NEECA

Prefeasibility Study

Pakistan Green Hydrogen Energy

Technical assistance consultant's report by

ASIAN DEVELOPMENT BANK

ADB

PREFEASIBILITY STUDY

Pakistan Green Hydrogen Energy

2023

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Acronyms

ADB	Asian Development Bank
AEC	Alkaline Electrolysis Cell
AEDB	Alternative Energy Development Board
ALK	Alkaline Electrolysis
APEC	Asia Pacific Economic Cooperation
BCR	Benefit Cost Ratio
CAPEX	Capital Expenditures
CCOE	Cabinet Committee on Energy
CCS	Carbon Capture and Storage
CH_4	Synthetic methane
Chemicals	Production of (intermediate) chemicals, such as methanol, ammonia (for fertilizer or chemical products) or final chemical products.
CHP	Heat and power via CHPs, for example in fuel cells or turbines
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
Coal Gasification + CCS	Hydrogen production from coal gasification (all types of coals and derivatives) coupled with CO_2 capture
CPPA-G	Central Power Purchasing Agency- Guarantee
DBE	Design Basis Earthquake
DISCOs	Distribution Companies
Domestic heat	Direct use in building for water and space heating
EIRR	Economic Internal Rate of Return
EPAs	Energy Purchase Agreements
FO	Furnace Oil
GENCOs	Generation Companies
GoP	Government of Pakistan
Grid Injection	Injection in natural gas or pure hydrogen grids
H_2	Hydrogen in molecular form
HPP	High Pressure Processing
IEA	International Energy Agency
Industrial Heat	Industrial applications such as refineries, steel plants or high temperature heat.
IPPs	Independent Power Producers
KE	K-Electric
LCOE	Levelized Cost of Energy
LCOH	levelized Cost of Hydrogen
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen =Carriers
LOI	Letter of Intent

MKT	Main Karakorum Thrust
Mobility	Used vehicles (road, off-road, rail, maritime or aviation).
MONENCO	Montreal Engineering Company
NDCs	Nationally Determined Contributions
OBE	Operation Basis Earthquake
OECD	Organization for Economic Co-operation and Development
PARCO	Pak-Arab Refinery Company Limited
PCRET	Pakistan Council for Renewable Energy Technologies
PEDO	Pakhtunkhwa Energy Development Organization
PEM	Proton exchange membrane electrolysis
PEM	Proton exchange membrane electrolysis
PID	Proportional Integral Derivative
PMD	Pakistan Meteorological Department
Power	Supply of electricity to the electricity grid with a gas turbine of fuel cell
PPAs	Power Purchase Agreements
SDG	Sustainable Development Goal
SEE	Safety Evaluation Earthquake
SHYDO	Sarhad Hydel Development Organization
SME	Small and Medium-sized Enterprise
SMR	Steam Methane Reformer
SOEC	Solid oxide Electrolysis Cells
Synthetic hydrocarbons	Synthetic liquid fuels
Synthetic hydrocarbons (MeOH)	Methanol
TLOS	Tripartite Letter of Support
WAPDA	Water and Power Development Authority
PPRA	Public Procurement Regulatory Authority
PSQCA	Pakistan Standard and Quality Control Authority
R&D	Research & Development
RPS	Renewable Portfolio Standards
SBP	State Bank of Pakistan
SEECA	Sindh Energy Efficiency & Conservation Agency
SMEs	Small and Medium Enterprises
SNGPL	Sui Northern Gas Pipelines Limited
SRO	Statutory Regulatory Order
SSGC	Sui Southern Gas Company
Unknown PtX	Undisclosed Electrolysis Type
UFG	Unaccounted for Gas
USD	United States Dollar
VFD	Variable Frequency Drives
WAPDA	Water and Power Development Authority

Currency Equivalents

USD 1.00 = 105 JPY

(as of 31st December 2020)

Weights and Measures

GJ	Giga Joule
GW	Gigawatt
GWh	Giga Watt-hour
kg	Kilogram
km	Kilometer
km²	Square kilometer
kW	Kilowatt
kWh	Kilowatt-hour
l	Liter

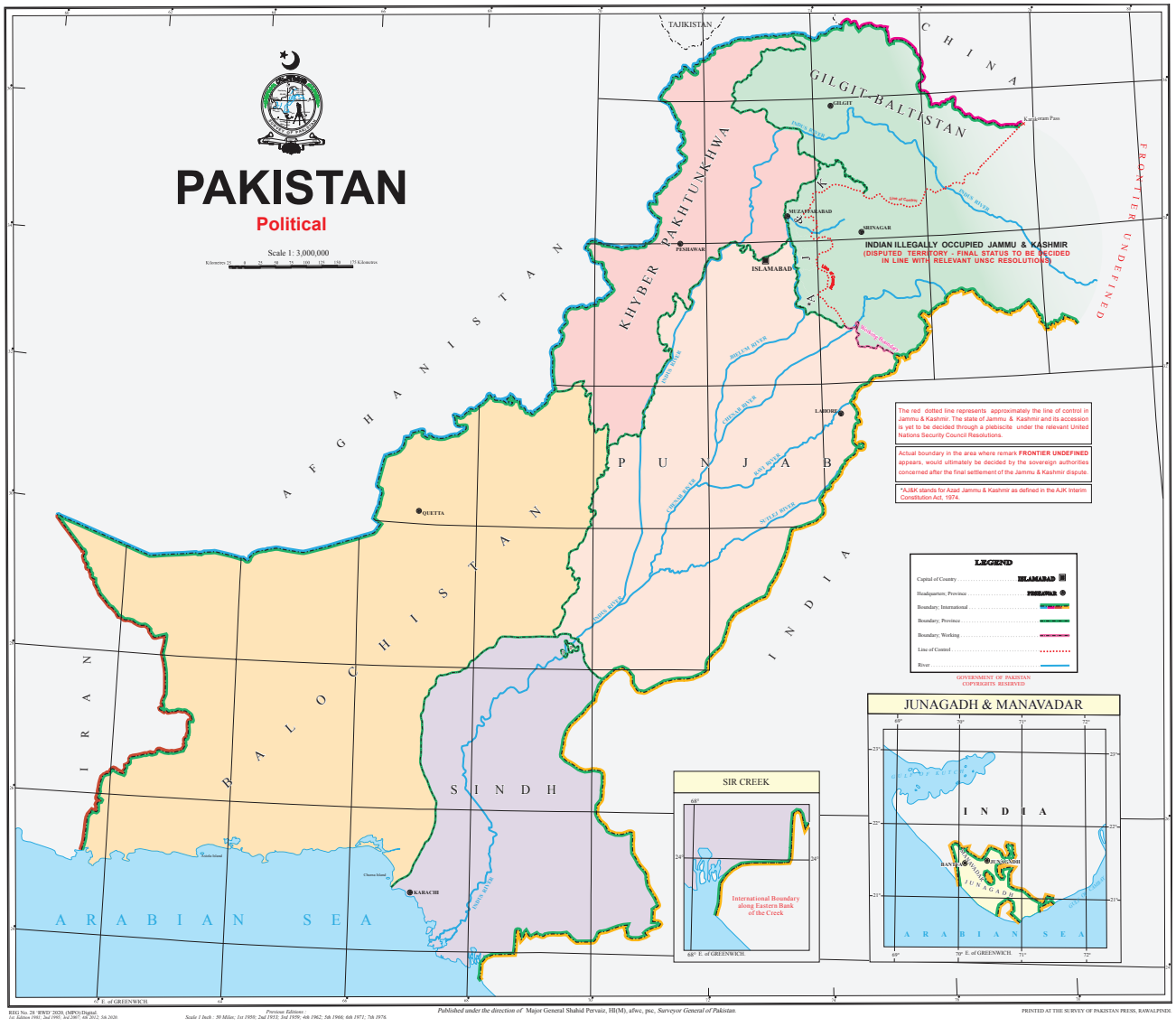
m	Meter
m²	Square Meter
m³	Cubic Meter
MW	Megawatt
ppm	Parts per Million
t	Ton (1,000 kg)
TWh	Terawatt-hour
bcfd	billion cubic feet per day
Domestic heat	Direct use in building for water and space heating

Notes

i. The fiscal year (FY) of 2021 ends on Jun 30.

ii. In this report, “$” refers to United States dollars

Map of Pakistan



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Executive Summary, Conclusions and Recommendations

A. The Renewable Hydrogen Imperative: Public Health, Planetary Health, and Affordable Energy Security

The past century has seen the flow of billions of dollars into the currency reserves of nations blessed with coal, crude oil, and natural gas fossil-fuel reserves under the ground. The next century will benefit nations that have renewable energy resources above the ground: wind, solar and hydro. Hydrogen is an essential energy vector to ensure that these renewable energy sources can be harnessed cost-effectively and reliably across wide geographic coverage. This study is therefore highly valuable to enable Pakistan to participate in this energy resources transformation.

Hydrogen holds a prominent position among renewable energy vectors due to its high-energy content, environmental compatibility and ease of storage and distribution. The issue of intermittency and seasonality of renewable power resources calls for high-capacity seasonal energy storage, which hydrogen can enable. Hydrogen will play a central role in securing the Paris Agreement mid-century target of 'net-zero' carbon dioxide emissions to which many nations aspire. Availability of renewable resources in Pakistan to build an economically sustainable domestic hydrogen industry can help meet Nationally Determined Contributions (NDCs) and address concerns around energy security.

Pakistan is blessed with high solar radiation and steady wind energy, which can produce renewable hydrogen from renewable power using electrolysis. Furthermore, use of the existing infrastructure, such as electrical power grid or gas pipeline network is also available to ensure a cost-effective implementation of hydrogen as an energy vector. Pakistan has widespread naturalgas and Liquefied Natural Gas (LNG) infrastructure like pipelines, LNG terminals and regasification facilities and Compressed Natural Gas (CNG) stations in transport sector across the country. Hence, hydrogen haspotential to be integrated with existing infrastructure effectively.

Pakistan has a very high intensity of urban population at 36.4%. Fossil fuel consumption, energy intensive lifestyles, population growth and economic development are drivers of air pollution in these urban areas. The country is highly under poor conditions in air quality on health with economic consequences. Air pollution is one of the major concerns in Metropolitan areas of Pakistan. A progressive transition from finite sources of methane to renewable hydrogen has thepotential to contribute to a stable energy supply, CO_2 reduction and air pollution reduction. In addition, Pakistan has the Renewable Energy Policy 2019, which clearly set the national goals, and they are aligned with SDG #7.

B. Pakistan Renewable Hydrogen Value Chain Selection for Detailed Analysis

This study proposed 13 value chains for the production, storage, distribution, and utilization of renewable hydrogen. Three of these were selected, in discussion with the project stakeholders, for financial modelling to assess their economic viability under a range of current and hypothetical future scenarios. The three hydrogen value chain cases that were selected for the above analysis were:

a. **Project #3** – hydrogen electrolysis from hydroelectricity on the existing Ghazi-Barotha dam (fed by a canal from the Tarbela dam) and admixing of the hydrogen at a low concentration into the local natural gas grid for use on existing equipment for heating, cooking and CNG applications to incrementally decarbonize the gas pipeline network and CNG mobility. Displacement of locally produced natural gas or imported LNG was the base-case for financial benchmarking.

b. **Project #13** – run of the river hydro power remote micro-grid with a portion of the power diverted for hydrogen production during 10 months of hydro power generation. The hydrogenwould be stored and released to a fuel-cell for 2 winter months when the hydro plant would be winterized to avoid ice damage. The system could be deployed generate all-year-round power in remote northern locations with severe winter weather (e.g., Naltar valley in Gilgit Baltisan). Displacement of bottled LPG gas or wood from deforestation were considered as the alternatives for financial benchmarking.

c. **Project #6** – use solar power from the Quaid e Azam solar park to produce hydrogen on an electrolyzer for admixing at a low concentration into the local natural gas grid for use on existing equipment heating, cooking and CNG applications to incrementally decarbonize the gas pipeline network and CNG mobility. Displacement of locally produced natural gas or imported LNG was the base-case for financial benchmarking.

These sensitivity analysis scenarios analyzed:

a. The competitiveness of hydrogen versus fossil fuels with a hypothetical cost of CO_2 emissionsbeing applied to the fossil fuels. This models the potential future introduction of a CO_2 emission tax.

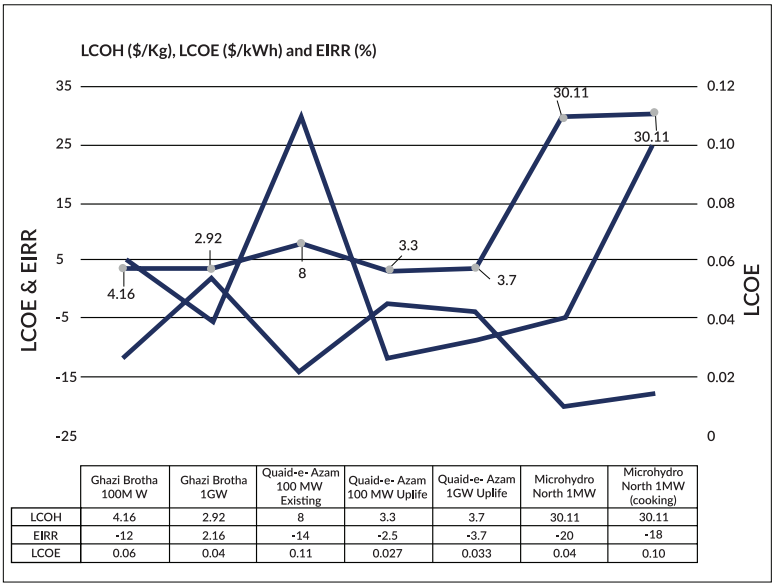
b. The competitiveness of hydrogen vs alternative fuels at various price points which were basedon local gas prices, and recent LNG and LPG import price data.

c. A range of project scale options (from 1 MW, through 100 MW to GW scale)

d. Alternative technical implementation options, for example a solar park upgrade vs additional new solar panels), or power purchase vs investment for additional self-generation.

e. An appropriate range of capex sensitivities for the main equipment items, for example alternative international sourcing options for hydrogen electrolyzers to minimize project capex.

C. Conclusions of the Value Chain Techno-economic Analysis



	Ghazi Brotha 100M W	Ghazi Brotha 1GW	Quaid-e- Azam 100 MW Existing	Quaid-e- Azam 100 MW Uplife	Quaid-e- Azam 1GW Uplife	Microhydro North 1MW	Microhydro North 1MW (cooking)
LCOH	4.16	2.92	8	3.3	3.7	30.11	30.11
EIRR	-12	2.16	-14	-2.5	-3.7	-20	-18
LCOE	0.06	0.04	0.11	0.027	0.033	0.04	0.10

Figure: *key financial metrics for the scenarios analyzed within the three chosen cases*

Fundamental observations from the financial analysis, as summarized in Figure above, are:

a. Some of the scenarios modelled for the Ghazi Barotha Scheme #2 have a positive EIRR. To achieve this, some hypothetical scenarios were considered that may become possible under certain policy conditions, e.g. zero power cost for curtailed potential hydro power generation and high CO_2 emissions tax on natural gas usage.

b. Levelized Cost of Energy (LCOE) and levelized Cost of Hydrogen (LCOH) are within international benchmarks for similar schemes at similar scale.

c. EIRR is low or negative for most scenarios. It should be noted that a 7% discount rate has been applied, according to investment case analysis practices in place for government supported projects in Pakistan.

d. For the two schemes where self-investment in new power generation capacity was compared to power purchase, according to the tariffs in place today, self-generation was estimated to be less expensive.

The results of the financial modelling for this study indicate that total system capital costs, including renewable power generation, hydrogen production, transmission, and utilization and electrolyzer utilization are the two most important factors to determine the LCOH and its financial feasibility. Furthermore, for the larger systems the system size does not matter a lot as increasing the scale from 100 MW to 1 GW in both cases (3 & 6) is not providing sufficient economies of scale or efficiency gains. It is because solar panels and electrolyzers are added in modular fashion, so output is augmented on the fixed ratio, and it involves few synergies with the other infrastructure. These conclusions are to be expected and align with other international studies on green hydrogen deployment.

Power cost also becomes an important determinant for all such scenarios where power is being purchased from the National Grid. Therefore, all such scenarios are not financially viable as the per kWh power tariff applied in these options is reasonably high i.e. $0.06

for hydel and $0.11 for solar. On the other hand, all such cases where power cost is being covered through incurring capital expenditures for new renewable power generation are also not financially viable though their Levelized Cost of Energy (LCOE) is very reasonable. This is because Capital Expenditures (CAPEX) is very high, particularly the cost involved to construct the new canal and reservoir is substantial in Case 3. In Case 6, it is the electrolyzer utilization factor (i.e. 42 percent due to Ltd. availability of Sun) though its LCOE is also very reasonable.

In general, most of the cases analyzed are not financially attractive and they only begin to come close to being financially attractive under the following sensitivity scenarios:

a. Low-cost Chinese AEC electrolyzer supply rather than high-cost European / North American supply, this was considered in the two cases where AEC equipment was specified.

b. High LNG cost for non-contracted spot purchases during seasonal peak gas demand, i.e. winter months where heating is required (LNG was the alternative fuel to be replaced in the two (2) cases analyzed). This conclusion favors long term hydrogen storage, for example underground hydrogen storage in new salt caverns which could be possible west of Lahore.

c. High CO_2 emissions cost based on potential taxation measures that may be considered in the future. This conclusion points to the importance of regulatory change to drive the transition from fossil fuels to clean hydrogen.

d. Access to the lower domestic electricity tariff rather than the higher industrial tariff, for the cases where self-generation was not included in the scheme. This conclusion points to the critical nature of power purchase costs in the scheme viability and would suggest a review of power supply costs to clean hydrogen projects could make them more attractive.

e. Zero power cost, under the assumption that curtailed variable hydel power might be available at some times of the year under a different regulatory pricing mechanism.

Although other utilization cases were not modelled, it is possible that hydrogen powered mobility (e.g. bus fleets), use of green hydrogen to substitute grey hydrogen for ammonia / urea fertilizer value chain or seasonal hydrogen energy storage may be more attractive that the LNG substitution grid injection case that was modelled. In addition to these ideas, hydrogen production and use as long-term energy storage with underground hydrogen storage in purpose-built salt caverns may be a utility scale project with national merit. For this concept to have a viable business case, the power pricing tariff would need adjustment to create a spread between the power purchase price at periods of low power demand on the grid and the power sale price at periods of high demand on the grid. This would enable a business model that utilizes cheap power during periods of excess capacity to generate hydrogen which can then be used to create power and sell that back to the grid at a higher rate during periods of high demand.

A regulatory change of this type to create a buy / sell spread to the power tariff based on grid loading may be considered in the future and may be beneficial as the percentage of variable renewable energy from solar (predictable daily variation) wind (less predictable weekly variation with predictable seasonal trends) and hydro (predictable seasonal trends) in the

national mix grows to be higher than the current levels. At utility scale, the best combination of hydrogen energy storage may be with curtailed hydro power due to the very high peak to trough generation potential of the large dams in Pakistan which is driven by the combination of monsoon rains and snowmelt on the Himalaya and causes extreme seasonal cyclicality to the Indus and other major river systems. Underground hydrogen storage can be used to create a national energy reserve to balance the seasonal fluctuations in power and heating demand.

Interestingly, in line with the above general conclusions, the case of Ghazi Barotha -100 MW with 3 months operations with zero power cost was analyzed to be a financially feasible scenario. Its BCR is 1.26:1 and EIRR is of 10.11 percent when the benefits are valued at High LNG Spot Price along and CO_2 emission reduction benefits are valued at \$80/tCO_2. The background to this case assumes curtailed hydel power for three months of the year. Meaning that there is the potential for more electricity to be produced than can be dispatched to the grid and therefore the electricity it has zero value. This is indeed the situation and hydel power generation is avoided to balance the grid. However, there is no power pricing tariff mechanism in place today that would allow the low-cots or free use of this surplus water energy or 'curtailed power' to produce renewable hydrogen.

D. Implications of the Financial Analysis on Pilot Demonstration Projects

The motivation for a pilot demonstration project goes beyond immediate financial viability of the scheme and includes objectives such as institutional capacity building, learning and public demonstration to show the potential of hydrogen as a clean energy vector for the future. These 'intangible greater goals' are impossible to quantify in a simple financial analysis but can be used to justify support for the vision of a clean energy transition, even if they come at a moderate but affordable cost today.

For these reasons, a 5 MW electrolyzer pilot at Ghazi Barotha is recommended as a potential pilot project. A 5MW electrolyzer would result in an affordable capex project and the smallest size that will achieve reasonable economies of scale for hydrogen production and will fuel a bus fleet of about 30 buses to serve one of the local cities of Peshawar, Nowshera, Islamabad or Rawalpindi. This could be proposed to demonstrate the accessibility and visibility to the potential use of hydrogen as clean energy.

The total capex for hydrogen generation would be around USD 5 million. Suitable hydrogen distribution and storage equipment, plus a large hydrogen refueling station for a bus fleet would be an additional similar amount. A fleet of 30 hydrogen fuel cell electric buses would cost about USD 30 million. Allowing for land purchase, import taxes, project contingencies, planning, project management and engineering costs the project could probably be executed for between USD 60 and 70 million. As a result of the hydrogen powered bus fleet, CO_2 emissions and air pollution would be reduced, in addition to the demonstration and learning value of the pilot project.

As an alternative or additional pilot project, a similar size electrolyzer with similar utilization case options could be considered for the solar park at Quaid e Azam. In that case, the cities of Bahawalpur or Multan would be potential choices for the hydrogen powered fuel cell

bus mobility scheme. Gas grid injection would be possible very close by at Bahawalpur. However, the Quaid e Azam solar park is regarded as variable renewable power that cannot be curtailed and is therefore one of the first power plants to dispatch to the grid (along with the nuclear base-load plants). For this reason, the potential for tapping into 'wasted' excess power generation potential does not exist in the same way that it does for the Ghazi Barotha scheme.

E. Implications of the Financial Analysis on Policy Initiatives for Hydrogen

Through the course of this study and the sensitivity cases considered in the financial analysis, various conclusions have been drawn for potential policy changes in Pakistan that will support the development of the hydrogen economy in support of the national renewable energy strategy and its commitment to the Paris Agreement goals for climate neutrality. These are:

- Review the power pricing tariffs to enable the use of excess potential curtailed hydroelectric power to be allocated at very low cost, or free of charge, for hydrogen generation during periods of excess water flow and low electricity demand. This will leverage the existing capital that has been invested in major hydro projects and ensure that they are able to produce power at their maximum capacity for the maximum benefit of the nation.
- Implement policy that will attribute a cost to CO_2 emissions (e.g., a tax on fossil fuel power generation, a tax on transportation fuels or a tax on CO_2 emissions). Renewable hydrogen has huge potential to curtail CO_2 emissions by displacing fossil fuels but in the absence of any financial penalty for CO_2 emissions, the cost of green hydrogen cannot compete with the cost of fossil fuel power generation, e.g., from imported LNG from Kuwait.
- Review the power pricing tariff to enable the purchase of power during periods of low demand at a low price and allow the sale of power to the grid when demand is high at a high price. This will generate a business case to produce hydrogen as an energy storage medium to support grid balancing and will contribute to a secure power supply on a year-round basis, even at times of maximum power demand during the summer months when air conditioning systems are in use.
- The price of imported LNG from Kuwait is very low compared to international benchmarks. This is of great benefit to Pakistan but means that energy and power costs surge in winter months when additional non-contracted LNG purchases are required. The production of hydrogen with high-capacity seasonal storage for use during these winter months for heating or power generation would help to reduce the cost of the winter LNG imports and reduce the pressure on foreign currency reserves. To enable this, a clear policy that would allow underground hydrogen storage in salt caverns (subject to suitable environmental and safety impact assessments) could be prepared.

The analysis suggests that the current power tariff prices for solar renewable power generation may be higher than current best practice technologies would permit. As the cost

of renewable power generation is expected to fall over time, a tariff that accurately reflects the power generation cost would support hydrogen generation in the future.

F. Proposals for Future Studies or Policy Development to Support Sustainable Development of the Energy and Power Sectors in Pakistan

During debate and discussion of the projects analyzed in detail and other projects that were not selected for detailed analysis, some conclusions were made, in addition to those that arose from the financial analysis. They are:

a. The Pakistan Energy Ministry could introduce hydrogen as an official new energy vector and provide a policy framework for its development. This could be combined with some rebate or concessions for tax and duties on imported capital components for hydrogen production and utilization, such as electrolyzers, fuel cells or hydrogen fired gas turbines. This would provide an incentive to the private sector to initiate investment in the hydrogen economy.

b. A massive ramp up in large scale, low-cost renewable power generation will be the most important foundation to enable cost-effective deployment of renewable hydrogen in the future. Pakistan has enormous potential for additional wind (onshore and offshore), solar (land-based and floating) and hydro power generation (big dams, run of the river and micro- hydro schemes).

c. The scope of this study did not extend to giga-scale new renewable power and green hydrogen options, such as a huge, combined wind and solar park in the Balochistan desert with integrated water desalination, hydrogen, and ammonia production. Ambitious, visionary, and complex transformative projects such as this could be the subject of future studies.

d. Seasonal hydrogen production and underground hydrogen storage in salt caverns could be a highly cost-effective option for seasonal energy storage to support power grid balancing and achieve power supply stability and security through the year. Confirmation of a policy position related to underground storage of energy gases (H_2 and CH_4) in salt caverns or depleted gas fields would enable this technology.

e. Higher value hydrogen use-cases (such as ammonia / urea production or mobility to displace diesel) will improve the hydrogen economics compared to the selected use cases of LNG displacement and could be considered during further studies. The use of hydrogen to displace diesel for mobility applications can also support air quality improvements and public health.

f. The geological potential for Carbon Capture and Storage (CCS) (with permanent underground CO_2 storage) for blue hydrogen production (and broader decarbonization of power generation and heavy industry) in Pakistan is believed to be high, especially in the south where LNG is imported for regasification, and natural gas fields are becoming depleted. To enable CCS, a clear policy that would allow underground CO_2 storage in suitable geological formations (subject to suitable environmental and safety impact assessments) could be prepared. A subsequent study may wish to look at additional modes of hydrogen production, in addition to those that were in the scope of this work. Confirmation of a policy position related to underground storage of energy gases (H_2 and CH_4) in salt caverns or depleted gas fields would enable this technology.

g. Turquoise hydrogen (methane pyrolysis) can be produced in multiple decentralized locations to decarbonize natural gas. The by-product is solid carbon which could either be utilized as a briquetted fuel in rural areas to avoid deforestation or stored permanently (e.g., in a disused mine) to lock away the carbon for many years. A subsequent study may wish to look at additional modes of hydrogen production, in addition to those that were in the scope of this work.

h. Given that Pakistan is likely to continue to use local natural gas and imported LNG for many years until renewable power and hydrogen ramp up significantly in the energy mix, continuous investment in methane leak prevention and emissions monitoring will be essential to ensure that greenhouse gas emissions are minimized. Hydrogen can support decarbonization and CO_2 emissions reduction but only methane emissions reduction can avoid the damaging effects of this highly potent greenhouse gas on the environment. A study to assess the economic cost and environmental impact of methane emissions reduction could be undertaken.

i. The transition from natural gas and re-gasified LNG in Pakistan to other energy vectors, such as hydrogen will take time and is likely to be progressive. For this reason, admixing of hydrogen into the existing natural gas transmission and distribution pipework grids is likely to be required. A study to map areas of high potential for hydrogen admixing or conversion to pure hydrogen use would be beneficial to support this transition.

j. Nuclear power is the lowest cost power source in Pakistan according to the established tariff. Pink hydrogen generation (electrolysis of water using nuclear power) may be considered in a future study and the economics may become favorable in the future, especially if a CO_2 emissions tax were to be introduced. This is highly compatible with SOE electrolyzers which consume a combination of waste heat from the power plant heat and power. A subsequent study may wish to look at additional modes of hydrogen production, in addition to those that were in the scope of this work.

k. The technical and safety standards framework and guidance for natural gas, LNG and CNG is moderately mature, however for hydrogen there is almost no explicit structure to follow. A similar level of detail as that which exists for natural gas, CNG and LNG could be desirable to enable the use of hydrogen as an energy gas.

The flow of water through the turbine tunnels of the hydro dams appears to be used for grid balancing in addition to controlling water flow for irrigation and other non-power generation

purposes. Given the power generation stack in Pakistan, every MW of power that is not generated on the dams must be substituted by power generation from fossil fuels with the associated CO_2 emissions. This is because even at the lowest power demand periods, some fossil fuel plants are operational. From an environmental perspective and to maximize the return on the high-capex hydro schemes, full use of their power generation capacity at all times would be recommended. To enable this, the inclusion of all power generation modes (thermal, nuclear, hydro, wind and solar) in a unified dispatch order is advocated. Notes may still be made about 'must run' facilities, but as the percentage of renewables in the mix increases this integrated and transparent approach will yield benefits in renewable power capacity planning and utilization. It will also support the planned decommissioning of older, less efficient more highly polluting and CO_2 intensive power generation.

I. An Overview of Energy Sector in Pakistan

A. Problem Statement – the Energy and Environmental Challenges Faced by Pakistan

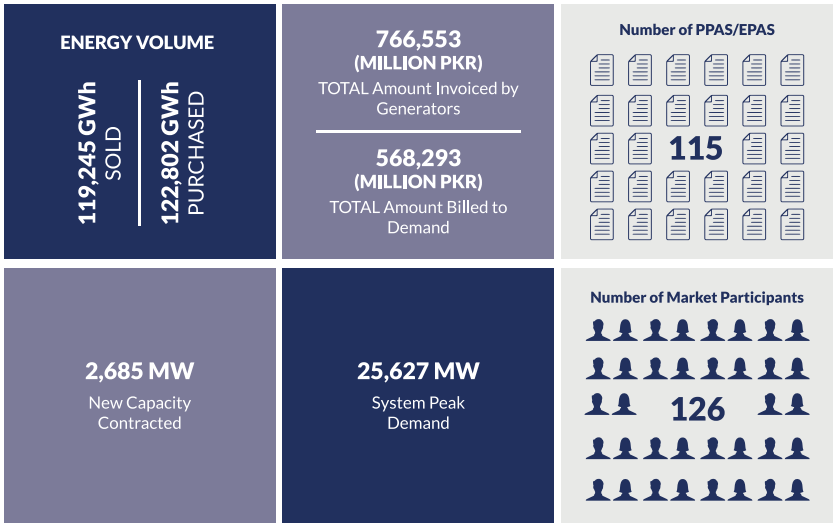
The economy and population in Pakistan are growing. Pakistan's energy requirements are expanding. The top three energy challenges faced by Pakistan today are:

- Energy supply security
- Energy self sufficiency
- Low-cost, affordable energy

1. Energy Supply Security

The availability of sufficient electric power generation capacity is necessary to meet the consumer demands for different sector of economy. For almost a decade (2008-2018) there was a period of electric power shortages until recently, Pakistan reached a position where the installed power generation capacity meets the demand in the country in FY 2019-20. From 2016 till June 2020, a total of 13,298 MW electrical power generation capacity was added to the power system of Pakistan. The total installed power generation capacity of Pakistan, excluding the K-Electric (KE) System, as on 30 June 2020 is 35,735 MW (National Transmission & Despatch Company (NTDC) Power Statistics). The total installed power generation capacity of KE's own power plants is 2,294 MW. In addition, some IPPs and CPPs with a total power generation capacity of 690 MW are also connected to the KE System.

Figure1 : *Overall Electricity Generation*[1]



1. CPPA-G, 2019. «Annual Report Fiscal Year 20-2019». Available at: www.cppa.gov.pk

Figure 1 above shows that total electricity purchased is 122,802 GWh by Central Power Purchasing Agency- Guarantee (CPPA-G) (a single buyer) and sold to Distribution Companies 119,245 GWh. In monetary terms, this translates into invoices generated for this purchase of 766,553 Million PKR and amount billed to the Distribution Companies (DISCOs) 568,293 Million PKR. The total Power Purchase Agreement (PPAs) / Energy Purchase Agreements (EPAs) are 115. There is a total of 126 Market Participants which includes Generation Companies (GENCOs), Independent Power Producers (IPPs), Water and Power Development Authority (WAPDA), and other transmission systems participants.

Figure 2: *New Capacity Contracted in FY2019 (MW)* [2]

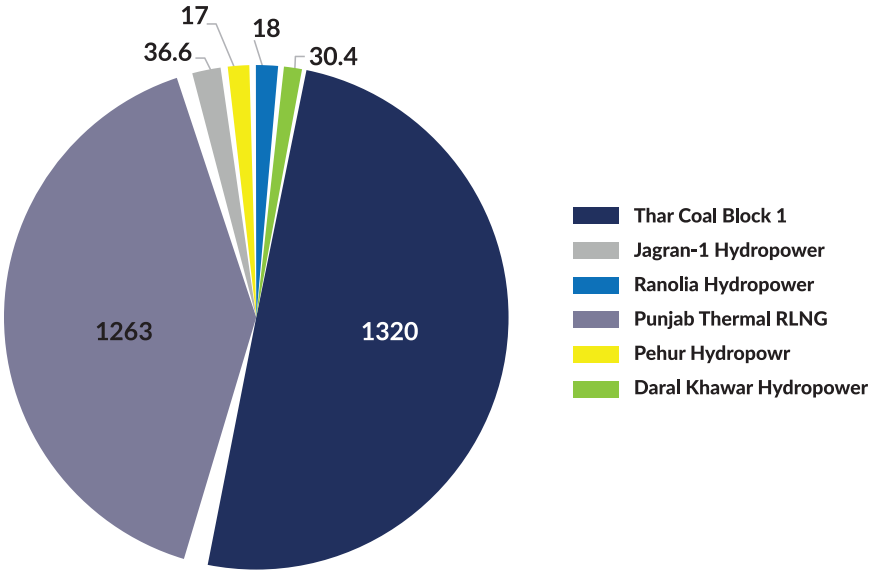
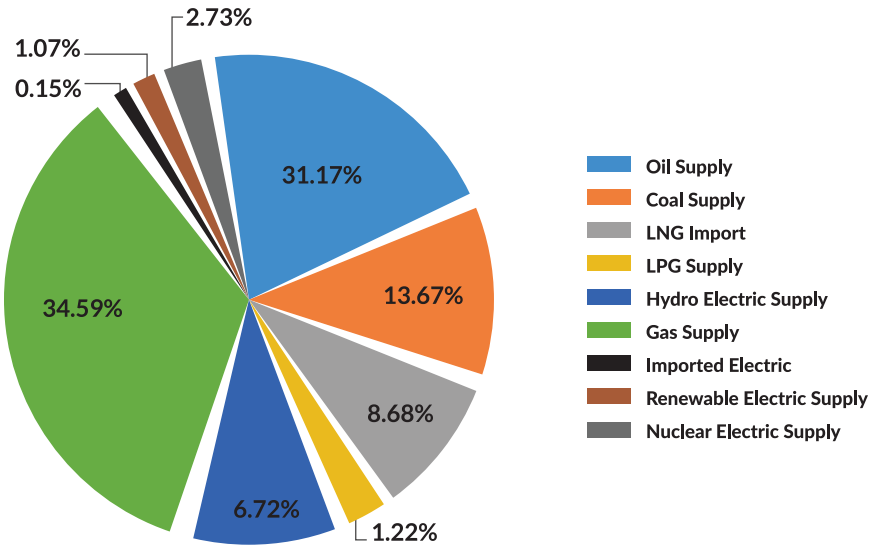


Figure 3: *Energy Mix 2017-2018* [3]



2. *CPPA-G, 2019. «Annual Report Fiscal Year 20-2019». Available at: www.cppa.gov.pk*
3. *Pakistan Energy Book 2018*

Figure 4: *Energy Mix 2018-2019* [4]

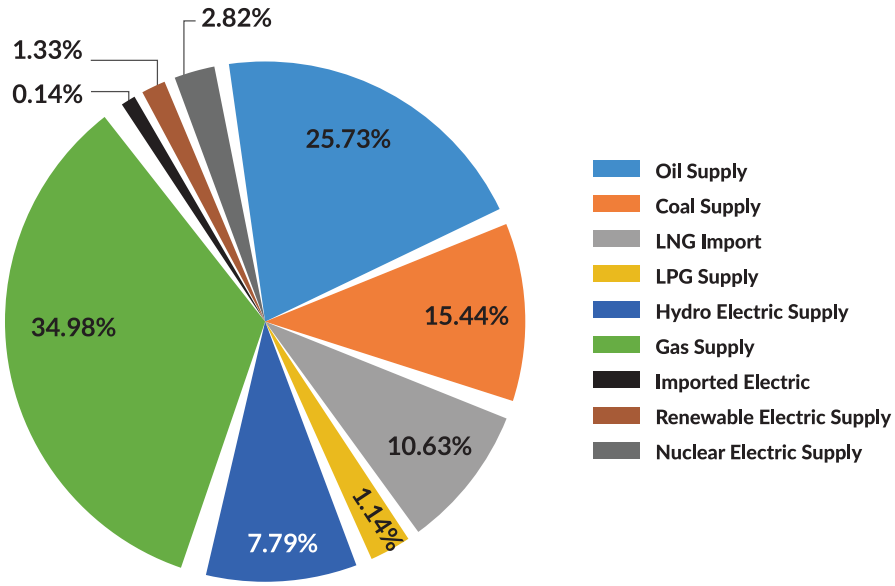


Figure 5: *Energy Mix from 2013 to 2019*[5]

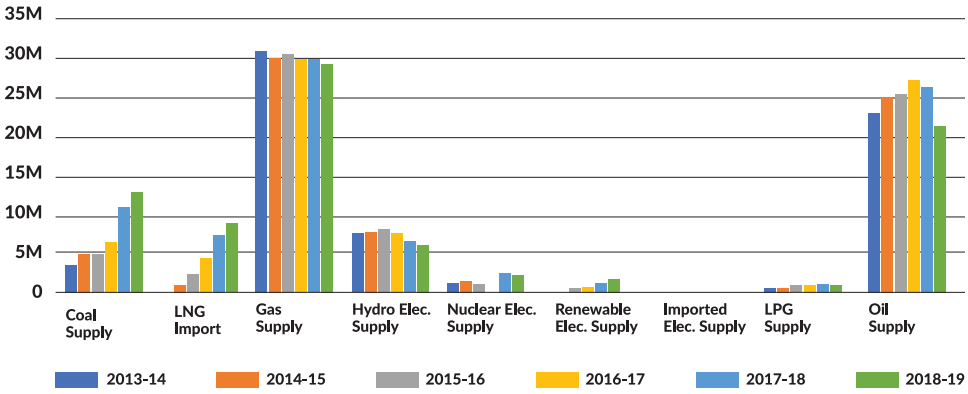
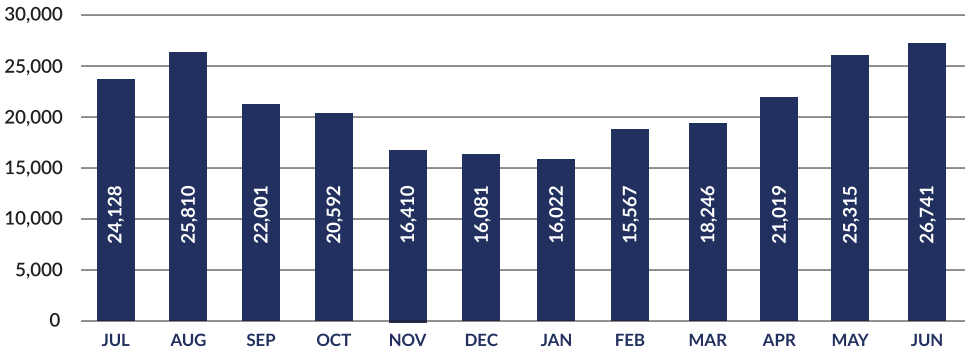


Figure 6: *Monthly Peak Load Profile-2017-18*[6]



4. *Pakistan Energy Book 2018*
5. *Pakistan Energy Book 2018*
6. *CPPA-G, 2019. «Annual Report Fiscal Year 20-2019». Available at: www.cppa.gov.pk*

Figure 7: *Monthly Peak Load Profile FY 2018-19*[7]

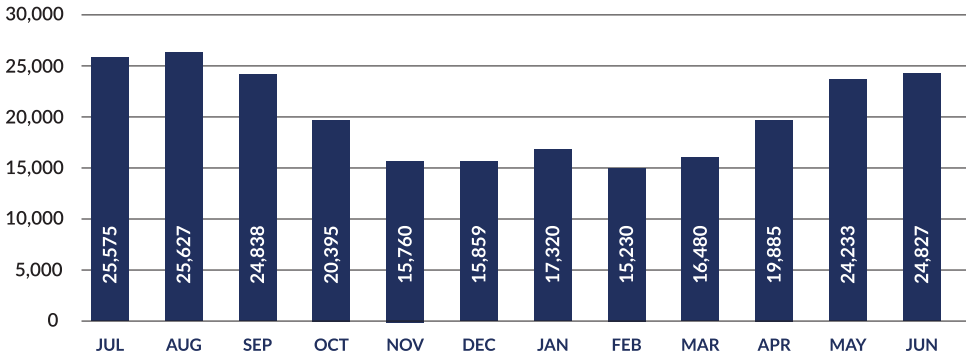


Figure 8: *Monthly Electricity Production 2018* [8]

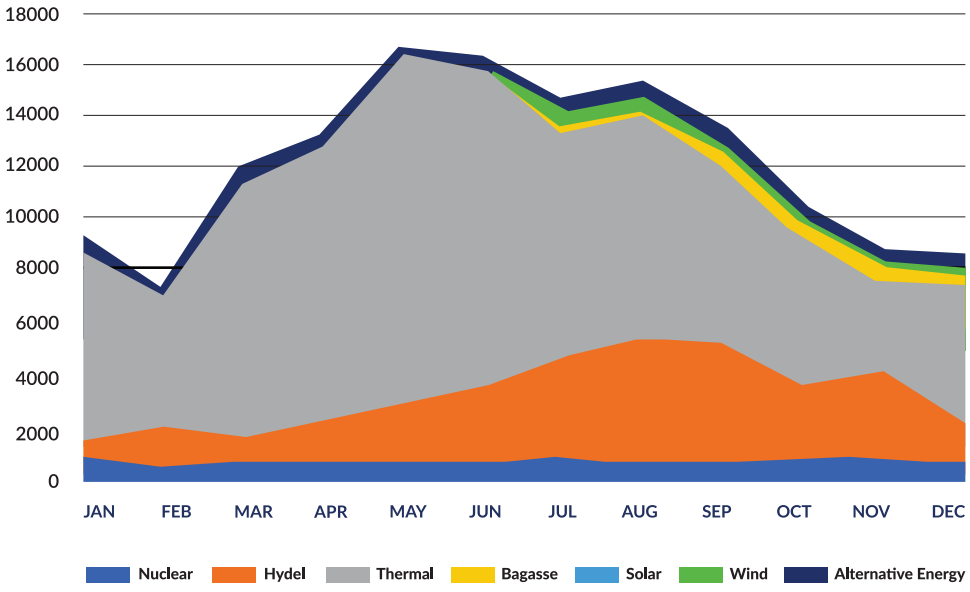
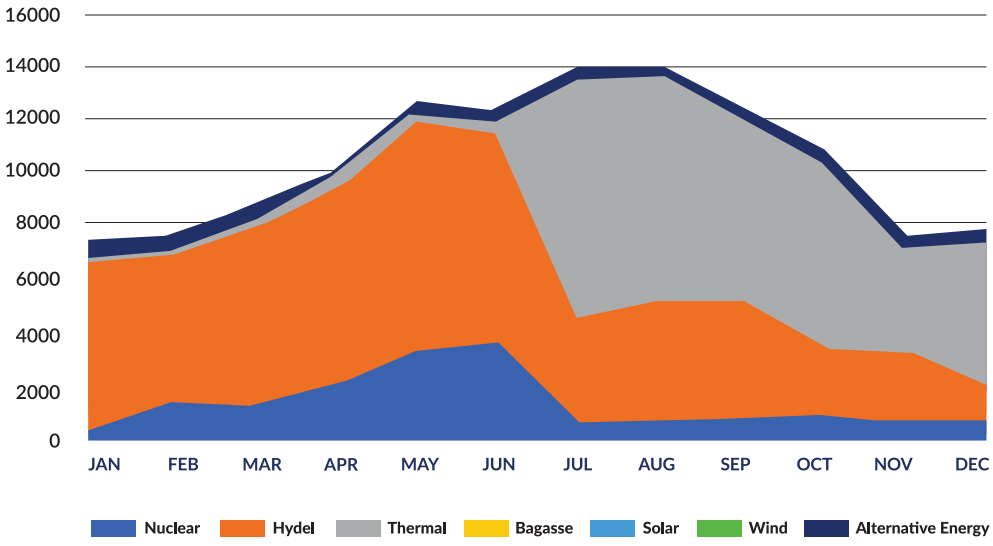


Figure 9: *Monthly Electricity Production 2017*[9]



2. Energy Self-sufficiency

Pakistan has largely overcome the energy crisis that existed 10 years ago. An increase in generation as well as in transmission capacity of the system and LNG have contributed to the resolution. However, the Energy Sector still has a demand supply gap, which needs to be filled with imports in the short term and an improvement in energy-mix to local renewables for sustainable energy supply at affordable cost.

In the cold winter months, when gas is used for heating, there is a deficit of gas, but electricity is in abundance. In the hot summer months, when electricity is used for air-conditioning, there is a deficit of electricity. Energy balancing through the seasons is required to avoid expensive over- investment in excess capacity. Hydrogen is an excellent energy-storage medium over the time of months and years and can assist with this load balancing issue.

Figure 10: *Energy Imports from 2013 to 2018*[10]

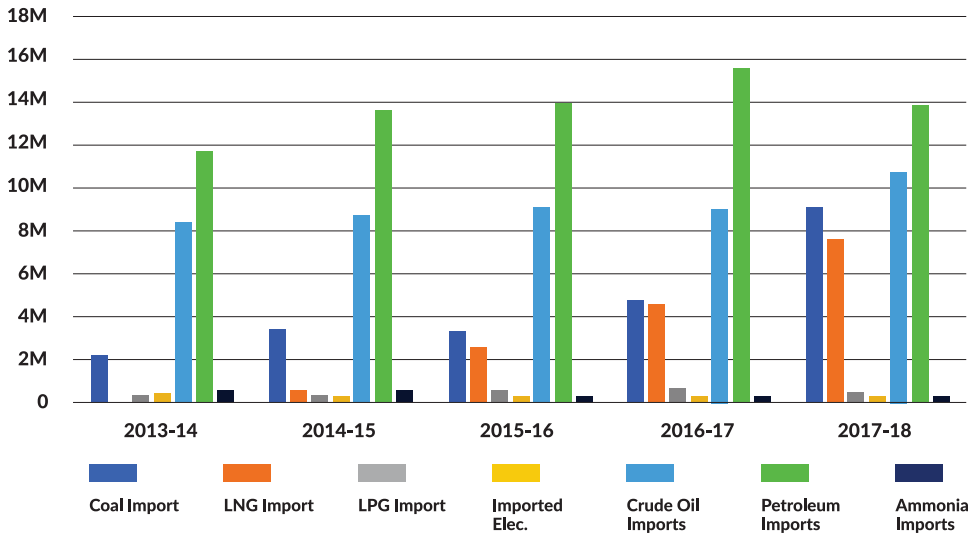
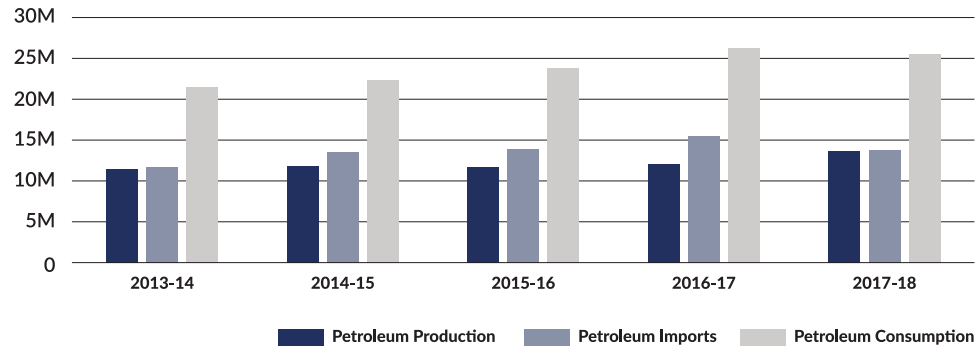


Figure 11: *Petroleum Production / Import / Consumption from 2013 to 2018*[11]



7. *CPPA-G, 2019. «Annual Report Fiscal Year 20-2019». Available at: www.cppa.gov.pk*
8. *Pakistan Energy Book 2018*
9. *Pakistan Energy Book 2018*
10. *Pakistan Energy Book 2018*
11. *Pakistan Energy Book 2018*

Figure 12: *Coal Production / Import / Consumption from 2013 to 2018* [12]

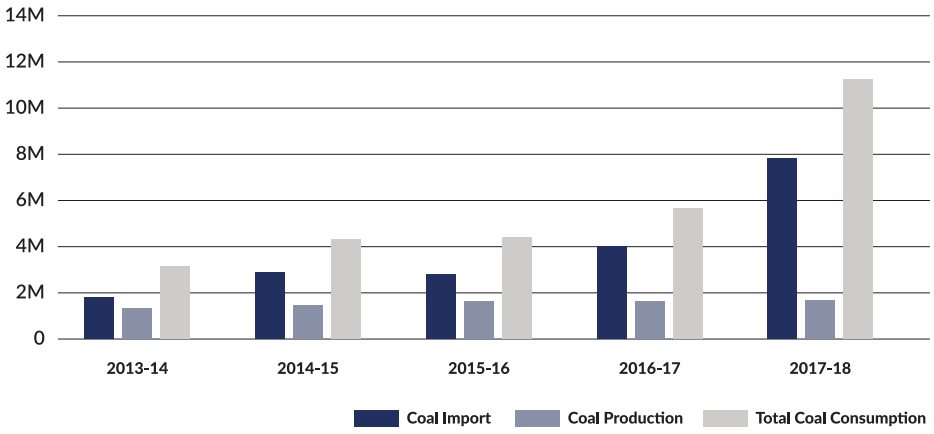


Figure 13: *Gas Production and Consumption 2013 to 2018*[13]

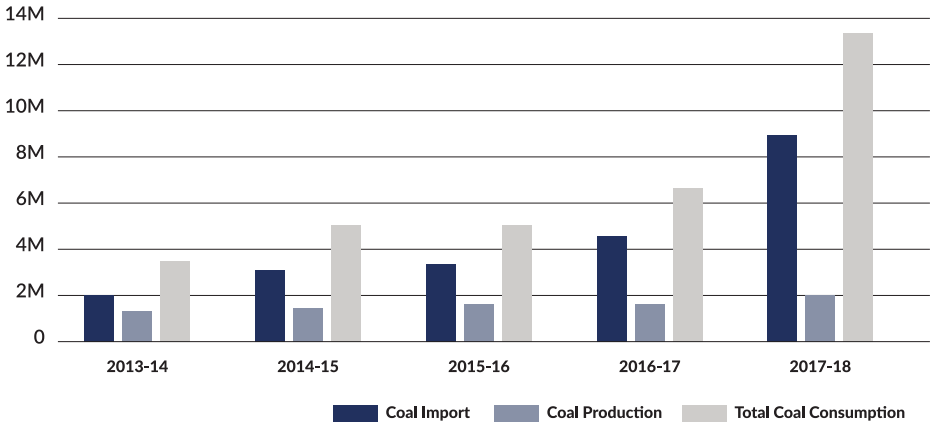
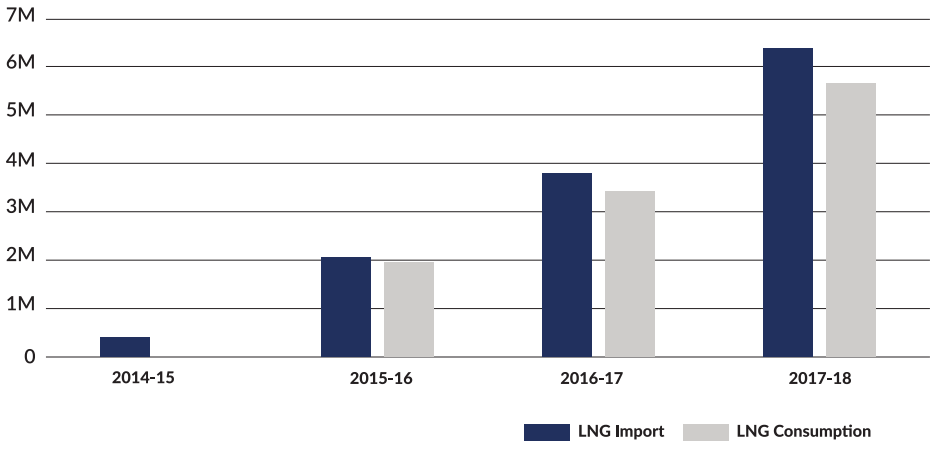


Figure 14: *LNG Import and Consumption 2014 to 2018* [14]



12. *Pakistan Energy Book 2018*
13. *Pakistan Energy Book 2018*
14. *Pakistan Energy Book 2018*

3. Low-cost, Affordable Energy

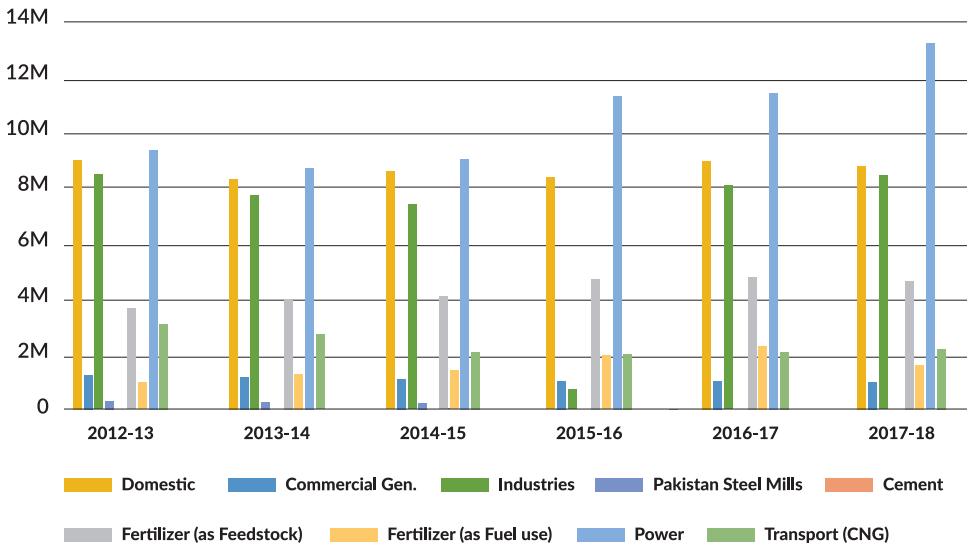
A hydrogen-based energy infrastructure is one of the way forwards to combat the long-term challenges of climate change and energy security for Pakistan. Local production of green hydrogen can support economic growth and ensuring the population has access to affordable mobility, heat, and power. Present knowledge indicates that Pakistan has huge potential and resources for Hydrogen fuel. In addition, the large-scale use of green hydrogen will pose no major environmental risk. Hydrogen is also no more hazardous than conventional fuels if the proper technical standards and safety rules are used. The hydrogen economy potentially offers the possibility to deliver a range of benefits for the country including reducing dependence on oil imports, environmental sustainability, and economic competitiveness. However, significant challenges exist, and these are unlikely to be overcome without serious efforts.

B. Sources of Pakistan's Molecular Energy Today

1. Pakistan Gas and LNG Sectors

Pakistan produces around 4 billion cubic feet per day (Bcf/D) of indigenous natural gas against an unconstrained demand of over six Bcfd. Government of Pakistan is pursuing its policies to enhance its indigenous gas production as well as imported gas to meet the increasing demand of energy in the country.

Figure 15: *Gas Consumption from 2013 to 2018*[15]



15. *Pakistan Energy Book 2018*

Figure 16: *LNG Import and Consumption from 2014 to 2018*[16]

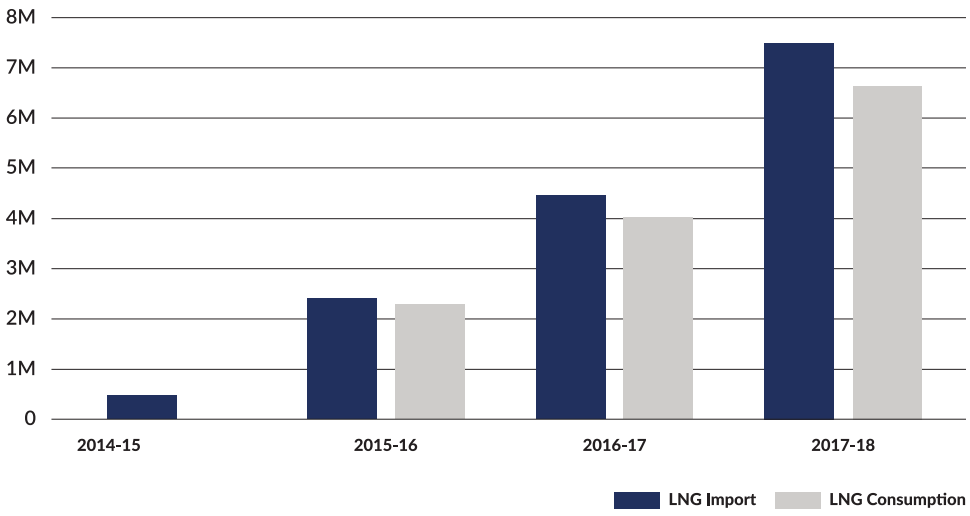
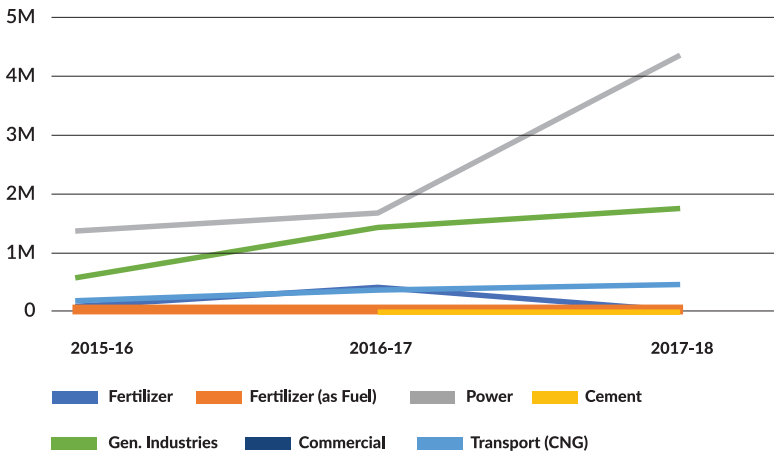


Figure 17: *LNG Consumption 2015 to 2018*[17]



16. *Pakistan Energy Book 2018*
17. *Pakistan Energy Book 2018*

2. CNG in Pakistan

Natural gas is clean and used to be abundant, and cost-effective. Compressed natural gas (CNG) it is a smart, low-emission alternative to traditional transportation fuels like gasoline and diesel. With an octane rating of approximately 130, it allows for increased engine compression and combustion efficiency in vehicles and non-mobile sources. Government of Pakistan introduced compressed Natural Gas (CNG) in the country in 1992. Due to available price differential between CNG and gasoline/diesel and investor friendly policy and regulatory framework, CNG sector has shown tremendous growth over the last ten years in the country. This growing demand of natural gas by CNG sector, results in gas shortages in the country.

The foundation stone of CNG program in Pakistan was laid down by HDIP (Hydrocarbon Development Institute of Pakistan) through the establishment of CNG refilling stations at Karachi in 1982. In 1992, Ministry of Petroleum and Natural Resources of Pakistan, announced the CNG Rules of 1992, which commercialized CNG as a transportation fuel in the country. The program really picked up in 1998 when the government declared a two-year goal of establishing 150 CNG stations and conversion of 100,000 vehicles.

Keeping in view the lack of domestic fuels, a large space always existed in the country for the development of alternative transportation fuels, particularly natural gas, which is locally available at a low cost, while a widespread infrastructure for transmission and distribution of natural gas is already in position.

Due to Government's consumer friendly policy, ample regulatory framework, and extensive efforts, CNG industry has developed significantly at an unprecedented rate of around 52.5% per annum during the start of millennium year. The country has 6.167 million total number of register vehicles[18], out of which there were 3,100,167 (89%) vehicles has been running on CNG while the rest, includes buses, trucks, and two wheelers, three wheelers etc. using gasoline and diesel.

3. LPG in Pakistan

Around 76 percent of the LPG consumed is met with Local Production in Pakistan, whereas the rest is imported. Refineries, Gas Producing Fields, and Imports are three main sources of LPG supply in the Country. LPG is gradually becoming popular domestic fuel among people who live in far-flung areas and where natural gas infrastructure does not exist. Currently, LPG accounts for about 1.2 percent of the total primary energy supply in the country. This low share of LPG in the total energy mix is mainly due to supply constraints and the higher price of LPG in relation to competing fuels like natural gas, wood etc. The current size of LPG market is around 1,061,447 MT/Annum.

18. National Transport & Research Centre (NTRC)-2010

Figure 18: *Gas Consumption from 2013 to 2018*[19]

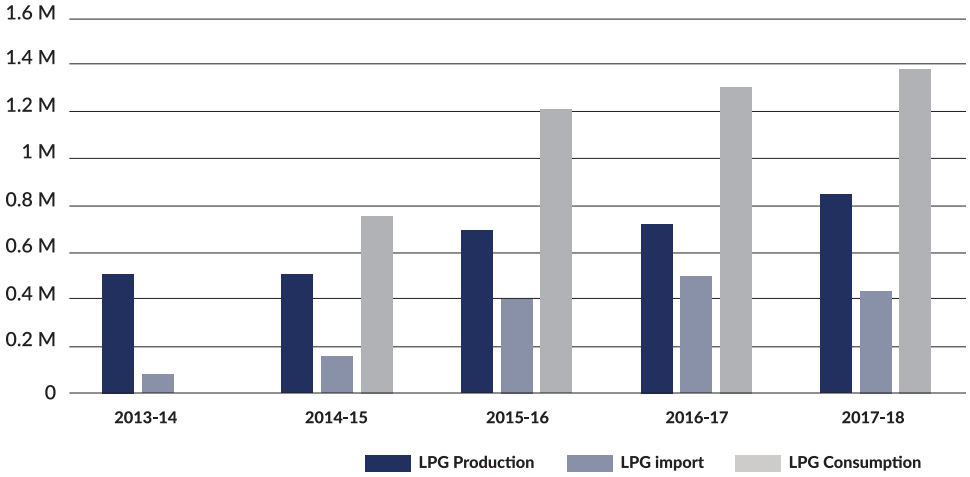


Figure 19: *LPG Consumption by Sector from 2013 to 2019*[20]

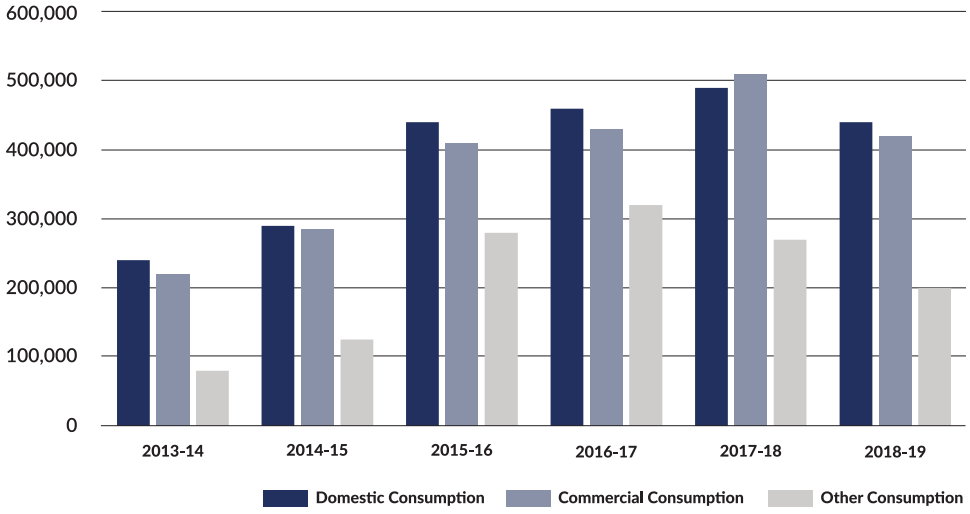
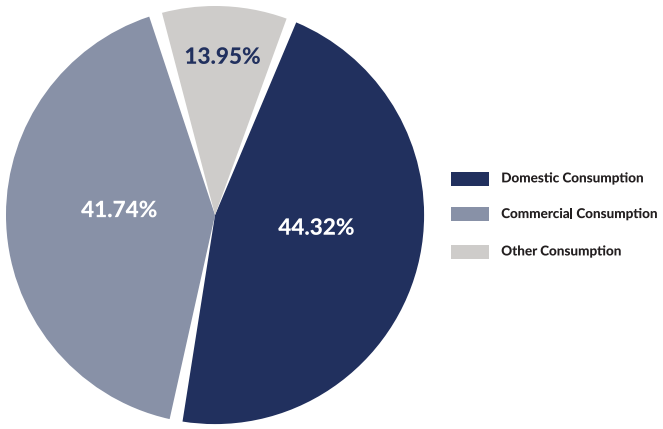
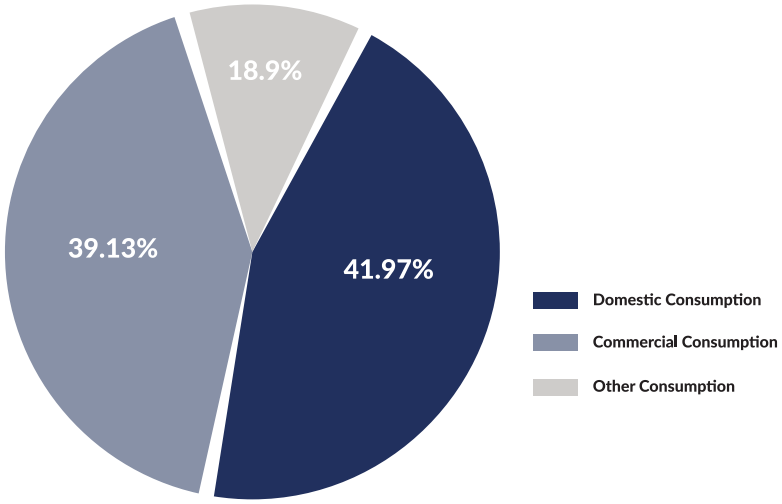


Figure 20: *LPG Consumption by Sector from 2013 to 2019*[21]



19. Pakistan Energy Book 2018
20. Pakistan Energy Book 2018
21. Pakistan Energy Book 2018

Figure 21: *LPG Consumption by Sector 2018-2019* [22]



4. Oil Sector in Pakistan

Oil prices volatility has been high in the past decade. As a net crude importer, this has a direct impact on foreign currency reserves and balance of trade. Low crude prices have been beneficial, but when they rise inflation comes into the economy and results in political and social concern.

The total refining capacity of the country is close to 20 million Bbl per year, however; the same is not being fully utilized on account of financial as well as technical problems. On financial side, the present Government after taking over, made concerted efforts to clear the circular debt, however, the same continued to rise. The government is engaged with IMF and World Bank to address it appropriately, to ease down the liquidity problem.

Most of the refineries in Pakistan are old with out-of-date technology and configurations except Pak-Arab Refinery Company Limited (PARCO) . Such refineries produce more than 40% of Furnace Oil (FO). A refinery producing large quantities of FO is generally losses money or has squeezed margins based on the pure crude/product price differential.[23]

22. Pakistan Energy Book 2018

23. Pakistan Economic Survey 2019-20

Figure 22: *Crude Oil Production and Import 2014 to 2018* [24]

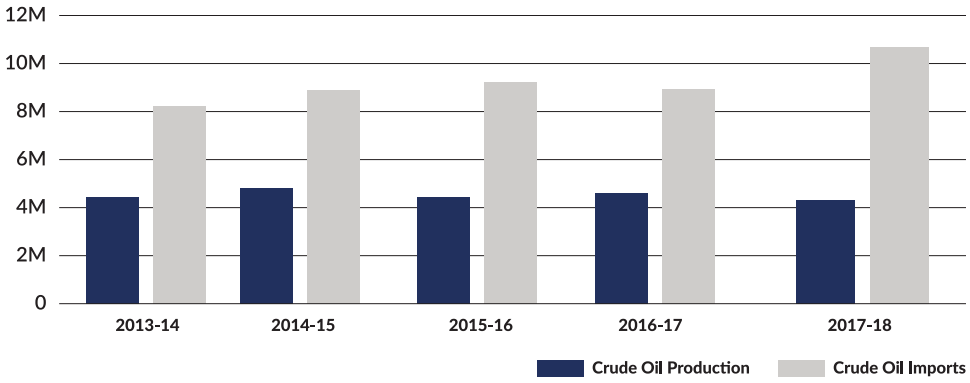


Figure 23: *Petroleum Production, Import and Consumption 2014 to 2018*[25]

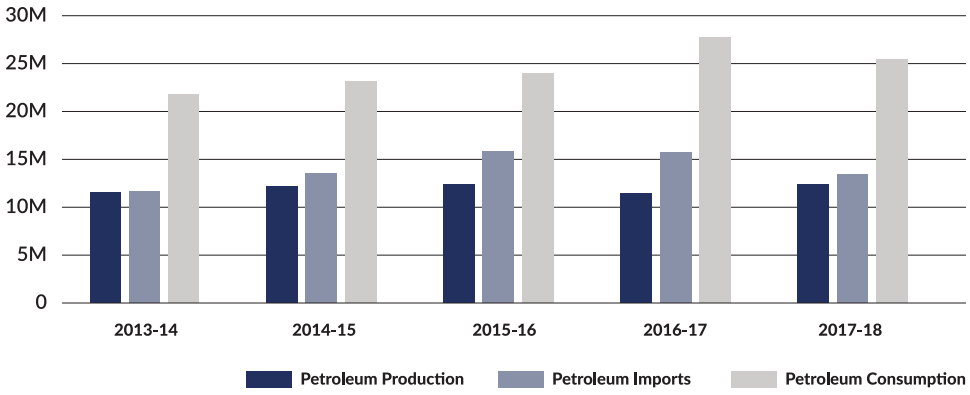
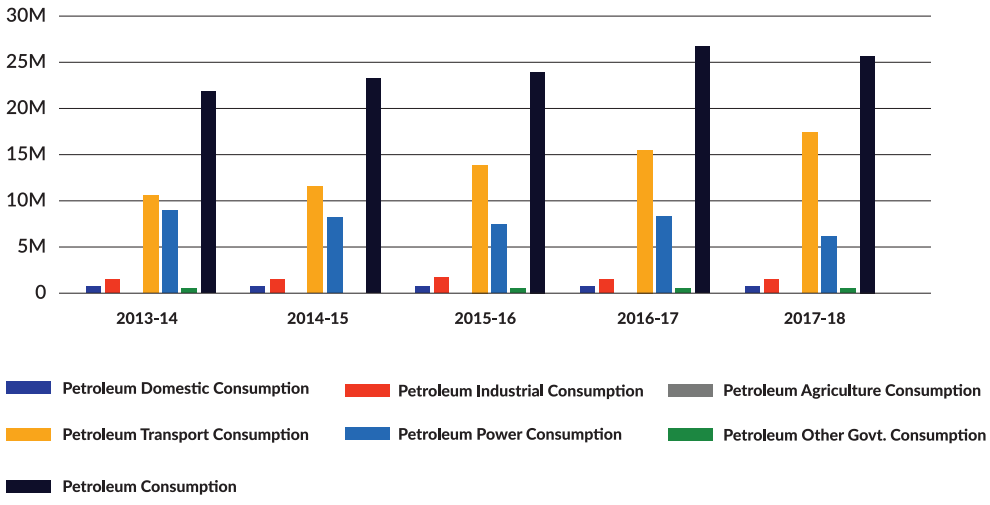


Figure 24: *Petroleum Consumption by Sector from 2014 to 2018* [26]



24. Pakistan Energy Book 2018
25. Pakistan Energy Book 2018
26. Pakistan Energy Book 2018

C. Waste Incineration – Waste to Energy

In the recent past, two main waste to energy projects were envisaged back by Sindh & Punjab government in 2014 & 2018 of 20 MW & 40 MW respectively. The Sindh government planned to establish 20 MW of waste to energy with municipal solid waste and agriculture waste in Khair Pur Special Economic Zone. A Request for Proposal was issued in January 2014 but due to poor Bid response the project was dropped / postponed.

In Punjab Lahore it was planned to build a 40 MW project with Municipal Solid Waste, Letter of Intent (LOI) was also approved by National Electric Power Regulatory Authority (NEPRA) but in the absence of updated Renewable Energy Policy, it was dropped. Now, after the approval of the new Renewable Energy Policy-2019, Punjab Power Development Board (PPDB) will re-consider in next development program.

D. Case Study from the Past: Domestic Biogas (Bio-methane) Production

1. History and Lessons to be Learned

Pakistan is typical of many countries around the world where the biogas technology has been tried with some success in the past but has yet to be widely adopted. The Government of Pakistan (GOP) started a comprehensive biogas scheme in 1974 and commissioned 4,137 biogas units by 1987 throughout the country. There were large plants with capacity of varying from 5 to 15m^3 gas productions per day. The program was developed in 3 phases. During the first phase, 100 demonstration units were installed under the grant of the government. During the second phase, the cost of biogas was shared between the beneficiaries and the government. In subsequent third phase, the government with drew financial support for the biogas plants, although technical support continued to be provided free of cost. Unfortunately, after the withdrawal of the government financial support the project did not progress any further.

Most of the biogas plants installed in past was smaller household design of between 3 & 5m^3 gas production per day compared to larger plants in 1970's and 80's. The current dissemination programs still largely have a piloting character; commercial promotion did not take place. Most involved organizations seem to follow the government promotions arrangements by providing a subsidy of 50% on the installation cost.

The Pakistan Council for Renewable Energy Technologies (PCRET) was tasked to lead domestic biogas dissemination in the country. PCRET installed 3000 plants, especially aiming at improved bio-slurry collection and correct plant sizing.

In Pakistan, household sector consumes more than 7,298,154 TOEs as fuel, which accounts for 54% (approx.) of total (commercial & renewable) energy consumption. Biofuel (Firewood, Dung & crop residue) accounts for 86% of total household energy consumption while firewood alone accounts for 54% of the total. About 70% of the population resides in rural areas which needs 95% of its domestic fuel needs by burning biofuels but in urban areas the bio-fuels consumption drops to 56% because they use kerosene oil, LPG and natural gas in addition to firewood to meet their domestic fuel need.

The forest area in Pakistan comprises about 5% of the land, which can hardly serve as a carbon sink. Besides, due to increase in population and domestic energy needs, the fuel wood cutting rate could surpass the growth rate leading to deforestation resulting in degradation of eco-system, environment, and land erosion. Moreover, the use of biomass leads to high level Indoors Air Pollution (IAP) by emitting detrimental particulates matters and chemicals, which is a serious potential health hazard. Since, women and children primarily involved in collecting and burning biomass, they are the worst surfers as they inhale most of the poisonous chemicals present in the smoke.

Similarly, Pakistan is not self-sufficient in fossil fuels production and must import kerosene oil for meeting domestic fuel needs. Besides the consideration also needs to be given to the fact the fossil fuels cause a great strain on the environment and have a large negative impact on human health. These are the main contributors to global greenhouse emissions.

Climate change has over the last decades evolved into an issue of global concern. Human understanding of the relation between emission levels, concentration of greenhouse gases in the atmosphere and changes to the global climatic system is improving and there is increasing consensus in both the scientific and political communities that significant reduction in emission are necessary to limit climate changes manageable level. The ultimate the solution therefore lies in improving excess to cleaner, convenient, efficient, environmentally friendly and renewable energy sources.

The biogas is a cheap, clean, soot free and extremely convenient cooking fuel. It contains 50 to 70% methane, which is inflammable. Biogas is produced from cattle dung in a biogas plant commonly known as “Gobar Gas Plant” through a process called anaerobic digestion. Based on the effective heat produced, 5m^3 biogas plant would replace, in a month fuel equivalent of 30 kg of LPG or 92.5 liters of Kerosene oil or 245 kg of charcoal or 838 kg of fuel wood or 1850 kg of animal dung or 750 kWh of electricity.

To the homemaker, a biogas is easy to use and safes time in the kitchen. Biogas stove has an efficiency of about 55% vis-à-vis 10% efficiency of conventional fuel wood stoves. Cooking on biogas is free from smoke and soot, and can substantially reduce the health problem, which are otherwise quite common in most rural area where biomass is the cheap source of fuel. The use of biogas is helpful to improve the quality of life in household.

The fertilizer value of the dung is also enhanced in process of bio-gasification; thus, a biogas plant helps in obtaining both fuels and bio-fertilizer from cattle dung.

2. Number of, Capacity and Location Map of Biogas to Bio-methane Upgrade Facilities in Pakistan

The project envisage installing 3000 biogas plants in the potential rural areas of Pakistan in 2006 to 2010 with the amount of PKR 108.594 million with beneficiary’s contribution of PKR 51.25 million. The project was undertaking by Pakistan Council of Renewable Energy Technologies (PCRET) quite successfully and drawing quantitative benefits even during the implementation period. The total biogas and bio-fertilizer produced more than expectation from biogas plants. It has created awareness about usefulness of biogas technology, among the rural masses in the target areas.

3. Project Analysis

The project envisages installing 3000 biogas plants in the potential rural areas of Pakistan. A total of 500 biogas plants of $3m^3$ and 2500 biogas plants of $5m^3$ daily gas production capacity were measured as 14,000m^3/day and 5.1 million m^3 per annum. It has replaced 1022 ton of LPG or 3.14 million liters of Kerosene oil or 8329 tons of charcoal or 28411 tons of fuel wood or 62853 tones dung, in term of kerosene oil (@PKR 36/liter). The project has saved the hard-earned foreign exchange of PKR 113 million/annum, which otherwise the government must defray for the import of kerosene oil[27].

In addition to production of biogas, these plants have produced 18360 tons of enriched bio-fertilizer per annum having 2.3 % Nitrogen (N), 1.29% phosphors (P_2O_5) and 1.75% K_2O. In terms of Nitrogen contents only the economic value of this fertilizer was PKR 25.00/Kg of Nitrogen comes to PKR 9.18 million per annum. The total fuel and fertilizer value comes to be PKR 122.18 million per annum.

4. Efficacy of Biogas Production in Pakistan

Domestic biogas production is an attractive option since it can provide solutions to a verity of problems simultaneously; in general, it has proven that the energy aspect alone does not justify the cost for biogas technology. However, the essential benefits of biogas plant are not manifested in individual cost, efficiency calculation. The overall object, to which biogas technology contributes, is environmental protection, which includes energy related objectives (decrease of greenhouse gas emissions as well as deforestation), and the improvement of livelihoods of biogas users.

Well-functioning biogas systems can yield a whole range of benefits for the users, the society, and the environment in general.

- Production of Energy (Heat, Light, Electricity)
- Transformation of organic waste into high quality fertilizer
- Improvement of hygienic conditions through reduction of pathogens, worm eggs and flies
- Reduction of un-pleasant odors
- Reduction of workload, mainly for women, in firewood collection and cooking
- Environmental advantages through protection of soil, water, air, and woody vegetation
- Micro economic benefits through energy in fertilizer substitution, additional income sources and increasing yields of animal husbandry and agricultural
- Macro-economic benefits through decentralized energy generation, import substation and environmental protection
- Biogas technology can substantially contribute to conservation and development if the conditions are favorable

27. PCRET Project of Biogas

5. Challenges and Lessons that the Project Exposed

The initiative depended highly on limited and scattered government support in which high subsidy levels have an inhibitory effect on the development of the market. The nature of the involvement of the private sector was also said to be a main factor for the failure of the project. Additional issues were:

- Ltd. awareness of benefits of biogas
- Ltd. access to the technology
- Low consumer confidence in biogas technology
- High investment cost
- Expectations of imminent access to piped natural gas

E. Renewable Power Generation

Pakistan power system has commissioned a relatively fair quantum of RE generation in the generation mix in the past few years. As of 31st December 2019, 400 MW utility scale solar and 1,086 MW wind power on grid projects (excluding 150 MW from WPPs namely Hydro China Dawood, Zephyr and Tenaga, which are currently supplying generation directly to K-Electric system), have been commissioned. After the Cabinet Committee on Energy (CCOE) decision of April 2019, several wind and solar projects are at different stages of development and will be added into the national grid during the next couple of years.

Furthermore, the GoP envisages to aggressively include 20% and 30% renewable energy generation by capacity by the year 2025 and 2030, respectively. However, these two energy resources due to their intermittency cannot be considered as a firm capacity, at all points in time or all around the clock therefore, appropriate amount of backup generation is also required to provide for reserve requirements of the system.

Wind power projects have been considered in three zones / corridors i.e. North, South and Mid Land. Based on the available wind mast data in these corridors, plant factor of 31% for North as well as Mid-country and 39% for South have been assumed. Similarly, for the candidate solar power projects a plant factor of 19% has been assumed, across the country.

Although solar and wind power plants can provide a significant quantum of generation at certain times, yet the corresponding generation also drops to zero or minimal at different times; this is evident from the dispatch record for the last few years. Further, forecast of wind availability and hence its corresponding generation has not matured enough to estimate the generation for long duration. Therefore, projection of historical trend of wind and solar on hourly basis has been carried out to estimate their future generation.

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

Trend of cost reduction for the renewable technology is set to continue in the future and will inevitably reduce the cost burdens, reliance on increasingly expensive fuels and hence lowering the overall generation cost. The cost of renewable especially winds and solar is

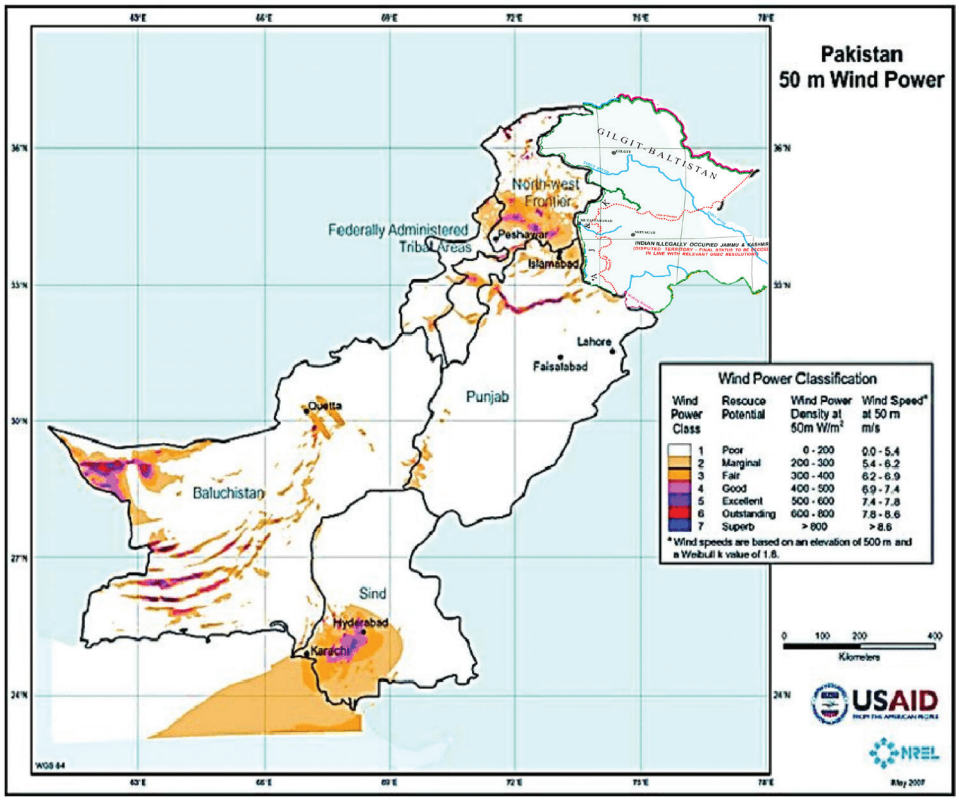
expected to be driven down further through energy policies, which focus on supporting the deployment of renewable power generators to reduce their costs. Renewable are needed to mitigate the negative externalities of fossil fuels since primary energy consumption will grow into the future, and this growing demand is currently dependent on fossil fuels. The degree to which intermittent renewable can displace fossil fuels, however, depends on the extent to which fossil fuel backup generators are needed to balance electricity grids.

It is apprised that in this regard, the CAPEX is degraded by almost 3.6% and 1% for solar and wind respectively every year up until 2030 in line with various international practices. As compared to today's solar power plant CAPEX i.e. 530 $/kW in 2020, it is degraded to 371 $/kW by the year 2030. Similarly, the CAPEX of wind is determined according to different regions. As we move towards North of the country, the transportation and other factors will be going to affect the CAPEX of wind power plants to be installed in North. The CAPEX of wind in the south comes out to be 1300 $/kW in 2019 and is decreased to 1164 $/kW in 2030. Furthermore, the CAPEX of wind power plants in Mid-country is determined by increasing 5% of the CAPEX of South Region Wind Power Plant. In the similar fashion, the CAPEX of wind power plants in North of Country is determined by increasing 5% of the CAPEX of Mid-country Wind Power Plants.

1. Wind Power

The high potential of wind power is found in the coastal areas of southern Sindh province,

Figure 25: *Average Wind Power of Pakistan*[28]



28. *Competitiveness of Wind Power with the Conventional Thermal Power Plants Using Oil and Natural Gas as Fuel in Pakistan, December 2014, Energy Procedia 52(2014):59-67.*

the southwestern area of Baluchistan province, the narrow west-to-east belt in the northern part of Punjab province, and the southern area of Khyber Pakhtunkhwa province.

The average wind power potential map of Pakistan at 50 m height developed by USAID-NREL is placed below. According to this map, high potential of wind power is found in the coastal areas of southern Sindh province, the southwestern area of Baluchistan province, the narrow west-to-east belt in the northern part of Punjab province, and the southern area of Khyber Pakhtunkhwa.

Table 1: Average Monthly Wind Speed Calculated for 50 m Height (Unit m/s)[29]

No.	Location	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Mean
1	Nooriabad	5.0	5.6	6.3	8.3	10.1	12.1	13.9	12.5	9.8	5.9	5.8	6.5	8.5
2	Kati Bandar	4.9	5.7	6.2	8.4	9.3	9.3	10.2	8.8	7.2	5.1	4.4	5.0	7.0
3	Shah Bander	4.9	4.8	5.0	7.3	9.3	10.6	10.4	9.7	8.1	4.2	4.4	4.9	7.0
4	Jamshoro	5.2	4.7	5.4	7.2	8.6	9.1	9.8	9.6	7.3	4.1	4.2	5.1	6.7
5	Hawks Bay	4.6	4.9	5.2	7.4	9.4	9.3	9.1	8.8	7.8	4.4	3.8	4.5	6.6
6	Hyderabad	4.4	4.4	4.3	6.5	8.9	10.0	9.9	8.5	7.8	3.9	3.9	4.8	6.4
7	Gharo	4.9	5.0	5.6	7.1	8.4	8.9	7.4	8.6	7.1	4.4	4.5	5.0	6.4
8	Chuhar Jamal	5.1	5.2	5.3	6.7	7.8	9.1	8.0	7.9	6.4	4.4	4.6	5.3	6.3
9	DHA Karachi	5.1	5.1	4.9	6.2	7.7	9.1	8.5	7.5	6.4	4.1	5.6	5.1	6.3
10	Thano Bula Khan	4.9	5.0	5.2	6.7	7.9	8.6	8.3	8.4	6.6	4.2	4.1	5.3	6.3
11	Jati	5.1	5.1	5.2	6.4	7.9	8.3	8.2	7.9	6.2	4.6	4.7	5.3	6.2
12	Mirpur Sakro	3.5	4.1	4.3	7.7	9.9	10.3	9.4	8.8	7.5	3.4	2.7	3.2	6.2
13	Golarchi	4.5	4.7	4.9	6.3	8.2	8.5	8.6	7.7	6.6	3.9	3.8	4.7	6.0
14	Sajawal	4.0	4.6	5.3	6.5	7.4	7.7	9.0	8.1	6.6	4.2	3.6	3.8	5.9
15	Baghan	4.4	4.9	4.3	5.9	7.6	8.0	7.9	7.5	6.5	3.9	4.1	4.7	5.8
16	Thatta	4.0	3.9	4.2	6.1	8.1	8.9	8.3	7.3	6.4	3.1	3.4	4.1	5.6
17	Karachi	4.0	4.4	5.4	6.4	7.1	6.9	7.1	6.2	5.6	3.7	3.2	4.0	5.3
18	Badin	2.9	3.0	3.1	6.4	8.1	8.5	7.6	7.5	5.8	3.3	2.7	2.7	5.1
19	Talhar	3.3	3.6	2.6	5.3	6.8	8.6	8.5	7.6	6.8	2.3	2.4	3.3	5.1
20	Matti	2.3	2.5	3.9	5.2	6.6	6.9	6.5	5.7	5.1	2.0	1.6	2.4	4.2

29. Pakistan Metrological Department (PMD)

a. Regional Areas of High Potential for Wind Power Generation

NREL indicates the following areas as major wind resource areas in Pakistan:

South Eastern Pakistan

- Hyderabad to Gharo Region in southern Indus Valley
- Coastal areas south of Karachi
- Hills and ridges between Karachi and Hyderabad

Northern Indus Valley

- Hills and ridges in Northern Punjab
- Ridges and wind corridors near Mardan and Islamabad

South Western Pakistan

- Near Nokkundi and hills and ridges in the Chagai area
- Makran area hills and ridges

Central Pakistan

- Wind corridors and ridges near Quetta Hills near Gendari
- Elevated mountain summits and ridge crests especially in northern Pakistan

2. Benchmark Wind Speeds in Coastal Area of Sindh

Mean monthly wind speed varies with season for climatic reason. Accordingly, the power product of wind power generation system also varies with season. In addition, the "monthly mean" of each month also varies every year.

This is a risk for developers, because it means that monthly power product of each month differs from year to year. Alternative Energy Development Board (AEDB) also introduced an innovative structure on "wind risk" which was formulated principally based on the previous Policy for Development of Renewable Energy for Power Generation.

Wind speed benchmarks were computed and set up by AEDB for specific areas based on the wind data acquired and computed by Pakistan Meteorological Department (PMD). These monthly benchmark wind speeds at specific areas (Kuttikun, Bhambore, and Jhimpir sites) provide reference for project developers.

Figure 26: *Locations of Wind Turbines in the Sindh Coasts for Wind Power*[30]

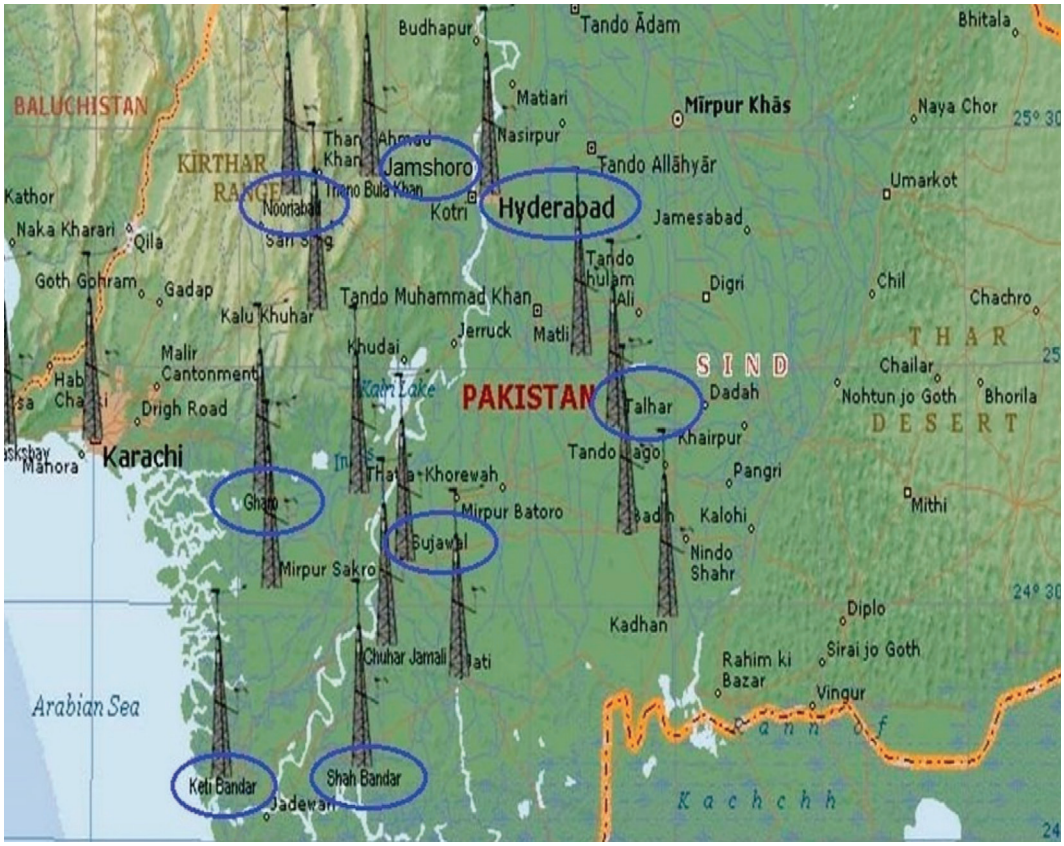


Table 2: Monthly Benchmark Wind Speeds for Khuttikun and Bhanbhore Sites[31]

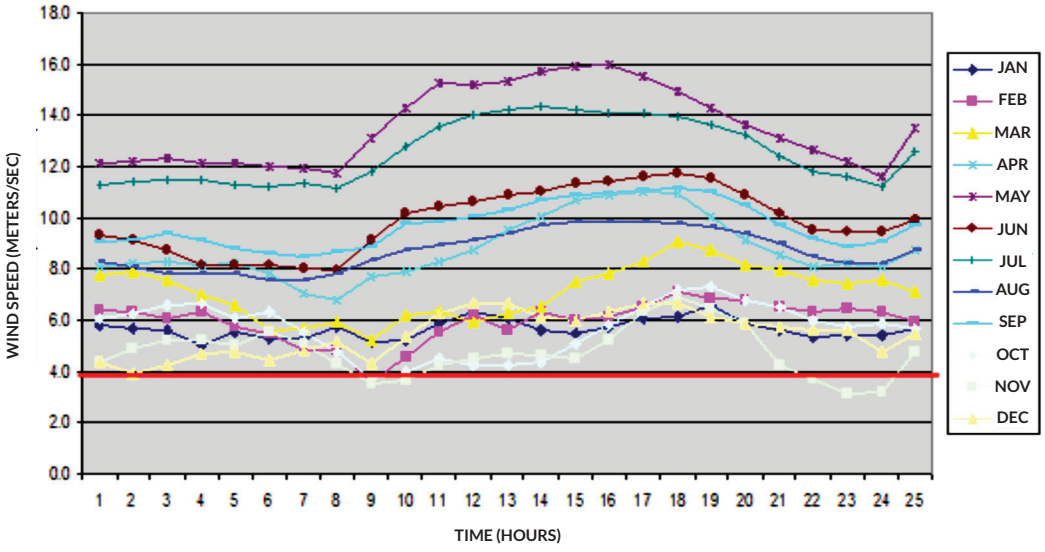
Month	Monthly Benchmark Wind Speed					
	30m	50m	60m	67m	80m	85m
January	4.7	5.1	5.2	5.3	5.4	5.5
February	5.1	5.4	5.5	5.6	5.7	5.8
March	5.3	5.7	5.8	5.9	5.9	6
April	7	7.3	7.4	7.6	7.6	7.7
May	8.9	9.4	9.6	9.7	9.8	9.9
June	10.3	10.9	11.1	11.2	11.3	11.4
July	8.4	8.9	9	9.2	9.2	9.3
August	9.3	9.8	10	10.2	10.3	10.4
September	7.6	8.1	8.2	8.3	8.4	8.5
October	4.3	4.6	4.7	4.7	4.8	4.9
November	3.8	4.1	4.2	4.3	4.4	4.5
December	4.6	4.9	5.1	5.2	5.3	5.4
Annual Average	6.6	7	7.1	7.2	7.3	7.4

30. Pakistan Metrological Department (PMD)
31. AEDB

Table 3: Monthly Benchmark Wind Speeds for Jhimpir sites[32]

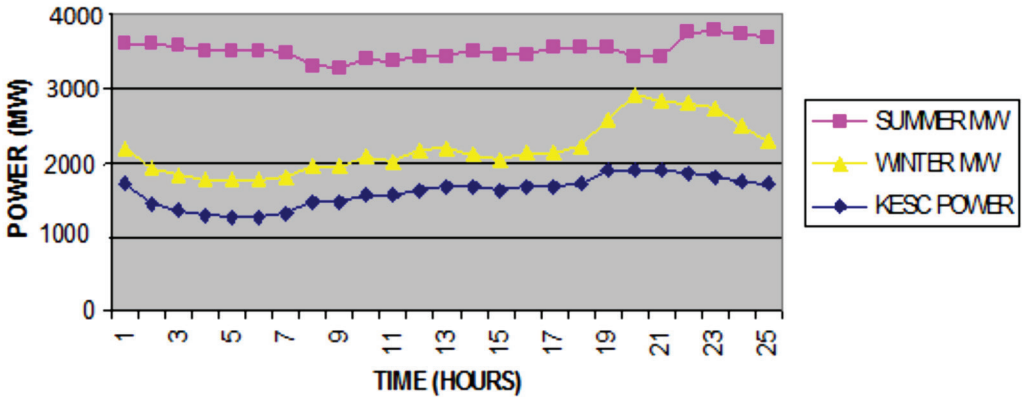
Month	Monthly Mean Wind Speeds (m/s)					
	30m	50m	60m	67m	80m	85m
January	4.25	4.70	4.90	5.02	5.24	5.3
February	4.50	4.98	5.18	5.32	5.55	5.7
March	4.77	5.28	5.50	5.64	5.89	6.0
April	6.39	7.03	7.29	7.46	7.75	7.9
May	8.29	9.05	9.36	9.56	9.90	10.0
June	8.79	9.50	9.78	9.96	10.25	10.4
July	8.83	9.59	9.89	10.08	10.40	10.5
August	8.20	8.89	9.16	9.34	9.63	9.6
September	6.63	7.28	7.54	7.72	8.01	8.1
October	4.22	4.68	4.87	5.0	5.22	5.3
November	3.59	3.98	4.14	4.24	4.43	4.5
December	3.96	4.38	4.56	4.67	4.88	5.0
Annual Average	6.0	6.6	6.8	7.0	7.3	7.4

Figure 27: *Monthly Average Wind Speed at Gharo[33]*



32. *AEDB*
33. *AEDB, PMD*

Figure 28: *Daily Load Pattern of during Winter and Summer*[34]



3. Wind Power Projects

Table 4: List of Wind Plant, Location & Project Capacity

S. No	Name of Company	Location	Project Capacity (MW)
1	FFC Energy Ltd.	Jhimpir	49.5
2	Zorlu Enerji Pakistan (Pvt.) Ltd.	Jhimpir	56.4
3	Three Gorges Pakistan First Wind Farm (Pvt.) Ltd.	Jhimpir	50
4	Foundation Wind Energy II (Pvt.) Ltd.	Gharo	50
5	Foundation Wind Energy –I Ltd.	Gharo	49.5
6	Sapphire Wind Power Company Ltd.	Jhimpir	52.8
7	Metro Power Company Ltd.	Jhimpir	50
8	Yunus Energy Ltd.	Jhimpir	50
9	Master Wind Energy (Pvt.) Ltd.	Jhimpir	52.8
10	Act Wind (Pvt.) Ltd. (Tapal Wind Energy (Pvt.) Ltd.	Jhimpir	50
11	Gul Ahmed Wind Power Ltd.	Jhimpir	50
12	Tenega Generasi Ltd.	Gharo	49.5
13	Hydro China Dawood Power (Pvt.) Ltd.	Gharo	49.5
14	Sachal Energy Development (Pvt.) Ltd.	Jhimpir	50
15	UEP Wind Power (Pvt.) Ltd.	Jhimpir	99
16	Jhampir Wind Power (Pvt.) Ltd.	Jhimpir	50
17	Hawa Energy (Pvt.) Ltd.	Jhimpir	49.5
18	Hartford Alternative Energy (Pvt.) Ltd.	Jhimpir	49.3
19	Three Gorges Second Wind Farm Pakistan Ltd.	Jhimpir	49.5
20	Three Gorges Third Wind Farm Pakistan (Pvt.) Ltd.	Jhimpir	49.5
21	Tricon Boston Consulting Corporation (Pvt.) Ltd. - A	Jhimpir	49.6

34. AEDB

Table 4: List of Wind Plant, Location & Project Capacity			
S. No	Name of Company	Location	Project Capacity (MW)
22	Tricon Boston Consulting Corporation (Pvt.) Ltd. - B	Jhimpir	49.6
23	Tricon Boston Consulting Corporation (Pvt.) Ltd. - C	Jhimpir	49.6
24	Zephyr Power (Pvt.) Ltd.	Gharo	50
25	Burj Wind Energy (Pvt.) Ltd.	Gujju	50
26	Western Energy (Pvt.) Ltd.	Jhimpir	50
27	Trans-Atlantic Energy (Pvt.) Ltd.	Jhimpir	50
28	Shaheen Renewable Energy - 1 (Pvt.) Ltd.	Jhimpir	49.5

There is a total of 23 wind generating power companies who have achieved commercial operation of their respective wind power projects. All these wind power projects are fixed offshore wind farms (GW production and map)[35]. Most of wind projects are in the Gharo-Keti Bandur Wind Corridor within an area of roughly 60 Km x 170 Km.

The Government of Pakistan is proactively pursuing the exploitation and utilization of its indigenous power generation resources as a part of its vision to achieve strategic objectives of energy security, decreasing dependence on imported fuels and providing sustainable energy supplies for economic growth. The development of renewable energy-based power generation projects is being pursued on IPP mode through private sector investors. ARE promises a higher proportion of the national energy supply mix and helps ensure universal and affordable access to electricity in all regions of the country.

Several ARE projects, initiated under the RE Policy 2006, were not able to proceed with their development due to restrictions imposed vide decisions taken by CCOE. Under the vision of the current Government to exploit clean energy resources and increase the share of ARE in the energy mix, the CCOE vide its decisions in case No. CCE-12/04/2019(V) dated February 27, 2019, allowed implementation of projects that had already achieved significant milestones of project development by placing them into the following three categories;

- Category - 1: 19 projects of 531 MW that have already been issued Letter of Support (LOS) subject to revision of tariff in case tariff determination has been done since more than one year or if the tariff validity period has lapsed

- Category - 2: 22 projects of 1199.3 MW that have acquired tariff and generation license subject to revision of tariff in case tariff determination has been done since more than one year or if the tariff validity period has lapsed

- Category - 3: 104 projects of more than 6000 MW cumulative capacity holding LOIs to be allowed to proceed ahead after becoming successful in a competitive bidding to be undertaken as per demand communicated by NTDC. In compliance of the CCOE's decision, AEDB has actively been facilitating the said projects as per the criterion set by the CCOE. Twelve (12) wind power projects with a cumulative capacity of 610 MW have been facilitated to successfully achieve Financial Closing in November 2019.

35. AEDB

Pakistan is blessed with tremendous wind resource. World Bank and AEDB in phase 1 has implemented Renewable Energy Mapping data for the period of 2000-2010, based on existing ground data, initial results indicate good wind regime in the country as shown in Figure below;

Figure 29: *Annual Simulated Wind Speed*

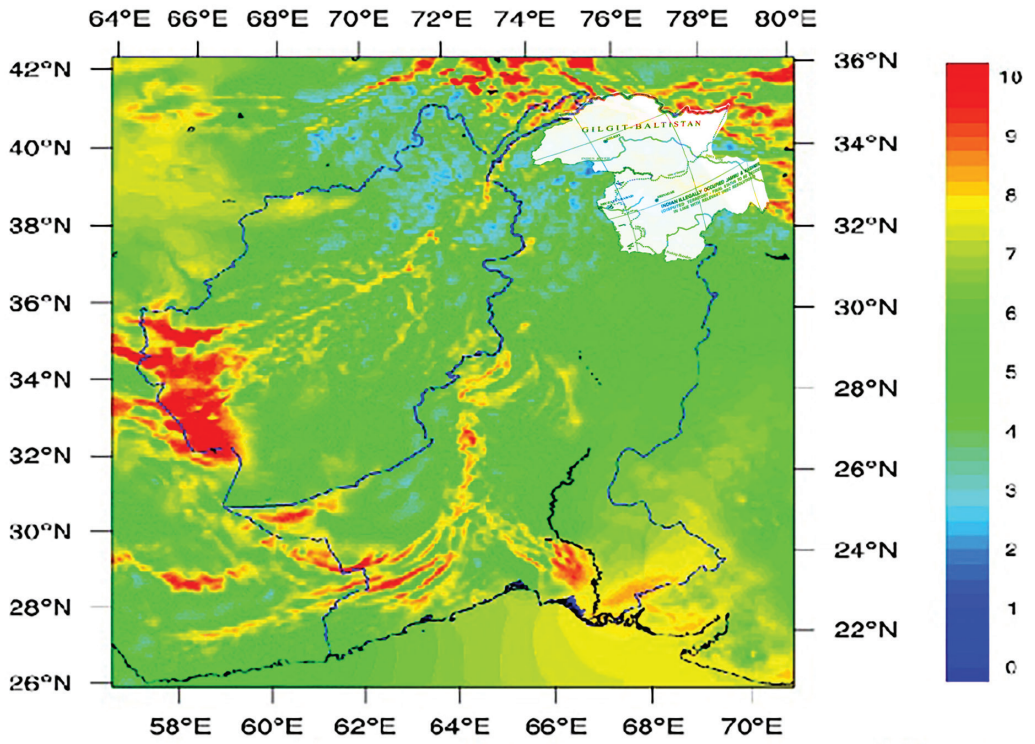


Figure shows mean annual simulated wind speed at 100 meter above ground level simulation at 5km x 5km grid spacing. The color spacing scale indicates wind speed in m/sec[36].

4. Hydroelectric Power (Hydel)

Water & Power Development Authority (WAPDA) is a public sector entity, which develops, operates, and controls the hydropower plants in the public sector of Pakistan. During FY 2019-20 WAPDA Hydel generated 37,425.41 GWh electricity compared to 31,167.85 GWh last year showing an increase of 6,257.56 GWh. During the same period, the hydel IPPs generated 1,562.55 GWh electricity as compared to 1,928.04 GWh during FY 2018-19 showing a decrease of 365.49 GWh. The share of hydel generation in the generation basket of CPPA-G during FY 2019-20 remained 30.77% while this share was 25.35% during FY 2018-19.

36. Source AEDB

Table 5: Maximum Installed Capacity of Power Generation of Hydel

No.	Power generation	Installed capacity MW
1	Alliai Khwar	121
2	Chashma	184
3	Dubair Khawar	130
4	Golen Gol	106
5	Jagran (AJK)	30
6	Jinnah	96
7	Karot Power Company (Pvt.) Ltd.	720
8	Khan Khwar	72
9	Kohala (China international Water & Electric Company)	1,124
10	Laraib New Bong Esc.	84
11	Malakand-III	81
12	Mangla	1,000
13	Mira Power Ltd.	102
14	Neelum Jehlum	969
15	S.K Hydro (Pvt.) Ltd.	870
16	Small Hydro< 25 MW	128
17	Tarbela	3,478
18	Tarbela 4TH Extension	1,410
19	Tarbela 5th Extension	1,410
20	Warsak	243
21	Patrind	147
22	Pehur	18
23	Ranolia	17
24	Daral Khwar	36
25	Ghazi Barotha	1,450

Table 6: Total Hydel Installed Generation Capacity and Variation[37]

Power Generation as on 30th June			Variation	
	2019	2020	Capacity	Percentage
WAPDA Hydel	9,389	9,389	0	0.00
IPPs Hydel	372	472	100	21.19
Total Hydel	9,761	9,861	100	1.02

37. NEPRA,2020. «State of industry report 2020». Available at: http://nepra.org.pk/publications

5. Hydel Power Generation

Hydroelectricity is considered as a clean source of electricity. However, the availability of hydropower generation is dependent upon the hydrology, which varies on seasonal basis. Further the remote location of hydropower plants, higher construction cost, longer transmission lines, higher tariff during debt servicing period etc. are the big challenges in development of hydropower projects in Pakistan; specially when the potential of solar and wind power is abundantly available, and the tariff of wind and solar power plants has considerably decreased. The tariff of WAPDA hydel power plants (combined for all power stations) is low due to old power plants i.e. Tarbella, Mangla, Warsak etc. However, the tariffs of newly inducted power plants during debt servicing period is at par or higher with some thermal IPPs.

During FY 2019-20 WAPDA hydel generated 37,425.41 GWh electricity compared to 31,167.85 GWh during FY 2018-19 recording an increase of 6,257.56 GWh. During the same period, the hydel IPPs generated 1,562.55 GWh electricity as compared to 1,928.04 GWh during FY 2018- 19 showing a decrease of 365.49 GWh. The increase in generation from WAPDA hydropower plants is a positive for Pakistan power sector while decrease in generation of private sector hydel IPPs is negative.

b. Hydropower Projects Completed

Pakhtunkhwa Energy Development Organization (PEDO) has operating seven Hydropower Projects (HPP) in Malakand, Swabi, Kohistan, Swat, Mardan and Chitral District. The total installed capacity of these HPPs is 161.22 MW.

Table 7: PEDO Hydropower Projects [38]

No.	Scheme	MW Capacity
1	Malakand-III HPP, Malakand	81.00
2	Pehur HPP, Swabi	18.00
3	Shishi HPP, Chitral	1.80
4	Reshun HPP, Chitral	4.20
5	Machai Canal HPP, Mardan	2.60
6	Ranolia HPP, Kohistan	17.00
7	Daral Khwar HPP, Swat	36.60
	Total Capacity	**161.22**

Table 8: Primary Energy Supply by Source (MTOE)

Source	Unit	2014-15	2015-16	2016-17	2017-18	2018-19
Hydro	Million TOE	7.751	8.267	7.682	6.665	6.526
Electricity	% share	11.031	11.176	9.652	7.723	7.786

38. NEPRA,2020. «State of industry report 2020». Available at: http://nepra.org.pk/publications

Figure 30: Primary Energy Supply by Source (MTOE)[39]

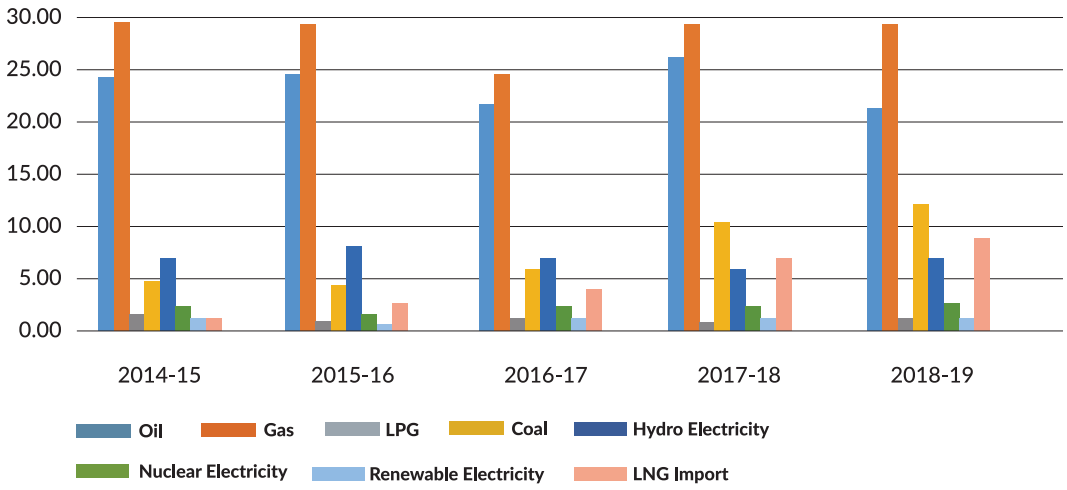


Table 9: Installed Capacity of Hydel (MW)[40]

HYDEL (as on 30th June)	2016	2017	2018	2019	2020
Wapda Hydel	6,902	6,902	8,341	9,389	9,389
IPPs Hydel	214	214	372	372	472
Sub-Total	7,116	7,116	8,713	9,761	9,861
% share (hybrid installed capacity)	27.99	24.78	24.22	25.03	25.47

39. NEPRA,2020. "State of industry report 2020". Available at: http://nepra.org.pk/publications
40. NEPRA,2020. "State of industry report 2020". Available at: http://nepra.org.pk/publications

Table 10: Plant-wise Installed Capacity (MW) as on 30th June 2020[41]							
Power Station	**Plant Location**	**Type of Power Station**	**2016**	**2017**	**2018***	**2019***	**2020***
A1: Hydel (WAPDA)							
Major Hydropower Units							
Tarbela	Tarbela, KPK	Reservoir	3,478	3,478	3,948	3,478	3,478
Tarbela 4th Ext.	Tarbela, KPK	Reservoir	-	-	-	1,410	1,410
Ghazi Barotha	Ghazi Barotha, Punjab	Run of River	1,450	1,450	1,450	1,450	1,450
Mangla	Mangla, AJ&K	Reservoir	1,000	1,000	1,000	1,000	1,000
Warsak	Warsak, KPK	Run of River	243	243	243	243	243
Chashma	Chashma, Punjab	Run of River	184	184	184	184	184
Khan Khwar	Shangla. KPK	Reservoir	72	72	72	72	72
Allai Khwar	Battagram, KPK	Reservoir	121	121	121	121	121
Jinnah Hydel	Mianwali, Punjab	Run of River	96	96	96	96	96
Duber Khwar	Kohistan, KPK	Reservoir	130	130	130	130	130
Neelum Jhelum	Muzaffarabad, AJ&K	Run of River	-	-	969	969	969
Golen Gol	Chitral, KPK	Run of River	-	-	-	108	108
Small Hydropower Units							
Dargai	Dargai, KPK	Run of Canal	20	20	20	20	20
Rasul	Rasul, Punjab	Run of Canal	22	22	22	22	22
Shadiwal	Shadiwal, Punjab	Run of Canal	14	14	14	14	14
Chichoki Mallian	Chichoki Mallian, Punjab	Run of Canal	13	13	13	13	13
Nandipur	Nandipur. Punjab	Run of Canal	14	14	14	14	14
Kurram Garhi	Kurram Garhi, KPK	Run of Canal	4	4	4	4	4
Renala	Renala, Punjab	Run of Canal	1	1	1	1	1
Chitral	Chitral, KPK	Run of Canal	1	1	1	1	1
Gomal Zam	South Waziristan, KPK	Reservoir	17	17	17	17	17
Malakand/Jabban	Malakand, KPK	Run of River	22	22	22	22	22
Total Hydel (WAPDA)			**6,902**	**6,902**	**8,341**	**9,389**	**9,389**
A2: Hydel (IPPs)							
Jagran (AJ&K)	Jagran, AJ&K	Hydro	30	30	30	30	30
Malakand-III (PEDO)	Malakand, KPK	Run of River/Canal	81	81	84	84	84
Pehur (PEDO)	Swabi, KPK	Canal Fall/Run of River	18	18	18	18	18
Laraib Energy (AJ&K)	Jhelum River, AJ&K	Hydro	84	84	84	84	84
Garam Chashma	Chitral, KPK	Hydro	1	1	1	1	1
Marala Hydro (PPDCL)	Sialkot, Punjab	Canal Fall/Run of River	-	-	8	8	8
Patrind Hydro (AJ&K)	Muzaffarabad, AJ&K	Run of River	-	-	147	147	147
Gulpur Hydro	Gulpur, Kotli, AJK	Run of River	-	-	-	-	100
Total Hydel (IPPs)			214	214	372	372	472
Total Hydel (A1+A2)			**7,116**	**7,116**	**8,713**	**9,761**	**9,861**

41. NEPRA,2020. «State of industry report 2020». Available at: http://nepra.org.pk/publications

Table 11: Average Cost of Generation (Rs/GWh)[42]

S. No.	Fiscal Year	2012	2013	2014	2015	2016	2017	2018
		Rs./GWh	Rs./GWh	Rs./GWh	Rs./GWh	Rs./GWh	Rs./GWh	Rs./GWh
A	Hydro							
1	Allai-Khwar	-	-	1.28	2.88	2.00	2.52	5.06
2	Chashma low Head	1.62	1.70	1.77	2.00	2.42	2.42	3.33
3	Chichoki Mallian	1.65	1.47	1.75	2.26	2.49	3.01	4.07
4	Chitral	11.61	7.95	11.04	10.85	10.69	9.42	12.26
5	Dargai	1.12	1.17	1.37	1.13	0.99	1.26	2.01
6	Duber khwar	-	-	-	1.51	1.50	1.22	2.24
7	Ghazi Barotha	1.09	1.07	1.03	1.07	1.49	1.46	2.17
8	Gomal Zam	N/A	N/A	9.55	6.28	44.33	40.58	N/A
9	Jinnah	1.20	1.90	1.47	7.91	3.74	3.20	7.46
10	Khan Khawr	1.90	2.76	2.36	3.52	21.67	2.81	5.22
11	Kurram Garhi	3.21	2.52	2.44	2.56	1.76	2.27	3.88
12	Malakand/Jabban	N/A	N/A	N/A	5.98	4.37	3.46	6.20
13	Mangla	0.95	0.96	0.64	0.62	0.71	1.12	1.57
14	Nandipur	1.40	1.49	2.04	2.93	2.11	2.36	8.18
15	Rasul	1.04	1.69	1.79	1.56	1.64	1.24	3.72
16	Renala	4.92	6.17	9.17	12.39	11.88	12.97	13.57
17	Shadiwal	1.37	1.52	1.75	2.88	2.38	2.80	5.55
18	Trabela	1.13	1.02	0.96	1.14	0.82	1.13	1.62
19	Warsak	0.81	1.26	1.35	0.95	1.11	1.18	1.94

42. NTDC,2020. "Power system statistics 44th edition". Available at https://ntdc.gov.pk/ntdc/public/uploads/services/planning/power%20system%20statistics/PSS%2044th%20Edition.pdf

Figure 31: Hydel Generation Cost

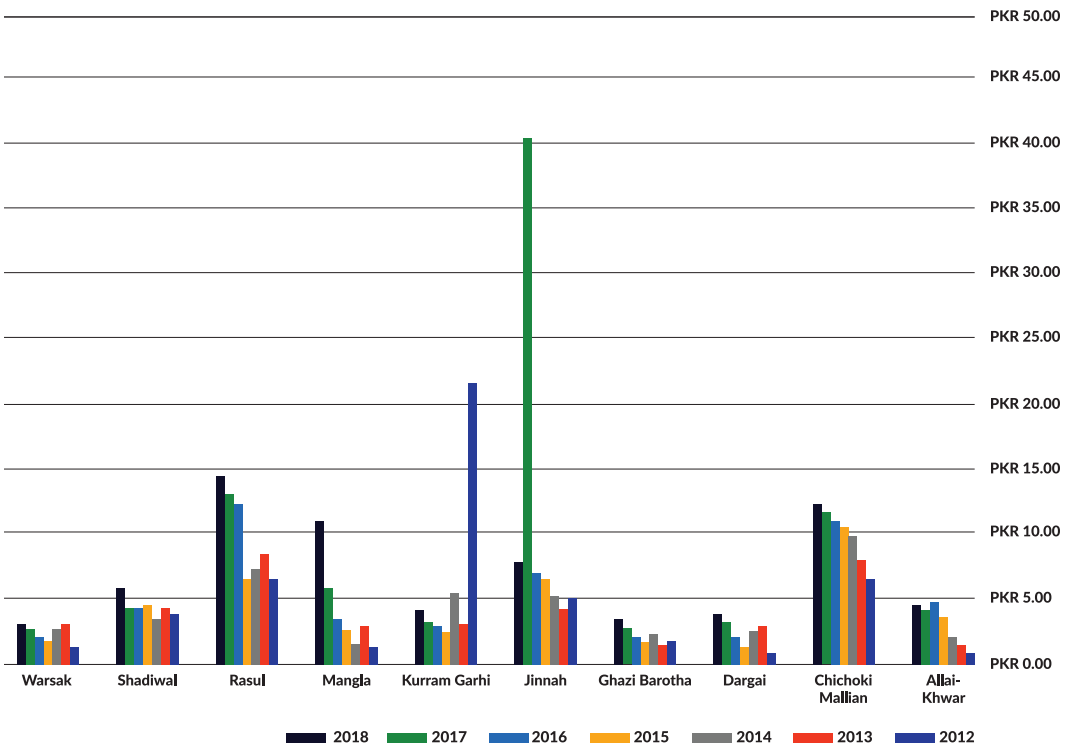


Table 12: Installed Capacity (WAPDA) Seasonal Variation P1 [43]

Sr. No.	Power Station	Location	Province	Type of Power Station	Date of Commissioning	Installed Capacity			Capability (MW)	
						Generating Units	Capacity (MW)	Sub-total (MW)	Summer	Winter
WAPDA Hydel (Major Plants)										
1	Tarbela	Tarbela	KPK	Reservoir	Apr 1977	2	175	350	3702	1874
					Jun 1977	1	175	175		
					Jul 1977	1	175	175		
					Aug 1982	1	175	175		
					Oct 1982	2	175	350		
					Dec 1982	1	175	175		
					Feb 1985	1	175	175		
					Apr 1985	1	175	175		
					May 1992	1	432	432		
					Jul 1992	1	432	432		
					Nov 1992	1	432	432		
					Feb 1993	1	432	432		
								3478		

43. NTDC,2020. "Power system statistics 44th edition". Available at https://ntdc.gov.pk/ntdc/public/uploads/services/planning/power%20system%20statistics/PSS%2044th%20Edition.pdf

Table 12: Installed Capacity (WAPDA) Seasonal Variation P1 [43]

Sr. No.	Power Station	Location	Province	Type of Power Station	Date of Commissioning	Installed Capacity			Capability (MW)	
						Generating Units	Capacity (MW)	Sub-total (MW)	Summer	Winter
2	Tarbela Ex. 4	Tarbela	KPK	Reservoir		1	470	470		
						1	470	470		
						1	470	470		
								1410		
3	Mangla	Mangla	AJK	Reservoir	Jul 1967	2	100	200	1120	450
					Mar 1968	1	100	100		
					Jun 1969	1	100	100		
					Dec 1973	1	100	100		
					Mar 1974	1	100	100		
					Jul 1981	2	100	200		
					Sep 1993	1	100	100		
					Jul 1994	1	100	100		
								1000		
4	Ghazi Brotha	Ghazi Brotha	Punjab		Jul 2003	1	290	290	1450	1160
					Aug 2003	1	290	290		
					Oct 2003	1	290	290		
					Dec 2003	1	290	290		
					Apr 2004	1	290	290		
								1450		
5	Warsak	Wasrsak	KPK	Reservoir	May 1960	2	40	80	190	20
					Jun 1960	1	40	40		
					Jul 1960	1	40	40		
					Dec 1980	1	41	41		
					Mar 1981	1	41	41		
								242		
6	Chashma Hydro	Chashma	Punjab	Head Power Channel	May 2001	8	23	184	184	184
								184		
7	Jinnah Hydel	Mianwali	Punjab	Canal	Mar 2012	1	12	12	68	68
					Oct 2012	1	12	12		
					Aug 2012	1	12	12		
					Mar 2013	1	12	12		
					Mar 2014	1	12	12		
						1	12	12		
						1	12	12		
						1	12	12		
								96		
8	Allai Khwar	Shangla	KPK	Canal	Mar 2013	2	61	122	68	68
								122		

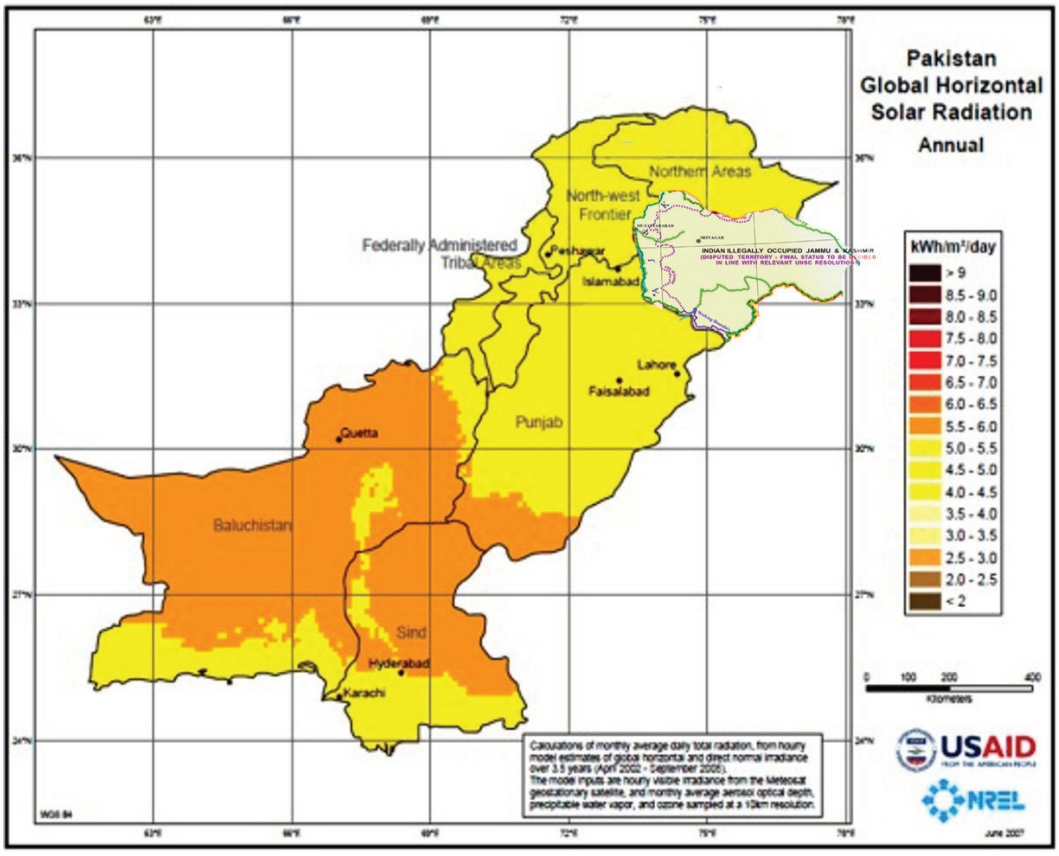
Table 12: Installed Capacity (WAPDA) Seasonal Variation P1 [43]										
Sr. No.	Power Station	Location	Province	Type of Power Station	Date of Commissioning	Installed Capacity			Capability (MW)	
						Generating Units	Capacity (MW)	Sub-total (MW)	Summer	Winter
9	Khan Khwar	Shangla	KPK	Canal	Oct 2010	1	34	34	68	68
					Nov 2010	1	34	34		
					Dec 2010	1	4	4		
								72		
10	Dubair Khwar	Shangla	KPK	Canal	Mar 2013	2	65	130	68	68
								130		
11	Neelam Jhelum	Muzaffarabad	AJK	Run of River	Under Commissioning	4	242	968	968	
								968		
12	Golen Gol	Chitral	KPK	Run of River	-	3	35	105	-	-
								105		
Total WAPDA Hydel								**9,257**	**7,886**	**3,960**
WAPDA Small Hydel										
13	Rasul	Rasul	Punjab	Canal	Jul 1952	2	11	22	128	41
14	Dargai	Dargai	KPK	Canal	Dec 1952	4	5	20		
15	Nandipur	Nandipur	Punjab	Canal	Mar 1963	3	4.6	13.8		
16	Shadiwal	Shadiwal	Punjab	Canal	Jan 1961	2	6.75	13.5		
17	Chichoki-Mallian	Chichoki-Mallian	Punjab	Canal	May 1959	1	4	4		
					Jun 1959	1	4	4		
					Aug 1959	1	4	4		
								12		
18	Kurram Garhi	Kurram Garhi	KPK	Canal	Feb 1958	4	1	4		
19	Renala	Renala	Punjab	Canal	Mar 1925	5	0.22	1.1		
20	Chitral	Chitral	KPK	Canal	1975	2	0.3	0.6		
					1982	2	0.2	0.4		
								1		
21	Gomal Zam	North Waziristan	KPK	Canal	Jun 2013	2	8.6	17.2		
22	Malakand (Jabban)	Malakand	KPK	Canal	Jul 2013	1	5.6	5.6		
					Oct 2013	1	5.6	5.6		
					Nov 2013	1	5.6	5.6		
					Dec 2013	1	5.6	5.6		
								22.4		
Total WAPDA Small Hydel								**127**	**128**	**41**
Total WAPDA Hydel								**9,384**	**8,014**	**4,001**

6. Solar Power

Generally, the entire Pakistan has a high potential for solar energy. The annual average horizontal solar radiation per day in these areas is more than 5.48 kWh/m^2. To develop the solar map of Pakistan, the National Renewable Energy Laboratory (NREL), in collaboration with USAID, Pakistan Meteorology Department (PMD), and AEDB have carried out detailed analysis to determine the solar energy potential in various regions of Pakistan. From the Figure below, it is evident that almost the entire area of Baluchistan province, excluding coastal area and the northeast province border area, receives 6.0 kWh/m^2 of annual average solar radiation. Northern Sindh to Southern Punjab also receives 6.0 kWh/m^2 of annual average solar radiation. In other regions such as Southern Punjab, the area from the north of Baluchistan to latitude 33°N, and the coastal area of Pakistan receive annual average solar radiation of around 5.5 kWh/m^2.

In the region below latitude 33°N, except the northern region of North-West Frontier, Northern Areas, and the northern area of Azad Kashmir province, the annual average solar radiation is around 5.0 kWh/m^2. Thus, it can be said that most part of Pakistan receives solar radiation of more than 5.0 kWh/m^2 annually. The annual average solar radiation of Pakistan is around 5.5 kWh/m^2 [4].

Figure 32: Horizontal Solar Radiation[45]



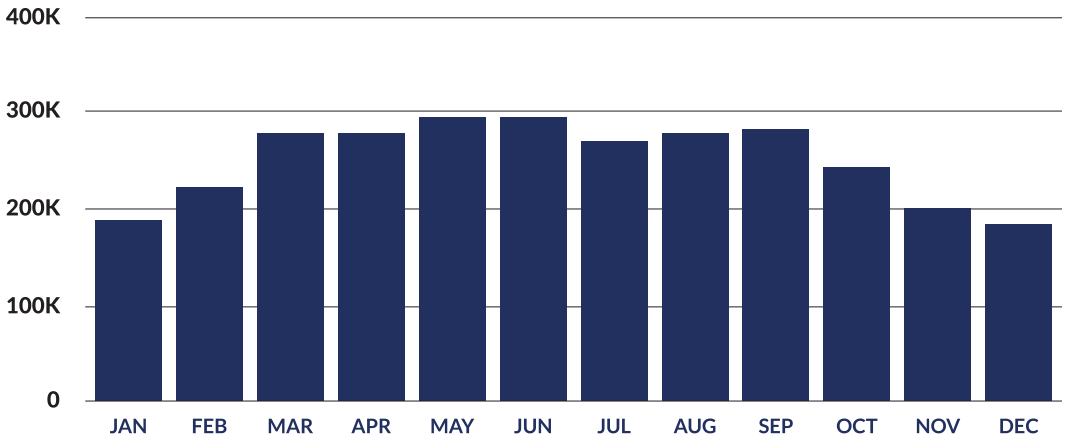
44. AEDB

45. NREL

Table 13 : ??													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Sindh Province													
Average	4.09	4.84	5.57	6.36	6.7	6.6	5.82	5.55	5.53	4.99	4.22	3.8	5.34
Minimum	3.61	4.36	4.77	5.9	6.19	5.97	4.93	4.91	5.1	4.49	3.86	3.4	
Maximum	4.68	5.26	6.14	6.87	7.15	7.14	6.32	6.06	5.91	5.41	4.59	4.24	
Punjab Province													
Average	3.42	4.25	5.09	6.03	6.67	6.78	6	5.6	5.31	4.7	3.8	3.2	5.07
Minimum	2.84	3.8	4.37	5.41	5.96	5.9	5.38	5.09	4.75	4.08	3.46	2.83	
Maximum	3.95	4.81	5.89	6.7	7.24	7.37	6.78	6.31	5.85	5.19	4.15	3.67	
Islamabad Capital City													
Average	3.18	3.87	4.95	6.31	7.27	7.54	6.44	5.72	5.69	5.07	3.89	2.99	5.24
Minimum	2.58	3.33	3.91	5.36	6.47	6.64	5.28	4.8	4.67	4.01	3.46	2.57	
Maximum	3.78	4.61	6.29	7.32	7.71	7.92	7.6	6.81	6.37	5.53	4.2	3.68	

Source: NASA Website Unit: kWh m^2 day^1

Figure 33: Monthly Solar Power Production in Pakistan



c. Solar Projects

Alternate Energy Development Board (AEDB) is pursuing 22 more solar PV power projects of cumulative capacity of approximately 890.80 MW. Presently, following 06 solar power projects of 430 MW capacities are operational.

Four IPPs with a cumulative capacity of 41.80 MW have obtained Letter of Support (LOS) from AEDB and are in the process of achieving Financial Closing of their projects. Another twelve new Solar PV Power Projects of 419 MW capacity have obtained LOI from AEDB and are at different stages of project development. As per the Cabinet Committee of Energy (CCoE) decisions, these 12 projects are required to participate in the upcoming competitive bidding to be carried out by AEDB.

AEDB issued Tripartite Letter of Support (TLOS) to 100 MW Solar Project of Zhenfa Pakistan. The signing ceremony was held in the Chief Minister's Secretariat, Lahore and was witnessed by the Honorable Chief Minister Punjab & Federal Minister for Energy. The Project is expected to be commissioned by December 2021 and will produce electricity at 3.7 Cents per kWh.

Table 14: Proposed Solar Plants

S. No.	Name of Company	Location of Land	Project Capacity (MW)
1	M/S Quaid-e Azam Solar (Pvt.) Ltd.	Bhawalpur	100
2	M/S Appolo Solar Pakistan Ltd.	Bhawalpur	100
3	M/S Crest Energy Pakistan Ltd.	Bhawalpur	100
4	M/S Best Green Energy Pakistan Ltd.	Bhawalpur	100
5	Harappa Solar (Pvt.) Ltd.	Sahiwal	18
6	AJ Power (Pvt.) Ltd.	Pind-dadan Khan	12
7	M/S Access Electric (Pvt.) Ltd.	Pind-dadan Khan	10
8	M/S Bukhsh Solar (Pvt.) Ltd.	Lodhran	10
9	M/S Safe Solar Power (Pvt.) Ltd.	Bahawal Nagar	10.28
10	M/S Access Solar (Pvt.) Ltd.	Pind-dadan Khan	11.52
11	IPS Solar Park-IPS 22 (Pvt.) Ltd.	Nooriabad, Sindh	50
12	IPS Solar Park-JA 23 (Pvt.) Ltd.	Nooriabad, Sindh	50
13	IPS Solar Park-Sb 24 (Pvt.) Ltd.	Nooriabad, Sindh	50
14	R.E Solar I (Pvt.) Ltd.	Dadu, Sindh	20
15	R.E Solar II (Pvt.) Ltd.	Dadu, Sindh	20
16	ET Solar (Pvt.) Ltd.	Thatta,Sindh	525
17	ACT Solar (Pvt.) Ltd.	Thatta,Sindh	50
18	Janpur Energy Ltd.	Rahim Yar Khan	12
19	Lalpir Solar Ltd.	Muzaffargarh	12
20	Siddiquesons Solar Ltd.	Kalar Kahar	50
21	ET Solar (Pvt.) Ltd.	Fateh Jang	50
22	Asia Petroleum Ltd.	Bahawalnagar	30

F. Power Tariffs and Pricing Mechanisms

In a tariff mechanism to support renewable energy, the government or the regulator may fix a price per unit of electricity produced from any technology, which it classifies as renewable. This price would typically be greater than the average generation price of electricity from traditional sources and thus would enable the generators to operate economically. Different tariff levels would be set for different technologies. The Government may provide subsidy from its own sources or complete distribution companies to purchase all the electricity produced from renewable sources, passing the costs on to its consumers. The distribution

companies are compelled to accept all electricity from specified technologies. This policy has advantages, which reduces the risks substantially. Generators receive a fixed price for a stipulated period, thus reducing volume and price risk to investors. Generators are also not subject to balancing risk as distribution companies are compelled to take all the electricity produced. There is also reduced electricity risk in comparison with other mechanisms in that once a plant is operational it is effectively guaranteed tariff for a fixed period.

For Example, the authority determines and approves the generation tariff along with terms and conditions for its 10 MWp Solar Power project for delivery of electricity to power purchaser.

Table 15: Project Costs [46]

Tariff Components	Year 1 -10	Year 11 – 25
Operation & Maintenance Cost	0.8981	0.7999
Insurance during Operation	0.2081	0.2195
Return of Equity	1.8762	1.9748
Debt Servicing	4.8039	
Total	7.7863	2.9824

- Levelized tariff works out to be US Cents 5.9374/kWh
- EPC cost of US$ 0.7035 million per MW was consider
- Project Development including land cost of US$ 538,090 has been considered
- Annual Plant Capacity Factor of 20.26% has been used

1. Residential Power Tariff

- Consumers up to 50 Units will pay PKR 2.00/unit
- Consumers up to 1-100 units will pay PKR 5.79/unit
- Consumers up to 101-200 units will pay PKR 8.11/unit
- Consumers up to 201-300 units will pay PKR 10.2/unit
- Consumers up to 301-700 units will pay PKR 17.6/unit
- Consumers above 700 units will pay PKR 20.7/unit
- Peak hour PKR 20.7/unit
- Off Peak hour PKR 14.83/unit
- Time of use Meter (TOU) Peak hours, in 2010 after installation of digital meters it was decided to charge peak hours rates, for residential consumer will pay 23.92 / unit the peak hour timings are from 5 to 9 pm (1st December to 28 February)

46. NEPRA,2020. "State of industry report 2020". Available at: http://nepra.org.pk/publications

- In second quarter timings are from 6 to 10 pm (1st March to 31st May)
- In third quarter timings are from 7 to 11 pm (1st June to 31st August)
- In fourth quarter peak hour timings are from 6 to 10 pm (1st September to 30th November)

Table 16: Residential Power Tariff

Description	Fixed Charges Rs./kW/M	Notified Tariff 01-01-2019	Industrial Support Package w.e.f. 01-07-2019	Qtr. Adjust. For 1st & 2nd quarter, Notified w.e.f. 01-07-2019	Qtr. Adjust. for 3rd & 4th quarter increase on account Distribution Margin, notified w.e.f. 01-10-2019	Quarterly Uniform Tariff 1st QTR. 2019-20 w.e.f. 01-12-2019	Total Applicable tariff Variable Charges	Monthly FCA for Oct. 2019 charged in January 2020	Total
	A	B	C	D	E	F	G=B+C +D+E+F		
Up to 50 units		2.00					2.00		2.00
For peak load requirement less than 5KW									
1-100 units		5.79				-	5.79	1.57	7.36
101-200 units		8.11				-	8.11	1.57	9.68
201-300 units		10.2				-	10.20	1.57	11.77
301-700 units		17.6		0.75	0.83	0.07	19.25	1.57	20.82
Above 700 units		20.7		0.75	0.83	0.07	22.35	1.57	23.92
For peak load requirement exceeding than 5KW									
Time of use (TOU)- Peak		20.7		0.75	0.83	0.07	22.35	1.57	23.92
Time of use (TOU)- Off-Peak		14.83		0.75	0.83	0.07	16.03	1.57	17.60

2. Commercial Power Tariff

Table 17: Commercial Power Tariff

Description	Fixed Charges Rs./kW/M	Notified Tariff 01-01-2019	Industrial Support Package w.e.f. 01-07-2019	Qtr. Adjust. For 1st& 2nd quarter, Notified w.e.f. 01-07-2019	Qtr. Adjust. for 3rd & 4th quarter increase on account Distribution Margin, notified w.e.f. 01-10-2019	Quarterly Uniform Tariff 1st QTR.2019-20 w.e.f. 01-12-2019	Total Applicable tariff Variable Charges	Monthly FCA for Oct. 2019 charged in January 2020	Total
	A	B	C	D	E	F	G=B+C+D+E+F		
For peak load requirement less than 5 kW		18		0	0.83	0.26	19.09	1.57	20.66
For peak load requirement exceeding than 5 kW									
Regular	400	19.68		1.8	0.83	0.26	22.57	1.57	24.14
Time of use (TOU)-Peak		21.6		1.8	0.83	0.26	24.49	1.57	26.06
Time of use (TOU) - Off-Peak	400	15.63		1.8	0.83	0.26	18.52	1.57	20.09
Temporary Supply		18.39		1.8	0.83	0.26	21.28	1.57	22.85

Note: Industrial Support Package (ISP) reduction shall be inclusive of any downward revision of Fuel Price Adjustment (FPA) notified from time to time.

Finance Cost (FC) Surcharge @ Rs 0.43/kWh and Neelam Jhelum (NJ) surcharge @0.10/kWh are applicable in addition to above on all consumer categories except lifeline

3. Industrial Power Tariff

Table 18: Industrial Tariff

Description	Fixed Charges Rs./kW/M	Notified Tariff 01-01-2019	Industrial Support Package w.e.f. 01-07-2019	Qtr. Adjust. For 1st&2nd quarter, Notified w.e.f. 01-07-2019	Qtr. Adjust.for 3rd& 4thquarter increase onaccount Distribution Margin, notified w.e.f01-10-2019	Quarterly Uniform Tariff 1st QTR.2019-20 w.e.f. 01-12-2019	Total Applicable tariffVariable Charges	Monthly FCA forOct. 2019 chargedin January2020	Total
	A	B	C	D	E	F	G=B+C+ D+E+F		
B1		15.28		1.8	0.83	0.26	18.17	1.57	19.74
B1 Peak		18.84	(3.00)	1.8	0.83	0.26	18.73	1.57	20.30
B1 Off-Peak		13.28		1.8	0.83	0.26	16.17	1.57	17.74
B2	400	14.78		1.8	0.83	0.26	17.67	1.57	19.24
B2 – TOU (peak)		18.78	(3.00)	1.8	0.83	0.26	18.67	1.57	20.24
B2 – TOU (Off-peak)	400	13.07		1.8	0.83	0.26	15.96	1.57	17.53
B3 – TOU (peak)		18.78	(3.00)	1.8	0.83	0.26	18.67	1.57	20.24
B3 – TOU (Off-peak)	380	12.98		1.8	0.83	0.26	15.87	1.57	17.44
B4 – TOU (peak)		18.78	(3.00)	1.8	0.83	0.26	18.67	1.57	20.24
B4 – TOU (Off-peak)	360	12.88		1.8	0.83	0.26	15.77	1.57	17.34

B-1 up to 25 kVJ (at 400/230 Volts)
B-1(a) exceeding 25-500 kW (at 400 Volts)

Time of Use

B-1 (b) up to 25 kW, peak hours Rs15.00/unit - Off Peak Rs 9.50/unit
B-2(b) exceeding 25-500 kW (at 400 Volts) - peak hours Rs15.00/unit - Off Peak Rs 9.30/unit
B-3 for All Loads up to 5000 kW (at 11, 33 kV) peak hours Rs14.70/unit - Off Peak Rs 9.20/unit
B-4 for All Loads (at 66,132 kV 8& above) peak hours Rs14.50/unit - Off Peak Rs 9.10/unit

Prime Minister Imran Khan unveiled a major relief package of the electricity tariff for general, small, and medium industries to encourage higher power consumption and manufacturing. Some salient features of the new package are appended below:

- Peak hours have been removed
- Small and medium industries using additional power as compared to their previous bills will be provided electricity at a discount of 50% till June 30, 2021
- For next three years, all industries will be given a discount of 25pc for using additional units as compared to their previous bills.

Government has decided that from November 1, 2020, small and medium industries using additional power as compared to their previous bills will be provided electricity at 50 per cent of the rate until June 30, 2021. For Example, if some industries were buying electricity for Rs 16/unit, now they will now pay Rs 8/unit for the additional power they consume, and this will be reviewed after June 2021. «However, all industries will be provided additional power at 25% of the rate for the next three years. There will be no longer "off -peak hours". The industrial peak hours were between 7pm to 11pm and during this period the electricity rates increased by 25% for industries. Industries with B-1, B-2 and B-3 connections will be given a discount of 50% on additional electricity until June 2021.[47]

47. NEPRA,2020. «State of industry report 2020». Available at: http://nepra.org.pk/publications

4. Agricultural Power Tariff

Table 19: Agricultural Power Tariff

Description	Fixed Charges Rs./kW/M	Notified Tariff 01-01-2019	Industrial Support Package w.e.f. 01-07-2019	Qtr. Adjust. For 1st & 2nd quarter, Notified w.e.f. 01-07-2019	Qtr. Adjust. for 3rd & 4th quarter increase on account Distribution Margin, notified w.e.f 01-10-2019	Quarterly Uniform Tariff 1st QTR. 2019-20 w.e.f. 01-12-2019	Total Applicable tariff Variable Charges	Monthly FCA for Oct. 2019 charged in January 2020	Total
	A	B	C	D	E	F	G=B+C +D+E+F		
Scarp		15.68		1.8	0.83	0.26	18.57	1.57	20.14
Time of use (TOU)- Peak		18.6		1.8	0.83	0.26	21.49	1.57	23.06
Time of use (TOU)- Off-Peak	200	11.35		1.8	0.83	0.26	14.24	1.57	15.81
Agricultural Tube-wells	200	5.35		1.494	0.83	0.26	7.934	1.57	9.50
Time of use (TOU)- Peak		5.35		1.494	0.83	0.26	7.934	1.57	9.50
Time of use (TOU)- Off Peak	200	5.35		1.494	0.83	0.26	7.934	1.57	9.50
Public Lighting- Tariff G		18.68		1.8	0.83	0.26	21.57	1.57	23.14
Residential colonies – Tariff H		18.68		1.8	0.83	0.26	21.57	1.57	23.14
Railway Traction Tariff I		18.68		1.8	0.83	0.26	21.57	1.57	23.14
Tariff K – AJK	360	15.9		1.8	0.83	0.26	18.79	1.57	20.36
Time of use (TOU)- Peak		21.6		1.8	0.83	0.26	24.49	1.57	26.06
Time of use (TOU)- Off Peak	360	14.7		1.8	0.83	0.26	17.59	1.57	19.16
Tariff K – Rawat Lab		18.68		1.8	0.83	0.26	21.57	1.57	23.14

Under this tariff, there shall be minimum monthly charges Rs.350/- per consumer per month, if no energy is consumed.

Note: The consumers having sanctioned load less than 5 k1V can opt for TOU metering

Note: Industrial Support Package (ISP) reduction shall be inclusive of any downward revision of Fuel Price Adjustment (FPA) notified from time to time

Finance Cost (FC) Surcharge @ Rs 0.43/kwh and Neelam Jhelum (NJ) surcharge @0.10/Kwh are applicable in addition to above on all consumer categories except lifeline [48]

48. *NEPRA,2020. «State of industry report 2020». Available at: http://nepra.org.pk/publications*

G. Merit Dispatch Order of Power and 'Must Run' Plants

The Power Division has illustrated the Cabinet Committee on Energy (CCoE) about the merit order for 'Must Run' power plants based on economic viability, except for nuclear power plants. The committee has described that 'Must Run' power plants are those where natural resource cannot be stored. If electricity is not dispatched, the resources go waste. In case of hydel, the driver is water indent, and the cost of power is the lowest. Nuclear plants once started must remain at fixed generation level because of technology constraints. The cost of nuclear power is still lower and qualifies for merit order. In case of bagasse, it is 'must run' during the crushing season.

Power Division also concedes that natural resource cannot be controlled, and energy is generated as and when resources remain available. In case of solar and wind, there is no fuel cost, and the entire cost is for the energy produced which cannot be stopped or stored. The Renewable Energy Policy, 2006 requires payments for the entire available energy. Must run condition of plants is a part of their Energy Price Agreements (EPAs). However, it may be noted that the current tariffs for solar and wind are much less than already contracted projects. With increase in intake from renewable energy projects, the cost will come down.

There are 108 plants having total installed capacity of 33,836 MW with de-rated capacity of 32,006 MW which includes 61 must run power plants having installed capacity of 12,969 MW with the de- rated capacity of 12,856 MW.

Table 20: kWh Prices of Electricity Generation Modes in Pakistan

Fuel Type	US$/KWh
High Speed Diesel	0.200
Residual Fuel Oil	0.130
Coal	0.080
Gas	0.055
Solar	0.140
Wind	0.130
Hydro	0.063
Nuclear	0.050

The low cost of nuclear power and gas as fuel increases the interest in the production of blue and pink hydrogen. Future studies can be conducted to determine the value chain of hydrogen production from nuclear, gas and solid carbon and display the benefits of CCS technologies.

The cost analysis of 2017-18 shows that energy generated from hydel was 28,239 million units, monthly average megawatts were 3,224 at a cost of Rs 135.265 billion. Energy generated from solar was 702 million units, average 80 MW with a cost of Rs 12.931 billion, and energy generated from wind was 2,145 million units, average 245 MW with a total cost of Rs 41.248 billion. Total electricity generate from bagasse was 1,060 million units, average 121 MW at a cost of Rs 10.282 billion and 8,720 million units from nuclear, average 995

MW at a cost of Rs 76.474 billion. This shows that total 40,866 million units were generated, average 4,665 MW at a total cost of Rs 276.200 billion.

Power Division declared that out of 97.3 billion units generated, 2.8 billion units (2.88 per cent) were generated by solar and wind power projects. With the contracted tariff of solar and wind at that time, this generation cost Rs 54 billion (3.36 per cent) out of a total generation cost billed at Rs 1.609 billion.

In December 2019, fuel-wise capacity is being generated through hydel (27%), RLNG (26%), oil (16%), gas (12%), coal (9%), nuclear (5%) and renewable (5%). The total number of power units in the country is 1077 with installed capacity of 33,836 MW. Their de-rated capacity is 31,006 MW. The merit order is a way of ranking available electricity generation plants, which is based on ascending order of price. Merit order is set in accordance with approved tariff by NEPRA, current fuel price and O&M charges. Lowest cost plants are first dispatched to meet demand and higher cost plants are dispatched in the last. Dispatching generation in this way minimizes cost of production of electricity. Power plants are operated based on dispatch merit order[49] approved by a technical committee. This is a standard operating procedure (SOP) to process and revise merit order for operation of plants. According to this procedure, CPPA-G intimates the revised applicable fuel prices and variable O&M cost based on NEPRA tariff fortnightly in respect of GENCOs and IPPs (thermal power plants). RLNG power plants could not be utilized against its allocation due to host of reasons like late commissioning of RLNG plants, forced outages, availability of higher hydel generation, and drop of temperature especially in October and November. It was pointed out that RLNG consumption may decrease in drawl of load / demand on lower side or tripping of RLNG plants. It was observed in this regard that sudden change in temperature is one of the factors affecting demand & supply of power, which entails change in demand of fuel for plants. However, firm demand of fuel for power generation can be anticipated by using artificial intelligence to avoid wastage of huge public exchequer on unnecessary purchase of fuel.

As can be seen in the following tables, the merit dispatch order covers only the fossil fuel fired plants. Predominantly coal and gas are the first to dispatch, with diesel and heavy fuel oil being the plants of 'last resort' to be used only at times of extremely high-power demand.

Table 21: The Merit Order of Thermal Power Plants to Dispatch Power to the National Grid

S. No.	Plant Groups	Fuel Type	Other Cost Rs./ kWh	Fuel Cost Rs./kWh	VO&M Cost Rs./ kWh	EPP Rs./ kWh	Status in Last Merit Order
1	Uch (upto 152,375 MWh	Gas	0.07649	1.34921	0.39399	1.81969	1
2	Liberty Power (upto 61,904 MWh)	Gas		1.69310	0.54673	2.23983	2
3	Engro Power Thar	Coal		2.69280	1.07950	3.77230	3
4	Port Qasim	Coal		4.43070	0.19380	4.62450	4
5	China Power Hub Genco	Coal		4.63870	0.51150	5.15020	5
6	747 MW Guddu (CCP)	Gas		5.94510	0.55060	6.49570	6
7	Sahiwal Power	Coal		6.88550	0.19080	7.07630	7
8	Uch (above 152,375 MWh	Gas	0.07649	6.64410	0.39399	7.11458	8
9	KAPCO B-1	Gas		6.80852	0.43768	7.24620	9

Table 21: The Merit Order of Thermal Power Plants to Dispatch Power to the National Grid							
S. No.	Plant Groups	Fuel Type	Other Cost Rs./ kWh	Fuel Cost Rs./kWh	VO&M Cost Rs./ kWh	EPP Rs./ kWh	Status in Last Merit Order
10	Guddu (CCP) B-I (Unit 11-13)	Gas		7.31270	0.06890	7.38160	11
11	Foundation Power	Gas		6.90815	0.61300	7.52115	13
12	Uch-II	Gas		7.33683	6.00000	13.33683	14
13	Engro Power Gen	Gas		7.35909	0.54140	7.90049	16
14	GTPS Faisalabad B-IV (Unit 5-9)	Gas		7.76900	0.16250	7.93150	17
15	KAPCO B-II	Gas		7.48781	0.51196	7.99977	18
16	NPPMC - HBS (CC)	RLNG		7.88127	0.19020	8.07147	10
17	NPPMC - Baloki (CC)	RLNG		7.94320	0.21220	8.15540	12
18	Guddu (CCP) B-II (Unit 5-10)	Gas		8.12500	0.06890	8.19390	19
19	QATPL - Bhikki (CC)	RLNG		7.95734	0.55050	8.50784	15
20	KAPCO B-III	Gas		7.72358	0.98682	8.71040	20
21	Liberty Power (Above 61,904 MWh)	Gas		8.46550	0.54673	9.01223	21
22	HCPC	Gas	1.88660	6.71361	0.83750	9.43771	23
23	Muzaffargarh B-II (Unit 4)	Gas		9.46890	0.16250	9.63140	28
24	Muzaffargarh B-I (Unit 3)	Gas		9.48230	0.16250	9.64480	29
25	Jamshoro B-II (Unit 4)	Gas		9.65670	0.09250	9.74920	31
26	Muzaffargarh B-I (Unit 1)	Gas		9.68440	0.16250	9.84690	32
27	Jamshoro B-II (Unit 3)	Gas		9.86160	0.09250	9.95410	33
28	Muzaffargarh B-I (Unit 2)	Gas		9.81200	0.16250	9.97450	34
29	Orient Power Company Ltd.	RLNG		9.71256	0.36850	10.08106	22
30	Jamshoro B-II (Unit 2)	Gas		10.12630	0.09250	10.21880	36
31	Muzaffargarh B-III (Unit 5)	Gas		10.06360	0.16250	10.22610	37
32	Sapphire Electric Co.	Gas		9.70596	0.62000	10.32596	24
33	Halmore Power	Gas		9.70654	0.62980	10.33634	25
34	Saif Power	Gas		9.71345	0.62700	10.34045	26
35	Nandipur (CC)	Gas		9.84560	0.62260	10.46820	27
36	Muzaffargarh B-III (Unit 6)	Gas		10.32980	0.16250	10.49230	38
37	KAPCO B-I	RLNG		10.13924	0.43768	10.57692	30
38	KAPCO B-I (S/Cycl)	Gas		10.21278	0.43768	10.65046	40
39	Guddu (W/o CCP) B-I (Unit 11-13)	Gas		10.96905	0.06890	11.03795	42
40	Rousch	RLNG		10.69198	0.46195	11.15393	35
41	Engro PowerGen	Mix. (***)		11.03350	0.54700	11.58050	44
42	KAPCO B-II	RLNG		11.12104	0.51196	11.63300	39
43	KAPCO B-II (S/Cycl)	Gas		11.20172	0.51196	11.71368	47
44	GTPS Faisalabad B-IV (Unit 5-9)	RLNG		11.56950	0.16250	11.73200	41
45	Altern Energy Ltd. (Ph-II)	RLNG		10.98950	1.13116	12.12066	43

Table 21: The Merit Order of Thermal Power Plants to Dispatch Power to the National Grid

S. No.	Plant Groups	Fuel Type	Other Cost Rs./ kWh	Fuel Cost Rs./kWh	VO&M Cost Rs./ kWh	EPP Rs./ kWh	Status in Last Merit Order
46	Jamshoro B-II (Unit 4)	Mix. (*****)		12.06450	0.09250	12.15700	48
47	Guddu (W/o CCP) B-II (Unit 5-10)	Gas		12.18750	0.06890	12.25640	49
48	KAPCO B-I	RFO		11.55657	0.75921	12.31578	53
49	FKPCL	RLNG		11.08925	1.24047	12.32972	45
50	Jamshoro B-II (Unit 3)	Mix. (*****)		12.32950	0.09250	12.42200	52
51	KAPCO B-III	RLNG		11.50193	0.98682	12.48875	46
52	Attock Gen	RFO		11.03350	1.50800	12.54150	50
53	KAPCO B-III (S/Cycl)	Gas		11.58537	0.98682	12.57219	54
54	Lalpir (Pvt.) Ltd.	RFO		12.40469	0.28270	12.68739	55
55	Jamshoro B-II (Unit 2)	Mix. (*****)		12.66550	0.09250	12.75800	56
56	Jamshoro B-II (Unit 4)	Mix. (**)		13.03670	0.09250	13.12920	59
57	Jamshoro B-II (Unit 3)	Mix. (**)		13.31575	0.09250	13.40825	62
58	KEL	RFO		12.55638	0.98691	13.54329	66
59	Davis Energen	RLNG		12.69573	0.84837	13.54410	51
60	Altas Power	RFO		12.18390	1.48730	13.67120	65
61	KAPCO B-II	RFO		12.68363	1.06860	13.75223	73
62	Jamshoro B-II (Unit 2)	Mix. (**)		13.68030	0.09250	13.77280	68
63	Narowal Power	RFO		12.47030	1.33880	13.80910	71
64	PakGen Power Ltd.	RFO		13.52839	0.28270	13.81109	72
65	Nishat Power Ltd.	RFO		12.60900	1.48730	14.09630	70
66	Nishat Chunian Power Ltd.	RFO		12.62080	1.48380	14.10460	77
67	Liberty Power Tech Ltd.	RFO		12.57334	1.63450	14.20784	61
68	Muzaffargarh B-II (Unit 4)	RLNG		14.10120	0.16250	14.26370	57
69	Muzaffargarh B-I (Unit 3)	RLNG		14.12110	0.16250	14.28360	58
70	SABA	RFO		14.05102	0.28280	14.33382	79
71	Muzaffargarh B-I (Unit 1)	RLNG		14.42200	0.16250	14.58450	60
72	Muzaffargarh B-I (Unit 2)	RLNG		14.61210	0.16250	14.77460	63
73	Jamshoro B-II (Unit 4)	RLNG		14.76840	0.09250	14.86090	64
74	Muzaffargarh B-II (Unit 4)	Mix. (**)		14.92820	0.16250	15.09070	61
75	Muzaffargarh B-I (Unit 3)	Mix. (**)		14.95045	0.16250	15.11295	82
76	Muzaffargarh B-III (Unit 5)	RLNG		14.90670	0.16250	15.06920	69
77	Jamshoro B-II (Unit 3)	RLNG		15.08160	0.09250	15.17410	67
78	Altern Energy Ltd. (Ph-I)	RLNG		14.12041	1.13116	15.25157	74
79	Jamshoro B-I (Unit 1)	RFO		15.34610	0.09250	15.43860	84
80	Muzaffargarh B-I (Unit 1)	Mix. (**)		15.27895	0.16250	15.44145	85
81	Muzaffargarh B-III (Unit 6)	RLNG		15.38310	0.16250	15.54560	76

Table 21: The Merit Order of Thermal Power Plants to Dispatch Power to the National Grid							
S. No.	Plant Groups	Fuel Type	Other Cost Rs./ kWh	Fuel Cost Rs./kWh	VO&M Cost Rs./ kWh	EPP Rs./ kWh	Status in Last Merit Order
82	Jamshoro B-II (Unit 2)	RLNG		15.48660	0.09250	15.57910	75
83	KAPCO B-I (S/Cycl)	RLNG		15.20886	0.43768	15.64654	78
84	Muzaffargarh B-I (Unit 2)	Mix. (**)		15.48595	0.16250	15.64845	86
85	Jamshoro B-II (Unit 4)	Mix. (****)		15.59255	0.09250	15.68505	80
86	Jamshoro B-II (Unit 3)	Mix. (****)		15.92575	0.09250	16.01825	83
87	Muzaffargarh B-III (Unit 5)	Mix. (**)		15.89550	0.16250	16.05800	89
88	Jamshoro B-II (Unit 2)	Mix. (****)		16.36045	0.09250	16.45295	88
89	Muzaffargarh B-III (Unit 6)	Mix. (**)		16.33030	0.16250	16.49280	90
90	Jamshoro B-II (Unit 4)	RFO		16.41670	0.09250	16.50920	91
91	Jamshoro B-II (Unit 3)	RFO		16.76990	0.09250	16.86240	95
92	KAPCO B-II (S/Cycl)	RLNG		16.68156	0.51196	17.19352	87
93	Muzaffargarh B-II (Unit 4)	Mix. (****)		17.10185	0.16250	17.26435	92
94	Muzaffargarh B-I (Unit 3)	Mix. (****)		17.12675	0.16250	17.28925	93
95	Jamshoro B-II (Unit 2)	RFO		17.23430	0.09250	17.32680	98
96	HUBCO	RFO		17.30342	0.23580	17.53922	99
97	Muzaffargarh B-I (Unit 1)	Mix. (****)		17.49840	0.16250	17.66090	96
98	Muzaffargarh B-I (Unit 2)	Mix. (****)		17.73280	0.16250	17.89530	97
99	KAPCO B-I (S/Cycl)	RFO		17.33486	0.75921	18.09407	102
100	KAPCO B-III (S/Cycl)	RLNG		17.25290	0.98682	18.23972	94
101	Muzaffargarh B-III (Unit 5)	Mix. (****)		18.19590	0.16250	18.35840	100
102	Muzaffargarh B-III (Unit 6)	Mix. (****)		18.68685	0.16250	18.84935	101
103	KAPCO B-I	HSD		19.11258	0.44011	19.55269	104
104	Orient Power Company Ltd.	HSD		19.14740	0.60420	19.75160	103
105	Halmore Power	HSD		19.07560	0.90920	19.98480	105
106	KAPCO B-II (S/Cycl)	RFO		19.02530	1.06868	20.09398	109
107	Saif Power	HSD		19.25030	0.90490	20.15520	106
108	Muzaffargarh B-II (Unit 4)	RFO		20.10250	0.16250	20.26500	107
109	Muzaffargarh B-I (Unit 3)	RFO		20.13240	0.16250	20.29490	108
110	Sapphire Electric Co.	HSD		19.47280	0.89490	20.36770	110
111	Muzaffargarh B-I (Unit 1)	RFO		20.57480	0.16250	20.73730	111
112	Muzaffargarh B-I (Unit 2)	RFO		20.85350	0.16250	21.01600	112
113	NPPMC - HBS (CC)	HSD		20.98115	0.24670	21.22785	113
114	NPPMC - Baloki (CC)	HSD		21.14197	0.26930	21.41127	114
115	QATPL - Bhikki (CC)	HSD		20.65729	0.76860	21.42589	115
116	Muzaffargarh B-III (Unit 5)	RFO		21.40510	0.16250	21.56760	116
117	KAPCO B-II	HSD		20.97628	0.59171	21.56799	117

Table 21: The Merit Order of Thermal Power Plants to Dispatch Power to the National Grid

S. No.	Plant Groups	Fuel Type	Other Cost Rs./ kWh	Fuel Cost Rs./kWh	VO&M Cost Rs./ kWh	EPP Rs./ kWh	Status in Last Merit Order
118	Muzaffargarh B-III (Unit 6)	RFO		21.99060	0.16250	22.15310	118
119	KAPCO B-III	HSD		21.69394	1.49423	23.18817	119
120	Engro PowerGen	HSD		22.99799	0.55260	23.55059	120
121	KAPCO B-I (S/Cycl)	HSD		28.66887	0.44011	29.10898	121
122	KAPCO B-II (S/Cycl)	HSD		31.46442	0.59171	32.05613	122
123	KAPCO B-III (S/Cycl)	HSD		32.54091	1.49423	34.03514	123

H. Ambient Air Quality and the Link to Fossil-fuel Energy Consumption

Air quality in major cities is often poor, and there are associated public health and environmental concerns. A migration to clean-burning fuels such as CNG is taking place. The goal to reduce pollutant emissions to air can be supported using hydrogen as a transportation fuel and for domestic heating and cooking applications.

Pakistan is the top six countries having 36.4% urban population. Fossil fuel consumption, energy intensive lifestyles, population and economic growths are drivers of air pollution. The country is highly under poor conditions in air quality on health with economic consequences. Air pollution is one of the major concerns in Pakistan. Currently Pakistan is facing worst air quality due to industrialization, transport. The major cities, which are highly polluted, have worsen air quality.

Air visual, an air quality monitor, ranks the major cities of Pakistan i.e. Karachi, Lahore, Faisalabad and Peshawar among the most polluted cities in the world. The major problem that has emerged in the past few years is smog- because of extreme air pollution. Smog is formed when smoke merges with fog; a hazy, grey air which is produced when heat from the sunlight reacts with fine particles and atmospheric pollutants that are released from burning fuels.

The major causes of air pollution include transportation, industrial and power plants emissions, crop waste burning and solid waste burning. Lahore, Karachi, Peshawar, Faisalabad, and Islamabad are worst polluted cities. World health organization estimates (WHO) estimates that Pakistanis on average are losing two and half years of their life expectancy due to exposure to harmful air. Air pollution, both indoor and outdoor, has the highest contribution to the environmental burden of disease in Pakistan. The World Bank estimates that in Pakistan 9% of the annual deaths are because of air pollution. The loss equivalent to 2% and 2.5% of GDP annually in 2016 is accounted for the costs of illnesses and premature deaths from ambient air pollution and household air pollution respectively.[50]

According to WHO safe Air quality guidelines the concentration of PM2.5 in air at 10 µg/m^3. PM10 concentrations of up to 8,555 µg/m^3 were observed inside the kitchens where biofuels were used as energy source in Pakistan. Cleaning and smoking were identified as a major

50. Ministry of Climate Change, 2020. " Pakistan Clean Air Programme". accessed from: mocc.gov.pk on December 9, 2020.

source of indoor particulate pollution and during these activities; concentrations of more than more than 2,000 µg/m^3 were recorded in the living room. However, Pakistan has an annual average of PM2.5 of 65.81µg/m^3 hence ranked as the second most polluted country (World Air Quality Report 14). The major cause of bad air quality is transportation; the problem of air pollution is increasing in the urban areas. In rural areas, the population is exposed to a PM2.5 concentration of 90-165µg/m^3 due to the use of solid fuel for cooking and heating. The level of PM10 in Pakistan's air is twice than that of China and India making it the highest in the world. Other significant pollutants found in Pakistan's air include SO_2, NO_X, O_3, CO, VOCs, and CO_2.

Concentration of Nitrogen Dioxide (NO_2), one of the most detrimental elements of the vehicular emissions, has reached a staggering level. The concentration of NO_2 has reached more than Concentration of PM2.5 is also no surprise. Significantly higher quantities of $PM^{2.5}$ in the atmosphere in Pakistan have become a critical health concern for the people and 0.35 Dobson. Cross many cities in Pakistan, while the optimal limit is 0.07 Dobson's with the expansion of transportation network, such numbers are anticipated to further exaggerate.

Pakistan must endure a substantial socioeconomic cost for its transport sector. Such cost includes escalating bill for fuel imports, economic burden of carbon, Sulfur and Oxides of Nitrogen.

Figure 34: *Concentration of NO^2 Across Various Areas of Pakistan*

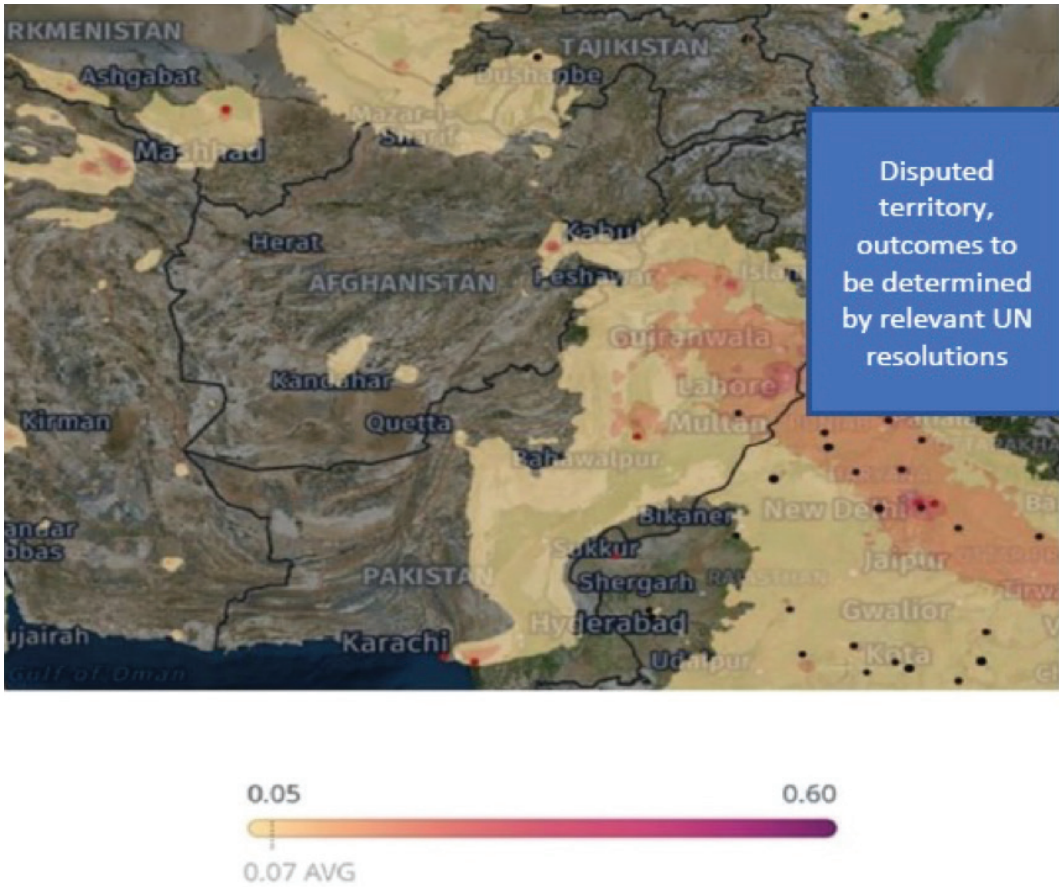


Figure 35: *Concentration of PM 2.5 Across Various Regions in Pakistan*

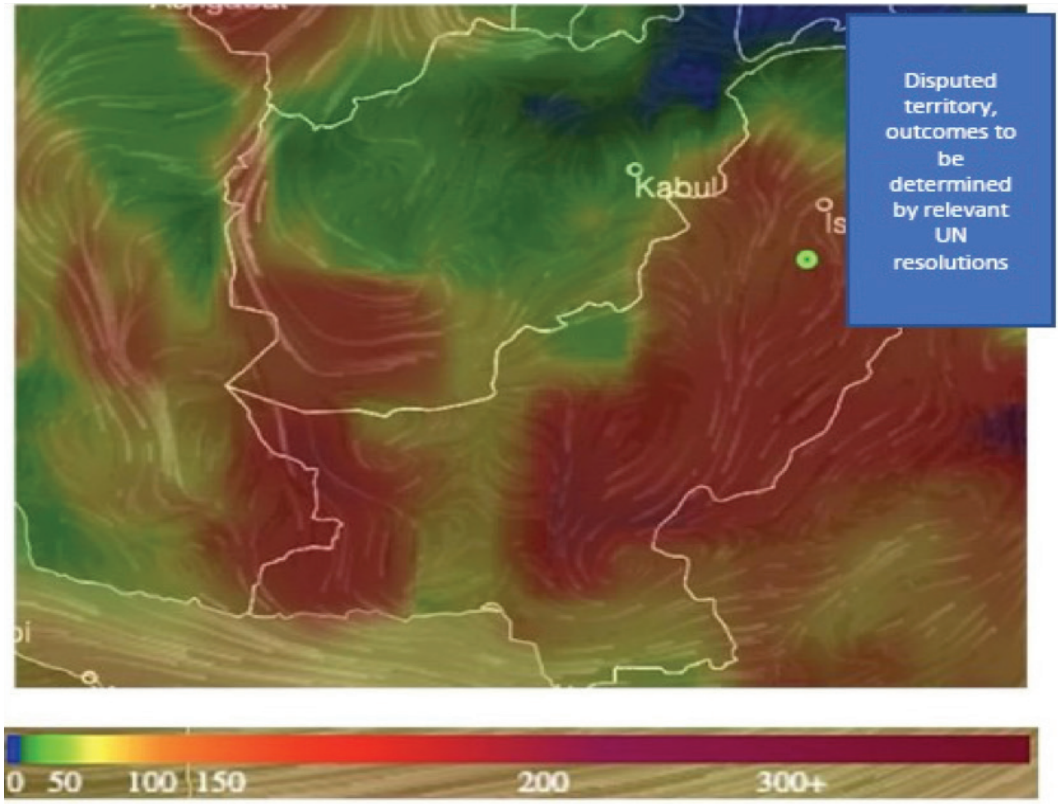
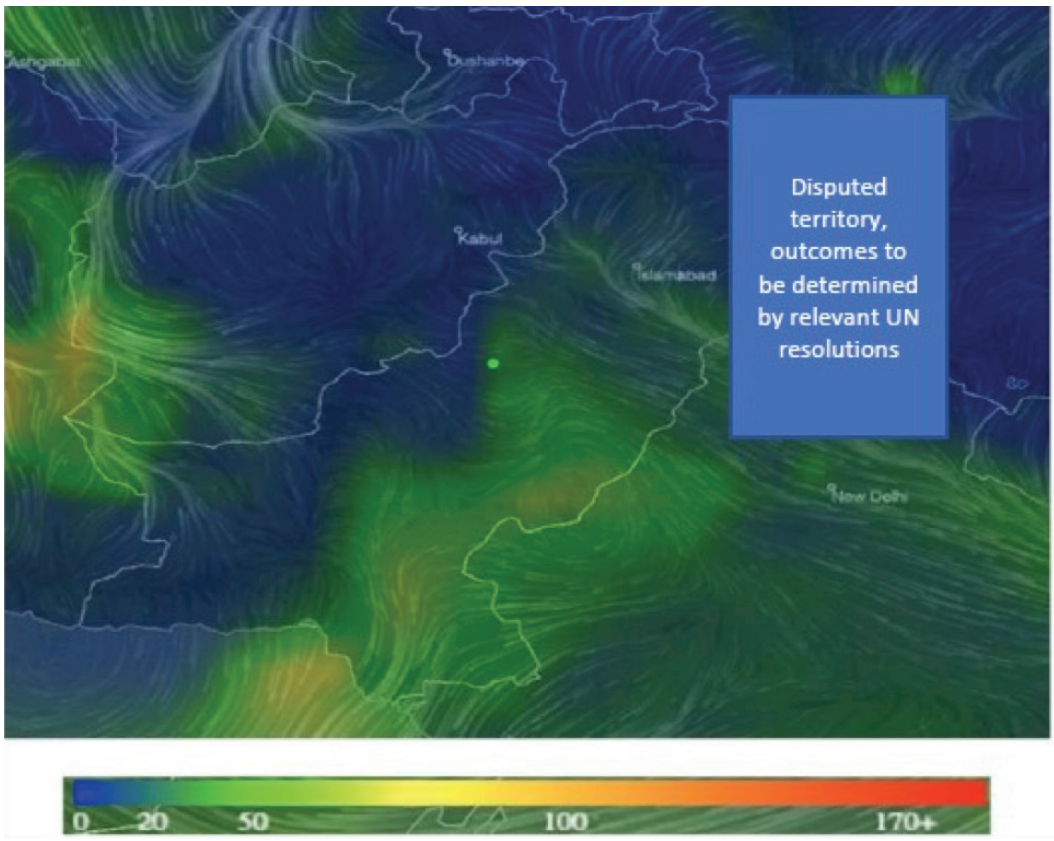


Figure 36: *Concentration of PM10 Across Various Area of Pakistan*



A hefty bill for the import of oil is one of the leading factors in escalating trade deficit of in the next few years, each ton of pollutants released in quantities higher than a fixed threshold will result in taxes paid by the government to the international community. Since, the transport sector of Pakistan is the leading contributor towards release of such environmental pollutants so by introducing hydrogen in the country, such colossal amount in form of taxes can be saved.[51]

As a clear fuel at the point of use, hydrogen can support a reduction in PM and gaseous pollutant emissions from the transportation sector.

Table 22: Ambient Air Quality Program Data [52]

Pollutants	*Time-weighted Average*	*Concentration in Ambient Air*		*Method of Measurment*
		Effective from 1st July 2010	*Effective from 1st January 2013*	
Sulpher Dioxide (SO_2)	Annual Average*	80 µg/m^3	80 µg/m^3	-Ultra Violet Fluorescence method
	24 hours**	120 µg/m^3	120 µg/m^3	
Oxide of Nitrogen as (NO)	Annual Average*	40 µg/m^3	40 µg/m^3	-Gas Phase Chemiluminescence
	24 hours**	40 µg/m^3	40 µg/m^3	
Oxide of Nitrogen as (NO_2)	Annual Average*	40 µg/m^3	40 µg/m^3	-Gas Phase Chemiluminescence
	24 hours**	40 µg/m^3	80 µg/m^3	
O_3	1 hour	180 µg/m^3	130 µg/m^3	-Non dispersive UV absorption method
Suspended Particulate Matter (SPM)	Annual Average*	400 µg/m^3	360 µg/m^3	-High Volume Sampling, (Average flow rate not less than 1.1 m^3/min)
	24 hours**	550 µg/m^3	500 µg/m^3	
Respirable particulate Matter. PM_{10}	Annual Average*	200 µg/m^3	120 µg/m^3	-β Ray Absorption method
	24 hours**	250 µg/m^3	150 µg/m^3	
Respirable Particulate Matter. $PM_{2.5}$	Annual Average*	25 µg/m^3	15 µg/m^3	-β Ray Absorption method
	24 hours**	40 µg/m^3	35 µg/m^3	
	1 hour	25 µg/m^3	15 µg/m^3	
Lead (Pb)	Annual Average*	1.5 µg/m^3	1 µg/m^3	ASS Method after sampling using EPM 2000 or equivalent Filter paper
	24 hours**	2 µg/m^3	1.5 µg/m^3	
Carbon Monoxide (CO)	8 hours**	5 mg/m^3	5 mg/m^3	Non Dispersive Infra Red (NDIR) method
	1 hour	10 mg/m^3	10 mg/m^3	

* Annual arithmetic mean of minimum 104 instruments in a year taken twice a week 24 hourly at uniform interval

** 24 hourly /8 hourly values should be met 98% of the in a year. 2% of the time, it may exceed but not on two consecutive days.

51. *Source: evPrinting.pdf (lums.edu.pk) Date Taken 26, January, 2021*

52. */www.environment.gov.pk/images/environmentalissues/PAKISTANCLEANAIRPROGRAMME.pdf Date Taken December,16, 2020*

II. Horizon 1 – The Role of Hydrogen to Meet the Energy Challenges Faced by Pakistan this Decade

A. Hydrogen as Part of the Solution to Help Pakistan Meet Economic, Social, and Environmental Goals

Renewable hydrogen energy has many benefits and enormous potential for use in Pakistan to support economic, social, and environmental development to benefit the population of 220 million people in the short-term. In the long-term, it may be produced at a sufficient scale to generate export revenue.

Pakistan presents the "perfect storm" for the production and use of hydrogen as a decarbonized energy vector. Pakistan has all the natural resources to produce, store and distribute unlimited. amounts of low-carbon hydrogen. The geography has unparalleled potential for solar, wind and hydroelectric power to feed electrolyzers for green hydrogen. Natural gas wells throughout the nation provide the feedstock for blue hydrogen production on reformers and the potential for carbon capture and storage to mitigate emissions. Indigenous coal can be gasified to produce hydrogen and the CO_2 emissions can be captured.

Hydrogen storage at scale can be achieved by harnessing natural underground salt formations. Hydrogen transmission and distribution through the established natural gas pipeline network will be possible with cost-effective modifications. Pakistan is one of only a handful of nations in the world with such a diverse potential to decarbonize their energy and transportation systems, industrial activities and domestic heating and cooking applications in this way.

Table 23: Hydrogen Potential for Pakistan

Strategic energy priorities	How hydrogen can help
National energy independence	Local renewable power generation can secure energy independence.
Continuous energy supply security	Conversion of some renewable power to hydrogen can balance seasonal, weekly and daily peaks and troughs associated with renewable power.
Affordable energy	Investment in renewable power is required. Pakistan has the potential to generate low-cost renewable power from solar, wind and hydro.

Carbon neutrality	As part of a renewable energy production and storage mix, hydrogen can support net – zero CO_2 emissions goals in Pakistan.
Pollution – free energy	A transition to low – carbon hydrogen as an energy vector will reduce pollution in urban areas. For some hydrogen production technologies, emissions mitigation during hydrogen production must be implemented to avoid shifting pollution.
Export revenue potential	There is theoretical potential to export hydrogen. However, the ambitions of other regional energy – nations would mean that Pakistan could struggle to compete. In addition, Pakistan has significant need for local energy development.
Leverage existing energy infrastructure	The existing gas transmission and distribution pipeline and the electricity grid can be leveraged in the transition to hydrogen.

1. Year-round Energy Supply Security to the Whole Nation

Hydrogen is versatile, but it should not be expected that hydrogen would replace all existing energy carriers in Pakistan. In line with Pakistan's 30% renewable energy by 2030, an appropriate mix of future energy sources and associated storage and transmission methods will be required. Conversion of some renewable power to hydrogen can balance seasonal, weekly, and daily peaks and troughs associated with renewable power.

The higher priority and the voracious demand for natural gas by power plants and industry, has meant that the government has occasionally rationed natural gas for CNG sector. It announces "gas holidays" where gas supply to CNG stations is cut off for several days a week, conducing to widespread dissatisfaction among CNG consumers. Owing to these gas shortage problems, the government is not in favor of further expansion of CNG sector in the country. The officials are struggling with the difficult task of trying to turn back the strategy and to ablactate vehicles back onto gasoline to divert the natural gas to industry and power plants. On one occasion, the government, imposed ban on import of CNG Kits and CNG Cylinders and restricted the OEM companies i.e. Pak Suzuki Motor Company, Indus Motors Company (Toyota) and after-market installers to stop conversion of vehicles to CNG. To rationalize the gas consumption, a load plan in October 2010 was implemented. Under the plan, gas feeding to the CNG stations was curtailed to five days a week in certain regions of the country. Locally produced green hydrogen can support the CNG sector and hydrogen can be blended into CNG at Ltd. concentrations as has been demonstrated with the "Hythane" product concept internationally.

It is noted that Pakistan has a target of 30% renewable energy by 2030. Achievement of this will require investment. It is also expected that the demand for power in Pakistan will grow as the economy expands and the population increases. The two points in this paragraph combine to give the need for investment in additional energy sources, much of which must be renewable.

The conversion of energy from one source to another results in losses. This is an inevitable fact of science. In some cases, losses are high, in other cases low; but losses always exist. The consequences of this are that the most efficient solution for the use of hydrogen will be the fewest possible energy transformations. For example, near-grid load balancing where power is converted to hydrogen during the day and re-converted to power at night results in losses twice. The conversion of power to hydrogen results in losses only once. In addition to simpler solutions involving fewer losses, they also cost less CAPEX to implement.

The CAPEX required to create renewable electricity that can produce hydrogen (wind, solar and hydro) is high, but these costs are rapidly decreasing in technologies such as solar and wind as they continue to be deployed at scale worldwide. Electrolyzers required to produce hydrogen from power are also scaling up rapidly, and their CAPEX costs are expected to fall significantly within the next decade. Pakistan is blessed with abundant solar radiation and has good potential for offshore wind power in the south. These dynamics lead to a focus on renewable hydrogen in this study.

The four points above combine to mean that: renewables will exist at circa 30% of the Pakistan energy mix by 2030; there will be other existing highly flexible energy / power sources, such as RLNG fired power stations in the national mix that are available for load-balancing, and simple solutions are favored to minimize operating and CAPEX costs. This is different, for example, for the requirements that may exist in Pakistan in 2050 when the national energy mix is more heavily oriented towards renewables. At 60% or more of energy being derived from renewables, the use of batteries and hydrogen energy storage will become important for load balancing. This is the challenge that some other countries (e.g., Austria) are facing today. This is not yet the main issue for Pakistan. The study will identify three horizons and propose solutions and goals that that fit within these: 2030, 2040 and 2050. This will ensure that a long-term vision can be presented in addition to tangible short-term actions being implemented.

2. Energy Independence and National Autonomy

Pakistan's economy is highly dependent on the consumption of imported fossil fuel like oil and gas. Economic growth of Pakistan is affected by the energy shortage. Currently, Pakistan has spending huge amount of (LNG) to meet the energy demand. On the other hand, depleting natural gas reserves are making the country energy insecure, making business less competitive. In addition, the consumption of fuel is not environmentally friendly and deteriorating health of many in Pakistan. Local renewable power generation can secure energy independence.

In the past five years, LNG imports have been used to boost the total energy supply, but these cost money, rely on fossil fuel, and create dependence on other nations. Additional energy is required and will continue to be required to enable the growth of the nation. Additional renewable electrical power generation combined with the production of hydrogen by electrolysis can both diversify and intensify local energy production.

Pakistan is a net importer of natural gas in the form of LNG. This means that the construction of steam methane reformers to produce hydrogen would require significant CAPEX and would deepen the reliance on imported products. That would consume currency reserves and increase Pakistan's dependence on supplies from other nations. Furthermore, there is no established carbon capture and storage scheme in Pakistan that could mitigate the CO_2 emissions from a steam methane reformer. For these reasons, the generation of green hydrogen from renewable power is likely to be a faster route to low-carbon hydrogen than generation of 'Blue' hydrogen produced from natural gas with CCS.

The import of LNG also restricts the option of using methane pyrolysis to produce 'Turquoise' hydrogen. This hydrogen production technology yields solid carbon as a byproduct and produces no CO_2 gas emissions, so it does not require CCS. However, technological maturity is low, and it has not been included in the scope of this study.

3. Low-cost Energy Provision in Industrial, Urban, and Rural Locations

Pakistan has an established natural gas and electricity distribution infrastructure. The use of CNG is also common for transportation. The CNG refueling infrastructure and CNG storage in vehicles are relatively mature. The use of LPG for cooking and heating applications is also common. These aspects mean that hydrogen as a gaseous energy vector is aligned to national energy consumption culture. Also, hydrogen admixing can potentially build on past investments and to accelerate hydrogen deployment at a more affordable cost.

4. Decarbonization of the Fossil Fuel Energy Supply

Pakistan has abundant coal reserves. These are used to generate electrical power. Gasification of coal to produce 'Black' hydrogen would be possible in Pakistan. Over time, the CO_2 emissions from this process could be mitigated if a carbon capture and storage scheme were to come into operation. It should be noted that there are no known plans for a national or local CCS scheme at a scale that could mitigate such emissions, and if such a scheme were to be built, there are existing power generation assets (gas-fired power stations, coal-fired power stations) that could be decarbonized through such a CCS scheme.

5. Pollution-free energy supply

The emissions of CO_2 are from the usage of fossil fuel. Hence, the major emissions have been reported in the energy sector of Pakistan. i.e., by 2030 emissions increased from 185.97 $MTCO_2$ to 898 $MTCO_2$.The implementation and usage of hydrogen in long run helps the country to act upon the Paris agreement i.e. Nationally Determined Contribution (NDC's), by usage of alternative source of fuel. Hydrogen is highly significance in terms of energy usage in Pakistan Hydrogen is expected to replace liquid and gaseous fossil fuels as the preferred fuel for transportation by the end of this century. Pakistan is blessed with rich renewable energy resources such as solar, wind and hydropower. A transition to low – carbon hydrogen as an energy vector will reduce pollution of Sox, NOX, PM, and VOCs in urban areas. For some hydrogen production technologies, emissions mitigation during hydrogen production must be implemented to avoid shifting pollution.

Baluchistan, Sindh, and Southern Punjab have a huge potential of solar while wind power is possible in southern coastal areas. With abundant potential for hydropower along the major rivers across the country with further utilization of these resources in the form of hydrogen, there is good potential for renewable power generation to support the resolution of energy issues in Pakistan.

B. Hydrogen Production Technologies

The physical and chemical properties of hydrogen are universal. However, the way that hydrogen can be applied to the benefit of each country depends on local conditions. For example, nations that are blessed with many years of natural gas reserves may choose to produce hydrogen through the process of steam methane reforming. Countries with extensive coal reserves may consider gasification as a viable hydrogen production route. These methods of hydrogen production can be combined with carbon capture and storage to

limit their environmental impact.

Nations, which are blessed with high solar radiation and steady wind patterns, may opt to produce renewable hydrogen from renewable power using electrolysis. Furthermore, use of the existing infrastructure, such as electrical power grid or gas pipeline network is also important to ensure a cost-effective implementation of hydrogen as an energy vector. The nature of this existing infrastructure is local. For these reasons, it is essential to conduct a study at national level rather than assume that the best solution for another country will also be optimal for Pakistan.

1. Renewable 'Green' Hydrogen from Renewable Power – the Focus of This Study

Renewable electricity production, mainly from solar and wind, increased considerably in the last two decades worldwide. Green hydrogen can be a clean energy carrier with seasonal storage potential and can generate electricity on demand.

It is anticipated that green hydrogen could contribute 20% of global energy in 2050. Renewable power to produce green hydrogen on electrolyzers is most likely to come from hydroelectric, wind, and solar sources – all of them will need to ramp up to accommodate the huge growth in green hydrogen demand. Many of the world's largest proposed renewable hydrogen electrolyzer schemes are planned to be supplied with a mix of wind and solar power this is an optimal combination that results in high electrolyzer utilization and attractive project economic returns, if the wind blows during the nighttime when the sun is not shining.

For large scale projects in the range of 5MW to 50GW, AEC (Alkaline) electrolyzers are being specified in the majority of cases. North American, European, and Chinese suppliers offer these products and Chinese suppliers also make components that western OEMs integrate into their completed systems. So, a wide range of sourcing options is possible with a similarly wide range of price points. For a large AEC system rated at more than 5MW, the capex for a turnkey system from a western supplier will be in the order of USD800,000 per MW of capacity. For a reputable Chinese supplier an equivalent unit may cost half this price but will require a larger amount of labour and technical expertise for local assembly and installation. However, significant savings can be made without compromising the quality of the electrolyzer to the point of adding material project risk. For this study, AEC systems have been specified for the large-scale cases. Western and Chinese supply costs have been used in the sensitivity analysis.

Table 24: Top 20 Planned Green Hydrogen Projects Worldwide by Proposed Hydrogen Capacity					
S. No.	Project	Total Power	H_2 Electrolysis	Location	Power source
1	HyDeal Ambition	95GW	67GW	Multiple, South-Western Europe	Solar
2	Western Green Energy Hub	50GW	28GW	Dundas Shire, Western Australia	Onshore wind and solar
3	Svevind	45GW	30GW	Kazakhstan (location TBD)	Onshore wind and solar
4	CWP Global: AMAN Power-to-X	30GW	16GW	Northern Mauritania	Onshore wind and solar
5	Asian Renewable Energy Hub	26GW	14GW	Pilbara, Western Australia	Onshore wind and solar
6	Green Energy Oman	25GW	14GW	Al Wusta Governate, Oman	Onshore wind and solar
7	North 2		10GW	Eemshaven, Netherlands	Offshore wind
8	Aqua Ventus		10GW	Heligoland, Germany	Offshore wind
9	Hy Energy Zero Carbon Hydrogen		8GW	Gascoyne, Western Australia	Onshore wind and solar
10	Murchison Renewable Hydrogen		5GW	Kalbarri, Western Australia	Onshore wind and solar
11	Beijing Jingneng Inner Mongolia		5GW	Eqianqi, Inner Mongolia, China	Onshore wind and solar
12	Helios Green Fuels Project		4GW	Neom, Saudi Arabia	Onshore wind and solar
13	Pacific Solar Hydrogen		3.6GW	Callide, Queensland, Australia	Onshore wind and solar
14	Base One		3.4GW	Pecem, Brazil	Onshore wind and solar
15	EI-H_2 and Zenith Energy		3.2GW	Bantry Bay, Ireland	Offshore wind
16	H_2-Hub Gladstone		3GW	Gladstone, Queensland, Australia	Onshore wind and solar
17	Yellow Sea		2GW	Qingdao, China	Floating wind
18	HyEx		1.6GW	Antofagasta, Chile	Onshore wind and solar
19	White Dragon		1.5GW	West Macedonia, Greece	Solar
20	Geraldton		1.5GW	Geraldton, Western Australia	Onshore wind and solar

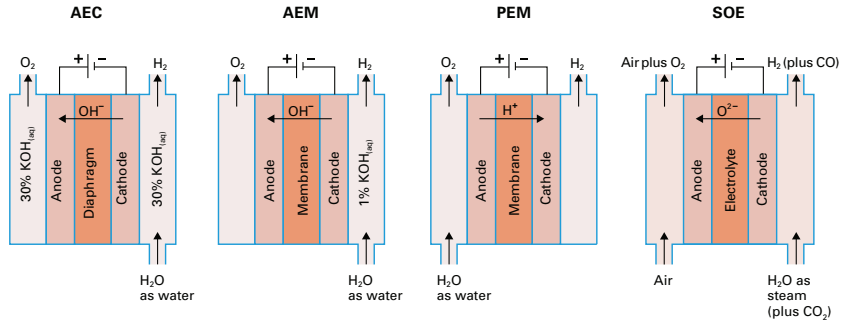
For smaller electrolyzer schemes up to 20MW, PEM electrolyzers are often specified. They offer a higher current density and can be more compact. This favors their use for city-center hydrogen refueling stations, for example. PEM systems are generally 20% more expensive to purchase than an AEC unit of similar capacity. Their operational efficiency is similar. The PEM system does not require Lye to be used. Lye is required to charge up the AEC electrolyzer during commissioning and after maintenance. It is a 30% KOH solution and is highly alkaline. Technical expertise is therefore required. PEM systems avoid the use of Lye and are therefore considered easier to maintain and have a lower environmental and safety risk profile. Most of the established OEMs are in Europe and North America. A PEM electrolyzer has been specified for a small-scale project in this study, which is in a very remote location.

Figure 37: *Main Commercial Electrolyzer Technologies and their Principle of Operation*

Electrolysers: AEC, AEM, PEM and SOE for hydrogen (and syngas) production © 2021 sbh4 GmbH

sbh4 consulting

Notes:
- In the AEC, AEM and PEM, lye or water flow from the electrolyser cell with the oxygen and/or hydrogen gases. These liquids are mixed and recirculated to the electrolyser.
- Air is used to purge the SOE anode to avoid oxygen accumulation which may present a hazard at the high operating temperature.
- Bipolar plates made of stainless steel (titanium for PEM) are used to stack adjacent cells in each electrolyser type.



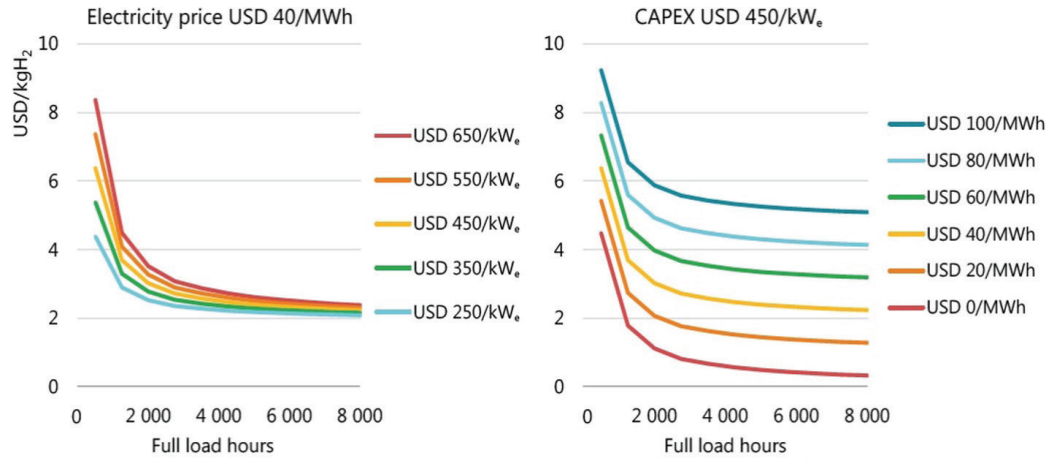
	Alkaline Electrolysis Cell AEC	Anion Exchange Membrane / Alkaline Electrolyte Membrane AEM	Polymer Electrolyte Membrane/ Proton Exchange Membrane PEM/PEMEC	Solid Oxide Electrolysis Cell SOE/SOEC
Electrode material	– Cathode: Ni, Co or Fe – Anode: Ni	– Cathode: Ni / Ni alloys – Anode: Fe, Ni, Co oxides	– Cathode: Pt/Pd – Anode: IrO_2/RuO_2	– Cathode: Ni – Anode: La/Sr/MnO (LSM) or La/Sr/Co/FeO (LSCF)
Electrolyte	Lye: 25-30% Potassium Hydroxide solution in water	Anion Exchange ionomer (e.g. AS-4)	Fluoropolymer ionomer (eg Nafion, a DuPont brand)	Zirconium Oxide with ~8% Yttrium Oxide
Energy source	100% electrical power	100% electrical power	100% electrical power	~25% heat from steam, ~75% electrical power
Current density	Up to 0.5 A/cm²	0.2 – 1 A/cm²	Up to 3 A/cm²	Up to 0.5 A/cm²
Hydrogen or syngas product	Hydrogen	Hydrogen	Hydrogen	Hydrogen (or syngas if fed with steam and CO_2)
Gas outlet pressure	Up to 40 bar	Up to 35 bar H_2, 1 bar O_2	Up to 40 bar	Close to atmospheric
Cell temperature	~80 °C	~60 °C	~60 °C	~750 to 850 °C

SOE electrolyzers are approximately twice the cost of AEC or PEM technologies to purchase and also have a high maintenance cost due to a short stack lifetime. They operate at elevated temperatures which cause thermal stresses that delaminate the catalysts from the electrode plates. On the other hand, they are fed with steam, not water, so they require 25% to 30% less electrical power to generate one kg of hydrogen than a PEM or AEC system. They can also be fed with CO_2 and steam to generate syngas. This is a valuable property if their application is for methanol of e-fuels production. This study proposed some hydrogen value chains where an SOE electrolyzer may be suitable, but these cases were not prioritized for detailed analysis.

AEM electrolyzers are at the lowest stage of technical maturity of the four main types. They are also being produced as small units at present. However, they offer significant advantages such as the use of cheaper materials and flexible performance characteristics, so they are likely to become mainstream in the coming decade. This study has not proposed the use of AEM electrolyzers, due to their comparatively low technological maturity level.

The capital cost of electrolyzers is expected to fall rapidly as production of these units scales up and additional capacity in low-cost manufacturing locations such as China emerges. Technological developments are likely to drive down the costs of materials used in the manufacture of electrolyzers. This will reduce the amount of titanium required for bipolar plates and reduce the amount of precious metals that are used as catalysts to coat the electrolyzer membrane and electrodes. Automation in the factories where electrolyzers are made will also be justified as production scales up. The 'learning rate' cost reductions are expected to follow a similar path to that which has been observed as fuel cell production has ramped up, or wind turbines and solar panel production scaled up in the past. For these reasons, the sensitivity analysis for this study has analyzed the capital costs of the electrolyzers at 50% of the 'today' cost to project forward to potential costs in the future.

Figure 38: *Future Levelized Cost of Hydrogen Production by Operating Hours for Different Electrolyzer Investment Cost (Left) and Electricity Costs (Right)*



Notes: MWh = megawatt hour. Based on an electrolyser efficiency of 69% (LHV) and a discount rate of 8%.

Source: IEA 2019. All rights reserved.

With increasing full load hours, the impact of CAPEX on hydrogen costs declines and the electricity becomes the main cost component for water electrolysis.

Figure 38 demonstrates the importance of a high electrolyzer utilization (ie 40% or more is beneficial) and low power cost as having the greatest influence on green hydrogen production project economics. The electrolyzer capex is also relevant, but less than the other two parameters. The broad conclusions here were used to propose projects for detailed analysis.

C. Alternative Hydrogen Production Technologies Not in Scope for This Study

It is likely that current and future ADB energy policy will favor pathways for renewable hydrogen generation. In some cases, low-carbon hydrogen for example methane gasification using CCS for permanent CO_2 capture and storage may be considered. However, it is expected that coal gasification, either with or without CCS, would not be within future ADB energy policy scope.

1. Low-carbon 'Blue' Hydrogen production from Natural Gas Reforming with CCS

At present, about 95% of the hydrogen that is produced globally is derived from fossil fuels using various thermochemical processes. Gasification consumes solids such as petcoke and coal. Other gas-phase reforming processes are fed with methane, naphtha, or refinery gas.

Auto Thermal Reforming (ATR), Steam Methane Reforming (SMR) and Partial Oxidation (POX) are the main thermochemical processes in play today. These processes produce syngas, which is a mixture of hydrogen and carbon monoxide. Sometimes, two out of the three processes are combined in series to produce the desired ratio of carbon monoxide to hydrogen. If hydrogen is the target gas, carbon monoxide may be reacted with steam and converted to carbon dioxide and hydrogen in a subsequent water-gas shift reactor.

Figure 39: *Thermolysis Processes for Syngas and Hydrogen Production*

SMR, ATR and POX processes for syngas production

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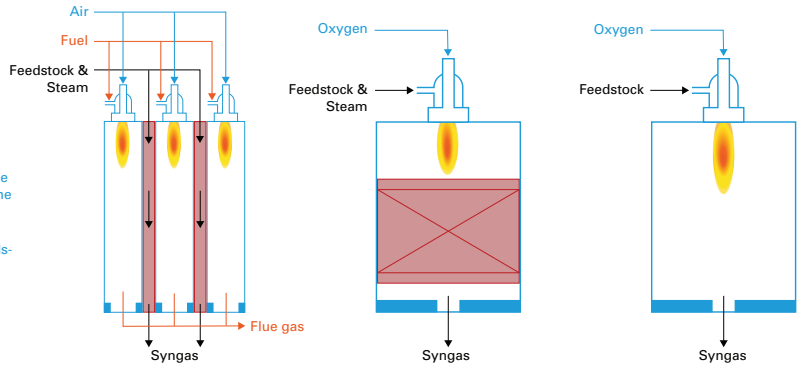

Notes:
- In the SMR the air/fuel combustion reaction takes place in a separate part of the process to the reforming reaction
- SMR may alternatively be side-fired or upwards-fired
- Shaded area denotes catalyst bed

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Process	Steam Methane Reforming – SMR	Auto Thermal Reforming – ATR (Oxidative Steam Reforming)	Partial Oxidation – POX (Gasification)
Carbon feedstock	Natural gas, refinery gas or naphtha	Natural gas or light gaseous hydrocarbons	Gaseous, liquid or solid hydrocarbons
Oxygen feedstock	Air for fuel combustion to heat the process (not used for hydrogen generation in the SMR reactor tubes)	Oxygen from ASU fed with controlled stoichiometry to limit CO_2 generation	Oxygen from ASU fed with controlled stoichiometry to limit CO_2 generation
Steam feedstock	Yes	Yes, often from combined SMR	No
Catalyst required	Yes, Nickel	Yes, Nickel, Cobalt and others	Not for thermal POX
Target chemical reactions	$CH4 + H_2O \rightarrow CO + 3H_2$	$CH_4 + H_2O \rightarrow CO + 3H_2$ $2CH_4 + O_2 \rightarrow 2CO + 4H_2$	$2CH_4 + O_2 \rightarrow 2CO + 4H_2$
Additional side reactions	$CO + H_2O \rightarrow CO_2 + H_2$	$CH_4 + O_2 \rightarrow CO_2 + 2H_2$	$CH_4 + O_2 \rightarrow CO_2 + 2H_2$
Energy required/released	Endothermic, requires heat input	Balance of endothermic and exothermic	Exothermic, releases heat for steam
Hydrogen content in syngas	~70%	~65%	~60%
Syngas pressure	15 to 40 bar	30 to 50 bar	40 to 80 bar
Syngas temperature	850 °C	1000 °C	1400 °C

These thermochemical processes produce about 10 kg of carbon dioxide for each kg of hydrogen. If the CO_2 is not captured, the resulting hydrogen is referred to as grey or black hydrogen.

It is becoming clear that carbon capture and storage will have a central role to play in securing the mid-century target of 'net-zero' carbon dioxide emissions which is the aspiration of many nations. To underline this point, on the 24th of September 2020, Dr Fatih Birol, Executive Director of the International Energy Agency said: "carbon capture is critical for ensuring our transitions to clean energy are secure and sustainable". Power generation and heavy industry will need to decarbonize, perhaps though the application of CCS or with a transition to renewable power from hydro-electric, wind and solar sources.

CCS presents challenges and opportunities. Process equipment required to operate CCS schemes, such as gas separation systems, high-pressure gas compression trains and distribution pipelines will need to be constructed and operated as new projects are confirmed.

CCS is also an established technology. In Europe, Equinor commenced capture and sequestration of CO_2 on the Sleipner West field in the Norwegian sector of the North Sea more than 20 years ago. The components of a CCS scheme, from the absorption tower to the multi- stage CO_2 compressor with integrated drying system are highly developed. Almost all major CCS schemes implemented up to now have been retrofits onto carbon-intensive processes. Beyond Norway, CCS has also been used in Australia, Canada, and the United States for many years.

Through the agreed scope of technical analysis and subsequent discussions during project inception, the focus of this study was aligned to renewable hydrogen from renewable power with electrolysis and excluded the pathway of blue hydrogen production.

2. Waste to Hydrogen

Thermochemical processes such as gasification, reforming and pyrolysis can convert hydrocarbon-rich solid wastes to hydrogen. These thermochemical processes yield syngas, which can be further processed to hydrogen, a clean, emission-free energy vector. The thermochemical processes that yield syngas differ from waste incineration, which takes place in an excess of oxygen to generate steam, carbon dioxide and ash. As an example, a waste to syngas technology provider, Concord Blue Energy, has commercialized this process in more than 10 operational plants across US, Asia and Europe. Many other companies, such as Modi, also offer technologies for waste to hydrogen and other products at a high maturity level.

Thermochemical processing of waste does produce some carbon dioxide, but the International Panel on Climate Change (IPCC) regards processing of the biogenic fraction of waste as carbon dioxide neutral. Animal carcasses, scrap wood, waste vegetable oils and post-consumer wastepaper meet this definition.

It is anticipated that ADB energy policy may support biomass waste to hydrogen projects. On the other hand, the non-biogenic fraction of waste may be out of scope for potential ANB TA support and project finance.

a. Integrated Thermolysis of Waste to Hydrogen

Integrated pyrolysis, reforming and gasification have a significant environmental advantage over incineration: the oxygen-deficient atmosphere prevents the formation dioxins and furans which are highly toxic pollutants. Organic materials ranging from municipal solid waste, biomass, sewage, manufacturing waste, plastic waste, hospital waste, agricultural and slaughterhouse waste are suitable feedstocks.

After removal of recyclables, the waste is shredded and fed into the first thermochemical processing reactor stage, which is pyrolysis. Pyrolysis takes place at around 750 °C in the absence of air. The reactor can be externally heated, or the heat may be applied to a heat carrier medium in a fluidized bed reactor or moving bed reactor. The feedstock is thermally decomposed into gaseous, solid, and liquid components.

As the gases leave the pyrolysis reactor, steam is added to enable reforming and cracking reactions. These generate hydrogen and break larger molecules such as tars to form short-chain hydrocarbons. Reforming generally takes place at around 920 °C.

As a third thermochemical processing stage, a partial oxidation reactor (POX) can be used. The POX reactor is fed with pure oxygen, rather than air, to avoid NOx generation. NOx causes air pollution and NOx generation within the reactor would require its removal using SCR or SNCR techniques. In the POX reactor a controlled amount of oxygen is added – less than the amount required for complete combustion. This ensures that carbon monoxide is produced in preference to carbon dioxide.

Syngas leaving the exothermic POX reactor is at a very high temperature. Recovery of heat from the syngas with a radiant/convective heat exchanger or direct quench improves the overall process efficiency. The high-grade heat can be used to produce steam for power generation or process heating.

Typical syngas clean-up and conditioning processes include cyclones and filters for particulates removal followed by wet gas scrubbing to remove fine particulates, ammonia, and chlorides. Solid absorbents such as activated carbon may also be used to remove mercury and other trace heavy metals.

Fischer-Tropsch conversion of the clean syngas to produce methanol or liquid fuels is a possible next step in the process. Or, if hydrogen is the target, the syngas is fed to water gas shift (WGS) reactors, which progressively increase the ratio of hydrogen to carbon monoxide (CO) in the syngas.

To maximize the hydrogen yield, the WGS reaction can be carried out in two stages. The first is a high-temperature shift (HTS) reactor, which operates at 300–450 °C. Then comes the low- temperature shift (LTS) reactor, which operates at 180–230 °C. Steam injection can be used to optimize the reaction conditions and favor hydrogen production.

Finally, pressure swing adsorption (PSA) is used to separate hydrogen from the syngas. CO and some hydrogen exit the PSA as 'tail-gas' which can be burned with some additional natural gas in a mixed-fuel burner system to create the energy that is required for the endothermic pyrolysis and reforming reactions.

The PSA equipment generates hydrogen at a purity between 98 and 99.999%. At the lower end of that purity range, hydrogen can be used for industrial and chemical processes such as desulphurization of crude oil to make clean fuels. It could also be used for direct reduction of iron to replace coke in a blast furnace. At higher purities close to 99.999%, the hydrogen can be fed to fuel cells for mobility and transportation applications.

Alternatively, Hydrogen can be fed to a Haber Bosch reactor to produce ammonia, which is also an energy vector. Ammonia and hydrogen emit zero carbon dioxide when they are burned. Therefore, they can help with the transition to green energy, decarbonization, and the battle against climate change. Conversion of hydrogen to ammonia is sometimes advantageous for long distance shipping to leverage existing ammonia distribution infrastructure and tankers.

b. Pyrolysis of Waste to Hydrogen

The critical success factors for running a successful pyrolysis plant include a stable feedstock composition, small size of feedstock particles and a low moisture content. Some moisture is good and can support the reaction chemistry, but there are cheaper

methods of drying very wet wastes than using a rotary kiln pyrolysis reactor.

A few percent of powdered additives such as calcium carbonate, calcium fluoride or calcium sulfate may also be required to ensure that sulfurous and halogenated gases are pulled into the solid phase ash. This is preferable to them being emitted with the pygas where they could become atmospheric air pollutants.

Thermolysis is a broad term that can include pyrolysis and reforming reactions. The common link is the use of heat to transform the chemicals. Pyrolysis takes place in the absence of oxygen and without the addition of steam. Reforming requires steam, which either can come from moisture in the feedstock or may be injected to the reactor. In some cases, the reforming reaction is promoted using a catalyst. Gasification is also sometimes categorized as a form of thermolysis and requires the introduction of a controlled amount of pure oxygen. Incineration relies on combustion and takes place with an excess of oxygen, which is generally supplied as air.

To generate hydrogen from pyrolysis, the optimum temperature is more than 900 °C. To achieve this, the temperature applied to the outside of the rotary kiln must be significantly higher to create a suitable temperature gradient and allow the heat energy to flow from the high temperature flame to the lower temperature kiln. If there is a low temperature differential, only a small amount of the heat energy flows to the kiln for pyrolysis and the majority is 'waste-heat' from the process that can be used for steam generation or other purposes. The implication is that high temperature heating and a low temperature pyrolysis kiln favor energy efficiency.

Using two rotary kilns in series can reduce the operating costs of hydrogen production from pyrolysis. The first rotary kiln operates at 500 °C and produced pyoil coke and pygas. The second, smaller kiln, uses a small amount of stem injection at about 15 to 20% by mass and takes the coke from the first kiln and operates at 900 °C to create a hydrogen-rich gas. The high temperature difference on the first larger kiln means that the overall process is more energy efficient that trying to achieve hydrogen in one single stage, which would require a large, kiln operating at high temperature with comparatively low energy efficiency.

The gas flowing from the second pyrolysis reactor can be purified to generate hydrogen for fuel cells or other applications. The pressure of hydrogen coming from the pyrolysis reactor is around 7 bar. This means that it would need to be compressed to be purified in a PSA system. As an alternative, we use a low-pressure purification technology that can achieve extremely high purities that are required for sensitive applications such as automotive fuel cells.

3. Turquoise Hydrogen from Methane Pyrolysis

Pyrolysis of methane is an alternative to methane reforming. In methane pyrolysis the carbon is released as solid carbon as the hydrogen is produced. This can make decarbonistion easier than reforming, where the CO_2 is released as a gas. Through the agreed scope of technical analysis and subsequent discussions during project inception, the focus of this study was aligned to renewable hydrogen from renewable power with electrolysis and excluded the

pathway of turquoise hydrogen production. Most technologies for turquoise hydrogen production are at a low TRL and were therefore deemed unsuitable for focus in this study.

Figure 40: *Characteristics of Some Emerging Methane Pyrolysis Technologies*

Methane pyrolysis (cracking/splitting) for turquoise hydrogen production

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Notes:
- Unreacted methane can be separated from the hydrogen using PSA and recycled to the reactor
- The size of the carbon granules is influenced by operating conditions and the residence time of the carbon in the reactor
- Heat may be from renewable electricity
- Methane can be from natural gas or biogas

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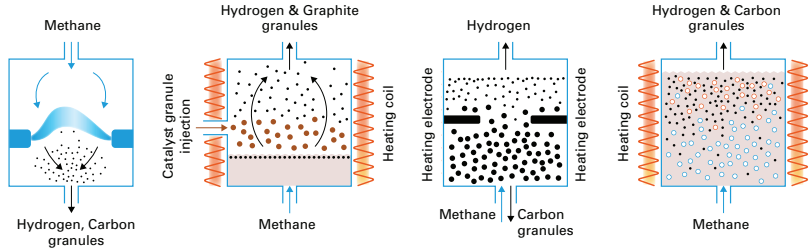


	Plasma Pyrolysis	Fluidised Bed	Moving Carbon Bed	Molten Metal or Molten Salt
Process shown	Monolith Materials	Hazer	BASF	TNO or C-Zero
Hydrogen content at reactor outlet	~95%	~92%	~92%	Up to 95%
Carbon production	Carbon black as powder or granules	80 to 95% graphite encapsulating iron particles	Carbon black as powder or granules	Carbon black as powder or granules
Catalyst required	No	Iron oxide granules	Carbon bed	Molten 27% Nickel-73% Bismuth Molten Manganese Chloride
Heating mechanism	Direct heating with plasma	Indirect heat applied around the reactor	Electrodes to heat the carbon bed and indirect heat applied around the reactor	Indirect heat applied around the reactor or electrodes to heat the melt in a separate vessel
Reactor temperature	2000 °C	900 °C	1000 to 1400 °C	Depends on melt, 650 to 1100 °C
Reactor pressure	Close to atmospheric pressure	Close to atmospheric pressure	Close to atmospheric pressure	Up to 5 bar

Methane pyrolysis is endothermic, meaning that it requires heat energy to convert methane to hydrogen and solid carbon. The reaction has the chemical formula: $CH_4 \rightarrow C(s) + 2H_2$. There are different options for the heat supply. Indirect heating using burners fueled by hydrogen or natural gas as a fuel is one option. Indirect electrical heating or direct heating with an electrical plasma are also possible. These heating modes could use renewable electricity, biomethane or low carbon hydrogen to minimize CO_2 emissions from the process.

Research into methane pyrolysis has been undertaken since the 1960's. In the past 10 years, methane pyrolysis has picked up momentum and several companies have piloted various technologies. Each project has sought to overcome some of the challenges inherent in this process. It is only in the past few years that we have seen commercial operations based on methane pyrolysis emerge as successful business entities.

a. Plasma Pyrolysis

Monolith Materials started development of their methane pyrolysis process in 2012. Methane is heated to 1,700 °C by means of a gas plasma created using renewable electricity. At this temperature, the methane molecule splits. This leads to the formation of carbon black, while the protons split off from the methane molecule and recombine to form hydrogen molecules. At this very high temperature, the reaction takes place without a catalyst. However, engineering a system to operate at these temperatures is challenging and careful material selection is essential.

In 2016, construction started on the Olive Creek1 plant at Lincoln, Nebraska in the United States. It was commissioned in 2020 and has a production capacity of 14,000 tons of carbon and 2,500 tons per year of hydrogen. A second plant named Olive Creek2 is planned to have a capacity of 194,000 tons of carbon black per year and will produce close to 40,000 tons per year of hydrogen.

b. Fluidized Bed Catalytic Process

Hazer has operated a fluidized bed methane pyrolysis reactor pilot plant in Kwinana, Western Australia since 2016. Work has commenced on planning a commercial-scale demonstration plant. In the Hazer process, a fluidized bed reactor is externally heated to 900 °C. Iron oxide powder is injected to act as a catalyst. Methane gas is introduced from the bottom of the reactor. As the methane molecule splits, carbon atoms form graphite on the catalyst surface and hydrogen is released. The upward flow of hot gases carries the low-density graphite particles out of the top of the reactor.

The graphite exits the reactor together with the hydrogen and any unreacted methane. The methane and hydrogen are separated, and the methane is recycled into the reactor. The graphite- coated iron particles formed through the reaction can be processed to produce functional materials.

c. Molten-Metal and Molten Salt Catalyzed Methane Bubble Reactors

In molten metal methane pyrolysis, methane gas is bubbled upwards through a column of molten metal, which is a catalyst to convert methane to carbon and hydrogen. The process has been researched extensively as part of the EMBER project at TNO in the Netherlands. It is also being considered by some Russian natural gas producers, such as Gazprom, for turquoise hydrogen production.

A challenge of the molten metal bubbler reactor is separation of the solid carbon from the molten metal at the top of the reactor. TNO has innovated a solution to this issue by floating a layer of molten salt on top of the molten metal. Other researchers have resolved the problem by replacing the molten metal with a molten salt in the entire bubble column. In California, C-Zero has experimented with this process and has determined that molten manganese chloride is a particularly effective catalyst for methane splitting.

D. Hydrogen Distribution Infrastructure: Leveraging Current Assets

1. Natural Gas Pipeline Network

Natural gas can be used as a hydrogen precursor to produce blue and turquoise hydrogen. The natural gas transmission and distribution grid can also be used to transport hydrogen to consumers. From a distribution point of view, natural gas and hydrogen are, in many ways, very similar energy vectors. It is therefore important to understand the natural gas distribution and transmission infrastructure in Pakistan and the role it can play in bringing gas to hydrogen production locations and moving hydrogen to utilization locations. Leveraging existing assets and locating hydrogen production with these aspects in mind will reduce the cost of the transition to clean energy.

Pakistan has an extensive gas network (SNGPL & SSGC) with over 12,971 km of Transmission pipelines and 139,827 km of distribution pipelines and 37,058 services gas pipelines to cater the requirement of more than 9.6 million consumers across the country.

Natural gas pipelines primarily serve as a means of moving gas from the field to consumers. Inter and inter-province pipelines are used for the transportation of natural gas produced from gas field's facilities through gathering systems to commercial, residential, industrial, and utility companies. The pipelines are usually constructed of carbon steel and different in sizes varies from 2 inches to 56 inches in diameter, depending on the type of pipeline. Pipeline infrastructure originates from the resource field comes from two main networks:

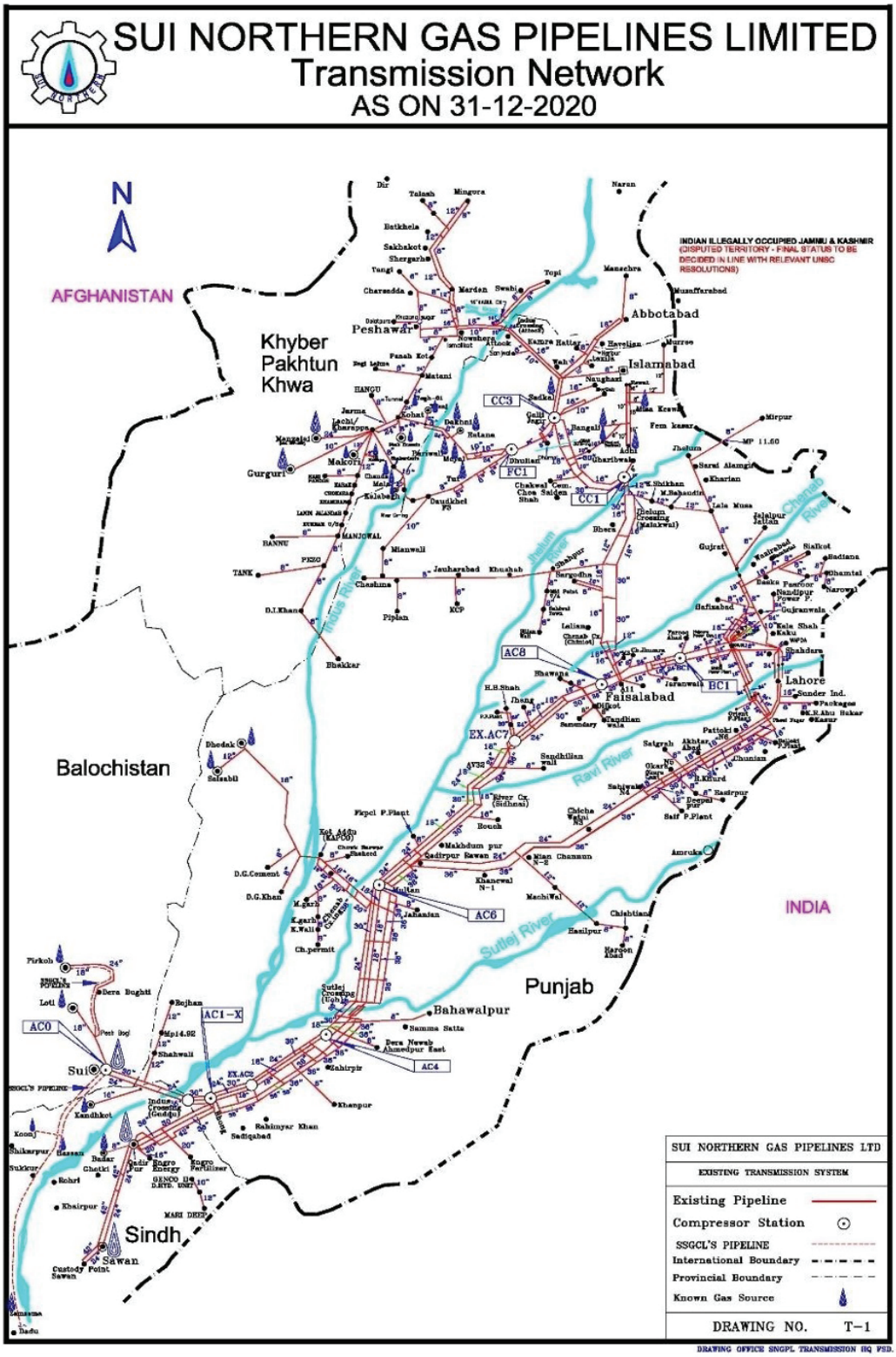
- High-pressure grid-transport network
- Low-pressure grid-distribution network

High-pressure lines are characterized by larger diameter and strong piping with compression stations after regular distance intervals. Low-pressure or distribution networks are identified by pressure reduction stations and a relatively small diameter piping network. The function of the pipeline network is in two-fold. It serves to supply energy to the consumer in the required quantity and at the same time, it provides storage for the fuel gas in a considerable quantity depending upon the dimensional capacity of pipeline and the demand–supply gap. CNG is delivered from locally produced pipeline gas and now imported LNG is being mixed with natural gas in the national gas transmission pipelines.

Given that Pakistan is likely to continue to use local natural gas and imported LNG for many years until renewable power and hydrogen ramp up significantly in the energy mix, continuous investment in methane leak prevention and emissions monitoring will be essential to ensure that greenhouse gas emissions are minimized. Hydrogen can support decarbonization and CO_2 emissions reduction but only methane emissions reduction can avoid the damaging effects of this highly potent greenhouse gas on the environment. A study to assess the economic cost and environmental impact of methane emissions reduction could be undertaken.

The transition from natural gas and regasified LNG in Pakistan to other energy vectors, such as hydrogen will take time and is likely to be progressive. For this reason, admixing of hydrogen into the existing natural gas transmission and distribution pipework grids is likely to be required. A study to map areas of high potential for hydrogen admixing or conversion to pure hydrogen use would be beneficial to support this transition.

Figure 41: *Northern and Southern Gas Network Connected at Sui*[53]



53. *https://www.ssgc.com.pk*

2. Electricity Grid Network

Some green hydrogen schemes will be able to co-locate the electrolyzer at the power generation facility, eg on the Quaid e Azam solar park or close to a hydro dam. In this study, colocation has been specified for all three projects to minimize power transmission losses and costs and to avoid adding stress to the power grid.

However, for many green hydrogen schemes in Pakistan, it will be necessary to move power from the renewable generation location to the electrolyzer. For this purpose, the national power transmission grid will be essential. Careful selection of electrolyzer sites will be required in the future to ensure there is sufficient grid transmission capacity for the route that power will need to flow from the generation source to the electrolyzer. For small schemes at less than 1 MW this may seem like a trivial point, but as green hydrogen scales up to GW schemes, this point will become material for technical and economic reasons.

The function of an electric power system is to provide and sustain a 24/7 reliable and continuous source of electricity. To make it happen, each of the three main components of an electric power system generation, transmission and distribution must perform in the optimal manner. The generation system consists of physical facilities that convert energy resources e.g. coal, oil, nuclear, hydro, wind and solar energy into electricity. The transmission system then transports the generated electricity to the load centers. The distribution system ultimately provides the actual connection to each customer and enables the customer to consume electricity upon demand. An electric power system is thus a dynamic system, which is a balance of supply and demand of electricity.

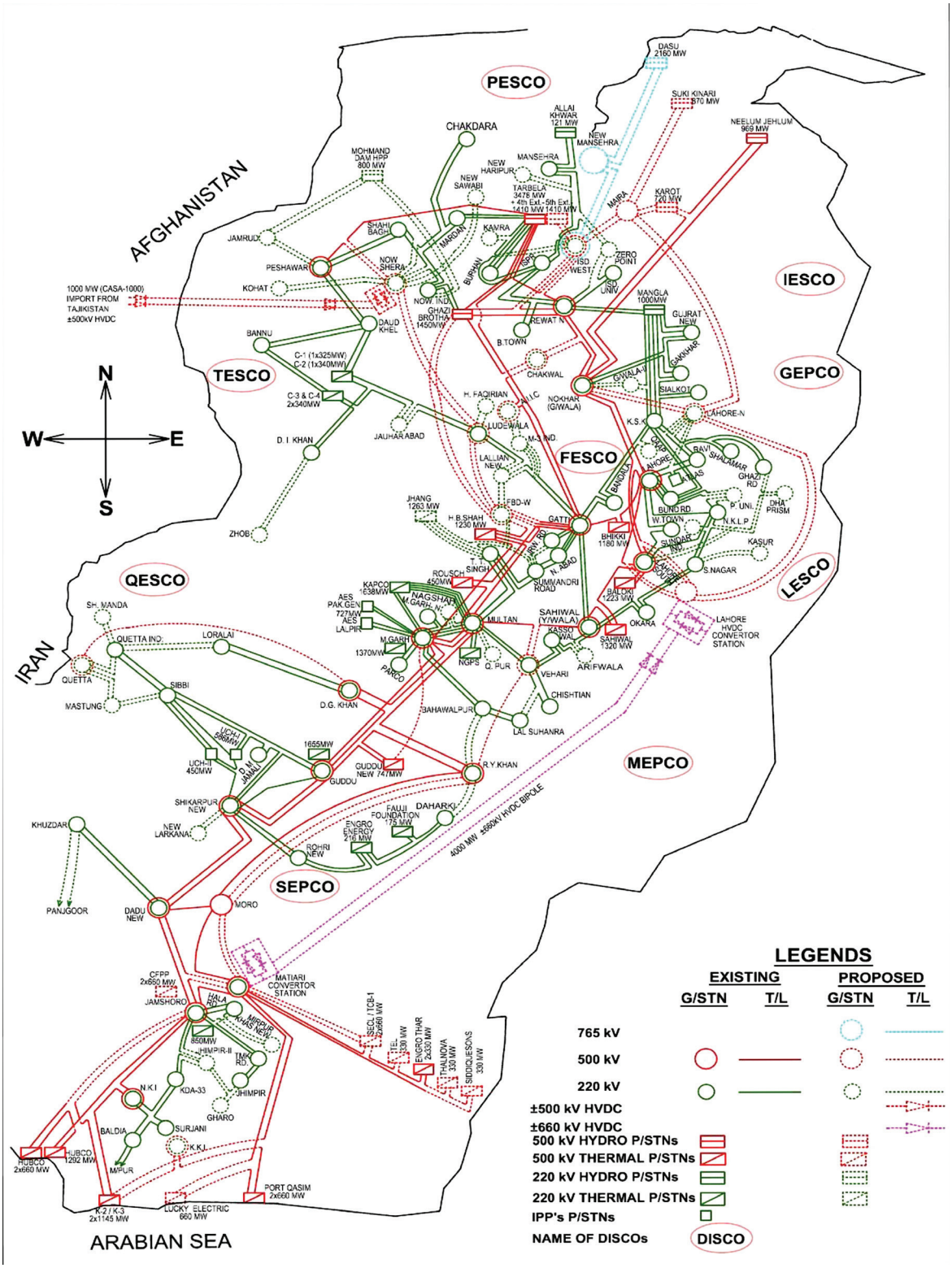
The national grid, which acts as the backbone of the country's power system, consists of 500, 220 kV lines, and the associated grid stations. Total 500 kV transmission network during FY 2018- 19 in the country extended well over 6,290 circuit-km supported by 16 grid stations with 22,950 MVA transformer capacities. The 220-kV transmission network extended over 10,928 circuit-km supported by 45 grid stations with aggregate total transformer capacity of 30,970 MVA. Distribution networks inclusive of 132 kV, 66 kV, and 33 kV voltage levels, collectively extends over 36,131 km, and were supported by 841 grid stations with total capacity of 52,055 MVA in delivering the electricity to end users dispersed around the country.

To effectively evacuate electric power from power generation facilities, the NTDC - the national grid and distribution network of DISCOs - have grown massively in terms of transmission line length over the last five years.

Table 25: Overloaded Substations Representing Pinch-Points in the Power Grid that Should Not be Further Stressed with Power Flowing from Renewable Sources to Electrolyzer Projects

Sr.No.	Name	Rating KV	Grid #	Total Capacity (MVA)	Total Capacity (MW)	Overloading Criterion (MW)	Overloading Criterion (%)	Year of Over-loading	Overloading Status (MW)	Power Factor (%)
1	Fateh Garh	132	38	120	106.80	106.80	100.00	21-2020	104.60	0.89
2	Pattoki	132	158	104	88.40	88.40	100.00	25-2024	87.00	0.85
3	Ravi	220	173	80	68.80	68.80	100.00	23-2022	68.60	0.86
4	Saidpur	132	184	106	94.34	94.34	100.00	26-2025	91.60	0.89
5	Basirpur	132	241	52	43.16	43.16	100.00	21-2020	42.60	0.83
6	Hujra	132	287	78	65.52	65.52	100.00	22-2021	63.60	0.84
7	Lalyani	132	314	65	57.20	57.20	100.00	21-2020	54.90	0.88
8	Rewaz Garden	132	357	80	71.20	71.20	100.00	25-2024	70.90	0.89
9	Sharqpur	132	372	52	44.20	44.20	100.00	23-2022	44.10	0.85
10	Wapda Town	220	503	120	108.00	108.00	100.00	25-2024	104.70	0.90
11	Shamky	132	508	118	103.84	103.84	100.00	27-2026	101.10	0.88
12	Nankana	132	520	78	65.52	65.52	100.00	27-2026	64.50	0.84
13	Sadar Gogera	132	540	52	43.68	43.68	100.00	25-2024	42.30	0.84
14	Mcleod Road	132	583	80	71.20	71.20	100.00	25-2024	68.40	0.89
15	Bund Road	220	599	80	68.00	68.00	100.00	25-2024	66.10	0.85
16	Mochi Gate	132	710	52	46.28	46.28	100.00	23-2022	46.20	0.89
17	Bhati Gate	132	711	80	68.00	68.00	100.00	27-2026	66.50	0.85
18	Aysha	132	912	80	68.80	68.80	100.00	24-2023	67.40	0.86
19	Sabzazar	132	950	92	81.88	81.88	100.00	23-2022	81.00	0.89
20	Daroghawala	132	1003	80	70.40	70.40	100.00	19-2018	68.30	0.88
21	Raiwind New	132	1016	66	59.40	59.40	100.00	24-2023	57.50	0.90
22	Kasur New	132	1020	78	65.52	65.52	100.00	24-2023	63.50	0.84
23	Momanpura G.T	132	1106	80	69.60	69.60	100.00	25-2024	68.90	0.87
24	Punjab Uni Town	132	1131	26	22.36	22.36	100.00	21-2020	21.80	0.86
25	Press Club	132	1152	52	46.28	46.28	100.00	27-2026	46.10	0.89

Figure 42: *NTDC Transmission Network 2025*



E. Hydrogen Utilization Cases

Hydrogen gas is a versatile energy carrier and feedstock, it has served mostly as an input into a range of industrial processes, it has the potential to be used across several applications. Further, if produced using low or zero CO_2 emissions sources, renewable or low-carbon hydrogen can enable deep decarbonization across the energy and industrial sectors.

1. Crude Oil Refining

Hydrogen is used on refineries for three main applications: hydrotreating of heavy molecules to produce higher value light molecules; desulfurization of crude to produce clean burning fuels and hydrogenation (especially of biofuels) to increase their viscosity. Some of the refineries in Pakistan produce grey hydrogen for their internal purposes today. Over time, this could be converted to green hydrogen production.

Current recoverable oil reserves in Pakistan are estimated at 568M million barrels with an annual production of 32M million barrels. The refining capacity in Pakistan is around 19 million tonnes per year and the crude processed is generally less that that at around 13 million tonnes annually. The total consumption of refined products is around 19 million tonnes per year and the balance is filled with imports. Although the national refining capacity on a tonnage basis appears to be matched with demand, the refinery configurations are old and geared to heavy fuel oil that is not in high demand and the popular lighter products such as gasoline or LPG are not produced in sufficient quantities and must therefore be imported.

An overview of Pakistan's refineries and their hydrogen production for their own use is below.

- **Pakistan Refinery Ltd. -** Pakistan refinery has reforming unit. But the consumption and production of hydrogen data is not available.
- **Attock Refinery Ltd. (ARL) -** In Attock Refinery Ltd., the hydrogen production unit produce **5000 Nm^3/h** of hydrogen (express as pure hydrogen).[54]
- **Byco Petroleum Pakistan Ltd. (Byco) -** BYCO has reforming unit. But the consumption and production of hydrogen data is not available
- **Pak Arab Refinery Ltd. (PARCO) -** Pakistan refinery has reforming unit. But the consumption and productio0n of hydrogen data is not available.
- **National Refinery Ltd. (NRL) -** The Hydrogen Production Unit (HPU – Unit 305) is designed to produce **12837.6 Nm^3/h** of hydrogen (expressed as pure hydrogen) with a minimum purity of 99.9 vol %. The hydrogen production unit uses Natural Gas and Heavy Naphtha Arabian Light as feedstocks according to the following cases at 100% plant capacity.

Table 26: National Refinery Ltd. Hydrogen Production

Feed	Hydrogen production
Natural Gas	12837.6 Nm^3/hr
Mixed Feed: 50% Natural Gas, 50% Naphtha	12881.8 Nm^3/hr

54. Interview conducted with Ejaz Randhawa General Manger Attock Refinery).

2. Iron and Steel Making

Hydrogen can be used to substitute coke from coal (from coal) in iron and steel making using a process called direct reduction of iron, or DRI. The investment cost required for the iron and steel industry to make this switch will be high because the existing blast furnaces must be replaced at great cost by new DRI furnaces. Whilst it is highly likely that many plants will make this change, others will decarbonize with CCS technology or the use of biochar as a coke substitute.

The iron and steel making industry in Pakistan has declined and has been in an unstable financial situation and has suffered from industrial labor disputes for many years. Furthermore, the focus of this study was confirmed to be power and energy sector applications, not industrial uses of hydrogen. For these reasons, a utilization case for iron and steel making was not proposed for this study.

Table 27: Production of Iron in Tones[55]

Product	Balochistan	Punjab	Sindh	KP	AJ&K	G-B	TOTAL
Iron Ore	155,247	400,966	0	17,481	0	0	573,694
Laterite	0	246,151	16,370	277,055	0	0	577,576

55. *Interview conducted with Deputy Director Minerals (Petroleum Division)*

Figure 43: *The use of Hydrogen for the Direct Reduction of Iron to Decarbonize the Process*

Difficult to decarbonise industries – Iron making

sbh4 consulting

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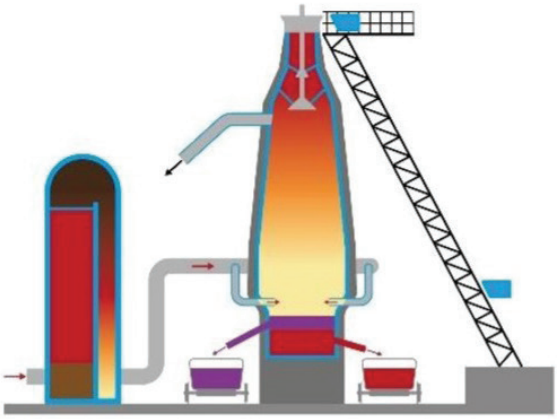
Notes:

- CO_2 emissions are also associated with the energy and power requirements for this industry sector
- These can potentially be decarbonised with renewable power and electrical heating or microwaves
- CCS to capture CO_2 from the process and / or the associated energy production is possible



Blast furnace

	Iron making
Application that releases CO_2	Reduction of iron ore to iron using coke
Chemical reaction producing CO_2	$2Fe_2O_3 + 3C \rightarrow 4Fe + 3CO_2$ $Fe_2O_3 + 3CO \rightarrow 2Fe + 3CO_2$
Decarbonisation approach for CO_2 generated by the process	Use hydrogen instead of coke; or substitute coke with carbon from turquoise hydrogen production
Reactions for the decarbonised process	As above using renewable carbon, or use hydrogen: $Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O$
Other industries with similar applications	None

3. Ammonia and Urea Fertilizer Production

In the urea fertilizer value chain, natural gas is reformed to produce hydrogen which is then converted to ammonia through the addition of nitrogen. The reforming also produces Carbon Dioxide for combination with ammonia on the Urea Plant to make the fertilizer product. One such operational plant in Pakistan was originally designed by CF Braun and re-engineered/ licensed by M.W. [56]

Table 28: Ammonia Production/ Hydrogen Production in Fertilizers

PAKISTAN	Unit	2017	2018	2019
Ammonia Produced	'000 Metric Tons	3817.5	3766.1	4008.2
Equivalent Nitrogen	'000 Metric Tons	3139.7	3097.4	3296.5
Equivalent Hydrogen	'000 Metric Tons	677.8	668.7	711.7

Significant decarbonization of the fertilizer value chain can be achieved by replacing the grey hydrogen production for ammonia with blue, green, or turquoise hydrogen generation. One of the value chains proposed in this study would have investigated this use case, but this scheme was not prioritized for detailed financial analysis.

4. Methanol Production

Currently, Pakistan has no production of methanol and therefore no utilization case for this purpose could be proposed in this study. Pakistan imports methanol as an industrial chemical. Methanol is a hydrogen derivative and therefore relies on hydrogen production. If Pakistan were to establish methanol production in the future, this could be done using low carbon hydrogen, either blue, green, or turquoise.

Table 29: Methanol Import by Economic Category (in Thousand Rupees)

Chemical No.	Item	Nov. 2019	From Jul-19	Nov. 2018	From Jul-18
290511	Saturated Methanol	675633	3014337	755320	3168495

5. Transportation and Mobility Applications

Hydrogen can be utilized in the transport sector, which consumed 4.48%[58] of the energy demand in Pakistan in FY 2018-19. Several projects proposed for this study would have investigated hydrogen mobility as the use case. However, they were not prioritized for detailed analysis. Despite that decision, this project will still suggest incorporating hydrogen mobility in a pilot demonstration project due to its high visibility and accessibility to the public to support the promotion of hydrogen as a clean energy vector for future deployment at greater scale.

The main vehicle types that are considered suitable for hydrogen mobility are:

- FORKLIFT TRUCKS - Internationally, dozens of companies with large indoor warehouse and distribution needs are turning to hydrogen fuel cells to power forklifts with zero emissions inside the warehouse.

56. Interview conducted with International Fertilizer Association (IFA) Published WORLD AMMONIA STATISTICS 2019 (shahzad Mehdi Director Fatima fertilizers).

57. https://www.pbs.gov.pk/ Date Taken 14, January, 2021

58. Energy Year Book 2019.

- HEAVY TRUCKS - Fuel cells boast both the range and power required for long-haul trucking and small local distribution.
- MINING AND CONSTRUCTION VEHICLES – Hydrogen powered fuel cells boast both the power and fast refueling times required for high capex mining vehicles, excavators and construction machinery.
- BUSES - Hydrogen power is being considered for other public transportation applications, including hydrogen fuel cell buses. Metro bus services will be the one of the best initiatives to covert to hydrogen.
- TRAINS - Hydrogen fuel cell trains such as the CORADIA iLint have now entered service in Europe to replace diesel powered locomotives without the need to electrify the track or install overhead power cables. In the next five years, other models are expected to come to Great Britain, France, Italy, Japan, South Korea, and the United States. Pakistan has an excellent opportunity to start Hydrogen train on ML1 railway Project.
- PERSONAL VEHICLES - Nine of the major auto manufacturers are developing hydrogen fuel cell electric vehicles (HFCEVs) for personal use. Notable models include the Toyota Mirai, Honda Clarity, Hyundai Nexo, and BMW I Hydrogen Next. Despite these developments, many observers believe that hydrogen is likely to penetrate heavy duty mobility and batteries will dominate in the smaller vehicles.
- PLANES - Several experimental projects like the Pathfinder and Helios prototypes have explored application of hydrogen fuel cells in aerospace. These long-range unmanned vehicles utilized a hybrid system with hydrogen fuel cells, which were replenished by electrical power from solar arrays, allowing for theoretically indefinite day and night continuous flight.

a. Characterization of Pakistan's National Vehicle Fleet

Table 30: Number of Vehicles on Road in Pakistan (Thousands)[59]

Year	M. Cycle / Scooter	Motor Car	M. Cab / Taxi	Motor Rickshaw	D. Van	Pick u p	Jeep/ D. Cabin	Station Wagon	Ambulance	Buses/ Mini Bus	Truck	Tract or	Oil/water Tanker	Other	Total
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2015-16	6669	6131	186	118	191	166	54	192	3.8	150	263	1351	14	75.5	15568
2016-17	11975	6954	197	122	204	176	69	201	5.7	156	276	1430	14.8	74.7	21858
2017-18 (R)	14060	7183	197	128	210	187	80	206	6.9	159	280	1460	15.2	92.4	24268
2018-19 (P)	14623	7470	205	133	218	194	83	214	7.2	165	291	1518	15.8	96.1	25238

59. *http://www.ntrc.gov.pk Date Taken 22, January, 2021*

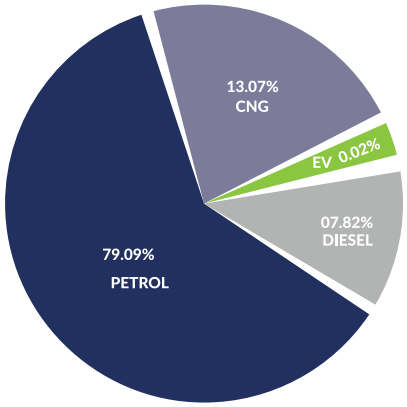
Currently Pakistan Railways has 190 working diesel-electric locomotives and the average life of the fleet is 25 years[60]. At end of life, it is likely that many of these could be converted to hydrogen.

b. Split of the Above Vehicle Fleet (and Each Segment within the Fleet) by BEV, Petrol, Diesel and CNG

National Transport Research Center categorizes the vehicles. In general view big trucks, tractor, oil tankers are on Diesel, the major chunk of the vehicles in Pakistan are two wheelers and tuk- tuk (rikshaws) which are petrol. CNG vehicles are 3.3 million[61]. On the above basis, the vehicle fleet breakdown is as follows:[62]

Figure 44: *Segmentation of Vehicles in Pakistan by Fuel Type*

Table 31: Vehicle Fleet, Segmented by Fuel Categories	
CNG	13.07%
Diesel	07.82%
Petrol	79.09%
E.V	0.02%



c. Case Study - Hydrogen Mobility in Wuppertal, Germany

Wuppertal, in the German state of Nordrhein Westfahlen has been a pioneer of transportation since the construction of a suspended railway, the Schwebebahn, in the late 1800's. 120 years after the Wuppertal's Schwebebahn opened, the city is putting itself on the map again for its innovative approach on this occasion combining waste handling with zero-emissions mobility.

Green hydrogen produced from the incineration of municipal waste will be used as an energy vector to power a fleet of fuel cell electric buses (FVEBs). This sector coupling concept, using hydrogen to link rubbish disposal to emissions-free public transport is one of many projects underway in the Hydrogen Competence Region taking place in Wuppertal, Düsseldorf and other towns in Nordrhein Westfahlen.

The electrical power for the electrolysis, which produces the hydrogen, is generated from the combustion of municipal solid waste. The Wuppertal waste incinerator burns over 1000 tons per day of municipal solid waste collected from local businesses and approximately 1.5 million people in the region. A fraction of the power generated by the incinerator will be used to charge the electrolyzer.

60. *http://www.railways.gov.pk/Publications Date Taken 23, January, 2021*
61. *https://www.abegas.org.br/wp-content/uploads/2019/03/04-Development-of-the-NGV-Market-Jeffrey-Seisler-CLEAN-FUELS.pdf Date Taken 7,January, 2020*
62. *Interview conducted with Deputy Director NTRC.*

One thousand buses operate in the region and many of them will switch from diesel power to emissions-free hydrogen as a fuel. The first A330 FC fuel cell and hydrogen-powered buses arrived in Wuppertal in 2019 from the Belgian manufacturer Van Hool and more arrived in 2020. Each 12 m long, double-axle bus can carry 75 passengers and is equipped with an 85 kW BallardPower Systems fuel cell to convert the hydrogen to motive force. For every ten FCEBs on the road, around 700 tons per year of carbon dioxide emissions from diesel fuel combustion can be eliminated.

In the overall project budget of approximately €12 million, just over half was allocated to the purchase of the new buses and the remainder has been allocated to the implementation of the hydrogen production, storage and refueling system.

The hydrogen for the FCEBs will be produced on a 1.25 MW electrolyzer, which has been suppliedby the Canadian company Hydrogenics, part of Cummins Inc. It uses a polymer electrolyte membrane (PEM) technology to generate high purity hydrogen gas. The purity is important to ensure compatibility with the sensitive fuel cells on the buses. Impurities in the hydrogen can poison the fuel cell catalysts and inert gases such as nitrogen accumulate over time to degrade the fuel cell performance, leading to a loss of motive power for the vehicle.

6. Urban Power, Heating, and Cooking

Hydrogen can be used as an alternative to LPG and Natural Gas in houses for cooking and heating. As an interim measure, hydrogen could potentially be blended with pipeline natural gas and distributed through existing pipeline infrastructure for these applications. To enable hydrogenadmixing into the existing gas transmission and distribution networks a comprehensive study related to mapping the existing pipeline network and its materials of construction and associatedmaterials testing could be undertaken.

The alternative would be to develop a pure hydrogen pipeline network in parallel to the existing infrastructure. The European Hydrogen Backbone is a relevant international benchmark for largescale hydrogen transmission. Pure hydrogen can be distributed to houses and used on fuel cellsfor the combined generation of heat and power. Hydrogen can also be used on boilers and cookers, subject to relevant equipment modifications or repurchase of new hydrogen-ready equipment.

7. Long term Energy Storage for Power Generation

Hydrogen can help manage the transition to a higher proportion of variable renewable electricity (VRE) in the electricity network by overcoming challenges associated with variable powergeneration. Hydrogen can be produced during times of excess power generation and stored. It can then be released to a fuel cell or hydrogen-compatible gas turbine power plant for power generation at times of high electricity demand. The driving and enabling factors for such a business model are a high percentage of renewable power generation in the national mix, accessto low-cost, high-capacity hydrogen storage (for example underground hydrogen storage in salt caverns) and a spread in the power tariff between period of high and low demand on the grid. Allthese things are potentially possible in Pakistan under the right regulatory frameworks and infrastructure development initiatives.

III. HORIZON 2 – HYDROGEN TO SUPPORT A RENEWABLES-LED POWER SECTOR BEYOND 2030

A. Time Shifting Applications with Long Term Hydrogen Storage, e.g. in Salt Caverns

The following section explores the location and possibility of underground hydrogen storage in Pakistan, which include salt caverns and other, depleted gas reservoirs.

- Depleted gas reservoirs in Potohar region are the realistic potentials for low-cost, large-scale underground hydrogen storage.
- The Khewra salt plateau region in the province Punjab is another realistic, low-cost potential location for underground hydrogen storage.

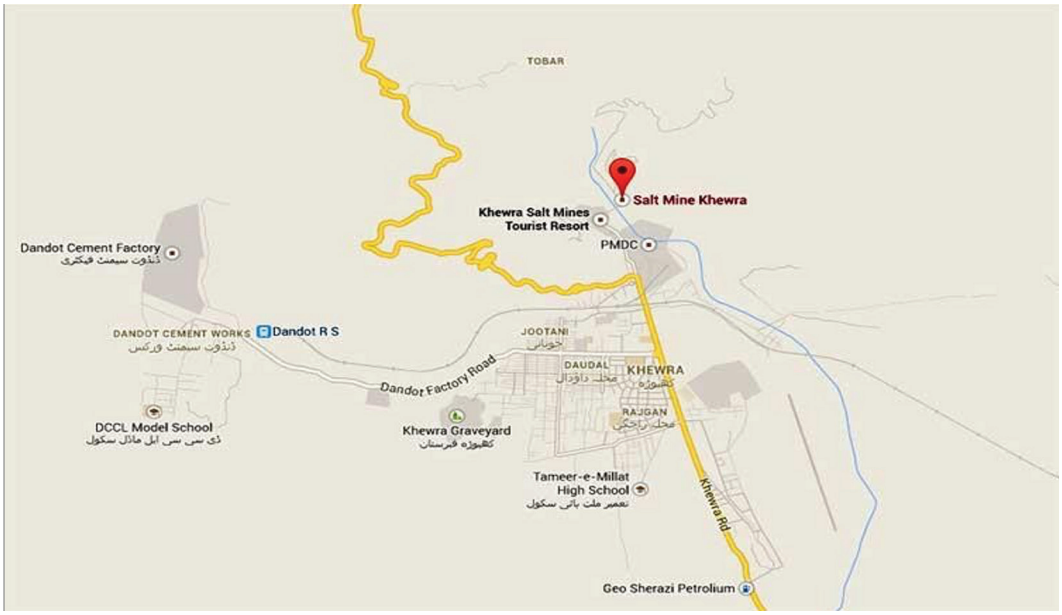
1. Salt Mines and Potential Future Salt Caverns for Underground Storage of Hydrogen

The presence of underground salt in Pakistan has been known for decades. Deep sub-surface mining has exploited this natural resource.

a. Khewra Salt Mines

Khewra Salt Mine is in Pind Dadan Khan Tehsil of Jhelum District. About 160 km (100 miles) from Islamabad and Lahore, it is accessed via the M-2 motorway, about 30 kilometers (20 miles) off the Lilla interchange while going towards Pind Dadan Khan on the Lilla road. The mine is in mountains that are part of a salt range, a mineral-rich mountain system extending about 200 km from the Jhelum river south of Pothohar Plateau to where the Jhelum river joins the Indus river. Khewra mine is about 288 meters (945 feet) above sea level and about 730 meters (2400 feet) into the mountain from the mine entrance. The underground mine covers an area of 110 km^2 (43 sq. miles).

Figure 45: *Khewra Salt Mine*



b. Warcha Salt Mines

Warcha is locate north East of Quaidabad in Khushab District. It is connected through Railway Line and Road via Quaidabad. The distance of Warcha from Quaidabad by road is 17.7 km and 13.6 km on railway line. Rails and road distance between Warcha and Lahore are 391 km and 288 km respectively. Warcha is a village and one of the 51 Union Councils (administrative subdivisions) of Khushab District in the Punjab Province of Pakistan. Warcha has salt mine. It is located 276km from Islamabad.

Figure 46: *Warcha Salt Mine*

c. Kalabagh Salt Mines

Kalabagh is a town and union council of Mianwali District in the Punjab province of Pakistan. It is part of Isakhel Tehsil. It is located on the western bank of the Indus River. It was the seat of the Nawab of Kalabagh. Kalabagh is known for its red hills of the salt range and the scenic view of the Indus traversing through the hills.

Figure 47: *Kalabagh Salt Mine*

d. Jatta / B.Khel Salt Mines

The Jatta /Bahadurkhel mine is a large salt mine located in the village Bahadur Khel, in the Khyber Pakhtunkhwa. Bahadurkhel represents one of the largest salt reserves in Pakistan having estimated reserves of 10.5 billion tonnes of Salt.[63]

Figure 48: *Jatta / B. Khel Salt Mine*

63. *Source: http://www.pmdc.gov.pk/ Date Taken 12, January,2021*

2. Underground Hydrogen Storage in Salt Caverns

The most cost-effective way to store large quantities of hydrogen is in underground salt caverns. This technology is common for the underground storage of natural gas. A salt cavern is created by drilling a well in the ground to the depth of the salt strata and then injecting water to dissolve the salt to make brine. The brine rises to the surface through the solution mining pipework and is either disposed of or processed to utilize the salt.

A salt cavern for underground gas storage will typically be 70m wide and 1000m high from a depth spanning 1000m to 2000m under the surface of the earth. It operates by cycling from a pressure of around 200 bar to 50 bar. As this pressure increases the amount of hydrogen in the cavern increases and vice versa. Many tons of hydrogen can be stored in a single cavern. Multiple salt caverns are used in proximity to achieve the desired storage capacity.

Utility scale underground hydrogen storage is being implemented with 100 caverns in Delta, USA to store hydrogen for power generation on modern gas turbines. In the UK, salt caverns are proposed for seasonal hydrogen storage to ensure there is sufficient heating capacity available to support the winter demand peak. The European Hydrogen Backbone, which is a proposed hydrogen transmission pipeline that will straddle the whole continent, also has plans to use underground hydrogen storage to buffer the capacity of the transmission grid.

The sub-surface geology in the area south of Islamabad and west of Lahore is believed to have ideal conditions for underground hydrogen storage. Data from many years of mining and oil and gas exploration in Pakistan has been gathered and analyzed to enable this conclusion. This location is close to the major hydro dams of Tarbela and Mangla and the major population centers between Lahore and Islamabad. There is a perfect combination of power generation for hydrogen production on electrolyzers, hydrogen storage potential and demand centers. A project was proposed for this study that would have investigated the financial viability of such a scheme, but it was not prioritized for detailed analysis.

A geological desk-study, commissioned for this report and conducted by Geostock, concluded that there is good potential in the Potwar Plateau at the top of the Anticlines. The positive attributesof this location are:

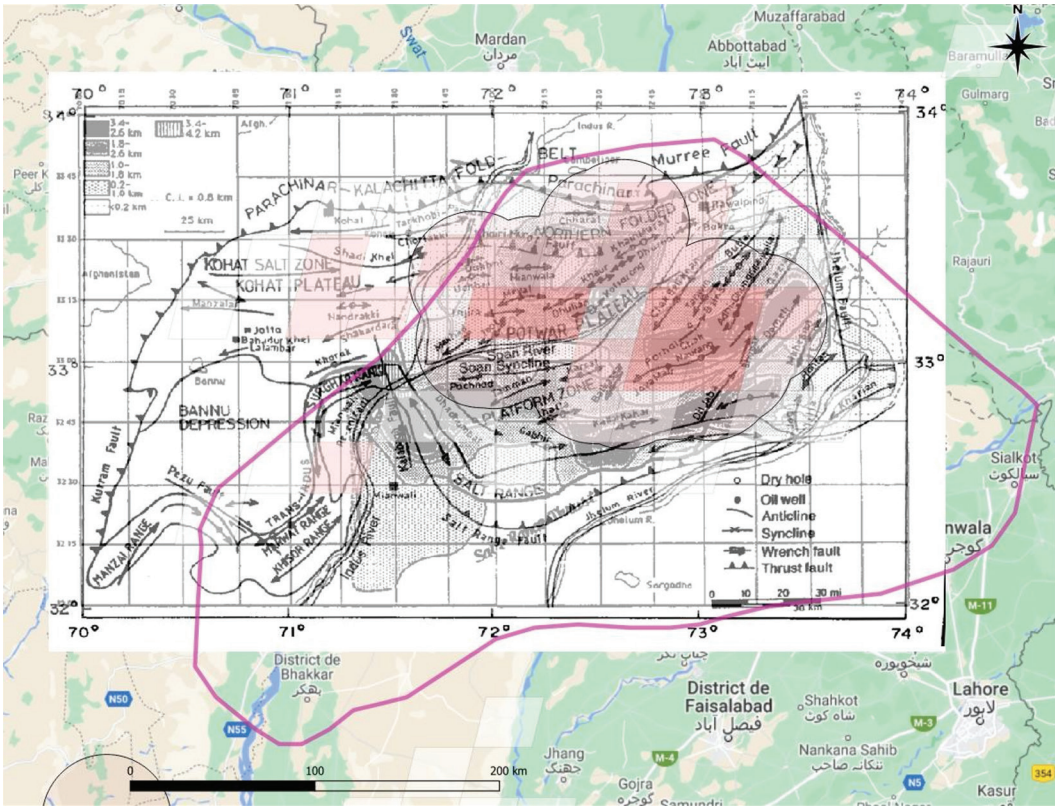
- Salt is thick (up to >3km)
- Salt is clean - 95% to 99%
- Potash might be present
- Folding and thrust in the internal part (Potwar plateau): anticlines are cored with salt formation
- Existing deep petroleum data: wells / seismic

The risks at this location are:

- Depth of the salt might be very deep >2000m
- High tecnical structuration (dome, decollement, thrusting)
- Borders of the area (less deep salt) are located on regional thrust belts, salt depth might be reduced to a thrust slice

Figure 49: *Coincidence of the High Potential Salt Formation, Hydro Dams and Major Population Centers in Northern Central Pakistan*

Figure 50: *Region of High Potential for Underground Hydrogen Storage in Salt Caverns, Geological Desk Study Conducted for This Report by Louis Londe, Geostock*



3. Depleted Natural Gas Reservoirs with Potential for Hydrogen Storage

Possible underground hydrogen storage (and / or permanent underground storage of CO_2 for CCS) exists in a number of partially depleted gas and oil reservoirs in the Potwar area i.e. Adhi, Dakhni, Ratana, Sadkal, Dhulian, Dhurnal, were considered and executed in initial screening process. Parameters used in the screening process included, reservoir type and location, compatibility of injected gas with the native gas, working storage capacity, estimated well deliverability, number of wells needed to meet peak day demand, and mechanical condition of wells. The partially depleted Sadkal Field appears to be a suitable candidate for the conversion to underground gas storage to meet storage need, while other candidate reservoirs were eliminated in the screening process. Due to deficiencies identified included reservoir type, compatibility of injected gas with the native gas, inconsistent working storage capacity was not consistent with the peak day demand, inadequate permeability to deliver gas at required rates without converting or drilling an excessive number of withdrawal wells. From a well deliverability perspective, Sadkal is next to the Dakhni reservoir in flow capability. With a permeability-thickness of some 24,000 MD-feet, a typical Sadkal well was estimated to have a wellhead Absolute Open Flow (AOF) of 70 MMSCF/D through 3½inch nominal tubing. The partitioned nature of the Margalla Hill Limestone has the added feature of being amenable to sequential development as the peaking need for underground gas storage increases into the more distant future. Therefore, only the Sadkal, Margalla Hill Limestone with a smaller IGIP and its partitioned nature has merit as a storage candidate.

Figure 51: *Adhi Oil & Gas Field*

Figure 52: *Sadkal Oil & Gas Field*

Figure 53: *Dakhni Gas Field*

Figure 54: *Dhurnal Oil Field*

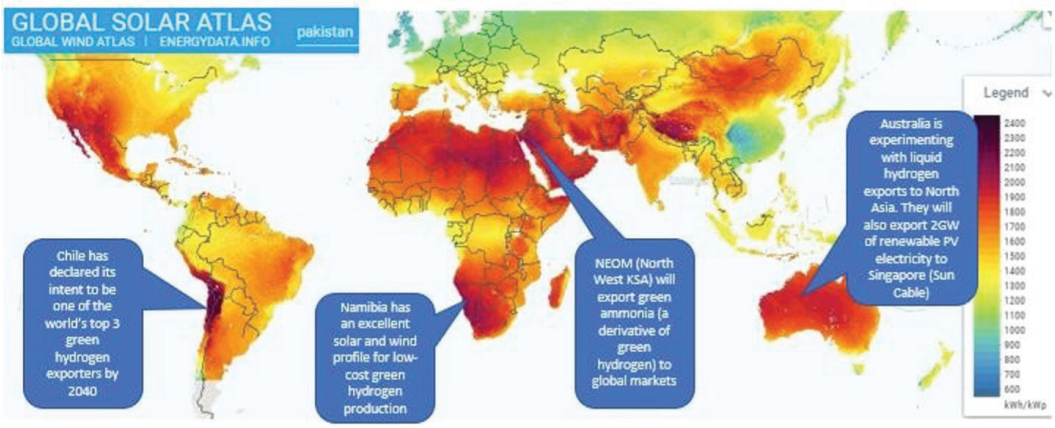
Figure 55: *Ratana Oil Field*

Figure 56: *Dhulian Oil and Gas Field*

IV. HORIZON 3 – HYDROGEN AS A POTENTIAL EXPORT PRODUCT FROM PAKISTAN BEYOND 2040

A. Global Renewable Hydrogen Producers and Exporters

Figure 57: *Global Solar Atlas*[64]



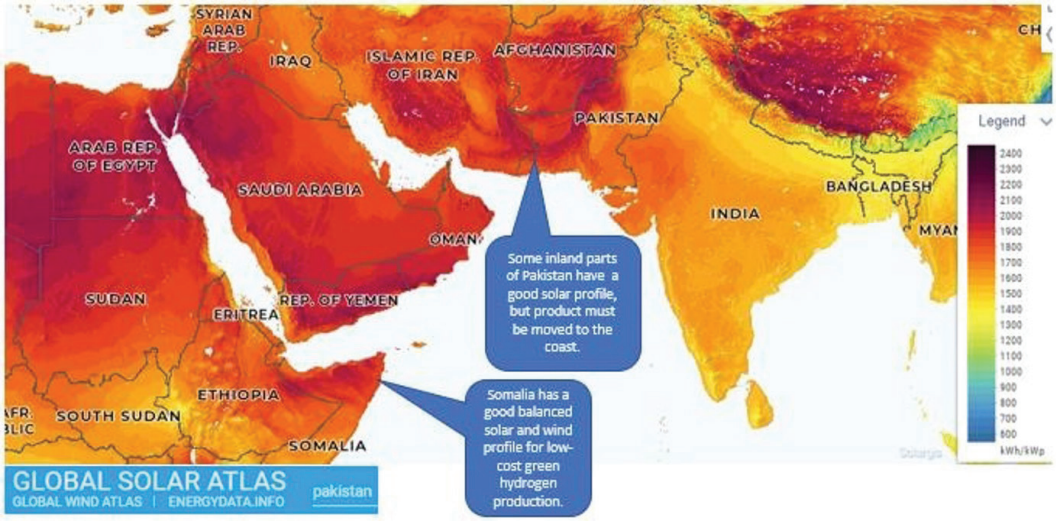
Green hydrogen exporters will most likely be countries close to large markets with low-costrenewable power (which would generally be located close to a seaport). For PV this would mean:

- Chile for North East Asia and USA
- North Africa and the Middle East for Europe
- Australia for South East Asia
- Namibia
- Saudi Arabia, Egypt, Somalia, Yemen, and Oman all have excellent PV intensity in locations close to the coast for export shipping
- Somalia also has excellent wind conditions to supplement the PV renewable power

Ideally, the daytime PV would be combined with nighttime wind, which especially favors Chile,Namibia, and Western Australia.

64. *https://energydata.info/*

Figure 58: *Global Solar Atlas*[65]



B. Regional Markets

The potential to export hydrogen will depend entirely on the landed cost of that hydrogen to the importer. This will be a combination of the cost of production and distribution.

At present, offshore wind and PV solar combined with electrolysis are the cheapest green hydrogen production routes. The technologies to produce renewable power in this way are internationally accessible – equipment pricing is broadly globally harmonized - any nation can access the same technology at a similar cost.

The cost drivers are therefore the PV solar efficiency, wind power availability and distribution costs. The distribution costs are a function of inland hydrogen distribution, overseas shipping costs and electrical power costs (power is required to compress or liquefy the hydrogen or convert it to ammonia). This power would, in effect, require excess renewable power generation.

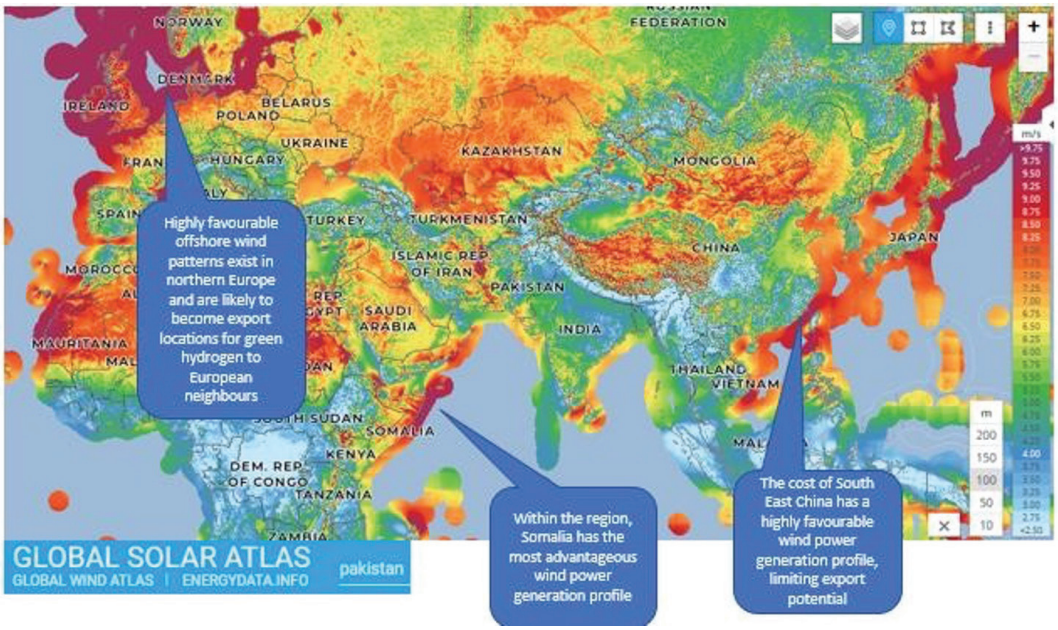
In some cases, e.g. North Africa or the Middle East to Europe, a hydrogen pipeline might substitute inland distribution and overseas shipping.

Pakistan might potentially serve export markets in South Central Asia with exports of green hydrogen produced from PV solar power, but these must compete with other potential regional exporters.

65. *https://energydata.info/*

C. The Realistic Potential for Hydrogen Exports from Pakistan is Limited

Figure 59: *Global Wind Atlas*[66]



Pakistan's renewable power profile, in comparison to these countries is unlikely to be the most cost-competitive source of green hydrogen.

Pakistan has some good potential onshore and offshore wind locations south and east of Karachi and in the desert areas in the west of the country. Whilst these locations have a good wind profile, they are only moderate when compared to the optimal locations such as Denmark, Sweden, The United Kingdom, The coast of Southeast China and the northeast Coast of Somalia.

From a globally competitive standpoint, it is unlikely that wind energy in Pakistan will be a major source of power for hydrogen exports.

Pakistan's solar intensity is good in some inland locations and the wind intensity is moderate in some inland and coastal locations – but these are poor when compared to the best global locations.

- The costs of producing green hydrogen from wind and solar in Pakistan are unlikely to be competitive with globally optimal locations such as Chile or Namibia
- The costs of producing green hydrogen from wind and solar in Pakistan are likely to be like other high-potential regional producers such as Saudi Arabia or Somalia

Pakistan's potential green hydrogen exports based on wind and solar schemes may be Ltd. due to the need to compete with likely global and regional leaders of wind and solar power generation.

66. *https://energydata.info/*

Pakistan is not located close to major potential hydrogen export markets such as Japan, South Korea, Taiwan, Europe, or North America so overseas shipping costs will be high, these must be offset by low hydrogen production costs and low inland power or hydrogen distribution costs.

The potential for low-cost hydrogen production from hydroelectricity exists in Pakistan, but PV and hydro in other countries will be compete.

- The costs of PV power are falling as utilization rates rise, CAPEX costs fall, and increasingly high solar intensity sites are being favored, so the advantage that Pakistan has with low-cost hydroelectric power will be eroded over time.
- The hydro schemes in Pakistan are far from seaports, through which exports must be channeled so inland hydrogen or electricity distribution costs will be high.
- The potential to re-use natural gas pipelines in the future as the energy transition takes hold may exist and this could reduce inland hydrogen distribution costs.
- China is the world's largest hydropower producer, and this will limit the potential for Pakistan to export green energy from hydro schemes to China, a major global energy importer.

V. BUSINESS MODELS AND VALUE CHAINS FOR THREE HIGH-POTENTIAL RENEWABLE HYDROGEN IMPLEMENTATION PROJECTS

The scope of this study was to propose many options for renewable hydrogen deployment in Pakistan with a diversity of power generation, geographical location, hydrogen storage, distribution and use cases. From this long list, 3 were to be selected for detailed analysis.

A. Evaluation Criteria to Select the Three High-potential Projects for Business Modelling

The scope of this study included selection of three high-potential renewable hydrogen deployment project options will be analyzed in detail using business models to understa23nd the economic feasibility and benefits of each project under current, or potential future regulatory and cost conditions. To prioritize the three most appropriate high-potential ideas for the deployment of renewable hydrogen in Pakistan the following points were considered as evaluation and ranking criteria:

- The required solutions for the current energy related issues in Pakistan. For example, the annual seasonal supply/demand gap, surplus renewable energy, the goal of energy self- sufficiency and the need to improve air quality for public health.
- Available natural resources, such as natural gas, hydro, wind, and solar energy.
- Compatibility with and leverage of existing infrastructure such as gas and power distribution grids.
- The high-level energy-efficiency of the proposed idea according to typical system energy losses and basic principles.
- Cost competitiveness, practicality and likelihood of public acceptance and societal change, when compared to alternative energy sources, for example fossil fuels.
- The contribution to Pakistan's CO_2 reduction and renewable energy deployment target which is to achieve 30% of energy derived from renewable sources by 2030.
- Alignment with current regulations and policies to enable rapid deployment of the pilots.
- Likely availability of funding and other resources for implementation.

B. Business Models and Detailed Scenario Analysis

The three projects for detailed financial analysis that NEECA requested, and ADB agreed to, are:

- Project #3 – hydrogen production from hydel on the Ghazi-Barotha dam and admixing into the natural gas grid for heating, cooking and CNG applications to incrementally decarbonize the gas pipeline network and CNG mobility
- Project #13 – hydro power micro-grid, hydrogen production storage and release to a fuel-cell for all-year-round power in remote locations (e.g Naltar valley in Gilgit-Baltistan)
- Project #6 – use DC solar power at the Quaid e Azam solar park to produce hydrogen for admixing into the natural gas grid for heating, cooking and CNG applications to incrementally decarbonize the gas pipeline network and CNG mobility.

Table 32: 13 Value Chains have been Proposed in Accordance to Top Three Priority Energy Challenges

#	Project	Location	Potential locations to replicate the scheme	Fit with top 3 energy priorities	Total potential impact estimate	Total potential impact (MW H_2 production)	Additional benefits	Suitability for pilot on 2 to 3 year timescale	Attractive ness on 10 to 15 year timescale
1	Large hydro dam to produce H_2 for transport in multiple cities in north	Mangla Dam, Azad Kashmir & northern cities	Multiple large dam schemes exist (eg Warsak, Ghazi-Barotha, Tarbela) with more in plan, in the north of Pakistan	Reduced crude oil imports	Circa 8GW of large dam hydro generation exists (total national potential estimated at 50GW) - of the current 8GW, circa 2GW could be converted to H_2	2,000	Emissions reduction in heavily major northern cities, decarbonizati on of transportation	High (if use only one city for H_2 mobility)	High
2	Small scale hydro power close to city to produce H_2 for mobility	Deg Outfall dam, Lahore, Punjab	Multiple run-of-the river schemes exist (e.g Taunsa barrage 100MW, close to Multan) with more in plan, generally in the north and center of Pakistan	Reduced crude oil imports	Circa 2GW of run- of-the-river and small dam hydro generation exists close to urban centers, circa 500MW could be converted to H_2	500	Emissions reduction in heavily polluted urban metropolis, decarbonizati on of transportation	High	High (Deg is small, but can replicate)
3	Use hydro power to produce hydrogen for gas grid admixing	Any hydro scheme closes to a gas pipeline	Multiple large dam and run-of-the river schemes, generally in the north and center of Pakistan	Reduced LNG imports	Circa 10GW of hydro generation exists (total national potential estimated at 50GW) - of the current 10GW, circa 2.5GW could be converted to H_2	2,500	Decarbonizati on of energy, leverage gas pipeline grid	High	High
4*	Mega-dam hydro power for H_2 pipeline to Lahore	Tarbela/ Mangla dams and Lahore, Punjab	Multiple large dam schemes in the north of Pakistan, eg Warsak and Ghazi-Barotha	Reduced LNG demand in major cities in the north of Pakistan	Circa 8GW of large dam hydro generation exists (total national potential estimated at 50GW) - of the current 8GW, circa 2GW could be converted to H_2	2,000	Decarbonizati on of industry, transportation and domestic applications, leverage gas pipeline grid	Low (must be a large project)	High

Table 32: 13 Value Chains have been Proposed in Accordance to Top Three Priority Energy Challenges									
#	Project	Location	Potential locations to replicate the scheme	Fit with top 3 energy priorities	Total potential impact estimate	Total potential impact (MW H_2 production)	Additional benefits	Suitability for pilot on 2 to 3 year timescale	Attractive ness on 10 to 15 year timescale
5*	Mega-dam hydro power for H_2 and salt caverns storage	Tarbela/ Mangla dams and Chakwal, Punjab	Multiple large dam schemes in the north of Pakistan, eg Warsak & Ghazi-Barotha. Salt caverns must be near Chakwal due to geology	Better energy supply / demand balance through year, Reduced LNG imports	Circa 8GW of large dam hydro generation exists (total national potential estimated at 50GW) - of the current 8GW, circa 2GW could be converted to H_2	2,000	Decarbonizati on of winter heating and power production, leverage gas pipeline grid	Low (must be a large project)	High
6	H_2 from solar power at Quaid e Azam for stable H_2 production	Bahawal pur, Punjab	Quaid e Azam is the only major solar scheme in Pakistan at present	Reduces imported LNG &reduces imported crude demand	Circa 600MW of solar power is in place with a total of 1GW in plan, circa 300MW could be converted to H_2	300	$_{H2}$ mobility on north / south route, decarbonize transportation, leverage gas pipeline grid	High	High
7	H_2 from solar power at Quaid e Azam for daily power balance	Bahawal pur, Punjab	Quaid e Azam is the only major solar scheme in Pakistan at present	Better energy supply / demand balance through each day: midday to evening	Circa 50MW of "excess" solar power may exist for conversion to H_2	50	H_2 mobility on north / south route, decarbonize transportation	Low (lots of energy conversions vs battery)	Low (economics likely to be poor vs battery)
8	Bagasse fired power to H_2 for ammonia production	Daharki, Sindh	There are about 20 bagasse-fired power stations in Pakistan, each with circa 20 to 30MW power	Reduces imported LNG demand	Total of circa 400MW, circa 30MW could be converted to H_2	30	Decarbonizati on of industry & agriculture	High	Medium (small scale, low utilization)
9	Solar power to H_2 for remote areas	Thar, Sindh	Mining locations & other provinces, remote villages in sunny locations (e.g., Balochistan)	Reduces imported crude demand	If we assume 20 schemes at 20 MW, this would be a total of 400MW for conversion to H_2	400+?	Emissions reduction in remote areas, decarbonizati on of industry	High	Medium (small scale, limited benefits)

Table 32: 13 Value Chains have been Proposed in Accordance to Top Three Priority Energy Challenges

#	Project	Location	Potential locations to replicate the scheme	Fit with top 3 energy priorities	Total potential impact estimate	Total potential impact (MW H_2 production)	Additional benefits	Suitability for pilot on 2 to 3 year timescale	Attractive ness on 10 to 15 year timescale
10	Wind power for H_2 to local use and LH_2 import/ export terminal	Jhimpir / Karachi, Sindh	Various schemes near Jhimpir are the main wind schemes in Pakistan at present, some additional offshore schemes near Karachi are also in plan	Reduces imported LNG demand, better energy supply / demand balance	Circa 1.5 GW of wind power is in place with more in plan, circa 500MW could be converted to H_2	500	Enables LH_2 exports, decarbonizati on of energy, leverage gas pipeline grid & gas power plants	Medium (complex, mid-scale project)	Medium (energy conversion s)
11	Off-peak surplus power from the Orange Line Metro system for H_2	Lahore, Punjab	Other underutilized dedicated power supply sub- stations that have a variable demand profile	Reduces imported crude demand, reduces imported LNG demand	If we assume 10 national schemes at 20MW, this would be a total of 200MW for conversion to H_2	200+?	Emissions reduction in heavily polluted urban metropolis, decarbonizati on of transportation & heat	High	Medium (Multiple small schemes)
12	Off-peak surplus heat and power from a potential geothermal plant	Karachi, Sindh	A study has shown multiple locations near Karachi and a few other locations in Pakistan are suitable	Reduces imported crude demand, reduces imported LNG demand	If we assume 10 national schemes at 20MW, this would be a total of 200MW for conversion to H_2	200+?	Emissions reduction in heavily polluted urban metropolis, decarbonizati on of transportation & heat	Low (geothermal plants do not yet exist)	Medium (good fit with H_2 but small schemes)
13	Micro-hydro power for micro-grids in northern Pakistan	Naltar valley, Gilgit Baltisan	Many remote mountain villages (eg, Budalas, Singul or Chalat) in northern Pakistan close to rivers	Security of power supply through the year, reduces imported LPGdemand (current alternative), affordable energy for a low-income region	If we assume 1,000 villages each with a 0.2 MW electrolyzer (or 200 villages with a 1MW electrolyzer)	200+?	Carbon- neutral, pollution free energy in the north	High	High (good fit with H_2, high social and economic impact

C. High Potential Project #3: Ghazi Barotha

This project would use hydroelectric power from the Ghazi Barotha dam to produce hydrogen for admixing into the natural gas grid for heating, cooking and CNG applications to incrementally decarbonize the gas pipeline network and CNG mobility. An Alkaline Electrolyte Cell (AEC) electrolyzer would be installed close to the existing Ghazi-Barotha run-of-the-river dam in Khyber Pakhtunkhwa to generate hydrogen. Some parameters of the project are summarized below:

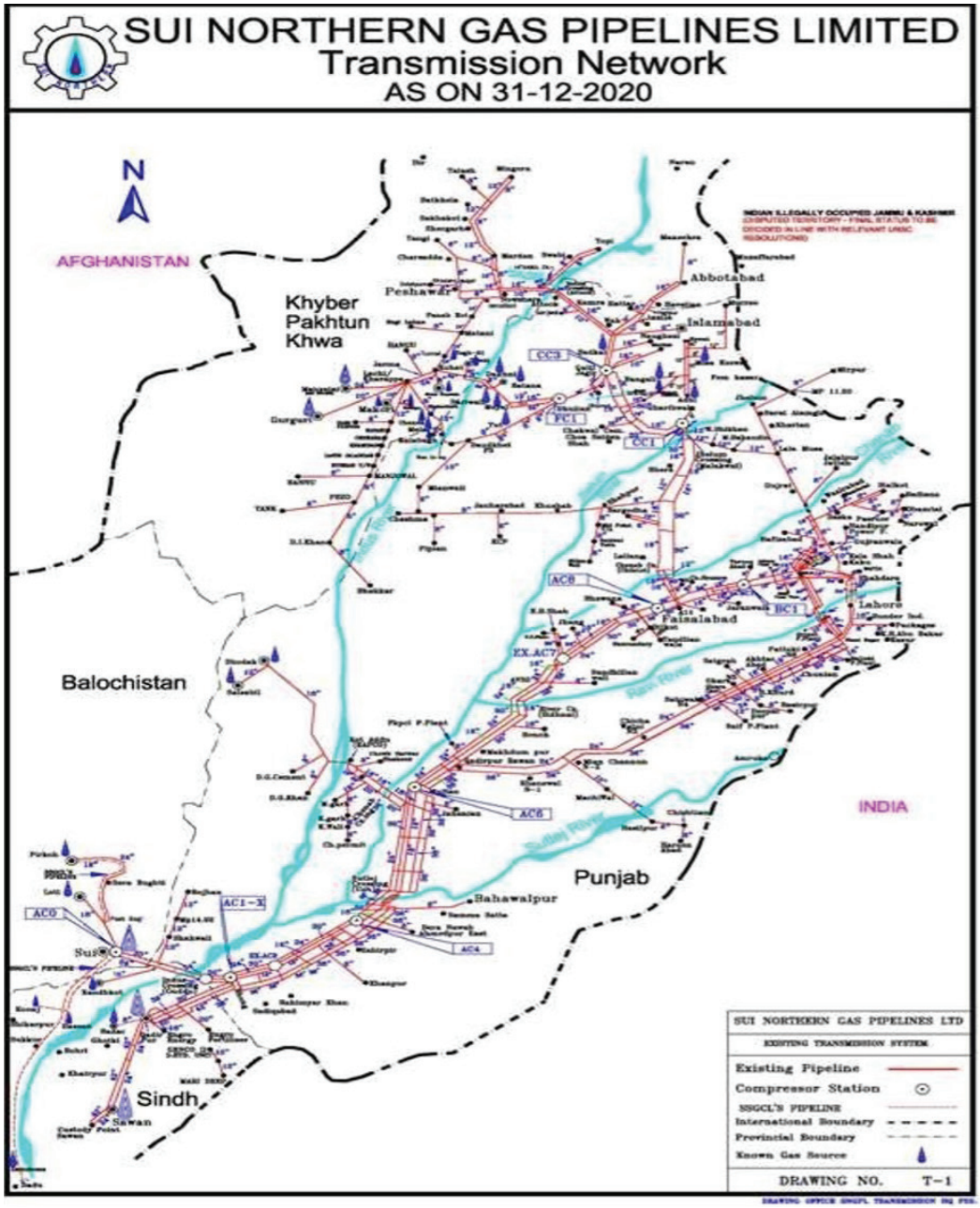
- AEC electrolyzer are the lowest CAPEX technology and can have a high efficiency (power to hydrogen)
- This AEC technology prefers constant electrical input and is ideally matched to combination with stable hydro-power production
- An electrolyzer of circa 100MW (circa 15,000 tonnes per year hydrogen) capacity can be modelled – this is a commercially available size
- An upgrade to the electrical power output of the hydro scheme (an additional 1GW with new powerhouse, dam and canal) will also be proposed to minimize the loss of power to the local electricity grid
- Feed the hydrogen into an existing natural gas pipeline running close to the scheme
- Subject to a safety review, the hydrogen could potentially be "ad-mixed" with natural gas in the existing natural gas pipeline (at circa 2% to 6% by volume)
- The hydrogen / methane mixture can be used for heating or transportation applications to boost domestic energy gases production and reduce LNG imports

According to international research hydrogen can be admixed into many existing natural gas pipeline transmission and distribution systems. Concentrations of 2 to 6% by volume (even up to 10%) are generally possible with few modifications to the gas distribution network and utilization equipment. For admixing to be implemented in Pakistan, a safety assessment must be conducted as part of a future feasibility study.

1. Gas Transmission Pipelines Close to the Location where Hydrogen would be Produced

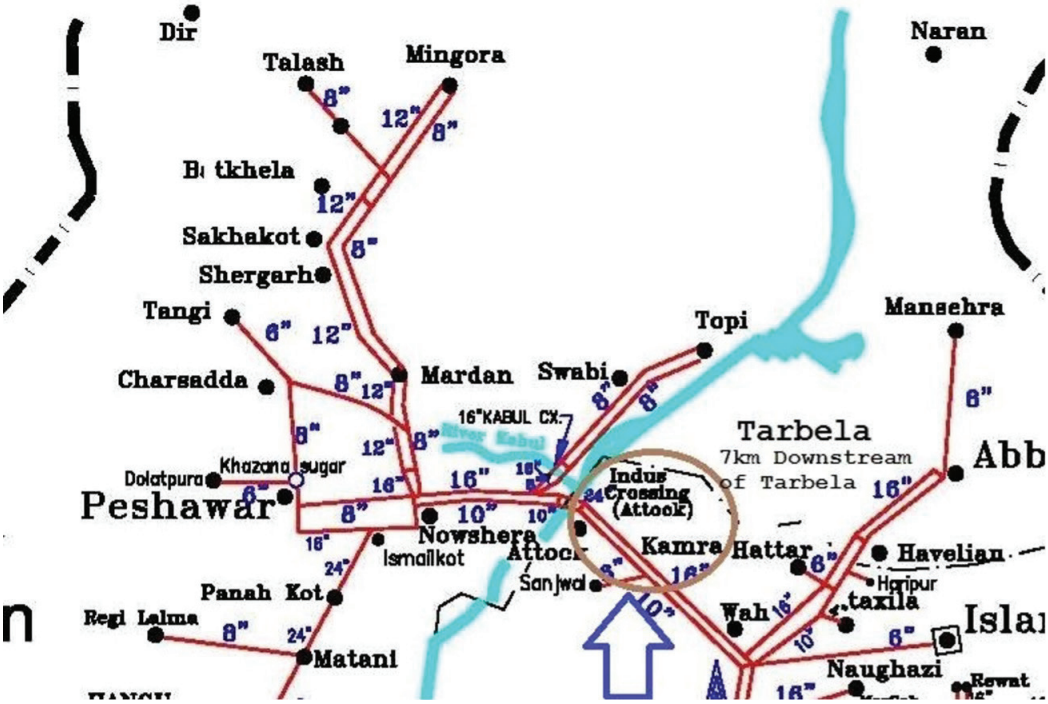
The use case for this project was hydrogen admixing into the natural gas grid. The gas transmission pipeline flows from east to west about 15 km to the north of the dam. The official map of main gas transmission pipelines passing through of Ghazi Barotha showing exact route. The transmission line is passing through main GT Road whereas, the hydro power plant is almost 7Km downstream of main Tarbela dam. The distance between the power plant and a suitable tie in point to the existing natural gas transmission line is between 10 and 15 Km.

Figure 60: *Transmission Gas Pipeline*



Note: ADB and the authors of this report recognize that the area of Jammu and Kashmir is disputed territory and the final status will be decided in line with relevant UNSC resolutions.

Figure 61: *Transmission Gas Pipeline Passing through Ghazi-Barotha near G.T Road*



The run-of-river Ghazi Barotha Hydroelectric project is located around 100km from Islamabad, on the Indus River in North West Pakistan. It involved the construction of a partial river diversion at Ghazi, 7km downstream from the Tarbela dam as shown in map above with circle.

The barrage diverts water into a 52km concrete-lined channel and delivers it to the 1,450MW powerhouse at Barotha. This is further downstream, near the confluence of the Indus and Haro rivers. In this reach, the Indus River drops by a height of 76m over 63km. After passing through the powerhouse, diverted water is returned to the Indus. In addition to these main works, power transmission lines stretch 340km.

a. Sui Northern Gas Pipeline Ltd. (SNGPL) Transmission System

The proposed scheme would add mix hydrogen to the SNGPL natural gas pipeline network at a location several km north of the dam.

Table 33: Punjab Province – Gas Received

Gas Source/Field	GCV (BTU/SCF)	Volume (MMCF)	Volume (MMCFD)
Dhodak	1151	62	2
Salsabil + Chiltan	998	124	4
Meyal Plant (Par + Dhul + Mey + Jand + Rat)	1072	191	6
Dakhni + Soghri	1076	559	18
Adhi	1076	1596	51
Kalabagh	1122	93	3
Sadkal	1177	31	1
Ratana	1131	62	2
Pindori + Turkwaal	1167	34	1.1

SNGPL transmission system extends from Sui in Baluchistan to Peshawar in Khyber Pakhtunkhwa comprising over 9,143.75 KM of transmission system (Main lines & Loop lines). The distribution activities covering 4,967 main towns along with adjoining villages in Punjab & Khyber Pakhtunkhwa are organized through 16 regional offices. Distribution system consists of 135,857 KM of pipeline. SNGPL has over 6.8 million consumers comprising Commercial, Domestic, General Industry, Fertilizer Power and Cement Sectors. Annual gas sales to the consumers were 623,724 MMCF during the period from Jul 2019 - Jun 2020.

At present construction activities of 42” diameter 21.85 Km loop lines are underway. The project is the first of its kind in Pakistan as it is the first time; a 42” diameter pipeline is being added in SNGPL’s network. Work on 24” diameter 54.50 Km Kohat-Dakhni and 24” diameter 50.41 Km Dhullian-Gali Jagir line is in progress. It is part of infrastructure development project comprising 145 Km of 24” diameter and 38 Km of 10” diameter natural gas transmission lines to absorb additional gas available from northern sources in Khyber Pakhtunkhwa and to make the system flexible.

With the planned receipt of additional 1200 MMCFD RLNG into SNGPL’s transmission system due to shortfall of indigenous gas supplies, SNGPL had managed to secure the completion of magnanimous pipeline infrastructure project involving approximately 1100 Kms pipelines of diameter 42” - 16” along with installation of 35000 HP compressions. This is the largest ever- completed project in the history of Pakistani gas market so far. With the energization of LNG terminals in the country and after completion of RLNG transport infrastructure & pipelines, RLNG is being supplied to all categories of consumers including Industrial, Power, cement, CNG, Commercial and Domestic throughout the year.

b. Natural Gas Pipelines – Technical Overview

Natural gas is moved through pipelines by a series of compressors creating pressure differentials, the gas flows from an area of high pressure to an area of relatively lower pressure. Compressors are powered by electric or natural gas fired engines that compress or squeeze incoming gas and push it out at a higher pressure. As one would expect compressor stations for large transmission lines are much bigger than the compressors used to move the gas through the small distribution lines to domestic users. Some gathering systems do not need compressors because the pressure of the gas coming out of the wells is enough to move the gas through the gathering lines.

Natural gas is compressed in transmission pipelines to pressures typically ranging from 500 to 1400 pounds of pressure per square inch. Compressor stations on transmission pipelines are generally built every 50 to 100 miles along the length of a transmission pipeline, allowing pressure to be increased as needed to keep the gas moving.

Some gas transmission pipelines are bi-directional meaning gas can be coming from both ends of the pipeline and depending on where gas is removed and where the compressors create the pressure differential, gas may flow either direction. These bi-directional pipelines boast of greater flexibility in both supply and price to customers. Many gas transmission pipelines are “looped,” which just means there are two or more pipelines running in parallel to each other normally in the same right of way.

Looping provides increased storage of gas in the system to meet demands during peak use periods. Gas pipeline operators monitor for any problems and handle the flow of gas through the pipeline using a Supervisory Control and Data Acquisition system (SCADA). A SCADA is a pipeline computer system designed to gather information such as flow rate through the pipeline, operational status, pressure, and temperature readings. This information allows pipeline operators to know what is happening along the pipeline and allows quicker reactions for normal operations and to equipment malfunctions and releases.

c. Materials Used for Natural Gas Pipelines

Materials used for transmission and gathering pipelines are made of high carbon steel. Generally, between 40 and 80 feet in length, they are designed specifically for their intended location in the pipeline. A variety of soil conditions and geographic or population characteristics of the route dictate different requirements for pipe size, strength, and wall thickness. Distribution pipelines may also be made of steel, but increasingly high strength plastic or composites are being used now days. Older distribution pipelines were frequently made of cast iron. Cast iron gets brittle with age and can be susceptible to fractures when subjected to ground movement from freeze/thaw cycles or other causes.

Pipe Coatings Several different types of coatings may be used to protect the exterior of steel pipe from corrosion. The most common coatings are fusion bonded epoxy or polyethylene heat-shrink sleeves. Many coatings are now installed in the factory, but field coating application is still required in these instances in the areas where the pipes are welded together.

At some access points close to Ghazi-Barotha, the pipeline run under ground. However, at some places there are sections, which are over the ground.

2. The Ghazi Barotha Hydro-Power Project Overview

Ghazi Barotha Hydropower Project is located on the Indus River downstream of Tarbela Dam. The Project utilizes the hydraulic head available between the tailrace at Tarbela Dam and the confluence of the Indus and Haro Rivers for power generation. In this reach, Indus River drops by 76 m over a distance of 63 km. This Project possesses the minimum of environmental and social impacts.

Ghazi Barotha Hydropower Project consists of three main components Barrage, Power Channel and Power Complex. The Project utilizes the normal Tarbela Dam releases to provide year-round maximum power generation during the daily hours of peak demand, including the months of May and June when reservoirs of Mangla and Tarbela Dams are historically at their lowest. This enhances the capacity of the whole power system by providing much needed relief in the form of cheap hydel energy.

Water from the Indus is directed to the turbines via a 52km-long canal and five pressure pipelines, each measuring 10.6m in diameter. The head of water at the power station is 69m. The flow rate through each turbine at rated power is 485m^3/s, with each turbine runner having a diameter of 6.5m. Voith delivered and assembled five 295MW Francis turbines, to operate the power station. Water A Japanese company supplied the generators. Austrian VA Tech Voest obtained an order for penstocks.

a. Original Motivation for Ghazi Barotha - Seasonal Power Output

The primary purpose of the project was to provide constant peak power at times when Tarbela is generating low. Furthermore, the sole purpose of Tarbela Dam is to provide water for irrigation. At times when irrigation requirement is low, water flow through the channel is low and so is the power generation. It is also possible to have no power generation from Tarbela.

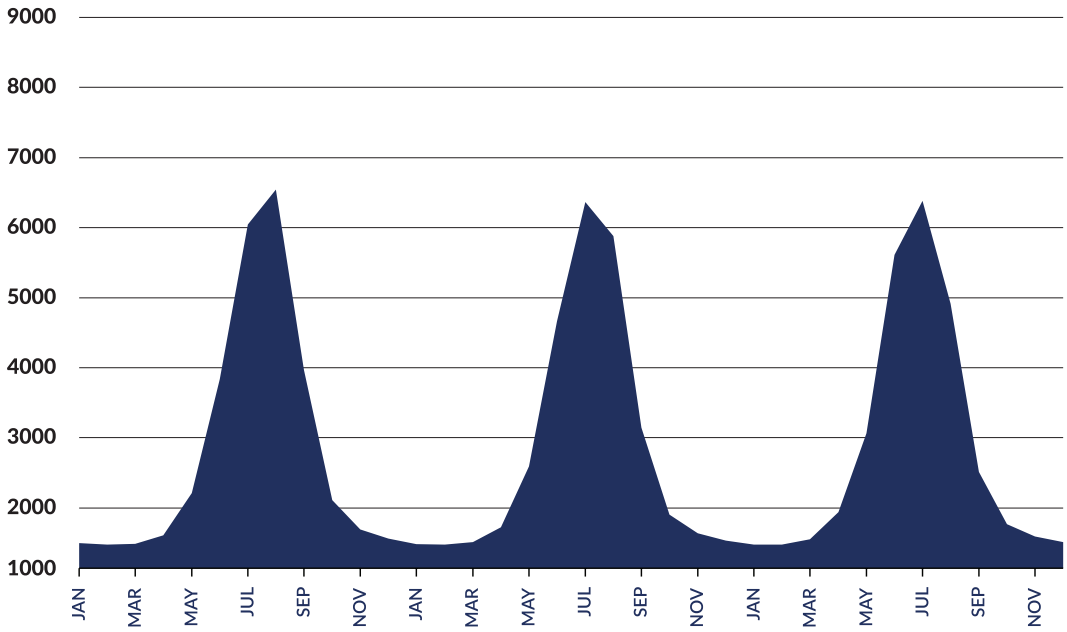
During the months from April to June when there is reduced generation of power from Tarbela and Mangla because of low reservoir levels. This brings the most outstanding feature of this project that it provides power peaking capacity throughout the year with full power generation. For hydrogen production 100 to 200 MW can easily be taken throughout the year from Ghazi-Barotha dam.

b. The Ghazi Barotha Barrage

The Barrage located 7 km downstream of Tarbela Dam, provides a pond, which re-regulates the daily discharge from Tarbela by diverting the flow into the Power Channel. The principal features include 20 No. standard bays, 8 No. under sluices and 8 No. head regulator bays in addition to rim embankments, fuse plug and dividing island.

The Barrage can pass the design flood of 18,700 cumecs, equivalent to the flood of record, through the standard bays and under sluices at the normal pond level of El. 340 m. The fuse plug has been provided to pass the extreme flood up to the capacity of Tarbela's spillway and tunnels equaling 46,200 cumecs.

Figure 62: *Tarbela Flow*



c. The Power Channel

Ghazi Barotha Hydropower Project holds the record for the biggest concrete lined channel in the world. The channel is 51.90 km long with a concrete lining and design flow of up to 1600 cubic meters per second (cumecs) at a water depth of 9 m. It has a bottom width of 58.4 m.

The Power Channel has a contour alignment with hills on the left side and the land naturally draining towards the Indus River on the right side. The Power Channel intercepts fifty-three nullahs (natural drains) of which twenty-seven major nullahs have been passed over the Power Channel by providing super-passages. The remaining twenty-four minor nullahs are being discharged into the Power Channel through individual inlets whilst one nullah is passing underneath the channel through a culvert.

In addition to the thirty-four road bridges, including bridges for both Islamabad-Peshawar Motorway and the G.T road, there are 12 pedestrian crossings over the Power Channel. The main railway line joining Rawalpindi to Peshawar also crosses the power channel and required the construction of the second longest single span railway bridge in Pakistan. This may be the last riveted bridge of its type, constructed in Pakistan.

d. The Power Complex

The Power Complex having two head-ponds with a combined live storage capacity of approximately 25.5 million cubic meter is sufficient for the daily requirement of 4 hours peak generation. This means that in May and June when there is reduced generation from Tarbela and Mangla power houses, due to low reservoir levels, Ghazi Barotha Hydropower Project provides peak production of 1450 MW.

The five generating units in the Powerhouse are each fed by a 10.6 m diameter steel lined penstock. Each of the five 290 MW Turbo Generators can take a peak flow of 460 cumecs. Power Complex has been provided with a self-priming siphon spillway of 1600

cumecs capacity, having energy dissipation in a stilling basin and a baffle chute. The power transmission is through 500 KV double circuit lines to WAPDA's national grid system.

e. Mechanical and Electrical Equipment

The installed power generating capacity is 1450 MW consisting of five units each of 290 MW. The units have a design flow of 400 cumecs at optimum gate opening and 460 cumecs at full gate opening for a design head of 69 m.

The principal items of power equipment are as follows:

- Five Francis turbines each with a 290 MW generator which together have a combined power generating efficiency of 94%
- Five three-phase banks of transformers, each single-phase unit being 107.5 MVA
- 500 KV conventional outdoor switchgear configured in one-and-a-half breaker arrangement
- 12 cranes with lifting capacities from 6 to 450 tons

Table 34: Power Complex Data	
Head-Ponds and Forebay	
Normal pond level	334m
Live volume	25.5 mm^3
Siphon spillway	
Discharge capacity	1600 cumecs
Crest level	334.5m
Intake	
No. of opening	10
Crest level	305.5
South Sill	
No. of openings	3
Sill level	323 m
North Sill	
No. of openings	10
Sill level	321 m

Table 35: Barrage Data	
Normal Pond level	340.0 m
Design Flood	18,700 cumecs
Survival flood	46,200 cumecs
Embankments	
Fuseplug, Rim and Dividing Island	
Standard Bays	
No. of openings	20
Crest level	332.2m
Head Regulator	
No. of opening	8
Crest level	333.0m
Under sluices	
No. of opening	8
Crest level	326.0m

Table 36: Power Channel Data	
Design flow	1,600 cumecs
Length	51,906 m
Full supply depth	9 m
Bed width	58.4 m
Side slope	IV: 2H
Lining thickness	135 mm

Table 37: Structures Data	
Road bridges	34
Railway bridge	1
Pedestrian Crossings	12
Super passages	27
Drainage Inlets	24
Escapes	5
Culverts	1
Road bridges	34

Table 38: Hydro Mechanical Equipment Data	
Penstocks	
No.	5
Diameter	10.6 m
Length	222 m
Turbine	
Type	Francis
Number	5
Full Gate output	295 MW
Generator/Transformers	
Number	5
Continuous Rated output	3x107.5 MVA
Rated Voltage HV:LV	515 \/ 3:18 KV
Switchyard	
No. of 500 KV Bays	6
Scheme of Layout	Breaker & Half Scheme

Table 39: Switchyard	
Number of 500 KV Bays	6
Scheme of Layout	Breaker and Half Scheme
Bay Width	32 m
Rated Voltage	550 kV
Rated Lightning Impulse Withstand Voltage	1,550 kV (peak)
Rated Switching Impulse Volt to Earth	1,175 kV (peak)
Rated P Frequency Withstand Volt to Earth	620 kV
Busbars Rated Current	3,150 A
Bay and/or Circuit Connection Rated Current	2000 A

Table 40: Generator Transformers	
Continuous Rated Output	3 x 107.5 mega volt-ampere
Winding Rated 1 Minute Power Frequency Withstand Voltage	
High-Voltage Line Terminal	630 kV
Low-Voltage Terminals	50 kV
Winding Rated Lightning Impulse Withstand Voltage	
High-Voltage Line Terminal	1,425 kV (peak)
Low-Voltage Terminals	125 kV (peak)
Winding Rated Switching Impulse Withstand Voltage of High-Voltage Terminal	1,180 kV (peak)

Table 41: Unit Transformers	
Rated Power	4,000 kilovolt-ampere
Rated Voltage	HV: LV 18:11 kV

Table 42: Generator Isolated Phase Bus	
Rated Voltage	18 kV
Rated Current	12 KA
Short Circuit Current Rating	237 KA
Power Frequency Withstand Voltage	50 kV
Switching Impulse Withstand Voltage	125 kV (peak)

Table 43: Medium Voltage Switchgear	
Rated Voltage	12 kV
Rated Current	1,250 A
One Minute Power Frequency Withstand Voltage of Circuit Breakers	36 kV
Rated Lightning Impulse Withstand Voltage of Circuit Breakers	95 kV (peak)

Table 44: Low-Voltage Switchgear	
Rated Operational Voltage	400/230 V
Rated Insulation Voltage	1,000/600 V
Busbar Ratings	4,000/3,000 and 1,000/630 A

Table 45: 500 KV Circuit Breakers	
Rated Voltage	550 kV
Rated Current	4,000 A
Rated Short Circuit Breaking Current	50 KA
Rated Short Circuit Making Current	125 KA
Rated Duration of Short Circuit	3 Second

Table 46: Generator Circuit Breakers	
Rated Voltage	24 kV
Rated Current	12 KA
Rated Breaking Current	100 KA
Rated Making Current	300 KA

Table 47: 11.3 500 KV Disconnectors	
Rated Voltage	550 kV
Rated Current	3,150 A
Rated Short Time Withstand Current	40 KA

Figure 63: *Ghazi Barotha Hydropower Project*

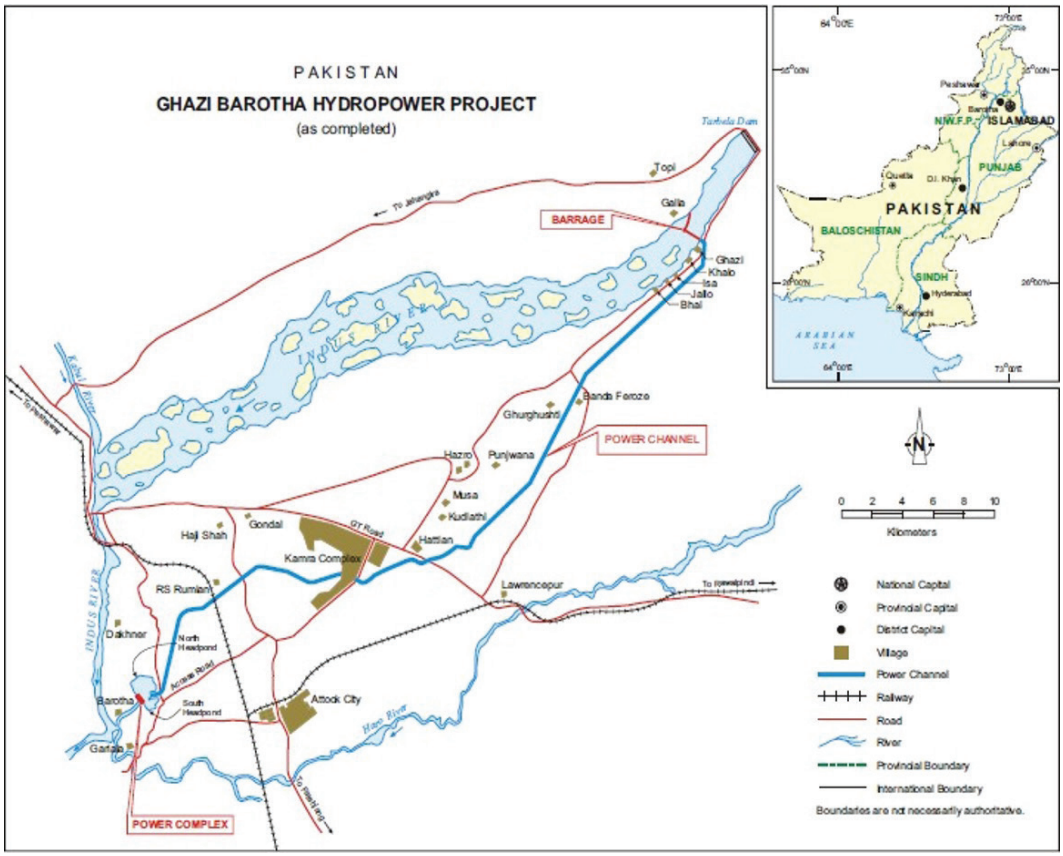


Figure 64: *Ghazi Barotha Hydropower Project - Barrage Layout*

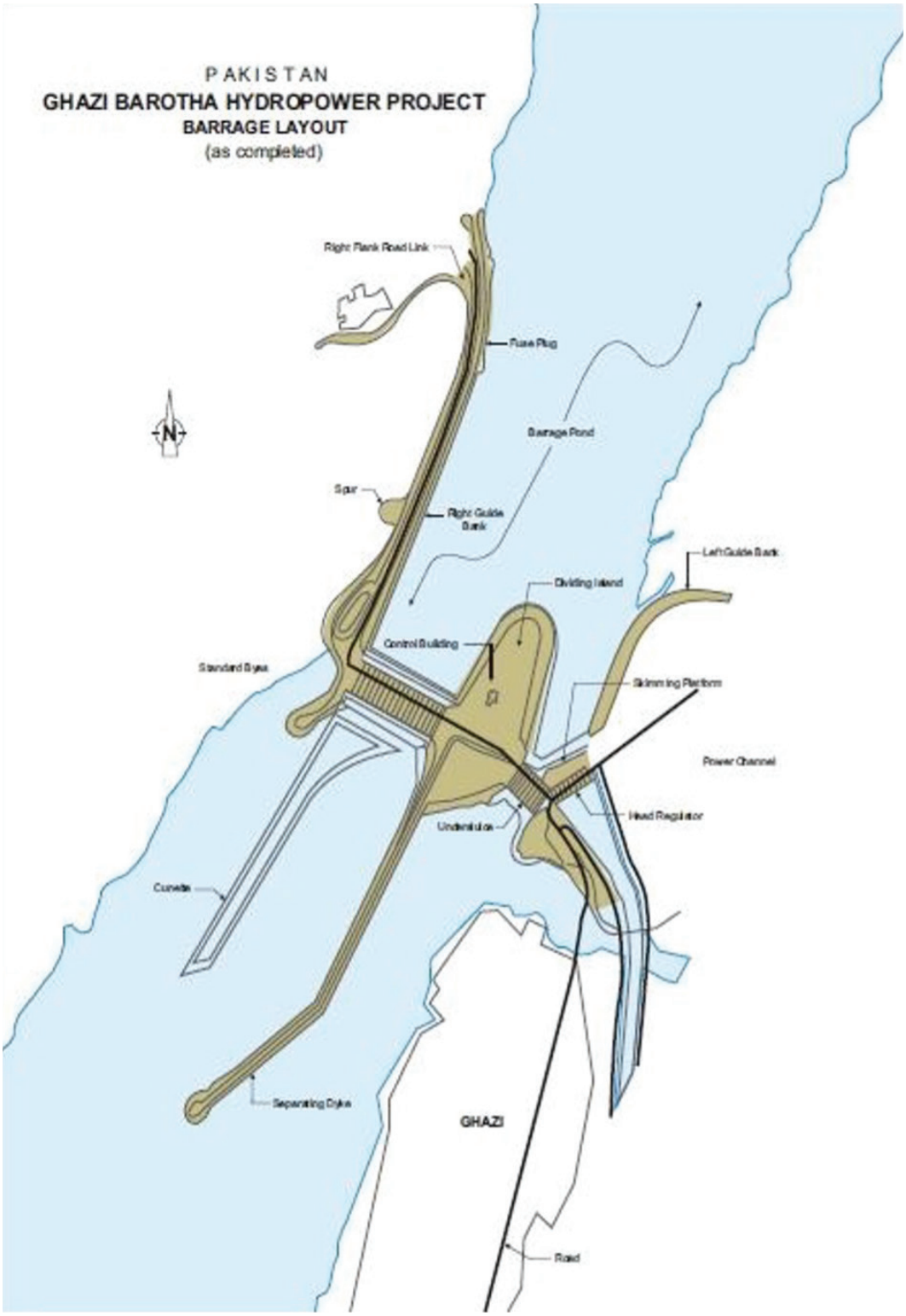


Figure 65: *Ghazi Barotha Hydropower Project Power - Complex Layout*

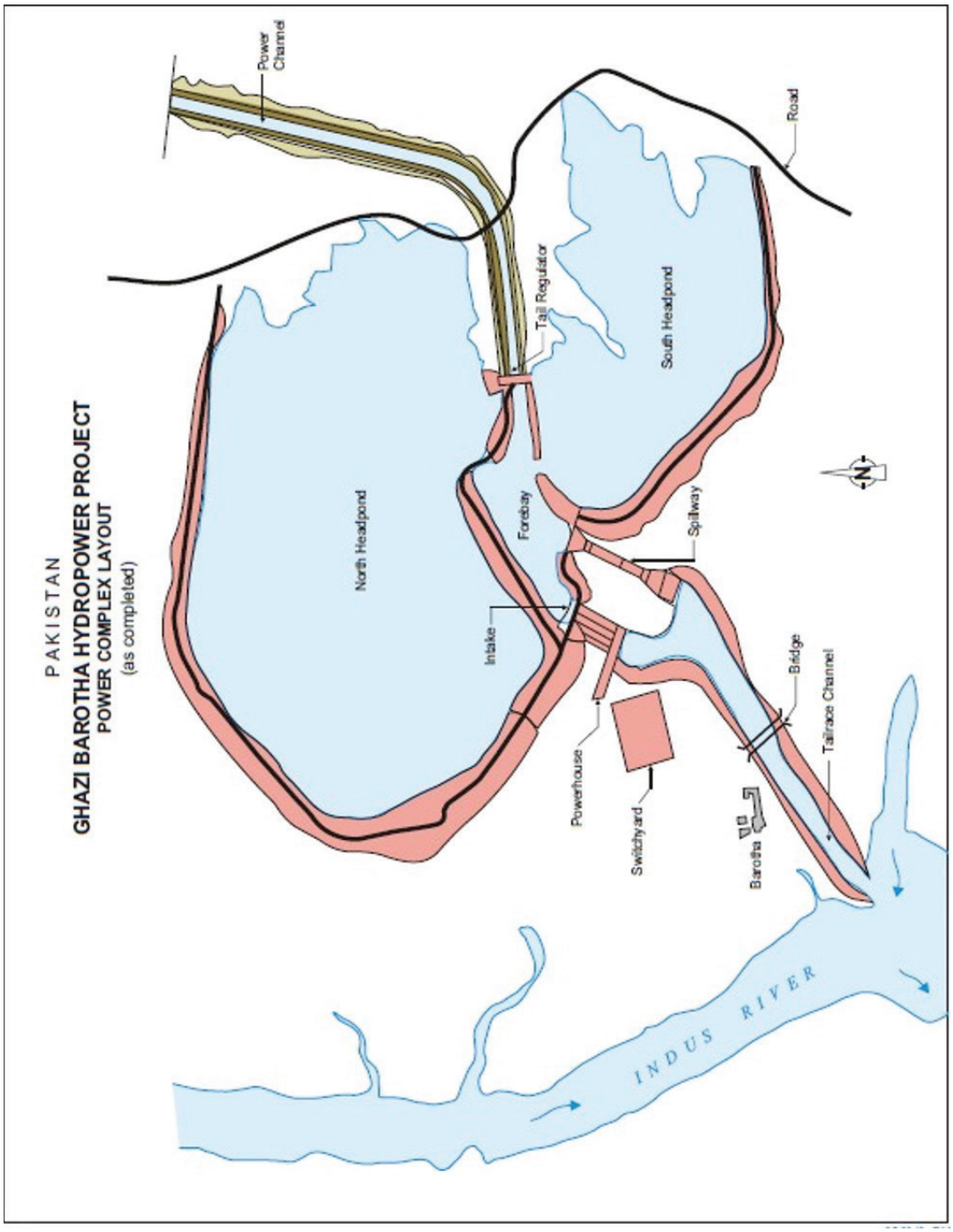
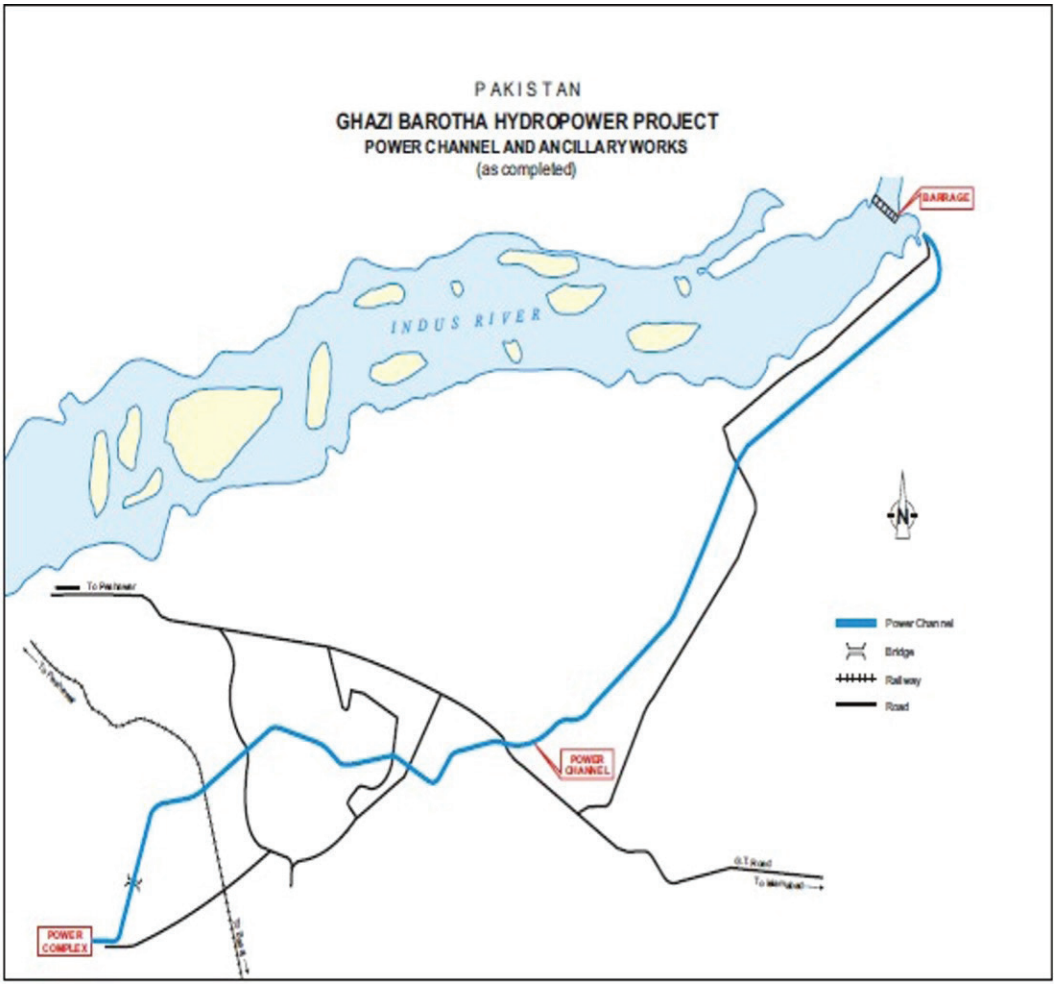


Figure 66: *Ghazi Barotha Hydropower Project Power - Power Channel and Ancillary Works*



f. Power Transmission from the Dam

Power transmission from the scheme has been developed over time.

Table 48: Transmission Network (km)

Year	Transmission Network (km)	% Increase Over Previous Year	% Age Increase
2010	7,585	3.24	109.88
2011	7,613	0.37	110.65
2012	7,654	0.54	111.79
2013	7,654	0.00	111.79
2014	7,733	1.03	113.97
2015	7,796	0.81	115.72
2016	7,941	1.86	119.73
2017	8,547	7.63	136.5
2018	8,876	3.85	145.6
2019	8,917	0.46	146.73
2020	9,106	2.12	151.96

Figure 67: Transmission Network (KMs)

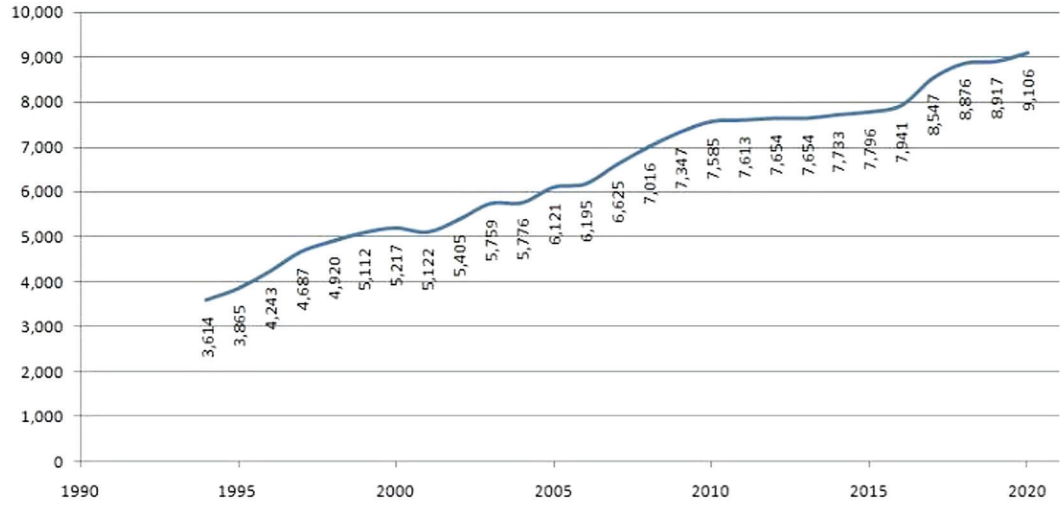


Table 49: Location and Length of Transmission Lines as on 31.12.2020

Section	Diameter in Inches	Mainline (Km)	Loopline (Km)
Hattar-Haripur	10	18.12	-
Hattar Offtake	6	0.39	-
Haripur-Mansehra	8	70.53	-
Haripur Offtake	8	1.53	-
Wah-Nowshera (1)	10	25.13	-
Wah-Nowshera (2)	16	-	23.68
Wah- Hattar	16	-	13.62

3. Costing Model for the Ghazi Barotha Hydrogen Scheme

a. Design Basis Phase 1

The base case for the canal-fed hydropower system is the 100 MW power from the existing Ghazi Barotha hydroelectric scheme operating for 10 months of the year.

- Continuous operation of the electrolyzer at peak load conditions are assumed during these 10 months of operation
- Assumed that for 2 months of the year in late winter / early spring there is still sufficient water and therefore sufficient power generation to produce hydrogen
- Assumed that the system will be shut down for maintenance 2 months of the year in summer when the demand of gas for heating is lowest
- Electrolyzer will be installed on spare land at the existing transmission hub on the western bank of the river

b. Design Basis Phase 2 - Second Canal and New Reservoir / Dam / Powerhouse

1GW additional hydropower from new canal, dam, and powerhouse with hydro turbines, dedicated to 1GW new electrolyzer

- Operational for 10 months of the year, not operational in the late winter / early spring dry season due to inadequate water flow for 1GW hydropower generation.

Table 50: Ghazi Barotha Project - Costing Assumptions as Inputs to the Financial Model		
Hydro (10 months / year) ===>	100MW electrolyzer from existing Ghazi Barotha dam (USD)	New canal, power house & electrolyzer to add 1GW power output (USD)
Second canal, reservoir, dam, 1GW power house, turbines (phase 2 option only)		$ 2 500 000 000
1GW electrolyzer hooked up to new Ghazi Barotha 2 power houses (phase 2 option only)		$ 1 000 000 000
Installed electrolyzer cost - 100MW McPhy AEC, phase 1	$ 80 000 000	
Import duties / tax	$ 16 000 000	
Electrolyzer 100MW phase 1 total capex (120m x 50m footprint)	$ 96 000 000	
Hydrogen gas pipeline to Indus crossing at Attock (10km to the north)	$ 10 000 000	$ 15 000 000
Gas letdown station for grid injection at Indus crossing	$ 3 000 000	$ 5 000 000
Months of year of electrolyzer utilization and hydrogen production	10	10
Lifetime of capex depreciation	25	25
Monthly capex depreciation cost allocation	$ 5 232 000	$ 168 960 000
Annual maintenance costs	$ 1 920 000	$ 20 000 000
Annual power cost		Zero, covered from capex
Electrolyzer power (MW)	100	1000
Hydrogen production kg / hour (55 kWh / kg H_2 71% efficiency)	1818	18182
Hydrogen production tonnes / year	13091	130909
Hydrogen cost USD / kg (levelized through 1 year)	From power, maintenance and capex	From power, maintenance and capex
Thermal energy value of hydrogen 143MJ/Kg	143	143
Thermal energy value of natural gas (assumes 100% methane rich) 55 MJ/Kg	55	55
Thermal energy value of hydrogen produced per year (MJ)	1872000 000	18720000000
Cost of hydrogen / MJ thermal energy value	TBD	TBD
Amount of natural gas displaced by hydrogen (tons per year)	34 036	340 364

D. High Potential Project #13: Hydropower Micro-grid in the North

A new micro-hydro scheme can provide power to remote communities in remote northern locations (e.g. Naltar valley in Gilgit Baltisan) that currently have no access to electricity. Hydrogen can be produced using a run of the river hydro scheme and stored in high pressure gas cylinder in the spring, autumn and summer months. The stored hydrogen can be used to produce electrical power on a fuel cell.

Figure 68: *Naltar Valley*

1. Stand-alone Power System (SAPS) Integrating a Hydrogen Electrolyzer, Fuel-cell and Hydrogen Storage System

For most of the year, the system operates to produce electricity and hydrogen. For the very cold winter period (one or two months) when there is very little water flow to feed the hydropower generator, stored hydrogen is released to a fuel-cell to produce electrical power.

Hydrogen could also potentially be used as an energy gas (if required, in combination with LPG or natural gas for heating and cooking).

The first location could be a village in the Naltar valley in Gilgit Baltisan. Locations such as Budalas, Singul or Chalat could also be suitable.

As a containerized system, it could be transported to the appropriate location by road or helicopter. If the village subsequently benefits from grid power, or gas pipeline network connection, the hydrogen system can be moved to another village in the future to avoid redundancy.

Figure 69: *Scenario 1 Scheme*

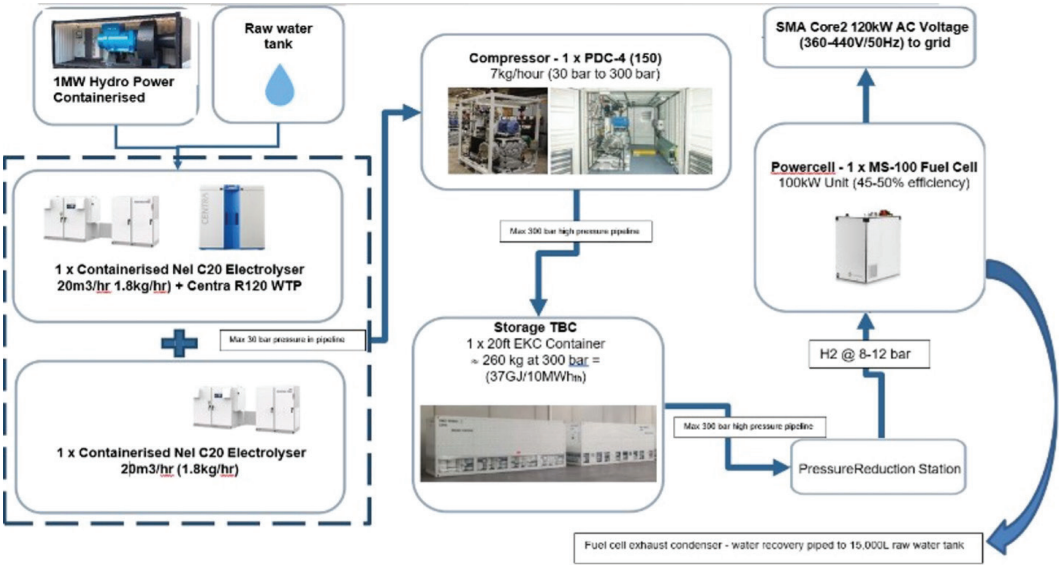


Table 51: Pakistan Hydrogen Standalone Power System - Concept and Budget Estimate Supply Only, Excluding Import Taxes and Duties

Key equipment	Equipment (Redundant Electrolyzer)	Equipment (No Redundant Electrolyzer)
Electrolyzer (2x 120kW containerized)	$3.5M	-$1.3M
Fuel cell (1MW containerized)	$1.5M	
Hydrogen compression (if required)	$1.0M	
Hydrogen storage (4500 kg) type to be confirmed	$3.0M	
Water systems (treatment and storage)	$0.35M	
Power conversion system (DC to 240V AC)	$0.45M	
Battery system (1MW/500kWh)	$1.2M	
Battery – power control- comms	$0.6M	
Transformer and grid connection to local network	$0.75M	
Switchboards and switchgears	$0.6M	
Total	**$12.95M**	**$11.65M**

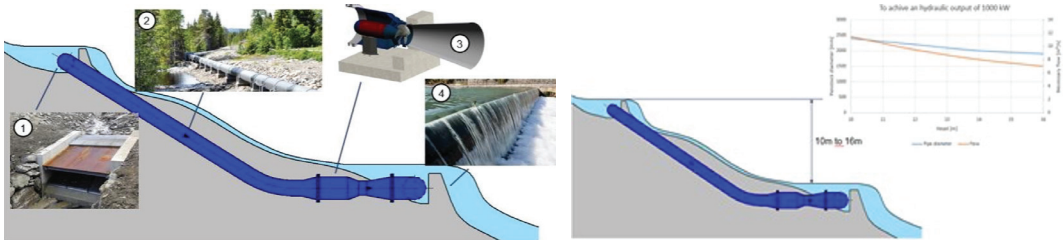
In these northern locations, wind and solar power are not suitable for local micro-grids due to theweather patterns, but hydropower may be. However, a solar power plant can be used as a combination with the hydropower in summer and battery for load following. The hydrogen production will come from surplus power from both hydro and PV systems. The battery system issized for load following and some backup power and to complement to the hydrogen-based energy storage and release system for winter.

To generate about 200MWh per year to support the system, a hypothetical 1 or 2 hectares of solar panels would be required. The land underneath the solar panels could still be used for grazing sheep and goats. Depending on the panel support design, it could also potentially be used in combination with other food-crops.

2. Run-of-the-River Hydro Plant

For this, two hydro plant concepts are proposed.

Figure 70: *Low Head Concept*



Note:

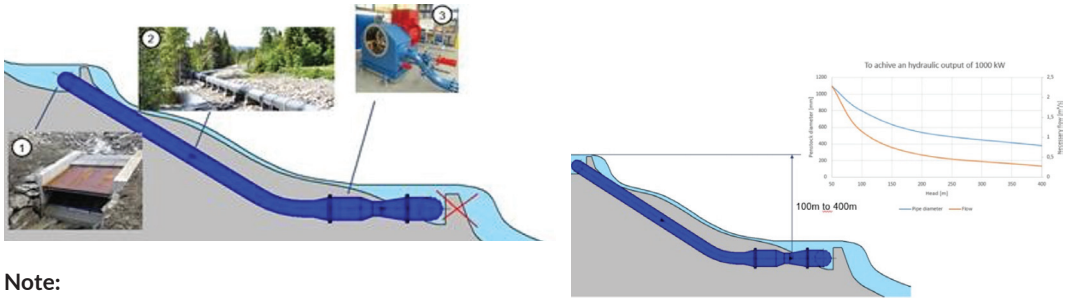
1: Intake – layout as Tiroler Wehr: nearly no headwater reservoir needed, low maintenance effort to clean the thrash rack;

2: GFK Penstock: lower transport effort then steel pipes, low maintenance effort (corrosion protection,);

3: In Pipe Stream Diver: Containerized premanufactured highly standardized turbine solution, oil free, lowest maintenance effort;

4: Tail-water Dam: Necessary to maintain a tail-water pressure on the stream diver.

Figure 71: *High Head Concept*



Note:

1: Intake – layout as “Tiroler Wehr” - same as concept 1 but much smaller

2: GFK Penstock. same as concept one but smaller diameter and much bigger length

3: Containerize small Pelton unit

4: No tailwater dam needed but a channel leading the water from the turbine back into the river

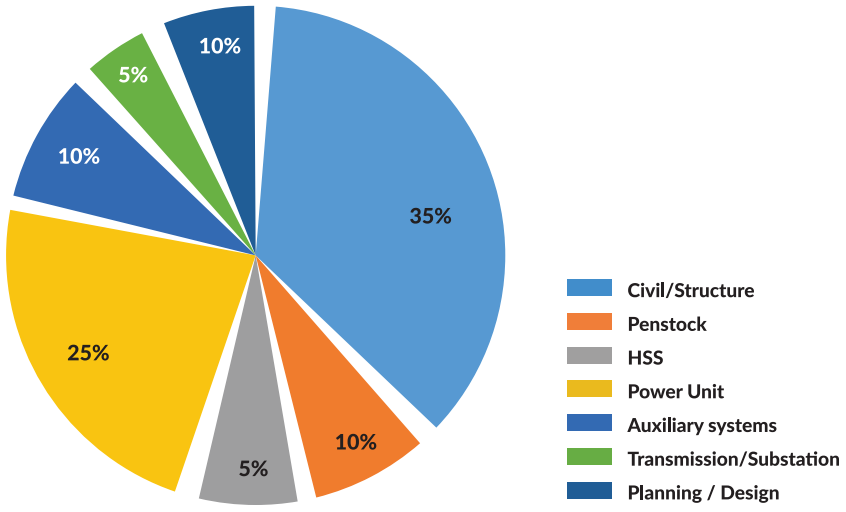
Table 52: Comparison Based on Preconditions

Criteria	Low Head concept	High Head concept
Civil Effort	Civil structures limited to a smaller area but bigger	Much longer penstock therefore the site is much bigger. intake structure much smaller and no need for a tail water dam
Maintenance	Intake: as there is a higher flow more clogging of the intake expected Turbine: no oil, no need to heat during wintertime, very low wear of the runner → lowest possible maintenance effort	High head means more load and wear for the turbine. Standard generator needs oil and heating during wintertime
Environmental risk	No oil → No risk for pollution	Oil/Grease inside the machine, but not directly in contact with water. Lower environmental impact at the intake/tail water
Regulation capacity	Unit can be regulated in an area down to approx. 40% load	Unit can be regulated down to 10% load with quick response times

Table 53: Typical Hydro Scheme Cost Split

No.	Type	Francis (Standard Values)	
		[Mio. $]	%
	$/MW Installed	3,2	
1	Civil/Structure	11,1	35
2	Penstock	3,2	10
3	HSS	1,6	5
4	Power Unit	7,9	25
5	Auxiliary systems	3,2	10
6	Transmission/Substation	1,6	5
7	Planning / Design	3,2	10
	Total	**31,7**	**100**

Figure 72: *Total Investment CAPEX*



3. Hydrogen Production

PEM electrolyzer is used to produce hydrogen from the locally generated hydro-electrical power. The hydrogen is used on a fuel cell to power a micro-grid

- An AEC electrolyzer system would be cheaper but requires KOH chemicals to be delivered to these remote regions and used by inexperienced people, which may prove to be difficult.
- A 0.2 MW electrolyzer can be modelled with 10 months out of 12 utilization – this is a commercially available size and an ideal utilization rate.
- A 1 MW fuel-cell can be modelled based on 2 months utilization and would provide enough power for circa 1000 to 2000 houses.
- For short-term energy storage, e.g., one day, a battery would be a good option. However, since the rivers freeze for perhaps one or two months of the year, the long-term storage benefits of hydrogen are required to provide all-year-round power.

4. Climate of Naltar

Naltar has the **semi-arid climate** prevailing. It hardly rains here. The average annual temperature for Naltar is 29° degrees and there is about 376 mm of rain in a year. It is dry for 207 days a year with an average humidity of 36% and an UV-index of 6.

Figure 73: *Naltar Location*

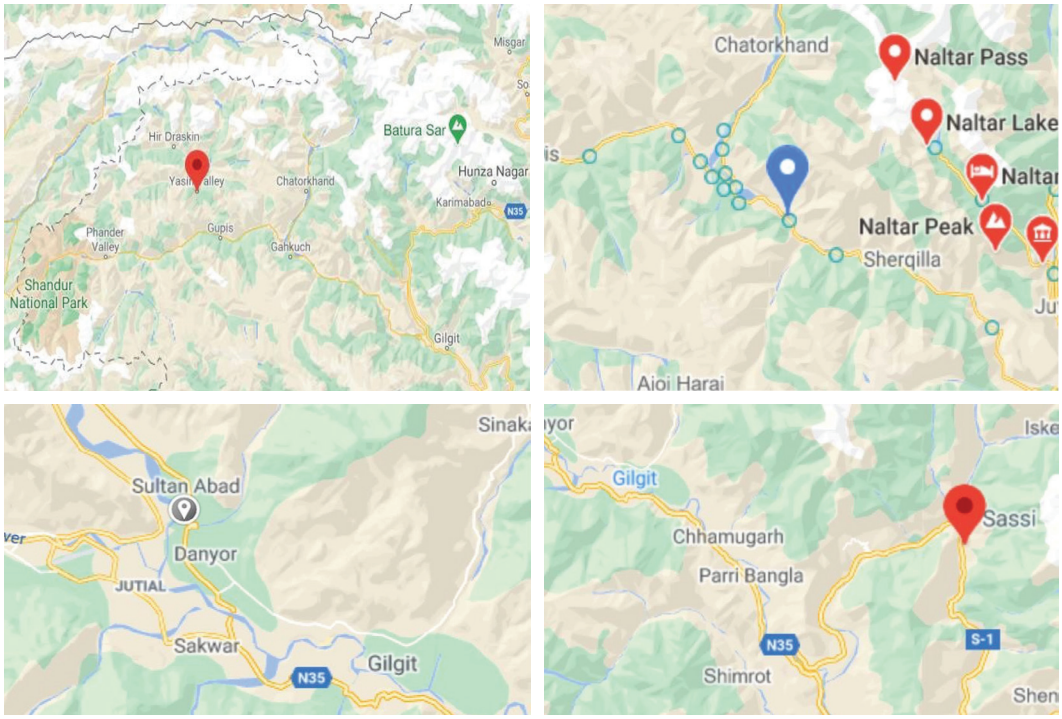


Table 54: Naltar Weather Data												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Day max (°C)	-14	-11	-7	-3	1	5	10	9	5	-1	-8	-12
Night min (°C)	-26	-24	-20	-15	-9	-3	2	2	-2	-9	-19	-24
Rain (mm)	6	12	20	24	17	20	29	35	36	14	7	4
Rain days	8	8	10	6	4	3	9	11	5	4	6	7
Snow days	11	14	17	15	11	9	6	8	13	10	7	9
Dry days	12	6	4	9	16	18	16	12	12	17	17	15
Sun hours per day	7	6	9	11	12	12	12	12	11	8	7	7
Wind force (Bft)	3	3	3	3	2	2	2	2	2	2	3	3
UV-index	2	2	2	2	2	2	3	2	2	2	2	2

Weather Naltar January

On average, it is maximum -14° in January in Naltar and at least around -26° degrees. In January there are 8 days of rainfall with a total of 6 mm. It dries 12 days this month in Naltar and on average, it snows 11 days in January.

Weather Naltar February

On average, it is maximum -11° in February in Naltar and at least around -24° degrees. In February there are 8 days of rainfall with a total of 12 mm. It dries 6 days this month in Naltar and on average, it snows 14 days in February.

Weather Naltar March

On average, it is maximum -7° in March in Naltar and at least around -20° degrees. In March there are 10 days of rainfall with a total of 20 mm. It dries 4 days this month in Naltar and on average, it snows 17 days in March.

Weather Naltar April

On average, it is maximum -3° in April in Naltar and at least around -15° degrees. In April there **are 6 days of rainfall with a total of 24 mm. It dries 9 days this month in Naltar and on average, it snows** 15 days in April.

Weather Naltar May

On average, it is maximum 1° in May in Naltar and at least around -9° degrees. In May there are 4 days of rainfall with a total of 17 mm. It dries 16 days this month in Naltar and on average, it snows 11 days in May.

Weather Naltar June

On average, it is maximum 5° in June in Naltar and at least around -3° degrees. In June there are 3 days of rainfall with a total of 20 mm. It dries 18 days this month in Naltar and on average, it snows 9 days in June.

Weather Naltar July

On average, it is maximum 10° in July in Naltar and at least around 2° degrees. In July there are 9 days of rainfall with a total of 29 mm. It dries 16 days this month in Naltar and on average, it snows 6 days in July.

Weather Naltar August

On average, it is maximum 9° in august in Naltar and at least around 2° degrees. In august there are 11 days of rainfall with a total of 35 mm. It dries 12 days this month in Naltar and on average, it snows 8 days in august.

Weather Naltar September

On average, it is maximum 5° in September in Naltar and at least around -2° degrees. In September there are 5 days of rainfall with a total of 36 mm. It dries 12 days this month in Naltar and on average, it snows 13 days in September.

Weather Naltar October

On average, it is maximum -1° in October in Naltar and at least around -9° degrees. In October there are 4 days of rainfall with a total of 14 mm. It dries 17 days this month in Naltar and on average, it snows 10 days in October.

Weather Naltar November

On average, it is maximum -8° in November in Naltar and at least around -19° degrees. In November there are 6 days of rainfall with a total of 7 mm. It dries 17 days this month in Naltar and on average, it snows 7 days in November.

Weather Naltar December

On average, it is maximum -12° in December in Naltar and at least around -24° degrees. In December there are 7 days of rainfall with a total of 4 mm. It dries 15 days this month in Naltar and on average, it snows 9 days in December.

E. High Potential Project #6: Solar Power for Hydrogen Production at the Quaid e Azam Solar Park

Use DC solar power at the Quaid e Azam solar park to produce hydrogen for ad-mixing into the natural gas grid for heating, cooking and CNG applications to incrementally decarbonize the gas pipeline network and CNG mobility. Hydrogen can be produced directly from DC PV power to avoid conversion losses and can be transmitted using a dedicated pure hydrogen pipeline to the nearby natural gas pipeline at Bahawalpur. The Quaid e Azam Solar Park has an existing power generation capacity of around 600MW with plans for expansion to 1GW.

- A 100MW pressurized AEC electrolyzer can be used to produce hydrogen
- The electrolyzer configuration will be considered as 2x50MW for flexibility
- The power generated by a solar scheme is DC, which is exactly what an electrolyzer requires to produce hydrogen

- Co-locating and direct-coupling the solar scheme to the electrolyzer avoids grid transmission losses and fees

- Co-location also avoids inverter / rectifier power losses and eliminates the cost of these capital items from the scheme

- A new power management system (such as the proprietary and innovative system under development by CQSola in Australia - https://www.cqsola.com.au/) could be retrofitted to the existing solar park PV panels to uplift the power output – this is likely to be a lower cost solution than installing new PV panels (which is also possible and modelled as a case). The CQSola equipment is likely to be commercially available in 2022 and pilot test kits are on offer at present. At the time of writing the technology proposed is uniquely available from CQSola, however, in the future other similar systems may be available for consideration.

1. Quaid-e-Azam Solar Park Overview

Quaid-e-Azam solar park situated in the Cholistan desert is planned to be a 1GW solar Power development. Quaid-e-Azam Solar Park had a maximum output of 84.05 MW /100 MW for each phase of the solar park at the time of commissioning (11th April 2015), while the current power output for each phase of the solar park is 74.85 MW/100 MW (11th April 2021).

Each string is composed of 20 panels with a power output of 255W for each. The open-circuit voltage of the used panels is 37.82 V. The age of the oldest array on the solar park since commissioning is 7 Years.

The CAPEX cost for building each phase of the solar park was 131.15 million dollars for 100 MW (1$ = 105PKR as of 2014), and an expected CAPEX cost of 53 million dollars is estimated for the next 100 MW expansion of the solar park.

In the base case with fixed mounted crystalline modules the power plant generates 3.860 GW hours of electricity over 25 years. To allow for some uncertainty in the irradiation assumptions the financial base case is based on a production of 97% - 3.750 GW hours for 25 years.

The tariff for the electricity injected to the grid of 21,73 PKR/kWh for the first 10 years and 9,76 PKR/kWh thereafter. The total project costs are assumed to be 150 million USD of which 70% was financed by a bank. The base case shows an IRR of 17% for the equity with a payback time of 5 years. The discounted cash flows (10%) amount to a Net Present Value of 21 million USD.

2. Alternative Hydrogen Utilization Case: Power Generation on Gas Turbines for Occasional Peak Shaving or LNG Substitution

As an alternative utilization case, hydrogen could be transmitted to the Kot Addu CCGT gas-fired power plant for co-combustion on one of the GE 9E turbines or Engro Power Generation Qadirpur Limited. Financial modelling of these alternative utilization cases has not been conducted as part of this study.

The concept for Kot Addu would involve a hydrogen transmission using a new dedicated hydrogen pipeline at 100 or 200 bars. The pipeline also acts as a storage buffer which is charged up during the day and emptied during the evening power peak. Power generation

would be during the evening peak on a CCGT plant close to the solar park. The Kot Addu plant (KOPCO / WAPDA) operates 4x GE 9E turbines that have a high potential to be converted to hydrogen operation. If hydrogen is not required on the CCGT on any day, it can be admixed to the gas grid to decarbonize heating and reduce LNG imports. Technical details of Kot Addu CCGT gas-fired power plant and Engro Power Generation Qadirpur Ltd. which are located west and southwest of Quad e Azam respectively are provided in an Appendix.

F. Backup Project #11 Hydrogen Production during Off-peak Hours from the "Orange Line" in Lahore 80MW Electricity Terminal

An additional project was considered as having good potential for a demonstration project pilot, if further analysis were to be undertaken by another project team in the future. It involves hydrogen production from a power sourced via the transmission grid and the "Orange Line" in Lahore. An 80MW power terminal exists there which is currently under-utilized. The hydrogen could be used for mobility applications in Lahore and any excess could be admixed into the natural gas grid.

To ensure that this project is generating green hydrogen from renewable power would need to be sourced through a power purchase agreement. The site is supplied by LESCO via the transmission grid. As part of the project, a simultaneous investment to uplift to the Quaid e Azam solar park could implemented to generate additional renewable power to ensure the scheme is producing renewable hydrogen. One obstacle to this concept is that there is no mechanism in Pakistan to set up a dedicated renewable power purchase agreement to connect a power consumer to a power generator with electricity transmission on the grid. So, the under some definitions, the hydrogen produced might be difficult to classify as 'green'.

Surplus power from the dedicated 80MW supply to the Lahore Orange Line metro system can be used to produce hydrogen during off-peak periods of travel. Power that is not required by the orange line trains or stations during off-peak hours can be used to generate hydrogen. Approximately 20MW is required for the trains and stations and circa 60MW is available for electrolysis.

A pressurized AEC electrolyzer would be the cheapest technology and could respond to changing power supply if the available power falls below 80MW. Two 20MW electrolyzers can be used (6,000 tons per year of H_2) one electrolyzer would be located at each sub-station (UET and Shahoor). By signing an electricity supply contract for this power with a renewable source (hydro, wind, solar) the hydrogen can be regarded as "renewable" on an electron balance basis.

Some of the hydrogen gas can be used for fuel-cell powered buses in Lahore. It would be necessary to build a hydrogen fueling station to compress the hydrogen for use in local bus fleet transportation applications and a fleet of fuel-cell powered buses would also need to be purchased and implemented. The air quality in Lahore can be improved by the replacement of diesel buses with zero emissions hydrogen mobility.

Hydrogen that is not required for the high-value mobility applications can be ad-mixed to the local natural gas pipeline grid at concentrations in the range of 0 to 2% by volume, and perhaps up to 6%.

VI. FINANCIAL ANALYSIS OF THE PROPOSED VALUE CHAINS

The cost of hydrogen can be derived from the capital cost and operating cost of the electrolyzer system, together with the amount of hydrogen generated each year. The Levelized Cost of Hydrogen (LCOH) was calculated by determining the ratio of the total discounted costs for the life of the system to the total discounted hydrogen production, as shown in Equation 1. In this equation, Y is the number of operational years, Sn is the system cost in year n, which includes capital costs in year 0 and operational costs (maintenance, electricity charges if not covered thru CAPEX and Human Resources etc.) from all operational years, Pn is the production of hydrogen in year n, and r is the discount rate.

$$LCOH = \frac{\sum_{n=0}^{Y} S_n \cdot (1-r)^n}{\sum_{n=0}^{Y} P_n \cdot (1-r)^n}. \qquad \text{(Equation 1)}$$

A. Key Assumptions

Two critical assumptions are same for all the three cases and subsequently their multiple scenarios; first, the project life/operation period is considered as 30 years and second, the discount rate of 7% is used which is in accordance with the Government of Pakistan's standards. As there are significant uncertainties in the actual value of many of the input parameters for calculating the cost of hydrogen. As a result, we have carefully worked out all the relevant costs and estimated various scenarios.

In Case No. 3 and 6, we built 4 scenarios regarding gas displaced by hydrogen; as – 1) Local Natural Gas at Well-head Cost, 2) LNG at Qatar Contract Price, 3) Average of Contracted and Winter Spot Price, 4) High LNG Winter Spot Price. While, for Case No. 13, we build two options. First option is with 3 scenarios for project regarding gas displaced by hydrogen assuming; 1) Local Natural Gas Cost at Wellhead, 2) Imported LPG Price 3) Average of LPG and Local Natural Gas Prices. Second option is with two scenarios to evaluate the potential of Hydrogen to be used as cooking fuel where value of annual benefits has been imputed using 1) Fuel wood prices and 2) Imported LPG Prices. All the prices used for this analysis are given in the table below.

Table 55: Prices Used in Various Scenarios			
S. No.	Prices Used in Various Scenarios	$/Ton	$/mmbtu
1	Local Natural Gas at Well-head Cost	125.44	2.23
2	LNG at Qatar Contract Price	115.29	2.23
3	Average of Contracted and Winter Spot Price	380.51	7.36
4	High LNG Winter Spot Price	530.96	10.27
5	Imported LPG Price	313.00	8.00
6	Average of LPG and Local Natural Gas Prices.	281.00	5.12

NOTE: All prices mentioned in $/ton adjusted for calorific value while converting them from MMbtu to tons.

B. Sensitivity Mapping

There are extreme differences among these scenarios, therefore, it can be a good proxy to capture the other variabilities and sensitivities of these projects. Though, each scenario was further evaluated by assuming a i) 10 percent increase in cost, ii) 20 percent increase in cost and iii) Simultaneous 10 percent increase in cost and 10 percent decrease in benefits.

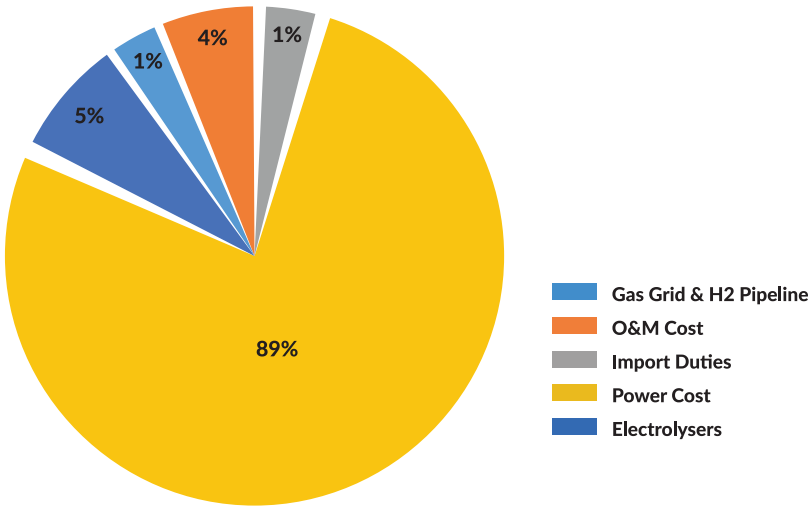
Furthermore, each scenario for all the projects was evaluated after adding the benefit in terms of reduction in the carbon dioxide (CO_2) emissions. Here, we used the two prices to value the emission reduction at $40 and $80 per ton sequentially. This analysis not only captures the environmental gains of hydrogen usage but also supplements the sensitivity analysis by enhancing the value of hydrogen benefits.

Our calculations also include additional factors that are region and application specific, such as the costs of storage, compression, transmission, and topography, which are needed if the hydrogen is not self-consumed; though we have not accounted for the taxes on the entity operating the plant, which could be province specific and depends on the business model (e.g., sale of hydrogen versus self-use). Besides, a single discount rate on all cash flows represents a simplification of the cost of debt and/or equity capital. These simplifications mean that the cost estimates are more generalized but remain valid and can be further adapted easily if necessary to consider more specific cases.

1. Case No. #3: Ghazi Barotha with Hydrogen for Gas Grid Admixing

In Phase I - 100 MW power from the existing Ghazi Barotha hydroelectric scheme operating for 10 months of the year is the base case for the canal-fed hydropower system. Electrolyzer will be installed on spare land at the existing transmission hub on the western bank of the river. The electrolyzer will continuously operate at optimum / peak load conditions during these 10 months of operation and the system will be shut down for maintenance during 2 months of the summer each year when the demand of gas for heating is at the lowest level. This project costs $109 Million as one-time CAPEX and $ 45.7 Million annually as OPEX. Key elements of the life cycle cost of the project are shown in the chart below .

Figure: *Cost Structure: Phase-I (100 MW)*



Phase I - 100 MW project is not financially/economically feasible in any scenario; it stays unfeasible even when the carbon emission's gains are valued at the highest price of $80/$tCO_2$ as shown in Table:01-A.

Few additional possibilities were worked out as shown in Table: 01-A. An option with 50 percent reduced cost of Electrolyzer (with a cheaper option available in the market) was calculated. Here, CAPEX reduces to $61 Million from $109 Million and OPEX reduces to $45.02 Million from $45.7 Million. Resultantly, LCOH reduces to $3.81 per Kg from $4.16 (i.e. 8.4% reduction). But yet project remains unfeasible even at the highest value of benefits i.e. High LNG Spot Price plus carbon emissions gain valued at $80/$tCO_2$.

Subsequently, we calculated the LCOH based on 2 months as well as 3 months operations with zero power cost (assuming electricity is surplus when the water flows at its maximum for irrigation purposes or in high monsoon period). Here, LCOH decreases from $4.16 per Kg to $2.34 for 2 months and to $1.56 for 3 months scenarios. Yet, the scenario with 2 months operations with zero power cost stays unfeasible. Interestingly, the scenario with 3 months operations with zero power cost becomes feasible (with BCR of 1.26:1 and EIRR of 10.11 percent) at the highest value of benefits i.e. High LNG Spot Price and CO_2 emission reduction gains valued at $80/$tCO_2$.

We also mapped the sensitivity of 100 MW option assuming; i) 10 percent increase in cost, ii) 20 percent increase in cost and iii) Simultaneous 10 percent increase in cost and 10 percent decrease in benefits. Results are presented in Table: 01-B and all scenarios stay financially unfeasible.

Table 56: Ghazi Barotha (US$ in Millions)								
Parameters	Phase I (100 MW)				Phase II (1 GW)			
CAPEX	109				3,520			
OPEX	45.7				20			
Electrolyzer Price $/kW	960				1,000			
Present Value of TotalCost	631.9				3,521.7			
Scenarios *	1	2	3	4	1	2	3	4
Annual Benefit's Value	4.3	3.9	13	18.1	42.7	39.2	129.5	180.7
Present Value Benefits	49.9	45.2	150.8	209.9	495.2	454.6	1501.8	2095.6
Net Present Value (NPV)	- 582	- 586.6	- 481.1	- 422	- 3026.5	- 3067.1	- 2019.8	- 1426.1
Benefit Cost Ratio (BCR)	0.08	0.07	0.24	0.33	0.14	0.13	0.43	0.60
EIRR in %	-	-	-	-	-8.4	- 9.2	-0.44	2.16
LCOH ($ per Kg)	4.16				2.32			
LCOE ($ per kWh)	0.06				0.04			
CO_2 Emissions @ $40								
Annual Benefit's Value	8.2	7.8	16.9	22	81.4	77.9	168.2	219.4
Present Value Benefits	94.8	90.3	195.7	254.8	943.7	903.1	1950.3	2544
Net Present Value (NPV)	- 537.1	- 541.5	- 436.2	- 377	- 2578	- 2618.6	-1571.4	-977.6
Benefit Cost Ratio (BCR)	0.15	0.14	0.31	0.40	0.27	0.26	0.55	0.72
EIRR in %	-	-	-	-	- 3.8	- 4.1	1.58	3.83
CO_2 Emissions @ $80								
Annual Benefit's Value	12	11.7	20.7	25.8	120.3	116.5	206.8	258
Present Value Benefits	139.5	135.1	240.4	299.6	1392	1351.4	2398.7	2992.4
Net Present Value (NPV)	- 492.4	-496.8	-391.5	-332.3	- 2129.7	-2170.2	-1123	-529.2
Benefit Cost Ratio (BCR)	0.22	0.21	0.38	0.47	0.40	0.38	0.68	0.85
EIRR in %	-	-	-	-	-1	-1.2	3.3	5.3
Remarks	Not Feasible in any Scenario				Not Feasible in any Scenario			
LCOH ($ per Kg) at 50% reduced cost of Electrolyzer	3.81				2.01			
Electrolyzer Price $/kW	480				500			
LCOH ($ per Kg), 2 months operations with zero powercost	2.34				NA			
LCOH ($ per Kg), 3 months operations with zero powercost	1.56 (Feasible)				NA			

** **Note:** We have 4 scenarios for each project regarding gas displaced by hydrogen assuming; 1) Local Natural Gas Cost at Wellhead, 2) LNG at Qatar Contract Price, 3) Average of Contracted and Winter Spot Price 4) High LNG Winter Spot Price.*

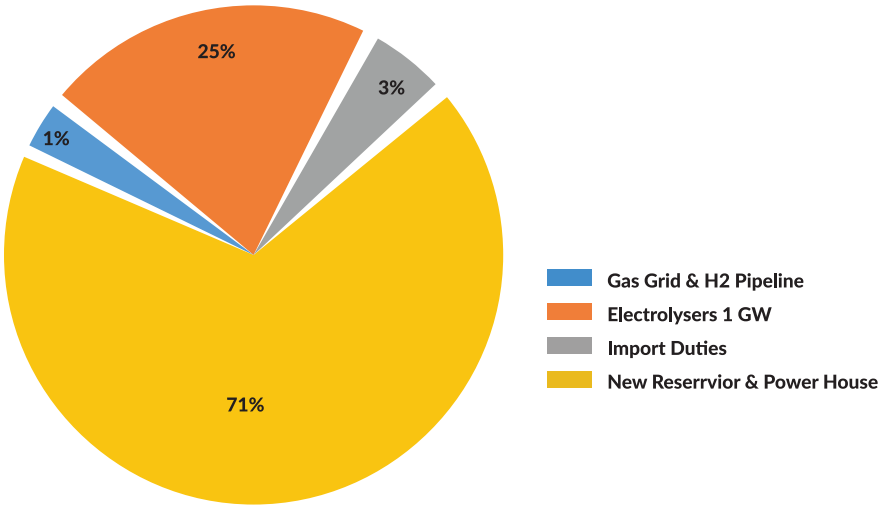
Table 57: Ghazi Barotha (US$ in Millions)

Parameters	Phase I (100 MW)				Phase II (1 GW)			
CAPEX	109				3,520			
OPEX	45.7				20			
Present Value of Total Cost	631.9				3521.7			
Scenarios *	1	2	3	4	1	2	3	4
10% increase in Cost								
Present Value of Total Cost	695.1				3,873.8			
Net Present Value (NPV)	-645.2	-649.8	-544.3	-485.1	-3,378.6	-3,419.2	-2,371.9	-1,778.2
Benefit Cost Ratio (BCR)	0.07	0.07	0.22	0.30	0.13	0.12	0.39	0.54
EIRR in %	-	-	-	-	-9.23	-9.99	-1.14	1.39
LCOH ($ per Kg)	4.6				3.2			
LCOE ($ per Kwh)	0.07				0.04			
20% increase in Cost								
Present Value of Total Cost	758.2				4,226			
Net Present Value (NPV)	-708.4	-713.0	-607.5	-548.3	-3,730.8	-3,771.4	-2,724.2	-2,130.4
Benefit Cost Ratio (BCR)	0.07	0.06	0.2	0.28	0.12	0.11	0.36	0.50
EIRR in %	-	-	-	-	-10.0	-10.8	-1.8	0.70
LCOH ($ per Kg)	4.9				3.5			
LCOE ($ per kWh)	0.07				0.05			
10% increase in Cost & decrease in Benefit								
Present Value of Total Cost	695.1				3,873.8			
Net Present Value (NPV)	-650.2	-654.1	-559.4	-506.1	-3,428.2	-3,464.7	-2,522.2	-1987.8
Benefit Cost Ratio (BCR)	0.06	0.06	0.20	0.27	0.12	0.11	0.35	0.49
EIRR in %	-	-	-	-	-10.17	-11.01	-1.90	0.56
LCOH ($ per Kg)	4.6				3.2			
LCOE ($ per kWh)	0.07				0.04			
Remarks	Not feasible in any scenario				Not feasible in any scenario			

** **Note:** We have 4 scenarios for each project regarding gas displaced by hydrogen assuming; 1) Local Natural Gas Cost at Wellhead, 2) LNG at Qatar Contract Price, 3) Average of Contracted and Winter Spot Price 4) High LNG Winter Spot Price.*

Phase 2 – 1 GW Design is based on new canal with new reservoir/dam and powerhouse with hydro turbines, dedicated to 1GW new electrolyzer. It will remain operational for 10 months of the year except in the late winter / early spring due to dry season and inadequate water flow for 1 GW hydropower generation. This project costs $3,520 Million as one-time CAPEX and $20 Million annually as OPEX. Key elements of the life cycle cost of the project are shown in the chart below.

Figure: *Cost Structure: Phase-II (1 GW)*



Phase 2 with 1GW option is not feasible in any scenario even after incorporating carbon emission gains valued at $80/tCO$_2$ as shown in the last 4 columns of the Table: 01-A. Even though it's LCOH is $2.32 per Kg with LCOE as low as $0.04 per kWh, it is not financially feasible. This shows that system size does not matter a lot as increasing the scale from 100 MW to 1 GW is only providing economies of scale or efficiency gains to the extent of 44.23 percent in LCOH i.e. a reduction of $1.84 per Kg which is not sufficient to make the project financially viable.

An option with 50 percent reduced cost of Electrolyzer (with a cheaper option available in the market) was calculated. Here, CAPEX reduces to $3,020 million from $3,520 million and OPEX remains the $20 Million. Resultantly, LCOH reduces to $2.01 per Kg from $2.32 (i.e. 13.36 % reduction). But yet it remains, marginally, unfeasible (with BCR 0.98:1 and 6.78% EIRR) even at the highest value of benefits i.e. High LNG Spot Price plus carbon emissions gain valued at $80/tCO$_2$. We did not run scenarios with zero power cost for 2 and 3 months. As it is not possible to acquire 1 GW of surplus electricity for such a long time, therefore it would be oversimplified assumption to do so.

We also mapped the sensitivity of 1GW option assuming a i) 10 percent increase in cost, ii) 20 percent increase in cost and iii) Simultaneous 10 percent increase in cost and 10 percent decrease in benefits. Results are presented in Table: 01-B and all scenarios stay unfeasible.

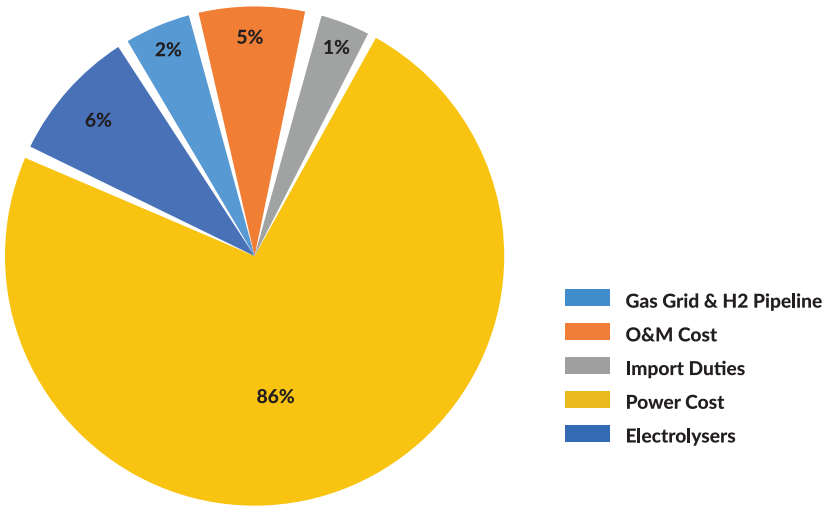
2. Case No. #6: Quaid-e-Azam Solar Park with Hydrogen for Gas Grid Admixing

This project is designed assuming that electrolyzer will operate 10 hours per day due to availability of sunlight only for 12 hours and weak solar incidence in morning and evening besides electrolyzer ramp up and shut down. Therefore, electrolyzer utilization is assumed

to be 42% for all the three options. Electrolyzer and hydrogen gas compression will be installed on spare land on the solar park. Water will be required for the electrolyzers; it is assumed that no additional pipeline is needed. Hydrogen produced here will be utilized as gas grid injection to substitute for LNG imports. A new pure hydrogen pipeline operating at a maximum of 160 bar is assumed to connect the electrolyzer to the natural gas pipeline at Bahawalpur (8» natural gas pipeline from main north south network).

In Option 1, a 100 MW McPhy AEC electrolyzer will be connected to the existing Quaid-e-Azam PV solar power scheme which will operate for 12 months of the year and maintenance will take place during the downtime i.e. overnight. This project costs $119 Million as one-time CAPEX and $42.7 Million annually as OPEX. Key elements of the life cycle cost of the project are shown in the chart below.

Figure: *Cost Structure: Phase-I Option 1 (100 MW)*



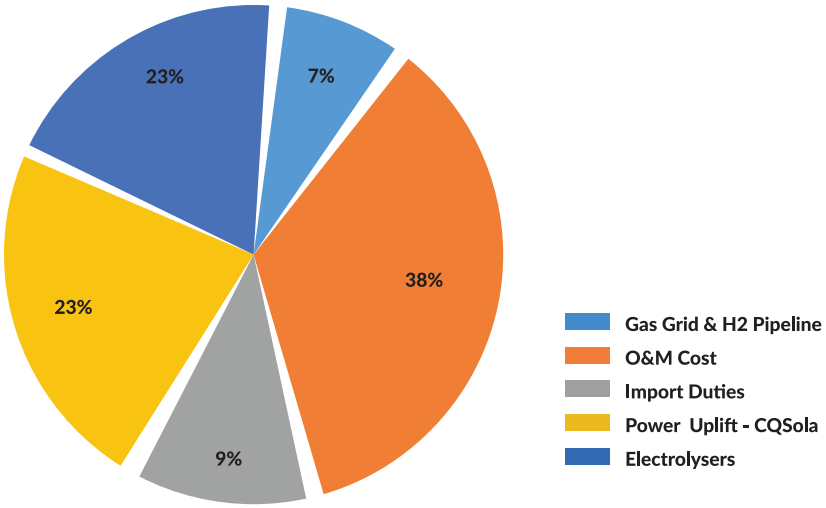
Phase I – Option 1: 100 MW Electrolyzer on existing solar Park is not financially feasible in any Scenario, it stays unfeasible even when the carbon emission's gains are valued at the highest price of $80/tCO$_2$ as shown in Table: 02-A. Its LCOH is quite high i.e. $8 per Kg, primarily it is due to very high annual power cost that accounts for 86 percent of the total life cycle cost of this project.

In Phase 1, Option 1A, a new CQSola power management systems will be installed for upgrading the solar park PV output to avoid reduction of electrical power dispatched to the grid. This project costs $215 Million as one-time CAPEX and $4.3 Million annually as OPEX. Key elements of the life cycle cost of the project are shown in the chart below.

Phase I – Option 1A: 100 MW Electrolyzer with 100 MW uplift with CQSola on the solar park is not financially feasible in any Scenario, it stays unfeasible even when the carbon emission's gains are valued at the highest price of $80/tCO$_2$ as shown in Table: 02-A. It is not feasible in spite of the fact that its LCOH is quite low i.e. $3.3 per Kg as compared to Option 1 i.e. $8 per Kg and its LCOE is also very reasonable i.e. $0.027 per kWh.

Phase II Design: 1 GW Electrolyzer from 1 GW power uplift with CQSola with an extension of the solar park is envisaged for this project. It will remain operational for 12 months of the year, 10 hours per day. This project costs $2400 Million as one-time CAPEX and $48 Million annually as OPEX. Key elements of the life cycle cost of the project are shown in the chart below. Gas grid Injection & Hydrogen pipeline cost is not included here as it is already covered during the Phase 1 – Option 1A.

Figure: *Cost Structure: Phase-I Option 1A (100 MW Uplift)*



Phase II – 1GW Electrolyzer with 1GW Power uplift (for example with proprietary equipment that is available for pilot testing from the Australian company CQ Sola) is not financially feasible in any Scenario. It stays unfeasible even when the carbon emission's gains are valued at the highest price of $80/tCO$_2$ and high LNG winter Spot prices as shown in Table: 02-A. Its LCOH slightly increases to $3.7 per Kg as compared i.e. $3.3 per Kg in Option 1A. It's LCOE also increases to $0.033 per kWh as compared to $0.027 per kWh in Option 1A.

We also mapped the sensitivity of all the three options assuming a i) 10 percent increase in cost, ii) 20 percent increase in cost and iii) Simultaneous 10 percent increase in cost and 10 percent decrease in benefits. Results are presented in Table: 02-B.

Table 58: Quaid-e-Azam Solar Park with Gas Grid Injection (US$ in Millions)

Parameters	100 MW Electrolyser on Existing Solar				100 MW Electrolyzer with 100 MW uplift with CQSola				1GW Electrolyzer from 1GW uplift with CQSola			
	Phase I - Option 1				Phase I - Option 1A				Phase II			
CAPEX	119				215				2400			
OPEX	42.7				4.3				48			
Electrolyzer Price $/kW	960				960				1,000			
Present Value of Total Cost	606.42				250.80				2,799.7			
Scenarios *	1	2	3	4	1	2	3	4	1	2	3	4
Annual Benefit's Value	2.14	1.96	6.48	9.04	2.14	1.96	6.48	9.04	21.35	19.60	64.76	90.36
Present Value Benefits	24.82	22.73	75.15	109.0	24.82	22.73	75.15	109.0	247.6	227.3	751.0	1,047.9
Net Present Value (NPV)	-581.6	-583.7	-531.3	-497.4	-225.9	-228.1	-175.7	-145.9	-2,552.1	-2,572.4	-2,048.6	-1,751.7
Benefit Cost Ratio (BCR)	0.04	0.04	0.12	0.18	0.10	0.09	0.30	0.42	0.09	0.08	0.27	0.37
EIRR in %	-	-	-	-	-	-	-6.4	-2.5	-	-	-8.1	-3.7
LCOH ($ per Kg)	8.00				3.30				3.70			
LCOE ($per kWh)	0.11				0.027				0.033			
CO_2 Emissions @ $40												
Annual Benefit's Value	4.07	3.89	8.41	10.97	4.07	3.89	8.41	10.97	40.70	38.93	84.09	109.69
Present Value Benefits	47.20	45.11	97.53	127.22	47.20	45.11	97.53	127.22	472.0	451.48	975.21	1,275.10
Net Present Value (NPV)	-559.2	-561.3	-508.9	-479.2	-203.6	-205.7	-153.27	-123.6	-2,327.7	-2,348.2	-1,824.5	-1,527.6
Benefit Cost Ratio (BCR)	0.08	0.07	0.16	0.21	0.19	0.18	0.39	0.51	0.17	0.16	0.35	0.45
EIRR in %	-	-	-	-	-	-	-	-0.46	-	-	-4.52	-1.60
CO_2 Emissions @ $80												
Annual Benefit's Value	6.01	5.83	10.35	12.91	6.01	5.83	10.35	12.91	60.02	58.27	103.43	129.03
Present Value Benefits	69.70	67.61	120.03	149.72	69.70	67.61	120.03	149.72	696.07	675.77	1,199.50	1,496.39
Net Present Value (NPV)	-536.7	-538.8	-486.4	-456.7	-181.1	-183.2	-130.8	-101.1	-2,103.6	-2,123.9	-1,600.2	-1,303.3
Benefit Cost Ratio (BCR)	0.11	0.11	0.20	0.25	0.28	0.27	0.48	0.60	0.25	0.24	0.43	0.53
EIRR in %	-	-	-	-	-7.53	-8.02	-1.06	1.23	-9.50	-10.14	-2.22	0.08
LCOH ($ per Kg) at 50% Costof Electrolyzer ($/Kg)	7.87 : 480				2.57 : 480				3.53 : 500			
Remarks	Not feasible in any scenario				Not feasible in any scenario				Not feasible in any scenario			

** Note: We have 4 scenarios for each project regarding gas displaced by hydrogen assuming; 1) Local Natural Gas Cost at Wellhead, 2) LNG at Qatar Contract Price, 3) Average of Contracted and Winter Spot Price 4) High LNG Winter Spot Price.*

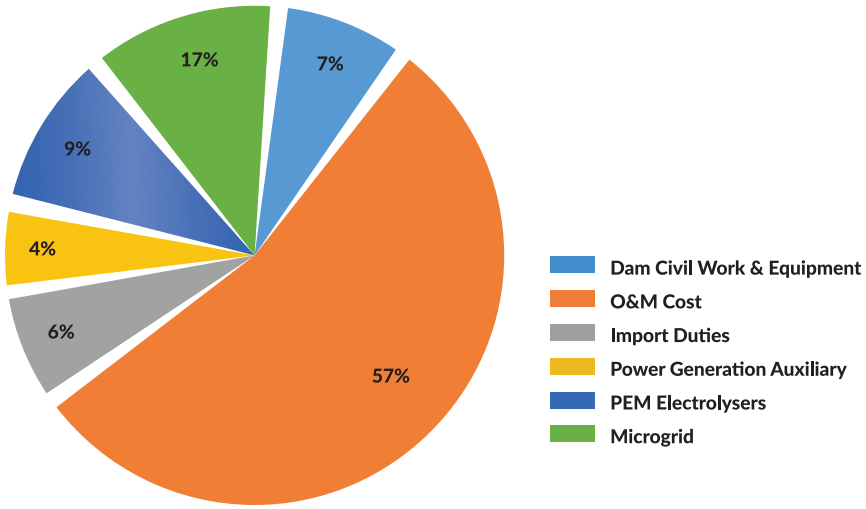
Table 59: Quaid-e-Azam Solar Park with Gas Grid Injection (US$ in Millions)												
Parameters	100 MW Electrolyzer on Existing Solar				100 MW Electrolyzer with 100 MWuplift with CQSola				1GW Electrolyzer from 1GW uplift withCQSola			
	Phase I - Option 1				Phase I - Option 1A				Phase II			
CAPEX	119				215				2400			
OPEX	42.7				4.3				48			
Present Value of Total Cost	606.42				250.80				2,799.7			
Scenarios *	1	2	3	4	1	2	3	4	1	2	3	4
10% increase in Cost												
Present Value of Total Cost	667.07				275.88				3,079.62			
Net Present Value (NPV)	-642.2	-644.3	-591.9	-558.0	-251.1	-253.2	-200.7	-171.0	-2,832.0	-2,852.3	-2,328.6	-2,031.7
Benefit Cost Ratio (BCR)	0.08	0.03	0.11	0.16	0.09	0.08	0.27	0.38	0.08	0.07	0.24	0.34
EIRR in %	-	-	-	-	-	-	-7.85	-3.52	-	-	-9.91	-4.80
LCOH ($ per Kg)	8.79				3.63				4.07			
LCOE ($ per kWh	0.12				0.030				0.036			
20% increase in Cost												
Present Value of Total Cost	727.70				300.96				3,359.59			
Net Present Value (NPV)	-702.9	-704.9	-652.6	-622.9	-276.2	-278.2	-255.8	-196.1	-3,111.9	-3,132.3	-2,608.6	-2,311.7
Benefit Cost Ratio (BCR)	0.03	0.03	0.10	0.14	0.08	0.08	0.25	0.35	0.07	0.07	0.22	0.31
EIRR in %	-	-	-	-	-	-	-9.41	-4.52	-	-	-12.24	-5.89
LCOH ($ per Kg)	9.59				3.96				4.44			
LCOE ($ per kWh)	0.13				0.032				0.040			
10% increase in Cost & decrease in Benefits												
Present Value of Total Cost	667.0		6		275.88				3,079.62			
Net Present Value (NPV)	-644.7	-646.7	-599.5	-572.7	-253.5	-255.5	-208.3	-181.5	-2,856.7	-2,875.1	-2,403.8	-2,136.5
Benefit Cost Ratio (BCR)	0.03	0.03	0.10	0.14	0.08	0.07	0.25	0.34	0.07	0.07	0.22	0.31
EIRR in %	-	-	-	-	-	-	-9.80	-4.73	-	-	-12.91	-6.13
LCOH ($ per Kg)	8.7		9		3.63				4.07			
LCOE ($ per kWh	0.1		2		0.030				0.036			
Remarks	Not feasible in		any scenario		Not feasible in any scenario				Not feasible in any scenario			

** Note: We have 4 scenarios for each project regarding gas displaced by hydrogen assuming; 1) Local Natural Gas Cost at Wellhead, 2) LNG at Qatar Contract Price, 3) Average of Contracted and Winter Spot Price 4) High LNG Winter Spot Price.*

3. Case No. 13: Run of the River Micro Hydro in the North

1MW power output hydroelectric scheme operating for 10 months of the year at flow of 1m^3 per second is the base case for the micro-hydro run of the river system. Similarly, 1MW electrical power supply for 2 months of the year in winter is the base design case for the energy storage and backup power system. This project costs $18.42 Million as one-time CAPEX and $0.92 Million annually as OPEX. Key elements of the life cycle cost of the project are shown in the chart below.

Figure: *Cost Structure: 1 MW Micro Hydro)*



A comparative analysis of all the three scenarios of Hydrogen for Electricity is presented in **Table 61**, which are not financially feasible as BCR remains very low. Its LCOE is $0.10 per kWh during the 10 months when water flows at its maximum level in the river. But when two months of frozen winter are included then LCOE increases to $0.40 per kWh as electricity during these two months is generated from Hydrogen which has been produced and stored during the 10 months period. Moreover, LCOH for this project is very high i.e., $30.11 per Kg. Therefore, it is not feasible even when the wider economic benefits such as carbon emission gains are valued at $40/t$CO_2$ and $80/t$CO_2$ as shown in **Table 61**.

We also mapped the sensitivity of all the three options assuming a i) 10 percent increase in cost, ii) 20 percent increase in cost and iii) Simultaneous 10 percent increase in cost and 10 percent decrease in benefits. Results are presented in **Table 62**. No Scenario is financially feasible.

Table 60: Micro Hydro with Energy Storage for the North Frozen Winter (US$ in Millions)							
Parameters	1 MW Electrolyzer (Hydrogen for Electricity)			1 MW Electrolyzer (Hydrogen for Cooking)**			
CAPEX	18.42			14.82			
OPEX	0.92			0.74			
PEM ElectrolyzerPrice $/kW	3580			3580			
Present Value ofTotal Cost	27.88			22.43			
Scenarios *	1	2	3	1 (Wood)		2 (LPG)	
Annual Benefits Value	0.008	0.021	0.019	0.079		0.021	
Present Value Benefits	0.093	0.244	0.220	0.916		0.244	
Net Present Value(NPV)	-27.79	-27.64	-27.66	-21.52		-22.19	
Benefit Cost Ratio(BCR)	0.003	0.009	0.008	0.041		0.011	
EIRR in %	-	-	-	-		-	
LCOH ($ per Kg)	30.11			30.11			
LCOE ($ per kWh)10 Months	0.10			0.10			
LCOE ($ per kWh)Whole Year	0.40			NA			
CO_2 Emissions @ $40							
Annual Benefit'sValue	0.017	0.029	0.031	CO_2 NeutralFuel		0.029	
Present ValueBenefits	0.196	0.337	0.362	-		0.337	
Net Present Value(NPV)	-27.68	-27.54	-27.52	-		-22.10	
Benefit Cost Ratio(BCR)	0.007	0.012	0.013	-		0.015	
EIRR in %	-	-	-	-		-	
CO_2 Emissions @ $80							
Annual Benefit'sValue	0.025	0.037	0.043	-		0.037	
Present ValueBenefits	0.295	0.430	0.503	-		0.430	
Net Present Value(NPV)	-27.59	-27.45	-27.38	-		-22.00	
Benefit Cost Ratio(BCR)	0.011	0.015	0.018	-		0.019	
EIRR in %	-	-	-	-		-	
Remarks	No Scenario is feasible			No Scenario is feasible			

** Note: We have 3 scenarios for each project regarding gas displaced by hydrogen assuming; 1) Local Natural Gas Cost at Wellhead, 2) Imported LPG Price, 3) Average of LPG and Local Gas Prices*

*** Though one more option with two scenarios is built to evaluate the potential of Hydrogen to be used as cooking fuel. Following two scenarios were built to impute the benefits value using; 1) Fuel wood prices, 2) Imported LPG Prices*

Table 61: Micro Hydro with Energy Storage for the North Frozen Winter (US$ in Millions)								
Parameters	1 MW Electrolyzer (Hydrogen for Electricity)				1 MW Electrolyzer (Hydrogen for Cooking)**			
CAPEX	18.42				14.82			
OPEX	0.92				0.74			
Present Value of Total Cost	27.88				22.43			
Scenarios *	1	2	3		1 (Wood)		2 (LPG)	
10% Increase in Cost								
Present Value of Total Cost	30.68				24.74			
Net Present Value (NPV)	-30.58	-30.43	-30.46		-23.83		-24.50	
Benefit Cost Ratio (BCR)	0.003	0.008	0.007		0.037		0.010	
EIRR in %	-	-	-		-		-	
LCOH ($ per Kg)	33.13				33.13			
LCOE ($ per kWh) 10 Months	0.11				0.11			
LCOE ($ per kWh) Whole Year	0.44				NA			
20% Increase in Cost								
Present Value of Total Cost	33.47				26.94			
Net Present Value (NPV)	-33.37	-33.22	-33.25		-25.99		-26.70	
Benefit Cost Ratio (BCR)	0.003	0.007	0.007		0.035		0.009	
EIRR in %	-	-	-		-		-	
LCOH ($ per Kg)	36.14				36.14			
LCOE ($ per kWh) 10 Months	0.12				0.12			
LCOE ($ per kWh) Whole Year	0.48				NA			
10% Increase in Cost & decrease in Benefits								
Present Value of Total Cost	30.68				24.74			
Net Present Value (NPV)	-30.59	-30.46	-30.49		-23.93		-24.52	
Benefit Cost Ratio (BCR)	0.003	0.007	0.006		0.033		0.009	
EIRR in %	-	-	-		-		-	
LCOH ($ per Kg)	33.13				33.13			
LCOE ($ per kWh) 10 Months	0.11				0.11			
LCOE ($ per kWh) Whole Year	0.44				NA			
Remarks	No Scenario is feasible				No Scenario is feasible			

* Note: We have 3 scenarios for each project regarding gas displaced by hydrogen assuming; 1) Local Natural Gas Cost at Wellhead, 2) Imported LPG Price, 3) Average of LPG and Local Gas Prices

** Though one more option with two scenarios is built to evaluate the potential of Hydrogen to be used as cooking fuel. Following two scenarios were built to impute the benefits value using; 1) Fuel wood prices 2) Imported LPG Prices

Moreover, another option (1MW Micro hydro – Hydrogen for cooking) was also evaluated that if the same hydrogen produced from 1MW electrolyzer is used as cooking fuel, instead of generating electricity, then both CAPEX and OPEX reduces by 19.54 and 19.57 percent respectively while benefits ensued to replace fuel wood worth $0.079 Million. Key elements of the cost of the project remain same, only costs associated with micro-grid i.e. $3.6 Million have been removed. However, LCOH remains the same while it's BCR substantially improves as shown in the Table: 03-A but the project stays unfeasible. The results of a sensitivity analysis on this case are presented in **Table 62**.

In addition to the financial analysis conducted, there are some safety and technical concerns related to hydrogen storage in this region that may be relevant to point out.

- High technology equipment would be in an extremely remote location where access for maintenance is difficult and local expertise will be low.
- A hydrogen compressor would be required, which would be operational for 10 months of the year. The associated noise levels may be unattractive in this mountain valley region.
- The hydrogen electrolyzer, fuel cell, compressor, powerhouse and power management systems will occupy several containers or buildings. In addition to this, to achieve the required amount of hydrogen storage an additional seventeen 20' containers of cylinders for high pressure compressed hydrogen at 300 bar would be required.
    - This would be a very 'ugly' concept in such a pristine natural environment.
    - This would present a large inventory of flammable hydrogen gas with 4,500 kg in total and with each module having a content of 260 kg of hydrogen.

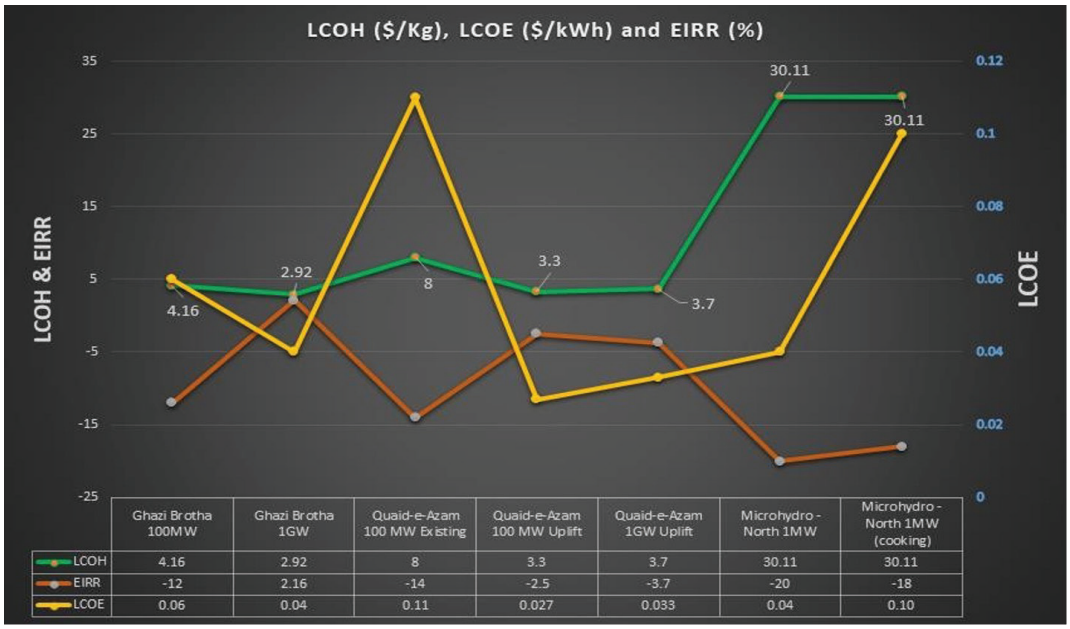
To enable power supply in this region, there are some potential alternative technologies to the hydrogen storage proposal analyzed here which may be possible in the short or long term.

- It must be borne in mind that the micro hydro scheme alone will deliver power for 10 out of 12 months of the year. Hydrogen energy storage has been proposed and would only be required to bridge two months of winter.
- Metal hydride storage was considered as an alternative to compressed gas hydrogen storage and was eliminated in an early phase of analysis of this scheme – it would be more invasive and expensive than compressed hydrogen.
- A diesel generator may be possible but would result in noise and air pollution. Transportation of the diesel will also be challenging in the remote location with cold temperatures. Heated storage for the diesel would be required to avoid solidification.
- Battery technology may be appropriate in the future but would not currently be recommended for a 2-month period: 30 x 2 x 24 x 1MW = 1,440 MWh of storage.
- A solid oxide fuel cell powered with LPG from LPG cylinders, or a small LPG storage tank may be a pragmatic solution for future investigation.

C. Conclusion of the Financial Modelling and Analysis

A summary of the financial analysis is presented in **Figure 74** below.

Figure 74: *Key Financial Metrics for the Scenarios Analyzed Within the Three Chosen Cases*



	Ghazi Brotha 100MW	Ghazi Brotha 1GW	Quaid-e-Azam 100 MW Existing	Quaid-e-Azam 100 MW Uplift	Quaid-e-Azam 1GW Uplift	Microhydro - North 1MW	Microhydro - North 1MW (cooking)
LCOH	4.16	2.92	8	3.3	3.7	30.11	30.11
EIRR	-12	2.16	-14	-2.5	-3.7	-20	-18
LCOE	0.06	0.04	0.11	0.027	0.033	0.04	0.10

Some important aspects to draw from the chart include:

- Some of the scenarios modelled for the Ghazi Barotha scheme have a positive EIRR. To achieve this, some hypothetical scenarios were considered that may become possible under certain policy conditions, eg zero power cost for curtailed potential hydro power generation.
- LCOE and LCOH are within international benchmarks for similar schemes at similar scale.
- EIRR is low or negative for most scenarios. It should be noted that a 7% discount rate has been applied, according to investment case analysis practices in place for government supported projects in Pakistan. In some other countries, schemes of a similar scale and technical nature may have positive EIRR due to lower discount rates and reduced cost of borrowing for infrastructure schemes.
- For the two schemes where self-investment in new power generation capacity was compared to power purchase, according to the tariffs in place today, self- generation was estimated to be less expensive. It is possible that the tariffs for hydro and solar renewable power generation are higher than current best practice technologies would permit. As the cost of renewable power generation is expected to fall over time, a tariff that accurately reflects the power generation cost would support hydrogen generation in the future.

Our results indicate that total system capital costs, including renewable power generation, hydrogen production, transmission, and utilization and electrolyzer utilization are the two most important factors to determine the LCOH and its financial feasibility. Furthermore, for the larger systems the system size does not matter a lot as increasing the scale from 100 MW to 1 GW in both cases (3 & 6) is not providing sufficient economies of scale or efficiency

gains. It is because solar panels and electrolyzers are added in modular fashion, so output is augmented on the fixed ratio, and it involves few synergies with the other infrastructure. These conclusions are to be expected and directionally align to other international studies on green hydrogen deployment.

Power cost also becomes an important determinant for all such scenarios where power is being purchased from the National Grid. Therefore, all such scenarios are not financially viable as the per kWh power tariff applied in these options is reasonably high i.e. $0.06 for hydel and $0.11 for solar. On the other hand, all such cases where power cost is being covered through incurring capital expenditures for new renewable power generation are also not financially viable though their LCOE is very reasonable. This is because CAPEX is very high, particularly the cost involved to construct the new canal and reservoir is substantial in Case 3. In Case 6, it is the electrolyzer utilization factor (i.e., 42 percent due to limited availability of sun) though its LCOE is also very reasonable.

In general, most of the cases analyzed are not financially attractive and they only begin to come close to being financially attractive under the following sensitivity scenarios:

- Low-cost Chinese AEC electrolyzer supply rather than high-cost European / North American supply, this was considered in the two cases where AEC equipment was specified.
- High LNG cost for non-contracted spot purchases during seasonal peak gas demand, i.e. winter months where heating is required (LNG was the alternative fuel to be replaced in 2 cases analyzed). This conclusion favors long term hydrogen storage, for example underground hydrogen storage in new salt caverns which could be possible west of Lahore.
- High CO_2 emissions cost based on potential taxation measures that may be considered in the future. This conclusion points to the importance of regulatory change to drive the transition from fossil fuels to clean hydrogen.
- Access to the lower domestic electricity tariff rather than the higher industrial tariff, for the cases where self-generation was not included in the scheme. This conclusion points to the critical nature of power purchase costs in the scheme viability and would suggest a review of power supply costs to clean hydrogen projects could make them more attractive.
- Zero power cost, under the assumption that curtailed variable hydel power might be available at some times of the year under a different regulatory pricing mechanism.

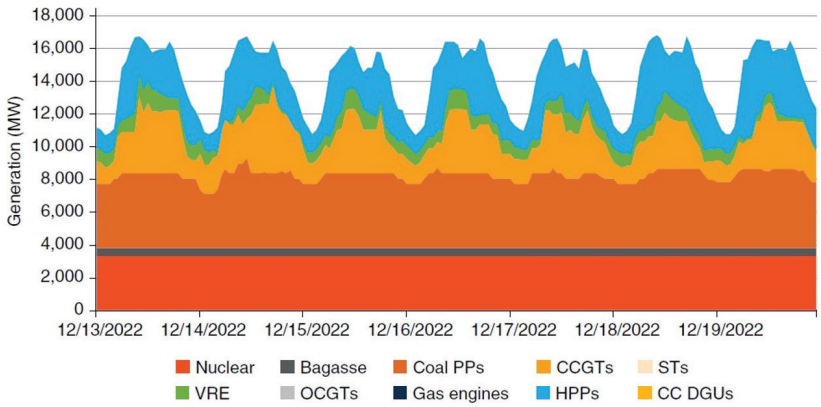
Although other utilization cases were not modelled, it is possible that hydrogen powered mobility (eg bus fleets), use of green hydrogen to substitute grey hydrogen for ammonia / urea fertilizer value chain or seasonal hydrogen energy storage may be more attractive that the LNG substitution grid injection case that was modelled. In addition to these ideas, hydrogen production and use as long-term energy storage with underground hydrogen storage in purpose-built salt caverns may be a utility scale project with national merit. For this concept to have a viable business case, the power pricing tariff would need adjustment to create a spread between the power purchase price at periods of low power demand on the grid and the power sale price at periods of high demand on the grid. This would enable a business model that utilizes cheap power during periods of excess capacity to generate hydrogen which can then be used to create power and sell that back to the grid at a higher rate during periods of high demand.

A regulatory change of this type to create a buy / sell spread to the power tariff based on grid loading may be considered in the future and may be beneficial as the percentage of variable renewable energy from solar (predictable daily variation) wind (less predictable weekly variation with predictable seasonal trends) and hydro (predictable seasonal trends) in the national mix grows to be higher than the current levels. At utility scale, the best combination of hydrogen energy storage may be with curtailed hydro power due to the very high peak to trough generation potential of the large dams in Pakistan which is driven by the combination of monsoon rains and snowmelt on the Himalaya and causes extreme seasonal cyclicality to the Indus and other major river systems.

Interestingly, in line with the above general conclusions, the case of Ghazi Brotha -100 MW with 3 months operations with zero power cost was analyzed to be a financially feasible scenario. Its BCR is 1.26:1 and EIRR is of 10.11 percent when the benefits are valued at High LNG Spot Price along and CO_2 emission reduction gains are valued at $\$80/tCO_2$. The background to this case assumes curtailed hydel power for three months of the year. Meaning that there is the potential for more electricity to be produced than can be dispatched to the grid and therefore the electricity it has zero value.

The merit dispatch order of power generation in Pakistan uses hydel for grid balancing. In an operational context, this can either be achieved by 'spilling' water over the top of the dam during periods of high water-level (eg the wet summer months) and not routing water to the electricity generation turbines in the powerhouse or simply shutting the gates to the turbines in the dryer months to conserve water in the dam. **Figure 75** below demonstrates that excess potential power generation capacity does indeed exist from the hydel generation in Pakistan and that this curtailed potential power generation capacity could potentially be profitably routed to generate hydrogen. The report from which this chart is extracted estimates that up to 50% curtailment rate would be reached by 2030 based on an additional 22GW of variable renewable power generation capacity (solar 11GW, wind 11GW) which corresponds to the Government of Pakistan's target by 2030. Under these circumstances, a review of the power tariff to enable curtailed power to be used for free, or a reduced cost for renewable hydrogen generation through electrolysis of variable renewable power and energy storage would have significant merit.

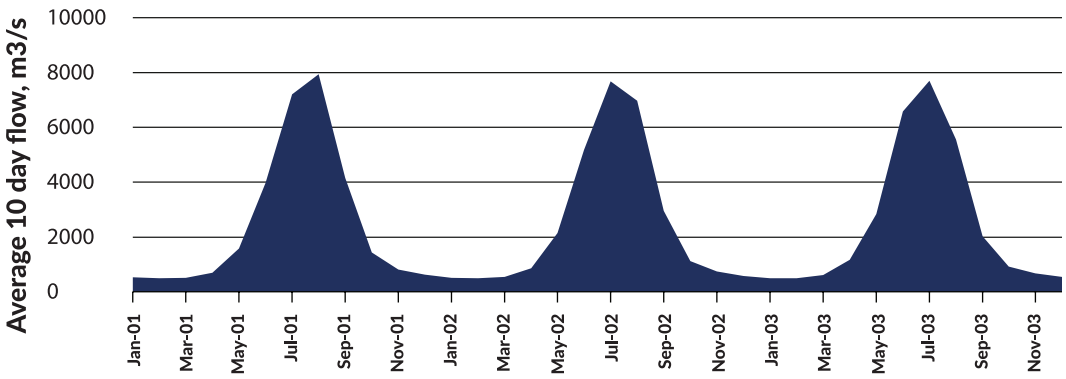
Figure 75: *Sample Dispatch for One Week in December 2022* [67]



67. *World Bank. 2020. Variable Renewable Energy Integration and Planning Study. Pakistan Sustainable Energy Series. Washington, DC: World Bank.*

Figure 76 demonstrates the seasonality of the power generation from the Tarbela dam. This indicates that there may indeed currently be 'wasted' excess power potential which might be available for approximately 3 months each year. Therefore, there is possibility that this case could exist. It is noted that the function of the Mangla and Tarbela dams is to serve many purposes, such as providing irrigation water at appropriate times of the year and avoiding catastrophic flooding in addition to power generation. So, a host of factors are continuously being balanced to optimize the use of these national resources.

Figure 76: *Seasonal Water Flow Through / Over the Tarbela Dam*[68]



However, in Pakistan today, there is no regulatory pricing mechanism to supply excess hydel power to a hydrogen electrolyzer at zero cost. There is also no CO_2 emissions tax which would make the costs of power generation from LNG high and equivalent to the costs of renewable hydrogen generation. So, this case is indeed interesting, and its financial merit shows what could be possible if curtailed potential power of this type could be made available for hydrogen generation through appropriate regulatory changes in the power tariff and a CO_2 emissions cost were to be associated with fossil fuel power generation. These factors point to this case being financially unviable under current policy regime but having the potential to be financially attractive under policies that may be considered for the future.

In contrast to the Ghazi Barotha case, the case of the 1 MW run of the river micro hydro with hydrogen energy storage for power generation during the frozen winter months is not financially feasible under any circumstances that were modelled. This conclusion applies for hydrogen production and storage for electricity generation as well as the idea of using the hydrogen for cooking. The social merits of this project are perceived to be very high, however, the financial considerations, high levels of technical risk and complexity of this project (which is proposed for a location that would be very difficult to access during critical periods for maintenance or support) make this project unattractive as a pilot.

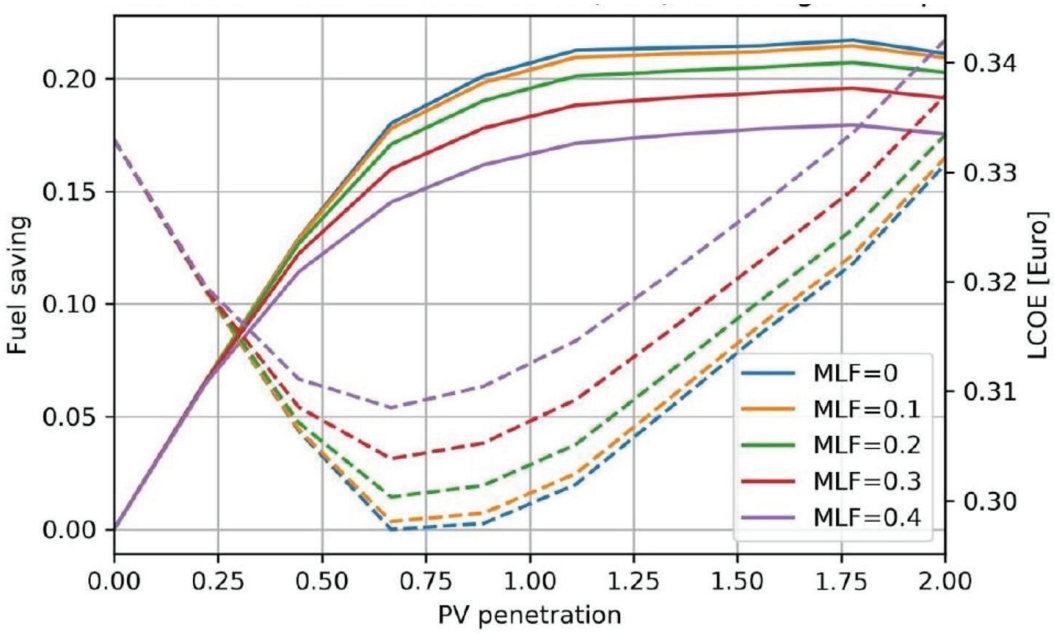
The conclusion on the unsuitability of this micro-grid with seasonal hydrogen energy storage concept for the region considered should not in any way discourage the development of micro-hydro schemes in the mountainous regions in the north of Pakistan for power generation. Nor should it discourage other micro grids with battery or hydrogen energy storage which may be appropriate to combine with wind or solar power generation in many other parts of

68. *World Bank Report No 60963-PK*

Pakistan. These cases have completely different technical and economic profiles than the case considered in this report which may make then highly attractive.

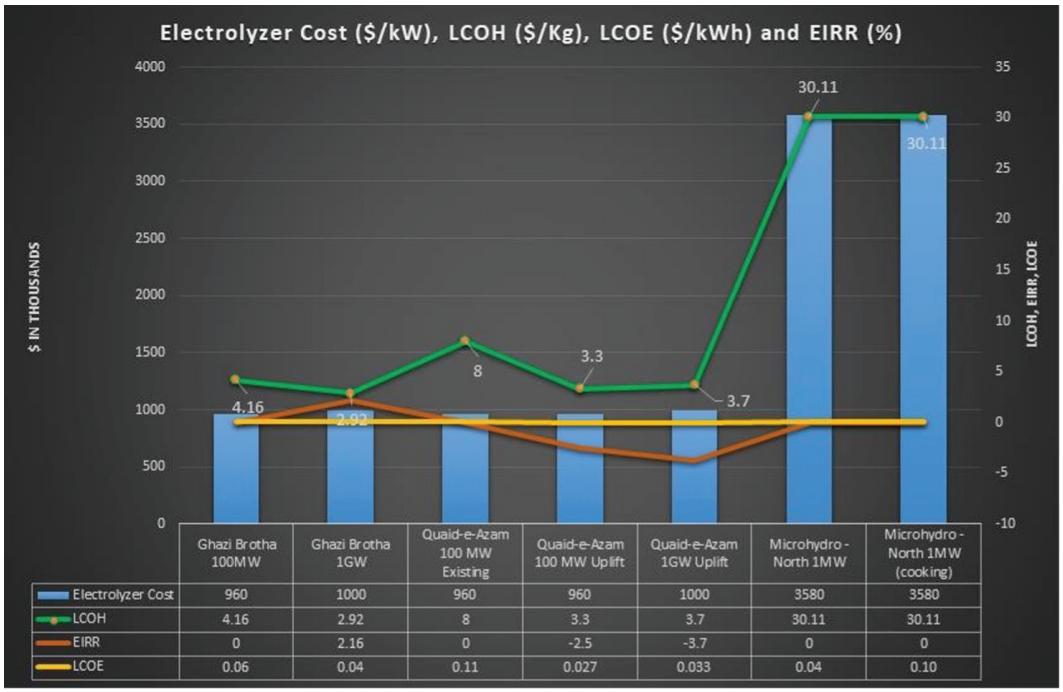
It should be noted that this system is intended to act as a microgrid system to provide stable power supply through the year. The conventional solution for power supply in a remote area would be a diesel engine system. **Figure 77** below shows a study in Nepal for such a case, with an LCOE of around 0.33$/kWh based on zero PV and a diesel oil price of €1.18/L (circa USD1.36/litre). In this 1MW micro hydro with hydrogen storage, the LCOE would be 0.35$/kWh, if no import tax is applied to the equipment. This zero-import taxation could be possible if government policy were to support hydrogen development as an energy vector within a national framework. This is competitive to the conventional solution. Furthermore, the hydrogen system will provide clean solution, without CO_2, PM, SOx and NOx emissions from the diesel generator. On this comparative basis, the system can be seen to have merit and potential for deployment.

Figure 77: *LCOE for a Diesel-Powered Stand-Alone Power System / Backup Generator for a Village in Nepal*[69]



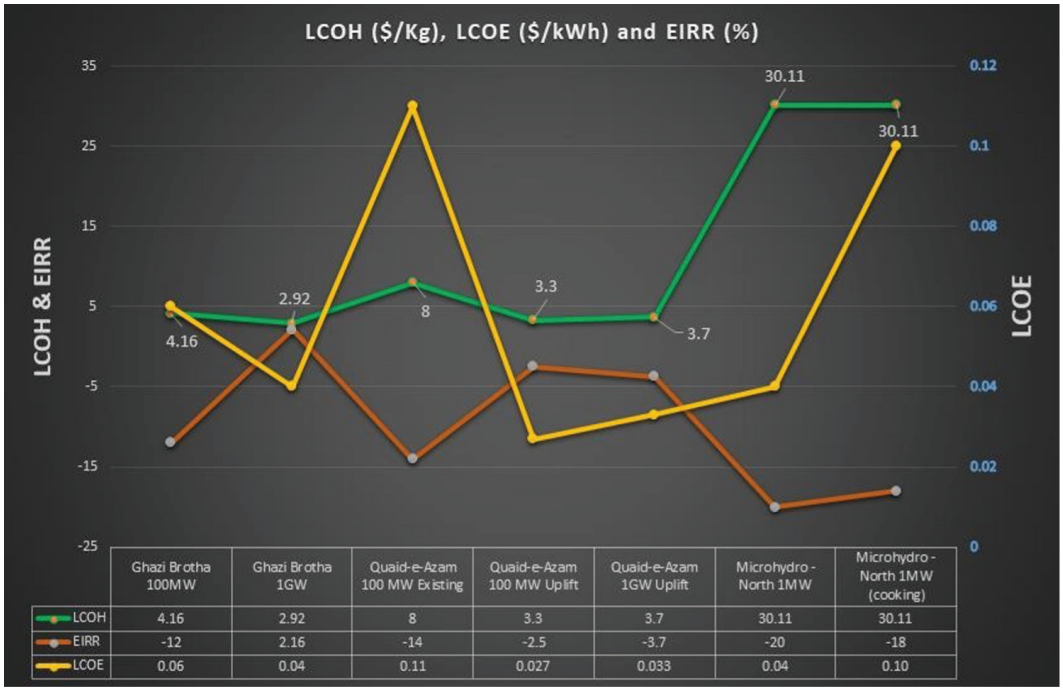
69. *Report IEA-PVPS T9-19:2019: IEA PVPS Task 9 Optimal Integration of Photovoltaics in Micro-Grids that are dominated by Diesel Power Plants*

Figure 78: *Electrolyzer Cost ($/kW), LCOH ($/Kg), LCOE ($/kWh) and EIRR (%)*



	Ghazi Brotha 100MW	Ghazi Brotha 1GW	Quaid-e-Azam 100 MW Existing	Quaid-e-Azam 100 MW Uplift	Quaid-e-Azam 1GW Uplift	Microhydro - North 1MW	Microhydro - North 1MW (cooking)
Electrolyzer Cost	960	1000	960	960	1000	3580	3580
LCOH	4.16	2.92	8	3.3	3.7	30.11	30.11
EIRR	0	2.16	0	-2.5	-3.7	0	0
LCOE	0.06	0.04	0.11	0.027	0.033	0.04	0.10

Figure 79: *Cost Structure ($Millions), LCOH ($ per Kg) and EIRR (%)*



	Ghazi Brotha 100MW	Ghazi Brotha 1GW	Quaid-e-Azam 100 MW Existing	Quaid-e-Azam 100 MW Uplift	Quaid-e-Azam 1GW Uplift	Microhydro - North 1MW	Microhydro - North 1MW (cooking)
LCOH	4.16	2.92	8	3.3	3.7	30.11	30.11
EIRR	-12	2.16	-14	-2.5	-3.7	-20	-18
LCOE	0.06	0.04	0.11	0.027	0.033	0.04	0.10

VII. PILOT PROJECT PROPOSALS

A. Priority Pilot Project - Hydrogen Electrolysis at the Ghazi Barotha Dam with Hydrogen Injection to the Local Natural Gas Grid

The motivation for a pilot demonstration project goes beyond immediate financial viability of the scheme and includes objectives such as institutional capacity building, learning and public demonstration to show the potential of hydrogen as a clean energy vector for the future. These 'intangible greater goals' are impossible to quantify in a simple financial analysis but can be justified to support the vision of a clean energy transition, even if they come at a moderate but affordable cost today.

For these reasons, a 5MW electrolyzer pilot at Ghazi Barotha is recommended as a potential pilot project. The utilization case could either be grid injection, as proposed in the financial analysis, or a small-scale hydrogen mobility scheme with one or more new dedicated FCEV bus fleets for the local cities of Peshawar, Nowshera, Islamabad or Rawalpini could be proposed for greater accessibility and visibility to the potential use of hydrogen as clean energy.

B. Alternative Pilot Project - Hydrogen Electrolysis at the Quaid e Azam Solar Park with Hydrogen Injection to the Local Natural Gas Grid

As an alternative or additional pilot project, a similar size electrolyzer with similar utilization case options could be considered for the solar park at Quaid e Azam. In that case, the cities of Bahawalpur or Multan would be potential choices for the hydrogen powered fuel cell bus mobility scheme. Gas grid injection would be possible very close by at Bahawalpur. However, the Quaid e Azam solar park is regarded as variable renewable power that cannot be curtailed and is therefore one of the first power plants to dispatch to the grid (along with the nuclear base-load plants). For this reason, the potential for tapping into 'wasted' excess power generation potential does not exist in the same way that it does for the Ghazi Barotha scheme.

VIII. INSTITUTIONAL APPARATUS AND LEGAL FRAMEWORK

A. Stakeholder Mapping

1. Ministry of Energy

The Ministry of Energy (MoE) erstwhile Ministry of Water and Power (MoWP) is the executive arm of the Government of Pakistan. The newly created ministry has two divisions - the Power Division and the Petroleum Division. The following sections will discuss Power and Petroleum Division in greater details respectively. [70]

a. Power Division

The Power Division deals with issues related to electricity generation, transmission, and distribution. It deals with the electricity sector through a set of agencies and autonomous bodies. Moreover, it executes the federal government's strategies and policies in the power sector of Pakistan. The Power Division coordinates with the provincial governments and relevant agencies in realizing national power policy objectives. MoE has designated Boards and Authorities to deal with matters related to Renewable Energy, Energy Access, Energy Demand Projections, Tariffs and Energy Efficiency and Conservation.[71]

NEPRA; AEDB, PPIB, PCRET, NEECA, DISCOs, CPPA-G

The National Electric Power Regulatory Authority (NEPRA) was established through an act in 1997 as an essential body to execute a strategic plan of privatizing the power sector. NEPRA's role was to supervise the functions of restructured power structure with the mandate of safeguarding the interests of various stakeholders. The authority was established to develop and follow a regulatory framework. The aim was to ensure reliable, affordable and effcient electricity to power consumers.

To transform the power sector from monopoly structure to competitive market; and to maintain a balance between consumers and service providers in the country. Moreover, the authority issues licenses for power generation, transmission, and distribution along with setting tariffs for such facilities. Regarding the RE development, NEPRA determines tariff for power generation from various RETs, both at the federal and the provincial levels. [72]

70. *http://www.mowp.gov.pk/ taken November 2020*
71. *http://www.mowp.gov.pk/ Date Taken November 26, 2020*
72. *https://www.nepra.org.pk/ Date Taken November 27, 2020*

Alternative Energy Development Board (AEDB) is the agency of the Federal Government with the main objective to facilitate, promote and encourage development of Renewable Energy in Pakistan and with a mission to introduce Alternative and Renewable Energies (AREs) at an accelerated rate. The administrative control of AEDB is with Ministry of Energy. The Government of Pakistan has inter alia mandated AEDB to:

- Implement policies, programs, and projects through private sector in the field of ARE.
- Assist and facilitate development and generation of ARE to achieve sustainable economic growth.
- Encourage transfer of technology and develop indigenous manufacturing base for ARE Technology.
- Promote provision of energy services that are based on ARE resources.
- Undertake ARE projects on commercial scale. (AEDB Act 2010)

In 2006 Policy, AEDB was tasked to ensure 5% of total national power generation capacity to be generated through renewable energy technologies by the year 2030. In addition, under the remote village electrification program, AEDB has been directed to electrify 7,874 remote villages in Sindh and Baluchistan provinces through ARE technologies.[73]

The Federal Government established AEDB as a statutory organization by announcing and promulgating the AEDB Act in May 2010. The Act bestowed upon AEDB the authorities and the responsibilities for the promotion and development of AREs. Recently, AEDB has prepared RE Policy 2019 with generation target of 20% RE generation by 2025 and 30% by 2030.

Private Power and Infrastructure Board (PPIB) was created in 1994 as a "One-Window Facilitator" to promote private investments in power sector. In 2012 PPIB was made a statutory organization through Private Power and Infrastructure Board Act 2012 (Act VI of 2012). The role of PPIB has been further expanded by the Government of Pakistan by allowing it to facilitate public sector power and related infrastructure projects in IPP mode, for which PPIB's Act has been amended in November 2015. PPIB approves IPPs, issues LOIs & LOSs (including Tripartite LOSs), approves Feasibility Studies, executes Implementation Agreements (IAs) and provides Government of Pakistan guarantees.

- Recommend and facilitate development of power policies.
- Consult the concerned Provincial Government, prior to taking a decision to construct or cause to be constructed a hydroelectric power station in any Province and to take decisions on matters pertaining to power projects set up by private sector or through public private partnership and other issues pertaining there.
- Coordinate with the Provincial Governments, local governments, Government of Azad Jammu and Kashmir (AJ and K) and regulatory bodies in implementation of the power policies, if so required.
- Coordinate and facilitate the sponsors in obtaining consents and licenses from various

73. *Source: http://www.aedb.org/ Date Take November, 25, 2020*

agencies of the Federal Government, Provincial Governments, local governments and Government of AJ and K.

- Work in close coordination with power sector entities and play its due role in implementing power projects in private Sector or through public private partnership or for public sector power projects as per power system requirements.
- Function as a one-stop organization on behalf of the Federal Government and its Ministries, Departments, and agencies in relation to private power companies, sponsors, lenders and whenever necessary or appropriate, other interested persons.
- Draft, negotiate and enter into security package documents or agreements and guarantee the contractual obligations of entities under the power policies.
- Execute, administer, and monitor contracts.
- Prescribe and receive fees and charges for processing applications and deposit and disburse or utilize the same, if required.
- Obtain from sponsors or private power companies (as the case may be) security instruments and encash or return them, as deemed appropriate.
- Act as agent for development, facilitation and implementation of power policies and related infrastructure in the Gilgit-Baltistan areas and AJ & K.
- Prescribe, receive, deposit, utilize or refund fees and charges, as deemed appropriate.
- Open and operate bank accounts in local and foreign currencies as permissible under the laws of Pakistan.
- Commence, conduct, continue and terminate litigation, arbitration or alternate dispute resolution mechanisms at whatever levels may be necessary or appropriate and hire and pay for the services of lawyers and other experts, therefore.
- Appoint technical, professional, and other advisers, agents, and consultants, including accountants, bankers, engineers, lawyers, valuers and other persons in accordance with section 11.
- Hire professional and supporting staff and, from time to time, determine the emoluments and terms of their employment, provided always that at no stage shall such emoluments be reduced from such as are agreed in the contracts with such persons.
- Perform any other function or exercise any other power as may be incidental or consequential for the performance of any of its functions or the exercise of any of its powers or as may be entrusted by the Federal Government to meet the objects of the Act. [74]

Pakistan Council of Renew Energy Technologies (PCRET) was established by merging the National Institute of Silicon Technology (NIST) and the Pakistan Council for Appropriate Technologies (PCAT) on May 8, 2001. PCRET is under the administrative control of Ministry of Science and Technologies. It is the prime institution in the country for coordinating R&D and promotional activities in different renewable energy technologies. Council has close interaction and working relationship with NGO's & Provincial Agriculture Welfare departments, Local Government & Rural development offices & other organization working for the socio-economic development of the rural & semi urban areas of the country. [75]

74. *Source: https://www.ppib.gov.pk/ Date Taken November 26, 2020*
75. *Source: http://www.pcret.gov.pk/ Date Taken November 29, 2020*

The National Energy Efficiency & Conservation Authority (NEECA) is an Authority established under the Ministry of Energy (Power Division) and serves as a federal focal agency mandated for initiating, catalyzing, and coordinating all Energy Conservation activities in different sectors of economy. The authority to provide for establishment of institutions and enunciation of mechanism and procedures to provide for effective conservation and efficient use of energy. NEECA has been charged with a wide range of responsibilities including (NEECA Act 2016):

- To formula energy conservation programs in all the potential energy consuming sectors.
- Planning and initiating energy conservation actions on nation-wide basis.
- To develop a comprehensive data base on opportunities for energy conservation.
- Supporting training activities on energy conservation applications.
- Undertaking field research and pilot demonstration activities on specific energy conservation options and technologies;[76] and
- Monitoring the implementation of conservation programs by other public and/or private sector entities.

b. Petroleum Division

Petroleum Division deals with issues related to Petroleum and Natural Gas i.e. exploration, upstream, midstream, and downstream issues. The Petroleum Division deals with Petroleum and Gas Sector through a set of agencies and autonomous bodies.[77]

OGRA, SNGPL, SSGC, OGDCL

Oil and Gas Regulatory Authority (OGRA) was established by the Federal Government on March 28, 2002, in pursuance of the Oil and Gas Regulatory Authority Ordinance, 2002. The objective of OGRA is to "foster competition, increase private investment and ownership in the midstream and downstream petroleum industry, protect the public interest while respecting individual rights and provide effective and efficient regulations". Consequent to the establishment of OGRA, the Natural Gas Regulatory Authority (NGRA) was subsumed by the OGRA. All properties and works done by the NGRA were transferred to and protected under the OGRA Ordinance.

The Authority has the exclusive power to grant licenses for regulated activities in the Natural Gas, Compressed Natural Gas (CNG), Liquefied Petroleum Gas (LPG), Liquefied Natural Gas (LNG), and Oil sectors. These activities include the construction of pipelines, development of transmission and distribution network, sale and storage of Natural Gas, installation, production, storage, transportation, and marketing of CNG, LPG and LNG, laying the pipelines, establishing/operating refineries, construction/operation of storages, lube oil blending plants and marketing of petroleum products in the oil sector. Some of the specific major functions are:

- Determination of revenue requirement and prescribed prices of natural gas utilities and notification of prescribed and consumers sale prices.

76. *Source: https://www.neeca.gov.pk/ Date Taken November 28,2020*
77. *Source: http://www.mpnr.gov.pk/ Date Taken November 30, 2020*

- Computes & notifies ex-refinery price of SKO including ex-depot prices of SKO & E-10 and Inland Freight Equalization Margin (IFEM) for all products.
- Monitoring the pricing of petroleum products under the deregulated scenario.
- Enforcement of technical standards and specifications (best international practices) in all the regulated activities.
- Resolution of public complaints and disputes against licensees and between licensees [78]

Sui Northern Gas Pipelines Ltd. (SNGPL) is the largest integrated gas company serving more than 6.8 million consumers in North Central Pakistan through an extensive network in Punjab, Khyber Pakhtunkhwa, and Azad Jammu & Kashmir. The Company has over 50 years of experience in operation and maintenance of high-pressure gas transmission and distribution systems. It has also expanded its activities as Engineering, Procurement and Construction (EPC) Contractor to undertake the planning, designing and construction of pipelines, both for itself and other organizations.

Sui Northern Gas Pipelines Ltd. (SNGPL) was incorporated as a private limited company in 1963 and converted into a public limited company in January 1964 under the Companies Act 1913, now The Companies Act 2017, and is listed on the Pakistan Stock Exchange (PSX).

SNGPL transmission system extends from Sui in Baluchistan to Peshawar in Khyber Pakhtunkhwa comprising over 9,123.75 KM of Transmission System (Main lines & Loop lines). The distribution activities covering 4,967 main towns along with adjoining villages in Punjab & Khyber Pakhtunkhwa are organized through 16 regional offices. Distribution system consists of 135,857 KM of pipeline. SNGPL has over 6.8 million consumers comprising Commercial, Domestic, General Industry, Cement and Fertilizer Power Sectors. Annual gas sales to the consumers were 623,724 MMCF during Jul 2019 - Jun 2020.

With the planned receipt of additional 1200 MMCFD RLNG into SNGPL›s transmission system due to shortfall of indigenous gas supplies, SNGPL had managed to secure the completion of magnanimous pipeline infrastructure project involving approximately 1100 Kms pipelines of diameter 42» - 16» along with installation of 35000 HP compression. With the energization of LNG terminals in the country and after completion of RLNG transport infrastructure & pipelines, RLNG is being supplied to all categories of consumers including Industrial, Power, Cement, CNG, Commercial and Domestic.[79]

Sui Southern Gas Company (SSGC) is a Public Listed Large-Scale Company (LSC) and is a Pakistan's leading integrated gas Company. The Government of Pakistan directly and indirectly owns the majority of the shareholding of Company. The company is engaged in the business of transmission and distribution of natural gas besides installation of high- pressure transmission and low-pressure distribution systems.

SSGCL transmission system extends in the Provinces of Balochistan and Sindh comprising over 3,614 KM of high-pressure pipeline ranging from 12" – 42" in diameter. The distribution activities covering over 1200 towns in the Sindh and Balochistan are managed through its regional offices. About 384,979 million cubic feet (MMCF) gas was sold in FY 2015-2016 to

78. *Source: http://www.ogra.org.pk/ Date taken 01 December,2020*
79. *https://www.sngpl.com.pk/web/ Date Taken 02, December, 2020*

around 2.8 million industrial, commercial, and domestic consumers in these regions through a distribution network of over 44,761 Km. The company also owns and operates the only gas meter manufacturing plant in the country, having an annual production capacity of 356,000 meters on single shift basis.[80]

Oil and Gas Development Company Ltd. OGDCL is the leading organization for oil and gas exploration owned by Government of Pakistan. The Company strategizes of accelerating oil and gas exploration, adding to its reserves, early development of newly discovered fields and strengthening of its oil and gas production base in order to enhance indigenous production of the country and create value for its shareholders.[81]

2. Ministry of Climate Change

Pakistan has been rated as one of the most climate-vulnerable country, which will have a recurrence of climate-related disasters. The Ministry of Climate Change has been vested with the mandate to comprehensively address disaster management along with spearheading national climate change initiatives both in adaptation and mitigation. According to the mandate given, this Ministry is engaged in the following activities:[82]

- To act as a focal federal institution to fulfill international obligations under various Multilateral Environmental Agreements (Conventions, Protocols, Treaties, etc).
- To establish National Environmental Quality Standards
- To facilitate and harmonize environmental standards, laws, acts, and policies at the national level.
- To undertake surveys, assessments, and maintain a national environmental database. It is a mandatory requirement under Pakistan Environment Protection Act '1997 to produce a State of Environment Report on annual basis; Surveys, assessments, and monitoring have to be regularly undertaken to respond to the Multilateral Environmental Agreements (MEAs).
- Coordination and monitoring of the implementation of the environment and climate change agreements with other countries, international agencies, and forums.
- Development of national strategies and action plans, to meet international obligations. As an obligation under MDGs and SDGs Ministry of Climate Change is currently engaged in the development of national strategies and action plans for implementation of National Environment Policy, National Sanitation Policy, National Drinking Water Policy, and National Climate Change Policy. To this end, the Division has revived National Environment Policy Implementation Coordination Committee and National Drinking Water and Sanitation Policies Implementation Coordination Committee, both the Committees comprise of all stakeholders including representatives from provinces / AJK / GB / FATA Governments / Administrations. The Ministry is also in the process of finalizing National Sustainable Development Strategy for which provincial consultation workshops have already taken place.

80. *https://www.ssgc.com.pk/web/ Date Taken 03, December, 2020*
81. *https://ogdcl.com/ Date Taken December 03, 2020*
82. *http://www.mocc.gov.pk/ Date Taken November 20, 2020*

- To deal with trans-boundary and regional environmental issues. Trans-boundary air pollution includes, Asian Brown Cloud (ABC), winter smog, health impact studies, water contamination and availability, climate change and glacial melt.
- Coordination between inter and intra-provincial governments in the context of climate change and global warming: e.g., water availability and contamination complaints from the lower riparian provinces, protection of forests in northern areas, development of interprovincial development projects of communication, energy pipelines and transmission lines etc.
- To promote research and technical cooperation, GCISC is working on climate change impact studies.
- To facilitate, organize, participate, and represent Pakistan at regional and international fora: Being Designated National Authority (DNA) for number of MEAs, it is an obligatory requirement for the Ministry of Climate Change to attend the meeting, Conference of Parties (COPs) and report country status.
- To liaise with international donors/agencies UN Agencies-UNDP, UNEP, UNESCAP, UN-Habitat, UNICEF, UNIDO; JICA, GEF, World Bank, Asian Development Bank etc.
- To deal with current and emerging International Environmental Funds, (GEF, Green Climate Fund, Adaptation Fund, Climate Investment Fund, REDD+, MLF, ABS, GSF, SWA NPRI etc) and act as the focal point for One UN Joint Program on Environment.
- To act as Secretariat to Pakistan Environment Protection Council (PEPC): PEPC is the apex body under the chairmanship of the Prime Minister to give policy direction for environmental compliance. Ministry of Climate Change is the secretariat of PEPC.
- Formulation of national policies, plans, strategies, and programs regarding ecology, forestry, wildlife, biodiversity, climate change and desertification. Coordination, monitoring and implementation of environmental agreements with other countries, international agencies, and fora.
- Facilitating inter-provincial coordination and national planning on forestry, wildlife, biodiversity, wetlands, and sustainable land management. Screening and processing of federal projects of PSDP funding. Facilitation in Global Environment Facility (GEF) and other donor-assisted projects implemented by provinces and NGOs.

- Supervision of:
  - Zoological Survey of Pakistan (ZSP)
  - Pakistan Environmental Protection Agency (Pak EPA) (with the jurisdiction to work in ICT to avoid any duplication)
  - National Disaster Management Authority (NDMA)
  - Global Change Impact Study Center (GCISC)
  - Pakistan Environmental Planning and Architectural Consultants (PEPAC)

Environmental Protection Agencies

Pakistan Environmental Protection Agency is an attached department of the Ministry of Climate Change and responsible to implement the Pakistan Environmental Protection Act, 1997 in the country. An Act to provide for the protection, conservation, rehabilitation, and improvement of environment, for the prevention and control of pollution, and promotion of sustainable development. Pakistan Environmental Protection Agency also provides all kind of technical assistance to the Ministry of Climate Change. These are the following agencies working under the umbrella of Ministry of Climate Change.

Environmental Protection Department, Punjab
Sindh Environmental Protection Agency
Environmental Protection Agency, KPK
Environmental Protection Agency, Balochistan
Environmental Protection Agency, AJK
Environmental Protection Agency, Gilgit Baltistan

3. Ministry of Planning Development and Special Initiatives

The Planning Commission (denoted as PC) is a financial and public policy development institution of the Government of Pakistan. The Commission comes under Ministry of Planning, Development and Reforms. The Planning Commission undertakes research studies and state policy development initiatives for the growth of national economy and the expansion of the public and state infrastructure of the country in tandem with the Ministry of Finance (MoF).

The commission have had a major influence and role in formulating the highly centralized and planned five-year plans for the national economy, for most of the 20th century in Pakistan. Although the five-year plans were replaced by Medium Term Development Framework, the commission still played an influential and central role in the development of the program.

Furthermore, the Public Sector Development Programs (PSDP) also placed under the domain of the planning commission.[83]

a. Energy Wing

Energy Wing works under Ministry of Planning Development and Special initiatives. All projects (PC-1) submitted from different government entities related to energy sector for budgetary allocation from PSDP (Public Sector Development Program) are reviewed by Energy Wing. Energy Wing plays very important role in appraisal process of PC-1s.

B. Post 18th Amendment Legal and Regulatory Framework

Passed by the National Assembly of Pakistan on April 8th, 2010, the 18 Amendment to the Constitution moves the structural affairs of the country from a mainly centralized to a largely decentralized federation. The amendment gives provinces the authority to regulate policy areas including the electricity and natural gas sector for enabling a conducive environment for the development of energy sector.

83. *https://www.pc.gov.pk/ Date Taken December 04, 2020*

1. Article 157 and 158 of the Constitution of Pakistan

After the 18th Amendment to the Constitution of Pakistan, electricity and natural gas are the subjects comes under Part II of the Federal Legislative List. The articles dealing with power is mentioned below:

Electricity

a. The Federal Government may in any Province construct or cause to be constructed hydro- electric or thermal power installations or grid stations for the generation of electricity or lay or caused to be laid inter-Provincial transmission lines [:] Provided that the Federal Government, prior to taking decision to construct or cause to be constructed, hydro- electric power station in any Province, shall consult the Provincial Government concerned.

b. The Government of any Province may —
   i. To the extent electricity is supplied to that Province from the national grid, requires supply to be made in bulk for transmission and distribution within the province;
   ii. Levy tax on the consumption of electricity within the province;
   iii. Construct power houses and grid stations and lay transmission lines for use within the province and;
   iv. Determine the tariff for distribution of electricity within the province.

c. In case of any dispute between the Federal Government and Provincial Government in respect of any matter under this article, any of the said Governments may move the Council of Common Interests for resolution of the dispute.

Priority of requirements of natural gas. The province in which a well-head of natural gas is situated shall have precedence over other parts of Pakistan in meeting the requirements from the well-head, subject to the commitments and obligations as on the commencing day.[84]

A general reading of article 157 indicates that the federal government may make laws as far as construction of power projects and grid installations and inter-provincial transmission lines are concerned. But the word «may» suggest that it is a directing provision rather than a mandatory one. This means that the subject is not under exclusive federal power. In fact, it implies that the relevant provincial governments need to be taken into confidence. It can be inferred that the federal government will not construct a hydro or a thermal power station without the consultation of the relevant province. Article 157 outlines provincial mandate with regards to electricity generation, transmission, and distribution. A province may construct power projects and grid installations and transmission lines on its own but only for use within the boundaries of that province. Moreover, any province may also determine tariff for electricity distribution within its geographical limits.

Similarly, in article 158 the priority of requirements of natural gas. That the province in which the reservoirs/well head of the natural gas have become the precedence over the other areas of the Pakistan to utilized it. But this utilization is the subject to commitments and obligations.

84. *Source: http://www.pakistani.org/pakistan/constitution/ Date Taken December 07, 2020*

2. Provincial Planning and Development Departments

Planning and Development (P&D) Departments, Provincial Governments are premier planning body in the provinces. It formulates all development; planning policy matters and plans to execute the policy. Provincial Five Years Plans (FYP) contain development policy while annual Public Sector Development Programs (PSDPs) are planned to implement FYP policies concerning social, infrastructure and productive sectors. Small and medium range projects are accommodated in PSDP. P&D department has various studies and surveys conducted for use in planning. District profiles, Poverty Reduction Strategy Paper and Multiple Indicator Cluster Survey (MICS) are some of instances of efforts for better planning.

3. Provincial Energy Departments

The provincial energy departments work under the purview of respective provincial governments for implementation of energy schemes within the provinces. These departments support the exploitation of Renewable Energy within their jurisdiction either on their own or in cooperation with AEDB. Most of the departments have organized their own one-window services to set up RE projects at the provincial level. Besides, the provincial agencies facilitate RE deployment by expediting land allocation process and permitting the private sector to develop RE projects.

Most of the provinces have initiated their own RE development programs. The Government of Punjab has allocated 6500 acres of land to develop 1000 MW of solar PV projects of which 400 MW has been commissioned and connected to the national grid (Quaid e Azam Solar Power (Pvt.) Ltd., 2017). Besides, the Punjab government has also decided to solarize 20,000 schools in the province with a primary focus on remote areas (PID, 2017). On the other hand, the Department of Energy, Sindh, has introduced Sindh Land Grant Policy for Renewable Energy Projects 2015 and issued letters of intent (LOIs) of 2485 MW capacity for wind and 1550 MW of solar PV projects. These projects have not progressed beyond their grid approvals due to changes in the regulatory framework at the federal level. Similarly, KPK and Baluchistan Government has taken steps for inclusion of RE, where the focus has been Hydro and Solar respectively.

4. Provincial Environmental Protection Departments

Environmental degradation is escalating rapidly at the national and global level. Provincial Environment Protection Departments was established to combat this problem. Environment Protection Departments, Provinces created Environment Protection Agencies (EPAs) which are responsible for the protection, conservation, rehabilitation, and improvement of the environment; the prevention and control of pollution; and promotion of sustainable development in the province.

EPAs are building on its successes with the environment through reliable and effective regulations, legislation and high-quality service delivery. EPAs sustains qualitative and quantitative standards for the discharge of effluents, wastes, air emissions or noise either for general applicability or for a particular area or from a particular source in the form of Provincial Environmental Quality Standards (PEQS) and other standards established under the laws, rules and regulations.

5. Provincial Transportation Departments

Ministry of Communications is central policy making body and administrative authority in roads infrastructure, road transportation, provision of communication link between individuals and businesses, provision of research & training to relevant stake holders and policing on National Highways & Motorways.

The Transport Department was created in 1987. Earlier there was a transport cell in the S&GAD (Services and General Administration) and transport authorities existed at the regional and provincial levels. The current set-up of the transport department includes the secretariat, attached departments, Transport Planning unit (TPU) and Transport Logistic and communication (LTC). The key important functions are:

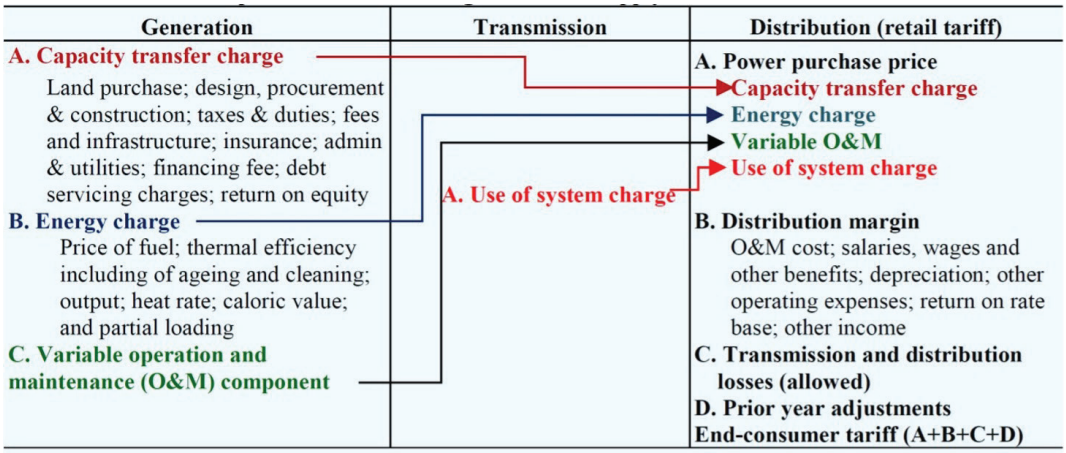
- Implementation of government policies for provision of affordable, comfortable, and efficient transport services across the province
- Preparation and Implementation of Development Plans
- Initiation of special public transport initiatives like subsidies, environment friendly transport etc.
- Fixation and Regulation of Public Transport Fares.

IX. POWER AND ENERGY TAXATION AND TARIFFS

In accordance with the NEPRA Tariff Standard & Procedure Rules, 1998, the authority determines the tariff for all the generation, transmission, and distribution companies. Details are summarized in Table below. At the generation level, the tariff (upfront, cost- plus, or solicited/reverse auction) is determined based on power purchase agreements (PPA) between power producers (IPPs and public GENCOs) and a single buyer: Central Power Purchasing Agency (CPPA). The PPA allows calculating the revenue requirements for an individual power producer based on:

- A capacity charge, which includes costs pertaining to the design and construction of power units, the guaranteed return on equity, and debt financing charges, among others; and
- An energy charge, that covers variable costs, primarily fuel (which is based on a benchmark for fuel price by (NEPRA), and operation and maintenance (O&M) costs.

Figure 80: *Tariff Components at Various Stages of Power Supply-Chain*



Importantly, the capacity charge is indexed periodically with multiple parameters including exchange rate, domestic interest rates, foreign interest rates, etc. Furthermore, power producersare allowed to impose this capacity charge irrespective of the amount of electricity (produced and) sold by them. In contrast, their variable cost depends on the estimated amount of electricity produced and sold, reference fuel mix (e.g., furnace oil, RLNG, coal) and their prices. Fuel costsabove or below the NEPRA benchmark are passed onto consumers as fuel price adjustment (FPA); these appear on end-consumers' electricity bills separately based on units consumed in the previous month (see the following tables for consumer end tariff in different categories).[85]

85. *http://www.sbp.org.pk/reports/quarterly/fy19/Third/Special-Section-1.pdf Date Taken 17 December, 2020*

The mechanism of capacity payments has been laid out in power purchase agreements with IPPs.

These can be driven by variation in the actual fuel mix versus NEPRA's reference mix (e.g., gasshortages that force power plants to substitute gas with more costly high-speed diesel); and/or changes in fuel prices in the global market. Either of these can automatically increase (ordecrease) the generation costs and is passed on to consumers through FPAs.[86]

A. Overview of Taxation and Tariffs on Energy Sources and Imports in Pakistan

1. Natural Gas

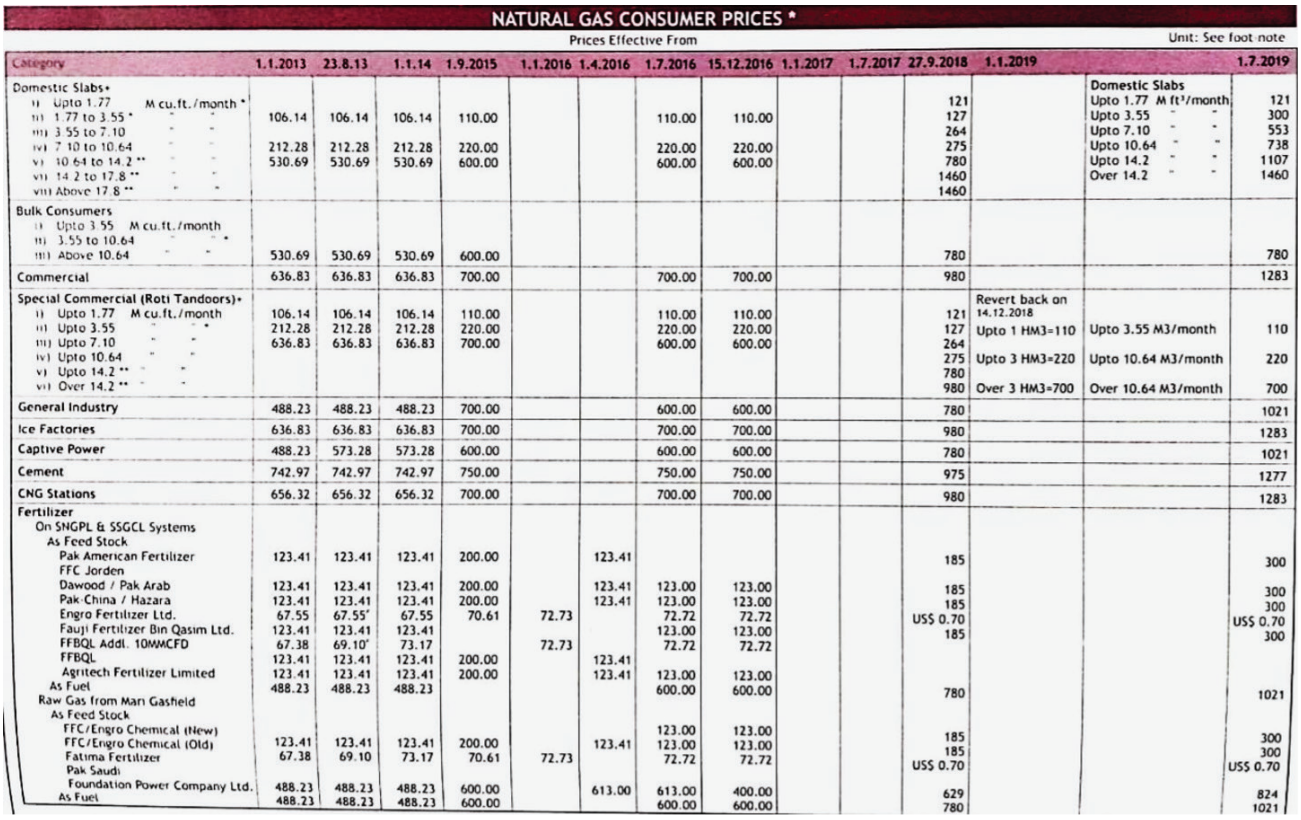
Table 62: Details of Unit Purchased, Sold, and Losses

Detail of Units Purchased, Sold and Losses in all DISCOs

DISCO	Year	Unit Purchased (GWh)			Unit Sold (GWh)	Losses	
		Through NTDC	Through CPPs, SPPs etc.	Total Unit Purchased		GWh	%age
PESCO	2015-16	11751.00	0.00	11751.00	7782.91	3968.09	33.77
	2016-17	12510.96	0.00	12510.96	8432.03	4078.93	32.60
	2017-18	14220.30	0.00	14220.30	8795.53	5424.77	38.15
	2018-19	14301.80	0.00	14301.80	9073.56	5228.24	36.56
	2019-20	14750.30	0.00	14750.30	9043.05	5707.25	38.69
TESCO	2015-16	1269.00	0.00	1269.00	1028.48	240.52	18.95
	2016-17	1450.58	0.00	1450.58	1227.13	223.45	15.40
	2017-18	1692.82	0.00	1692.82	1481.85	210.97	12.46
	2018-19	1821.00	0.00	1821.00	1603.06	217.94	11.97
	2019-20	2151.00	0.00	2151.00	1802.76	348.24	16.19
IESCO	2015-16	9652.00	0.00	9652.00	8774.00	878.00	9.10
	2016-17	10582.64	0.00	10582.64	9627.55	955.09	9.03
	2017-18	11672.97	0.00	11672.97	10605.94	1067.03	9.14
	2018-19	11837.79	0.00	11837.79	10789.05	1048.74	8.86
	2019-20	11435.52	0.00	11435.52	10442.03	993.49	8.69
GEPCO	2015-16	9045.48	0.00	9045.48	8088.83	956.65	10.58
	2016-17	9778.56	0.00	9778.56	8777.78	1000.78	10.23
	2017-18	10986.45	0.00	10986.45	9886.84	1099.61	10.01
	2018-19	11099.96	0.00	11099.96	10004.34	1095.62	9.87
	2019-20	10991.19	0.00	10991.19	9945.63	1045.56	9.51
LESCO	2015-16	20151.92	0.00	20151.92	17341.98	2809.94	13.94
	2016-17	20621.54	0.00	20621.54	17782.81	2838.73	13.77
	2017-18	23731.24	0.00	23731.24	20448.50	3282.74	13.83
	2018-19	24338.45	0.00	24338.45	21132.00	3206.45	13.17
	2019-20	23528.33	0.00	23528.33	20610.00	2918.33	12.40
FESCO	2015-16	11920.35	0.00	11920.35	10700.29	1220.06	10.24
	2016-17	12857.80	0.00	12857.80	11498.76	1359.04	10.57
	2017-18	12548.87	1897.54	14446.41	12924.57	1521.84	10.53
	2018-19	13889.66	1079.09	14968.75	13499.68	1469.07	9.81
	2019-20	13879.33	640.00	14519.33	13123.24	1396.09	9.62
MEPCO	2015-16	13328.75	1441.50	14770.25	12340.67	2429.58	16.45
	2016-17	12156.93	3794.65	15951.58	13253.20	2698.38	16.92
	2017-18	14928.56	4077.41	19005.97	15853.22	3152.75	16.59
	2018-19	13494.60	5872.05	19366.65	16309.61	3057.04	15.79
	2019-20	14972.84	4351.84	19324.68	16381.93	2942.75	15.23
HESCO	2015-16	3245.50	1839.86	5085.36	3739.17	1346.19	26.47
	2016-17	3298.98	2057.46	5356.44	3718.13	1638.31	30.59
	2017-18	3815.59	1927.43	5743.02	4026.96	1716.06	29.88
	2018-19	3567.80	1987.35	5555.15	3916.68	1638.47	29.49
	2019-20	3853.27	1612.09	5465.36	3890.00	1575.36	28.82
SEPCO	2015-16	4168.17	20.24	4188.41	2414.59	1773.82	42.35
	2016-17	4457.32	25.33	4482.65	2787.73	1694.92	37.81
	2017-18	4653.40	25.33	4678.73	2962.81	1715.92	36.67
	2018-19	4386.30	25.33	4411.63	2780.61	1631.02	36.97
	2019-20	4252.20	0.28	4252.48	2710.10	1542.38	36.27
QESCO	2015-16	5538.01	0.00	5538.01	4219.84	1318.17	23.80
	2016-17	5788.76	0.00	5788.76	4452.58	1336.18	23.08
	2017-18	6338.40	0.00	6338.40	4915.97	1422.43	22.44
	2018-19	6251.40	0.00	6251.40	4778.76	1472.64	23.56
	2019-20	6604.01	0.00	6604.01	4842.01	1762.00	26.68
Total in CPPA-G System	2015-16	90070.18	3301.60	93371.78	76430.76	16941.02	18.14
	2016-17	93504.07	5877.44	99381.51	81557.70	17823.81	17.93
	2017-18	104588.60	7927.71	112516.31	91902.19	20614.12	18.32
	2018-19	104988.76	8963.82	113952.58	93887.35	20065.23	17.61
	2019-20	106417.99	6604.21	113022.20	92790.75	20231.44	17.90

86. *https://nepra.org.pk/publications/State%20of%20Industry%20Reports.php Date Taken 21 December, 2020*

Table 63: Natural Gas Consumer Prices



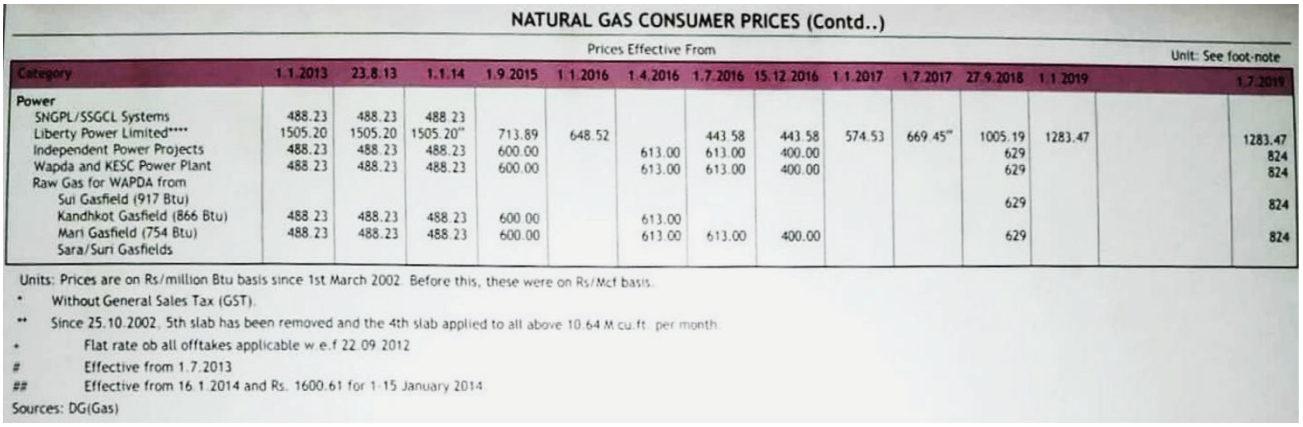
NATURAL GAS CONSUMER PRICES *

Prices Effective From — Unit: See foot-note

Category	1.1.2013	23.8.13	1.1.14	1.9.2015	1.1.2016	1.4.2016	1.7.2016	15.12.2016	1.1.2017	1.7.2017	27.9.2018	1.1.2019		1.7.2019
Domestic Slabs+													Domestic Slabs	
i) Upto 1.77 M cu.ft./month *											121		Upto 1.77 M ft³/month	121
ii) 1.77 to 3.55 * " "	106.14	106.14	106.14	110.00			110.00	110.00			127		Upto 3.55 " "	300
iii) 3.55 to 7.10 " "											264		Upto 7.10 " "	553
iv) 7.10 to 10.64 " "	212.28	212.28	212.28	220.00			220.00	220.00			275		Upto 10.64 " "	738
v) 10.64 to 14.2 ** " "	530.69	530.69	530.69	600.00			600.00	600.00			780		Upto 14.2 " "	1107
vii) 14.2 to 17.8 ** " "											1460		Over 14.2 " "	1460
viii) Above 17.8 ** " "											1460			
Bulk Consumers														
i) Upto 3.55 M cu.ft./month														
ii) 3.55 to 10.64 " " *														
iii) Above 10.64 " "	530.69	530.69	530.69	600.00							780			780
Commercial	636.83	636.83	636.83	700.00			700.00	700.00			980			1283
Special Commercial (Roti Tandoors)+												Revert back on		
i) Upto 1.77 M cu.ft./month	106.14	106.14	106.14	110.00			110.00	110.00			121	14.12.2018		
ii) Upto 3.55 " " *	212.28	212.28	212.28	220.00			220.00	220.00			127	Upto 1 HM3=110	Upto 3.55 M3/month	110
iii) Upto 7.10 " "	636.83	636.83	636.83	700.00			600.00	600.00			264			
iv) Upto 10.64 " "											275	Upto 3 HM3=220	Upto 10.64 M3/month	220
v) Upto 14.2 ** " "											780			
vi) Over 14.2 ** " "											980	Over 3 HM3=700	Over 10.64 M3/month	700
General Industry	488.23	488.23	488.23	700.00			600.00	600.00			780			1021
Ice Factories	636.83	636.83	636.83	700.00			700.00	700.00			980			1283
Captive Power	488.23	573.28	573.28	600.00			600.00	600.00			780			1021
Cement	742.97	742.97	742.97	750.00			750.00	750.00			975			1277
CNG Stations	656.32	656.32	656.32	700.00			700.00	700.00			980			1283
Fertilizer														
On SNGPL & SSGCL Systems														
As Feed Stock														
Pak American Fertilizer	123.41	123.41	123.41	200.00		123.41					185			300
FFC Jorden														
Dawood / Pak Arab	123.41	123.41	123.41	200.00		123.41	123.00	123.00			185			300
Pak-China / Hazara	123.41	123.41	123.41	200.00		123.41	123.00	123.00			185			300
Engro Fertilizer Ltd.	67.55	67.55'	67.55	70.61	72.73		72.72	72.72			US$ 0.70			US$ 0.70
Fauji Fertilizer Bin Qasim Ltd.	123.41	123.41	123.41				123.00	123.00			185			300
FFBQL Addl. 10MMCFD	67.38	69.10'	73.17		72.73		72.72	72.72						
FFBQL	123.41	123.41	123.41	200.00		123.41								
Agritech Fertilizer Limited	123.41	123.41	123.41	200.00		123.41	123.00	123.00						
As Fuel	488.23	488.23	488.23				600.00	600.00			780			1021
Raw Gas from Mari Gasfield														
As Feed Stock														
FFC/Engro Chemical (New)							123.00	123.00						
FFC/Engro Chemical (Old)	123.41	123.41	123.41	200.00		123.41	123.00	123.00			185			300
Fatima Fertilizer	67.38	69.10	73.17	70.61	72.73		72.72	72.72			185			300
Pak Saudi											US$ 0.70			US$ 0.70
Foundation Power Company Ltd.	488.23	488.23	488.23	600.00		613.00	613.00	400.00			629			824
As Fuel	488.23	488.23	488.23	600.00			600.00	600.00			780			1021

Effective from 16.01.2014 and Rs.1600.61 from 01-15 January 2014.

Table 64: Natural Gas Consumer Prices



NATURAL GAS CONSUMER PRICES (Contd..)

Prices Effective From — Unit: See foot-note

Category	1.1.2013	23.8.13	1.1.14	1.9.2015	1.1.2016	1.4.2016	1.7.2016	15.12.2016	1.1.2017	1.7.2017	27.9.2018	1.1.2019		1.7.2019
Power														
SNGPL/SSGCL Systems	488.23	488.23	488.23											
Liberty Power Limited****	1505.20	1505.20	1505.20""	713.89	648.52		443.58	443.58	574.53	669.45""	1005.19	1283.47		1283.47
Independent Power Projects	488.23	488.23	488.23	600.00		613.00	613.00	400.00			629			824
Wapda and KESC Power Plant	488.23	488.23	488.23	600.00		613.00	613.00	400.00			629			824
Raw Gas for WAPDA from														
Sui Gasfield (917 Btu)											629			824
Kandhkot Gasfield (866 Btu)	488.23	488.23	488.23	600.00		613.00								
Mari Gasfield (754 Btu)	488.23	488.23	488.23	600.00		613.00	613.00	400.00			629			824
Sara/Suri Gasfields														

Units: Prices are on Rs/million Btu basis since 1st March 2002. Before this, these were on Rs/Mcf basis.

* Without General Sales Tax (GST).

** Since 25.10.2002, 5th slab has been removed and the 4th slab applied to all above 10.64 M cu.ft. per month.

\+ Flat rate ob all offtakes applicable w.e.f 22.09.2012

\# Effective from 1.7.2013

\## Effective from 16.1.2014 and Rs. 1600.61 for 1-15 January 2014

Sources: DG(Gas)

The tariff and the taxes are adjusted time to time by OGRA.[87]

87. *Energy Year Book 2019.*

2. Coal

Local Coal

Pakistan produces **4,506,243.28 tons** (short tons, «st») of Coal per year (as of 2016) ranking **34th** in the world. Two types of taxes are implemented on the local coal Royalty and Excise Duty. Excise duty is taken by Federal government and the royalty is taken by province.

Coal Imports

Pakistan imports **70% of its Coal consumption** (7,107,638 tons in 2016). Custom duty with the average of 15% is implemented on imported coal.[88]

3. Power

Generally, Electricity tariff charged to consumer is divided into two parts (I) Distribution charges (II) Government charges.

Distribution Charges:

- The electricity units consumed can be calculated by peak and off-peak consumption.
- Fuel Price Adjustment (FDA).
- Quarterly Tariff adjustment.
- Finance Cost surcharge fixed at 0.43 rupees per unit.
- Distribution margin charges.

Government Charges:

- Government Imposed Electricity duty charges with the ratio of 1.5%.
- 35 Rupees Pakistan Television Fee.
- Government Sales Tax (GST) with the ratio of 17%.
- Neelam Jehlam surcharge 0.10 RS/unit.

Electricity duty on fuel price adjustment 17%.[89]

88. *Interview conducted with Deputy Director Minerals, Ministry of Petroleum.*
89. *https://www.nepra.org.pk/ Date Taken 29, December, 2020*

Table 65: Sector-wise Tariff

Description	Fixed Charges	PESCO	TESCO	IESCO	GEPCO	LESCO	FESCO	MEPCO	HESCO	SEPCO	QESCO	Uniform Tariff		Determined Tariff		Applicable Tariff	
		Variable Charges										Fixed Charge	Variable Charges	Fixed Charges	Variable Charges	Fixed Charges	Variable Charges
		Rs./kWh										Rs./kW/M	Rs./kWh	Rs./kW/M	Rs./kWh	Rs./kW/M	Rs./kWh
Agricultural Tube-wells - Tariff D																	
SCARP		17.39	11.68	17.90	16.44	19.10	15.89	16.12	25.34	22.40	14.83		23.17		11.22		5.35
Time of Use (TOU) - Peak		23.33	15.66	22.26	20.94	22.00	20.07	20.67	24.75	23.31	19.64		20.87		16.50		5.35
Time of Use (TOU) - Off-Peak	200	16.63	10.88	13.10	14.14	12.02	11.27	14.64	18.85	17.06	12.88	200	14.03	200	10.80	200	5.35
Agricultural Tube-wells	200	17.49	11.18	15.85	15.44	19.10	15.89	16.52	20.65	19.36	14.21	200	14.56				
Time of Use (TOU) - Peak		23.33	15.86	17.90	20.94	20.50	20.12	19.75	24.75	23.31	19.08		20.27				
Time of Use (TOU) - Off-Peak	200	16.63	10.88	13.10	14.10	13.46	13.21	12.22	18.85	15.96	12.68	200	13.04				
Public Lighting - Tariff G		19.14	11.68	15.95	12.50	19.78	15.32	17.47	222.60	20.46	14.18		18.78		13.90		18.68
Resid. Col. attached to ind. premises		19.14	11.68	15.18	12.64	20.39	15.47	17.90	22.60	20.46	14.18		18.42		14.00		18.68
Railway Traction						17.90							17.90				
Tariff K - AJK	380	18.62		13.55	15.21							360	13.55				
Time of Use (TOU) - Peak		23.37		17.28	18.12								18.56				
Time of Use (TOU) - Off-Peak	360	17.57		9.84	12.87							360	12.20				
Tariff K - Rawat Lab				16.24									16.24				
Special Contract - Tariff-J																	
J-1 For Supply at 66 kV & above	380	19.24	11.73	14.16	10.48	11.77	14.79	17.65	25.15	22.69	13.75	360	16.14	360	12.00	360	17.88
Time of Use (TOU) - Peak		24.04	16.03	16.36	18.28	18.60	19.07	21.05	29.05	25.59	18.55		20.66		16.50		21.60
Time of Use (TOU) - Off-Peak	380	18.19	11.23	10.51	9.48	11.62	12.97	14.95	23.14	19.34	11.65	360	14.33	360	11.25	360	14.70
J-2 (a) For Supply at 11, 33 kV	380	19.34	11.83	14.26	10.56	14.10	14.89	17.75	25.25	22.79	13.85	380	16.46	380	12.50	380	17.98
Time of Use (TOU) - Peak		24.04	16.03	18.36	16.28	18.60	19.07	21.05	29.05	25.59	18.55		20.86		16.50		21.60
Time of Use (TOU) - Off-Peak	380	18.29	11.33	10.63	9.58	11.72	13.07	15.05	23.34	19.44	11.95	380	14.44	380	11.50	380	14.80
J-2 (b) For Supply at 66 kV & above	360	19.24	11.73	14.16	10.48	14.00	14.79	17.65	25.15	22.69	13.75	360	16.36	360	12.00	360	17.88
Time of Use (TOU) - Peak		24.04	16.03	18.36	16.28	18.60	19.07	21.05	29.05	25.59	18.55		20.66		16.50		21.60
Time of Use (TOU) - Off-Peak	360	18.19	11.23	10.51	9.48	11.62	12.97	14.95	23.14	19.34	11.85	360	14.33	360	11.25	360	14.70
J-3 (a) For Supply at 11, 33 kV	380	19.34	11.83	14.26	10.58	14.10	14.89	17.75	25.25	22.79	13.85	380	16.46	380	12.50	380	17.98
Time of Use (TOU) - Peak		24.04	16.03	18.36	16.28	18.60	19.07	21.05	29.05	25.59	18.55		20.66		16.50		21.60
Time of Use (TOU) - Off-Peak	380	18.29	11.33	10.63	9.58	11.72	13.07	15.05	23.34	19.44	11.95	380	14.44	380	11.50	380	14.80
J-3 (b) For Supply at 66 kV & above	360	19.24	11.73	14.16	10.48	14.00	14.79	17.65	25.15	22.89	13.75	360	16.36	360	12.00	360	17.88
Time of Use (TOU) - Peak		24.04	16.03	18.36	15.28	18.60	19.07	21.05	29.05	25.59	18.55		20.66		16.50		21.60
Time of Use (TOU) - Off-Peak	360	18.19	11.23	10.51	19.34	11.62	12.97	14.95	23.14	19.34	11.85	360	14.33	360	11.25	360	14.70

Source: NEPRA

Table 66: Tariff and Taxes are Adjusted Time to Time by NEPRA [90]

National Average Uniform Tariff with PYA 2018

Description	Fixed Charges	DISCOs										Uniform Tariff		K-Electric			
		PESCO	TESCO	IESCO	GEPCO	LESCO	FESCO	MEPCO	HESCO	SEPCO	QESCO			Determined Tariff		Applicable Tariff	
		Variable Charges										Fixed Charge	Variable Charges	Fixed Charges	Variable Charges	Fixed Charges	Variable Charges
		Rs./kWh										Rs./kW/M	Rs./kWh	Rs./kW/M	Rs./kWh	Rs./kW/M	Rs./kWh
Residential																	
Up to 50 Units		4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00		4.00		4.00		2.00
For peak load requirement less than 5 kW																	
01-100 Units		17.25	11.18	10.87	11.19	12.09	13.35	15.45	18.80	14.37	17.13		13.85		9.10		5.79
101-200 Units		20.44	13.34	14.00	13.15	13.54	16.72	16.00	20.45	16.51	19.58		15.86		10.70		8.11
201-300 Units		20.95	14.36	15.58	14.60	15.27	17.47	17.07	21.85	19.21	20.03		16.83		12.25		10.20
301-700 Units		22.29	14.60	16.85	17.54	16.91	18.03	19.81	23.10	21.06	21.03		18.54		13.95		17.60
Above 700 Units		24.05	15.68	18.95	18.67	19.24	19.47	20.79	24.75	23.45	24.27		20.94		16.30		20.70
For peak load requirement exceeding 5 kW																	
Time of Use (TOU) - Peak		23.32	15.68	17.59	18.14	18.81	19.10	20.76	24.75	23.46	24.48		19.33		16.50		20.70
Time of Use (TOU) - Off-Peak		15.89	11.18	10.11	11.64	12.50	13.30	15.08	19.25	17.51	18.10		12.80		12.27		14.38
Temporary Supply		23.33	15.68	22.68	18.14	18.15	20.12	20.17	24.65	21.11	24.50		20.84		14.00		20.84
Commercial - A2																	
For peak load requirement less than 5 kW		23.32	15.75	17.00	17.14	19.08	18.12	19.23	23.65	23.36	15.20		19.26		13.25		18.00
For peak load requirement exceeding 5 kW																	
Regular	400	18.79	13.75	14.00	13.64	16.81	17.87	17.59	21.65	21.36	15.05	400	18.01	400	12.50	400	19.68
Time of Use (TOU) - Peak		24.33	15.75	17.90	18.14	19.18	19.12	20.40	24.75	23.46	19.10		20.09		16.50		21.60
Time of Use (TOU) - Off-Peak	400	18.09	11.25	10.50	11.64	12.26	13.32	14.47	19.29	17.51	12.68	400	13.48	400	12.27	400	15.63
Temporary Supply		23.33	15.75	17.00	17.11	18.47	19.12	20.07	23.65	23.36	19.10		18.39		15.00		18.39
General Services-A3		20.99	14.28	18.90	13.94	17.60	16.97	18.72	21.30	19.00	16.37		17.56		13.45		17.56
Industrial																	
B1		20.85	13.68	16.00	14.64	17.59	18.14	19.07	21.15	22.86	15.88		18.32		13.50		12.28
B1 Peak		23.33	15.68	17.90	18.14	19.68	19.64	20.17	24.74	23.47	19.06		20.14		16.50		15.84
B1 Off Peak		17.78	11.18	10.20	12.05	12.03	12.03	14.47	19.25	17.51	12.64		13.46		12.50		10.28
B2	400	18.34	11.18	13.50	12.14	14.95	14.64	16.58	20.65	20.36	14.03	400	15.79	400	12.65	400	11.78
B2 - TOU (Peak)		23.33	15.68	17.90	18.14	19.35	19.57	20.17	24.75	23.46	19.03		19.93		16.50		15.78
B2 - TOU (Off-peak)	400	117.58	10.98	10.30	9.33	12.64	13.20	14.27	19.05	17.31	12.48	400	13.23	400	12.00	400	10.07
B3 - TOU (Peak)		22.89	15.68	17.90	18.14	20.58	19.33	20.64	24.75	23.47	19.08		20.39		16.50		15.78
B3 - TOU (Off-peak)	380	17.48	10.88	10.10	11.74	11.61	13.12	13.17	18.85	16.21	12.38	380	12.61	380	11.50	380	9.98
B4 - TOU (Peak)		23.33	15.68	18.20	16.14	20.25	19.12	20.17	24.75	23.46	19.08		20.27		16.50		15.78
B4 - TOU (Off-peak)	360	17.85	10.78	10.50	11.24	12.00	13.02	14.07	18.75	17.11	12.28	360	13.25	360	11.25	360	9.88
B5 - TOU (Peak)															16.50		15.78
B5 - TOU (Off-peak)														340	10.50	340	9.00
Temporary Supply		18.83	11.68	18.20	16.14	14.70	17.60	16.92	25.15	20.66	19.08		16.36		15.05		16.36
Single Point Supply for further Distribution																	
C1(a) Supply at 400 Volts-less than 5 kW		21.34	13.18	17.50	17.14	16.20	18.14	16.57	22.67	23.76	16.08		21.32		13.50		18.68
C1(b) Supply at 400 Volts-exceeding 5 kW	400	20.84	12.68	17.00	16.64	15.70	17.64	18.07	22.15	22.21	15.58	400	20.13	400	12.50	400	18.18
Time of Use (TOU) - Peak		23.33	15.68	19.98	21.14	19.00	20.62	21.10	24.75	23.46	20.08		21.52		16.50		21.60
Time of Use (TOU) - Off-Peak	400	20.09	11.18	10.50	14.64	12.50	14.72	12.91	19.25	17.51	12.66	400	14.99	400	12.00	400	15.00
C2 Supply at 11 kV	380	18.64	11.48	13.83	15.44	15.21	18.44	16.02	20.95	20.66	14.39	380	15.61	380	12.50	380	17.98
Time of Use (TOU) - Peak		24.27	15.68	18.04	21.14	19.00	20.62	18.15	24.75	23.46	19.08		19.73		16.50		21.60
Time of Use (TOU) - Off-Peak	380	17.58	10.98	8.27	14.44	12.10	14.52	14.12	19.05	17.31	12.46	380	12.57	380	11.50	380	14.80
C3 Supply above 11 kV	360	18.54	11.36	13.70	15.34	13.97	18.34	15.92	20.85	20.56	14.28	360	14.42	360	12.00	360	17.88
Time of Use (TOU) - Peak		23.33	15.68	16.21	21.14	19.00	18.24	20.17	24.75	23.46	19.08		18.49		16.50		21.60
Time of Use (TOU) - Off-Peak	360	17.48	10.88	10.38	14.34	12.00	12.49	14.07	18.85	17.21	12.38	360	11.59	360	11.25	360	14.70

90. *NEPRA,2020. "State of industry report 2020". Available at: http://nepra.org.pk/publications.*

4. Oil

Taxation and tariff on Oil sector is split in different components. These components are:

- Ex- refinery price,
- Customs / excise duty,
- Fixed development surcharges,
- Distribution margin,
- Dealer commission,
- Inland freight Margin,
- Development surcharges,
- Government sales tax.[91]
-

B. Overview of Taxation and Tariffs on Power / Energy Transmission / Distribution: Power, Gas Grid etc.

1. Power Transmission and Distribution Tariff

Table 67: System Energy, Energy Billed, Consumed and Losses

Fiscal	Energy purchased by	Transmission losses		Unit Supplied to	Unit Purchased Directly by	Distribution Losses		Unit sold by DISCOs	Transmission & Distribution Losses	
Year	CPPA	Total	% age	DISCOs by CPPA	DISCOs	Total	% age	(incl IPPs & KE)	Total	% age
	(MkWh)	(MkWh)	%	(MkWh)	(MkWh)	(MkWh)	%	(MkWh)	(MkWh)	%
2014	93,777	2,587	2.8	91,190	1,367	16,326	17.90	76,543	18,913	20.7
2015	96,463	2,620	2.7	93,843	1,498	16,744	17.84	78,113	19,364	20.6
2016	100,871	2,623	2.6	98,248	251	16,762	17.06	81,737	19,385	19.7
2017	106,796	2,466	2.3	104,330	272	17,834	17.09	86,763	20,300	19.4
2018	120,062	2,923	2.4	117,139	665	20,607	17.59	97,197	23,530	20.0

2. Transmission and Distribution Taxes

NTDC charges its users for provision of transmission and allied services the following two-part tariff i.e., a fixed and variable charge:

- Fixed charge (USCF) = Rs.176.16/kW/Month
- Variable charge (USCV) = Rs.0.18/kWh x LAL Factor Where:
- LAL Factor is a factor for Adjustment of Losses and Load imposed on the transmission system by user. LAL Factor of unity will be applied till benchmarks are defined by NEPRA.
- In case of DISCOs, NTDCL shall charge the fixed charges i.e. Rs. 176.16/kW/Month.
- The variable charge shall only be applicable to the energy in kilowatt-hours (kWh) transmitted/ delivered during a billing period.[92]

91. *Energy Year Book 2019*
92. *https://www.nepra.org.pk/ Date Taken 15, January, 2021*

Table 68: Average Sale Price is in Pak-Rupees					
Description	2013-14	2014-15	2015-16	2016-17	2017-18
Energy Sales (GWh)					
Energy Sales (PEPCO)	76,543	78,113	81,737	86,763	97,197
Energy Sales (KE)	11,453	12,295	12,865	12,981	13,860
Energy Sales (Country)	87,996	90,408	94,602	99,744	111,057
Number of Customers					
Number of Consumers (PEPCO)	22,587,870	23,519,247	24,516,699	25,571,803	27,016,545
Number of Consumers (KE)	2,111,336	2,156,831	2,226,677	2,424,920	2,583,435
Number of Consumers (Country)	24,699,206	25,676,078	26,743,376	27,996,723	29,599,980
Per Capita Electricity Consumption (kWh)					
Consumption Per Consumer (PEPCO)	3,389	3,321	3,334	3,393	3,598
Consumption Per Consumer (KE)	5,425	5,700	5,778	5,353	5,365
Average Sale Price (Rs./kWh)					
Average Sale Price (PEPCO)	13	13	12	12	13
Average Sale Price (KE)	12	12	13	13	13
Losses					
NTDC Transmission Losses (500/220 kV)	2,327	2,620	2,623	2,467	2,923
NTDC Transmission Losses (500/220 kV. %)	2.5	2.7	2.6	2.3	2.3
DISCOs Distribution Losses (132/11 kV)	16,278	16,744	16,762	17,834	20,607
DISCOs Distribution Losses (132/11 kV. %)	17.5	17.7	17.0	17.9	18,3
Auxiliary Consumption (%, KE)	8	8	7	8	8
Transmission & Distribution Losses (%, KE)	25	24	22	22	20
Maximum Demand (MW) *					
Recorded Maximum Demand (PEPCO)	16,170	16,233	17,261	19,020	20,795
Recorded Maximum Demand (KE)	2,929	3,056	3,195	3,270	3,257
Transmission Length/S, & MVA Capacity**					
Total Length of Transmission Lines (km)	49,768	50,989	52,291	50,268	51,484
Total number of Grid Stations	765	780	816	853	873
Total Transformation Capacity (MVA)	71,120	77,759	83,656	88,162	92,065

C. Natural Gas Tariff and taxation

1. Domestic Sector

a. Standalone Meter

Mosque, churches, temples, Madarass other religious places and hostels attached thereto;

Sale Price in Pak Rupees/MMBTU

- Up to 0.5 hm^3 per month in 121.00 PKR.
- Up to 1 hm^3 per month in 300.00 PKR
- Up to 2 hm^3 per month in 553.00 PKR
- Up to 3 hm^3 per month in 738.00 PKR
- Up to 4 hm^3 per month in 1,107.00 PKR
- Above 4 hm^3 per month in 1,460.00 PKR.

The billing mechanism will be revised so that the benefit of one previous/preceding slab is available to domestic consumer (residential use).

- Minimum charges **172.58** per month

Government and Semi-Government Offices, Hospitals, Clinics, Maternity Homes, Government Guest Houses, Armed Forces Messes, Langars, Universities, Colleges, Schools and Private Educational Institutions, Orphanages and other Charitable Institutions along-with Hostels and Residential Colonies to whom gas is supplied through bulk meters including Captive Power.

The tariff for captive gas use in this category will be charged as per captive power category i.e. Rs. 1,087 per MMBTU.

- All off-takes at flat rate of **Rs 780.00** per MMBTU
- Minimum Charges: **Rs. 3,900.00** per month

2. Commercial

All establishments registered as commercial units with local authorities or dealing in consumer items for direct commercial sale like cafes, bakeries, milk-shops, tea stalls, canteens, barber shops, laundries, hotels including hotel industry, malls, places of entertainment like cinemas, clubs, theaters and private offices, corporate firms etc.

All off-takes at a flat rate of **Rs. 1283.00** per MMBTU Minimum charges: **Rs. 6,415.00** per month

3. Special Commercial (Roti Tandoors)

Sale Price in Rupees/ MMBTU

- Up to 0.5 hm^3 per month 110.00
- Up to 1 hm^3 per month 110.00
- Up to 2 hm^3 per month 220
- Above 3 hm^3 per month 700
- Minimum charges: Rs. 148.50 per month

4. Industries

a. General Industrial

All consumers engaged in the processing of industrial raw material into value added finished products irrespective of the volume of gas consumed but excluding such industries for which a separate rate has been prescribed.

- All off-takes at a flat rate of Rs. 1,054.00 per MMBTU
- Minimum charges: Rs. 35,540.00 per month

b. Export Oriented (General Industry)

- All off-takes at flat rate of **Rs. 819.00** per MMBTU
- Minimum charges: **Rs. 27,616.00** per month

c. Export Oriented (Captive)

- All off-takes at flat rate of Rs. 852.00 per MMBTU
- Minimum charges: Rs. 28,729.00 per month

d. CNG Region-I

- All off-takes at flat rate of **Rs. 1,371.00** per MMBTU
- Minimum charges: **Rs. 46,229.00** per month

e. CNG Region-II

- All off-takes at flat rate of **Rs. 1,350.00**per MMBTU
- Minimum charges: **Rs. 45,521.00** per month

f. Cement

- All off-takes at flat rate of **Rs. 1,277.00** per MMBTU
- Minimum charges: **Rs. 45,588.90** per month

g. Fertilizer Companies

- Sales Price: All off-takes at a flat rate of **Rs. 302.00** per MMBTU for gas used as feedstock.
- **Rs. 1,023.00** per MMBTU for gas used as fuel for generation of electricity, steam and for usage of housing colonies.

h. Independent Power Producers

- All off-takes at a flat rate of **Rs. 824.00** per MMBTU
- Minimum charges: **Rs. 21,209.88** per month

i. Power Stations (WAPDA and KESC's Power Stations)

WAPDA's and KESC's Power Stations and other electricity utility companies.

- All off-takes at a flat rate of **Rs. 824.00** per MMBTU
- Minimum Charges **Rs. 21,209.88** per month[93]

93. https://www.ssgc.com.pk/web/?page_id=103 Date Taken 11, January, 2021

D. Overview Current Financial Instruments: CO_2 Emissions Costs, Financial Incentives, Subsidies for Renewables

1. CO_2 Emissions Taxation Emissions Credits Cost / Policy Overview

There is no carbon taxation policy in the country. The CO_2 emissions through GHG Inventory are prepared by Global Climate Change Impact Study Center (GCISC), Ministry of Climate Change. There are different studies underway to explore the options for carbon pricing and emission trading schemes in Pakistan. The Climate Change Policy (2012) addresses some aspect with regards to forestry and carbon sequestration. The following table provides GHG emission submitted for NDCs by Pakistan.[94]

Table 69: Inventory of GHG Emissions (in MT CO_2- equivalent)

Sectors	1994	2008	2012	2015
Energy	85.8	168.47	171.44	185.97
Agriculture	71.63	125.97	162.86	174.56
Industrial Processes	13.29	18.54	19.59	21.85
Land Use Change & Forestry	6.52	9.29	9.67	10.39
Waste	4.45	7.24	10.55	12.29
Total	**181.7**	**329.51**	**374.10**	**405.07**

94. *https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Pakistan%20First/Pak-INDC.pdf Date Taken 27, December, 2020*

X. REGULATORY / POLICY FRAMEWORK RELATED TO THE DEVELOPMENT OF HYDROGEN AS AN ENERGY VECTOR

As per the National ARE (Alternative and Renewable Energy) Policy 2019 by the Government of Pakistan, hydro is not categorized as Renewable. However, the policy does cover the Hydrogen or Synthetic Gas (made from any source except fossil fuel) – The Green Hydrogen as Renewable. Section 1.4 of policy covers projects for Renewable Energy as well as Alternate Energy Technologies, as follows:

- Biomass (including but not limited to bagasse, agricultural waste, and other waste)
- Geothermal
- Ocean /Tidal Wave energy
- Solar (PV or Thermal, or any technology that uses heat and/or light of the sun to make electricity)
- Wind
- Storage Technologies (Battery systems, Cells of all types, compressed gas, pumped storage)
- Biogas using any organic material (except fossil fuels)
- Energy from Waste (including but not limited to municipal solid waste, industrial waste, sewage, Refuse Derived Fuel).
- ***Hydrogen or Synthetic Gas*** (made from any source except fossil fuels)
- Hybrids of any of the above Technologies

The policy in its scope categorically defines "***hydro projects*** shall not be covered under this policy" (ARE Policy 2019). Therefore, the hydro in this case is not considered as renewable.

A. Overview of Current Safety and Technical Regulations

In the current situation with regards to the technical / safety framework for moving hydrogen around Pakistan on the road is closely related to the transport of LPG (Liquefied Petroleum Gas). The laws/ regulation governing the transportation of LPG is based on the international technical codes and standards.

To ensure safety throughout the LPG supply chain i.e., LPG Extraction Plants, LPG Storage Tanks, LPG Transporters and Distribution Outlets, the Licensees will meet the minimum safety standards in accordance with NFPA 58 or equivalent standards as updated from time to time.

1. Regulations Governing Transportation of Compressed Hydrogen Gas on Roads / Rail

Currently Pakistan has no reserves or static storage of hydrogen as gas or liquid used as a fuel.

The Hazardous substance rules 2016 are clear about the transportation of Hydrogen. These Rules make provisions for the granting of licenses for the collection, treatment, storage, importation, transportation, etc. of hazardous substances.

- Transport of hazardous goods shall be subject to proper labeling as per UN adopted "Globally Harmonized System of Classification and Labelling of Chemicals" Rev 6, 2015
- The flammability shall be determined by tests or by calculation in accordance with methods adopted by International Standards Organization ISO Number 10156 of 1990[95]

a. Regulations Governing the Transportation of Liquid Hydrogen on Roads / Rail

- Transport of hazardous goods shall be subject to proper labeling as per UN adopted "Globally Harmonized System of Classification and Labelling of Chemicals" Rev 6, 2015
- The flammability shall be determined by tests or by calculation in accordance with methods adopted by International Standards Organization ISO Number 10156 of 1990[96]

b. Regulations Governing the Transportation of CNG on Roads / Rail

Pakistan has no laws/ regulation related to the transportation of CNG on the roads/ rail. As, the CNG in Pakistan is transported through gas pipelines network. Two gas supply companies i.e., SNGPL and SSGC supply gas to the CNG station across the country.

The Safety of CNG cylinders used in vehicles can be based on the Pakistan CNG rules1992 based on NZS 5454—1989[97]

- In Pakistan Compressed Natural Gas (CNG) used as a fuel and transported through the pipelines to the Gas stations. But on the other hand, Government of Pakistan prescribe the rules regarding the safety of human life. Under Motor Vehicle Rules 1969.

Fuel Tanks

- No fuel tanks shall be placed in any public service vehicle under any part of gangway which is within two feet of any entrance or exit of a single-decked vehicle or the lower deck of a double-decked vehicle.

95. *http://www.environment.gov.pk/images/rules/20160201CORRECTEDHAZARDOUS2016.pdf Date taken 20, December,2020*
96. *http://www.environment.gov.pk/images/rules/20160201CORRECTEDHAZARDOUS2016.pdf Date Taken 20, December, 2020*
97. *https://www.hdip.com.pk/contents.php?cid=34 Date Taken 12, January, 2021*

- The fuel tanks of all goods vehicles shall either be mounted on the rear side or offside chassis frame side-members or on the frame overhang to the rear of the back axle, and in any case shall be underneath the body of the vehicle.

- The fuel tank every public service vehicle shall be so placed that no over-flow therefrom shall fall upon any woodwork or accumulate where it can be readily ignited. The filling points of all fuel tanks shall be outside body of the vehicle and the filler caps shall be so designed and constructed.[98]

c. Regulations Governing the Transportation of LNG on Roads / Rail

LNG (liquefied Natural Gas) is import through gas terminals. The laws/ regulation governing the transportation of LNG is based on the international technical codes and standards.

2. LNG Technical Codes and Standards

a. LNG

- The design, construction and operation of the LNG terminal and allied facilities will satisfy inter-alia the following internationally recognized and proven codes, standards and guidelines for land based and offshore LNG installations (or equivalent):

- Shipping and Marine Facilities standards.
- Standard for the Production, Storage and Handling of Liquefied Natural Gas (LNG) – 2006, NFPA 59A, NFPA.
- Installations and Equipment for Liquefied Natural Gas – Design of Onshore Installations – 1997, (BS EN 1473) CEN.
- Installations and Equipment for Liquefied Natural Gas – Design and Testing of Loading/Unloading Arms – 1996, (BS EN 1474) CEN.
- Installations and Equipment for Liquefied Natural Gas – Ship to Shore Interface for Liquefied Natural Gas – 1996, (BS EN 1532) CEN.
- Installations and Equipment for Liquefied Natural Gas – General Characteristics of Liquefied Natural Gas – 1997, (BS EN 1160) CEN.
- Maritime Structures – Part 1, General Criteria – 1984. (BS 6349), BSI.
- Maritime Structures – Part 4. Code of Practice for Design of Fendering and Mooring Systems – 1994, (BS 6349), BSI.
- IGC Code – IMO-104E – International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk – IGC Code, 1993 including amendments.
- Guidance Notes, Classification and Certification of Floating Offshore Liquefied Gas Installations – Lloyd's Register, April 2004, Revision 2.
- Guidance Notes, Classification and Certification of Offshore Gravity Based Liquefied Gas Terminals – Lloyd's Register, April 2004, Revision 1.

98. *http://punjablaws.gov.pk/laws/7a.html Date Taken 13, January,2021*

b. Maritime LNG Guidelines

- Recommendations on the Safe Transport of Dangerous Cargoes and Related Activities in Port Areas – 1995, (IMO 290E) IMO, ISBN 92-801-1329-1.
- Dangerous Goods in Ports: Recommendations for Port Designers and Port Operators – 1985, PIANC.
- Mooring Equipment Guidelines – 1996, (OCIMF) Oil Companies International Marine Forum, ISBN 1 85609 088 4. 13
- Prediction of Wind Loads on Large Liquefied Gas Carriers – 1985, SIGTTO, ISBN 0 90088697 8.
- Big Tankers and their Reception – 1974, PIANC.
- Guidelines on Port Safety and Environmental Protection – 1989, IAPH.

c. Onshore LNG Terminal Standards

- Standard for the Production, Storage and Handling of Liquefied Natural Gas (LNG) – 2006, NFPA 59A, NFPA.
- Design and Construction of Large, Welded, Low – Pressure Storage Tanks, Appendix R - Low pressure Storage tanks for Refrigerated Products, (API 620 R).
- Installations and Equipment for Liquefied Natural Gas – Design of Onshore Installations – 1997, (BS EN 1473) CEN. Flat-Bottomed, Vertical, Cylindrical Storage Tanks for Low Temperature Service, (BS 7777).
- Installations and Equipment for Liquefied Natural Gas – General Characteristics of Liquefied Natural Gas – 1997, (BS EN 1160) CEN. Criteria for design and construction of refrigerated liquefied gas storage tanks – 'EEMUA 147'.[99]

3. Laws / Regulations Governing the Static Storage of CNG

Pakistan has no laws/ regulation related to the static storage of CNG. As, the CNG in Pakistan is transmitted from well-head through gas pipelines network. Two gas supply companies i.e., SNGPL and SSGC supply gas to the CNG station across the country.

4. National Regulatory Framework to Underground Storage of Energy Gases (H_2 or CH_4)

Pakistan has no policy or regulation framework regarding underground storage of hydrogen and methane (natural gas / re-gasified LNG).

99. Liquefied Natural Gas (LNG) Policy 2011.

XI. POSSIBILITY OF POTENTIAL CARBON CAPTURE AND STORAGE (CCS) SCHEMES IN PAKISTAN

A. National Policy / Regulatory Framework to Underground Storage of CO_2 for CCS

In February 2013, Pakistan launched its first National Climate Change Policy, which underscores the need to develop low-carbon technologies - including (CCS)—to reduce carbon footprints in agriculture, transport, and industry. In the energy sector, Pakistan is endowed with vast renewable energy resources such as hydropower, solar, and wind. The government is promoting hydropower, wind, solar, and natural gas project development and other low-GHG technologies for power generation. However, for a reliable, affordable, and secure electricity supply system, it needs a significant portion of power supply from fossil fuel power generation. The challenge of reducing emissions and simultaneously increasing energy supply is daunting. Hydropower's contribution to the energy mix has declined from 72% in 1980 to 32% in 2012, whereas fossil power has increased from 28% to 61% during the same period. Diversifying away from expensive fuel oil generation to coal will increase carbon emissions further despite an increase in renewable energy in the medium term. CCS will be a critical technology for meeting the country's goal of reducing carbon emissions.

1. Pakistan's President Decision on CCS 2013

The President, acting under the authority delegated by the Board, has approved ADB administering technical assistance not exceeding the equivalent of $1,000,000 to the Government of Pakistan to be financed on a grant basis by the Carbon Capture and Storage Fund under the Clean Energy Financing Partnership Facility for Determining the Potential for Carbon Capture and Storage.[100]

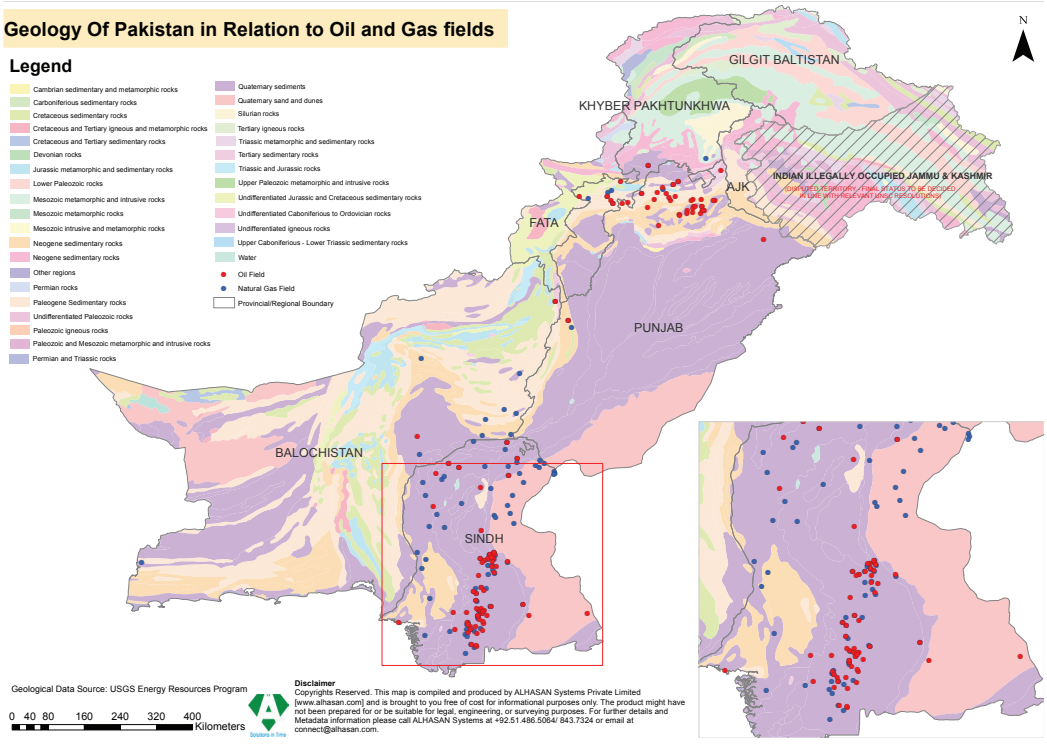
Blue hydrogen production (which was out of scope of this work) relies on CCS. CCS can also be used to decarbonize heavy industry and power generation. A brief overview of CCS potential in Pakistan is covered in this section. Current ADB energy policy may support some CCS activities related to decarbonization of gas fired power generation or blue hydrogen production. It would not stretch to CCS from coal gasification of hydrogen production.

100. https://www.adb.org/sites/default/files/project-document/80807/47277-001-tar.pdf Date Taken 20, January,2021

B. Potential Geological CO_2 Storage Sites in Pakistan

Based on reserve estimates provided by the figure the total storage capacity in oil and gas fields in Pakistan is estimated to be approximately 1.7 Gt CO_2. Four of the gas fields (Sui, Mari, Qadirpur and Uch) are estimated to have the potential to store >200 Mt CO_2, but none of the oil fields are thought to have significant storage capacity (10 Mt or more). None of Pakistan's coal fields are thought to have potential as CO_2 storage sites as, except for Thar, they are all shallow and actively mined. The saline aquifers in the Kohat-Potwar Basin and Indus Basin are considered likely to have good CO^2 storage potential, and there may also be potential in the Balochistan Basin.[101]

Figure 81: *Potential Use of Depleted / End of Life Gas Fields in Pakistan*



101. *Holloway S. et al (2009) "An Assessment of the CO_2 Storage Potential of the Indian Subcontinent" National Environment Research Center, published by Elsevier Ltd.*

CCS in depleted gas fields is likely to be possible and the opportunity is summarized here:

- A significant number of depleted or end of life gas fields in Pakistan are potential candidates for CO_2 storage.
- After producing significant gas production and value during their lives, some of these fields may be suitable for use in Carbon Capture and Storage (CCS) schemes.
- Most of these gas fields are in the Middle and Lower Indus Basin in the Sindh Province.
- Many of the depleted gas fields are now low pressure, sandstone reservoirs in the Lower Goru Formation.
- There is a significant amount of domestic coal production planned for large coal fired power plants and there may be an opportunity to capture GHG emissions at source for reinjection into the southernmost depleted gas fields between Karachi and the Thar coalfields to the east.

With appreciation to Dave Hartell of Stellae Energy, who provided this information specifically to support the preparation of this report.

Figure 82: *Overlap of CO_2 Emissions Source Locations and Potential CCS Areas*

Note: *ADB and the authors of this report recognize that the area of Jammu and Kashmir is disputed territory and the final status will be decided in line with relevant UNSC resolutions.*

1. Industrial Point Sources of CO_2 in Pakistan

Pakistan's total annual CO_2 emissions are estimated to have been 126 Mt in 2004.[102] Annual CO_2emissions from large point sources were estimated in this study to have been approximately 45 Mt CO_2, just over half of which comes from the power sector.

Matching CO_2 sources and storage potential geological CO_2 storage sites in Pakistan is essential for cost-effective CCS. Figure 82 shows the location of oil and gas fields, coalfields, sedimentary basins with good and fair aquifer storage potential and sources of CO_2 in Pakistan. There is a very good match between sedimentary basins with perceived good saline aquifer storage capacity and CO_2 sources.

Given that the estimated gas field CO_2 storage capacity alone is of the order of 35 times larger than the current annual emissions of CO_2 from large point sources, it appears that Pakistan is well placed to deploy carbon dioxide capture and storage technology.

102. https://www.researchgate.net/figure/Storage-potential-and-CO_2-sources-in-Pakistan_fig1_229304711 Date Taken 12 December,2020

APPENDIX 1: Q&A FROM THE PROJECT INCEPTION MEETING

Question from Dr Irfan Yusuf, NEPRA: hydrogen is a secondary source of energy and therefore there will be additional costs that will impact the energy basket price. Despite this, NEPRA sees potential, and we have already included hydrogen in our plans. Through this study we would appreciate guidance on four points: what regulations NEPRA should consider changing; what tariff structure we should move to; what transportation / distribution can be used for hydrogen – can we re-use existing assets; how can we derive heat from hydrogen in addition to power? We have already spoken with Siemens and their indication is that some gas turbines can be adapted for use with hydrogen as part of the natural gas fuel mix quite quickly.

Answer from Stephen B. Harrison ADB Hydrogen Energy Expert: yes, these four points will be addressed in the study at a broad level and our recommendations will most certainly be made with recognition of the existing infrastructure in Pakistan and every attempt will be made to propose schemes that re-use existing assets to ensure cost-effective energy transition and safe deployment to of hydrogen in Pakistan. For specific answers related to the reuse of natural gas distribution infrastructure a follow up detailed technical feasibility study must follow this pre- feasibility study to avoid any safety risks. The broad international consensus is that up to circa 6% hydrogen can be ad-mixed into existing natural gas pipelines without issues – but this must be validated locally in a more detailed technical feasibility study. It is also the case that 6% hydrogen in natural gas would be a suitable fuel for most existing gas turbines for power generation and specific discussions with the equipment suppliers must take place to confirm this broad generalization.

Question from Hussain??, OGRA: due to the low energy density of hydrogen, it must be stored at pressure in pipelines and steel cylinders. However there exists a safety-risk of hydrogen embrittlement and rupture. We could use a hydrogen & natural gas mixture such as Hythane® (20% hydrogen in methane, a type of HCNG), but we must first understand the safety implications. Also, we can use flared natural gas to make hydrogen which would be cheaper than using expensive electrolyzers.

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: yes, risks exist for using high concentrations of hydrogen with some grades of steel. This pre-feasibility study will identify the potential for hydrogen deployment in Pakistan and will propose broad applications for hydrogen deployment. After this pre-feasibility study, some follow-up detailed technical feasibility studies must then follow to ensure safe deployment in specific selected cases. Regarding flared gases from oil and gas extraction – these light hydrocarbon gases can potentially be captured, stored, and transported for use in the energy system without conversion to hydrogen. The conversion of these hydrocarbons to hydrogen would cause energy losses and their direct use might therefore be preferred. However, these options will not be analyzed through this study which has a focus on renewable hydrogen deployment and therefore excludes fossil-fuel based hydrogen production pathways.

Question from Dr Nadeem?? & Odid Dazeel??, unknown department: we would need a safety and hazard analysis before we introduce hydrogen into our existing gas distribution and storage infrastructure

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: yes, a full technical and safety study would be recommended in those cases and that should follow with a full technical and safety feasibility study after this pre-feasibility study. Many of the hydrogen deployment proposals that we are considering will rely on hydrogen ad-mixing in the existing natural gas pipelines so this point will be very important. A few deployment proposals that are under consideration will also refer to new pure hydrogen pipelines where there is a technical justification in the value chain for recommending investment in new infrastructure.

Question from Syed Aqeel Hussain Jafferry, AEDB: we see this as a good initiative and a stepping-stone to hydrogen deployment in Pakistan. Do you think that the implications of the study and hydrogen deployment will be restricted to electrical power generation or that there will be broader implications to transportation, industry, and the private sector?

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: the implications of hydrogen deployment in Pakistan will impact power generation and will also stretch into many other areas. Sectors such as industrial and domestic heating, transportation, production of ammonia for urea fertilizers in agriculture, the replacement of coke for iron and steel making and the production of hydrogen for desulfurization of crude on refineries will all be potential consumers of renewable hydrogen. It is therefore highly advisable to build awareness of the potential for hydrogen in Pakistan and across a wide range of stakeholders at an early stage to ensure that all relevant parties can begin to prepare for the required energy transition.

Question from unknown speaker of unknown department: what are the relative economics of using hydrogen versus the alternatives of solar power? Are there broad lessons from other countries that can help to answer this point?

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: renewable hydrogen is a secondary source of energy. There are losses when converting solar power to hydrogen and expensive equipment is also required. However, some of the benefits of hydrogen are that it can be stored cost-effectively over long periods of time (e.g., days, and months) and it can be transported in the existing natural gas pipeline infrastructure (perhaps with some minor modifications) and therefore re-use existing infrastructure assets. These benefits mean that despite the additional costs of converting renewable electrical power to hydrogen when considered on an instantaneous basis there are economic benefits and long-term cost-savings of using hydrogen as part of an integrated energy production, storage, and distribution system. For example, the alternative solution to long term energy storage is to over-size power production assets to meet the instantaneous maximum demand at all periods. This would be extremely expensive and inefficient. Energy storage can ensure that the most cost-effective solution for the long term (ie 1-year) over daily and seasonal cycles is achieved. On the point of low-cost renewable power within Pakistan and as an international benchmark: in Pakistan we can look to the existing large hydro-electric schemes and new hydro-electric dams as being the lowest cost of renewable power. The wind and solar profiles in Pakistan are good, but not leading in the world. On the other hand, Pakistan's hydro-electric potential is of a very high level.

Question from Asic?? from unknown department: can the commercialization of fuel cells be achieved in Pakistan with respect to our ambient climatic conditions of dust, heat, and humidity? We understand that these PEM fuel cells require very high purity hydrogen at 99.999% pure. Can we achieve that with mass-scale deployment in Pakistan?

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: indeed, fuel cells require very pure hydrogen to avoid damage to the catalysts that are used to coat the membrane so that the fuel cell can function effectively. Some of the value chains that we are considering for deployment will produce hydrogen for admixing into the existing gas grid. In these cases, the purity is not such an issue. Other cases that we are considering for detailed analysis or pilots will produce and distribute very high purity hydrogen for fuel cell applications, for example in FCEBs (Fuel Cell Electric Buses) or heavy vehicles. In these cases, the study would recommend the appropriate equipment throughout the value chain to ensure that the hydrogen purity is retained at an appropriate level. The issues dust, heat and humidity are not unique to Pakistan… and, for example, California is an early adopter of hydrogen for mobility applications that require fuel cells and in many parts of California there are similarly humid, hot, and dusty areas. These points are valid to raise and the technology that is in place today can address them effectively.

Question from Muhammad Ali, Balochistan EPA: this study must think about how hydrogen can be deployed alongside existing solutions. For example, the conversion of methane to hydrogen would consume a valuable resource. We also need this study to work alongside new infrastructure developments such as the future TAPI (Turkmenistan- Afghanistan-Pakistan-India) gas pipeline.

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: since this study will focus on renewable hydrogen, the conversion of natural gas to hydrogen on steam methane reformers will not be in focus. However, hydrogen is a secondary source of energy, and we must consume primary energy to produce it, for example hydro-electric power or solar power. These forms of energy could be used without conversion to hydrogen. The most beneficial deployment of hydrogen will take these factors into consideration and the study will make recommendations that respect the need for electrical power in Pakistan in addition to the potential use of hydrogen. However renewable power and hydrogen can be very synergistic because hydrogen is an excellent and low-cost way to store energy in the long term (days / months) and means that we can use excess electrical power from one time of the year to generate energy at another time when it is most required. Hydrogen requires electrical power for its production but the use of hydrogen in an integrated energy system will be economically beneficial. This study will take these factors into consideration and make recommendations for the most beneficial hydrogen production, storage, distribution, and utilization value chains. On the point of utilizing existing or future infrastructure it will be highly recommended that all stakeholders continuously ask the question about the future readiness of power utilities or infrastructure schemes such as pipelines to be used with hydrogen. We must avoid the risk of “stranded assets” – investment in capital projects that will quickly become obsolete when the transition to hydrogen takes place. It would be recommended that every project is considered both as a minimum cost basis and with the incremental cost of making it hydrogen ready and a conscious decision made between these two alternatives.

Question from unknown speaker of unknown department: how will the ramp rates of hydrogen fired gas turbine power plants compare to the current natural gas fed system?

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: generally speaking, gas turbines can be modified or built to operate on natural gas, natural gas plus hydrogen mixtures, pure hydrogen or to switch between different fuels. All these options are within the scope of current technology from leading suppliers such as Siemens, GE and Mitsubishi. The use of gas fired power generation to fill in the hourly and daily gaps that variable renewable energy sources (wind and solar) leave versus the demand profile is currently essential and will remain so in the future. In fact, as more variable renewable energy is used in Pakistan the importance of flexible gas fired power generation will become even more important. The good news is that the ramp rates of hydrogen fired turbines or hydrogen / natural gas mixture fired turbines is broadly comparable to the current performance of natural gas fired turbines. Modifications will be advisable, and the turbine suppliers must be consulted, but the ongoing combination of wind, solar and hydrogen fired GTCC will be a very suitable combination for Pakistan in the long term.

Question from Muhammad Asif Masood, ADB contracted expert: how is the modification of natural gas pipelines for use with hydrogen achieved?

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: the use of compatible materials and equipment is the key. The difference between the cost of a natural gas system or a system that could also work with hydrogen is often very little. As an example, the internal walls of steel pipes can be coated with a thin layer of durable plastic to avoid direct contact between the hydrogen and the steel and eliminate the risks of embrittlement and ensure long term safe pipeline operation with hydrogen.

Question from Zakia Javeed, Khyber Pakhtunkhwa EPA: many people have invested in CNG and LNG filling stations. Will there be subsidies from GoP or ADB as these transition to hydrogen?

Answer from Stephen B. Harrison, ADB Hydrogen Energy Expert: one of the key roles of this study will be to review the current regulations, subsidies and incentives in Pakistan that might favor or inhibit the penetration of hydrogen. Recommendations will also be made to modify legislation or develop new legislation to accelerate and enable hydrogen deployment. Also, the mandate for this study is to consider leveraging existing assets such as CNG powered cars and CNG fueling stations where possible to avoid the cost, waste and frustration of "stranded assets". For CNG fueling stations and CNG powered vehicles it is broadly acknowledged that up to 20% hydrogen can be added to the CNG to produce a gas mixture which can be filled into the vehicle and will yield acceptable driving performance at reduced emissions. Beyond 20% of hydrogen there may be requirements to modify engines and other equipment. The situation at present in Pakistan is that we produce no hydrogen and mix no hydrogen into the natural gas pipelines. When we produce the first quantities of hydrogen and begin to introduce them into the existing infrastructure the percentages of hydrogen will be very low – perhaps 1 or 2%. Over time, as we produce more and more hydrogen this will ramp up. At some point we will be at 20%. That might be 5, 10 or 15 years from now. This gradual transition will give companies and individuals time to make decisions about the cars they purchase or modify the cars that they own to be ready for higher amounts of hydrogen. The transition here can be gradual and with good communication the costs of changing the equipment that uses the fuels can be transitioned cost effectively also.

Closing Remarks from Dr Mohazzam, NEECA: Appreciation and thanks to all stakeholder groups for joining the meeting and the lively engagement in the discussion and questions. Appreciation and thanks to the ADB team for the presentations and Q&A session. As this project moves from pre-feasibility study to feasibility studies and pilot implementations to make hydrogen tangible for people in Pakistan, it is likely that other departments will need to take ownership. Moving ahead in the light of this initial study, it is likely that AEDB and ADB may wish to collaborate in the future on harnessing renewable hydrogen as a fuel in Pakistan Additionally, OGRA, NEPRA and the Engineering Development Board will all, of course, need to be engaged as required.

APPENDIX 2: ENERGY AND POWER DATA

Natural Gas		
Natural Gas[103]	2017 – 18	2018 - 19
Reserve (Bal Recoverable)	19.5 trillion feet	21.4 trillion Cubic feet
Production	3,997 million CFt/day	3,936 million CFt/day
Consumption	1,455 billion CFt	1,453 billion CFt
LPG Supplies	1.19 million tonnes	1,057 million tonnes
LPG Consumption	1.28 million tonnes	1,061 million tonnes
LNG Imports	313,902,345 MMBTu	373,410,403 MMBTu
LNG Import bill	2,452 million US$	3,392 million US$

LPG Consumption by Sector (tons)							
Sector[104]	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	ACGR
Domestic	239,850	288,963	430,212	454,623	495,809	445,496	13.2%
Commercial	225,892	287,762	413,426	431,220	515,780	415,368	13.0%
Others	75,491	122,428	275,152	323,577	268,962	200,583	21.6%
Total	541,233	699,153	1,118,790	1,209,420	1,280,550	1,061,447	14.4%

LPG Consumption by Region and by Sector 2018-19				
Province/ Region	Domestic	Commercial	Industrial	Total
Punjab	212,360	257,090	149,502	618,952
SINDH	25,607	47,148	30,117	102,872
KPK	72,874	24,220	7,127	104,221
Balochistan	12,047	13,200	4,434	29,681
A.J. KASHMIR	40,253	16,753	870	57,876
Newly Merged Ex-FATA Districts of KP	26,195	9,690	-	35,885
Northern Area	45,449	37,798	-	83,247
Federal Area	10,712	9,469	8,533	28,714
Total	445,496	415,368	200,583	1,061,447

103. Pakistan Energy Book 2018 & 2019
104. Pakistan Energy Book 2019

Import of LNG						
UNIT	2014-15	2015-16	2016-17	2017-18	2018-19	ACGR
MMBTU	19795505	100720923	186672977	313902345	373410403	
Toe	472503	2404128	4455734	7492597	8913006	
Import Value (Million USD)	(151)	(642)	(1278)	(2452)	(3392)	
Annual Growth Rate of Imports		408.81%	85.34%	68.16%	18.96% [105]	

LNG Consumption by Sector				
Sector	2014-15	2015-16	2016-17	2018-19
Domestic	-	--	--	5
Fertilizer (As feedstock)	4397	18080	1219	11696
Fertilizer (as fuel use)	1198	3817	296	2838
Power	58934	71930	186251	227739
Cement	--	138	296	10
Transport (CNG)	8319	16028	20046	16584
Gen. Industries	25004	61360	75210	63281
Commercial	--	--	432	2052
SSGC*	--	--	--	53261
Total	97851	171353	283749	377469

Oil Data		
Oil Sector[106]	2017 - 18	2018 - 19
Reserve (Bal Recoverable)	348 million barrels	568 million barrels
Production	33 million barrels	32 million barrels
Refining Capacity	19.37 million tons/year	19.37 million tons/year
Crude Processed	14.0 million tons	12.8 million tons
Refinery Production	13.6 million tons	12.3 million tons
Consumption	24.7 million tons	19.2 million tons
Import of Crude	10.3 million tons	8.9 million tons
Import of POL	13.3 million tons	8.8 million tons
Import Bill	11.9 billion US$	10.6 billion US$

105. *Pakistan Energy Book 2019*
106. *Pakistan Energy Book 2019*

A. Renewable Energy Technology Generation Cost

Renewable Energy Technology Generation Cost				
FY	Solar	Wind		
	Base ($/kW)	South Base ($/kW)	Mid Country 5% More than base ($/kW)	North 5% More than Mid Country ($/kW)
2019	549	1300	1365	1433
2020	530	1287	1351	1419
2021	511	1274	1338	1405
2022	494	1261	1324	1391
2023	476	1249	1311	1377
2024	460	1236	1298	1363
2025	444	1224	1285	1349
2026	428	1212	1272	1336
2027	413	1200	1260	1323
2028	399	1188	1247	1309
2029	385	1176	1234	1296
2030	371	1164	1222	1283[107]

B. Solar Projects

Operational Solar Power Projects				
Sr. No.	Projects	Capacity (MW)	Location	Date of Completion
1	M/S Quaid-e-Azam Solar (Pvt.) Ltd.	100	Quaid-e-Azam Solar Park, Bahawalpur	15 July 15
2	M/S Applo Solar Pakistan Ltd.	100	Quaid-e-Azam Solar Park, Bahawalpur	31 May 16
3	M/S Crest Energy Pakistan Ltd.	100	Quaid-e-Azam Solar Park, Bahawalpur	31 July 16
4	M/S Best Green Energy Pakistan Ltd.	100	Quaid-e-Azam Solar Park, Bahawalpur	31 July 16
5	Harappa Solar (Pvt.) Ltd.	18	Sahiwal	14 Oct 17
6	Aj Power (Pvt.) Ltd.	12	Pind Dadan Khan	13 Dec 17

107. AEDB

IPPs in the Process of Achieving Financial Closing of Their Projects			
Sr. No.	Project	Capacity (MW)	Location
1	M/S Access Electric (Pvt.) Ltd.	10	Pind Dadan Khan
2	M/S Bukhsh Solar (Pvt.) Ltd.	10	Lodhran
3	M/S Safe Solar Power (Pvt.) Ltd.	10.28	Bahawalnagar
4	M/S Access Solar (Pvt.) Ltd.	11.52	Pind Dadan Khan

Future Projects			
Sr. No.	Project	Capacity (MW)	Location
1	IPS Solar Park- IPS 22 (Pvt.) Ltd.	50	Nooriabad, Sindh
2	IPS Solar Park-JA 23 (Pvt.) Ltd.	50	Nooriabad, Sindh
3	IPS Solar Park-SB 24 (Pvt.) Ltd.	50	Nooriabad, Sindh
4	R,E Solar I (Pvt.) Ltd.	20	Dadu Sindh
5	R,E Solar II (Pvt.) Ltd.	20	Dadu Sindh
6	ET Solar (Pvt.) Ltd.	25	Thatta, Sindh
7	ACT Solar (Pvt.) Ltd.	50	Thatta, Sindh
8	Janpur Energy Ltd.	12	Sultanabad, Rahim Yar Khan
9	Lalpir Solar Ltd.	12	Mehmood kot, Muzafargarh
10	Siddiqsons Solar Ltd.	50	Kalar Kahar, Chakwal
11	ET Solar (Pvt.) Ltd.	50	Fateh Jang, Attock
12	Asia Petroleum Ltd.	30	Bahalwalnager, Punjab

C. Installed Power Plants

List of Wind Turbine Plants, Location & Project Capacity			
Sr. No.	Name of Company	Location	Project Capacity (MW)
1	FFC Energy Ltd.	Jhimpir	49.5
2	Zorlu Enerji Pakistan (Pvt.) Ltd.	Jhimpir	56.4
3	Three Gorges Pakistan First Wind Farm (Pvt.) Ltd.	Jhimpir	50
4	Foundation Wind Energy II (Pvt.) Ltd.	Gharo	50
5	Foundation Wind Energy –I Ltd.	Gharo	49.5
6	Sapphire Wind Power Company Ltd.	Jhimpir	52.8
7	Metro Power Company Ltd.	Jhimpir	50
8	Yunus Energy Ltd.	Jhimpir	50
9	Master Wind Energy (Pvt.) Ltd.	Jhimpir	52.8
10	Act Wind (Pvt.) Ltd. (Tapal Wind Energy (Pvt.) Ltd.	Jhimpir	50
11	Gul Ahmed Wind Power Ltd.	Jhimpir	50
12	Tenega Generasi Ltd.	Gharo	49.5
13	Hydro China Dawood Power (Pvt.) Ltd.	Gharo	49.5
14	Sachal Energy Development (Pvt.) Ltd.	Jhimpir	50
15	UEP Wind Power (Pvt.) Ltd.	Jhimpir	99
16	Jhampir Wind Power (Pvt.) Ltd.	Jhimpir	50
17	Hawa Energy (Pvt.) Ltd.	Jhimpir	49.5
18	Hartford Alternative Energy (Pvt.) Ltd.	Jhimpir	49.3
19	Three Gorges Second Wind Farm Pakistan Ltd.	Jhimpir	49.5
20	Three Gorges Third Wind Farm Pakistan (Pvt.) Ltd.	Jhimpir	49.5
21	Tricon Boston Consulting Corporation (Pvt.) Ltd. - A	Jhimpir	49.6
22	Tricon Boston Consulting Corporation (Pvt.) Ltd. - B	Jhimpir	49.6
23	Tricon Boston Consulting Corporation (Pvt.) Ltd. - C	Jhimpir	49.6
24	Zephyr Power (Pvt.) Ltd.	Gharo	50
25	Burj Wind Energy (Pvt.) Ltd.	Gujju	50
26	Western Energy (Pvt.) Ltd.	Jhimpir	50
27	Trans-Atlantic Energy (Pvt.) Ltd.	Jhimpir	50
28	Shaheen Renewable Energy - 1 (Pvt.) Ltd.	Jhimpir	49.5

List of Solar Plant, Location & Project Capacity			
S. No.	Name of Company	Location of Land	Project Capacity (MW)
1	M/S Quaid-e Azam Solar (Pvt.) Ltd.	Bhawalpur	100
2	M/S Appolo Solar Pakistan Ltd.	Bhawalpur	100
3	M/S Crest Energy Pakistan Ltd.	Bhawalpur	100
4	M/S Best Green Energy Pakistan Ltd.	Bhawalpur	100
5	Harappa Solar (Pvt.) Ltd.	Sahiwal	18
6	AJ Power (Pvt.) Ltd.	Pind-dadan Khan	12
7	M/S Access Electric (Pvt.) Ltd.	Pind-dadan Khan	10
8	M/S Bukhsh Solar (Pvt.) Ltd.	Lodhran	10
9	M/S Safe Solar Power (Pvt.) Ltd.	Bahawal Nagar	10.28
10	M/S Access Solar (Pvt.) Ltd.	Pind-dadan Khan	11.52
11	IPS Solar Park-IPS 22 (Pvt.) Ltd.	Nooriabad, Sindh	50
12	IPS Solar Park-JA 23 (Pvt.) Ltd.	Nooriabad, Sindh	50
13	IPS Solar Park-Sb 24 (Pvt.) Ltd.	Nooriabad, Sindh	50
14	R.E Solar I (Pvt.) Ltd.	Dadu, Sindh	20
15	R.E Solar II (Pvt.) Ltd.	Dadu, Sindh	20
16	ET Solar (Pvt.) Ltd.	Thatta,Sindh	525
17	ACT Solar (Pvt.) Ltd.	Thatta,Sindh	50
18	Janpur Energy Ltd.	Rahim Yar Khan	12
19	Lalpir Solar Ltd.	Muzaffargarh	12
20	Siddiquesons Solar Ltd.	Kalar Kahar	50
21	ET Solar (Pvt.) Ltd.	Fateh Jang	50
22	Asia Petroleum Ltd.	Bahawalnagar	30

List of Thermal Power Plants, Location & Project Capacity			
S. No.	Name of Company	Location of Land	Project Capacity (MW)
1	Kot Addu Power Company	Kot Addu, Punjab	1600
2	Hub Power Company	Hub, Balochistan	1292
3	Hubco Narowal Power Plant	Narowal Punjab	225
4	Gul Ahmed Energy	Karachi, Sindh	136
5	Nishat Power ltd	Lahore, Punjab	200
6	Nishat Chunain Power Ltd.	Lahore, Punjab	200
7	Saba Power Company Ltd.	Sheikhpura, Punjab	125
8	Tapal Energy Ltd.	Hub, Balochistan	126
9	Southern Electric Power Company Ltd.	Raiwind, Lahore	136
10	Japan Power Generation Ltd.	Raiwind, Punjab	135
11	Kohinoor Energy Ltd.	Lahore, Punjab	131
12	Liberty Power Tech	Faisalabad, Punjab	200
13	AES Lal Pir Power	Muzaffargarh, Punjab	362
14	AES Pak Gen	Muzaffargarh, Punjab	365
15	Attock Gen Ltd.	Rawalpindi, Punjab	165
16	Jamshoro Power Station	Jamshoro, Sindh	850
17	K-Electric Bin Qasim Power Plant	Karachi, Sindh	1260
18	Sitara Energy Ltd.	Faisalabad, Punjab	85
19	Attock Refinery Ltd.	Rawalpindi, Punjab	18
20	Atlas Power Ltd.	Sheikhupura, Punjab	225

List of Coal Power Plants, Location & Project Capacity			
S. No.	Name of Company	Location of Land	Project Capacity (MW)
1	Master Power (Pvt.) Ltd.	Raiwind, Punjab	20
2	Sitara Chemical Industries Ltd.	Faisalbad, Punjab	40
3	Fauji Fertilizer Power Plant	Karachi, Sindh	118
4	Sahiwal Coal Power Plant	Sahiwal, Punjab	1320
5	Maple Leaf Power Ltd.	Mianwali, Punjab	40
6	Port Qasim Coal Power Project	Karachi, Sindh	1320
7	DG Cement Coal Power Plant	DG Khan, Punjab	30
8	Hub Coal Power Project	Hub, Balochistan	1320
9	Engro Powergen Thar	Tharparkar, Sindh	660

List of Natural Gas Power Plant, Location & Project Capacity			
S. No.	Name of Company	Location of Land	Project Capacity (MW)
1	Guddu Thermal Power Plant	Guddu, Sindh	2402
2	Fauji Foundation Power Company Daharki, Ltd.	Daharki, Sindh	185
3	Uch-I, II Power Plant	Dera Murad Jamali, Balocistan	1000
4	Nandipur Power Project	Gujranwala, Pinjab	425
5	Habibullah Coastal Power (Pvt.) Ltd.	Quetta, Balochistan	140
6	WAPDA Quetta Thermal Power Station	Quetta, Balochistan	35
7	Liberty Power Project	Daharki, Sindh	235
8	Rouch Power Ltd.	Abdul Hakeem, Punjab	450
9	Engro Powergen Qadirpur Ltd.	Ghotki, Sindh	227
10	Halmore Power Generation Company Ltd.	Sheikhupura, Punjab	225
11	Orient Power Company Ltd.	Kasur, Punjab	229
12	Saif Power Ltd.	Sahiwal, Punjab	229
13	K-Electric Bin Qasim Power Plant II	Karachi, Sindh	560
14	Fauji Kabirwala Power Complex Ltd.	Kabirwala, Punjab	157
15	Sapphire Electric Company Ltd.	Muridke, Punjab	234
16	Sindh Nooriabad Power Company Ltd.	Jamshoro, Sindh	100
17	Haveli Bahadur Shahpur Plant	Jhang, Punjab	1230
18	Bhikki RLNG-based Power Plant	Sheikhupura, Punjab	1180
19	Balloki Power Plant	Balloki, Punjab	1223
20	Altern Energy Ltd.	Fateh Jang, Punjab	32

D. Retirement Schedule of Existing Power System

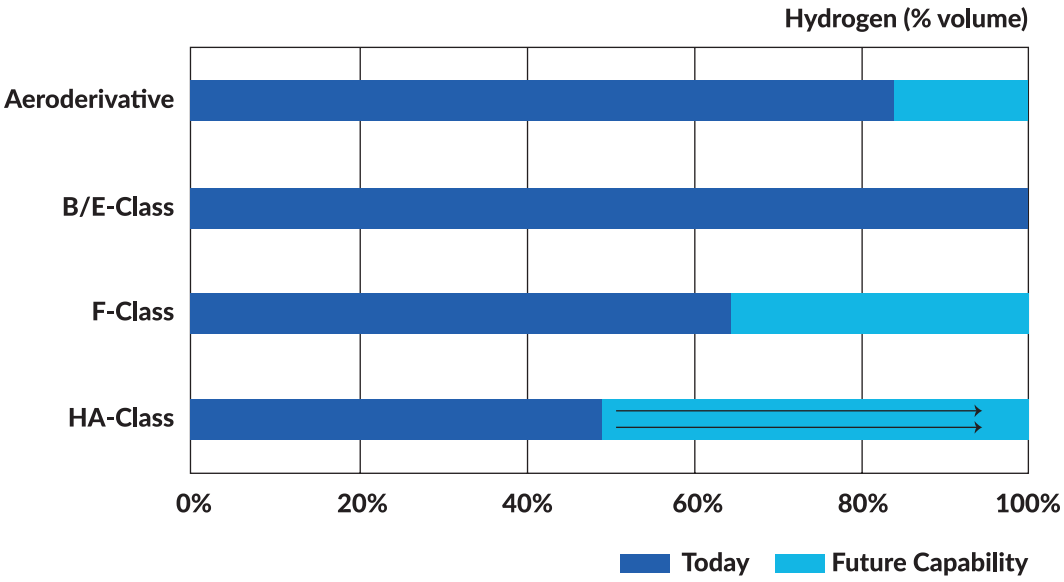
A significant quantum i.e., 1,951 MW of existing thermal power plant mentioned below are scheduled to be retired during next four years. A plant is supposed to be declared as retired upon completing its PPA term.

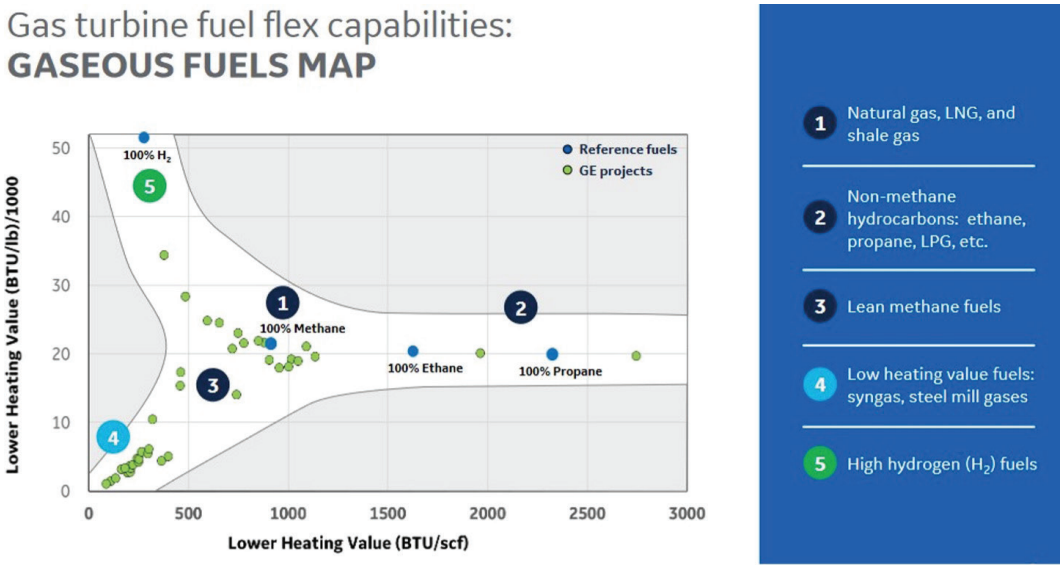
Name of Power Station	Capacity (MW)	Fuel Type	2020	2021	2022	2023
Reshma	85	Furnace Oil (FO)	•			
KAPCO 1	341	FO		•		
KAPCO 2	746	FO		•		
KAPCO 3	249	FO		•		
Guddu -I	260	Gas			•	
Guddu-II	270	Gas				•

APPENDIX 3: TECHNICAL DETAILS OF GAS FIRED POWER PLANTS CLOSE TO QUAID E AZAM SOLAR PARK

A. Engro Power Generation Qadirpur Ltd.

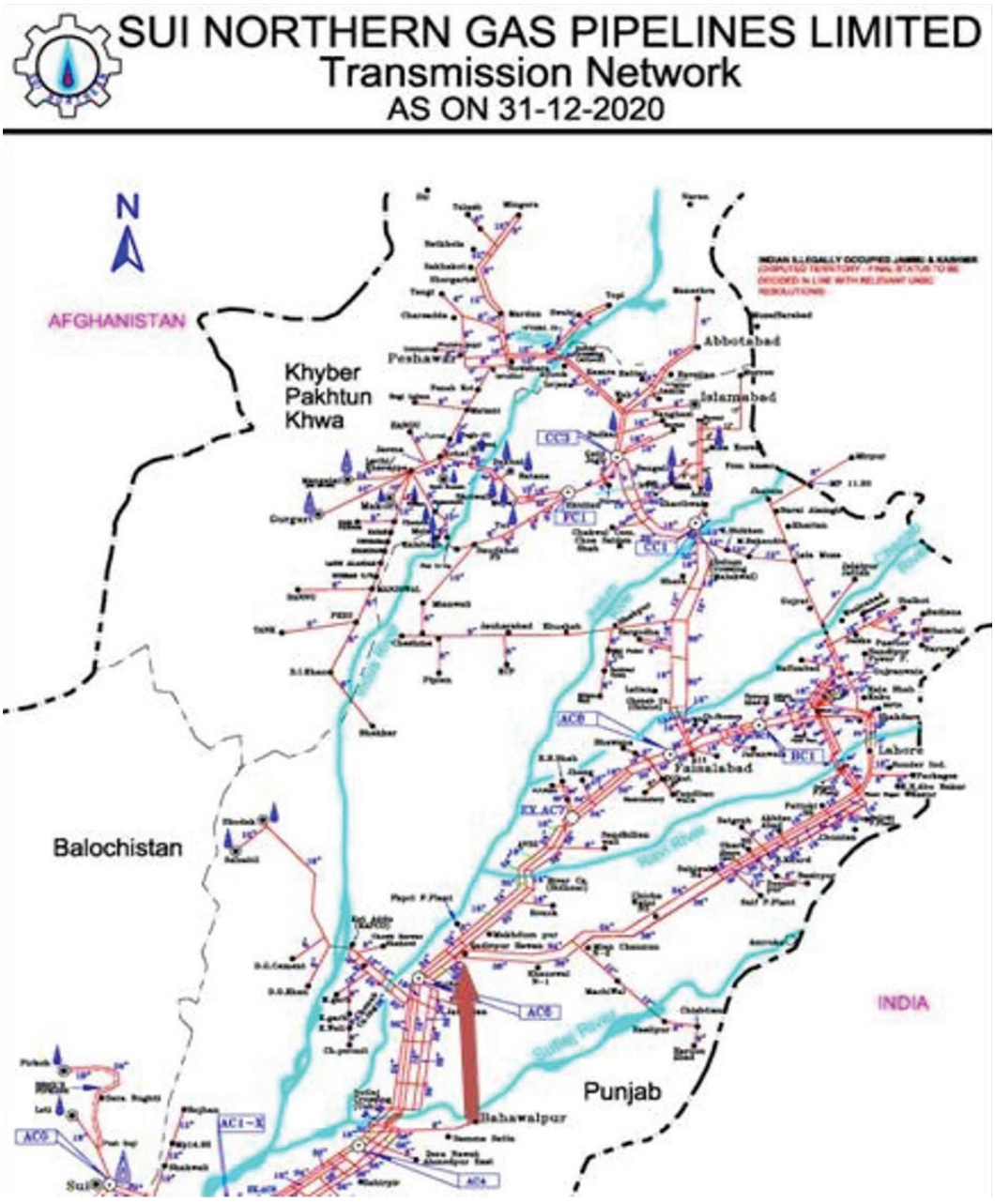
GE Gas turbine hydrogen capability





General Information

Engro Chemical Pakistan Ltd. (ECPL), owns and operates at 217 MW power plant in Qadirpur, Ghotki, Sindh and runs on permeate gas, Thermal Generation (Combined Cycle), which was previously being flared. This unique aspect makes the ECPL, Qadirpur plant one of the few green power plants in Pakistan earning carbon credits.



Distance between Bahawalpur to Qadirpur (295.4 Km)

The above transmission map indicating the existing natural gas pipeline routes that flow from Engro Chemical Pakistan Ltd. (ECPL), Qadirpur to locations. The distance between Qadirpur and Quaid e Azam Solar Park is almost 300 KM. The transmission line can be used but not from Qadirpur for any additional hydrogen pipeline. There is no information about any redundant pipeline exist that can be used for hydrogen.

Project Background

Private Power Infrastructure Board (PPIB) pre-qualified and issued letter of interest (LOI) to Engro Chemical Pakistan Ltd. (ECPL) for setting up of 150 to 250 MW Combined Cycle Power Plant (CCPP) by utilizing the low BTU gas (a byproduct of membrane processing facility, being flared to atmosphere of Qadirpur gas field located in district Ghotki, in Sindh province.

The plant consists of 1 x Gas Turbine (126.57 MW), 1 x Heat Recovery Steam Generator (HRSG) and 1 x steam Turbine (99.95 MW) with total installed capacity of 226.52 MW (gross). The power generated from power plant is bring disbursed by making an in-out arrangement from 220 KV D/C foundation power CCPP- Rohri T/Line at Engro Energy Ltd. and another 220 KV T/Line from Rohri (220 KV) grid Station to Shikarpur. The salient features are:

- De-Rated Capacity of the plant commensurate with low heating value of Permeate gas and efficiency of Plant
- The option of supplementary firing in HRSG to avoid flaring of permeate gas resulting in increase the capacity of power plant but lowering the efficiency of the Combined Cycle Power Plant (CCPP)
- Plant availability and part load operation
- Low BTU Gas operation as back-up and depletion in allocated gas supply
- Interconnection Facility / Transmission Facility (IF / TF) financing and simultaneous completion of IF/TF and plant

The Power plant is dispersing the power directly to HESCO load center at 220/132 KV voltage level. 220 KV transmission line for making in-out of the proposed Daharki CCPP-Rohri new 220 KV DC transmission line at Engro Energy CCPP. The approximate length of the double circuit transmission line will be (5+5) 10 km on twin bundled rail conductor.

- 220 KV Rohri new-Shikarpur D/C transmission line, (approx. 50 KM long) on twin bundled Rail Conductor.
- 132 KV Rohri new 220 KV Grid Station – Gambat SDT transmission line, approx. 53 KM long on Rail conductor.

EEPL allocated with permeate gas of 75 MMSCFD with LHV of 520 BTU/SCF would result in generation of 226.52 MW gross output & gross efficiency of 47.5%. The plant capacity of 226.52 MW would be de-rated to 223.80 MW at Mean site conditions with an efficiency of 47.0%. The plant exists with GE 9171 9E Gas turbine utilizing 57 MMSCFD of the gas whereas the remaining of 18MMSCFD is utilizing supplementary firing in the HRSG to ensure all allocated gas for power generation instead of being flared to atmospheres causing environmental hazards.

Plant Configuration	
Plant Size Installed Capacity (Gross ISO)	226.52 MW
Type of Technology	Combined Cycle Power Plant (With Supplementary Firing)
Number of Units/Size (MW)	1x126.57 MW (Gas Turbine)
	1x99.95 MW (Steam Turbine)
Unit Make & Model	Gas Turbine – GE PG9171E
	Steam Turbine – Harbin Turbine Machine
De-rated Capacity (at Mean Site Conditions)	223.80 MW
Auxiliary Consumption	7.00 MW
Expected Life of the Facility from Commercial Operation	25 Years
Commissioning and Commercial Operation date	October 31, 2009

Fuel Details	
Primary Fuel	Low BTU Permeate Gas (565-625 Btu/Scf)
Alternate / Back-up Fuel	High Speed Diesel (HSD)
Fuel Source (Imported/Indigenous)	Indigenous (Qadirpur Field)
Fuel Supplier	Sui Northern Gas Pipeline Ltd. (SNGPL)
Supply Arrangement	Through Gas Pipeline with an approx length of 2 KM from Qadirpur gas treatment facilities
No of Storage Tanks of Alternate /Backup fuel (HSD)	01
Storage Capacity of HSD Tank	8500 m^3
Gross Storage of HSD	8500 m^3 (Net Storage)

Emission Values		
	Natural Gas	High Speed Diesel (HSD)
SOx	54 mg/Nm^3	400 mg/Nm^3
NOx	79 mg/Nm^3	143 mg/Nm^3
CO	103.3 mg/Nm^3	86.7 mg/Nm^3
PM10	53.3 mg/Nm^3	43.3 mg/Nm^3

Cooling System	
Cooling Water Source/Cycle	Canal (Primary) and Well (Back up) / Closed Cycle

Plant Characteristics	
Generation Voltage	13.8 Kv
Frequency	50 Hz
Power Factor	0.8 Lagging – 0.9 Leading
Automatic Generation	Yes
Ramping Rate	10 MW/Minutes above minimum load
Time Required to Synchronize to Grid and loading the complex to full load	7 hours & 40 minutes for cold start
Installed Capacity Gross ISO	226.52 MW
De-Rated Capacity Mean at site Conditions	223.80 MW
Auxiliary Consumption	7.00 MW
Net Capacity of the Plant at Mean Site Condition	216.80 MW

The above transmission map indicating the existing natural gas pipeline routes that flow from Kot Addu Power Company (KAPCO) to locations. The distance between Kot Addu, District Muzaffargarh, Punjab and Quaid e Azam Solar Park is almost 175 KM. The transmission line can be used but not from Kot Addu for an additional hydrogen pipeline. There is no information about any redundant pipeline exist which can re-use for hydrogen.

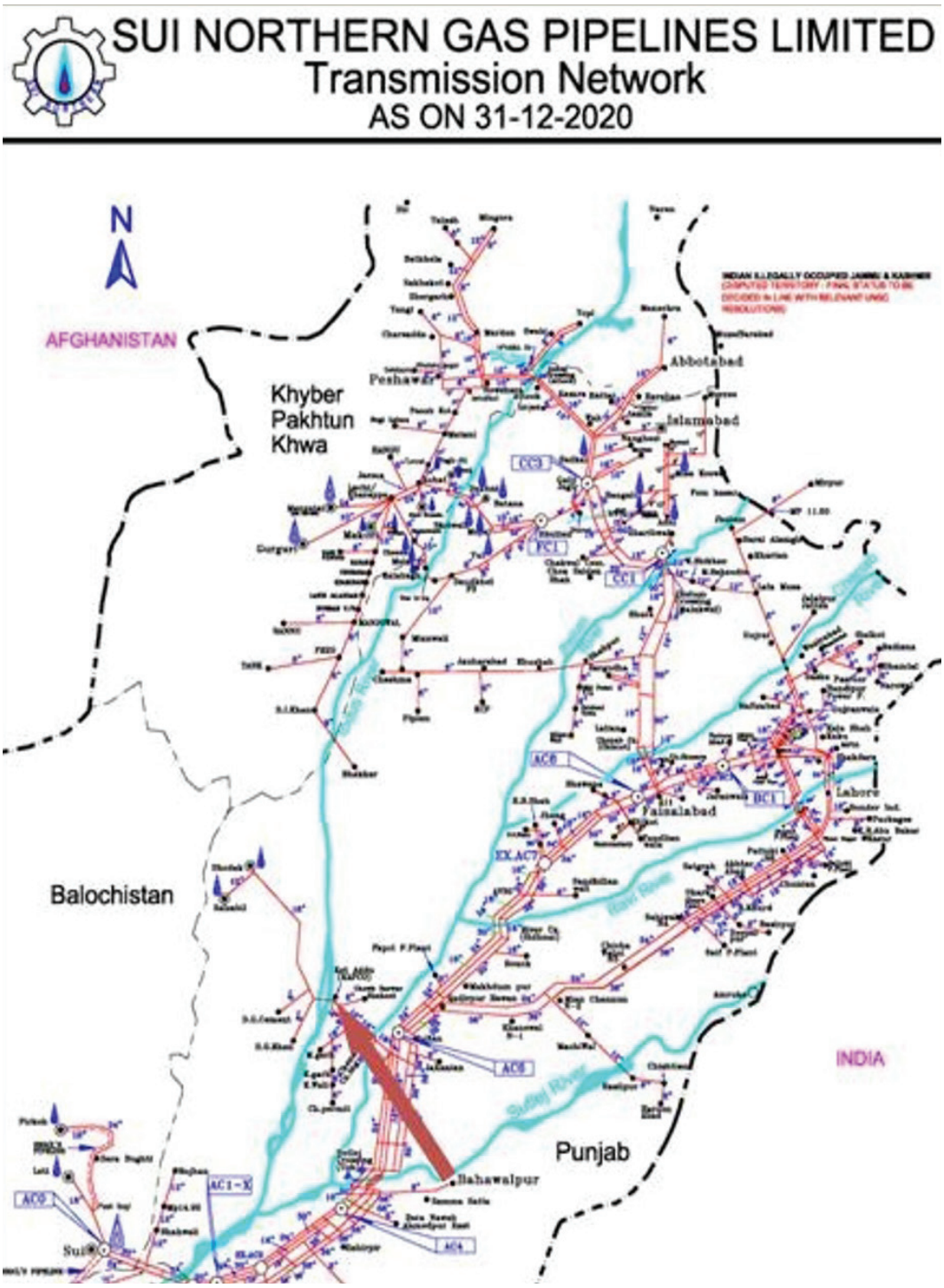
Project Historical Background

Kot Addu Power Plant (KAPCO) was built by the Pakistan Water and Power Development Authority (WAPDA) in five phases between 1985 and 1996 in District Muzaffargarh, Punjab, almost 90 KM, north west of Multan on the left bank of the River Indus at a distance of 16 KM from Taunsa Barrage.

In April 1996, Kot Addu Power Company Ltd. (KAPCO) was incorporated as a public Ltd. company under the Companies Ordinance, 1984 with the objective of acquiring the Power Plant from WAPDA. The principal activities of the Company include the ownership, operation and maintenance of the Power Plant.

In June 27, 1996, international competitive bidding by the Privatization Commission Government of Pakistan, the Company was privatized. At the time of privatization and following privatization, WAPDA divested 36% of its shareholding in the Company to the strategic investor. In August 2013, the strategic investor sold its entire shareholding in the Company to local corporate entities and individuals.

In February 2005, the Privatization Commission (on behalf of WAPDA) sold another 18% of WAPDA shareholding in the Company to the General Public. On April 18, 2005 the Company was formally listed on the Pakistan Stock Exchange (formerly the Karachi Stock Exchange, the Lahore Stock Exchange and the Islamabad Stock Exchange).



Kot Addu Power Company (KAPCO)
Distance between Bahawalpur to Kot Addu (177.4 Km)

The Kot Addu Power Company (KAPCO) is a Pakistani power company owns, operates, and maintains a multi-fuel fired power plant in Kot Addu, District Muzaffargarh, Punjab, Pakistan. It produces 1,600 MW of electricity. In, 2005, the company was formally listed on the stock exchanges of Pakistan.

During the second quarter, the power Plant generated 320 GWh of electricity at a load factor of 10.8% with an overall commercial availability of 96/9%. In the larger interest and to maintain the sustainability of the power sector, at the request of the GoP, the company inter alia signed a Master Agreement and the third amendment to Power Purchase Agreement with WAPDA in February 11, 2021. The details of Power Purchase Agreement (PPA) are as mentioned below.

Expiry of Power Purchase Agreement (PPA)

The existing PPA which is for the term of 25 years is due to expiry on coming June 26,2021. In line with terms and conditions of PPA, the company had taken up the matter for renewal / extension or revision of PPA with WAPDA and other relevant quarters of Government of Pakistan.

Due to expiry of the current PPA, a material uncertainty exists that may cast significant doubt on the company's ability to continue as a going concern beyond June 26, 2021. In June 03,2020, the Government formed a negotiation committee to initiate discussion with Independent Power Producers (IPPs) on various matters, which inter alia, included tariff concession and other terms and conditions of respective PPAs and also to coordinate with other GOP institutions, including Ministry of Energy, Central Power Purchasing Agency Guarantee Limited (CPPA-G), WAPDA, National Transmission and Dispatch Company, (NTDC) etc. for this purpose. After several discussions with the Committee, a Memorandum of Understanding (MoU) was signed between the Committee and the company on August 19, 2020.

Government of Pakistan through notification dated October 7, 2020, constituted the implementation Committee to finalize the binding agreement based on the MoU. After detail discussion with Implementation Committee, WAPDA (Power Purchaser) signed the third amendment to PPA and Master Agreement on February 11, 2021. Pursuant to the terms of these agreement, the outage due to fuel shortage during the period 2008-16 will be treated as Force Majeure Event under the PPA and consequently, existing Terms of PPA will be extended to another 16 months. During this extended period the company agrees to waive off any rights to receive Capacity Payments in lieu of the capacity payment already received during the outage period. However, during this extended period, the company will receive Energy Payments and other pass-through items. Further, as per terms of Master Agreement, WAPDA shall consent to the extension of the PPA for an additional term following the expiry of the extended term. The company will also have the option to sell electricity to other Bulk Power consumers through wheeling arrangement. The agreement has been approved by Federal Cabinet and the Company's Board of Directors; however, it shall be binding on the company and WAPDA only after the required approval has been obtained from its shareholders and amendments to the facilitation agreement have been approved by the GoP. The management is confident that these Agreements will be duly approved in due course.

National Electric Power Regulatory Authority
(NEPRA)
Islamabad – Pakistan

GENERATION LICENCE

No. IPGL/020/2004

In exercise of the Powers conferred upon the National Electric Power Regulatory Authority (NEPRA) under Section 15 of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (XL of 1997), the Authority hereby grants a Generation Licence to:

Kot Addu Power Company Limited

Incorporated under the Companies Ordinance, 1984
Under Certificate of Incorporation

No. I-01977 Dated 25th April 1996

to engage in generation business subject to and in accordance with the Articles of this Licence.

Given under my hand this 22nd **day of** September**, Two Thousand & Four, and expires on** 21st **day of** September**, Two Thousand & Twenty One.**

22.09.04

Registrar

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR

Plant Description

The generation facility consists of ten gas turbines and five steam turbine units, plus ten Heat Recovery Steam Generators (HRSG). Comprising five independent combined cycle Modules each consist of 2 x Gas Turbines units, 2 x HRSG's and 1 x Steam Turbine Unit associated with ancillary plant. The ancillary plant includes water extraction and treatment system and also equipped with cooling towers, oil storage tanks, fuel oil treatment plants and other equipment. The plant burns residual fuel, high speed diesel and natural gas.

Plant Start up Time

Startup of a unit and synchronize to Grid System varies according to length of time till the unit has been shut down. The tables below show the length required for various conditions of start up for gas and steam units. The steam turbine start time must be added to the start times of the gas turbines used to provide such turbines with steam.

Start – Up Times for Gas Turbines				
Units	**1 – 2**	**3 -4**	**5 – 8**	**13 - 14**
Starting Time (In Minutes)	4	28	10	3.3

Units	**9 – 10**	**11 – 12**	**15**
Starting Time (In Minutes)	c/s – 140 w/s – 60 h/s - 15	c/s – 20 w/s – 20 h/s - 10	c/s – 42 w/s – 25 h/s - 15

Reference to starts, starting or started means the process of firing the boiler, running up the turbine generator and synchronizing it to the Grid System.

Start-Up of a Steam Turbine Unit be classified as set of forth below:

Units	**9 – 10**	**11 – 12**	**15**
Drum Pressure (bar)	c/s – <12 w/s – 12 - 20 h/s - > 20	N/A	N/A
Steam Pressure	N/A	c/s – <100 w/s – 100-250*C h/s - >250*C	N/A
Time after Shutdown	N/A	N/A	c/s – >60 hrs w/s – 6 – 60 hrs h/s - <6 hrs
Recommended Starts/Year	c/s – 5 w/s – 50 h/s – Agreed by all parties	c/s – 8 w/s – 80 h/s - 365	No manufacturer limits

Complex Loading

The units loading ramping rates are steady rates at which the load can be raised. The maximum design load ramping rates are in (M/W per Minute). The maximum design load ramping rates results of the functional test as mentioned below:

Units	1 – 2	3 – 4	5 – 8	9 – 10	11 – 12	13 – 14	15
Ramping Rate	11* 30**	5	8	c/s – 1.5 w/s – 12 h/s - 20	c/s – 2 w/s – 3 h/s - 3	11* 30**	c/s – 14 w/s – 14 h/s - 14
Load Range	20 -90	0 – 100	0 – 100	0 – 100	c/s - 35- 100 w/s– 35-100 h/s – 5-100	15 - 100	c/s – 0-50 w/s –0-65 h/s – 0-80

The unit load ranges expressed in percentage in this structure refer to gross load range for which maximum ramping rates apply. Ramping rates outside of these load range will be slower.

Temperature Stabilization

During cold start only, once reaching full speed and no loading the unit 15 load will be required to be held steady for twenty-five minutes for temperature stabilization of the turbine during load increases.

Any required stabilization for unit 9 & 10 loads will depend on axial surface stresses controlled by airmax. Step changes in dispatched load of up to 5% of each generator are allowable provided that the generator load is greater than 0%.

Interconnection Facility & Transmission Facility

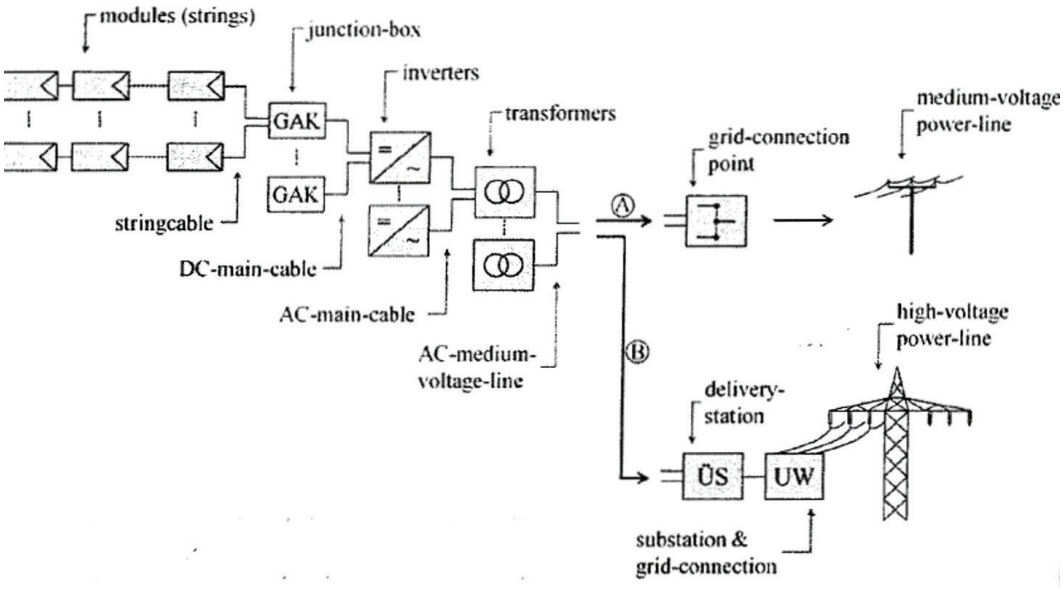
The complex included 132 KV and 220 KV switchyards. The switchyards are owned, operates and maintain by the company. The WAPDA transmission lines connected to the complex consist of 132 KV and 220 KV feeders which serve the local regions around Kot Addu, Muzaffar Garh, D I Khan & Multan. 6 x 132 KV feeders and 4 x 220 KV feeders are connected to 132 KV & 220 KV bus bars to be owned by the company.

- Installed ISO (Gross) 1600 MW
- Net Capacity 1345 MW

APPENDIX 4: TECHNICAL DESCRIPTION OF THE QUAID E AZAM SOLAR PARK

The overall Quaid-e-Azam Solar Park - located in the Cholistan desert region of the Bahawalpur district - shall be started in the first phase with a 100 MW installation. This part shall be connected to the 132 kV overhead power line that runs past the park. Solar photovoltaic plants use the global irradiation (GI), which is converted into electric energy. Adequate project locations should offer at least1.200 kWh/m^2 per year.

Single Line Diagram Photovoltaic System



The efficiency of a solar cell is the percentage of power from solar energy, incident on the panel, converted to electrical energy. This term is calculated using the ratio of the maximum power point of the cell, Pm, divided by the light power that reaches the cell, the global irradiance E, in W I m^2) under standard conditions (STC, 1000 W/m^2, 25*C, AM 1,5), and the surface area of the solar cell (Ac in m^2).

Inverter Technology

Because photovoltaic panels generate DC electricity, it must be converted to alternating current before it can be fed into the grid. This is to be achieved by an electronic device called an inverter that performs this function. State of the art inverters offer a broad range of operational stages, which generally fulfill all the requirements of the international grid codes in terms of fault-ride-through and reactive power provision. Inverter stations provide a protective shell in which PV-strings can be connected to inverters. Centralized inverters typically have a capacity from 500 kWp to 1.5 MWp of DC PV-Power, depending on the size of inverter. From the inverter stations the AC power is stepped-up by a MV or HV-Transformer, and then connected to a medium or high voltage grid (for instance 132 kVas in Pakistan).

Control System

A PV plant typically is controlled by a SCADA System (Supervisory Control and Data Acquisition) and can remotely be managed and supervised. However, for preventive, planned and corrective maintenance, adequate staff and qualified contractors must be identified for the Operations & Maintenance (O&M) of the plant.

Climate Conditions

Climate conditions have influence on construction and foundation lay-out as well as energy production. The region is part of the Cholistan Desert. The name might be a little misleading as the site is surrounded by agricultural used land. There are seasonal variations from cold winters to hot summers with up to 40 or even 50°C. The monsoon season lasts from May through September with a peak in July and August. 60-70% of the yearly rainfall is in those months. The average rain fall per year is about 170-200mm.

There is an average of 8 to 9 hours of clear sky per day throughout the year and 2900 hrs-3300 hrs sun hours annually. The region is a distinctly low wind area with means of less than 2.5 m/s. With the monsoon season the wind speed up especially at daylight. Storm events are logged by the meteorological station of Bahawalpur with maximum gust wind speeds of 20-30 m/s and single events of up to 40 m/s (~15m above ground).

Microclimate effects can cause dusty and windy conditions which should be evaluated more deeply. Broken up surface causes swirling dust at wind speeds of higher 5-6 m/s (4Bfd) Seasonal flooding could be a point to consider as the inflows of the Indus, Satluj and Panjnad are all close by and at similar elevation (~115 m site level to ~110m river level above sea level). Recent events of flooding did have no impact in this specific region.

Meteorology including Solar Resource

Pakistan is exposed to strong solar radiation, long hours of sunshine and abundant solar energy resources. The annual sunshine hours range between 2900 hrs - 3300 hrs, with a daily average of 8.1-9.2 sunshine hours. Bahawalpur District is located in the south of Punjab Province. The Meteorological Station in Bahawalpur District is located at 71.78 degrees east longitude and 29.4 degrees north latitude (in terms of the geographical coordinates) and the Observation Field is 116 meters above the sea level. The basic available meteorological data and the sunshine hours from 1982 to 1991 and from 1996 to 2012 (27 years) of this Meteorological Station have been collected by QA Solar.

The region of Cholistan desert is over all hot and dry as shown in the following table:

Months	Sun hours* (h)	T Amb (C*)	Wind Vel (m/s)
January	10	13.5	2.0
February	11	17.8	2.3
March	12	23.2	2.6
April	13	30.2	2.6
May	13	36.5	2.7
June	14	39.4	4.2
July	14	39.0	3.4
August	13	36.8	2.9
September	12	32.9	2.3
October	11	27.8	2.1
November	11	22.2	1.9
December	10	15.5	2.3
Annual Average[108]	2900-3300	27.9	2.6

108. Source; Solar GIS & Metrological Station Bahawalpur District Sun Hours: Hours (Metronome 7*, Explanation In); T Amb: Average Ambient Temperature; Wind Vel: Average Wind Velocity*

Results from Different Sources for Irradiance Data			
Irradiation Sources Bahawalpur Average Monthly Sum	Metronome 7	Solar GIS	NASA
	1986-2005	1999-2012	1981-2011
	GlobHor	GlobHor	GlobHor
	kWh/m² .mth	kWh/m² .mth	kWh/m² .mth
January	104	102	112
February	118	124	125
March	157	180	163
April	179	197	180
May	194	209	202
June	182	190	200
July	184	181	193
August	182	185	176
September	170	`175	159
October	144	160	144
November	114	115	115
December	99	103	104
Annual Average	1827	1921	1873

Power Supply Infrastructure

For this first Phase of 100 MW of the Quaid-e-Azam Solar Park an 11 kV overhead power line is used, and it comes from the north. This power line will be large enough for supply the auxiliary power, but not large enough to evacuate the produced electricity of the park.

Power Plant Technology Configurations

In general, several technology configurations were realized. Easiest and cheapest technology configuration was fixed mounted module installation with a 25-30° tilt to the south with central inverters. The density of installed PV power to ground space is highest and the specific energy output by installed PV power is lowest. Alternatively, a dual axis tracking system was complete in opposite, it was more expensive and has lowest density of installed PV power to ground space and the highest specific energy output of installed PV Power. A compromise of these two technologies forms single axis tracking system and this option offered a good cost to power ratio. Due to this insight, several versions of single axis tracking systems (with horizontal North-South axis) were compared.

Grid Connection

A grid connection, for this first phase of 100 MW, was realized by connecting the park to the north- south running overhead 132 kV power line that runs right along the east border of the park. Suitable step-up transformers (park internal) and substation were required.

System Size

The system comprises of about 350,000- 400,000 modules with an aggregate DC capacity of 100 MWp.

Annual Energy Yield

The annual specific energy yield of the base case system is 1.603 kWh/kWp.

Annual Degradation of Module Efficiency

The assumed annual degradation of module efficiency amounts 0.30%

Start of Operations

The start of operations of solar was the date of grid connection commissioning. The start of operations was October 1st, 2014. For the financial case feed into the grid and payments by December 1st, 2014.

All the system components for the following DC functions on SLD include:

- Module Arrays (fixed - tilted)
- Combiner and Re-combiner Boxes
- Inverters
- DC cables
- DC connectors
- Disconnects, switches, protection, fuses
- Grounding
- Switchgear

- Transformers (including LV /MV and MV/132kV)
- AC cables
- AC connectors
- Protection
- Grounding
- Grid Connection
- Electric meter etc.

The evacuation scheme for 1000 MW (gross capacity) solar power from Quaid-e-Azam solar park at Cholistan comprises of three phases. Phase-1 comprises of power evacuation of solar power plants (gross capacity 100 MW) at 132 kV voltage level to the MEPCO network. In Phase-2 additional solar power plants (gross capacity of 300 MW) at 132 kV voltage level can evacuate power. Later on, additional 600 MW (gross capacity) solar power generations has been planned to be evacuated in Phase-3 through interconnection scheme at 220 kV voltage level.

Phase-1: First 100 MW Solar Power Evacuation at 132 kV Voltage

- A 132 kV D/C transmission line approx. 4 km long on Rail conductor for looping In/Out of the proposed 132 kV Bahawalpur-Lal Suhanra SIC at solar power plants.

Phase-2: Additional 300 MW Solar Power Evacuation at 132 kV Voltage

- A 132 kV D/C transmission line approx. 8 km long on Rail conductor for looping In/Out of the proposed 132 kV Bahawalpur Cantt-Lal Suhanra SIC at solar power plants.
- A 132 kV D/C transmission line approx. 4 km long on Rail conductor for looping In/Out of the proposed 132 kV Bahawalpur - Lal Suhanra SIC at solar power plants.
- A 132 kV D/C transmission line approx. 40 km long on Rail conductor from Bahawalpur New to Lodhran & looping in/out of one circuit at Baghdad-ul-Jaded

Phase-3: Additional 600 MW Solar Power Evacuation at 220 kV Voltage

- A 220/132 kV collector substation at/around Lal Suhanra substation with 3x250MVA, 220/132 kV transformers
- A 220 kV D/C transmission line, approx. 40 km long on twin-bundled Rail conductor from 220 kV Lal Suhanra to Bahawalpur substation
- Three 132 kV D/C transmission lines, each approx. 8 km (total 24 km) long on Rail conductor, from 220 kV collector substations to individual solar power projects.

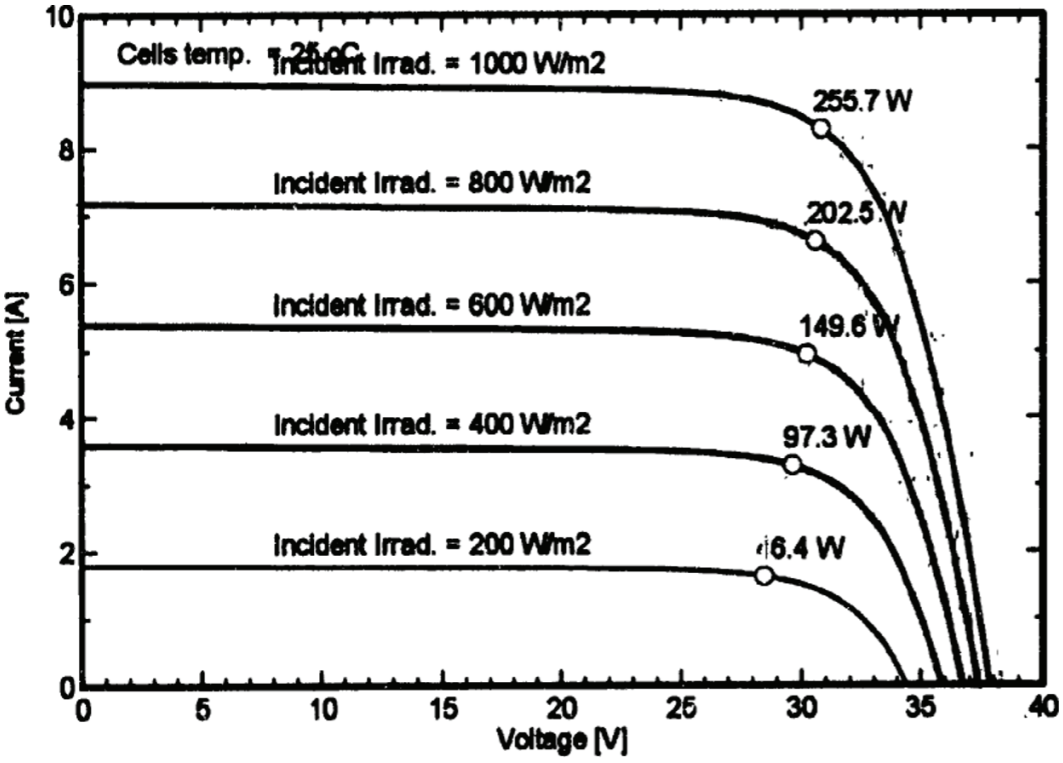
Following are Salient Features of the Quaid e Azam solar Energy Project	
Parameters	**Details**
Type of Area	Desert
Magnitude of the project	100 MWp
Solar power generation area	404 acres
Installation of other facilities	101 acres
Total land for proposed project area	505 acres
Type of technology	Photovoltaic (PV)
Width of utility corridor	170 meter
Nearest TL interconnection	1 km
Traffic planning	Parallel to existing 132 KV TL
Type of equipment to be used	Fixed installation type X-Si solar cells
Project components	Grid station, switchyard, TL

Technical Details	
Total Installed Gross ISO Capacity of the Generation Facility I Solar Plant (MW)	100MWpDC
Total Annual Full Load (Hours)	1865
Average Sun Availability	5.18 hours per day
Total Gross Generation of the Generation Facility /Solar Farm (in kWh)	160,313,000 kWh per Annum
Annual Energy Generation (25-year equivalent Net AEP) KWh	3,727,585,500 kWh
Net Capacity Factor	18.2%

Technical Details of Equipment	
Solar Panels — PV Modules	
Type of Module	Polycrystalline PV Module Type Peak Energy 255
Type of Cell	Polycrystalline
Dimension of each Module	1650mmx991mmx4Omm
Module Surface Area	1.635m^2
No. of Panel / Modules	391,600
Total Module Area	445 acres
Total Land Area Used	498 acres
Panel's Frame	Anodized Aluminum Alloy
Weight of one Module	18.2 kg
Module Output Warranty	For first year: Not more than 2.5% Output Reduction For 2nd to 25 years: Not more than 0.7% Output Reduction Each Year
Number of Solar Cells in each module	60 Cells
Efficiency of Module	15.6%
Environment Protection System	Encapsulation and sealing arrangements for protection from environment
Nominal Maximum Power (Pmax) at STC	255 W
Power Tolerance at STC	0 ~ +5W
Optimum Operating Voltage at STC	30.29 V
Optimum Operating Current at STC	8.42A
Open circuit voltage (Voc) at STC	37.82 V
Short circuit current (lsc) at STC	8.98 A
Optimum Operating Voltage at NOCT	27.71 V
Optimum Operating Current at NOCT	6.68 A
Open circuit voltage (Voc) at NOCT	34.88 V
Short circuit current (Isc) at NOCT	7.18 A
Maximum system Voltage at STC	1000V(IEC)
PV Array	
No. of PV modules	100
Modules in a string	22
Total number of strings	17800

PV Capacity		
Total	100 MWp	
Inverters		
Max. DC power Input	560kW	
Inverter Model	SG 500MX	
Rated Input Voltage	460VDC-850VDC	
Minimum Input Voltage	460VDC	
Number of Inverters	200	
Efficiency	euro:98.5%; CEC:98.7%	
Max. Allowable Input voltage	DC 1000V	
Max. input Current	DC1220 A	
Output Electrical System	3-phase, 3-wire	
Nominal Output Voltage (AC)	315 V	
Rated Frequency	50 Hz /60Hz	
Power Factor	Adjustable 0.9 Induction to 0.9 Capacitance	
Power Control	MPP Tracker	
EnvironmentalEnclosures	Operating Temperature Range	-30° C to 55° C
	Relative Humidity	0 - 95% non-condensing
	Audible Noise	<55 dB(A)
	Operating Elevation	6000m (Derating above 3000m)
Grid OperationProtection	(a)	DC circuit breaker
	(b)	AC circuit breaker
	(c)	DC overvoltage protection
	(d)	Lightning protection level III
	(e)	Grid monitoring
	(f)	Insulation monitoring
	(g)	Anti-Islanding
Isolating Transformer		
Rating	1000kVA	
Type of Transformer	33kV Box-type transformer	
Input voltage	AC315V	
Output Voltage	AC33KV	
Purpose of Transformer	Step Up Voltage	
Efficiency	99.6%	

V- I Curve of Solar Cell PV Module: JAP640-255



Financial Details of the Existing Quaid-e-Azam Solar Park Power Generation Facility

For solar power plant (poly-silicon fixed type) investment per kilowatt for a Photovoltaic power plant was about US$ 2,131/ kWp as per the market price of main equipment and materials of photovoltaic power generation system. Accordingly, the total investment for power generation facilities of all power plants is about US$ 2,131 million.

The infrastructure in Quaid-e-Azam Solar Park mainly includes the roads, water supply and sewerage work, electricity supply, communication facilities and erosion & torrent control works. As per the development sequences the Project is divided into Phase I, Phase II and Phase III respectively for preparing preliminary cost. The total investment of the infrastructure facilities is US$ 250 million out of investment for Phase-I will be US$ 16.748 million while for Phase II and Phase III, it will be US$ 34.31 million and US$ 198.94 million.

Cost Exclusions Were:

a. The land cost.

b. The solar farm developer's step-up the power to 132 kV before connection in to the 132 kV lines

c. in the main corridor.

d. The cost of 220 kV step-up station was also not included.

e. Costs of environmental protection and water & soil conservation and arrangement of labor safety and industrial hygiene were not covered

Total Investment: US$ 31x106 (millions)					
No.	Name of Engineering or Costs	Phase I	Phase II	Phase III	Total
1	Public facilities in the Park Zone	8.71	23.8	150.5	183.00
2	Road & access works	0.862	1.82	3.34	6.02
3	Water supply and drainage works	0.736	0.22	0.567	1.52
4	Electrical Works	6.96	21.5	146.23	175.00
5	Communicative works	0.157	0.888	0.348	0.792
6	Comprehensive service zone	2.48	0	0	2.48
7	Environmental protection, water and soil conservation works	0.155	0.252	1.46	1.86
8	Labor safety and industrial hygiene	0.052	0.084	0.486	0.621
9	Other costs	3.16	5.70	20.56	29.42
I0	Construction unit management fee	1.47	2.71	7.92	12.10
11	Production preparatory expense	0.185	0.30	I.II	1.59
12	Scientific investigation and design	0.586	1.20	6.96	8.75
13	Miscellaneous taxes and dues	0.92	1.49	4.57	6.98
14	Basic reserve fund	2.19	4.48	25.95	32.60
15	Total. Static investment	16.7	34.3	198.9	250.00

APPENDIX 5: ELECTRICITY NETWORK

FY	Length of Transmission & Distribution Lines					Total
	500 KV	220 KV	132 KV	66KV	33KV	
2015	5,077	9,624	27,272	7,566	1,450	50,989
2016	5,113	9,632	28,726	7,365	1,456	52,291
2017	5,127	10,063	25,691	7,025	2,362	50,268
2018	5,618	10,478	26,844	6,182	2,362	51,484
2019	6,290	10,928	27,775	5,994	2,362	53,349

Transmission Statistics – 2018-19	
Length of 500 KV Transmission Lines	6,290 Km
Length of 220 KV Transmission Lines	10,928 Km
Number of Grid Stations 500 KV	16
Number of Grid Stations 220 KV	45
MVA Capacity 500 KV	22,950
MVA Capacity 220 KV	30,970
Transmission losses	2.8%

Summary – Length of 500 kV Transmission Lines				
S. No.	Region	Total Route length (Km)		Total circuits Length (Km)
		Single Circuit	Double Circuit	
1	Lahore	1,998	216	2,214
2	Islamabad	1,244	0	1,244
3	Hyderabad	1,993	110	1,203
4	Multan	981	41	1,022

Summary – Length of 220 kV Transmission Lines				
S. No.	Region	Total Route length (Km)		Total circuits Length (Km)
		Single Circuit	Double Circuit	
1	Lahore	971	1,139	3,250
2	Islamabad	671	1,125	2,921
3	Hyderabad	1,993	110	2,213
4	Multan	302	722	1,745

Detailed Description of Transmission Statistics						
Description	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Transmission Statistics						
Total Length of Transmission Line 500 kV(Km)	5,077	5,077	5,113	5,127	5,618	6,290
Total Length of Transmission Line 220 kV (km)	8,547	9,624	9,632	10,063	10,476	10,928
Total Number of Grid Stations 500 KV	12	13	14	14	16	16
Total Number of Grid Stations 500 KV	31	37	36	38	42	45
Total Transmission Capacity 500 KV (MVA)	15,750	16,950	18,150	18,150	20,850	22,950
Total Transmission Capacity 220 kV (MVA)	19,174	22,854	24,040	25,610	22,500	30,970
Energy Sales (GWh)						
PEPCO	71,101	72,690	76,697	81,685	92,069	94,089
K Electric	11,453	12,295	12,865	12,961	13,860	14,318
Country	82,554	84,985	89,544	94,666	105,929	108,407
Number of Customers						
PEPCO	22,587,870	23,519,247	24,516,699	25,571,803	27,016,545	28,472,069
K Electric	2,111,336	2,156,831	2,226,677	2,424,920	2,583,435	2,808,070
Country	24,699,206	25,676,078	26,743,376	27,996,723	29,599,980	31,281,139
Electricity Consumption (KWh)						
PEPCO	3,148	3,091	3,128	3,194	3,406	3,305
K Electric	5,425	5,700	5,778	5,353	5,365	5,099

Average Sales Price (Rs./KWh)						
DISCO (s)	12.62	12.98	12.20	12.20	13.06	15.54
K Electric	12.15	12.07	12.97	12.84	12.72	12.83
Losses						
Transmission Losses PEPCO (GWh)	2,187	2,620	2,623	2,466	2,949	3,464
Transmission Losses PEPCO (%)	2.8	2.7	2.6	2.3	2.5	2.8
Distribution Losses (PEPCO, Including KE &IPPs)	16,326	16,744	16,762	17,834	20,607	20,199
Transmission and Distribution Losses % (KE)	25.3	23.7	22.2	21.7	20.4	19.1
Maximum Demand (MW)						
Recorded Maximum Demand (PEPCO)	16,170	16,233	17,261	19,020	20,795	21,736
Recorded Maximum Demand (K Electric)	2,929	3,056	3,195	3,270	3,257	3,530

Summary of Grid Station & MVA Capacities

Province	500 kV		220 kV		132 kV		66 kV		33kV		Total	
	No. of grid stations	Capacity (MVA)	No. of grid stations	Capacity (MVA)	No. of grid stations	Capacity (MVA)	No. of grid stations	Capacity (MVA)	No. of grid stations	Capacity (MVA)	No. of grid stations	Capacity (MVA)
Punjab	10	16,050	28	22,610	446	35,385	29	671	2	24	515	74,740
Sindh	5	5,500	5	4,010	116	5,140	24	349	0	0	150	15,048
KPK	1	1,350	7	2,320	88	6,570	23	509	6	32	125	10,780
Balochistan	0	0	5	2,03030,970	72	3,183	3	33	32	160	112	5,406
Total	16	22,950	45		722	50,278	79	1,561	40	216	902	105,975

Distribution Statistics 2018-19	
Energy Sales	94,089 GWh
Number of Consumers	28,473,069
Maximum Demand recorded	21,736 MW
Maximum Demand Computed	25,627 MW
DISCOs Distribution Losses 132/11 KV	17 %

Number of Consumers Category Wise - PEPCO							
Fiscal Year	Domestic	Commercial	Industrial	Agricultural	Public Lighting	Bulk Supply &others	Total
2016	21,040,707	2,814,234	325,816	321,055	9,857	5,030	24,516,699
2017	21,991,479	2,905,517	336,045	323,524	10,124	5,114	25,571803
2018	23,173,856	3,028,054	339,853	315,021	10,426	149,335	27,016,545
2019	24,465,300	3,144,247	342,949	326,656	10,567	183,350	28,473,069

Electricity Consumption Per Consumer				
Fiscal Year	Domestic	Commercial	Industrial	Agricultural
2016	1,764	1,925	64,913	26,050
2017	1,883	2,105	59,712	28,016
2018	1,990	2,230	68,485	31,677
2019	1,863	2,108	70,813	29,621[109]

Province wise Number of Villages Electrified					
Fiscal Year	Punjab	KPK	Sindh	Balochistan	Total
2016	3,467	2,566	1,068	1,164	8,265
2017	2,610	3,228	920	2,027	8,785
2018	8,426	4,277	1,109	2,953	16,765
2019	3,139	3,294	625	1,336	8,394

Three scenarios of long-term forecast, as per Grid Code, are prepared for the Low, Normal and High GDP growth of 4.5%, 5.5% and 6.5% respectively.

FY	Low		Normal		High	
	Energy	Peak Demand	Energy	Peak Demand	Energy	Peak Demand
	GWh	MW	GWh	MW	GWh	MW
2019-20	155,203	26,844	156,840	27,128	158,365	27,391
2024-25	177,021	32,076	188,792	34,209	200,096	36,257
2029-30	212,418	39,111	237,996	43,820	264,595	48,718
2034-35	264,492	48,699	311,828	57,414	365,189	67,239
2039-40	336,026	61,870	418,798	77,110	519,636	95,676

109. *Power System Statistics (NTDC) March 2020*

System Losses				
Description	June-19	June -20	Jul-June 2019	Jul-June 2020
NTDC Network Losses (%age)	2.34%	2.29%	2.83%	3.31%
DISCOs network Losses (%age)	21.17%	22.42%	17.71%	17.82%
DISCOs network Losses (%age) including KE & IPPs	20.31%	21.53%	16.94%	16.97%
System Losses	22.17%	23.32%	19.28%	19.72%

Monthly (DSICOs Transmission & Distribution Losses)									
DISCOs	%Age Losses[110]								
	June-20			June-19			INC/DEC (%AGE)		
	TRANS	DISTB	T&D	TRANS	DISTB	T&D	TRANS	DISTB	T&D
LESCO	0.26	19.41	19.63	0.77	19.46	20.08	-0.51	-0.05	-0.45
GEPCO	1.27	11.79	12.91	1.35	11.75	12.94	-0.08	0.04	-0.03
FESCO	1.77	11.42	12.99	2.26	11.95	13.94	-0.50	-0.52	-0.96
IESCO	1.80	14.85	16.38	2.05	11.08	12.90	-0.25	3.77	3.48
MEPCO	1.85	18.27	19.78	2.13	18.56	20.29	-0.28	-0.29	-0.52
PESCO	2.89	43.63	45.26	1.45	36.00	36.93	1.44	7.63	8.33
TESCO	2.21	9.70	11.70	-0.95	6.91	6.02	3.16	2.79	5.67
HESCO	-0.67	28.93	28.45	-0.01	27.88	27.88	-0.66	1.04	0.57
SEPCO	0.95	37.81	38.41	-2.09	38.63	37.35	3.04	-0.82	1.05
QUESCO	1.54	27.43	28.55	1.52	27.71	28.81	0.01	-0.28	-0.26
Total DISCOs	1.39	21.33	22.42	1.34	20.10	21.17	0.06	1.23	1.26
Grand Total (With KE & IPPs)	1.34	20.46	21.53	1.28	19.28	20.31	0.05	1.19	1.21

110. Data of Electricity Transmission & Distribution shows heavily & less loaded. Visual maps cannot be shared with Public (PEPCO)

Progressive (DSICOs Transmission & Distribution Losses)[111]									
DISCOs	%age Losses								
	July- June 20			July- June 19			INC/DEC (%AGE)		
	TRANS	DISTB	T&D	TRANS	DISTB	T&D	TRANS	DISTB	T&D
LESCO	0.49	11.97	12.40	0.94	12.35	13.17	-0.45	-0.38	-0.77
GEPCO	1.10	8.51	9.51	1.24	8.73	9.87	-0.15	-0.23	-0.36
FESCO	1.51	8.78	9.56	1.73	8.24	9.82	-0.22	-0.06	-0.26
IESCO	1.74	7.07	8.69	1.79	7.20	8.86	-0.05	-0.12	-0.17
MEPCO	1.51	13.93	15.23	1.82	14.22	15.79	-0.31	-0.30	-0.56
PESCO	2.13	37.53	38.87	2.41	35.56	37.11	-0.27	1.98	1.76
TESCO	1.03	8.98	9.92	2.24	9.94	11.96	-1.20	-0.96	-2.04
HESCO	2.88	26.79	28.89	3.86	26.69	29.52	-0.98	0.10	-0.63
SEPCO	2.80	34.44	36.27	3.28	34.83	36.97	-0.48	-0.39	-0.69
QUESCO	1.92	25.24	26.68	1.68	22.32	23.63	0.24	2.92	3.05
Total DISCOs	**1.49**	**16.57**	**17.82**	**1.79**	**16.20**	**17.71**	**-0.30**	**0.37**	**0.11**
Grand Total (WITH KE & IPPs)	**1.42**	**15.78**	**16.97**	**1.71**	**15.49**	**16.94**	**-0.29**	**0.29**	**0.04**

111. *CP-22MS & CPPA*

Progressive (132 kV & Below System)						
DISCOs	July- June 20 (M.kWh)			%age Losses		
	Purchased	Sold	Lost	Jul-June 2020	Jul-June 2019	Inc/Dec.
LESCO	23,528	20,611	2,918	1.240	13.17	-0.77
GEPCO	10,991	9,946	1,045	9.51	9.87	-0.36
FESCO	14,510	13,123	1,387	9.56	9.82	-0.26
IESCO	11,435	10,442	993	8.69	8.86	-0.17
MEPCO	19,325	16,382	2,943	15.23	15.79	-0.56
PESCO	14,792	9,043	5,749	38.87	37.11	1.76
TESCO	2,001	1,803	198	9.92	11.96	-2.04
HESCO	5,471	3,890	1,581	28.89	29.52	-0.63
SEPCO	4,253	2,710	1,543	36.27	36.97	-0.69
QUESCO	6,604	4,842	1,762	26.68	23.63	3.05
Total DISCOs	**112,911**	**92,792**	**20,120**	**17.82**	**17.71**	**0.11**
KE Export	5,426	5,426	0	0.00	0.00	0.00
IPPs	189	189	0	0.00	0.00	0.00
Total	**118,527**	**98,407**	**20,120**	**16.97**	**16.94**	**0.04**

11kV & Below System[112]						
DISCOs	July- June 20 (M.Kwh)			%age Losses		
	Purchased	Sold	Lost	Jul-June 2020	Jul-June 2019	Inc/Dec.
LESCO	23,413	20,611	2,803	11.97	12.35	-0.38
GEPCO	10,870	9,946	925	8.51	8.73	-0.23
FESCO	14,292	13,123	1,169	8.18	7.24	-0.06
IESCO	11,237	10,442	795	7.07	7.20	-0.12
MEPCO	19,033	16,382	2,651	13.93	14.22	-0.30
PESCO	14,477	9,043	5,434	37.53	35.56	1.98
TESCO	1,981	1,803	178	8.98	9.94	-0.96
HESCO	5,313	3,890	1,423	26.79	26.69	0.10
SEPCO	4,133	2,710	1,423	34.44	34.83	-0.39
QUESCO	6,477	4,842	1,635	25.24	22.32	2.92
TOTAL DISCOs	111,226	92,792	18,434	16.57	16.20	0.37
KE Export	5426	5426	0	0.00	0.00	0.00
IPPs	189	189	0	0.00	0.00	0.00
TOTAL	116,841	98,407	18,434	15.78	15.49	0.29

112. CP22 & CPPA

System Losses (NTDC & DISCOs System Including KE & IPPs)[113]		millions (KWh)
Description	July-June 2020	July-June 2019
Energy purchased by CPPA	122,451	122,302
Energy Sold to DISCO by CPPA	118,357	118,838
Energy Loss in NTDC Network (1-2)	4,094	3,464
Energy Loss in NTDC Network as %age of energy purchased by CPPA (3/1) x100	3.34%	2.83%
Energy Purchased by DISCOs from SPPs, CPPs etc.	170	407
Energy Purchased for the total system (1+5)	122,621	122,709
Total energy purchased by DISCOs (Units Received 132 kV)	112,911	114,086
Total energy purchased by DISCOs (Including KE & IPPs) (2+5)	118,527	119,245
Energy sold to consumers by DISCOs	97,792	93,887
Energy sold to consumers by DISCOs (including KE & IPPs)	98,407	99,046
Energy Loss in DISCOs Network (Including KE & IPPs) (8-10)	20,120	20,199
Energy Loss in DISCOs Network as %age of energy Purchased (11/7) x100	17.82%	17.71%
Energy Loss in DISCOs Network as %age of energy Purchased (Including KE & IPPs) (11/8) x 100	16.97%	16.94%
System Losses (6-10)/6*100	19.75%	19.28%
DISCOs System		
Energy Purchased from 132 kV, CPPA & SPPs	112,911	114,086
Energy Purchased from CPPA & SPPs etc. (Including KE&IPPs)	118,527	119,245
Energy sent out on 11kV system	111,226	112,043
Energy sent out on 11kV system (Including KE &IPPs)	116,841	117,202
Energy loss in 132kV System (16-18)	1,685	2,043
Energy loss in 132kV System as %age of energy purchased (19/15) x100 Transmission Loss 132 kV to 11kV	1.49%	1.79%
Energy loss in 132kV System as %age of energy purchased 19/16) x100 Transmission Loss 132 kV to 11kV (Including KE & IPPs)	1.42%	1.71%
Energy sold to consumers	97,792	93,887
Energy sold to consumers (Including KE & IPPs)	98,407	99,046
Energy loss on 11kV System (18-23)	18,434	18,156
Energy loss on 11kV System as %age of energy sent out on 11kV System (24/17) x100 (DISCOs Losses)	16.57%	16.20%
Energy loss on 11kV System as %age of energy sent out on 11kV System (24/18) x100 (Including KE & IPPs)	15.78%	15.49%

113. *PEPCO Discos Performance Statistics*

APPENDIX 6: FINANCIAL MODEL DETAILS

A. Calculation Methodology of CO_2 Emissions (from LNG combustion as the basis for USD40/ton CO_2 and USD80/ton CO_2)

Carbon Emission Factor				
Fossil fuel		CO_2 emission factor (kg/TJ)	Net calorific value (TJ/Gg) Gg=1000t	CO_2 emission factor (t-CO_2/t (Fuel))
Liquid Fossil	Crude Oil	73,300	42.3	3.101
	Motor Gasoline	69,300	44.3	3.070
	Other Kerosene	71,900	43,8	3.149
	Gas/Diesel Oil	74,100	43,0	3.186
	Liquefied Petroleum Gases	63,100	47.3	2.985
Solid Fossil	Anthracite	98,300	26.7	2.625
	Sub-Bituminous Coal	96,100	18.9	1.816
	Lignite	101,000	11.9	1.202
Gaseous Fossil	Natural Gas	56,100	48.0	2.693
2006 IPCC Guidelines for National Greenhouse Gas Inventories, p. 1.24-1.18, Intergovernmental Panel on Climate Change, 2006. [Default carbon oxidation factor is 1] [CO_2 emission factors t-CO_2/t (Fuel) are calculated for this document and do not appear in the IPCC guideline]				

The above IPCC data was used to calculate the CO_2 emissions from power generation using regasified LNG to enable the calculation of a hypothetical cost of that CO_2 to be included in the financial analysis.

B. Case #3: Ghazi Barotha Dam

Case #3: Ghazi Barotha Dam		(US$ Millions)
Parameters	Phase I (100 MW)	Phase II (1 GW)
CAPEX	61	3,020
OPEX	45.02	20
Electrolyzer Price $/kW	480	500
Present Value of Total Cost	578.88	3,054.37
Annual Benefits Value (High LNG Spot + CO_2 @ $80)	25.83	258.03
Present Value Benefits	299.56	2,992.43
Net Present Value (NPV)	-279.33	-61.94
Benefit Cost Ratio (BCR)	0.52: 1	0.98: 1
EIRR in %	-	6.78
LCOH ($ per Kg)	3.81	2.01
LCOE ($ per kWh)	0.06	0.04
Breakeven Level of CO_2 Price per ton	$330/t	$90/t
Annual Benefits Value (High LNG Spot + CO_2 atBreakeven)	50.00	267.69
Present Value Benefits	579.86	3,104.46
Net Present Value (NPV)	0.98	50.09
Benefit Cost Ratio (BCR)	1.01:1	1.02: 1
EIRR in %	7.17	7.18
3 Months Operations at Zero Power Cost		
LCOH ($/ Kg)	1.56	NA
Annual Benefit's Value (High LNG Spot + CO_2 @ $80)	7.75	
Present Value Benefits	89.88	
Net Present Value (NPV)	18.72	
Benefit Cost Ratio (BCR)	1.26:1	
EIRR in %	10.11	

Analysis to show the break-even price of CO_2 emissions for the three options analyzed for case #3. In the above table, only two scenarios are presented for each option regarding value of gas displaced by hydrogen assuming: high LNG Winter Spot Price plus reduction in CO_2 emission gains at $80/t$CO_2$ and Breakeven Level of CO_2 price per ton. Besides, a 3-month operation at zero power cost has been modeled for Phase 1- 100 MW.

A working spread sheet for the financial analysis has been presented to ADB. A pasted extractis below.

Hydro (10 months/ year) ===>	100MW electrolyse, from existing Ghazi Barotha Dam	New canal, power house & electrolyserto add 1GW to Ghazi Barotha power output (USD)	
Second canal, reservoir, dam, 1GW power house, turbines (phase 2 option only)		$2,500,000,000	
1GW electrolyser hooked up to new Ghazi Barotha 2 power house (phase 2 option only)		$1,000,000,000	
Installed electrolyser cost- I00MW McPhy AEC, phase 1	$80,000,000		
Import duties /tax	$16000000		
Electrolyser I00MW phase 1 total capex (120m x 50m footprint)	$96,000,000		
Hydrogen gas pipeline to Indus crossing at Attack (10km to the north)	$10,000,000	$15,000,000	
Gas letdown station for grid injection at Indus crossing	$3,000,000	$5,000,000	
Months of year of electrolyser utilization & hydrogen production	10	10	
Lifetime of capex depreciation	25	25	
Monthly capex depreciation cost allocation	$5,232,000	$168,960,000	
Annual maintenance costs	$1,920,000	$20,000,000	
Annual power cost @Rs 9,406	$43,800,000	Zero, covered from capex	
Electrolyser power (MW)	100	1,000	
Hydrogen production kg/ hour (55 kWh/ kg H_2 71% efficiency)	1,818	18,182	
Hydrogen production Tonnes/ year	13,091	130,909	
Thermal energy value of hydrogen 143 MJ/Kg	143	143	
Thermal energy value of natural gas (assumes 100% methane rich) 55 MJ/Kg	55	55	
Thermal energy value of hydrogen produced per year (MJ]	1,872,000,000	18,720,000,000	
Amount of natural gas displaced by hydrogen (Tonnes per year)	34,036	340,364	Per Tonne Price in US$
Value of gas displaced by hydrogen assuming local natural gas production	4,269,521	42,695,215	125

Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	3,924,086	39,240,864	115	
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	12,951,245	129,512,448	381	
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	18,071,914	180,719,136	531	
Economic cost or benefit of local hydrogen production for cases as above				
CAPEX ($)	109,000,000	3,520,000,000		
OPEX ($)	45,720,000	20,000,000		
CAPEX (M$)	109	3520		
OPEX (M$)	45.7	20		
Value of gas displaced by hydrogen assuming local natural gas production	4.3	42.7		
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	3.9	39.2		
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	13.0	129.5		
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	18.1	180.7		
Including Wider Economic Benefits			One Tonne of LNG emits 2.84 Tonne of CO_2	
CO_2 Emissions tax @ $40 per Tonne	3,866,531	38,665,309	If CO_2 Emissions tax@ $40 per Tonne	$113.60
CO_2 Emissions tax@ $80 per Tonne	7,733,062	77,330,618	CO_2 Emissions tax @$80 per Tonne	$227.20
CO_2 Emissions tax @l $40 per Tonne (Millions]	3.9	38.7		
CO_2 Emissions tax@ $80 perTonne (Millions)	7.7	77.3		
Benefit value after adding CO2 emission gains @$40				
Value of gas displaced by hydrogen assuming local natural gas production	8.17	81.37		
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	7.79	77.87		
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	16.87	168.17		
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	21.97	219.37		

Benefit value after adding CO_2 emission gains @$80		
Value of gas displaced by hydrogen assuming local natural gas production	12.03	120.03
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	11.65	116.53
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	20.73	206.83
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	25.83	258.03
Sensitivity Analysis		
Scenario 1: Costs increase by 10% and benefits remain at same level		
CAPAEX (M$)	119.9	38.72
OPEX (M$)	50.27	22
Value of gas displaced by hydrogen assuming local natural gas production	4,3	42,7
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	3,9	39,2
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	13,0	129,5
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	18,1	180,7
Scenario 2: Costs increase by 20 % benefits remain at same level		
CAPAEX (M$)	130,8	4224
OPEX (M$)	54,84	24
Value of gas displaced by hydrogen assuming local natural gas production	4,3	42,7
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	3,9	39,2
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	13,0	129,5
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	18,1	180,7
Scenario 3: Costs increase by 10 % while benefits decrease by 10% simultaneously		
CAPAEX (M$)	119,9	3872
OPEX (M$)	50,27	22

Value of gas displaced by hydrogen assuming local natural gas production	3,87	38,43
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	3,53	35,28
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	11,70	116,55
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	16,29	162,63

Levelized Cost of Electricity (LCOE)	(US$)	Millions US$
CAPEX	3 000 000 000	3000
OPEX	20000000	20
Units Produced (Million KWh)	7 320 000 000	7320
Benefits@$ 0.06 (Household Tariff)	439200000	439.2

LCOH at 50% less Electrolyser Cost		
CAPEX $	61000000	3020000000
OPEX $	45020000	20000000
Units Produced (Tonnes of H_2)	13091	103 909

C. Case #6: Quaid e Azam Solar Park

A working spread sheet for the financial analysis has been presented to ADB. An pasted extract is below.

Solar (12 months/year, 10 hours per day)===>	OR Phase 1 (No CQSola) 100MW electrolyse, from existing Ghazi Barotha Dam	Phase 1, Option 1a (CQSola) 100MW electrolyser from 100MW power uplift on existing solar park with retrofit of CQSola equipment	Phase 2 (plus 1GW solar plus CQSola) 1GW electrolyser from 1GW solar park extension with CQSola system		
Installed electrolyser cost- l00MW McPhy AEC, phase 1	$80,000,000	$80,000,000		Electrolyzer Price $/kW	
CQSola power upgrade system (Phase 1, option 1a only) to yield circa l00MW extra power		$80,000,000		96,000,000	960
1GW new solar capacity including CQSola system (phase 2 only)			1,000,000,000	1,000,000,000	1,000
1GW electrolyser hooked upto new solar capacity (phase 2 only)			1,000,000,000		
Capex uplift for taxes, import duties and shipping				20%	
Import duties /tax	$16,000,000	32,000,000	400,000,000		
Hydrogen gas pipeline to 8” pipeline at Bahawalpur (20km to the North West)	$20,000,000	$20,000,000	Zero already built in phase 1		
Hydrogen gas letdown station for gas grid injection at Bahawalpur	$ 3000000	$ 5000000	Zero already built in phase 1		
Lifetime of capex depreciation	25	25	25		
Annual capex depreciation cost allocation	$ 4760 000	$ 8600000	96000000		
Annual maintenance costs at capex				2%	
Annual maintenance costs (2% of capex)	$2380000	4300000	48000000		
Annual power cost for 100MW suppky to electrolyser @ $0.112 per kWh	$40,320,000	Zero from capex	Zero from capex		
Maximum electrolyser power (MW) (levelised MW of electrolysis is less than this)	100	100	1000		

Solar (12 months/year, 10 hours per day)===>	Phase 1 (No CQSola) 100MW electrolyse, from existing Ghazi Barotha Dam	OR Phase 1, Option 1a (CQSola) 100MW electrolyser from 100MW power uplift on existing solar park with retrofit of CQSola equipment	Phase 2 (plus 1GW solar plus CQSola) 1GW electrolyser from 1GW solar park extension with CQSola system	
Hours of day of electrolyser utilization & hydrogen production	10	10	10	
Electrolyser utilistation % (due to less than 24 hours of sunlight per day)	42%	42%	42%	
Hydrogen production kg / hour (55 kWh / kg H_2, 71% efficiency, utilisation as shown)	758	758	7576	
Hydrogen production Tonnes / year (360 days per year operation)	6,545	6,545	65455	
Thermal energy value of hydrogen 143MJ/ Kg	143	143	143	
Thermal energy value of natural gas (assumes 100% methane rich) 55 MJ/Kg	55	55	55	
Thermal energy value of hydrogen produced per year (MJ]	936,000,000	936,000,000	9,360,000,000	
Amount of natural gas displaced by hydrogen (Tonnes per year)	17,018	17,018	170,182	Per tonne price in US$
Value of gas displaced by hydrogen assuming local natural gas production	2,134,761	2,134,761	21,347,607	125
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	1,962,043	1,962,043	19,620,432	115
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	6,475,622	6,475,622	64,756,224	381
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	9,035,957	9,035,957	90,359,568	531
Economic cost or benefit of local hydrogen production for cases as above				
CAPEX ($)	119,000,000	215,000,000	2,400,000,000	
OPEX ($)	42,700,000	4,300,000	48,000,000	

Solar (12 months/year, 10 hours per day)===>	OR Phase 1 (No CQSola) 100MW electrolyse, from existing Ghazi Barotha Dam	OR Phase 1, Option 1a (CQSola) 100MW electrolyser from 100MW power uplift on existing solar park with retrofit of CQSola equipment	OR Phase 2 (plus 1GW solar plus CQSola) 1GW electrolyser from 1GW solar park extension with CQSola system		
CAPEX (M$)	119	215	2,400		
OPEX (M$)	42.7	4.3	48		
Value of gas displaced by hydrogen assuming local natural gas production	2.14	2.14	21.35		
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted co	1.96	1.96	19.60		
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	6.48	6.48	64.76		
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	9.04	9.04	90.36		
Including Wider Economic Benefits				One Tonne of LNG emits 2.84 Tonne of CO_2	
CO_2 Emissions tax @ $40 per Tonne	1,933,265	1,933,265	19,332,655	If CO_2 Emissions tax@ $40 per Tonne	$113.60
CO_2 Emissions tax@ $80 per Tonne	3,866,531	3,866,531	38,665,309	CO_2 Emissions tax @$80 per Tonne	$227.20
CO_2 Emissions tax @l $40 per Tonne (Millions]	1.93	1.93	19.33		
CO_2 Emissions tax@ $80 perTonne (Millions)	3.87	3.87	38.67		
Benefit value after adding CO_2 emission gains @$40					
Value of gas displaced by hydrogen assuming local natural gas production	4.07	4.07	40.7		
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted co	3.89	3.89	38.93		
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	8.41	8.41	84.09		

Solar (12 months/year, 10 hours per day)===>	OR Phase 1 (No CQSola) 100MW electrolyse, from existing Ghazi Barotha Dam	OR Phase 1, Option 1a (CQSola) 100MW electrolyser from 100MW power uplift on existing solar park with retrofit of CQSola equipment	OR Phase 2 (plus 1GW solar plus CQSola) 1GW electrolyser from 1GW solar park extension with CQSola system
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	10.97	10.97	109.69
Benefit value after adding CO_2 emission gains @$80			
Value of gas displaced by hydrogen assuming local natural gas production	6.01	6.01	61.02
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	5.83	5.83	58.27
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	10.35	10.35	103.43
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	12.91	12.91	129.03
Sensitivity Analysis			
Scenario 1: Costs increase by 10% and benefits remain at same level			
CAPAEX (M$)	130.90	236.50	2,640
OPEX (M$)	46.97	4.73	52.80
Value of gas displaced by hydrogen assuming local natural gas production	2.14	2.14	21.35
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted co	1.96	1.96	19.60
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	6.48	6.48	64.76
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	9.04	9.04	90.36

Solar (12 months/year, 10 hours per day)===>	OR		
	Phase 1 (No CQSola) 100MW electrolyse, from existing Ghazi Barotha Dam	Phase 1, Option 1a (CQSola) 100MW electrolyser from 100MW power uplift on existing solar park with retrofit of CQSola equipment	Phase 2 (plus 1GW solar plus CQSola) 1GW electrolyser from 1GW solar park extension with CQSola system
Scenario 2: Costs increase by 20 % benefits remain at same level			
CAPAEX (M$)	142.80	258.0	2,880
OPEX (M$)	51.24	5.16	57.60
Value of gas displaced by hydrogen assuming local natural gas production	2.14	2.14	21.35
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted co	1.96	1.96	19.60
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	6.48	6.48	64.76
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	9.04	9.04	90.36
Scenario 3: Costs increase by 10 % while benefits decrease by 10% simultaneously			
CAPAEX (M$)	130.90	236.50	2,640
OPEX (M$)	46.97	4.73	52.80
Value of gas displaced by hydrogen assuming local natural gas production	1.93	1.93	19.22
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted cost	1.76	1.76	17.64
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	5.83	5.83	58.28
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	8.14	8.14	81.32

Parameters	100 MW Option - 1	100 MW Option – 1A	1GW
CAPEX	111	167	2,300
OPEX	42.54	3.34	46
Electrolyzer at 50 % Price ($/kW)	480	480	500
Present Value of Total Cost	597.08	194.81	2,683.01
Annual Benefit's Value (High LNG Spot + CO_2 @ $80)	12.91	12.91	129.03
Present Value Benefits	149.72	149.72	1,496.39
Net Present Value (NPV)	-447.36	-45.09	-1186.61
Benefit Cost Ratio (BCR)	0.25:1	0.77:1	0.56:1
EIRR in %	-	3.9	0.52
LCOH ($ per Kg)	7.87	2.57	3.53
LCOE ($ per kWh)	0.11	0.027	0.033
Breakeven Level of CO_2 Price per ton	$880/t	$162/t	$295/t
Annual Benefits Value (High LNG Spot + CO_2 at Breakeven)	51.57	16.87	232.94
Present Value Benefits	598.07	195.65	2,701.46
Net Present Value (NPV)	0.98	0.84	18.45
Benefit Cost Ratio (BCR)	1:1	1:1	1:1
EIRR in %	7.09	7.05	7.09

Analysis to show the break-even price of CO_2 emissions for the three options analyzed for case #6. In the above table, only two scenarios are presented for each option regarding value of gas displaced by hydrogen assuming: High LNG Winter Spot Price plus reduction in CO_2 emission gains at \$80/tCO_2 and Breakeven Level of CO_2 price per ton.

Sensitivity Analysis			
Scenario 1: Costs increase by 10 % and benefits remain at same level			
CAPAEX (M$)	130,90	236,50	2 640,0
OPEX (M$)	46,97	4,73	52,80
Value of gas displaced by hydrogen assuming local natural gas production	2,14	2,14	21,35
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted co	1,96	1,96	19,60
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	6,48	6,48	64,76
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	9,04	9,04	90,36
Scenario 2: Costs increase by 20 % benefits remain at same level			
CAPAEX (M$)	142,80	258,0	2 880,0
OPEX (M$)	51,24	5,16	57,60
Value of gas displaced by hydrogen assuming local natural gas production	2,14	2,14	21,35
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted co	1,96	1,96	19,60
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	6,48	6,48	64,76
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	9,04	9,04	90,36
Scenario 3: Costs increase by 10 % while benefits decrease by 10% simultaneously			
CAPAEX (M$)	130.90	236,50	2 640,0
OPEX (M$)	46,97	4,73	52,80
Value of gas displaced by hydrogen assuming local natural gas production	1,93	1,93	19,22
Value of gas displaced by hydrogen assuming imported LNG at low LNG contracted co	1,76	1,76	17,64
Value of gas displaced by hydrogen assuming imported LNG at mid LNG cost	5,83	5,83	58,28
Value of gas displaced by hydrogen assuming imported LNG at high LNG spot cost	8,14	8,14	81,32

Levelized Cost of Electricity (LCOE)		
CAPAEX ($)	$ 96 000 000	$ 1 200 000 000
OPEX ($)	$ 9 600 000	$ 24 000 000
Units Produced in (Million KWh)	365 000 000	3 650 000 000
Benefit @ $ 0.112 cent per KWh	$ 40 880 000	408 800 000
CAPAEX (M$)	96	1200
OPEX (M$)	9.6	24
Units Produced in (Million KWh)	365	3650
Benefit @ $ 0.112 cent per KWh	40.9	408.8

D. Case # 13: Micro Hydro Run of the River

Case # 13: Micro Hydro Run of the River	
Parameters	**Phase I (100 MW)**
CAPEX	5.98
OPEX	0.30
Electrolyzer Price $/kW	3,580
Present Value of Total Cost	9.07
Annual Benefit's Value (High LNG Spot + CO_2 @ $80)	0.043
Present Value Benefits	0.50
Net Present Value (NPV)	-8.57
Benefit Cost Ratio (BCR)	0.05 :1
EIRR in %	-
LCOH ($ per Kg)	30.11
LCOE ($ per kWh)	0.10
LCOE ($ per Kwh) Whole Year	0.40
Breakeven CO_2 Price Per ton	$3,825/t
Annual Benefit's Value (High LNG Spot + CO_2 at Breakeven)	0.79
Present Value Benefits	9.16
Net Present Value (NPV)	0.09
Benefit Cost Ratio (BCR)	1:1
EIRR in %	7.17

Analysis to show the break-even price of CO_2 emissions for the three options analyzed for case #13. In the above table, we have only one scenario for each project regarding value of gas displaced by hydrogen assuming average of imported LPG & Local Natural Gas plus reduction in CO_2 emission gains at \$80/tCO_2 and Breakeven Level of CO_2 price per ton.

1. Scenario 01

- 1MW power output hydroelectric scheme operating for 10 months of the year at flow of 1m^3 per second is the base case for the micro-hydro run of the river system.
- 1MW electrical power supply for 2 months of the year in winter is the base design case for the energy storage and backup power system.

A working spread sheet for the financial analysis has been presented to ADB. A pasted extract is below.

Options for hydro (10 months / year) ===>	Micro hydro scheme head 5m		
Hydraulic machine including dam, penstock, automation equipment, planning, civil structures, with P=1000kW,	$ 2 928 000		
Hydrogen polymer electrolyte membrane (PEM) electrolyser - 2x 500kW including water treatment (reliability & flexibility) + Hydrogen Accumulator & Fuel Cell	$ 12 900 000		
Microgrid (simple - wire e.g. india)	$ 100 000		
Import duties / tax @ 20%	$ 3 185 600		Electrolizer @ 50 Cost
Topography charges and contigencies @30%	$ 4 778 400	Capex	$ 15 928 000
Total CAPEX	$ 23 892 000	Opex	$ 1 114 960,00
Maintinence and OPEX @ 7%	$ 1 672 440		
Hydrogen Production in Tonnes per Year	1 307		
Benefits			
Amount of natural gas displaced by hydrogen (Tonnes per year)	3400	Per Tonne Price in US$	
Value of gas displaced by hydrogen assuming local natural gas production	426,496	125	
Value of gas displaced by hydrogen assuming imported LPG @ $8	1,065,050	313	
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	955,400	281	

CAPEX	23,892,000	
OPEX	1,672,440	
CAPEX ($ Millions)	23,83	
OPEX ($ Millions)	1,67	
Benefits		
Value of gas displaced by hydrogen assuming local natural gas production	4,3	
Value of gas displaced by hydrogen assuming imported LPG @ $8	10,7	
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	9,5	
CO_2 Emissions tax @ $40 per Tonne - LPG	$ 118,80	
CO_2 Emissions tax @ $80 per Tonne - LPG	$ 237,60	
CO_2 EmissionTax @ $40 perTonne -Natural Gas	$ 125,60	
CO_2 EmissionTax @ $80 perTonne -Natural Gas	$ 251,20	
Benefit value after adding CO_2 emission gains @ $40 (in Millions)		In Thousands
Value of gas displaced by hydrogen assuming local natural gas production	8,50	$ 853 536
Value of gas displaced by hydrogen assuming imported LPG @ $8	14,70	$ 1 468 970
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	13,60	$ 1 359 320
Benefit value after adding CO_2 emission gains @ $80 (in Millions)		
Value of gas displaced by hydrogen assuming local natural gas production	12,80	$ 1 280 576
Value of gas displaced by hydrogen assuming imported LPG @ $8	18,70	$ 1 872 890
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	17,60	$ 1 763 240

Sensitivity Analysis	
Scenario 1: Costs increase by 10 % and benefits remain at same level	
CAPAEX (M$)	26,213
OPEX (M$)	1,837
Value of gas displaced by hydrogen assuming local natural gas production	4,3
Value of gas displaced by hydrogen assuming imported LPG @ $8	10,7
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	9,5
Scenario 2: Costs increase by 20 % benefits remain at same level	
CAPAEX (M$)	28,596
OPEX (M$)	2,004
Value of gas displaced by hydrogen assuming local natural gas production	4,3
Value of gas displaced by hydrogen assuming imported LPG @ $8	10,7
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	9,5
Scenario 3: Costs increase by 10 % while benefits decrease by 10% simultaneously	
CAPAEX (M$)	26,213
OPEX (M$)	1,837
Value of gas displaced by hydrogen assuming local natural gas production	3,9
Value of gas displaced by hydrogen assuming imported LPG @ $8	9,6
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	8,6

Hydrogen as Cooking Fuel	
Removing the followings: Power Conversion System (DC to 240V AC) $0.45M Battery System (1MW/500kWh) $1.2M Battery & Power Controls & Comms $0.6M Transformer & grid connection to local network $0.75M Switchboards / Switchgear $0.6M = $ 3.6 Million	
CAPEX ($ Million)	20,22
OPEX ($ Million)	1,42
Benefits in replacing the fuel wood ($ Million)	13,52
Scenario 1 : Costs increase by 10 % and benefits remain at same level	
CAPAEX (M$)	22,242
OPEX (M$)	1,562
Benefits in replacing the fuel wood ($ Million)	13,52
Scenario 2 : Costs increase by 20 % benefits remain at same level	
CAPAEX (M$)	24,264
OPEX (M$)	1,704
Benefits in replacing the fuel wood ($ Million)	13,52
Scenario 3 : Costs increase by 10 % while benefits decrease by 10% simultaneously	
CAPAEX (M$)	22,242
OPEX (M$)	1,562
Benefits in replacing the fuel wood ($ Million)	12,168

2 Scenario 02

- 100 KW power output hydroelectric scheme operating for 10 months of the year at flow of 1m^3 per second is the base case for the micro-hydro run of the river system.
- 100 KW electrical power supply for 2 months of the year in winter is the base design case for the energy storage and backup power system.

Options for hydro (10 months / year) ===>	Micro hydro scheme head 5m			
Hydraulic machine including dam, penstock, automation equipment, planning, civil Structures with P=100kW, (1/4th of the previous case)	$ 73 200			
Hydrogen polymer electrolyte membrane (PEM) electrolyser - 2x 50kW including water treatment (reliability & flexibility) + Hydrogen Accumulator & Fuel Cell	$ 3 500 000			
Microgrid (simple - wire e.g. india)	$ 25 000			
Import duties / tax @ 20%	$ 719 640			
Topography charges and contigencies @30%	$ 1 079 460			$ 3 598 200
Total CAPEX	$ 5 397 300			
Maintinence and OPEX @ 7%	$ 377 811			
Hydrogen Production in Tonnes per Year	130,00			
Benefits			Benefits Value	
Amount of natural gas displaced by hydrogen (Tonnes per year)	340	Per Tonne Price in US$	US $	
Value of gas displaced by hydrogen assuming local natural gas production	42,650	125	42,650	
Value of gas displaced by hydrogen assuming imported LPG @ $8	106,505	313	106,505	
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	95,540	281	95,540	
	-			
CAPEX ($ Millions)	5.4			
OPEX ($ Millions)	0.37			
Value of gas displaced by hydrogen assuming local natural gas production	0.04			
Value of gas displaced by hydrogen assuming imported LPG @ $8	0.11			
Value of gas displaced by hydrogen assuming ave. imported LPG & Local Natural Gas	0.10			

Sensitivity Analysis	
Scenario 1 : Costs increase by 10 % and benefits remain at same level	
CAPAEX (M$)	5.94
OPEX (M$)	0.407
Value of gas displaced by hydrogen assuming local natural gas production	0.04
Value of gas displaced by hydrogen assuming imported LPG @ $8	0.11
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	0.1

Scenario 2 : Costs increase by 20 % benefits remain at same level	
CAPAEX (M$)	6.48
OPEX (M$)	0.444
Value of gas displaced by hydrogen assuming local natural gas production	0.04
Value of gas displaced by hydrogen assuming imported LPG @ $8	0.11
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	0.1

Scenario 3 : Costs increase by 10 % while benefits decrease by 10% simulteneously	
CAPAEX (M$)	5,94
OPEX (M$)	0,407
Value of gas displaced by hydrogen assuming local natural gas production	0,036
Value of gas displaced by hydrogen assuming imported LPG @ $8	0,099
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	0,08595

Removing the followings: Power Conversion System (DC to 240V AC) Battery System, Battery & Power Controls & Comms Transformer & grid connection to local network Switchboards / Switchgear = $ 0.82 Million (i.e. 6.6th proportion of the Capex – inputed on the basis of previous Case 1MW)	
CAPEX ($ Million)	4.58
OPEX ($ Million)	0.32
Benefits in replacing the fuel wood ($ Million)	1.35

Scenario 1 : Costs increase by 10 % and benefits remain at same level	
CAPAEX (M$)	5,038
OPEX (M$)	0,352
Benefits	1,35
Scenario 2 : Costs increase by 20 % benefits remain at same level	
CAPAEX (M$)	5,496
OPEX (M$)	0,384
Benefits	1,35
Scenario 3 : Costs increase by 10 % while benefits decrease by 10% simulteneously	
CAPAEX (M$)	5,038
OPEX (M$)	0,352
Benefits	1,215

CO_2 Emissions tax @ $40 per Tonne - LPG	$ 118,80
CO_2 Emissions tax @ $80 per Tonne - LPG	$ 237,60
CO_2 EmissionTax @ $40 perTonne -Natural Gas	$ 125,60
CO_2 EmissionTax @ $80 perTonne -Natural Gas	$ 251,20

Benefit value after adding CO_2 emission gains @ $40 (in Millions)			**in Millions**
Value of gas displaced by hydrogen assuming local natural gas production	$ 0.083	$ 42 704	0,043
Value of gas displaced by hydrogen assuming imported LPG @ $8	$ 0,150	$ 40 392	0,04
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	$ 0,138	$ 41 548	0,042
Benefit value after adding CO_2 emission gains @ $80 (in Millions)			
Value of gas displaced by hydrogen assuming local natural gas production	$ 0,125	$ 85 408	0,085
Value of gas displaced by hydrogen assuming imported LPG @ $8	$ 0,191	$ 80 784	0,081
Value of gas displaced by hydrogen assuming average of imported LPG & Local Natural	$ 0,179	$ 83 096	0,083

E. Levelized Cost of Hydrogen $ per kg (LCOH $ per kg)

Years	Capital Cost	O & M Cost	Total Cost	Net Cash Flow (Million $)	Units Produced (Million)
0	119,00	-	119	-119,000	-
1	-	42,70	42,700	-42,700	0,0065
2	-	42,70	42,700	-42,700	0,0065
3	-	42,70	42,700	-42,700	0,0065
4	-	42,70	42,700	-42,700	0,0065
5	-	42,70	42,700	-42,700	0,0065
6	-	42,70	42,700	-42,700	0,0065
7	-	42,70	42,700	-42,700	0,0065
8	-	42,70	42,700	-42,700	0,0065
9	-	42,70	42,700	-42,700	0,0065
10	-	42,70	42,700	-42,700	0,0065
11	-	42,70	42,700	-42,700	0,0065
12	-	42,70	42,700	-42,700	0,0065
13	-	42,70	42,700	-42,700	0,0065
14	-	42,70	42,700	-42,700	0,0065
15	-	42,70	42,700	-42,700	0,0065
16	-	42,70	42,700	-42,700	0,0065
17	-	42,70	42,700	-42,700	0,0065
18	-	42,70	42,700	-42,700	0,0065
19	-	42,70	42,700	-42,700	0,0065
20	-	42,70	42,700	-42,700	0,0065
21	-	42,70	42,700	-42,700	0,0065
22	-	42,70	42,700	-42,700	0,0065
23	-	42,70	42,700	-42,700	0,0065
24	-	42,70	42,700	-42,700	0,0065
25	-	42,70	42,700	-42,700	0,0065
26	-	42,70	42,700	-42,700	0,0065
27	-	42,70	42,700	-42,700	0,0065

28	-	42,70	42,700	-42,700	0,0065
29	-	42,70	42,700	-42,700	0,0065
30	-	42,70	42,700	-42,700	0,0065

	Results @	7%	
		Base Case	
PRESENT VALUE OF TOTAL COST (M $):		606,42	
PRESENT VALUE OF UNIT PRODUCED (Million Tonnes):		0,08	
		$/Tonne	LCOH $/KG
		7989,27	7,99
All Units must be in same denomination i.e. either all in Millions or All in Thousands etc.			
Levelized Cost of the H_2 over Life of the Project @7 % Discount Rate			

F. Levelized Cost of Electricity (LCOE) $ per KWh)

Years	Capital Cost	O & M Cost	Total Cost	Net Cash Flow (Million $)	Units Produced (Million)
0	1200.00	-	1200,000	-1200,000	-
1	-	24.00	24,000	-24,000	3650.00
2	-	24.00	24,000	-24,000	3650.00
3	-	24.00	24,000	-24,000	3650.00
4	-	24.00	24,000	-24,000	3650.00
5	-	24.00	24,000	-24,000	3650.00
6	-	24.00	24,000	-24,000	3650.00
7	-	24.00	24,000	-24,000	3650.00
8	-	24.00	24,000	-24,000	3650.00
9	-	24.00	24,000	-24,000	3650.00
10	-	24.00	24,000	-24,000	3650.00
11	-	24.00	24,000	-24,000	3650.00
12	-	24.00	24,000	-24,000	3650.00
13	-	24.00	24,000	-24,000	3650.00
14	-	24.00	24,000	-24,000	3650.00
15	-	24.00	24,000	-24,000	3650.00

16	-	24.00	24,000	-24,000	3650.00
17	-	24.00	24,000	-24,000	3650.00
18	-	24.00	24,000	-24,000	3650.00
19	-	24.00	24,000	-24,000	3650.00
20	-	24.00	24,000	-24,000	3650.00
21	-	24.00	24,000	-24,000	3650.00
22	-	24.00	24,000	-24,000	3650.00
23	-	24.00	24,000	-24,000	3650.00
24	-	24.00	24,000	-24,000	3650.00
25	-	24.00	24,000	-24,000	3650.00
26	-	24.00	24,000	-24,000	3650.00
27	-	24.00	24,000	-24,000	3650.00
28	-	24.00	24,000	-24,000	3650.00
29	-	24.00	24,000	-24,000	3650.00
30	-	24.00	24,000	-24,000	3650.00
		Results @	7%		
				Base Case	
	PRESENT VALUE OF TOTAL COST (M $):			1399.83	
	PRESENT VALUE OF UNIT PRODUCED (Million kWh):			42329.91	
	LCOE			$/kWh	
				0.03	
All Units must be in same denomination i.e. either all in Millions or All in Thousands etc.					
Levelized Cost of Electricity over Life of the Project @7 % Discount Rate					

APPENDIX 7: MICRO HYDRO CASE STUDIES

A. Shigo Kas Hydropower Project

1. Project Background

Pakistan is blessed with such topography that its province of Khyber Pakhtunkhwa offers a huge potential for the development electric power using its water resources. In order to attract the local and foreign investors for investing in the province, the Govt. of Khyber Pakhtunkhvva formulated and announced a policy for the development hydel potential.

Shigo kas Hydropower Project was proposed as run-of-river scheme on Panjkora River in lower Dir District of Khyber Pakhtunkhwa. Originally the feasibility study for Shigo Kas Hydropower Project was proposed for 26 MW but later, planning studies and surveys reveal that the project can be upgraded to as much as 102 MW capacity instead of 26 MW. The Site is located at 10 Km downstream of Timergara Town.

Topographic Survey has been carried out in the project area for establishing, inter alia, the existing ground levels. Locations of physical features like rivers, streams, roads, and communication systems have been marked.

The project is proposed to be a Run-of-River scheme on Panjkora River located at about 10 Km downstream of Timergara Town in district lower Dir of the province of Khyber Pakhtunkhwa. The headwork is proposed near Shigo kas village comprises of concrete weir having two distinct sections i.e., one overflow section and other gated section. The intake of water is located on the left bank of Panjkora River and the sand trap is just downstream the intake. In this regard, three chambered sand traps have been proposed along the left bank for sediment exclusion. From the end of the sand trap, the water is conveyed to the headrace tunnel by a 65 m connecting rectangular channel. The headrace tunnel is 10.22 Km long having 7m diameter having horseshoe section with cross-sectional area of 40.63 m^2. A surge shaft (20 m diameter) is located at end of the tunnel is exposed to the surface. A horizontal pressure tunnel of 6m diameter leads to a valve chamber. An inclined penstock 5.5 m in diameter will drop from valve chamber to penstock manifold, feeding three generating units accommodated in the powerhouse in open cut on the left bank of Panjkora River. The powerhouse is located at village Mitta which is downstream of village Utala. A 31 m long tailrace channel conveys water from powerhouse and discharges into the Panjkora River.

2. Geotechnical Engineering and Construction Materials

Geological and geotechnical investigations have been carried out to study regional and local area geological and tectonic set up through geological mapping, scan line discontinuity survey, drilling works and geophysical survey. Test pits were excavated for determining potential sources of construction materials.

The project area lies at the margin of Kohistan Island arc and Higher Himalaya near the Main Mantle Thrust (MMT). The southern part of project area is comprised of Higher Himalayan rocks while the northern part comprised of rock of Kohistan sequence.

Higher Himalayan rocks are comprised of granite gneisses and its cover metamorphosed amphibolite. These units further extended westward to Dir, Bajaur and Afghanistan. Two distinct varieties of gneisses can be characterized in the project area i.e., Granite Gneiss and Schistose Gneiss. Rocks of Kohistan sequences are found in the north of MMT and it is comprised of ultramafic-mafic rocks of ophiolites and Kamila amphibolite and volcanic.

Stratigraphic sequence of the project area consists of Indian mass rocks of lower Sawat Buner group mainly consists of granitic gneiss (Chakdara Granite Gneisses), it is granite with siliceous schist layers on the peripheries. These rocks are medium to coarse grained with association of Schistose Gneisses and Quartz mica Schist phyllitic gneiss, Phyllite and quartzite intercalations have been observed in the project area at higher elevations. Major rock group of the project area are Granitic gneiss and widely spread along weir, Intake area, Sand trap, intake of tunnel, along the tunnel and powerhouse areas. Poorly to well Inputs required – energy law and regulatory affairs outcropped in and around Tunnel and outlet portal, in most of the reaches along Tunnel, rock of the area is well exposed and widely distributed under thin to thick cover of Secree / Colluviums and terrace deposits, details are described in next relevant sections.

The riverbed is composed of medium to coarse grained sand, gravel, pebble, cobble even boulders. These materials belong to all three-type crustal rock but especially at weir metamorphic with few igneous boulder and gravel material are dominated. Riverbed of Panjkora River itself is narrow to sufficiently wide at places.

Geotechnical investigation study was carried out, aimed at provide the required surface and sub- surface information about the Rock, Overburden materials/Colluviums, terraces / river deposits (Alluviums) and Scree materials, sliding zones and the rock strata at the significant structures in the Project area and to develop the geotechnical design parameters for all the structures and most important part of this stage of study is to define the structures at sound and safe areas regarding geological and geotechnical conditions.

The Panjkora riverbed and its higher terraces are the major source of nearly all types of the construction materials. The coarse and fine (sand) aggregates are currently being mined at numerous places from the riverbed for local use. Second sources are the manufacturing crush plants in the vicinity of project area. Cohesive soils for the blanket can also be obtained from the upper terraces of Panjkora river, selecting the terraces which are relatively barren.

3. Hydraulic Design

The hydraulic design of Shigo kas Hydropower Project include design of weir, intake, sand trap, power tunnel, surge shaft. penstock, powerhouse and tailrace. The hydrological studies show that minimum and maximum mean monthly discharges in Panjkora River at Shigo Kas site are 40m^3/s and 366m^3/s respectively. Based on economic evaluation and optimization, it was decided that power intake would be designed for rated discharge of 150m^3/s that will produce approximately 102 MW of electric power.

The overall weir length is 113 m comprising of an overflow section of 25m and two gated sections. The full reservoir elevation is 650 masl. The average riverbed level is at El. 639 masl. The total height of the weir is 11m above the average bed. The weir is designed to pass a flood of 5600m^3 /s corresponding to a flood level of 654 masl. The gated section with stilling basin will be provided in the center of existing river course. It will be used to spill excess flows and small floods in summer season while the powerhouse is still in operation. It has a discharge capacity of up to 2000m^3 /s at normal operating level of 650 masl.

The gated section with roller buckets will be provided at the left bank. It will only be used during extreme floods when the tail water level is sufficiently high for proper operation of roller buckets.

The intake structure off takes from the left bank of Panjkora River, the intake consists of 03 no. culvert inlets each 9.8m x 5m. The height of inlet gradually reduces from 5m to 3m through a parabolic profile of roof curve. The width of inlets reduces from 5m to 3.5m in a length of 5m. Three vertical lift type intake gates, each 5.8m x 3.5m, are provided after the bend section. There is provision of stop logs at the downstream side of intake gates to carry our repairs of one gate while the other gate is still open and transferring flows to the connecting channel.

The inlet of sand trap is located 15 m downstream of the centerline of gates for intake structure The flows from intake directly enter the sand trap. The inlet width of sand trap is 20.5 m which gradually increases to its maximum width of 49 m in a length of 31.1 m. The sand trap is divided into three main chambers each 15m in width. Each chamber has been further divided into three hopper shaped compartments through vertical vanes/walls. There will be two locations for flushing ducts/galleries along the entire 115 m length of sand trap. This arrangement is required because the optimal depth of sand trap could not be achieved due to the relatively mild slope of river viz- a-viz the lower elevation of sand trap flushing ducts as compared to riverbed level. It is designed to retain 0.2 mm and bigger sized sediment.

The flows from sand trap will be carried to the tunnel inlet through a 65m concrete lined rectangular headrace channel (18m bed width and 8m depth) excavated along the left bank of river. A freeboard of 0.5 m will still be available for operation at maximum headwater level with design flow velocity at normal operating level will be 2.1 m/s using a Manning's roughness coefficient of n=0.016.

The power tunnel is designed as a Horseshoe conduit of 7 m diameter having 40.63 m^2 area. It is 10.22 km long and has a slope of 1 in 500. At start of the power tunnel the invert has an elevation of 630 masl and at the end elevation of 610 masl. The velocity in the power tunnel will be 3.5 m/sec.

A 197.96m horizontal pressure tunnel having 6m inner diameter, comprises of two sections 107.97 concrete lined ant 90m steel lined, leads to a valve chamber at El. 606. An inclined Penstock 105 m having diameter 5.5m will drop from valve chamber at El. 606 masl up to El. 558 masl from where penstock manifold starts, branches to the three units.

The project carried out the GIS to determine the arrangement for dispersal of electric power from the proposed generation facility/hydel power plant. According to the said study, the interconnection arrangement for dispatch of electric power will be on 132 kV, consisting of a

double circuit (D/C) transmission line (on ACSR Rail conductor measuring around 25.00 km) for connecting the generation facility/hydel power plant to 132 kV Chakdara Grid Station of PESCO. The distribution company has vetted and approved the GIS, confirming that all the relevant parameters are within permissible limits of the Grid Code.

4. Hydrology and Sedimentation

Flow measurements are being performed on Panjkora River at hydrological station since the installation of the gauge by PEDO at Zulam Bridge. the flows of Panjkora River were extended with the help of runoff relationship of nearby rivers with long term recorded data. Extension of flows for Panjkora River at Shigo Kas has been made with the help of available long term recorded daily flows of nearby rivers having same characteristics.

In this regard nearby rivers Panjkora at Koto, Zulam, Bibior, Sharmai, Swat at Kalam and Chitral River at Chitral were considered and relationships were investigated. Long term flow series of Panjkora River at Shigo kas have been used for the final selection of flow pattern for water availability.

From flow duration curve and the subsequent optimization studies, it has been concluded that the optimum discharge for power generation is the one that is available for about 37% of the time during the year which comes to 150 m^3/s.

Flood studies have been carried out using statistical approach, Flood Frequency Analysis, Unit Hydrograph method, Regional Method, Method of Relationship with Peak Floods in Sub- catchments, Slope Area Method, 24 hours maximum rainfall data and estimation of floods using HEC-HMS. It is concluded that 10,000-year return period flood of 5,569 m^3/s is appropriate for the design of weir. Total sediment load at proposed dam site has been computed by adding the bed load to the estimated suspended sediment load as given below:

Total Sediment Load	
Description	**Sediment Load (million Tonnes)**
Mean Annual Suspended Sediment Load	4.66
Mean Annual Bed Load	0.89
Total Annual Load	5.55

The results show a large amount of sediment inflow which requires appropriate arrangements and design for effective and timely flushing of the sediments for proper operation of the power plant.

5. Mechanical Equipment Studies

Mechanical equipment and systems will include turbines, governors, inlet valves, gates, stop logs, trash racks, cranes, and hoists etc. The turbine selection was made considering 78.5 m as rated head. As stated earlier, for the installed capacity of power plant 150 m^3 /sec flow at 38% exceedance has been selected. From the comparative study of various turbine sizes

and combinations, three units of vertical Francis turbines each with 50m^3/sec flow have been selected. Considering turbine efficiency of 92% for the net head of 78.5 m and design flow of 50m^3/s, the power will be 35.4 MW for each turbine. These values will result in the turbine specific speed (Ns) of 272.7 rpm. An average runner diameter is considered as 2.46 m.

6. Electrical Equipment Studies

The most important components of the main electrical equipment are the 11 kV with all its excitation equipment and other auxiliary equipment as specified. The generators with generating capacity of 40 MVA have thus been selected. The electric power generated at Shigo kas hydropower station will be fed to Timergara Grid Station through single circuit 132 kV transmission line.

7. Construction Planning

The construction planning for 102 MW Shigo kas Hydropower project is largely dependent on Construction of weir, power tunnel and powerhouse, which are on the critical path, High and low flow periods in the Panjkora River, Excavation in hard strata of powerhouse & power tunnel and Transmission line. Main components of the project are Weir & intake, Connecting channel, Sand trap, Power Tunnel, Surge Tank, Penstock, Powerhouse, Switchyard, Colony and Transmission line.

Table 70: Coordinates of the Generation Facility/Hydro Power Plant

Site	Latitude	Longitude
Weir Intake	34* - 45' - 33.3"	71* - 48' - 18.2"
Power House	34* - 45' - 12.2"	71* - 47' - 58.6"

Table 71: Salient Features

Hydrology	
Catchment Area	5816 km^2
Design Discharge	150 m^3 /s
Working Head	
Normal Head Water Level	650 masl
Tailrace Water Level	558.5 masl
Gross Head	91.5 m
Net Head	78.5 m
Diversion Weir	
Type of Intake	Gated (3 Nos. Each Gate 5.8m x 3.5m)
Height Above River Bed	11 m
Length of the Overflow Crest	25 m
Gated Section with stilling basin	56 m with 4 radial gates (10m x 12m)

Sluicing section (Gated Section with roller bucket)	28 m with 2 radial gates (10m x 12m)
Type of Energy Dissipater	Stilling Basin Type II
Stilling Basin Length	75 m
Sand Trap	
Number of Chambers	3
Total Width of Sand Trap	53.5 m
Length of Sand Trap	115 m
Height of Chamber	09 m
Headrace Tunnel	
Length	10.22 km
Diameter	7 m Horseshoe
Surge Shaft	
Diameter	20 m
Height	42 m
Power House	
Type	Surface
Size (l x w x h)	73m x 35m x 36m
No. of Turbines	3
Type of Turbine	Francis vertical
Tailrace Channel	
Section (w x h)	20m x 9.5m
Length of the Channel	31 m
Power Potential	
Gross Power	102 MW
Annual Energy	520 GWh
Plant Factor	58.2 %
Project Cost & Economic Viability	
Total Project Cost	32,623 million Rs.
Benefit / Cost Ratio	1.61
Unit Cost Generated	8.05 Rs. / kWh
Unit Cost Generated	8.13 US cent / kWh
Capacity & Plant Factor	
Installed Capacity Electrical	102.00 MW
Average Annual Plant Factor	58%
No. of Units generated per annum	520 GWh

Headrace Channel	
Section	Rectangular
Length	65 m
Bed Width	18 m
Height	8 m
L-Slope	1:1000
Power House	
Rated Turbine Capacity	35.40 MW
Each Unit Discharge	50 m^3 /s
Minimum Unit Discharge	19.8 m^3 /s
Unit efficiency at rated discharge	92.0%
Turbine Speed	272.7 r.p.m.
Runner outer diameter	2.46 meter
Runner weight	10.6 ton
Turbine setting	approx. -3.3 m
Valve type	Butterfly type
Design head	78.50 meter
Approximate diameter	2.75 m
Sealing system, main seals	Steel / Carbon Steel
Generators	
Number of units	3 No.
Type of construction	IM8425/W41
Rated output	34 MW
Synchronous condenser operation	not required
Rated speed	272.70 r.p.m.
Runaway speed	504.00 r.p.m.
Direction of rotation	anticlockwise when viewed from top
Rated power factor	0.85 lagging
Rated frequency	50 Hz
Rated voltage	11 kV
Rated range of voltage regulation	5.00 %
Range of frequency variation	3.00 %
Insulation class Rotor/Stator	F/F
Stator winding connection	Star (Y)
Protection class	IP 44

Other Information	
COD of the Generation Facility/Hydel Power Plant	March 30, 2024 (Expected)
Expected Minimum Useful Life of the Generation Facility from COD	30 Years
Total Installed Gross Capacity of the Generation Facility/Hydel Power Plant (3 x 35.40 MW Francis Turbine)	106.20 MW
Total De-Rated Capacity of the Generation Facility/Hydel Power Plant at Mean Site Conditions (3 x 35.40 MW Francis Turbine)	106.20 MW
Total De-Rated Capacity (Electrical) of the Generation Facility/ Hydel Power Plant at Mean Site Conditions (2 x 34.00 MW Francis Turbine)	102.00 MW
Auxiliary Consumption of the Generation Facility/Hydel Power Plant (3 x 0.027 MW Francis Turbine)	001.02 MW
Net Capacity of the Generation Facility/Hydel Power Plant at Mean Site Conditions Condition (3 x 33.66 MW Francis Turbine)	100.98 MW

B. Turen More – Kari Hydropower Project (350 MW), Khyber Pakhtunkhwa

1. Project Introduction

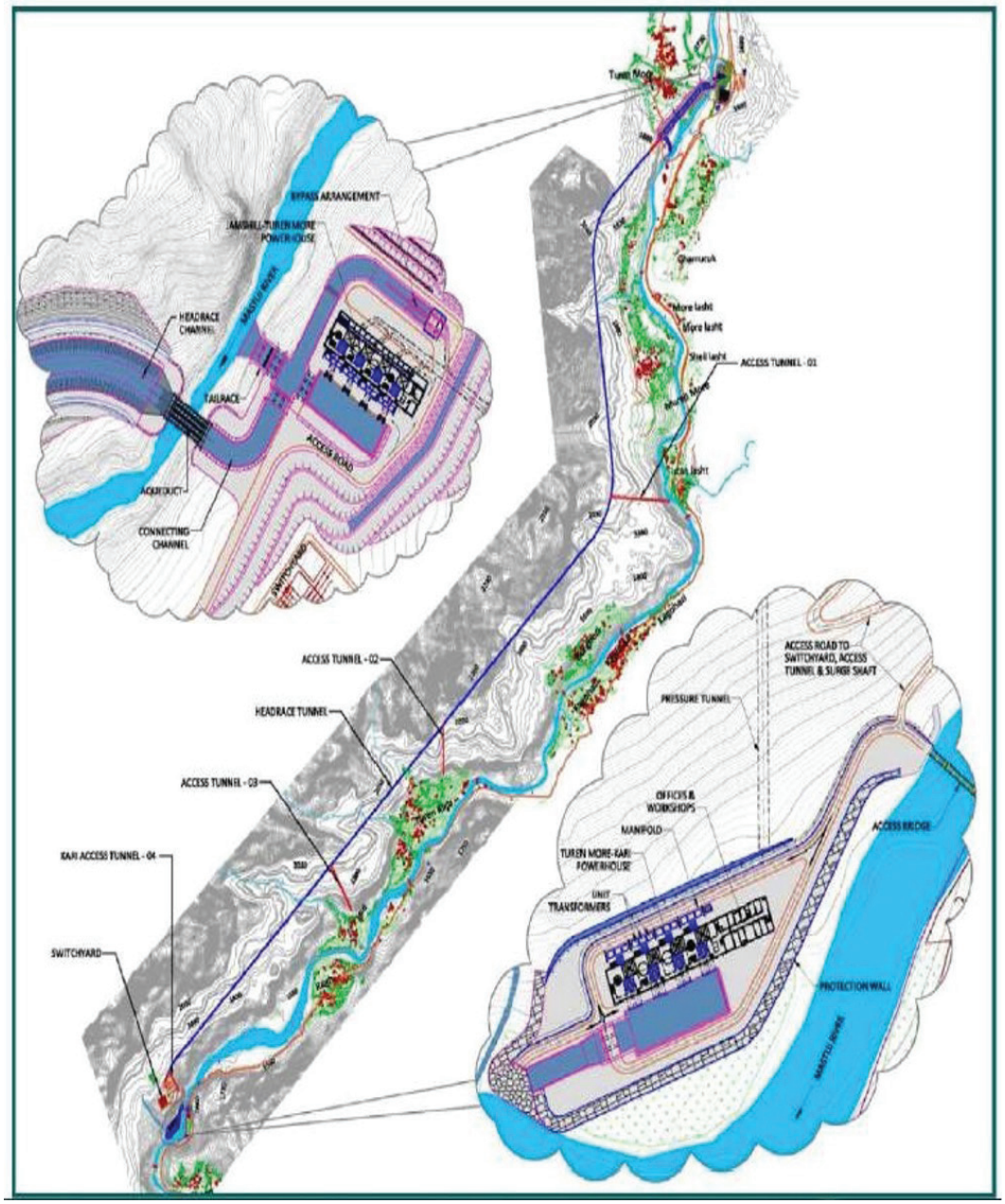
Pakistan is presently facing acute power crisis which is hindering economic growth and hence impacting the life of more than 190 million people. Although, Allah Almighty has blessed Pakistan, particularly Khyber Pakhtunkhwa with abundant hydropower potential, such potential is yet to be materialized in true spirit. The total identified hydropower potential in Pakistan is more than 60,000 MW, of which Khyber Pakhtunkhwa Province alone has a contribution of more than 25,000 MW. Unfortunately, only 6,900 MW hydropower potential has been developed throughout the country, while rest of the potential remains unharnessed.

With the commissioning of Tarbela Dam in 1976-77, the need for advance planning of major hydropower projects became evident. Consequently, the Government of Pakistan (GOP) engaged Montreal Engineering Company «MONENCO» of Canada to undertake preparation of an inventory and ranking study of potential storage and hydropower generation sites along the upper reaches of Indus River and its main tributaries Jhelum (above Mangla); Swat and Chitral basins.

To explore and develop the hydropower potential at provincial level, Government of the NVVFP (now Khyber Pakhtunkhwa) constituted Small Hydel Development Organization in 1986-87 which was later on renamed as Sarhad Hydel Development Organization (SHYDO), under the SHYDO Act 1993. SHYDO has recently been transformed to PEDO, Pakhtunkhwa Energy Development Organization. After the 18th amendment in the constitution of Pakistan, the provinces can now implement power projects with capacities of more than 50 MW.

During the 80s and 90s, identification and ranking studies for hydropower schemes on the rivers and their tributaries in Azad Jammu and Kashmir (AJK); North West Frontier Province (NVVFP) and Northern Areas were also carried out by VVAPDA and Sarhad Hydel Development Organization (currently renamed as PEDO) in collaboration with GIZ, German Agency for Technical Co-operation (currently renamed as GIZ). As a result of the study, several sites for development of small and medium size hydropower projects were identified.

Figure 83: *Identified Sites for Future Small and Medium Hydropower Project*



2. Hydrological and Sedimentation

Chitral River originates from Chiantar glacier at Broghil and runs through Chitral valley upto Mastuj village, the river is known as Yarkhun River. From here till its confluence with Lutkho River just north of the regional center of Chitral, it is called the Mastuj River. Thereafter, it is called Chitral River till it flows south into upper Kunar Valley of Afghanistan, where it is referred to as Kunar River. Kunar River joins Kabul River east of Jalalabad city in Afghanistan and is named as Kabul River. Kabul River then flows eastward into Pakistan where it is joined by River Swat at Charsadda. Flowing further, ii joins Indus River at Khairabad / Mock.

Chitral valley is not affected by the Indian summer monsoon at all due to the high mountain barriers, except for the extreme southern part of the district (around Darosh), where monsoonal rains account for about 11% of the annual rainfall. Almost the entire annual precipitation falls during winter and spring months, while the summers are almost dry. The annual amount of precipitation is around 400 mm in central Chitral, reaching a maximum of 500 mm in the southern mountain ranges (Darosh, 500 mm) and decreases to around 200 mm in the north where precipitation is mostly as snow.

Long term record of flow and sediment measurements at Chitral River in Chitral town have been used to estimate the river flows available for power generation from the upstream Jamshill — Turen More Hydropower Project. As the tail water of Jamshill -Turen More Hydropower Project will be used as inflows for Turen More — Kari Hydropower Project, the flows available for power generation will be the same for both the cascade hydropower projects.

Estimated Flow Available for Power Generation

Months	10 Daily	Flow Available for Power Generation	Months	10 Daily	Flow Available for Power Generation
January	I	59	July	I	626
	II	57		II	673
	III	54		III	674
February	I	52	August	I	686
	II	51		II	607
	III	49		III	492
March	I	49	September	I	373
	II	50		II	285
	III	53		III	203
April	I	58	October	I	149
	II	68		II	121
	III	88		III	102
May	I	109	November	I	90
	II	147		II	83
	III	195		III	78
Jun	I	269	December	I	72
	II	378		II	67
	III	511		III	64

3. Geological and Seismic Hazard Evaluation

District Chitral is occupied by the Hindukush Range of the south-western Pamirs that terminates southwest in Afghanistan as the Nooristan Range. Eastwards, the Hindukush Range swings and merges with the Karakoram Range. The Pamir Range of the Central Asia borders with the Hindukush Range in its north and Kohistan Ranges of Swat and Dir bound in the South.

District Chitral lies in northwestern part of Pakistan. This region has high mountain ranges and deep valleys. It covers about 15000 km^2 area in the mountain ranges of the Hindukush, stretching from central Afghanistan. The Hindukush range is the western continuation of the Karakorum and represents the western part of the Himalayan System. During Mesozoic period, the site of these mountains was the southern margin of the Asian Plate. Later, subduction in the northward's direction took place along the margin and the Kohistan. Ladakh island Arc was accreted along with the Main Karakorum Thrust (MKT) with the development of the Northern Suture Melange (NSM) in the early late cretaceous period. It was followed by the India-Asia collision in the Eocene period. Chitral and its surroundings are characterized by this suture zone between the Asian and Indian plates. The under Thrusting of the Indian Plate beneath the Hindukush and Pamir has made this area seismically an active zone. Historical earthquake data shows that intensity up to 7 (as per M.M scale) has been felt in the region.

4. Geotechnical and Geophysical Investigations

Geotechnical investigations including seismic Refraction Survey, Test Pits, borehole drilling followed by various in situ and laboratory tests on samples have been carried out. The results of such geotechnical investigations have been used to estimate the depth of bed rock available at various project locations and to design underground structures and associated protection works. The headrace tunnel support gasses required along various tunnel lengths have also been estimated based on geotechnical and geophysical investigations. These include analysis of borehole logs and determining the corresponding rock classifications using RMR, Q and GSI systems. Similarly, availability and locations for construction materials such as boulders, aggregate and sand have been estimated identified and their quality assessed.

5. Power Market and Demand Forecast

The installed capacity in the Pakistan Energy and Power Company (PEPCO) system is about 23,000 MW of which hydropower accounts for approximately 30 % of this capacity. Thermal plants take up about 67 % and nuclear 3 % of the total capacity. The maximum energy demand in the country in 2011-12 was over 24,000 MW, However, since electricity is generated at almost fifty per cent of the installed capacity due to inefficient recovery system, wear and tear of plants and inappropriate fuel mix, the unmet demand is significant and has led to even over 12 hours of load shedding per day. Therefore, it is evident that the current generation capacity is unable to meet the increasing demand.

Decline of natural gas, increase in use of expensive furnace oil and decrease of hydel share in the energy mix system have resulted in high cost of electricity, the cost of energy delivered to Distribution Companies (DISCOS) at their interface point was Rs. 9.12 per kWh in 2011-12 including transmission losses in high voltage lines.

The estimated hydropower generation potential of Khyber Pakhtunkhwa province is more than 25,000 MW. The Current hydropower potential of the province identified by PEDO is more than 6000 MW, which can be developed.

PEDO has completed four hydropower projects with an installed capacity of 105.3 MW, out of which 81 MW Malakand-III HPP and 18 MW Pehur HPP have been connected to national grid. The other two are, Shishi HPP 1.8 MW and Reshun HPP 4.2 MW. Both are in Chitral and their generated power is consumed locally. PEDO has planned to develop 56 MW within next three years, 600 MW in five years and 1500 MW within next 10 years. Golen Gol Hydropower Project with an installed capacity of 105 MW is currently under construction at Golen Gol, a major tributary of the Mastuj River.

Since, KP has significant hydropower potential, the demand for electricity on one hand is increasing steadily in Pakistan and the growth in supply has been sluggish. Furthermore. as hydropower projects are capable to supply cheaper electricity as compared to thermal or nuclear plants, significant market opportunities would be there for hydropower projects in the years to come. As KP has significant hydropower potential, it can prove a major source of revenue for the province.

6. Project Layout Planning

Based on project evaluation, two cascade projects; namely Jamshill Turen-More and Turen-More-Kari have been finalized. Jamshill-Turen More HPP lies along with left bank of the river while, Turen-More-Kari HPP along right bank of the river. Flows from Jarnshill-Turen - More powerhouse tailrace would be diverted directly to Turen- More - Kari waterway without discharging it into the river. With this arrangement the need of new diversion structure dam and sand trap for the downstream part of the cascade i.e., Turen More-Kari could be eliminated, thereby decreasing its cost significantly.

Flows from the tailrace or bypass arrangement of Jamshill –Turen-More powerhouse would be conveyed to the waterway of Turen More-Karl HPP through an aqueduct located immediately downstream of the powerhouse to cross the main river. The change in alignment of the waterway for the downstream project is due to poor geology along the left bank downstream of Turen- More and longer length of waterway.

To reduce dependence on the upstream hydropower plant a bypass arrangement comprising of hollow jets along with stilling basin have been provided at Turen-More powerhouse. In case Jamshill-Turen-More powerhouse needs to be closed for maintenance the flows can be routed through the bypass arrangement into the aqueduct. Therefore, the bypass arrangement is an integral part of the cascade development.

The aqueduct is followed by an 849 m long concrete lined trapezoidal headrace channel which falls into the inlet pond located near the inlet portal of Turen-More-Kari HPP headrace tunnel. A super passage has been provided over the headrace channel to route the flows from Morisan Gol to the river. A free overflow spillway has been provided in the left side wall of the inlet pond to divert the flows to the river in case of emergency closure of Turen-More - Kari H PP powerhouse.

At the inlet portal of the headrace tunnel, a coarse trash rack has been provided to prevent entry of logs and large floating debris into the conveyance system. The headrace tunnel designed to be 14.1 km long with finished diameter of 9.7m, modified horseshoe shaped. The entire headrace tunnel will be concrete lined for hydraulic efficiency.

In the tunnel alignment, two major bends have been proposed based on the findings of the geological and geotechnical investigations. The first bend is southwards and the second one towards the west. These bends are aimed to reduce the stress induced problems due to high overburden. With a straight tunnel alignment, the length could be shortened by about 1 km, but the overburden would be more than 800 m, resulting in significant cost increase and longer construction period. With the bends, the maximum overburden has been brought to acceptable limit with no squeezing zone in most of the reach. However due to emerging ridge in front of Kaghozi village still a small reach of squeezing exists.

To reduce the construction period of headrace tunnel, four access tunnels (adits) have been provided, each access tunnel will provide two working fronts for the construction of headrace tunnel. The access tunnels have been located based on the distance between consecutive access tunnel, lengths of access tunnels and ease of access to the portals so that excavation, mucking and lining works could be carried out easily. Elevations suitable for gravity drainage of the headrace tunnel and location of adit portals in exposed rock were the other important criteria for the adits. Based on the above criteria, the locations of the access tunnels are as follow:

- Near Kaghozi village
- Near Dalo Gal
- At Muren Kuju Village
- Near surge/pressure shaft

The locations of surge shaft and pressure shaft depend on the location of powerhouse and geology of the area. The surge shaft has been located about 600 m upstream of the powerhouse where both the geology and topography are adequate to fulfill the requirements of the surge shaft.

The pressure shaft has been located nearly 75 m downstream of the surge shaft while, the 550 m long horizontal pressure tunnel has been provided from the bottom of the pressure shaft to the powerhouse. The finalized dimensions of these underground waterway structures are as follows:

Structure	Diameter (m)	Length / Height (m)	Lining
Surge Shaft	27.0	93.0	Concrete Lined
Pressure Shaft	8.5	109.0	Steel Lined embedded in concrete
Pressure Tunnel	8.5	550.0	Steel Lined embedded in concrete

The pressure tunnel is followed by a 65 m long buried penstock to convey the flows from the pressure tunnel to the turbines. The main penstock pipe has been branched into four manifolds to feed the turbines.

Due to complex geology of the region, attempts have been made to find location suitable for surface powerhouse rather than cavern. The selected site is a terrace of adequate size with exposed rocks all along towards the river. The site located oh right bank of the Mastuj River just upstream of Kari village, is suitable for a surface powerhouse.

The powerhouse building comprises of a main machine hall and a separate control room and offices. The powerhouse comprises of four generating units with vertical Francis turbines.

The outflows from the powerhouse would be discharged into a stilling pond and onwards to the river via an open channel. The switchyard needs to be located close to the powerhouse so that transmission losses and length of the cables can be minimized. The upper terrace to the north of powerhouse has been found suitable for the switchyard. The lines from the transformers would be raised directly to the upper terrace of the switchyard. This location is not only the nearest to the powerhouse but also isolated from the main villages.

About 116 m by 112 m area has been estimated to be adequate for the switchyard. From the switchyard, a 220 kV double circuit transmission line would convey the generated electrical energy to the grid station at Chitral, about 12 km from the switchyard.

7. Estimation of Power & Energy

The initial layout of selected project, the next step was optimization of the project parameters. However, as Turen-More-Kari hydropower is stage-II of the cascade project, the discharge optimization became irrelevant. The project will receive flows from the tailrace of the upstream project; therefore, the design flow (305 m^3/s) will be same as that of the upstream project i.e. Jamshill-Turen-More Hydropower Project (260 MW). Similarly, optimization of the darn height is also irrelevant as no dam is required in this case. Once the layout is fixed, the gross head also becomes fixed. Thus, mainly the headrace tunnel needs to be optimized for the design flow. Based on marginal cost benefit analysis, the tunnel diameter has been optimized as 9.75 m.

The estimated power based on the optimized tunnel diameter and other parameters is 350 MW. The corresponding annual energy generation has been estimated as 1574.28 GWh. Auxiliary consumption and loss of energy during maintenance and forced closure has been considered to be 2.5%. Based on this, the estimated available annual energy for sale is presented below:

Annual Energy available for Sale		
Description	**Unit**	**Value**
Installed Capacity	MW	350.00
Annual Energy	GWh	1,534.93
Annual Energy	GWh	255.82
Annual Energy	GWh	1,279.11
Plant Factor	%	50.10

8. Design of Civil Components

The discharge for Turen-More-Kari Hydropower project will be diverted from the tailrace of Jamshill-Turen-More powerhouse or from its bypass arrangements. Being a cascade development and Turen-More-Kari Hydropower project is stag-II of tile cascade. its design discharge (305 m^3/s) is the same as the upstream project. The Bypass comprises of two Hollow jet valves of 2.4m diameter, a stilling basin (45rn long and 15.5 m deep) and a 100m long rectangular concrete channel (16.0m high and 7.0m wide) section. The water level at the end of bypass channel is at 1688.0m asl which is consistent with Jamshill-Turen-More powerhouse tail water level.

The design discharge either from the bypass arrangements or tailrace pond enters a junction pond. From the pond the flow is conveyed into a channel where stop log arrangement has been provided. This channel is rectangular shaped and is 227 m long, 20.5 m wide and 6.5 m deep. At the design flow of 305 m^3/s depth in the channel will be 5 m.

The conveyance system of Turen- More-Kari Hydropower Project lies along right bank of the river while, Jamshill-Turen-More Hydropower Project along its left bank. Being a cascade development, Turen-More-Kari HPP is dependent on Jamshill-Turen-More HPP. It, therefore, requires a river crossing structure to interlink the tailrace of Turen-More powerhouse to the headrace of Turen- More-Kari HPP. Fortunately, the river at Turen-More powerhouse site passes through a narrow gorge of nearly 50 m width with exposed stable rocks along both banks, making the location more attractive for an aqueduct to cross the river. Normal water level in the river is about 25m below the bed level of the tailrace channel of Turen-More powerhouse, allowing 1000 years return period flood with more than enough freeboard. The aqueduct comprises of four parallel channels each 4.5m wide and 6.5m deep. The flow depth in the aqueduct at the design discharge of 306 m^3/s will be 5.0 m. Reinforced concrete abutments have been provided on both banks of the river to support the aqueduct.

The aqueduct will convey the flows to a concrete lined trapezoidal headrace channel along the right bank of the Mastuj River, A 25 m long smooth transition has been provided between the aqueduct and the headrace channel to minimize head losses.

The headrace channel is 849 m long having bed width of 15 m and flow depth 5.08 m. Total depth of the channel is 6.5 m having a freeboard of 1.42 m. The lining comprises of three layers, two 100 mm thick PCC layers with HPDE material sheet in between to improve its seepage tightness. A natural drain Morison Gol crosses the headrace channel. A super passage with cascade channel has been proposed to convey the drain water to the river. The super passage has been designed to safely manage 100-year return period flood of 22m^3/s.

The outflow from the headrace channel will enter an inlet pond. The purpose of the inlet pond is to reduce flow velocity and allow turbulence free flow into the headrace tunnel. The pond is a rectangular concrete structure of 30 m width, 60 m length and 17.77 m depth. Due to pressurized conveyance system downstream of the inlet pond sufficient submergence has been provided above the headrace tunnel crown at the inlet pond.

The spillway is Labyrinth shaped, sized to spill the design discharge of 305 m^3/s 3D5 with 1.0 m surcharge. To accommodate the overflow depth during the spillage of the design flow a freeboard of 1.4 has been provided in the headrace channel. The freeboard is sufficient to accommodate the surcharge. Crest width of the spillway is 59.0m and its elevation is

1687.35 m asl. Downstream of the spillway, a 30m wide stepped channel has been proposed to dissipate the flow energy and safely discharge it into the river at 1,650 m asl.

The Headrace tunnel is of modified horseshoe shape with 9.7 m diameter and 14.1 km length. The tunnel has 300 mm thick concrete lined section designed for internal and external loads. Five types of tunnel support comprising combinations of rock bolts. shotcrete. Concrete and steel ribs have been proposed. The selected support types for the headrace tunnel are based on geology of the concerned reach.

To accommodate surges during operation of the powerhouse, a surge shaft with restricted orifice has been provided at the end of the headrace tunnel. The diameter of the surge shaft is 27m and its height is 93 m. At the end of the surge shaft a 109 m long, 8.5m diameter circular pressure shaft has been provided. To withstand the high hydraulic pressure in the shaft, steel lining of thickness varying from 30mm to 56mm has been provided depending upon the magnitude of pressure. At the end of the pressure shaft a 549 m long steel lined horizontal pressure tunnel has been proposed. The pressure tunnel is 8.5 m in diameter with 55 mm thick steel lining to convey the flows to the penstock.

A buried penstock, 8.5 m in diameter, 65 m long, 60 mm thick has been proposed between the pressure tunnel and the powerhouse. The penstock has four manifolds, each 4.2m diameter to feed the four turbines.

The powerhouse main hall would be 111 m long and 25 m wide. Control rooms along with offices have been provided separately, adjacent to the main hall. Loading/unloading bay, gantry crane and other requirements for the powerhouse building have also been provided. There will be four generating units comprising of vertical Francis turbines. The machine floor level and the turbine center line are at 1545.65 m and 1534.00 m respectively. The tail water level fluctuates between 1537.00 m and 1542.00 m respectively, depending on available flows and the number of units in operation.

The outflows from the turbines are to discharge into a stilling pond 84 m long, 31 m wide and 21.2 m deep. From the stilling basin, the flows will be discharged into the Mastuj River via tailrace channel.

9. Structural Design

Pseudo-static method of analysis has been adopted for structural analysis based on static solution of the system subjected to inertia forces equal to the product of the mass of the system and the acceleration acting in a selected direction. The effect of earthquake forces impacting earth pressures have been calculated by using Mononobe Okabe method. Similarly, hydrodynamic forces have been calculated using Zanger method. Calculations of forces under various loading conditions have been done using three-structural analysis. Boundary spring elements have been adopted for modeling sub-soil supporting the structures.

Since a dam structure is not required, therefore, risks due to dam failure and consideration of the corresponding Safety Evaluation Earthquake (SEE) criterion are not relevant for this project. For earthquake considerations in the powerhouse building, Pakistan Building Code specified value of 0.32 g has been adopted. For other major project structures, a Design Basis Earthquake (DBE) of 0.29g (475 years return period) has been adopted, Similarly, PGA of 0.20g with a return period of 145-year has been adopted for Operation Basis Earthquake

(OBE) for minor structures. These parameters have also been adopted for the upstream Jamshill-Turen-More Hydropower Project.

10. Hydro-Mechanical Components of the Project

Given the head and flow range for the project, the optimum configuration of four vertical shaft Francis Turbines has been proposed. The rated speed of the turbine has been proposed to be 253 RPM and the rated power at the turbine shaft would be 90.0 MW.

Digital, microprocessor type Proportional Integral Derivative (PID) governors have been proposed and each turbine would be provided with such an independent governor. The governor regulator would have an independent hydraulic actuator of sufficient capacity to control the turbine under all operating conditions**.** There would be four inlet valves at the manifolds, one for each turbine. The diameter of the valve has been proposed to be 4.0 m.

Two overhead travelling cranes have been provided in the powerhouse for installation and dismantling of the electro-mechanical equipment each with 100-tonne capacity. The maximum weight of the single heaviest component of the electromechanical equipment is the generator rotor which will be about 227 tonnes. Therefore, the rotor needs to be lifted by operating both overhead travelling cranes together. 300-tonne total capacity of the cranes allows for over 20% higher lifting capacity.

A bypass arrangement has been proposed at Turen-More powerhouse to reduce operational dependence of Turen-More-Kari HPP on the upstream Jamshill-Turen-More This arrangement comprises of two sets of bonneted slide gates followed by hollow jets discharging into a stilling basin. From the stilling basin, the flows would be routed to the tailrace of the Turen-More powerhouse. Other required major hydro-mechanical equipment and accessories are:

Upstream of Powerhouse

- Stop logs at intake, upstream of the aqueduct
- Safety rack at aqueduct inlet
- Trashrack at tunnel inlet
- Bulkhead gates at access tunnels (1 and 4) and headrace tunnel junction
- Penstock inlet valve (PIV) downstream of surge shaft

At Powerhouse

- Draft tube gates in the powerhouse
- Units Cooling Water System
- Heating, Ventilation and Air Conditioning (HVAC) System
- Firefighting system.

11. Electromechanical Components of the Project & Transmission Line

Four 87.5 MW, 0.85 power factor, 50 Hz, 11 kV vertical shaft, silent pole synchronous generators along with necessary auxiliary equipment complete with control, monitoring, switch gear / protection system have been provided to produce 350 MW installed capacity. To evacuate the generated power from the project to national grid, four (3 single phase bank) step-up power transformers with capacity 40/50 MVA have been designed.

The 220 kV high voltage switch gear equipment such as SF6 circuit breakers, disconnecting switches with and without earthing switches, instrument transformers and control, monitor and protection of outdoor switch yards' equipment have been selected.

One 4 / 5 MVA, 220 / 11 kV three phase transformers with required protection and control switchgears have been proposed to cater for power supply from national grid to power station services, outdoor switch yard, housing colony, inlet pond and channel area. This transformer would be in addition to the backup supply to power station service. Two 750 kVA transformers have also been proposed to tap from the generator's bus. Similarly, five 300 kVA auxiliary transformers have been proposed to supply low voltage, 400 V to housing colony.

By accumulating the upstream power projects, a 500 kV transmission line would be required to transmit the power to Chitral grid. Due to the transportation 500 kV transformers cannot be transported to the site. Therefore, two separate 220 kV transmission lines have been proposed. The transmission line of Turen-More-Kari Hydropower Project would be linked separately with the Chitral grid and upstream cumulative power will be separately transmitted to the grid.

12. Salient Features of the Project

By Pass Arrangements	
No of bypass pipes	2 Nos
Diameter of Bypass pipes	4.2 m
Energy dissipation type	Hollow Jet with Stilling Basin
Diversion angle of pipe	60 degrees
Invert level of Basin	1674.60 m asl
Size of Hollow Jet Basin	45x16 m
Water level in Stilling Basin	1688.1 m asl
Length of bypass channel	100 m
Size of Bypass	16x7 m
Flow Control	Stop logs
No of stop logs	3 m
Size of stop logs	5.5m x 7 m

Connecting Channels	
Upstream channel section	Rectangle Concrete Lined
Invert Level of Channel	1683.0 m asl
Design Discharge	306 m^3/s
Water Level in Channel Start	1688.0 m asl
Length of Channel	117 m
Depth of Flow	5.0 m
Size of Channel	20.5 m x 6.5 m
Freeboard	1.5 m
Bed Slope	0.00045 m/m
Flow velocity	2.98 m/sec
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Trough Channels	Rectangular Reinforced Concrete
No. of Trough Channels	4
Water Level at start Trough Channel	1687.99 m asl
Bed Level at start	1682.98 m asl
Trough span	50 m
Depth of flow	5.0 m
Size of Channel	4.5 m x 6.5 m
Freeboard	1.5 m
Bed Slope	0.001 m/m
Flow Velocity in Trough	3.39 m/s
Trough Support	Reinforced Concrete abutments
Length of abutments	49.4 m
Size of Abutments	7 m x 24.7 m
Down Stream Transition	Rectangular to Trapezoidal
Length of Transition	25 m
Headrace Channel	
Type	Trapezoidal Concrete Lined
Headrace Channel Side Slope	2H: 1V
Design Discharge	306 m^3/sec
Lining Thickness	100 mm + 100 mm
Seepage Control	Geomembrane
Size of Headrace Channel (WxD)	15 m x 6.5 m

Length of Headrace Channel	849 m
Depth of Flow in Headrace Channel	5.08 m
Freeboard	1.42 m
Flow Velocity	2.38 m/s
Water Level at start of Headrace Channel	1687.51 m asl
Head Loss in Headrace Channel	0.241 m asl
Super Passage	
Length of Super Passage Trough	62.8 m
Clearance from Headrace Channel Water level	7.8 m
Bed Level of Super Passage Channel	1695.15 m asl
Design Flood	100-year return period
Flood Peak	22 m^3/sec
Size of Channel	5x4 m
Super Passage Through Support	4 Nos. Piers
Upstream Protection	Stone Masonry Step Drop
Size of steps (WxL)	7m x 3 m
Drop per Step	1 m
Inlet Pond	
Type	Reinforced Concrete Rectangular
Invert Elevation at Start	1687.25 m asl
Invert Elevation at Tunnel Inlet	1669.00 m asl
Size of Inlet Pond	30 m x 60 m
Depth of Flow	17.77 m
Submergence to Headrace Tunnel	6.9 m
Elevation of Inlet Pond side Walls	1689.00 m asl
Velocity at Design Discharge	0.68 m/sec
Type of Spillway	Labyrinth
Crest Level of Spillway	1687.35 m asl
Surcharge Level Due to Design Discharge	1688.35 m asl
Width of Spillway	59 m
Length of Labyrinth Wall	181.4 m
Design Discharge	305 m^3/sec
Downstream Level	1686.0 m asl
Energy Dissipation	Stepped Drop Channel

Material	Gabions
Width of Channel	30 m
Downstream Floor Level	1650.0 m asl
Length of Stepped Channel	205 m
Size of End Basin	14 m x 30 m
Headrace Tunnel	
Type	Concrete Lined Pressure Tunnel
Shape	Modified horseshoe
Invert Elevation of Tunnel	1670.00 m asl
Flow Area	76.53 m^2
Average Flow Velocity	3.99 m/sec
Tunnel Diameter	9.70 m
Length of Tunnel upto surge shaft	14.1 Km
Invert Level of tunnel at Surge Shaft	1634.85 m asl
Head loss in Tunnel	15.3 m
Access Tunnels	
No. of Access Tunnels	4 (A1, A2, A3, A4)
Shape	Inverted U shaped (A1, A2, A3) Modified Horseshoe (A4)
Diameter / Height of Tunnels	6.00 m (A1, A2, A3) 9.70 m (A3)
Length of Tunnels	820 m (A1) 560 m (A2) 530 m (A3) 240 m (A4)
Control for Maintenance	Bulkhead Gates (A1, A4)
Surge Shaft	
Type	Restricted Orifice concrete Lined
Geometry	Circular
Maximum Surge Level	1717.6 m asl
Minimum Surge Level	1652.4 m asl
Diameter of Surge Shaft	27.00 m
Diameter of Throat	4.20 m
Full Operational Water Level	1671.98 m asl
Top Level of Surge Shaft	1737.5 m asl
Height of Surge Shaft	99.0 m

Pressure Shaft / Pressure Tunnel	
Type	Steel Lined
Geometry	Circular
Centerline of Pressure Shaft at Start	1639.65 m asl
Diameter of Pressure Shaft and Tunnel	8.50 m
Flow Area	56.75 m^2
Height of Pressure Shaft	109 m
Length of Pressure Shaft	549.70 m
Average Flow Velocity	5.37 m/sec
Steel Lining Thickness	30 – 55 mm
Invert Level of Pressure Tunnel End	1534.0 m asl
Head loss in Pressure Shaft / Tunnel	2.3 m
Pen Stock	
Length of Penstock	65.00 m
Diameter of Penstock	8.50 m
Thickness of Steel Lining	60.00 mm
Velocity in Penstock at Design Discharge	5.37 m/sec
Manifold	
Type	Straight Symmetrical Wye
Number of Branches	4
Diameter of each Branch Pipe	4.25 m
Velocity in Manifold at Design Discharge	5.37 m /sec
Thickness of Steel Lining	60 mm
Powerhouse	
Type	Surface Powerhouse
Size of Powerhouse	25 x 111 m
Turbine	Vertical Francis
Generating Units	4 x 87.5 MW
Unit Discharge	87.5 m^3/sec
Generator Type	Synchronous Vertical, 11 kV, 50 Hz
Power Transformers	12+1 Nos. Single Phase, 40 / 50 MVA, 11 / 220 kV

Tail Race Channel	
Type	Rectangular Concrete Section
Length of Tailrace Channel	95 m
Submergence for Draft Tube	7.80 m
Tailrace Channel Size	16 m x 6 m
Depth of Flow in Channel	5.00 m
Freeboard	1.00 m
Flow Velocity in Tailrace Channel	3.81 m/sec
Invert Level of Channel	1537.00 m asl
Switchyard	
Size of Switchyard Area	112 m x116 m
Switch Gear	220 kV, SF 6, Circuit Breaker
Transmission Line Length	
Transmission Line Length	2 x 12 KM
Type	220 kV, Double Circuit with Three Bundle Drake Conductors
Head and Discharge	
Gross Head	150.25 m
Rated Net Head	127.41 m
Head loss at Design Discharge	22.84 m
Design Discharge	305.00 m^3/s
Capacity & Discharge	
Plant Capacity	350.00 MW
Capacity per Unit	87.5 MW
Plant Factor	50.10 %
Average Annual Energy	1,534.93 GWh
Project Cost	
Project Construction Cost	48,735 million PKR
Project Base Cost	52,390 million PKR
Project Total Cost	70,544 million

Economic & Financial Indicators	
Economic Parameters	
Net Present Value (NPV)	76,523 million PKR
B/C Ratio	3.38
EIRR	48.74%
Financial Parameters	
Net Present Value (NPV)	121,914 million PKR
B/C Ratio	3.62
FIRR	20.27%
Implementation	
Pre-Construction	12 months
Construction Period	60 Months
Total Implementation	72 Months

NEECA

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