

Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30

MAY 2021

Driven by the Future



Load Forecast and Generation Planning
Power System Planning
National Transmission and Despatch Company, Pakistan

Indicative Generation Capacity Expansion Plan

IGCEP 2021-30

May 2021

Driven by the Future

Power System Planning
National Transmission and Despatch Company





Acknowledgements

Commissioning of a study and preparation of a country wide power generation plan, such as the IGCEP, rely extensively on the input data provided by a wide range of stakeholders. In case of IGCEP 2021-30, these stakeholders include Pakistan Atomic Energy Commission (PAEC), Alternative Energy Development Board (AEDB), National Electric Power Regulatory Authority (NEPRA), Private Power Infrastructure Board (PPIB), Pakhtunkhwa Energy Development Organization (PEDO), Punjab Power Development Board (PPDB), Sindh Energy Board, Sindh Transmission & Dispatch Company (STDC), Azad Jammu & Kashmir Private Power Cell (AJKPPC), Azad Jammu & Kashmir Power Development Organization (AJKPDO), Central Power Purchasing Agency-Guarantee (CPPA-G) and Water and Power Development Authority (WAPDA) this output could have not been materialized without the contribution by these stakeholders.

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The LF&GP-PSP Team is, therefore, highly grateful to all those who contributed in preparation and finalization of the IGCEP 2021-30.



Disclaimer

This Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30 is prepared by NTDC under the obligations set in the chapter Planning Code of the Grid Code, major regulatory instrument for NTDC. The plan, as mentioned in its name, is indicative in nature, to be reviewed and approved by NEPRA – the electricity regulator, and is to be updated every year. The IGCEP 2021-30 is developed to thereafter enable project executing agencies for procurement of power from generation facilities from both public and private sectors subject to the fulfillment of other pre-requisites, NTDC to formulate its Transmission System Expansion Plan and Transmission Investment Plan and assist policy makers for aligning the prevailing policies with the ongoing challenges and/or technological advancements.

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List of Contents

Acknowledgements	i
Disclaimer.....	ii
List of Contents.....	iii
List of Figures	vii
List of Charts.....	viii
List of Tables.....	x
List of Acronyms.....	xi
Stakeholder Entities.....	xv
Foreword	xvii
Executive Summary	xviii
1. Setting the Perspective	1
1.1. Generation Planning – A Subset of Power System Planning	1
1.2. Preamble.....	2
1.3. Introduction	2
1.4. Objectives of the IGCEP.....	3
1.5. Scope and Planning Horizon	3
1.6. Nature of the IGCEP.....	3
1.7. Rationale for Preparation of the IGCEP	4
2. Power System of Pakistan	9
2.1. Economics of Pakistan Power Sector	9
2.2. Power Generation	10
2.3. Power Transmission	12
2.4. Power Distribution	13
3. The IGCEP Methodolgy	17
3.1. Regulatory Compliance	17
3.2. Data Collection Process	17
3.3. The IGCEP Data Sources and Associated Data Types	17
3.4. Financial Parameters.....	19
3.5. The IGCEP Preparation Process Map	19
3.6. Criteria and Other Important Considerations for the IGCEP.....	19
3.6.1. Planning Timeframe	19

3.6.2. Economic Parameters	19
3.6.3. Generation System Reliability.....	20
3.6.4. Hydrological Risk.....	20
3.6.5. Renewable Energy (RE) Generation	20
3.6.6. System Reserve Requirement.....	20
3.6.6.1. Contingency Reserve	20
3.6.6.2. Secondary Reserve.....	21
3.6.7. Scheduled Maintenance of the Generation Projects	21
3.6.8. System Load Characteristics	21
3.6.9. Fuel Prices Indexation.....	21
3.6.10. CAPEX of Renewable Energy Technology	22
4. Long Term Energy and Demand Forecast	27
4.1. Energy and Power Demand Forecast.....	27
4.2. Long-Term Demand Forecasting Methodology.....	27
4.3 Data Sources.....	28
4.4 Key Considerations	28
4.4.1 Demand Side Management.....	28
4.4.2. Power Export to K Electric	29
4.4.3. Load Management	29
4.5. Demand Forecast Scenarios: Regulatory Requirement	29
4.5.1. Low Demand	29
4.5.2. Normal Demand	29
4.5.3. High Demand	29
4.6. Preparation of Demand Forecast.....	30
4.7. Demand Forecast Numbers.....	31
4.8. Hourly Demand Forecast.....	32
5. Inside the IGCEP.....	37
5.1. Introduction	37
5.2. Base Case as per Assumption Set approved by CCoE	37
5.3. Other Scenarios	39
5.4. Adherence to Contractual Obligations	39
5.5. Approach and Methodology.....	39
5.6. Planning Basis.....	40

5.7.	Existing Power Generation of Pakistan.....	41
5.8.	Retirement of Existing Power Plants.....	41
5.9.	Committed Generating Units	42
5.9.1.	Committed Projects	43
5.10.	New Generation Options	48
5.11.	Hydro Projects and Screening	49
5.12.	Performance Characteristics of Generic Thermal Candidates	49
5.13.	Economic Parameters of the Candidate REs.....	51
6.	The IGCEP Study Output – Base Case.....	55
6.1.	Introduction	55
6.2.	Future Demand and Capacity Additions (Base Case).....	55
6.3.	Annual Capacity Factors	66
6.4.	Year-wise Discounted and Un-Discounted Cost	73
6.5.	Indigenization of Energy Mix.....	74
6.6.	Clean and Green Power for Pakistan	75
6.7.	Salient Features of the IGCEP	76
6.8.	Comparison of Scenarios	83
6.9.	Strategy for Feedback	84
7.	The Way Forward.....	87
7.1	Must Do Actions for the Future Generation Plans.....	87
7.2	Making Way for the High Share of Renewables in the Grid	87
7.2.1	Hybridization of Variable Renewable Energy Projects	87
7.2.2	Upcoming Wind Power Projects	88
7.3	Future is Here - Time to Understand, Accept and Adopt the New Norms	88
7.4	Focusing on Indigenization through Harnessing the Potential of Local Coal	90
7.5	Thinking, Synergizing and Enhancing the Vision Beyond the Borders	90
7.6	Preparation and Submission of TSEP alongwith IGCEP.....	91
Annexure A.	Load Forecast Data.....	97
A-1.	Projected GDP Growth by Sector – Normal Demand Scenario (Base Case)	97
A-2.	Historical GDP at Factor Cost Constant 2005-06, Consumer Price Index.....	97
A-3.	Category-Wise Nominal Tariff.....	100
A-4.	Category wise Real Tariff	101
A-5.	Electricity Consumption by Category (Excluding K Electric).....	102

A-6.	Category Wise Number of Consumers (Exclduing K Electric).....	104
Annexure B. Generation Planning Data.....		106
B-1.	Existing Installed Capacity (As of May 2021)	106
B-2.	Cost Data of Existing, Committed and Candidate Thermal Plants	110
B-3.	Indexed Capital Cost Calculations of Candidate Hydro Power Plants	114
B-4.	Screening Curve for Candidate Thermal Plants.....	122
B-5.	Annualized Cost of Candidate Hydro Power Plants	123
Annexure C: Low Demand Scenario.....		130
C-1.	Annual Energy Generation Vs Annual Energy Demand (GWh)	130
C-2.	Installed Capacity Vs Peak Demand (MW) 2021-30	130
C-3.	Future Generation Capacity Additions	131
C-4.	List of Projects uptill 2030 (Committed + Candidate)	132
C-5.	IGCEP Generation Mix 2021-2030 (GWh).....	136
C-6.	IGCEP Generation Mix 2021-30 (MW).....	137
C-7:	Total Capacity Contribution in 2030.....	139
Annexure D: High Demand Scenario		140
D-1.	Annual Energy Generation Vs Annual Energy Demand (GWh)	140
D-2.	Installed Capacity Vs Peak Demand (MW) 2021-30	140
D-3.	Future Generation Capacity Additions	141
D-4.	List of Projects uptill 2030 (Committed + Candidate)	142
D-5.	IGCEP Generation Mix 2021-2030 (GWh).....	147
D-6.	IGCEP Generation Mix 2021-30 (MW).....	148
D-7:	Total Capacity Contribution in 2030.....	150



List of Figures

Figure E1: Summary of Results of Base Case Scenario xix

Figure 1-1: Planning Cycle Leading to Procurement 1

Figure 1-2: The IGCEP Objectives 3

Figure 3-2: The IGCEP Preparation Process 19

Figure 4-1: Process Flow of Methodology of Long-Term Demand Forecast 28

Figure 5-1: The IGCEP Data Modelling Approach 40

Figure 5-2: Committed Projects Criteria 42

Figure 6-1: IGCEP 2021-30: Generation Sequence (2021-30) 59

List of Charts

Chart 2-1: GDP (million PKR) vs Sale of Electricity (GWh).....	9
Chart 2-2: Installed Capacity (MW) as of May 2021	10
Chart 2-3: Annual Energy Generation (GWh) as of 2019-20	11
Chart 2-4: Historical Annual Energy Generation (GWh) from 2014-15 to 2019-20.....	11
Chart 2-5: Historical Peak Electricity Demand (MW) from 2014-15 to 2019-20	12
Chart 2-6: Percentage Mix of Number of Electricity Consumers.....	13
Chart 2-7: Percentage Mix of Category-wise Sale (GWh) of Electricity	14
Chart 2-8: Historical Consumer Wise Percentage Share in Electricity Consumption	14
Chart 4-1 Peak Demand (MW) Forecast 2021-2030	32
Chart 4-2: Load Duration Curve (2025 & 2030).....	33
Chart 5-1: Fuel-wise Generation Mix (MW) as of May 2021	41
Chart 6-1: Installed Capacity vs Peak Demand (MW) 2021-30.....	55
Chart 6-2: Annual Energy Generation vs Annual Energy Demand (GWh) 2021-30	56
Chart 6-3: % wise Share of Total Installed capacity (MW) - 2030.....	57
Chart 6-4: IGCEP 2021-30 Base Case Indigenization Ratio of Primary Energy	75
Chart 6-5: IGCEP 2021-30 Annual CO ₂ Emission and Emission per Unit of Generation	76
Chart 6-6: The IGCEP Generation Mix 2021 (MW)	78
Chart 6-7: The IGCEP Generation Mix 2025 (MW)	78
Chart 6-8: The IGCEP Generation Mix 2030 (MW)	79
Chart 6-9: The IGCEP Generation Mix 2020 (GWh).....	79
Chart 6-10: The IGCEP Generation Mix 2025 (GWh).....	80
Chart 6-11: The IGCEP Generation Mix 2030 (GWh).....	80
Chart 6-12 The IGCEP Monthly Generation Mix 2021-25 (GWh)	81
Chart 6-13: The IGCEP Monthly Generation Mix 2026-30 (GWh)	82
Chart C-1: Annual Energy Generation Vs Annual Energy Demand (GWh).....	130
Chart C-2: Installed Capacity Vs Peak Demand (MW) 2021-30	130
Chart C-3: IGCEP Generation Mix 2021 (GWh)	136
Chart C-4: IGCEP Generation Mix 2025 (GWh)	136
Chart C-5: IGCEP Generation Mix 2030 (GWh)	137
Chart C-6: IGCEP Generation Mix 2020 (MW).....	137
Chart C-7: IGCEP Generation Mix 2025 (MW).....	138

Chart C-8: IGCEP Generation Mix 2030 (MW).....	138
Chart D-1: Annual Energy Generation Vs Annual Energy Demand (GWh).....	140
Chart D-2: Installed Capacity Vs Peak Demand (MW) 2021-30	140
Chart D-3: IGCEP Generation Mix 2021 (GWh)	147
Chart D-4: IGCEP Generation Mix 2025 (GWh)	147
Chart D-5: IGCEP Generation Mix 2030 (GWh)	148
Chart D-6: IGCEP Generation Mix 2020 (MW).....	148
Chart D-7: IGCEP Generation Mix 2025 (MW).....	149
Chart D-8: IGCEP Generation Mix 2030 (MW).....	149

List of Tables

Table E1: Summary of Load Forecast (2021-30).....	xviii
Table E2: Summary of Installed Capacity (MW) of All Scenarios by 2030	xx
Table E3: Summary of Energy Generation (GWh) of All Scenarios by 2030	xx
Table E4: Summary of Total Generation Cost.....	xxi
Table 2-1: Length of Transmission & Distribution lines (ckm)	12
Table 2-2: Voltage wise Grid Stations and MVA Capacities	13
Table 3-1: Fuel Price Indexation Factors.....	21
Table 3-2: CAPEX Indexation of Solar and Wind Based Technologies	22
Table 4-1: NEECA Energy Efficiency Targets	29
Table 4-2: Description of Dependent and Independent Variables.....	30
Table 4-3: Annual Long-Term Energy and Power Demand Forecast	31
Table 5-1: Generation Planning Criteria	40
Table 5-2: Retirement Schedule of Existing Power System.....	41
Table 5-3: List of Committed Projects	43
Table 5-4: Performance Characteristics of Generic Thermal Power Plants	49
Table 5-5: Economic Parameters of Generic Power Plants.....	50
Table 5-6: Economic Parameters of Candidate Wind and Solar Blocks	51
Table 6-1: Candidate Generation Capacity Additions (2021-30).....	58
Table-6-2: Break-up of Blocks for Hydro, Solar, Wind and Bagasse Power Plants.....	60
Table 6-3: PLEXOS Annual Addition of Power Plants 2021-30	62
Table 6-4: Annual Capacity Factors (%age).....	66
Table 6-5: Year wise Discounted Cost	73
Table 6-6: Year wise Un-Discounted Cost	73
Table 6-7: Year wise Installed Capacity Addition (MW)	77
Table 6-8: Summary of Installed Capacity & Energy Generation of Scenarios by 2030.....	83
Table 6-9: Total NPV Cost of all Scenarios	84

List of Acronyms

Acronym	Description
\$/GJ	US Dollar per Giga joule
\$/kW	US Dollar per kilowatt
\$/MWh	US Dollar per Mega Watt hour
ACGR	Annual Compound Growth Rate
ADB	Asian Development Bank
AEDB	Alternative Energy Development Board
AGL	Attock Generation Limited
Agr	Agriculture
AJKPDO	Azad Jammu & Kashmir Power Development Organization
AJKPPC	Azad Jammu and Kashmir Private Power Cell
ARE	Alternative and Renewable Energy
AT&C	Aggregate Technical & Commercial
BCF	Billion Cubic Feet
BESS	Battery Energy Storage System
c/Gcal	Cents per Giga calorie
c/kWh	Cents per Kilowatt hour
ckm	Circuit Kilo Metre
CAPEX	Capital Expenditure
CASA	Central Asia South Asia
CCGT	Combined Cycle Gas Turbine
CCoE	Cabinet Committee on Energy
CFPP	Coal Fired Power Project
COD	Commercial Operation Date
Com	Commercial
CPEC	China Pakistan Economic Corridor
CPI	Consumer Price Index
CPPA-G	Central Power Purchasing Agency – Guarantee
Cumm.	Cumulative
Cus.	Customer
DISCO	Distribution Company
DOM	Domestic
DSM	Demand Side Management
EIA	US Energy Information Agency
EOI	Expression of Interest
EPA	Energy Purchase Agreement
EV	Electric Vehicle
FC	Financial Closure
FCC	Fixed Cost Component
FESCO	Faisalabad Electric Supply Company
FKPCL	Fauji Kabirwala Power Company Limited
FS	Feasibility Studies
G.R.	Growth Rate

Acronym	Description
G/s	Grid Station
G2G	Government to Government
GDP	Gross Domestic Product
GENCOs	Generation Companies
GEPCO	Gujranwala Electric Power Company
GoP	Government of Pakistan
GT	Gas Turbine
GTPS	Gas Thermal Power Station
GWh	Gigawatt-hour
HCPC	Habibullah Coastal Power Company
HESCO	Hyderabad Electric Supply Company
HFO	Heavy Furnace Oil
HPP	Hydro Power Projects
HR&A	Human Resource and Administration
HSD	High Speed Diesel
IAEA	International Atomic Energy Agency
IDC	Interest During Construction
IEP	Integrated Energy Plan
IESCO	Islamabad Electric Supply Company
IGCEP	Indicative Generation Capacity Expansion Plan
IIEP	International Institute of Electric Power Ltd.
IMF	International Monetary Fund
Imp.	Imported
Ind	Industry
IPP	Independent Power Producer
JICA	Japan International Corporation Agency
K2	Karachi Coastal Nuclear Unit 2
KAPCO	Kot Addu Power Company
kcal/kWh	kilo calorie per Kilowatt hour
KE	K-Electric
KPI	Key Performance Indicator
KPK	Khyber Pakhtunkhwa
kV	kilo volts
LCP	Least Cost Plan
LED	Light Emitting Diode
LESCO	Lahore Electric Supply Company
LF&GP-PSP Team	Load Forecast and Generation Planning of Power System Planning, NTDC
LNG	Liquified Natural Gas
LOI	Letter of Intent
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LOS	Letter of Support
LT	Long-term
M/s	Messers

Acronym	Description
MEPCO	Multan Electric Power Company
MEPS	Minimum Energy Performance Standards
MoPD & R	Ministry of Planning Development & Reforms
MT	Medium Term
MVA	Mega volt ampere
MW	Megawatt
NEECA	National Energy Efficiency and Conservation Authority
NEPRA	National Electric Power Regulatory Authority
NPCC	National Power Control Center
NPHS	Naya Pakistan Housing Scheme
NPP	National Power Plan
NPSEP	National Power System Expansion Plan
NTDC	National Transmission and Despatch Company
O&M	Operation and Maintenance
OECD	Organization for Economic Cooperation and Development
OLS	Ordinary Least Squares
PAEC	Pakistan Atomic Energy Commission
PASA	Projected Assessment System Adequacy
PC	Planning Code
PEDO	Pakhtunkhwa Energy Development Organization
PEPCO	Pakistan Electric Power Company
PESCO	Peshawar Electric Supply Company
PITC	Power Information Technology Company
PP	Project Planning
PPA	Power Purchase Agreement
PPDB	Punjab Power Development Board
PPIB	Private Power Infrastructure Board
PSP	Power System Planning, NTDC
QESCO	Quetta Electric Supply Company
RE	Renewable Energy
RFO	Residual Furnace Oil
RLNG	Re-gasified Liquid Natural Gas
ROR	Run of the river
RP	Resource Planning
Rs./kWh	Rupees per Kilowatt hour
RTPSS	Real Time Power System Simulator
SCADA	Supervisory Control & Data Acquisition
SEPCO	Sukkur Electric Power Company
SS	System Studies
SSRL	Sino Sindh Resources Limited
STs	Steam Turbines
T&D	Transmission and Distribution
TEL	Thar Energy Limited
TESCO	Tribal Electric Supply Company
TRP	Transmission Planning

Acronym	Description
TSEP	Transmission System Expansion Plan
TWh	Terawatt hour
USA	United States of America
USAID	United States Agency for International Development
VRE	Variable Renewable Energy
WAPDA	Water and Power Development Authority
WPP	Wind Power Project

Stakeholder Entities

Stakeholder Entities	Cyber Link
Alternative Energy Development Board (AEDB)	http://www.aedb.org/
Azad Jammu Kashmir Power Development Organization (AJKPDO)	http://ajkpdo.com/
Central Power Purchasing Agency (CPPA)	http://www.cppa.gov.pk/
Energy Department, Government of Punjab	http://www.energy.punjab.gov.pk/
Energy Department, Government of Sindh	http://sindhenergy.gov.pk/
Faisalabad Electric Supply Company (FESCO)	http://www.fesco.com.pk/
Federal Ministry of Energy	http://www.mowp.gov.pk/
Federal Ministry of Finance	http://www.finance.gov.pk/
Federal Ministry of Planning, Development & Reforms	https://www.pc.gov.pk/
Government of Azad Jammu and Kashmir	http://www.ajk.gov.pk/
Government of Baluchistan	http://www.balochistan.gov.pk/
Government of Gilgit Baltistan	http://www.gilgitbaltistan.gov.pk/
Government of Khyber Pakhtunkhwa	http://kp.gov.pk/
Government of Pakistan	http://pakistan.gov.pk/
Government of Punjab	https://www.punjab.gov.pk/
Government of Sindh	http://www.sindh.gov.pk/
Gujranwala Electric Power Company (GEPCO)	http://www.gepco.com.pk/
Hyderabad Electric Supply Company (HESCO)	http://www.hesco.gov.pk/
International Monetary Fund	https://www.imf.org/en
Islamabad Electric Supply Company (IESCO)	http://www.iesco.com.pk/
K-Electric (KE)	https://www.ke.com.pk/

Stakeholder Entities	Cyber Link
Lahore Electric Supply Company (LESCO)	http://www.lesco.gov.pk/
Multan Electric Power Company (MEPCO)	http://www.mepco.com.pk/
National Electric Power Regulatory Authority (NEPRA)	http://www.nepra.org.pk/
National Transmission and Despatch Company (NTDC)	http://www.ntdc.com.pk/
Pakhtunkhwa Energy Development Organization (PEDO)	http://www.pedo.pk/
Pakistan Atomic Energy Commission (PAEC)	http://www.paec.gov.pk/
Pakistan Bureau of Statistics	http://www.pbs.gov.pk/
Peshawar Electric Supply Company (PESCO)	http://www.pesco.gov.pk/
Private Power Infrastructure Board (PPIB)	http://www.ppib.gov.pk/
Quetta Electric Supply Company (QESCO)	http://www.qesco.com.pk/
Sukkur Electric Power Company (SEPCO)	http://www.sepc.com.pk/
Tribal Areas Electric Supply Company (TESCO)	http://www.tesco.gov.pk/
Water and Power Development Authority (WAPDA)	http://www.wapda.gov.pk/

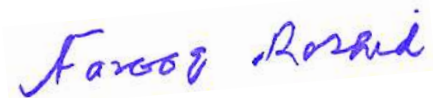
Foreword

The Report on “Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30” presents the results of the latest expansion planning studies conducted by the Load Forecast and Generation Planning (LF&GP) team of Power System Planning (PSP), National Transmission and Despatch Company (NTDC) as per the criteria specified in the Assumption Set approved by Cabinet Committee on Energy (CCoE) on 22nd April, 2021 - a pre-requisite directed by NEPRA vide letter dated 15th October 2020.

This report facilitates a comprehensive view of the future electricity demand forecast, existing generating system and future power generation options in addition to the expansion study results. It is pertinent to highlight that annual updating of this plan remains a regulatory obligation on the part of the NTDC.

In a bid to manage higher level of transparency as well as to make this report comprehensive, various aspects have been included such as comparison of all scenarios in addition to base case, list of stakeholder entities who have shared the input data for the IGCEP; software tools used; generation planning process, etc. However, the LF&GP-PSP Team would certainly welcome suggestions and comments for adding further value to this important regulatory obligation of NTDC.

I am extremely pleased to share that IGCEP 2021-30 has been prepared through the exclusive efforts of NTDC professionals precisely the LF&GP-PSP Team. This team is young yet upbeat and committed to continue learning, delivering and growing. In view of their enthusiastic willingness to learn and contribute in the best interest of NTDC and Pakistan, I envisage this team, in a short span of time, to shape into a bench of professionals complementing towards securing and sustaining self-sufficiency in terms of outputs at par with the international standards.



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May, 2021

Executive Summary

Pursuant to the provisions of the National Electric Power Regulatory Authority (NEPRA) Grid Code i.e., Planning Code (PC) – 4 and PC 4.1, National Transmission and Despatch Company (NTDC) has prepared Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30 covering 0 – 10 years time frame i.e., from 2021 to 2030 encapsulating power generation additions required to meet the future energy and power demand of NTDC system.

The report presents the results of the generation capacity expansion planning study carried out by Load Forecast and Generation Planning (LF&GP) team of Power System Planning (PSP), NTDC.

This generation planning study is composed of two key processes: 1) Load forecast; followed by 2) Generation capacity expansion and despatch optimization. Both processes involve complex statistical and computation efforts performed using dedicated softwares.

Pursuant to the provisions of the Grid Code, three scenarios of long-term forecast are prepared i.e. based on Low, Normal and High GDP growth.

Table E1 shows a summary of the forecast results for the horizon 2021 to 2030.

Table E1: Summary of Load Forecast (2021-30)

Year	Low		Normal		High	
	Energy	Peak Demand	Energy	Peak Demand	Energy	Peak Demand
	GWh	MW	GWh	MW	GWh	MW
2020-21	128,979	24,102	129,001	24,106	129,024	24,110
2023-24	148,664	27,076	149,897	27,311	150,839	27,490
2026-27	160,351	29,473	165,927	30,540	170,347	31,386
2029-30	172,641	32,015	184,900	34,377	195,244	36,369
ACGR 2021-30	3.29%	3.21%	4.08%	4.02%	4.71%	4.67%

The least cost, long-term generation expansion plan for NTDC system for the period 2021 to 2030 is developed using generation planning software - PLEXOS. The IGCEP 2021-30 is developed through a rigorous data modelling and optimization exercise based on the existing and future generation power plants, existing policy framework, existing contractual obligations, natural resource allocations, relevant provisions of Grid Code, CCoE approved Assumption Set.

In addition to the base case, further two (02) scenarios are developed to facilitate the decision makers in reaching to an informed decision which include i) Low Demand Scenario and ii) High Demand Scenario. For all the scenarios, 6,447 MW of existing power generation capacity is retired during the plan horizon.

Catering to the software pre-requisites, hourly demand forecast is developed specially to account for the intermittency of variable renewable energy resources such as wind and solar.

The base case results show that to meet a demand of 34,377 MW by the year 2030, a generation capacity of 53,315 MW is proposed, which include utilization of existing generation facilities, consideration of committed power plants and optimization of candidate power plants by the tool. It is to highlight that to meet the demand by the year 2030, the share from variable renewable energy (VRE) resources stands out to be 1,964 MW, 3,795 MW and 749 MW of Solar, Wind and Bagasse, respectively.

Salient features of this plan include i) inclusion of VREs; ii) Minimal reliance on imported fuels i.e. imported coal, Re-gasified Liquid Natural Gas (RLNG) and Residual Furnace Oil (RFO) based technologies; and iii) increased share of hydropower as well as local coal. Inclusion of VREs, hydro and Thar coal will help in lowering the basket price of the overall system thus providing much needed relief, though in the long run, to the end consumers.



Figure E1: Summary of Results of Base Case Scenario

The self-sufficient ratio of primary energy i.e. the contribution of energy generation by indigenous power sources stands at 58.9% in the year 2021, where, as per base case scenario, indigenization of energy generation is envisaged to achieve 90.2% by 2030 which corresponds to higher energy security in the country.

Similarly, the IGCEP 2021-30 also addresses the impact of carbon emissions due to addition of power generation in future. Carbon emissions in the country by power generation accounts for 0.353 kg-CO₂/kWh in the year 2021 and this indicator reduces to 0.202 kg-CO₂/kWh by 2030 which is even less than average of Organization for Economic Co-operation & Development (OECD) countries.

It is evident from the results of the base case simulation that during the coming five years, the contribution of gas fired power plants in the generation mix (GWh) will decrease from present 12% to mere 5%. Similarly, with the induction of new local coal based committed power plants in Thar, during the next 5 years, share of local coal in the generation mix will enhance to 15%;

The RLNG based plants, though installed and available are envisaged to have a decreasing share in the energy mix from 2021 to 2030 i.e. from 19% to 1% in 2025 and then eventually falling nearly to 0% in 2030. Similar trend is there for imported coal-based plants whose contribution in the overall generation mix falls from 22% in 2021 to only 10% by the year 2030. Moreover, the share of solar and wind in the overall energy mix increases from about 3% in 2021 to 10% in 2030. Tables E2 & E3 show the Installed Capacity (MW) & Energy Generation (GWh) respectively by year 2030 for all scenarios.

Table E2: Summary of Installed Capacity (MW) of All Scenarios by 2030

Technology	Base	Low Demand	High Demand
	Installed Capacity (MW) by 2030		
Imported Coal	4,920	4,920	4,920
Local Coal	3,630	3,630	3,630
RLNG	6,786	6,786	6,786
Gas	2,582	2,582	2,582
Nuclear	3,635	3,635	3,635
Bagasse	749	749	749
Solar	1,964	882	4,954
Hydro	23,035	23,035	23,035
Cross Border	1,000	1,000	1,000
Wind	3,795	2,795	4,694
RFO	1,220	1,220	1,220
Total (MW)	53,315	51,233	57,204

Table E3: Summary of Energy Generation (GWh) of All Scenarios by 2030

Technology	Base	Low Demand	High Demand
	Energy Generation (GWh) by 2030		
Imported Coal	18,007	17,532	18,136
Local Coal	19,985	14,490	20,499
RLNG	36	-	61
Gas	5,278	5,226	5,573
Nuclear	24,912	24,912	24,912
Bagasse	3,380	3,380	3,380
Solar	3,478	1,432	9,127
Hydro	91,866	91,866	91,866
Cross Border	3,443	3,443	3,443
Wind	14,514	10,360	18,247
RFO	-	-	-
Total (GWh)	184,900	172,641	195,244

The overall generation capacity in the system increases from 34,100 MW in 2021 to 53,315 MW in 2030. Major increase in the capacity is observed in the hydropower, solar and wind plants. New solar and wind plants are optimized by PLEXOS being cheaper source of energy.

This results in the capacity addition of 1,083 MW of solar & 2,000 MW of Wind up till 2030. The comparison of the results shows that the base case, simulated using normal demand forecast, has an increased share of solar and wind, as compared with the same case of low demand, in the total available capacity, by the year 2030. On the other hand, the results also show that the base case using normal demand forecast, has decreased share of solar and wind, as compared with the same case of high demand. However, the percentage share of the rest of the fuels is exactly the same for base, low demand and high demand scenarios.

PLEXOS also computes Net Present Value (NPV) of the power generation operations and investments of existing and future power plants by 2030, based on the objective function for the optimization exercise. Table E4 shows the total NPV of investment required to manage generation infrastructure construction and operations by 2030 separately for all the scenarios. The base case scenario indicates 31.6 billion US \$ NPV investment requirements including CAPEX and OPEX. It is pertinent to mention here that the total NPV cost neither include the existing capacity payments nor the CAPEX of committed plants.

Table E4: Summary of Total Generation Cost

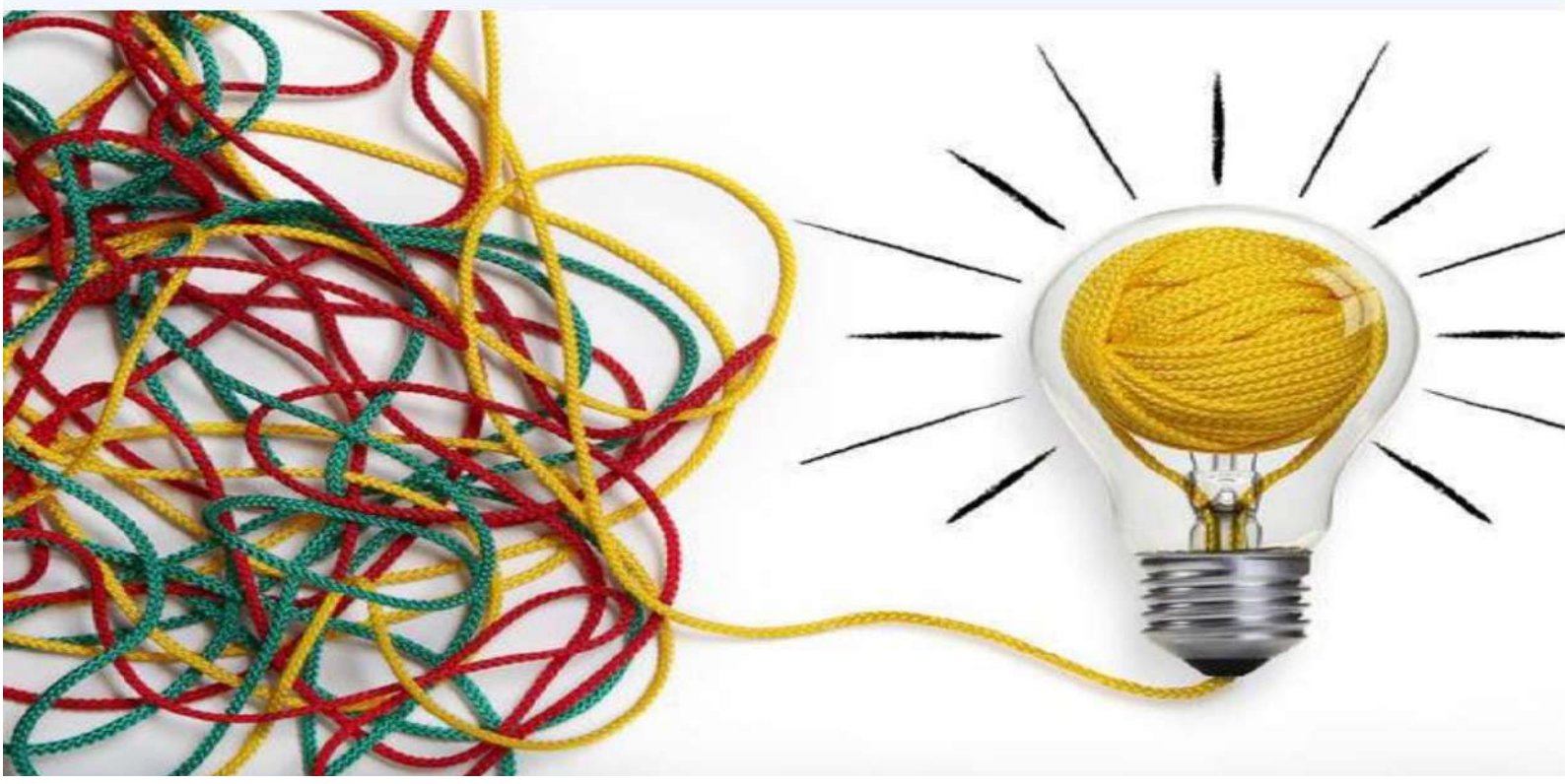
#	Scenario	Total Cost NPV (Billion US \$)
1	Base Case	31.6
2	Low Demand	31.0
3	High Demand	32.2

The generation planning exercise demands extensive data collection and strenuous efforts to streamline access to data for future exercises pertaining to forecasting and generation capacity expansion and despatch optimization. The team look forward to proactive response by the input data providing entities for this purpose.

The IGCEP 2021-30 also facilitates a food for thought through ‘The Way Forward’ with respect to structural changes in the power sector planning process with enhanced role of distributed generation and reduction in the large plants distant from the load centers. Further, indigenization of RE technologies through local manufacturing is also suggested to lower the basket price and thus providing a relief to the end consumer as well as saving precious foreign exchange while maximizing the nature’s endowment bestowed upon Pakistan.

The Annexures C and D present the detailed results of all the scenarios.

1. SETTING THE PERSPECTIVE



1. Setting the Perspective

1.1. Generation Planning – A Subset of Power System Planning

Power system planning is an important subset of the integrated energy planning. Its objective is, therefore, to determine a minimum cost strategy for long-range expansion of the power generation, transmission and distribution systems adequate to supply the load forecast within a set of prevailing technical, economic and political constraints.

Generation expansion planning concerns decisions for investment pertaining to development of different types of power plants over the long-term horizon – 10 years for IGCEP 2021-30. The goal of this plan is to improve decision-making under different long-term uncertainties while assuring a robust generation expansion plan with least cost and minimum risk.

As depicted in the Figure 1-1, generation planning is at the heart of planning cycle. In an idealistic scenario, the Integrated Energy Plan (IEP), a mandate of Ministry of Planning, Development and Special Initiatives is meant to provide the fuel mix targets for all sectors of the economy including the power sector and such targets are adopted under the electricity policy. The IGCEP is prepared to ensure its maximum contribution in energy security, sustainability and affordability while considering policy inputs and broader macroeconomic perspectives. Under Section 32 of NEPRA Act, such integration should be ensured that brings the full dividends of the integrated planning.

However, in absence of the natural resource allocation targets for power generation, the IGCEP optimizes the generation costs to ensure that adequate generation is added at least-cost to meet the load of the future with its given load shape, which also brings tremendous benefits over back of the envelop based plans, leading to higher costs, shortages or surpluses.

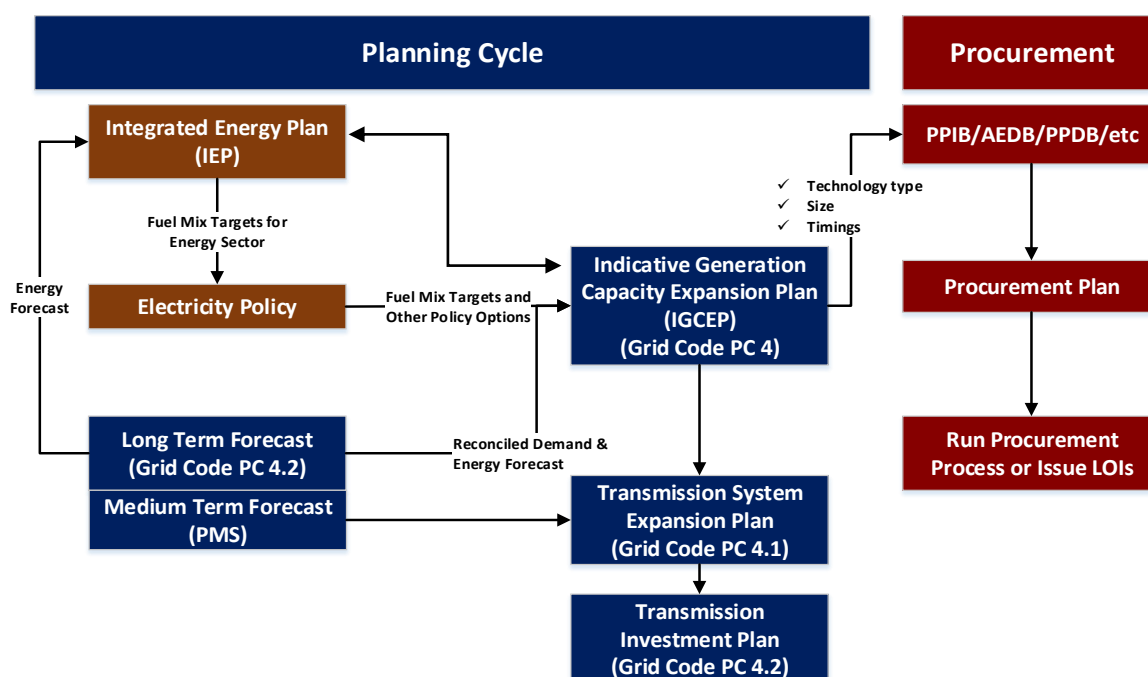


Figure 1-1: Planning Cycle Leading to Procurement

1.2. Preamble

Looking back at the relevant previous milestones, following five (05) major generation expansion plans have been formulated by the then WAPDA and now NTDC with the assistance of foreign/local consultants coupled with in-house efforts:

- a. National Power Plan (NPP 1994-2018) developed by Canadian Consultant, M/s ACRES International Limited;
- b. National Power System Expansion Plan (NPSEP 2011-2030) developed by Canadian Consultant, M/s SNC Lavalin;
- c. Least Cost Plan (LCP 2016-2035) developed by Japanese Consultant, M/s International Institute of Electric Power, Ltd. (IIEP); and
- d. Indicative Generation Capacity Expansion Plan (IGCEP) 2040
- e. Indicative Generation Capacity Expansion Plan (IGCEP) 2047

In order to ensure regulatory compliance pursuant to the Grid Code, and sustain it on annual basis, NTDC formulated the IGCEP 2047 and submitted to the Authority in April 2020. However, the Authority asked NTDC to incorporate certain comments / suggestions and update the IGCEP accordingly. The Authority further directed to obtain prior approval of the same from the concerned higher forum.

In compliance to above, after detailed deliberations between NTDC and MoE (Power Division), the IGCEP 2021-30 Assumption Set was presented by MoE (PD) to CCoE dated April 20, 2021 and the same were approved on April 22, 2021.

The IGCEP 2021-30 has been formulated based on the approved Assumption Set by CCoE, using generation planning tool i.e. PLEXOS, by considering all the existing as well as committed and candidate power plants.

1.3. Introduction

In view of its rapidly increasing dependence for enhanced access thereof, electricity is today recognized as the most critical pre-requisite for improving the lives of people of a country and Pakistan is not an exception. Therefore, certain electricity indices such as per capita consumption of electricity and access to electricity are used to express the economic strength of a country. Electricity is a unique kind of commodity since it is economically not viable to store its large quantum and it has to be consumed instantaneously. Further, certain ground realities such as seasonal variations, consumers' varying choices make the demand forecast process quite difficult. On the other hand, insufficient as well as surplus generation capacity adversely affects the economy. Careful planning of the power sector is, therefore, quite complex while carrying great importance since the decisions to be taken involve the commitment of large resources, with potentially serious economic risks for the electrical utility and the economy as a whole.

The best utility practices pertaining to planning methodologies are there for all the three main components of a power system, and each one is in itself a major field of study. Least cost generation planning is one of the important elements of overall integrated planning of electricity sector. Therefore, and further in compliance to NERPA's approved Grid Code clause PC-4 (Forecasts and Generation Expansion Plan) and PC-4.1 (Generation Capacity

Additions), this long-term least cost generation plan or the IGCEP is prepared for review and approval by NEPRA, the Regulator.

The IGCEP is prepared based on long-term electricity demand forecast prepared by NTDC, updated generation commitment schedule and other parameters updated as of May 2021.



Figure 1-2: The IGCEP Objectives

1.4. Objectives of the IGCEP

The IGCEP is envisioned to meet the following objectives, as highlighted in the Figure 1-2:

- a. **Identify** new generation requirements by capacity, fuel technology and commissioning dates on year-by-year basis;
- b. **Satisfy** the Loss of Load Probability (LOLP) not more than 1% year to year, as initially set under the Grid Code: PC - 4.1;
- c. **Cater** for the long-term load growth forecast and reserve requirements pursuant to the Grid Code; and
- d. **Provide** a least cost optimal generation expansion plan for development of hydroelectric, thermal, nuclear and renewable energy resources to meet the expected load demand up to the year 2030

1.5. Scope and Planning Horizon

The IGCEP covers the whole country except Karachi. K-Electric, a vertically integrated power utility, managing all three key stages – generation, transmission and distribution – of producing and delivering electrical energy to consumers within the geographical jurisdiction of the city of Karachi. However, the IGCEP 2021-30 includes a fixed export of 1,400 MW from NTDC system to K-Electric by the year 2023, which is then increased to 2,050 MW till the end of study horizon. The planning horizon of the IGCEP is from the year 2021 to 2030.

1.6. Nature of the IGCEP

Overall purpose of the IGCEP is the fulfillment of outlines, actions, and strategies as stipulated in the relevant policies and decisions of Government of Pakistan, latest generation

technologies, constraints and certain regulatory obligations. The focus of this plan is to identify generation additions, by capacity and fuel type along with commissioning dates, for a certain plan period, through optimal use of all available generation resources. The system's optimum expansion is determined by the IGCEP considering various limitations and factors such as governmental policies, investment costs, operation costs, contractual obligations, fuels, reserve requirements, maintenance allowance, etc. For this purpose, generation optimization model based on the state-of-the-art generation planning tool i.e. PLEXOS include elaboration of projected electric power demand upto the year 2021-30 and various other characteristics such as hydrology of existing and future hydro power projects, fuel costs estimations and all technical and financial data pertaining to existing and potential generation options i.e. feasible hydro power, thermal and renewables future projects potential generation options, simulation of different scenarios and optimization of all options. The IGCEP is developed as a suggested starting point for the preparation of a determinative Transmission System Expansion Plan as next step for the overall PSP process.

However, the IGCEP is meant to be considered as an indicative generation expansion plan, since it will be updated on yearly basis to account for any change in generation technologies trends, governmental policies, progress/priorities of different project execution agencies and project sponsors in developing the generation facilities, etc.

1.7. Rationale for Preparation of the IGCEP

Pursuant to the provisions of the Grid Code i.e. Planning Code (PC) - 4 and PC - 4.1, NTDC is mandated for preparation of the IGCEP on annual basis for review and approval of NEPRA. This plan shall take-into account the objectives/criteria as mentioned under sub-section 1.1 above and shall be used as an input for NTDC's Transmission System Expansion Plan (TSEP) as stated in the PC 4.2. Relevant excerpts from the PC 4 of the Grid Code are as follows:

PC 4: "Each year, the NTDC shall prepare and deliver to NEPRA a Ten-Year "Indicative Generation Capacity Expansion Plan (IGCEP)" covering 0-10 Year timeframe. NTDC shall provide this IGCEP of NTDC Plan."

PC 4: "The Plan shall be subject to review and approval by NEPRA."

PC 4.1: "The NTDC Plan shall be based on a twenty-year Load Demand and Energy Forecast and shall be prepared according to a Loss of Load Probability (LOLP) methodology established under this Grid Code, and NEPRA Transmission Performance Standard Rules."

PC 4.1: "The NTDC Plan shall be submitted to NEPRA on or before April 15 for the next financial year."

The IGCEP plays a key role in the expansion of the power system. The Plan ensures that the demand in the system is adequately met by adding generation capacity on least cost basis. The plan takes long term view and therefore is indicative in nature in the long run, however, it provides a perspective to potential investors and other players in the market regarding the future demand and supply situation and the probable generation mix.

Along with serving as guiding document for procurement of power for regulated consumers, the IGCEP will also provide basis for the expansion of the transmission network. The IGCEP identifies the types of generation to be added to the system and also the location in case of hydro power plants. The IGCEP is used as one of the main inputs to the TSEP along with spatial demand growth to work out the power evacuation requirements and serving the load in a reliable manner.

2. POWER SYSTEM OF PAKISTAN



2. Power System of Pakistan

2.1. Economics of Pakistan Power Sector

Electricity is a critical input for economic development and correspondingly power sector comprises an indispensable infrastructure in any economy. Providing adequate, reliable and affordable electric power is essential for economic development, human welfare and better living standards. The growth of economy along with its global competitiveness hinges on the availability of reliable and affordable power to all consumers throughout the country. Electricity is central to achieving economic, social and environmental objectives of sustainable human development. Development of different sectors of economy is impossible without matching development of the power sector.

As an emerging economy, country's demand for electricity is enormous and its GDP is positively related with the sale of electricity as shown in Chart 2-1. This is in concurrence with a similar trend with all developing nations where GDP and sale of electricity have a direct relationship and growth in GDP causes increased sale of electricity as opposed to the developed nations where the causal relationship between GDP and sale of electricity is either opposite than that of developing countries or the two determinants of economic growth are decoupled from each other.

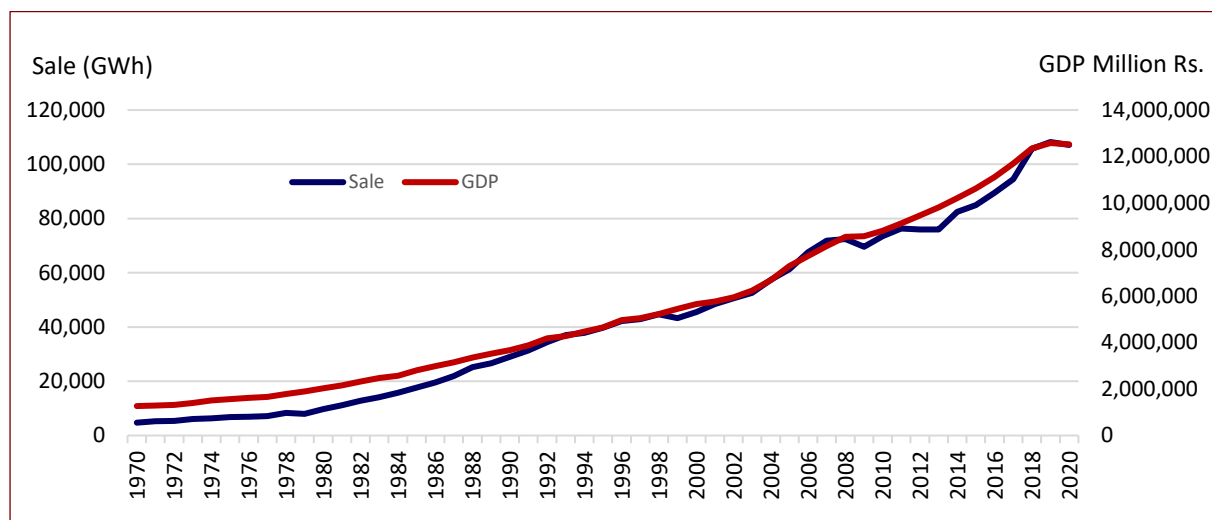


Chart 2-1: GDP (million PKR) vs Sale of Electricity (GWh)

During the fiscal year 2019-20, the country has seen -0.38% growth rate in total GDP (source: Economic Survey of Pakistan) whereas growth rates of 2.67%, -2.64% and -0.59% was observed in agriculture, industrial and commercial/services sectors, respectively. During the same period (FY 2019-20), -1.05% growth rate in consumption of electricity has been observed. This decline in GDP as well as in usage of electricity shows strong association between GDP and electricity.

Pakistan per capita consumption of electricity was 516 kWh in 2020 whereas India had per capita consumption of electricity of 1,208 kWh for the same year. Thus, there are a lot of opportunities to seize and gaps to be filled in the Pakistan power sector in order to serve the people of Pakistan with adequate, affordable, reliable and sustainable supply of electricity.

2.2. Power Generation

By the end of May, 2021, the total installed generation capacity in the country reached 34,501 MW of which 34% remains RE comprising of hydro-electric, solar, wind and bagasse based technologies and 66% thermal plants which comprises of natural gas, local coal, imported coal, RFO and RLNG based technologies, as shown in the Chart 2-2.

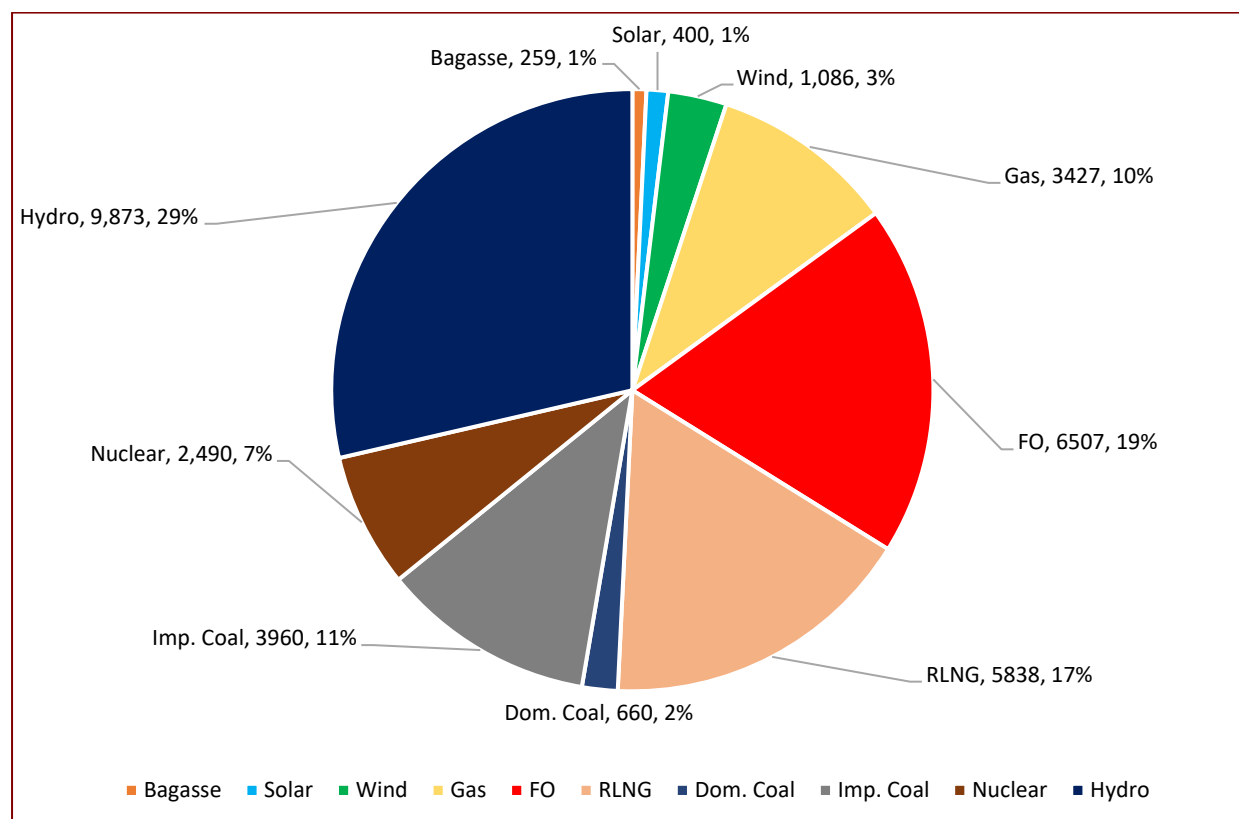


Chart 2-2: Installed Capacity (MW) as of May 2021

The energy produced by power generation fleet during the fiscal year 2019-20 totaled 121,691 GWh and was contributed approximately 32% by hydroelectric plants, 57% by thermal plants which contains natural gas, local coal, imported coal, RFO and RLNG based technologies, 8% by nuclear plants, and 3% by renewable energy power plants which covers solar, wind and bagasse based technologies as shown in the Chart 2-3.

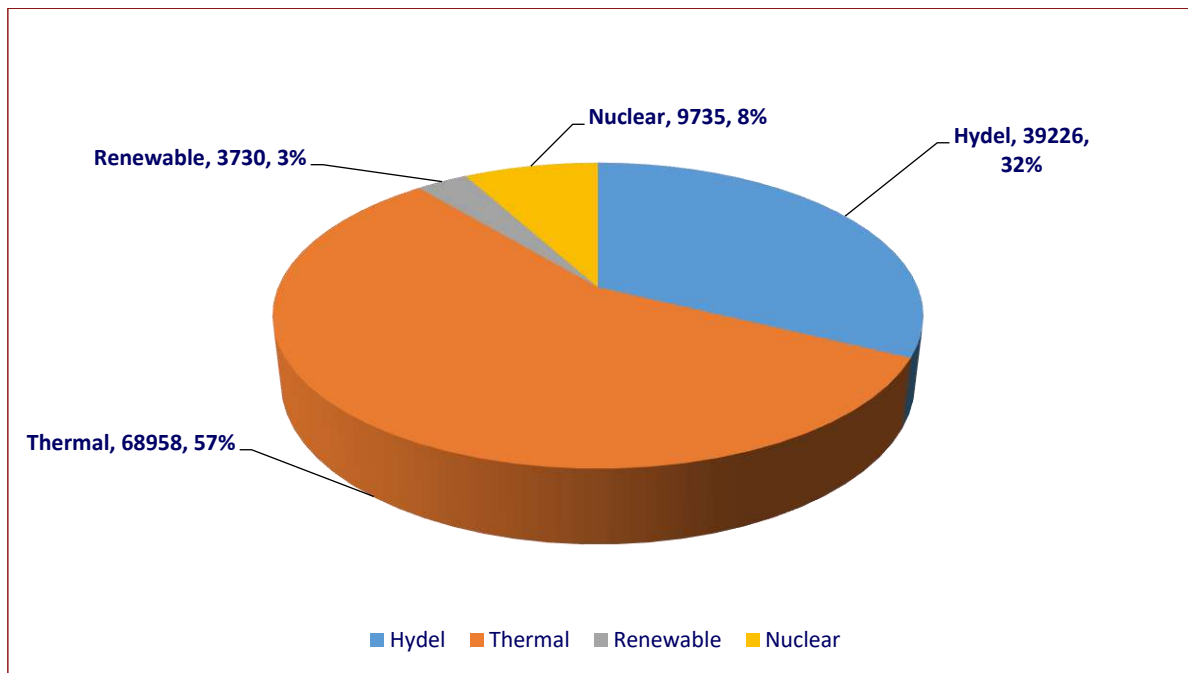


Chart 2-3: Annual Energy Generation (GWh) as of 2019-20

Furthermore, there has been an increasing trend in the electricity generation (GWh) statistics from 2014 to 2019, however, a slight decrease is observed in the year 2020 due to lesser demand owing to struggling economy coupled with the impacts of Covid-19 pandemic as shown in the Chart 2-4.

Overall, the power demand (MW) has been growing steadily with improved development of electricity supply in the country as it is evident from the electricity peak demand trend as shown in the Chart 2-5.

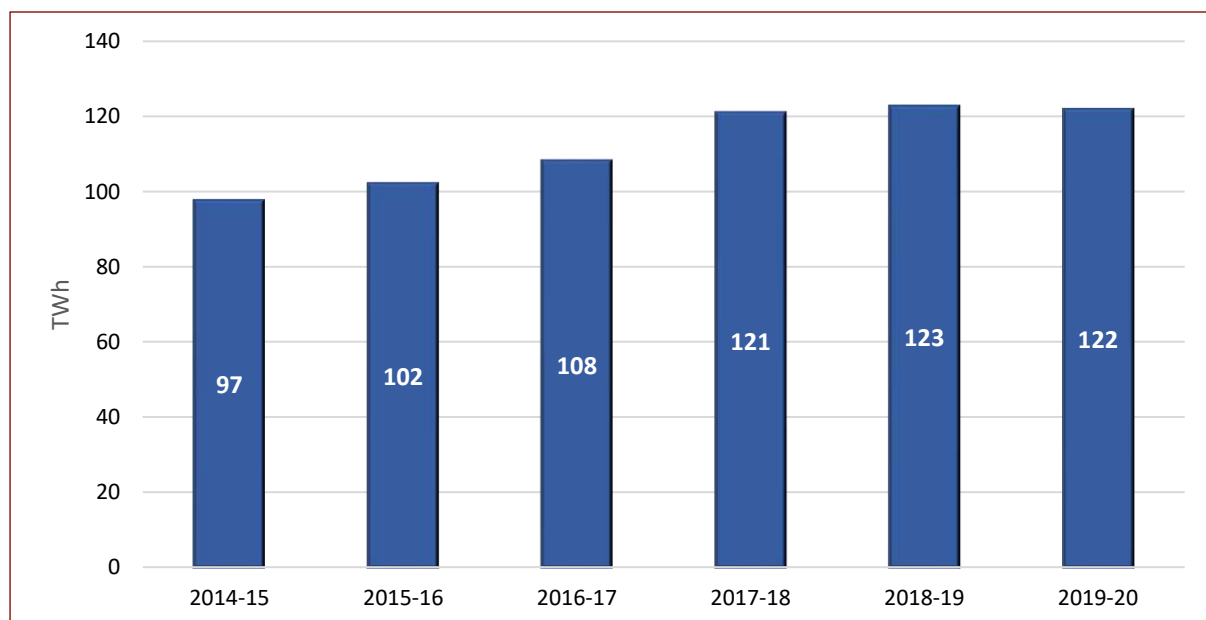


Chart 2-4: Historical Annual Energy Generation (GWh) from 2014-15 to 2019-20

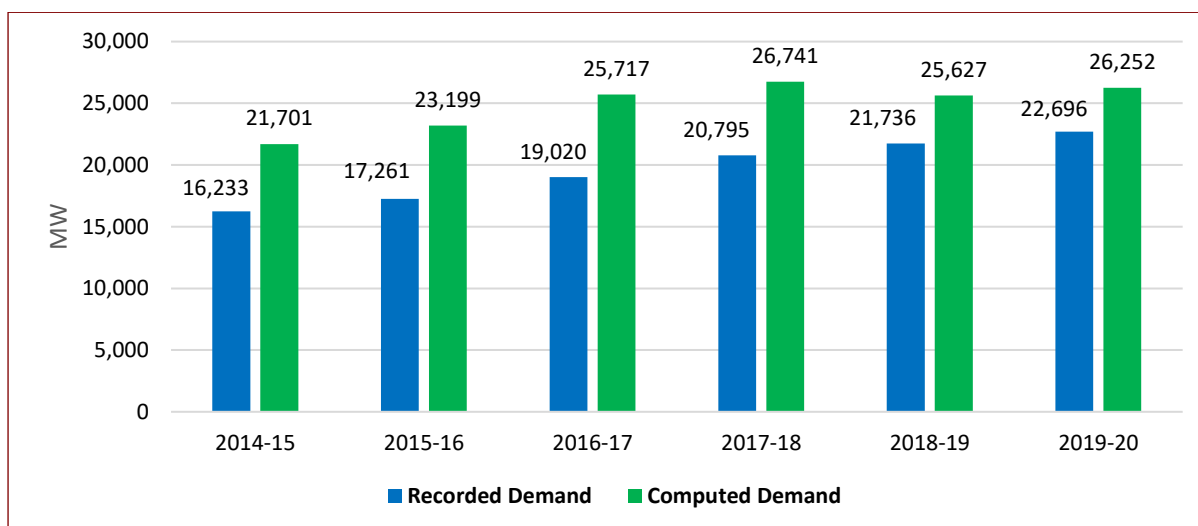


Chart 2-5: Historical Peak Electricity Demand (MW) from 2014-15 to 2019-20

Peak demand in the country during 2019-20 was 22,696 MW - recorded during the month of September 2019, reflecting a slight shift from its historic occurrence every year in the month of June. The lowest demand of 5,635 MW was recorded during January 2020, merely 25% of the corresponding summer peak.

2.3. Power Transmission

In order to effectively evacuate electric power from power generation facilities, the national grid and distribution network of DISCOs have grown massively in terms of transmission line length over the last five years as shown in Table 2-1.

The national grid which acts as the backbone of the country's power system consists of 500 and 220 kV lines and the associated grid stations. Total 500 kV transmission network during 2019-20 in the country extended well over 7,470 circuit-km supported by 16 grid stations with 25,460 MVA transformer capacities. The 220 kV transmission network extended over 11,281 circuit-km supported by 45 grid stations with aggregate total transformer capacity of 30,440 MVA. Distribution networks inclusive of 132 kV, 66 kV, and 33 kV voltage levels, collectively extends over 37,735 km, and were supported by 928 grid stations with total capacity of 53,263 MVA in delivering the electricity to end users dispersed around the country as shown in Table 2-2.

Table 2-1: Length of Transmission & Distribution lines (ckm)

Year	Length of Transmission & Distribution lines (ckm)					Total (ckm)
	500 kV	220 kV	132 kV	66 kV	33 kV	
2016	5,113	9,632	28,726	7,365	1,456	52,291
2017	5,127	10,063	25,691	7,025	2,362	50,268
2018	5,618	10,478	26,844	6,182	2,362	51,484
2019	6,290	10,928	27,775	5,994	2,362	53,349

Year	Length of Transmission & Distribution lines (ckm)					Total (ckm)
	500 kV	220 kV	132 kV	66 kV	33 kV	
2020	74,70	11,281	29,327	6,046	2,362	56,486

Table 2-2: Voltage wise Grid Stations and MVA Capacities

Year	500 kV		220 kV		132 kV		66 kV		33 kV		Total	
	No. G/S	Capacity (MVA)	No. G/S	Capacity (MVA)	No. G/S	Capacity (MVA)	No. G/S	Capacity (MVA)	No. G/S	Capacity (MVA)	No. G/S	Capacity (MVA)
2016	14	18,150	36	24,040	624	38,940	136	2,474	6	52	816	83,656
2017	14	18,150	38	25,610	650	42,116	111	2,071	40	215	853	88,162
2018	16	20,850	42	22,500	689	46,828	86	1,674	40	212	873	92,065
2019	16	22,950	45	30,970	722	50,278	79	1,561	40	216	902	105,975
2020	16	25,460	45	30,440	809	51,496	80	1,545	39	222	989	109,163

2.4. Power Distribution

By the year 2020, total number of electricity consumers have reached to 29,957,369 out of which 25,803,759 belong to domestic category, 3,245,508 belong to commercial category, 348,087 consumers fall under industries, there are 344,689 agriculture consumers, bulk supply consumers are 4,397, public lighting connections have been recorded as 10,932 and 199,970 consumers are categorized as general services consumers as shown in Chart 2-6.

During the year 2020, domestic consumption had a share of 47,643 GWh, commercial consumption used 6,260 GWh, industrial consumption was 21,489 GWh, agriculture consumption had a share of 9,642 GWh and 7,757 GWh has been consumed by other categories as shown in Chart 2-7.

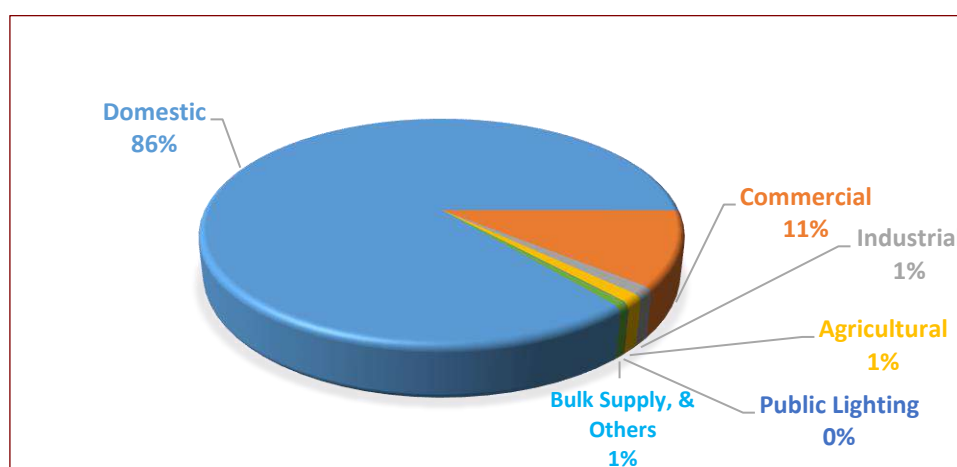


Chart 2-6: Percentage Mix of Number of Electricity Consumers

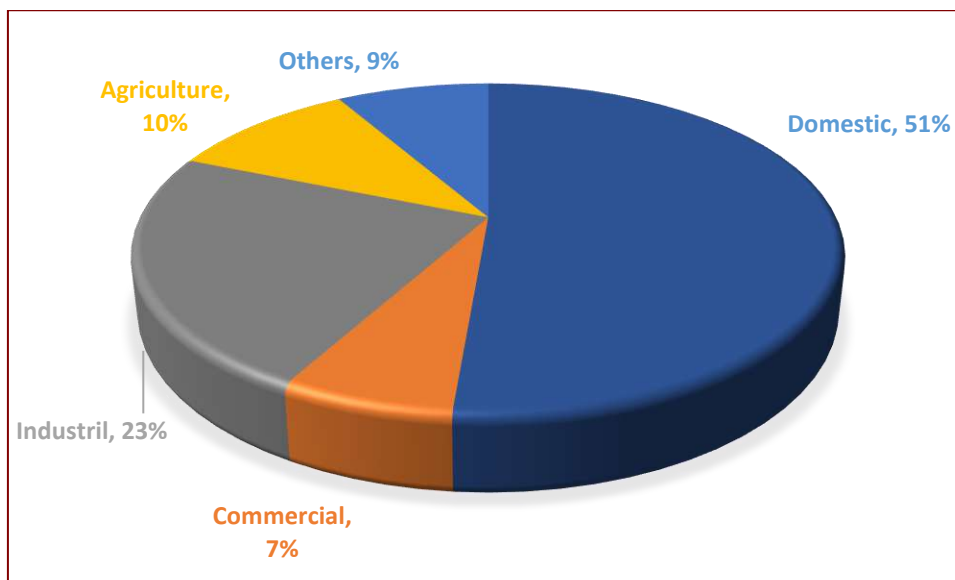


Chart 2-7: Percentage Mix of Category-wise Sale (GWh) of Electricity

Electricity consumption in Pakistan is dominated by the domestic sector followed by industrial and agricultural sector. The historical trend of electricity consumption in different categories is highlighted in the Chart 2-8.

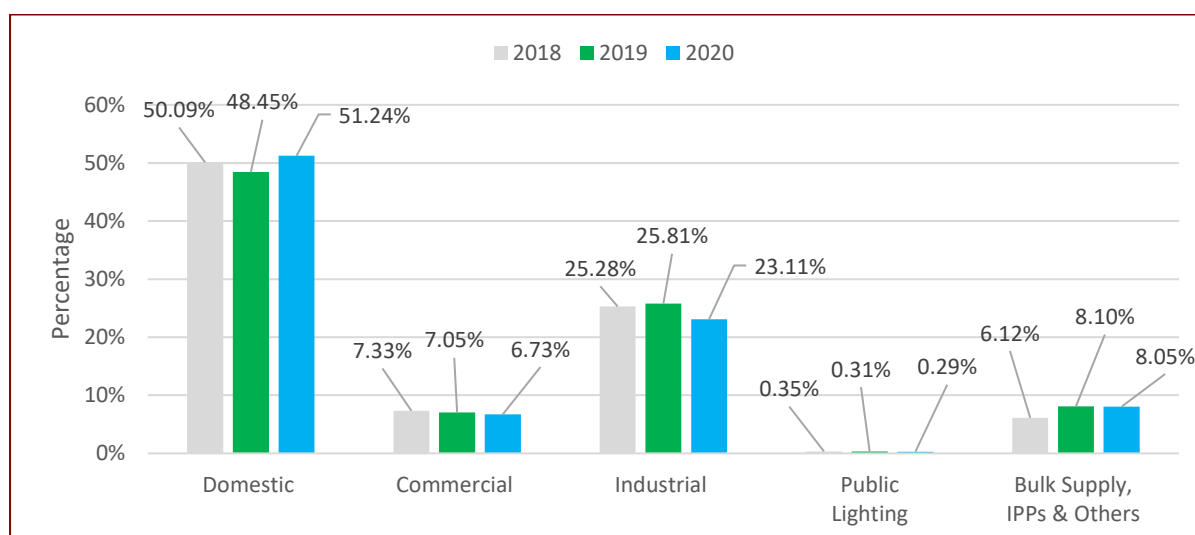


Chart 2-8: Historical Consumer Wise Percentage Share in Electricity Consumption

A total of 7,132 villages were electrified during the year 2020 increasing the cumulative total to 240,859 in the country. There are 350,121 applications still pending for connecting to the grid (320,535 for domestic, 18,436 for commercial, 2,972 for industrial, 7,969 for agricultural and 209 for other connections).

It is to highlight that during the year 2020, out of 121,691 GWh energy generated in the country, an aggregated sum of 20,120 GWh (19.75%) was lost during its transmission, distribution, and delivery to end consumers (including non-technical losses) as sales were recorded at 92,791 GWh only. The share of domestic consumption in the total sales was recorded at 51%, commercial at 7%, industrial at 23%, agriculture at 10%, and other consumers at 9%.

3. THE IGCEP METHODOLOGY



3. The IGCEP Methodolgy

3.1. Regulatory Compliance

Pursuant to the Grid Code, the IGCEP covers the future development of hydroelectric, thermal, nuclear and renewable energy resources to meet the anticipated load demand up to the year 2030. It identifies new capacity requirements by capacity, technology, fuel and commissioning dates on year-by-year basis by complying with the various regulatory requirements as set out through the provisions of the Grid Code including Loss of Load Probability (LOLP), the long-term load growth forecast and system reserve requirements.

3.2. Data Collection Process

The data gathering process for the purpose of this study was quite rigorous; all the concerned project executing entities were approached to provide the requisite data on the prescribed format. For the first time, the data proformas were made available Online on NTDC website through Google Forms ([available at the web link http://ntdc.gov.pk/planning-power](http://ntdc.gov.pk/planning-power)) for providing the requisite input data on the prescribed format, the said link was shared with all the concerned project executing entities. The following process was followed for the collection of various inputs / data / information pertaining to power plants from the concerned entities:

- a. Specific data input formats were customized, involving suitable conversions, as per requirements of the generation planning modelling tool i.e. PLEXOS.
- b. Concerned entities were approached to share required data on customized data input formats. Multiple reminders were despatched to ensure timely provision of requisite data.
- c. Three awareness workshops on “Data Preparation and Submission by the Project Execution Agencies for Inclusion in the Indicative Generation Capacity Expansion Plan – IGCEP” were organized in Lahore during October-Novemeber 2020.
- d. All the data received was precisely analyzed for accuracy and completeness, and gaps were identified and rectified / adjusted accordingly.
- e. The data was developed / formulated as per requirement of the generation planning tool.

3.3. The IGCEP Data Sources and Associated Data Types

Following agencies shown in Figure 3-1 have contributed for the preparation of input data to be used in IGCEP 2021-30 as listed below:

- a. Alternative Energy Development Board (AEDB)
 - Existing and future renewable energy projects
- b. Azad Jammu Kashmir Power Development Organization (AJKPDO)
 - Existing and future hydro power plants under the jurisdiction of AJ&K
- c. Azad Jammu Kashmir Private Power Cell (AJKPPC)
 - Existing and future hydro power plants under the jurisdiction of AJ&K
- d. Central Power Purchasing Agency Guarantee Limited (CPPA-G)

- Fuel prices and existing system merit order
- e. Energy Department Sindh / Sindh Transmission and Dispatch Company (STDC)
 - Future hydro, thermal and renewables power plants under the jurisdiction of the Sindh province
- f. International Monetary Fund
 - GDP projections upto 2025 from IMF World Economic Outlook, April 2021:
(<https://www.imf.org/en/Publications/WEO/weo-database/2021/April>)
- g. GENCOs
 - Existing and future thermal power plants in the public sector
- h. National Electric Power Regulatory Authority (NEPRA)
 - Different types of input data were collected from NEPRA's publications / website i.e. the latest values from NEPRA quarterly indexation were used to update the costs to December 2020.
- i. National Power Control Centre (NPCC)
 - Monthly energy and MW capacities for existing wind and solar power plants
- j. Pakhtunkhwa Energy Development Organization (PEDO)
 - Existing and future hydro power plants under the jurisdiction of KPK
- k. Pakistan Atomic Energy Commission (PAEC)
 - Existing and future nuclear power plants
- l. Pakistan Bureau of Statistics
 - Input data for long-term forecast such as historic GDP and its components, Consumer Price Index (CPI), etc.
- m. Pakistan Electric Power Company (PEPCO)
 - Category-wise sale, generation, number of consumers, transmission and distribution losses etc.
- n. Private Power Infrastructure Board (PPIB)
 - Existing and future hydro and thermal power plants under IPP mode
- o. Punjab Power Development Board (PPDB)
 - Existing and future hydro, thermal and renewables power plants under the jurisdiction of the Punjab province
- p. State Bank of Pakistan
 - GDP projection for the year 2020-21
- q. Water and Power Development Authority (WAPDA)
 - Existing and future hydro power plants to be developed by WAPDA

3.4. Financial Parameters

For existing system, cost data has been obtained from the latest merit order provided by CPPA-G whereas for the future power plants, cost data shared by the concerned project executing agencies, after indexation, have been considered.

3.5. The IGCEP Preparation Process Map

The IGCEP is prepared after following the process illustrated through Figure 3-2 and is submitted to NEPRA for review and approval, following an extensive internal consultative process.

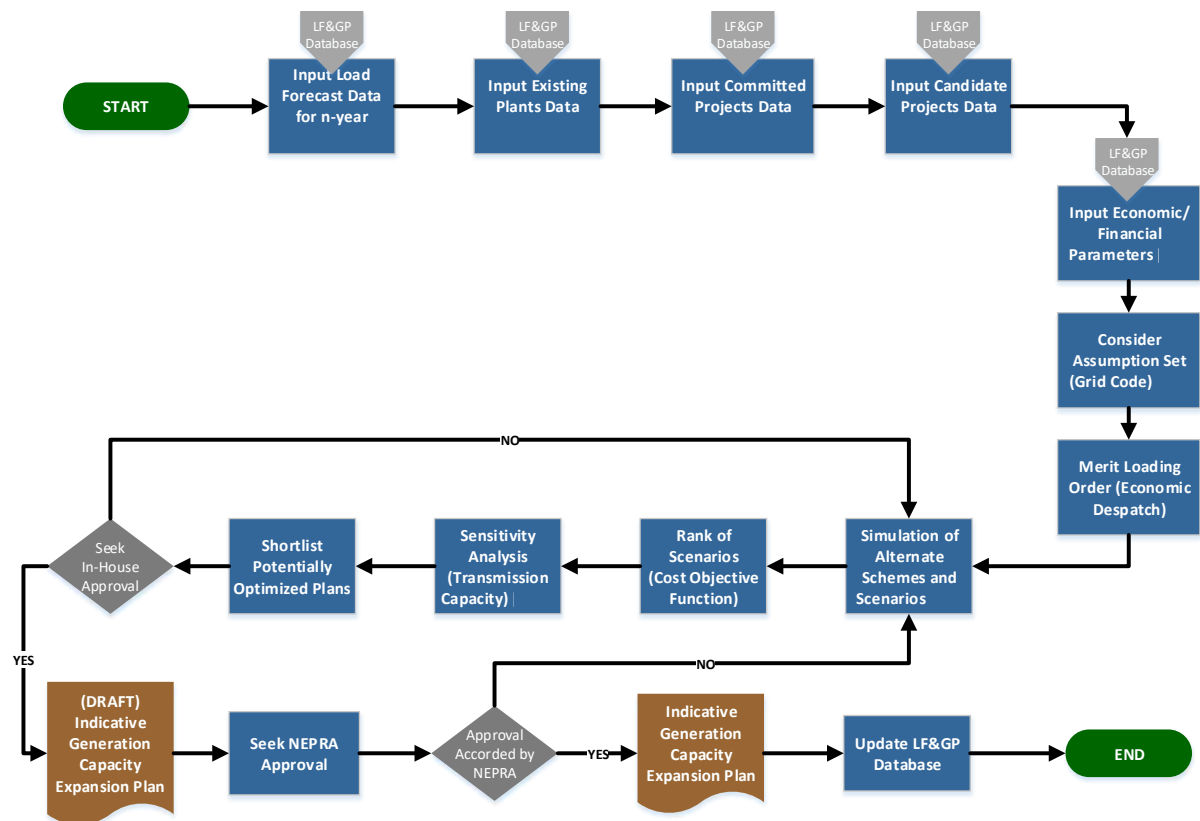


Figure 3-2: The IGCEP Preparation Process

3.6. Criteria and Other Important Considerations for the IGCEP

3.6.1. Planning Timeframe

The planning period taken for this study is 10 years i.e from July 1, 2020 to June 30, 2030.

3.6.2. Economic Parameters

The governing economic parameters considered for IGCEP 2021-30 are presented in Annexure B-2 and B-3.

3.6.3. Generation System Reliability

The capability of the generating system to meet the forecast peak demand remains a major challenge in the generation planning. In this perspective, the IGCEP takes into account the scheduled maintenance and forced outages allowance of all the generating units as well as the seasonal variability in the energy and capacity of the hydroelectric and RE plants.

Loss of Load Expectation (LOLE-days) or equivalently Loss of Load Probability (LOLP-%) is considered as generating system reliability criteria. For the purpose of the IGCEP, yearly LOLP criteria of not more than 1%, as stipulated in the Grid Code, has been adopted.

3.6.4. Hydrological Risk

For the IGCEP, average seasonal values of monthly energy and capacity, as conveyed by the concerned project executing agencies, have been used to capture the seasonality for the hydroelectric plants.

3.6.5. Renewable Energy (RE) Generation

Pakistan power system has commissioned a relatively fair quantum of RE generation in the generation mix in the past few years. As of May, 2021, 400 MW utility scale solar and 1,086 MW wind power on grid projects (excluding 150 MW from WPPs namely 50 MW Hydro China Dawood, 50 MW Zephyr and 50 MW Tenaga, which are currently supplying generation directly to K-Electric system), have been commissioned. Subsequent to Cabinet Committee on Energy (CCoE) decision of April 4, 2019, defined under Category-I & II, several wind, solar and bagasse power projects at different stages of development are envisaged to be added into the national grid during the next couple of years.

Furthermore, the GoP through ARE Policy 2019 aims to include at least 20% and 30% renewable energy generation by capacity by the year 2025 and 2030, respectively. However, these two energy resources due to their intermittency cannot be considered as a firm capacity, at all points in time or all around the clock; therefore, appropriate amount of backup generation is also required to provide for reserve requirements of the system. Based on the available wind mast data, plant factor of 42.5% have been assumed for candidate wind power projects and for the candidate solar power projects a plant factor of 23% has been assumed.

3.6.6. System Reserve Requirement

Reserve of a generating system is a measure of the system's ability to respond to a rapid increase in load or loss of the generating unit(s). In this study, two types of reserves have been modelled as per provisions of the Grid Code i.e. contingency and secondary.

3.6.6.1. Contingency Reserve

The contingency reserve is the level of generation over the forecasted demand which is required from real time plus 24 hours so as to cover for uncertainties. This reserve is provided by the generators which are not required to be synchronized but they can be synchronized within 30 minutes of the initiation of the Contingency and the corresponding fall in frequency. As per best industry practices, this is equal to the capacity of the largest thermal generator in the system. In this model, the Contingency Reserve is considered equivalent to 1,145 MW in view of the induction of Karachi Nuclear (K-2), being the largest thermal unit in the system.

3.6.6.2. Secondary Reserve

The secondary reserve is a type of spinning reserve and it is the increase in power output of the online generators following the falling frequency and is fully sustainable for 30 minutes after achieving its maximum value in 30 seconds. It is equal to the one third of the largest unit in the system. Hence, in this model 382 MW of the Secondary Reserve is considered throughout the planning horizon.

3.6.7. Scheduled Maintenance of the Generation Projects

Scheduled maintenance plays an important role in retaining the desired efficiency and reliability while at the same time preserving the useful life of a generating unit. It is assumed, for the preparation of the IGCEP, that all generating units, except for VRE, will undergo an annual maintenance program as provided by the concerned project executing agency.

3.6.8. System Load Characteristics

From the planning perspective, the system load to be met by the generating system is represented by the system's hourly load for each year up till 2030 which totals to 87,648 hours of load for the entire planning horizon. The load forecast provides the hourly load demands. Normal scenario of the load forecast has been adopted in the base case of this study. The load forecast developed by the LF&GP-PSP Team is presented in Table 4-3.

3.6.9. Fuel Prices Indexation

Pakistan's electricity generation mix relies heavily on fossil fuels including RLNG, imported / domestic coal, natural gas and furnace oil, hence, fuel price uncertainty is one of the major determinants for a long-term generation expansion plan. The prices are expected to escalate or de-escalate over the planning horizon, especially during the periods of high demand where an increasing demand results in higher fuel prices. Increase in demand and fear of supply disruption exert an upward pressure on fuel prices. In this regard, the base fuel prices have been taken as per merit order of December 2020. These fuel prices are then indexed for future years as per the Energy Information Authority (EIA) Annual Energy Outlook 2021 (except for domestic coal where Thar Coal & Energy Board tariff was applied). The variable price index for each of the fuel-based technologies is given in Table 3-2.

Table 3-1: Fuel Price Indexation Factors

Year	Fuel Oil	Natural Gas/ RLNG	Imported Coal	Uranium	Thar Coal
	Variable Price Index for Fuel Based Technologies				
2021	1.00	1.00	1.00	1.00	1.00
2022	1.09	1.19	1.02	1.00	1.00
2023	1.21	1.17	1.00	1.00	0.99
2024	1.34	1.10	0.98	1.01	1.01
2025	1.43	1.07	0.97	1.01	0.94

Year	Fuel Oil	Natural Gas/ RLNG	Imported Coal	Uranium	Thar Coal
	Variable Price Index for Fuel Based Technologies				
2026	1.51	1.10	0.95	1.01	0.95
2027	1.57	1.13	0.95	1.01	0.95
2028	1.61	1.15	0.94	1.01	0.94
2029	1.65	1.19	0.93	1.02	0.95
2030	1.69	1.21	0.93	1.02	0.93

3.6.10. CAPEX of Renewable Energy Technology

Fuel prices volatility have encouraged calls for investments in renewables. Renewable energy, including wind and solar, are quickly becoming cheapest forms of new electricity generation across the globe. They have started replacing the conventional fuels to great extent for power generation to meet the future demand growth throughout the world. The cheaper and widely accessible renewable energy has the potential to substantially decrease the reliability of power sector on expensive imported fuels.

Trend of cost reduction for the renewable technology is set to continue in the future and will inevitably reduce the cost burdens, reliance on increasingly expensive fuels and hence lowering the overall generation cost. The costs of renewables especially solar, wind and hybrid are expected to be driven down further through energy policies, global trends and continuous developments in solar and wind technologies. Renewables are needed to mitigate the negative externalities of fossil fuels since primary energy consumption will grow into the future, and this growing demand is currently dependent on fossil fuels.

It is appraised that for the IGCEP 2021-30, the CAPEX is degraded by 3.6% and 1% for solar and wind respectively every year up till 2030 in line with various international projections including Lazard, IRENA, etc. As compared to today's solar power plant CAPEX i.e. 505 \$/kW, it is gradually lowered to 363 \$/kW by the year 2030. The CAPEX of wind is currently 908 \$/kW which is steadily decreased to 830 \$/kW in 2030. Similarly CAPEX of BESS is currently 386 \$/kW which is steadily decreased to 221 \$/kW in 2030.

Future prices up till the year 2030, pertaining to REs i.e. Wind, Solar and BESS are given below:

Table 3-2: CAPEX Indexation of Solar and Wind Based Technologies

Year	Solar PV (3.6%)	Wind (1%)	BESS (~6%)
	(\$/kW)	(\$/kW)	(\$/kW)
2021	505	908	386

Year	Solar PV (3.6%)	Wind (1%)	BESS (~6%)
	(\$/kW)	(\$/kW)	(\$/kW)
2022	487	899	363
2023	469	890	341
2024	452	881	321
2025	436	873	301
2026	420	864	283
2027	405	855	266
2028	391	847	250
2029	377	838	235
2030	363	830	221

4. LONG TERM ENERGY AND DEMAND FORECAST





4. Long Term Energy and Demand Forecast

4.1. Energy and Power Demand Forecast

Energy and power demand forecast provides the basis for all planning activities in the power sector. It is one of the decisive inputs for the generation planning. Planning Code (PC4) of the Grid Code states:

Three levels of load forecasts i.e. high growth, medium growth and low growth projections should be employed for a time horizon of at least next twenty years for the long-term.

Factors that are to be taken into account while preparing the load forecasts include economic activity, population trends, industrialization, weather, distribution companies' forecasts, demand side management and load shedding, etc.

The methodology employed to develop the energy and power demand forecast fulfills the criteria specified in the Grid Code. The methodology and its results are explained in the following sections.

4.2. Long-Term Demand Forecasting Methodology

The long-term demand forecast is based on multiple regression analysis, which is practiced internationally as an econometric technique to develop robust mathematical relationship between dependent and independent variables. Electricity sale is the variable under study. The electricity consumption pattern varies for different economic sectors of the country namely domestic, industrial, commercial and agriculture. In regard to this, multiple variables most likely to affect the electricity sales were studied, for every sector individually, and tested for significant quantitative relationships. These include electricity prices, GDP, population, number of consumers, lag variables etc. The variables that impacted the sales most significantly were selected for the final equations for electricity sales. Electricity consumption (GWh) is then regressed on these independent variables using historical data for the period 1970-2020. The methodology of long-term load forecast is illustrated in the process flow map in Figure 4-1.

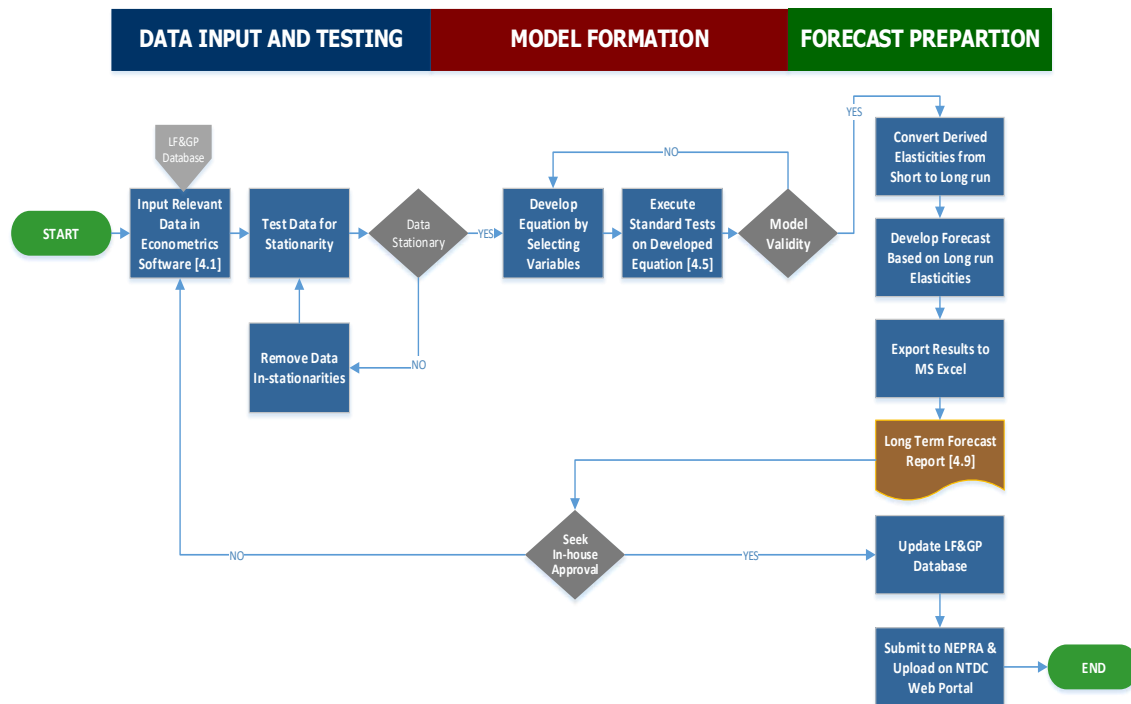


Figure 4-1: Process Flow of Methodology of Long-Term Demand Forecast

4.3 Data Sources

The data sources for the long-term demand forecast are as under:

- GDP and Consumer Price Index (CPI) is obtained from Economic Survey of Pakistan 2019-20 published by Finance Division, Government of Pakistan.
- The GDP projection for the FY 2021 has been taken from the latest values issued by State Bank of Pakistan. The GDP projections for successive years have been taken from International Monetary Fund (IMF) as of April 2021.
- Energy Sales, Transmission & Distribution Losses and Energy Purchased data is obtained from DISCOs Performance Statistics by PEPCO – June 2020
- Category-wise average tariff is obtained from DISCOs Performance Statistics by PEPCO – June 2020.
- Peak Demand (MW) and Load management data is obtained from NPCC and PITC
- The demand side management targets have been provided by NEECA.

4.4 Key Considerations

4.4.1 Demand Side Management

The impact in terms of energy (GWh) pertaining to demand side management has been provided by NEECA considering an improvement in the energy efficiency of the electric fixtures i.e. LEDs, fans, air conditioning, refrigeration etc. According to the study conducted by NEECA, there will be an increase of upto 3% in the use of LEDs every year. NEECA has also predicted an increase in usage of energy efficient fans and other equipments complying to Minimum Energy Performance Standard (MEPS). The annual targets set by NEECA are given in Table 4-1.

Table 4-1: NEECA Energy Efficiency Targets

Year	Energy Saving through Energy Standards & Labeling
	(GWh/Year)
2020-21	2,190
2021-22	3,765
2022-23	5,340
2023-24	6,916
2024-25	8,491
2025-26	10,066
2026-27	11,642
2027-28	13,217
2028-29	14,792
2029-30	16,368

4.4.2. Power Export to K Electric

The export to K Electric is increased from 650 MW to 1,400 MW from 2021 and subsequently from 2023 onwards, the export is further enhanced to 2,050 MW.

4.4.3. Load Management

For preparation of the Long Term Demand Forecast, Load management is incorporated to account for the impact of load shedding being enforced in the country. Currently, multiple factors are contributing towards load being shed such as emergency situations, DISCOs Industrial cut and the technical constraints of NTDC and DISCOs. Hence, the impact of these factors has been accounted for in the load management data..

4.5. Demand Forecast Scenarios: Regulatory Requirement

4.5.1. Low Demand

For this scenario, GDP growth rate gradually decreases from 3.94% to 3.70% from the year 2021 to 2025 and then it remains constant till 2030.

4.5.2. Normal Demand

For this scenario, GDP growth rate gradually increases from 3.94% to 5.00% from the year 2021 to 2025 and then it remains constant till 2030.

4.5.3. High Demand

For this scenario, GDP growth rate gradually increases from 3.94% to 6.02% from the year 2021 to 2025 and then it remains constant till 2030.

4.6. Preparation of Demand Forecast

The electricity consumption of Pakistan is segregated into the following four major sectors:

- a. Domestic;
- b. Commercial;
- c. Industrial; and
- d. Agriculture

These aforesaid sectors typically show different consumption patterns throughout the year. Hence, they are forecasted separately. The load demand forecast of these sectors is then combined to obtain the forecast of total electrical energy demand. In order to forecast the annual consumption of electricity up to the year 2030, a multiple regression model has been used. Electricity energy sale of the respective category is the dependent variable in the regression model, whereas, the independent variables for each category are as follows:

- a. Annual total GDP and its components i.e. agriculture sector, industrial sector and services sector;
- b. Tariff-wise electricity prices i.e. domestic, commercial, agriculture and industrial;
- c. Number of consumers;
- d. Lag of dependent and independent variables;
- e. Consumer Price Index; and
- f. Dummy variables

Considering the above mentioned factors, four equations are selected, one for each category of electricity consumption. For statistical analysis, popular statistical software namely EViews is used.

Ordinary Least Square technique is selected for the estimation of regression equation. The equations are written in logarithmic form to evaluate elasticity in percentage. Various statistical tests were performed to establish the significance of the relationship between the dependent variable and the independent variables.

After thorough statistical analysis using EViews, the appropriate elasticity coefficients were selected for all the four equations. These elasticities were then converted into long-term elasticities. On the other hand, growth rates for independent variables such as total GDP, electricity price, etc. were projected based on the past data. The long-term elasticities and the projected independent variables were subsequently used in the equation to develop the long-term energy forecast of each category using the equation below.

$$Y_T = Y_{T-1} * (1+GR \text{ of } G)^b * (1+GR \text{ of } R)^c * (1+GR \text{ of } L)^d$$

Table 4-2 provides the description of all the variables used in this equation:

Table 4-2: Description of Dependent and Independent Variables

Variable	Description
Y_T	Electricity Demand of current year (Sales GWh)
Y_{T-1}	Electricity Demand of previous year (Sales GWh)

Variable	Description
GR	Growth Rate
G, R, L	Independent variable (GDP, Real Price, Lag)
b, c, d	Elasticities of independent variables (GDP, Real Price and Lag respectively)

The demand forecast results of the four categories were combined to calculate the sale forecast at the country level. It is important to mention here that, in order to calculate the elasticities of commercial and industrial sectors the impact of load shedding on their historical data has been considered for the study, provided the fact that load shedding does not hinder or majorly affect the activities in these sectors. This is due to the alternative energy supplies widely used in the sectors which keep their activities going.

Required generation (GWh) was calculated after adding projected distribution losses at 11 kV and Transmission Losses at 132 kV and 500/220 kV according to the loss reduction plan of respective DISCOs and NTDC. In order to convert the energy in peak demand, load factor was calculated from energy generated and peak demand of the base year. The calculated load factor was then projected for the future years. The projected load factor was then used along with projected energy generation to forecast the peak demand.

4.7. Demand Forecast Numbers

Based on the variables and methodology explained above, the Table 4-3 highlights forecast results for the Low, Normal and High growth scenarios; comparison of different demand forecast scenarios is also graphically illustrated in Chart 4-1.

Table 4-3: Annual Long-Term Energy and Power Demand Forecast

Year	Low Demand		Normal Demand (Base Case)		High Demand	
	Generation	Peak Demand	Generation	Peak Demand	Generation	Peak Demand
	GWh	MW	GWh	MW	GWh	MW
2019-20*	123,657	22,891	123,657	22,891	123,657	22,891
2020-21	128,979	24,102	129,001	24,106	129,024	24,110
2021-22	136,739	25,077	136,866	25,101	137,043	25,134
2022-23	139,355	25,623	139,842	25,715	140,308	25,804
2023-24	148,664	27,076	149,897	27,311	150,839	27,490
2024-25	152,552	27,870	154,923	28,322	156,719	28,664
ACGR 2021-25	4.29%	3.70%	4.68%	4.11%	4.98%	4.42%

Year	Low Demand		Normal Demand (Base Case)		High Demand	
	Generation	Peak Demand	Generation	Peak Demand	Generation	Peak Demand
	GWh	MW	GWh	MW	GWh	MW
2025-26	156,433	28,666	160,266	29,398	163,231	29,964
2026-27	160,351	29,473	165,927	30,540	170,347	31,386
2027-28	164,343	30,297	171,916	31,749	178,058	32,927
2028-29	168,434	31,143	178,238	33,027	186,356	34,588
2029-30	172,641	32,015	184,900	34,377	195,244	36,369
ACGR 2026-30	2.50%	2.80%	3.64%	4.0%	4.58%	4.96%
ACGR 2021-30	3.29%	3.21%	4.08%	4.02%	4.71%	4.67%

* Actual Demand (MW) & Energy Generation (GWh)

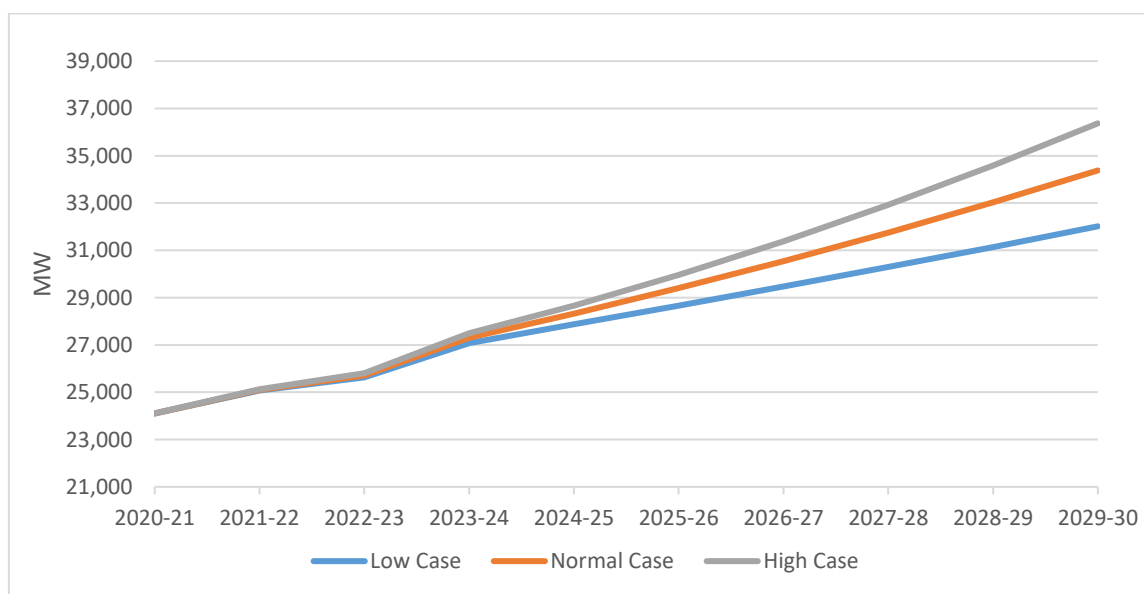


Chart 4-1 Peak Demand (MW) Forecast 2021-2030

4.8. Hourly Demand Forecast

Hourly demand forecast has been developed to cater for the intermittency of variable renewable energy sources. This is particularly important in view of the aggressive targets envisioned by the GoP pertaining to renewable energy. Hence, the demand forecast of 87,648 hours have been estimated for the plan horizon. In this process, the forecasted annual peak demand was converted into hourly demand based on the recent historical hourly demand and generation pattern. The load duration curve for the year 2025 and 2030 is given Chart 4-2.

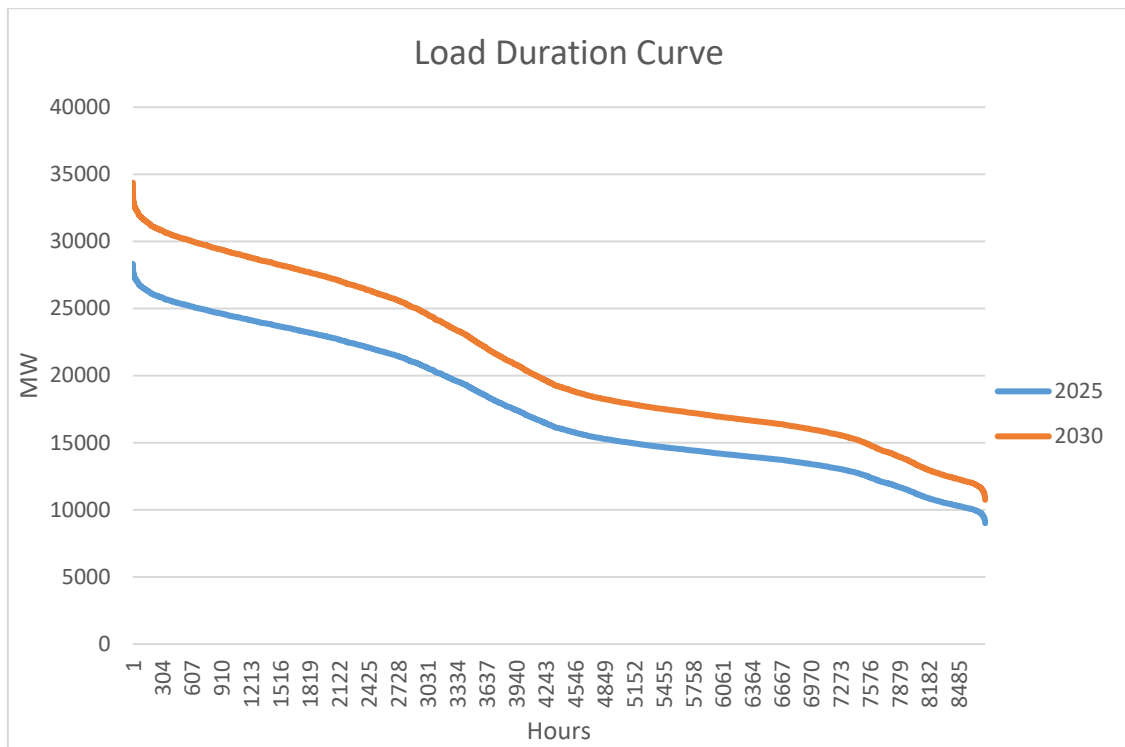


Chart 4-2: Load Duration Curve (2025 & 2030)

5. INSIDE THE IGCEP



5. Inside the IGCEP

5.1. Introduction

The key objective of the generation expansion planning activity is to develop a least cost, long-term generation expansion plan for NTDC system for the period 2021-30 to meet the maximum load and energy demand whilst taking into account the regulatory requirements as stipulated under PC 4 of the Grid Code, Assumption Set approved by CCoE and identified constraints. The following section describes the key parameters and results of the generation planning study.

5.2. Base Case as per Assumption Set approved by CCoE

The IGCEP 2021-30 Assumption Set has been approved by Cabinet Committee on Energy (CCoE) dated April 22, 2021. Hence the IGCEP 2021-30 Base Case is developed as per following details:

Demand Projection Assumptions:

1. Use 'normal' served demand forecast scenario for base case, out of the three load forecast scenarios (Low, Normal, High) developed based on the following inputs:
 - i. Historical Gross Domestic Product (GDP) and Consumer Price Index (CPI) is obtained from Economic Survey of Pakistan, published by Ministry of Finance, Government of Pakistan.
 - ii. The long term GDP projections are developed in the light of projections made by International Monetary Fund (IMF) (Source: International Monetary Fund. 2020. World Economic Outlook: A Long and Difficult Ascent. Washington, DC, October) as per direction of NEPRA vide letter no NEPRA/ADG(Lic)/LAT-01/21832-34 dated 20th August 2020.
 - iii. Sale and prices of electricity is obtained from Power Distribution Book, June 2020 - an annual publication by PEPCO.
2. Planning horizon of the study will be 2021-30 (10 years) with annual updation.
3. Reserve and reliability requirements (LOLP = 1%) will be considered as per Grid Code.
4. Retirement of existing thermal power plants including GENCOs will be considered as per expiry of contractual term of corresponding PPA and relevant CCoE decisions.
5. Existing RLNG and imported coal-based projects will be given a minimum dispatch as per their contractual obligations/bindings (Take or Pay contracts), up till expiry of their respective contract and CCoE decisions to change the contracts, applicable for RLNG only.

Assumptions for Cost Data for Existing System:

6. Fuel costs and variable O&M costs will be based on the latest indexation/determination by NEPRA. Fixed O&M costs will be based on NEPRA's latest quarterly indexation (December 2020), as available on NEPRA's website.
7. Fixed O&M costs of power plants built under 1994 Power Policy are not available on NEPRA's website, so these costs are obtained from previous data available with Power System Planning, NTDC and CPPA (G).

Assumptions/criteria for Project selection:

8. A project will be input as 'committed' and its capital cost or CAPEX will be not entered in the model, provided the project fulfills at least one of the following pre-requisites:
 - i. Has obtained LOS as of December 2020 for private sector projects. For Federal Government Public Sector projects, the PC-I has been approved and funding secured (As of March 2021). However, M/s Jamshoro Unit-2 & M/s Chashma-5 nuclear power project shall be modelled as candidate projects to be evaluated under least cost principle.
 - ii. G2G project: Power Generation projects which are listed under Federal Government's international (bilateral or multilateral) commitments, if project / financing agreements signed.
 - iii. Where timelines of completion of a project under G2G are not firmed up yet. The tool shall determine the timeline by which such a project must come online based on its tariff optimization with respect to other available options.
 - iv. RE plants (Wind, Solar, Bagasse) enlisted in Category I & II of CCoE's decision dated 4th April 2019.
 - v. RE on-grid power projects in balance target block share as stipulated in the ARE Policy 2019 i.e. 20% by year 2025 and 30% by year 2030 (including net-metering), candidate block will be considered on respective wind/solar/hybrid technologies from the year 2023-24 onwards on least cost principle.
 - vi. CODs for 'committed power projects' will be taken as per project security documents (PPA/IA) or as conveyed by the competent forum / concerned organization / entity.

Cost Data for Committed Power Projects:

9. Cost data of committed projects would be taken as per data/information provided by the concerned project executing agency and NEPRA determined tariff.
10. For nuclear power plants Variable O&M cost and Fixed O&M cost and operational data as conveyed by Pakistan Atomic Energy Commission (PAEC) will be considered.

Cost Assumptions for Candidate Power Plants:

11. For nuclear power plants: Capital cost, Variable O&M cost and Fixed O&M cost and operational data as conveyed by Pakistan Atomic Energy Commission (PAEC) will be considered.
12. Local and imported coal power plant: Capital Cost, Variable O&M cost and Fixed FCC and Fixed O&M cost will be taken from the latest NEPRA determined tariff for respective technologies.
13. RLNG based CCGT power plant: Capital cost, Variable O&M cost and Fixed O&M cost will be taken from the latest NEPRA determined tariff for RLNG based CCGT.
14. RLNG based OCGT power plant: Fuel cost, Fixed O&M cost and Variable O&M cost of latest available OCGT plant be considered while Capital cost for OCGT will be considered as conveyed by the concerned project executing agency or as per best international practice.
15. Wind, Solar and Bagasse based power plants: Capital cost, Variable O&M cost and Fixed O&M cost will be taken from the latest available NEPRA's tariff determination. Fuel

price of bagasse based power plants will be considered as per latest available NEPRA determined tariff.

16. Hybrid RE resources based power plant: Capital Cost, Variable O&M cost and Fixed O&M cost shall be considered as conveyed by the concerned project executing agencies.
17. Hydro power plant: Capital cost and Fixed O&M cost will be considered as shared by the concerned project executing entities.

Process Assumptions:

18. All years correspond to fiscal years e.g. 2025 is the fiscal year July 1, 2024 to June 30, 2025.
19. All costs will be indexed as of December 2020.

For Hydro, the cost data shared by concerned project execution agencies has been indexed to December 2020 (Annexure B-3). The values for indexation were obtained from NEPRA's website.

5.3. Other Scenarios

In addition to the base case, following scenarios have also been simulated through this study:

a. Scenario - I: Low Demand Scenario

Demand numbers are considered as defined in Section 4.5.1 (Low Demand Forecast Scenario). The results of this scenario are attached as Annexure-C.

b. Scenario - II: High Demand Scenario

Demand numbers are considered as defined in Section 4.5.3 (High Demand Forecast Scenario). The results of this scenario are attached as Annexure-D.

5.4. Adherence to Contractual Obligations

In order to develop an effective least cost generation capacity expansion plan that will meet the future power needs of the country, the IGCEP adheres to the existing constraints such as take or pay contractual obligations of minimum annual despatch of 66% for certain RLNG, 50% for imported coal-based power plants and low btu gas-based plants on dedicated gas fields.

5.5. Approach and Methodology

The development of the least cost generation capacity expansion plan is the process of optimizing i) existing and committed generation facilities and ii) addition of generation from available supply technologies/options, which would balance the projected demand while satisfying the specified reliability criteria. For the purpose of the IGCEP, following methodology has been adopted as illustrated in Figure 5-1:

- a. First Step: Review the existing generation facilities, committed power projects and explore the range of generation addition options available to meet the future demand.
- b. Second Step: Determine the economically attractive / viable generation option (s) and generation mix.

- c. Third Step: Define the Base Case subsequent to identification of the economically attractive options.
- d. Fourth Step: Develop the least cost plan whilst considering the reliability criteria and reserve requirements under the already defined Base Case using the PLEXOS tool.

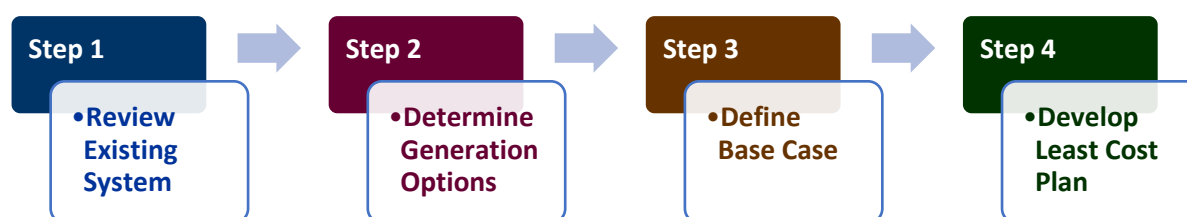


Figure 5-1: The IGCEP Data Modelling Approach

5.6. Planning Basis

In order to ensure that the base case scenario meets the requirements in terms of performance, the generation planning criteria tabulated in the Table 5-1 was adopted.

Table 5-1: Generation Planning Criteria

Parameter	Value
Discount Rate	10%
Reference date for costs	December 2020
Reliability Criteria (LOLP)	1%

5.7. Existing Power Generation of Pakistan

Total installed capacity of existing NTDC system is 34,501 MW as May 2021 whereas the de-rated capacity is equivalent to 32,385 MW. The fuel wise break-up is shown in Chart 5-1.

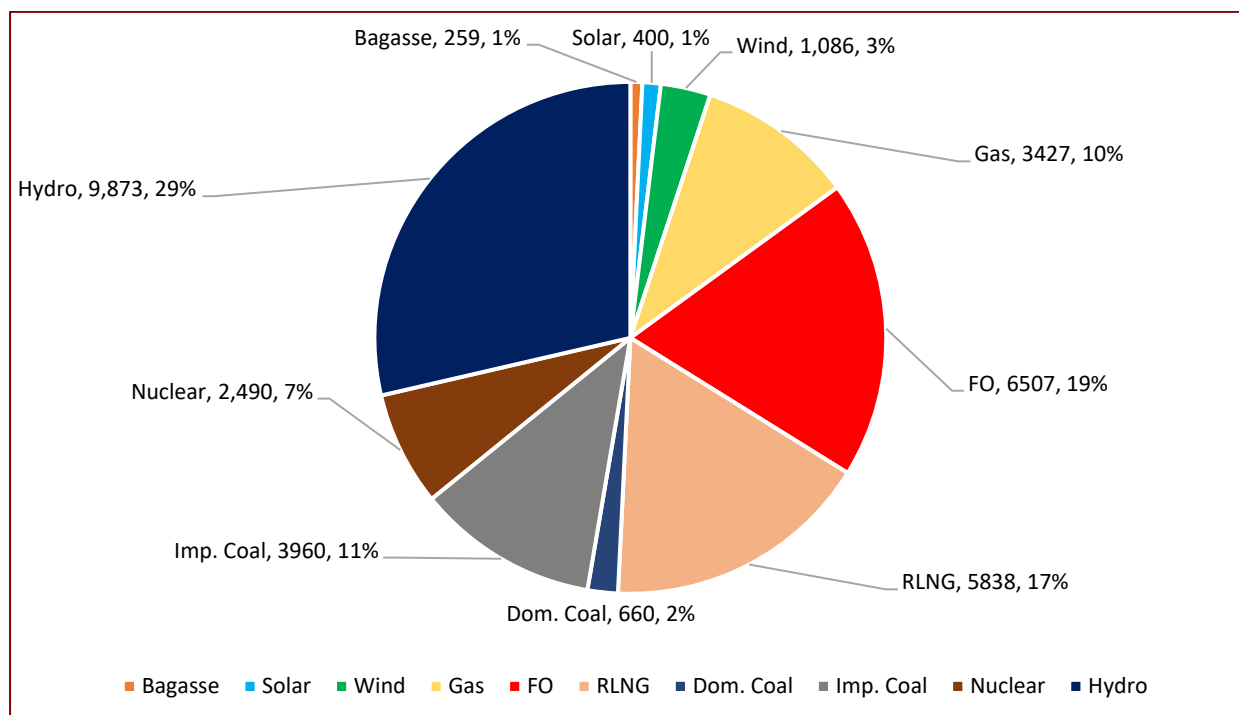


Chart 5-1: Fuel-wise Generation Mix (MW) as of May 2021

5.8. Retirement of Existing Power Plants

A significant quantum i.e. 6,447 MW of existing thermal power plants are scheduled to be retired during the planning horizon of the IGCEP 2021-30. The retirement schedule for the IGCEP 2021-30 is provided in the Table 5-2. For the purpose of the IGCEP, a power plant stands retired either as per its PPA/EPA term or relevant CCoE decision. Major retirement of generation capacity for the IGCEP 2021-30 corresponds to RFO based power plants, followed by natural gas and then RLNG based power plants.

Table 5-2: Retirement Schedule of Existing Power System

Name of the Power Station	Installed Capacity (MW)	Fuel Type	Retirement Year (FY)						
			21	22	23	27	28	29	30
GTPS Block 4 U(5-9)	144	RLNG		✓					
KAPCO 1	400	RFO			✓				
KAPCO 2	900	RFO			✓				
KAPCO 3	300	RFO			✓				
Guddu-II U(5-10)	620	Gas			✓				
Jamshoro-I U1	250	RFO			✓				

Name of the Power Station	Installed Capacity (MW)	Fuel Type	Retirement Year (FY)						
			21	22	23	27	28	29	30
Jamshoro-II U4	200	RFO			✓				
Muzaffargarh-I U1	210	RFO			✓				
Muzaffargarh-I U2	210	RFO			✓				
Muzaffargarh-I U3	210	RFO			✓				
Muzaffargarh-II U4	320	RFO			✓				
HUBCO	1,292	RFO				✓			
Kohinoor	131	RFO				✓			
Liberty	225	Gas				✓			
Lalpir	362	RFO						✓	
AES Pakgen	365	RFO						✓	
FKPCL	172	RLNG							✓
Saba	136	RFO							✓
Total (MW)	6,447								

5.9. Committed Generating Units

Power Plants considered as committed projects based on the criteria stipulated in Assumption Set approved by CCoE is shown in the Figure 5-3.

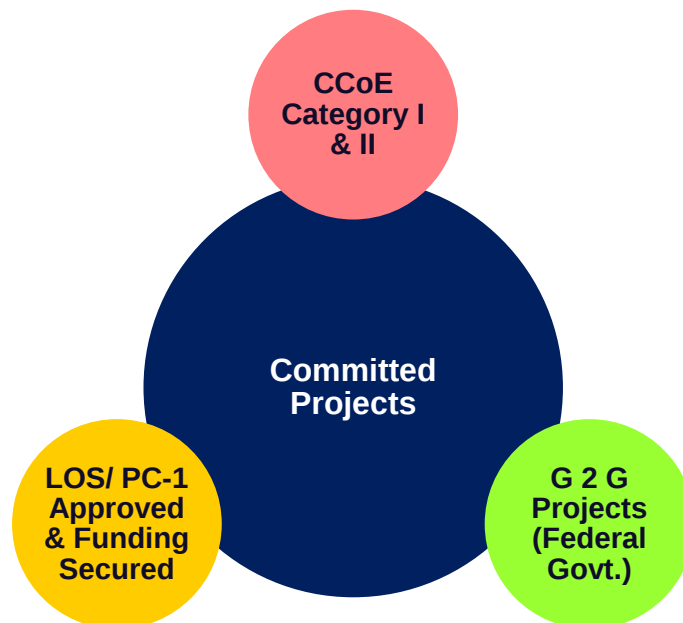


Figure 5-2: Committed Projects Criteria

5.9.1. Committed Projects

Committed projects considered in the IGCEP are listed in the Table 5-3.

Table 5-3: List of Committed Projects

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
1	Jhing	Hydro	AJK	14.4	PC-I Approved. & Financing Secured	May-21
2	Master_Green	Wind	AEDB	50	Category-II Project	Jul-21
3	Ranolia	Hydro	PEDO	17	PC-I Approved. & Financing Secured	Jul-21
4	Lucky	Local Coal	PPIB	660	LOS (Issued)	Sep-21
5	Tricom	Wind	AEDB	50	Category-II Project	Oct-21
6	Jabori	Hydro	PEDO	10.2	PC-I Approved. & Financing Secured	Dec-21
7	Karora	Hydro	PEDO	11.8	PC-I Approved. & Financing Secured	Dec-21
8	Metro_Wind	Wind	AEDB	60	Category-II Project	Dec-21
9	Lakeside	Wind	AEDB	50	Category-II Project	Dec-21
10	NASDA	Wind	AEDB	50	Category-II Project	Dec-21

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
11	Artistic_Wind_2	Wind	AEDB	50	Category-II Project	Dec-21
12	Din	Wind	AEDB	50	Category-II Project	Dec-21
13	Gul_Electric	Wind	AEDB	50	Category-II Project	Dec-21
14	Act_2	Wind	AEDB	50	Category-II Project	Dec-21
15	Liberty_Wind_1	Wind	AEDB	50	Category-II Project	Dec-21
16	Liberty_Wind_2	Wind	AEDB	50	Category-II Project	Dec-21
17	Indus_Energy	Wind	AEDB	50	Category-II Project	Dec-21
18	Zhenfa	Solar	AEDB	100	Category-II Project	Dec-21
19	Trimmu	CCGT_RLNG	PPIB	1,263	LOS (Issued)	Jan-22
20	K-3	Nuclear	PAEC	1,145	Under construction	Jan-22
21	Thar TEL	Local Coal	PPIB	330	Under construction	Mar-22
22	Helios	Solar	AEDB	50	Category-II Project	Mar-22
23	HNDS	Solar	AEDB	50	Category-II Project	Mar-22
24	Meridian	Solar	AEDB	50	Category-II Project	Mar-22
25	Thar-I (SSRL)	Local Coal	PPIB	1,320	LOS (Issued)	May-22

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
26	Jagran-II	Hydro	AJK	48	PC-I Approved. & Financing Secured	May-22
27	Thal Nova	Local Coal	PPIB	330	LOS (Issued)	Jun-22
28	Karot	Hydro	PPIB	720	LOS (Issued)	Jul-22
29	Access_Electric	Solar	AEDB	11	Category-I Project	Aug-22
30	Access_Solar	Solar	AEDB	12	Category-I Project	Aug-22
31	Jamshoro Coal (Unit-I)	Imported Coal	GENCO	660	PC-I Approved. & Financing Secured	Oct-22
32	Lawi	Hydro	PEDO	69	PC-I Approved. & Financing Secured	Nov-22
33	Gorkin Matiltan	Hydro	PEDO	84	PC-I Approved. & Financing Secured	Nov-22
34	Zorlu	Solar	AEDB	100.00	Category-II Project	Jun-23
35	Siachen	Solar	AEDB	100	Category-II Project	Jun-23
36	Gwadar	Imported Coal	PPIB	300	LOS (Issued)	Jun-23
37	Siddiqsons	Local Coal	PPIB	330	LOS (Issued)	Jul-23
38	Suki Kinari	Hydro	PPIB	884	LOS (Issued)	Jul-23
39	Riali-II	Hydro	PPIB	7	LOS (Issued)	Jul-23

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
40	Safe	Solar	AEDB	10	Category-I Project	Sep-23
41	Western	Wind	AEDB	50.0	Category-II Project	Nov-23
42	Trans_Atlantic	Wind	AEDB	48	Category-II Project	Dec-23
43	Alliance	Bagasse	AEDB	30.0	Category-I Project	Dec-23
44	Bahawalpur	Bagasse	AEDB	31.2	Category-I Project	Dec-23
45	Faran	Bagasse	AEDB	27	Category-I Project	Dec-23
46	Hamza-II	Bagasse	AEDB	30.0	Category-I Project	Dec-23
47	HSM	Bagasse	AEDB	26.5	Category-I Project	Dec-23
48	Hunza	Bagasse	AEDB	50	Category-I Project	Dec-23
49	Indus	Bagasse	AEDB	31.0	Category-I Project	Dec-23
50	Ittefaq	Bagasse	AEDB	31	Category-I Project	Dec-23
51	Kashmir	Bagasse	AEDB	40.0	Category-I Project	Dec-23
52	Mehran	Bagasse	AEDB	27	Category-I Project	Dec-23
53	RYK_Energy	Bagasse	AEDB	25	Category-I Project	Dec-23

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
54	Shahtaj	Bagasse	AEDB	32	Category-I Project	Dec-23
55	Sheikhoo	Bagasse	AEDB	30	Category-I Project	Dec-23
56	TAY	Bagasse	AEDB	30.0	Category-I Project	Dec-23
57	Two_Star	Bagasse	AEDB	50	Category-I Project	Dec-23
58	Tarbela_Ext_5	Hydro	WAPDA	1,530	Under construction	Feb-24
59	Chapari Charkhel	Hydro	PEDO	10.56	PC-I Approved. & Financing Secured	Jun-24
60	CASA	Cross Border Interconnection	GOP	1,000	G2G	Aug-24
61	Kathai-II	Hydro	PPIB	8	LOS (Issued)	Dec-24
62	Harpo	Hydro	WAPDA	34.5	PC-I Approved. & Financing Secured	Oct-25
63	Dasu_1	Hydro	WAPDA	2,160	PC-I Approved. & Financing Secured	Unit 1-3: Apr-25 Unit 4-6: Nov-25
64	Mohmand	Hydro	WAPDA	800	PC-I Approved. & Financing Secured	Apr-26
65	Keyal Khwar	Hydro	WAPDA	128	PC-I Approved. &	Unit 1: May-26 Unit 2: Aug-26

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
					Financing Secured	
66	Balakot	Hydro	PEDO	300	PC-I Approved. & Financing Secured	Mar-27
67	Azad Pattan	Hydro	PPIB	700.7	LOS (Issued)	Sep-27
68	Kohala	Hydro	PPIB	1,124	LOS (Issued)	Jul-28
69	Diamer Bhasha	Hydro	WAPDA	4,500	PC-I Approved. & Financing Secured	Feb-29
Total (MW):		22,180				

5.10. New Generation Options

The candidate generation technologies, selected to be fed into the model, are as follows:

- Steam PP on Imported Coal (660 MW); reference - China HUBCO
- Steam PP on Thar Coal (660 MW); reference - SSRL (operational data) and Siddiq Sons (cost data)
- Combined Cycle PP on RLNG (1,263 MW); reference - Trimmu
- Gas Turbine on RLNG (400 MW); reference – Trimmu Open Cycle (operational data) and CAPEX as per data available with PSP
- Nuclear Steam PP on Uranium (1,100 MW); reference - PAEC candidate
- Wind Turbine (Block of $\leq 1,000$ MW); reference – Latest Tariff
- Solar PV (Block of $\leq 1,000$ MW); reference – Latest Tariff
- Bagasse (Block of ≤ 100 MW); reference - Upfront Tariff 2017
- Battery Energy Storage System (BESS), (100 MW with 100 MWh storage); reference - Lazard Report 2020
- Rahim Yar Khan Imported Coal Based Power Plant (660 MW)
- Hybrid Re-powering of Existing Muzaffargarh (Unit-4), CCGT-RLNG (933 MW)
- KAPCO Imported Coal (660 MW)
- Jamshoro Imported Coal Unit-II (660 MW)

n. C-5 Nuclear Power Plant (1,100 MW)

5.11. Hydro Projects and Screening

Data for hydro power projects was obtained from the relevant project executing agencies. The Annualized Cost for all hydro plants indexed as of December, 2020 is presented in Annexure B-5.

5.12. Performance Characteristics of Generic Thermal Candidates

Generic Candidate thermal options include Gas Turbines (GTs), Combined Cycle Gas Turbines (CCGTs) using RLNG and Steam Turbines (STs) using Imported Coal, Local Coal and Nuclear Fuel. In order to develop a least cost generation expansion plan, it is necessary to examine the economic viability of each thermal option and select the least cost supply options taking into account technical characteristics, economic and financial parameters and operational requirements. Table 5-4 shows the performance characteristics of the thermal candidate plants.

Table 5-4: Performance Characteristics of Generic Thermal Power Plants

Performance Characteristics		Imported Coal Fired Steam	Coal Fired Steam Thar	Combined Cycle on RLNG	Combustion Turbine on RLNG	Nuclear
		660 MW	660 MW	1,263 MW	400 MW	1,100 MW
A	Net Capacity (MW)	625	607	1,243	396	1,018
B	Minimum Load (%)	50	54	40	50	81
C	Technical Parameters					
	Heat Rate at Maximum Load	9.23	9.23	5.88	9.464	9.73
D	Scheduled Outage (d/year)	36	36	36	30	40
E	Forced Outage (Hours)	594 (6.78%)	596 (6.8%)	350 (4%)	438 (5%)	87.6 (1%)
F	Economic Life (years)	30	30	30	30	60
G	O & M Cost					
	Fixed (\$/kW/year)	24.56	24.76 + 314.8*	12.94	12.94	43
	Variable (\$/MWh)	3.07	5.61	2.98	2.98	0

*314.8 is the Fixed Fuel Cost Component (FCC) of Engro Thar Coal as of December 2020

The economic parameters of thermal candidate plants are highlighted in the Table 5-5.

Table 5-5: Economic Parameters of Generic Power Plants

#	Technology	Capital Cost with IDC (\$/kW)	Discount Rate (%)	Fuel Price (\$/Giga Joule)
1	Nuclear (1,100 MW)	4,227	10%	0.49
2	OCGT. (400 MW)	445		7.27
3	CCGT. (1,263 MW)	595		7.27
4	Imported Coal (660 MW)	1,604		2.92
5	Thar Coal (660 MW)	1,327		1.67
6	RYK Imp. Coal (660 MW)	1,196		5.40
7	Hybrid Muzaffargarh RLNG (933 MW)	407		5.55
8	KAPCO Imp.Coal (660 MW)	1,344		2.79
9	Jamshoro Coal Unit 2 (660 MW)	626		4.35
10	C-5 Nuclear (1,100 MW)	4,227		0.49
11	Battery Energy Storage System (100 MW/ 100 MWH)	386		--
12	Bagasse (100 MW)	891		2.31

All candidate thermal technologies are assessed and ranked in terms of annualized unit cost by using screening curve analysis. Screening curves are used to determine the best possible technology to be inducted at a particular time frame from the available supply options. Two types of screening curves are given below:

- Annualized Cost (\$/kW/yr) - Screening Curve (Annexure B-4.1)
- Unit Generation Cost (cents/kWh) - Screening Curve (Annexure B-4.2)

Although the mechanism of plant selection by the tool is done through complex computations and optimization techniques, however, these curves give the generic idea / trend about the selection / viability of different candidate thermal power plants at various plant factors.

These curves are the plots of unit generation cost on the y-axis and the plant capacity factors on the x-axis. The total cost includes the annual capital recovery factor, fuel cost and annual O&M cost. The plants are ranked for each range of operating factors i.e. base load,

intermediate and peak load operation. The plant ranked lowest is introduced / selected first and remaining plants follow based on increasing order of merit / rank as per the system's requirement.

5.13. Economic Parameters of the Candidate REs

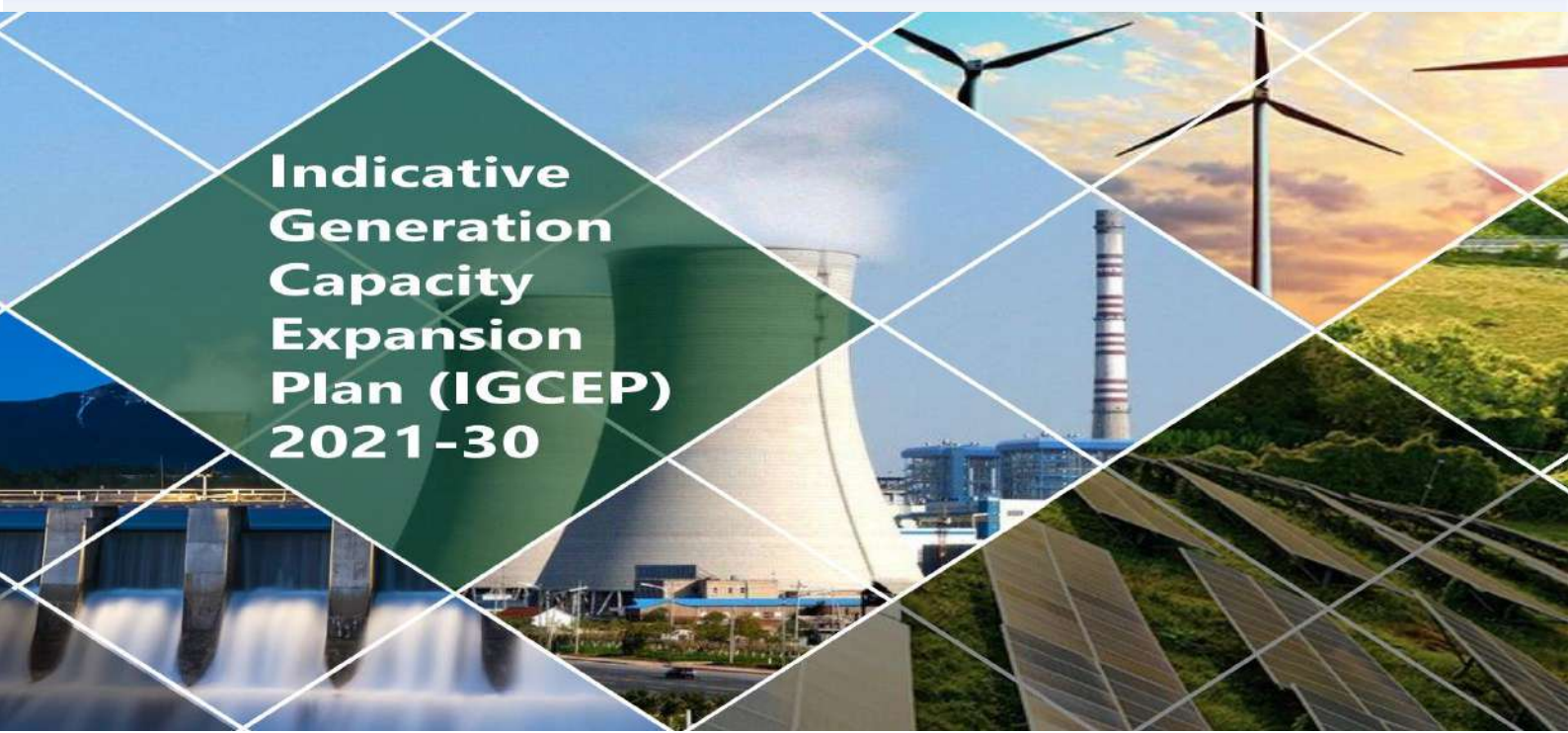
Other viable RE generation options include Solar, Wind, Battery Energy Storage System (BESS), hybrid and bagasse based projects. In this perspective, it is important to highlight that pursuant to Assumption Set approved by CCoE, hybrid technologies are also to be modelled as candidate along with solar and wind, subject to data provision by the relevant agencies. In this regard, in response to NTDC's request to relevant agencies, AEDB informed that they do not have the data pertaining to hybrid technologies. However, they further intimated that a detailed technical and financial feasibility study will be undertaken in due course of time for this purpose.

Consequently, due to non availability of data (cost, hourly profile, etc.), hybrid technologies are not modelled in the current iteration of the IGCEP. It is to add here that apart from BESS, for all other technologies yearly block wise allocation have been made. Table 5-6 shows the economic parameters of the candidate wind and solar projects.

Table 5-6: Economic Parameters of Candidate Wind and Solar Blocks

#	Technology	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Plant Factor	Annualized Cost of Energy	
		(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(%)	(c/kWh)	(\$/kW/Yr)
1	Solar	1	2024	7.69	505	2.01	23%	3.14	63.33
2	Wind	1	2024	18.75	908	3.72	42%	3.19	118.83

6. THE IGCEP STUDY OUTPUT – BASE CASE



**Indicative
Generation
Capacity
Expansion
Plan (IGCEP)
2021-30**

6. The IGCEP Study Output – Base Case

6.1. Introduction

Based on the input data and assumptions, the base case was developed and simulated using the PLEXOS tool. The results obtained through optimization, based on least cost criteria and given existing system constraints are discussed in this section.

6.2. Future Demand and Capacity Additions (Base Case)

Chart 6-1 depicts the relationship between the projected peak demand of the system and the future capacity additions, in terms of different types of energy sources for the period 2021 – 2030. It is evident that the trend of the demand is similar to the capacity additions as both are increasing in the positive direction and there is gradual increment during the horizon of this plan. In the year 2021, the Installed capacity from all generation sources hovers around 34,100 MW whereas the demand is equivalent to 24,106 MW. From the year 2021, gap between the demand and installed capacity is steadily widening. Let us take the snapshot of two random years i.e. 2025 and 2030 to closely assess the demand and capacity situation. In the year 2025, the cumulative installed capacity is approximately 46,504 MW whereas the peak load is projected as 28,322 MW, including 21,048 MW from REs; similarly, in the year 2030, to meet a demand of 34,377 MW an installed capacity of 53,315 MW is envisaged including a capacity of 30,542 MW from RE sources. Chart 6-1 shows that sufficient generation has been added to satisfy the specified reliability criteria and reserve requirements of the system.

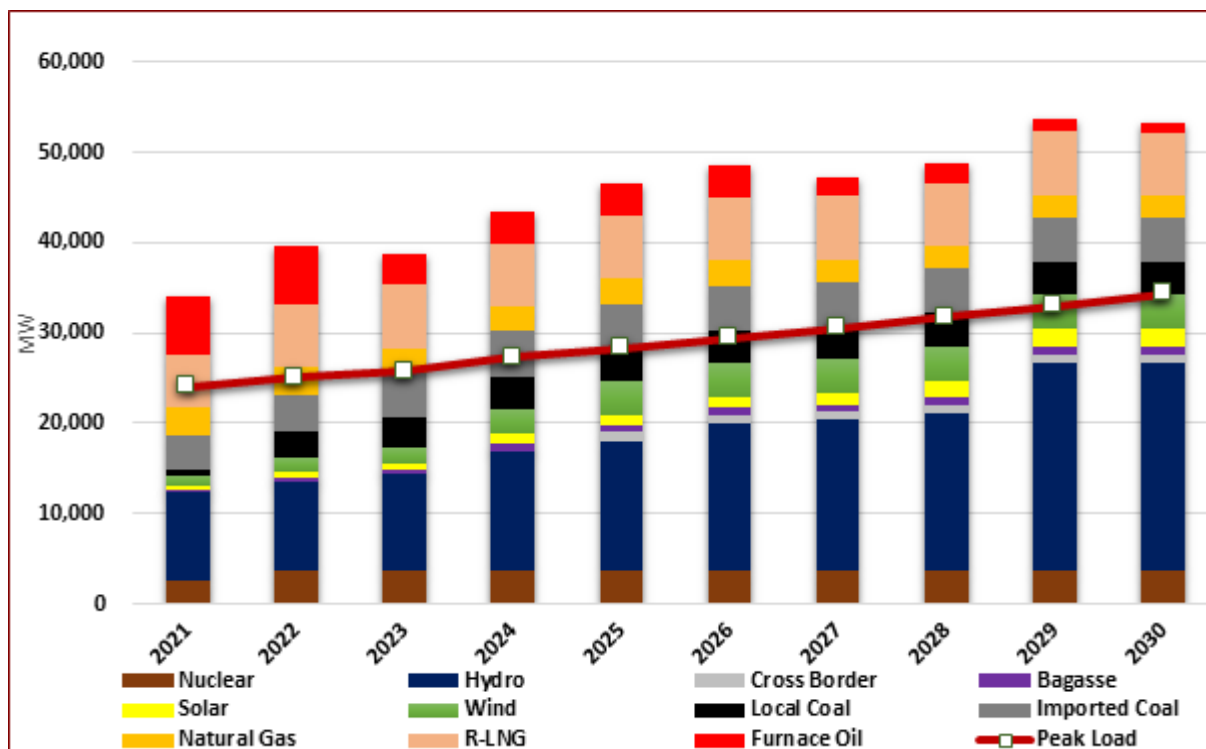


Chart 6-1: Installed Capacity vs Peak Demand (MW) 2021-30

On the other hand, energy generation by the power plants has been optimized equally with the energy forecast required by the year 2030 as shown in Chart 6-2. By the year 2030, 184,900 GWh of energy demand is met, in which 63% of generation is contributed by RE sources comprising of 2%, 8%, 2% and 51% by bagasse, wind, solar and hydro respectively.

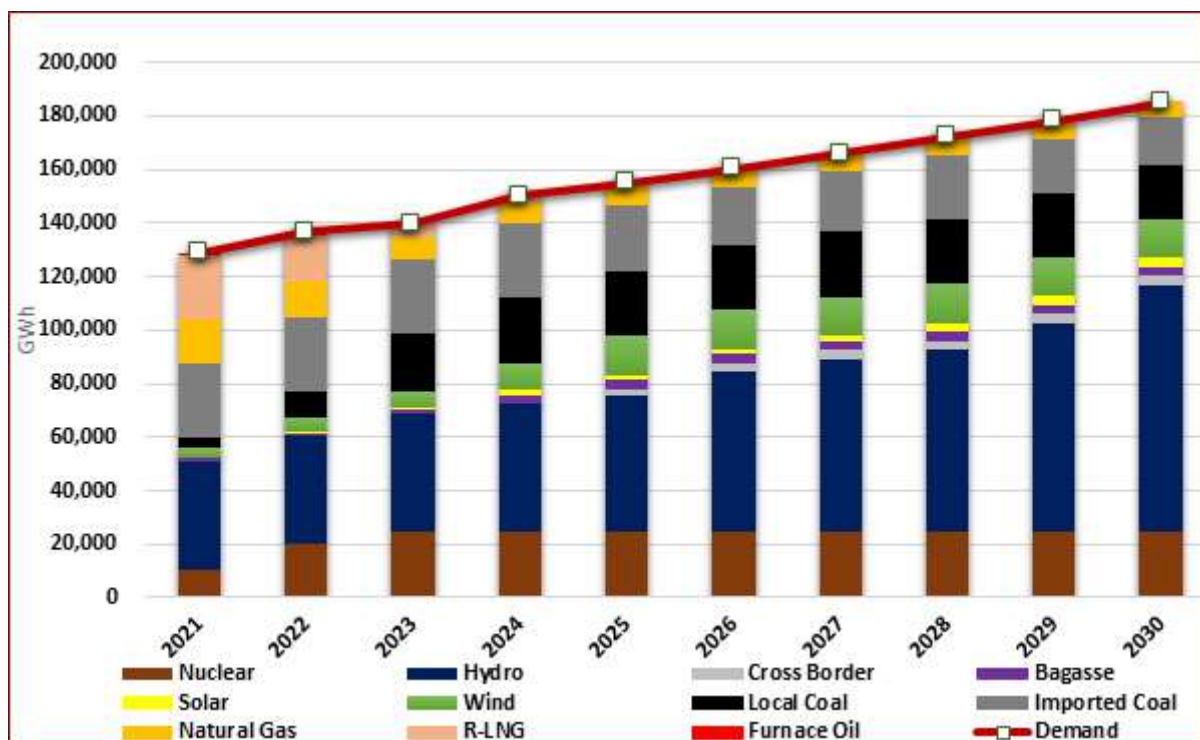


Chart 6-2: Annual Energy Generation vs Annual Energy Demand (GWh) 2021-30

The PLEXOS model optimizes wind and solar from the year 2024 in view of the techno economic viability of the technology. It is worth mentioning here that the tool optimizes 3,083 MW of candidate solar & wind power projects till 2030 and does not select any other candidate technology. Table 6-1 shows the technology wise yearly future candidate generation capacity additions by the year 2030.

Chart 6-1 shows that the capacity selected by PLEXOS after satisfying reliability criteria i.e. LOLP and reserves is sufficient enough to balance power (MW) as well as energy (GWh) demand of NTDC system by the year 2030. Energy generation by different sources / fuel types is shown in Chart 6-2. It is to be noted that although the system does have Furnace Oil (FO) based capacity available but its share in despatch from the year 2021 declines drastically, being low in merit order it is being replaced by the cheaper fuels.

Chart 6-3 shows the total share of the existing (excluding retirements), committed and candidate power plants in the installed capacity as of the year 2030. It can be seen that apart from existing installed capacity, major share is of committed power plants.

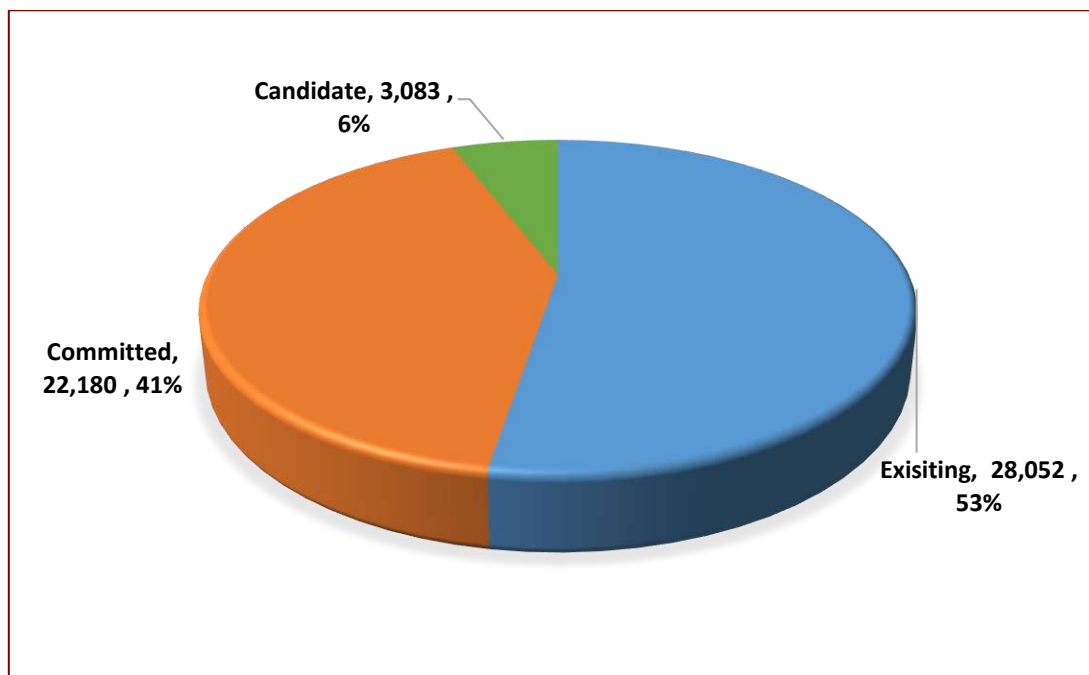


Chart 6-3: % wise Share of Total Installed capacity (MW) - 2030

Table 6-1: Candidate Generation Capacity Additions (2021-30)

Fiscal Year	Coal Fired Steam Imported Coal	Coal Fired Steam Local Coal	Combined Cycle on RLNG	Combustion Turbine on RLNG	Nuclear	Hydro	Solar	Wind	Bagasse	BESS	Per Year Capacity Addition	Cumulative Capacity Addition
	MW											
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	256	1,000	-	-	1,256	1,256
2025	-	-	-	-	-	-	-	1,000	-	-	1,000	2,256
2026	-	-	-	-	-	-	-	-	-	-	-	2,256
2027	-	-	-	-	-	-	-	-	-	-	-	2,256
2028	-	-	-	-	-	-	827	-	-	-	827	3,083
2029	-	-	-	-	-	-	-	-	-	-	-	3,083
2030	-	-	-	-	-	-	-	-	-	-	-	3,083
Total	-	-	-	-	-	-	1,083	2,000	-	-	3,083	

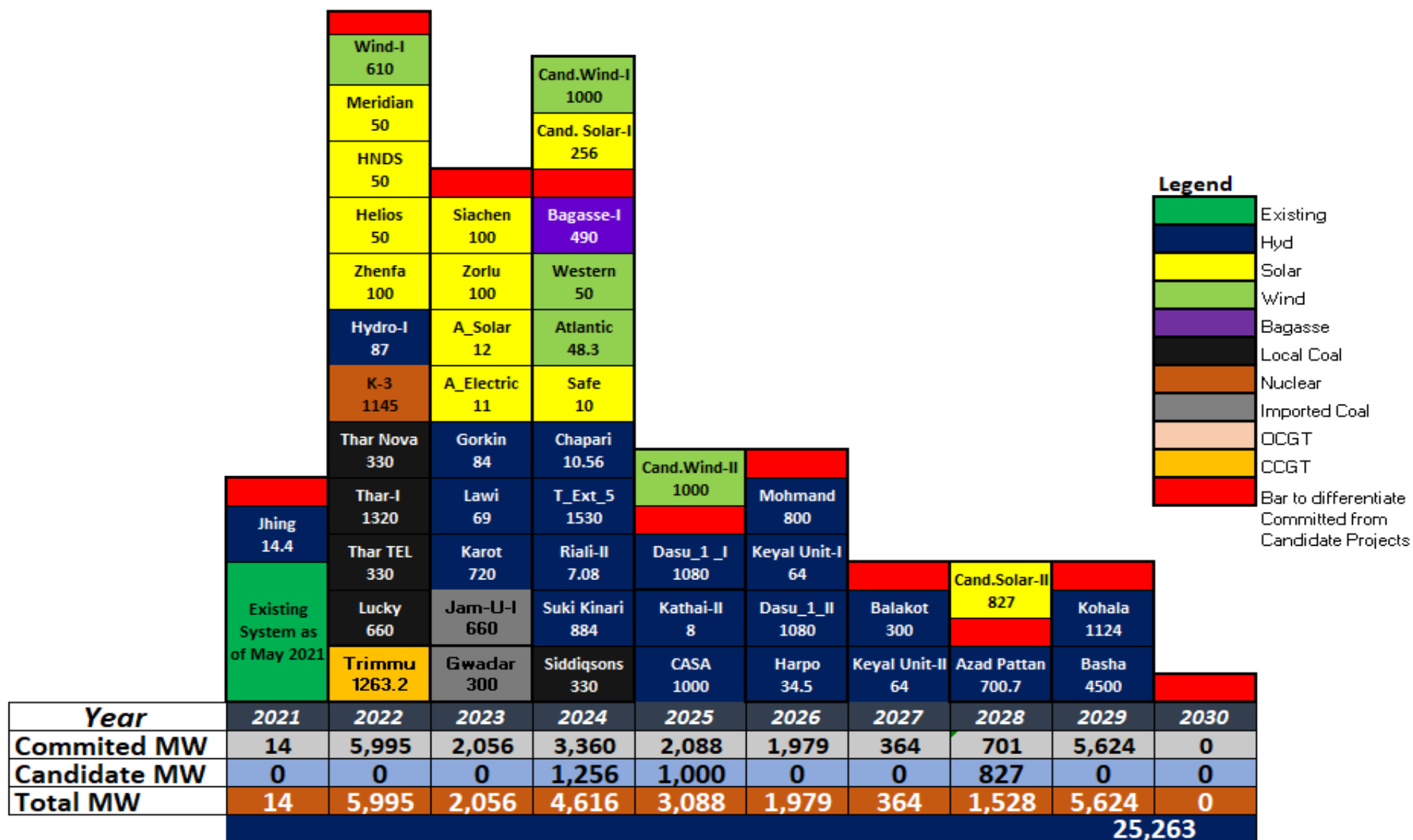


Figure 6-1: IGCEP 2021-30: Generation Sequence (2021-30)

The break-up of the projects lumped as blocks in the Figure 6-1 is provided in Table 6-2.

Table-6-2: Break-up of Blocks for Hydro, Solar, Wind and Bagasse Power Plants

Sr. No.	Year	Block	Name of Project	Installed Capacity
				MW
1	2022	Hydro-I	Ranolia	17
2			Jabori	10
3			Karora	12
4			Jagran-II	48
5		Wind-I	Act_2	50
6			Artistic_Wind_2	50
7			Din	50
8			Gul_Electric	50
9			Indus_Energy	50
10			Lakeside	50
11			Liberty_Wind_1	50
12			Liberty_Wind_2	50
13			Metro_Wind	60
14			Tricom	50
15			Master_Green	50
16			NASDA	50
Total (2022)				697
1	2024	Bagasse-I	Alliance	30
2			Bahawalpur	31.2
3			Faran	26.5
4			Hamza-II	30
5			HSM	26.5
6			Hunza	49.8
7			Indus	31

Sr. No.	Year	Block	Name of Project	Installed Capacity
				MW
8			Ittefaq	31.2
9			Kashmir	40
10			Mehran	26.5
11			RYK_Energy	25
12			Shahtaj	32
13			Sheikhoo	30
14			Tay	30
15			Two_Star	50
Total (2024)				490

PLEXOS final output comprising year-wise addition of all committed and candidate power plants is given below in Table 6-3.

Table 6-3: PLEXOS Annual Addition of Power Plants 2021-30

#	Name of Project	Fuel Type	Installed Capacity (MW)	Nominal Capacity (MW)	Agency	Status	Schedule of Commissioning
2021							
1	Jhing	Hydro	14.4	14.4	AJK	Committed	May-21
Generation Additions in 2021 (MW)			14.4	14.4			
Cumulative Addition uptill 2021 (MW)			14.4	14.4			
2022							
1	Master_Green	Wind	50	50	AEDB	Committed	Jul-21
2	Ranolia	Hydro	17	17	PEDO	Committed	Jul-21
3	Lucky	Local Coal	660	607	PPIB	Committed	Sep-21
4	Tricom	Wind	50	50	AEDB	Committed	Oct-21
5	Jabori	Hydro	10.2	10.2	PEDO	Committed	Dec-21
6	Karora	Hydro	11.8	11.8	PEDO	Committed	Dec-21
7	Metro_Wind	Wind	60	60	AEDB	Committed	Dec-21
8	Lakeside	Wind	50	50	AEDB	Committed	Dec-21
9	NASDA	Wind	50	50	AEDB	Committed	Dec-21
10	Artistic_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
11	Din	Wind	50	50	AEDB	Committed	Dec-21
12	Gul_Electric	Wind	50	50	AEDB	Committed	Dec-21
13	Act_2	Wind	50	50	AEDB	Committed	Dec-21
14	Liberty_Wind_1	Wind	50	50	AEDB	Committed	Dec-21
15	Liberty_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
16	Indus_Energy	Wind	50	50	AEDB	Committed	Dec-21
17	Zhenfa	Solar	100	100	AEDB	Committed	Dec-21
18	Trimmu	RLNG	1,263	1,243	PPIB	Committed	Jan-22
19	K-3	Nuclear	1,145	1,059	PAEC	Committed	Jan-22
20	Thar TEL	Local Coal	330	300	PPIB	Committed	Mar-22
21	Helios	Solar	50	50	AEDB	Committed	Mar-22
22	HNDS	Solar	50	50	AEDB	Committed	Mar-22
23	Meridian	Solar	50	50	AEDB	Committed	Mar-22

#	Name of Project	Fuel Type	Installed Capacity (MW)	Nominal Capacity (MW)	Agency	Status	Schedule of Commissioning
24	Jagran-II	Hydro	48	48	AJK	Committed	May-22
25	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	Committed	May-22
26	Thal Nova	Local Coal	330	300	PPIB	Committed	Jun-22
Generation Additions in 2022 (MW)			5,995	5,670			
Cumulative Addition uptill 2022 (MW)			6,010	5,684			
2023							
1	Karot	Hydro	720	720	PPIB	Committed	Jul-22
2	Access_Electric	Solar	10.52	10.52	AEDB	Committed	Aug-22
3	Access_Solar	Solar	12	12	AEDB	Committed	Aug-22
4	Jamshoro Coal (Unit-I)	Imp.Coal	660	629	GENCO	Committed	Oct-22
5	Lawi	Hydro	69	69	PEDO	Committed	Nov-22
6	Gorkin Matiltan	Hydro	84	84	PEDO	Committed	Nov-22
7	Zorlu	Solar	100	100	AEDB	Committed	Jun-23
8	Siachen	Solar	100	100	AEDB	Committed	Jun-23
9	Gwadar	Imp.Coal	300	273	PPIB	Committed	Jun-23
Generation Additions in 2023 (MW)			2,056	1,998			
Cumulative Addition uptill 2023 (MW)			8,065	7,682			
2024							
1	Siddiqsons	Local Coal	330	304	PPIB	Committed	Jul-23
2	Suki Kinari	Hydro	884.0	884.0	PPIB	Committed	Jul-23
3	Riali-II	Hydro	7	7	PPIB	Committed	Jul-23
4	Safe	Solar	10	10	AEDB	Committed	Sep-23
5	Western	Wind	50	50	AEDB	Committed	Nov-23
6	Trans_Atlantic	Wind	48	48	AEDB	Committed	Dec-23
7	Alliance	Bagasse	30	30	AEDB	Committed	Dec-23
8	Bahawalpur	Bagasse	31	31	AEDB	Committed	Dec-23
9	Faran	Bagasse	27	27	AEDB	Committed	Dec-23
10	Hamza-II	Bagasse	30	30	AEDB	Committed	Dec-23
11	HSM	Bagasse	27	27	AEDB	Committed	Dec-23
12	Hunza	Bagasse	50	50	AEDB	Committed	Dec-23

#	Name of Project	Fuel Type	Installed Capacity (MW)	Nominal Capacity (MW)	Agency	Status	Schedule of Commissioning
13	Indus	Bagasse	31	31	AEDB	Committed	Dec-23
14	Ittefaq	Bagasse	31	31	AEDB	Committed	Dec-23
15	Kashmir	Bagasse	40	40	AEDB	Committed	Dec-23
16	Mehran	Bagasse	27	27	AEDB	Committed	Dec-23
17	RYK_Energy	Bagasse	25	25	AEDB	Committed	Dec-23
18	Shahtaj	Bagasse	32	32	AEDB	Committed	Dec-23
19	Sheikhoo	Bagasse	30	30	AEDB	Committed	Dec-23
20	TAY	Bagasse	30	30	AEDB	Committed	Dec-23
21	Two_Star	Bagasse	50	50	AEDB	Committed	Dec-23
22	Tarbela_Ext_5	Hydro	1,530	1,530	WAPDA	Committed	Feb-24
23	Chapari Charkhel	Hydro	11	11	PEDO	Committed	Jun-24
24	Candidate_Solar	Solar	256	256	To be decided	Candidate	2024
25	Candidate_Wind	Wind	1,000	1,000	To be decided	Candidate	2024
Generation Additions in 2024 (MW)			4,615	4,589			
Cumulative Addition uptill 2024 (MW)			12,681	12,271			
2025							
1	CASA	Import	1,000	1,000	GOP	Committed	Aug-24
2	Kathai-II	Hydro	8	8	PPIB	Committed	Dec-24
3	Dasu_1 Unit 1-3	Hydro	1,080	1,080	WAPDA	Committed	Apr-25
4	Candidate_Wind	Wind	1,000	1,000	To be decided	Candidate	2025
Generation Additions in 2025 (MW)			3,088	3,088			
Cumulative Addition uptill 2025 (MW)			15,769	15,359			
2026							
1	Harpo	Hydro	35	35	WAPDA	Committed	Oct-25
2	Dasu_1 Unit 4-6	Hydro	1,080	1,080	WAPDA	Committed	Nov-25
3	Mohmand	Hydro	800	800	WAPDA	Committed	Apr-26
4	Keyal Khwar Unit 1	Hydro	64	64	WAPDA	Committed	May-26
Generation Additions in 2026 (MW)			1,979	1,979			
Cumulative Addition uptill 2026 (MW)			17,747	17,338			

#	Name of Project	Fuel Type	Installed Capacity (MW)	Nominal Capacity (MW)	Agency	Status	Schedule of Commissioning
2027							
1	Keyal Khwar Unit 2	Hydro	64	64	WAPDA	Committed	Aug-26
2	Balakot	Hydro	300	300	PEDO	Committed	Mar-27
Generation Additions in 2027 (MW)			364	364			
Cumulative Addition uptill 2027 (MW)			18,111	17,702			
2028							
1	Azad Pattan	Hydro	701	701	PPIB	Committed	Sep-27
2	Candidate_Solar	Solar	827	827	To be decided	Candidate	2028
Generation Additions in 2028 (MW)			1,528	1,528			
Cumulative Addition uptill 2028 (MW)			19,639	19,230			
2029							
1	Kohala	Hydro	1,124	1,124	PPIB	Committed	Jul-28
2	Diamer Bhasha	Hydro	4,500	4,500	WAPDA	Committed	Feb-29
Generation Additions in 2029 (MW)			5,624	5,624			
Cumulative Addition uptill 2029 (MW)			25,263	24,854			

6.3. Annual Capacity Factors

The annual capacity factors information based on the Installed Capacity for the corresponding year, as shown in the Table 6-4 is one of the most important output of the PLEXOS tool. The drastic change in capacity factor of some plants between the years 2021 to 2030 is due to certain rationale. For example, up to January 2022, the power purchaser is obligated to utilize / despatch 66% of the three (03) RLNG based power plants i.e. Haveli Bahadur Shah, Balloki and Bhikki, under contractual binding. Beyond January 2022, these RLNG based plants will be despatched as per merit order. Similarly, for the existing imported coal-based power plants (Sahiwal CFPP, China HUBCO CFPP and Port Qasim CFPP) as well as three (03) existing local gas based power plants (Engro, Foundation & Uch-II), a minimum annual despatch of 50% is modelled as per contractual obligation, from the date of their respective CODs till the expiry of their PPAs.

Table 6-4: Annual Capacity Factors (%age)

#	Plant Name	Fuel Type	2021	22	23	24	25	26	27	28	29	2030
			(%)									
1	Engro	Gas	79.68	57.24	50.66	50.51	50.66	50.63	50.64	50.51	50.64	50.64
2	Foundation	Gas	77.47	70.90	50.54	50.39	50.54	50.51	50.52	50.40	50.53	50.52
3	Guddu-I U(11-13)	Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Guddu-II U(5-10)	Gas	26.63	20.69	4.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Guddu-V (747)	Gas	68.87	65.09	33.96	23.79	16.75	8.46	9.05	12.44	12.20	0.83
7	Liberty	Gas	46.12	44.01	38.11	38.00	38.16	38.12	37.65	0.00	0.00	0.00
8	Uch	Gas	68.29	64.59	41.02	35.22	33.03	33.03	33.03	32.94	33.06	33.06
9	Uch-II	Gas	81.44	59.62	49.48	49.43	49.52	49.54	49.46	49.31	49.51	49.65
10	KAPCO 1	RFO	15.76	14.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	KAPCO 2	RFO	7.71	9.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	KAPCO 3	RFO	1.64	1.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	Balloki	RLNG	65.68	38.73	4.98	1.10	0.00	0.00	0.00	0.00	0.00	0.00
14	Bhikki	RLNG	65.67	25.91	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	FKPCL	RLNG	3.69	0.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	GTPS Block 4 U(5-9)	RLNG	3.97	2.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Halmore	RLNG	20.61	12.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Haveli	RLNG	65.66	49.35	12.73	6.35	0.29	0.15	0.25	0.39	0.17	0.00

#	Plant Name	Fuel Type	2021	22	23	24	25	26	27	28	29	2030
			(%)									
19	Nandipur	RLNG	13.96	10.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Orient	RLNG	28.20	14.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	Rousch	RLNG	11.87	6.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Saif	RLNG	20.19	12.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	Sapphire	RLNG	24.22	13.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Trimmu	RLNG	0.00	57.75	26.10	16.61	7.81	3.56	3.32	5.06	5.13	0.33
25	AGL	RFO	3.53	5.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	Atlas	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	HuB N	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Kohinoor	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	Liberty Tech	RFO	1.12	2.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	Nishat C	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Nishat P	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Davis	RLNG	2.45	1.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	Altern	Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	China HUBCO	Imp.Coal	80.20	79.97	77.46	74.13	60.75	50.38	50.91	59.03	50.36	50.29
35	Gwadar	Imp.Coal	0.00	0.00	84.81	74.62	68.55	37.60	65.41	65.50	26.91	11.84
36	Jamshoro Coal	Imp.Coal	0.00	0.00	63.28	41.64	25.83	18.58	17.41	21.91	18.95	4.35
37	Port Qasim	Imp.Coal	79.61	79.32	79.35	78.61	77.01	70.24	74.01	73.72	64.23	50.28
38	Sahiwal Coal	Imp.Coal	79.54	78.72	55.52	50.15	50.28	50.29	50.29	50.14	50.31	50.29
39	Engro Thar	Local Coal	67.95	67.88	67.93	67.91	67.32	66.96	67.35	67.38	64.46	57.21
40	Lucky	Local Coal	0.00	77.29	77.98	76.57	76.84	75.82	76.96	76.94	70.65	16.92
41	Siddiqsons	Local Coal	0.00	0.00	0.00	78.15	78.13	78.17	78.22	78.21	78.23	78.28
42	Thal Nova	Local Coal	0.00	0.00	77.05	77.02	76.86	76.76	76.94	77.11	73.85	76.20
43	Thar TEL	Local Coal	0.00	77.53	77.05	77.01	77.08	76.63	77.09	76.93	73.79	76.00
44	Thar-I (SSRL)	Local Coal	0.00	84.26	78.00	78.02	77.99	78.02	78.08	78.07	77.26	78.15

#	Plant Name	Fuel Type	2021	22	23	24	25	26	27	28	29	2030
			(%)									
45	C-1	Nuclear	73.46	73.45	73.46	73.44	73.46	73.47	73.47	73.46	73.48	73.49
46	C-2	Nuclear	70.22	70.21	70.22	70.20	70.22	70.23	70.23	70.21	70.24	70.24
47	C-3	Nuclear	73.73	73.72	73.73	73.71	73.73	73.74	73.74	73.73	73.75	73.76
48	C-4	Nuclear	73.73	73.72	73.73	73.71	73.73	73.74	73.74	73.73	73.75	73.76
49	K-2	Nuclear	86.75	81.24	81.32	81.30	81.27	81.33	81.33	81.32	81.39	81.43
50	K-3	Nuclear	0.00	80.74	81.20	81.28	81.20	81.31	81.33	81.32	81.38	81.43
51	AES Pakgen	RFO	0.41	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	HUBCO	RFO	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Jamshoro-I U1	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54	Jamshoro-II U4	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	Lalpir	RFO	2.34	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	Muzaffargarh-I U1	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Muzaffargarh-I U2	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Muzaffargarh-I U3	RFO	0.18	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	Muzaffargarh-II U4	RFO	0.34	0.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Saba	RFO	0.27	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Allai Khwar	Hydro	43.31	43.28	43.63	43.58	43.60	43.63	43.63	43.58	43.63	43.63
62	Chashma	Hydro	46.62	46.62	46.62	46.63	46.62	46.62	46.62	46.63	46.62	46.62
63	Daral Khwar	Hydro	46.95	46.89	46.83	46.78	46.95	46.95	46.90	46.85	46.95	46.95
64	Dubair Khwar	Hydro	48.98	48.98	48.98	48.89	48.99	48.99	49.00	48.90	49.00	49.00
65	Ghazi Brotha	Hydro	51.16	51.16	51.16	51.14	51.16	51.16	51.16	51.14	51.16	51.16
66	Golen Gol	Hydro	10.58	10.58	10.58	10.56	10.58	10.58	10.58	10.56	10.58	10.58
67	Gulpur	Hydro	53.75	53.61	53.66	53.50	53.64	53.75	53.75	53.73	53.75	53.75
68	Jagran-I	Hydro	48.85	48.85	48.85	48.74	48.85	48.85	48.85	48.74	48.85	48.85
69	Jinnah	Hydro	23.98	23.98	23.98	23.95	23.98	23.98	23.98	23.95	23.98	23.98
70	Khan Khwar	Hydro	43.37	43.36	43.37	43.32	43.36	43.37	43.37	43.33	43.37	43.37

#	Plant Name	Fuel Type	2021	22	23	24	25	26	27	28	29	2030
			(%)									
71	Malakand-III	Hydro	51.30	51.30	51.30	51.21	51.30	51.30	51.30	51.21	51.30	51.30
72	Mangla	Hydro	51.64	51.81	52.09	52.13	51.96	52.09	52.09	52.13	52.09	52.09
73	Neelum Jehlum	Hydro	57.39	56.89	57.56	57.40	57.37	57.63	57.62	57.52	57.56	57.63
74	New Bong	Hydro	63.64	63.57	63.91	63.88	63.91	63.91	63.91	63.88	63.91	63.91
75	Patrind	Hydro	47.62	47.51	47.69	47.60	47.67	47.71	47.73	47.63	47.73	47.73
76	Small Hydel	Hydro	34.20	34.10	34.23	34.26	34.23	34.29	34.29	34.28	34.29	34.29
77	Tarbela 1-14	Hydro	48.13	48.13	48.13	48.07	48.13	48.13	48.13	48.07	48.13	48.13
78	Tarbela_Ext_4	Hydro	30.36	30.36	30.36	30.31	30.36	30.36	30.36	30.31	30.36	30.36
79	Warsak	Hydro	45.78	45.82	46.12	46.06	46.12	46.12	46.12	46.06	46.12	46.12
80	Azad Pattan	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.17	52.17	52.17
81	Balakot	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	38.15	38.07	38.15	38.15
82	Chapari Charkhel	Hydro	0.00	0.00	0.00	80.66	80.63	80.69	80.72	80.66	80.70	80.72
83	Dasu_1	Hydro	0.00	0.00	0.00	0.00	59.88	59.99	59.99	59.88	60.15	60.19
84	Diamer Bhasha	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.23	44.23
85	Gorkin Matiltan	Hydro	0.00	0.00	44.73	44.61	44.60	44.73	44.73	44.61	44.73	44.73
86	Harpo	Hydro	0.00	0.00	0.00	0.00	0.00	50.24	50.30	50.24	50.30	50.30
87	Jabori	Hydro	0.00	76.70	77.19	77.20	77.14	77.23	77.23	77.27	77.23	77.25
88	Jagran-II	Hydro	0.00	48.84	48.84	48.73	48.84	48.84	48.84	48.73	48.84	48.84
89	Jhing	Hydro	48.72	48.83	48.83	48.72	48.83	48.83	48.83	48.72	48.83	48.83
90	Karora	Hydro	0.00	62.97	64.77	64.73	64.76	64.80	64.80	64.76	64.80	64.80
91	Karot	Hydro	0.00	0.00	48.42	48.36	48.43	48.43	48.44	48.38	48.44	48.44
92	Kathai-II	Hydro	0.00	0.00	0.00	0.00	60.51	60.51	60.51	60.43	60.51	60.51
93	Keyal Khwar	Hydro	0.00	0.00	0.00	0.00	0.00	29.31	27.78	29.31	29.36	29.36
94	Kohala	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.37	63.39
95	Lawi	Hydro	0.00	0.00	48.08	47.99	48.08	48.08	48.08	47.99	48.08	48.08
96	Mohmand	Hydro	0.00	0.00	0.00	0.00	0.00	42.94	43.01	42.94	43.01	43.01

#	Plant Name	Fuel Type	2021	22	23	24	25	26	27	28	29	2030
			(%)									
97	Ranolia	Hydro	0.00	61.72	61.91	61.80	61.84	61.93	61.94	61.84	61.94	61.94
98	Riali-II	Hydro	0.00	0.00	0.00	55.45	55.54	55.58	55.58	55.47	55.58	55.58
99	Suki Kinari	Hydro	0.00	0.00	0.00	40.30	40.38	40.38	40.38	40.30	40.38	40.38
100	Tarbela_Ext_5	Hydro	0.00	0.00	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05
101	CASA	Cross Border	0.00	0.00	0.00	0.00	39.31	39.30	39.31	39.21	39.30	39.31
102	Act	Wind	31.63	31.56	31.57	31.51	31.57	31.57	31.63	31.57	31.63	31.63
103	Act_2	Wind	0.00	38.54	38.54	38.42	38.54	38.62	38.62	38.54	38.62	38.62
104	Artistic_wind	Wind	34.77	34.77	35.25	35.27	35.31	35.31	35.31	35.27	35.31	35.31
105	Artistic_Wind_2	Wind	0.00	38.45	38.50	38.45	38.62	38.62	38.62	38.54	38.62	38.62
106	Din	Wind	0.00	38.54	38.52	38.41	38.54	38.62	38.62	38.54	38.62	38.62
107	FFC	Wind	31.92	32.01	32.57	32.99	33.55	33.55	33.55	33.50	33.55	33.55
108	FWEL-I	Wind	32.13	32.13	32.57	32.99	33.04	33.55	33.55	33.50	33.55	33.55
109	FWEL-II	Wind	32.36	32.36	33.01	33.18	33.22	33.55	33.55	33.50	33.55	33.55
110	Gul Ahmed	Wind	31.63	31.56	31.56	31.51	31.57	31.57	31.63	31.57	31.63	31.63
111	Gul_Electric	Wind	0.00	38.62	38.50	38.46	38.62	38.54	38.62	38.54	38.62	38.62
112	Hawa	Wind	34.77	34.28	35.31	35.27	35.31	35.31	35.31	35.27	35.31	35.31
113	Indus_Energy	Wind	0.00	38.62	38.52	38.45	38.62	38.60	38.62	38.54	38.62	38.62
114	Jhimpir	Wind	34.77	35.30	34.77	35.27	35.31	35.31	35.31	35.27	35.31	35.31
115	Lakeside	Wind	0.00	39.06	39.06	38.98	39.06	39.06	39.06	38.98	39.06	39.06
116	Liberty_Wind_1	Wind	0.00	38.62	38.50	38.43	38.62	38.54	38.62	38.54	38.62	38.62
117	Liberty_Wind_2	Wind	0.00	38.54	38.48	38.46	38.62	38.54	38.62	38.54	38.62	38.62
118	Master	Wind	31.63	31.56	31.57	31.51	31.57	31.58	31.63	31.57	31.63	31.63
119	Master_Green	Wind	0.00	38.49	38.50	38.45	38.52	38.54	38.62	38.54	38.62	38.62
120	Metro_Power	Wind	30.13	30.16	30.68	31.35	31.11	31.58	31.56	31.98	31.56	32.04
121	Metro_Wind	Wind	0.00	38.62	38.52	38.46	38.62	38.62	38.62	38.54	38.62	38.62
122	NASDA	Wind	0.00	39.06	39.06	38.98	39.06	39.06	39.06	38.98	39.06	39.06

#	Plant Name	Fuel Type	2021	22	23	24	25	26	27	28	29	2030
			(%)									
123	New_Wind	Wind	0.00	0.00	0.00	41.81	41.90	41.90	41.90	41.81	41.90	41.90
124	Sachal	Wind	31.61	31.56	31.57	31.51	31.57	31.57	31.63	31.57	31.63	31.63
125	Sapphire_Wind	Wind	31.63	31.56	31.55	31.51	31.63	31.63	31.63	31.57	31.63	31.63
126	Three_Gorges_I	Wind	29.87	29.78	30.60	31.05	31.43	31.56	31.56	32.00	32.00	32.04
127	Three_Gorges_II	Wind	35.31	34.77	35.31	35.27	35.31	35.31	35.31	35.27	35.31	35.31
128	Three_Gorges_III	Wind	35.17	35.07	35.31	35.27	35.31	35.31	35.31	35.27	35.31	35.31
129	Trans_Atlantic	Wind	0.00	0.00	0.00	41.81	41.90	41.90	41.90	41.81	41.90	41.90
130	Tricom	Wind	0.00	38.62	38.49	38.45	38.62	38.62	38.62	38.54	38.62	38.62
131	Tricon_A	Wind	34.77	35.22	35.31	35.27	35.31	35.31	35.31	35.27	35.31	35.31
132	Tricon_B	Wind	34.75	34.77	34.77	35.27	35.31	35.31	35.31	35.27	35.31	35.31
133	Tricon_C	Wind	35.31	35.30	35.31	35.27	35.31	35.31	35.31	35.27	35.31	35.31
134	UEP	Wind	31.57	31.56	31.57	31.51	31.63	31.57	31.63	31.57	31.63	31.63
135	Western	Wind	0.00	0.00	0.00	38.45	38.54	38.60	38.62	38.54	38.62	38.62
136	Yunus	Wind	31.63	31.56	31.57	31.51	31.59	31.57	31.63	31.57	31.63	31.63
137	Zorlu_Wind	Wind	30.25	30.15	30.60	31.04	31.56	31.56	31.58	31.51	32.04	32.04
138	Access_Electric	Solar	0.00	0.00	18.27	18.31	18.31	18.31	18.31	18.31	18.31	18.31
139	Access_Solar	Solar	0.00	0.00	18.27	18.31	18.31	18.31	18.31	18.31	18.31	18.31
140	Appolo	Solar	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23
141	Best	Solar	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23
142	Crest	Solar	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23
143	Helios	Solar	0.00	21.57	21.57	21.57	21.57	21.57	21.57	21.57	21.57	21.57
144	HNDS	Solar	0.00	21.57	21.57	21.57	21.57	21.57	21.57	21.57	21.57	21.57
145	Meridian	Solar	0.00	21.57	21.57	21.57	21.57	21.57	21.57	21.57	21.57	21.57
146	New_Solar	Solar	0.00	0.00	0.00	21.57	21.57	21.57	21.57	21.57	21.57	21.57
147	QA_Solar	Solar	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23
148	Safe	Solar	0.00	0.00	0.00	20.17	20.40	20.40	20.40	20.40	20.40	20.40

#	Plant Name	Fuel Type	2021	22	23	24	25	26	27	28	29	2030
			(%)									
149	Siachen	Solar	0.00	0.00	21.57	21.57	21.57	21.57	21.57	21.57	21.57	21.57
150	Zhenfa	Solar	0.00	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40
151	Zorlu	Solar	0.00	0.00	18.31	18.31	18.31	18.31	18.31	18.31	18.31	18.31
152	Alliance	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
153	Almoiz	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
154	Bahawalpur	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
155	Chanar	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
156	Chiniot	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
157	Faran	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
158	Hamza	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
159	Hamza-II	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
160	HSM	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
161	Hunza	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
162	Indus	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
163	Ittefaq	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
164	JDW-II	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
165	JDW-III	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
166	Kashmir	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
167	Mehran	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
168	RYK_Energy	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
169	Ryk_Mills	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
170	Shahtaj	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
171	Sheikhoo	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
172	TAY	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
173	Thal_Layyah	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
174	Two_Star	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68

(All numbers in red color, in this table, represent retirement of the corresponding plant.)

6.4. Year-wise Discounted and Un-Discounted Cost

The year wise cost breakup is shown in Table 6-5 and 6-6.

Table 6-5: Year wise Discounted Cost

Year	Present Worth Cost for Each Year of the Plan Horizon				
	Annualized Construction Cost	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
	(k\$)				
2021	-	1,664,944	3,136,851	4,801,794	4,801,794
2022	-	1,826,574	2,852,210	4,678,784	9,480,579
2023	-	1,973,937	1,858,463	3,832,400	13,312,979
2024	82,489	1,846,313	1,617,954	3,546,756	16,859,735
2025	140,680	1,701,423	1,299,403	3,141,507	20,001,241
2026	127,891	1,563,236	1,091,988	2,783,115	22,784,356
2027	116,264	1,415,720	1,007,307	2,539,291	25,323,647
2028	123,979	1,285,898	946,296	2,356,173	27,679,820
2029	112,708	1,191,686	808,355	2,112,749	29,792,570
2030	102,462	1,102,257	633,053	1,837,771	31,630,341

Table 6-6: Year wise Un-Discounted Cost

Year	Un-Discounted Cost for Each Year of the Plan Horizon				
	Annualized Construction Cost	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
	(k\$)				
2021	-	1,664,944	3,136,851	4,801,794	4,801,794
2022	-	2,009,232	3,137,431	5,146,663	9,948,457
2023	-	2,388,464	2,248,741	4,637,204	14,585,661
2024	109,793	2,457,443	2,153,496	4,720,732	19,306,393
2025	205,970	2,491,054	1,902,456	4,599,480	23,905,873

Year	Un-Discounted Cost for Each Year of the Plan Horizon				
	Annualized Construction Cost	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
	(k\$)				
2026	205,970	2,517,608	1,758,657	4,482,234	28,388,108
2027	205,970	2,508,034	1,784,505	4,498,509	32,886,617
2028	241,600	2,505,852	1,844,063	4,591,515	37,478,131
2029	241,600	2,554,486	1,732,781	4,528,866	42,006,998
2030	241,600	2,599,063	1,492,706	4,333,369	46,340,367

6.5. Indigenization of Energy Mix

World Energy Council defines energy security as the management of primary energy supply from domestic/indigenous and external sources, reliability of energy infrastructure, ability to meet current and future demand. Energy security reflects a nation's capacity to meet current and future demand reliably and bounce back swiftly from system shocks with minimal disruption to supplies. Pakistan ranks #99 among 110 countries in terms of energy security by the World Energy Council for the year 2020.

Pakistan imports nearly one third of its energy resources in the form of oil, coal, and RLNG, and currently 47% of existing installed capacity relies on imported fuel for energy generation. Pakistan remains an energy insecure country in context of the on-going economic situation of Pakistan. Large reliance on imported fuel for firm supply of energy not only increases the import bill of the country, but also put Pakistan susceptible to ever changing global and geo politics.

The IGCEP 2021-30 deals with long-term energy security with timely investments to supply energy in line with economic developments and environmental needs. According to IGCEP 2021-30 simulation results, indigenization ratio, which is ratio of electrical energy generated by indigenize generation resources to the electrical energy generated by all generation resources, has been computed for base case scenario as shown in Chart 6-3 and all other sensitivity scenarios to indicate how much energy security, the IGCEP aims to achieve by the year 2030 pertaining to electric power generation. In 2020-21, the indigenization ratio of energy is 58.9% that increases with a steep slope to 76.9% by the year 2023 due to inclusion of local coal, hydro, wind and solar based power plants. Subsequently, the indigenization ratio turns out to be around 90.2% until 2030. This remains an invaluable aspect for Pakistan power sector on the part of IGCEP 2021-30.

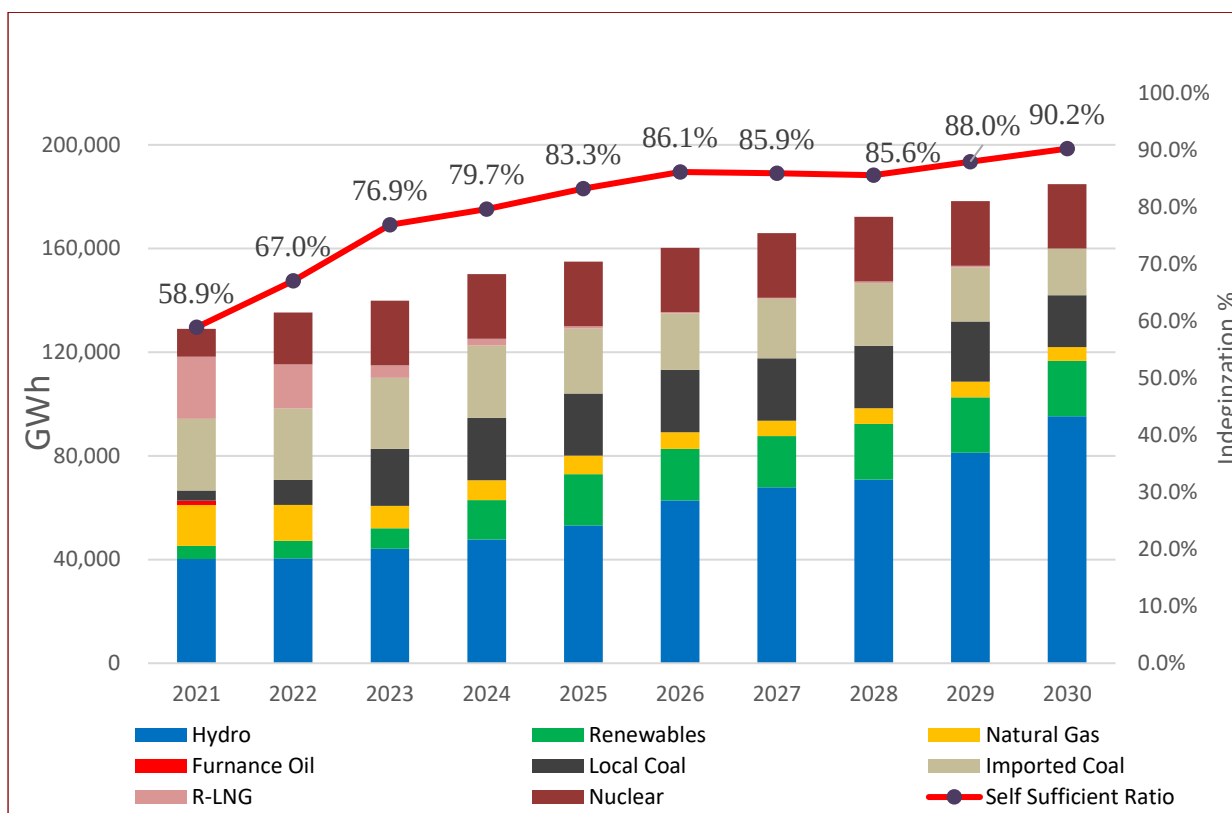


Chart 6-4: IGCEP 2021-30 Base Case Indigenization Ratio of Primary Energy

6.6. Clean and Green Power for Pakistan

Pakistan, like other South Asian countries, grapples with the challenges of a large and growing population, combined with rapidly growing energy needs. Heavily dependent on fossil-fuel imports, the country finds itself vulnerable to global oil price volatility and effects of increased carbon footprint due to power generation by fossil-fuel based technologies.

Pakistan has abundant renewable energy resources that can be utilized for power generation. Hydropower, with its potential in the northern part of the country, has traditionally been the most prominent source of renewable energy in Pakistan. In addition to hydropower potential, Pakistan is blessed with huge variable renewable resources, however, its harnessing, in true sense, is yet to be materialized.

Pakistan ranks #26 globally, #10 in Asia, #2 among SAARC member states in carbon emissions index, with 249 MtCO₂ territorial emissions, all GHG emissions from a country's territory, apart from those associated with international aviation and shipping, in 2019 according to the Global Carbon Atlas.

The IGCEP 2021-30 addresses the pursuit of low-carbon energy alternatives for electric power generation, to sustain the relatively low carbon emissions levels, to bolster energy security and to spur sustainable economic growth in the country. Based on the IGCEP output, carbon emissions have been calculated for existing and upcoming power generation for base case scenario as shown in Chart 6-4 and for all other scenarios. Carbon emissions in the country by power generation accounts for 0.353 kg-CO₂/kWh in year 2021 and this indicator reduces to 0.202 kg-CO₂/kWh by year 2030 which is even less than current average of the OECD countries.

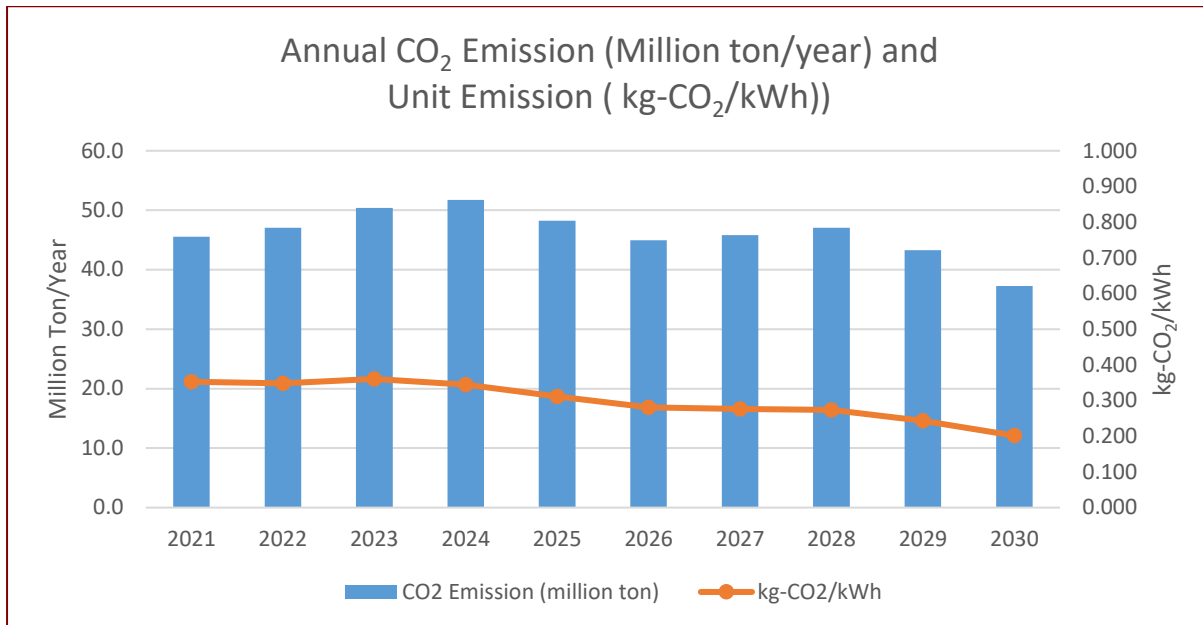


Chart 6-5: IGCEP 2021-30 Annual CO₂ Emission and Emission per Unit of Generation

6.7. Salient Features of the IGCEP

In order to balance a projected peak load of 34,377 MW by the year 2030, the PLEXOS model proposes 53,315 MW of installed generation capacity in base case; salient features of the study are as follows:

- a. Significant Induction of REs (clean and indigenous)
- b. Tapping of indigenous coal-based power
- c. Balancing the overall basket price with increased share of hydro power
- d. Optimal indigenization: less reliance on imported fuel i.e. coal, RFO, RLNG etc.
- e. Substantial reduction in carbon emission owing to induction of REs and hydro

Meanwhile, by the year 2030, a capacity of 6,447 MW is meant to be retired. In order to provide a quick understanding of the generation mix of the IGCEP 2021-30, the report includes the Table 6-7 which highlights addition of different types of generation capacities. Moreover, fuel-wise capacity in megawatts, energy in GWh and their monthly share in the total generated energy respectively, over the period of this plan, are further illustrated by the Chart 6-5 through 6-7, Chart 6-8 through 6-10 and Chart 6-11 through 6-13 respectively.

Table 6-7: Year wise Installed Capacity Addition (MW)

Year	Net Capacity Addition Over the Plan Period (2021-30)										
	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Natural Gas	Furnace Oil	Cross Border	Yearly Addition	Cumulative Total
	(MW)										
2021	660	9,888	5,839	2,490	3,960	1,746	3,012	6,506	0	34,100	-
2022	2,310	87	1,119	1,145	0	860	0	0	0	5,521	39,621
2023	330	873	0	0	960	222	-205	-3,000	0	-820	38,801
2024	330	2,432	0	0	0	1,854	0	0	0	4,615	43,416
2025	0	1,088	0	0	0	1,000	0	0	1,000	3,088	46,504
2026	0	1,979	0	0	0	0	0	0	0	1,979	48,483
2027	0	364	0	0	0	0	-225	-1,423	0	-1,284	47,199
2028	0	701	0	0	0	827	0	0	0	1,528	48,726
2029	0	5,624	0	0	0	0	0	-727	0	4,897	53,623
2030	0	0	-172	0	0	0	0	-136	0	-308	53,315
Total	3,630	23,035	6,786	3,635	4,920	6,508	2,582	1,220	1,000	53,315	

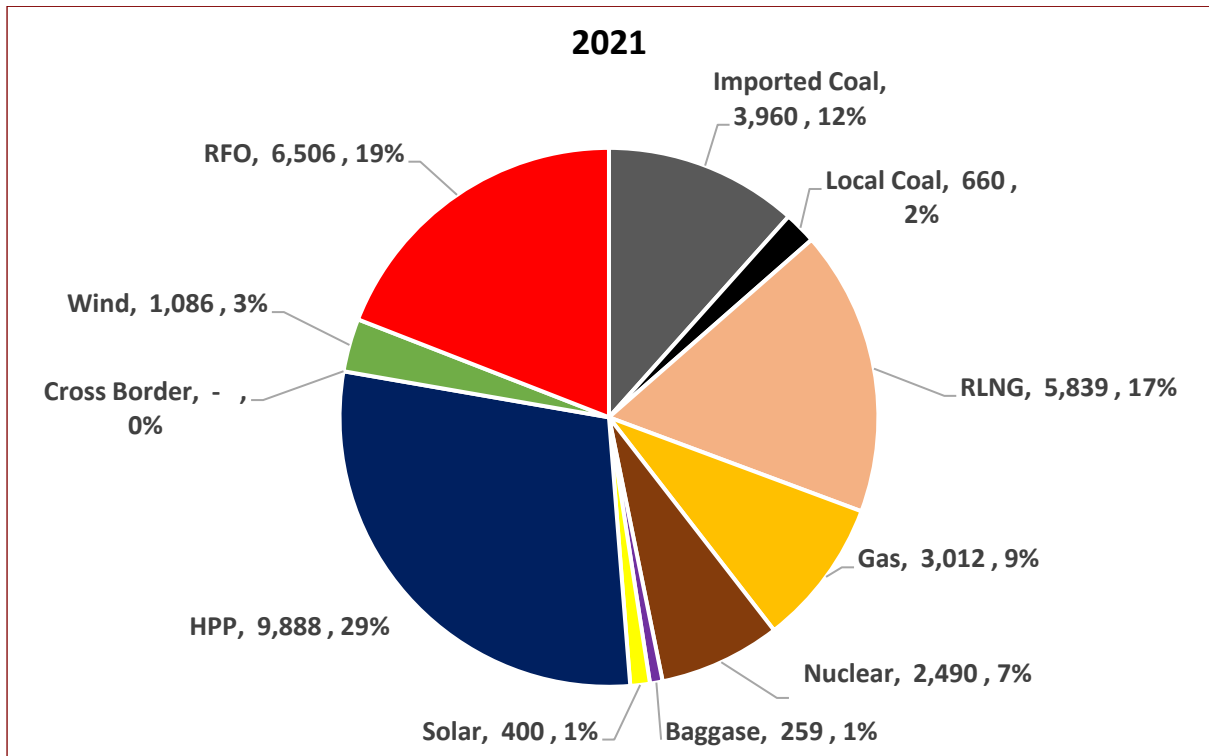


Chart 6-6: The IGCEP Generation Mix 2021 (MW)

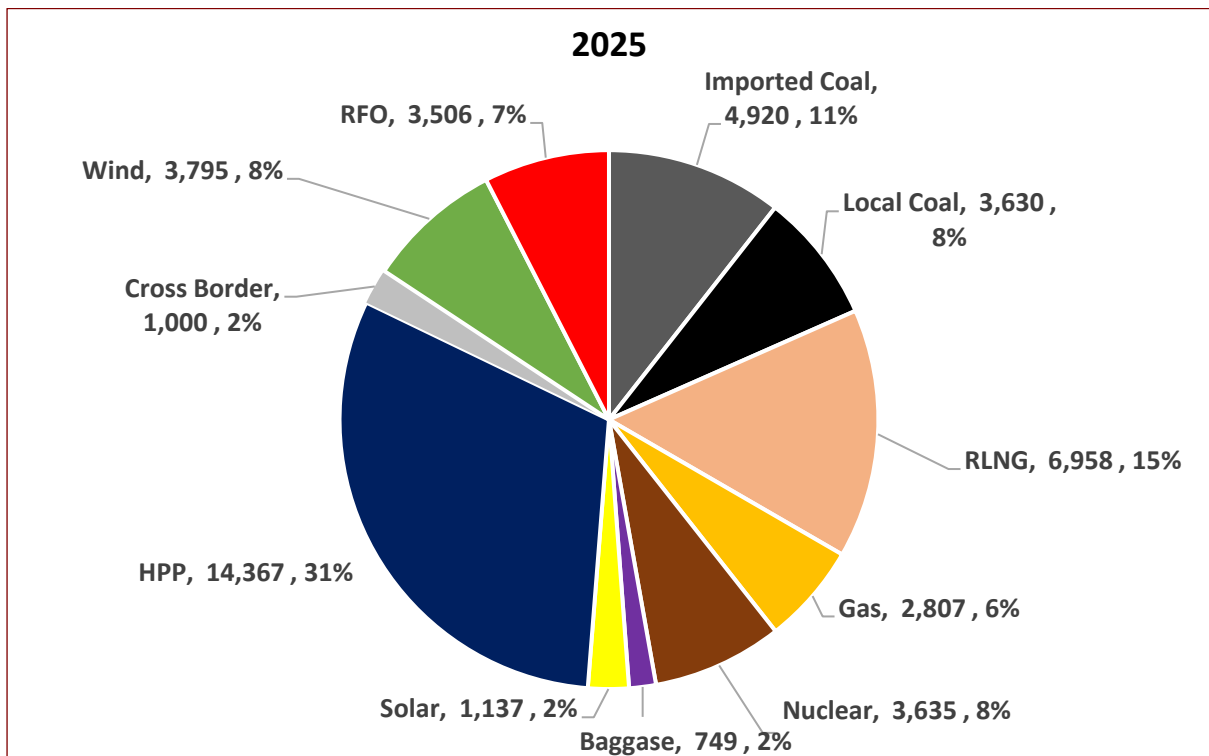


Chart 6-7: The IGCEP Generation Mix 2025 (MW)

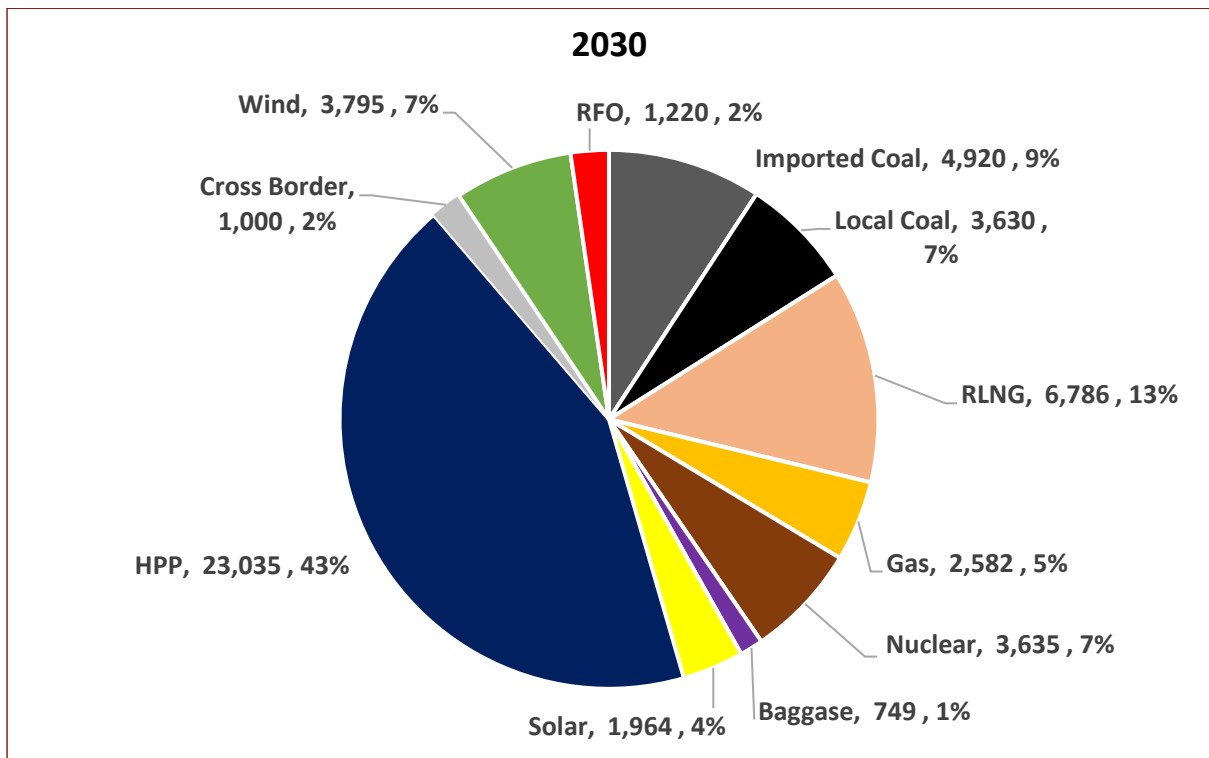


Chart 6-8: The IGCEP Generation Mix 2030 (MW)

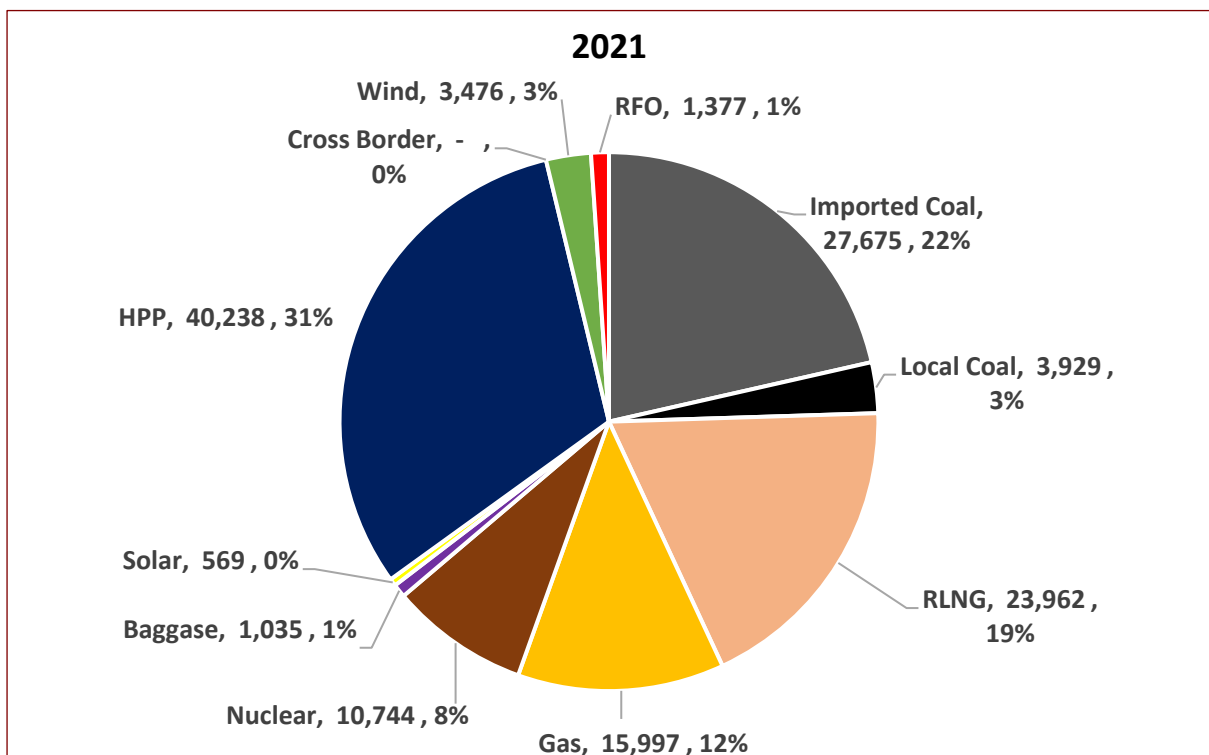


Chart 6-9: The IGCEP Generation Mix 2020 (GWh)

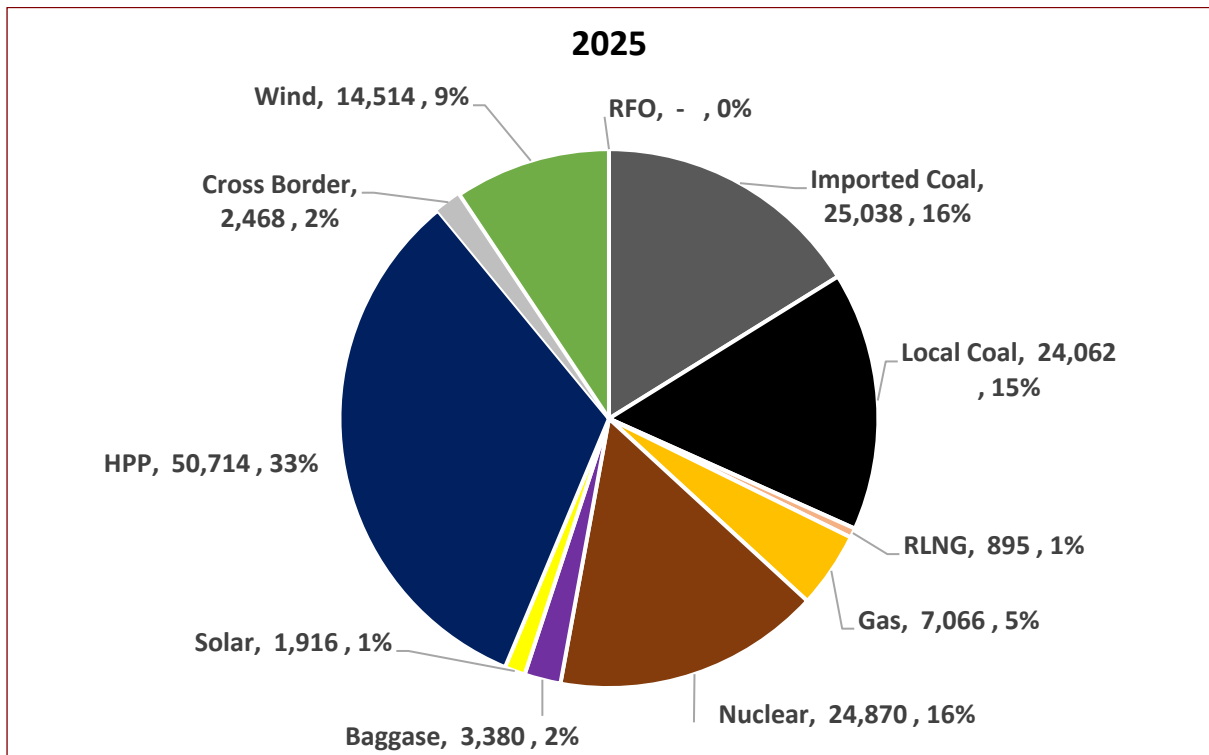


Chart 6-10: The IGCEP Generation Mix 2025 (GWh)

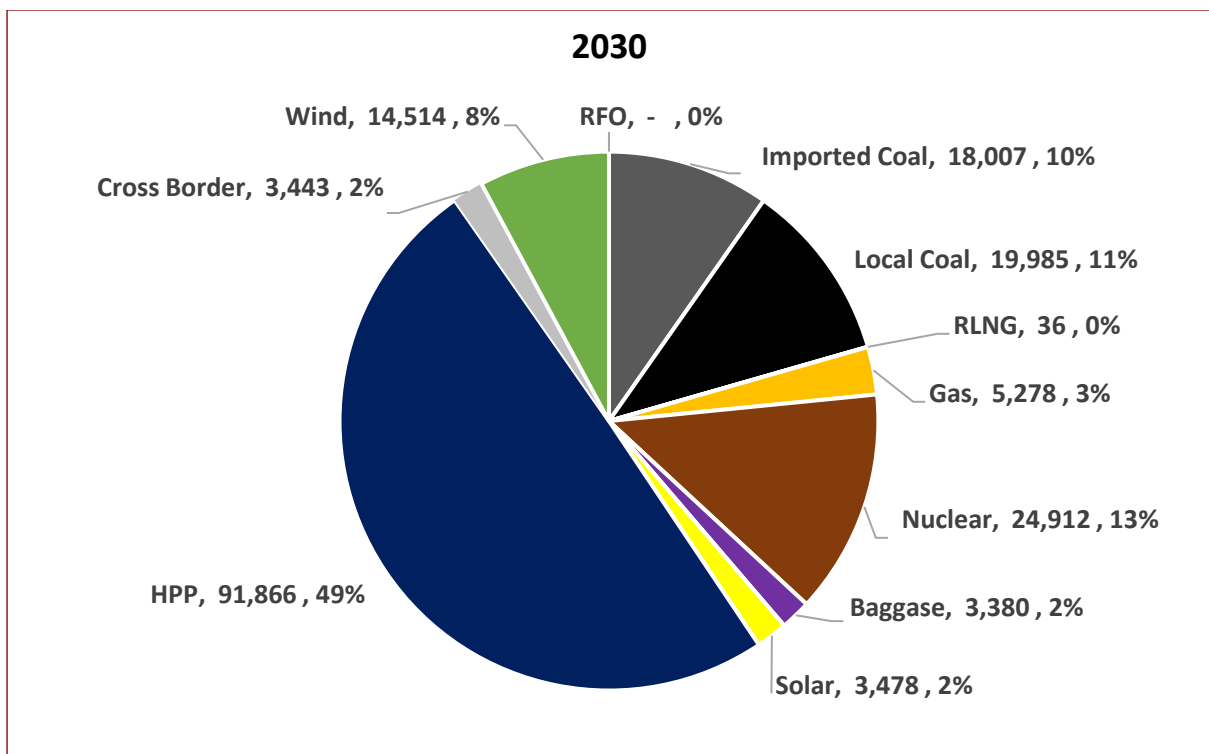


Chart 6-11: The IGCEP Generation Mix 2030 (GWh)

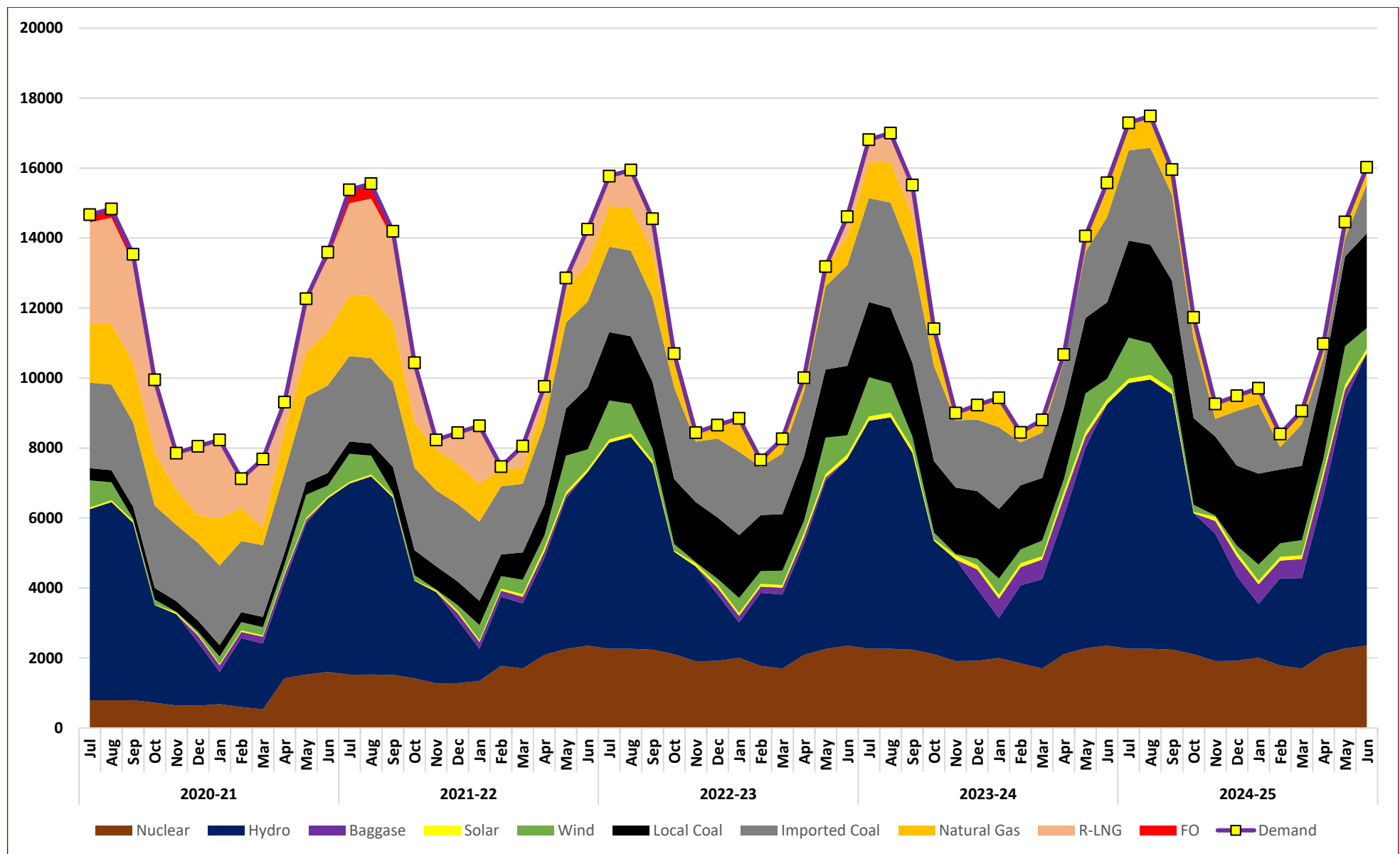


Chart 6-12 The IGCEP Monthly Generation Mix 2021-25 (GWh)

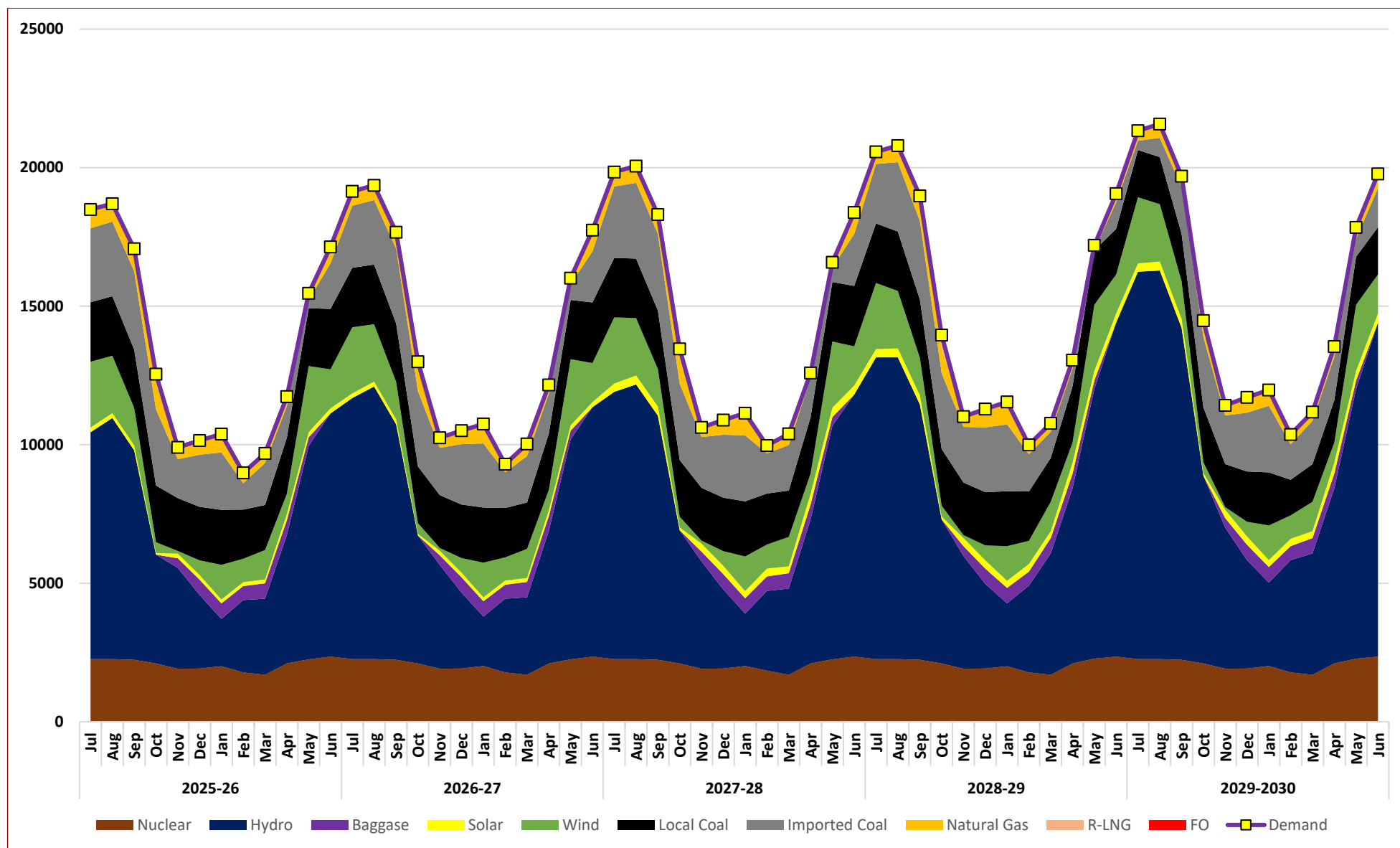


Chart 6-13: The IGCEP Monthly Generation Mix 2026-30 (GWh)

6.8. Comparison of Scenarios

As already explained, in addition to the base case, further two scenarios i.e. Low Demand Forecast and High Demand Forecast have been developed to facilitate the decision makers to reach an informed decision. The results show that base case has a capacity addition of 1,083 MW of solar and 2,000 of wind only throughout the study horizon. In Scenario-1 (Low Demand), only 1,000 MW of candidate wind is added in the system in the year 2024. Since the demand in Scenario-1 is considerably low and it is evident that the existing + committed capacity will suffice the said demand, hence there is very meagre candidate addition.

In Scenario-2 (High Demand), a total of 4,073 MW of solar and 2,899 MW of wind is added in the system and no other candidate technology is selected / optimized by the tool.

The Installed capacities (MW) & Energy Generation (GWh) for all scenarios for the year 2030 are shown in Table 6-8.

Table 6-8: Summary of Installed Capacity (MW) & Energy Generation (GWh) of Scenarios by 2030

Technology	Base Case		Low Demand		High Demand	
	MW	GWh	MW	GWh	MW	GWh
Imported Coal	4,920	18,007	4,920	17,532	4,920	18,136
Local Coal	3,630	19,985	3,630	14,490	3,630	20,499
RLNG	6,786	36	6,786	-	6,786	61
Gas	2,582	5,278	2,582	5,226	2,582	5,573
Nuclear	3,635	24,912	3,635	24,912	3,635	24,912
Bagasse	749	3,380	749	3,380	749	3,380
Solar	1,964	3,478	882	1,432	4,954	9,127
Hydro	23,035	91,866	23,035	91,866	23,035	91,866
Cross Border	1,000	3,443	1,000	3,443	1,000	3,443
Wind	3,795	14,514	2,795	10,360	4,694	18,247
RFO	1,220	-	1,220	-	1,220	-
Total (MW)	53,315	184,900	51,233	172,641	57,204	195,244

The net present value (NPV) of total cost of the all the scenarios are given in the table 6-9. In order to meet the system's requisite power and energy demand, base case indicates that 31.6 billion US \$ NPV cost is required both in terms of OPEX and CAPEX (excluding committed projects). The existing capacity payments and the CAPEX of committed plants having fixed value are not included in all the scenarios.

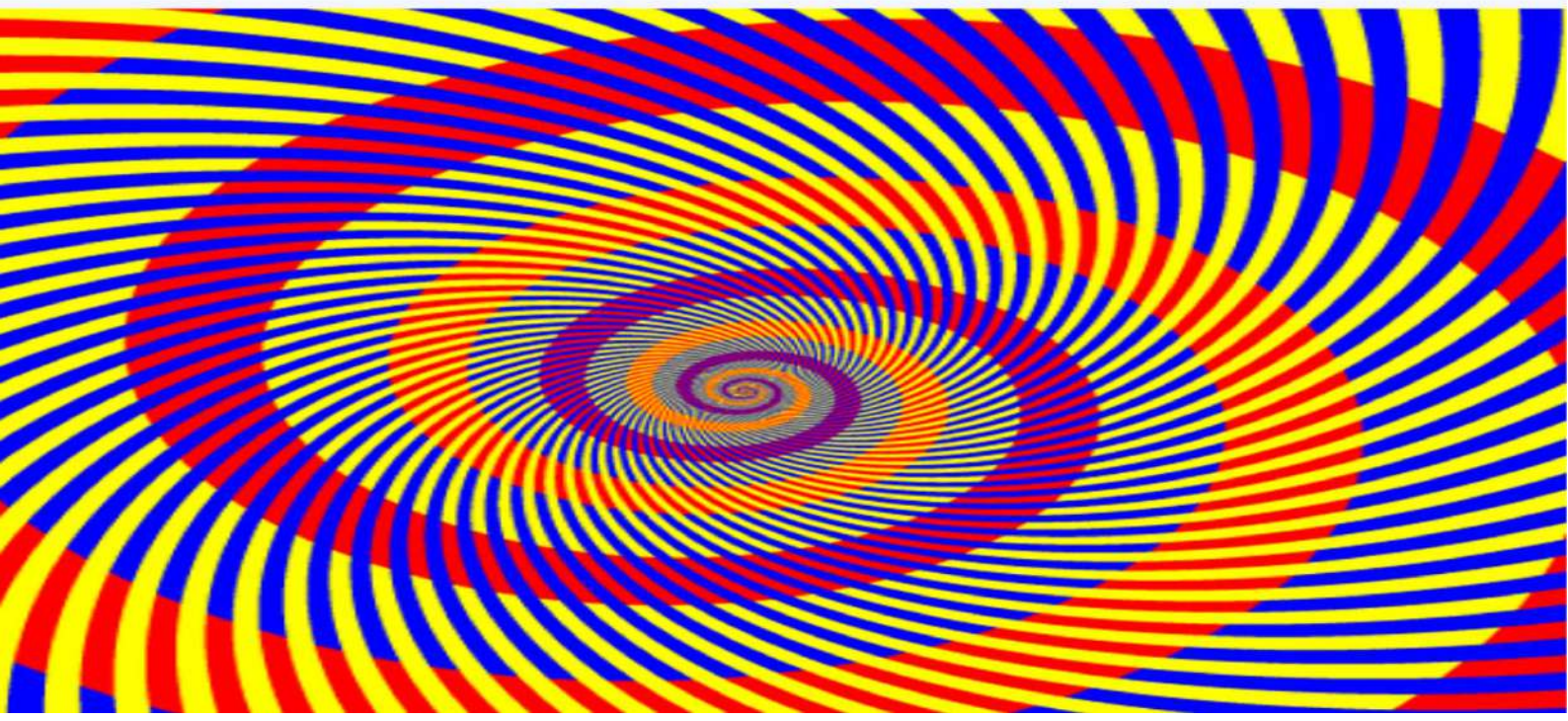
Table 6-9: Total NPV Cost of all Scenarios

#	Scenario	Total Cost NPV (Billion US \$)
1	Base Case	31.6
2	Low Demand	31.0
3	High Demand	32.2

6.9. Strategy for Feedback

There is no room bigger than the room for improvement. The IGCEP has been prepared after taking inputs from all the relevant agencies; the LF&GP-PSP Team is more than willing to discuss and incorporate further suggestions from the stakeholders to shape it into a meaningful output. As per PC4 of the Grid Code, NEPRA will review and approve the IGCEP. All kind of suggestions, comments and concerns are most welcome at **ce.glf@ntdc.com.pk**; **+92-42-99200695**. For wider dissemination and seeking generous feedback, the IGCEP 2021-30 would be published on the NTDC website.

7. THE WAY FORWARD



7. The Way Forward

A few suggestions are offered in this section to further enhance the contents and quality of the future editions of the IGCEP as well as the planning process on the whole.

7.1 Must Do Actions for the Future Generation Plans

- a. Demand Side Management (DSM) options other than energy efficiency targets, provided by NEECA for the IGCEP 2021-30, should also be studied and incorporated in the next iterations of the IGCEP by coordinating and working closely with all relevant entities in the country.
- b. Power generation policies should be regularly reviewed and updated to align the policy instruments with the latest trends in generation technologies and other factors that can influence both the demand and supply side of the electricity business.
- c. Planning process should be more comprehensive, both in scope and depth. Instead of yearly updating, the IGCEP should be revised every three (03) years. It will reduce unpredictability and will also minimize risks for the potential investors. Appropriate modification to this effect should be made in the Grid Code.
- d. Access to data and quality data must be facilitated and further improved. A central data repository may be formed to facilitate planners and policy makers, having specific data privileges and to ensure access to quality data, for data modeling and decision making. In a similar vein, project execution agencies should enhance and accelerate their response, with respect to provision of project data to NTDC, for updating of the IGCEP, in a precise and timely manner.
- e. Keeping in view the latest technological changes and latest advancements in the power supply and delivery business, customized trainings should be provided, especially for the power system planners, system operators, and DISCO staff.

7.2 Making Way for the High Share of Renewables in the Grid

Aggressive targets with respect to induction of renewable energy resources, set by the government and optimized through the generation planning software will need to be incorporated in the future plans to give these promising new options their due share in future supply portfolios:

7.2.1 Hybridization of Variable Renewable Energy Projects

- a. Though not envisaged in the prevailing schemes, wind power projects can provide grid support such as frequency regulation, voltage regulation, and reserve power provided hybridization is opted with solar PV as well as battery energy storage. Grid impact and economic implication studies for individual wind power plant will need to be carried out by the stakeholders.
- b. The combination of wind and solar has the advantage that the two sources will complement each other since the peak operating times for each system occur at different times of the day and year. The power generation of such a hybrid system including battery storage, is more continuous i.e. fluctuates less in terms of time and frequency if these are developed and operated jointly. Enabling environment including regulatory and

commercial arrangements as well as technical studies should be undertaken for this purpose to maximize the value of indigenous energy resources.

- c. All the stakeholders including the sponsors should join hands on setting up and sustaining an energy forecasting system with consensus on some suitable business model for the above purpose. This will significantly help in combatting the existing challenges with respect to despatch of renewable energy.

For the IGCEP 2021-30, NTDC was set to model hybrid RE technologies pursuant to Assumption Set approved by CCoE and for this purpose relevant project execution agencies were approached to provide input data. However, AEDB informed that they do not have the requisite data and intimated that a detailed technical & financial feasibility study would require to be undertaken for this purpose. Hence, due to non data provision (cost, hourly profile etc.) hybrid technologies are not modelled in the current iteration of the IGCEP. NTDC looks forward to the completion of this study for securing requisite data and utilize it for the next iteration of the IGCEP.

7.2.2 Upcoming Wind Power Projects

In order to utilize huge renewable resources potential of Pakistan in a sustainable manner, the wind power projects supported by appropriate energy storage should be able to provide the following grid support:

- a. Base load operation for certain number of hours
- b. Support in frequency control and regulation
- c. Reserve power even when the renewable resource is not available
- d. Support in maintaining the reactive power balance

Further, those technologies should be promoted which can be manufactured locally with the ultimate goal of achieving manufacturing of complete WTG including sophisticated control equipment. All stakeholders should try to maximize local value addition.

7.3 Future is Here - Time to Understand, Accept and Adopt the New Norms

A fundamental transformation is currently underway around the world in the way electricity is produced, transmitted, and delivered to end-users. The 'utility of the past' that relied primarily on large and central-station power generating facilities intertied through extensive and complex T&D grids to serve demand located far away from generation sites is now giving way to a new 'utility of the future' concept that strives to serve demand right at the spot through a blend of options including energy conservation, demand-side management, and distributed sources of power generation.

Power sector in Pakistan is also at a crossroads at the moment and in fact faces a defining moment in its history. Ample evidence already exists to suggest that the former approach to managing the power sector entities and their affairs is not proving successful. A continuation of business-as-usual approach in the power sector will be akin to inviting trouble not only for this particular sector but for the nation on the whole. It is high time, therefore, to abandon the old approach and replace it with a new flexible and adaptable approach to running this critical sector of the economy.

Pakistan's transition to 'utility of the future' will require a thorough revamping of the power sector's legal and regulatory frameworks, institutional structure, physical systems, business operating model, and leadership and managerial styles. As planning holds a critical enabling link in smoothly managing the above transition, the LF&GP-PSP Team would like to propose a brief description of how planning's role and scope should change in the future.

Unlike the past, the strategic horizon for the power sector has shrunk considerably, in particular, for power generation schemes. Five years is now a long-term for generation capacity expansion planning as small-scale and modular generation technologies, both conventional and non-conventional, are available for quick deployment with cost and performance features comparable, and in some cases even superior, to their large-sized competitors.

Though the typical lead-times for T&D schemes still remain more-or-less the same, the availability of inexpensive information and communication technologies (ICTs) is changing their role in a number of important ways. From just a conduit to transmit electricity from generating stations to end-users in the recent past, the T&D grid is now being designed to function as a smart and intelligent platform to enable a host of actors and business interests to come together in serving the society's electricity demands more cost-effectively, with superior reliability and quality, and in socially and environmentally sustainable ways.

Both planning and plans are assuming a new and critical role in the 'utility of the future'. Instead of providing their leaderships with iron-clad strategic plans for the next 10 years or so, planners are now called upon to help them in refining and crystallizing their crude and sketchy business ideas by studying the viability and implications of these ideas, in strategizing based on these insights, and in taking informed decisions on key business issues. The three critical building blocks of the future power sector planning will necessarily include: (i) a strong strategic foresight and technical expertise; (ii) an appropriate set of tools and skills; and (iii) a frequently updated data and information base on local conditions and emerging business and technology trends in the market.

Focus of planning should also shift now. From its previous concentration mainly on generation expansion schemes and planning the T&D systems just as add-ons and addendums to these plans, T&D systems will have to take a center-stage in the future planning of the power sector. While some large central-station power generation options such as hydroelectric, coal, and nuclear plants will continue to maintain their relevance in the 'utility of the future', a major share of future power generation will come from small, distributed, and dispersed technologies to be connected with the grid at its tail end at distribution voltage levels.

A new source of demand as well as supply will come from the electrified transportation sector of the country. The battery packs on the future electrical vehicles (EVs), if carefully planned and managed, will not only be a source of new demand on the system but could also contribute to improving the overall utilization of generation assets in the system by flattening the load curve. These EV-based battery-packs can also contribute to system support (ancillary) services to the grid which to this day are largely supplied by central-station power plants.

The future planning efforts will necessarily have to be evenly distributed among three levels: 'central planning', 'operational planning', and 'distributed resource planning', each requiring its own skills, tools, and data and information bases, and complementing the other two. Essentially, it builds on the idea that in the future the power system will be composed of micro-

and mini-grids (studies as well as pilot projects are required to be launched sooner than later for this purpose), mostly operating in an autonomous manner, but tied with each other through the national grid of the country.

Central Planning will mainly be of an indicative nature identifying the future electricity needs of the consumers in different parts of the country, assessing the resource and technology options available for serving the demands as much as possible at the spot and complementing the remaining demands from other regions and central-station facilities, and planning a robust transmission grid to facilitate that objective. Sufficient freedom should be provided to potential investors and developers to offer innovative, cost-competitive, and socio-economically acceptable power supply solutions. Coordination with other stakeholders of policy planning especially Planning Commission (or Ministry of Planning), Ministries of Oil & Gas, Finance, Industry & Commerce, and respective Ministries/Departments of Provinces, would be very essential for realistic central planning.

Operational Planning will essentially focus on optimal scheduling and despatch of transmission-connected generation to serve the residual demand that is left on the system after despatch of all local plants in the distribution systems. Operational planning will also be responsible with weather and renewable resource availability forecasting to maximize use of the intermittent and variable output from these plants and backing these up from the central grid resources for mitigating the intermittency and variability effects of RE generation.

Distributed Resource Planning will be carried out at the DISCO levels and will involve much more sophistication than the other two planning efforts stated above. It will be based on rigorous load research as well as local energy resource endowments and operating conditions to identify the most feasible option of serving consumer demand, through demand management options, behind-the-meter supplies, from a nearby located distributed plant, or from neighboring DISCO or central-station facilities.

7.4 Focusing on Indigenization through Harnessing the Potential of Local Coal

Thar coal reserves are estimated by the Geological Survey of Pakistan to be approximately 175 billion tons – making it one of the largest lignite coal reserves in the world. Thar coalfield, Block II area has exploitable lignite coal reserves of 1.57 billion tons. The total mining capacity of the project is due to be 20.6 MT/annum. (Source: Engro).

The power system planners should be communicated, by the project execution agencies, of the study-based analysis of block-wise potential of Thar coal that can be exploited for generation of electric power so it can be adequately modelled in the generation capacity expansion software for the next iterations. Similarly, the precision and authenticity of data and information pertaining to hydrology of upcoming hydro power projects needs to be validated by the concerned project execution agencies in the most meticulous manner.

7.5 Thinking, Synergizing and Enhancing the Vision Beyond the Borders

It is a well-known fact that there is a severe lack of research culture in the country. It is high time that concrete initiatives are taken to inculcate a thinking culture in the power sector of Pakistan. It is believed that initiatives like NEPRA Energy Week 2020 may pave the way for this very purpose provided NEPRA sustains its focus in this direction. Role of academia, which is currently restricted to at best a couple of initiatives, may be further encouraged and enhanced by launching certain projects especially envisioned for this purpose. Academia

along with the established think-tanks may add much needed value to the power sector interventions in all three segments. For this purpose, securing maximum benefits from the regional and international experience is critical. Power sector professionals need to know the success as well as failure stories of rest of the world in order to customize the best strategies for power sector of Pakistan. Perhaps our professionals and decision makers need to understand that borders are not the hurdles but opportunities for exponential growth.

7.6 Preparation and Submission of TSEP alongwith IGCEP

Pursuant to the directions by NEPRA dated 15th October 2020, NTDC is obligated to prepare TSEP along with IGCEP for submission to NEPRA, to maintain the true least cost principle at least for candidate projects optimized by the PLEXOS model. However, subsequent to approval of Assumption Set by CCoE and its notification on 28th April 2021, stringent timeline was set by Power Division for finalizing the report and, hence, NTDC could not prepare the TSEP at the time of submission of IGCEP to NEPRA.

Presently IGCEP is being submitted, whereas, TSEP will be submitted to NEPRA after carrying out detailed studies on the basis of IGCEP 2021-30. For the next submission of the IGCEP, NTDC would ensure simultaneous submission of TSEP to NEPRA.

ANNEXURES (A – D)



IGCEP 2021-30

ANNEXURES

Annexure A. Load Forecast Data

A-1. Projected GDP Growth by Sector – Normal Demand Scenario (Base Case)

Year	Gross Domestic Product (%)			
	Total	Agriculture	Industrial	Commercial
2019-20*	-0.38	2.67	-2.64	-0.59
2020-21	3.94**	2.77**	3.57**	4.43**
2021-22	4.00***	2.93	3.93	4.57
2022-23	4.50***	3.09	4.20	4.72
2023-24	5.00***	3.24	4.40	4.86
2024-25	5.00***	3.40	5.00	5.00
2025-26	5.00	3.40	5.00	5.00
2026-27	5.00	3.40	5.00	5.00
2027-28	5.00	3.40	5.00	5.00
2028-29	5.00	3.40	5.00	5.00
2029-30	5.00	3.40	5.00	5.00

* Economic Survey of Pakistan 2019-20.

** State bank of Pakistan

*** International Monetary Fund, World Economic Outlook database, April 2021.

A-2. Historical GDP at Factor Cost Constant 2005-06, Consumer Price Index

Year	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Agriculture	Industrial	Commercial		
	(Rs. Million)					
1970	1,267,148	521,916	186,873	579,134	3	-
1971	1,282,783	505,894	198,788	593,912	4	7.4%
1972	1,312,525	523,451	195,834	614,983	4	11.4%
1973	1,401,790	532,168	216,100	674,281	5	14.6%
1974	1,506,259	554,416	234,278	740,292	6	26.3%
1975	1,564,685	542,669	238,861	814,601	7	22.6%
1976	1,615,587	566,951	250,572	826,442	8	5.9%
1977	1,661,513	581,271	257,955	851,476	8	9.0%

Year	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Agriculture	Industrial	Commercial		
	(Rs. Million)					
1978	1,789,964	597,667	282,498	940,936	9	7.2%
1979	1,888,907	616,179	304,037	998,416	10	9.3%
1980	2,027,311	656,898	336,778	1,057,387	11	11.2%
1981	2,157,094	680,931	368,373	1,126,941	13	15.0%
1982	2,320,205	713,097	407,931	1,215,949	14	7.8%
1983	2,477,711	744,506	428,075	1,328,322	14	7.0%
1984	2,576,152	708,587	458,308	1,433,216	15	6.7%
1985	2,800,486	785,995	494,209	1,546,770	17	7.8%
1986	2,978,681	832,752	534,241	1,636,012	17	3.5%
1987	3,151,767	859,847	580,428	1,731,923	18	5.6%
1988	3,354,619	883,332	637,433	1,849,120	20	7.4%
1989	3,515,920	944,020	667,081	1,919,566	21	8.1%
1990	3,677,255	972,630	709,973	2,005,528	23	9.1%
1991	3,881,980	1,020,893	758,666	2,110,021	26	12.6%
1992	4,181,463	1,117,891	817,322	2,252,633	28	9.4%
1993	4,276,440	1,058,799	862,378	2,357,019	31	9.1%
1994	4,470,624	1,114,148	901,548	2,456,064	35	11.9%
1995	4,655,373	1,187,322	907,776	2,573,905	39	12.1%
1996	4,962,585	1,326,513	950,655	2,702,388	43	10.3%
1997	5,047,083	1,328,153	947,564	2,799,969	48	12.5%
1998	5,223,424	1,388,155	1,005,511	2,846,025	51	6.5%
1999	5,441,961	1,415,205	1,054,993	2,988,080	53	3.7%
2000	5,654,536	1,501,445	1,068,409	3,112,150	56	5.1%
2001	5,765,774	1,468,754	1,112,558	3,208,310	57	2.5%
2002	5,945,199	1,470,272	1,142,575	3,361,116	59	3.7%
2003	6,226,156	1,531,248	1,190,981	3,536,447	61	1.9%

Year	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Agriculture	Industrial	Commercial		
	(Rs. Million)					
2004	6,692,079	1,568,451	1,384,670	3,743,003	66	8.5%
2005	7,291,537	1,670,176	1,552,429	4,060,859	71	8.7%
2006	7,715,777	1,775,346	1,616,157	4,324,274	77	7.6%
2007	8,142,969	1,836,125	1,741,085	4,565,759	82	7.0%
2008	8,549,148	1,869,310	1,888,600	4,791,238	100	21.5%
2009	8,579,987	1,934,691	1,790,263	4,855,033	117	17.0%
2010	8,801,394	1,939,132	1,851,565	5,010,697	129	10.1%
2011	9,120,336	1,977,178	1,935,022	5,208,136	146	13.7%
2012	9,470,255	2,048,794	1,984,316	5,437,145	163	11.0%
2013	9,819,055	2,103,600	1,999,207	5,716,248	175	7.4%
2014	10,217,056	2,156,117	2,089,776	5,971,163	190	8.6%
2015	10,631,649	2,202,043	2,198,027	6,231,579	198	4.5%
2016	11,116,802	2,205,433	2,323,169	6,588,200	204	2.9%
2017	11,696,934	2,253,565	2,428,902	7,014,467	212	4.2%
2018	12,343,500	2,342,373	2,548,496	7,452,631	221	3.9%
2019	12,580,174	2,357,095	2,483,243	7,739,836	237	7.3%
2020	12,531,790	2,420,109	2,417,615	7,694,066	262	10.4%

A-3. Category-Wise Nominal Tariff

Nominal Tariff (Excluding K Electric)									
Year	Dom	Com	Ind	Agr	Year	Dom	Com	Ind	Agr
	Paisa/kWh								
1971	20	25	13	8	1996	136	537	336	131
1972	20	26	14	9	1997	156	566	375	163
1973	20	27	14	10	1998	185	655	411	187
1974	20	32	18	11	1999	235	718	448	233
1975	21	36	21	12	2000	233	704	416	231
1976	23	46	28	16	2001	259	704	416	258
1977	25	53	34	16	2002	318	708	419	293
1978	24	60	37	14	2003	334	703	442	333
1979	29	72	46	21	2004	434	685	446	351
1980	35	95	57	28	2005	340	660	425	349
1981	40	100	63	32	2006	345	1,003	425	340
1982	42	108	68	36	2007	376	821	517	364
1983	43	118	76	38	2008	464	946	568	429
1984	44	121	76	43	2009	540	1,154	748	502
1985	44	123	78	38	2010	656	1,324	894	615
1986	49	143	92	43	2011	731	1,490	960	799
1987	48	140	89	37	2012	841	1,664	1,090	935
1988	52	171	111	40	2013	873	1,793	1,220	1,003
1989	62	213	133	46	2014	948	2,127	1,583	1,202
1990	66	246	150	55	2015	1,022	2,224	1,539	1,400
1991	76	276	166	57	2016	1,048	2,017	1,375	1,266
1992	81	316	189	63	2017	1,065	2,022	1,412	1,064
1993	84	331	199	66	2018	1,114	2,104	1,492	1,125
1994	96	386	229	74	2019	1,300	2,600	1,800	1,100
1995	110	427	268	94	2020	1,362	2,977	2,318	1,060

A-4. Category wise Real Tariff

Real Tariff (Excluding K Electric)									
Year	Dom	Com	Ind	Agr	Year	Dom	Com	Ind	Agr
	Paisa/kWh								
1971	543	685	353	210	1996	318	1,254	785	305
1972	494	635	338	221	1997	323	1,174	778	338
1973	421	567	305	213	1998	361	1,277	801	365
1974	336	538	298	181	1999	441	1,351	843	439
1975	288	499	293	165	2000	417	1,259	745	413
1976	300	605	366	202	2001	452	1,228	726	450
1977	299	638	401	188	2002	536	1,192	704	493
1978	270	665	417	160	2003	551	1,160	730	550
1979	291	731	471	214	2004	661	1,043	679	534
1980	317	868	524	261	2005	476	924	595	489
1981	316	798	503	256	2006	449	1,304	553	442
1982	308	797	501	265	2007	457	998	628	442
1983	299	816	522	266	2008	464	946	568	429
1984	284	786	495	276	2009	461	986	639	429
1985	264	737	472	231	2010	509	1,028	694	477
1986	288	830	534	251	2011	499	1,017	656	546
1987	262	768	490	203	2012	517	1,024	670	575
1988	268	878	570	204	2013	500	1,027	699	575
1989	295	1,012	631	217	2014	500	1,122	835	634
1990	287	1,068	653	237	2015	516	1,122	777	706
1991	294	1,066	639	218	2016	514	990	675	621
1992	284	1,113	666	223	2017	502	952	665	501
1993	272	1,070	643	214	2018	505	954	676	510
1994	277	1,113	661	213	2019	549	1,098	760	465
1995	284	1,101	691	241	2020	521	1,138	886	405

A-5. Electricity Consumption by Category (Excluding K Electric)

Year	Dom	Com	Ind	Agr	Street-Light	Bulk	Others	Exp to KE	Total
	GWh								
1970	367	125	1,646	956	20	487	0	0	3,600
1971	382	152	1,689	1,080	24	638	0	0	3,966
1972	392	142	2,109	997	75	422	0	0	4,137
1973	462	165	2,236	1,184	22	530	0	0	4,599
1974	523	179	2,267	1,142	20	569	42	0	4,742
1975	566	184	2,245	1,531	20	604	63	0	5,212
1976	678	222	2,262	1,386	26	697	45	0	5,315
1977	780	246	2,357	1,400	29	597	43	0	5,452
1978	1,004	305	2,596	1,718	42	784	42	0	6,490
1979	1,240	336	2,770	1,666	70	856	43	0	6,981
1980	1,564	389	3,154	2,057	50	900	46	0	8,160
1981	1,858	445	3,482	2,125	58	1,056	44	0	9,068
1982	2,408	574	3,960	2,357	74	873	42	0	10,288
1983	2,866	634	4,427	2,546	78	992	44	0	11,587
1984	3,470	739	4,708	2,663	75	1,069	38	0	12,762
1985	3,887	796	5,061	2,783	77	1,115	37	0	13,756
1986	4,513	875	5,894	2,880	90	1,215	36	0	15,504
1987	5,357	991	6,436	3,452	110	1,361	38	0	17,745
1988	6,290	1,054	7,236	4,394	117	1,571	40	0	20,702
1989	6,939	1,068	7,578	4,356	127	1,795	35	82	21,982
1990	7,647	1,106	8,360	5,004	148	1,646	38	171	24,121
1991	8,617	1,152	9,115	5,596	178	1,700	33	194	26,585
1992	9,691	1,192	10,213	5,823	229	1,799	29	292	29,267
1993	11,220	1,303	10,913	5,595	195	1,925	27	94	31,272
1994	11,963	1,318	10,532	5,743	216	1,964	27	368	32,131
1995	13,448	1,490	10,604	6,220	252	2,112	22	884	35,032

Year	Dom	Com	Ind	Agr	Street-Light	Bulk	Others	Exp to KE	Total
	GWh								
1996	14,792	1,648	10,335	6,657	301	2,377	20	795	36,925
1997	15,594	1,757	10,115	7,018	308	2,485	19	1,233	38,529
1998	16,367	1,768	10,238	6,888	307	2,694	16	1,145	39,422
1999	16,927	1,825	9,945	5,575	159	2,646	15	1,808	38,900
2000	18,942	2,003	10,773	4,512	150	2,676	15	1,840	40,910
2001	20,019	2,120	11,744	4,896	146	2,634	14	1,811	43,384
2002	20,549	2,285	12,637	5,582	149	2,662	12	1,329	45,204
2003	20,855	2,516	13,462	5,986	166	2,626	10	1,801	47,421
2004	22,668	2,884	14,476	6,624	192	2,796	9	1,843	51,492
2005	24,049	3,192	15,568	6,921	227	2,892	12	2,416	55,278
2006	27,009	3,768	16,596	7,873	279	3,031	13	3,836	62,405
2007	28,944	4,289	17,603	8,097	316	3,252	13	4,905	67,419
2008	28,711	4,358	17,299	8,380	340	3,319	11	4,072	66,489
2009	27,755	4,203	16,035	8,695	347	3,188	10	5,014	65,248
2010	29,479	4,465	16,372	9,585	371	3,357	10	5,208	68,847
2011	30,972	4,683	17,700	8,847	374	3,607	10	5,449	71,642
2012	30,365	4,563	18,403	8,414	360	3,509	43	5,684	71,341
2013	30,329	4,435	18,636	7,548	351	3,659	60	5,463	70,481
2014	33,325	4,795	20,550	8,130	351	3,872	32	5,441	76,496
2015	34,567	4,853	21,086	7,866	330	3,909	33	5,427	78,071
2016	37,123	5,417	21,150	8,364	295	4,239	34	5,059	81,682
2017	41,412	6,114	20,067	9,063	298	4,566	31	5,077	86,628
2018	46,114	6,753	23,274	9,978	319	5,014	450	5,128	97,030
2019	45,590	6,629	24,285	9,676	291	5,082	2,335	4,957	98,844
2020	47,643	6,260	21,489	9,642	273	4,887	2,597	5,426	98,197

A-6. Category Wise Number of Consumers (Exclduing K Electric)

Year	Dom	Com	Ind	Agr	Street Light	Bulk & Others	Total
	Numbers						
1971	930,350	238,147	64,494	50,212	587	434	1,284,224
1972	998,922	258,328	67,056	52,343	663	477	1,377,789
1973	1,070,192	275,273	72,158	58,472	684	530	1,477,309
1974	1,137,676	300,219	78,277	63,730	718	534	1,581,154
1975	1,232,621	322,252	80,730	69,687	740	560	1,706,590
1976	1,347,122	347,167	85,250	76,508	801	524	1,857,372
1977	1,498,747	376,284	91,365	81,813	926	722	2,049,857
1978	1,670,213	422,901	95,036	90,341	1,018	832	2,280,341
1979	1,866,550	462,950	100,946	95,666	1,315	787	2,528,214
1980	2,049,728	471,757	101,228	98,268	1,477	821	2,723,279
1981	2,479,453	571,800	111,484	104,108	2,090	1,010	3,269,945
1982	2,732,903	624,900	115,890	111,278	2,161	1,118	3,588,250
1983	2,989,397	674,600	119,417	114,390	2,390	1,225	3,901,419
1984	3,261,362	724,462	123,508	118,265	2,511	1,428	4,231,536
1985	3,500,171	770,465	128,441	120,905	2,447	1,541	4,523,970
1986	3,779,838	834,127	133,573	124,918	2,647	1,684	4,876,787
1987	4,106,424	898,118	139,537	130,034	2,801	1,772	5,278,686
1988	4,525,987	964,377	147,439	136,860	3,017	1,943	5,779,623
1989	5,077,686	1,039,033	153,042	143,869	3,462	2,075	6,419,167
1990	5,467,690	1,088,932	158,800	149,554	3,453	2,250	6,870,679
1991	5,805,382	1,134,754	162,624	152,169	3,531	2,261	7,260,721
1992	6,219,656	1,185,723	169,436	155,305	3,759	2,362	7,736,241
1993	6,622,977	1,221,223	172,145	153,088	3,829	2,488	8,175,750
1994	6,995,561	1,257,887	174,577	157,710	3,730	2,577	8,592,042
1995	7,376,032	1,342,946	179,392	162,303	3,954	2,649	9,067,276
1996	7,783,832	1,344,975	181,092	165,114	3,990	2,728	9,481,731
1997	8,154,894	1,354,940	184,301	167,245	4,064	3,168	9,868,612
1998	8,455,442	1,396,973	186,539	170,562	4,645	2,911	10,217,072
1999	8,911,587	1,517,199	190,084	173,078	4,708	2,979	10,799,635
2000	9,553,828	1,653,870	194,566	174,456	4,892	3,045	11,584,657

Year	Dom	Com	Ind	Agr	Street Light	Bulk & Others	Total
	Numbers						
2001	10,045,035	1,737,199	195,511	180,411	4,993	3,195	12,166,344
2002	10,482,804	1,803,132	199,839	184,032	4,854	3,361	12,678,022
2003	11,043,530	1,867,226	206,336	191,961	5,441	3,739	13,318,233
2004	11,737,078	1,935,462	210,296	198,829	5,800	3,873	14,091,338
2005	12,490,189	1,983,216	212,233	200,756	6,171	3,677	14,896,242
2006	13,389,762	2,068,312	222,283	220,501	6,550	3,753	15,911,161
2007	14,354,365	2,151,971	233,162	236,255	6,990	3,811	16,986,554
2008	15,226,711	2,229,403	242,401	245,640	7,337	3,874	17,955,366
2009	15,859,373	2,291,628	253,089	258,368	7,680	3,976	18,674,114
2010	16,673,015	2,362,312	263,507	271,268	8,034	4,088	19,582,224
2011	17,322,140	2,421,221	273,067	280,603	8,386	4,066	20,309,483
2012	17,978,395	2,482,702	286,401	286,287	8,698	4,128	21,046,611
2013	18,713,537	2,550,808	296,849	301,115	9,107	4,184	21,875,600
2014	19,323,307	2,635,086	305,294	310,578	9,369	4,236	22,587,870
2015	20,148,495	2,723,708	315,116	318,081	9,554	4,293	23,519,247
2016	21,040,707	2,814,234	325,816	321,055	9,857	5,030	24,516,699
2017	21,991,479	2,905,517	336,045	323,524	10,124	5,114	25,571,803
2018	23,173,856	3,028,054	339,853	315,021	10,426	149,335	27,016,545
2019	24,465,300	3,144,247	342,949	326,656	10,567	183,350	28,473,069
2020	25,803,759	3,245,508	348,087	344,690	10,932	204,393	29,957,369

Annexure B. Generation Planning Data

B-1. Existing Installed Capacity (As of May 2021)

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
Public Sector				
WAPDA Hydro				
1	Allai Khwar	Hydro	121	121
2	Chashma	Hydro	184	184
3	Dubair Khwar	Hydro	130	130
4	Ghazi Brotha	Hydro	1,450	1,450
5	Golen Gol	Hydro	108	108
6	Jinnah	Hydro	96	96
7	Khan Khwar	Hydro	72	72
8	Mangla	Hydro	1,000	1,000
9	Nelum Jehlum	Hydro	969	969
10	Small Hydel	Hydro	128	128
11	Tarbela 1-14	Hydro	3,478	3,478
12	Tarbela_Ext_04	Hydro	1,410	1,410
13	Warsak	Hydro	243	243
Sub Total: WAPDA Hydro (MW)			9,389	9,389
GENCOs				
14	Jamshoro - I U1	RFO	250	200
15	Jamshoro - II U4	RFO	200	170
Sub Total: GENCos – I (MW)			450	370
16	Guddu - I U(11-13)	Gas	415	391
17	Guddu - II U(5-10)	Gas	620	537
18	Guddu 747	Gas	747	721
Sub Total: GENCos – II (MW)			1,782	1,649
19	Muzaffargarh - I U1	RFO	210	190
20	Muzaffargarh - I U2	RFO	210	183
21	Muzaffargarh - I U3	RFO	210	184

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
22	Muzaffargarh - II U4	RFO	320	272
23	GTPS Block 4 U(5-9)	RLNG	144	114
24	Nandipur	RLNG	525	491
Sub Total: GENCOs – III (MW)			1,619	1,434
Total GENCOs (Public Sector) (MW)			3,851	3,453
Private Sector				
Nuclear				
25	CHASHNUPP - I	Nuclear	325	300
26	CHASHNUPP-II	Nuclear	340	300
27	CHASHNUPP-III	Nuclear	340	315
28	CHASHNUPP-IV	Nuclear	340	315
29	K-2	Nuclear	1,145	1,059
Sub Total: Nuclear (MW)			2,490	2,289
Hydel IPPs				
30	Jagran - I	Hydro	30.4	30.4
31	Malakand - III	Hydro	81	81
32	New Bong	Hydro	84	84
33	Darwal Khwar	Hydro	36.6	36.6
34	Gul Pur	Hydro	102	102
35	Patrind	Hydro	150	150
Sub Total: IPPs Hydro (MW)			484	484
Thermal IPPs				
36	AES Pakgen	RFO	365	335
37	AGL	RFO	163	153
38	Altern	Gas	31	26
39	Atlas	RFO	219	209
40	Balloki	RLNG	1,223	1,147
41	Bhikki	RLNG	1,180	1,108
42	China HUBCO	Imp. Coal	1,320	1,249
43	Davis	RLNG	14	10

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
44	Engro	Gas	226	205
45	Engro Thar	Local Coal	660	545
46	FKPCL	RLNG	172	147
47	Foundation	Gas	184	161
48	Halmore	RLNG	225	191
49	Haveli	RLNG	1,231	1,158
50	HuB N	RFO	225	208
51	HUBCO	RFO	1,292	1,108
52	KAPCO 1	RFO	400	344
53	KAPCO 2	RFO	900	743
54	KAPCO 3	RFO	300	258
55	Kohinoor	RFO	131	117
56	Lalpir	RFO	362	338
57	Liberty	Gas	225	208
58	Liberty Tech	RFO	202	192
59	Nishat C	RFO	209	191
60	Nishat P	RFO	202	191
61	Oreint	RLNG	225	197
62	Port Qasim	Imp. Coal	1,320	1,243
63	Rousch	RLNG	450	389
64	Saba	RFO	136	112
65	Sahiwal Coal	Imp. Coal	1,320	1,244
66	Saif	RLNG	225	197
67	Sapphire	RLNG	225	196
68	Uch	Gas	586	535
69	Uch-II	Gas	393	370
Sub Total (IPPs Fossil Fuels) (MW)			16,541	15,025
Bagasse Based Power Projects				
70	Almoiz	Bagasse	36	36
71	Chanar	Bagasse	22	22

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
72	Chiniot	Bagasse	63	63
73	Hamza	Bagasse	15	15
74	JDW - II	Bagasse	26	26
75	JDW - III	Bagasse	26	26
76	Ryk_Mills	Bagasse	30	30
77	Thal_Layyah	Bagasse	41	41
Sub Total Bagasse (MW)			259	259
Wind Power Projects				
78	Act	Wind	30.0	30.0
79	Artistic_wind	Wind	49.3	49.3
80	FFC	Wind	49.5	49.5
81	FWEL-I	Wind	50.0	50.0
82	FWEL-II	Wind	50.0	50.0
83	Gul Ahmed	Wind	50.0	50.0
84	Hawa	Wind	49.7	49.7
85	Jhimpir	Wind	49.7	49.7
86	Master	Wind	52.8	52.8
87	Metro_Power	Wind	50.0	50.0
88	Sachal	Wind	49.5	49.5
89	Sapphire_Wind	Wind	52.8	52.8
90	Three_Gorges_I	Wind	49.5	49.5
91	Three_Gorges_II	Wind	49.5	49.5
92	Three_Gorges_III	Wind	49.5	49.5
93	Tricon_A	Wind	49.7	49.7
94	Tricon_B	Wind	49.7	49.7
95	Tricon_C	Wind	49.7	49.7
96	UEP	Wind	99.0	99.0
97	Yunus	Wind	50.0	50.0
98	Zorlu_Wind	Wind	56.4	56.4
Sub Total Wind Power Plants (MW)			1,086	1,086

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
Solar Power Projects				
99	Appolo Solar	Solar	100	100
100	Best	Solar	100	100
101	Crest	Solar	100	100
102	QA_Solar	Solar	100	100
Sub Total Solar Power Plants (MW)			400	400
Total Public Sector (MW)			13,240	12,842
Total Private Sector (MW)			21,261	19,543
Total Installed Capacity / Capability (MW)			34,501	32,385

B-2. Cost Data of Existing, Committed and Candidate Thermal Plants

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	FLD Cost
			(\$/KW/Year)	(\$/MWh)	(\$/GJ)	(GJ/MWh)	(\$/MWh)
Existing Power Plants							
GENCOs							
1	GTPS Faisalabad-Block 4 U(5-9)	RLNG	28.3	0.98	7.27	9.56	70.51
2	Guddu 747 CC	Gas	175.46	3.31	4.88	7.32	39.04
3	Guddu-I U(11-13)	Gas	18.85	0.41	4.88	13.50	66.33
4	Guddu-II U(5-10)	Gas	18.85	0.41	4.88	10.00	49.24
5	Jamshoro-I U1	RFO	757.50	0.56	8.05	11.46	92.78
6	Jamshoro-II U4	RFO	757.50	0.56	7.47	11.89	89.31
7	Muzaffargarh-I U1	RFO	28.3	3.29	7.27	11.92	89.96
8	Muzaffargarh-I U2	RFO	28.3	0.98	7.27	12.08	88.79
9	Muzaffargarh-I U3	RFO	28.3	0.98	7.27	11.67	85.84
10	Muzaffargarh-II U4	RFO	28.3	0.98	7.27	11.66	85.72
11	Nandipur	RLNG	17.61	3.74	8.05	7.35	62.89
IPPs							
12	AES Pakgen	RFO	21.6	1.7	8.29	9.81	83.00
13	AGL	RFO	26.76	9.06	7.89	8.40	75.37

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	FLD Cost
			(\$/KW/Year)	(\$/MWh)	(\$/GJ)	(GJ/MWh)	(\$/MWh)
14	Altern	Gas	102.83	6.8	7.71	9.79	82.25
15	ATLAS	RFO	22.51	8.94	8.72	8.40	82.16
16	Balloki	RLNG	16.98	1.28	7.27	6.57	49.02
17	Bhikki	RLNG	17.81	3.31	7.27	6.58	51.13
18	C-1	Uranium	145	0	0.55	10.91	6.00
19	C-2	Uranium	135	0	0.55	10.91	6.00
20	C-3	Uranium	110	0	0.55	10.91	6.00
21	C-4	Uranium	110	0	0.55	10.91	6.00
22	K-2	Uranium	35	0	0.49	9.73	4.77
23	China HUBCO	Imp.Coal	24.56	3.07	2.92	9.54	30.95
24	Davis	RLNG	41.28	5.1	7.71	9.90	81.40
25	Engro	Gas	17.65	3.25	5.41	8.17	47.48
26	Engro Thar	Local Coal	26.28	6.49	1.67	9.72	22.67
27	FKPCL	RLNG	21.6	7.45	5.46	12.20	74.09
28	Foundation	Gas	24.76	3.68	5.41	7.68	45.20
29	Halmore	RLNG	19.44	3.78	8.05	7.25	62.11
30	Haveli	RLNG	16.82	1.14	7.27	6.52	48.50
31	HuB N	RFO	22.85	8.05	9.36	8.00	82.99
32	HUBCO	RFO	36.05	1.42	10.58	9.83	105.41
33	KAPCO 1	RFO	22.6	2.63	7.27	8.38	63.56
34	KAPCO 2	RFO	22.6	3.08	7.27	9.19	69.91
35	KAPCO 3	RFO	22.6	5.93	7.27	9.51	75.05
36	Kohinoor	RFO	21.6	5.93	8.51	8.86	81.39
37	Lalpir	RFO	21.6	1.7	7.60	9.81	76.25
38	Liberty	Gas	77.99	3.29	6.30	8.08	54.16
39	Liberty Tech	RFO	23.39	1.7	8.31	9.09	77.26
40	Nishat C	RFO	23.29	8.92	9.03	8.40	84.77
41	Nishat P	RFO	23.33	8.94	9.02	8.40	84.72
42	Orient	RLNG	26.4	2.21	8.05	7.25	60.58
43	Port Qasim	Imp.Coal	26.29	1.16	2.96	8.99	27.79

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	FLD Cost
			(\$/KW/Year)	(\$/MWh)	(\$/GJ)	(GJ/MWh)	(\$/MWh)
44	Rousch	RLNG	21.6	2.78	7.27	8.84	67.03
45	Saba	RFO	21.6	1.7	8.71	9.69	86.14
46	Sahiwal Coal	Imp.Coal	24.56	1.15	4.63	8.92	42.41
47	Saif	RLNG	19.91	3.77	8.05	7.25	62.14
48	Sapphire	RLNG	19.18	3.73	8.05	7.24	62.06
49	Uch	Gas	33.86	2.37	3.72	10.86	42.76
50	Uch-II	Gas	25.38	2.14	5.37	8.21	46.23
Committed Power Plants							
51	Gwadar	Imp.Coal	33.27	1.13	2.99	9.66	30.07
52	Jamshoro Coal U-I	Imp.Coal	4.15	2.44	4.35	8.71	40.28
53	K-3	Uranium	35	0	0.55	9.73	5.35
54	Lucky	Local Coal	25.13	3.03	2.59	9.23	26.93
55	Siddiqsons	Local Coal	24.76	5.61	1.67	9.23	20.98
56	Thal Nova	Local Coal	26.88	5.92	1.67	9.73	22.12
57	Thar TEL	Local Coal	26.88	5.92	1.67	9.73	22.12
58	Thar-I (Shanghai Electric)	Local Coal	25.1	5.92	1.67	9.23	21.29
59	Trimmu	RLNG	12.94	2.98	7.27	5.89	45.77
Candidate Power Plants							
60	C-5	Uranium	43	0	0.49	9.73	4.77
61	Hybrid Muzaffargarh	RLNG	16.42	2.08	5.55	6.00	35.35
62	Jamshoro Coal Unit 2	Imp.Coal	4.15	2.44	4.35	8.71	40.28
63	K-4	Uranium	43	0	0.49	9.73	4.77
64	K-5	Uranium	43	0	0.49	9.73	4.77
65	KAPCO Coal	Imp.Coal	28.36	1.29	2.79	9.23	27.08
66	M-1	Uranium	43	0	0.49	9.73	4.77
67	M-2	Uranium	43	0	0.49	9.73	4.77
68	New_CCGT	RLNG	12.94	2.98	7.27	5.89	45.77
69	New_Imp.Coal	Imp.Coal	24.56	3.07	2.92	9.23	30.04
70	New_Local_Coal	Local Coal	24.76	5.61	1.67	9.23	20.98
71	New_Nuclear	Uranium	43	0	0.49	9.73	4.77

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	FLD Cost
			(\$/KW/Year)	(\$/MWh)	(\$/GJ)	(GJ/MWh)	(\$/MWh)
72	New_OCGT	RLNG	12.94	2.98	7.27	9.46	71.78
73	RYK Coal	Imp.Coal	33.2	0.91	5.40	9.01	49.57

B-3. Indexed Capital Cost Calculations of Candidate Hydro Power Plants

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
1	Alka	1.8	2.5	2	4.5	2.07	2.19	4.25	2,362
2	Arkari Gol	99	137.25	77.3	214.55	112.89	83.63	196.52	1,985
3	Artistic-I	62.606	187.47	49.37	236.84	178.79	49.89	228.68	3,653
4	Artistic-II	55.032	101.8646	31.9815	133.8461	97.15	32.32	129.47	2,353
5	Ashkot	300	0	780.306	780.306	0.00	863.85	863.85	2,880
6	Asrit Kedam	215	266.9667	143.75	410.7167	255.81	147.81	403.62	1,877
7	Athmuqam	450	0	1301.3	1301.3	0.00	1341.99	1341.99	2,982
8	Balakot-II	100	283	94.33	377.33	269.90	95.32	365.22	3,652
9	Balkani	7.7	17	7	24	16.21	7.07	23.29	3,024
10	Balmi	2	2.24	0.96	3.2	2.14	0.97	3.11	1,553
11	Bankhwar	35	67.17	25.91	93.08	64.06	26.18	90.24	2,578
12	Basho	40	72.3	37.85	110.15	59.69	41.35	101.05	2,526
13	Bata Kundi	96	108.42	79.87	188.29	90.68	87.28	177.96	1,854
14	Batdara	4.8	5.3	2.3	7.5	5.01	2.27	7.28	1,517
15	Bhango	2.1	2.35	1.01	3.36	2.24	1.02	3.26	1,553
16	Bhedi Doba	1	1.2	0.5	1.7	0.96	0.55	1.51	1,512
17	Bheri -II	2.85	4.422	1.56	5.982	3.99	1.79	5.78	2,027
18	Bhimbal Katha	26	30	32	62	28.77	33.00	61.77	2,376

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
19	BS Link Tail	9	11.34	7.56	18.9	9.42	8.28	17.70	1,966
20	Bunji	7100	9119.6	4378.6	13498.2	8284.25	4902.00	13186.24	1,857
21	Chakoti Hatian	500	0	983.12	983.12	0.00	1088.38	1088.38	2,177
22	Chamfall	3.2	3.1	1.4	4.5	2.99	1.37	4.37	1,365
23	Chenawan	3	4.5	3	7.5	4.79	3.60	8.38	2,795
24	Chicha Watni	1.6	2.2	1.8	4	1.81	1.95	3.76	2,348
25	Chiniot_HPP	80	188.85	25.75	214.6	187.10	26.09	213.19	2,665
26	Chowkel Khwar	60	70	50	120	66.76	50.53	117.29	1,955
27	CJ	25	28.5	19	47.5	22.80	20.46	43.26	1,730
28	Daar	3	3.36	1.44	4.8	3.20	1.46	4.66	1,553
29	Daral Khwar-II	9.5	21.257	7.862	29.119	20.37	8.08	28.45	2,995
30	Dasu (Stage-I & II)	2160	2924.326	2185.475	5109.801	2414.37	2387.74	4802.12	2,223
31	DG Khan	4.65	5.85	3.906	9.756	5.13	4.03	9.16	1,970
32	Dhadar	18.18	36.75	12.25	49	30.23	13.25	43.48	2,392
33	Dhani	48	53.76	23.04	76.8	51.27	23.28	74.55	1,553
34	Dowarian	40	42.0	18.0	60.0	40.06	18.19	58.25	1,456
35	Gabral Kalam	88	87.02	77.57	164.59	94.19	78.73	172.92	1,965
36	Gabral Utror	79	147.01	52.64	199.65	140.21	53.19	193.40	2,448
37	Gahret	377	1351.03	486.59	1837.62	1132.45	538.69	1671.14	4,433

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
38	Garhi Habibullah	100	252.9	84.3	337.2	241.19	85.19	326.38	3,264
39	Gharata	1.7	2.98	1.28	4.26	2.84	1.29	4.14	2,433
40	Ghorband	20.6	0	69.366	69.366	0.00	77.36	77.36	3,755
41	Gugera	3.6	5.16	3.44	8.6	4.13	3.70	7.83	2,176
42	Gumat Nar	49.5	0	163.453	163.453	0.00	179.90	179.90	3,634
43	Gurha	1.5	1.68	0.72	2.4	1.60	0.73	2.33	1,553
44	Gwaldai	20.4	51.37	0	51.37	48.99	0.00	48.99	2,402
45	Harigehl-Majeedgala	40.32	70.301	37.858	108.159	58.04	41.36	99.40	2,465
46	Hundi	3.5	3.92	1.68	5.6	3.74	1.70	5.44	1,553
47	Istaro-Booni	72	150	110	260	137.89	122.25	260.14	3,613
48	Jabri Bedar	3.6	10.435	1.95	12.385	8.75	2.16	10.91	3,029
49	Jagran-III	35	64.64	60.98	125.62	58.27	69.96	128.24	3,664
50	Jagran-IV	22	27.4	11.8	39.2	26.14	11.87	38.02	1,728
51	Jamshil	610	844	691.2	1535.2	836.20	700.25	1536.45	2,519
52	Janawai	12	13.44	5.76	19.2	12.82	5.82	18.64	1,553
53	Javed-III	65	119.34	39.78	159.12	113.82	40.20	154.02	2,369
54	Javed-IV	45	82.6	27.5	110.2	78.80	27.83	106.63	2,369
55	Jhing-II	6.05	10.0	8.1	18.1	8.36	8.80	17.16	2,836
56	Kaigah-II	39.6	59.23	60.69	119.92	48.05	63.95	112.00	2,828

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
57	Kalam Asrit	238	281.613	152.522	434.135	268.58	154.13	422.71	1,776
58	Kalamula	2.2	2.46	1.06	3.52	2.35	1.07	3.42	1,553
59	Kalkot Barikot	47	113.1	29.4	142.5	100.67	32.81	133.48	2,840
60	Kappa-II	2	2.1	0.9	3.0	2.00	0.91	2.91	1,456
61	Kari Mashkur	495	761.04	403.53	1164.57	823.72	409.56	1233.28	2,491
62	Kasorkot Talwari	2.9	3.05	1.31	4.36	2.91	1.32	4.23	1,460
63	Kasur	2.45	2.9	2.0	4.9	2.35	2.11	4.46	1,821
64	Kathai-III	1.2	1.9	0.5	2.4	1.56	0.55	2.11	1,755
65	Khanewal	1	1.5	1	2.5	1.18	1.06	2.24	2,240
66	Khanki Barrage	14	17.7	11.8	29.5	12.59	14.02	26.60	1,900
67	Khokhra	2.8	3.08	2.52	5.6	2.53	2.73	5.26	1,878
68	Koto	40.8	68.3	65.4	133.7	54.64	70.39	125.03	3,064
69	Laspur Murigram	232	453.03	177.1	630.13	490.34	179.75	670.09	2,888
70	LCC	7.55	10.872	7.248	18.12	8.94	7.84	16.78	2,223
71	Lower Palas	665	680.2	583.7	1263.9	564.85	639.24	1204.09	1,811
72	Lower Spat Gah	496	558.8	462.87	1021.67	500.09	516.47	1016.55	2,050
73	Luat	49	0.0	197.2	197.2	0.00	212.42	212.42	4,335
74	Lucky_HPP	20	27.304	14.162	41.466	22.58	15.68	38.25	1,913
75	Machai-III	1.72	3.215	1.45	4.665	3.07	1.47	4.53	2,635

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
76	Madyan	157	153.69	347.51	501.2	153.69	347.51	501.20	3,192
77	Mahandri	10.04	19.69	10.29	29.98	16.19	11.13	27.33	2,722
78	Mahl	640	0	992.98	992.98	0.00	1051.22	1051.22	1,643
79	Makari	1	1.1	0.5	1.5	1.00	0.45	1.46	1,456
80	Malkan	2.2	2.46	1.06	3.52	2.35	1.07	3.42	1,553
81	Mandi	3.3	4.356	3.564	7.92	3.62	3.90	7.52	2,279
82	Mastuj	48.6	92.2	27.35	119.55	76.56	29.95	106.52	2,192
83	Mehar	10.49	15.735	10.485	26.22	13.07	11.48	24.55	2,340
84	Meragram	70	172.5	57.5	230	164.52	58.11	222.62	3,180
85	Mujigram	64.26	142.477	35.619	178.096	127.51	39.74	167.25	2,603
86	Murree	12	14.5	9.5	24	11.63	10.14	21.77	1,814
87	Nagdar	35	36.8	15.8	52.5	35.05	15.92	50.96	1,456
88	Nairy Bela	3.2	3.36	1.44	4.8	3.20	1.46	4.66	1,456
89	Nandihar	12.3	0	47.097	47.097	0.00	52.52	52.52	4,270
90	Nandihar-II	10.97	13.37	15.5	28.87	13.37	15.50	28.87	2,632
91	Naran	188	269.35	161.93	431.28	247.61	179.96	427.57	2,274
92	Nardagian	3.2	3.4	1.4	4.8	3.20	1.46	4.66	1,456
93	Nausari	48	50.4	21.6	72	48.07	21.83	69.89	1,456
94	Naushera	1.95	3.901	1.671	5.572	3.47	1.86	5.34	2,737

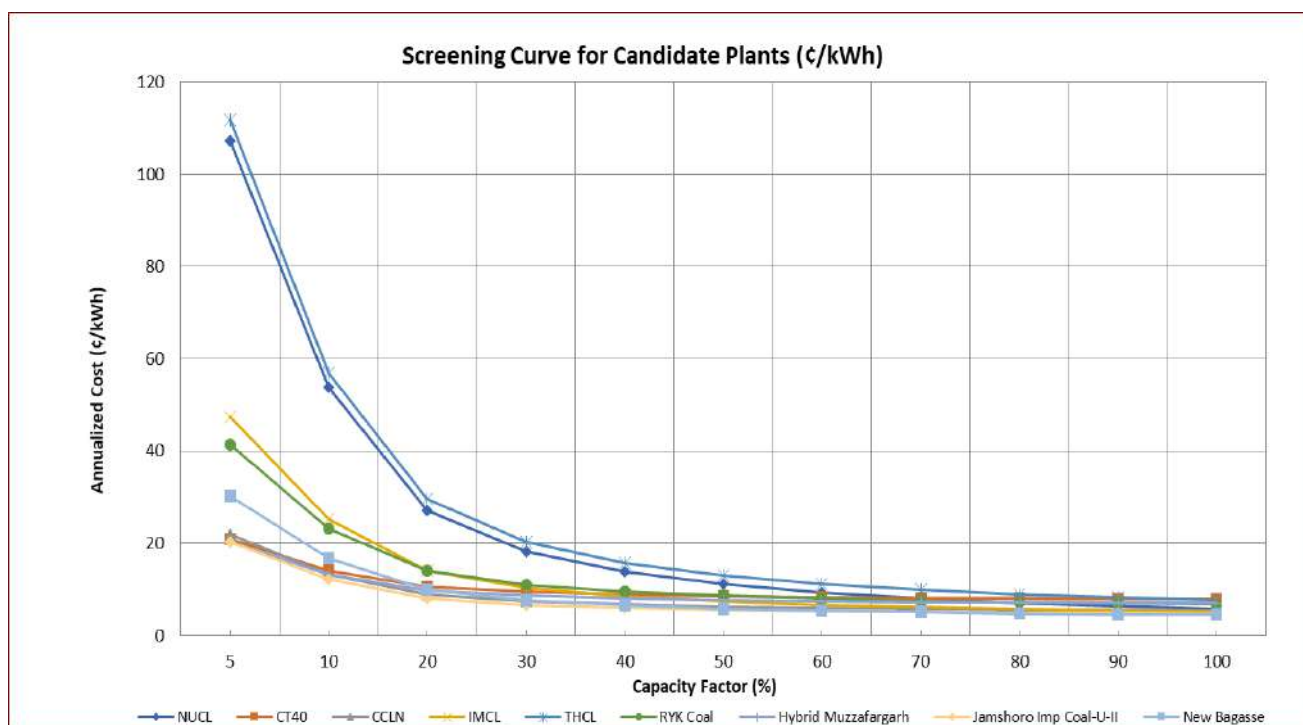
#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
95	Nila Da Katha	34	17.539	70.158	87.697	16.81	72.14	88.95	2,616
96	Okara	4.8	6.65	4.39	11.04	5.33	4.68	10.02	2,087
97	Paddar	3	3.36	1.44	4.8	3.20	1.46	4.66	1,553
98	Panagh	1.8	2.02	0.86	2.88	1.93	0.87	2.80	1,553
99	Patan	2400	2235	2331	4566	1842.22	2547.75	4389.98	1,829
100	Patrak Sheringhal	22	63.7	16.7	80.3	56.67	18.60	75.27	3,421
101	Phandar	80	71.6	80.7	152.3	64.52	92.72	157.24	1,966
102	Punjnad	15	18.9	12.6	31.5	17.34	15.21	32.55	2,170
103	Qadirabad	23	29.1	19.4	48.5	20.69	23.05	43.74	1,902
104	QB Link	9.18	11.6	7.7	19.3	9.30	8.22	17.52	1,908
105	Rajdhani	132	0	173	173	0.00	247.47	247.47	1,875
106	Rasul	18	22.68	15.12	37.8	20.81	18.25	39.06	2,170
107	Ravi	4.6	11.04	0	11.04	9.12	0.00	9.12	1,983
108	Riali-I	1.6	1.68	0.72	2.4	1.60	0.73	2.33	1,456
109	Sahiwal	4.8	6.9	4.6	11.5	4.48	5.27	9.75	2,032
110	Sammargah	28	41.024	25.795	66.819	26.37	29.67	56.04	2,001
111	Sandoa	1.75	1.96	0.84	2.8	1.87	0.85	2.72	1,553
112	Sarral-Dartiyan	8.51	26.44	4.25	30.69	20.77	4.51	25.28	2,971
113	Serai	6.9	9.591	1.28	10.871	9.15	1.29	10.44	1,513

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
114	Shalfalam	60	137.22	34.3	171.52	131.49	35.27	166.76	2,779
115	Sharda-II	5	5.25	2.25	7.5	5.01	2.27	7.28	1,456
116	Sharmai	152.12	143.45	257.33	400.78	116.37	271.15	387.52	2,547
117	Shigo Kas	102	202.17765	104.594174	306.771824	166.29	113.16	279.45	2,740
118	Shogosin	137	254.06	112.182	366.242	206.10	118.21	324.31	2,367
119	Shounter	48	53.76	23.04	76.8	51.27	23.28	74.55	1,553
120	Shushghai	144	238.129	102.055	340.184	235.93	103.39	339.32	2,356
121	SHYOK	640	1206	650	1856	1194.85	658.51	1853.36	2,896
122	Soan	25	37	15	52	29.68	16.00	45.68	1,827
123	Tajian	4	4.2	1.8	6	4.01	1.82	5.82	1,456
124	Tangar	25.91	35.28	34.209	69.489	29.02	37.01	66.03	2,548
125	Taobut	10	11.2	4.8	16	10.68	4.85	15.53	1,553
126	Taunsa	135	235.5	170.5	406	195.56	186.72	382.29	2,832
127	Thakot-I	2220	2031.3	1224.2	3255.5	1727.51	1277.92	3005.44	1,354
128	Thakot-II	963	990.5	692.1	1682.6	842.37	722.47	1564.84	1,625
129	Thakot-III	1490	1279.6	962.9	2242.5	1088.23	1005.16	2093.39	1,405
130	Torkhow	70	157.5	52.5	210	150.21	53.05	203.26	2,904
131	TP	9	8.28	5.52	13.8	7.55	6.23	13.78	1,531
132	Trappi	32	77.37	19.33	96.7	67.89	19.93	87.82	2,744

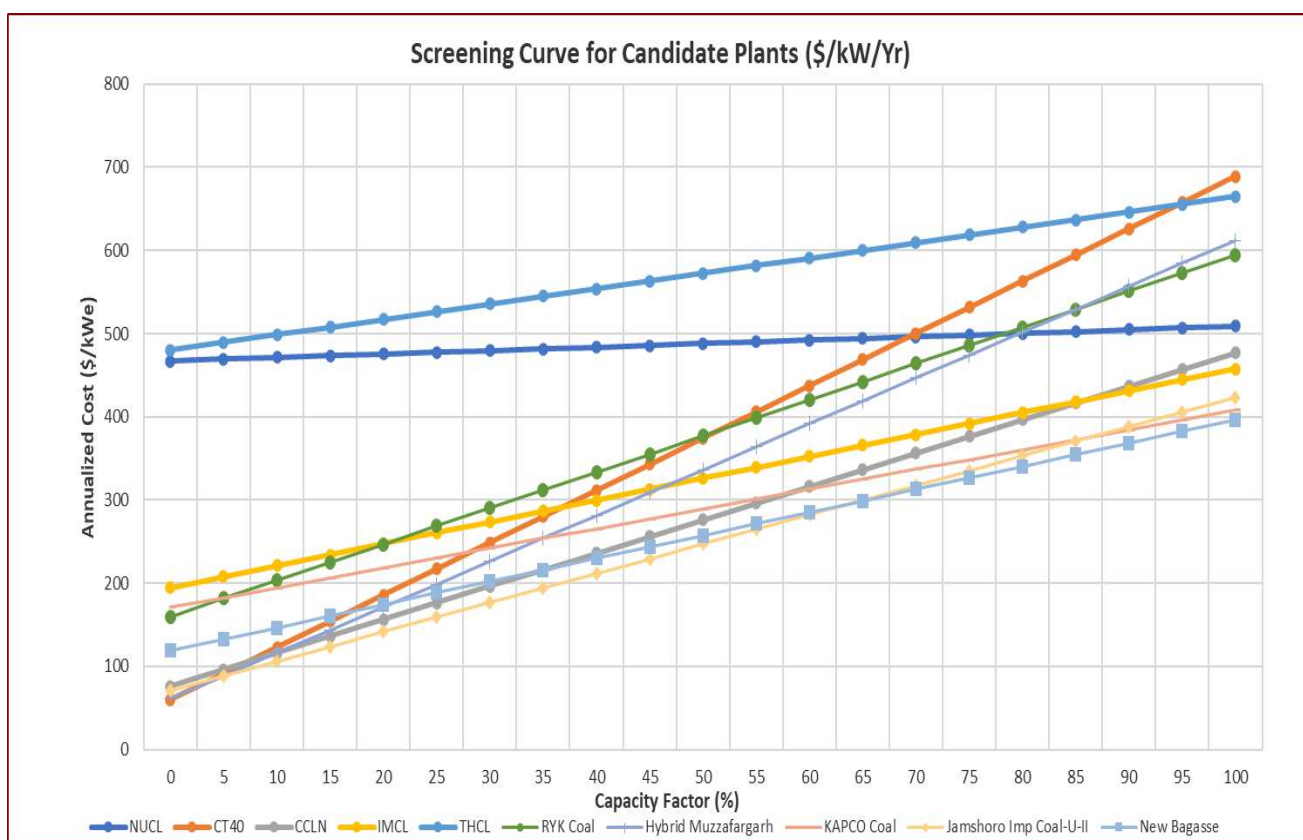
#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US\$)			Rev. Dec '20 Capital Cost with IDC (Million US\$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	\$/kW
133	Trimmu_HPP	13	16.4	10.9	27.3	13.49	11.79	25.28	1,945
134	Turtonas Uzghor	82.25	94.798	84.066	178.864	83.19	86.66	169.85	2,065
135	UCC Bhambhwal	5	7.2	4.8	12	5.77	5.12	10.90	2,179
136	Wari	43.7	77.84	57.63	135.47	61.32	61.01	122.33	2,799
137	Wazirabad	90	148	98.7	246.7	141.82	101.49	243.30	2,703

B-4. Screening Curve for Candidate Thermal Plants

B - 4.1. Screening Curve For Candidate Plants (¢/kWh)



B - 4.2 Screening Curve for candidate Plants (\$/kW/Yr)



B-5. Annualized Cost of Candidate Hydro Power Plants

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(Years)	(%)	c/kWh	\$/kW/Yr
1	Alka	PPDB	1.8	2025	50.30	2,362	12	50	75%	0.75	288.53
2	Arkari Gol	PEDO	99	2026	35.70	1,985	373	40	43%	0.43	238.69
3	Artistic-I	PEDO	62.606	2028	40.85	3,653	301	50	55%	0.55	409.26
4	Artistic-II	PEDO	55.032	2027	45.74	2,353	208	50	43%	0.43	283.02
5	Ashkot	PPIB	300	2030	30.00	2,880	1249	50	48%	0.48	320.47
6	Asrit Kedam	PEDO	215	2028	12.05	1,877	931	50	49%	0.49	201.40
7	Athmuqam	PPIB	450	2029	41.77	2,982	1953	50	50%	0.50	342.55
8	Balakot-II	PEDO	100	2028	46.33	3,652	538	50	61%	0.61	414.70
9	Balkani	PEDO	7.7	2026	42.24	3,024	44	50	65%	0.65	347.27
10	Balmi	AJK	2	2025	14.75	1,553	9	30	49%	0.49	179.52
11	Bankhwar	PEDO	35	2027	22.55	2,578	122	50	40%	0.40	282.60
12	Basho	WAPDA	40	2030	1.51	2,526	148	50	42%	0.42	256.29
13	Bata Kundi	PEDO	96	2028	8.20	1,854	358	50	43%	0.43	195.16
14	Batdara	AJK	4.8	2025	14.75	1,517	21	30	51%	0.51	175.66
15	Bhango	AJK	2.1	2033	14.75	1,553	9	30	49%	0.49	179.52
16	Bhedi Doba	AJK	1	2022	15.50	1,512	4	30	49%	0.49	175.85
17	Bheri -II	AJK	2.85	2027	31.29	2,027	16	50	63%	0.63	235.74
18	Bhimbal Katha	PEDO	26	2026	33.20	2,376	114	50	50%	0.50	272.80
19	BS Link Tail	PPDB	9	2035	16.43	1,966	48	50	61%	0.61	214.74
20	Bunji	WAPDA	7100	2040	188.08	1,857	25937	50	42%	0.42	375.40
21	Chakoti Hatian	PPIB	500	2030	26.57	2,177	2392	50	55%	0.55	246.12

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(Years)	(%)	c/kWh	\$/kW/Yr
22	Chamfall	AJK	3.21	2022	14.75	1,365	14	30	49%	0.49	159.58
23	Chenawan	PPDB	3	2030	17.99	2,795	21	50	81%	0.81	299.88
24	Chicha Watni	PPDB	1.6	2028	22.23	2,348	11	50	82%	0.82	259.06
25	Chiniot_HPP	WAPDA	80	2028	6.59	2,665	273	50	39%	0.39	275.36
26	Chowkel Khwar	PEDO	60	2025	62.65	1,955	244	30	46%	0.46	270.01
27	CJ	PPDB	25	2026	22.13	1,730	108	50	49%	0.49	196.65
28	Daar	AJK	3	2035	14.75	1,553	13	30	49%	0.49	179.52
29	Daral Khwar-II	PEDO	9.5	2025	26.73	2,995	44	30	53%	0.53	344.45
30	Dasu_2	-	2160	2032	11.74	2,223	12046	50	64%	0.64	235.98
31	DG Khan	PPDB	4.65	2027	21.18	1,970	21	50	51%	0.51	219.86
32	Dhadar	PEDO	18.18	2027	39.36	2,392	96	50	60%	0.60	280.58
33	Dhani	AJK	48	2031	14.75	1,553	205	30	49%	0.49	179.52
34	Dowarian	AJK	40	2026	14.75	1,456	171	30	49%	0.49	169.22
35	Gabral Kalam	PEDO	88	2026	20.20	1,965	325	50	42%	0.42	218.38
36	Gabral Utror	PEDO	79	2028	32.14	2,448	306	50	44%	0.44	279.05
37	Gahret	PEDO	377	2030	60.70	4,433	1713	50	52%	0.52	507.78
38	Garhi Habibullah	PEDO	100	2028	51.44	3,264	514	50	59%	0.59	380.62
39	Gharata	AJK	1.7	2034	14.75	2,433	7	30	49%	0.49	272.81
40	Ghorband	PEDO	20.6	2028	42.24	3,755	131	50	72%	0.72	420.99
41	Gugera	PPDB	3.6	2025	21.92	2,176	21	50	66%	0.66	241.34
42	Gumat Nar	AJK	49.5	2026	27.31	3,634	280	50	65%	0.65	393.88
43	Gurha	AJK	1.5	2034	14.75	1,553	6	30	49%	0.49	179.52

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(Years)	(%)	c/kWh	\$/kW/Yr
44	Gwaldai	PEDO	20.4	2026	37.48	2,402	82	50	46%	0.46	279.70
45	Harigehl-Majeedgala	AJK	40.32	2027	0.01	2,465	226	50	64%	0.64	248.66
46	Hundi	AJK	3.5	2032	14.75	1,553	15	30	49%	0.49	179.52
47	Istaro-Booni	PEDO	72	2030	45.15	3,613	284	50	45%	0.45	409.56
48	Jabri Bedar	PEDO	3.6	2026	69.19	3,029	26	30	83%	0.83	390.54
49	Jagran-III	AJK	35	2026	0.04	3,664	159	30	52%	0.52	388.70
50	Jagran-IV	AJK	22	2027	14.79	1,728	94	30	49%	0.49	198.10
51	Jamshil	PEDO	610	2029	34.46	2,519	2678	50	50%	0.50	288.50
52	Janawai	AJK	12	2031	14.75	1,553	51	30	49%	0.49	179.52
53	Javed-III	PEDO	65	2027	33.40	2,369	266	50	47%	0.47	272.38
54	Javed-IV	PEDO	45	2027	35.37	2,370	195	50	49%	0.49	274.35
55	Jhing-II	AJK	6.05	2023	0.70	2,836	34	50	63%	0.63	286.78
56	Kaigah-II	PEDO	39.6	2026	17.30	2,828	190	30	55%	0.55	317.32
57	Kalam Asrit	PEDO	238	2029	11.84	1,776	931	50	45%	0.45	190.98
58	Kalamula	AJK	2.2	2031	14.75	1,553	9	30	49%	0.49	179.53
59	Kalkot Barikot	PEDO	47	2028	11.86	2,840	197	50	48%	0.48	298.28
60	Kappa-II	AJK	2	2027	14.75	1,456	9	30	49%	0.49	169.22
61	Kari Mashkur	PEDO	495	2028	23.34	2,491	2171	50	50%	0.50	274.63
62	Kasorkot Talwari	AJK	2.9	2028	14.75	1,460	12	30	49%	0.49	169.58
63	Kasur	PPDB	2.45	2026	11.36	1,821	11	50	50%	0.50	195.07
64	Kathai-III	AJK	1.2	2023	0.48	1,755	5	50	48%	0.48	177.50
65	Khanewal	PPDB	1	2027	15.93	2,240	6	50	74%	0.74	241.87

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(Years)	(%)	c/kWh	\$/kW/Yr
66	Khanki Barrage	PPDB	14	2036	24.41	1,900	38	50	31%	0.31	216.07
67	Khokhra	PPDB	2.8	2025	22.23	1,878	17	50	69%	0.69	211.70
68	Koto	PEDO	40.8	2022	35.30	3,064	209	50	58%	0.58	344.37
69	Laspur Murigram	PEDO	232	2029	27.40	2,888	843	30	41%	0.41	333.79
70	LCC	PPDB	7.55	2025	22.23	2,223	43	50	65%	0.65	246.45
71	Lower Palas	WAPDA	665	2042	17.30	1,811	2444	50	42%	0.42	199.93
72	Lower Spat Gah	WAPDA	496	2040	14.28	2,050	2059	50	47%	0.47	220.99
73	Luat	AJK	49	2025	63.48	4,335	211	50	49%	0.49	500.72
74	Lucky_HPP	PPDB	20	2026	63.57	1,913	86	50	49%	0.49	256.48
75	Machai-III	PEDO	1.72	2026	43.01	2,635	10	30	67%	0.67	322.48
76	Madyan	PEDO	157	2029	38.32	3,192	755	30	55%	0.55	376.96
77	Mahandri	PEDO	10.04	2027	49.16	2,722	43	50	49%	0.49	323.69
78	Mahl	PPIB	640	2029	25.31	1,643	3670	50	65%	0.65	190.98
79	Makari	AJK	1	2024	14.75	1,456	4	30	49%	0.49	169.22
80	Malkan	AJK	2.2	2035	14.75	1,553	9	30	49%	0.49	179.53
81	Mandi	PPDB	3.3	2024	22.51	2,279	18	50	62%	0.62	252.35
82	Mastuj	PEDO	48.6	2026	45.45	2,192	238	30	56%	0.56	277.94
83	Mehar	PPDB	10.49	2026	22.23	2,340	66	50	72%	0.72	258.27
84	Meragram	PEDO	70	2026	44.82	3,180	257	50	42%	0.42	365.59
85	Mujigram	PEDO	64.26	2030	38.14	2,603	294	50	52%	0.52	300.64
86	Murree	PPDB	12	2028	21.93	1,814	64	50	61%	0.61	204.87
87	Nagdar	AJK	35	2027	14.75	1,456	150	30	49%	0.49	169.22

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(Years)	(%)	c/kWh	\$/kW/Yr
88	Nairy Bela	AJK	3.2	2027	14.75	1,456	14	30	49%	0.49	169.22
89	Nandihar	PEDO	12.3	2027	48.03	4,270	81	50	75%	0.75	478.71
90	Nandihar-II	PEDO	10.97	2025	21.90	2,632	64	50	67%	0.67	287.33
91	Naran	PEDO	188	2028	8.34	2,274	693	50	42%	0.42	237.72
92	Nardagian	AJK	3.21	2023	14.75	1,456	14	30	49%	0.49	169.22
93	Nausari	AJK	48	2029	14.75	1,456	205	30	49%	0.49	169.22
94	Naushera	AJK	1.95	2027	33.01	2,737	10	50	59%	0.59	309.03
95	Nila Da Katha	PEDO	34	2025	17.22	2,616	147	30	49%	0.49	294.73
96	Okara	PPDB	4.8	2033	21.93	2,087	29	50	69%	0.69	232.42
97	Paddar	AJK	3	2030	14.75	1,553	13	50	49%	0.49	171.41
98	Panagh	AJK	1.8	2034	14.75	1,553	8	30	49%	0.49	179.50
99	Patan	WAPDA	2400	2032	62.41	1,829	12301	50	59%	0.59	246.90
100	Patrak Sheringhal	PEDO	22	2028	10.37	2,168	93	50	48%	0.48	229.05
101	Phandar	WAPDA	80	2026	2.18	1,966	360	50	51%	0.51	200.42
102	Punjnad	PPDB	15	2037	15.71	2,170	58	50	44%	0.44	234.58
103	Qadirabad	PPDB	23	2034	24.41	1,902	51	50	25%	0.25	216.21
104	QB Link	PPDB	9.18	2038	16.00	1,908	30	50	37%	0.37	208.49
105	Rajdhani	PPIB	132	2029	37.19	1,875	666	50	58%	0.58	226.28
106	Rasul	PPDB	18	2027	11.78	2,170	96	50	61%	0.61	230.65
107	Ravi	PPDB	4.6	2025	51.03	1,983	27	50	66%	0.66	251.04
108	Riali-I	AJK	1.6	2025	14.75	1,456	7	30	49%	0.49	169.22
109	Sahiwal	PPDB	4.8	2030	12.10	2,032	29	50	68%	0.68	217.02

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(Years)	(%)	c/kWh	\$/kW/Yr
110	Sammargah	PEDO	28	2026	63.07	2,001	100	50	41%	0.41	264.92
111	Sandoa	AJK	1.75	2035	14.75	1,553	7	30	49%	0.49	179.52
112	Sarral-Dartiyar	PEDO	8.51	2026	73.01	2,971	47	30	63%	0.63	388.13
113	Serai	PEDO	6.9	2026	21.48	1,513	30	50	50%	0.50	174.10
114	Shalfalam	PEDO	60	2025	27.76	2,779	264	30	50%	0.50	322.58
115	Sharda-II	AJK	5	2030	14.75	1,456	21	30	49%	0.49	169.22
116	Sharmai	PEDO	152.12	2026	52.16	2,547	680	50	51%	0.51	309.10
117	Shigo Kas	PEDO	102	2026	32.65	2,740	461	50	52%	0.52	308.97
118	Shogosin	PEDO	137	2029	29.50	2,367	535	30	45%	0.45	280.62
119	Shounter	AJK	48	2031	14.75	1,553	205	30	49%	0.49	179.52
120	Shushghai	PEDO	144	2029	29.38	2,356	501	30	40%	0.40	279.34
121	SHYOK	WAPDA	640	2030	23.50	2,896	3731	50	67%	0.67	315.58
122	Soan	PPDB	25	2035	21.93	1,827	107	50	49%	0.49	206.22
123	Tajian	AJK	4	2030	14.75	1,456	17	30	49%	0.49	169.22
124	Tangar	PEDO	25.91	2027	49.02	2,548	127	50	56%	0.56	306.05
125	Taobut	AJK	10	2030	14.75	1,553	49	30	56%	0.56	179.52
126	Taunsa	PPDB	135	2026	22.29	2,832	640	50	54%	0.54	307.89
127	Thakot-I	WAPDA	2220	2039	42.49	1,354	10352	50	53%	0.53	179.03
128	Thakot-II	WAPDA	963	2037	21.92	1,625	4713	50	56%	0.56	185.81
129	Thakot-III	WAPDA	1490	2029	29.23	1,405	7280	50	56%	0.56	170.93
130	Torkhow	PEDO	70	2026	40.42	2,904	262	50	43%	0.43	333.29
131	TP	PPDB	9	2032	16.93	1,531	38	50	48%	0.48	171.34

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	(\$/kW/Yr)	(\$/KW)	(GWh)	(Years)	(%)	c/kWh	\$/kW/Yr
132	Trappi	PEDO	32	2026	36.28	2,744	162	30	58%	0.58	327.41
133	Trimmu_HPP	PPDB	13	2036	16.23	1,945	57	50	50%	0.50	212.38
134	Turtonas Uzghor	PPIB	82.25	2028	25.12	2,065	377	50	52%	0.52	233.39
135	UCC Bhambhwal	PPDB	5	2033	16.00	2,179	30	50	68%	0.68	235.80
136	Wari	PEDO	43.7	2028	20.08	2,799	256	50	67%	0.67	302.42
137	Wazirabad	WAPDA	90	2030	3.19	2,703	376	50	48%	0.48	275.85

Annexure C: Low Demand Scenario

C-1. Annual Energy Generation Vs Annual Energy Demand (GWh)

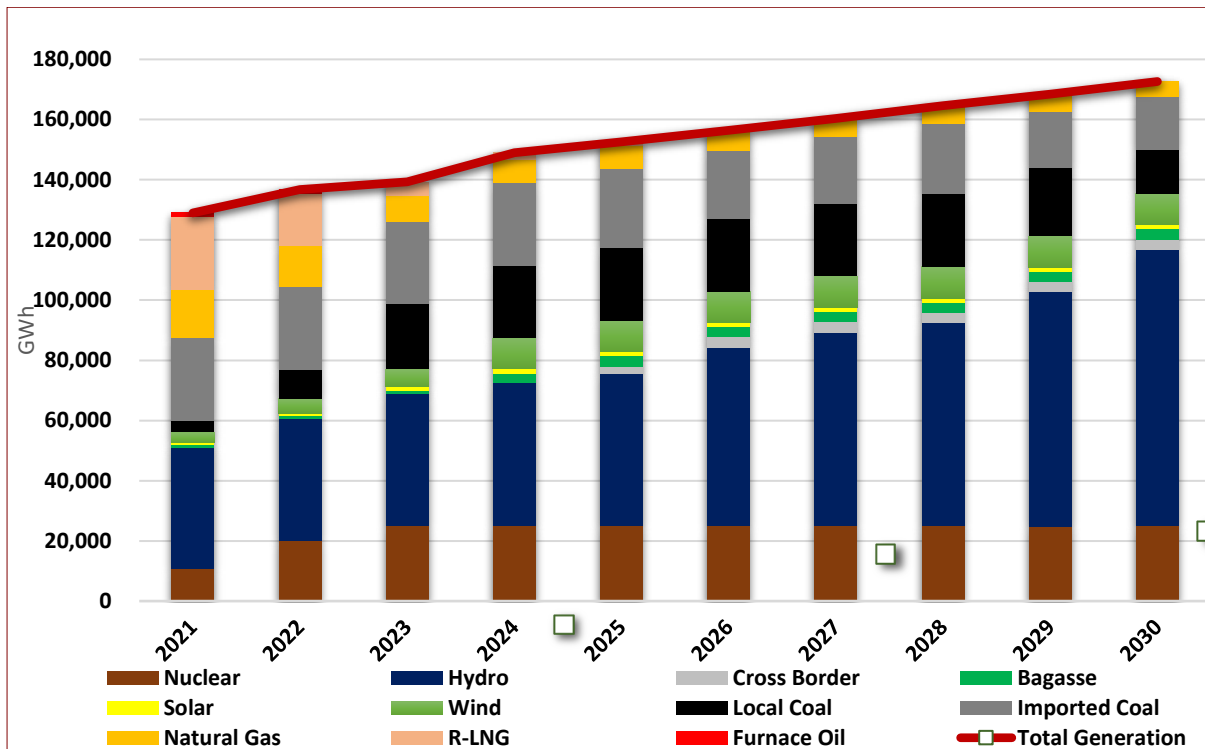


Chart C-1: Annual Energy Generation Vs Annual Energy Demand (GWh)

C-2. Installed Capacity Vs Peak Demand (MW) 2021-30

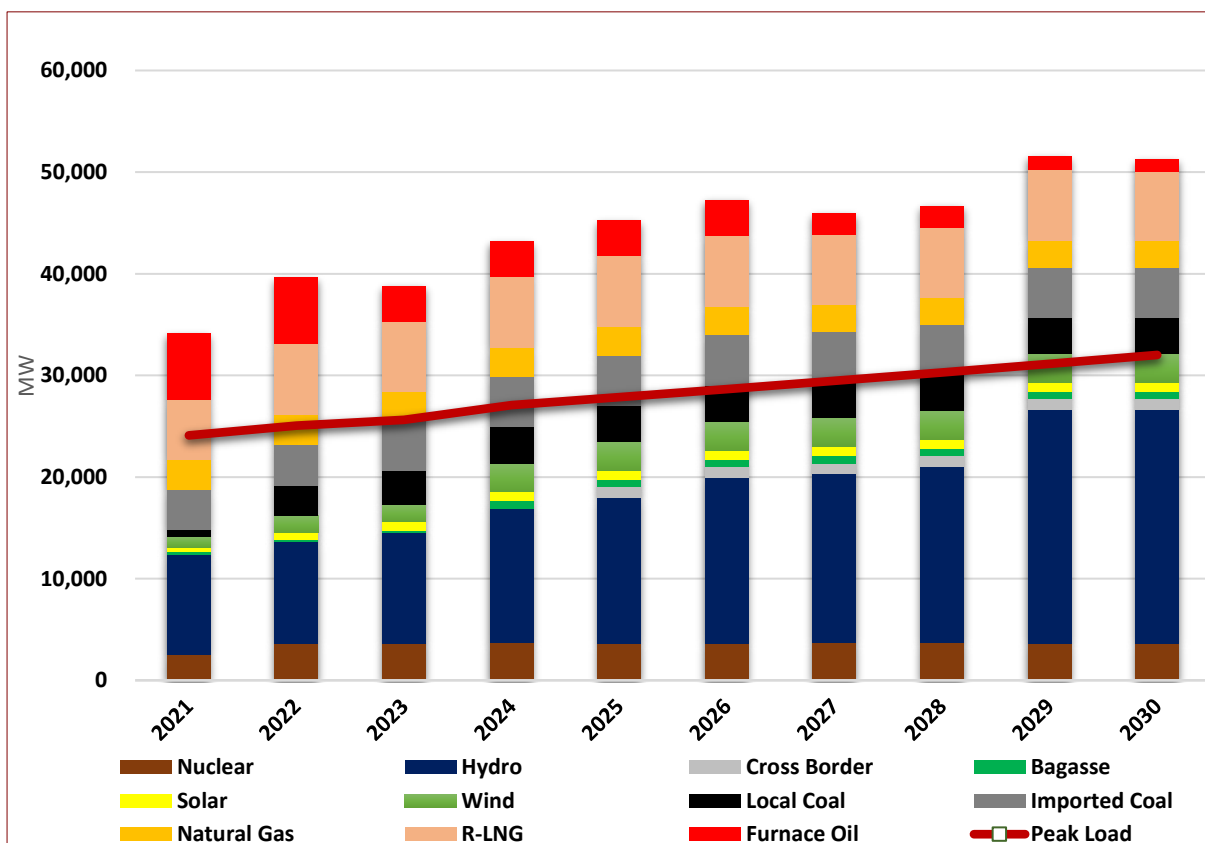


Chart C-2: Installed Capacity Vs Peak Demand (MW) 2021-30

C-3. Future Generation Capacity Additions

Fiscal Year	Coal Fired Steam Imported Coal	Coal Fired Steam Local Coal	Combined Cycle on RLNG	Combustion Turbine on RLNG	Nuclear	Hydro	Solar	Wind	Bagasse	BESS	Per Year Capacity Addition	Cumulative Capacity Addition
	MW											
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	1,000	-	-	1,000	1,000
2025	-	-	-	-	-	-	-	-	-	-	-	1,000
2026	-	-	-	-	-	-	-	-	-	-	-	1,000
2027	-	-	-	-	-	-	-	-	-	-	-	1,000
2028	-	-	-	-	-	-	-	-	-	-	-	1,000
2029	-	-	-	-	-	-	-	-	-	-	-	1,000
2030	-	-	-	-	-	-	-	-	-	-	-	1,000
Total	-	-	-	-	-	-	-	1000	-	-	1,000	

C-4. List of Projects uptill 2030 (Committed + Candidate)

#	Name of the Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
2021							
1	Jhing	Hydro	14.4	14.4	AJK	Committed	May-21
Generation Additions in 2021 (MW)			14.4	14.4			
Cumulative Addition uptill 2021 (MW)			14.4	14.4			
2022							
1	Master_Green	Wind	50	50	AEDB	Committed	Jul-21
2	Ranolia	Hydro	17	17	PEDO	Committed	Jul-21
3	Lucky	Local Coal	660	607	PPIB	Committed	Sep-21
4	Tricom	Wind	50	50	AEDB	Committed	Oct-21
5	Jabori	Hydro	10.2	10.2	PEDO	Committed	Dec-21
6	Karora	Hydro	11.8	11.8	PEDO	Committed	Dec-21
7	Metro_Wind	Wind	60	60	AEDB	Committed	Dec-21
8	Lakeside	Wind	50	50	AEDB	Committed	Dec-21
9	NASDA	Wind	50	50	AEDB	Committed	Dec-21
10	Artistic_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
11	Din	Wind	50	50	AEDB	Committed	Dec-21
12	Gul_Electric	Wind	50	50	AEDB	Committed	Dec-21
13	Act_2	Wind	50	50	AEDB	Committed	Dec-21
14	Liberty_Wind_1	Wind	50	50	AEDB	Committed	Dec-21
15	Liberty_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
16	Indus_Energy	Wind	50	50	AEDB	Committed	Dec-21
17	Zhenfa	Solar	100	100	AEDB	Committed	Dec-21
18	Trimmu	RLNG	1,263	1,243	PPIB	Committed	Jan-22
19	K-3	Nuclear	1,145	1,059	PAEC	Committed	Jan-22

#	Name of the Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
20	Jagran-II	Hydro	48	48	AJK	Committed	May-22
21	Thar TEL	Local Coal	330	300	PPIB	Committed	Mar-22
22	Helios	Solar	50	50	AEDB	Committed	Mar-22
23	HNDS	Solar	50	50	AEDB	Committed	Mar-22
24	Meridian	Solar	50	50	AEDB	Committed	Mar-22
25	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	Committed	May-22
26	Thal Nova	Local Coal	330	300	PPIB	Committed	Jun-22
Generation Additions in 2022 (MW)			5,995	5,670			
Cumulative Addition uptill 2022 (MW)			6,009	5,684			
2023							
1	Karot	Hydro	720	720	PPIB	Committed	Jul-22
2	Access_Electric	Solar	10.52	10.52	AEDB	Committed	Aug-22
3	Access_Solar	Solar	12	12	AEDB	Committed	Aug-22
4	Jamshoro Coal (Unit-I)	Imp.Coal	660	629	GENCO	Committed	Oct-22
5	Lawi	Hydro	69	69	PEDO	Committed	Nov-22
6	Gorkin Matiltan	Hydro	84	84	PEDO	Committed	Nov-22
7	Zorlu	Solar	100	100	AEDB	Committed	Jun-23
8	Siachen	Solar	100	100	AEDB	Committed	Jun-23
9	Gwadar	Imp.Coal	300	273	PPIB	Committed	Jun-23
Generation Additions in 2023 (MW)			2,056	1,998			
Cumulative Addition uptill 2023 (MW)			8,065	7,682			
2024							
1	Siddiqsons	Local Coal	330	304	PPIB	Committed	Jul-23
2	Suki Kinari	Hydro	884	884	PPIB	Committed	Jul-23
3	Riali-II	Hydro	7	7	PPIB	Committed	Jul-23

#	Name of the Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
4	Safe	Solar	10	10	AEDB	Committed	Sep-23
5	Western	Wind	50	50	AEDB	Committed	Nov-23
6	Trans_Atlantic	Wind	48	48	AEDB	Committed	Dec-23
7	Alliance	Bagasse	30	30	AEDB	Committed	Dec-23
8	Bahawalpur	Bagasse	31	31	AEDB	Committed	Dec-23
9	Faran	Bagasse	27	27	AEDB	Committed	Dec-23
10	Hamza-II	Bagasse	30	30	AEDB	Committed	Dec-23
11	HSM	Bagasse	27	27	AEDB	Committed	Dec-23
12	Hunza	Bagasse	50	50	AEDB	Committed	Dec-23
13	Indus	Bagasse	31	31	AEDB	Committed	Dec-23
14	Ittefaq	Bagasse	31	31	AEDB	Committed	Dec-23
15	Kashmir	Bagasse	40	40	AEDB	Committed	Dec-23
16	Mehran	Bagasse	27	27	AEDB	Committed	Dec-23
17	RYK_Energy	Bagasse	25	25	AEDB	Committed	Dec-23
18	Shahtaj	Bagasse	32	32	AEDB	Committed	Dec-23
19	Sheikhoo	Bagasse	30	30	AEDB	Committed	Dec-23
20	TAY	Bagasse	30	30	AEDB	Committed	Dec-23
21	Two_Star	Bagasse	50	50	AEDB	Committed	Dec-23
22	Tarbela_Ext_5	Hydro	1,530	1,530	WAPDA	Committed	Feb-24
23	Chapari Charkhel	Hydro	11	11	PEDO	Committed	Jun-24
24	Candidate_Wind	Wind	1,000	1,000	To be decided	Candidate	2024
Generation Additions in 2024 (MW)			4,361	4,335			
Cumulative Addition uptill 2024 (MW)			12,426	12,017			
2025							
1	CASA	Import	1,000	1,000	GOP	Committed	Aug-24
2	Kathai-II	Hydro	8	8	PPIB	Committed	Dec-24

#	Name of the Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
3	Dasu_1 Unit 1-3	Hydro	1,080	1,080	WAPDA	Committed	Apr-25
Generation Additions in 2025 (MW)			2,088	2,088			
Cumulative Addition uptill 2025 (MW)			14,514	14,105			
2026							
1	Harpo	Hydro	35	35	WAPDA	Committed	Oct-25
2	Dasu_1 Unit 4-6	Hydro	1,080	1,080	WAPDA	Committed	Nov-25
3	Mohmand	Hydro	800	800	WAPDA	Committed	Apr-26
4	Keyal Khwar Unit 1	Hydro	64	64	WAPDA	Committed	May-26
Generation Additions in 2026 (MW)			1,979	1,979			
Cumulative Addition uptill 2026 (MW)			16,493	16,084			
2027							
1	Keyal Khwar Unit 2	Hydro	64	64	WAPDA	Committed	Aug-26
2	Balakot	Hydro	300	300	PEDO	Committed	Mar-27
Generation Additions in 2027 (MW)			364	364			
Cumulative Addition uptill 2027 (MW)			16,857	16,448			
2028							
1	Azad Pattan	Hydro	701	701	PPIB	Committed	Sep-27
Generation Additions in 2028 (MW)			701	701			
Cumulative Addition uptill 2028 (MW)			17,558	17,149			
2029							
1	Kohala	Hydro	1,124	1,124	PPIB	Committed	Jul-28
2	Diamer Bhasha	Hydro	4,500	4,500	WAPDA	Committed	Feb-29
Generation Additions in 2029 (MW)			5,624	5,624			
Cumulative Addition uptill 2029 (MW)			23,182	22,773			

C-5. IGCEP Generation Mix 2021-2030 (GWh)

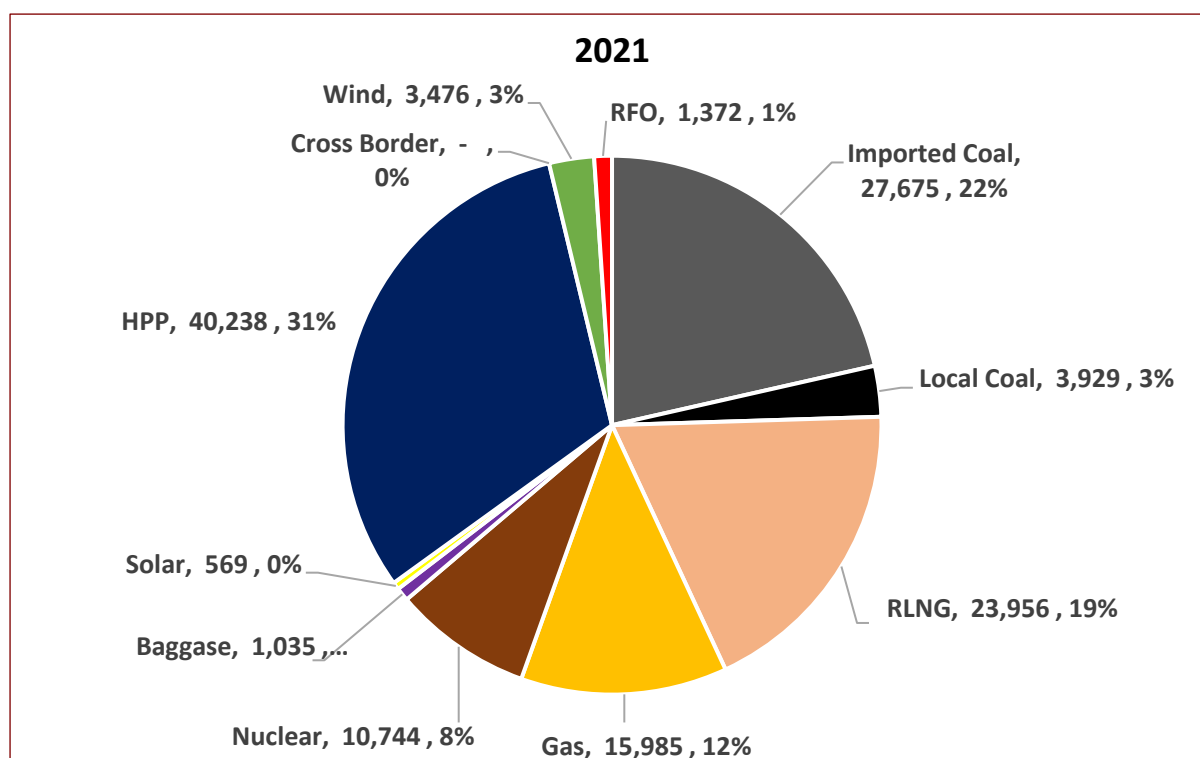


Chart C-3: IGCEP Generation Mix 2021 (GWh)

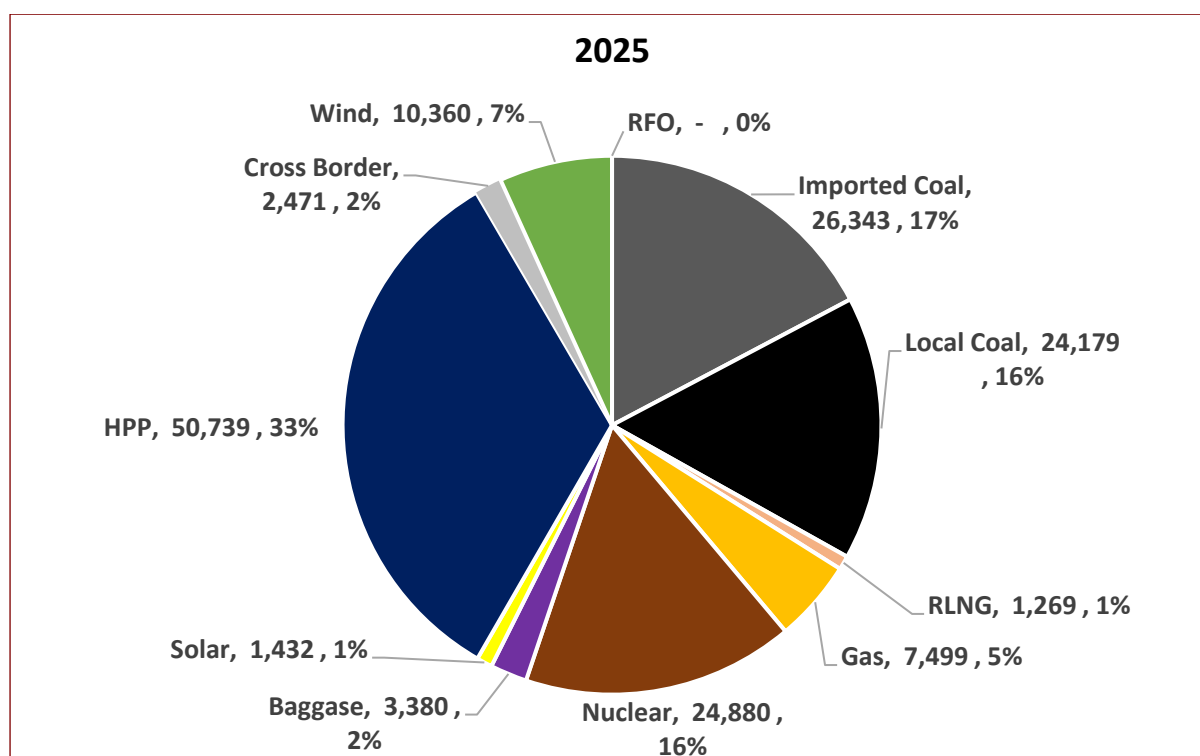


Chart C-4: IGCEP Generation Mix 2025 (GWh)

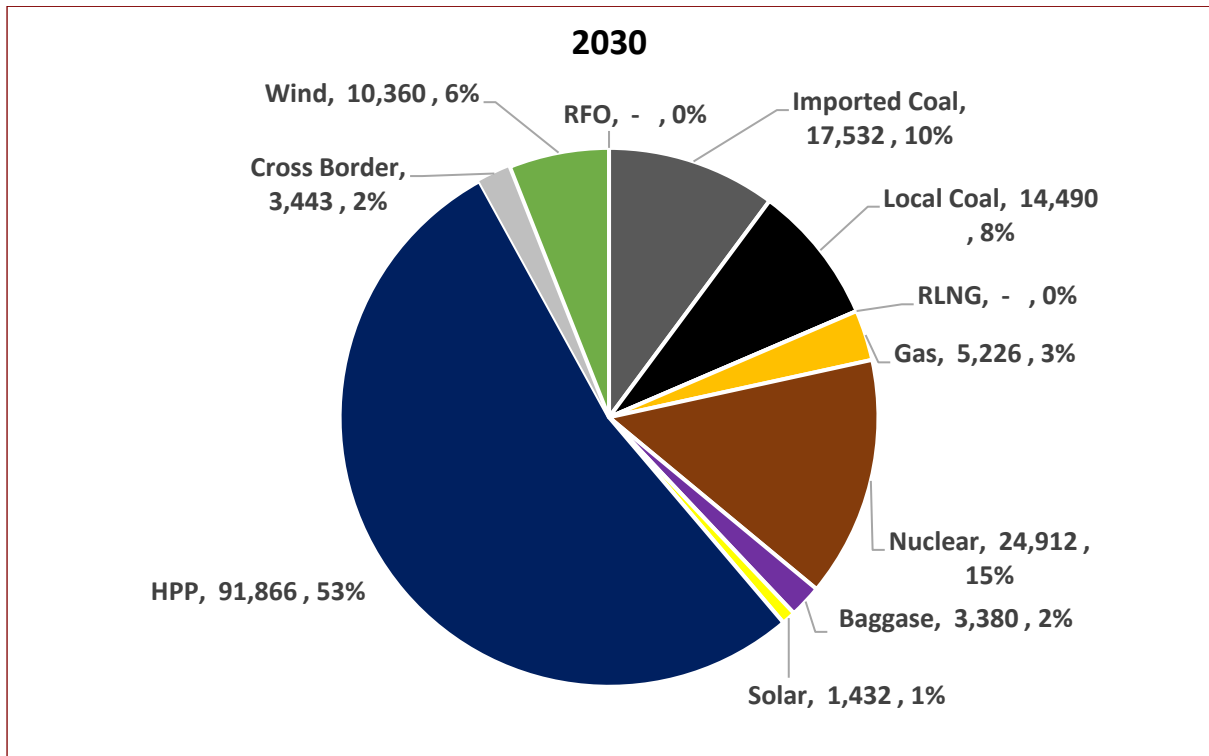


Chart C-5: IGCEP Generation Mix 2030 (GWh)

C-6. IGCEP Generation Mix 2021-30 (MW)

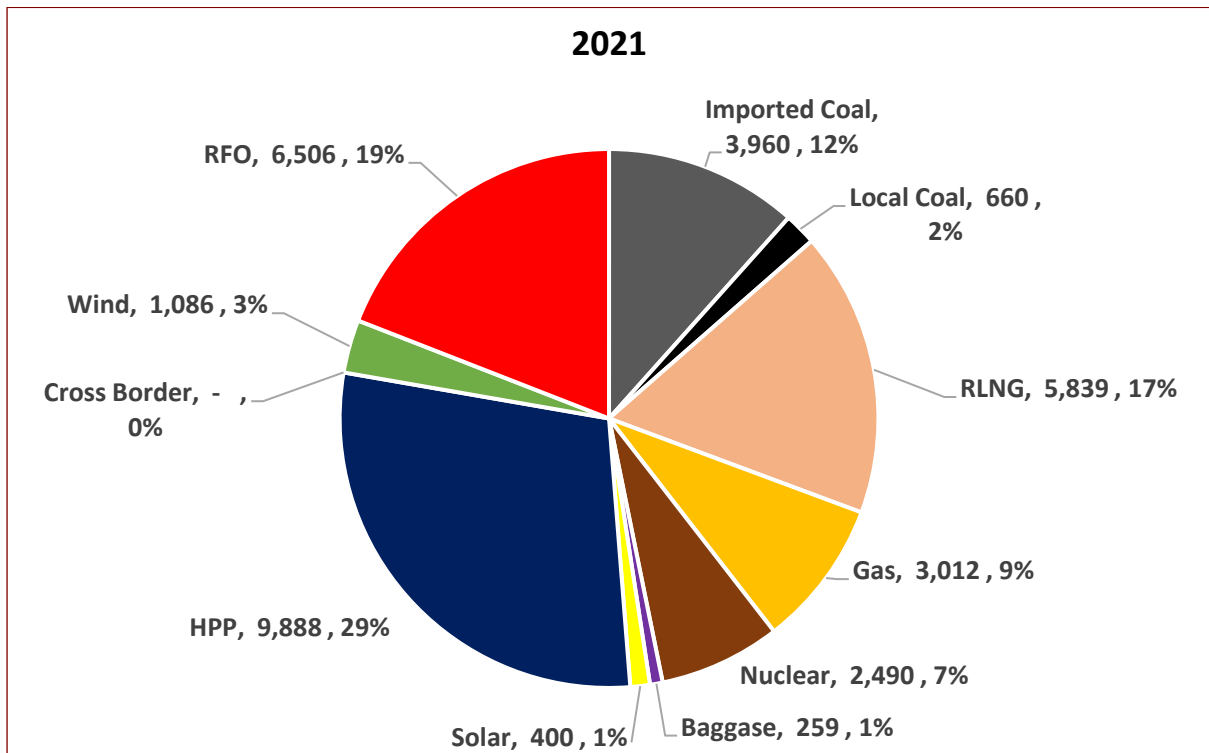


Chart C-6: IGCEP Generation Mix 2020 (MW)

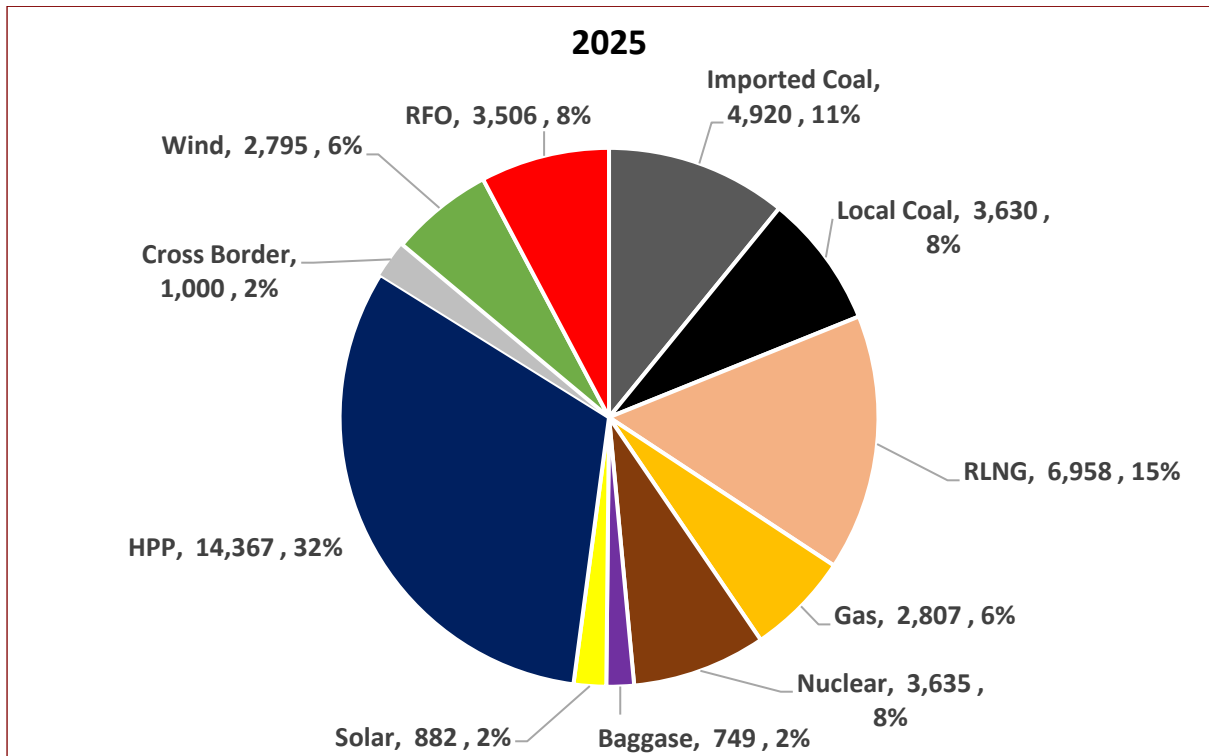


Chart C-7: IGCEP Generation Mix 2025 (MW)

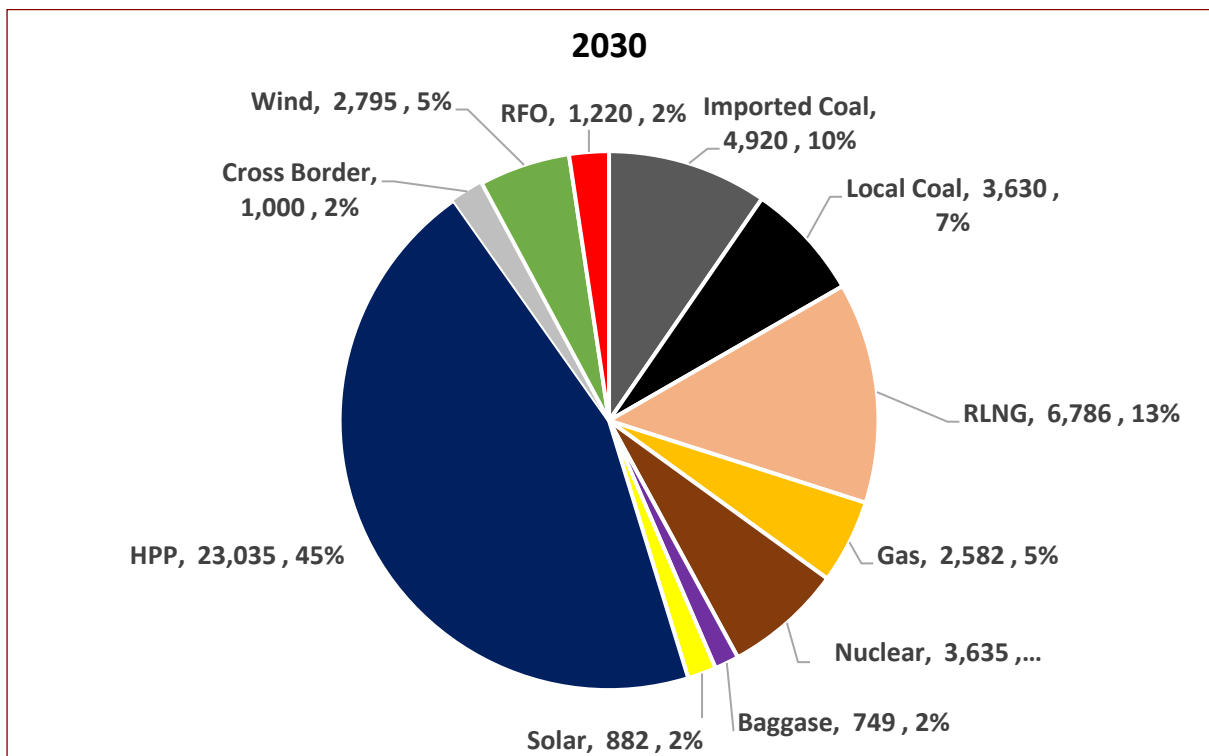
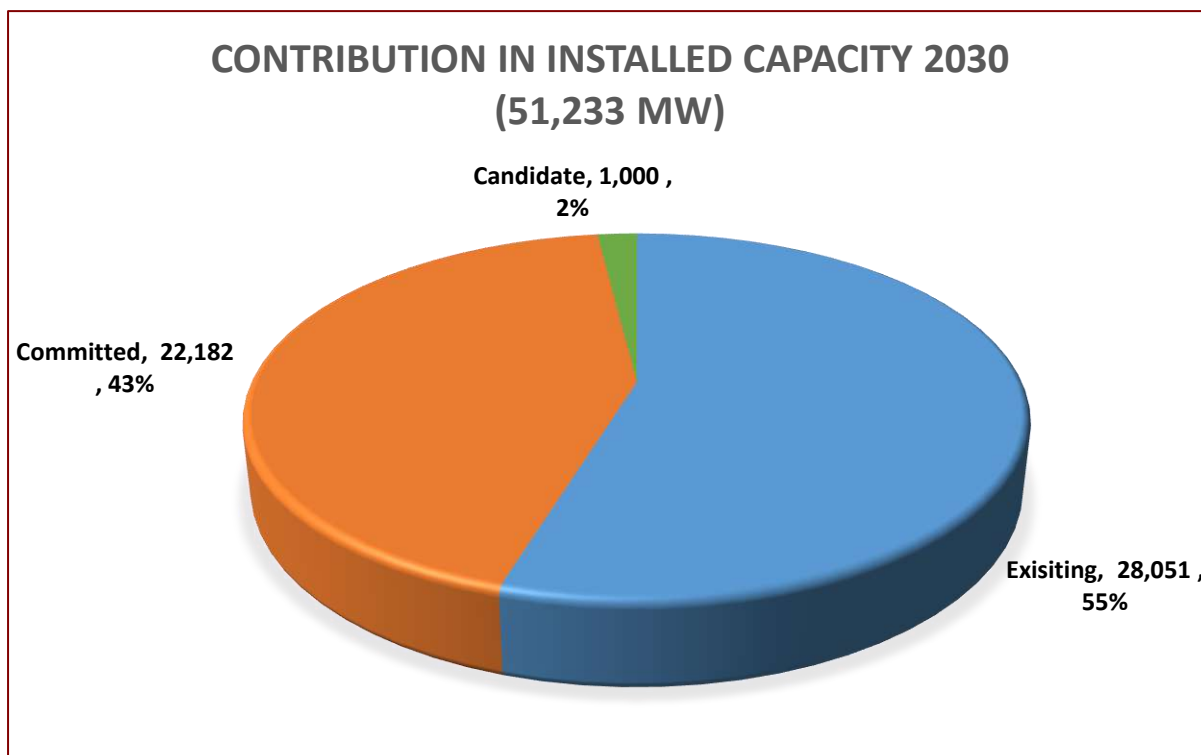


Chart C-8: IGCEP Generation Mix 2030 (MW)

C-7: Total Capacity Contribution in 2030



*Existing capacity contribution is after the retirement of the plants till 2030

Annexure D: High Demand Scenario

D-1. Annual Energy Generation Vs Annual Energy Demand (GWh)

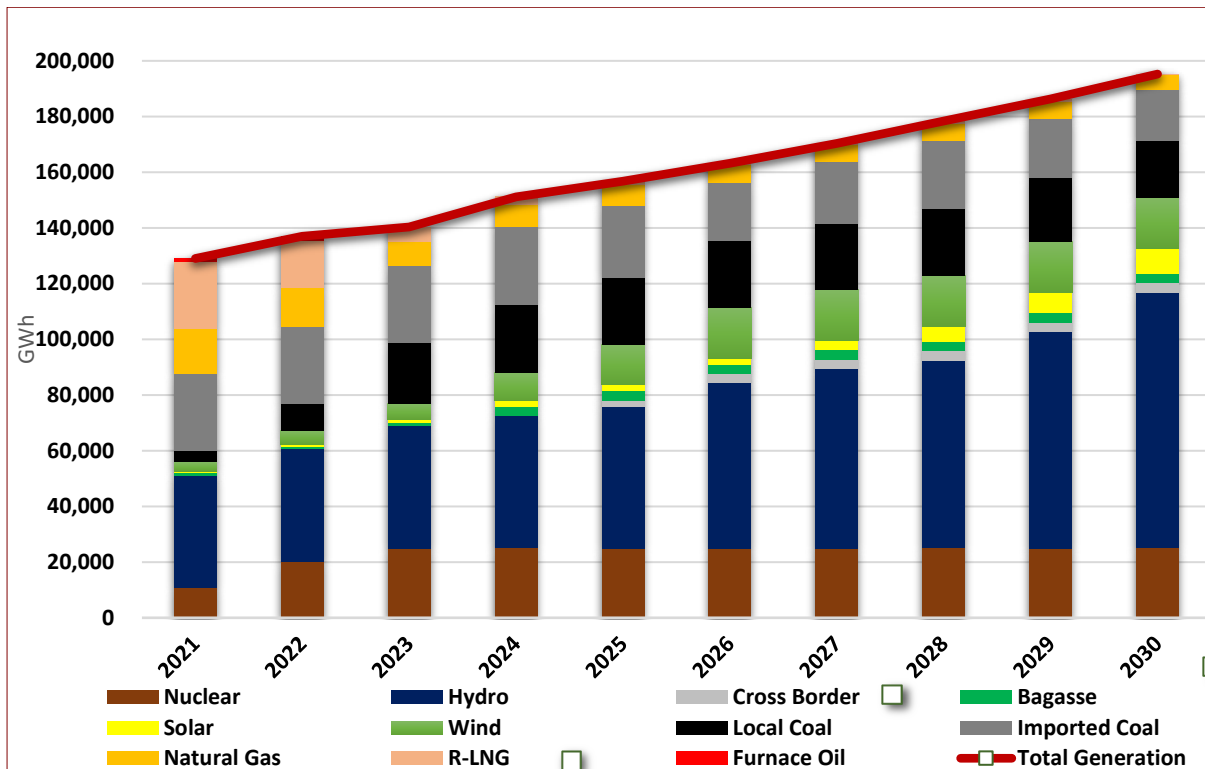


Chart D-1: Annual Energy Generation Vs Annual Energy Demand (GWh)

D-2. Installed Capacity Vs Peak Demand (MW) 2021-30

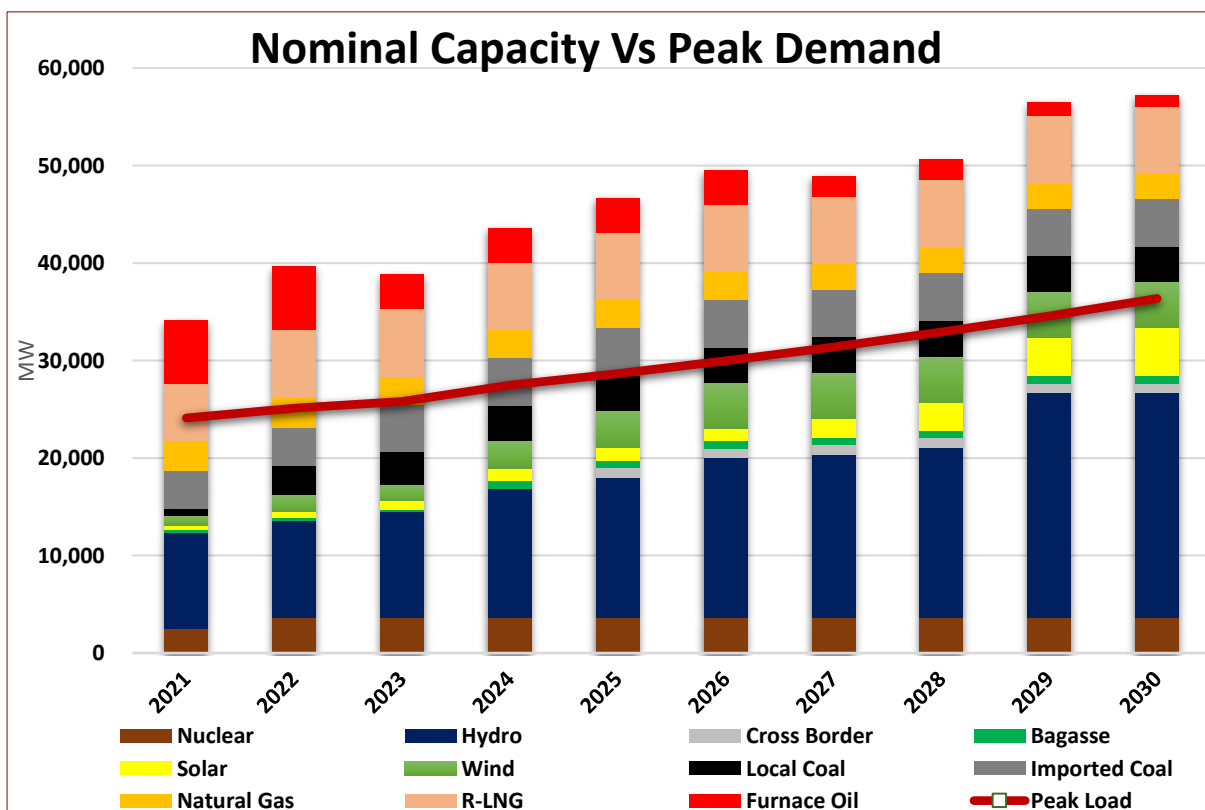


Chart D-2: Installed Capacity Vs Peak Demand (MW) 2021-30

D-3. Future Generation Capacity Additions

Fiscal Year	Coal Fired Steam Imported Coal	Coal Fired Steam Local Coal	Combined Cycle on RLNG	Combustion Turbine on RLNG	Nuclear	Hydro	Solar	Wind	Bagasse	BESS	Per Year Capacity Addition	Cumulative Capacity Addition
	MW											
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	407	1,000	-	-	1,407	1,407
2025	-	-	-	-	-	-	-	1,000	-	-	1,000	2,407
2026	-	-	-	-	-	-	-	899	-	-	899	3,306
2027	-	-	-	-	-	-	666	-	-	-	666	3,972
2028	-	-	-	-	-	-	1,000	-	-	-	1,000	4,972
2029	-	-	-	-	-	-	1,000	-	-	-	1,000	5,972
2030	-	-	-	-	-	-	1,000	-	-	-	1,000	6,972
Total	-	-	-	-	-	-	4,073	2,899	-	-	6,972	

D-4. List of Projects uptill 2030 (Committed + Candidate)

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
2021							
1	Jhing	Hydro	14.4	14.4	AJK	Committed	May-21
Generation Additions in 2021 (MW)			14.4	14.4			
Cumulative Addition uptill 2021 (MW)			14.4	14.4			
2022							
1	Master_Green	Wind	50	50	AEDB	Committed	Jul-21
2	Ranolia	Hydro	17	17	PEDO	Committed	Jul-21
3	Lucky	Local Coal	660	607	PPIB	Committed	Sep-21
4	Tricom	Wind	50	50	AEDB	Committed	Oct-21
5	Jabori	Hydro	10.2	10.2	PEDO	Committed	Dec-21
6	Karora	Hydro	11.8	11.8	PEDO	Committed	Dec-21
7	Metro_Wind	Wind	60	60	AEDB	Committed	Dec-21
8	Lakeside	Wind	50	50	AEDB	Committed	Dec-21
9	NASDA	Wind	50	50	AEDB	Committed	Dec-21
10	Artistic_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
11	Din	Wind	50	50	AEDB	Committed	Dec-21
12	Gul_Electric	Wind	50	50	AEDB	Committed	Dec-21
13	Act_2	Wind	50	50	AEDB	Committed	Dec-21
14	Liberty_Wind_1	Wind	50	50	AEDB	Committed	Dec-21
15	Liberty_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
16	Indus_Energy	Wind	50	50	AEDB	Committed	Dec-21
17	Zhenfa	Solar	100	100	AEDB	Committed	Dec-21
18	Trimmu	RLNG	1,263	1,243	PPIB	Committed	Jan-22
19	K-3	Nuclear	1,145	1,059	PAEC	Committed	Jan-22
20	Jagran-II	Hydro	48	48	AJK	Committed	May-22

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
21	Thar TEL	Local Coal	330	300	PPIB	Committed	Mar-22
22	Helios	Solar	50	50	AEDB	Committed	Mar-22
23	HNDS	Solar	50	50	AEDB	Committed	Mar-22
24	Meridian	Solar	50	50	AEDB	Committed	Mar-22
25	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	Committed	May-22
26	Thal Nova	Local Coal	330	300	PPIB	Committed	Jun-22
Generation Additions in 2022 (MW)			5,995	5,670			
Cumulative Addition uptill 2022 (MW)			6,009	5,684			
2023							
1	Karot	Hydro	720	720	PPIB	Committed	Jul-22
2	Access_Electric	Solar	10.52	10.52	AEDB	Committed	Aug-22
3	Access_Solar	Solar	12	12	AEDB	Committed	Aug-22
4	Jamshoro Coal (Unit-I)	Imp.Coal	660	629	GENCO	Committed	Oct-22
5	Lawi	Hydro	69	69	PEDO	Committed	Nov-22
6	Gorkin Matiltan	Hydro	84	84	PEDO	Committed	Nov-22
7	Zorlu	Solar	100	100	AEDB	Committed	Jun-23
8	Siachen	Solar	100	100	AEDB	Committed	Jun-23
9	Gwadar	Imp.Coal	300	273	PPIB	Committed	Jun-23
Generation Additions in 2023 (MW)			2,056	1,998			
Cumulative Addition uptill 2023 (MW)			8,065	7,682			
2024							
1	Siddiqsons	Local Coal	330	304	PPIB	Committed	Jul-23
2	Suki Kinari	Hydro	884	884	PPIB	Committed	Jul-23
3	Riali-II	Hydro	7	7	PPIB	Committed	Jul-23
4	Safe	Solar	10	10	AEDB	Committed	Sep-23
5	Western	Wind	50	50	AEDB	Committed	Nov-23

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
6	Trans_Atlantic	Wind	48	48	AEDB	Committed	Dec-23
7	Alliance	Bagasse	30	30	AEDB	Committed	Dec-23
8	Bahawalpur	Bagasse	31	31	AEDB	Committed	Dec-23
9	Faran	Bagasse	27	27	AEDB	Committed	Dec-23
10	Hamza-II	Bagasse	30	30	AEDB	Committed	Dec-23
11	HSM	Bagasse	27	27	AEDB	Committed	Dec-23
12	Hunza	Bagasse	50	50	AEDB	Committed	Dec-23
13	Indus	Bagasse	31	31	AEDB	Committed	Dec-23
14	Ittefaq	Bagasse	31	31	AEDB	Committed	Dec-23
15	Kashmir	Bagasse	40	40	AEDB	Committed	Dec-23
16	Mehran	Bagasse	27	27	AEDB	Committed	Dec-23
17	RYK_Energy	Bagasse	25	25	AEDB	Committed	Dec-23
18	Shahtaj	Bagasse	32	32	AEDB	Committed	Dec-23
19	Sheikhoo	Bagasse	30	30	AEDB	Committed	Dec-23
20	TAY	Bagasse	30	30	AEDB	Committed	Dec-23
21	Two_Star	Bagasse	50	50	AEDB	Committed	Dec-23
22	Tarbela_Ext_5	Hydro	1,530	1,530	WAPDA	Committed	Feb-24
23	Chapari Charkhel	Hydro	11	11	PEDO	Committed	Jun-24
24	Candidate_Solar	Solar	407	407	To be decided	Candidate	2024
25	Candidate_Wind	Wind	1,000	1,000	To be decided	Candidate	2024
Generation Additions in 2024 (MW)			4,768	4,742			
Cumulative Addition uptill 2024 (MW)			12,833	12,424			
2025							
1	CASA	Import	1,000	1,000	GOP	Committed	Aug-24
2	Kathai-II	Hydro	8	8	PPIB	Committed	Dec-24
3	Dasu_1 Unit 1-3	Hydro	1,080	1,080	WAPDA	Committed	Apr-25

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
4	Candidate_Wind	Wind	1,000	1,000	To be decided	Candidate	2025
Generation Additions in 2025 (MW)			3,088	3,088			
Cumulative Addition uptill 2025 (MW)			15,921	15,512			
2026							
1	Harpo	Hydro	35	35	WAPDA	Committed	Oct-25
2	Dasu_1 Unit 4-6	Hydro	1,080	1,080	WAPDA	Committed	Nov-25
3	Mohmand	Hydro	800	800	WAPDA	Committed	Apr-26
4	Keyal Khwar Unit 1	Hydro	64	64	WAPDA	Committed	May-26
5	Candidate_Wind	Wind	899	899	To be decided	Candidate	2026
Generation Additions in 2026 (MW)			2,878	2,878			
Cumulative Addition uptill 2026 (MW)			18,799	18,390			
2027							
1	Keyal Khwar Unit 2	Hydro	64	64	WAPDA	Committed	Aug-26
2	Balakot	Hydro	300	300	PEDO	Committed	Mar-27
3	Candidate_Solar	Solar	666	666	To be decided	Candidate	2027
Generation Additions in 2027 (MW)			1030	1030			
Cumulative Addition uptill 2027 (MW)			19,829	19,420			
2028							
1	Azad Pattan	Hydro	701	701	PPIB	Committed	Sep-27
2	Candidate_Solar	Solar	1,000	1,000	To be decided	Candidate	2028
Generation Additions in 2028 (MW)			1,701	1,701			
Cumulative Addition uptill 2028 (MW)			21,530	21,121			
2029							
1	Kohala	Hydro	1,124	1,124	PPIB	Committed	Jul-28
2	Diamer Bhasha	Hydro	4,500	4,500	WAPDA	Committed	Feb-29
3	Candidate_Solar	Solar	1,000	1,000	To be decided	Candidate	2029

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
			(MW)				
Generation Additions in 2029 (MW)			6,624	6,624			
Cumulative Addition uptill 2029 (MW)			28,154	27,745			
2030							
1	Candidate_Solar	Solar	1,000	1,000	To be decided	Candidate	2030
Generation Additions in 2030 (MW)			1,000	1,000			
Cumulative Addition uptill 2030 (MW)			29,154	28,745			

D-5. IGCEP Generation Mix 2021-2030 (GWh)

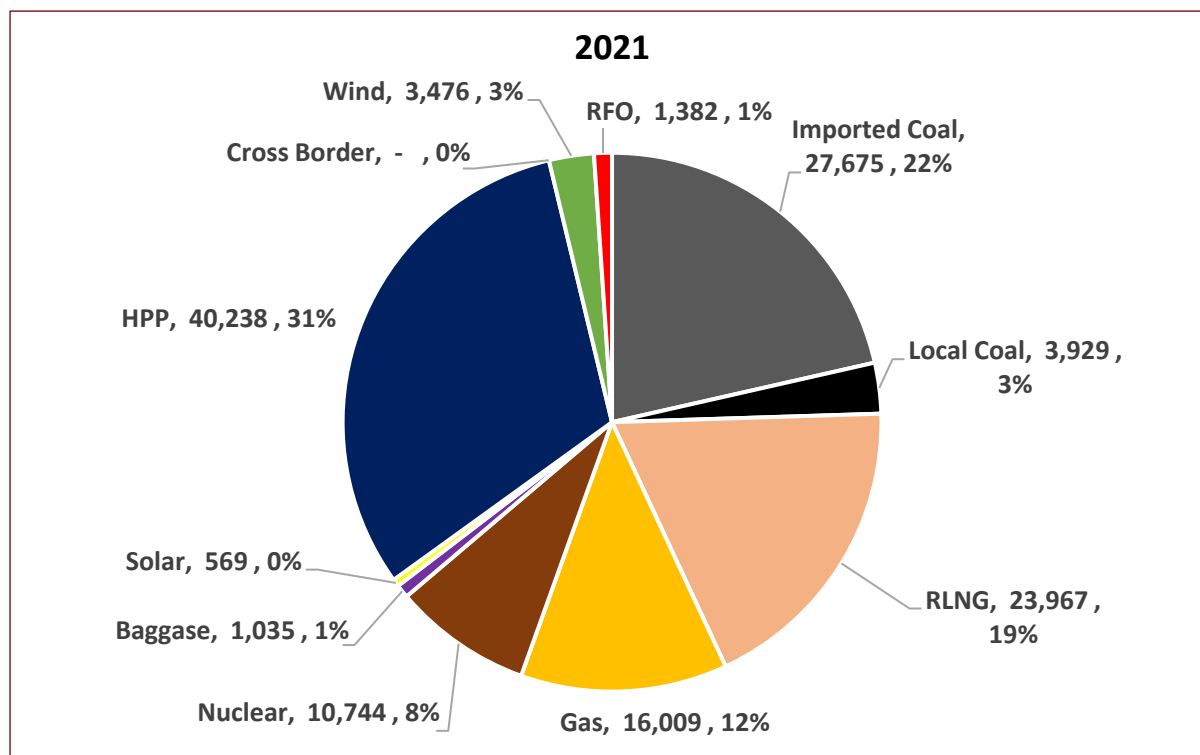


Chart D-3: IGCEP Generation Mix 2021 (GWh)

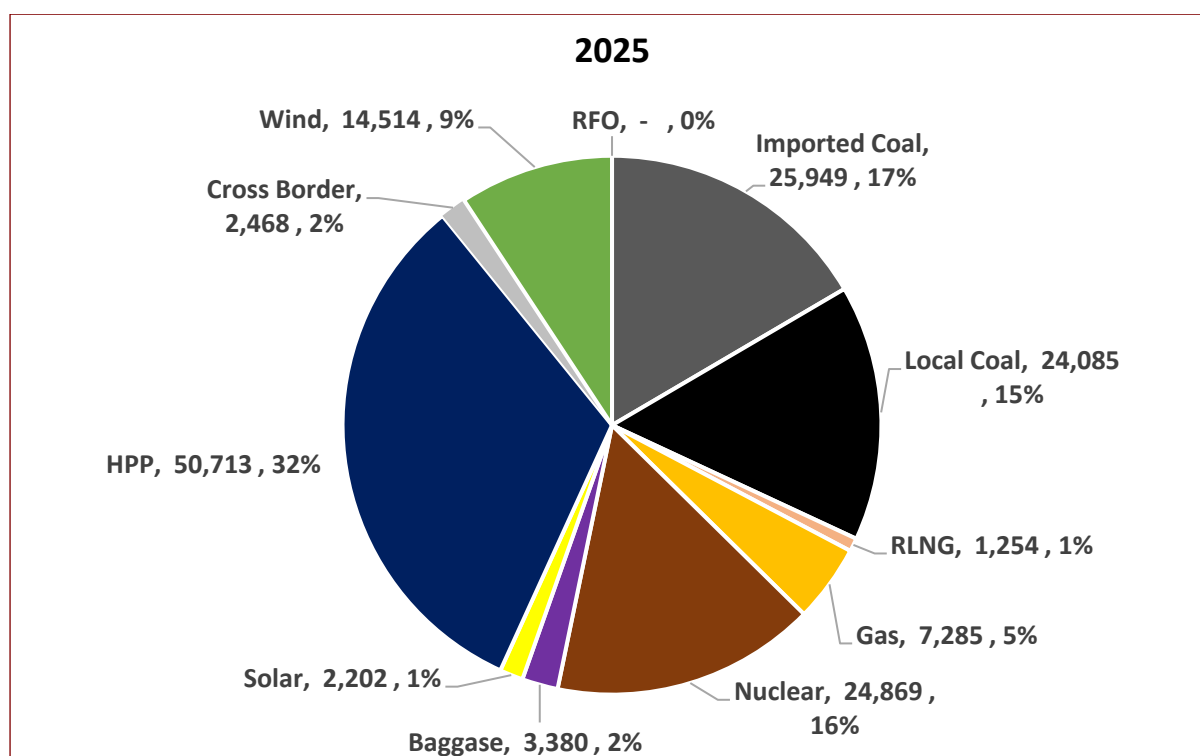


Chart D-4: IGCEP Generation Mix 2025 (GWh)

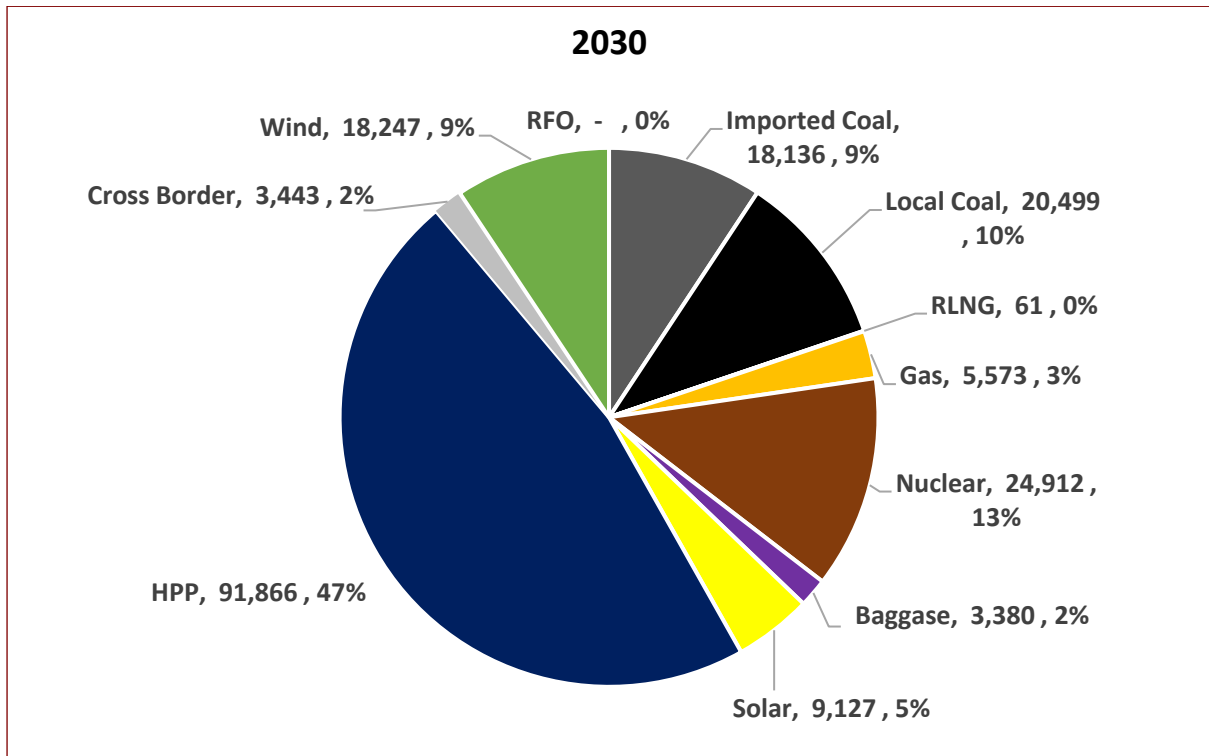


Chart D-5: IGCEP Generation Mix 2030 (GWh)

D-6. IGCEP Generation Mix 2021-30 (MW)

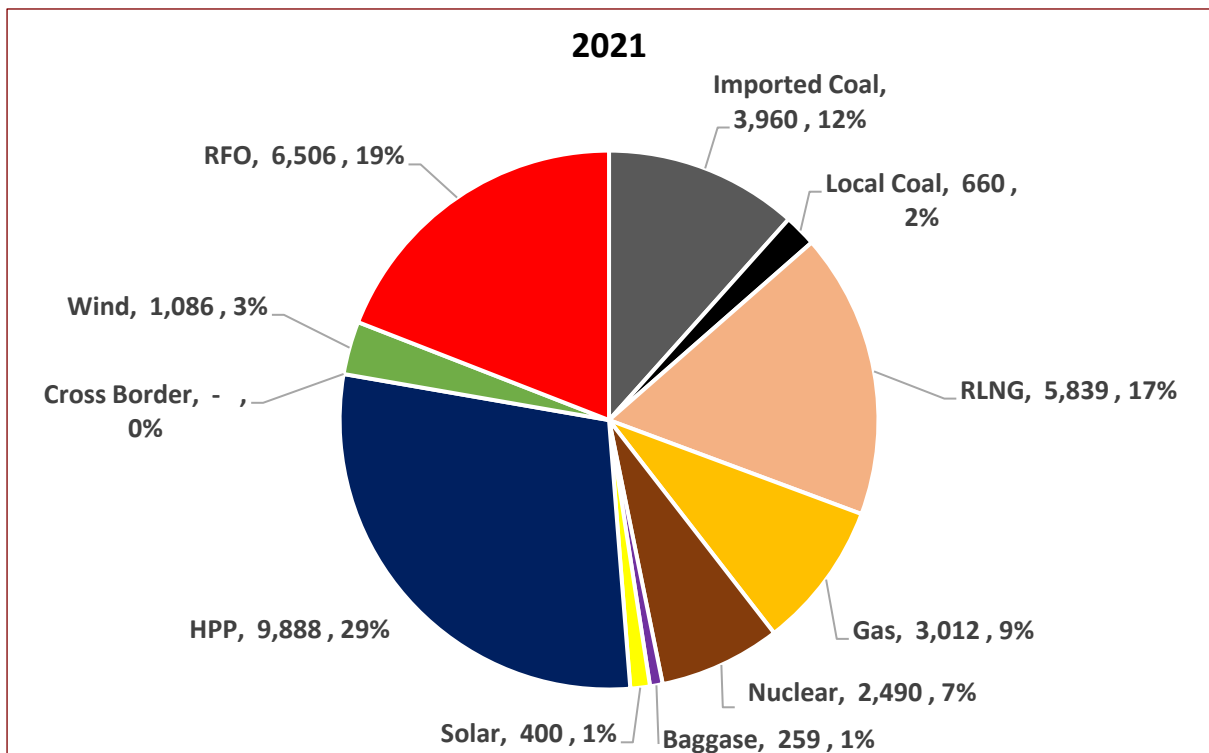


Chart D-6: IGCEP Generation Mix 2020 (MW)

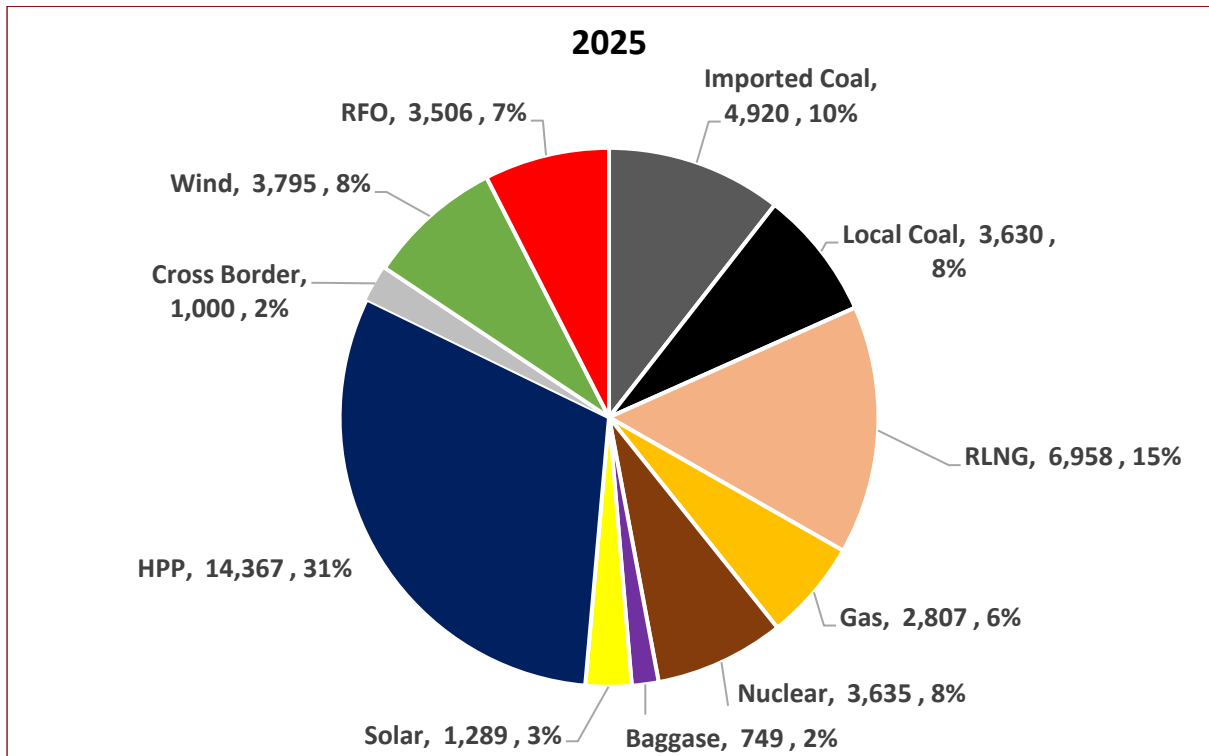


Chart D-7: IGCEP Generation Mix 2025 (MW)

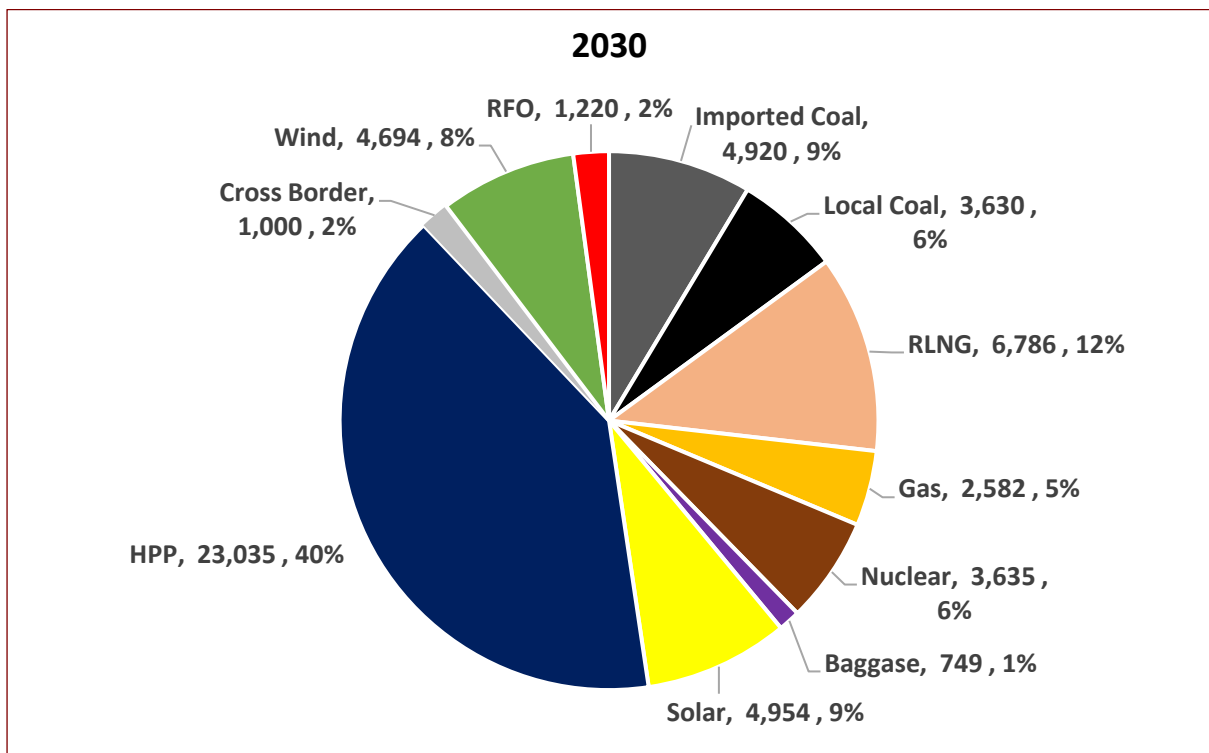
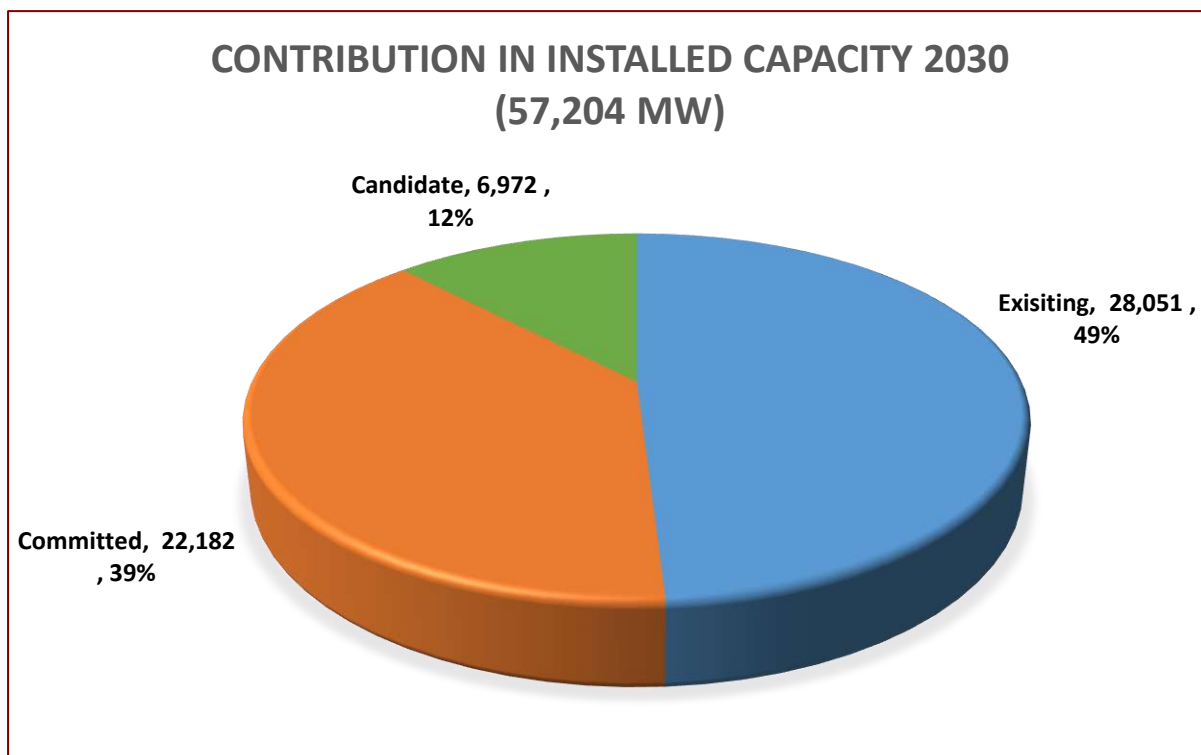


Chart D-8: IGCEP Generation Mix 2030 (MW)

D-7: Total Capacity Contribution in 2030



*Existing capacity contribution is after the retirement of the plants till 2030



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For comments, suggestions and concerns, please contact at +92 42 99200696 | ce.glf@ntdc.com.pk

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