net delivered energy for each day of the month will be delivered not later than one week before the beginning of each month. • Forecasting update: Once a month • Forecasting range: one month • Delivery time: on 20th of each month at 10:00AM Pakistan local time • Time resolution: 1 day
	(iv)	Year ahead forecast: Year-ahead forecast of net delivered energy for each month shall be delivered not later than thirty (30) Days before the beginning of each year. • Forecasting update: Once a year • Forecasting range: one year • Delivery time: on Oct.1st at 10:00AM Pakistan local time • Time resolution: 1 month

These forecasts are used not only in Operational Planning but also by Control Room engineers for real-time system control.

3.1.5 Short Term Demand Forecast

Presently, NPCC relies on the day ahead load forecast provided by individual DISCO PDCs for unit commitment and hourly generation scheduling. The accuracy of DISCO provided forecast has a considerable margin of improvement for incorporating different parameters such as weather, expected high loss ATC load shedding, expected schedule of industrial feeders (e.g. furnaces), maintenance shutdowns on 11 kV feeders and local events such as holidays, shutter down protests etc.

After obtaining all information from DISCOs, NPCC is also required to carry out its own load forecast as per new Grid Code. For this, a specialized load forecasting software is being acquired that can consider all relevant input parameters and provide hourly load forecast within acceptable levels of error. A separate load forecasting department is being developed with appropriate manpower trained on the software. A UK based Load Forecast expert, Mr. Derek Bunn, has been hired to support NTDC in acquisition of such a tool as well as for development of forecast model and training of NTDC engineers. As of May 2022, RFP for demand forecast tool/service has been floated through World Bank as donor agency. Approximately 06 months are required for training of personnel, data collection and entry, and development of initial forecast model. Once the initial model is ready, reducing the forecast error and improving accuracy of results is a continuous process.

3.2 TRANSMISSION OPERATIONAL PLANNING & STUDIES

NTDC has a robust team trained on PSS/E software to carry out different transmission network studies. A brief overview of the different activities carried out in this regard are as follows:

- Generation Evacuation Schemes

  This includes studies in multiple scenarios to evaluate various different generation evacuation schemes in the network, to ensure the maximum possible utilization of cheaper generation considering the constraints in the network.'

- Network Contingency Studies

    Contingency studies are carried out on regular basis to evaluate the loading of network equipment under various disturbances, to ensure system stability and reliability of supply under different system conditions.

    - The loading to be maintained on hybrid HVDC –HVAC network under different network topologies / loading conditions, contingencies on HVAC/HVDC network and generators is assessed, to ensure stable and reliable operation of national grid.

- Voltage Control Studies

  Real time data of voltages at all 132, 220 & 500kV grid stations is collected and different studies are conducted to evaluate the most feasible solution to maintain the voltages within permissible limits.

- Optimal Power Flow Studies

  This includes studies to evaluate the most appropriate power transmission path in the network, that ensures minimum losses and enhanced power quality.

- Fault Impact Studies

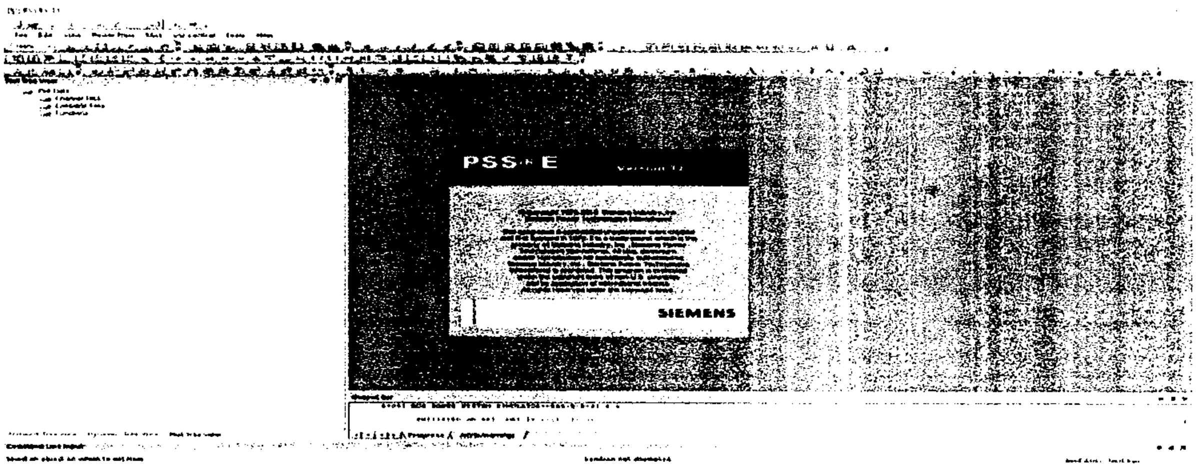
  Faults at various locations in the network are studied and remedial measures are proposed like design of protection schemes etc. to minimize the impact of faults.

- Network Interconnection Studies

  NTDC undertakes, studies related to interconnection of transmission/ generation facilities, by undertaking dynamic security assessment and N-1/N-2 contingency compliance prior to change in network topology.

- Design Of Protection Schemes
  - NPCC regularly carries out studies to evaluate the performance of various system-vide protections schemes under different operating system conditions, like Under-Frequency Load Shedding, Rate of Change of Frequency Load tripping scheme, Cross trip schemes to cater over-loading and low voltage issues at certain points in the network.
  - The Under Frequency Load Shedding are designed to arrest the decay in frequency due to loss of generation, the automatic load tripping restores the frequency while keeping other parameters like voltages and equipment loading etc. within permissible range. Furthermore, to strengthen the frequency response of the network against tripping of large scale generators, NPCC designed the Rate of change of frequency based load tripping scheme, to arrest sharp decays in the frequency.
  - To cater for the events of cascaded trippings in the network, NPCC has proposed various cross trip schemes after simulating the faults in various different system operating scenarios to evaluate the amount of load/ generators to be tripped to maintain the system parameters.

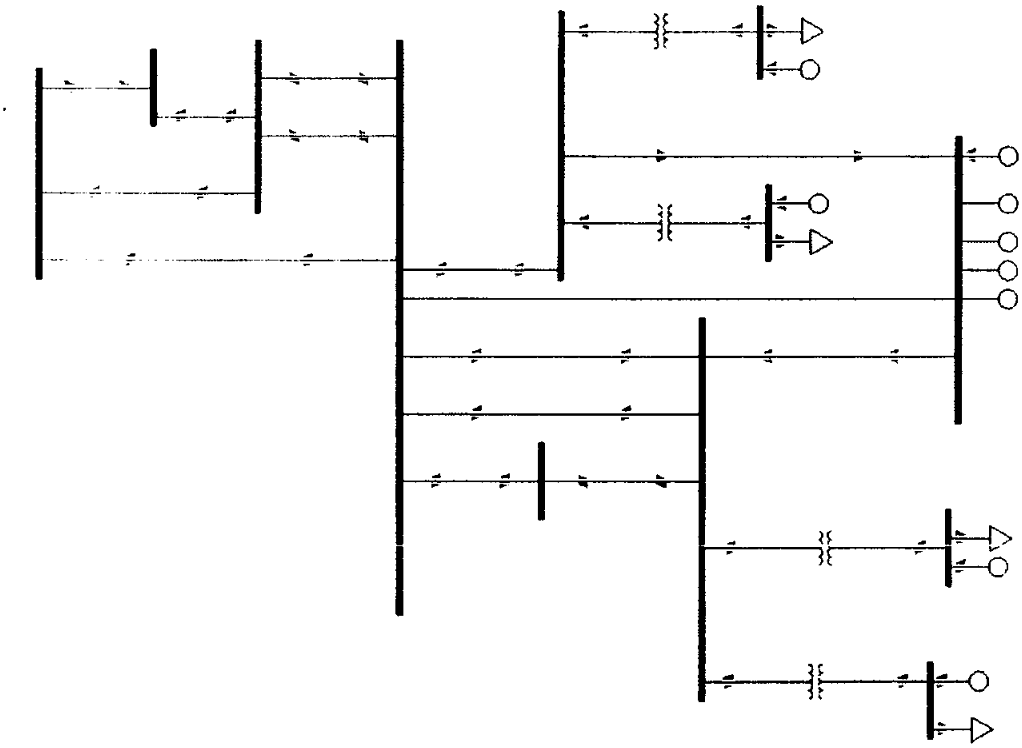
Most of these studies are performed using PSS E software. PSS/E software is used by many countries throughout the world to carry out various analysis, PSS/E comes along with several modules, the detail of each module is as under:



A. Base Module

This includes:

- Power flow solution for network models.
- Graphical User Interface and Contour Plotting.
- Contingency Analysis including automatic corrective actions and remedial action scheme modelling.
- Voltage Stability (PV/QV) Analysis with plot generation.
- Python and IPLAN Scripting.
- Transmission Reliability Assessment.



B. Balance and Unbalance Fault Analysis Module

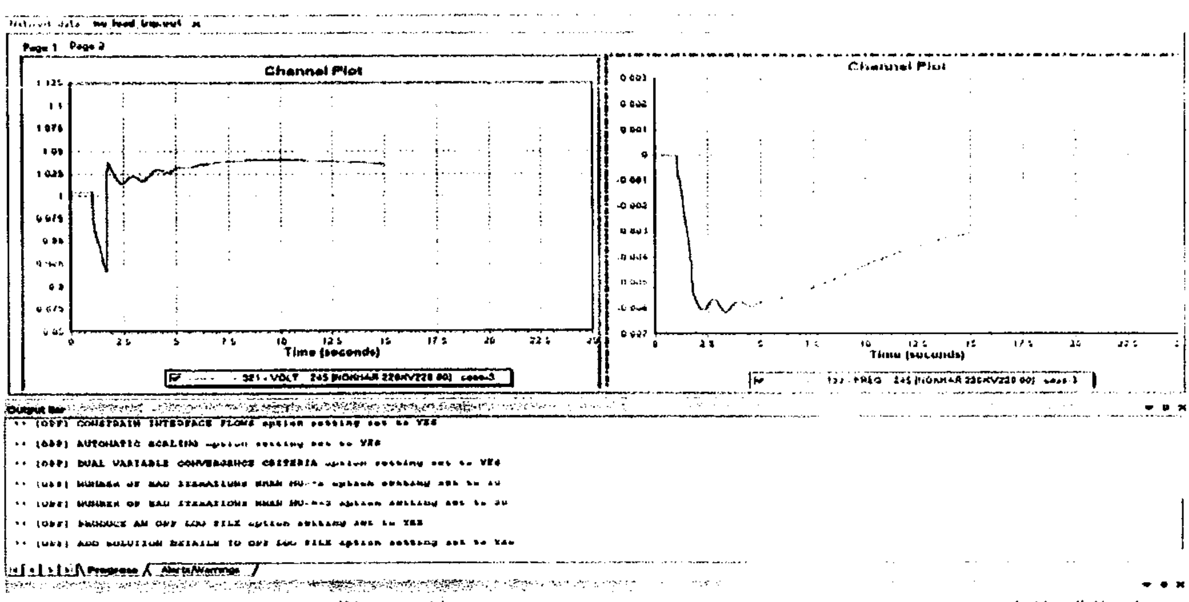
- Perform balanced and unbalanced short circuit analysis
- Automatic sequencing of short circuit calculations for large models
- Circuit breaker duty calculations based on ANSI and / or IEC standards
- Circuit breaker detailed fault analysis

PSS®E Short Circuit module has a number of short circuit calculation algorithms to meet the diverse needs of fault analyses. All algorithms are self-contained analyses in PSS®E. They require a valid power flow working case and the power system sequence data.

C. Dynamic Simulation Module

- Analyse the dynamic system response and stability of the grid to disturbances
- Includes a vast library of built-in dynamics models for modelling many types of equipment
- Users can define custom models of any complexity using the modelling interface
- An integrated dynamic simulation plotting package allows for quick generation and export of plots from the dynamic simulations

The PSS®E Dynamic Simulation module is a versatile tool to investigate system response to disturbances that cause large and sudden changes in the power system. The dynamic simulation module employs a vast library of built-in models for modelling different types of equipment, and with capability to create user defined models of any complexity. An integrated dynamic simulation plotting package allows for quick generation of plotting with ability to export to several popular graphic formats.



Furthermore, considering the complexities in the network after the integration of HVDC and overall transmission and generation system enhancement, the requirement for detailed dynamic stability study has been increased and in order to cater this NTDC/NPCC is in process of procuring four copies of latest version of PSS/E software, this will equip NTDC/ NPCC to carry out Optimal Power-Flow analysis, Small Signal Stability analysis to study stability problems like inter-area oscillations, which are quite common in large interconnected systems.

D. Optimal Power Flow

- Go beyond traditional load flow analysis to provide the ability to fully optimize and refine your transmission system plans.
- Includes functions to minimize fuel costs, transmission losses, interface flows, and many more objectives.
- Accurately models the many controls and constraints on the network.
- Includes soft and hard limit penalties to allow more robust solutions.

PSS®E OPF improves the efficiency and through put of power system performance studies by adding intelligence to the load flow solution process. Whereas the conventional load flow relies on the engineer to systematically investigate a variety of solutions before arriving at a satisfactory "good solution". PSS®E OPF automatically adjusts controls to determine "best solution". From virtually any reasonable starting point, you are assured that a unique global optimal solution is attained, a solution that simultaneously satisfies system constraints given a pre-determined objective.

E. Small Signal Stability Analysis (NEVA)

- Provides an extension of analytical methods to examine wide-area system oscillations
- Includes methods to investigate long-term stability
- Allows a deeper view into eigenvectors, determines the best damping locations, and allows
- Evaluation of damping strategies

Stability problems, such as inter-area oscillations, have become increasingly common in large, interconnected power systems. The Eigenvalue and Modal Analysis module provides an extension of the classical large-signal analytical methods in the time-domain with small-signal methods in the frequency domain to examine these oscillations.

3.3 PRIVATE POWER CONTROL

A dedicated department is functional in NPCC to handle all Power Purchase Agreements (PPA) related activities and information exchange with CPPA-G. PPC section performs following functions as part of the System Operation organization:

3.3.1 PREPARATION OF MERIT ORDER

Chief Financial Officer CPPA-G intimates to NPCC the revised applicable fuel prices and variable O&M cost on fortnightly basis in respect of GENCOs and IPPs plants. On receipt of information from CFO CPPA-G, office of GM(SO) NPCC consolidates/prepares the revised Merit Order and submits to the members of Merit Order Committee for final approval. After approval from members of Merit Order Committee, the revised Merit Order is issued for implementation by GM(SO) NPCC, being the convener of Merit Order Committee.

3.3.2 SOURCE INFORMATION DATA OF 1994 POWER POLICY IPPS:

PPC section prepares Source Information data of 1994 power policy IPPs in accordance with NPCC Control room record and their Power Purchase Agreements. Scope of work also covers verification of start-up claims, PLAC calculation and resolution of disputes. Finalized data is sent to CPPA-G for further processing.

3.3.3 VERIFICATION OF CAPACITY ANNEXURES OF 2002 AND 2015 POWER POLICY IPPS:

Other than 1994 power policy IPPs, PPC section is also responsible for verification of monthly Capacity Annexures submitted by power plants to CPPA-G in light of NPCC record and their Power Purchase Agreements. Scope of work also covers finalization of Operating Procedures, Verification of Start-up charges claims sent by plants and resolution of technical issues in accordance with relevant Power Purchase Agreements.

3.3.4 VERIFICATION OF NPMV CLAIMS OF [illegible] POWER PLANTS:

PPC section is responsible for verification of Non Project Missed Volume (NPMV) claims of all renewable power plants commissioned under 2006 Power policy in light of NPCC record. These claims are duly verified by detailed assessment from Regional Control Centre(North) and Regional Control Centre(South) and finalized in light of their Power Purchase Agreements. Verified data is sent to CPPA-G for further processing.

Following organizational structure is implemented within PPC for efficient handling of workload:

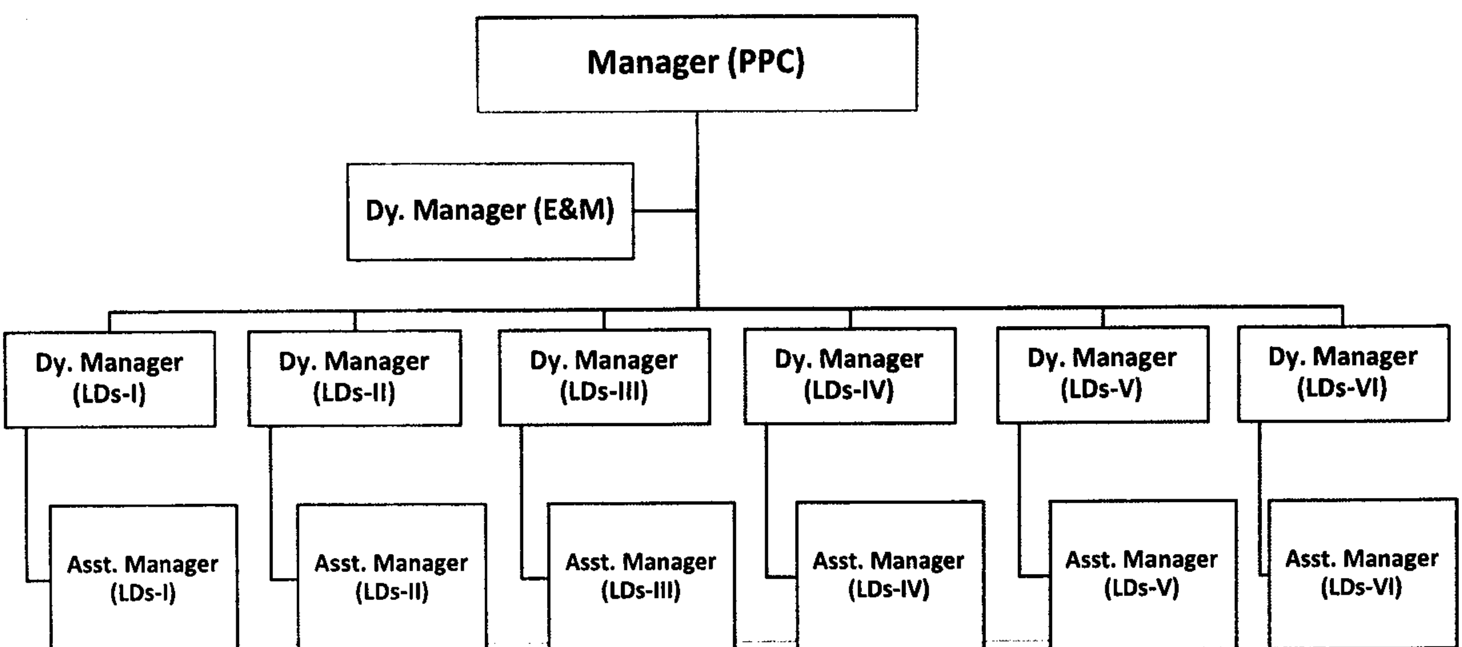


Figure-10: Hierarchy of Private Power Control Department

All the Thermal generating units and Hydel IPPs have been distributed among the mentioned Deputy Managers for timely completion of the work as work is time limited being linked with Financial settlement at CPPA-G end.

3.4 Regulatory Affairs and Database

A dedicated Regulatory Affairs department has been established in NPCC to specifically look after the formal documentary and reporting requirements of NEPRA and ensure timely compliance of all NEPRA related directions and queries. The different reports/data submitted to NEPRA on regular basis include:

- **Daily Log Report (DLR)** which includes hourly spot MW readings of all plants, hydrological data, plant major events, fuel allocation and consumption information, hourly load management data, hourly system demand and peak load, peak capability etc.
- Analysis of Objections raised by NEPRA on Daily plant operations of NPCC regarding Under-Utilization and Out of Merit RFO generation.
- Preparation of counter justifications to reduce the financial impact of objections raised by NEPRA.
- Annual and Quarterly reports for Performance Standards for Transmission Rules (PSTR) 2005 and State of Industry Report including data for frequency and voltage variations, number and frequency of trippings on primary network (SAIFI, SAIDI), overloaded and underloaded equipment details etc.
- Day-Ahead Dispatch developed through NCP software and comparison with actual dispatch and reasons for deviations
- Any special queries and data requirements from NEPRA from time to time

Additionally, all relevant formations of NTDC also vigilantly strive to fulfil all regulatory requirements of NEPRA such as maintenance of Grid Code, preparation of Indicative Generation Capacity Expansion plan (IGCEP), Transmission Expansion Plan (TSEP) etc.

Moreover, this section also performs correspondence and prepares the data required for submission to following authorities with approvals as applicable.

- National Assembly
- National Assembly Standing Committee
- Senate
- Senate Standing Committees
- Public Accounts Committee (PAC)
- Departmental Accounts Committee (DAC)
- NAB
- Audit

SECTION 04

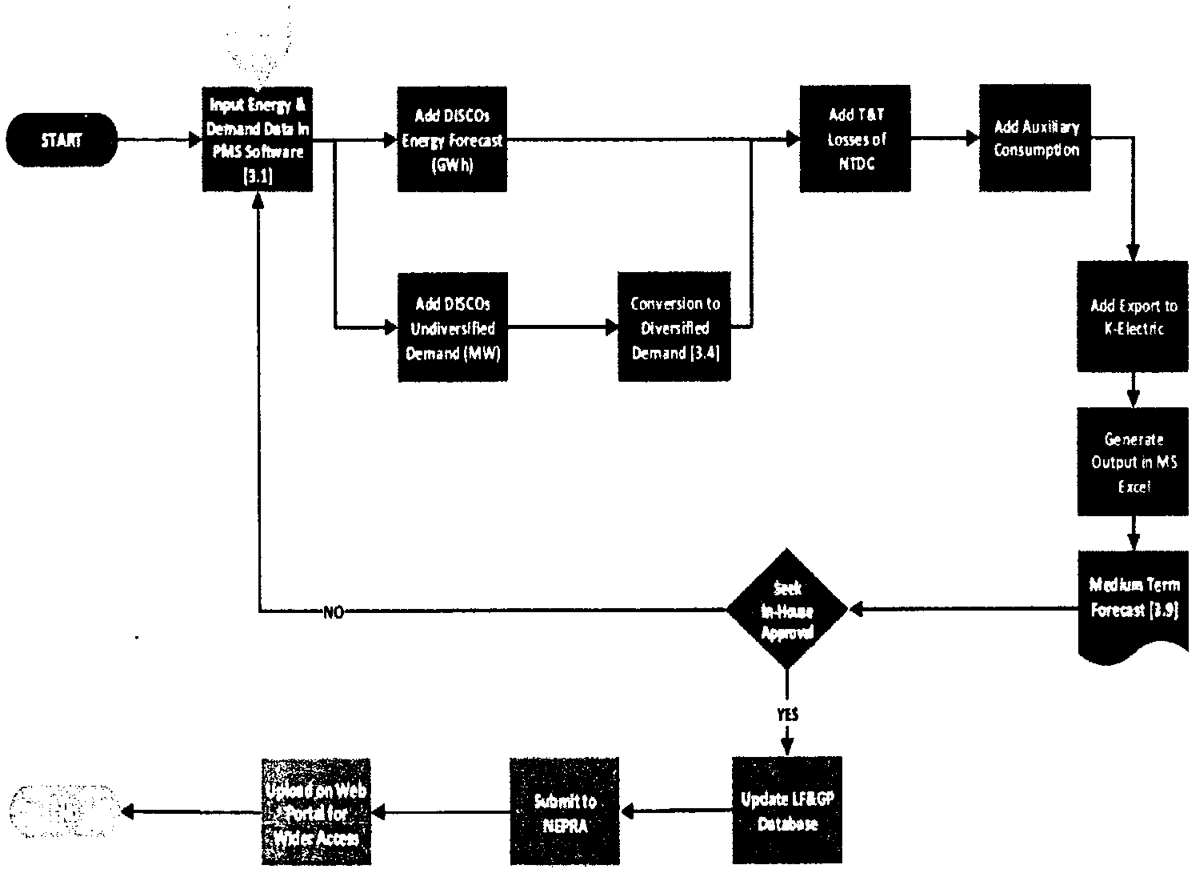
LONG TERM EXPANSION PLANNING

NTDC is mandated, as per transmission license, to "develop short term and long term plans of the Licensee's transmission system in accordance with the Grid Code". Similarly, the company is obligated to develop and submit to NEPRA load forecast and Indicative Generation Capacity Expansion Plan for the power sector. In addition to demand and supply plans, NTDC needs to submit to NEPRA its Transmission System Expansion Plan and Transmission Investment Plan. Following sections detail the current status of the planning functions carried out in NTDC:

4.1 DEMAND FORECASTING

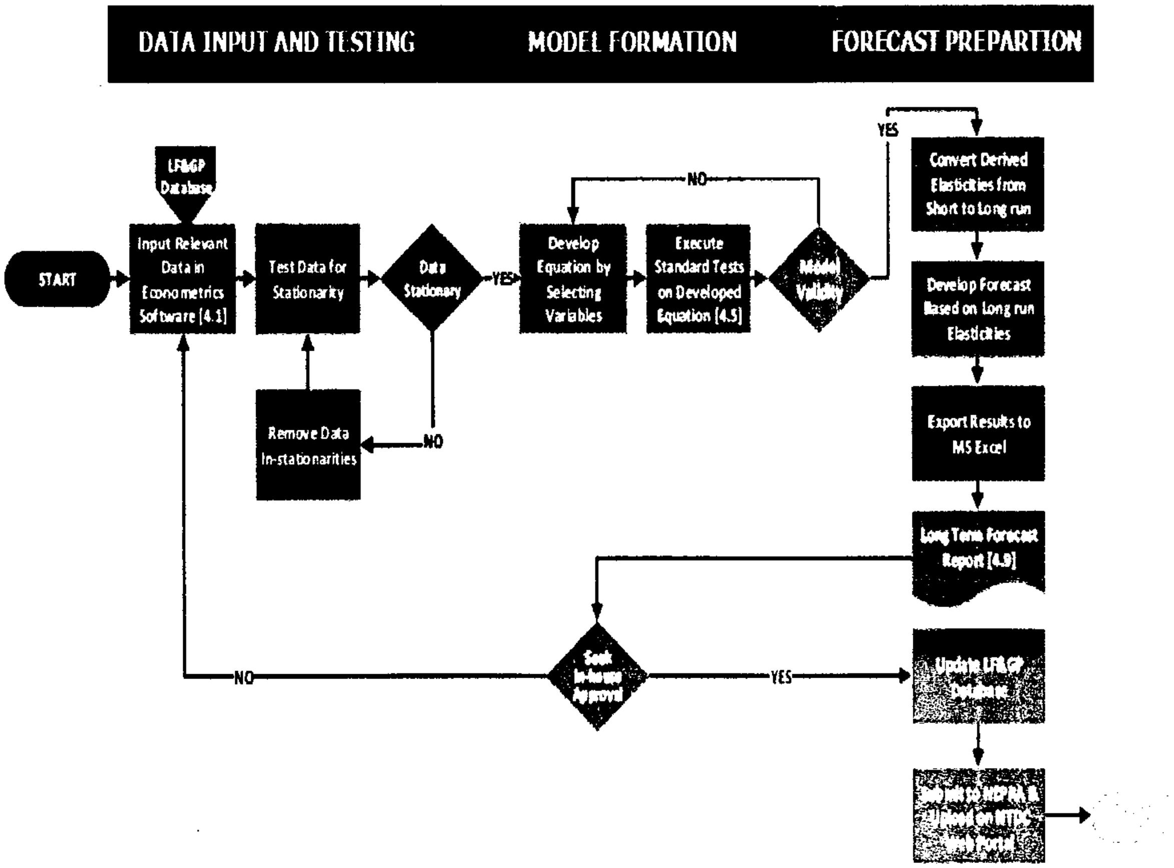
Each year NTDC performs two forecasting exercises: for long term forecast and medium term forecast. Long term forecast is used for Indicative Generation Capacity Expansion Plan (IGCEP) and medium term forecast, in collaboration with DISCOs, is used for Transmission Planning and 5-year Demand versus Supply Power Balance.

The principle behind the medium term forecast is the bottom up approach i.e. collecting input data from DISCOs (power indicators – existing MW and/or GWh, future DISCO plans, load factors and load shedding) at the 132kV grid station level of each consumer category (domestic, commercial, agriculture, public lightening, bulk, small industries and medium and large industries), aggregating up to each DISCO level and then computing up-to Country level. The process flow of PMS is shown in following figure.



DISCOs are called for a period of 2 weeks at the office of General Manager (Power System Planning), NTDC to develop the forecast using the software Power Market Survey (PMS) developed by Harza, Canadian Consultants. Each DISCO provides the input data from their respective planning and operations departments and subsequently, the representatives from DISCOs perform the forecasting exercise on PMS for their respective DISCOs. After the completion of DISCOs forecast, NTDC consolidates the DISCOs forecast to Country level.

The long-term forecast is a top-down approach and carried out by multiple regression analysis techniques. Electricity consumption (GWh) is regressed on electricity price, GDP, population and number of consumers using historical data from 1970 onwards. The process of forecast is illustrated in the process flow map in following figure.



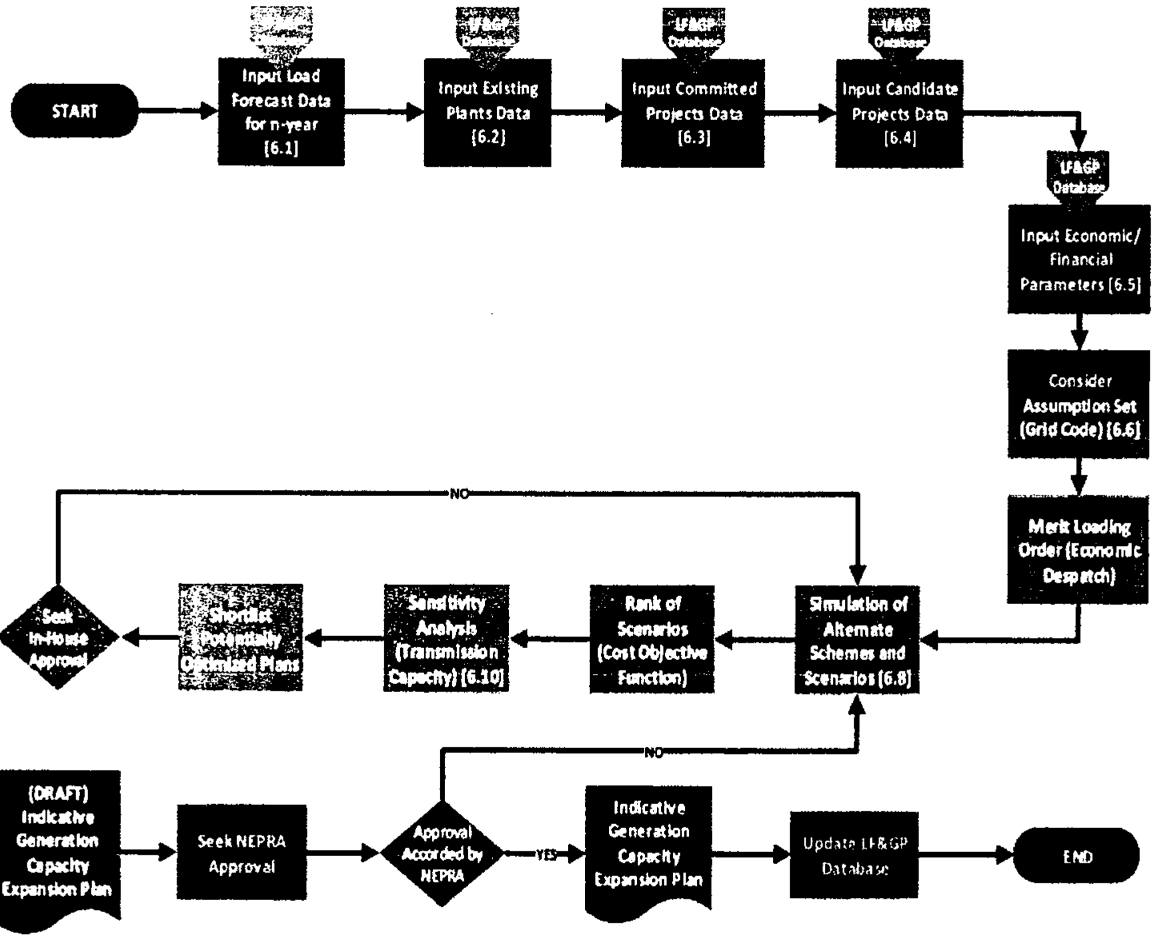
A detailed regression analysis involves the review of fundamental quantitative relationships between the electricity demand and the independent variables of the equation like electricity price, sector's GDP, and population of Pakistan etc.

4.2 GENERATION EXPANSION PLANNING

The generation planning covers rigorous data analysis and optimization exercises for the development of hydroelectric, thermal, nuclear and renewable energy resources to meet the expected load. It identifies new capacity requirements by capacity, technology and commissioning dates on year by year basis by complying with the various regulatory requirements as set out in the Grid Code including Loss of Load Probability (LOLP), the long-term load growth forecast and reserve margins.

Pursuant to the provisions of the Grid Code, NTDC is mandated for preparation of the Indicative Generation Capacity Expansion Plan (IGCEP) on annual basis for review and approval of NEPRA. The plan is used as an input for NTDC's Transmission System Expansion Plan (TSEP).

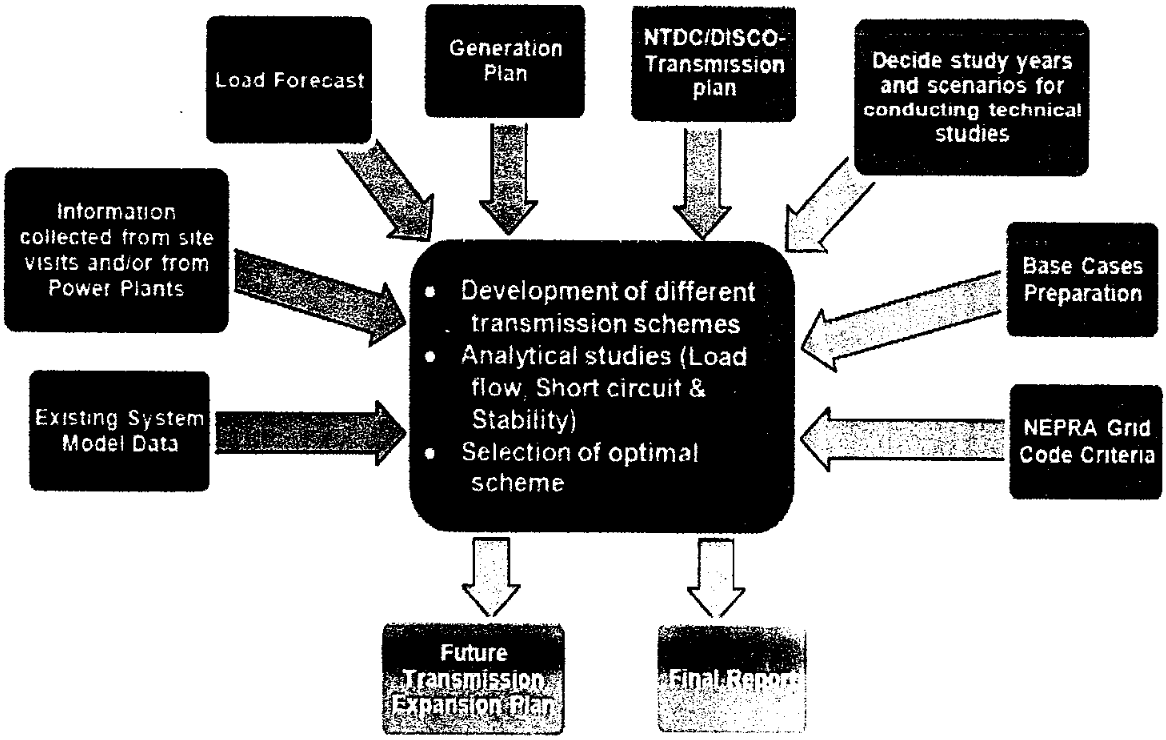
The IGCEP is prepared after following the process given in figure below; and is submitted to NEPRA for review, following an extensive consultative process prior to approval by the regulator.



4.3 TRANSMISSION EXPANSION PLANNING

Transmission planning is carried out by NTDC under connection code and planning code of NEPRA grid code to ensure reliable 500 kV and 220 kV transmission network. The core purpose of transmission planning is to make sure transmission network reliability and resiliency of the existing transmission network and carry out technical assessment of the new entity connecting with national grid e.g. generation facility, distribution company, bulk power consumer, provincial grid company, special purpose transmission line, etc. or any modification of the existing entity.

The following figure describes the process map of transmission planning.



The planning process includes:

- selection of study scenarios,
- modelling of study scenarios,
- perform technical analysis on software,
- load flow and contingency studies, short circuit studies, transient stability studies,
- preparation of interconnection alternatives,
- recommendations of the most technically feasible scheme.

SECTION 5

GRID CODE

5.1 INTRODUCTION:

Pursuant to the Section 23H of the NEPRA Act (referred to as "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 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 Operator(s) (the TNO(s)) 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.

In light of approved CTBCM design, new market players (such as Suppliers, multiple Distribution Network Operators and Transmission Networks Operators), new technological advances such as HVDC & VREs, and functional separation of SO from NGC, the NEPRA Grid Code 2005 has been revamped by a specialized cross-functional team of NTDC engineers with support from international consultants (CESI, DNV-GL, MRC) and local energy experts (LUMS, PPI, CPPA-G).

The main objectives of the Grid Code are:

1. To facilitate the planning, development, operation, and maintenance of an efficient, co-ordinated, 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;

This Grid Code includes the following sub-codes:

CODE MANAGEMENT

This sub code covers governance arrangements through a Grid Code Review Panel (GCRP) including interpretation, the procedures to amend the Grid Code subject to NEPRA approval, dispute resolution mechanism etc. and general conditions.

PLANNING CODE

This sub code establishes the principles, standards, processes, and procedures for long term expansion planning, including data exchange to ensure an efficient, economic, and timely development of the National Grid to meet the forecasted total system demand and reserve margin requirements. It also describes in detail the data that the users must provide in a timely manner to meet the planning responsibilities of the SO. In accordance to the Planning Code, the SO has to develop the Transmission System Expansion Plan (TSEP) and Indicative Generation Capacity Expansion Plan (IGCEP).

CONNECTION CODE

This sub code establishes the principles, procedures and technical requirements for new connections by generation, distribution companies, consumers that want to connect directly to transmission (transmission connected consumers), and international interconnections.

OPERATION CODE

This sub code sets out the principles, technical and operating standards, procedures, and guidelines to be followed by SO and users to ensure the safe and efficient operation of the transmission system, covering mid- and short-term operational planning of the system, characteristics and requirements of ancillary services, real-time operations, and procedures for normal and abnormal circumstances. Therefore, this sub-code establishes the procedures for the System Operator to carry out its functions and deliver system operation services, as well as the operational responsibilities and procedures for transmission network operators and all grid users. Users have the obligation to cooperate with the SO and follow the technical and operation criteria and procedures established in this sub code.

[illegible] DISPATCH CODE

This sub code covers the principles, standards and procedures for day-to-day least cost generation scheduling (Indicative Operations Schedule) and real-time dispatch within system reliability and security constraints, the allocation and administration of ancillary services, and timely exchange of information between the SO and users.

PROTECTION AND CONTROL CODE

This sub code establishes the protection and control requirements (standards and design) and procedures for users and for transmission network operators.

METERING CODE

This sub code establishes the metering requirements (standards and design and procedures) for Metering Service Provider (MSP) and Market Participants/Service Providers.

DATA REGISTRATION CODE

This sub code identifies the data requirements, and how the information will be exchanged. Therefore, this sub-code has the purpose of collating all data required in all other sections (connections, operation, planning, etc.).

SECTION 6

IT STRATEGY

6.1 INTRODUCTION

Since the National Grid is expanding continuously with new stakeholders emerging in the power sector such as new Generators in CTBCM, multiple Suppliers and Distribution Network Operators, provincial grid companies, NTDC is highly committed to revolutionize its IT structure for effective data and information sharing with all market players. Technology is upgrading day by day and intruders are trying their best to breach network and to gain access of critical systems. So, it is very important to mitigate all type of attacks and to minimize their impact timely. NTDC information system is very critical and to secure it against known and unknown threats, information security standard guidelines such as those suggested by the ISO/IEC 27001 have to be followed. By adopting these guidelines, we can use defined in-depth concepts to secure critical systems and to provide its 24/7 availability to users. IT strategy in terms of infrastructure includes physical hardware and facilities (including data centres), data storage and retrieval, network systems, legacy interfaces, and software to support the business goals of NTDC. Of course, no strategy is complete without policy, testing, operations, upgrades, maintenance, as well as hiring and training. Following IT strategy will be followed in NTDC w.r.t System Operations.

6.2 INFRASTRUCTURE & SECURITY

The following IT strategies and security policies are being deployed in NTDC/NPCC:

- Server and User network will be separated to control the traffic.
- On server network, separate zones on firewall will be created for each server category to provide further security.
- Each server will be in separate VLAN which will provide extra layer of security inside the network and control the server communication with end-users and peers.
- Security policies to control IP based communication of each user with server network are being developed.

- For IPPs access, SSL VPN connectivity will be provided to access the server resources.
- For Server security, antivirus security shall be deployed.

For User network,

- IAM (Sangfor) for user network management has been deployed.
- Active Directory domain network inside NPCC has been deployed to authenticate end-users and to track/control the system resources.
- DC users will be connected to IAM to deploy further security policies and restrict the access of end users to allowed resources only.

RAID level 1+0 will be used to provide fault tolerance and redundancy.

  - SAN (OceanStor V6-3000 Dorado) will be used as a backup storage for all applications.
  - Three Servers (Inspur, Lenovo) will be used for the SDXP and Database.
  - One SAN and Server will be placed for Disaster Recovery site at NTDC Lahore.

- SOFTWARE
  - **VMware:** vSphere will be used to utilize maximum output of H/W resources and to deploy our software infrastructure as per the company.
  - **VCenter:** HA will be used to provide mirroring of all resources whereas NIC teaming and DRS will be used in future.
  - **Veeam:** Solution will be used for the backup of DBs.
  - **SIEM:** solution (OS) will be used to monitor the daily logs.
  - **Antivirus:** server will be used to monitor known malwares on daily basis.
  - Active Directory Domain Controller will be used to manage users centrally.
  - Moreover, all software products will be licensed on yearly basis to mitigate future threats.

6.4 SDXP

The SDXP web portal has been developed in **Microsoft Tools & Technologies by using Microsoft .Net Core and Microsoft SQL Server using MVC framework and Microsoft SQL Server as Database**. The application uses following front end technologies:

i) HTML 5.0

ii) CSS 3.0

iii) Bootstrap 3.0

iv) AJAX/JQuery/Angular

6.5 DATABASE

6.5.1 SQL SERVER BACKUP POLICY

a. WEEKLY FULL BACKUP:

A full backup is a complete backup of your SQL Server database. It backs up all of the objects of the database: tables, procedures, functions, views, indexes, etc.

b. DAILY DIFFERENTIAL BACKUP:

A differential backup contains only the data that has been changed since the last full database backup was created. Creating differential backup usually takes less time than a full backup, because you back up only modified data instead of backing up everything.

c. HOURLY TRANSACTIONAL LOG BACKUP

A transaction log (T-log) backup is the most granular backup type in SQL Server because it backs up the transaction log which only contains the modifications made to the SQL Server database since the last transaction log backup. It's effectively an incremental backup.

6.5.2 SQL SERVER RECOVERY POLICY

a. SIMPLE RECOVERY

For databases using the Simple Recovery model, SQL Server automatically truncates the log on checkpoint operations, freeing up used space in the transaction log for additional transactions. When using Simple Recovery, transaction log backups are not supported.

Example:

Recovery steps: Last Full + differential Backup and losses data possibility.

b. FULL RECOVERY

Under a Full Recovery model, all transactions remain in the transaction log file until you run a transaction log backup. The transaction log will never be auto-truncated as would occur under the Simple Recovery model.

Example:

Recovery steps: Last Full +differential Backup + Transactional log and Data loss is minimized.

c. BULK-LOGGED RECOVERY

The Bulk-Logged Recovery model is similar to Full Recovery except that certain bulk operations are not fully logged in the transaction log (this is called minimal logging). Operations like SELECT INTO, BULK import, and TRUNCATE operations are examples of minimally logged operations.

EXAMPLE:

Recovery steps: Last Full +differential Backup+ minimally log and Data loss is minimized.

SECTION 7

HUMAN RESOURCES

7.1 IN-HOUSE TEAM

The strength of an organization is primarily measured by the strength of its human resources. For last several years, the applicant has been working on enhancing the strength of its professionals in the capacity of System operations. The following table provides summary of the professionals currently working in the System Operation are given below:

Sr.	Name	Designation	Grade
1	Sajjad Akhtar	General Manager (System Operation)	BPS-20
2	Waseem Younus	General Manager (Power System Planning)	BPS-20
3	Mehtab Ahmed	Chief Engineer (Network Operations)	BPS-20
4	Muhammad Zakria	Chief Engineer (Operation Planning)	BPS-20
5	Javaid	Chief Engineer (SCADA)	BPS-20
6	Nasir Ahmed	Chief Engineer (Load Forecast & Generational Planning)	BPS-20
7	Farooq Rasheed	Chief Engineer (Transmission Planning)	BPS-20
8	Shahida Wazir	Chief Enginner (Resource Planning)	BPS-20
9	Shahbaz	Manager (Load Forecast & Generational Planning)	BPS-19
10	Javed	Manager (Transmission Planning)	BPS-19
11	Nadia Ahsan	Manager (Transmission Planning)	BPS-19
12	Shakoor	Manager (Transmission Planning)	BPS-19
13	Shahid Abbas	Staff Economist	BPS-19
14	Aijaz Ahmed	Manager (Power Control)	BPS-19
15	Abdul Kabir	Manager (RCC-N)	BPS-19

16	Tahir Sheikh	Manager (RCC-S)	BPS-19
17	Shakir-Ullah	Manager Database	BPS-19
18	Saeed Akhtar	Manager (Operation Planning)	BPS-19
19	Umm-e-Kulsoom	Manager (Private Power Control)	BPS-19
20	Jawaid Rehman	Manager (I.T)	BPS-19
21	Muhammad Ali Waqar	Additional Manager (SCADA)	BPS-19
22	Sumair Memon	Manager SCADA-III	BPS-19
23	Saqib Javed	Manager SCADA-III	BPS-19
24	Shahrukh Saleem	Deputy Manager (SCADA)	BPS-18
25	Salman Gul	Deputy Manager (Generation Op Planning)	BPS-18
26	Nabeel Ali Paracha	Deputy Manager (Generation Op Planning)	BPS-18
27	Saeed Ahmed	Deputy Manager (System Operator)	BPS-18
28	Mubashir Khan	Deputy Manager (Shutdown)	BPS-18
29	Muhammad Kaleem	Deputy Manager (Power Control-II)	BPS-18
30	Muhammad Kashif	Assistant Manager (System Operator)	BPS-17

Table-1: Summary of Professionals working in System Operation

7.2 Consultants

In addition to the in-house team of system operation and power system experts, several international and local consultants have also been engaged with expertise of system operation, system studies, generation planning software modelling, demand forecasting, SCADA, organizational restructuring, business process reengineering, Connection Agreements and PPAs etc. The Consultants and international companies available to NTDC for technical support in SO function are mentioned below:

M/S CESI

CESI

CESI is a technical consulting and engineering company in the field of technology and innovation for the electric power sector with an experience of more than 60 years and operating in 70 countries. NTDC has acquired services of CESI to carry out wide range of offline system studies for review of the grid system performance & proposals for system stability improvement. The studies and analysis involve following:

1. Defence Plans and Remedial Management System
2. Protection Relays Set-Point identification for.
3. Studies to design Relay coordination schemes.
4. Reactive Power Management plans for Summer and Winter seasons.
5. Determination of Maximum Loading Limits of equipment under summer and winter scenario in normal and contingency conditions.
6. Identification of clusters for splitting the power system at various voltage levels in case of major system disturbance.
7. Short circuit analysis of NTDC Systems, to determine the rating of existing switchgear ratings.
8. Undertaking Large and Small Signal Stability Analysis of NTDC network, to identify the oscillatory modes.
9. Undertaking Electromagnetic Transient Studies to determine the correct rating and sizing of shunt reactors, surge arrestors and other related switchgear.
10. Conducting GAP Analysis on NTDC SCADA and communication system, to determine the requirement of Wide Area Management etc.
11. Capacity building of NTDC (NPCC/PSP/P&C) to carry out above mentioned studies at their own in the future.

M/S HATCH

HATCH

HVDC technology has been introduced in Pakistan's National Grid for the very first time in the form of ±660kV Matiari-Lahore HVDC Project. NTDC hired M/S HATCH as Owner Engineer to provide the expertise in the field of HVDC. Clientele of HATCH spans over 150 countries around the world in the metals, energy, infrastructure, digital, and investments market sectors. The consultant is providing following services:

1. Review of Documents related to HVDC Design and Control parameter tuning.
2. Review and FAT (Factory Acceptance Tests), FST (Factory Setting Testing) reports.
3. Preparation & Review of various Commissioning & Testing Documents.
4. Creating Punch Lists for Commissioning Tests.
5. Detailed Review of Commissioning Test Reports and passing the commissioning tests.
6. Review of various studies regarding protection schemes of HVDC system.
7. HVDC Supplementary Control Features Setting & Testing.
8. Lead Engineer to overlook the commissioning process and Guide NTDC engineers regarding commissioning tests.

SAGE AUTOMATION

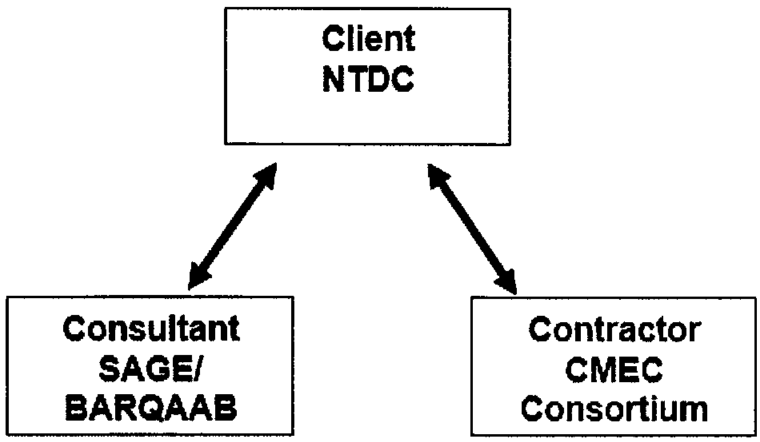
SAGE Automation

M/s SAGE Automation, based in Australia, in Consortium with M/s BARQAAB Consulting Services Pvt. Limited is providing Consulting Services for SCADA – III Project "Procurement of Plant – Design, Supply, Installation, Testing and Commissioning of SCADA Phase-3 and Revenue Metering System (RMS) for NTDC". The said project is funded by ADB under Contract No. ADB-202R-2019, Loan No. 3577-PAK. Project organization and management approach between the three key participants in the NTDC Rehabilitation and Upgradation of SCADA and EMS System and Revenue Metering System project (The LDPIII Project) is as follows:

The Client - National Transmission & Despatch Company Ltd (NTDC)

The Consultant - SAGE Automation (Australia) and BARQAAB Consulting Services (Pakistan) Joint Venture

The Contractor - CMEC Consortium (China Machinery Engineering Corporation (Consortium Lead) & Hitachi Energy)



The Consultant will monitor and review the performance of the Contractor and report to the Client. The scope of work for the Consultant includes:

- Supervision of Implementation by acting on behalf of the client on project management and contract management
- Review the existing environmental reports that have been prepared and identify the gaps and additional work to be carried out
- Review and Approval of Contractor's Detailed Design
- Inspection of the quality of materials, workmanship and performance of the major items of the work and equipment to be furnished by contractor
- Act as representative of the Client to ensure the expeditious and economical construction of the project
- Verification/ Certification of Contractor's Invoices
- Act as representative of the Client in the supervision of testing, pre-commissioning and commissioning of the equipment supplied by the contractor
- Review of Contractor's as Built Manuals/ Drawings
- Assist Client on Project and Contract Management

- Provide support to Client on implementation of EMP and LARP
- Assist on Program for Post-Construction Services
- Provide Technical & Professional Assistance and Training to Client's Staff

The SCADA Design, Engineering and Integration experts from Sage include Mr. Gary Brooks (20 years of experience) and Mr. Maciej Ficek (more than 30 years of experience).

DEMAND FORECAST CONSULTANT

NTDC has acquired the services of Dr. Derek Bunn, a UK based demand forecast expert with an experience of over 40 years in Harvard and London Business School. He is engaged with NPCC for:

- Analysing the requirements of NTDC/ NPCC (System Operator) for short-medium term system demand forecast
- Identify load forecasting techniques and standards used in international power utilities, and identify which international standards (IEEE, IEC etc.) and load forecasting methodologies are suitable for NPCC/NTDC, while keeping in view NEPRA Grid Code requirements and real time operational constraints in Pakistan's power system (e.g. spinning reserve availability, VRE intermittency, network constraints etc.).
- Assist NPCC/NTDC in preparing RFPs/TORs and evaluating candidates to hire a suitable load forecast service
- Support NPCC for development of forecast model, data acquisition, validation of data
- Engage with the forecast service in real time to evaluate accuracy of results, identify causes of error and suggest remedial measures
- Training and capacity building of NTDC engineers in demand forecast techniques

7.2.1 LOCAL CONSULTANTS

The local Consultants available to NTDC for different System Operation related activities are listed below:

Sr.	Name	Area of expertise
1.	Muzammil Hussain	Policy, Regulations and PPAs
2.	Tariq Saeed	SCADA EMS design and implementation

3.	Dr. Fiaz Chaudhry	Grid System Performance Review & System Stability Improvement Project
4.	Abdul Rauf	Transmission Network Studies (PSS/E)

Table 2: Summary of Local Consultants

SECTION 8

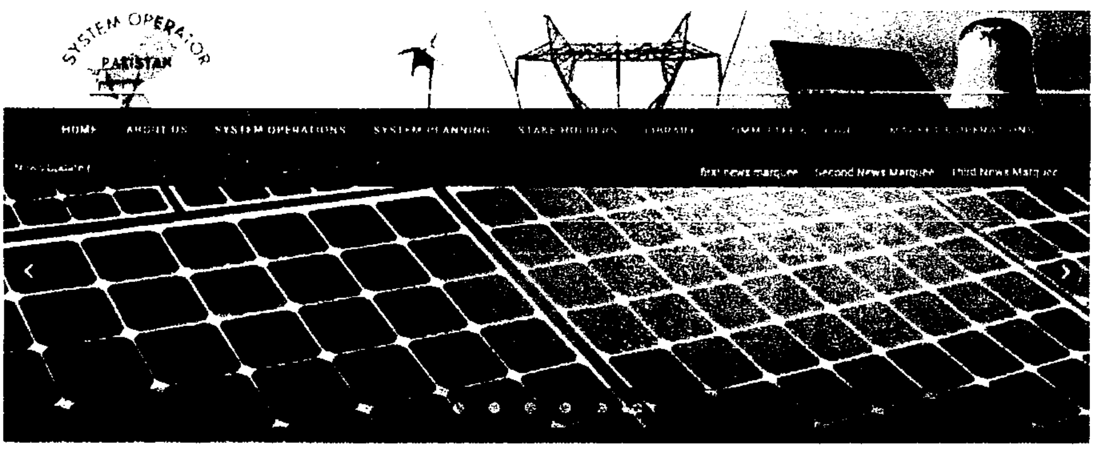
SYSTEM OPERATOR WEBSITE

One of the key objectives of System Operator would be to ensure transparency in the processes of System Operation functions to build up confidence of market participants and provide easy and instant access of System data to the market players for timely decision making & other services.

To ensure this objective, among other required IT interventions, state-of-the-art website is being developed for availability and accessibility of information, processes and data to the targeted audience.

Reporting of the planning and actual operations summary is being published as per the methodology and frequency established in the Grid Code and the Commercial Code. For the purpose of transparency and data reporting, SO's website is being revamped and necessary information as desired under the relevant codes from the system operator are being published on the website.

Following are some of the screenshots of the System Operator Website:




SYSTEM OPERATOR
Today's Snapshot
NaN
23271
23271
Available Capacity: 08-06-2022
Fuel Mix
VRE
Time (Hours)
Time (Hours)
Time (Hours)
Time (Hours)
Gas - Fuel
HSD - Fuel
Pakistan Load Map
Data Source: FITC 2022-06-08 14:02:07
Northern Areas
N.W.F.P.
Azad Kashmir
F.A.T.A.
Punjab
Baluchistan
Sindh
Pakistan Energy Cost Map
FESCO,TESCO
PESCO
Kashmir
TESCO
IESCO
QESCO
KE/HESCO

ALI ZAIN BANATWALA
DEPUTY MANAGING DIRECTOR, SYSTEM OPERATION

SUMMARY OF QUALIFICATION

Mr. Alizain Banatwala is a power sector expert with 15+ years of national and international power sector experience. His core competencies include power systems optimization and modelling, grid integration of renewable energy and energy risk managament. As a consultant for the Asian Development Bank (ADB) and the German Technical Cooperation Agency (GIZ), he has provided consultancy in power transmission, smart grids and grid integration of renewable energy to transmission and distribution companies in Vietnam, Bangladesh, Georgia, Ghana and Pakistan.

PROFESSIONAL EXPERIENCE

2022 -	**Deputy Managing Director (System Operation), NTDC,** Islamabad
2019 - 2022	**Consultant, Deutsche GIZ:** Pakistan & Bangladesh
2019 - 2019	**Consultant, Switzerland State Secretariat for Economic Affairs:** Ghana
2016 - 2019	**Consultant, Asian Development Bank:** Pakistan, Vietnam, Bangladesh, Georgia
2018 - 2019	**Utilities Expert, SAP Middle East & North Africa LLC,** Karachi
2008 - 2017	**Various Roles, E.ON Energy Trading & E.ON Connecting Energies,** Germany
2005 - 2007	**Quant Developer, North American Power Trading, Morgan Stanley CA,** Canada
2003 - 2005	**Software Engineer, CGI,** Montreal, Canada
1997 - 1999	**Business Development, Asiatic Shipping Agencies,** Karachi

EDUCATION

M.Sc. Electrical Power Systems, University of Bath, United Kingdom

M.Sc. Finance, London Business School, United Kingdom

B.A. Mathematics, Duke University, USA

SAJJAD AKHTAR
GENEAL MANAGER SYSTEM OPERATION NPCC

SUMMARY OF QUALIFICATION

Mr. Sajjad Akhtar has a versatile professional career of over 32 years with hands on Technical expertise and Managerial experience in Power System Operation while working in National Transmission and Dispatch Company (NTDC) and Power Distribution Company (IESCO) at various positions. Also worked abroad for more than ten years in KSA in the field of Power Dispatch and Network Control Operation. Practical working experience as an Electrical Engineer in Private Industry in Pakistan.

His field of particular experience includes Power System Operations, Security Constrained Economic Dispatch, System and Network Operation Planning, Operating Procedures of Power Plants, Power Purchase Agreements, VRE Forecasting, Merit Order Preparation, Generation Planning, Fuel Planning, SCADA Systems, Regulatory and Policy matters related to System Operations, Distribution System Operations, CTBCM/Electricity Market matters related to System Operator. His collaborative work includes working with Ministries, Regulator, Power Utilities, International Consultants, National Assembly, Senate, Prime Minister Office, DAC, PAC and other key institutions pertaining to the relevant power sector affairs.

PROFESSIONAL EXPERIENCE

2022- To Date **General Manager (System Operational), NPCC, Islamabad Pakistan**

As General Manager (System Operation) he is responsible for Management, Supervision, Monitoring and Co-ordination of all activities related to Power System & Network Operation of NTDC Primary Network including 500&220 kV HVAC and 660kV HVDC System, IPPs, GENCOs, WAPDA Power Plants, DISCOs, CPPA-G and other Power utilities i.e. KE. He is also responsible for proper coordination with all Private Power Companies and other generators to deal these in accordance with their respective PPAs. He leads different teams in the organization in coordinated manner to ensure smooth system and network operation enabling NPCC/SO to generate the power at low cost and to transmit it qualitatively to various Distribution Companies and other utilities. He is Convener of Economic Merit Order Committee and ensures its preparation and finalization in coordination of all concerned. He is leading his respective teams for Short Term and Medium Term operation planning including Generation, Fuel, Transmission and Distribution Network Planning to ensure economic, reliable, safe and stable power system operation. He guides his team in reviewing technical specifications and preparation/finalization of SOPs of existing and upcoming IPPs and other Power Generating Plants in accordance with their respective PPAs in coordination of CPPA-G and other concerned. He acts as a focal person of NTDC organization regarding pertinent matters and issues from System Operation point of view to deal with CPPA-G, NEPRA, Ministries, PPIB, AEB, IPPs, DISCOs, PAC, National Assembly & Senate Standing Committees. He leads and guides his various section heads regarding Financial/Procurement matters, Administration and Civil Works/Projects being executed at NPCC. He supervises, guides and administers his relevant team in Procurement, Evaluations, Contract Preparation and timely completion of key projects and works at NPCC.

2020- 2022 **Chief Engineer (Network Operation), NPCC Islamabad, Pakistan**

Worked as the head of overall Power System and Network control and supervised the working of NCC, RCC(N) and RCC(S) directorates through effective and close coordination with all stakeholders to ensure economic commitment and dispatch of power plants, safe and reliable operation of 500 & 220 kV Primary HVAC and 660kV HVDC System and smooth dispersal of power to all DISCOs and other utilities through respective CDP points. Led the team in crises whenever emerged in the system for quick and safe recovery of the system and apprised all relevant concerned in effective manner. Ensuring strict adherence of all laid down SOPs by the control room engineers to safeguard the system against any possible eventualities. Imparting continuous guidance and feedback to the team members for better and efficient system operation. Lead the team at NPCC for successful Testing and Operating the first ever 660kV, 4000 MW, 877 Km Long HVDC System between Matiari and Lahore Converter Stations. Coordination with all relevant formations and organizations for sorting out all possible means for safe and stable network operation. Led and guided the team in preparing SOPs for the relevant sections of NPCC to ensure effective work environment.

2018- 2020 **Manager Regional Control Centre North (RCCN), NPCC, Islamabad Pakistan**

As Manager RCC(N), he was responsible for supervision of overall Directorate of RCCN which Operates, Monitors and Controls 132 & 66kV Network of Discos that include PESCO, TESCO, IESCO, GEPCO, FESCO, LESCO and partial MEPCO regions through close liaison and coordination of NCC, RCC(S) and concerned DISCO's PDCs. To supervise and guide for the smooth functioning of all activities being done by the RCC(N) Control Room shift Personnel through proper chain of command in accordance with the relevant SOPs. Ensuring safe and secured operating limits of Network Components and other system parameters as per grid code to ascertain continuous power supply to all DISCOs and equipment safety. Prepared various SOPs for the Control Room Shift engineers and Operators to operate the network effectively and to safe guard the network component and personnel from any hazards. Coordinated with relevant NTDC and DISCOs formations for addressing network constraints for safe, economical and reliable system operation.

2016- 2018 **Deputy Manager (Transmission Shut Down), NPCC, Islamabad, Pakistan**

As DM (Transmission shut Down), he was responsible for studying 500 and 220 kV transmission lines and grid components keeping in view various system scenarios and prepare a plan for NCC Control Room Engineers for execution during the outages in real time system operation. Analysis and preparing system tripping report for appraisal to concerned formations for remedial measures. Proposing and devising various Cross Trip Protection Schemes for further study and implementation by NTDC relevant quarters to safeguard the system against cascaded effect and to ensure stability to the possible extent.

2005-2015 **Power Dispatch Engineer MARAFIQ, Kingdom of Saudi Arabia**

Worked as Supervisory Shift Engineer and responsible for the Supervision, Monitoring, Operation and Control of 380 &115 kV MYAS unmanned System of Yanbu industrial city, KSA through SCADA System. Ensuring economic commitment and dispatching of various Gas Turbines and Steam turbine to meet the system demand as well as to maintain the scheduled power Exchange with SEC Western Region. Carrying out all switching operations and isolation of grid equipment from Remote keeping in view the safety precautions and being the API issuing PTWC to the concerned party through proper procedure for utmost safety of equipment and personnel. Maintaining and operating all transmission and Sub Station equipment in permissible operating limits and ensuring its Corrective Maintenance through effective follow up process using advanced and sophisticated SAP system. Analyzing and reporting system incidents to the concerned formations of the Company and appraisal to the Regulator ECRA. Reviewed and updated various SOPs according to the prevailing system requirements.

2003- 2005 **Deputy Manager (Supervisory Shift Engineer) NCC, NPCC, Islamabad, Pakistan**

Worked as overall in charge of NCC shift and was responsible for economic power dispatch and supervision, monitoring and control of 500 & 220 kV WAPDA Primary system. Also supervised both the Regional Control centers RCCN & RCCS to ensure smooth operation of 132 & 66kv network to ensure reliable power supply to various DISCOs.

1992- 2003 **Assistant Manager, NPCC, Islamabad, Pakistan**

Worked on various positions during this period and performed different tasks and assignment related to Economic Load Dispatch, Power System Operation, Power Position Planning, Network Outage Planning, System Tripping Analysis, Protection Schemes Proposal and Shift Control Engineer.

1991- 1992 **Sub Divisional Officer (E), WAPDA, AEB Islamabad, Pakistan**

Responsible for Supervision of technical and other general staff working in different sections of the sub division office. Supervision and Maintenance of 11 kV and 400 volts distribution system. Power connection to domestic, commercial and industrial consumers. Billing of different tariff consumers and revenue collection. Planning and execution of Energy Loss Reduction (ELR) in the distribution system for optimum and economical system operation.

1990- 1991 **Junior Engineer Trainee, WAPDA, Pakistan**

Received Basic Induction training on Managerial and Technical side at WAPDA Training Institute at Tarbela and Faisalabad academies after induction in WAPDA organization as a Junior Engineer.

1988- 1990 **Assistant Manager Electrical, Nowshera Sheet Glass Industries, Adam Zai.**

Worked as Assistant Manager Electrical in Nowshera Sheet Glass Industries and fulfilled the responsibilities and tasks related to supervision of all technical staff of electrical section to ensure smooth functioning and operation of electric installations in the in the company including maintenance and troubleshooting of all kind of 11kv and 400 v equipment, switchgears, Induction Motors, DC Motors, DG Sets 1000KVA, Power Transformers, DC Battery Banks and Chargers, Electronic and pneumatic Control Instruments etc. Remained team member for installation and commissioning of tempered glass plants in collaboration of Chinese team of experts.

EDUCATION

BSc Electrical Engineering Power university of Engineering & Technology (UET) Peshawar, 1988.

MSc Electrical Engineering Power System University of Engineering & Technology (UET) Lahore, 1998.

Master in Human Resource Management (HRM), Virtual University Islamabad, 2020.

HONORS

- As Convener of Economic Merit Order Committee which prepares and issues Economic Merit Order of thermal power plants being operated on fossil fuel keeping in view the prices of various types of fuel, heat rate and efficiency of generators, O&M cost of plants. The merit order is prepared fortnightly by considering the fuel prices fixed by OGRA and issued to the System Operator for implementation to commit and dispatch the plants in economic order giving due consideration to system congestions and stability.
- Act as Team member to in testing, commissioning, and operation of maiden HVDC system in the country along with NTDC, PMLTC, IE and OE HATCH experts.
- Prepared nomenclature and codes for HVDC system configuration at Matiari and Lahore Converter stations.
- Participated in Technical discussion for review of Operation Procedure related to DCO for CASA 1000 with concerned stakeholders.
- Act as a member of steering committee regarding revision of Grid Code.
- Prepared Standard Operating Procedures (SOPs) for Regional Control Centers to carryout Monitoring, Operation and Control of NTDC and DISCOs system in compliance of NEPRA Grid Code.
- Prepared SOP of System Restoration after Partial and Complete collapse for speedy recovery of the system.
- Led the team in restoration of power system after partial and complete collapse in 2018 and 2021.
- Actively participated in proposing and devising UFLS and Cross Trip Schemes for System Stability and Network Security.
- Devised Rate of Change of Frequency (ROCOF) protection Scheme to safeguard the system against decay of frequency in case of loss of huge generation quantum.
- Participated in MIMG Meetings and Discussion regarding CTBCM, SDXP and MSP implementation leading towards the open energy market.
- Leading towards strengthening of SO to meet the challenges of free Energy Market in future.

TRAININGS/COURSES/WORKSHOPS

- Six months training of Basic Management at WAPDA Academy Tarbela in 1990.
- Six months Technical Training at WAPDA Academy Faisalabad in 1990-91.
- Three weeks LDC level-II training at WAPDA Academy Faisalabad in 1992.
- Ten days training of LIHTO and SYRAP computer program conducted by PPA (Power Planning Associates) from 8th Jan, 2001 to 18th Jan, 2001 at NPCC Islamabad.
- Nine weeks Middle Management Course MMC in 2017 at WAPDA Administrative Staff College, Islamabad.
- Four weeks Technical Refresher Course in 2018 at WAPDA Engineering Academy Faisalabad.
- Three weeks Technical Refresher Course for BPS-18 at TSG Training Center Lahore in 2018.
- Three weeks Senior Management Course (SMC) in 2018 at LUMS Lahore.
- Three days Leadership training at NTDC in Nov'2021 at TSG Training Centre Lahore.
- Two Weeks Senior Leader Ship training in Aug'2022 at WAPDA Administrative Staff College, Islamabad.
- Besides above a number of short training and refresh courses regarding safety, management, capacity building, Report Writing etc. received while working in MARFIQ, YANBU in KSA during 2005 to 2015.

NASIR AHMED
CHIEF ENGINEER POWER SYSTEM PLANNING (PSP)

SUMMARY OF QUALIFICATION

Mr. Nasir Ahmed has been working with NTDC/WAPDA for over 31 years with technical as well as managerial experinces in both organization. His experience includes operation & control of WAPDA's (Mangla) PowerStation, operatation & control of 132/66 KV DISCOs Network in South Jamshoro (RCC South), Operation & control NTDC's Primary Network at NPCC Islamabad both as supervisory control engineer and higher managerial positions.

PROFESSIONAL EXPERIENCE

Feb-22- To Date	**Chief Engineer (Load Forecast & Generation Planning), PSP, NTDC Lahore, Pakistan** Development of consolidated Demand Forecast and using the forecast to develop Indicative Generation Capacity Expansion Plan (IGCEP).
Dec-21- Feb-22	**Chief Engineer (Transmission), PSP, NTDC Lahore, Pakistan** Development of Transmission System Expansion Plan (TSEP).
Oct-21-Dec-21	**Chief Engineer (O&M), HVDC, NTDC Hyderabad, Pakistan** Supervision of maintenance activities of ±660 kV HVDC Matiari-Lahore T/Line and also monitoring the construction activities of 500 kV D/C SSRL-Matiari Circuits.
2018-2021	**Manager (Power Control), NPCC, NTDC Islamabad, Pakistan** Manager of NPCC Control Room & Generation Planning, Outage Planning, Protection Schemes and Network related activities, Islamabad.
2011-2018	**Additional Manager (SO), NPCC, NTDC Islamabad, Pakistan** Supervisory Control Engineer & Incharge NPCC Control Room, Islamabad.
2008-2011	**Deputy Manager, NPCC, NTDC Islamabad, Pakistan** Operation & control of NTDC's network as Supervisory Shift Engineer at NPCC, Islamabad.
1994-2008	**Junior Engineer Reginal Control Centre (South), NTDC Jamshoro, Pakistan** Operation & control of NTDC/DISCOs network at RCC South, Jamshoro as Shift Engineer.
1992-1994	**Junior Engineer, Mangla PowerStation (WAPDA), Pakistan** Operation & control of 1,000MW Hydel Power Station Mangla as Shift Engineer.
1991-1992	**Junior Engineer (Trainee)** 06 months Basic Management Course at WAPDA Academy Tarbela & 06 months Operation and Maintenance Course (Generation, Transmission & Distribution of Power) at WAPDA Engineering Academy, Faisalabad.

EDUCATION

- B.E Electronics Engineering from Dawood College of Engineering and Technology, Karachi, Pakistan in First Division in 1990.
- Master of Business Administration (MBA) from Preston University, Islamabad, Pakistan in First Division in 2016.

TRAININGS/COURSES/WORKSHOPS

- Two weeks 2nd Technical Refresher Course for BPS-19 at TSG Training Centre NTDC, NKLP, Lahore in Jul, 2019.
- Three weeks Senior Management Course at Lahore University of Management Sciences (LUMS), Lahore in Apr, 2019.
- Six weeks Technical Refresher Course (Pre-Promotion) for Senior Engineers Dist./T&G (T-800) Session 38th at WAPDA Engineering Academy, Faisalabad in Nov, 2017.
- Nine weeks 104th Middle Management Course at WAPDA Administrative Staff College, Islamabad in Sep, 2017.
- Six weeks Sector Specific Course at WAPDA Engineering Academy, Faisalabad in 2006.
- One year Hydel O&M Training Course at Training Centre, Mangla in 1992-93.
  (Including 06 months on Job Training at Control Room of Mangla PowerStation)
- Six months Basic Management Course at WAPDA Academy, Tarbela in Oct, 1991
- Six months Operation and Maintenance Course (Generation, Transmission & Distribution of Power) at WAPDA Engineering Academy, Faisalabad in May, 1991

MEHTAB AHMED
CHIEF ENGINEER NETWORK OPERATIONS NPCC

SUMMARY OF QUALIFICATION

Mr. Mehtab is a seasoned techincal professional with hands on Technical expertiese and Managarial experience in power transmission & dispatch company (NTDC) and power system planning of 34 years, including Control Room operations, Security Contrained Economic Dispatch, Liquidity Damages, Operating Procedures of Power Plants, Power Purchase Agreements, Merit Order Preparation, Generation Planning and Demand Forecast.

PROFESSIONAL EXPERIENCE

2021- To Date **Chief Engineer (Network Operations), NPCC, Islamabad Pakistan**

As Chief Engineer (Network Operations) he is responsible for Management, supervision, monitoring and co-ordination of all activities related to Control Room and System Operations. He is responsible for administrative oversight of all employees working in National Control Center as well as the two Regional Control Centers (North & South), along with allied technical offices of Power Control and Transmission Outage Management and Protection.

2018- 2021 **Additional Chief Engineer (Transmission Planning), PSP, NTDC Lahore**

Worked as incharge of Transmission Planning department in o/o Power System Planning, NTDC Lahore that carried out Grid Interconnection Studies, Transmission Expansion Planning studies and other protection related studies in coordination with system Operator.

2016- 2018 **Manager Planning (Load Forecast), PSP, NTDC, Lahore.**

As Manager (Load Forecast), he was responsible for supervision of preparation of long term demand forecast which is ultimately used in preparation of IGCEP and TSEP. This includes all types of forecasts including Power Market Survey (PMS) in coordination with DISCOs as well as regression based modelling.

2010- 2016 **Deputy Director (Private Power Control), NPCC, Islamabad.**

Worked as Team-Lead/Director Private Power Companies in NPCC and supervised preparation of Power Plants Dispatch data, Schedule and Forced Outages, Event verification and provision of reports to CPPA-G. He also supervised preparation of Merit Order for thermal power plants and various technical issues of Renewable Energy power plants.

2005 - 2010 **Deputy Director (Power System Operational Planning)**

2001 – 2005 **Power Planning Engineer**

1996 – 2001 **Load Dispatch & Co-ordination Engineer**

1993 – 1996 **Shutdown and System Design / Drawing Engineer**

1990 – 1993 **Power Control Engineer North Regional Control Center**

1989 – 1990 **Lecturer, Electrical Engineering Department. NED University, Karachi.**

1988 – 1989 **Marketing Executive, Hayat Sons, Karachi**

1988 – 1989 **Consultant Engineer, S.H.Zariff Associates, Karachi**

EDUCATION

2018	**MBA (Executive), Project Planning** Preston University, Lahore.
2000	**MSc. Electrical Engineering (Power)** University of Engineering & Technology, Taxila
1989	**B.E. Electrical Engineering (Power)** N.E.D. University of Engineering & Technology, Karachi
1983	**B.Sc. Mathematics** Karachi University, Karachi

HONORS

- WAPDA's Meritorious Services Award 2005

INGS/COURSES/WORKSHOPS

- One-week training course on "Power System Operation & dispatch" under USAID Energy Policy Project.
- Six-week Group training course" Electric Power Management by benchmarking. fiscal year 2006" organized by **JICA (Japan international Coordinating Agency) in Japan.**
- Six-month Management Training at WAPDA Academy Tarbela.
- Six-month Technical Training at Wapda Engineering Academy, Faisalabad.
- Three weeks Load Dispatch training by GTZ, WEA, Faisalabad.
- Two weeks Economic Load Dispatch training of SYRAP.
- Eight weeks 97th Middle Management Course from WAPDA Staff College, Islamabad.

MUHAMMAD ZAKRIA
CHIEF ENGINEER OPERATIONAL PLANNING NPCC

SUMMARY OF QUALIFICATION

Mr. Zakria has an excellent professional career of over 22 years with hands on Technical expertiese and Managarial experience in power transmission & dispatch company (NTDC) and power distribution company (IESCO) at various positions.

His field of particular experience include Power System Operations, Security Contrained Economic Dispatch, Liquidity Damages, Operating Procedures of Power Plants, Power Purchase Agreements, VRE Forecasting, Merit Order Preparation, Generation Planning, Fuel Planning, SCADA Systems, Regulatory and Policy matters related to System Operations, Distribution System Operatons, Construction and Maintenance, CTBCM/Electricity Market matters related to System Operator. His collaborteive work includes working with ministries, regulator, utilitities, international consultants, courts, NAB, National Assembly, Senate, Prime Minister Office, DAC, PAC and other key institutions in the power sector supply chain.

PROFESSIONAL EXPERIENCE

2022- To Date **Chief Engineer (Operational Planning), NPCC, Islamabad Pakistan**

As Chief Engineer (Operational Planning) he is responsible for Management, supervision, monitoring and co-ordination of all activities related to Private Power Companies (PPC), SCADA Phase-2, R&D, Renewable Energy, Generation Planning, Fuel Planning, IT, Accounts, Financial/Procurement matters, Administration and Civil Works/Projects at NPCC. Based on his rich experience, expertise and knowledge he is leading team of engineers reporting to him and working in different fields which include Short to Medium term operational planning (daily, weekly, monthly and yearly), advanced notification to Thermal Plants for fuel arrangement, Scheduling of maintenance shutdowns on Power Plants. Managing preparation of Merit Order for Thermal Power Plants. Preparation of monthly reports of NPCC. NPCC office management and financial disbursement. Managing audit paras and attending Departmental Accounts Committee and Public Accounts committee. Energy Forecasting of wind power plants. Procurement, evaluations, contract preparation and negotiation and later administration to ensure successful completion of key projects at NPCC. Review technical specification for PPAs and negotiation with Power Plants. Negotiations with Power Plants for finalization of the Operating Procedures.

2018- 2022 **Director, Private Power Companies (PPC), NPCC Islamabad, Pakistan**

Worked as Team-Lead/Director Private Power Companies in NPCC and supervised preparation of Power Plants Dispatch data, Schedule and Forced Outages, Event verification and provision of reports to CPPA-G. He also supervised preparation of Merit Order for thermal power plants and various technical issues of Renewable Energy power plants.

2010- 2018 **Deputy Manager (DM), NPCC, Islamabad Pakistan**

As DM (NPCC), he was responsible for supervision of engineers / staff working in NPCC control rooms (NCC, RCC) and all activities regarding switching operations on primary and secondary transmission power network, frequency & voltage control, real time security assessment, restoration after disturbance on system and load dispatching.

2006- 2010 **Assistant Manager (AM), NPCC, Islamabad, Pakistan**

As AM NPCC, he was responsible for, switching operations on primary and secondary transmission network, frequency & voltage control, AGC & economic dispatch, real time security assessment, system stability and integrity.

1999- 2006 **SDO/Assistant Manager (AM), IESCO, Islamabad, Pakistan**

As SDO/AM, he was responsible for, Distribution System Planning and Designing of new electrification and improvement of existing system. Construction, Operation & Maintenance, of both underground and overhead Distribution System.

EDUCATION

- **BSc Electrical Engineering** University of Engineering & Technology (UET) Taxila, 1999

HONORS

- As Convener of committee for Competitive Trading Bilateral Contract Market Model & Plan (CTBCM), at NPCC he is managing/liaising the process for designing, developing, and devising plan for power market transition, facilitating the initiatives to bring in desired change, leading NPCC's re-structuring to System Operator under competitive regime and inter alia activities.
- His role in CTBCM inter-alia is particularly significant in Dispatch & Process improvement, SO Data Exchange Portal (SDXP), Wind Forecasting, Load Forecasting, System Operator Restructuring and Development of Support IT infrastructure at NPCC.
- As Convener Project Steering Committee for the Project of Consultancy Services (Firm Selection), for System Studies to review the Grid System Performance and proposals for Stability Improvement he is liaising the Committee to conduct pre-award negotiations, coordination of all activities during execution, review and acceptance of deliverables & progress monitoring/reporting to NTDCs management and BoD.
- He was assigned special task regarding implementation of 66% take or pay clause for 3 GPPs (Bhikki, Balloki and HBS). With good planning of 3GPPs, monitoring and liaising with Control Room (NCC) the Take-or-Pay requirements of 3GPPs were fulfilled to avoid NPD (Net Proceed Differential)
- Actively participated in restoration of partial/ complete power system blackouts in Pakistan in year 2013, 2016 and 2021.

TRAININGS/COURSES/WORKSHOPS

- Completed Two Weeks Technical Refresher Course for BPS-19 at TSG Training Center Lahore in 2019.
- Completed Senior Management Course in 2019 at LUMS Lahore.
- Completed a Training on Preparation of PC1 2018 in at Pakistan Planning Management Institute Islamabad.
- Completed 4 Weeks Technical Refresher Course in 2018 at Wapda Engineering Academy Faisalabad.
- Completed 8 Weeks Middle Management Course in 2017 at Wapda Administrative Staff College, Islamabad.
- Completed 3 Weeks Training on Linux, Windows Server and Network Management in 2011 arranged by Alstom in Messy France.
- Completed Training on Power System & Dispatch in 2010 arranged by USAID at Wapda Administrative Staff College Islamabad.
- Completed 9 Weeks Junior Management Course in 2009 at Wapda Staff College Islamabad.

- Completed 6 Weeks Sector Specific Course in 2007 at Wapda Engineering Academy Faisalabad.
- Completed Induction Management Course in 2003 at Wapda Staff College Islamabad.
- Completed Induction Course in 1999 at Wapda Engineering Academy Faisalabad.

MUHAMMAD TAHIR SHAIKH
MANAGER REGIONAL CONTROL CENTRE (SOUTH) NPCC NTDC JAMSHORO

SUMMARY OF QUALIFICATION

Mr. Muhammad Tahir has an outstanding over 20 years of professional career, with numerous successes to his credit. Since August 2018, he is heading as Manager Regional Control Centre (South) to ensure smooth operation of secondary transmission network in Southern region. His responsibilities include management of schedule outages, liaison with counterparts in RCC-N, NCC for power production, interchange transformers loading and system operational issues.

PROFESSIONAL EXPE

2018- To Date **Manager, Regional Control Centre (South), National Power Control Centre Islamabad at Jamshoro**

The Manager RCC shall be responsible for effective oversight of 24-hours RCC Control Room operations, coordinating shutdowns, review of relevant reporting and work certification. As RCC(S) being bestowed upon the responsibility of power dispatch to MEPCO, QESCO, SEPCO & HESCO including the dispatch of Wind Energy from Pakistan's Wind Corridor i.e. Gharo & Jhampir.

2016- 2018 **Deputy Manager (Technical), Regional Control Center (South), National Power Control Centre Islamabad at Jamshoro**

Deputy Manager (Technical) shall be responsible for preparation and oversight of implementation of Transmission Outage Planning for Transmission assets' maintenance while ensuring optimization of outages. His role would include mitigation measures to overcome network constraints arising out of the outage in coordination with NCC and respective RCC.

2014- 2016 **Senior Engineer, Procurement NTDCL Lahore**

To investigate the market with specification and performance requirements for Transmission line and Grid Station material, evaluate technical and commercial data based on the responses received, re-iterates with bidders, recommending those most desirable using tools like bid comparison BOQs. On approval, issues the Purchase Order, takes and expedites the supply, handles inspections and delivery to site. As Procurement Engineer also provides assistance in supplier site co-ordination for site handling, storage installation and commissioning.

2013- 2014 **Senior Transmission Engineer, NTDCL Dadu**

As a Senior Engineer, has to ensure the reliability and continuity of Power Supply through Supervision and maintenance of 500kV (OHTLs) Transmission lines / (Network) in entire Southern Region comprising a total length of 1281 Kms of 500kV OHTLs.

2012- 2013 **Transmission Engineer, (Saudi Electricity Company) KSA**

As Transmission Engineer, he was responsible to develop and review project **SOW** (Scope of Work) for new and maintenance of 380/230/115/69kV OHTL, to develop and review bid clarification documents for new and maintenance project 380/230/115/69kV OHTL, to develop and review projects base design submittals of 380/230/115/69kV Over Head Transmission Lines, to develop and review projects detailed design submittals of 380/230/115/69kV Over Head Transmission Lines, to develop and review Suppliers submittals.

2011- 2012 **Senior Protection Engineer NTDCL**

To review all the Schematic Drawings of Grid stations for vetting / approval as per Wapda Specifications, analyzation of daily system tripping occurred in Wapda, allocation of Relays / Protective devices for Wapda Grid Stations.

2007- 2010 **Assistant Manager 500kV OHTL Live Line Crew (Maintenance)**

Always alert to meet the emergencies on such 500kV OHTL important circuits. Supervise and attended all the emergencies on 500kV OHTL during breakdowns. Supervise and attended the replacement of flashed over / broken disk insulators, Supervise and attended the repairing of damaged / injured conductor with mid span joint / repair sleeve joint. Co-ordination with Contractor and consultant for project works. To manage the shutdowns for maintenance of OHTL.

2002- 2007 **Assistant Manager Maintenance Sub Station, GEPCO, Pakistan**

Maintenance of all equipment of grid station / substation. Replacement/installation of circuit breakers/CTs and PTs and battery banks. To carry out the annual maintenance and testing of grid station equipment as per Wapda S.O.P.

EDUCATION

- **MBA** (majors in Management), University of Sindh, Pakistan, *(Still in progress)*
- **BE Electrical Engineering** Quaid e Awam University of Engineering & Technology (QUEST), Pakistan, 2000

ACHIEVEMENTS

- Performance recognition monetary honoraria from the General Manager (GSO) NTDC in 2014 for extraordinary performance in attending the breakdowns at 500kV HUBCO- Jamshoro & 500kV NKI – Jamshoro Transmission Lines.
- Performance recognition monetary honoraria from the Managing Director NTDC Lahore in 2017 for extraordinary performance for running Southern System under isolation for many days due to breakdowns at 500kV Shikarpur – Dadu Double Circuit Transmission Lines.

TRAININGS/COURSES/WORKSHOPS

- Senior Management Course (BPS-19 to BPS-20) at LUMS Lahore.
- Technical Refresher Course – 1 Session 3, BPS-19 to BPS-20 at TSG Center NKLP Lahore.
- Long term Grid Maintenance Course at GSO Training Center Lahore, Pakistan.
- Junior Management Training Course (JMC) from WAPDA Staff College Islamabad, Pakistan.
- Management Induction Training Course (MIC) from WAPDA Staff College Islamabad, Pakistan.

- Promotion Training Course (Sector Specific Course) from WAPDA Engineering Academy Faisalabad, Pakistan.
- Induction Training Course from WAPDA Engineering Academy Faisalabad, Pakistan.

AIJAZ ALI
MANAGER POWER CONTROL NPCC

SUMMARY OF QUALIFICATION

Mr. Aijaz Ali has been working with NTDC for over 22 years with hands on Technical expertise and Managarial experience in power transmission & dispatch company (NTDC). His experience includes Power System Operations, Security Contrained Economic Dispatch, Operating Procedures of Power Plants, Power Purchase Agreements.He is responsible for administrative supervision of National Control Center including logistics, supervision of system operation in real-time, implementation of decision of management in Control Room operations and preparation of different post-dispatch reports.

PROFESSIONAL EXPERIE

2020- To Date **Manager (Power Control), NPCC, Islamabad Pakistan**

As Manager (Power Control) he is responsible for management, supervision, monitoring and co-ordination of all activities related to Control Room and System Operations. He is responsible for administrative oversight of all employees working in National Control Center as well as allied technical offices of Power Control and Transmission Outage Management and Protection.

2019-2020 **Manager (Performance Assessment), NTDC Lahore, Pakistan**

Worked as DM (Performance Assessment) to oversee performance evaluation of different departments of NTDC all over Pakistan and carry out different enquiries of technical nature.

2018-2019 **Manager (Technical), NTDC Lahore, Pakistan**

Worked as DM (Technical) to coordinate all Regulatory Affairs of NTDC which includes coordination with all NTDC formations for collection of data and preparation of reports such as annual Performance Standard Transmission Report, State of Industry Report etc.

2011- 2018 **Deputy Manager (Power Control), NPCC Islamabad, Pakistan**

Worked as DM (Power Control) to oversee preparations of Daily Log Reports and necessary information of network for higher Authority, preparations of SOPs for smooth system operation, managerial and technical decisions taking job and give necessary instructions to the Shift Supervisors of all shifts.

2009- 2011 **Deputy Manager (NCC Shift), NPCC, Islamabad Pakistan**

As DM (NCC), he was responsible for supervision of engineers / staff working in NPCC control rooms (NCC, RCC) and all activities regarding switching operations on primary and secondary transmission power network, frequency & voltage control, real time security assessment, restoration after disturbance on system and load dispatching.

2000- 2009 **Assistant Manager (AM), NPCC, Islamabad, Pakistan**

As AM NPCC, he was responsible for, switching operations on primary and secondary transmission network, frequency & voltage control, AGC & economic dispatch, real time security assessment, system stability and integrity.

EDUCATION

- B.E Electrical Engineering Power from Quaid-e-Awam University of Engineering Sciences & Technology Nawab Shah, Pakistan in First Division in 2000.
- MBA from Virtual University Islamabad.

HONORS

- Awarded appreciation letter from GM (SO) in 2005 for smooth system operation during heavy fog/canal closure period.
- Awarded appreciation letter from GM (SO) in 2015 for smooth system operation during system splitting due to heavy fog/canal closure period and stable operation of islands.
- Awarded appreciation letter from GM (SO) in 2016 for smooth system operation during system splitting at 500 kV Jamshoro and stable operation of North and South islands.

TRAININGS/COURSES/WORKSHOPS

- Six weeks Technical Training at WAPDA Engineering Academy Faisalabad in 2002.
- Six months Training of Basic Management at WAPDA Staff College Islamabad in 2002.
- Three weeks LDC level-11 training at WAPDA Engineering Academy Faisalabad in 2004.
- Two months Management Course at WAPDA Staff College Islamabad in 2010.
- Six days System Operation & Economic Load Dispatch Training through USAID Program from American Experts at WAPDA Staff College Islamabad in 2010.
- 6 weeks Technical Sector Specific Course from WAPDA Engineering Academy Faisalabad in 2010.

ABDUL KABIR
MANAGER (REGIONAL CONTROL CENTER NORTH) NPCC

SUMMARY OF QUALIFICATION

Mr. Abdul Kabir has an excellent professional career of over 24 years with hands on Technical expertiese and Managarial experience in power transmission & dispatch company (NTDC), Saudi electricity Company (SEC) KSA, Power distribution companies (IESCO & AJK Electricity Department), and Telecom Companies (ETSS & TSS) at various positions.

His field of particular experience include Supervising, Monitoring, Controlling, Operating & management of all activities relating to Power Control Centre involving real time operation & control up to 500 kV HVAC & HVDC interconnected transmission system & Generation (Hydel, Thermal, Solar, Wind & Nuclear) in safe, reliable, economic and efficient manner.

PROFESSIONAL EXPERIENCE

2021- To Date **Manager RCC (North), NPCC, NTDC, Islamabad Pakistan.**

As Manager RCC (North) he is responsible for Management, supervision, monitoring and co-ordinating all the activities related to RCC(North) including smooth and reliable operation of 132 & 66 kV North Region network (i.e PESCO, TESCO, IESCO, GEPCO, LESCO, FESCO and partially MEPCO) fed from NTDC 500/220 and 220/132 kV grid stations. Judicious dispatch of power to all DISCO's according to their respective demand in view of available generation. Supervise/assign the duties and tasks to the shift staff and the staff working in general duty. Planning and arranging network shutdown (schedule and emergent) in coordination with all concerned. Issuance of new, revised and updated single line diagrams of Transmission lines, Grid stations & Power Houses. Supervise preparation of reports and provide recommendations to amend existing operational policies and procedures. Lead the team in restoration of power system network in case of Major system disturbances. Discuss and guide the RCCN team regarding improvement in network operation.

2019- 2021 **Dy. Manager (Technical)/Shift Supervisor, NCC, NPCC, Islamabad Pakistan.**

2012- 2019 **Sr. Engineer (Power Dispatch)/Shift Supervisor, Saudi Electricity Company (SEC), COA Riyadh, Saudi Arabia.**

2011- 2012 **Dy. Manager (Technical)/Shift Supervisor, NCC, NPCC, Islamabad Pakistan.**

2006- 2011 **Assistant Manager (Technical)/Shift Engineer (NCC & RCC), NPCC, Islamabad Pakistan.**

As Deputy Manager, Sr. Engineer (Power dispatch) & Assistant Manager, he was responsible for supervision of engineers / staff working in control rooms (NCC, RCCN & SEC) and monitoring/coordinating all activities relating to Power Control Centres involving operation and control of 500, 380, 230, 220 & 132 kV interconnected transmission system & power plants (Hydel, Thermal, Solar, Wind & Nuclear). Frequency, voltage & reactive power control.

2002- 2006 **SDO/Assistant Manager (AM), Islamabad Electric Supply Company (IESCO), Islamabad, Pakistan.**

As SDO/AM, he was responsible for, Distribution System Operation, Planning and Designing of new electrification and improvement of existing system. Construction, Operation & Maintenance, of both underground and overhead Distribution System.

1999- 2002	**Site Engineer (OSP): Efficient Technical Support Services Pvt. Ltd.** Survey/planning of primary and secondary cable network of telephone exchange. Supervision of PVC laying, Cabinets, dp poles, Cable pulling, Jointing cables, Testing of cables and preparation of BOQ, diagrams and reconciliation of material.
1998- 1999	**SDO/Assistant Engineer: Electricity Department Muzaffarabad Govt of AJ&K** As SDO/AE, he was responsible for, Distribution System Operation, Planning and Designing of new electrification and improvement of existing system. Construction, Operation & Maintenance of overhead Distribution System.
1997- 1998	**Site Engineer (OSP): Technical Support Services Pvt. Ltd Islamabad.** Survey/planning of primary and secondary cable network of telephone exchange. Supervision of PVC laying, Cabinets, dp poles, Cable pulling, Jointing cables, Testing of cables and preparation of BOQ, diagrams and reconciliation of material.

EDUCATION

- **MSc Electrical (Power) Engineering** (MUST Mirpur) AJK, 2012.
- **BSc Electrical (Power) Engineering** (UCET Mirpur) University of AJ&K, 1996.

CERTIFICATION

- Certification of Power System operation (Power Dispatch Engineer), from MHI (Manitoba Hydro International) CANADA.

HONORS

- **1st** Position in Bachelor of Science in Electrical Engineering final professional Exam.
- **1st** Position in Technical Refresher Course (Promotion Training: Manager to Chief Engineer).
- **2nd** Position in Technical Refresher Course (Promotion Training: Dy. Manager to Manager).
- **2nd** Position in Middle Management Course (Promotion Training: Dy. Manager to Manager).
- **3rd** Position in Tech Course (Promotion Training: Asstt Manager to Dy. Manager).
- **1st** Division throughout educational career

TRAININGS/COURSES/WORKSHOPS

- Technical Refresher Course (Promotion Training: Manager to Chief Engineer) from TSG (Technical services Group) Training Centre, NTDC, New Kot lakpat Lahore Pakistan (3 weeks).
- Middle Management Course (Promotion Training: Dy. Manager to Manager) from WAPDA Administrative Staff College (WASC) Islamabad Pakistan (7 weeks).
- Technical Refresher Course (Promotion Training: Dy. Manager to Manager) from TSG (Technical services Group) Training Centre, NTDC, New Kotlakpat Lahore Pakistan (4 weeks).
- HVDC Operation and Control Training (CET/PMLTC State Grid Corp of China) (One week)
- Junior Management Course (Promotion Training: Asstt Manager to Dy..Manager) from WASC ISB Pakistan (9 weeks).
- Sector Specific Course (Promotion Training: Asstt Manager to Dy. Manager) from Wapda Engg Academy Faisalabad Pakistan (6 weeks).
- Technical induction course (Distribution, Transmission & Grids) from Wapda Engineering Academy Faisalabad Pakistan (6 weeks).

- Management induction course from WASC Islamabad Pakistan (6 weeks).
- In service Training on HRM from Pakistan Manpower institute Islamabad Pakistan (2 weeks).
- Training from Fauji Cement co. ltd, Fateh Jhang Rawalpindi, Pakistan (1 month).
- Certification of Power System operation (Power Dispatch Engineer), from MHI (Manitoba Hydro International) Canada.

ENGR.MUHAMMAD SAEED AKHTAR
MANAGER (OPERATION PLANNING) NPCC.

SUMMARY OF QUALIFICATION

Mr. Muhammad Saeed Akhtar has a professional career of over 19 years with hands on Technical expertiese and Managarial experience in power transmission & dispatch company (NTDC) at various positions. His field of particular experience includes Power System Operations, Economic Dispatch, Operating Procedures of Power Plants, Power Purchase Agreements, , Generation Planning, Fuel Planning, LDS Project, Neelum Jhelum Project, CASA Project, +/- 660KV HVDC Lahore Matiari Commissioning/Testing, Live Line Maintenance of EHV Transmission Lines, Worked in TSG NTDC , Collaborteive work includes working with ministries, regulator, utilitities, international consultants, courts, NAB, National Assembly, , DAC, and other key institutions in the power sector.

PROFESSIONAL

2022- To Date **Manager (Operation Planning), NPCC, Islamabad Pakistan**

As Manager (Operational Planning) he is responsible for Management, supervision, monitoring and co-ordination of all activities related to Generation Operational Planning, including detailed modelling in SDDP (Specialized software developed by PSR for medium term generation planning), Development of detailed model in NCP (Specialized software developed by PSR for short term generation planning), Generation Planning, Fuel Planning. He is team member of engineers reporting to Chief Engineer (Operation Planning) NPCC and working in different fields which includes Short to Medium term operational planning (daily, weekly, monthly and yearly), advanced notification to Thermal Plants for fuel arrangement, scheduling of maintenance shutdowns on Power Plants Plants outage scheduling and allocation of MM, NM and Demonstration period and allocation of PWF as per PPA and outage plan. NPCC office management. Energy Forecasting. Review technical specification for PPAs and negotiation with Power Plants. Being Member of Operating Committee of various IPP's negotiate with Power Plants for finalization of the Operating Procedures, other operational matters like outage plan and any specific issues as per agenda of operating committee.

2021- 2022 **Project Director CASA-1000 Project, NTDC, Islamabad Pakistan**

Successfully handed over the 500 kV HVAC Substation site Nowshera to EPC contractor M/s CNTIC and SEC (JV) and carried out demarcation of land for construction of Electrode Station Charsadda with the coordination of District Administration, Revenue Staff and Survey team. Supervised and inspected the overall construction activities at site including transformers pads, firewalls, ventilation rooms, service building, store building, relay buildings, gantries foundations, small equipment foundation and boundary walls and CASA +/- 500KV HVDC Transmission Line part in Pakistan.

2012- 2021 **Deputy Manager (DM), NPCC, Islamabad Pakistan**

As DM (NPCC), he was responsible for supervision of engineers / staff working in NPCC control rooms (NCC) and all activities regarding switching operations on primary transmission network, frequency & voltage control, real time security assessment, restoration after disturbance on system and load dispatching. Real Time Network Monitoring and Operations Voltage Control Shutdowns Of Emergent Nature Switching operation of 500KV, 220KV and 132KV transmission lines and auto / power transformers for routine and emergent shutdowns. Worked with HVDC NPCC team for testing and commissioning activities of +/- 660KV HVDC Matiari-Lahore and CASA 1000 project. Contract Management of Load Despatch System Upgrading Project. Management of Loan agreement with JICA and Consultancy Contract with NESPAK. Live Line OPGW Installation/Maintenance on 500km lengthy lines. Project Technical Correspondence with Consultant NESPAK, JICA , Contractor (Alstom,VISCAS) and other Government Departments like Custom, Ministry of water and power, and NTDC Head Office. Monthly/Quarterly /Annually Expenditure statements preparation. Budget preparation and financial / Technical progress preparation. Invoice processing and Disbursements/ Reimbursements. Arranging joint meetings for project issues.

2003-2012 **Assistant Manager (AM) LLC, NTDC, Islamabad, Pakistan**

Management/Performed maintenance works of Transmission Lines on Live Line (500KV and 220KV Transmission Lines). Management of maintenance work of Transmission Lines on Dead Line. (500 KV (5 NO) and 220KV (14 NO). Approval of Hold Off, Shutdowns from NPCC for maintenance work on Transmission Lines.

EDUCATION

- MBA in HRM, from Virtual University of Pakistan, in year 2016.
- B.sc, Engineering (Electrical)with honors from University of Engineering and Technology, Peshawar, Pakistan, in year 2001.

HONORS

- Factory Acceptance Test (FAT) at Arteche China for Capacitive Voltage Transformers (CVTs) for 1320MW Port Qasim Coal-Fired Power Plant.
- ABB warehouse inspection and checking of equipment at Karachi.

TRAININGS/COURSES/WORKSHOPS

- Refresher Course at TSG, Lahore (From 10-12-2018 to 04-01-2019).
- Live Line Training, TSG, NTDC (From 07-04-2008 to 28-06-2008).
- Protection and instrumentation (P&I) training, TSG, NTDC (From 28-11-2005 to 12-08-2006).
- 36TH Sector Specific Course for Junior Engineers, WAPDA Training Academy Faisalabad (From 03-01-2011 to 12-02-2011).
- 33rd Integrated Induction Course for Junior Engineers, WAPDA Training Academy Faisalabad (From 01-09-2003 to 11-10-2003).
- PLC Training, KEL Lahore.
- VSAT Training, SUPERNET, Islamabad.

- Executive Development Program at Lahore University of Management Sciences (LUMS) (From 24-09-2018 to 19-10-2018).
- 79th Junior Management Course, WAPDA Staff College Islamabad
- 22nd Management Induction Course, WAPDA Staff College Islamabad
- Participated in CASA 1000 System workshop.

SHAHBAZ AHMED
MANAGER LOAD FORECAST & GENERATION PLANNING

SUMMARY OF QUALIFICATION

Mr. Shahbaz has a diverse professional career of over 24 years with hands on Technical expertiese and Managarial experience in power transmission & dispatch company (NTDC) and Saudi Electric Company in the field of Power System Planning and Long Term Load Forecast. He has played key supervisory role in preparation of IGCEP and presenting it to higher Authority including Ministry of Energy and NEPRA.

PROFESSIONAL EXPERIENCE

2019- To Date **Manager (Load Forecast & Generation Planning), PSP, NTDC, Lahore**

- Participated in the Formulation of the Integrated Generation Capacity Expansion Plan (IGCEP-2047) up to 2047 using PLEXOS generation planning software.
- Actively formulated the National Power System Expansion Plan up to 2030 using WASP and SYPCO generation planning software's.
- Part of building the Power System Expansion Plan up to 2030 using WASP generation planning software in 2008.
- Formulation and Analysis of current data regarding existing power plants to input in WASP and SYPCO generation planning software's.
- To run WASP, PLEXOS, OptGen/SDDP and SYPCO program for the updating of least cost generation expansion plan taking into account the generic / candidate plants.

2013- 2019 **Project Manager, Saudi Electric Company (SEC), KSA**

- Worked as Project Manager for the development of Long-Term Generation Expansion Plan (2016-2040) for Kingdom through international consultants CESI using OptGen/SDDP.
- Formulated KSA National Power System Expansion Plan up to 2030 using WASP and Strategist generation planning software's.
- Formulation and Analysis of current data regarding existing power plants to input in WASP and Fichtner generation planning software's.
- Operational analysis of KSA existing plants.
- To study position of different proposed plants in the least cost generation expansion plan for SEC system.
- Liaison with different organizations like Saudi-ARAMCO/ECRA/SWCC/WEC owned departments to discuss future power policies.

2003- 2013 **Assistant Manager (Load Forecast), PSP, NTDC, Lahore.**

- Formulation of Long-Term Load Forecast from 2019-2047.
- Collection and formulation of data regarding energy sale, peak demand and energy generated category wise i.e. domestic, commercial, industrial and agriculture etc.
- Working on E-Views software to calculate elasticity coefficients for different customer categories on the basis of historical data from 1970 onwards.

- Medium Term Forecasting for the country, main utilities WAPDA & KESC and then for Distribution Companies, using Power Market Survey software.
- Long Term Forecasting for the country, main utilities WAPDA & KESC and then for Distribution Companies, using Regression Analysis.

1996- 2005 **Plant Engineer, Master Tiles & Ceramic Industries Plant**

- Trouble shooting and fault clearance of ball mills, kilns, presses and glaze lines in Master Tiles and Ceramic Industries Gujranwala Pakistan.
- Switch gear maintenance and design for new equipment to be installed.
- Propose and design development plans and projects.
- To maintain and look after the operations of the plant.

EDUCATION

- **BSc Electrical Engineering** University of Engineering & Technology (UET) Lahore.

HONORS

- Employee of the year - Saudi Electricity Company
- Gold Medalist in F.Sc. from Gujranwala Education Board.
- First Position in Management training from WAPDA Staff College Islamabad.

TRAININGS/COURSES/WORKSHOPS

- Three weeks training on generation expansion planning tool OptGen/SDDP from international consultant PSR in Lahore
- One-week training on generation expansion planning tool PLEXOS from International consultant Lahmeyer in October, 2019 in Lahore
- One-week training on generation expansion planning tool Strategist from International German consultant at Dammam Saudi Arabia
- Two weeks training on Wien Automatic System Planning (WASP) from International Atomic Energy Agency at Vienna Austria in November 2009
- Two months training on Markal / Times for Integrated Energy Modeling including all energy sectors of Pakistan containing three weeks at International Resource Group (IRG) Washington DC USA in April 2010
- One-week training on load forecasting techniques and the evaluation methods, from Pakistan Institute of Management (PIM).
- Four weeks training on System Production costing (SYPCO) from international consulting firm SNC-Lavalin Canada at Lahore Pakistan
- Integrated Induction Course for Junior Engineers (06 Weeks) completed from WAPDA Engineering Academy Faisalabad.
- Management Induction Course (6 Weeks) completed from WAPDA Staff College, Islamabad
- Special Sector Specific 06 weeks Course (Pre-promotion) completed from WAPDA Engineering Academy, Faisalabad
- Junior Management Course (09 weeks) completed from WADPA Staff College, Islamabad.

UMM-E-KULSOOM ALI
MANAGER, NPCC

SUMMARY OF QUALIFICATION

Ms. Umm-e-Kulsoom has rich academic background of Electrical Engineering, Business & Administration as well as social sciences with a dedicated career of more than 25 years including 18 years of working in National Power Control Center (NPCC) on various positions. Presently she is supervising Private Power Cell, where she is managing the performance supervision of the contractual obligations as emanating from the concerning Power Purchase Agreements (PPAs) executed between the IPPs and CPPA-G.

PROFESSIONAL EXPERI

2021- To Date **Manager (PPC), NPCC, Islamabad Pakistan**

The responsibilities of Manager PPC include close coordination with power generation units, clarification & settlement of the dispute related to IPPs. In particular context of clean energy projects, dealing with renewable energy (wind power) projects and their contractual performance in the light of concerning Energy Purchase Agreements (EPAs). Supervision of all LDs related matters I am responsible for recommending the imposition of Liquidated Damages (LDs).

Nov 2021- Dec 2021. **Manager (Power Systems Planning), GM PSP, Lahore**

As Manager (PSP), tasks performed included dealing with matters relating to short and long term planning related to overall transmission of power, expansion of the networks and the load dispatchment associated with base load and RE plants. With the team of GM PSP, she got rich exposure with the matters relating to seasonal and other variations in electrical demand as well as managing the load curve in the future perspective of demand at different segments of consumers and the parallel deployment of power projects as envisaged in the IGCEP.

2013- 2021 **Deputy Manager (Liquidated Damages), NPCC, Islamabad Pakistan**

As DM (LDs), she has been playing spearheaded role towards management of Merit Order and the critical analysis of underneath challenges in light of the executed PPAs and EPAs. In this regard, she has been part of technical management teams dealing with the different Power Plants and event and invoice verification.

2004- 2013 **Assistant Manager (AM), NPCC, Islamabad, Pakistan**

As AM NPCC, she was responsible for dealing with various assignments relating to efficient and economic dispatch of power in NPCC as part of core team including but not limited to management of staff, ensuring system reliability and stability etc. In the above capacity, she learnt about the complex configuration of power systems in Pakistan and multiple levels of coordination amongst different power system entities, their roles as well as stakeholder management in changing circumstances.

2002- 2004 **Assistant Manager, Office of Chief Engineer GSO Hyderabad**

In this capacity, she has been working in the Resident Representative Karachi (RRK) office and was responsible for the custom clearance of the electrical equipment and the cross border shipments of the machinery and parts. This gave her a thorough outlook upon the quality assurance matters relating power systems machinery and the import related issues as well as coordination with customs and other relevant departments.

2000-2002 **Junior Engineer, HESCO**

In her capacity as 'Junior Electrical Engineer' she was responsible for the maintenance of distribution lines right from the grid station to different locations of the city of Hyderabad. This also involved the maintenance of various power distribution accessories e.g. transformers, relays and circuit breakers.

1995-1997 **Trainee Engineer, Sui Southern Gas Company (Ltd)**

While working in the Headquarters in the City of Karachi, she coordinated with various gas distribution offices in Karachi for the smooth operation of electrical support systems and equipment. This also involved maintenance of necessary electrical instruments in the field units as well as inventory management.

EDUCATION

B.E Electrical Engineering Mehran University of Engineering & Technology, Jamshoro,
Masters in Business Administration (MBA), Preston University
Masters in Arts (MA), University of Sindh.

TRAININGS/COURSES/WORKSHOPS

- Completed Session 4 Weeks, Technical Refresher Course for BPS19 to BPS20 at TSG Training
  Center Lahore in 20-12-2021.
- Completed Technical Refresher Course 3Weeks in 2021 at TGS Training Center BPS 18 to BPS 19, TSG Training Center Lahore in 02-08-2021
- Completed 9 Weeks Junior Management Course (121st Batch) from 16-11-2020 at Wapda Staff College Islamabad.
- Sector Specific Course (Pre-Promotion) at Wapda Engineering Academy Faisalabad.
- Completed 6 Weeks Sector Specific Course in 2013 at Wapda Engineering Academy Faisalabad.

- Completed Induction Management Course in 05-11- 2007 at Wapda Staff College Islamabad.
- Completed Junior Engineer Induction Course in 08-01-2007 at Wapda Engineering Academy Faisalabad.

JAWAID RAHMAN
MANAGER INFORMATION TECHNOLOGY, NPCC

SUMMARY OF QUALIFICATION

A bright, talented and ambitious professional with 22 years of working experience as Chief Technology Officer, Application Architect, Project Manager, Business Analyst and Software Engineer in international software solutions and public sectors projects to the highest standards. I have a long track record of ensuring projects are delivered to the highest quality with international companies like Empire Today US (empiretoday.com), Weber US (weber.com), Life Time US (lifetimefitness.com), TodayTimesheet US (todaytimesheet.com). Always wanting to be actively involved in all aspects of the project life-cycle, I can deliver high-value projects in matrixes organizations and across different geographies. I have worked on more than thirty successful projects by using Microsoft tool and technologies.

PROFESSIONAL EXPERIENCE

2022- To Date **Manager (IT), NPCC, Islamabad Pakistan**

- Head of IT section at National Power Control Center (NPCC)
- Manage IT related activities at NPCC, including software development, web portals, IT Infrastructure and Networks.
- Identify, compare, select and implement technology solutions to meet current and future needs
- Create overall technology standards and practices and ensure adherence

2016 to 2022 **Chief Technology Officer (CTO), Carbon8 (Pvt.) Ltd**

- Proposal writing for Software relative Projects.
- Design application architecture by using Microsoft Tool & Technologies (.Net, Azure Cloud, SharePoint), Oracle EBS and Open Source like PHP, ODOO (Open ERP). For Database using Azure DB, Microsoft SQL Server, MY SQL, Oracle DB, Azure DocumentDB. For Mobile using Native Development.
- Requirement Gathering (AS-IS, Analysis, TO-BE and Future Process Model) for different client's projects.

2014 to 2016 **Application Architect, Today Timesheet Inc (US Based – IT Firm)**

Design application architectures with respect to business requirements on Microsoft Platform (C#, ASP .Net, Angular JS, Node JS, MVC 5, Web API, Azure DocumentDB etc.).

2010 to 2014 **Project Manager, Electronic Government Directorate, MoIT, GOP.**

- Manage project activities during each phase of project life.
- Manage the contracts with the implementing IT firms. This will involve establishing commitments with the contractor, and tracking and reviewing the contractor's performance and results. This exercise will cover the management of software-related contracts, as well as the management of the total project that includes Hardware, Data center, Networking, Licensed Software and other system components.

2008 to 2010 **Business Analyst, Electronic Government Directorate, MoIT, GOP.**

Responsibilities included requirement gathering and analysis, strategic planning, preparation project proposals, process reengineering and project repository management

2006 to 2008 **Director Web, Electronic Government Directorate, MoIT, GOP.**

- Consult with various government agencies in the development of their IT plans and to ensure that systems are adhere to standards.
- Identification of tools & technologies to be incorporated into the different e-Government projects those are to be outsourced. And also evaluation of alternate tools & technologies and select the most suitable one for specific e-Government projects.
- Preparation & evaluation of Request for Proposal & Technical bids for Software projects.
- Preparation of contracts & Statement of Work for software projects

2005 to 2006 **Senior Software Engineer, Netpace Systems (Pvt.) Ltd**

- To lead & Mange a team of Software Engineers working on Microsoft Tool & Technology
- Requirement Gathering and Business Process Reengineering of different projects
- Design application architectures on Microsoft Platform.
- Development of complex logic for applications
- Implementation of projects at Clients different locations and monitor the training of End users

2001 to 2005 **Software Engineer, Hambra Consulting (USBased – IT Consultant)**

- An analytical Senior-level software developer with deep expertise in ASP.NET and Siebel technologies.
- Versed in both agile and waterfall development techniques.
- Skilled in requirements analysis and project documentation.
- Able to communicate effectively with both technical and non-technical project stakeholders
- Expertise in current and emerging trends and techniques.
- Proficient in coding and developing the new program.

EDUCATION

- **Master of Science (M.Sc.), Computer Technology** *University of Sindh, Pakistan 1999 – 2000*
- **Bachelor of Science (Horns), Computer Technology** *University of Sindh, Pakistan 1996-1999*

HONORS

- Played key role in CTBCM to development of SO Data Exchange Portal (SDXP) and Marginal Price Application. Integration of SDXP with Wind Forecasting, SMS Metering application and Market Management System (MMS). Also providing support to IT infrastructure at NPCC.
- Recommended by Inter-Services Selection Board for Commission in Pakistan Navy as Sub Lieutenant in Computer Branch on May 2002.

TRAININGS/COURSES/WORKSHOPS

- Three Months Diploma of Leadership Training Project at Fauji Foundation - Session July-95
- Six Months Diploma of Computer Science at SAM Computers, Hyderabad- Session Sept-95

SAQIB JAVAID
MANAGER SCADA-III NPCC

SUMMARY OF QUALIFICATION

Mr. Saqib Javaid has an experienceof over 20 years in the field of particular experience include preparation of planning and design of SCADA and Teleecommunication network for different NTDC's projects, preparation of scope of works, bids evaluation, execution of projects. He also has a site experience of maintenanace and troubleshooting of differnet equipments constitute a Telecommunication network. The core responsibility is to ensure the data of different power houses and grid stations to be displayed at scada system in NPCC in real time.

PROFESSIONAL EXPERIENCE

2021- To Date **Manager SCADA-III, NPCC, Islamabad Pakistan**

As Manager SCADA-III core duties are related to monitoring of ADB-202R-2019 "Procurement of Plant-Design, Supply, Installation, Testing and Commissioning of SCADA Phase-III and Revenue Metering System (R.M.S.) For NTDC" Project. The project includes the up-gradation of existing SCADA system installed at NPCC Islamabad. In existing SCADA system 49 Stations are integrated, whereas in new projects additional 130 power stations and grid stations shall be integrated.

2015- 2020 **Deputy Manager (Telecom & SCADA) NTDC, WAPADA House Lahore Pakistan**

The main duties are Preparation of Scope of Work (SOW), Bill of Quantity (BOQ), design review and site supervision of Telecom and SCADA works

a) IPPs (Wind, Hydel, Thermal) etc.
b) 550/220kV NTDC Grid Stations.
c) OPGW

2012- 2014 **Assistant Manager (Telecom & SCADA) NTDC, Islamabad Pakistan**

As Assistant Manager, he was responsible for site supervision of different installation and testing activities of SDH/PDH and RTU Equipment under LDS-II Project. Preparation of snag lists and project progress reports for onward submission to higher offices. End to End Testing of Telecom links/channels meant for Speech, Teleprotection and Data transmission from different stations up to NPCC Islamabad.

2009- 2011 **Telecom Engineer – Power Transmission and Distribution Division, Mott MacDonald Group, UAE**

Worked as Telecommunications Engineer with Mott MacDonald Abu Dhabi for the consultancy services for new 400kV substations across UAE.

Major responsibilities include tender preparation, specifications, evaluation, clarifications, design review of telecommunications and associated equipment, interacting with client engineers in design matters. Duties also include attending site for supervision of erection and witness of commissioning activities for following projects that are completed/being executed currently.

2008 **Section Engineer Telecom – EHV Projects Saudi Electric Co (SEC), KSA**

Worked as Section Engineer Telecom with Jacobs Zate for Saudi Electric Company (SEC) for the design review of all new 380/110kV substation projects in Saudi Arab. The brief description is as under

- Design review of telecom equipment SDH/STM-16/4/1, DVM, Teleprotection of ABB, Siemens and NEC make as per Tender documents and SEC specifications.
- Design review of RTU & SER and respective signal lists.

2002- 2007 **Resident Engineer (Telecom & SCADA) NTDC, Tarbela & Islamabad Pakistan**

Worked as Resident Engineer (Telecom) at WAPDA's Hydel Power Station in Tarbela and Islamabad, Major responsibilities were Operation, maintenance and troubleshooting of telecom equipment (SDH/STM-1, PLC, Teleprotection, PAX etc.) and RTU in large Wapda Telecom Network having more than 50 Power/Substations.

EDUCATION

- **BSc Electrical Engineering** University of Engineering & Technology (UET) Peshawar, 2001.
- **MBA (HR)** COMSATS University Islamabad, 2017

HONORS

- Part of team for preparation of EPA of different wind power projects at Jhimpir and Gharo area.

TRAININGS/COURSES/WORKSHOPS

- Completed 3 Weeks Technical Refresher Course BPS-19 in 2021 at TSG Training Center Lahore.
- Completed 6 Weeks Technical Refresher Course BPS-18 in 2019 at TSG Training Center Lahore.
- Completed 8 Weeks Middle Management Course in 2019 at Wapda Staff College, Islamabad.
- Completed 2 Weeks SELTA SDH equipment (SAFN) training in 2018 at Piacenza Italy.
- Completed 1 Week Alstom DPLC equipment (T-390) training in 2015 at Dubai UAE.
- Completed 4 Weeks Sector Specific Course in 2014 at Wapda Staff College Islamabad.
- Completed 9 Weeks Junior Management Course in 2012 at Wapda Staff College Islamabad.
- Completed 1 Week Alstom SDH equipment (MSE-5100) training at Lahore.
- Completed 6 Weeks Telecom Induction Course in 2003 at Wapda Staff College Islamabad.
- Completed Induction Management Course in 2003 at Wapda Staff College Islamabad.

SUMAIR MEMON
MANAGER TECHNICAL (SCADA-III) NPCC

SUMMARY OF QUALIFICATION

Mr. Sumair Memon has an experience of over 20 years in the field of Telecommunication and SCADA at power transmission & dispatch company (NTDC) at various positions. His field of particular experience includes more than 8 years field experience in Telecommunication and SCADA Network (NTDC Power Network), almost 9 Years Telecommunication / SCADA Planning and Design experience, couple of Years served at TSG North Lahore, and Now serving at NPCC SCADA ADB-202R-19 Project, known as SCADA-III.

PROFESSIONAL EXPERIENCE

2021 to Date **Manager Technical (SCADA-III), NPCC, Islamabad Pakistan**

As Manager Technical (SCADA-III) at NPCC NTDC Islamabad, his prime duties involve monitoring activities such as survey, execution, and testing of recently initiated SCADA up-gradation project (ADB-202R-2019) comprising 64 Microwave Stations, 4085 km of Optical Ground Wire, 25 Exchanges, more than 60 Digital Power Line Carrier equipment, and 113 SDH (Fiber Optic) Multiplexers. Job Description includes project monitoring, generating monthly progress reports, Database integration in SCADA and other project-related activities.

2019 - 2021 **Addl. Manager Technical (T.S.G, Technical Services Group), Lahore NTDC**

During his stay at T.S.G North Lahore, he Initially served in the R&D section and later on attached to 'Protection & Metering Section' during which participated in different pieces of training such as "Distance Relay & Auto-Recloser" and "SMS Energy Meters", simultaneously attended field visits to better understand the field. Finally headed Grids Directorate at T.S.G NTDC Lahore, as Manager Grids.

2010- 2019 **Deputy Manager (DM), Telecommunications and SCADA, Wapda House Lahore,**

As Deputy Manager Telecom / SCADA Wapda House Lahore, he was involved in the 'Planning and Design activities' of various ongoing and Upcoming Projects such as SCADA-III, his major responsibilities included Tender Preparation, Evaluation, and Project-Management.

2009- 2010 **Executive Engineer (XEN) Telecommunication / SCADA**

As XEN Telecommunication / SCADA, his main responsibility included leading Telecom / SCADA Professionals posted throughout Sind Province for Troubleshooting and Maintenance of NTDC Telecommunication / SCADA Network.

2002- 2009 **Resident Engineer Telecommunication / SCADA (Field)**

Since his appointment in 2002 as Assistant Manager Telecom / SCADA, he remained in different field offices (Multan, Dadu, Jamshoro, and Hyderabad) and served as Resident Engineer, where he was responsible for Troubleshooting / Maintenance of Telecom & SCADA Network (Power Line Carrier, Fiber Optic System, Exchanges, and Remote Terminal Unit & Microwave System).

2001- 2002 **Database and Network Administrator (MUET Jamshoro)**

During his stay at MUET Jamshoro, he designed a Client / Server Database Application for the Examination Branch of Mehran University of Engineering and Technology Jamshoro. His other responsibilities were to maintain and troubleshoot any fault in the examination branch Database and its Network.

EDUCATION

ME	MUET Jamshoro, "Communication Systems & Networks"	2009-14
MS	Sindh University Jamshoro, M.B.A (Management)	2007-09
BE	MUET Jamshoro, "Electronics"	94-2001
DVPN	MUET Jamshoro, "Diploma in Visual Programming & Networking.	2000-01

HONORS

- As Design Engineer actively involved in Planning / Design of SCADA Upgradation Project SCADA-III Project in 2015.
- In 2020, he was assigned special Task for Development of 'CTBCM Website', said Job was completed in Time using API's from (PITC, NTDC and IT Section NTDC).
- In 2021 he developed an application for Monitoring Progress on Project Activities of SCADA-III ADB-202R-19 Project. The Application Generates Monthly Reports.
- In 2021 he developed a Tool to access data from more than 1500 Excel Sheets and Generates Reports. The Excel Sheets were prepared by Network Operation Section on daily basis.

TRAININGS/COURSES/WORKSHOPS

- Completed 2 Weeks Technical Refresher Course BPS-19 in 2021 at TSG Lahore.
- Completed 2 Weeks Training on 'Energy Meters and its Communication' in 2020 at TSG Lahore.
- Completed 2 Weeks Training on 'Distance Relay and Auto-recloser' in 2020 at TSG Lahore.
- Completed 3 Weeks Technical Refresher Course BPS-18 in 2020 at TSG Lahore.
- Completed 8 Weeks Middle Management Course in 2017 at WAPDA Administrative Staff College Islamabad.
- Completed 1 Month Training on 'SCADA System' in 2017 arranged by USAID in AUSTRALIA.
- Completed Two Weeks of Training on 'Alstom PLC and SOPHO PABX' in 2016 at Dubai.
- Completed 2 Day 'ADB Procurement Training' in 2015 at Wapda House Lahore.
- Attended 1-day Workshop on 'ADB Workshop on FIDIC' in 2015 at Wapda House Lahore.
- Completed 1 Day Training on PPRA Rules arranged by PPRA Cabinet Division, GoP, Islamabad in 2014 at Islamabad.
- Completed 2 Weeks of Training on Fiber Optic Multiplexer (PDH - ALSTOM) in 2012 arranged by Alstom in Lahore.

- Completed 2 Weeks of Training on Fiber Optic Multiplexer (SDH - ALSTOM) in 2011 arranged by Alstom in Messy France.
- Completed 4 Weeks Sector Specific Course in 2008 at Wapda Staff College Islamabad
- Completed 9 Weeks Junior Management Course in 2007 at Wapda Staff College Islamabad.
- Completed 1 Week of PLC Training (ETL-600) at ABB University Switzerland.

SHAKIR ULLAH
MANAGER SCADA / DATABASE NPCC

SUMMARY OF QUALIFICATION

Mr. Shakir Ullah has a professional career of over 18 years with hands on Technical expertiese and Managarial experience in power transmission & dispatch company (NTDC) at various positions including Drawing & Disbursing Officer. His field of particular experience include SCADA System Operations & Maintenance, Teleprotection of Transmissionn Lines, Power Line Carriers, PABX, RTUs, Optical Fiber and Terminal Equipment (SDH & PDH).

PROFESSIONAL EXPERIE

2022- To Date **Manager (SCADA/DB), NPCC, NTDC, Islamabad.**

As Manager (SCADA & Database), he is responsible for Monitoring of reliability, configuration and maintenance of the SCADA System and its related hardware and software application, ensure that staff training needs are identified and to enable the acquisition of the required skills and knowledge, preparation of SOPs pertaining to SCADA Section, whilst identifying the applicable operating requirements and ensuring incorporation of global best practices. He also supervises all administrative matters of employees under SCADA Directorate NPCC, review and finalize the technical specifications for SCADA projects preparation of reports / data for GM (SO) regarding MoE, NAB, NEPRA, Govt. Audit, NA, Senate Committees, PAC & DAC issues and preparation of replies regarding Audit Paras.

2004- 2022 **NTDC Telecommunication Lahore/Peshawar/Islamabad**

Joined NTDC as Assistant Manager (Tel) in February 2004 at Telecom Head Office WAPDA House Lahore. Transferred as RE (Tel) at 500kV G/S Peshawar in April 2006. Promoted as Deputy Manager (Tel) and posted at WAPDA House Lahore in May 2012. Transferred to NKLP Lahore in April 2013. Then Transferred to NPCC Islamabad in May 2017 as Deputy Manager / DDO (Tel). Detail of the responsibilities during service in NTDC Telecom department include technical / design evaluation of Telecom equipment such as OPGW & OLTE (SDH & PDH), Outdoor Telecom Equipment (Line Trap, Coupling Capacitors, Line Matching Unit), Power Line Carrier, Remote Terminal Unit, PABX, Battery & Battery Charger, MDF and Coaxial cable, troubleshooting of Telecom equipment such as Fiber Optic Multiplexers and Terminal Equipment (SDH & PDH), PLC, Remote Terminal Unit (RTU) and Battery Chargers of different manufacturers.

EDUCATION

- **BSc Electrical Engineering,** University of Engineering & Technology (UET) Peshawar, 2002

HONORS

- Have been awarded twice with Honoraria by the Competent Authority for vigilance in O&M of Telecom equipment and Divisional Office Administration.
- Have conducted several successful Audit negotiations as DDO.

TRAININGS/COURSES/WORKSHOPS

- 04 weeks Induction Management Course at WSC Islamabad, 2004.
- 04 weeks Sector Specific Course (Telecom) at WSC Islamabad, 2006.
- 10 Days PDH Training at ALSTOM Training Institute France, 2011.
- 08 weeks Junior Management Course at WSC Islamabad, 2011.
- 03 weeks Middle Management Course at LUMS Lahore, 2019.
- 04 weeks Technical Refresher Course at TSG NTDC Lahore, 2019-20.

MUHAMMAD ALI WAQAR
ADDITIONAL MANAGER SCADA

SUMMARY OF QUALIFICATION

Mr. Muhammad Ali Waqar has a professional career of over 17 years. He possesses experience in the areas of power system operation, control & dispatch along with development, operation, maintenance & troubleshooting of SCADA Energy Management System (EMS).

He has also worked for the project office of Load Dispatch System Upgradation (LDSU), SCADA Phase-II, where he got exposure of contracts, project management, conflict resolution and technical reporting. Later on, he actively participated in the preparation of PC-I for SCADA-III project and remained an active member of Technical Evaluation Committee in year 2019 for Bid evaluations of SCADA-III.

PROFESSIONAL [illegible]

2012 to Date **Deputy Manager/Addl. Manager SCADA, NPCC, NTDC, Islamabad.**

ıd Ali Waqar has worked as a Lead Engineer of developing Team of SCADA SWIG (Software Integrated Group).

- Development of SCADA Database Models such as SCADA Top, NET Model, and GEN Model using Database builder.
- Development of SCADA displays using full Graphic Builder.
- Keeping all the models error free, ensuring the project run smoothly in cooperation with ALSTOM for SAT (site acceptance tests).
- Maintaining Real Time Historian and Archival System
- Preventive Maintenance measures of EMS on Daily, Weekly and Monthly basis
- Monitoring and Ensuring SCADA Cyber Security
- Correspondence with CPPA-G/EHV/GSO/Telecom on SCADA related Issues.
- Modification in SCADA/EMS System Frontends Servers to update Real Time changes done in field.
- Providing timely support and troubleshooting of any problems faced by despatchers/end users in different areas of SCADA/EMS to ensure effective utilization of SCADA/EMS System

2005 to 2012 **Assistant Manager/Deputy Manager (RCC/ NCC), NPCC, NTDC, Islamabad.**

- To Monitor the power system parameters (frequency, voltage, active/ reactive power) through SCADA system & to maintain continuity of power supply & high reliability of the power system network in addition to quality power supply.
- Planning day ahead and month ahead notifications for power generation companies (hydro, thermal)
- Outage planning and asset management. Updating the plan of replacing/upgrading aging equipment.
- To control the active & reactive power flow on 500kV, 220kV, 132kV & 66kV transmission lines & power transformers.
- To control high / low voltages through available reactive & capacitive resources as well as through power transformers taps.

EDUCATION

- **MSc Electrical Engineering (Power),** University of Engineering & Technology Taxila, Pakistan 2009
- **Master of Business Administration (Human Resource),** COMSATS Institute of Information Technology Islamabad 2016
- **BSc Electrical Engineering,** University of Engineering & Technology, Peshawar, Pakistan 2003

- Appreciation from Authority for restoration of completely defected Storage Area Network (SAN) of NPCC SCADA System. The said activity was carried out without any vendor support using local resources.
- Performance recognition by authority for evaluation of SCADA/ EMS portion of Technical Bids of upcoming SCADA-III project. The said evaluation process was completed well within stipulated time and evaluation report submitted to Management for timely completion of the bid evaluation process.
- Letter of appreciation from General Manager (SO) for restoration of faulty SCADA Wall Board System at NPCC Islamabad in minimum possible time without any foreign assistance resulting in saving an amount of about 21000 USD to organization.
- Delivered training sessions to Chinese engineers of Sahiwal Coal & Port Qasim power plants in year 2017 & 2018 in order to make them familiar with the working environment of power system operation and dispatch in Pakistan.
- Actively participated in restoration of partial/ complete power system blackouts in Pakistan in year 2013, 2016 and 2021.

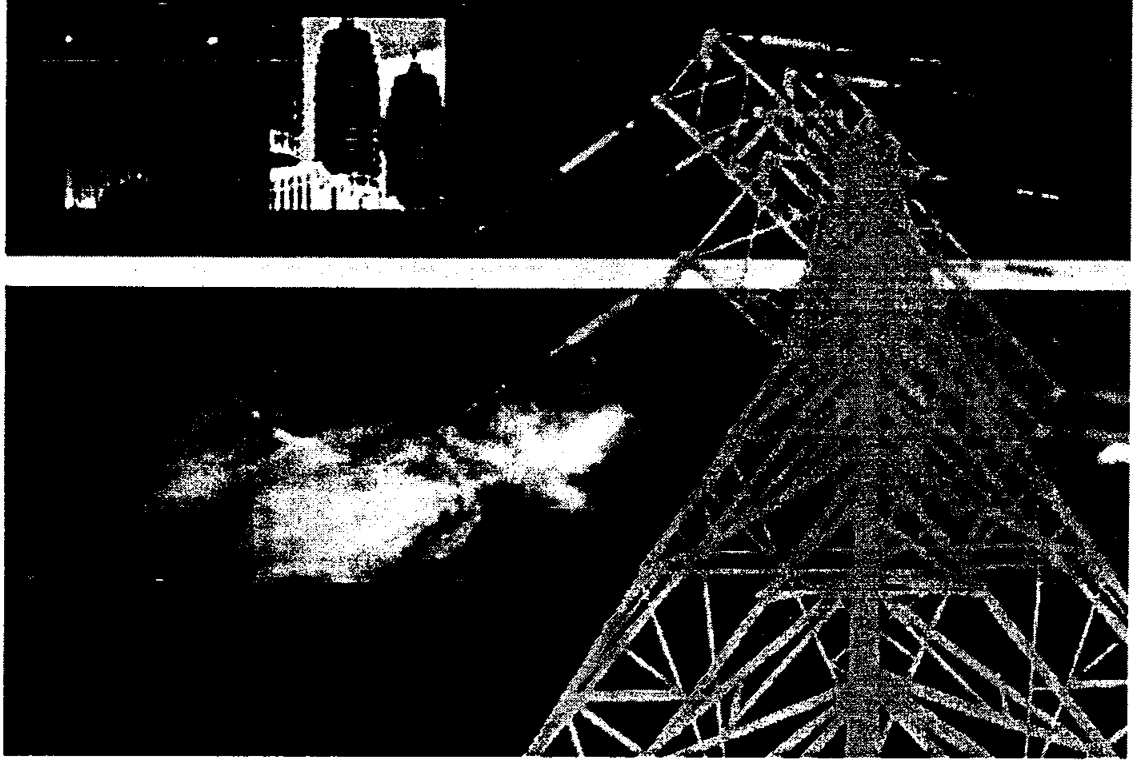
TRAININGS/COURSES/WORKSHOPS

- Attended 2 Weeks Training on RE by KOICA Korea in October 2021 at Islamabad, Pakistan.
- Attended a 4 Weeks Middle Management Course in 2019 at LUMS, Lahore, Pakistan.
- Attended a 4 Weeks Technical Refresher Course in 2019 at TSG Center, Lahore, Pakistan.
- Attended a Seminar on SCADA System by CHESI ITALY in July 2016 at Lahore, Pakistan.
- Participated in a 10 Days Refresher Course on SCADA - EMS System in December 2014 at NPCC, Islamabad, Pakistan.
- SCADA/EMS Training by ALSTOM for hardware and networking at Massy France in 2011
- Attended a 9 Weeks Junior Management Course in 2011 at WAPDA Administrative Staff College, Islamabad, Pakistan.
- Attended a 6 Weeks Sector Specific Pre-Promotion Training Course for Junior Engineers in 2011 at WAPDA Engineering Academy Faisalabad, Pakistan.
- SCADA Training Course by Areva at Serena Hotel Islamabad E-terrahabitat Databases, Building full Graphic Displays using e-terrabrowser, EMS Date Model, Database building with DBB in 2010.
- Participated in 6 Weeks Management Induction Training Course in 2006 at WAPDA Administrative Staff College, Islamabad, Pakistan.

- Participated in 6 Weeks Technical Induction Training Course in 2006 at WAPDA Engineering Academy Faisalabad, Pakistan.

NATIONAL TRANSMISSION
& DESPATCH COMPANY LIMITED

Strategic Business Plan for System Operator (5 years)



NATIONAL TRANSMISSION
& DESPATCH COMPANY LIMITED

STRATEGIC BUSINESS PLAN FOR THE SYSTEM OPERATOR

Deputy Managing Director, System Operation (DMD SO)

AUGUST 2022

Table of Contents

1. RESTRUCTURING

DRIVERS FOR RESTRUCTURING

1.1

1. As per NEPRA approved CTBCM detailed design, restructuring of System Operator (SO) w.r.t CTBCM is to be carried out under Item No. 9 of NEPRA approved CTBCM Implementation Roadmap. NEPRA in its approved detailed design of CTBCM states that,

   "The successful implementation of the CTBCM will depend on the efficient and transparent functioning of the SO and it is, therefore, considered vital that the SO develops its capacity and improves its ability to perform its activities in an effective, transparent, and non-discriminatory manner. The Authority considers that it is need of the hour that NPCC is restructured and equipped with adequate human, technical, financial, and IT resources to turn it into a state-of-the-art SO."

2. The sanctioned number of technical posts in NPCC/RCC was last increased in 2016 to 83. In 2016, the network consisted of 71 power plants and 954 132kV grid stations, whereas the network in July 2022 contains 111 power plants and 1230 132kV grid stations. Therefore, Power Control requires an increase in sanctioned technical posts.

3. The SCADA department is fully occupied in maintaining the existing SCADA and lacks resources to develop the databases and network models required for rolling out the upcoming SCADA-III.

4. The wholesale power market (CTBCM) increases the System Operator's regulatory and reporting obligations, including data provision for imbalance settlement (already underway in the Market Operator's dry run) and Grid Code compliance monitoring. These new obligations require new technical positions to be sanctioned and staffed.

5. As per the new (draft) Grid Code, the System Operator is required to provide network needs assessment and network expansion options to the various transmission network operators as part of long-term generation and transmission expansion planning. Network modelling capabilities of the System Operator are currently at an extremely rudimentary level, with only one Assistant Manager capable of operating modelling software such as PSS/E.

6. Operational Procedures / formats / forms for Reporting and Analysis of System Operator data, as per international practices, for the following functions are also being prepared:
    - Generation Scheduling
    - Reserves requirements
    - Calculation of Marginal Cost
    - Generation availability determination and registration
    - Real Time dispatch
    - Information sharing with Market Operator
    - Data publishing and dissemination

7. The increased penetration of power electronics (PE) interfaced devices such as thyristor-based systems such as HVDC and SVC and inverter-based VRE generation can create new behaviours, thereby posing a challenge from a system stability perspective. For example, the share of VRE during winter off-peak hours could be above 25%.

8. These challenges include:
    - New behaviours of the power system
        - Reduction of transient stability margins
        - Sub-synchronous controller interaction
        - Introduction of new low frequency power oscillations
        - Decreased damping of existing power oscillations
        - Larger voltage dips and larger propagation of low voltages during disturbances due to reducing system strength
        - LCC-HVDC commutation failure due to reducing system strength
    - Reduced system strength
        - Increasing Rate of Change of Frequency (RoCoF) and excessive frequency deviations due to reduced inertia
        - Reduced reactive power and short-circuit power levels
        - Provision of ancillary services from VRE

1.2 RESTRUCTURING PROPOSAL

1.2.1 Creation of four new departments

1. Transmission Planning
2. Generation Planning
3. Research and Development
4. Regulatory Affairs and Grid Code Compliance

1.2.2 Change in reporting structure

- Three Chief Engineers report to the General Manager System Operation (GM SO): CE Network Operation & Control, CE Southern Network & VRE Operations and CE Operational Planning

- A new reporting line (Technology and Innovation) is created, along with a newly created position of Chief Technology and Innovation Officer (CTIO). The reporting line consists of Managers responsible for IT, OT (SCADA) and R&D departments. The CTIO reports directly to the Dy. Managing Director. The CTIO position will not be filled through additional charge or promotion even if a suitable candidate is not available on contract.

1.2.3 Increase in head count of Technical Staff

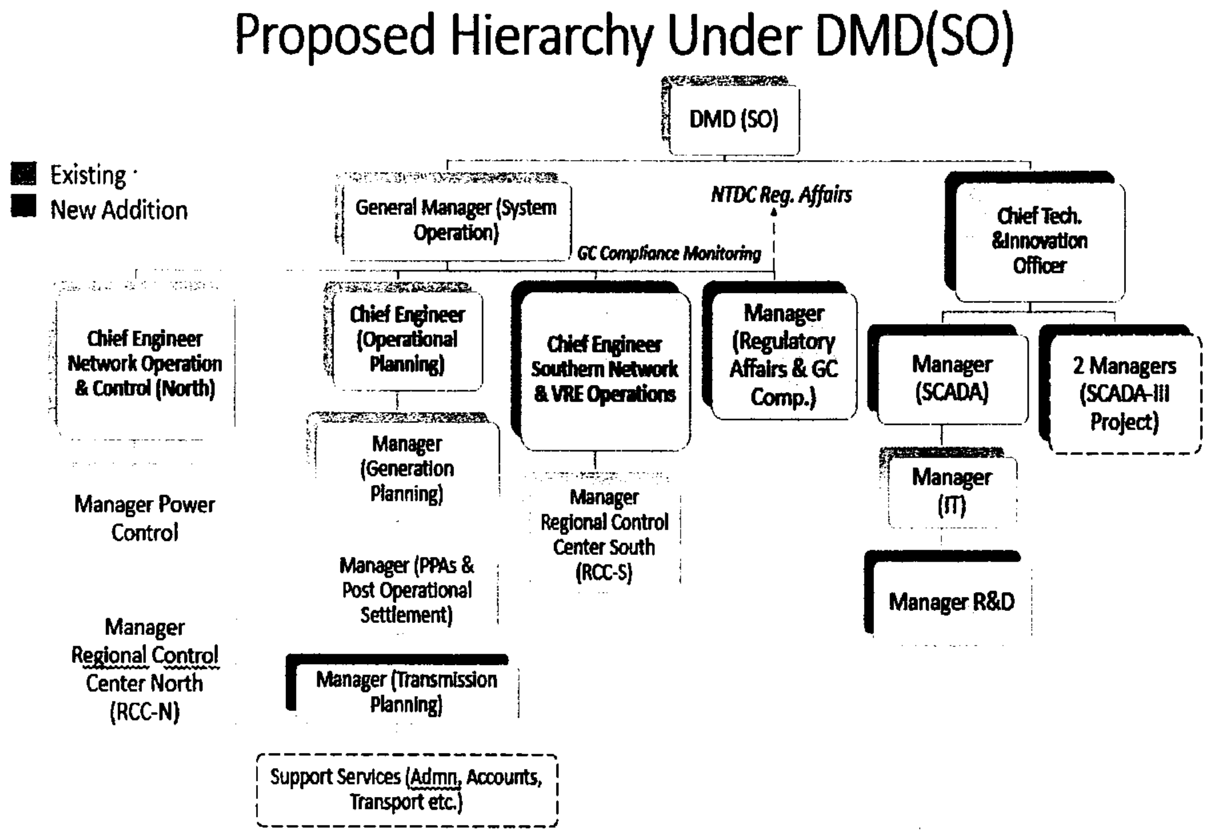
- One Hundred & Nineteen (119) positions under GM(SO) would be filled by adjusting the existing staff, including the proposed Chief Engineer Network Operations South.
- Remaining fifty-five (55) positions would be filled through recruitment. Forty-One (41) junior engineers to be hired through NTS based recruitment (32 North and 9 South) whereas fourteen (14) contract-based positions would be hired from the market.

	Designation	Dept.	No.	
New Hiring (55)	Chief T&I Officer	Technology & Innovation	One (1)	New Hire (market)
	Manager	Transmission Planning	One (1)	New Hire (market)
	Asst. Manager	Transmission Planning	One (1)	New Hire (market)
	Manager	Research & Development	One (1)	New Hire (market)
	Dy. Manager	Research & Development	One (1)	New Hire (market)
	Manager	Regulatory Affairs	One (1)	New Hire (market)
	Dy. Manager	IT (Data Scientist)	One (1)	New Hire (market)
	Dy. Manager	IT (Cyber Security)	One (1)	New Hire (market)
	Dy. Manager	IT (Software Developer)	Two (2)	New Hire (market) – currently consultants
	Dy. Manager	IT (QA)	One (1)	New Hire (market)
	Asst. Managers	IT Help Desk	Three (3)	New Hire (market)
	Assistant Managers	New Recruitment	Forty-One (41)	NTS quota-based recruitment
Existing Employee Adjustment (119)	Chief Engineer	South Net. & VRE Ctrl.	One (1)	Adjust existing employee
	Chief Engineer	Existing	Two (2)	Adjust existing employees
	Managers	Existing	Seven (7)	Adjust existing employees
	Deputy Managers	Existing	Forty-Four (44)	Adjust existing employees
	Assistant Managers	Existing (including IT cadre AMs from WAPDA House)	Sixty-Five (65)	Adjust existing employees

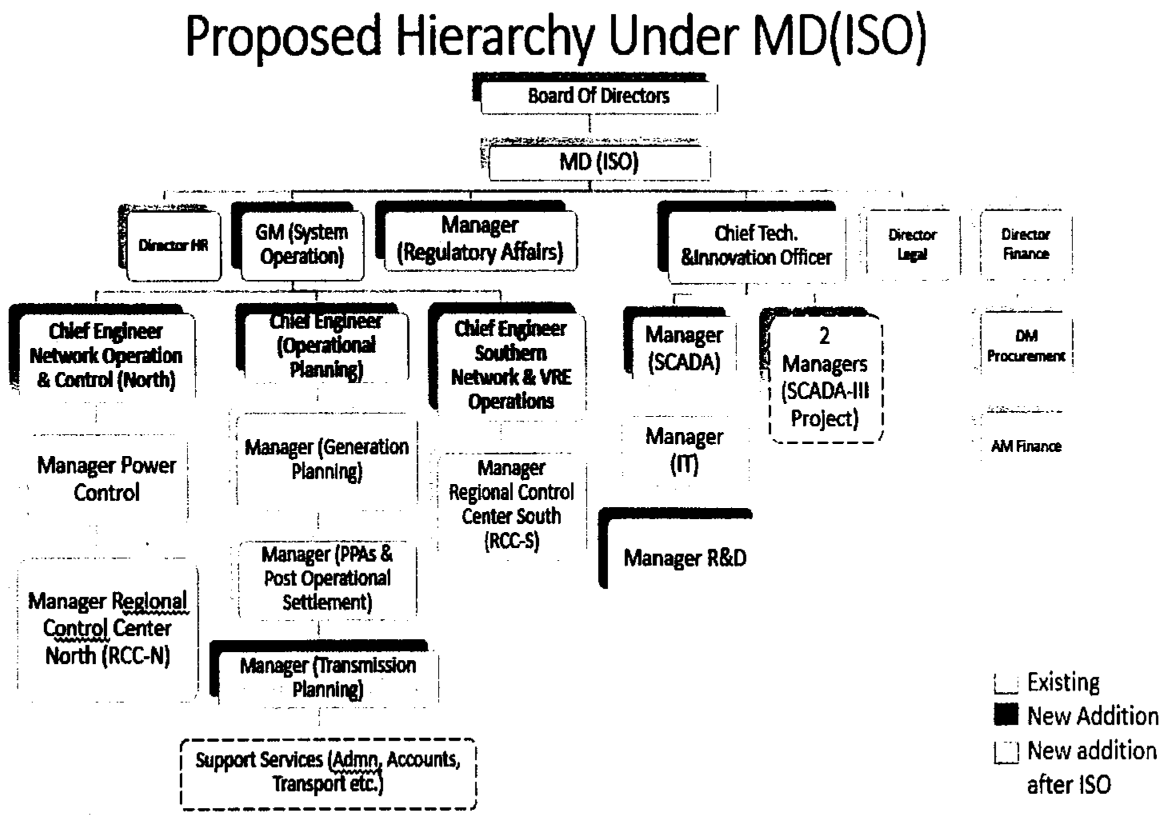
1.2.4 Additional changes / recruitment prior to spin-off

The DMD SO position in NTDC would transfer to the new company as Managing Director. Support functions required to operate as an independent company are to be added at this later stage, which is three months prior to launch of an independent company. These positions include Directors for HR, Legal and Finance, Deputy Manager Procurement and Assistant Manager Finance.

1.2.5 *Organogram for System Operator while part of NTDC*



1.2.6 Organogram for Independent System Operator (ISO)



2. DETAILS OF TECHNICAL DEPARTMENTS AFTER RESTRUCTURING

NETWORK OPERATIONS

2.1.1 Chief Engineer (Southern Network & VRE Operations)

2.1 The increase in VRE sources (wind and solar PV) since 2016 has been significant, and is expected to increase further in the coming years. Furthermore, Wind Farms are currently operated at unity power factor whereas the Grid Code Addendum for Wind IPPs provides the SO with the ability to regulate power factor, voltage and reactive power to support the network.

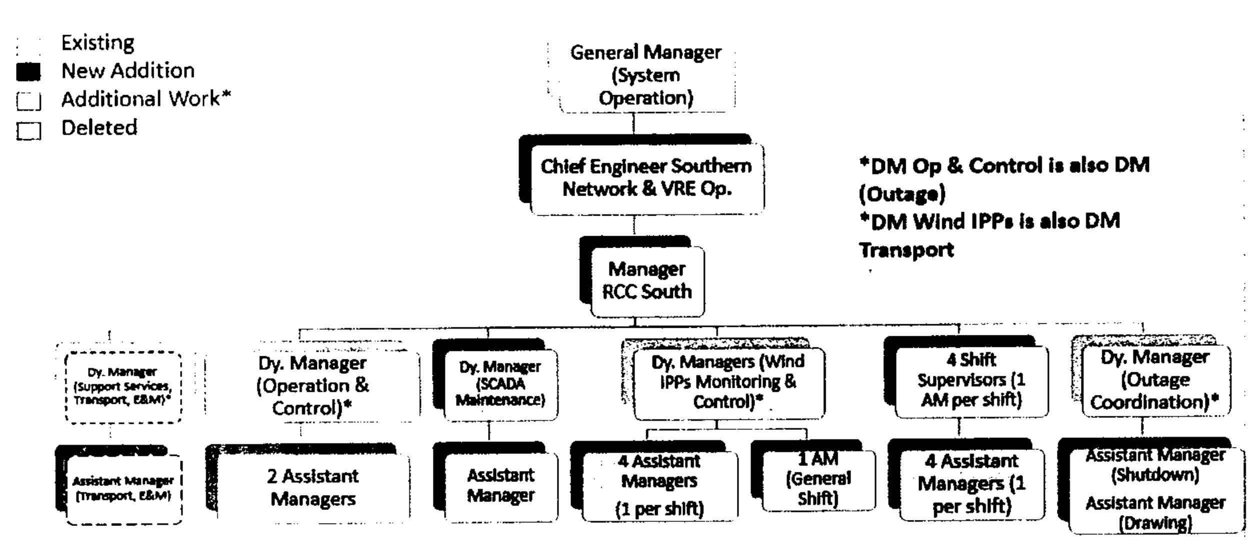
It is therefore planned to transfer VRE management to RCC South, so that Jhimpir and Gharo wind farms, and PV systems in QESCO, MEPCO, HESCO & SEPCO zones can be managed by RCC South, based on their knowledge of the 132kV network and reactive power requirements (leading and lagging based on seasonal requirements).

Secondly, increased thermal power generation capacity in the South requires better coordination between the System Operator and Asset Management South, particularly with regards to unplanned outages of transmission lines.

Finally, RCC South is currently understaffed due to insufficient (quota-based) recruitment in the South. Due to the shortage of technical staff, a number of engineers are working on more than one technical posts. Therefore, it is imperative to increase headcount of technical staff at Jamshoro.

The proposed headcount includes a newly created post of Chief Engineer (Southern Network & VRE Control) and a control room shift structure comprising of a Supervisor, one engineer for Network Monitoring & Control and one engineer for VRE Operations.

Hierarchy Under CE NOP –South(Manager RCC-S)



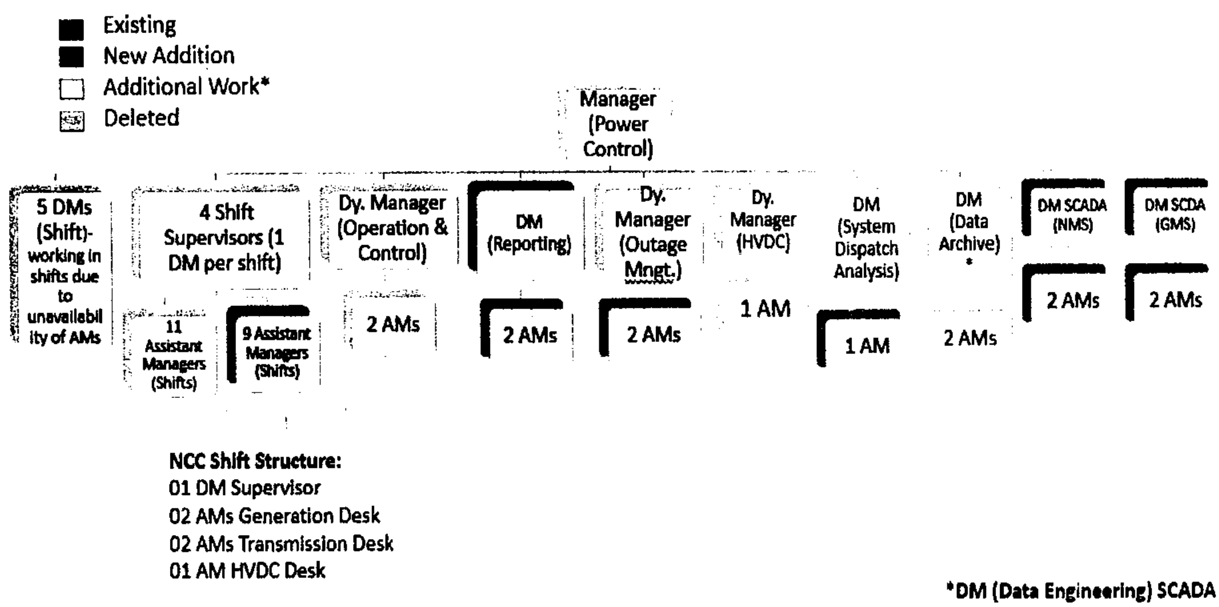
2.1.2 *Chief Engineer Network Operations North*

The NCC shift structure comprises of one Supervisor, two Generation engineers (generation control and SDXP), two Transmission engineers (shutdowns/outages and network control) and one HVDC engineer.

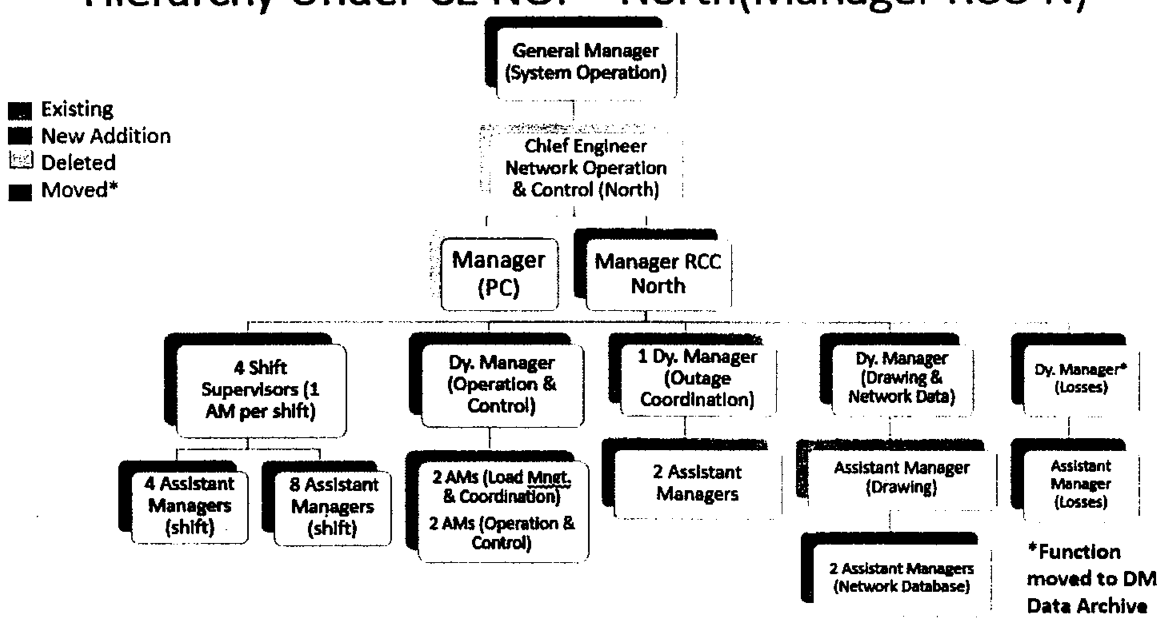
Presently, five Deputy Managers are working in shifts due to unavailability of junior engineers.

The shift structure of RCC North comprises of a Supervisor and two engineers for network monitoring and control.

Hierarchy Under CE N.OP –North(Manager Power Control)



Hierarchy Under CE NOP –North(Manager RCC-N)



2.2 OPERATIONAL PLANNING

Operational Planning takes on ever greater importance with an increasingly complex hybrid AC-DC network and with the commencement of a wholesale electricity trading market. Therefore, a new structure is proposed under the leadership of CE Operations Planning that includes three new departments:

- Regulatory Affairs & Grid Code Compliance
- Generation Planning
- Transmission Planning

Furthermore, several engineers are currently working on two different posts due to insufficient staff. Once headcount is increased, technical posts will no longer be required to be manned on additional charge.

2.2.1 Regulatory Affairs & Grid Code Compliance Department

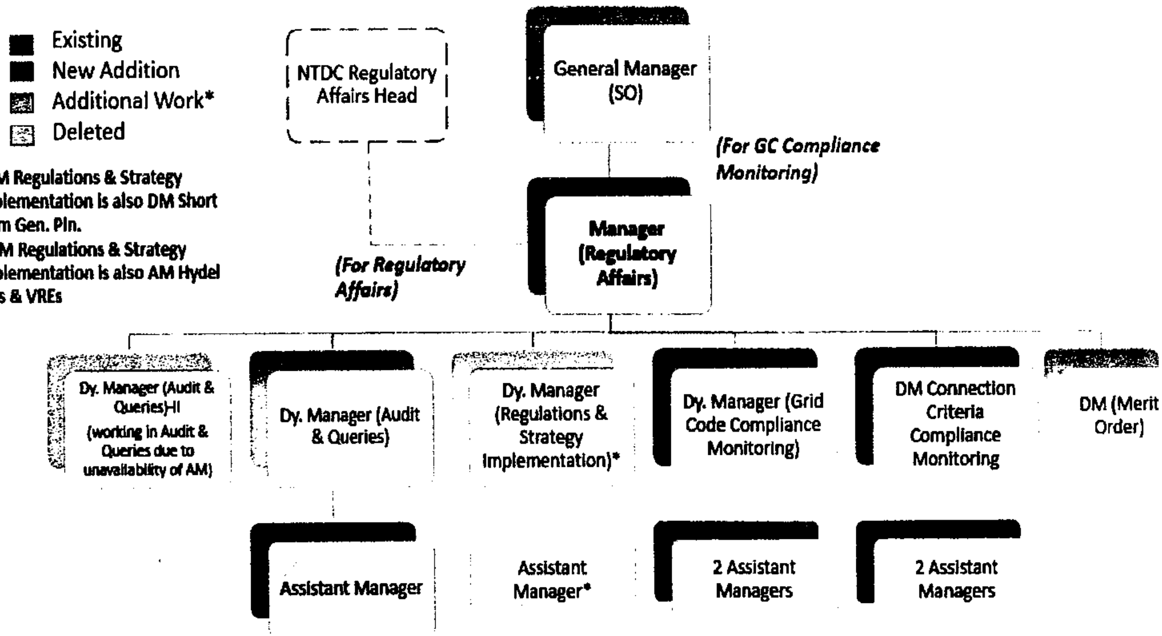
The System Operator is expected to make extensive regulatory filings and appearances in NEPRA. Regulatory Affairs should be handled by Experts in Utility Regulation, Tariffs and Law. Instead, these tasks are currently being attended to by the CE OP and some of his staff who are not trained for these activities. This creates a sub-optimal outcome for both the System Operator and the Regulator.

As per Section 23H of the NEPRA Act, the System Operator is responsible for monitoring Grid Code compliance. As the Grid Code applies to all Users at 66kV and above, the number of regulatory filings will increase significantly, especially with the expected increase in sub-transmission connected solar PV generators. Furthermore, the System Operator is a key service provider for the CTBCM and various market development tasks are assigned to the SO that require additional human resources. These tasks include:

- Regulatory filings with respect to the Grid Code and the System Operator's license
- Grid Code compliance monitoring for Users including Interconnection Agreements and Performance Tests (heat-rate, annual capacity dependence, transmission facilities, etc.)
- Dispute resolution of non-compliance by a User (as per OC 11.4)
- Coordination with Service Providers such as the Metering Service Provider
- Coordinating the activities of the Grid Code Review Panel (GCRP)
- Monitoring the Transparency Data Portal and SDXP:
- Reporting of generation schedules & unplanned outages
- Validation of half-hourly meter data collection for billing and settlement
- Monitoring the System Marginal Price calculation based on daily Merit Order Curve (received from MO) and SMP calculation mechanism in SDXP

The same Manager (Regulatory Affairs) will report to NTDC Head of Reg. Affairs (currently GM Tech) for regulatory affairs and also to GM SO directly for Grid Code compliance monitoring, since the System Operator is the custodian of the Grid Code and is responsible for compliance monitoring of all Code Participants.

Hierarchy Under (Manager Regulatory Affairs)



2.2.2 *Generation Planning Department*

All operational planning from day ahead generation scheduling to year ahead/month ahead fuel planning will be carried by this department. The Generation Planning department will own the following planning tasks of the System Operator as listed in Section PC 2.1 of the Grid Code.

(a) Preparation of Spatial Demand Forecast by consolidating the PMS based area forecasts;

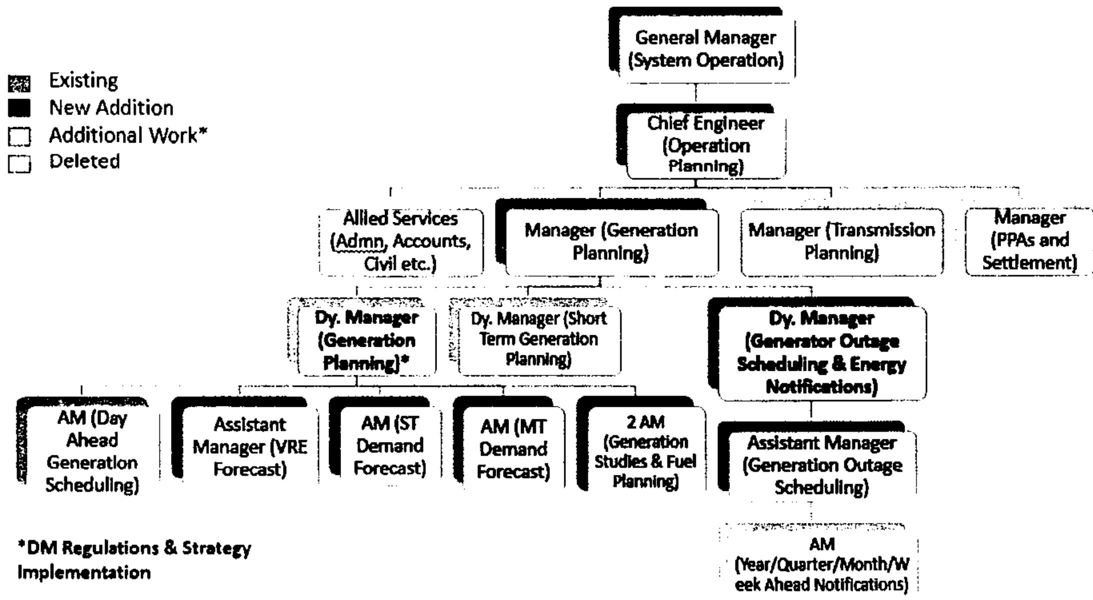
(b) Preparation of Global Demand Forecast for different growth rates scenarios (low, medium and high);

(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/processes as well as adhering to the stipulated system reliability criteria;

It is expected that some posts in the Load Forecasting and Generation Planning department in NTDC (under GM PSP) related to IGCEP preparation will eventually be transferred to the System Operator.

Dy. Manager (Generation Planning) will be responsible for overseeing short-term (up to week-ahead) and medium term (month-ahead to year-ahead) generation planning which is used for outage planning and fuel procurement planning. Dy. Manager (Generation Planning) will also be responsible for short-term demand forecasting.

Hierarchy Under CE OP(Manager Generation Op Planning)



2.2.3 Transmission Planning Department

A dedicated department has been proposed to fulfil all transmission planning needs of NPCC and coordinate with other TNOs and DISCOs including:

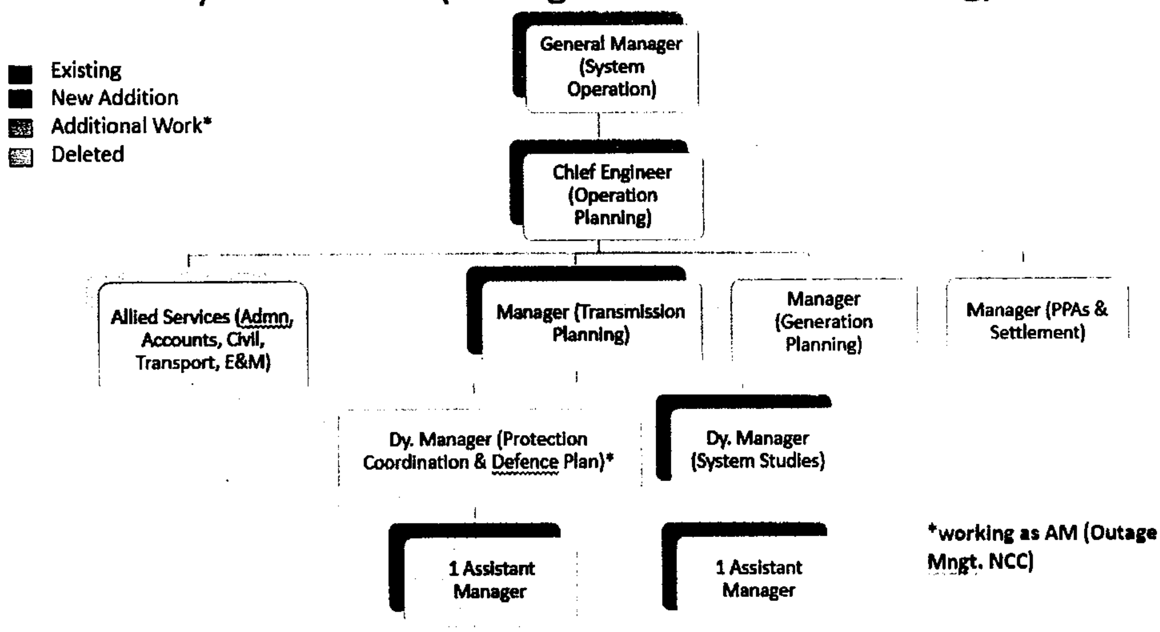
- Providing modelling expertise for both long-term planning needs assessment and short-term (day-ahead to month-ahead) operational planning (including dynamic vulnerability assessment).
- Evaluating Grid Interconnection Studies submitted by prospective power plants.
- Collaborating with TNOs and DISCOs to ensure model robustness

<u>The Transmission Planning department will own the following planning tasks of the System Operator as listed in Section PC 2.1 of the Grid Code.</u>

- Review the "Transmission System Expansion Plan" (TSEP) submitted by the National Grid Company (NGC) and ascertain its adequacy;
- Annual submission of IGCEP and TSEP together as "Integrated System Plan" to the Authority for approval by 30th June each year;
- Perform or cause to perform the required system studies for the applications of any User Development submitted by the potential or existing Generator(s);
- Verify the results of required system studies submitted by TNOs for the applications of any User Development submitted by the potential or existing Demand Users;
- Preparation of an Annual System Reliability Assessment and Improvement Report (ASRAIR) for submission to the Authority. 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. The ASRAIR will be developed in consultation with the relevant TNOs, which may propose remedial measures in their jurisdictions.

Hierarchy Under CE OP(Manager Transmission Planning)



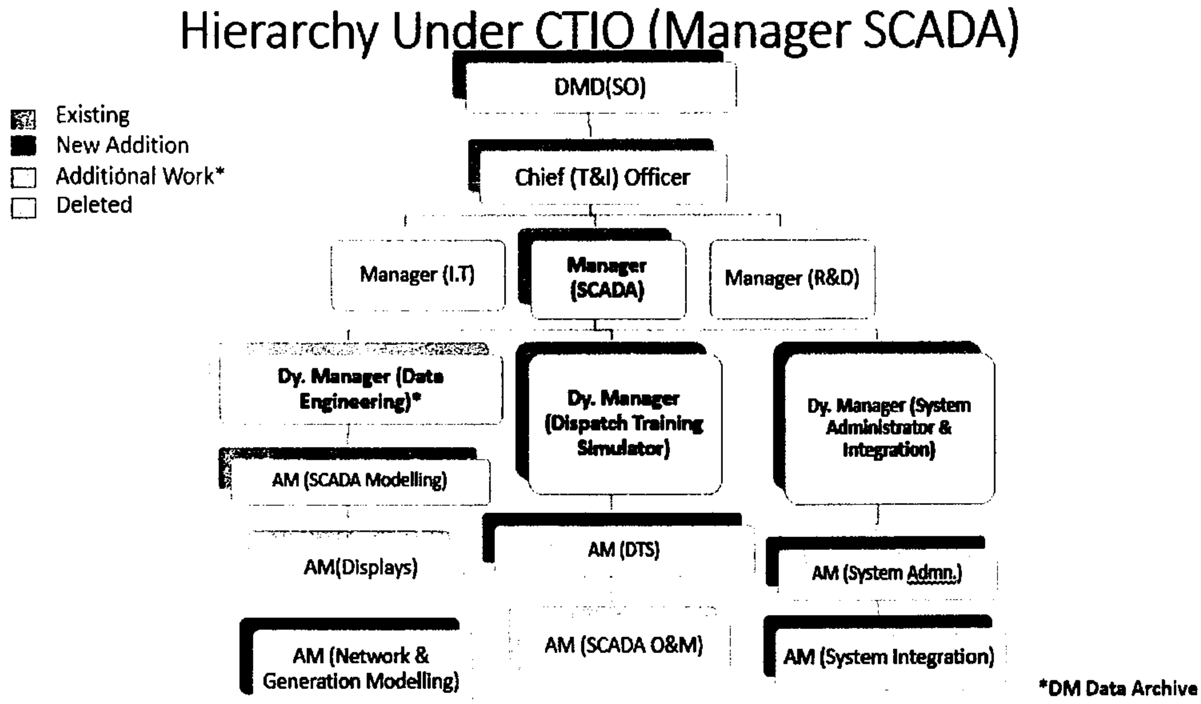
2.3 TECHNOLOGY & INNOVATION

2.3.1 SCADA Department

The SCADA team is fully occupied in daily operations with tasks such as database/UI model updates, signal list verification for power plants and supporting field teams to troubleshoot the existing 114 RTUs.

Increased headcount in the SCADA department is essential for:

- Implementation of the software modules of the new SCADA system (e.g. GMS, EMS). These positions would report to Manager (Power Control).
- Integration of SCADA historian data with transmission models to enable important system studies such as dynamic vulnerability assessment.



2.3.2 *IT Department*

The IT department currently working in NPCC consists primarily of application developers maintaining the SO Data Exchange Platform (SDXP). It is proposed that the IT department be enhanced with at least the following resources:

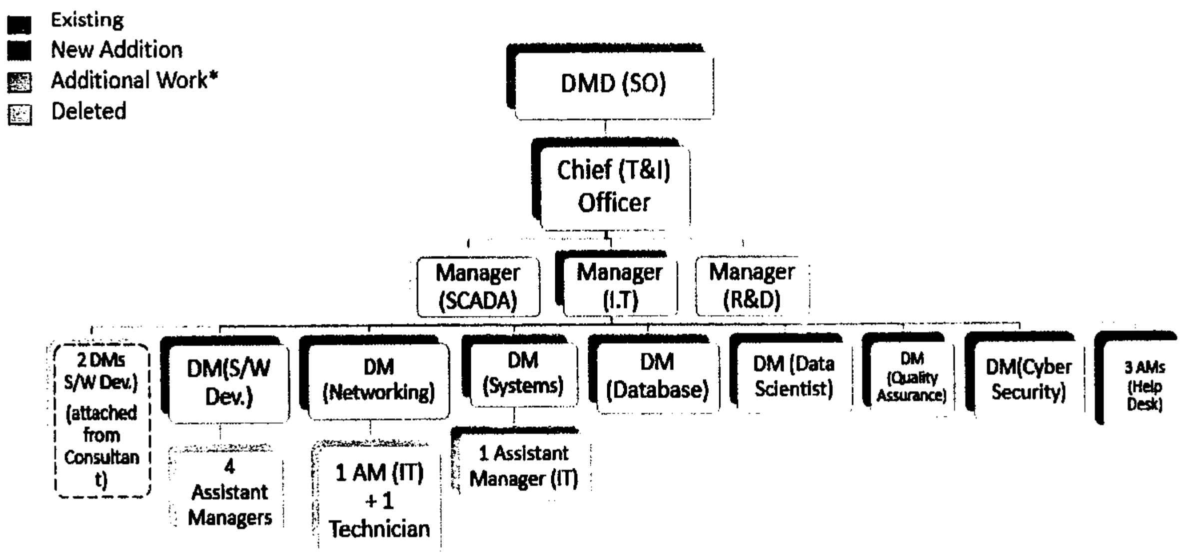
- **Data Scientist:** The System Operator has vast amounts of operational data and new algorithms including load forecasting (World Bank tender) and security-constrained unit commitment. A Data Scientist proficient in statistical analysis (and preferably machine learning) is required to support time series analysis and implement data mining for enhanced operational planning.

- **Cyber Security Expert:** Maintaining cyber security is undoubtedly a critical task for the System Operator. Although the SCADA system is on its own network, other systems such as SDXP, weather forecasting and load forecasting are networked applications. Therefore, an expert is required to ensure the highest levels of cyber security whilst detecting and reporting intrusion attempts from sophisticated intruders.

- **Quality Assurance Expert**: Ensure validity of data in SO's business processes as well as data integrated with MSP (SMS) and the Market Operator (e.g. daily merit order curves, hourly SMPs, etc.). Testing new software development in SDXP and ensuring bug-free deployments.

- **IT Help Desk:** Require 24-hour IT support for Network Operations and CTBCM tasks.

Hierarchy Under CTIO (Manager IT)



2.3.3 *Research & Development Department*

Several operational tasks related to System Planning, New Connections, Operations, Scheduling and Dispatch required in the Grid Code will be owned by the Transmission Planning and Generation Planning departments (under CE Operations Planning).

The R&D department on the other hand is expected to study new behaviours in the power system and develop new methods and algorithms to improve network operations. The R&D Department is crucial to increasing the long-term efficiency and performance of the System Operator.

Examples of models and algorithms to be developed by R&D for Transmission Planning and Generation Planning include:

- Studies emerging phenomena (e.g., converter-based instability and resonance instability) and develops models for electromagnetic transient (EMT) simulation using Real Time Digital Simulator (RTDS)
- Publishes white papers on the SO's future needs assessment that form the basis of discussion with other stakeholders including the Ministry of Energy, TNOs and NEPRA.
- Engages with academia, development partners (JICA, USAID, etc.) and international forums for ISOs/TSOs such as CIGRE.
- Development of methodologies assigned to the System Operator under the Commercial Code and the Grid Code, e.g.,

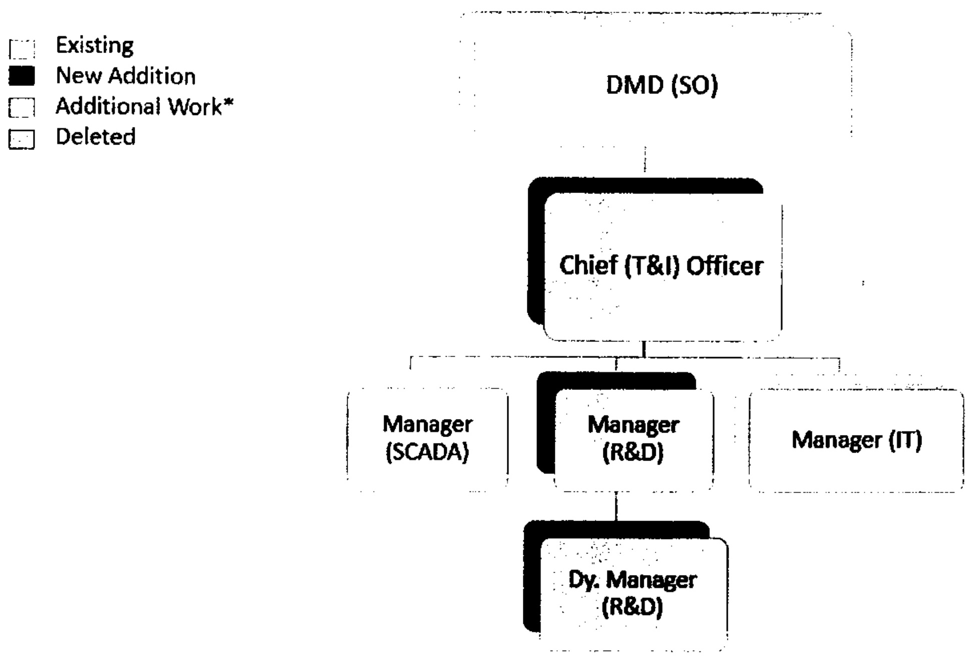
1 Compensation criteria for provision of ancillary services, and procedure for the administration of the Balancing Mechanism for Capacity, i.e., determining the "critical hours" when the power system was under maximum stress.

2 Methodology for allocation of firm capacity certificates and the methodology for the Balancing Mechanism for Capacity (BMC)

3 Security-Constrained Economic Dispatch (SCED) algorithm for determination of the hourly System Marginal Price (SMP) for imbalance pricing in the Balancing Mechanism for Energy (BME)

4 Working out transmission losses and optionally proposing a methodology (beyond the copper plate approach) for efficient transmission cost allocation

Hierarchy Under CTIO (Manager R&D)



3. RESTRUCTURING TIMELINE (GANT CHART)

Tasks	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23
BOD approval of Strategic Biz Plan & SO application		◆											
Submission of SO application and Grid Code to NEPRA		◆											
SO license approved by NEPRA					◆								
Preparation and submission of tariff application for SO license						◆							
Tariff provided by NEPRA									◆				
Sections 23G, 23H activated by default (5y moitorium ends)										◆			
ISO company formation												◆	
Hiring of Technical Positions						◆							
Hiring of non-Technical staff										◆			
Review of NTDC & WAPDA policies by external consultant									◆				
Rental of additional office space										◆			
ISO starts operations													

4. FIVE YEAR FINANCIAL FORECAST

	2023	2024	2025	2026	2027	Assumptions
			Rs in millions			
Revenue						
Revenue requirement (Cost + ROCB)	1,267	1,315	1,840	1,924	2,017	ROCB is 13% as allowed by NEPRA to NTDC
Operating Expenses						
Salaries, wages and other benefits (Note 1)	623	686	754	830	913	Increase in salaries is assumed as 10%
Rent (for new building)	10	11	12	13	14	Rent is based on the allocated space as per designation and @ 160 per sq.ft and is increased @10%
Repairs and Maintenance	9	9	10	11	11	Expected Inflation rate as per global economy: 2023=8.18%, 2024= 7.03%, 2025=6.5%, 2026= 6.5%, 2027=6.5%
Utilities	38	40	43	46	49	
Vehicle running expenses	8	9	9	10	10	
Travelling and conveyance	7	7	8	8	9	
Others	7	8	8	9	9	
Legal & Professional charges	10	5	5	5	5	License payment and consulting fees
Depreciation	389	389	589	589	589	Additional depreciation of SCADA III, furniture and vehicles is added. Deprecíation is charged on straight line basis therefore a flat figure of Rs. 977.4 million is added.
Finance charges	25	-	190	183	175	Financial Charges of SCADA III, estimated @ 12%, proportionately charged on the basis of software cost only.
Total Expenses	**1,121**	**1,164**	**1,629**	**1,703**	**1,785**	
Net Profit	**146**	**151**	**212**	**221**	**232**	

	2023	2024	2025	2026	2027	
CAPEX			Rs. in millions			
Assets						
SCADA-II Hardware	850	850	850	850	850	Out of Rs. 4.5 Bln total capitalization, Rs. 1.2 bln (hardware and software) is booked in NPCC, the rest of Rs. 3.3 Bln is booked in telecom (total hardware).
SCADA-II Software	412	412	412	412	412	
SCADA-III Software			2,000	2,000	2,000	Depreciated @ 10% (p.a dep= Rs.200m)
Furniture and Fixtures	29	29	29	29	29	Depreciated @10%, based on the furniture purchased in WAPDA House ISD.
Vehicles	45	45	45	45	45	Depreciated @10%, 10 vehicles (45 lacs per vehicle)
Total Assets	**1,336**	**1,336**	**3,336**	**3,336**	**3,336**	

5. APPENDICES

Appendix A: Tasks assigned in the Commercial Code

5.1	Section 5.5: Determination of the applicable system marginal price	Sub-Section 5.5.1.2: Within eighteen [18] month from the approval of this Code, the System Operator shall, in collaboration with the Market Operator, make and submit to the Authority for approval a methodology for determining the hourly System Marginal Price. Until such methodology is approved, the procedure included in Appendix 1 shall be used, as an interim measure, for calculation of the System Marginal Price.
	Section 6.4: Compensation for provision of ancillary services	Sub-Section 6.4.1.2: Within eighteen [18] month from the approval of this Code, the System Operator shall make a CCOP whereby a procedure shall be devised to identify a Generator which may be eligible to receive the compensation as well as to determine the quantity of Energy for which compensation may be paid as provided in Clause 6.4.1.1 above. Till such time, the procedure included in Appendix I shall be applicable.
	Section 9.2: Procedure for the administration of the BMC	Sub-section 9.2.1.2: Within eighteen [18] months of the CMOD, the System Operator shall, in collaboration with the Market Operator, make a CCOP for determining the Critical Hours, of the previous year, during which the power system was under maximum stress. The said CCOP shall include: a) the characteristics of the Demand; b) the production of Energy by certain technologies, which, due to their characteristics, are not able to fully control their Energy injection into the Grid System; c) the specific characteristics of the constraints of the hydro Generation; d) the Generation Units maintenance plans; and e) the minimum reserve requirements of the power system.
		Sub-section 9.2.2.3: Within eighteen [18] months after the approval of this Code, the System Operator shall, in collaboration with the Market Operator, make a CCOP describing the detailed methodology for implementing the calculations indicated in Clause 9.2.2.2. Such methodology shall take due consideration of: a) Generation Units maintenance plans and eventual modifications of such plan, instructed by the System Operator; b) Availability Declarations of each Generation Plant or Generation Unit, as the case may be, and eventual changes to such declarations informed by the Generators or other Market Participants during real time operations; c) the results of tests performed or instructed by the System Operator to verify the Availability Declarations submitted by the Generators or other Market Participants, including compliance with instructions of start-up, synchronizing and production of Energy; d) the results of audits, performed by the System Operator, aimed to verify the appropriateness of the Availability Declarations submitted by the Generators or other Market Participants.

Appendix B: Sample overview of Tasks assigned in the (Draft) Grid Code

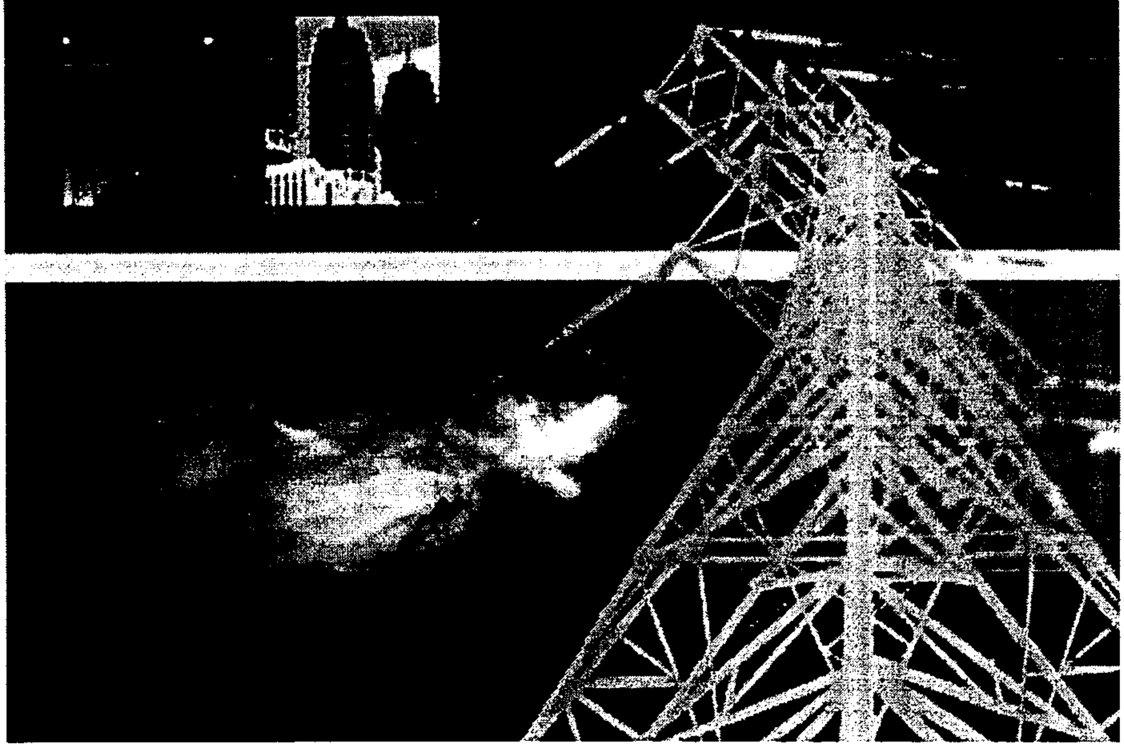
5.2	CM 4: Grid Code Review Panel	CM 4.1: The SO shall establish and maintain the Grid Code Review Panel (GCRP), which shall be a standing body and shall undertake the functions detailed in CM 4.4. CM 4.3: The detailed rules for representation of each category shall be developed by the SO in consultation with GCRP as per CM 4.5 and approved by the Authority; CM 4.5: The GCRP shall establish and comply with, at all times, its own rules and procedures relating to the "Conduct of its Functions", 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 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 Power System.
	OC 5.4.12: Operating Reserve Policy	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 [six (6)] months of the approval of this GC, the SO shall establish, and maintain permanently updated, an SOP (The "Operating Reserve Requirements" SOP) detailing the methodology to be used to determine the amounts of different types of reserve required by the Transmission System in different operational conditions.
	SDC 1.7: Preparation of Indicative Operations Schedule (IOS)	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. 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; (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 OC10 and/or commissioning/acceptance testing prior to connection or re-connection or commissioning under the Connection Code; 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 will run the SCED_M in two different scenarios: (n) 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 (o) 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. 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. 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. The monitoring of the Operating Reserves by the SO will be regular and revised NIOMs may be sent out from time to time. These will reflect any changes in the declared Availability which have been notified to the SO and will reflect any Demand Control which has also been notified. They will also reflect generally any changes in the forecast Demand and the relevant Operating Reserve.
PC 2.1: Responsibilities of the SO	The SO shall be responsible for the following activities: (a) Preparation of Spatial Demand Forecast by consolidating the PMS based area forecasts; (b) Preparation of Global Demand Forecast for different growth rates scenarios (low, medium and high); **(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/processes as well as adhering to the stipulated system reliability criteria; **(d) Review the "Transmission System Expansion Plan" (TSEP) submitted by the** National Grid Company (NGC) and ascertain its adequacy; **(e) Annual submission of IGCEP and TSEP together as "Integrated System Plan" to the** Authority for approval by 30th June each year; (f) Perform or cause to perform the required system studies for the applications of any User Development submitted by the potential or existing Generator(s); (g) Verify the results of required system studies submitted by TNOs for the applications of any User Development submitted by the potential or existing Demand Users;

	(h) Preparation of an Annual System Reliability Assessment and Improvement Report (ASRAIR) for submission to the Authority. 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. The ASRAIR will be developed in consultation with the relevant TNOs, which may propose remedial measures in their jurisdictions.
OC 4.5.4: Planning Generation Outages & Reliability Analysis OC 4.12.3: Planning Transmission Outages & Reliability Analysis	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. 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.

NATIONAL TRANSMISSION
& DESPATCH COMPANY LIMITED

Undertaking and Statement of Compliance by Managing Director NTDC



E-STAMP

ID : PB-LHR-BDC94D9C35A016D3

Type : Low Denomination

Amount : Rs 100/-

Description : AFFIDAVIT - 4

Applicant : Rana Abdul Jabbar Khan[34101-4940598-9]

S/O : Rana Abdul Ghaffar Khan

Address : Gujranwala

Issue Date : 16-Aug-2022 2:41:11 PM

Delisted On/Validity : 23-Aug-2022

Amount in Words : One Hundred Rupees Only

Reason : in favour of MD - NTDC.

Vendor Information : Muhammad Zia Ul Mustafa | PB-LHR-865 | Abbot Road Lahore

نوٹ :یہ ٹرانزیکشن تاریخ اجرا سے سات دنوں تک کے لیےقابل استعمال ہے۔

SYED IFTIKHAR HAIDER ADVOCATE HIGH COURT & OATH COMMISSIONER Lic No. 54

UNDERTAKING

I, **Rana Abdul Jabbar Khan**, Managing Director of National Transmission and Despatch Company Limited ("**NTDCL**"), holding CNIC No. 34101-4940598-9 duly authorized by Board of Directors of NTDCL hereby undertake for and on behalf of NTDCL that it will comply with any and all requirements and conditions, which are or may be notified by the Federal Government in the Eligibility Criteria Rules and relevant regulations issued by National Electric Power Regulatory Authority (the "**Authority**") for grant of System Operator License to NTDCL.

Rana Abdul Jabbar Khan
Managing Director (NTDCL)
CNIC: 34101-4940598-9

Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

WITNESS:

Name: SHANZA BAIG
CNIC #: 35202-2252495-0
Address: Hall No 1 2nd Floor Shaheen Complex Lahore

Name: M. AYUB DMD (P&E).
CNIC #: 37405-7186266-3
Address: Room No 419 Wapda House Lahore.

1/1

ATTESTED

SYED IFTIKHAR HAIDER
ADVOCATE HIGH COURT &
OATH COMMISSIONER LAHORE
Notification No. 54/Genl/X.B.9(b)

E-STAMP

ID :	PB-LHR-BDC94D9C35A016D3
Type :	Low Denomination
Amount :	Rs 100/-
Description :	AFFIDAVIT - 4
Applicant :	Rana Abdul Jabbar Khan[34101-4940598-9]
S/O :	Rana Abdul Ghaffar Khan
Address :	Gujranwala
Issue Date :	16-Aug-2022 2:41:11 PM
Delisted On/Validity :	23-Aug-2022
Amount in Words :	One Hundred Rupees Only
Reason :	in favour of MD - NTDC.
Vendor Information :	Muhammad Zia Ul Mustafa | PB-LHR-865 | Abbot Road Lahore

نوٹ :یہ ٹرانزیکشن تاریخ اجرا سے سات دنوں تک کے لیےقابل استعمال ہے۔

SYED IFTIKHAR HAIDER ADVOCATE HIGH COURT & OATH COMMISSIONER Lic No. 56

UNDERTAKING

I, **Rana Abdul Jabbar Khan**, Managing Director of National Transmission and Despatch Company Limited ("**NTDCL**"), holding CNIC No. 34101-4940598-9 duly authorized by Board of Directors of NTDCL hereby undertake for and on behalf of NTDCL that it will comply with any and all requirements and conditions, which are or may be notified by the Federal Government in the Eligibility Criteria Rules and relevant regulations issued by National Electric Power Regulatory Authority (the "**Authority**") for grant of System Operator License to NTDCL.

Rana Abdul Jabbar Khan
Managing Director (NTDCL)
CNIC: 34101-4940598-9

Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

WITNESS:

Name: SHANZA BAIG
CNIC #: 35202-2252495-0
Address: Hall No 1 2nd Floor Shaheen Complex Lahore

Name: M. AYUB DMD(P&E).
CNIC #: 37405-7186266-3
Address: Room No 419 Wapda House Lahore.

1/1

ATTESTED
SYED IFTIKHAR HAIDER
ADVOCATE HIGH COURT &
OATH COMMISSIONER LAHORE

Declaration of Conflict of Interest

1. *I hereby declare that my close relation has become a member in a business organisation carrying out identical or similar activity as that of NTDCL or maintaining regular economic relationship with NTDCL,*

   YES *NO*

2. *Furthermore he/she has established work relationship or other legal relationship aiming at carrying out work with NTDCL as an employer pursuing such activity.*

   YES *NO*

In case of Yes;

a) Name, Grade of kinship of Close Relative:

....

b) Name Of Business Company:

....

c) Registered Offices:

....

d) Form of acquiring ownership (private unlimited company member, general partnership internal/external member, owner of participation, shareholder:

....

e) Description of activity of business organisation identical or similar with that of .... (company name):

....

f) If business organisation maintains regular economic relations with NTDCL, description of economic relation.

....

g) Description of legal relationship established as an employee by close relative in the particular company:

....

I have made present declaration in the complete understanding of my responsibility and being provided with adequate information. I hereby authorise NTDCL to verify the contents of present declaration during my work relationship at any time. I also understand that in case my declaration is found to be untrue, NTDCL shall have the right to take all legal and disciplinary action against me and that any damages or liabilities arising form my non-disclosure shall be borne solely by me.

Dated: 18.08.2022

Signature

Name: ALI ZAIN BANATWALA
Designation: DY. MANAGING DIRECTOR
CNIC: 42301-5045637-5

I establish that no cause for a conflict of interest is maintained based on the report.

Dated:

Managing Director (NTDCL)

Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

I establish that a cause for a conflict of interest is maintained as is included in the clause herein.

Dated:

Managing Director (NTDCL)

Declaration of Conflict of Interest

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   YES *NO* ✓

2. *Furthermore he/she has established work relationship or other legal relationship aiming at carrying out work with NTDCL as an employer pursuing such activity.*

   YES *NO* ✓

In case of Yes;

a) Name, Grade of kinship of Close Relative:

....

b) Name Of Business Company:

....

c) Registered Offices:

....

d) Form of acquiring ownership (private unlimited company member, general partnership internal/external member, owner of participation, shareholder:

....

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f) If business organisation maintains regular economic relations with NTDCL, description of economic relation.

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Dated: 18th Aug' 2020.

Signature

Name: SAJJAD AKHTAR.
Designation: GM(SO), NPCC
CNIC: 17301-4278020-1

I establish that no cause for a conflict of interest is maintained based on the report.

Dated:

Managing Director (NTDCL)
Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

I establish that a cause for a conflict of interest is maintained as is included in the clause herein.

Dated:

Managing Director (NTDCL)

Declaration of Conflict of Interest

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   YES *NO* ✓

2. *Furthermore he/she has established work relationship or other legal relationship aiming at carrying out work with NTDCL as an employer pursuing such activity.*

   YES *NO* ✓

In case of Yes;

a) Name, Grade of kinship of Close Relative:
....N/A..

b) Name Of Business Company:
....N/A..

c) Registered Offices:
....N/A..

d) Form of acquiring ownership (private unlimited company member, general partnership internal/external member, owner of participation, shareholder:
....N/A..

e) Description of activity of business organisation identical or similar with that of .... (company name):
....N/A..

f) If business organisation maintains regular economic relations with NTDCL, description of economic relation.
....N/A..

g) Description of legal relationship established as an employee by close relative in the particular company: N/A
....

I have made present declaration in the complete understanding of my responsibility and being provided with adequate information. I hereby authorise NTDCL to verify the contents of present declaration during my work relationship at any time. I also understand that in case my declaration is found to be untrue, NTDCL shall have the right to take all legal and disciplinary action against me and that any damages or liabilities arising form my non-disclosure shall be borne solely by me.

Dated: 18-8-2022.

Signature

Name: Muhammad Zakria

Designation: Chief Engineer op' plang NPCC

CNIC: 61101-7783034-3

I establish that no cause for a conflict of interest is maintained based on the report.

Dated:

Managing Director (NTDCL)

Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

I establish that a cause for a conflict of interest is maintained as is included in the clause herein.

Dated:

Managing Director (NTDCL)

Declaration of Conflict of Interest

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   YES *NO* ✓

2. *Furthermore he/she has established work relationship or other legal relationship aiming at carrying out work with NTDCL as an employer pursuing such activity.*

   YES *NO* ✓

In case of Yes;

a) Name, Grade of kinship of Close Relative:

....

b) Name Of Business Company:

....

c) Registered Offices:

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g) Description of legal relationship established as an employee by close relative in the particular company:

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I have made present declaration in the complete understanding of my responsibility and being provided with adequate information. I hereby authorise NTDCL to verify the contents of present declaration during my work relationship at any time. I also understand that in case my declaration is found to be untrue, NTDCL shall have the right to take all legal and disciplinary action against me and that any damages or liabilities arising form my non-disclosure shall be borne solely by me.

Dated: 18-08-2022.

Signature

Name: MEHTAB AHMED

Designation: Chief Engineer (Net.Opn)

CNIC: 61101-1869854-9

I establish that no cause for a conflict of interest is maintained based on the report.

Dated:

Managing Director (NTDCL)

Dr. Rana Abdul Jabbar Khan
Managing Director NTDC

I establish that a cause for a conflict of interest is maintained as is included in the clause herein.

Dated:

Managing Director (NTDCL)