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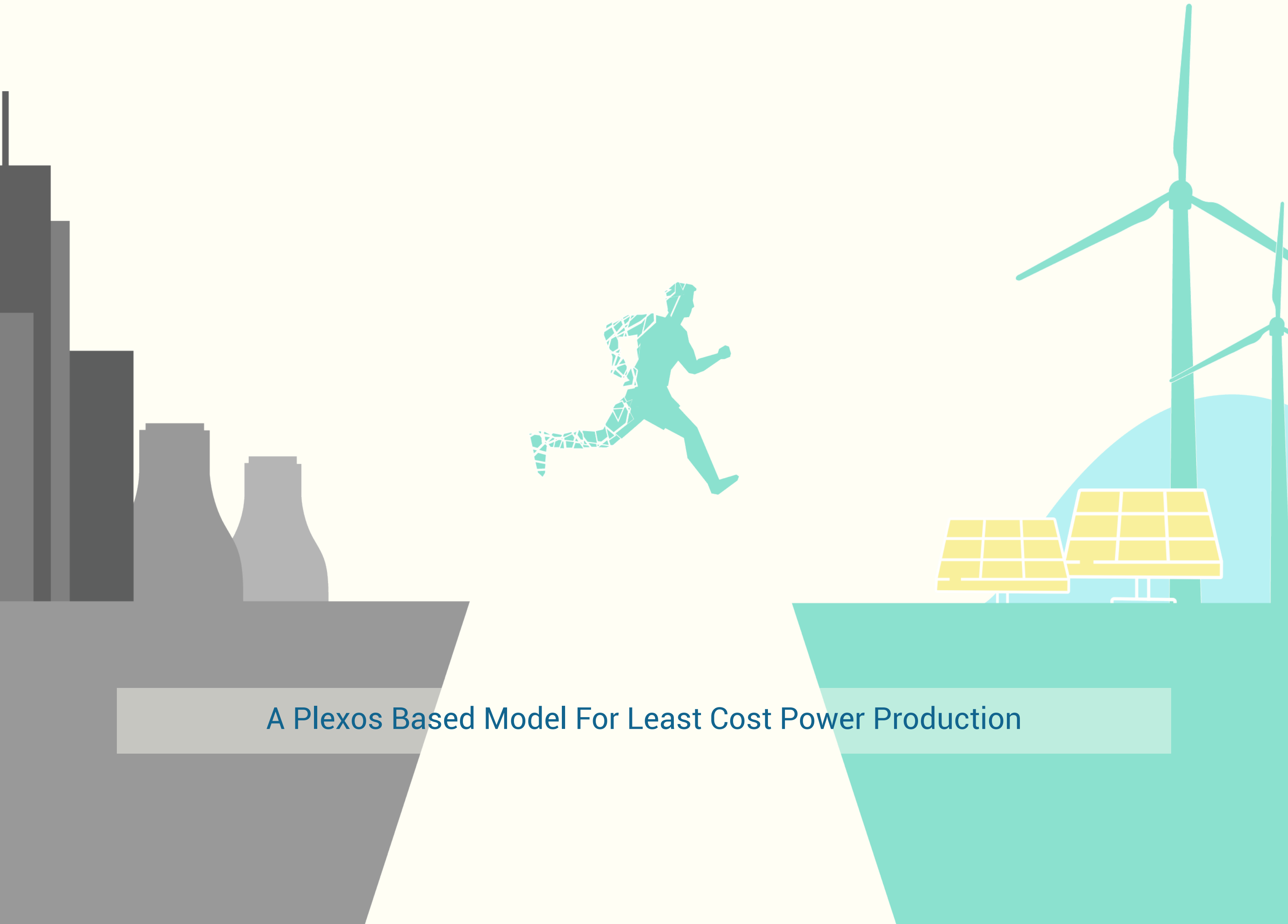
PAKISTAN'S FUTURE

Pathways to Optimize Affordable and Sustainable Electricity Generation, Beyond IGCEP 2024-34



A Plexos Based Model For Least Cost Power Production

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About Us

Renewables First (RF) is a think tank for energy and the environment. RF's work addresses critical energy and natural resource issues with the aim of making energy and climate transitions just and inclusive through impactful research, advocacy, and strategic partnerships.

Policy Research Institute for Equitable Development (PRIED) is a think-tank committed to sustainable and equitable development and a low carbon future. We produce high quality research to partake in and promote a global discourse on transition to renewable sources of energy; institutionalize interaction between all energy sector stakeholders in Pakistan; provide regulatory input, policy critique and research support to the parliament, government departments, aid organizations and international financial institutions; and organize events for networking and information-sharing.

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Disclaimer

All the information and analysis provided in this document are accurate and to the best of our knowledge and understanding, in case you identify any error, please email: info@renewablesfirst.org

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Foreword by CEO (PRIED & RF)

Salman Faruqui, a seasoned civil servant with over seven decades of experience, recently authored his memoir, Dear Mr. Jinnah -- 70 years in the life of a Pakistani civil servant. The book chronicles his journey through Pakistan's bureaucracy, offering insightful reflections on some of the most significant events in the country's history. During a book launch in Karachi, when questioned about the hefty capacity payments being made to Independent Power Producers (IPPs), Faruqui highlighted two important details: in 1993, the government predicted that Pakistan's electricity demand would reach 55,000 megawatts by 2018, and it sought to cap the share of electricity production in this demand by IPPs at 2,500 megawatts to avoid excessive capacity payments.

As of 2024, while the total capacity of IPPs has soared to over 12,000 megawatts, contributing to massive capacity payments running into hundreds of billions of rupees annually, the country's peak demand remains well below 30,000 megawatts, far short of the 55,000-megawatt forecast for 2018. Faruqui's memoir suggests that the government has been building power plants for years to cater for a demand that was simply not there, leaving Pakistan with more electricity than it can consume and more capacity payments than it can afford.

It is notable here, however, that these erroneous "assumptions" and "plans" on part of the government were never formally conducted, never published, and never subjected to independent reviews or consultations. It was only in 2021 that the first long-term electricity generation plan, the IGCEP, was approved by the regulator. There is a consistent pattern here: governmental institutions, bureaucrats, and politicians have repeatedly made ill-informed, last-minute decisions within the hidden corridors of power, resulting in the disaster we see in the energy sector today.

Where do things stand today? The approval of IGCEP in 2021 and the Transmission System Expansion Plan (TSEP) in 2022-mark major milestones in Pakistan's history. For the first time, long-term electricity generation and transmission plans were developed through structured processes, subject to public scrutiny – at least in principle - and made publicly accessible. These plans have garnered significant attention from various stakeholders and brought greater clarity to the consumers and developers alike.

However, some issues remain which indicate that the government's mindset has not changed. While the earlier editions of the IGCEP indicated significant promise with regards to renewable energy sources and least cost planning, the latest IGCEP has reduced the optimizable candidate projects to merely 1% of the total planned. This means that the rest 99% are not subject to least cost optimization. This means that only 1% of Pakistan's electricity in the next decade will be generated from projects optimized under the least-cost principle, while the vast majority will be produced through pre-committed projects—regardless of their cost. This is in sharp contrast to the previous edition of IGCEP, where the share of candidate projects open to optimization was significantly higher.

This situation is both problematic and absurd. Despite the use of advanced modeling software like PLEXOS, policymakers have effectively rendered the entire process moot by committing to projects whose necessity is questionable and which the software is not allowed to comment on. Large shares of hydroelectric and nuclear in the form of Diamer Bhasha and C-5 have been declared as committed even when, as our study shows, they are neither least-cost nor needed for their capacity in the electric grid.

While this is the situation on the supply side, there is little effort on the demand side to reign in new consumers. Captive power plants, which can raise utilization rates of idle plants, remain outside the national grid due to industrial mistrust in the government's ability to ensure stable and reliable electricity. At the same time, there is no initiative by the government to consider new technologies such as battery storage or electric vehicles, both of which could increase electricity consumption through the grid and lower average electricity costs.

The government may have been wrong in its assumptions about the projected power demand in the past, but demand can always be increased through proactive measures and initiatives. The government must also realize that reduced demand of electricity in the grid is not independent of its own behavior. Flawed planning, coupled with erratic policies, has alienated consumers and investors alike and the recent rise in roof-top net metering is an evident example of the public's growing distrust in the government's ability to provide reliable energy.

In the current study, our team has made an attempt to discuss the above scenarios and more with the intention of improving transparency and quality in power sector planning. By shedding light on the severe shortcomings in the current plan and proposing alternative scenarios, the authors hope to provide policymakers with the insights they need to correct course. Without careful reassessment, Pakistan risks burdening itself with unnecessary electricity projects—projects that could impose unsustainable costs for generations to come, a mistake that we have continued to make in the past and are in the process of making yet again.

Contents

List of Abreviations

Key Documents

IGCEP	Indicative Generation Capacity Expansion Plan
TSEP	Transmission System Expansion Plan
ISP	Integrated System Plan
ARE Policy 2019	Alternative & Renewable Energy Policy

Institutions & Entities

MoE	Ministry of Energy
NTDC	National Transmission and Desptach Company Limited
CPPA-G	Central Power Purchasing Agency
DISCO	Distribution Company (Total 10 in Pakistan)
KE	K-Electric
AEDB	Alternative Energy Development Board
IPP	Independent Power Producer
GENCO	Government Owned Generation Company
CPP	Captive Power Plants
WAPDA	Water and Power Development Authority
NEPRA	National Electric Power Regulatory Authority
GENCOs	State-owned Generation Companies
NEECA	National Energy Efficiency & Conservation Authority
IPPs	Independent Power Producers
CPPs	Captive Power Producers

Others

ISP	Integrated System Plan
VRE	Variable Renewable Energy
kW, MW, GW	Units of Power
kWh, MWh, GWh	Units of Energy

Executive Summary

Pakistan's power generation capacity expansion planning process continues to face credibility challenges despite being regularly conducted within an established regulatory framework. The newly launched Indicative Generation Capacity Expansion Plan (IGCEP) 2024-2034 (IGCEP 2024), succeeding the previous IGCEP 2022-2032 (IGCEP 2022), launched after a one-year delay, reveals significant changes in load patterns, generation patterns, and capacity expansion plan. The IGCEP is a comprehensive planning document prepared annually by the National Transmission and Despatch Company (NTDC) as per the Grid Code 2022 and approved by the National Electric Power Regulatory Authority (NEPRA).

NTDC has defined its base case for the IGCEP 2024 predicated on an average GDP growth rate of 3.5%, a figure considered low compared to the previous year's plan. In 2023-24, Pakistan's installed capacity stood at 43.7 GW, projected to scale up to 56 GW by 2033-34 according to the latest plan. While this increase corresponds to rising electricity demand, the projected peak demand is significantly lower than in the 2022 version. For instance, the financial year 2030-2031 is now expected to see a peak demand of 34 GW — about seven GW less than previously envisaged.

Additionally, total energy consumption is reduced by 18%, and peak demand projections have been notably lowered, with the high growth scenario for 2034 now equivalent to the low growth scenario from the previous plan. Notably, although overall electricity demand and consumption have dropped since last year, the generation expansion planning still needs to uphold the principles of reliable, affordable, and sustainable energy supply across the country. Alarmingly, over 99% of the capacity additions over the planning period of 2024 to 2034 are committed projects, leaving no room for least cost optimization by the power sector generation planning software PLEXOS. This report, a sequel to our previous study 'Powering Pakistan's Future' launched in 2023, endeavors to verify the outputs of the latest plan, along with bringing forward the outcomes of a true least cost generation expansion modeling exercise. We do so by first replicating the 2024 base case and extending it to various realistic and futuristic scenarios and sensitivities. Using this approach, we believe that the people of Pakistan can be better informed about the status quo of energy sector planning, its deficiencies, and the opportunity costs of paths undertaken by the government.

This assessment is also critical as the existing thermal 'take or pay' power plants are rendering the power sector financially unviable and becoming a financial burden because of their low utilization rates but persisting capacity payments. Therefore, it is indispensable to critically analyze any future capacity additions in terms of impact on the overall system cost, be they strategic or committed. The IGCEP plays a crucial role in this regard, as it outlines the specific power plants that need to be constructed following the least cost criteria, along with their respective timelines, to ensure a seamless transition to a more efficient and economically viable energy mix.

To conduct this rigorous exercise, we have leveraged our previous dataset and modified it to incorporate the latest available information. In addition, we have engaged with NTDC in the acquisition of the latest load profile data, whereas no other agency we reached out to provide the data we needed. Data acquisition and availability challenges have remained, but we have managed to bring forth this report in a condensed time of four to five months, using the best-suited assumptions wherever required.

The formation of a long-term capacity expansion plan is a praiseworthy effort as it sets a baseline direction for the power sector. However, there are certain transparency and methodology issues, which include:

- Incomplete disclosure of committed and strategic projects' cost data
- Missing technical data such as ramp-up, ramp-down rates, and scheduled and forced outages of thermal plants.
- Missing information and rationale behind macroeconomic assumptions such as forming base case on a low GDP growth rate.
- Over 19 GW capacity additions have been modeled as committed keeping the modeling tool blind to their capital costs.
- Heavily relying on hydro projects that will generate electricity from far away from the load centers. Also, the impact of dry seasons such as winter should also be considered.
- No weightage given to projected alternate and renewable energy shares in the national grid mandated by the ARE Policy 2019
- No scenario built on assessing how PLEXOS optimizes the generation expansion if committed projects are taken as candidate generation options.
- Not exploring the financial implications of delayed or early retirements of expensive thermal power plants.

The latest iteration of IGCEP specifies that about 20 GW of new capacity will be constructed and integrated into the national grid over the next decade, increasing generation capacity to 56,046 MW. This capacity expansion endeavor demands a substantial investment, estimated at USD 63.31 billion as per IGCEP 2024. The committed Diamer Basha Dam and Chashma Nuclear Unit-5 projects constitute a major portion of this required investment; but are they truly needed to meet the system demand; this is a question that we explore in this report.

This report is a continuation of an effort that started in 2021, in collaboration with Renewables First (RF) and the Policy Research Institute for Equitable Development (PRIED), to verify the generation planning process being followed in Pakistan and understand its implications for an average end consumer in terms of affordability and sustainability. We performed the same modeling exercise as NTDC did in formulating the IGCEP 2022 using the publicly available data, and assumptions, constraints, and data provided in the IGCEP 2022. Yet the results varied, and renewables were heavily optimized by our model. The 2024 iteration of the IGCEP, however, depicts an energy mix that not only contradicts our previous study results but also contradicts its previous 2022 iteration. Therefore, it is critical to evaluate IGCEP 2024 results, and what has led to such a stark shift in installed capacity by 2034 from different technologies.

The study underscores the vital need to incorporate a range of scenarios and sensitivities in power generation capacity expansion planning, integrating macroeconomic factors for sound decision-making. To further enhance this process, we aim to involve academic institutions and utilize advanced methodologies like Multi-Criteria Decision Making (MCDM) and Fuzzy Failure Mode and Effect Analysis (FFMEA). By fostering collaboration with academia, research institutions, and policy planning departments, we can ensure our strategies are both innovative and robust, ultimately strengthening Pakistan's energy resilience and sustainability for the future

Some of the major findings of our analysis are as follows:

1. If committed projects are treated as candidate projects and evaluated on merit in the base case, nearly $5.79 billion can be saved in total system cost, and VRE share can reach 13% in the grid by 2033. In medium and high growth scenarios, the VRE share can further improve to 25% and 26% respectively.

Committed projects are plants that have not been built or entered commercial operation to date, yet their feasibility is not evaluated by the IGCEP. In this scenario we fed both the initial capital expenditure (CAPEX) and ongoing operational expenditure (OPEX) of these projects into PLEXOS and allowed it to select, reject or optimize them. As a result, installed capacity by 2033 reaches 46.6 GW with 6.2 GW VREs in the base case, 55.4 GW with 14 GW VREs in the medium growth, 59.3 GW with 15.56 GW VREs, respectively.

2. As net metering quantum continues to increase because of soaring electricity prices and declining solar PV prices, no capacity additions will be required in the grid except for committed projects until the year 2027.

IGCEP 2024 projects 2.1 GW of net metering additions by 2034, however, the net metering additions have already crossed 2 GW. As electricity consumers continue to become prosumers with rooftop solar installations, large scale generators away from load centers can be avoided, bringing total installed capacity to 44.7 GW by 2033 with 4.7 GW of VRE, and enabling total system cost savings of $3.7 billion.

3. If the load of captive power plants is shifted on to the national grid, utilization rates of existing fleet become better, and no significant capacity has to be added to cater their load in the NTDC system. Whereas, in the KE system, 2.77 GW of Solar & wind, 82 MW of hydro, and 1.22 GW of coal is optimized.

IGCEP 2024 has no scenario which discusses the impact of shifting industry load on the national grid owing to the frequent shortage of gas. If load of industries is shifted on the national grid in phases (40% by FY 2027, 30% by FY 2029, and 30% by 2030), the installed capacity reaches 60 GW by 2033 with 10.4 GW VREs (17% VRE share). The utilization rates of the existing generation fleet also improve as a result.

4. When EVs charging demand is considered in the system, with pessimistic estimate of 2000 MW (400 MW in KE system and 1600 MW in NTDC system), no substantial capacity is optimized in the NTDC system leveraging the surplus capacity. Whereas, in the KE system, 1 GW of wind, 82 MW of hydro, and 305 MW of coal is optimized.

The total cost in this case is $62 billion owing to new capacity additions and utilization rates of the existing fleet also improve as a result.

5. When transmission capacity between NTDC and KE system is increased the need for optimizing new generation options in KE system is reduced

When tie-line transmission capacity is realistically assumed to increase to 3600 MW, the utilization of KE's fleet reduces significantly since the cheaper power from the national grid is available. Increasing the interconnection capacity also reduces the need for additional thermal power plants in the KE system. The results further suggest that the total installed capacity by 2033 will be 56.7 GW with a total system cost of around 60 billion USD.

6. **Diamer Bhasha Dam and CHASHNPP-5 are both expensive and not needed in the system**

Treating these high-cost projects as candidate options show that they are not optimized by the model due to their high cost and lack of need in the grid, and if forcibly added, they will lead to unnecessarily incurred costs of up to $7.6 billion (Diamer) and $5.52 billion (Chashma) as well as causing a reduction in potential shares of renewable energy.

Recommendations

Transparent Evaluation of Committed Projects: Rigorously assess all committed projects against least-cost criteria to ensure economic viability and alignment with policy goals, particularly in increasing renewable energy adoption.

Focus on Renewable Integration and Grid Modernization: Prioritize investments in grid infrastructure to accommodate renewable energy sources and BESS, enhancing flexibility, reducing losses, and preventing theft.

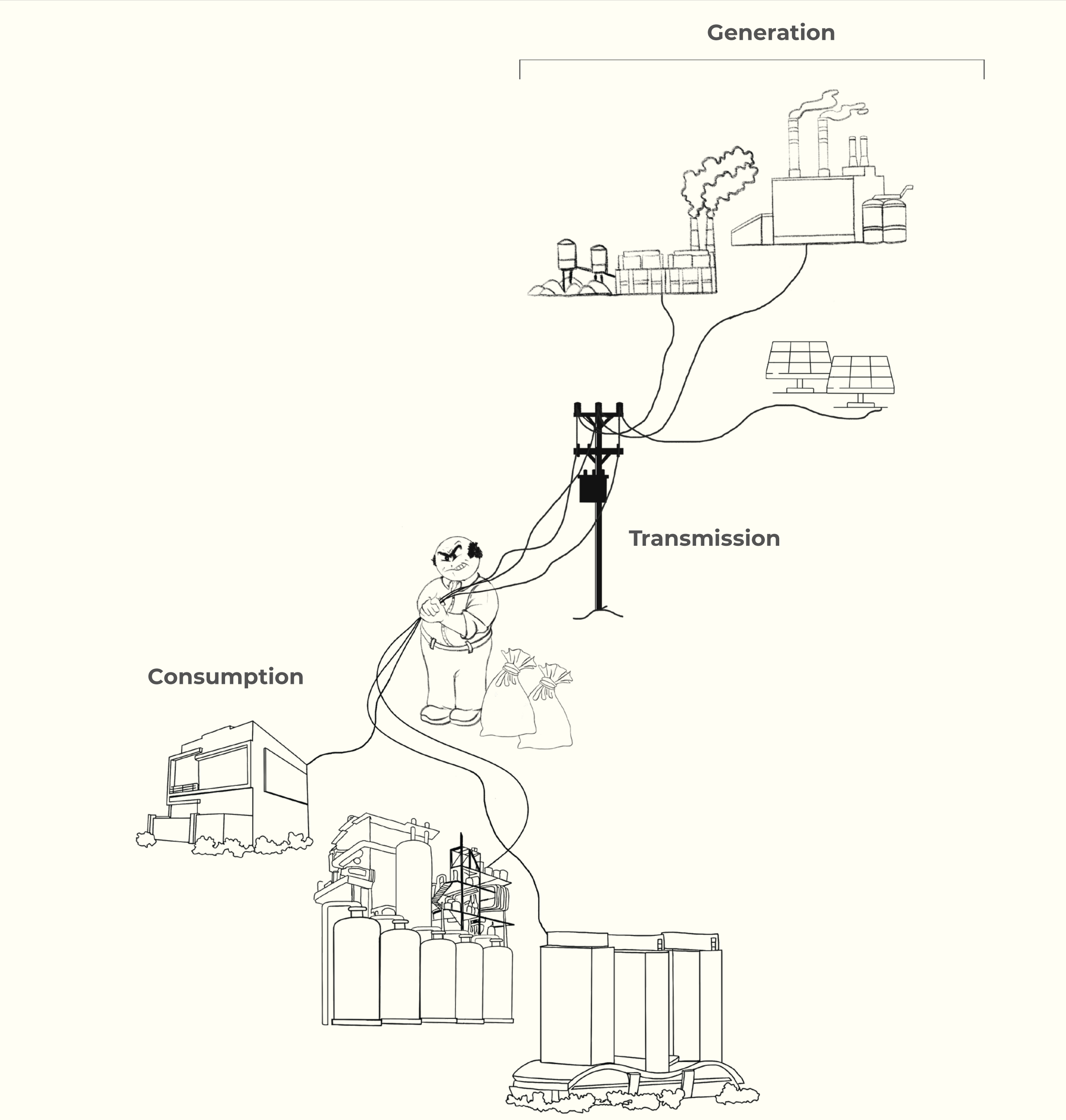
Enhance NTDC-KE Connectivity: Increase the tie-line capacity between NTDC and KE to supply affordable electricity, reducing KE's reliance on costly and environmentally unsustainable local coal and fossil fuels.

Leverage Rooftop Solar Growth: Encourage rooftop solar installations to meet energy demands without additional capacity investments, capitalizing on declining solar PV prices.

Incorporate EV and CPP Loads Strategically: Integrate EV charging infrastructure and shift CPP loads to the national grid to optimize existing capacity and promote renewable energy utilization.

Avoid Unnecessary Capacity Additions: Given surplus capacity and underutilized plants, refrain from new capacity additions unless they meet strict least-cost and sustainability criteria.

Finally, it is worth mentioning that significant resources and energy have been dedicated to conducting the above analysis. Driven by a genuine commitment to enhancing Pakistan's power sector, our team has worked year-long to address the shortcomings in the IGCEP 2024-2034 diligently. We urge the government and planning agencies to be more open to our insights and recommendations. By integrating our findings, they can better serve the needs of Pakistan's citizens and advance towards a more sustainable and efficient energy future.



Chapter 1:

An Overview of Pakistan's Power Sector

The power sector of Pakistan can be broadly divided into three separate categories based on the flow of electricity: generation, transmission & distribution, and consumption.

Generation

Generation of electricity across the country is carried out by a combination of state-owned Generation Companies (GENCOs), large hydro power plants (maintained by WAPDA), nuclear plants, and Independent Power Producers (IPPs) which include thermal, hydro and renewables.

Transmission & Distribution

Transmission of electric power across the country is the responsibility of NTDC which operates the primary transmission network of Pakistan and supplies electricity to all areas of the country except the zone of K-Electric (KE). KE, being a privately owned and vertically integrated utility, possesses its own transmission system, which is the sole network for transmitting power to Karachi and some surrounding regions. However, NTDC relates to the KE system through a 1100 MW tie-line, the capacity of which has augmented to 2050 MW, after commissioning of KANUPP – K-Electric Interconnection grid in June 2024. This way cheaper electricity can flow from NTDC's system to the KE system up to transmission capacity as and when needed.

Distribution is being carried out through eleven publicly owned Distribution Companies (DISCOs). These are responsible for electric power distribution in their respective areas. The only exception is KE, which is a vertically integrated utility and carries out all three main functions of generation, transmission, and distribution within a 6500 km2 territory including Karachi and its adjoining areas.

Consumption

Electricity consumption (or demand) in Pakistan is distributed across four main areas: residential, commercial, agricultural, and industrial. Pakistan's daily and annual consumption patterns are highly variable, with a consistent increase in peak demand over the years and little to no increase in the base load. These features make variable renewable energy sources (VRE) such as solar, wind, and hydro attractive for Pakistan as they naturally complement each other.

End-Users

End users are connected through electricity meters with the DISCOs infrastructure to power their homes, businesses, industries, Farms, and Government. These end users are further categorized based on their consumption patterns (e.g., peak/off-peak hours), load profiles and tariff structures (e.g., residential, commercial, industrial, agricultural), and metering arrangements (e.g., prepaid, postpaid, smart meters).

42,501 MW NTDC's Installed Capacity	**3,384 MW** KE's Installed Capacity	**27,333 MW** Peak demand of Country FY 2022 - 2023
129,030 GWhs NTDC's Total Generation FY 2022	**8,998 GWhs** KE's Generation Fleet FY 2022	**16.45%** Transmission and Distribution Losses

Overseeing Bodies

Federal

MOE (Ministry of Energy)

CCOE (Cabinet Committee on Energy)

Mediator

CCI (Council of Common Interests)

Provincial

Provincial Energy Departments

NEPRA (System Regulator)

NTDC (System Planner and Operator)

Generation

60 Fossil Fuel Plants
7 Nuclear Plants
22 Hydel Plants
14 Small Hydel (<30 MW)
12 Solar Plants
45 Wind Plants
10 Bagasse Plants

Transmission

Lines

8,825 km of 500 kV (71 circuits)
11,633 km of 220 kV (166 circuits)

Grid Stations

19 grid stations of 500 kV
50 grid stations of 220 kV

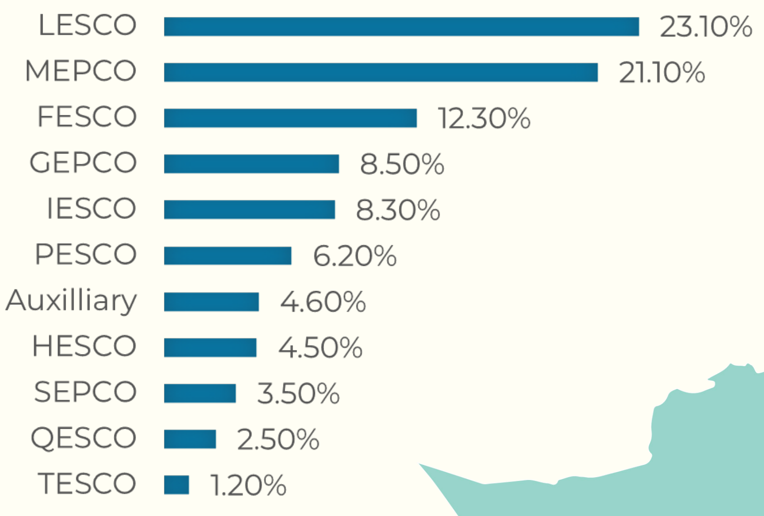
Transformers

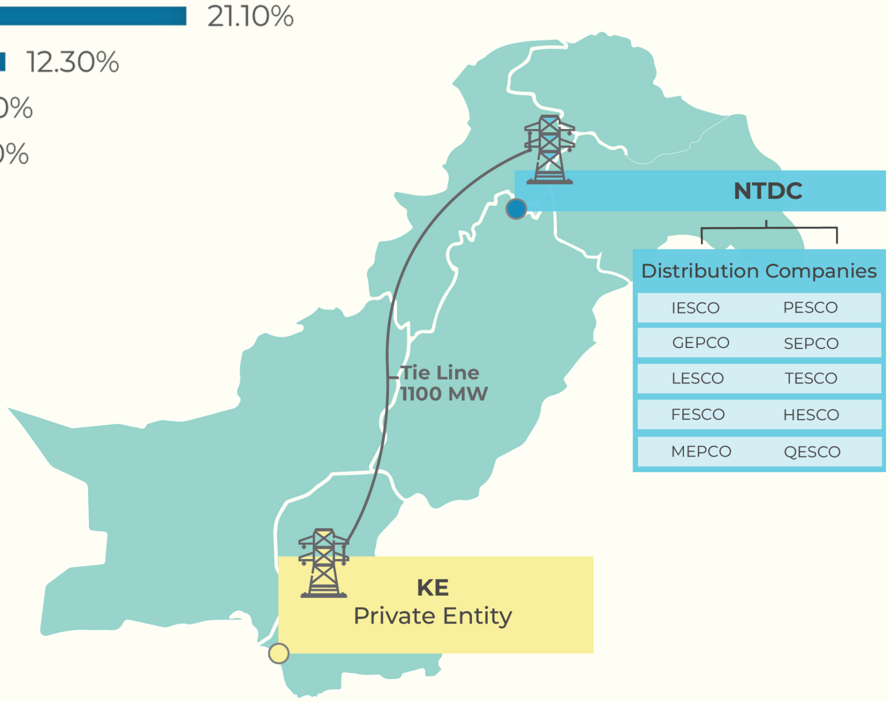
47 transformers of 500/220 kV
179 transformers of 220/132 kV

Distribution

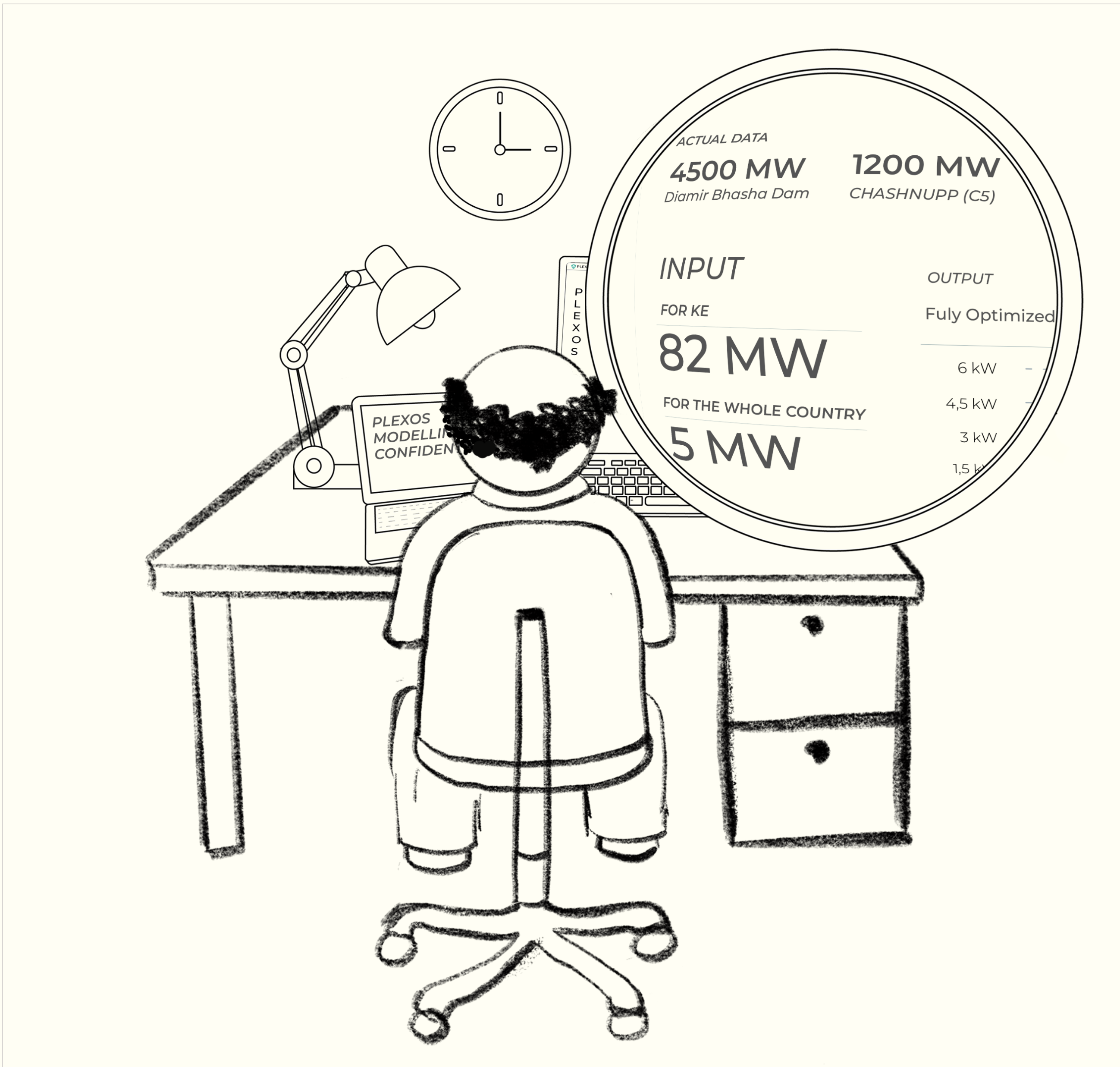
31,656 km of 132 kV lines
941 Grid Stations of 132 kV
2,267 Power Transformers
58,042 Distribution Transformers
358,219 Feeders of 11 kV

Share of electricity consumption - FY 2023





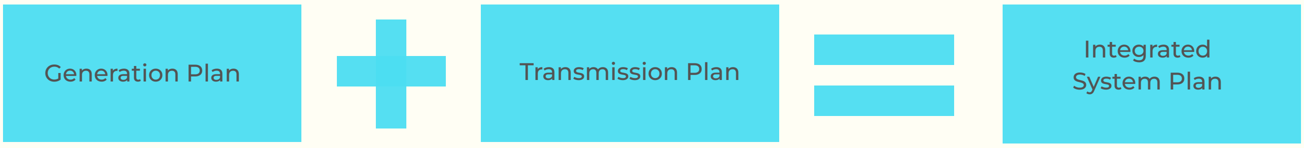
In Pakistan, a two island approach is followed in which the power sector is split into two subsystems: NTDC and KE. Both sectors manage their own supply and demand which results in more expensive dispatch in the KE system. This approach also fails to benefit from demand-curve superposition.



Chapter 2:

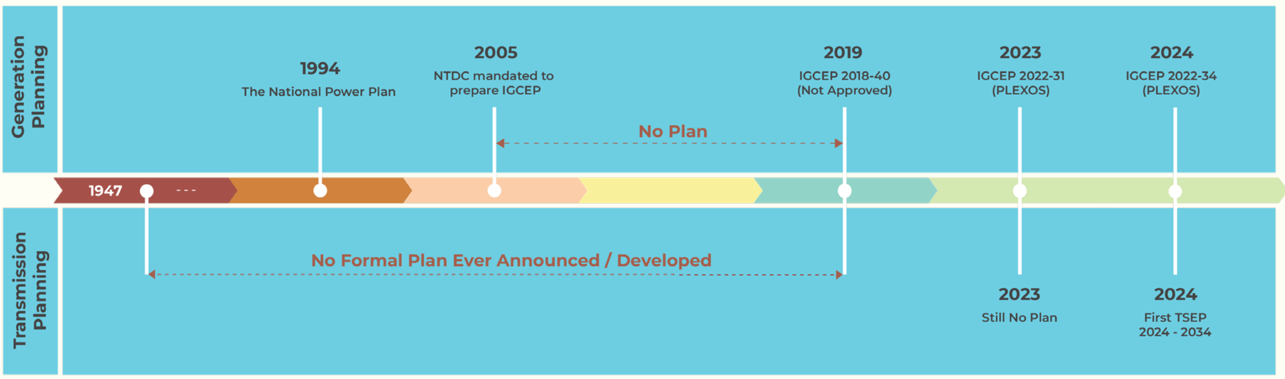
Power Sector Planning Process

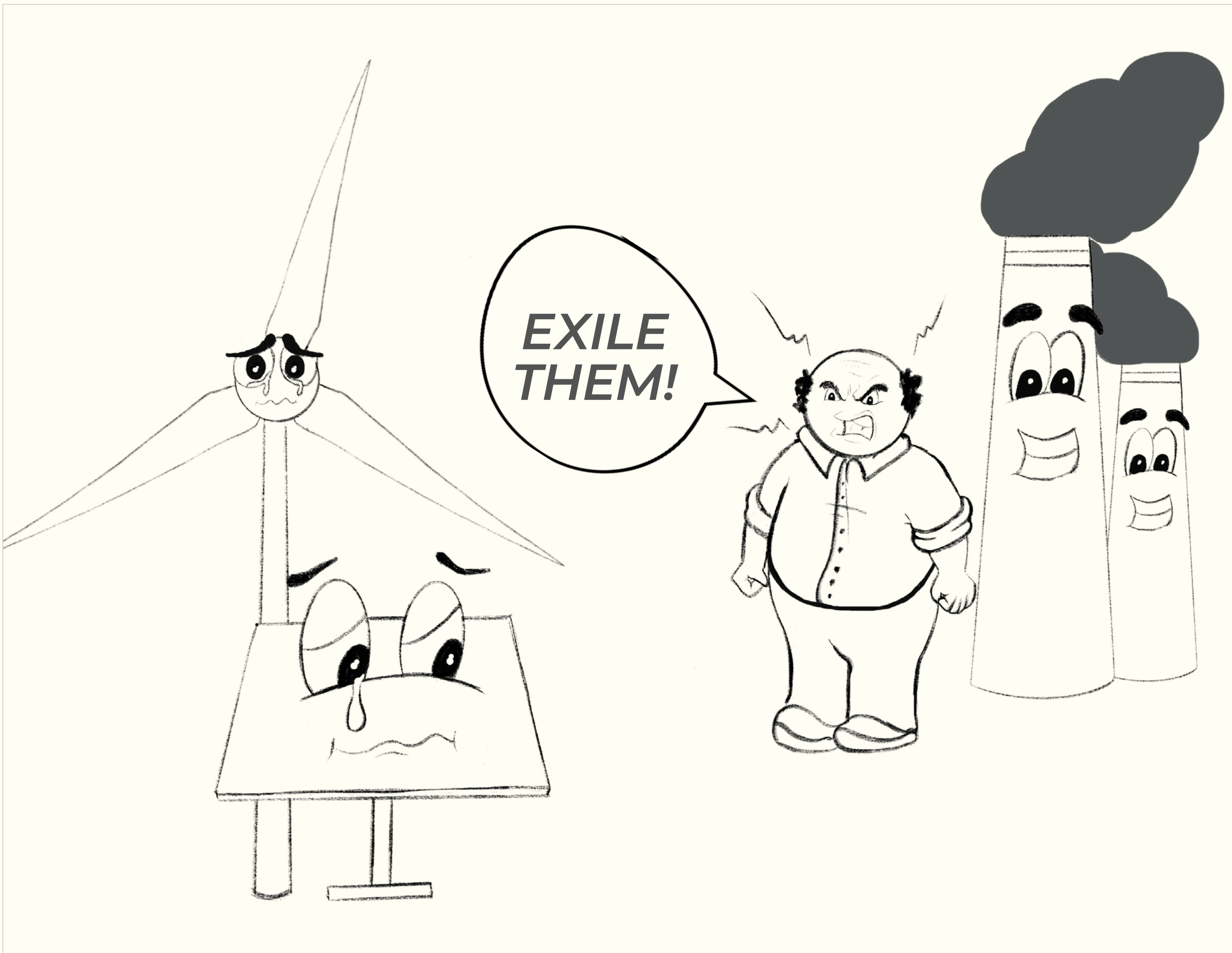
The planning process in the power sector can be divided into two major categories: generation planning (laid out in the IGCEP) and the transmission planning (laid out in the TSEP). The IGCEP is of at least 10 years, prepared every year with rolling horizon, whereas the Transmission System Expansion Plan (TSEP) may be prepared for one, three, five or ten years. The first IGCEP in the history of Pakistan was approved in 2021 whereas the first TSEP has come to light in 2024. Principally, both IGCEP and TSEP are required to be in place to form an Integrated System Plan, that lays out the viability of any generation project. This year, IGCEP 2024 has come together with the TSEP but has not been infused into an Integrated System Plan (ISP) document.



In early decades of post-independence, more emphasis was given to water resources management rather than energy concerns. WAPDA was established in 1958 mainly for managing water resources to boost the country's agricultural economy. Although various studies on power system planning were undertaken afterwards to supplement the regular five-year medium-term plans of the Government, no energy policy was formally announced by any government until 1994. It was only in 2005 that NTDC was mandated by the grid code to prepare a comprehensive capacity expansion plan, the IGCEP, which it failed to produce for the next 15 years. Power plants continued to be built on an ad-hoc and arbitrary basis, the disastrous economic implications of which have culminated in the economic crisis that we live in today.

When the NTDC finally submitted its first plan to NEPRA in 2019 and 2020, they were found inadequate and subsequently rejected. Only when in 2021 the World Bank made the disbursement of a $400 million loan contingent on the approval of IGCEP, was it hastily approved by the regulator. The subsequent plan, however, which was due in June next year, came more than three months late. Such institutional failures to deliver and arbitrary delays are a routine occurrence in the power sector of Pakistan and have cost the country dearly. While the grid code 2005 augmented by the latest approved grid code in 2023 also required NTDC to submit the TSEP along with the IGCEP, only recently in 2024, we have seen both planning documents coming into public together. Although the power sector planning is becoming continuous, now the challenge remains in making the planning process credible, transparent, and accessible to the relevant stakeholders.





Chapter 3:

Assumptions & Methodology

Our goal in this study is to assess the credibility of the IGCEP prepared by NTDC in terms of reliability and least cost criteria. To achieve this objective, we have developed a base case model that considers the same assumptions and constraints as provided in the IGCEP 2024. The planning horizon in this study is considered as 10 years as per the Grid Code 2023 — which stipulates a planning horizon of at least 10 years — under section PC 2.1 c, as per which we have shown the results until the FY33. The IGCEP 2024, however, extends it a year further and shows the results until the FY34. The base year is considered as Fiscal year 2024 (July 2023-June 2024). Where any data is found missing or incomplete, we have referred to data available on NEPRA's website to fill such gaps. We have also taken additional assumptions where required to get equivalent results as in the IGCEP 2024. Some of the key assumptions for our base case have been listed below for reference:

◊ Business as usual demand forecast has been considered for developing the base case which corresponds with low rate of GDP growth.

◊ For candidate local coal (330 MW coal fired Steam at Thar), the fixed fuel cost component of 113.205 $/kW-year and fuel price of 1.45 $/GJ has been considered respectively.

◊ For candidate local coal (660 MW coal fired Steam at Thar), the fixed fuel cost component of 107.72 $/kW-year and fuel price of 1.70 $/GJ has been considered respectively.

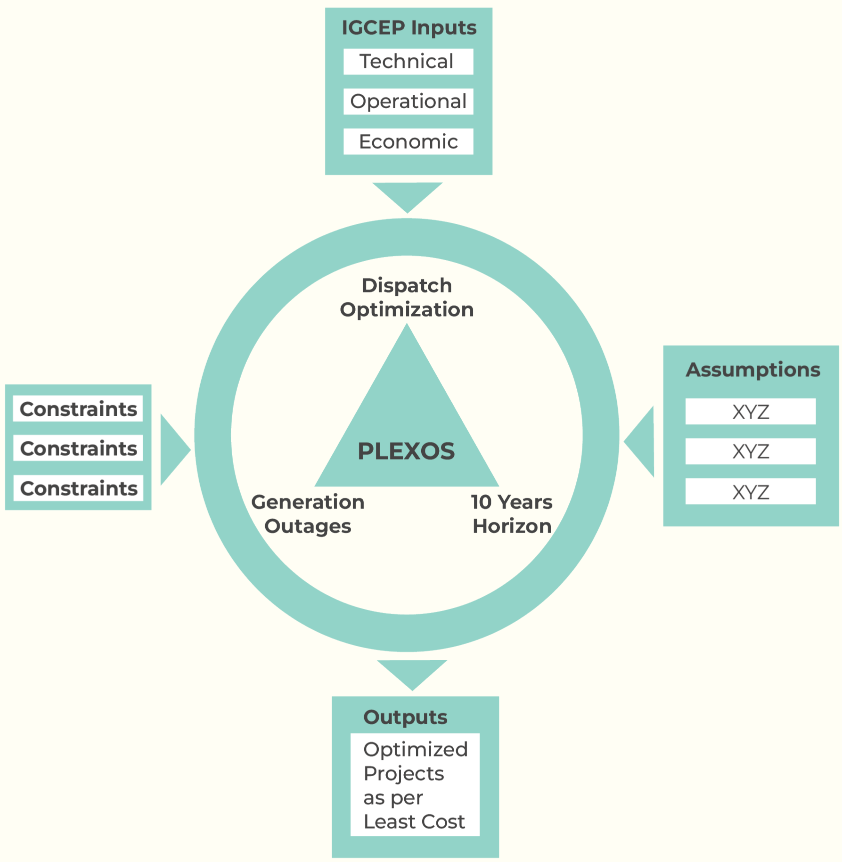
◊ The lead time of four years for candidate local coal projects and a 2-year for wind and solar technologies has been considered in the model.

◊ Only 1000 MW of wind can be added each year starting from July 2027 as candidate generation option. Only 1300 MWp of solar can be added each year starting from July 2027 as candidate generation option.

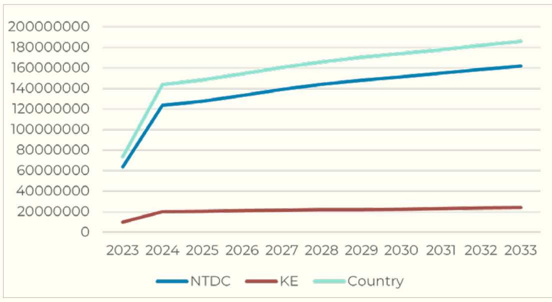
◊ A yearly block of 100MW of a new/disruptive/nascent technology has been considered from 2028 onwards until the end of study horizon. The cost parameters for the new technology have been added considering an average price lower than the basket price of electricity.

◊ Existing projects located near the load center have been considered as "Must Run", for summer months, i.e., May to September up till year 2027.

For the committed Hydel, we have used reference power purchase prices as issued by NEPRA in the Reference Power Purchase Prices for FY 2024 – 2025 dated June 14, 2024

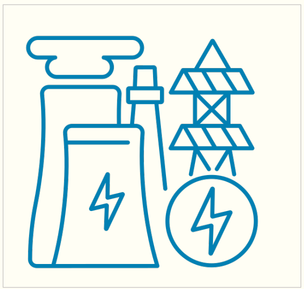


RF-PRIED PLEXOS Modelling Process



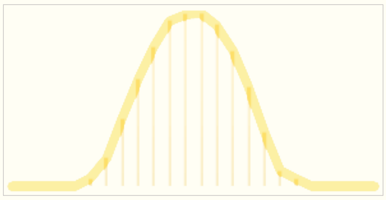
Load Forecast

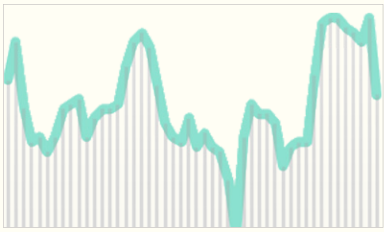
Based on projected GDP growth rate of 3.5% in the base case for a 10-year period, whereas CAGR stands at 3.1%.



Feeding 300+ Generation Options

Technical data such as capaciity, min stable level, heat rates, ramp rates etc. from existing, committed, and candidate power is fed into PLEXOS for analysis.



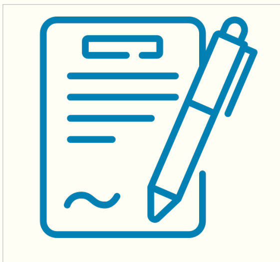


Wind and Solar Profiles

Hourly solar and wind data were fed into the model for 8,760 hours of the year. Separate data is entered for utility-scale, distributed generation, net metering, and existing plants.

Hourly Load Profiles

NTDC provided detailed hourly profiles for 175,200 hours, greatly improving the model's accuracy and reliability.

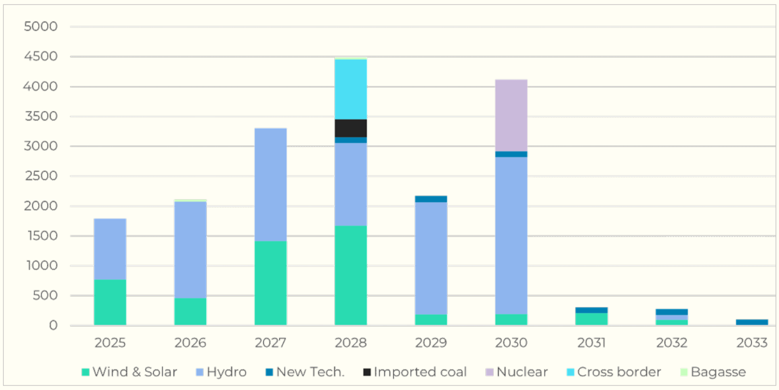


Contractual Obligations & Constraints

Constraints such as minimum energy off take requirements, must run statuses, and retirements are added in the model in line with IGCEP 2024.

Economic & Financial Parameters

Parameters such as build costs, operations and maintenance costs, economic life (e.g. 50 years for hydro and nuclear), fuel costs etc. are fed into the model based on EIA projections.



Projects Optimized by PLEXOS

Considering all respective constraints, assumptions, build costs, dispatch capability, and financial parameters, PLEXOS recommends technology builds on a least-cost principle, year by year.

Data Availability and Acquisition Challenge Still Exists

The best approach in power sector modeling is using practical and realistic data, which helps the model capture complex and rapidly changing ground conditions. The more accurate and practical data we procure the more accurately we predict future demand, optimal resource allocation and dispatch, future transmission and distribution planning, and prevent faults, losses, and blackouts.

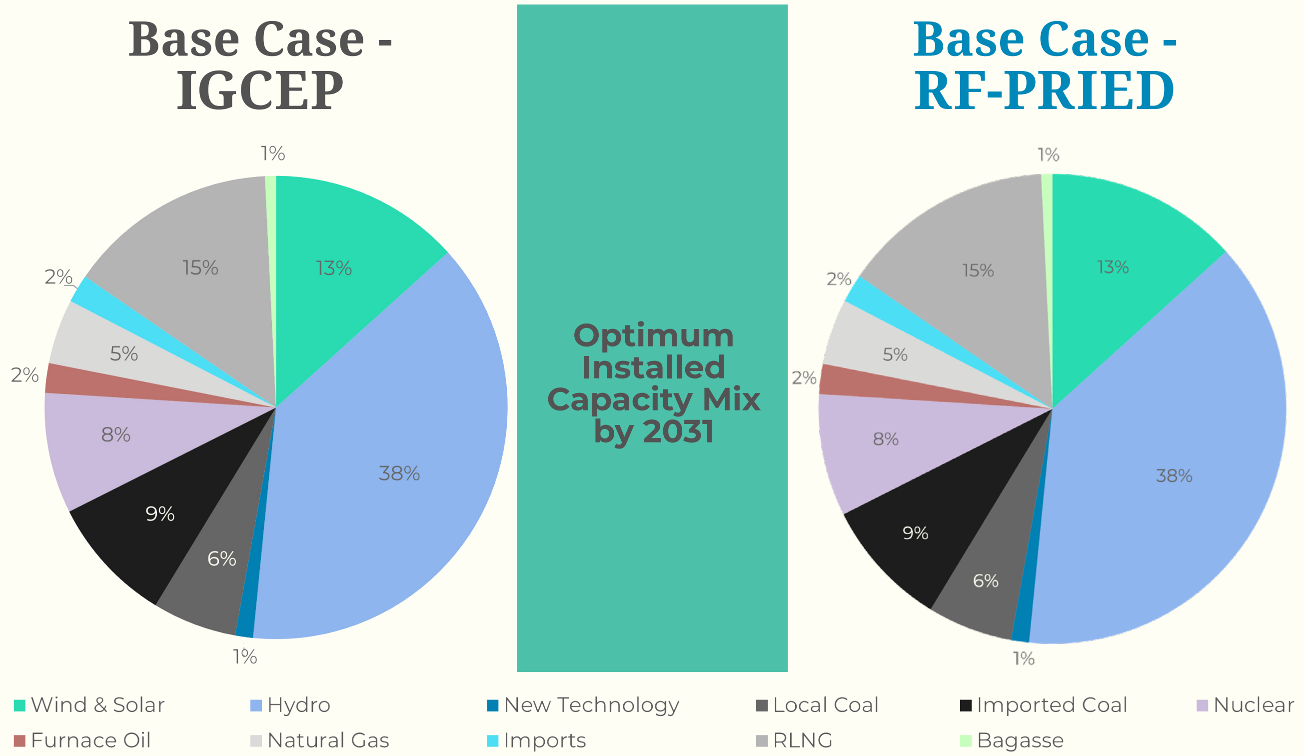
Data plays a crucial role in energy planning, but its availability, accessibility and usability, is often compromised. While some generation planning data can be found in the State of Industry Reports, tariff determinations, and generation licenses, the formats are not easily readable or understandable. While conducting this study, our major challenge has been data collection. Although we were provided load forecasting data by the NTDC, cooperation from other entities has been limited. Furthermore, data available on NEPRA's website is either not complete for power generators or is not updated. For example, tariff determinations at the stage of commercial operations start of recent coal-fired power plants are missing, and for nuclear no specific data is available on NEPRA's website or Pakistan Atomic Energy Commission.

Particularly for hydel committed projects, whose cost details are not available in IGCEP 2024, various websites were surfed to find relevant cost data and generation profiles. The ramp rates essential for increasing and decreasing energy generation as per variations in demand are missing; the ramp rate fluctuation may impact plant efficiency and indirectly the cost of generation, which is again missing in the document.

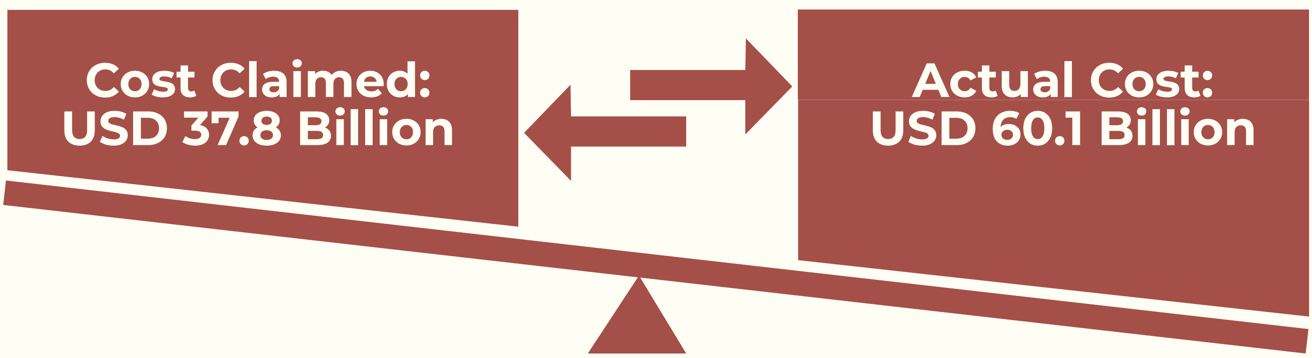
Pakistani citizens pay taxes for all their basic utilities, which helps the government in running the power sector; they have the right to know where their taxes have been spent. Therefore, data transparency is indispensable and its accessibility is crucial to ensure accountability, improving stakeholder participation, making informed decisions for generating revenue, reducing risks, potential research and planning, and attracting foreign investment in the power sector.

Comparison of IGCEP & RF-PRIED Base Case

The figure below illustrates the differences between NTDC's IGCEP and RF-PRIED's base case, with the most significant disparity being the total system cost claimed by NTDC. This discrepancy primarily arises from the tariff assumptions for committed hydropower projects totaling approximately 10.47 GW. Notably, the IGCEP lacks clear tariff assumptions for these committed projects, and it appears that NTDC has significantly underestimated these tariffs. As a result, the cost projections do not accurately reflect the true financial implications of the committed hydropower projects.



2033		
13% (7.5 GW)	Share of Wind and Solar	13.4% (7.6 GW)
56.8 GW	Total Installed Capacity	56.8 GW



*The total costs represent the NPV and are without inclusion of project costs of the committed projects. Since NTDC has not mentioned the projects costs of committed projects, we have also excluded the same from above, which is quite significant. A comprehensive comparison must take the cost of committed projects into account. The total scenario-wise investments are listed separately for each scenario in the results section.

3.1 Demand Forecasting

Demand forecasting is done by using PLEXOS and all the assumptions have been taken from IGCEP. While determining the demand, NEECA's energy efficiency targets have also been rationalized into the model. The demand forecast also considers the non-AT&C losses gradually in the system.

Table: Demand forecasting (NTDC System)

FY	Low growth		Medium Growth		High Growth	
	Load (GWh)	Peak Demand (MW)	Load (GWh)	Peak Demand (MW)	Load (GWh)	Peak Demand (MW)
2024	122,743	24,453	128,240	24,812	139,039	26,902
2025	126,330	25,090	131,012	25,579	142,901	27,767
2026	130,991	25,936	135,536	26,706	144,672	28,231
2027	137,285	27,099	141,361	28,112	148,013	29,007
2028	141,619	27,870	148,822	29,872	152,829	30,080
2029	145,809	28,819	154,340	31,059	159,156	31,461
2030	150,200	29,817	160,690	32,420	166,852	33,125
2031	152,579	30,422	167,363	33,853	175,887	35,072
2032	156,799	31,401	175,103	35,510	186,304	37,312
2033	159,357	32,197	183,343	37,374	197,995	40,004

Table: Demand forecasting (K-Electric System)

FY	Low growth		Medium Growth		High Growth	
	Load (GWh)	Peak Demand (MW)	Load (GWh)	Peak Demand (MW)	Load (GWh)	Peak Demand (MW)
2024	19,975	4,114	21,874	4,168	21,897	4,172
2025	20,257	4,234	21,969	4,290	22,271	4,349
2026	20,813	4,347	22,256	4,404	22,334	4,420
2027	21,271	4,463	22,545	4,522	22,861	4,586
2028	21,714	4,571	22,877	4,631	22,948	4,646
2029	22,032	4,706	23,100	4,768	23,747	4,901
2030	22,377	4,833	23,363	4,896	24,148	5,060
2031	22,768	4,963	23,682	5,028	24,891	5,285
2032	23,323	5,084	24,167	5,150	25,315	5,395
2033	23,852	5,235	24,622	5,303	26,007	5,602

3.2 New Generation Options

For the base case scenario, to keep the set of assumptions similar to what is mentioned in the IGCEP, we have kept the candidate generation options the same as given in the IGCEP. However, for the additional scenarios such as unconstrained renewable energy addition, the number of solar and wind power plants along with the new technologies such as Battery Energy Storage Systems (BESS) is increased and left for the PLEXOS to optimize as required. The CAPEX and tariff assumptions for additional solar and wind power projects are kept like the IGCEP and for the BESS, the CAPEX is estimated by consulting with independent consultants and research-based institutes like Bloomberg New Energy Finance and IRENA.

3.2.1. Candidate Generation Options

Keeping in line with the IGCEP, the following candidate options have been built in the NTDC and KE's system, for optimization by PLEXOS:

NTDC System

◊ Steam Turbine New Local Coal candidate (330 MW)

◊ Steam Turbine New Local Coal candidate (660 MW)

◊ Gas Turbine on RLNG (400 MW)

◊ Combined Cycle Gas Turbine on RLNG (1263 MW)

◊ Nuclear Steam PP on Uranium (1,200 MW)

◊ Wind Turbines 1000 MW each year starting from July 2027

◊ Utility-scale solar of 1300 MWp each year starting from 2027

KE System

◊ Steam Turbine New Local Coal candidate (330 MW)

◊ Steam Turbine New Local Coal candidate (660 MW)

◊ Wind Turbine (Block of ≤ 300 MW in July 2025 and Block of ≤ 100 MW each year till the end of study horizon)

◊ Solar PV (Block of ≤ 300 MWp in July 2025 and Block of ≤ 200 MWp each year till the end of study horizon)

3.2.2. Committed projects

Following is the list of projects which have been entered into the base case model as committed projects. When the projects are added in the model as committed, their cost is taken as 'zero', so that the modeling software (PLEXOS) can select them irrespective of their need in the system or affordability.

A review of the provided list below shows that most of the committed projects are based on hydropower technology.

Technology	Project Name	Capacity (MW)	Expected Date
Hydro	Balakot	300	Dec-2027
	Chamfall	3.22	June-2024
	Dasu 1	360	Mar-2027
	Dasu 2	360	Apr-2027
	Dasu 3	360	May-2027
	Dasu 4	360	Oct-2027
	Dasu 5	360	Nov-2027
	Dasu 6	360	Dec-2027
	Diamer Bhasha U1	375	Jan-2029
	Diamer Bhasha U2	375	Feb-2029
	Diamer Bhasha U3	375	Apr-2029
	Diamer Bhasha U4	375	May-2029
	Diamer Bhasha U5	375	June-2029
	Diamer Bhasha U6	375	Jul-2029
	Diamer Bhasha U7	375	Aug-2029
	Diamer Bhasha U8	375	Sep-2029
	Diamer Bhasha U9	375	Oct-2029

Hydro	Diamer Bhasha U10	375	Nov-2029
	Diamer Bhasha U11	375	Jan-2030
	Diamer Bhasha U12	375	Feb-2030
	Gorkin Matiltan	84	Aug-2025
	Jabori	10.2	May-2024
	Jagran II	48	Dec-2024
	Karora	11.8	Jul-2024
	Kathai-II (U#1)	4	Jul-2026
	Kathai-II (U#2)	4	Jul-2026
	Koto	40.8	Jun-2024
	Kurram Tangi	18	Jun-2024
	Lawi	69	Dec-2024
	Mohmand Dam U1	200	Dec-2026
	Mohmand Dam U2	200	Jan-2027
	Mohmand Dam U3	200	Mar-2027
	Mohmand Dam U4	200	Apr-2027
	Nardagian	3.22	Dec-2025
	Riali-II (U#1)	3.5	Jun-2025
	Riali-II (U#2)	3.5	Jun-2025
	Suki Kinari (U#1)	221	Aug-2024
	Suki Kinari (U#2)	221	Sep-2024
	Suki Kinari (U#3)	221	Oct-2024
	Suki Kinari (U#4)	221	Nov-2024
	Tarbela_Ext_5 (U#1)	510	Nov-2025
	Tarbela_Ext_5 (U#2)	510	Dec-2025
	Tarbela_Ext_5 (U#3)	510	Jan-2026
Imported Coal	Gwadar	300	Dec-2027
	Jamshoro Coal	660	June-2024
Bagasse	CSP	30	Jan-2028
	Shahtaj	32	June-2024
	TAY	30	Aug-2025
Nuclear	C5	1200	July-2029
Import	CASA	1000	Aug-2027
Wind	Trans-Atlantic	50	June-2028
	Western	50	June-2028
Solar	Access Electric	10	Dec-2023
	Access Solar	11.52	Dec-2023
	Helios	50	Dec-2023
	HNDS	50	Dec-2023
	Manjhand	50	June-2028
	Meridian	50	Jan-2024
	Safe	10	Nov-2024
	Siachen	100	June-2028
	Zorlu	100	Oct-2024
	PV_Comm_A	600	Jan-2027
	PV_Comm_B	600	Apr-2027
	PV_Comm_C	1200	Nov-2027
	Net Metering	2107	Throughout study horizon

3.3. Fuel price indexation factors

For fuel prices modelling we have relied on the same mechanism as provided in the IGCEP. The IGCEP uses the Energy Information Administration (EIA)'s Annual Energy Outlook 2023 for fuel price indexations over the study horizon. The factors of indexations used are provided in the table below.

Table: Fuel Price Indexations

FY	RFO	RLNG/NG	Imp. coal	Uranium	Thar coal	Bagasse
2024	1	1	1	1	1	1
2025	0.992	0.797	0.998	1	0.99	1.02
2026	0.938	0.688	0.99	1	1.01	1.02
2027	0.936	0.602	0.976	1	0.94	1.04
2028	0.939	0.549	0.967	1	0.95	1.04
2029	0.939	0.528	0.955	1	0.95	1.061
2030	0.942	0.527	0.949	0.999	0.94	1.061
2031	0.946	0.534	0.95	0.999	0.95	1.082
2032	0.949	0.546	0.947	0.999	0.93	1.082
2033	0.953	0.561	0.932	0.999	0.7	1.104

3.4. Scenarios & Sensitivity Analysis

The IGCEP 2024 constitutes four scenarios on top of the base case. The base case has been modelled on a low-demand growth scenario. The other two scenarios are based on the sensitivities of demand forecasting such as medium growth and high demand growth. Two additional scenarios include the delay in the committed Diamer Bhasha HPP and considering two candidate HPPs Azad Pattan and Kohala as committed in the model.

In our study, we have replicated the base case as in the IGCEP 2024. In addition, we have developed following scenarios and sensitivities in our model:

1. The base case

The base case scenario is designed to keep the same assumptions as used in the IGCEP 2024 base case scenario so that the starting point of our study aligns with NTDC's IGCEP. All the constraints such as must-run obligations and committed projects are like the IGCEP base case, the only difference is the tariff assumptions of committed projects. Since the tariff assumptions of committed projects are missing in the IGCEP, therefore the tariff assumptions of such projects are considered as per the latest reference power purchase prices for the year 2023-2024 as available on NEPRA's website.

2. The True Load Scenario

In this scenario, we assess the impact of true load on the overall power sector generation planning. We do so by incorporating the industrial load of captive power plants (CPPs) in the model, which is not part of the base case. We estimate that by shifting the load that the industries are currently meeting through CPPs to the national grid it will improve the system performance and utilization of existing capacity. Moreover, the fuel (usually natural gas) provided to the industries at subsidized prices for operating their CPPs could also be directed to alternate needs and be used efficiently given the depletion of local natural gas reserves. In this scenario we shift the load that the industries are currently meeting through their captive power generators — fueled by either diesel or gas — onto the national grid. According to well-informed sources and industrial leaders, the estimated quantum of captive-based industrial load is around 5 to 7 Gigawatts. In our model, we considered three estimates for captives based on pessimistic, realistic, and optimistic considerations.

Sensitivities:

◊ **Pessimistic:** 4000 MW (2000 MW in KE's system and 2000 MW in NTDC's system)

◊ **Realistic:** 7,000 MW (3500 MW in KE's system and 3500 MW in NTDC's system)

◊ **Optimistic:** 10,000 MW (5000 MW in KE's system and 5000 MW in NTDC's system)

3. Electric Vehicles Impact on Grid

In this scenario, we assess the impact of an increase in electricity demand on generation expansion planning, owing to an increased quantum of electric vehicles (EVs) in the country's transportation fleet over the study horizon. Pakistan introduced its first national EV policy in 2019, which aimed at gradually increasing the share of EVs in the country, as well as creating a local market for EV development. However, this government direction, and public interest towards EVs, requires careful generation planning and enabling infrastructural developments such as the erection of charging stations. It will further set the stage for deliberation on required incentives to manage the load on the grid instead of straining the grid. An EVs' charging station typically ranges between 2kW— 43kW in the case of an AC charging station and 50kW—1 50kW and more in the case of a DC charging station. The projections of EVs and their charging station loads are taken from the technical brief "Scaling up Electric Mobility in Pakistan" by NEECA developed under the UNDP NDC Support Programme. The sensitivities for the load of EV charging stations in Pakistan are as follows:

Sensitivities:

◊ **Pessimistic Projection:** 2000 MW by FY 2033

◊ **Realistic Projection:** 3500 MW by FY 2033

◊ **Optimistic Projection:** 4500 MW by FY 2033

The demand as mentioned above is factored in the cumulative load profile of Pakistan and then the impact on utilization rates of the existing fleet and optimization of new generation mix is analyzed.

4. No Capacity Additions (NCA)

Since the installed power generation capacity is considerably higher than the utilized capacity due to which, Pakistan is facing the issues of surplus power capacity and capacity payments, a unique scenario of "No Capacity Additions (NCA)" is also simulated and analyzed. The objective of this scenario is to check whether the installed generation capacity would be enough to meet the future demand if no further power plants are added to the generation fleet. Another major assumption used in this scenario is solarization. One of the most critical oversights in the IGCEP 2024 is the net metering projections. The IGCEP 2024 assumes 2,107MW from net metering by FY2034. However, as of April 2024, the installed net metering capacity had already exceeded 2,000MW, and this trend is expected to always accelerate due to rising electricity prices and solar PV prices lowest in Pakistan. Additionally, the federal and provincial governments are aggressively promoting solarization to maximize the use of indigenous and renewable sources. It is believed that one reason for the decline in energy demand of the system is due to solarization whether net metered or non-net metered. According to *Bloomberg*, Pakistan imported around 13,000MW of solar modules in the first six months of 2024 alone, making it the third-largest destination for Chinese exporters. This massive import volume and the growing trend of rooftop solar installations necessitate a prudent consideration of solarization's impact on demand side. Incorporating rooftop solar, both net-metered and non-metered, across all consumer types—industrial, three-phase, and single-phase is crucial. In the NCA scenario, the committed generation capacity until FY 2027 is considered along with the net metering quantum of 10GW(around 1000 MW each year). The impact of net metering quantum is considered on the demand side.

5. Increased Electricity flow from NTDC to KE - Affordable Electricity for KE Consumers

In NTDC's current approach, both dispatch and expansion planning for KE and NTDC systems is carried out separately. A limited quantum of electricity — 1100 MW which has now been increased to 2,050 MW under a new agreement with the NTDC — is allowed to flow from NTDC to the KE system. This approach results in a cost discrepancy between the two systems. NTDC has a diverse energy generation pool comprising 64.4% thermal power, 27.4% hydro, 4.2% renewables, and 4% nuclear energy, the overall generation basket rate is thus lower than KE's. If the interconnection capacity between NTDC and KE is further increased in the future, more affordable power will flow from the NTDC network to the KE's network — as currently the per unit price is higher in the KE system due to the dominance of thermal power generation in their network.

For sensitivity analysis, we considered different scenarios: increasing the supply to K-Electric from 2,050 MW to 2,800 MW, 3,600 MW, and 4000 MW, respectively. The result of this analysis is explained in the Results Section.

Sensitivities:

◊ Supply to KE = 2800 MW

◊ Supply to KE = 3600 MW

◊ Supply to KE = 4000 MW

6. Collective impact of CPPs and EVs – Building Synergies

This scenario aims to see the impact of better utilization of the existing grid on long-term generation planning by a) shifting the captive power plants on the national grid and b) incorporating EVs' charging demand. Considering the envisaged drop in the energy demand as outlined in the IGCEP 2024 and surplus generation capacity, more benefits can be reaped by first utilizing the existing capacity. Doing this strategically, electricity from variable renewables can be optimally utilized further by aligning EV charging with their peak generation which may also reduce curtailments from the must-run plants. Overall, the synergy in increased energy utilization could alleviate the financial burden of idle capacity, improve the efficiency, reliability, and flexibility of the system, and increase the potential for renewable energy integration. It further paves the way for sustainable development by reducing carbon footprint in the transportation sector, contributing to a cleaner environment.

Sensitivities:

◊ Realistic only – 4000 MW captive load and 2000 MW EVs load by 2033

7. Collective impact of CPPs, EVs and enhanced electricity flow to KE – The Efficiency Trio

In continuation to building synergies, this scenario is designed to analyze the combined effect of captives, EVs and enhanced electricity flow to the KE system – "The efficiency trio". This integrated approach will not only enable grid operators and utilities to increase grid flexibility, improve reliability, and optimize energy efficiency but also create capacity for integrating more renewable energy sources. By harnessing the strengths of this trio, the peak demand can be managed efficiently and achieve maximum efficiency in energy generation and utilization.

Sensitivities:

◊ CPPs load of 4000MW (2000MW in the KE system and 2000MW in the NTDC System)

◊ Increase in demand by 2000 MW to facilitate EV charging

◊ Increase in transmission capacity (from NTDC to KE) of 4000 MW from 2050MW

8. Unconstrained VRE additions: The Greener Future

In the current IGCEP about 20GW of capacity expansion in the next 10 years is on a committed basis i.e., the model has not been allowed to assess their optimization on the least cost basis. In our unconstrained RE scenario, we are treating the committed hydro and nuclear projects as candidate generation options for the software to optimize if needed in the system. With respect to solar and wind, their yearly addition constraints have been removed. Their unlimited addition with a block size of 100MW has been allowed in the model for optimization on a least cost basis.

Committed hydro projects (7.76 GW) and nuclear projects modeled as candidate generation options are as follows:

◊ Balakot HPP (300 MW) as a candidate option from 1st December 2027

◊ Dasu (Units 1 to 6 total 2160 MW, each unit of 360 MW)

◊ Diamer Bhasha Dam (4500 MW)

◊ Mohmand Dam (800 MW, 4 units each of 200MW)

◊ C-5 (1200 MW) Nuclear as a candidate option in FY-30

9. Additional Cost of Diamer Bhasha Dam and CHASHNUPP-5 (C-5)

In the IGCEP 2024, a majority of power projects are classified as committed; however, the underlying justifications and rationales for their inclusion remain largely unexplained. Critical details such as CAPEX, tariff assumptions, and comprehensive cost evaluations are absent, raising concerns about whether these projects meet the least-cost selection criteria. Among these committed projects, the Diamer Bhasha Dam (4,500 MW) and CHASNUPP-5 (C-5, 1,200 MW) stand out due to their substantial capital costs. According to recent media reports and reliable sources, the estimated cost for C-5 is approximately $5 billion, while the Diamer Bhasha Dam is projected at $4.86 billion. Notably, IGCEP 2024 only accounts for their levelized tariffs, which appear to be significantly underestimated.

To accurately reflect the true costs and implications of these projects, a scenario analysis was conducted. In the first iteration, C-5 was treated as a candidate project with all other assumptions consistent with the base case scenario. In the second iteration, Diamer Bhasha was evaluated as a candidate project. Finally, in the third iteration, both Diamer Bhasha and C-5 were considered as candidate options to analyze cost differentials and determine whether these projects would be optimized by PLEXOS. This approach aims to provide a clearer understanding of the economic feasibility of these projects and whether they align with least-cost planning principles, ensuring that the generation expansion strategy remains both financially sound and aligned with policy goals.

Chapter 4: The Study Outputs

4.1. Base Case

The base case scenario is built along the assumptions, constraints, and obligations as determined by the IGCEP. In case of any missing data inputs in the IGCEP and non-provision of data from relevant energy sector agencies on request, we have used the closest suitable assumptions. In the current IGCEP, the base case has been developed on a demand forecast based on low GDP growth rate. Additionally, we see that the 99.95% capacity which could have been added to the system based on least cost, is added as committed. As a result, the model optimizes only 87 MW of hydel capacity. For solar and wind, we see that except for the already committed capacity, no additional capacity is being optimized. For Hydropower, in addition to what has been added as committed, 87.2 MW gets optimized by the model.

Key features

- The tariffs for both existing and candidate projects align with those in the NTDC IGCEP 2024, ensuring consistency in cost assumptions across the board.
- Renewable energy projects totaling 640 MW within the K-Electric system are treated as committed projects, as their Request for Proposals (RFPs) have been issued and are included in K-Electric's approved Power Acquisition Program (PAP) for 2024.
- Total **installed capacity** reaches **56.8 GW** with **VRE share of 13 % and hydel share of 37%**.
- The **total system cost (NPV)** in our analysis is estimated at **$60.1 billion**, excluding the capital costs of committed projects. The required investments for these **committed projects** amount to approximately **$23.9 billion**.
- In contrast, **NTDC's projections** indicate a **total system cost** of **$38.1 billion**, excluding committed project costs. When these project costs are included, **NTDC** estimates the **total system cost (NPV)** to be **$63.31 billion**, highlighting a potential discrepancy in cost evaluations between the analyses.

Capacity Addition and Investment Required

- New Capacity Built: 20.256 GW
- Total System Cost (NPV) = $60.1 billion

	Solar	Wind	Nuclear	Hydro	Imported Coal
Capacity (MW)	5608	232	1200	10564.2	960
CAPEX ($ billion)	3.86	0.325	5	14.08	0.714

Total Investments required = **$ 23.9 billion**

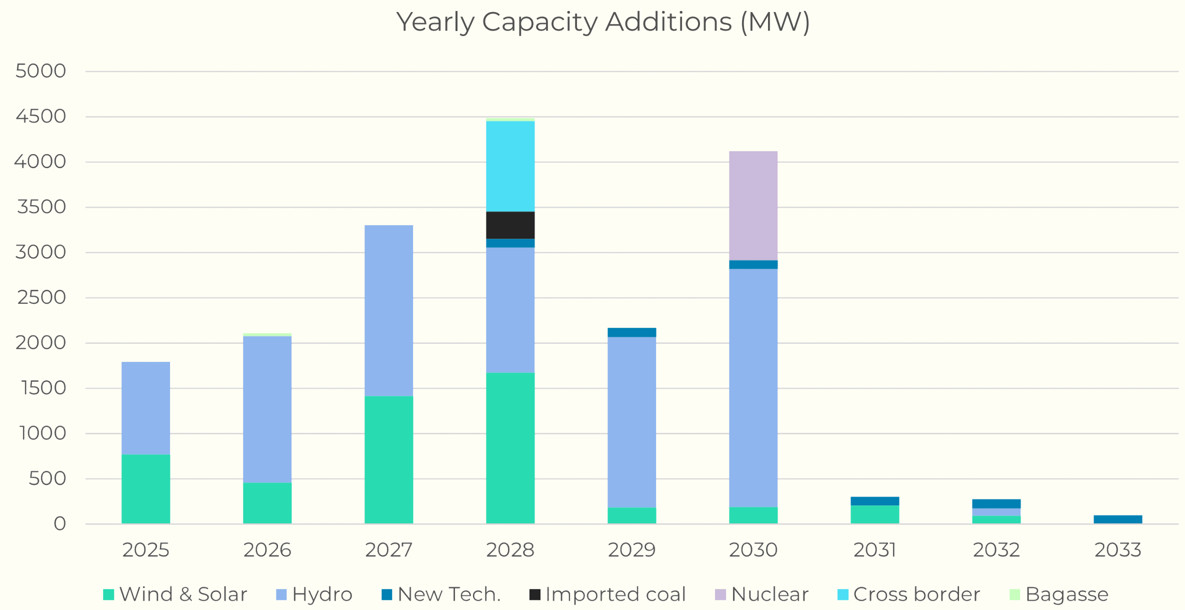
Committed Projects (MW)

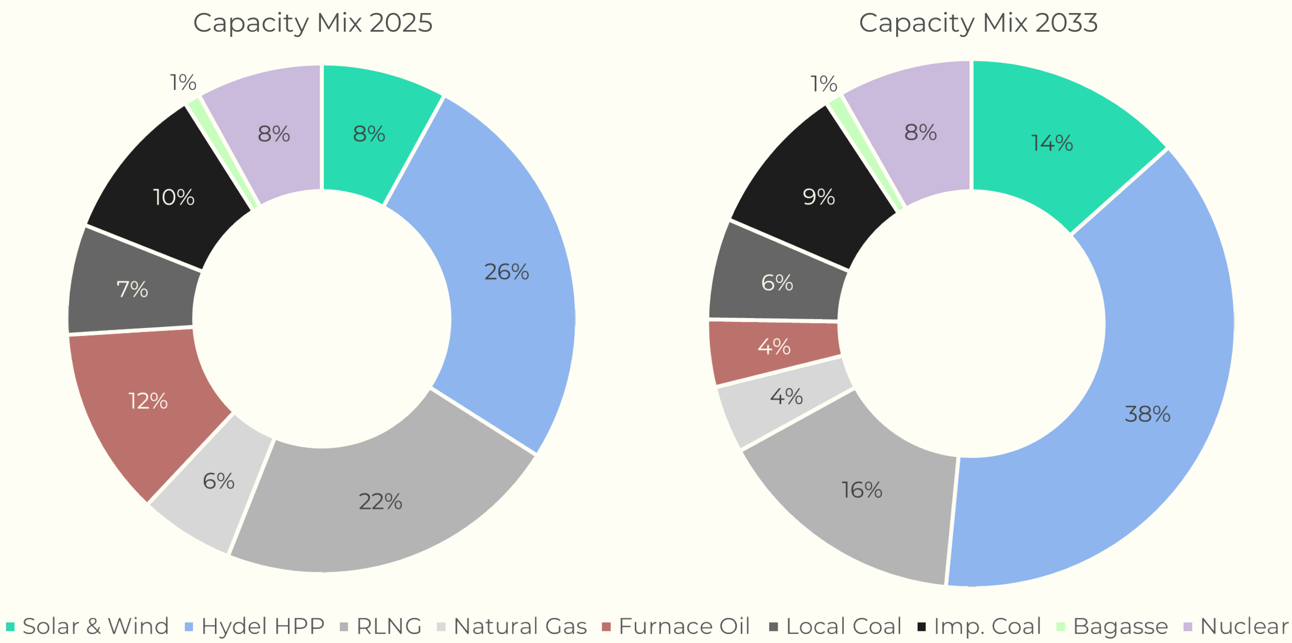
FY	Hydro	Imp. Coal	Local Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	0	171.52	0	0	0	32	936
2025	357	0	0	0	770	0	0	0	0	1127
2026	818	0	0	132	329	0	0	0	30	1309
2027	1299	0	0	0	1465	0	0	0	0	2764
2028	1591	300	0	100	1645.4	1000	0	100	30	4766
2029	4310	0	0	0	236	0	0	100	0	4646
2030	1310	0	0	0	241	0	1200	100	0	2851
2031	360	0	0	0	255	0	0	100	0	715
2032	360	0	0	0	142	0	0	100	0	602
2033	0	0	0	0	353	0	0	100	0	453
Total	10477	960	0	232	5608	1000	1200	600	92	20,169

Inclusive of KE's committed projects and net-metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	5.2	0	0	0	0	0	0	0	0	0	0	5.2
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	82	0	0	0	82
2033	0	0	0	0	0	0	0	0	0	0	0	0
Total	5.2	0	0	0	0	0	0	82	0	0	0	87.2





4.2. Unconstrained VRE – The Green Future

In this scenario we evaluate the impact of treating committed projects as candidate generation options on long-term generation expansion planning. It is critical to evaluate committed projects with full transparency based on their costs, as about one third of our intended generation capacity by the end of 2033 is added in the IGCEP 2024 as committed. In the current IGCEP about 20GW of capacity expansion in the next 10 years is on committed basis i.e. the model has not been allowed to assess their optimization on the least cost basis.

Key features

The unconstrained scenario suggests that the share of variable renewable energy sources can be increased if the hard constraints are removed from the model and committed projects are left open for optimization. Three sensitivities on demand growth are performed in unconstrained VRE scenario i.e., business -as-usual demand, medium demand and high demand.

4.2.1. Unconstrained VRE – Business as usual demand

- ◊ Total installed capacity reaches to 46.6 GW by 2033 with 6.2 GW VREs (13% VRE share).
- ◊ The share of hydel power generation increases from 10.75 GW to 13.6 GW (29% of total capacity) out which 2.7GW is committed quantum (until FY 2027) and only 216 MW is optimized by PLEXOS.
- ◊ The total cost savings amount to $5.79 billion (Total system cost NPV $54.31 billion) as compared to the Bas Case scenario.

4.2.2. Unconstrained VRE – Medium growth

- ◊ In this sensitivity, the total installed capacity reaches to 55.4 GW by 2033 with 14 GW VREs (25% VRE share).
- ◊ The share of hydel power generation increases from 10.75 GW to 14.3 GW (25% of total capacity) out which 2.7GW is committed quantum (until FY 2027) and only 956 MW is optimized by PLEXOS
- ◊ The total cost savings amount to $2 billion (Total system cost NPV $58 billion) as compared to the Bas Case scenario.

4.2.3. Unconstrained VRE – High demand

- ◊ In this sensitivity, the total installed capacity reaches to 59.3 GW by 2033 with 15.56 GW VREs (26% VRE share).
- ◊ The share of hydel power generation increases from 10.75 GW to 16.7 (28% of total capacity) GW out which 2.7GW is committed quantum (until FY 2027) and only 1173 MW is optimized by PLEXOS.
- ◊ The total system cost (NPV) in this sensitivity is $61.7 billion and this is due to new capacity optimization of 13.9 GW.

Capacity Optimized by PLEXOS for 10-year Horizon

- ◊ New Capacity Built: 10.26 GW
- ◊ Total System Cost (NPV) = $58 billion

	Solar	Wind	Nuclear	Hydro	Imported Coal
Capacity (MW)	10836	1232	1200	3673.2	960
CAPEX ($ billion)	7.45	1.72	5	2.03	0.714

Total Investments required = **$ 11.93 billion**

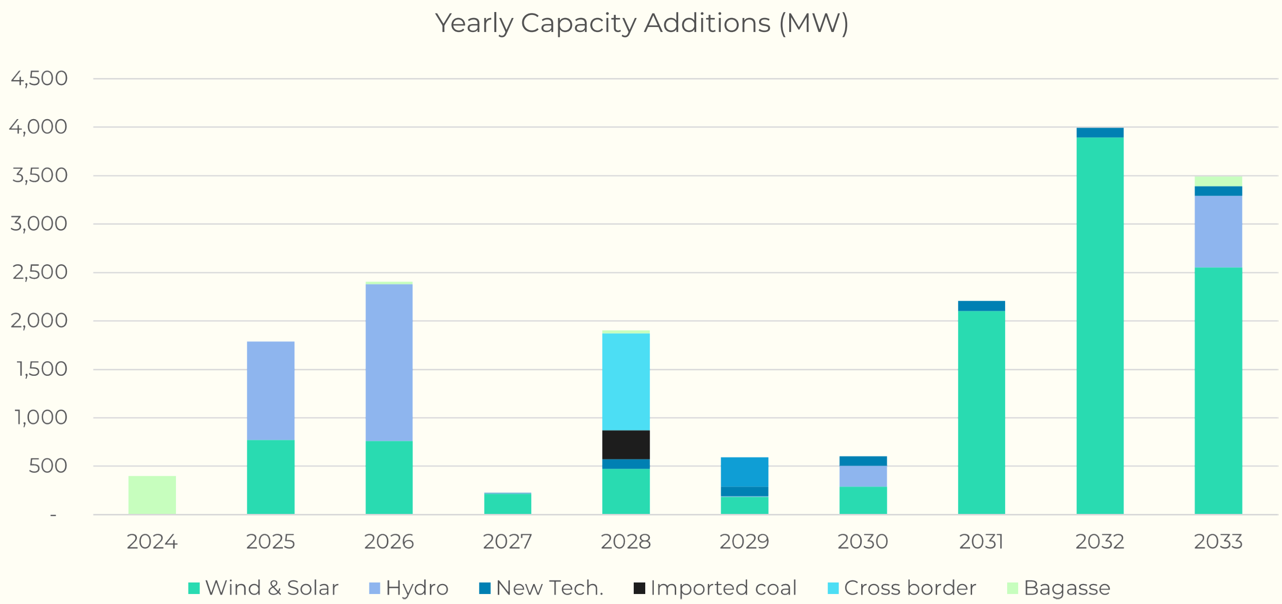
Committed Projects (MW)

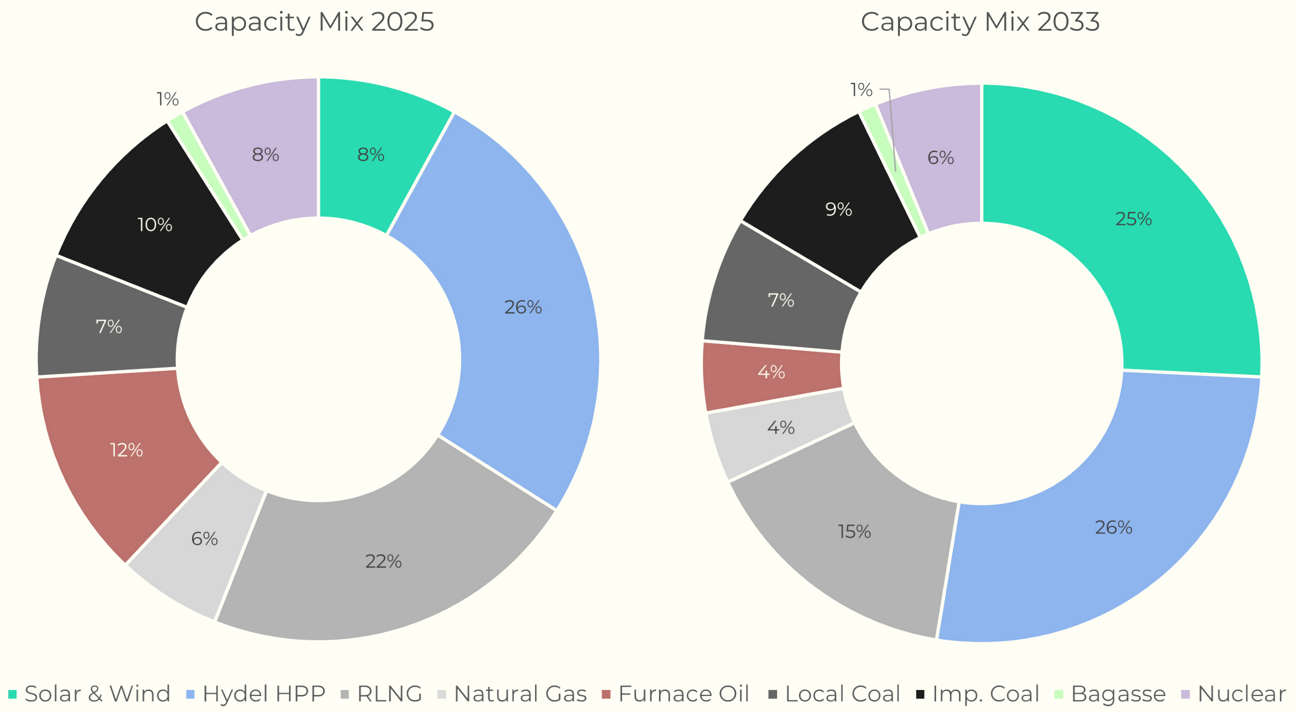
FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	171.52	0	0	0	32	936
2025	1020	0	0	770	0	0	0	0	1790
2026	1617	0	132	329	0	0	0	30	2108
2027	8	0	0	265	0	0	0	0	273
2028	0	300	100	373	1000	0	100	30	1903
2029	0	0	0	236	0	0	100	0	336
2030	0	0	0	241	0	0	100	0	341
2031	0	0	0	255	0	0	100	0	355
2032	0	0	0	142	0	0	100	0	242
2033	0	0	0	353	0	0	100	0	453
Total	2717	960	232	3136	1000	0	600	92	8,737

Inclusive of KE's committed projects and net-metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	305	300	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	605
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	5.2	0	0	0	0	0	0	0	0	0	0	5.2
2030	211	0	0	0	0	0	0	0	0	0	100	311
2031	0	0	0	1600	0	0	0	0	0	200	100	1900
2032	0	0	0	3600	0	0	0	0	0	0	200	3800
2033	740	0	0	2000	0	0	0	0	0	300	600	3640
Total	956.2	0	0	7200	0	0	0	0	0	500	1000	10261.2





4.3. No Capacity Additions

In the IGCEP 2024, the net metering projections are assumed to reach at 2107 MW by the year 2034 however, as of April 2024, the installed net metering capacity had already exceeded 2,000MW, and this trend is expected to always accelerate due to rising electricity prices and solar PV prices lowest in Pakistan. In the sensitivity of the NCA, the committed generation capacity until FY 2027 is also considered along with the net metering quantum of 10GW. The NCA scenarios suggest that no further capacity addition is required given the increased rooftop solar additions along with the adequacy of the existing generation fleet. The results show that the total system cost (NPV) is around 56.4 billion USD, and this increased system cost shows that an additional 19 billion USD would be needed on the generation side for the projects that are committed until FY 2027. Another important finding in this scenario is that with 10 GW of rooftop solar along with 4.7 GW of committed VREs, Pakistan can successfully meet and even exceed the ARE Policy 2019 targets of having at least a 30% share of renewables without making significant investments.

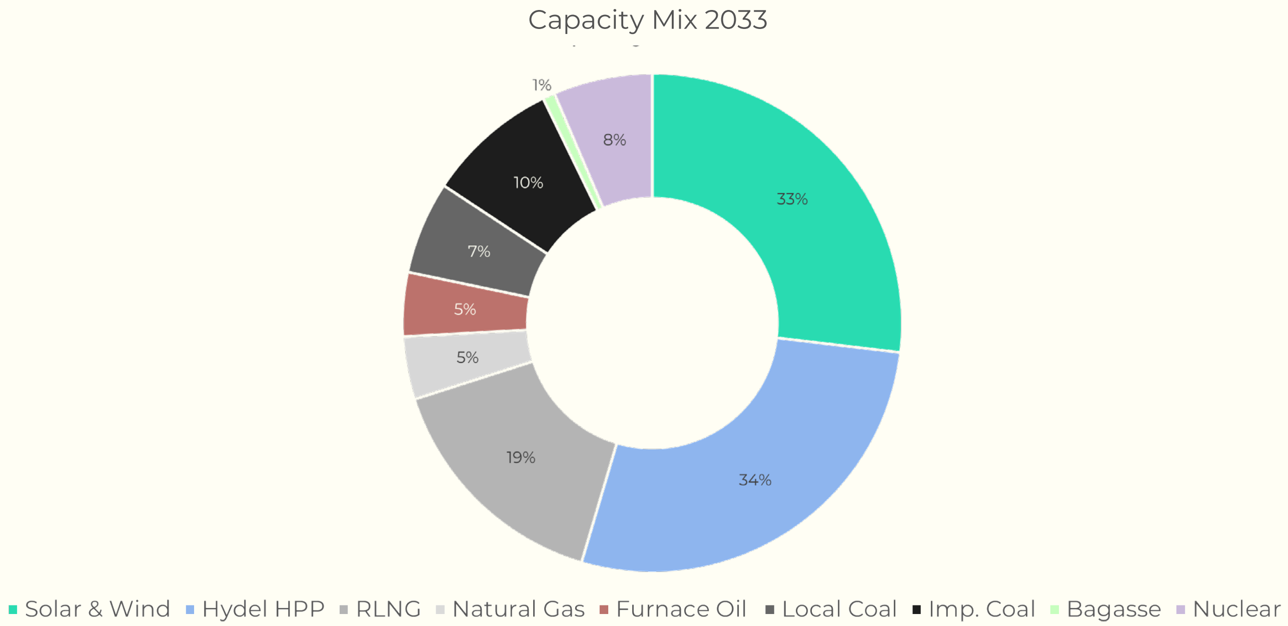
Key features:

- The total installed capacity reaches 44.7 GW by 2033 with 4.7 GW VREs (11 % VRE share), it is pertinent to mention here that 10GW of rooftop solar is also considered in the demand side, with this quantum the VRE share becomes 27%.
- The share of hydel power generation increases from 10.75 GW to 15.2 GW (34% of total capacity) and this increase only includes the committed quantum of hydel till FY 2027.
- The total cost savings amount to $3.7 billion (Total system cost NPV $56.4 billion) as compared to the Base Case scenario.

Committed Projects (MW)

FY	Hydro	Imp. Coal	Local Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	62	660	0	0	171.52	0	0	0	32	926
2025	1020	0	0	0	530	0	0	0	0	1550
2026	1617	0	0	132	88	0	0	0	30	1867
2027	1880	0	0	0	1200	0	0	0	0	3080
2028	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0
Total	4579	600	0	132	1990	0	0	0	62	7423

Inclusive of KE's committed projects and net-metering



Share of solar & Wind includes 10 GW rooftop solar as well

4.4. True Load Scenario

For the captive's load to be connected to the grid, we have assumed that 40% of the captive load would be connected to the grid by FY 2027, 30% by FY 2029, and 30% by FY 2030. For the growth rate of the captive load, the GDP rate of 3.5 % is considered, and the projected captive load is calculated accordingly for the entire planning horizon. Moreover, the model is also given the option to optimize BESS. As a result, in addition to the committed capacity, the NTDC system only optimizes a micro hydro project to meet the increased load on the system implying better utilization of the existing fleet. Whereas the KE system needs additional capacity to serve increased industrial load which could be met by the energy mix comprising 2770 MW of solar and wind and 1320 MW of local coal along with BESS of 350 MW with up to 08 hours of backup. It is pertinent to mention that the KE system needs the coal power plant to meet the base load requirements, given the global sanctions on local coal along with other socio-environmental factors, the option of local coal remains no longer feasible. To meet the base load demand, the interconnection capacity of the KE system with NTDC must be enhanced so that cheaper electricity can flow from the NTDC system to the KE.

Key features:

- ◊ The total installed capacity reaches 60 GW by 2033 with 10.4 GW VREs (17% VRE share).
- ◊ The share of hydel power generation increases from 10.75 GW to 21.2 GW (35%) out of which 10.4GW is committed quantum and only 87.2MW is optimized by PLEXOS..
- ◊ The total cost in this case is $64.2 billion owing to new capacity additions and increased utilization of existing fleet (see annexures for utilization rates).
- ◊ The utilization rates of existing fleet of both KE and NTDC (RLNG and imported coal) have been increased as shown below:
    - ➢ **RLNG = 78%**
    - ➢ **Imported coal = 6.1%**

Optimum Capacity Addition and Investment Required

- ◊ New Capacity Built: 24.6 GW
- ◊ Total System Cost (NPV) = $64.2 USD

	Solar	Wind	Nuclear	Hydro	Imp. Coal	BESS	Local Coal
Capacity (MW)	8258	352	1200	10564.2	960	350	1320
CAPEX ($ billion)	5.7	0.5	5	14.08	0.714	0.84	2.17

Total Investments required = **$ 29 billion**

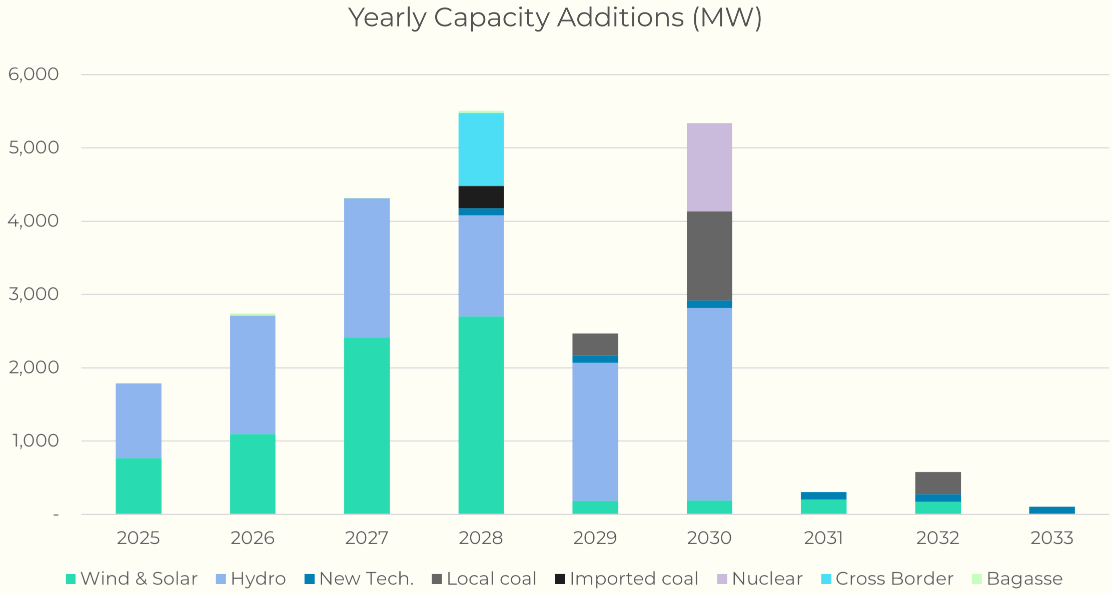
Committed Projects (MW)

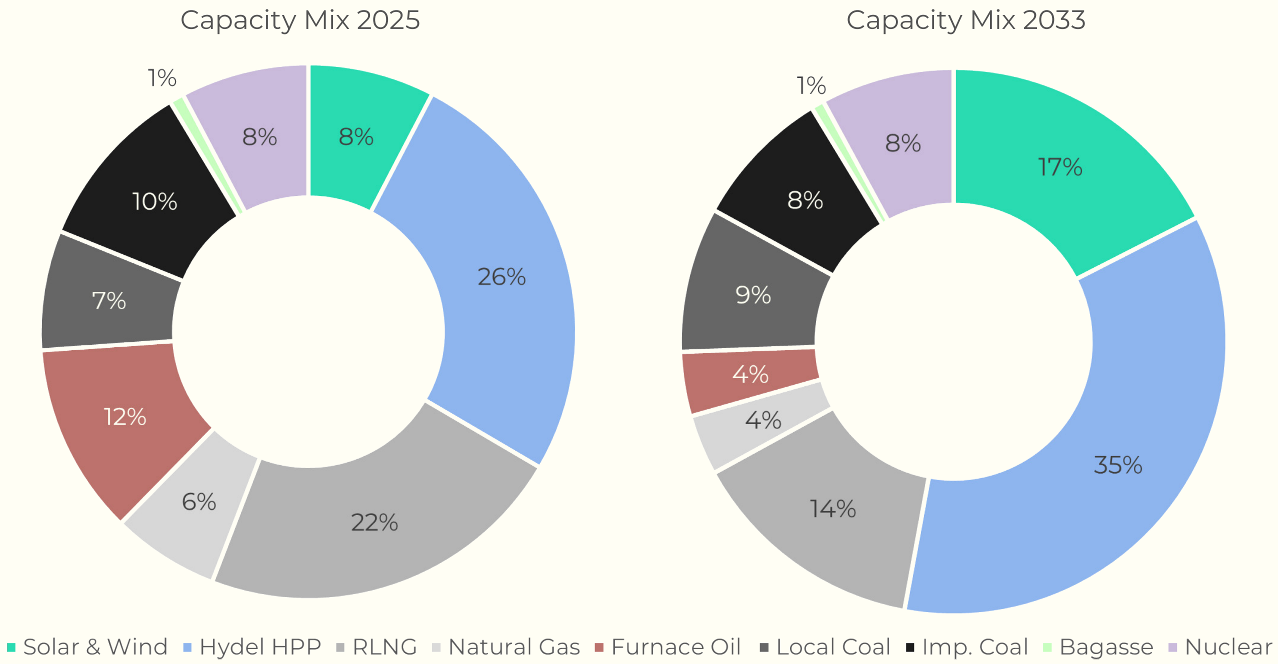
FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	171.52	0	0	0	32	936
2025	357	0	0	770	0	0	0	0	1127
2026	818	0	132	329	0	0	0	30	1309
2027	1299	0	0	1465	0	0	0	0	2764
2028	1591	300	100	1645.42	1000	0	100	30	4766
2029	4310	0	0	236	0	0	100	0	4646
2030	1310	0	0	241	0	1200	100	0	2851
2031	360	0	0	255	0	0	100	0	715
2032	360	0	0	142	0	0	100	0	602
2033	0	0	0	353	0	0	100	0	453
Total	10477	960	232	5608	1000	1200	600	92	20,169

Inclusive of KE's committed projects and Net metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	300	0	300
2027	0	0	0	0	0	0	0	0	0	900	0	900
2028	5.2	0	0	0	0	0	0	0	0	1000	0	1000
2029	0	0	0	0	0	0	0	0	305	0	0	310.2
2030	0	0	0	0	0	0	0	0	915	0	0	915
2031	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	82	0	0	0	82
2033	0	0	0	0	0	0	0	0	0	450	120	570
Total	5.2	0	0	0	0	0	0	82	1220	2650	120	4077.2





4.5. Electric Vehicles (EVs) Impact on Grid

The quantum of the load of EV's charging stations is proportionated into KE's system and NTDC's system i.e., the 2000 MW load of EV's charging stations proportionated as 400 MW into KE's system by 2033 and 1600 MW into NTDC's system by 2033. The results of the pessimistic sensitivity i.e., 2000 MW are shown below:

Key features:

- The total installed capacity reaches 57.5 GW by 2033 with 8.4 GW VREs (15 % VRE share).
- The share of hydel power generation increases from 10.75 GW to 21.1 GW (36% of total capacity) out of which 10.4GW is committed quantum (until FY 2027) and only 5.2 MW is optimized by PLEXOS.
- The total cost in this case is $62 billion owing to new capacity additions and increased utilization of existing fleet (see annexures for utilization rates).
- The utilization rates of existing fleet of NTDC (RLNG) have been increased by 10% while utilization rates of KE's fleet (RLNG) reduced by 7% because of the addition of 1000MW wind.

Capacity Optimized by PLEXOS for 10-year Horizon

- New Capacity Built: **21.56 GW**
- Total System Cost (NPV) = **$62 billion**

	Solar	Wind	Nuclear	Hydro	Imp. Coal	Local Coal
Capacity (MW)	5608	1232	1200	10482.2	960	330
CAPEX ($ billion)	3.8	0.5	5	13.91	0.714	0.54

Total Investments required = **$ 24.4 billion**

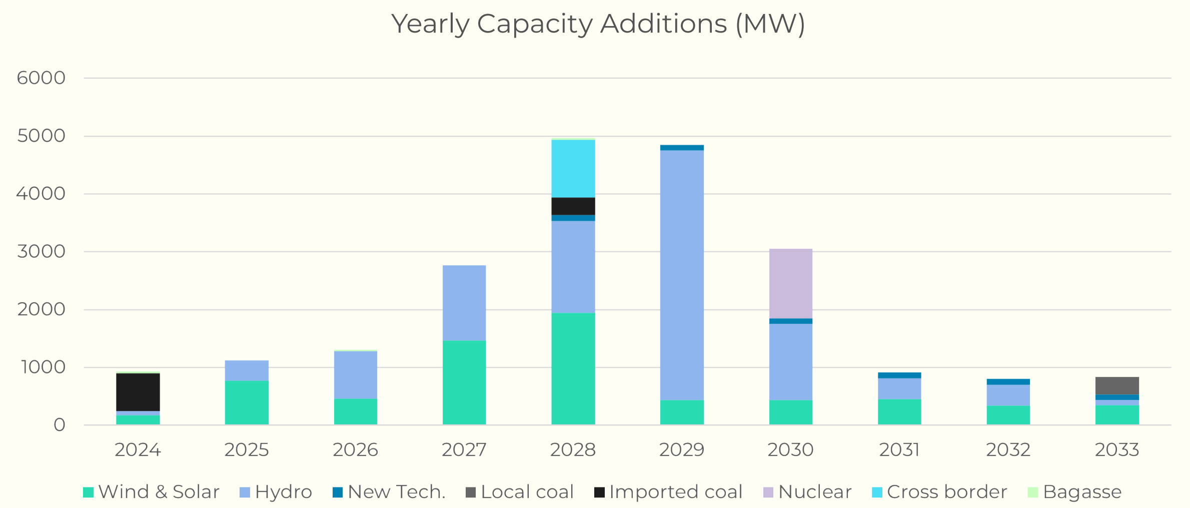
Committed Projects (MW)

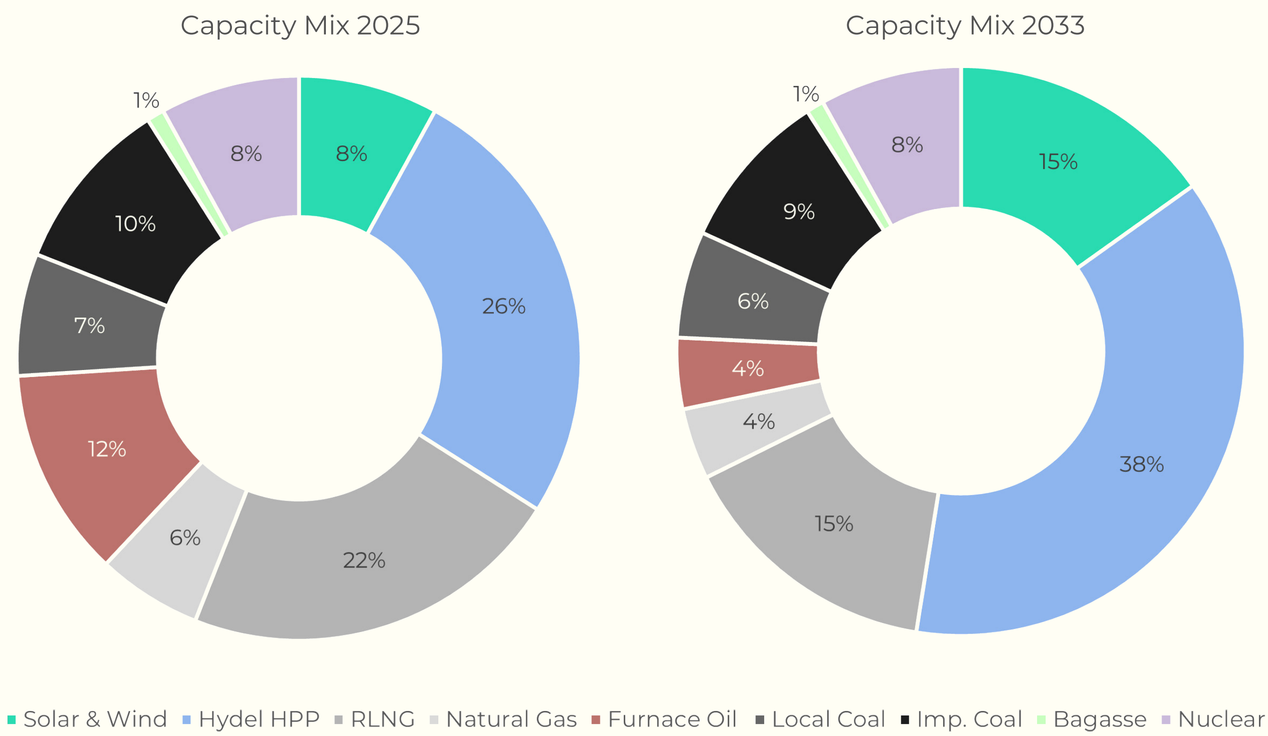
FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	171.52	0	0	0	32	936
2025	357	0	0	770	0	0	0	0	1127
2026	818	0	132	329	0	0	0	30	1309
2027	1299	0	0	1465	0	0	0	0	2764
2028	1591	300	100	1645.42	1000	0	100	30	4766
2029	4310	0	0	236	0	0	100	0	4646
2030	1310	0	0	241	0	1200	100	0	2851
2031	360	0	0	255	0	0	100	0	715
2032	360	0	0	142	0	0	100	0	602
2033	0	0	0	353	0	0	100	0	453
Total	10477	960	232	5608	1000	1200	600	92	20,169

Inclusive of KE's committed projects and Net metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0		0
2028	0	0	0	0	0	0	0	0	0	0	200	200
2029	5.2	0	0	0	0	0	0	0	0	0	200	205.2
2030	0	0	0	0	0	0	0	0	0	0	200	200
2031	0	0	0	0	0	0	0	0	0	0	200	200
2032	0	0	0	0	0	0	0	0	0	0	200	200
2033	0	0	0	0	0	0	0	82	305	0	0	387
Total	5.2	0	0	0	0	0	0	82	305	0	1000	1,392.2





4.6. Collective impact of CPPs and EVs – Building Synergies

In this scenario we evaluate the collective impact of shifting industries on the main grid and increased demand from erection of charging stations for EVs. For this we taken realistic assumption of shifting 4000 MW load of CPPs and 2000MW EVs load on the main grid. As a result, in addition to the committed capacity, only a 5.2 MW hydro project is optimized in the NTDC system and 4.3 GW of energy mix comprising 990 MW local coal, 1600 MW wind and 1700 MW solar along with 01 unit of BESS (430 MW with up to 9 hours backup) are optimized in the KE system.

It is worth noting that KE system needs additional thermal power of 990 MW to meet the base load requirements, however given the global sanctions of coal financing along with its environmental impacts, coal is no longer a feasible option. This entails enhancement of tie line capacity from NTDC to KE as already mentioned in 4.6 section that will enable the flow of cheaper power from NTDC system to KE's system.

Key features:

- ◊ The total installed capacity reaches 61.1 GW by 2033 with 10.75 GW VREs (17.5 % VRE share).
- ◊ The share of hydel power generation increases from 10.75 GW to 21.2 GW (34% of total capacity) out of which 10.4GW is committed quantum (until FY 2027) and only 87.2 MW is optimized by PLEXOS.
- ◊ The total cost in this case is $64.5 billion owing to new capacity additions and increased utilization of existing fleet (see annexures for utilization rates).
- ◊ The utilization rates of existing fleet of both KE and NTDC (RLNG and imported coal) have been increased as shown below:
    - ➢ **RLNG = 90%**
    - ➢ **Imported coal = 7.1%**

Capacity Optimized by PLEXOS for 10-year Horizon

- ◊ New Capacity Built: 24.47 GW
- ◊ Total System Cost (NPV) = $64.5 billion

	Solar	Wind	Nuclear	Hydro	Imp. Coal	BESS	Local Coal
Capacity (MW)	7308	1832	1200	10564.2	960	430	990
CAPEX ($ billion)	5.03	2.57	5	14.08	0.714	1.16	1.63

Total Investments required = **$ 30.17 billion**

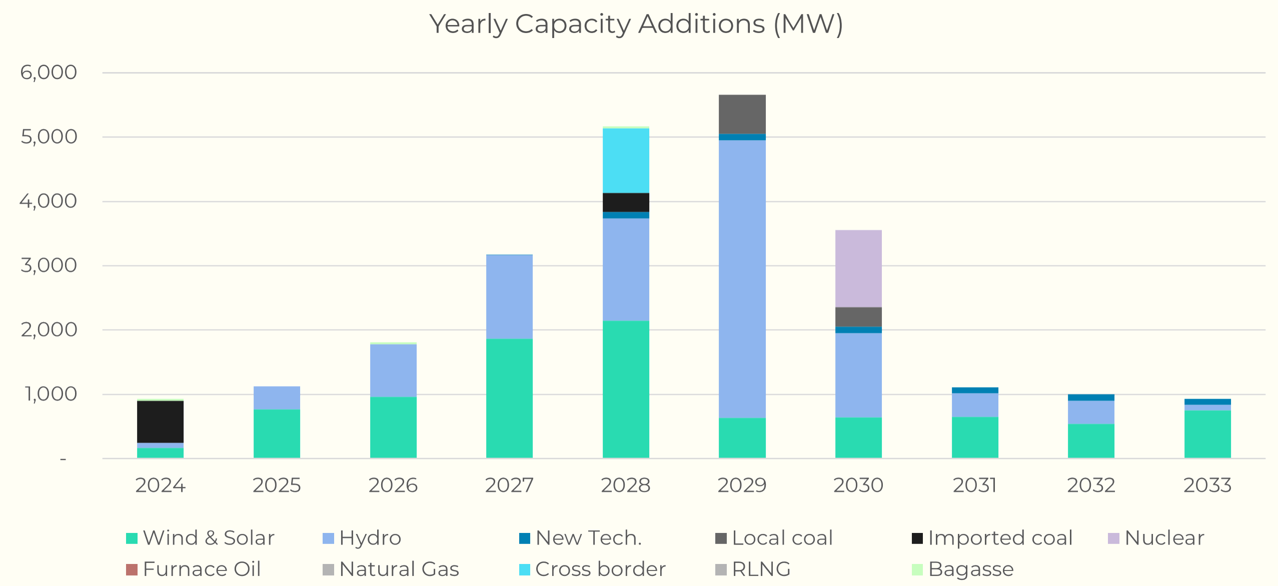
Committed Projects (MW)

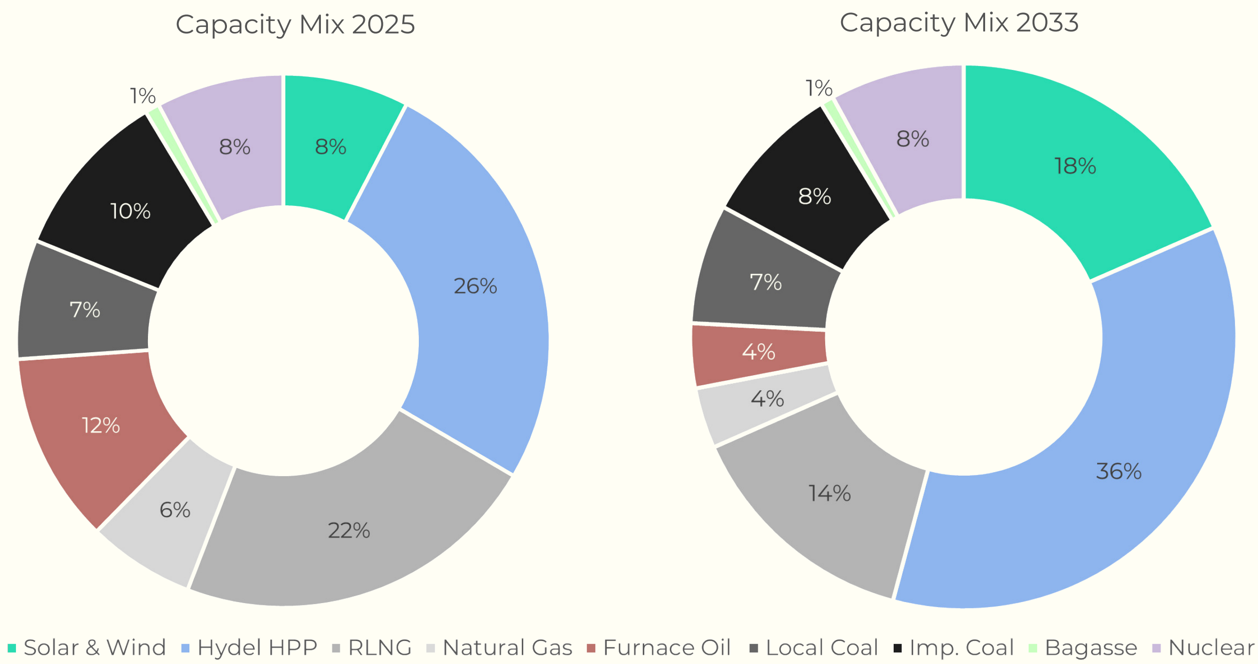
FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	171.52	0	0	0	32	936
2025	357	0	0	770	0	0	0	0	1127
2026	818	0	132	329	0	0	0	30	1309
2027	1299	0	0	1465	0	0	0	0	2764
2028	1591	300	100	1645.42	1000	0	100	30	4766
2029	4310	0	0	236	0	0	100	0	4646
2030	1310	0	0	241	0	1200	100	0	2851
2031	360	0	0	255	0	0	100	0	715
2032	360	0	0	142	0	0	100	0	602
2033	0	0	0	353	0	0	100	0	453
Total	10477	960	232	5608	1000	1200	600	92	20,169

Inclusive of KE's committed projects and Net metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	300	200	500
2027	0	0	0	0	0	0	0	0	0	200	200	400
2028	0	0	0	0	0	0	0	0	0	200	200	400
2029	5.2	0	0	0	0	0	0	0	607	200	200	1012.2
2030	0	0	0	0	0	0	0	0	305	200	200	705
2031	0	0	0	0	0	0	0	0	0	200	200	400
2032	0	0	0	0	0	0	0	0	0	200	200	400
2033	0	0	0	0	0	0	0	82	0	200	200	482
Total	5.2	0	0	0	0	0	0	82	912	1700	1600	4299.2





4.7. Enhanced Electricity Flow from NTDC to KE

In this scenario, we assess the impact on generation planning for the KE system by increasing the flow of electricity from NTDC's system to the KE system from 2050MW to 4000MW. The potential benefit of increased reliance on NTDC's system could be in the form of lesser utilization of expensive generation fleets in the KE system. As a result, the PLEXOS model does not optimize any generation option in the KE system for the next 10 years, and only a small hydel project of 5.2 capacity in the NTDC's system. Other than this, the majority of capacity additions are only those which have been treated as committed in the model. This also brings attention to the surplus capacity available in the main grid — sufficient for both the NTDC's and KE's systems — in the provision of affordable electricity to the end consumers. Another major observation in this scenario is that the need for a base load option i.e., local coal additions would no longer be needed even if the captive load along with the EV's load increases in the KE system because of the allowance of cheaper power to KE system via enhanced tie line capacity.

It is important to note that for the enhancement of tie-lines, the timelines have also been considered i.e., first augmentation in FY 27, the other one in FY 30 to make the scenario more realistic.

Key features:

- ◊ The total installed capacity reaches 56.7 GW by 2033 with 7.6 GW VREs (13 % VRE share).
- ◊ The share of hydel power generation increases from 10.75 GW to 21.1 GW (37 % of total capacity) out of which 10.4 GW is committed quantum (until FY 2027) and only 5.2 MW is optimized by PLEXOS.
- ◊ The total cost in this case is $60 billion as compared to the base case scenario.

Capacity Optimized by PLEXOS for 10-year Horizon

- ◊ New Capacity Built: **20.175 GW**
- ◊ Total System Cost = **$60 billion**

	Solar	Wind	Nuclear	Hydro	Imp. Coal	BESS
Capacity (MW)	5608	232	1200	10482.2	960	0
CAPEX ($ billion)	3.86	0.325	5	13.91	0.714	0

Total Investments required = **$ 23.8 billion**

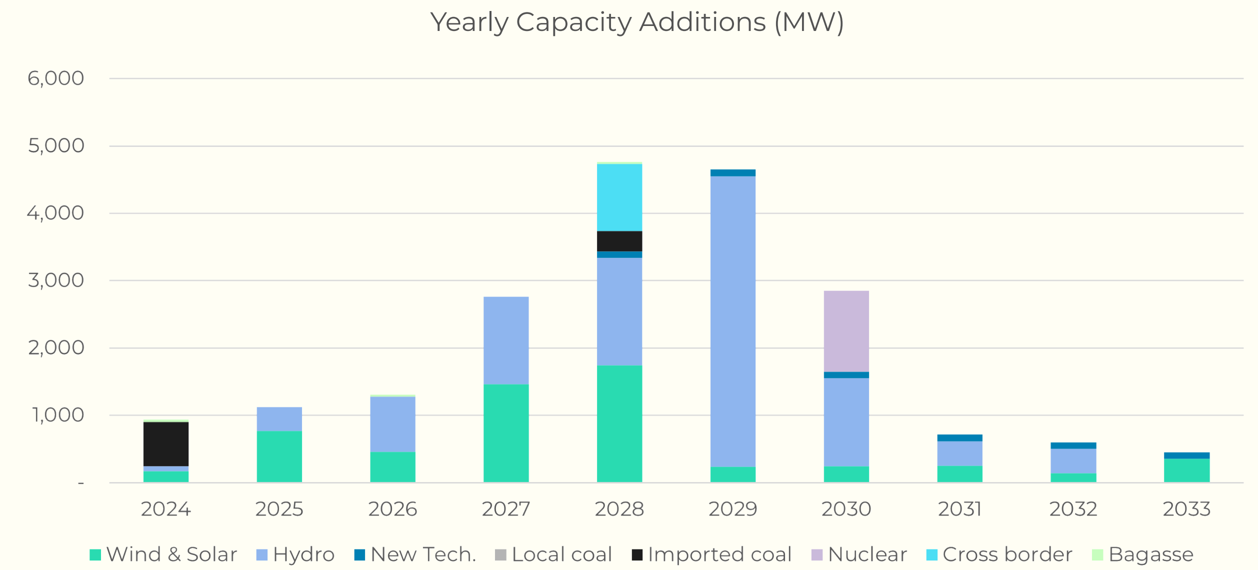
Committed Projects (MW)

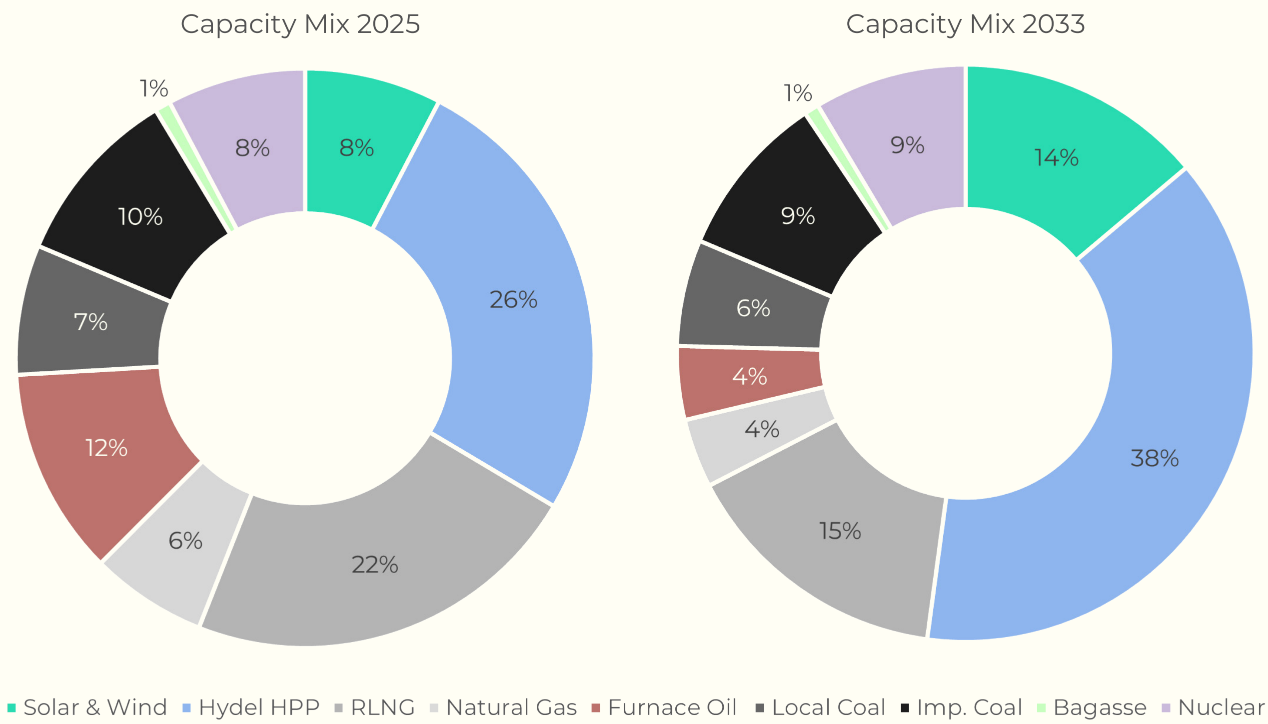
FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	171.52	0	0	0	32	936
2025	357	0	0	770	0	0	0	0	1127
2026	818	0	132	329	0	0	0	30	1309
2027	1299	0	0	1465	0	0	0	0	2764
2028	1591	300	100	1645.42	1000	0	100	30	4766
2029	4310	0	0	236	0	0	100	0	4646
2030	1310	0	0	241	0	1200	100	0	2851
2031	360	0	0	255	0	0	100	0	715
2032	360	0	0	142	0	0	100	0	602
2033	0	0	0	353	0	0	100	0	453
Total	10477	960	232	5608	1000	1200	600	92	20,169

Inclusive of KE's committed projects and Net metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	5.2	0	0	0	0	0	0	0	0	0	0	5.2
2030	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
Total	5.2	0	0	0	0	0	0	0	0	0	0	5.2





4.8. Collective impact of CPPs, EVs and Enhanced Electricity Flow to KE – The Efficiency Trio

In this scenario, we evaluate the collective impact of shifting industries on the main grid, increased demand from the erection of charging stations for EVs and enhanced electricity flow to KE from the main NTDC system. For this, we assessed the realistic case only in which we have used the following three main assumptions: Realistic only – Captives load = 4000MW, EVs load = 2000MW, flow to KE = 4000MW

As a result, in addition to the committed capacity, the model optimizes 176 MW of hydropower in the NTDC system and 1400 MW of wind power in the KE system. The renewable energy optimization by PLEXOS strengthens the need for an affordable yet sustainable energy system while ensuring the maximum utilization of the existing system. The results of this scenario also back the findings of scenario 4.7 (Collective impact of CPPs and EVs) in which additional thermal power generation is optimized into KE's system as there were no other options for the base load. In this scenario, since the tie-line capacity from NTDC to KE has been enhanced, there is no need for additional thermal power generation in KE's system.

Key features:

- The total installed capacity will reach 58.1 GW by 2033 with 9.06 GW VREs (15 % VRE share).
- The share of hydel power generation increases from 10.75 GW to 21.1 GW (36% of total capacity) out of which 10.4GW is committed quantum (until FY 2027) and only 5.2 MW is optimized by PLEXOS.
- The total cost in this case is $63.4 billion owing to new capacity additions and increased utilization of existing fleet (see annexures for utilization rates).
- The utilization rates of existing fleet of both KE and NTDC (RLNG and imported coal) have been increased as shown below:
    - **RLNG = Utilization increased by 2.3 times** (118.3 TWh generation as compared to 51.2 TWh in the base case)
    - **Imported coal = Utilization increased by 10%**

Capacity Optimized by PLEXOS for 10-year Horizon

- New Capacity Built: 21.57 GW
- Total system cost (NPV) = $63.4 billion

	Solar	Wind	Nuclear	Hydro	Imp. Coal	BESS	Local Coal
Capacity (MW)	5608	1632	1200	10482.2	960	0	0
CAPEX ($ billion)	3.85	2.28	5	13.91	0.714	0	0

Total Investments required = **$ 25.67 billion**

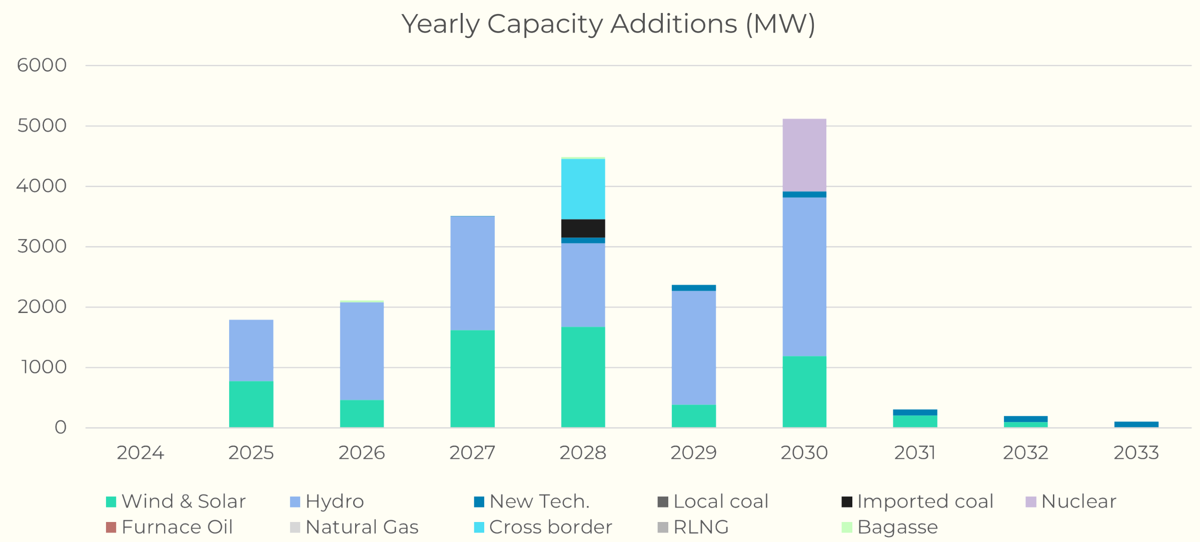
Committed Projects (MW)

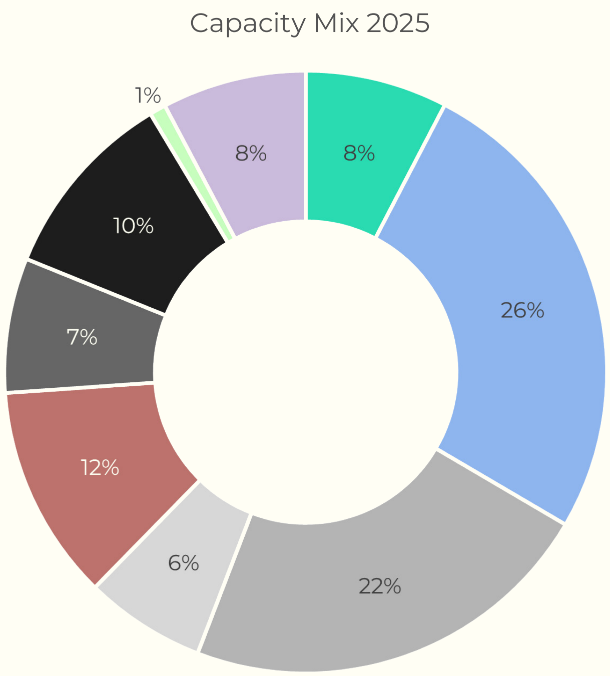
FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	171.52	0	0	0	32	936
2025	357	0	0	770	0	0	0	0	1127
2026	818	0	132	329	0	0	0	30	1309
2027	1299	0	0	1465	0	0	0	0	2764
2028	1591	300	100	1645.42	1000	0	100	30	4766
2029	4310	0	0	236	0	0	100	0	4646
2030	1310	0	0	241	0	1200	100	0	2851
2031	360	0	0	255	0	0	100	0	715
2032	360	0	0	142	0	0	100	0	602
2033	0	0	0	353	0	0	100	0	453
Total	10477	960	232	5608	1000	1200	600	92	20,169

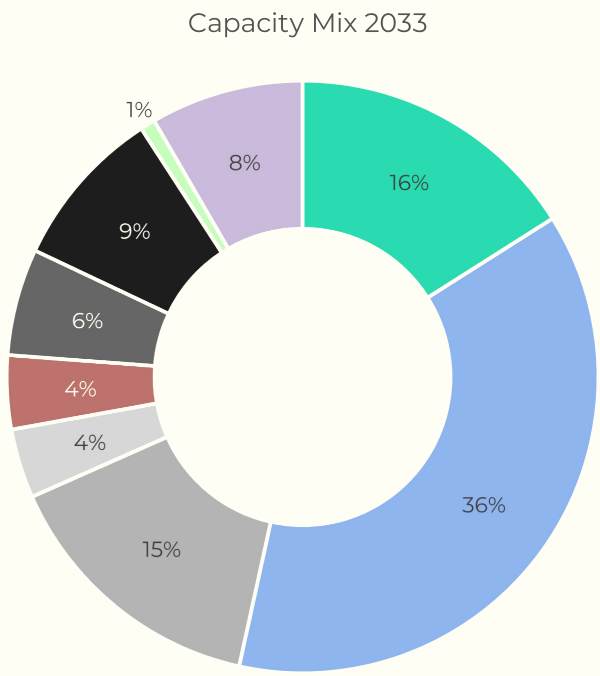
Inclusive of KE's committed projects and Net metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	200	200
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	5.2	0	0	0	0	0	0	0	0	0	200	205.2
2030	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	1000	1000
2032	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0
Total	5.2	0	0	0	0	0	0	0	0	0	1400	1405.2







Solar & Wind ▪ Hydel HPP ▪ RLNG ▪ Natural Gas ▪ Furnace Oil ▪ Local Coal ▪ Imp. Coal ▪ Bagasse ▪ Nuclear

4.9. Additional Cost of Diamer Bhasha Dam and CHASHNUPP-5 (C-5)

In this scenario, we assess the impact of incorporating the full costs of the Diamer Bhasha Dam (4,500 MW) and C-5 (1,200 MW) projects, beyond the levelized tariffs currently considered in the IGCEP 2024, where these projects are listed as committed. The current approach does not fully reflect the actual costs that will be incurred if these power projects come online, such as capital expenditures and increased capacity payments during the debt servicing periods.

Key features (with C-5 as a candidate option):

- The total installed capacity reaches 56.2 GW by 2033 with 8.2 GW VREs (15 % VRE share) and C-5 is not picked by PLEXOS.
- The share of hydel power generation increases from 10.75 GW to 21.2 GW (37% of total capacity) out of which 10.4GW is committed quantum (until FY 2027) and only 87.2 MW is optimized by PLEXOS.
- The total cost savings in this case amount to $5.52 billion (Project cost and running costs) as compared to the base case.

Key features (with Diamer Bhasha Dam as a candidate option):

- The total installed capacity reaches 52.9 GW by 2033 with 8.2 GW VREs (15 % VRE share) and Diamer Bhasha is not picked by PLEXOS.
- The share of hydel power generation increases from 10.75 GW to 16.7 GW (31% of total capacity) out of which 5.9 GW is committed quantum and only 87.2 MW is optimized by PLEXOS.
- The total cost savings in this case amount to $7.6 billion (Project cost and running costs) as compared to the base case.

In the first iteration, C-5 is evaluated as a candidate project, and results indicate that PLEXOS does not optimize C-5 due to its higher costs. This leads to a reduction in the total system cost (NPV) by 0.52 billion USD compared to the base case scenario where C-5 is committed. It is pertinent to mention that if this reduction does not include the project cost, and if the project cost is also included, the total reduction in total system cost amounts to $5.52 billion. Additionally, the share of renewable energy sources increases to 15%.

In the second iteration, Diamer Bhasha is treated as a candidate project, and similarly, PLEXOS does not optimize it due to higher costs. The analysis shows that the total system cost (NPV) is reduced by 2.74 billion USD compared to the base case scenario where Diamer Bhasha is committed. It is pertinent to mention that if this reduction does not include the project cost, and if the project cost is also included, the total reduction in total system cost amounts up to $7.6 billion with an increase in the renewable energy share to 16%.

These findings raise critical questions for the agencies concerned about whether these projects should be classified as committed, given that they do not meet the least-cost criteria and may displace more affordable energy sources. True costs of such projects must be transparently included in generation capacity expansion plans to ensure alignment with the least-cost criteria and policies promoting a higher share of renewable energy, especially since Pakistan is a signatory to the Paris Agreement.

4.9.1. Without C-5

- New Capacity Built: 19.6 GW
- Total system cost (NPV) = $59.5 billion

	Solar	Wind	Nuclear	Hydro	Imp. Coal	BESS	Local Coal
Capacity (MW)	5608	832	0	10564.2	960	0	0
CAPEX ($ billion)	3.85	1.165	0	14.08	0.714	0	0

Total Investments required = **$ 19.8 billion**

Committed Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	Bagasse	Yearly Addition
2024	72	660	0	171.52	0	0	0	32	936
2025	357	0	0	770	0	0	0	0	1127
2026	818	0	132	329	0	0	0	30	1309
2027	1299	0	0	1465	0	0	0	0	2764
2028	1591	300	100	1645.42	1000	0	100	30	4766
2029	4310	0	0	236	0	0	100	0	4646
2030	1310	0	0	241	0	0	100	0	1651
2031	360	0	0	255	0	0	100	0	715
2032	360	0	0	142	0	0	100	0	602
2033	0	0	0	353	0	0	100	0	453
Total	10477	960	232	5608	1000	0	600	92	18969

Inclusive of KE's committed projects and Net metering

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	100	100
2029	87.2	0	0	0	0	0	0	0	0	0	100	187.2
2030	0	0	0	0	0	0	0	0	0	0	100	100
2031	0	0	0	0	0	0	0	0	0	0	100	100
2032	0	0	0	0	0	0	0	0	0	0	100	100
2033	0	0	0	0	0	0	0	0	0	0	100	100
Total	5.2	0	0	0	0	0	0	0	0	0	600	687.2

4.9.2. Without Diamer Bhasha Dam

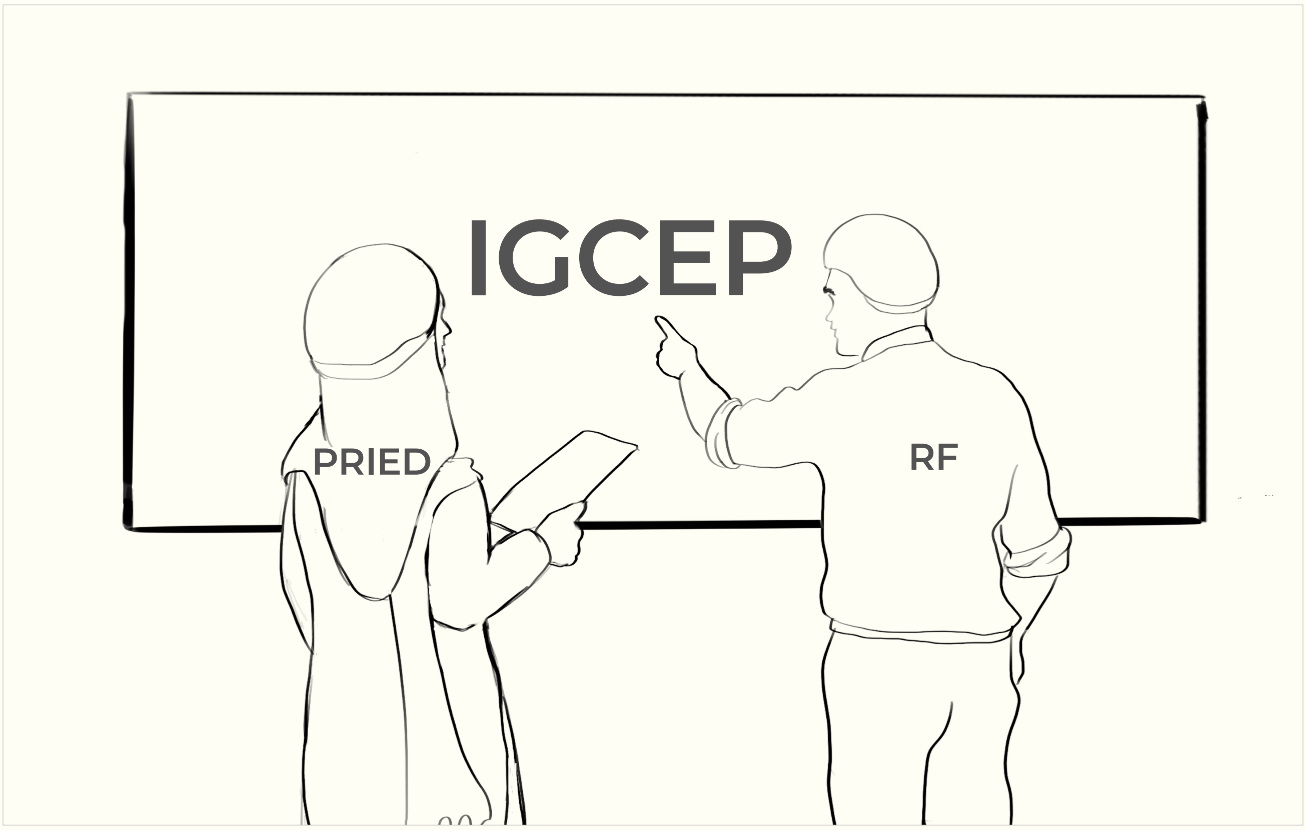
- New Capacity Built: **19.6 GW**
- Total system cost (NPV) = **$57.36 billion**

	Solar	Wind	Nuclear	Hydro	Imp. Coal	BESS	Local Coal
Capacity (MW)	5608	832	0	5977	960	0	0
CAPEX ($ billion)	3.85	1.165	0	9.215	0.714	0	0

Total Investments required = **$ 14.9 billion**

Optimized Candidate Projects (MW)

FY	Hydro	Imp. Coal	Wind	Solar	Cross Border	Nuclear	New Tech	KE Hydro	KE Local Coal	KE Solar PV	KE Wind	Capacity Addition Per Year
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	100	100
2029	87.2	0	0	0	0	0	0	0	0	0	100	187.2
2030	0	0	0	0	0	0	0	0	0	0	100	100
2031	0	0	0	0	0	0	0	0	0	0	100	100
2032	0	0	0	0	0	0	0	0	0	0	100	100
2033	0	0	0	0	0	0	0	0	0	0	100	100
Total	5.2	0	0	0	0	0	0	0	0	0	600	687.2



Chapter 5:

Generation Sequence & Recommendations

	Scenario 4.1	Scenario 4.2	Scenario 4.3	Scenario 4.4	Scenario 4.5	Scenario 4.7	Scenario 4.6	Scenario 4.8	Scenario 4.9
Solar	0	7700	0	2650	0	1700		0	0
Wind	0	1000	0	120	1000	1600		1400	1000
Local Coal	0	330	0	1320	330	990		0	0
Hydro	87.2	956.2	0	87.2	87.2	87.2	5.2	87.2	87.2
BESS	0	0	0	350	0	430		0	0

The generation sequence analysis indicates that hydropower projects, particularly Batdara (5.2 MW) and Uzghor (82 MW), are optimized across all scenarios except Scenario 4.6, which involves the enhanced flow of power to KE. According to IGCEP 2024, the concerned agencies for Batdara and Uzghor are NTDC and KE respectively, with both projects optimized within their respective regions. Notably, since Uzghor is integrated into KE's system, applicable wheeling charges for power evacuation must be factored into the overall cost analysis. A thorough assessment is necessary to determine if the inclusion of these wheeling charges affects the economic feasibility of these projects for the responsible agencies. Local coal power plants are optimized within KE's system in scenarios where significant electric vehicle (EV) and captive loads are included on the demand side. To serve these captive loads, a reliable base load option is required, with current options limited to local coal or the conversion of existing imported coal plants to local coal within KE's system. However, due to global sanctions on coal financing and socio-environmental concerns, coal is no longer a sustainable option for KE.

Moreover, for captive users, particularly export-oriented industries, compliance with the Carbon Border Adjustment Mechanism (CBAM) and heightened accountability on Scope 2 and Scope 3 emissions make coal an impractical choice, especially given KE's already fossil fuel-dominated energy mix. Considering these constraints, it is imperative to explore cleaner and more reliable energy alternatives for KE, such as enhancing the tie-line capacity between NTDC and KE or integrating renewable energy sources like solar and wind with Battery Energy Storage Systems (BESS). It is important to highlight that while an agreement has been established between KE and NTDC to supply power to the KE system based on the tie-line capacity, there is a critical need for a separate agreement ensuring a firm dedicated to power supply to KE. This would always guarantee a consistent and reliable power flow TO KE, rather than relying on pro-rata-based power flow arrangements, which may not adequately meet the demand or operational stability required for KE's system. Establishing such an agreement would enhance predictability and ensure the continuous availability of power to KE, aligning with the long-term energy security goals for the region.

The declining cost of BESS, expected to decrease further, makes it a compelling option for peak shaving, mitigating the intermittency of renewables, and providing ancillary services. Notably, PLEXOS also optimizes BESS in KE's system when captive and EV loads are incorporated, underscoring its viability. The scenarios also show a significant increase in the share of renewable energy sources, particularly when large projects like CHASNUPP-5 (C-5) and Diamer Bhasha Dam are treated as candidates rather than committed options. These projects were not selected by PLEXOS due to their high costs and reduced demand, indicating that such expensive commitments would impose an undue burden on consumers.

New capacity additions should strictly adhere to the least-cost criteria, especially as the government encourages captives to connect with the national grid and KE's system. In a business-as-usual scenario, it is advisable to pursue a no-capacity-addition approach, considering Pakistan's substantial imports of solar PV modules—13 GW in the first half of 2024 alone. Current large-scale solar projects in Pakistan have an average power purchase price of PKR 37/kWh, while rooftop solar can deliver electricity to nearby loads at PKR 27/kWh due to the absence of additional system charges. Rooftop solar provides a stable price per kWh without the need for sovereign guarantees or tariff indexations, which simplifies financial obligations for the government. Given the underutilization of power plants and burdensome capacity payments, future investments should prioritize modernizing the distribution grid to better accommodate renewable energy, rather than expanding generation capacity. Grid modernization offers the dual benefits of improved theft prevention, reduced losses, and increased renewable energy absorption capabilities. This approach would enable Pakistan to meet and even exceed the Alternative and Renewable Energy (ARE) Policy 2019 target of achieving a 30% renewable energy share without substantial new investments. To address peak demand, particularly at night, encouraging the deployment of battery energy storage systems among consumers will be crucial. Furthermore, retiring power plants can be retained on a take-and-pay basis, providing ancillary services and improving system stability by converting generators into synchronous condensers.

The primary objective of this study extends beyond presenting multiple scenarios; it emphasizes the critical importance of considering a range of scenarios and sensitivities in power generation capacity expansion planning. The final scenario selection must integrate all macroeconomic factors to ensure robust decision-making. Moving forward, we aim to integrate academic institutions into our generation planning processes, employing advanced decision-making methodologies from operations research, such as Multi-Criteria Decision Making (MCDM) and Fuzzy Failure Mode and Effect Analysis (FFMEA). This interdisciplinary approach will harness expertise from academia, research institutes, think tanks, and policy planning departments, ensuring that our strategies are comprehensive, cutting-edge, and aligned with the latest developments in the power sector. This collaborative effort will strengthen our strategic decision-making capabilities, enhancing the resilience and sustainability of Pakistan's energy future.

In summary, we strongly recommend the following to the relevant planning agencies, policymakers and the ministry:

◊ **Evaluate Committed Projects on Merit:**

  Treat committed projects as candidate options and evaluate their feasibility to save $5.79 billion in system costs and increase VRE share to 13% by 2033 (up to 26% in high-growth scenarios).

◊ **Avoid Capacity Additions Until 2027:**

  Given the rise in net metering, rapid solarization and declining solar PV prices, avoid capacity additions beyond committed projects until 2027, potentially saving $3.7 billion.

◊ **Incentivize & Facilitate Transfer of Captive Power Plant (CPP) Load to National Grid:**

  Shift CPP load to the national grid to improve utilization rates and optimize generation capacity without significant new additions. However, such initiative would require augmentation and rehabilitation of the transmission and distribution system. It is pertinent to mention that this will not only ensure the reliable and un-interrupted supply of power to CPPs but would also help avoid out of merit operations i.e., running costly fossil-fuel based power plants amid network constraints along with maximum RE absorption.

◊ **Expand NTDC-KE Transmission Capacity:**

  Increase tie-line transmission capacity between NTDC and KE based on a firm agreement to reduce the need for new generation in KE and decrease reliance on costly thermal power plants.

◊ **Avoid High-Cost Projects:**

  Do not forcibly add high-cost projects like Diamer Bhasha Dam and CHASNUPP-5, as they are not optimized and will lead to unnecessary costs ($7.6 billion for Diamer and $5.52 billion for Chashma).

◊ **Promote Rooftop Solar:**

  Encourage rooftop solar installations to meet demand without adding large-scale generation, benefiting from falling PV prices.

◊ **Optimize Grid for Renewables:**

  Focus on grid modernization to reduce losses, prevent theft, and integrate renewable energy, avoiding unnecessary generation capacity expansion.

◊ **Leverage BESS for Flexibility:**

  Utilize the declining cost of Battery Energy Storage Systems (BESS) to manage peak demand, intermittent renewables, and provide ancillary services.

◊ **Encourage EV and CPP Integration:**

  Strategically shift captive power plant loads and integrate EV charging demand to better utilize the existing generation fleet.

APPENDIX (Utilization Rates)

Scenario 4.1 – Utilization Rates (%)

Fiscal Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CASA	0	0	0	0	42	42	42	42	42	42
FPCL	54.11	3.94	0	0	0	0	0.01	0.02	0.02	0.02
Gul Ahmed	51.52	0	0	0	0	0	0	0	0	0
SNPC 1	92	92	92	92	92	92	64.77	64.55	66.91	69.31
SNPC 2	92	92	92	92	92	92	67.35	67.19	69.28	71.18
Tapal	46.21	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 01	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 02	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 05	0.01	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 06	0	0	0	0	0	0	0.02	0.02	0.02	0.02
BQPS 2	20.71	0.88	1.22	1.75	2.38	3.22	4.18	4.19	6.33	9.64
BQPS 3 Unit 01	67.68	13.2	14.09	17.9	39.14	24.09	28.52	49.63	51.43	39.93
BQPS 3 Unit 02	86	39.9	39.32	42.59	27.48	48	48.66	26.59	31.13	49.54
KGTPS	0.01	0	0	0	0	0	0.02	0.02	0.02	0.14
KPC	0.68	0	0	0.01	0.04	0.1	0.13	0.1	0.26	0.42
SGTPS	0.01	0	0	0	0	0	0.02	0.02	0.02	0.02
Engro	77.3	85	85	85	85	85	85	85	85	85
Foundation	79.37	84.71	84.94	84.92	84.96	84.94	0	0.66	0.97	0.45
Guddu II	78.38	83.7	84.78	84.96	84.96	85	84.96	84.94	31.59	0.82
Guddu V	84.57	84.93	85	85	85	85	84.99	84.99	84.99	6.9
Liberty	2.96	2.96	2.96	2.96	85	0	0	0	0	0
Uch	2.95	2.96	2.96	2.96	2.95	2.96	2.96	85	0	0
Uch II	50	78.78	80.1	81.39	50	50.64	50	50	50	50
AES Lalpir	0	0	0	0	0	0	0	0	0	0
AES Pakgen	0	0	0	0	0	0	0	0	0	0
AGL	0	0	0	0	0	0	0	0	0	0
Atlas	0	0	0	0	0	0	0	0	0	0
Engro 127MW	0	0	0	0	0	0	0	0	0	0
Hub N	0	0	0	0	0	0	0	0	0	0
HUBCO	0	0	0	0	0	0	0	0	0	0
Jamshoro I U1	0	0	0	0	0	0	0	0	0	0
Jamshoro II U4	0	0	0	0	0	0	0	0	0	0
Kohinoor	0	0	0	0	0	0	0	0	0	0
Liberty Tech	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U1	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U2	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U3	0	0	0	0	0	0	0	0	0	0
Muzaffargarh II U4	0	0	0	0	0	0	0	0	0	0
Nishat C	0	0	0	0	0	0	0	0	0	0
Nishat P	0	0	0	0	0	0	0	0	0	0
Saba	0	0	0	0	0	0	0	0	0	0
C1	82	82	82	82	82	82	82	82	82	82
C2	80	80	80	80	80	80	80	80	80	80
C3	82	82	82	82	82	82	82	82	82	82
C4	82	82	82	82	82	82	82	82	82	82

C5	0	0	0	0	0	0	90	90	90	90
K2	85	85	85	85	85	85	85	85	85	85
K3	85	85	85	85	85	85	85	85	85	85
China HUBCO	81.69	80.99	82.47	83.67	75.05	50	50	50	50	50
Port Qasim	61.81	75.19	77.64	50	50	50	50	50	50	50
Sahiwal Coal	50	50	50	50	50	50	50	50	50	50
Engro Thar	85	85	85	85	85	84.98	21.5	8.71	84.91	84.99
Lucky	10.56	34.48	0	0	0	0	0	0	0	0
Thal Nova	85	85	85	85	85	84.96	21.39	8.98	84.96	84.96
Thar I SSRL	84.96	84.98	84.98	84.99	84.34	84.36	0	0.16	0.56	84.76
Thar TEL	85	85	85	85	85	85	84.93	84.96	84.96	85
Altern	0	0	0	0	0	0	0	0	0	0
Balloki	0.48	2.28	3.97	1.94	0.93	0.59	0	0	0	0
Bhikki	0	0.16	0.5	0.38	0.04	0	0	0	0	0
Davis	0	0	0	0	0	0	0	0	0	0
FKPCL	0	0	0	0	0	0	0	0	0	0
Halmore	0	0	0	0	0	0	0	0	0	0
Haveli	5.32	11.25	39.89	86.64	3.55	1.55	0	0	0	0
KAPCO 1	0	0	0	0	0	0	0	0	0	0
Nandipur	0	0	0	0	0	0	0	0	0	0
Orient	0	0	0	0	0	0	0	0	0	0
Rousch	0	0	0	0	0	0	0	0	0	0
Saif	0	0	0	0	0	0	0	0	0	0
Sapphire	0	0	0	0	0	0	0	0	0	0
Trimmu	0	0	0	0	0	0	0	0	0	0
Gwadar	0	0	0	0	0	0	0	0	0	0.19
Jamshoro Coal	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	43.77	43.35	0	0	0	0.2
Shahtaj	45.62	45.62	45.62	45.6	44.52	44.47	0	0	0	0.2
TAY	0	0	45.62	45.6	44.57	44.37	0	0	0	0.2

Scenario 4.4 – Utilization Rates (%)

Fiscal Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CASA	0	0	0	0	42	42	42	42	42	42
FPCL	54.23	3.68	0	0.08	0.94	0	0	0.53	0.56	1.39
Gul Ahmed	51.98	0	0	0	0	0	0	0	0	0
SNPC 1	92	92	92	92	92	92	92	92	92	92
SNPC 2	92	92	92	92	92	92	92	92	92	92
Tapal	45.88	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 01	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 02	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 05	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 06	0	0	0	0	1.88	0.45	0.9	1.32	1.42	0.75
BQPS 2	20.62	0.8	0.88	8.01	34.97	23.58	27.04	29.77	29.97	26.27
BQPS 3 Unit 01	67.48	27.45	35.6	33.16	70.75	66.83	66.16	64.97	70.77	67.23
BQPS 3 Unit 02	86.31	25.51	9.89	50.8	63.66	48.26	54.47	53.76	54	50.08
KGTPS	0	0	0	0.25	5.63	1.98	2.76	3.43	3.94	3.2
KPC	0.61	0.01	0	1.01	12.08	4.15	6.13	8.26	8.57	6.53
SGTPS	0	0	0	0	3.12	1.14	1.8	2.49	2.47	1.92
New Coal 330	0	0	0	0	0	85	85	85	85	85
New Coal 660	0	0	0	0	0	0	0	0	0	0
Engro	78.25	85	85	85	85	85	85	85	85	85
Foundation	79.3	84.81	84.95	85	85	85	85	85	85	84.98
Guddu II	78.66	83.93	84.83	85	85	85	85	85	85	85
Guddu V	84.65	84.94	85	85	85	85	85	85	85	85
Liberty	2.96	2.96	2.96	2.96	85	0	0	0	0	0
Uch	2.95	2.96	2.96	2.96	2.95	2.96	2.96	85	0	0
Uch II	50	78.99	79.89	84.58	83.74	84.92	53.47	50	50	82.73
AES Lalpir	0	0	0	0	0	0	0	0	0	0
AES Pakgen	0	0	0	0	0	0	0	0	0	0
AGL	0	0	0	0	0	0	0	0	0	0
Atlas	0	0	0	0	0	0	0	0	0	0
Engro 127MW	0	0	0	0	0	0	0	0	0	0
Hub N	0	0	0	0	0	0	0	0	0	0
HUBCO	0	0	0	0	0	0	0	0	0	0
Jamshoro I U1	0	0	0	0	0	0	0	0	0	0
Jamshoro II U4	0	0	0	0	0	0	0	0	0	0
Kohinoor	0	0	0	0	0	0	0	0	0	0
Liberty Tech	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U1	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U2	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U3	0	0	0	0	0	0	0	0	0	0
Muzaffargarh II U4	0	0	0	0	0	0	0	0	0	0
Nishat C	0	0	0	0	0	0	0	0	0	0
Nishat P	0	0	0	0	0	0	0	0	0	0
Saba	0	0	0	0	0	0	0	0	0	0
C1	82	82	82	82	82	82	82	82	82	82
C2	80	80	80	80	80	80	80	80	80	80
C3	82	82	82	82	82	82	82	82	82	82

C4	82	82	82	82	82	82	82	82	82	82
C5	0	0	0	0	0	0	90	90	90	90
K2	85	85	85	85	85	85	85	85	85	85
K3	85	85	85	85	85	85	85	85	85	85
China HUBCO	81.67	80.89	82.53	84.91	84.87	84.46	50	50	72.65	84.52
Port Qasim	61.82	76.33	78.22	50	50	50	50	50	50	50
Sahiwal Coal	50	50	50	50	50	50	50	50	50	50
Engro Thar	85	85	85	85	85	85	85	85	85	85
Lucky	10.73	32.51	0	0	0	0	0	0	0	1.69
Thal Nova	85	85	85	85	85	85	85	85	85	85
Thar I SSRL	84.96	84.99	84.98	85	85	85	84.99	84.99	84.99	85
Thar TEL	85	85	85	85	85	85	85	85	85	85
Altern	0	0	0	0	0	0	0	0	0	0
Balloki	0.41	2.18	3.65	42.66	3.38	1.67	0	0.02	0.22	0.05
Bhikki	0	0.14	0.46	0.77	0.88	0.55	0	0	0	0
Davis	0	0	0	0	0	0	0	0	0	0
FKPCL	0	0	0	0	0	0	0	0	0	0
Halmore	0	0	0	0	0	0	0	0	0	0
Haveli	5.05	11.25	37.16	90	87.48	56.75	0.17	0.7	1.29	0.86
KAPCO 1	0	0	0	0	0	0	0	0	0	0
Nandipur	0	0	0	0	0	0	0	0	0	0
Orient	0	0	0	0	0	0	0	0	0	0
Rousch	0	0	0	0	0	0	0	0	0	0
Saif	0	0	0	0	0	0	0	0	0	0
Sapphire	0	0	0	0	0	0	0	0	0	0
Trimmu	0	0	0	0.04	0.08	0	0	0	0	0
Gwadar	0	0	0	0	0	0	0	0	0	2.87
Jamshoro Coal	0	0	0	0	0	0	0	0	0	0
New Bagasse	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	44.5	44.5	44.45	21.67	44.42	44.47
Shahtaj	45.62	45.62	45.62	45.62	45.62	45.62	45.57	22.28	45.57	45.59
TAY	0	0	45.62	45.62	45.62	45.62	45.54	22.27	45.56	45.59

Scenario 4.5 – Utilization Rates (%)

Fiscal Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CASA	0	0	0	0	41.89	42	42	42	42	42
FPCL	53.79	2.51	0	0.01	0	0	0.01	0.01	0	0.01
Gul Ahmed	53.94	0	0	0	0	0	0	0	0	0
SNPC 1	92	92	92	92	92	92	65.81	64.01	63.32	63.58
SNPC 2	92	92	92	92	92	92	67.62	67.21	65.5	64.29
Tapal	48.18	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 01	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 02	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 05	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 06	0	0	0	0	0.01	0.01	0.01	0.01	0.01	0.01
BQPS 2	19.32	0.5	1.07	1.39	2.18	2.27	2.23	1.95	1.83	2.06
BQPS 3 Unit 01	86.44	10.88	13.07	18.67	40.43	23.17	22.92	32.8	47.3	31.22
BQPS 3 Unit 02	68.24	41.3	41.83	47.45	32.12	50.03	50.53	36.28	19.26	34.48
KGTPS	0	0	0	0.01	0.01	0.01	0.01	0.01	0.01	0.01
KPC	0.14	0	0	0.01	0.01	0.01	0.01	0.01	0.01	0.02
SGTPS	0	0	0	0	0.01	0.01	0.01	0.01	0.01	0.01
New Coal 330	0	0	0	0	0	0	0	0	0	0
New Coal 660	0	0	0	0	0	0	0	0	0	0
Engro	77.19	85	85	85	85	85	85	85	85	85
Foundation	79.41	84.97	84.97	84.96	85	84.97	0.01	0.48	1.01	0.64
Guddu II	77.83	83.86	84.96	84.99	85	85	84.97	84.97	61.44	0.69
Guddu V	84.75	84.97	85	85	85	85	85	84.99	85	31.5
Liberty	2.96	2.96	2.96	2.96	148.75	0	0	0	0	0
Uch	2.95	2.96	2.96	2.96	2.95	2.96	2.96	99.17	0	0
Uch II	50	78.66	80.05	82.11	79.55	82.71	50	50	50	50
AES Lalpir	0	0	0	0	0	0	0	0	0	0
AES Pakgen	0	0	0	0	0	0	0	0	0	0
AGL	0	0	0	0	0	0	0	0	0	0
Atlas	0	0	0	0	0	0	0	0	0	0
Engro 127MW	0	0	0	0	0	0	0	0	0	0
Hub N	0	0	0	0	0	0	0	0	0	0
HUBCO	0	0	0	0	0	0	0	0	0	0
Jamshoro I U1	0	0	0	0	0	0	0	0	0	0
Jamshoro II U4	0	0	0	0	0	0	0	0	0	0
Kohinoor	0	0	0	0	0	0	0	0	0	0
Liberty Tech	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U1	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U2	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U3	0	0	0	0	0	0	0	0	0	0
Muzaffargarh II U4	0	0	0	0	0	0	0	0	0	0
Nishat C	0	0	0	0	0	0	0	0	0	0
Nishat P	0	0	0	0	0	0	0	0	0	0
Saba	0	0	0	0	0	0	0	0	0	0
C1	82	82	82	82	82	82	82	82	82	82
C2	80	80	80	80	80	80	80	80	80	80
C3	82	82	82	82	82	82	82	82	82	82
C4	82	82	82	82	82	82	82	82	82	82

C5	0	0	0	0	0	0	90	90	90	90
K2	85	85	85	85	85	85	85	85	85	85
K3	85	85	85	85	85	85	85	85	85	85
China HUBCO	81.65	80.84	82.8	84.27	81.61	55.98	50	50	50	50
Port Qasim	62.89	75.38	77.94	50	50	50	50	50	50	50
Sahiwal Coal	50	50	50	50	50	50	50	50	50	50
Engro Thar	85	85	85	85	85	84.98	41.44	27.34	84.96	85
Lucky	10.26	38.1	0	0	0	0	0	0	0	0.01
Thal Nova	85	85	85	85	85	85	41.04	27.14	84.96	84.98
Thar I SSRL	84.99	84.99	84.98	85	84.84	84.81	0	0.23	0.59	84.91
Thar TEL	85	85	85	85	85	85	84.97	84.97	84.99	85
Altern	0	0	0	0	0	0	0	0	0	0
Balloki	0.42	1.67	3.7	11.91	0.86	0.53	0	0	0	0
Bhikki	0	0.18	0.54	0.49	0.05	0	0	0	0	0
Davis	0	0	0	0	0	0	0	0	0	0
FKPCL	0	0	0	0	0	0	0	0	0	0
Halmore	0	0	0	0	0	0	0	0	0	0
Haveli	4.55	10.29	44.91	90	4.35	1.09	0	0	0	0
KAPCO 1	0	0	0	0	0	0	0	0	0	0
Nandipur	0	0	0	0	0	0	0	0	0	0
Orient	0	0	0	0	0	0	0	0	0	0
Rousch	0	0	0	0	0	0	0	0	0	0
Saif	0	0	0	0	0	0	0	0	0	0
Sapphire	0	0	0	0	0	0	0	0	0	0
Trimmu	0	0	0	0	0	0	0	0	0	0
Gwadar	0	0	0	0	0	0	0	0	0	0.37
Jamshoro Coal	0	0	0	0	0	0	0	0	0	0
New Tech Y1	0	0	0	0	40	40	40	40	40	40
New Tech Y2	0	0	0	0	0	40	40	40	40	40
New Tech Y3	0	0	0	0	0	0	40	40	40	40
New Tech Y4	0	0	0	0	0	0	0	40	40	40
New Tech Y5	0	0	0	0	0	0	0	0	40	40
New Tech Y6	0	0	0	0	0	0	0	0	0	40
CSP	0	0	0	0	44.09	43.81	0	0	0.01	0.25
Shahtaj	45.62	45.62	45.62	45.6	45.02	44.8	0	0.01	0.01	0.32
TAY	0	0	45.72	45.6	44.88	44.92	0	0	0.01	0.32

Scenario 4.6 – Utilization Rates (%)

Fiscal Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CASA	0	0	0	0	42	42	42	42	42	42
FPCL	54.23	3.68	0.04	0.14	1.02	0	0.07	0.73	0.7	1.37
Gul Ahmed	51.98	0	0	0	0	0	0	0	0	0
SNPC 1	92	92	92	92	92	92	92	92	92	92
SNPC 2	92	92	92	92	92	92	92	92	92	92
Tapal	45.88	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 01	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 02	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 05	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 06	0	0	0	0	1.94	0.54	1.01	1.4	1.5	0.72
BQPS 2	20.62	0.8	1.2	9.2	36	24.61	28.06	30.78	30.99	25.53
BQPS 3 Unit 01	67.5	27.45	36.59	35.14	71.66	67.73	66.99	68.34	71.53	66.45
BQPS 3 Unit 02	86.29	25.51	11.44	51.94	64.5	49.4	55.53	57.55	55.04	49.06
KGTPS	0	0	0	0.38	6.78	2.11	2.84	3.72	4.2	3.11
KPC	0.61	0.01	0	1.32	12.62	4.46	6.74	9	9.39	6.03
SGTPS	0	0	0	0.03	3.42	1.19	1.9	2.6	2.67	1.76
New Coal 330	0	0	0	0	0	85	85	85	85	85
New Coal 660	0	0	0	0	0	0	0	0	0	0
Engro	78.25	85	85	85	85	85	85	85	85	85
Foundation	79.3	84.81	84.95	85	85	85	85	85	85	85
Guddu II	78.66	83.93	84.83	85	85	85	85	85	85	85
Guddu V	84.65	84.94	85	85	85	85	85	85	85	85
Liberty	2.96	2.96	2.96	2.96	85	0	0	0	0	0
Uch	2.95	2.96	2.96	2.96	2.95	2.96	2.96	85	0	0
Uch II	50	78.99	80.2	84.77	84.48	84.98	84.88	72.06	65.21	83.44
AES Lalpir	0	0	0	0	0	0	0	0	0	0
AES Pakgen	0	0	0	0	0	0	0	0	0	0
AGL	0	0	0	0	0	0	0	0	0	0
Atlas	0	0	0	0	0	0	0	0	0	0
Engro 127MW	0	0	0	0	0	0	0	0	0	0
Hub N	0	0	0	0	0	0	0	0	0	0
HUBCO	0	0	0	0	0	0	0	0	0	0
Jamshoro I U1	0	0	0	0	0	0	0	0	0	0
Jamshoro II U4	0	0	0	0	0	0	0	0	0	0
Kohinoor	0	0	0	0	0	0	0	0	0	0
Liberty Tech	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U1	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U2	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U3	0	0	0	0	0	0	0	0	0	0
Muzaffargarh II U4	0	0	0	0	0	0	0	0	0	0
Nishat C	0	0	0	0	0	0	0	0	0	0
Nishat P	0	0	0	0	0	0	0	0	0	0
Saba	0	0	0	0	0	0	0	0	0	0
C1	82	82	82	82	82	82	82	82	82	82
C2	80	80	80	80	80	80	80	80	80	80
C3	82	82	82	82	82	82	82	82	82	82

C4	82	82	82	82	82	82	82	82	82	82
C5	0	0	0	0	0	0	90	90	90	90
K2	85	85	85	85	85	85	85	85	85	85
K3	85	85	85	85	85	85	85	85	85	85
China HUBCO	81.67	80.89	82.79	84.93	84.91	84.73	55.57	50	84.71	84.82
Port Qasim	61.82	76.33	78.33	50	50	50	50	50	50	50
Sahiwal Coal	50	50	50	50	50	50	50	50	50	50
Engro Thar	85	85	85	85	85	85	85	85	85	85
Lucky	10.73	32.51	0	0	0	0	0	0	0	2.09
Thal Nova	85	85	85	85	85	85	85	85	85	85
Thar I SSRL	84.96	84.99	84.98	85	85	85	85	85	85	85
Thar TEL	85	85	85	85	85	85	85	85	85	85
Altern	0	0	0	0	0	0	0	0	0	0
Balloki	0.41	2.18	4.09	55.23	16.77	2.14	0	0.07	0.38	0.14
Bhikki	0	0.14	0.56	0.96	1.07	0.7	0	0	0	0
Davis	0	0	0	0	0	0	0	0	0	0
FKPCL	0	0	0	0	0	0	0	0	0	0
Halmore	0	0	0	0	0	0	0	0	0	0
Haveli	5.05	11.25	41.07	90	90	72.23	0.27	0.87	1.59	1.12
KAPCO 1	0	0	0	0	0	0	0	0	0	0
Nandipur	0	0	0	0	0	0	0	0	0	0
Orient	0	0	0	0	0	0	0	0	0	0
Rousch	0	0	0	0	0	0	0	0	0	0
Saif	0	0	0	0	0	0	0	0	0	0
Sapphire	0	0	0	0	0	0	0	0	0	0
Trimmu	0	0	0.01	0.09	0.14	0.02	0	0	0	0
CSP	0	0	0	0	44.5	44.5	44.47	44.47	44.47	44.5
Shahtaj	45.62	45.62	45.62	45.62	45.62	45.62	45.59	45.59	45.59	45.62
TAY	0	0	45.62	45.62	45.62	45.62	45.6	45.59	45.59	45.62

Scenario 4.8 – Utilization Rates (%)

Fiscal Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CASA	0	0	0	0	41.89	42	42	42	42	42
FPCL	53.79	2.51	0	0.01	0	0	0	0	0	0
Gul Ahmed	53.94	0	0	0	0	0	0	0	0	0
SNPC 1	92	92	92	92	92	92	92	92	92	92
SNPC 2	92	92	92	92	92	92	92	92	92	92
Tapal	48.18	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 01	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 02	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 05	0	0	0	0	0	0	0	0	0	0
BQPS 1 Unit 06	0	0	0	0.01	0.01	0.01	0.09	0	0	0
BQPS 2	19.32	0.5	0.75	12.13	4.04	3.35	25.83	0.02	0.29	0.73
BQPS 3 Unit 01	86.71	10.88	11.04	45.04	40.21	28.6	55.19	13.15	26.37	19.19
BQPS 3 Unit 02	67.98	41.3	41.07	63.99	46.56	53.81	71.68	12.01	4.71	18.51
KGTPS	0	0	0	0.01	0.01	0.01	0.95	0	0	0
KPC	0.14	0	0	0.32	0.02	0.04	4.43	0	0	0.01
SGTPS	0	0	0	0.01	0.01	0.01	0.26	0	0	0
Engro	77.19	85	85	85	85	85	85	85	85	85
Foundation	79.41	84.97	84.97	85	85	85	85	85	85	85
Guddu II	77.83	83.86	84.95	85	85	85	85	85	85	85
Guddu V	84.75	84.97	85	85	85	85	85	85	85	85
Liberty	2.96	2.96	2.96	2.96	148.75	0	0	0	0	0
Uch	2.95	2.96	2.96	2.96	2.95	2.96	2.96	99.17	0	0
Uch II	50	78.66	79.86	84.43	84.95	84.98	84.97	84.97	84.95	84.95
AES Lalpir	0	0	0	0	0	0	0	0	0	0
AES Pakgen	0	0	0	0	0	0	0	0	0	0
AGL	0	0	0	0	0	0	0	0	0	0
Atlas	0	0	0	0	0	0	0	0	0	0
Engro 127MW	0	0	0	0	0	0	0	0	0	0
Hub N	0	0	0	0	0	0	0	0	0	0
HUBCO	0	0	0	0	0	0	0	0	0	0
Jamshoro I U1	0	0	0	0	0	0	0	0	0	0
Jamshoro II U4	0	0	0	0	0	0	0	0	0	0
Kohinoor	0	0	0	0	0	0	0	0	0	0
Liberty Tech	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U1	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U2	0	0	0	0	0	0	0	0	0	0
Muzaffargarh I U3	0	0	0	0	0	0	0	0	0	0
Muzaffargarh II U4	0	0	0	0	0	0	0	0	0	0
Nishat C	0	0	0	0	0	0	0	0	0	0
Nishat P	0	0	0	0	0	0	0	0	0	0
Saba	0	0	0	0	0	0	0	0	0	0
C1	82	82	82	82	82	82	82	82	82	82
C2	80	80	80	80	80	80	80	80	80	80
C3	82	82	82	82	82	82	82	82	82	82
C4	82	82	82	82	82	82	82	82	82	82
C5	0	0	0	0	0	0	90	90	90	90

K2	85	85	85	85	85	85	85	85	85	85
K3	85	85	85	85	85	85	85	85	85	85
China HUBCO	81.65	80.84	82.51	84.97	84.99	84.95	84.93	84.92	84.97	84.98
Port Qasim	62.89	75.38	77.66	50	50	50	50	50	50	50
Sahiwal Coal	50	50	50	50	50	50	50	50	50	50
Engro Thar	85	85	85	85	85	85	85	85	85	85
Lucky	10.26	38.1	0	0	0	0	0	0	0	84.76
Thal Nova	85	85	85	85	85	85	85	85	85	85
Thar I SSRL	84.99	84.99	84.98	85	85	85	85	85	85	85
Thar TEL	85	85	85	85	85	85	85	85	85	85
Altern	0	0	0	0	0	0	0	0	0	0
Balloki	0.42	1.67	3.29	48	69.75	39.51	0.02	0.68	20.97	1.22
Bhikki	0	0.18	0.47	0.69	1.68	0.84	0	0.26	0.63	0.33
Davis	0	0	0	0	0	0	0	0	0	0
FKPCL	0	0	0	0	0	0	0	0	0	0
Halmore	0	0	0	0	0	0	0	0	0	0
Haveli	4.55	10.29	41.18	90	90	90	31.02	74.43	90	72.89
KAPCO 1	0	0	0	0	0	0	0	0	0	0
Nandipur	0	0	0	0	0	0	0	0	0	0
Orient	0	0	0	0	0	0	0	0	0	0
Rousch	0	0	0	0	0	0	0	0	0	0
Saif	0	0	0	0	0	0	0	0	0	0
Sapphire	0	0	0	0	0	0	0	0	0	0
Trimmu	0	0	0	0	0.53	0.23	0	0	0.01	0
Gwadar	0	0	0	0	0.02	0	0	0	0	85
Jamshoro Coal	0	0	0	0	0	0	0	0	0	0
CSP	0	0	0	0	44.5	44.5	44.48	44.48	44.5	44.5
Shahtaj	45.62	45.62	45.62	45.62	45.62	45.62	45.6	45.6	45.62	45.62
TAY	0	0	45.72	45.62	45.62	45.62	45.6	45.6	45.62	45.62

Glossary

Base load:

Base load/demand represents the consistent and continuous demand of electricity over an extended period such as a day, a month or a year. Base demand is linked with the essential services that occur continuously such as streetlights, refrigeration and some industries.

Candidate Power Plants:

These are potential projects that can be considered as an option in the future generation capacity expansion. These power plants are included in future capacity expansion models as possible additions, depending on the system's needs, economic viability, policy support, or market conditions. These plants serve as options for future capacity, and their inclusion depends on various scenarios or uncertainties, such as future demand growth, policy shifts, or technology changes.

Captive power plants:

Captive power plants (CPPs) refer to small-scale power generation facilities that are set up by industries or businesses to meet their own electricity needs, rather than relying entirely on the national grid. These plants help industries avoid power outages and reduce costs, especially in areas where the grid supply is unreliable or expensive.

Capacity factor:

Capacity factor is a term used in the context of power plants to describe the ratio of actual generation over a specified time interval to the maximum possible generation if the plant were operating at full capacity. It is calculated as the ratio of actual power output to the maximum power output.

Committed Power Plants:

These are projects that have already been planned, approved, or are under construction with a high degree of certainty that they will be operational within the specified planning horizon. In other words, these projects have received the necessary approvals, financing, and other required permits, and construction may have already begun.

Fixed Operations & Maintenance (FO&M) costs:

Expressed in USD per kilo-watt-year, FO&M costs refers to the expenses associated with ongoing operations and maintenance of a power plant or an energy storage facility that remain constant irrespective of the output of a power plant or an energy storage facility.

IGCEP:

Indicative Generation Capacity Expansion Plan refers to the power generation planning which involves strategy for producing electricity to meet the demand of consumers. IGCEP includes determination of optimum mix of power generation sources that can meet the electricity demand based on least cost. In Pakistan, the System Operator (National Transmission & Despatch Company) is mandated to prepare the IGCEP every year with a ten-year rolling horizon.

Net Present Value (NPV):

NPV is a financial metric used to evaluate the profitability and viability of future investments in power generation infrastructure, such as building new power plants or upgrading existing facilities. NPV calculates the difference between the present value of cash inflows (e.g., revenues from selling electricity) and the present value of cash outflows (e.g., initial capital investment, operating and maintenance costs) over a specified time horizon.

Peak demand:

Peak demand refers to the instance when electricity demand is maximum. It represents the highest level of electricity consumption that occurs during the periods of high activity such as turning on an air conditioner during heat wave, during a hot summer day

Peaking plants:

Refers to thermal power plants that are operated to meet the short duration demand spikes (peak demand) in a system. These power plants are usually HSD/RFO based power plants having fast ramp rates but significantly higher operating costs.

Scope 2 emissions:

Represents indirect greenhouse gas (GHG) emissions resulting from purchased electricity generation by an organization. These GHG emissions occur outside of the organization's direct control but are linked with the organization's electricity consumption.

Scope 3 emissions:

Include all the indirect greenhouse gas (GHG) emissions that arise throughout an organization's value chain, including activities such as procurement, transportation, waste disposal, and employee commuting. These emissions are not directly owned or controlled by the organization but are associated with its operations and activities.

Total cost:

Total cost of generation refers to the sum of generation costs (fuel costs, variable O&M costs) and fixed costs (FO&M costs).

Variable Operations & Maintenance (VO&M) cost:

Expressed in USD per Mega-Watthour, VO&M refers to the costs associated with ongoing operations and maintenance of a power plant or an energy storage system. The span of these costs varies and depends upon the nature of operations and the sort of maintenance that is required. Typically, VO&M costs include fuel costs, labor costs, lubricants costs and repairs & overhauling etc.

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