Implications of Declining Costs of Solar, Wind and Storage Technologies on Regional Power Trade in South Asia (BBIN Countries)

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Preface

We are pleased to present the report "Implications of Declining Costs of Solar, Wind and Storage Technologies on Regional Power Trade in South Asia (BBIN Countries)", carried out under the Energy and Economic Growth Program supported by UKAID. It was felt that long-term modelling assessment in the BBIN (Bangladesh, Bhutan, India and Nepal) region is essential to assess the potential impact of technological cost decline on the cross-border electricity trade as the trade has technical and economic benefits for all the participating countries. Further, long-term projections of gains from multilateral electricity trade in the region will help in building investor confidence and steady planning with progressive streamlined projects among participant countries.

Each country in the BBIN region has its own unique generation and capacity mix. For instance, India and Bangladesh have predominately coal and gas-based power capacity mix, respectively, whereas Bhutan and Nepal are having the hydro-based capacity installation. Moreover, Bhutan and Nepal have a combined hydro potential of more than 70 GW (feasible potential) whereas their current combined domestic demand is less than 2 GW. Hence, both countries have immense potential for the development of their domestic hydropower potential for exporting into the BBIN region. Already, bilateral trade between India- Nepal, India-Bhutan and India-Bangladesh is happening but this is more or less negotiated based on government-to-government agreements often at predetermined prices. However, many new electricity trade contracts are now market-determined. As on 1 January 2022, Bhutan and Nepal are already participating in the Indian Energy Exchange and soon Bangladesh will join too.

In contrast to the above, with declining renewable energy and storage technology costs policy-makers and system planners in the region have questioned the future of absorption of hydro potential, and the direction and volume requirement of regional electricity trade in the BBIN region. We had earlier undertaken bilateral and multilateral trade studies showcasing the benefits of electricity trade, although they lacked the higher renewable and storage cost decline perspective. Hence, building on our previous studies we have undertaken the current study, wherein we updated our IRADe's electricity model for Bangladesh, India and Nepal, and developed a new IRADe's Bhutan electricity model. In addition to model development, we held many discussions with stakeholders, focused groups and electricity planners from all the countries for our current modelling study.

This was a painstaking and novel exercise and it helped us to assess the scope for trade for the first time where four BBIN countries' models were integrated into an interactive mode. It shows different power flow patterns and chose different investment options. For example, more pumped hydropower plants in Nepal and Bhutan complement higher shares of renewable energy due to clean energy transition in India and all countries. The resultant economic gains for countries in the BBIN region due to cost decline in renewable and storage technology costs are shown to be substantial. In addition to cost decline, we undertake sensitivity analysis based on energy security constraints, the possibility of higher renewable potentials and carbon emission constraints. In the study, the benefits accrue in terms of higher trade volumes, lower coal capacity installation, higher RE and hydro potential utilization, reduced CO_2 emissions and lower capital requirements by the power sector in the BBIN region compared to the Base case where electricity trade was restricted to 2017 volumes.

We are grateful to UKAID for supporting this path-breaking modelling exercise and extend my gratitude to our collaborators in Bangladesh, Bhutan, India and Nepal for their frequent feedback. We hope that this study will give a new direction to cross-border electricity in the BBIN region.

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This research study has benefited from the help and guidance of various individuals in Bangladesh, Bhutan, India and Nepal.

In **Bhutan**, we thank all relevant officials of the Department of Hydropower and Power Systems (DHPS) & the Department of Renewable Energy under the Ministry of Economic Affairs, Druk Green Power Corporation, Bhutan Electricity Authority and Bhutan Power System Operator (BPSO) under Bhutan Power Corporation for their support and coordination. We received valuable feedback during our inception meeting held in June 2019 and the stakeholder consultation meeting held in November 2019. We especially thank Mr. Karma P Dorji, Director of the Department of Hydropower and Power Systems (DHPS) and his team for providing support for undertaking inception and stakeholder meetings in Bhutan. We would also like to thank Mr. Samdrup K Thinley, Chief Executive Officer of Bhutan Electricity Authority for his feedback and support during the inception meetings.

In **Bangladesh**, we thank all relevant officials of Power Cell, Bangladesh, Sustainable and Renewable Energy Development Authority (SREDA), Bangladesh Power Development Board, Bangladesh Investment Development Authority (BIDA), Power Grid Company of Bangladesh, Bangladesh Electricity Regulatory Commission and Electricity Generation Company of Bangladesh for their feedback and suggestions during the inception meeting held in December 2020. We especially thank Mr. Mohammad Hossain, Director General of Power Cell, Bangladesh for his guidance and support. We would also like to thank sectoral experts Mr. Siddique Zobair, Expert on Energy, Environment and Climate Change & Ex-Additional Secretary and Member, SREDA, Dr. Aminul Hoque, Vice-Chancellor, Eastern University and Mr. Mohammad Shah Alam, Director, Policy Advocacy and Planning, Bangladesh Investment Development Authority (BIDA) for their valuable feedback during the inception meeting.

In **Nepal**, we especially thank Mr. Prabal Adhikari, Director, Power Trade Department and Spokesperson, Mr. Durga Nanda Bariyait, Director, Grid Development Department, Transmission Directorate and Mr. Braj Bhushan Chaudhary, Director, Transmission Directorate of the Nepal Electricity Authority, and in Alternative Energy Promotion Centre, we thank Mr. Narayan Prasad Adhikari, Director, Technology Division for giving their valuable feedback during the inception meetings held in February 2020. We also thank Dr. Krishna Prasad Oli, Member- Energy, Water Resources and Irrigation, National Planning Commission, Nepal for his guidance and support.

In **India**, we would like to thank IRADe for organising KP@85 Festschrift Conference on 9th January 2021 wherein we presented the results from our India model. From India, the event witnessed participation from Central Electricity Authority, Power System Operation Corporation, Bharat Heavy Electricals Limited, Centre for Fuel Studies and Research and many more. We thank all representatives for their valuable feedback and suggestions provided during the conference. In March 2022, we presented the results from our study at a four hours session on interconnected regional grids at the India Smart Grid Week (ISUW 2022) wherein we could get the feedback from other regional grids of the world as well.

We would also like to thank the government of the United Kingdom for funding this project through their Applied Research Programme on Energy and Economic Growth (EEG), managed by Oxford Policy Management which has provided the opportunity to conduct this project and develop a report. We also thank Mr. Simon Trace, Principal Consultant and the project management team of Oxford Policy Management.

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Abbreviations

°C	Degrees Celsius
BBIN	Bangaldesh, Bhutan, India and Nepal
BEA	Bhutan Electricity Authority
BES	Battery Energy Storage
BESS	Battery Energy Storage Systems
BPDB	Bangladesh Power Development Board
BTN	Bhutan Ngultrum
CAPEX	Capital Expenditure
CBET	Cross Border Electricity Trade
CCGT	Combined Cycle Gas Turbines
CdTe	Cadmium Telluride
CEA	Central Electricity Authority
CIGS	Copper Indium Gallium Selenide
CO-50	Carbon Emission reduction of 50% Scenario
CSP	Concentrated Solar Power
DGPC	Druk Green Power Corporation
DHPS	Department of Hydropower & Power Systems
DISCOMs	Distribution Companies
EE	Energy Efficiency
Evs	Electric Vehicles
FO	Furnace Oil
GDP	Gross Domestic Product
Gigawatt Hour	GWh
GNH	Gross National Happiness
GNI	Gross National Income
GoB	Government of Bangladesh
GW	Gigawatt
HCD	Higher Cost Decline Scenario
HFO	Heavy Fuel Oil
HiRePo	Higher RE Potential Scenario
HSD	High-Speed Diesel
HTF	Heat Transfer Fluid
IbhTec	IRADe Bhutan Technology Model
IBTec	IRADe Bangladesh Technology Model
IEA	International Energy Agency
IITec	IRADe India Technology Model
INR	Indian Rupee
INTec	IRADe Nepal Technology Model
IPPs	Independent Power Producers
IRENA	International Renewable Energy Agency
ITRPV	International Roadmap of Photovoltaic
KE	Kinetic Energy
Kilowatt Hour	kWh
LA	Lead-Acid
LCD	Lower Cost Decline Scenario
LCOE	Levelised Cost of Electricity
LEDS GP	Low Emission Development Strategies Global Partnership

LFP	Lithium Iron Phosphate
LNG	Liquified Natural Gas
LTO	Lithium Titanate
Megawatt Hour	MWh
MEWR	Ministry of Energy, Water and Resources
MOEFCC	Ministry of Environment, Forest and Climate Change
MoU	Memorandum of Understanding
Mtoe	Million Tonnes of Oil Equivalent
NaNiCl	Sodium Nickel Chloride
NaS	Sodium Sulphur
NC	No Cost Decline Scenario
NCA	Nickel Cobalt Aluminium
NDC	Nationally Determined Contributions
NEA	Nepal Electricity Authority
NMC/LMO	Nickel Manganese Cobalt Oxide/Lithium Manganese Oxide
NPR	Nepalese Rupee
NREL	National Renewable Energy Laboratory
NTGMP	National Transmission Grid Master Plan of Bhutan
O&M	Operation and Maintenance
PerC	Passivated Emitter rear Contact
PES	Political Energy Security Scenario
PLF	Plant Load Factor
PPAs	Power Purchase Agreements
PROR	Pondage Run of River
PSMP	Power System Master Plan
PV	Photovoltaic
R&D	Research & Development
RE	Renewable Energy
RE&S	Renewable Energy and Storage Technologies
RoR	Run-of-River
SE	Solar Energy
SPV	Solar Photovoltaic
SREDA	Sustainable and Renewable Energy Development Authority
STG	Storage
T&D	Transmission & Distribution
Terrawatt Hour	TWh
TFEC	Total Final Energy Consumption
TIMES	The Integrated MARKAL-EFOM System
Tk	Bangladeshi Taka
USD	United States Dollar
VRFB	Vanadium Redox Flow Battery
VRLA	Valve-Regulated Lead-Acid
WECS	Water and Energy Commission Secretariat
WEM	World Energy Model
WPT	Wind Power Technology
ZBFB	Zinc Bromine flow battery

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Executive Summary

Bangladesh, Bhutan, India, and Nepal (BBIN) strive for higher economic growth and an improved standard of living but require access to affordable and reliable electricity as a key element to fuel development. However, BBIN countries lag behind their more developed counterparts, with per capita electricity consumption significantly lower that the global average in the region (except for Bhutan). Further, two of these countries rely heavily on fossil fuels, with the Indian power sector dependent in part on coal while Bangladesh's power sector relies on natural gas and oil. Although the power systems of Nepal and Bhutan both largely rely on hydropower generation, Nepal currently also needs access to imported electricity from India to meet dry season shortages.

In 2019-20, India exported 1839 GWh to Nepal, 6168 GWh to Bangladesh, and 7 GWh to Myanmar, while it imported 6165 GWh from Bhutan (Ministry of Power, 2020). Although electricity trade in the region was originally based on government-to-government treaties, more recently many new electricity trade contracts have been market-determined, a trend that is expected to further increase volumes of electricity trade in the region. Nepal and Bhutan currently have huge untapped hydro resources which, if exploited, could have the potential to dramatically change their economies through the export of hydropower to India and Bangladesh. However, the falling cost of storage technologies and other renewables (solar and wind) has raised questions over whether the cost of hydropower will remain competitive in the long term and, if not, what the impact might be on the direction and volume of cross-border electricity trade in the region in future.

For the current study, IRADe developed a modelling framework for analysing the impact of the declining cost of other renewable energy and storage technologies (RE&S) on cross-border electricity trade between the BBIN countries. The power system technology modelling framework for Bangladesh, India and Nepal was taken from the previous studies conducted by IRADe and updated for this study for the base year 2015. In addition, a fully functional Bhutan electricity model was also developed for this study. Since the primary interest of the study was to analyse the consequences of regional trade, an integrated model was developed wherein all the four countries in the Bangladesh-Bhutan-India-Nepal region could trade electricity with each other. Due to the geographic conditions, the trade amongst the countries has to be through India (which is already facilitating such trilateral trade arrangements).

The power system model for each country is modelled as a least-cost, dynamic linear programming model representing the physical aspects and functioning of the energy (power) system, with technological details and options. The model covers alternative technologies for power generation that include sub-critical coal, supercritical coal, nuclear, gas, hydro (three types - reservoir, run of the river and run of the river with pondage), and other renewables such as solar and wind. The model provides the least-cost solution for meeting the required electricity demand for each sub-period of a year, taking into account potential supply options (resource, technology, various costs, etc.) in each country. Since electricity demand varies from hour to hour and month to month, and the electricity available from hydro, wind and solar plants also has seasonal and hourly variation, sub-periods are taken as hours of an average day for each month to balance supply, demand and trade. The Answer TIMES software is used for the analysis in this study.

To assess the impact of the cost decline of RE&S on the potential of cross-border electricity trade among the BBIN countries following scenarios were developed:

- **Base** –The Base scenario assumes that the power trade among the BBIN nations will be restricted to 2017 volumes from 2017 to 2050.
- **NC** – This scenario assumes no cost decline for renewable and storage technologies and the cost is fixed to the year 2015 throughout the model horizon.
- **LCD** – This scenario assumes a lower cost decline for renewable and storage technologies.
- **HCD** – This scenario assumes a higher cost decline for renewable and storage technologies.

Apart from the above four scenarios, sensitivity analysis was also undertaken using the following themes:

- **PES** (Political Energy Security) – This scenario assumes that the maximum electricity import volume for each year is capped at 20% of domestic demand for Bangladesh, Bhutan and Nepal.
- **HiRePo** (Higher RE Potential) – This scenario assumes a higher RE potential for BBIN countries that is currently assumed in national plans (around twice the potential compared to that considered in the other scenarios).
- **CO-50 (Carbon Emission reduction of 50%)** – This scenario assumes a cumulative reduction of CO_2 emissions from the power sector of 50% of the Base scenario for Bangladesh and India i.e. limiting power sector emission for India to 31 MT and for Bangladesh to 5 MT for the period 2012 to 2050. (No emissions reduction targets are assumed for the Bhutan and Nepal power sectors given that they are largely dependent on hydropower).

The study has multiple key messages for the BBIN region as a whole and also for the individual countries.

At the regional level, with cost decline in RE&S technologies, the regional electricity trade could grow from 13 TWh in 2019 to as high as 986 TWh by 2050. Even with a PES constraint (where electricity imports in a year are restricted to 20 percent of domestic demand) the regional trade reaches 416 TWh by 2050.

Analysis shows that removal of current trade restrictions alone would lead to a dramatic growth in Cross Border Electricity Trade (CBET) comparted to the Base scenario, even in the NC scenario when there is no cost decline assumed for the RE&S technologies. However, in case of the NC scenario, the increase in CBET leads to higher coal utilisation and increased emissions in the region.

One important question considered during the study was whether Nepal and Bhutan, who are already developing the hydro capacity to service CBET, will be left with stranded assets if the cost decline of RE&S technologies leads to a drop in demand for hydropower. The analysis shows that this is unlikely to be an issue in practice under any of the scenarios. At the country level, both Bhutan and Nepal will gain from RE&S cost decline in the region as the net trade increase from both the countries under various RE&S cost decline scenarios. One reason for this is that the demand for flexible hydro such as pondage-based run of river and storage-based hydropower plants will grow as they can generate electricity in non-solar generation hours and during the winter season. In addition to this, RE&S cost decline will support the higher installation of other (non-hydro) renewable energy capacities in both countries.

Amongst the four countries, Bangladesh's situation is quite different to the others as its generation options are more limited and it has to choose between power imports from the other three countries and domestic generation using imported fuels, due to limited domestic fuel availability. As a result of this, under RE&S cost decline scenarios, Bangladesh's electricity imports could be as high as 93 percent of its domestic demand by 2050. On the other hand, the RE&S cost decline will help India in achieving higher non-hydro renewable energy (RE) installed capacity as it has the highest RE potential within the BBIN region. India could be a net exporter of power if power imports by Bangladesh are not restricted.

To support the above trade numbers, the regional transmission capacity needs to increase from 3.8 GW in 2020 to as high as 174 GW by 2050 under the HCD+HiRePo scenario. Further, with higher RE capacities in the BBIN region, the time at which electricity trade is required will change. For instance, hydro-exporting nations such as Nepal and Bhutan will supply more electricity to the region during the hours when solar generation is not possible than during solar generation hours.

From the various stakeholder meetings undertaken for this study, we understand that the current RE potentials in the region are underestimated and need to be reassessed to account for technology development. With RE&S technology cost decline, the RE share of total installed capacity for the BBIN region could go as high as 75 percent by 2050 under the HCD+HiRePo scenario, whereas it reaches only 55 percent in the Base scenario. This increase in RE capacity will help reduce installed coal capacity in the region by between 33 and 45 percent compared to the Base scenario. A combined effect of higher RE and reduced coal capacities will reduce CO2 emissions from the power sector in the region.

Apart from the above technical gains, with RE&S cost decline, the region has the potential to save on the total system costs. The BBIN region could save around 227 billion USD on the total discounted system cost (2015 to 2050) at 2015 prices under the HCD scenario and close to 312 billion USD under the HCD+HiRePo, compared to the Base scenario.

To summarize, this study demonstrates that the declining costs of RE&S technology leads to increased regional electricity trade amongst BBIN nations, including increased trade in hydroelectricity. It also leads to a declining share of coal as a proportion of total regional installed capacity, reducing CO_2 emissions and bringing huge system cost savings and environmental benefits.

Chapter 1: Global Overview of RE & Storage Technologies

1. Overview

In the current century, the focus is on limiting average global temperature rise below 2°C compared to pre-industrial levels as committed in the Paris agreement with each country voluntarily committing to climate change actions based on their respective Nationally Determined Contributions (NDC's); this can be achieved by increasing the use of RE and enhancing Energy Efficiency (EE) of energy systems (UNFCCC, 2015). RE-based systems with higher EE can help to achieve more than 90% of CO_2 emission reduction targets (UN, Global Status Report 2017).

Energy systems are globally transcending from fossil-based energy systems to those powered by Renewable Energy (RE) with a spectacular reduction in the cost of solar, wind and storage technologies resulting in a drastic decline in the position of fossils in the global electricity generation mix (GWEC, 2017). The study of CAPEX (Capital Expenditure) and Levelised Cost of Electricity (LCOE) for all leading RE/ non-RE technologies suggest that the generation of power from fossils is facing tremendous challenge in terms of – bulk generation supply, dispatchable generation supply, and the provision of flexibility (SolarPower Europe, 2017).

The renewables power generation and capacity as a share of global power from 2007-19 has been showcased in Figure 1.1 given below; the RE technologies considered are wind, solar, small hydro, bio-mass, geothermal and waste-to-energy projects, excluding large hydro; the black line shows percentage of net new capacity added in each year that is made up of renewable technologies (excluding large hydro), it has increased from 20% in 2007 to 72% in 2019; the blue line shows the percentage of cumulative world generating capacity that is accounted for by renewables excluding large hydro, this has increased from 7.5% in 2007 to 34.7% in 2019, as the gigawatts of new wind and solar plants added have grown and the net additions of fossil power stations have decreased; wind and solar will account for a higher proportion of capacity than generation, because they cannot produce power when the wind does not blow and the sun does not shine; the grey line shows that in 2019, the share of total electricity produced grew to 24.7% in 2019 as compared to 5.2% in 2007.

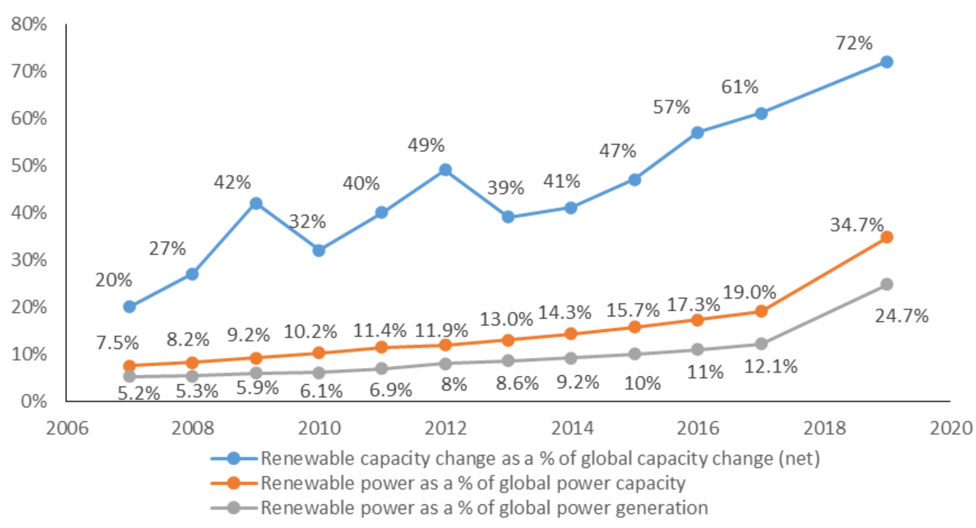

Figure 1.1 Renewable power generation and capacity as a share of global power, 2007-19Source: IRENA Renewable Capacity Statistics 2021 (* *RE considered: wind, solar, small hydro, biomass, geothermal & waste-to-energy projects, large hydro excluded)*

A total of 101 GW of solar was installed across the globe in the year 2012, solar exceeded the 200 GW mark in 2015, 300 GW level in 2016 and in 2019 the total global solar power capacity was 578 GW (IRENA, 2020). In the year 2019, solar PV addition was nearly twice as compared to wind i.e. almost 118 GW of solar was installed in one year.

A major issue with solar and wind energy is their intermittency, Battery Energy Storage Systems (BESS) can offer an excellent solution by storing the excess power generated from RE and supplying it as and when the sun is not shining or the wind is not blowing, as a result making the system more stable (ibid). As per IRENA, 2017 the total stock of electricity storage capacity has to grow from an estimated 4.67 terawatt-hours (TWh) in 2017 to 11.89-15.72 TWh by 2030 i.e. 155- 227% higher than in 2017 in order to double the share of RE in the energy system by 2030. BESS can help Distribution Companies (DISCOMs) to store excess power from off-peak hours and supply the same to the consumers at peak hours without burdening the DISCOMs. A large-scale battery energy storage (> 50 MW) can help to manage power fluctuations on day-to-day basis along with the variability and intermittency of RE sources as they grow to provide large proportions of energy to grids of all sizes (IEA and World Bank, 2017).

In the coming years, solar and wind technologies along with low-cost battery storage will have a significant share in the overall energy mix. In the next section, the global cost trend of Solar, Wind and Storage technologies has been studied and discussed in detail.

1.1 Solar Energy (SE) Technologies

The global energy crisis of the 1970s shifted the focus on developing highly efficient solar technologies for meeting thermal and electrical demand worldwide; these technologies do not emit any greenhouse gases; solar energy technologies have been classified into Solar Photovoltaic (SPV) and Concentrated Solar Power (CSP) (WEC, 2013). In solar PV technology the generation of electron pairs within the semiconductor material results in the generation of electricity and in the case of CSP the solar radiation gets reflected and concentrated on a receiver by the means of mirrors which heat the Heat Transfer Fluid (HTF) to very high temperatures, the HTF carries the heat to a steam generator where the superheated steam from the steam generator moves the steam turbine, which runs the electric generator just as in the case of fossil fuel based conventional power plant (Solar Power Europe, 2017). In the next section, we have studied Capex and LCOE global trends for SPV and CSP technologies.

1.1.1 Solar Photovoltaic (SPV) - Capex and LCOE Trends

For solar PV, the capex and LCOE declined due to continuous technical advancement, decline in solar PV module prices and Balance of System (BoS) cost reduction along with favourable global policy landscape. As shown in Figure 1.2, total installed cost (CAPEX) and LCOE are continuously declining for solar PV globally. From 2010 to 2019, global solar PV installation cost fell by 74% while global solar PV LCOE fell by 82%. The cost decline has boosted the competitiveness of solar PV against conventional technologies like coal and natural gas. Further, from 2013 to 2019, the solar PV module price has fallen drastically in major global economies. Particularly, the decline in module price is in the range of 50-60% in countries like China, Brazil, the US, UK, Germany, India and South Korea. The cost of modules in these countries has been reduced due to economies of scale and technological improvements.

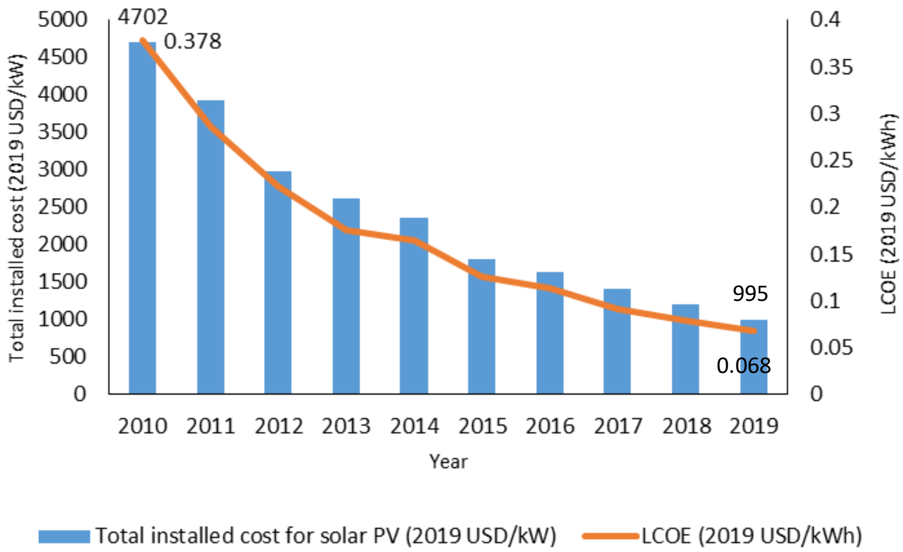

Figure 1.2 Solar PV Total Installed Cost (2019 USD/kW) and LCOE (2019 USD/kWh)
Source: IRENA, Renewable Power Generation Costs in 2019

Some of the key reasons for the boost in the deployment of Solar PV technologies globally can be attributed to a significant reduction in module prices and their manufacturing costs; improvement in module technology and production processes; increased adoption of newer cell designs leading to higher solar cell efficiency and intense market competition (EERE, 2018). Various global research agencies have made projections for CAPEX cost decline for solar PV from 2015 to 2050. They estimate cost decline for solar PV will be in the range of 40-60% compared to 2015 cost levels. Further details on the country wise cost decline of module price and LCOE of solar PV is provided in Annexure 1.

1.1.2 Concentrated Solar Power (CSP) - Capex and LCOE Trends

CSP can provide reliable electricity that can be dispatched to the grid when required, including after sunset to match late evening peak demand and to meet base-load demand; it has been projected that CSP would need to account for 8-10% of global electricity supply by 2050 and to achieve this the installed capacity of CSP would need to reach 800 GW along with expansion of CSP capacity in developing countries (REN21, 2019). CSP technology has better technical performance and exhibit better electrical output as compared to SPV. However, SPV technology is economically more feasible and highlights far better economic performance.

Figure 1.3 shows the decline in capex cost of CSP from 2010 to 2019, which is a 35% reduction over the last decade. For LCOE, the global reduction from 2010 to 2019 is 47% from \$0.33/kWh to \$0.182/kWh. The various global agencies have estimated that the cost decline for CSP by 2050 will be in the range of 30-50% compared to 2015 cost levels in Annexure 1.

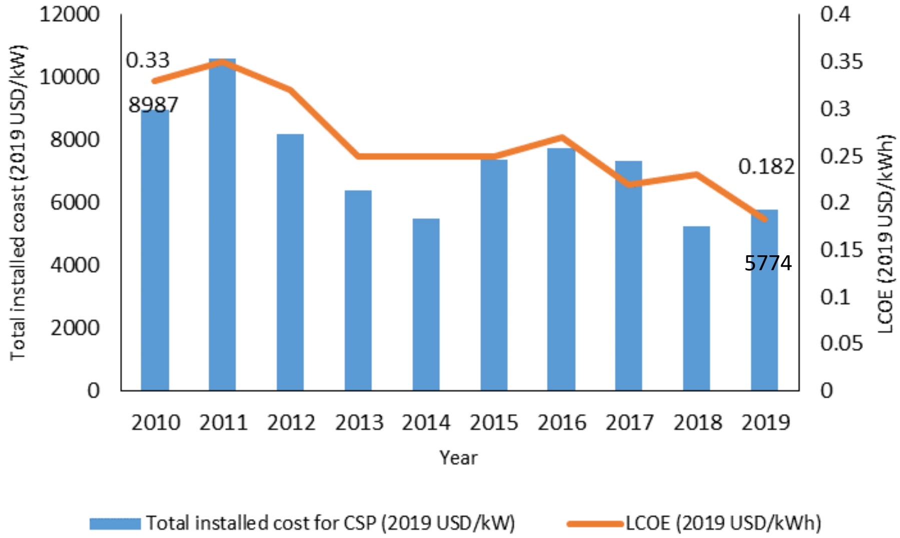

Figure 1.3 **CSP Total Installed Cost (2019 USD/kW) and CSP LCOE (2019 USD/kWh)**
Source: IRENA, Renewable Power Generation Costs in 2019

1.2 Wind Power Technology (WPT)

In the last two decades, wind energy has become one of the most successful forms of RE technology in terms of employment generation. High wind speeds yield more power because wind power is proportional to the cube of wind speed. The wind potential estimation depends upon elevation, solar irradiance and geographic location; wind potential is region specific.

Hitherto, majority of the wind power deployment is done onshore and in future, offshore wind is expected to grow faster than onshore wind. During 2021, global installed capacity of wind power was 743 GW (Global Wind Energy Council, 2021). About 93 GW was added globally in 2020 only, of which China accounted for 72 GW followed by USA (14 GW). In terms of continents, Asia added 167 GW, the highest among all continents. Further, 2015 was a record year for wind installation in China and after then, installations have been declining till 2019 while 2018 was a record year for India and Europe. In some of the largest wind power markets, strong growth was driven by looming regulatory changes; elsewhere, wind energy's cost-competitiveness and its potential environmental and developmental benefits drove deployment. Rapidly falling prices for wind power have made it the least-cost option for new power capacity in a large and growing number of countries. The country wise wind capacity for the ten largest wind capacity countries is provided in Annexure 2.

In the year 2017, the bid prices drastically reduced for both onshore and offshore wind power capacity in auctions around the world. Bid prices were down due to technology innovation and scale, expectations of continued technology advances, reduced financing costs due to lower perceived risk, and fierce competition in the industry. Electric utilities and large oil and gas companies continued to move further into the industry. Wind power had its strongest year ever in 2020, with more than 93 GW added, for a total of 743 GW (IRENA,2021).

1.2.1 Onshore WPT - Capex and LCOE Trends

Onshore WPT is a mature technology as compared to offshore WPT. The CAPEX of onshore WPT was expected to drop further, but at a moderate rate. The drop was partially due to the scaling up of power ratings of the wind farms with time (JRC, 2014), thus improving economies of scale and reducing cost. Figure 1.4 shows the global weighted-average installed costs of onshore WPT that have declined by 70% in the past 35 years from around USD 5000/kW in 1983 to USD 1473/kW in 2019. The decline was due to the reduction in wind turbine price and balance of project costs (balance of project refers to the various supporting and auxiliary components of a power plant system). Other drivers for cost reduction includes greater competition among suppliers and technological innovations like higher rated turbines, hub heights, and rotor diameters that have increased yields from the same or lower wind resource. Additionally, improved logistical chains and streamlined administrative procedures contributed to the observed cost declines (IRENA, 2018). Various agencies estimate cost decline of onshore WPT in the range of 10-30% compared to 2015 cost levels and these projections are available in Annexure 2.

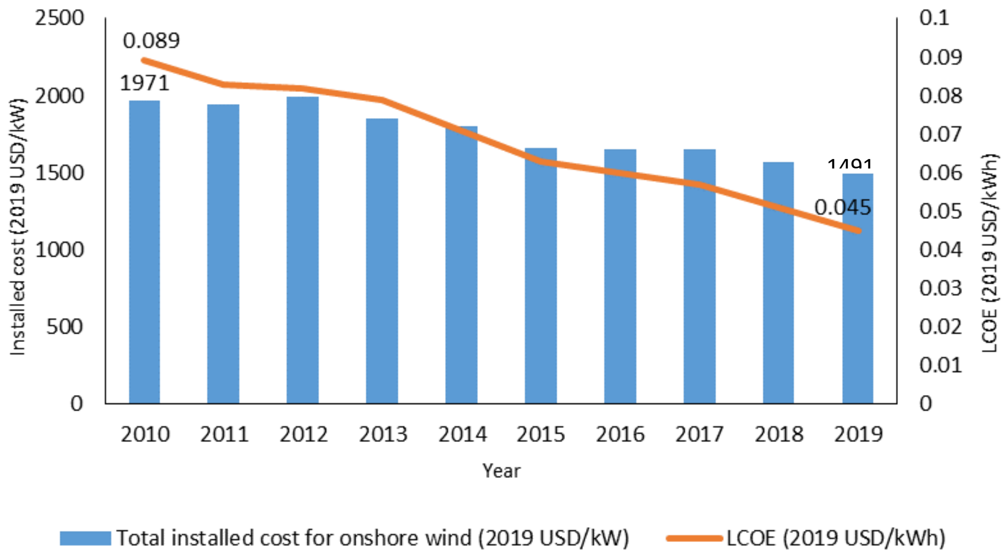

Figure 1.4 Onshore Wind Total Installed Cost (2019 USD/kW) and LCOE (2019 USD/kWh)

Source: IRENA, Renewable Power Generation Costs in 2019

1.2.2 Offshore WPT – Capex and LCOE Trends

Figure 1.5 shows the total global installed cost of offshore wind projects commissioned in 2019 was 18.2% lower than those commissioned in 2010 (IRENA, 2019). The major drivers of this reduction in the cost of electricity from offshore wind have been innovations in wind turbine technology, installation and logistics; economies of scale in O&M (from larger turbine and offshore wind farm clustering); and improved capacity factors from higher hub heights, better wind resources (despite increasing cost in deeper waters offshore), and larger rotor diameters. Various agencies estimate cost decline in the range of 30-40% compared to 2015 cost levels and these projections are available in Annexure 2.

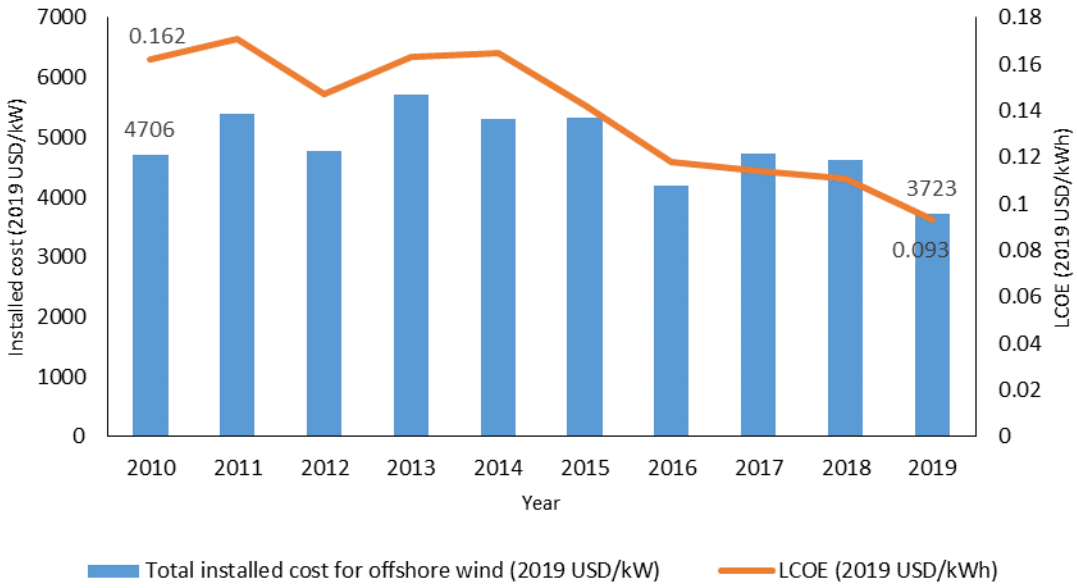

Figure 1.5 Offshore Wind Total Installed Cost (2019 USD/kW) and LCOE (2019 USD/kWh)

Source: IRENA, Renewable Power Generation Costs in 2019

1.3 Storage Technology

Globally each country has specific energy storage potential, which is based on a combination of factors such as energy resources, infrastructure, electricity market structure, regulatory framework, population demographics, energy-demand patterns and trends, and general grid architecture. The traditional function of energy storage systems is to absorb energy during periods of excess generation marked by low prices to release it back to the electricity system in times of scarcity or high prices. Storage facilities can be located with the consumer, with the generator or at the transmission or distribution grid level. There are a variety of storage technologies including mechanical (for example, compressed air, pumped hydro), electrochemical (for example, lithium-ion battery, flow battery), and thermal (for example, ice, phase change materials). On commercial scale, battery and thermal based storage technologies are used on very limited scale due to their higher cost of installation and operation. However, with the expected fall in cost of storage technologies storage will become increasingly competitive, and the range of economical services it can provide will only increase.

Traditionally, pumped hydro has been the largest deployed technology for energy storage around the world. However, it is a mature technology with site-specific costs. Therefore, it has little potential to reduce total installed cost from a technology perspective; lead times for project development tend to be long, and it is not as modular as some of the new and emerging electricity storage technologies, which can scale down to very small sizes (IRENA, 2017). Therefore, for our analysis, we will focus only on Li-Ion base storage system in this report.

1.3.1 Lithium-Ion Battery Storage System

Li-ion batteries are being foreseen as the primary candidate for Electric Vehicles (EVs) and residential renewable system applications as well. More than 500 MW of stationary Li-ion batteries were deployed worldwide by the year 2015, which further increased up to 1,629 MW by 2018. Their commercialization started in the early 1990s; Li-ion batteries are prevalent across a variety of industries due to their high specific energy, power, and performance. According to Bloomberg New Energy Finance New Energy Outlook (BNEF 2018), over 1,200 GW of additional Li-ion battery capacity is expected to be added by the year 2050.

Arriving at the CAPEX number for a battery energy system is a difficult task due to relatively limited dataset of actual battery systems and the rapidly changing costs. As per NREL's Cost Projections for Utility-Scale Battery Storage report- 2021 update, the overnight capital cost of a 4-hour battery storage system was 345 USD per kWh in the year 2020 and as per the report projects it is expected to decline to as low as 87 USD per kWh by 2050, which is almost 75 percent cost decline. Further details on storage technologies can be seen in Annexure 3.

Chapter 2. BBIN Region Overview

This chapter presents an overview of the BBIN region's socio-economic situation and power sector.

2.1 BBIN Overview

BBIN nations together are home to 21 percent of the world's population. Though these countries are tied by history and culture, they are still not well integrated and remained among some of the poorest in the world.

2.1.1 Socio-economic

Even after being endowed with rich reserves of clean energy like solar, wind and hydro, this region still predominantly depends on fossil fuels to meet its energy needs. With sustained economic growth, rising urbanization and growing population, electricity demand in the region is expected to rise exponentially. However, due to its dependence on fossil fuels, the region also faces climate concerns. Table 2.1 provides the key socio-economic indicators for BBIN nations.

Table 2.1 Geographic and Socio-economic indicators for BBIN nations

Key indicators	Bangladesh	Bhutan	India	Nepal
Geographical area (square km)	148,460	38,394	3,287,263	147,516
Forest cover (%)	17.5%	71%	21%	41%
Population (million) in 2019	163	0.76	1,366	28
Population density (people per square km) in 2018	1,240	20	419	196
GDP at Current Market Price (million $) in 2019	302,571	2,530	2,868,930	30,641
Per capita GDP at Current Market Price ($) in 2019	1,855	3,316	2,099	1,071
Structure of Output (% of GDP at current basic prices)	*for 2019*	*for 2018*	*for 2019*	*for 2019*
Agriculture	13%	16%	18%	24%
Industry	31%	38%	27%	18%
Services	56%	46%	55%	51%
Electricity Generation (GWh) in 2019	71,419	8,857	1,383,000	6,012
Per capita electricity consumption (kWh) in 2019	378	3,164	1,208	245

Data Source: World Bank Indicators, Bangladesh Power Development Board Annual Report 2019-20, Central Electricity Authority Annual Report 2019-20, Nepal Electricity Authority Annual Report 2019-20, National Statistics Bureau, Statistical Yearbook of Bhutan 2020

2.1.2 Power Sector

Bangladesh, Bhutan, India and Nepal strive for the higher economic growth and improved standard of living but require access to affordable and reliable electricity which is a key element for economic growth and development. However, BBIN countries lag behind their developed counterparts in terms of key power sector indicators like electricity access and per capita electricity consumption. The per capita electricity consumption is disproportionately low in BBIN countries (except for Bhutan) compared to global average, implying the need for a rapid expansion of electricity supply systems in the region and optimal utilisation of power resources to mitigate current shortages and meet future demand. These countries also rely heavily on fossil fuels. While India depends heavily on coal, Bangladesh is dependent on natural gas. Though Nepal and Bhutan have a high share of hydro generation, Nepal is dependent on imported electricity from India.

The distribution of energy resources is not uniform across the countries of BBIN region and thus, Cross Border Electricity Trade (CBET) can be an effective solution to reduce this energy distribution distortion. CBET in the South Asian region has the potential to grow to 76,000 MW by 2045 (IRADe, 2018). At present, within the South Asia Region, only four nations – Bangladesh, Bhutan, India and Nepal- account for a large part of the CBET in the region. This exchange of power is undertaken primarily through bilateral power purchase pacts signed as part of special agreements between the governments. Improving power connectivity between BBIN nations has the potential to add significantly to the gross domestic product of the region but requires each country to take a regional perspective and aggressively assess the renewable potential.

The installed capacities for Bangladesh, Bhutan, India and Nepal as of March 2020 have been shown in Table 2.2 with India having the highest installed capacity. Nepal has a large untapped hydro potential of 83 GW with installed capacity of only 1.4 GW while Bhutan has a hydro potential of 41 GW with only 2.3 GW installed capacity as of March 2019. Nepal and Bhutan were expected to dramatically change their economies by exporting hydropower to India and Bangladesh but falling prices of renewables and storage technologies have raised issues over the possible role of hydropower in the future.

Table 2.2 Installed capacity for BBIN nations as of March 2020

Country	**Installed Capacity**								
	Coal (MW)	Gas (MW)	Oil (Diesel and Furnace Oil) (MW)	Hydro (MW)	Nuclear (MW)	Solar PV (MW)	Wind (MW)	Bio-Power (MW)	Total (MW)
Bangladesh	1146 (6%)	10,979 (54%)	6830 (33%)	230 (1%)	-	38 (<1%)	-	-	20,383
Bhutan (March 2019)	-	-	7	2,334 (99%)	-	-	1	-	2,342
India	205,134 (55%)	24,955 (7%)	509 (1%)	50,382 (13%)	6,780 (2%)	34,627 (9%)	37,693 (10%)	10,022 (3%)	370,106
Nepal	-	-	53 (4%)	1,397 (96%)	-	1	-	-	1,451

Data Source: BPDB Annual Report 2019-20; Statistical Yearbook of Bhutan 2020; CEA – March 2020 and NEA Annual Report 2019-20

The nations within the South Asia region are working together towards greater energy cooperation. The study will focus on the BBIN countries in the South Asia region. The renewable energy potential for the BBIN region is given in Table 2.3.

Table 2.3 Renewable energy potential in BBIN region

Country	Solar Power Potential (MW)	Hydro Power Potential (MW)	Wind Power Potential (MW)	Biomass Potential (MW)
Bangladesh	2,680	330	637	286
Bhutan	12,000	41,000	760	-
India	750,000	150,000	302,000	-
Nepal	2,100	83,000	448	-

Data Source: For Bangladesh- SREDA-World Bank "Scaling Up Renewable Energy in Low Income Countries (SREP) Investment Plan for Bangladesh", October 2015; Ministry of New and Renewable Energy, Govt. of India; IRENA 'Kingdom of Bhutan' (2019); Singh et al. (2020); The World Bank 'Solar Resource and Photovoltaic Potential of Nepal' (2017)

Regional power trade in South Asia is currently limited to bilateral government-to-government negotiations, which is a slow process. In 2019-20, India exported 1839 GWh to Nepal, 6168 GWh to Bangladesh and 7 GWh to Myanmar, while imported 6165 GWh from Bhutan (Ministry of Power, 2020). The government consent opens up trade, recently there is an increased interest in Power markets based on the current demand – supply which can primarily help to expedite the trade.

The Power sector and economy of each country within in the BBIN region is further discussed in detail in Annexure 4.

Chapter 3. Approach and Methodology

3.1 Approach

IRADe developed the modelling framework for analysing the impact of cost decline of renewable and storage technologies on cross border trade between Bangladesh, Bhutan, India, and Nepal. Since the primary interest of the study was to analyse the consequences on the regional trade, the integrated model is developed wherein all four countries in the region Bangladesh – Bhutan – India- Nepal could trade electricity among each other as shown in Figure 3.1. The trade among the countries has to be through India and we assume that India will facilitate this. The power system technology modelling framework for Bangladesh, India and Nepal was taken from the previous studies conducted by IRADe and updated for this study for the base year 2015. Apart from this, a fully functional Bhutan electricity model is developed for this study.

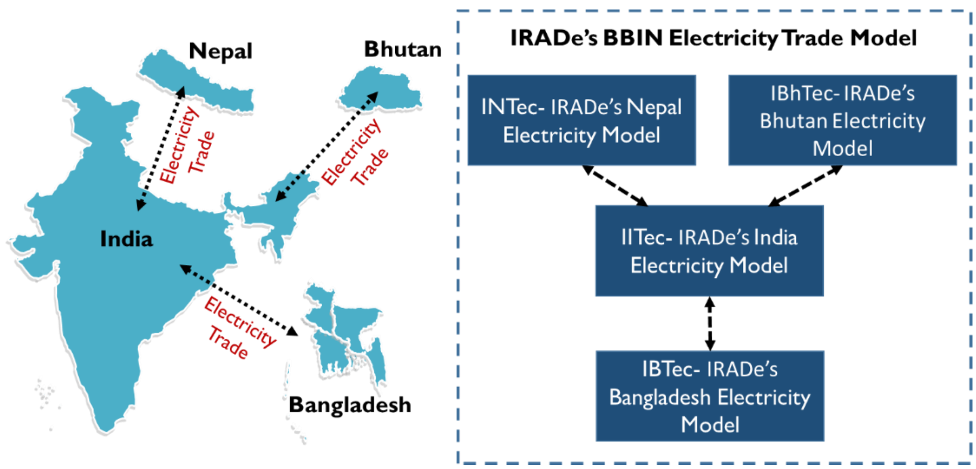

Figure 3.1 Set up of IRADe's BBIN Electricity Trade Model (Bangladesh-Bhutan-India-Nepal Region)

3.2 Model

The physical power systems of each of the four countries are modelled separately using energy system modelling software AnswerTIMES. This software uses TIMES as its model generator which is the successor of MARKAL. The TIMES1 is a technology-rich, least-cost, dynamic linear programming model representing the physical aspects and functioning of the energy (power) system. It quantifies new investment needs in generation and grid, including interconnection, cost of generating electricity to meet the requirement for each time-period and sub-periods. The demand is specified for each hour assuming that for a given month hourly demand remains the same. Thus 24 hours for 12 months give us 288 sub-periods of each year over the period 2015–2050. This captures the variation in demand and supply across the hours of the day and across the months of the year. The model provides the least cost solution for meeting the requirement for each sub-period taking into account potential supply options (resource, technology, various costs, etc.) in the country. These four models are named as IBTec (IRADe Bangladesh Technology) model for Bangladesh, IBhTec (IRADe

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[1] Wherein TIME refers to The Integrated MARKAL-EFOM System

Bhutan Technology) model for Bhutan, IITec (IRADe India Technology) model for India, and INTec (IRADe Nepal Technology) model for Nepal.

Since, electricity demand varies from hour to hour and month to month and so does electricity availability from hydro, wind, and solar plants, sub-periods are taken as hours of an average day for each month to balance supply, demand and trade.

Although the power system of each country is modelled separately in the TIMES model generator, the ANSWER –TIMES software allows the integration of four national power system models into one. The integrated model gives the quantity of electricity trade for each sub-period and price along with investment on new capacity in each system in each period, which minimizes the net present value of the total power system costs taking all the four countries together. This integrated model is named as integrated IBBINET (IRADe Bangladesh-Bhutan-India-Nepal Electricity Trade) model depicted in Figure 3.1. These models are based on several assumptions on domestic energy resource availability, fuel imports, scheduled construction of power projects, available technology options and their respective technical and economic performances, fuel prices, cost of capital (discount rate), energy and environment policies, macroeconomic policies, development in productivity and savings rate over a period of 40 years. Experts in the respective countries were consulted for these assumptions, which were listed in the upcoming chapter.

3.3 Scenarios

To assess the impact of renewable and storage cost decline on the potential of cross border electricity trade among the BBIN countries following scenarios were developed:

- **Base** –The Base scenario assumes that the power trade among the BBIN nations will be restricted to 2017 volumes from 2017 to 2050.
- **NC** – This scenario assumes no cost decline for renewable and storage technologies and the cost is fixed to the year 2015 throughout the model horizon.
- **LCD** – This scenario assumes lower cost decline for renewable and storage technologies.
- **HCD** – This scenario assumes higher cost decline for renewable and storage technologies.

Apart from the above four scenarios, sensitivity analysis has also been undertaken on the following themes:

- **PES** (Political Energy Security)– This scenario assumes that the maximum import volume for each year is capped at 20% of domestic demand for Bangladesh, Bhutan and Nepal.
- **HiRePo** (Higher RE Potential)– This scenario assumes higher RE potential for BBIN countries compared to potential considered in other scenarios as shown in Table 3.1.

Table 3.1 Renewable Potential considered for HiRePo Scenario*

RE Potential in GW		HiRePo Scenario	Other Scenarios
Bhutan	Solar- PV	**58**	12
	Wind- On shore	**4.8**	0.8
Nepal	Solar- PV	**5.3**	2.1
	Wind- On shore	**3**	0.4
Bangladesh	Solar- PV	**30**	2.7
	Wind- On shore	**30**	0.6
India	Solar- PV	**1250**	750
	Wind- On shore	**695**	302

** The current RE potential estimated (under the heading other scenarios in Table 3.1) in the BBIN region was estimated by individual country's agencies and many of them have been estimated decades back. With the change in technology and cost decline, we believe that these RE potential numbers need to be reassessed. Therefore, to capture the impact of higher RE potential on the regional trade we assumed a higher RE potential for all the countries than what is prescribed in other scenarios. The RE potential numbers in the HiRePo Scenario are taken from different government and non-government assessment reports, wherein it provides theoretical potentials which were higher than the government numbers except for solar potential of India and Nepal wherein assumption of increased waste land utilization is assumed to arrive at potential number.*

- **CO-50 (Carbon Emission reduction of 50%)–** This scenario assumed cumulative reduction of CO_2 emissions from the power sector by 50% of the Base scenario for Bangladesh and India as shown in Table 3.2. The scenario constraint is not applicable to Bhutan and Nepal as their power system is predominantly hydropower based.

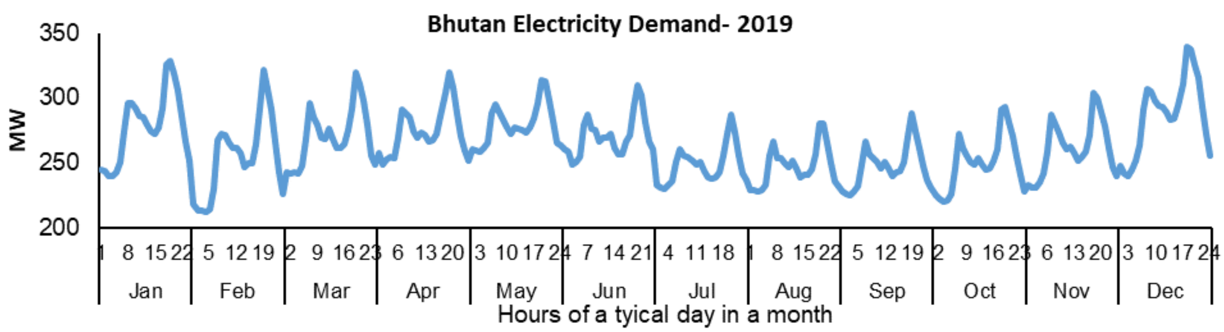
Table 3.2 Assumption on cumulative emission caps for the power sector of Bangladesh and India under CO-50 scenario

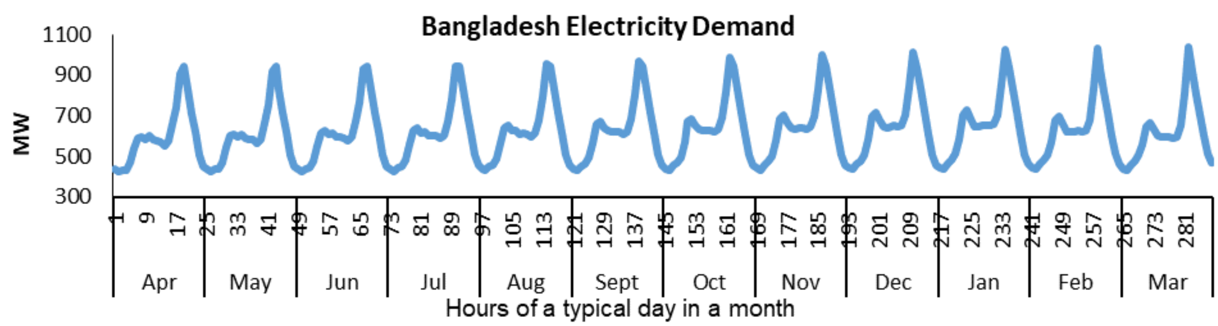
Emission from Power Sector for 2012 to 2050 in MT		
Country	**Base Scenario**	**CO-50 Scenario**
India	**63**	**31**
Bangladesh	**10**	**5**

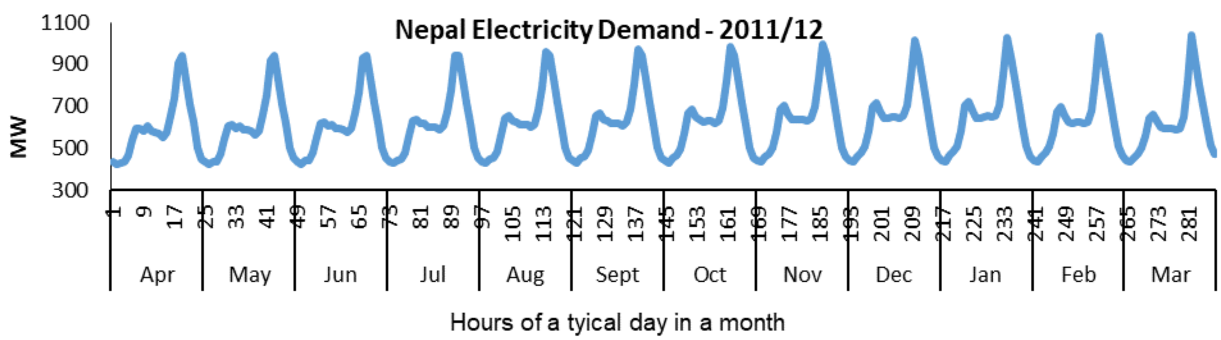
Further details on assumptions on key parameters and cost decline assumptions for each country are provided in chapter 4.

Chapter 4. Assumptions

The existing power system of 2014–15 is the starting point for all the reference energy systems of each country. A mathematical representation of the current electricity supply system is created within the TIMES modelling framework. This includes characteristics of the various existing generating stations (vintage, techno-economic performance, etc.), transmission and distribution, electricity flows, demand, load characteristics, energy resources and import/export links. Variations in seasonal and daily load patterns as well as hydro generation and availability of solar and wind energy sources are captured by modelling hourly load and generation supply curves. Based on the analyses of 8,760 hourly load and generation data for each country (depending on data availability), the entire year is divided into 12 seasons (meaning each month represents a season). The average hourly load pattern for a day in a month (or season) represents the daily load pattern for that particular season (or month). Thus, average hourly load over 24 hours of a day in each month represents daily load pattern of each month in the model. Thus, we have 288 = 24 x 12 sub-periods for each year. Figure 4.1 presents the organised form of the 288 sub-periods load curve for a year for all the BBIN countries used in the model.







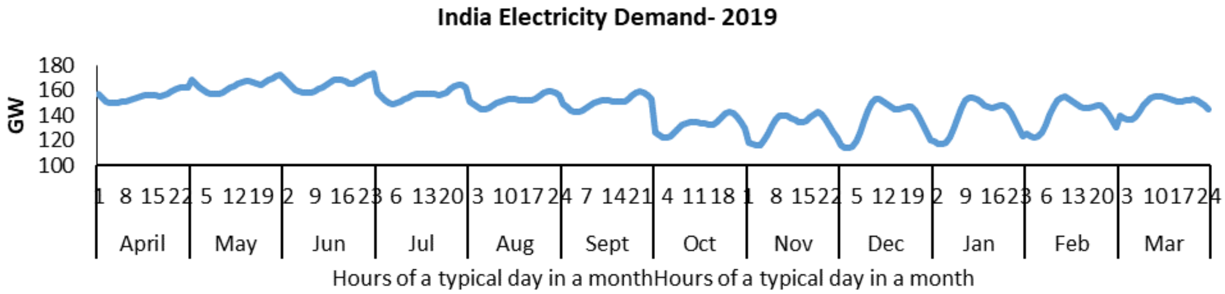


Figure 4.1 Load Curve Representation in the Model for Bangladesh, Bhutan, India and Nepal

The base year for all the country models and regional model is taken as 2014-15 and all cost data are at constant 2014–15 US dollars. Exchange rates for Bangladesh, Bhutan, Indian and Nepalese currencies are respectively 78 Tk, 64 BTN, 64 INR and 102 NPR for 1 USD. The discount rate for the BBIN Regional model is taken as 4%. Country-specific key assumptions are described below.

4.1 Bhutan

The **electricity demand projection** for IRADe's Bhutan electricity model is taken from the National Transmission Grid Master Plan of Bhutan published in June 2018 by the Department of Hydropower & Power Systems (DHPS) under the Ministry of Economic Affairs, Bhutan. As per the master plan, Bhutan's electricity requirement will be 6,404 MUs by 2040 with a peak demand of 1,150 MW. This demand was further projected to the year 2050 using the CAGR in demand growth from 2034 to 2040 as in the master plan resulting in electricity demand of 7,222 MUs by 2050 at the generation side.

The Bhutan power system is quite simple compared to India and Bangladesh as a major part of installed capacity is based on hydro. Potential technologies for the future expansion of the Bhutan power system include the following: hydro (run of the river [ROR] with some pondage and reservoir-based storage hydropower plants (STG)), solar PV, and wind power plants. Table 4.1 presents the technical and economic data related to these technologies. For the model, the total hydropower potential is taken as 27 GW (IRENA 2019), Solar PV potential as 12 GW, and Wind onshore potential as 0.8 GW as per consultation with DHPS officials. Solar and wind CAPEX numbers are provided in section 4.5 of this chapter.

Table 4.1 Assumptions on Technical and Economic Performance of Future Technology Options for Bhutan *to 2040. With the capacity ranging from 118 MW to 1200 MW.*

Technology Data	Hydropower Plant	
	ROR	**STG**
Availability factor	48%	36%
Operational lifetime (Year)	40	40
Construction Period (Year)	8#	8#
Economic data		
Capital cost ($/kW)	1216*	974**
O&M cost ($/kW/yr)	30	24

 # Average construction time of 17 upcoming hydropower plants
**ROR cost calculated as a weighted average of 14 ROR hydropower plants expected to be commissioned between 2019*

*** Storage cost is calculated as a weighted average of 3 Storage power plants with capacities of 5405 MW (Sankosh Hydro Plant 2585 MW, Bunakha Reservoir Hydro Plant 180 MW and Kuri-Gongri Hydro Plant 2640 MW).*

A total of 17 hydropower plants with a total capacity of 15 GW have been individually modelled in the Bhutan electricity model based on the data from the National Transmission Grid Master Plan of Bhutan (June 2018) and the DHPS officials. These plants are expected to be commissioned from 2019 to 2040. The generation pattern from Run of River (ROR) hydropower plants is assumed to be similar to the generation pattern of existing hydropower plants (all are ROR based) in Bhutan as shown in Figure 4.2. For Storage based hydropower plants' annual limit on generation is assumed to be limited based on the annual Plant Load Factors (PLFs).

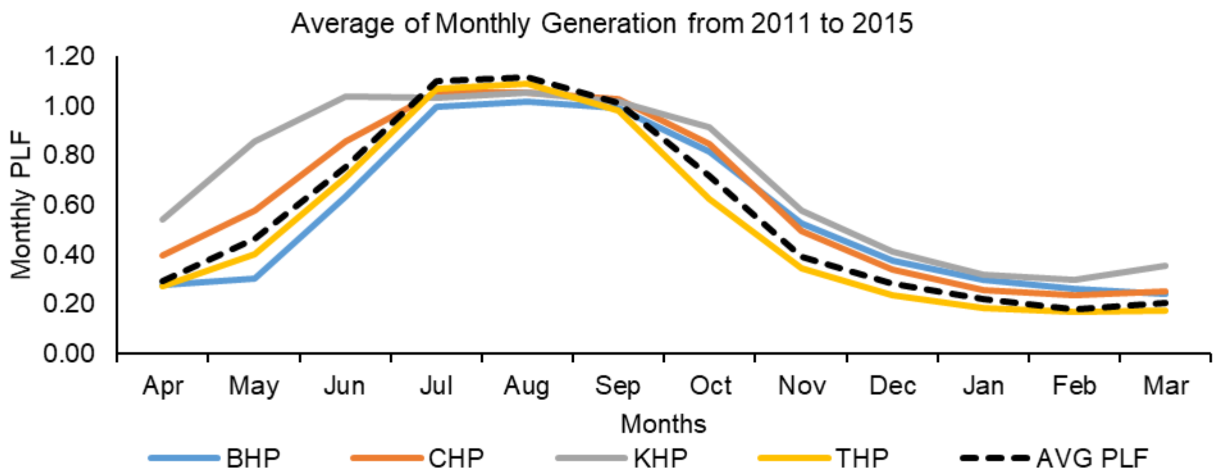


Figure 4.2: Monthly PLF of Existing Hydro Power Plants (Bhutan)

Data Source: Annual Reports of Druk Green Power Corporation, Bhutan

The losses at transmission and distribution sides are assumed to 1.3% and 4.83% (average of 2010 to 2017) throughout the modelling period (2015-50) respectively. On the investment side, capital expenditure on transmission and distribution is taken as a ratio of generation, transmission, and distribution which is assumed to be 2: 0.5: 0.5 based on discussion with DHPS officials. The O&M per year is assumed to be 1% and 3% of capital expenditure for transmission and distribution assets as per the Bhutan Electricity Authority (BEA) cost benchmark. The useful life of the transmission and distribution assets is assumed to be 25 years with a transmission system availability of 98% and distribution system availability of 95%.

4.2 Nepal

The long-term electricity demand projection for the Nepal power system is available from Nepal Electricity Authority (NEA) and Water and Energy Commission Secretariat (WECS) as shown in Figure 4.3. For our analysis, we have used the WECS-BAU scenario demand projection that considers electricity demand to reach 43,017 GWh by 2040 witnessing a CAGR of 10 percent. The electricity demand for 2040 to 2050 for the Nepal electricity model is projected based on demand growth in the terminal years reaching 89,969 GWh by 2050.

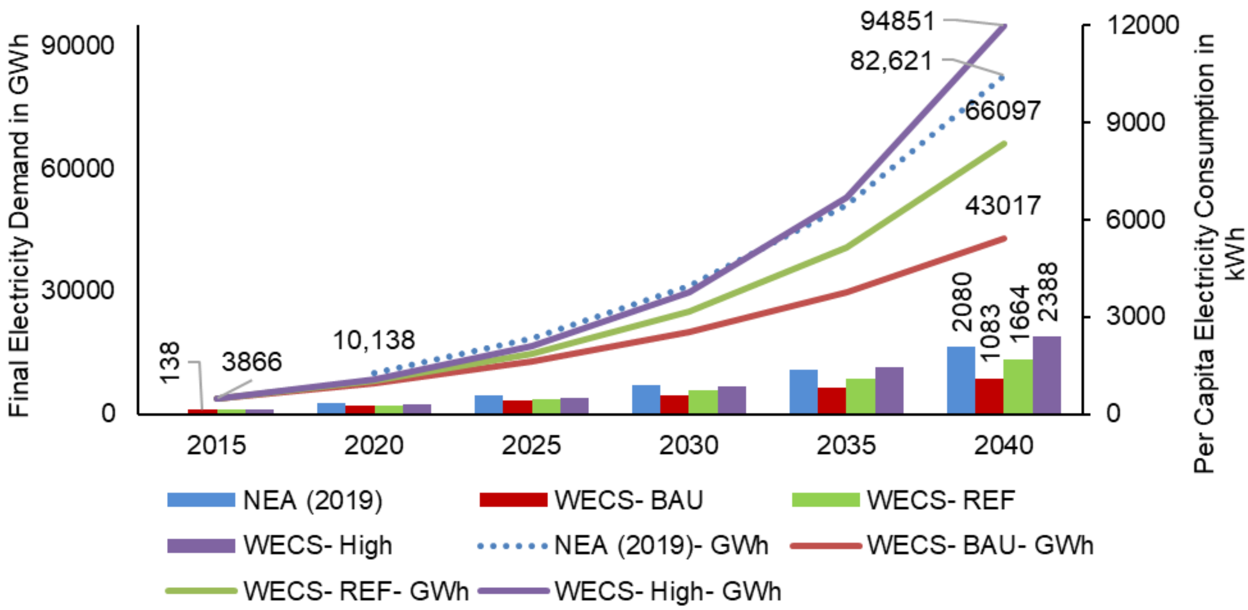


Figure 4.3: Electricity Demand Projection- Nepal

Data Source: WECS and NEA

The potential technologies for the future expansion of the Nepal power system include the following: hydro (run of the river [ROR], pondage ROR (PROR) having storage for a day, and storage plants having seasonal storage), solar PV, wind on shore, and thermal plants based on oil products. Table 4.2 presents the technical and economic data related to these technologies. The total hydropower potential is taken as 42 GW for the Nepal electricity model. The solar PV and Wind (Onshore) potential is taken as 2.1 GW and 0.4 GW respectively.

Table 4.2 Assumptions on Technical and Economic Performance of Future Technology Options (Nepal)

	Hydropower Plant			**Solar PV**
Technology Data	ROR	Pondage ROR	STG	PV-W/O STG
Availability factor	0.66	0.55	0.41	0.18
Operational lifetime (Year)	40	40	40	25
Economic Data				
Capital cost ($/kW)	1602	1562	2025	Section 4.5
O&M cost ($/kW/yr)	48	47	51	Section 4.5

A major part of planned and proposed upcoming power plants in Nepal is modelled based on information provided in the White Paper on Energy published by the Ministry of Energy, Water and Resources (MEWR), Nepal on 8 May 2018. A total of 33 hydropower plants of NEA and NEA's Subsidiary with cumulated capacity of 11 GW has been modelled in the Nepal electricity model. From IPPs, it is expected they will add a total of 2.8 GW between July 2018 to 2025. Apart from this, three export oriented and one multipurpose hydropower plant (Nepal's share in Pancheshwar Multi-Purpose Project) has also been modelled. These hydro capacities will be commissioned between 2019 to 2030. In addition to hydro, solar capacity of 0.5 GW has also been modelled which will be commissioned between 2019 to 2024. The total mode wise planned and proposed capacity addition as per various government plans from 2019 to 2030 is provided in Table 4.4.

Table 4.4 Mode wise Planned & Proposed Capacity addition during 2019 to 2030

Period	ROR (in MW)	PROR (in MW)	Storage (in MW)	Solar (in MW)	Total (in MW)
2019-2030	4,728	4,632	10,081	525	19,966

Source: Compiled by the Author from various Country Reports

The generation availability from Hydropower plants such as Run of River (ROR), Pondage ROR, and Storage hydropower plants is assumed to be similar to the generation pattern of existing hydro power plants of NEA in Nepal as shown in Figure 4.4. For Storage based hydropower plants annual limit on generation pattern is assumed based on the annual PLFs. Similar to hydro, solar and wind power plants are also provided hourly generation patterns as shown in Figure 4.4

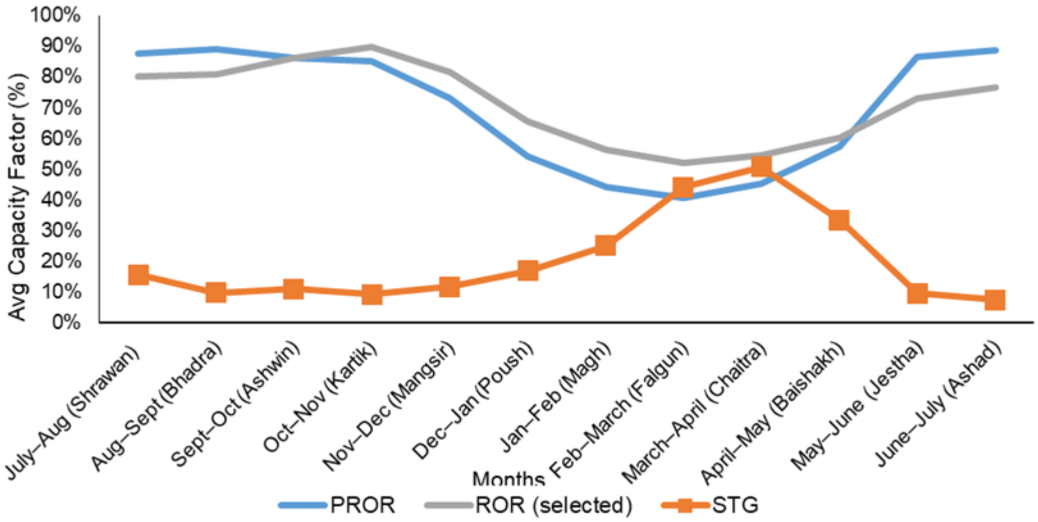


Figure 4.4 Monthly PLF of NEA's Existing Hydro Power Plants (Nepal)

*Selected ROR includes plant with Annual PLF greater than 50%

Data Source: Annual Reports of Nepal Electricity Authority, Nepal

The current losses at transmission and distribution side in Nepal are 4% and 11% respectively for the year 2018-19 (Annual Report, NEA). Based on discussions with various stakeholders in Nepal, we have assumed that the transmission and distribution losses will reduce to 4% and 6% by 2030 respectively and remain the same thereafter for Nepal electricity Model. On the investment side, capital expenditure on transmission and distribution is taken as a ratio of generation, transmission and distribution which is assumed to be 2: 1: 1. The O&M per year is assumed to be 1% and 3% of the capital expenditure for transmission and distribution assets. The useful life of the transmission and distribution assets is assumed to be 25 years with a transmission system availability of 98% and distribution system availability of 95%. Nepal is expected to continue to import fuels (petroleum products) for power generation from India.

4.3 Bangladesh

The long-term electricity demand projection for Bangladesh is undertaken on a periodic basis by the Power Division of Bangladesh. As per the recent 'Revisiting Power System Master Plan (PSMP) 2016' document published in November 2018 by the Power Division of Bangladesh, the forecasted electricity demand (generation end) will be 473 TWh (with peak demand of 82 GW), 446 TWh (with peak demand of 77 GW) and 416 TWh (with peak demand of 72 GW) by 2041 under the High, Base and Low scenario respectively without considering the energy efficiency measures. All the assumed scenario in the document, assumes similar GDP growth (8- 10% in the initial years) except for slightly higher growth in High scenario compared to other scenarios. For the IRADe's Bangladesh electricity model, we have assumed the Base case and projected the electricity demand up to year 2050 with growth rate of 6 percent per annum as assumed in the Base case between 2035 to 2040. The electricity demand by 2050 under the Base case will be 655 TWh.

On the generation side, a number of power generation technologies fuelled by domestic and imported fuels is assumed for the future expansion of the Bangladesh power system. This includes supercritical and ultra-supercritical coal power plants, combined cycle and open cycle gas power plants, nuclear, wind, solar PV and biomass. Technical and costs assumptions made on these technologies are shown in Table 4.5.

Table 4.5 Technical and Economic Assumptions for Power Generation Technologies

Parameter/Tech	Gas (CC)	Gas (OC)	Oil	Dual Fuel	Nuclear	Coal (Sub)	Coal (SC)	Coal (USC)	Wind	Solar PV	Bio Mass
Technology Data											
Fuel Type	Gas	Gas	Oil	Gas and Oil	Uranium	Coal	Coal	Coal			Rice Husk
Net Thermal Efficiency	0.57	0.38	0.35	Gas - 0.45 Oil - 0.43	0.35	0.35	0.37	0.43			0.30
Specific fuel consumption*	0.15 (cubic m/kWh)	0.22 (cubic m/kWh)	0.23 (kg/kWh)			0.41 (kg/kWh)	0.39 (kg/kWh)	0.33 (kg/kWh)			0.83 (kg/kWh)
Annual Availability Factor	<.85	<.90	<.80	<.85	<.90	<.80	<.80	<.80	<.17	<.18	<.60
Operational Lifetime (Year)	25	20	20	25	60	30	30	30	25	25	20
Construction Period (Year)	3	2	2	3	8	4	5	5	2	2	2
Economic Data											
Overnight Cost ($/kW)	667	899	899	667	5000	1038	1038	1400	Provided in Section 4.5		2059
Fixed O&M Cost ($/kW/year)	30	30	30	30	78	24	25	39			125

Data Source: Das, et al., 2018, "Bangladesh power supply scenarios on renewables and electricity import." Energy, Volume 155, 15 July 2018, Pages 651-667

*Assuming GCV value of Imported and Domestic gas as 10350 Kcal/kg, Imported Coal as 6000 Kcal/kg and rice husk as 3450 Kcal/kg

As per the Bangladesh Power Development Board (BPDB) Annual report of 2019, about 18 GW of capacities will be added to the power generation sector of Bangladesh between 2019 to 2023. The 18 GW capacity addition between 2019 to 2023 will include 6.8 GW of coal (38%), 4.9 GW of gas (28%), 2.8 GW of Oil (16%), 1.4 GW of Multi fuel (8%), and 1.8 GW of Imported Electricity (10%) which has been incorporated into the model. For Coal capacity addition, we have assumed the capacity addition from BPDB and other upcoming coal power plants that are in various stages of development (under construction and planning). A total of 12 coal power plants have been considered and their type of capacity split assumed for Bangladesh electricity model is provided in Table 4.7. No new subcritical power plants are assumed to be built after 2018. In addition to this, the total electricity generation from coal plants is assumed to be capped at 35% of available electricity by 2040 as assumed in Revisiting PSMP 2016.

Table 4.7 Expected Coal Based Capacity Addition in Bangladesh

Capacity Addition from Coal Power Plants				
Technology	**Status**	**Period**		
		2018-22	**2023-2027**	**2028-2032**
Sub-Critical	Commissioned	274	-	-
Super-Critical	Under Construction	1320	307	
Ultra Super Critical	Under Construction	1320	4,540	
	Planning		1,320	2,900

Data Source: PSMP 2016, BPDB Annual Report, CPGCBL Website and Annual Report

According to the Government plan, two units of 2,400 (2×1,200) MW Rooppur nuclear power plant will come into operation by 2025-2026. For Nuclear capacity addition, the capacity targets in the model are kept bounded as per the capacity addition with the high case of “Revisiting PSMP 2016”- Nov 2018. Hence, the maximum possible capacity addition from nuclear by 2041 will be 6.7 GW (Revisiting PSMP 2016). Thereafter, the maximum capacity bound for nuclear is increased at a CAGR of 7 percent based on the growth rate observed between 2035 to 2041 in high case of “Revisiting PSMP 2016”. In addition to this, for hydro capacity addition, no new hydro capacity addition has been modelled except from the existing 230 MW Katpai Hydropower plant. The seasonal availability of the existing 230 MW reservoir based Katpai Hydropower plant is provided in Figure 4.5.

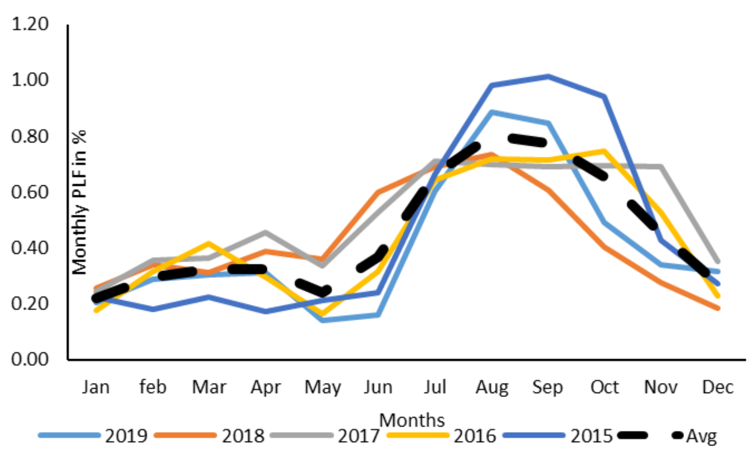
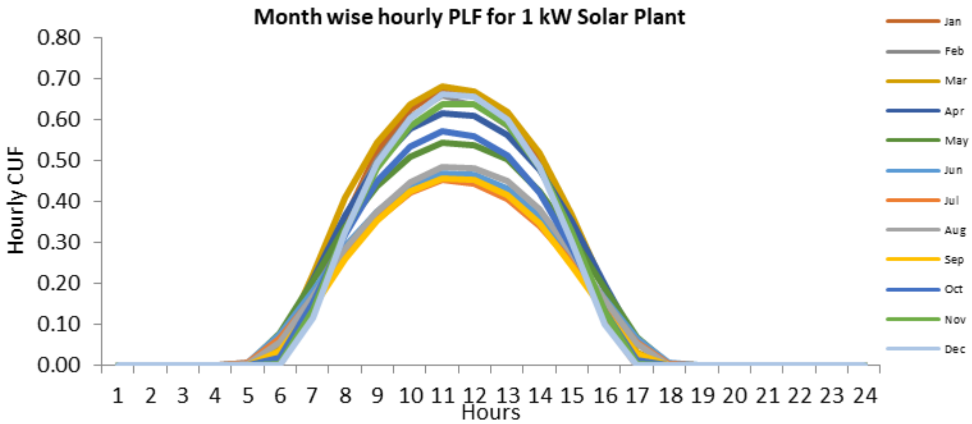


Figure 4.5 Monthly PLF of 230 MW Katpai Hydropower plant, Bangladesh

Data source: Monthly Report, Power Grid Corporation of Bangladesh

Solar and wind capacity addition in the model is limited by the resource potential of 2680 MW and 637 MW as per the SREDA-World Bank "Scaling Up Renewable Energy in Low Income Countries (SREP) Investment Plan for Bangladesh" report published in October 2015. The hourly behaviour for solar and wind power plants assumed for the Bangladesh electricity model is provided in Figure 4.6.



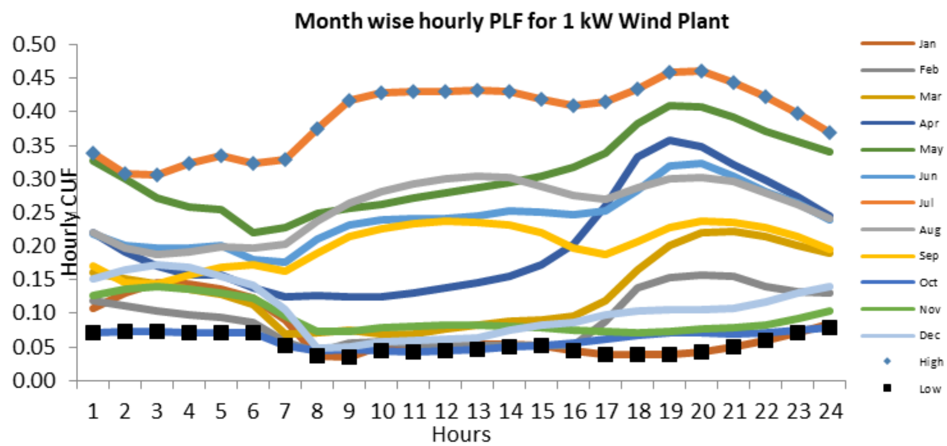


Figure 4.6 Solar and wind power plant hourly variations for Bangladesh

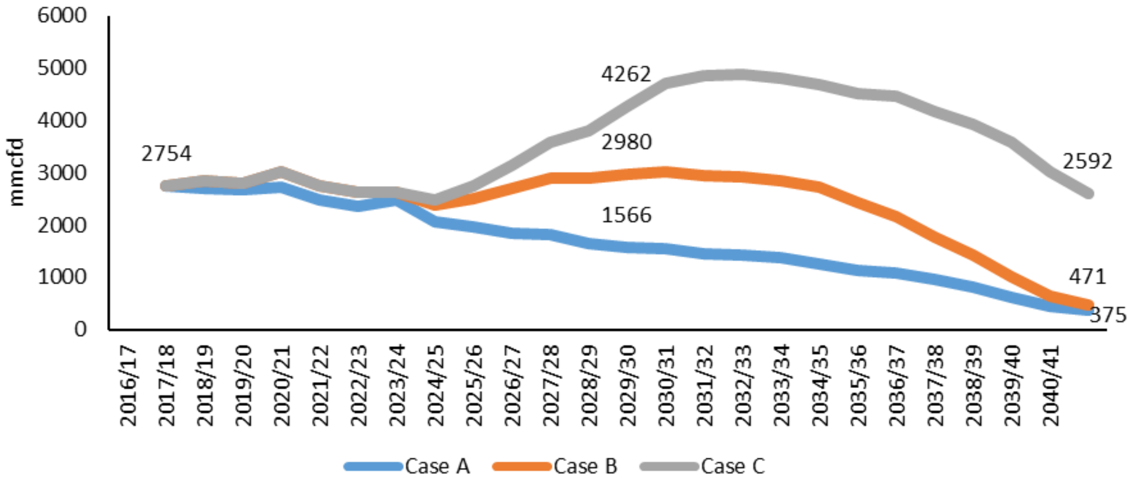
Data source: Renewables Ninja dataset

The availability of domestic natural gas for Bangladesh electricity model has been limited as per the Case B[2] of the Gas Master Plan 2018 of Bangladesh and for coal as per the Base Case of PSMP 2016. The production of domestic natural gas and coal is provided in Figure 4.7. From the available domestic natural gas and coal, the power sector will receive 41 percent and 67 percent respectively based on past year average sectoral

[2] Case B assumes – Proven, Probable and Possible (3P) Reserves with 6.4 tcf yet to find contribution

consumption share. The assumed domestic and imported natural gas and coal price for the Bangladesh electricity model are provided in section 4.7.

Domestic Gas Supply from Gas Master Plan 2017



Range of domestic coal production considered from PSMP 2016

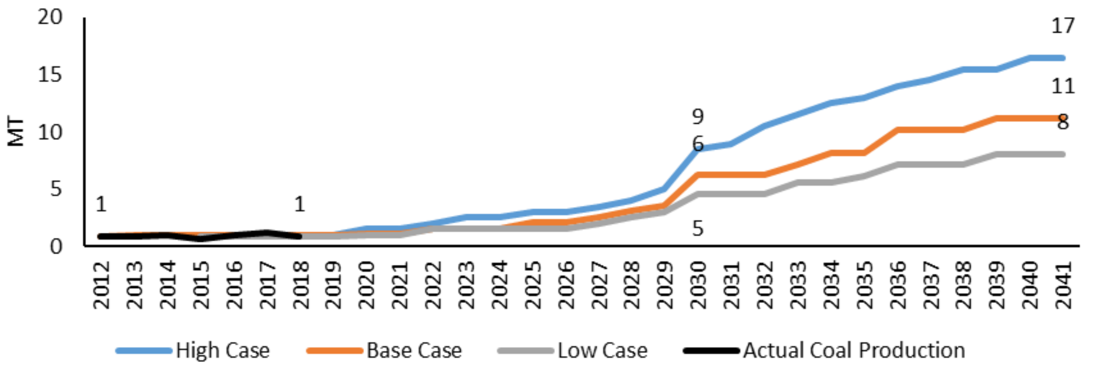


Figure 4.7 Production forecast of domestic natural gas and coal for Bangladesh

Data source: Gas Sector Master Plan 2017 and PSMP 2016

The current losses at transmission and distribution side in Bangladesh are 3.2 percent and 9 percent respectively for years 2018-19 (BPDB, 2020). As per the Revisiting PSMP 2016, the transmission and distribution losses will reduce to 10 percent by 2028 and will remain the same thereafter. We have assumed the same decline keeping the transmission loss at 3 percent throughout the model horizon. On the investment side, the CAPEX cost for new transmission and distribution assets has been assumed as 319 and 363 USD per kW respectively. The O&M per year is assumed to be 1% and 3% for capital expenditure for transmission and distribution assets. The useful life of the transmission and distribution assets is assumed to be 25 years with transmission system availability of 98% and distribution system availability of 95%.

4.4 India

The long-term electricity demand projection for India is undertaken by the Central Electricity Authority of India (CEA) and published at five-year intervals. The electricity demand for India's electricity model is taken from the recent 19th Electric Power Survey (EPS) of CEA. As per the report, the electricity consumption demand will grow at a CAGR of 5 percent from 2017 to 2037 and will reach 2672 TWh with a peak demand of 448 GW by 2037. For IRADe's India electricity model, we have projected the electricity demand up to year 2050 from 2037 at a growth rate of 4 percent as observed between 2032 to 2037 in the 19th EPS report. The projected electricity demand (at consumption end) by 2050 will be 4471 TWh. For electricity generation and expansion, several existing and upcoming power generation technologies have been considered in the India electricity model. This includes supercritical and ultra-supercritical coal power plants, combined cycle, and open cycle gas power plants, nuclear, wind, solar PV, biomass, and so on. Technical and cost assumptions made on these technologies are shown in Table 4.8.

Table 4.8: Technical and Economic Assumptions for Power Generation Technologies for India

	Coal (Sub)	Coal (SC)	Coal (USC)	Gas (OC)	Gas (CC)	Nuclear (LWR)	Nuclear (PHWR)	Oil	Hydro	Solar PV	Solar CSP	Wind-on Shore	Wind off-Shore	Biomass	SHP
Technology Data															
Net Thermal Efficiency	0.33	0.35	0.41	0.29	0.42			0.29						0.26	
Fuel Type	Domestic & Imported Coal			Domestic & Imported Gas				HSD/ FO						Biomass/ Bagasse	
Annual Availability Factor	< 0.8	< 0.8	< 0.8	< 0.8	< 0.8	< 0.8	< 0.8	< 0.8	0.39	0.20	0.18	0.25	0.33-0.37	0.30	0.38
Specific fuel consumption (Domestic fuel)	0.71 (kg/kWh)	0.66 (kg/kWh)	0.56 (kg/kWh)	0.28 (cubic m/kWh)	0.20 (cubic m/kWh)			0.28 (kg/kWh)						1.05 (kg/kWh)	
Specific fuel consumption (Imported fuel)	0.44 (kg/kWh)	0.40 (kg/kWh)	0.35 (kg/kWh)												
Operational Lifetime (Year)	25	25	25	25	25	30	30	25	35	25	25	25	25	20	35
Construction Period (Year)	4	4	4	2	2	6	6	2	8	0.5		1.5		3	5
Economic Data															
Overnight Cost ($/kW)	1012	1118	1291	530	620	4500	1778	885	1667	Cost decline in Section 4.5				812	1083
Fixed O&M Cost ($/kW/year)	23	26	39	11	25	112	44	35	42					16	27

*Assuming GCV value of Imported and Domestic gas as 10350 Kcal/kg, Imported Coal as 6000 Kcal/kg, Domestic Coal as 3700 Kcal/kg and Biomass as 3100 Kcal/kg

(Data Source: Central Electricity Authority, Central Electricity Regulatory Commission & NITI Aayog)

For coal capacity addition, no new sub-critical coal capacity addition has been considered after 2017 except for those, which are already under construction. Similarly, capacity addition for Super Critical coal power plants has been considered as per the latest CEA's National Electricity plan of 2018. In addition to this, Ultra Super Critical coal power plants capacity addition is provided as an option to the model from 2022 onwards. Furthermore, the retirement of 48 GW of coal capacity by 2027 has been modelled as per CEA's National Electricity plan of 2018. For Nuclear and Hydropower plant capacity addition, the targets by 2027 has been considered as per the CEA's National Electricity plan of 2018. In addition, the total capacity addition for hydro is limited by its potential of 145 GW. The monthly capacity factor of hydro capacities is modelled based on the average monthly hydro capacity factor from 2011 to 2016 as provided in Figure 4. 9. As observed in the figure, the typical high generation months for hydro capacities are from July to October.

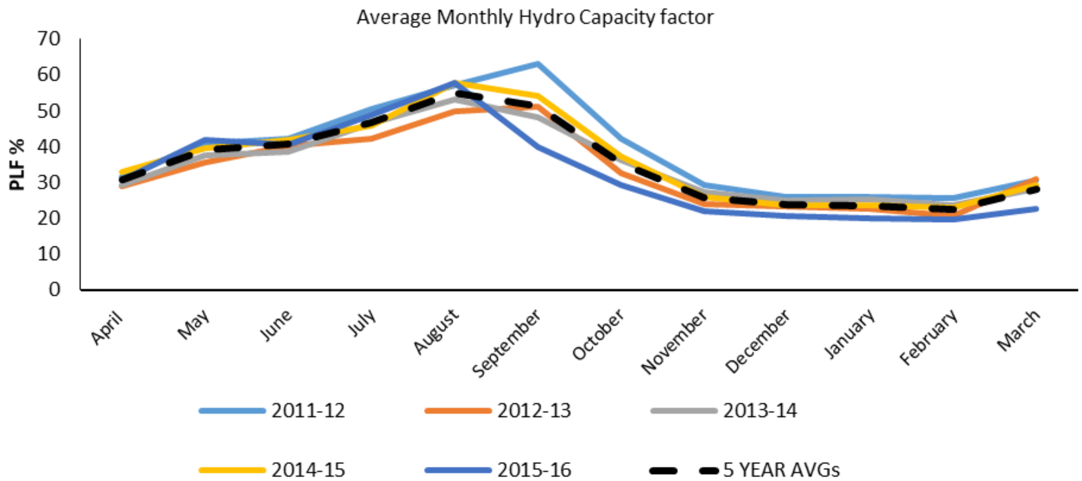


Figure 4.9: Monthly Hydro power plant capacity factor *(Data Source: Hydro Performance Review, CEA, India)*

The potential for Solar PV and Wind-on Shore capacity is assumed as 749 GW (assuming 3% land availability) and 302 GW (at 100-meter hub height) as per MNRE Annual reports. In addition to wind-onshore, the model also assumed the possibility to add around 251 GW of wind-offshore installed capacity by 2050 in addition to wind-onshore capacities. The potential for wind-offshore capacities is assumed based on the highest capacity assumption as taken in the NITI Aayog's Indian Energy Security Scenario 2047 calculator for wind offshore capacity addition. The hourly behaviour for solar and wind power plants assumed for the India electricity model is provided in Figures 4.9 and Figure 4.10 respectively.

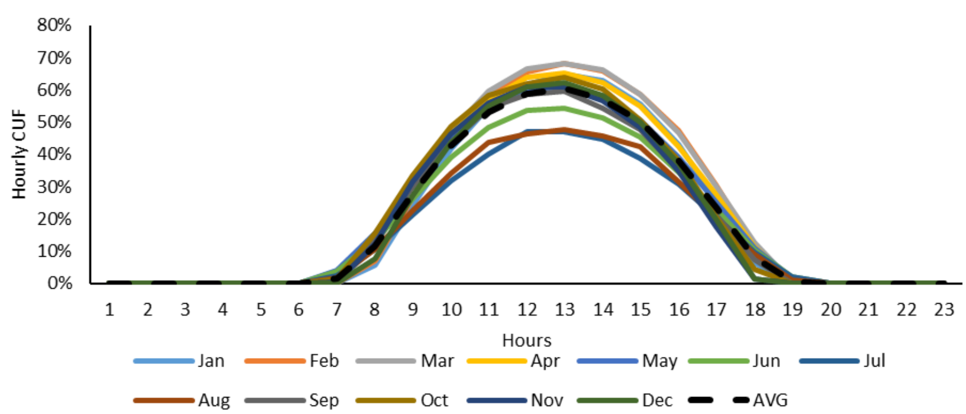


Figure 4.10 Solar power plants hourly variations for India (*Data source: PV watt calculator, NREL)*

* AVG Solar PLF for All India (considering 5 locations- Jodhpur, Gandhinagar, Bhopal, Hyderabad, Chennai)

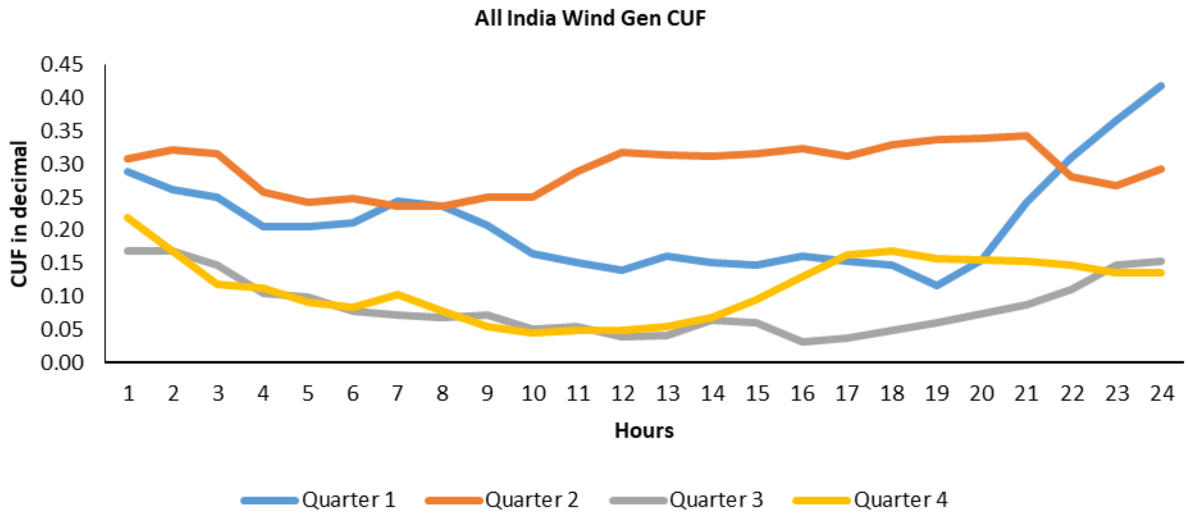


Figure 4.11: Wind Power Plants Hourly variations for India *(Data source: Draft National Electricity Plan- Vol 2-Transmission, CEA)*

The Government of India targets to increase the domestic coal production of India from 729 MT[3] in 2019 to a minimum of 1.5 BT[4] per annum by 2030. For forecasting domestic coal production, the target of 1.5 BT per annum by 2030 is considered, and thereafter the increase in coal production is at a CAGR of 7 percent as observed from 2019 to 2030. Whereas, the lignite production is assumed to increase at a CAGR of 1 percent as observed from 2012 to 2019. Figure 4.12 provides the assumed coal and lignite forecast from 2020 to 2050. From the total coal production forecast for India, around 83% (average offtake of coal between 2012 to 2019[5]) is assumed to be available for the power sector.

[3] Provisional Coal Statistics, Coal Controller's Organisation, Ministry of Coal, Government of India

[4] Coal Vision 2030, Coal India Limited, India

[5] From Coal Directory, Coal Controller's Organisation, Ministry of Coal, Government of India

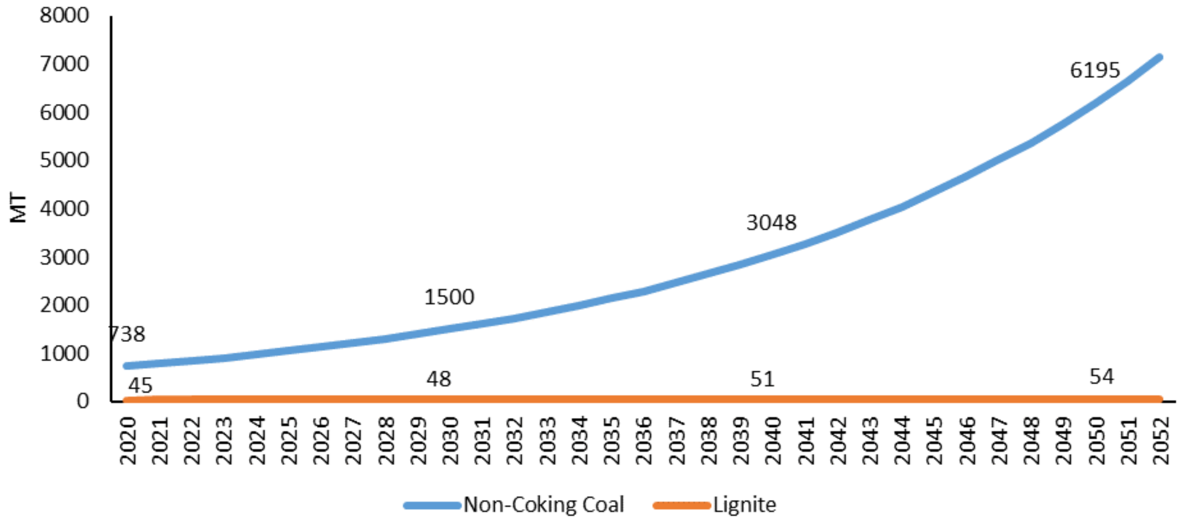


Figure 4.12 Domestic coal and lignite forecast from 2020 to 2050 *Source: Estimated by the Author*

Domestic gas production is assumed to grow at a CAGR of 3% as assumed in the "Vision 2030" Natural Gas Infrastructure in India by Petroleum and Natural Gas Regulatory Board. Figure 4.13 provides the actual and forecasted natural gas supply forecast. From the total domestic natural gas production forecast for India, around 32% (average domestic natural gas consumed by Indian power sector from 2013 to 2019[6]) is assumed to be available for the power sector. The Prices of imported and domestic fuels are provided in section 4.7.

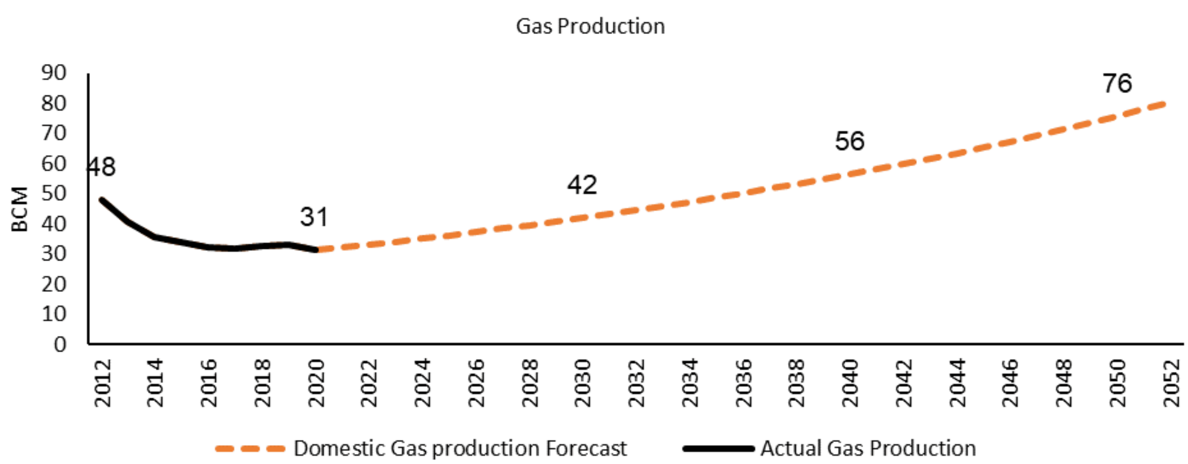


Figure 4.13 Domestic natural gas forecast from 2020 to 2050 (Source: Estimated by the Author)

The All-India T&D loss in the year 2018 was 21.15[7] percent. For forecasting reduction in T&D loss at all India levels, we have used the loss reduction trajectory as provided in the 19th EPS report of CEA. Hence, the T&D

[6] Thermal Review, Central Electricity Authority, Government of India

[7] Energy Statistics 2019, Central Statistics Office, Ministry of Statistics and Programme Implementation, Government of India

loss by 2050 will reduce to 10 percent which includes transmission loss of 4[8] percent. On investment side, the capex cost for new transmission and distribution asset has been assumed as 220 and 235 USD per kW[9] respectively. The O&M cost per year is assumed to be 1% and 3% for capital expenditure for transmission and distribution assets. The useful life of the transmission and distribution assets is assumed to be 25[10] years with transmission system availability of 98%[11] and distribution system availability of 95%[12].

4.5 Solar and Wind Power Plant Cost Decline

Capital cost for solar and wind projects varies across countries within the BBIN region due to different scales of operations, regulatory procedures, and other country specific costs. For our regional model, we have assumed that solar and wind installations will reach economies of scale leading to convergence of different costs in the region to a uniform cost.

It is expected that the solar cell efficiency increase can be a major element of cost reduction. The land requirement goes down correspondingly. Also, an integrated market for BBIN countries is likely to emerge, in which case the price of solar plants, excluding land and local labour costs will be harmonized and the benefits of economies of scale will be available to all. Nepal and Bhutan are concerned about their hydropower export potential when the cost of renewable goes down, it requires a significant fall in renewable prices. So this extreme assumption is relevant to address this problem.

Moreover, consultations with solar developers in India showed that the technological cost of Solar in Nepal and Bhutan are almost the same as in India. As a major section of solar plant components are being imported from China or Southeast Asian countries. Only regulatory costs and slight amount of transportation cost brings the difference in cost between Indian and Nepal/Bhutan or on average the cost increases because of the small size of the plants that are currently being built up in Nepal and Bhutan. On the basis of this comment, we supported the thought that the BBIN region as a whole will see cost decline because of the economies of scale achieved in India.

For Bangladesh, land can be an issue but the assumption of 30 GW solar is taken from the web-based stakeholder discussion wherein Bangladesh stakeholders shared that they are planning to make huge flood dams/dikes across rivers in Bangladesh (kind of infrastructure) to reduce flooding and on that raised land levels they will install solar panels.

Therefore, as shown in Figure 4.15 and Figure 4.16 we observe different starting CAPEX costs for solar PV and wind power plants in each country and converging to single cost according to HCD or LCD cost decline assumption by 2030. The cost for 2030 and 2050 is arrived at by analysis of long-term cost decline projections by international agencies such as NREL and IRENA.

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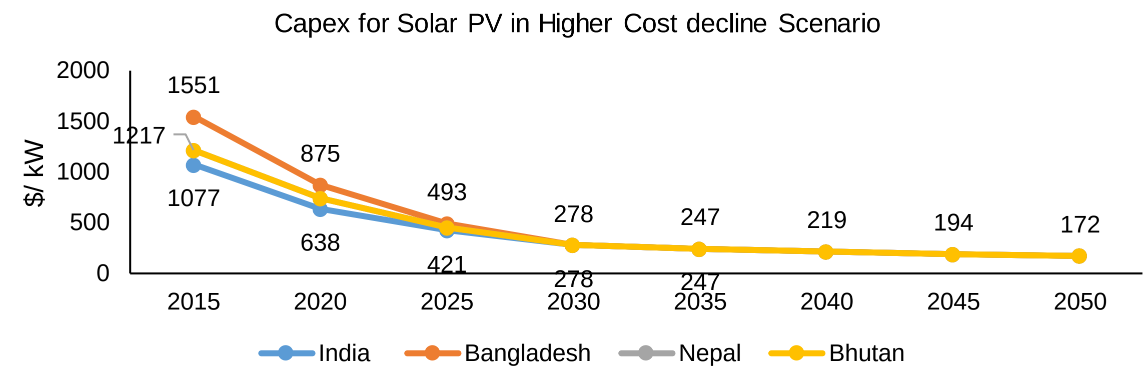
[8] The average transmission loss on all India basis was 4% from 2014 to 2017 as per CEA General Review report.

[9] Based on all India capital investment in Transmission and distribution asset during 12th plan period by utilities in India.

[10] Niti Aayog IESS 2047

[11] CERC Terms and Conditions of Tariff Regulations, 2019

[12] Model Regulations for Multi Year Distribution Tariff, Forum of Regulators, India



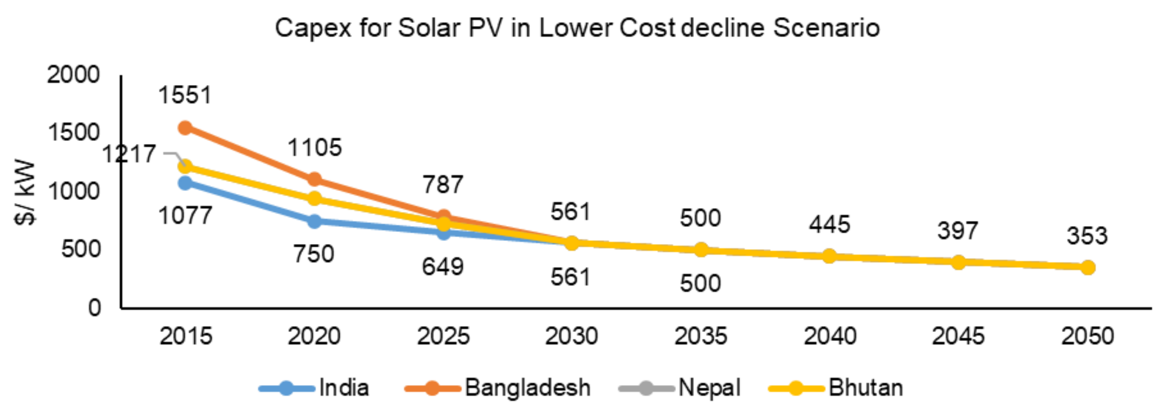
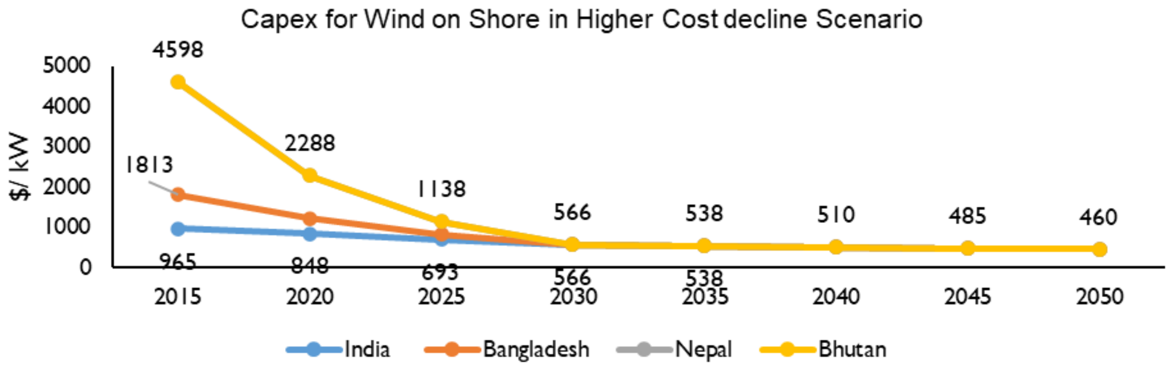


Figure 4.15 HCD and LCD case cost decline assumptions for solar PV in BBIN region*

**Since no cost data were available for Bhutan therefore the Nepal cost numbers were assumed for Bhutan power system.*



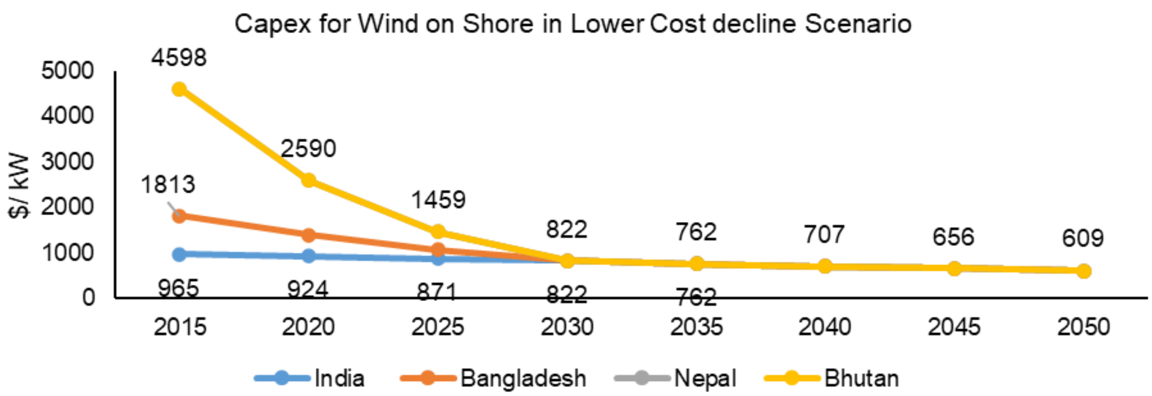


Figure 4.16 : HCD and LCD case cost decline assumptions for Wind On Shore in BBIN region*

**Since no cost data was available for the Nepal therefore the Bhutan cost numbers were assumed for Nepal power system.*

Based on the above assumption for the capital cost decline, the arrived cost decline in percentage for Solar PV and Wind On Shore is provided in Table 4.11 and Table 4.12.

Table 4.11 Capital cost decline assumptions for solar PV

		2015-30	2030-50	2015-50
Higher cost decline	India	74%	38%	84%
	Bangladesh	82%	38%	89%
	Nepal	77%	38%	86%
	Bhutan	77%	38%	86%
Lower cost decline	India	48%	37%	67%
	Bangladesh	64%	37%	77%
	Nepal	54%	37%	71%
	Bhutan	54%	37%	71%

Table 4.12 Capital cost decline assumptions for wind onshore

		2015-30	2030-50	2015-50
Higher cost decline	India	41%	19%	52%
	Bangladesh	69%	19%	75%
	Nepal	88%	19%	90%
	Bhutan	88%	19%	90%
Lower cost decline	India	15%	26%	37%
	Bangladesh	55%	26%	66%
	Nepal	82%	26%	87%
	Bhutan	82%	26%	87%

Annexure 5 contains the combined table for technical and economic assumptions for power generation technologies for Bangladesh, Bhutan, India and Nepal.

4.6 Battery Based Storage System

Apart from the conventional power generation sources, we have also modelled storage technologies in the electricity model of Bangladesh, Bhutan, India and Nepal based on Li-Ion based Battery Storage system. Table 4.10 and Table 4.11 provide the key technical characteristics of the Li-Ion storage system modelled.

Table 4.10 Technical Assumptions for Li-Ion Battery Energy Storage System

Technology Parameters	
Operational life time (Year)	15
Round – Trip Efficiency	85%
Depth of Discharge	90%

Data Source: Cost Projections for Utility-Scale Battery Storage, 2019, NREL and Electricity Storage and Renewables: Costs and Markets to 2030, IRENA

Table 4.11 Capital Cost Assumptions for Li-ion Battery Energy Storage System with different storage hours

Scenario	Assumed capex (% reduction) by 2050 compared to 2017	Capex* in USD per kW		O&M as a % of Capex
		2017	2050	
Storage 1 Hour				
LCD	30%	890	623	2.50%
HCD	79%	890	187	
Storage 2 Hour				
LCD	30%	1100	770	2.50%
HCD	79%	1100	231	
Storage 3 Hour				
LCD	30%	1310	917	2.50%

HCD	79%	1310	275	
Storage 4 Hour				
LCD	30%	1520	1064	2.50%
HCD	79%	1520	319	

* Capex includes both Energy/Storage and Power system cost *(Data Source: Cost Projections for Utility-Scale Battery Storage, 2019, NREL)*

4.7 Domestic and Imported Fuel Cost for India and Bangladesh

Prices of imported fuels are projected considering the Current Policy Scenario of the World Energy Model (WEM) published by the International Energy Agency (IEA). The international imported fuel price of coal and gas are then adjusted for transportation charges. The domestic coal and gas prices are taken from the official government documents and are assumed to remain constant at 2015 prices. Figure 4.17 provides fuel price projections considered in the India and Bangladesh electricity model.

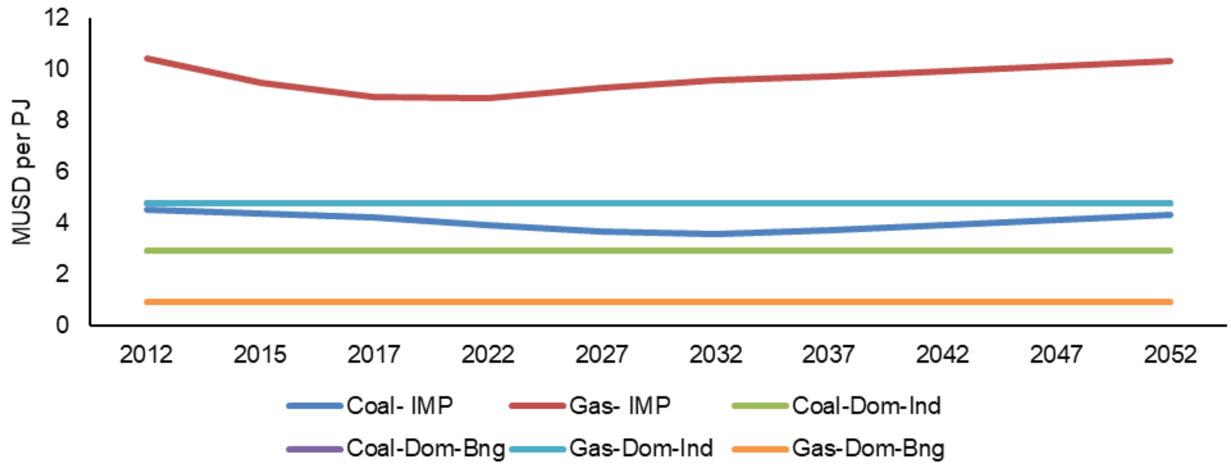


Figure 4.17 Domestic and Imported Fuel Cost for India and Bangladesh *(Source: IRADe Analysis and IEA)*

Chapter 5. Result and Analysis

For assessing the impact of cost decline of solar, wind and storage technologies on the regional cross border electricity trade within the BBIN region, we ran the IRADe's BBIN Electricity model under various scenarios as explained in Chapter 3. For our analysis, the results from different scenario runs are arranged into following sections:

- 5.1: Impact of RE&S cost decline on BBIN Trade
- 5.2: Impact of RE&S cost decline and Political Energy Security (PES) on BBIN Trade
- 5.3: Impact of RE&S cost decline and High RE potential (HiRePo) on BBIN trade
- 5.4: Impact of RE&S cost decline and carbon emission reduction scenario on BBIN Trade
- 5.5: Regional Implications of RE&S cost decline and other selected scenario on BBIN Trade
- 5.6: Impact on Hourly Generation for BBIN Countries under Cost Decline Scenarios

5.1 Impact of RE&S cost decline on BBIN trade

This section discusses the results and insights obtained from the different scenarios being run in the IRADe's BBIN Electricity model and measures the impact of RE&S cost decline on various parameters such as net trade, installed capacity, CO2 emissions and system costs. Table 5.1 provides the variations for scenario construction among the key parameters.

Table 5.1 : Key Variation for Scenario Construction

Scenario Abbreviation	RE & Storage cost decline	Trade Restriction	Political Energy Security Constraint of 20% on Energy imports	Higher RE Potential Considered	Carbon Emission Reduction
Base (Limiting Trade to 2017 volumes)	Lower	Yes	No	No	No
NC (No Cost Decline)	No Decline	No	No	No	No
HCD (Higher Cost Decline)	Higher	No	No	No	No

In the following sections, we will assess the impact of the above scenarios on individual countries within the in BBIN region. Further, for ease of understanding, we have clubbed the results for Bhutan and Nepal together as they represent hydropower exporting countries and on the other hand, we have clubbed results for India and Bangladesh as they represent power importers in the BBIN region.

Note on NC Scenario: The analysis shows that removal of trade restrictions would lead to a dramatic growth in CBET comparted to the Base scenario even in the NC scenario when there is no cost decline assumed for the RE&S technologies. However, in case of NC scenario, the increase in CBET is happening at the expense of higher coal utilisation and increased emissions in the region. It is to be noted that the CBET is already happening with increased market-based trade between the BBIN countries and is expected to lead to higher hydro capacities in Nepal and Bhutan due to higher regional demand. Hence, the question being tested with the help of the NC scenario, is whether the two hydro rich countries will be left with stranded assets if the cost of RE&S decline? will the level of trade predicted by the NC scenario would reduce or will it change the preference of hydro utilization in the region.

5.1.1 Key results for Bhutan and Nepal (Base vs Cost Decline Scenario)

a) Impact on Net Trade – Bhutan and Nepal

The cost decline for RE and storage technologies will have major implications on the volumes and flow of cross-border electricity trade among the countries within the BBIN region. However, for Bhutan and Nepal allowing trade between the countries in the region itself helps to further develop hydropower potential for regional trade. Whereas cost decline for RE and storage technologies additionally helps these two countries to further utilize there RE potential. In the Base case, as shown in Figure 5.1, where trade is limited to 2017 volumes, it could be observed that Bhutan is a net exporter of electricity in the years 2030 and 2050, although volumes are small due to scenario restrictions. However, with no trade restrictions and only cost decline assumptions for RE&S, for Bhutan there is more than 20 times increase in net export volumes with respect to the Base case as shown in Figure 5.1. In the case of the HCD scenario for 2030 and 2050, there is a further increase in exports compared to the NC scenario due to higher solar capacity installations in addition to full utilization of hydropower potential in Bhutan.

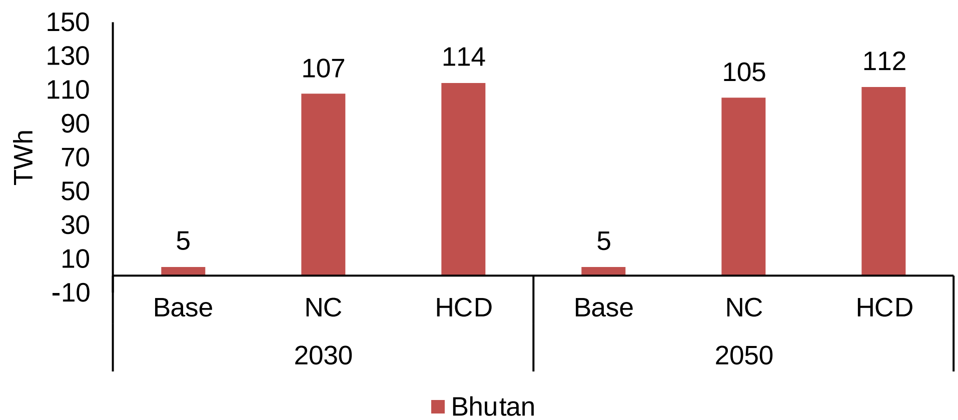


Figure 5.1 Net Trade* for Bhutan in 2030 and 2050 for Base, NC and HCD Scenario

** Net Trade = Export - Import*

Similar to Bhutan, the cost decline in RE&S will have an impact on Nepal's Net power trade (Net Trade = Export - Import) as well. Figure 5.2 indicates that in the Base scenario for 2050, Nepal remains a net importer. However, for the NC and HCD scenarios for 2030 and 2050, Nepal transitions from being a net importer to a net exporter of electricity. Compared to the NC scenario, under HCD scenario in 2050, net exports will fall slightly due to higher installation of storage-based hydropower in Nepal (for details refer Figure 5.6).

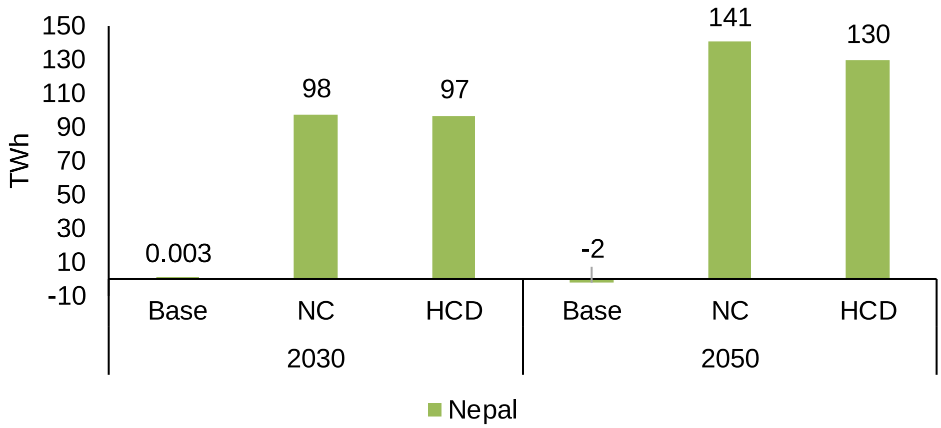


Figure 5.2 Net Trade* for Nepal in 2030 and 2050 for Base, NC and HCD Scenario

** Net Trade = Export - Import*

b) Impact on Installed Capacity– Bhutan and Nepal

The potential for power trade is highly impacted by the installed capacity established by the model within the BBIN region. Figure 5.3 shows that there is underutilisation of hydropower potential in Bhutan in the Base scenario. However, full hydropower potential of 27 GW is utilised in other two scenarios for Bhutan with installed hydro capacity of 27 GW in the years 2030 and 2050. In addition to this, full utilisation of 12 GW solar potential due to cost decline of RE&S in the HCD scenario by 2030 and 2050 is also observed for Bhutan.

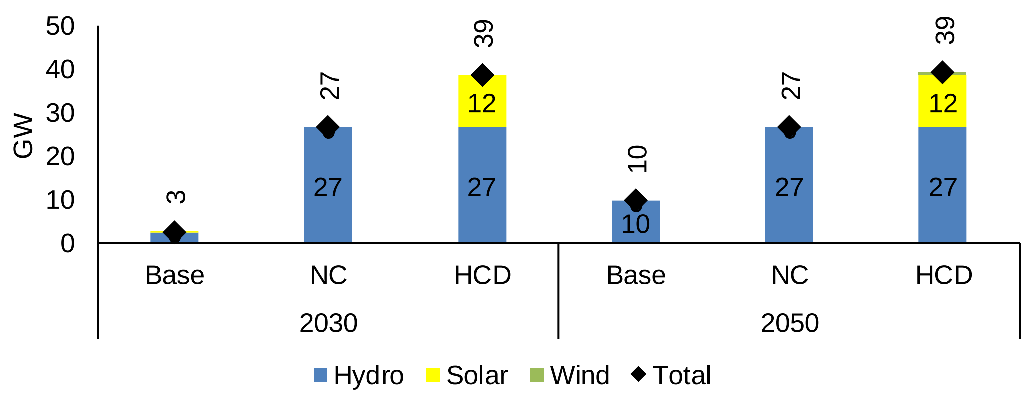


Figure 5.3 Installed Capacity mix for Bhutan in 2030 and 2050 for Base, NC and HCD Scenario

In the case of Nepal, Figure 5.4 shows the underutilisation of 42 GW of hydropower potential in Nepal for the Base scenario due to trade restrictions. However, with no trade restrictions in the other two scenarios, there is full hydropower potential utilisation in both NC and HCD scenarios with 42 GW of installed hydro capacity by 2050, while the solar potential is fully utilised only in the HCD scenario by 2050.

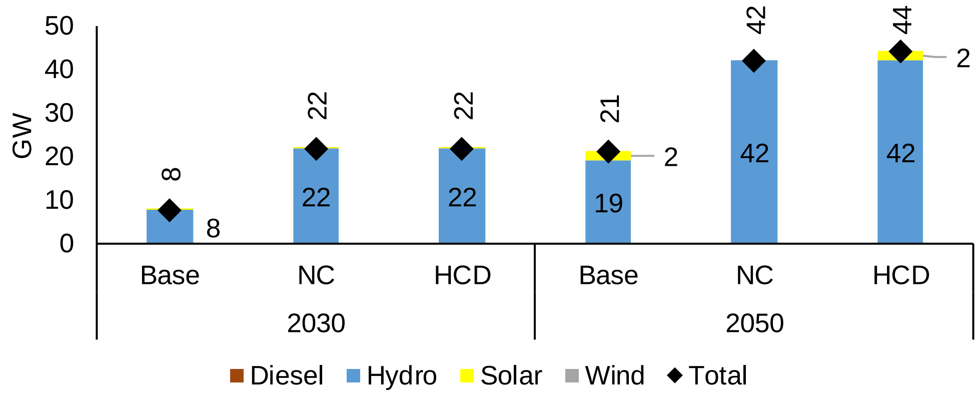


Figure 5.4 Installed Capacity mix for Nepal in 2030 and 2050 for Base, NC and HCD Scenario

c) Impact on type of Hydro Capacity selected– Bhutan and Nepal

Apart from the total installed capacity mix, the type of hydro capacity installed by the model within the hydropower exporting countries like Bhutan and Nepal is a critical element. Figure 5.5 shows that under the Base scenario, although total installed capacity requirements for Bhutan are reduced, it will require more storage capacity for meeting domestic demand as installation of a large percentage of storage hydro in total hydro capacity by 2050 is almost 90 percent. Whereas in NC scenario for 2030 and 2050, the share of storage based hydro capacity remains around 48 percent. However, almost all the hydro installed capacity is storage based on the HCD scenario for 2030 and 2050 due to higher installation of renewable energy in the BBIN region.

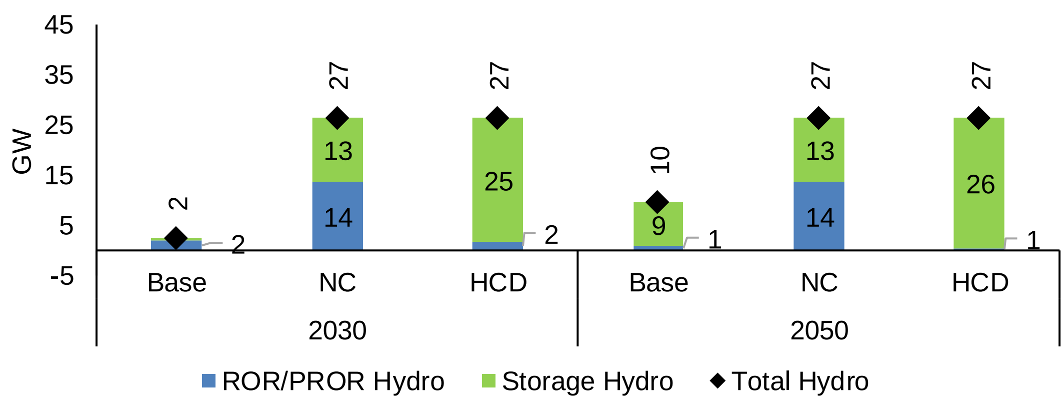


Figure 5.5 Installed Hydro Capacity mix for Bhutan in 2030 and 2050 for Base, NC and HCD Scenario

In the case of Nepal, Figure 5.6 shows that in 2050, Pondage run-of-river (PROR) is chosen over storage hydro or ROR hydro plants because in Nepal there is very high capex of storage hydro plants, which is almost twice the capex of a storage hydro plant in Bhutan. For Nepal, the capex for storage hydro was arrived by averaging cost number for more than 10 upcoming storage hydropower plants with average capacity of 550 MW. Whereas for Bhutan, the capex for storage hydro was arrived by averaging the cost of 3 upcoming hydro power plants with average capacity of 1800 MW. This major reason for lower cost number in Bhutan is availability of sites with higher capacity installation potential leading to higher economies of scale.

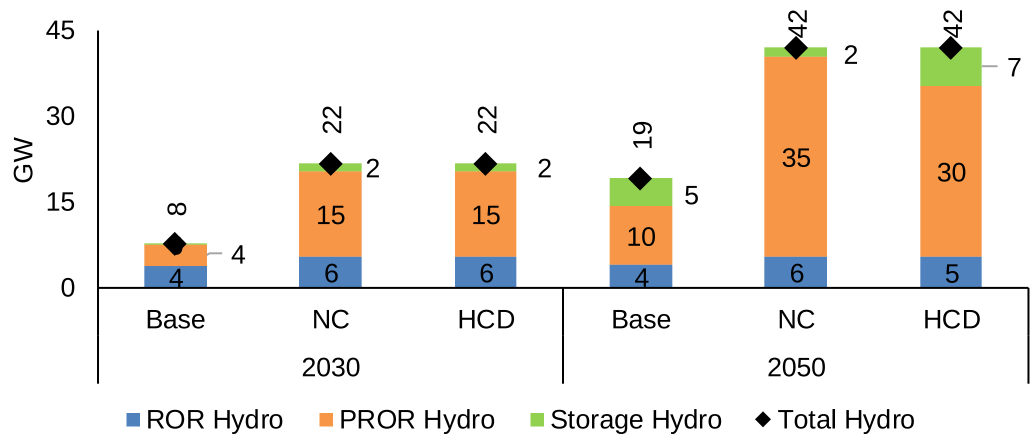


Figure 5.6 Installed Hydro Capacity mix for Nepal in 2030 and 2050 for Base, NC and HCD Scenario

5.1.2 Key results for Bangladesh and India (Base vs Cost Decline Scenario)

a) Impact on Net Trade – Bangladesh and India

Similar to Bhutan and Nepal, the cost decline in RE&S will have an impact on both Bangladesh and India's power systems. Figures 5.7 and 5.8 show that in the Base scenario for 2030 and 2050, there is no significant volume of trade for both countries due to trade restrictions. However, in the case of Bangladesh, it remains a net importer of power in 2030 and 2050 for all scenarios as shown in Figure 5.7. Further, in 2050, net imports by Bangladesh will rise drastically due to cheaper imports and limited domestic renewable potential. This leads to almost 93% of Bangladesh's electricity demand being met by power imports. For India, there is a shift from net importer to net exporter from 2030 to 2050 as shown in Figure 5.8 because of higher volume of exports to Bangladesh, as there are no trade restriction conditions under the NC and HCD scenario.

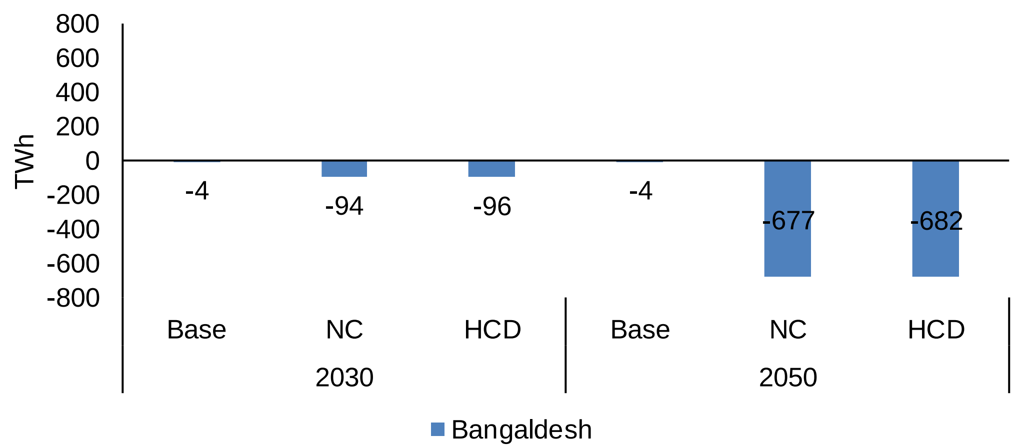


Figure 5.7 Net Trade* for Bangladesh in 2030 and 2050 for Base, NC and HCD Scenario

** Net Trade = Export - Import*

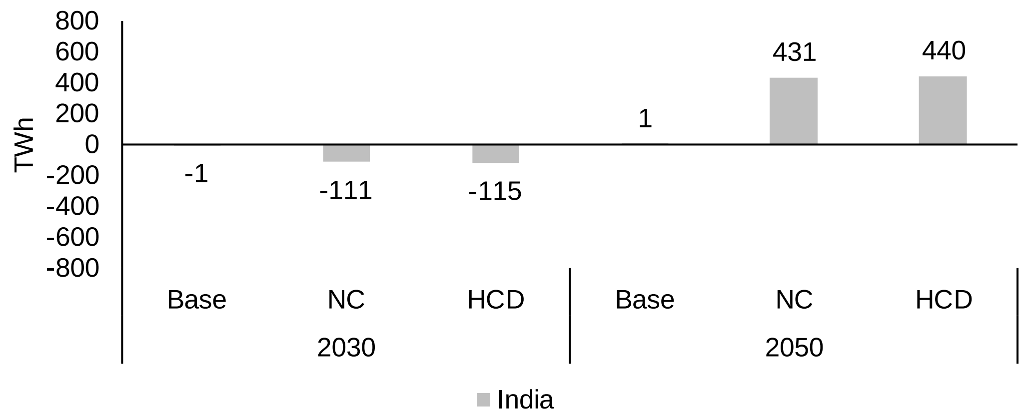


Figure 5.8 Net Trade* for India in 2030 and 2050 for Base, NC and HCD Scenario

** Net Trade = Export - Import*

b) Impact on Installed Capacity – Bangladesh and India

Under the Base scenario, with trade restrictions, Bangladesh's dependence on coal-based power will increase if no capacity mix or no emission-related constraints are introduced, as shown in Figure 5.9. Power import is a cheaper option than installing domestic coal or gas-based capacity in Bangladesh. As seen in Figure 5.9, even with a higher cost decline in renewable energy, imports from India and the BBIN region are cheaper than installing domestic capacity within Bangladesh. The scenarios in 2050 indicate a much lower installed capacity compared to 2030 because of higher dependence on power imports, i.e. more than 90 percent of demand is met through power imports. The possibility of solar and wind installation increasing is limited with RE potential numbers which is quite low.

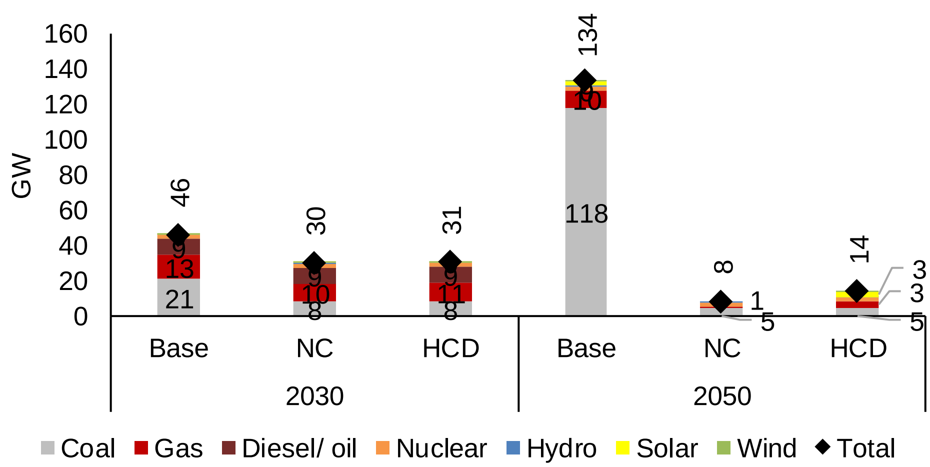


Figure 5.9 Installed Capacity mix for Bangladesh in 2030 and 2050 for Base, NC and HCD Scenario

Under the Base scenario, the generation mix is seen to be diverse in 2030 and 2050 for India due to lower cost reduction in RE&S as shown in Figure 5.10. However, the Government of India's RE target of installing 500 GW RE by 2030 is only met under the HCD scenario. This shows that for achieving higher RE targets, significant cost declines will be crucial. Further, by 2050, full wind potential (both onshore and offshore) utilisation is observed in all scenarios. On the other hand, full solar potential (mainly solar PV as solar CSP is not installed by the model) utilization is only observed in the HCD scenario by 2050. In addition to RE potential utilization and possibility of power imports, full hydro potential in India is seen to be utilized in all scenarios by 2050.

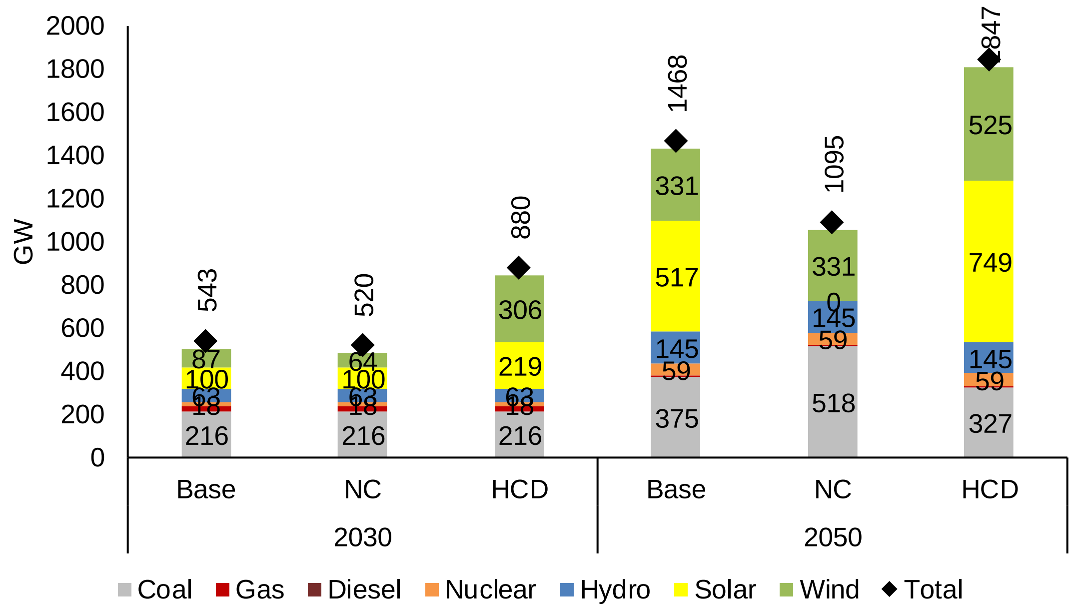


Figure 5.10 Installed Capacity mix for India in 2030 and 2050 for Base, NC and HCD Scenario

c) Impact on annual CO2 emissions – Bangladesh and India

The possibility of power trade in combination with RE&S cost decline will change the current capacity mix significantly, leading to decarbonisation of the system. This will lead to significant reduction in CO2 emissions from the power sector. As discussed above, in the Base scenario, the imports are restricted, which leads to higher coal-based capacity installation on the Bangladesh side, thus resulting in higher annual CO2 emissions from the Bangladesh power sector as shown in Figure 5.11. Further, in the NC and HCD scenario for Bangladesh, around 42% of demand is met by imports in the year 2030 and thus, this reduces domestic capacity installation and consequently, CO2 emissions. In the year 2050, 93% of demand is met by imports and thus, it greatly reduces domestic capacity installation and CO2 emissions. Reduction in annual CO2 emissions also reduces the CO2/kWh emissions as shown in Figure 5.12. The reduction in CO2 emissions on Bangladesh side will increase CO2 emissions on India side but at regional level overall CO2 emission reduces for further details refer section 5.5 (d).

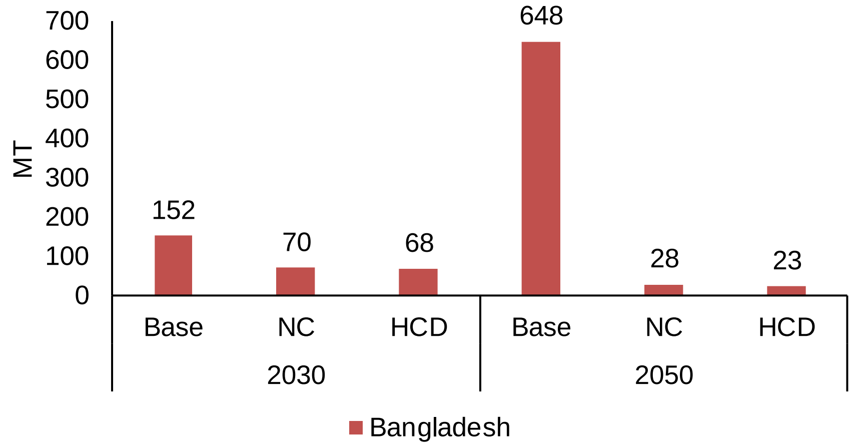


Figure 5.11 Annual CO2 emissions in the power sector in Bangladesh for Base, NC and HCD scenario

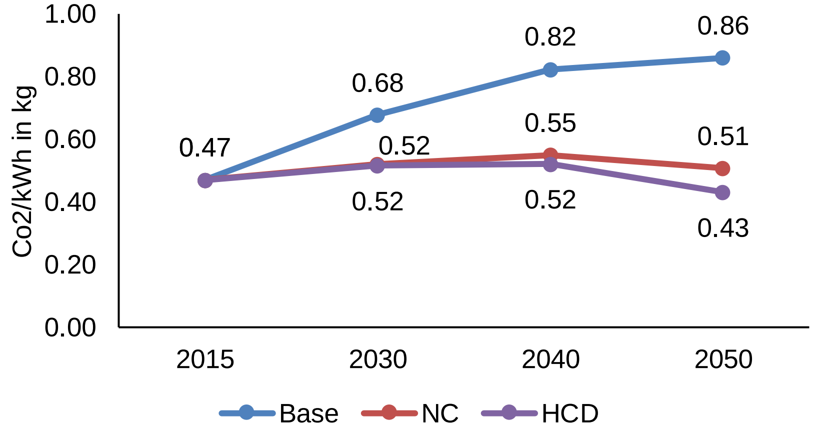


Figure 5.12 Annual CO2/kWh emissions in the power sector in Bangladesh for Base, NC and HCD Scenario

For India, the CO2 emissions are highest for the NC scenario in 2050 as shown in Figure 5.13 due to higher coal capacity installation, high power export and no cost decline assumed for RE&S, leading to lower installation of solar capacities. Whereas in the HCD scenario for 2050, there are lower CO2 emissions due to higher renewable and lower coal capacity installation. Reduction in annual CO2 emissions also reduces the CO2/kWh emissions as shown in Figure 5.14.

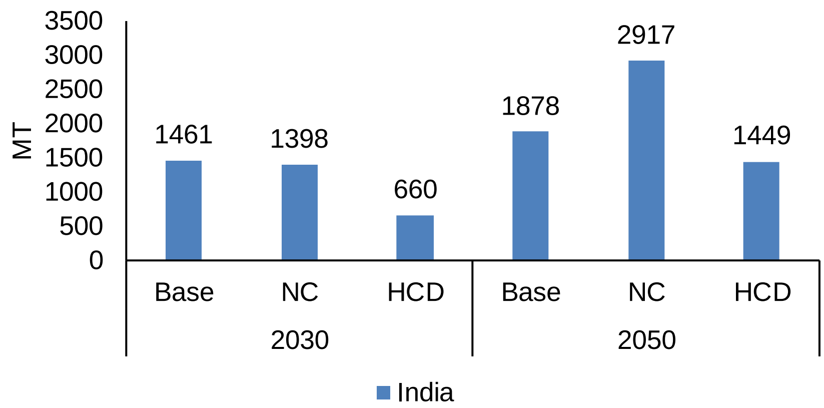


Figure 5.13 Annual CO2 emissions in the power sector in India for Base, NC and HCD case

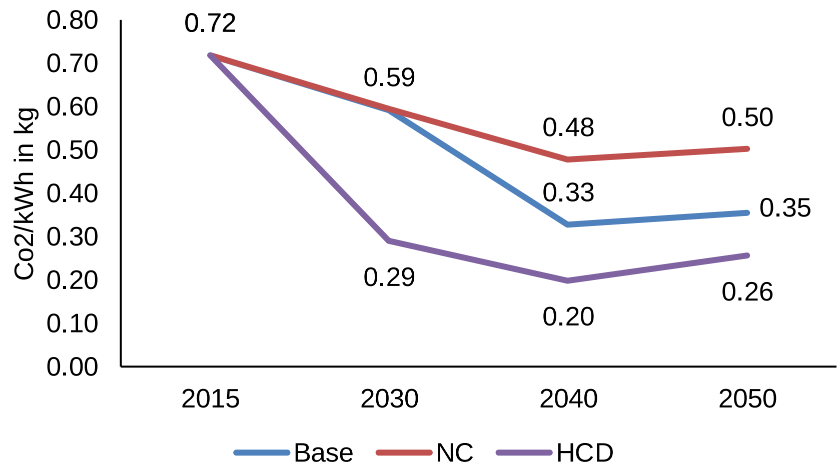


Figure 5.14 Annual CO2/kWh emissions in the power sector in India for Base, NC and HCD Scenario

5.1.3 Impact on Discounted System cost

This section studies the impact on discounted total system cost (objective function of the model) in billions USD at 2015 prices. The objective of the TIMES model is to minimize the total cost of the system. Therefore, the objective function includes total cost for each year, which includes elements such as capital cost, operation and maintenance cost, domestic and imported fuel cost, revenues from exports, etc. Further, all cost elements are appropriately discounted to a user-selected year in the model.

Table 5.2 shows the discounted system cost (Objective Function) in Billion USD in 2015 prices for BBIN countries and the region for Base, NC and HCD scenarios. It is to be observed that for major hydro exporting nations like Nepal and Bhutan, the increase in hydro capacity installation and higher revenues from electricity exports lead to lower system cost in the NC and HCD scenario with respect to the Base scenario over the model horizon from 2015 to 2050. The negative value for Nepal and Bhutan represents that the revenues from power exports were more than the total system total cost's, hence the cost is negative. For Nepal, the cost reduction in the HCD scenario is maximum compared to the Base with a potential of 120 percent in total cost reduction due to the possibility of trade and higher cost decline. Similarly, for Bhutan, the potential for cost reduction in the HCD scenario is more than 10 times the Base scenario.

For Bangladesh, the total system cost declines in both the NC and HCD scenarios are over the Base as there are no trade restrictions, resulting in a higher volume of imports from the region, thus saving costs on system installations. Similarly, for India, system cost reduces by 5 percent in the HCD scenario compared to the Base due to higher RE push into the system. However, in the case of NC scenario where there is no RE cost decline, the system installs more coal technology for domestic as well as for additional exports to Bangladesh, thus leading to an increase in overall system cost by 5.5 percent.

Table 5.2: Discounted System cost (Objective Function) in Billion USD in 2015 prices for BBIN countries and region in Base, NC and HCD Scenario

	BBIN Region	India	Bangladesh	Nepal	Bhutan
Base (Trade limited to 2017)	2714	2389	301	22	2
NC (No Cost Decline)	2759	2521	257	-4	-16
HCD (Higher Cost Decline)	2487	2272	239	-5	-20
Change in system cost over Base (negative represent % reduction and positive represent % increase over Base)					
NC (No Cost Decline)	2%	5.5%	-14%	-117%	-844%
HCD (Higher Cost Decline)	-8%	-5%	-20%	-120%	-1068%

The potential for revenues in 2050 from electricity export from Bhutan and Nepal can be as high as 5 and 6 billion USD at 2015 prices respectively, as shown in Table 5.3. Similarly, for India, the potential for revenues in 2050 from electricity export will be 21 and 15 billion USD at 2015 prices for NC and HCD scenarios respectively. For Bangladesh, the net trade revenues have negative net trade revenue due to higher dependence on imports from the BBIN region.

Table 5.3: Annual Average Marginal Net Trade Revenues in 2050 in Billion USD @ 2015 prices in Base, NC and HCD Scenario

(Net trade= Export – Imports)	India	Bangladesh	Nepal	Bhutan
Base (Trade limited to 2017)	-0.9	-0.5	-0.1	0.3
NC (No Cost Decline)	21	-71	6	5
HCD (Higher Cost Decline)	15	-71	6	5

5.1.4 Key Conclusions

The following are the key conclusions derived from the Base, NC and HCD scenarios:

For Bhutan and Nepal:

- **Trade:** With RE&S cos decline, both Nepal and Bhutan evolve as net exporters of power in the BBIN region. Bhutan's exports increase from 5 TWh in 2017 to 112 TWh of net exports by 2050 in the HCD scenario, which is a 20-time increase compared to the Base scenario. Similarly, Nepal from an importer of 2 TWh in 2017 emerges as a net exporter of 130 TWh by 2050 in the HCD scenario.
- **Capacity Installation:** The full hydropower potential of 27 GW in Bhutan and 42 GW in Nepal is utilised for cross-border electricity trade in all scenarios. With higher cost decline in RE&S, it further supports higher installation of renewable energy in both Bhutan and Nepal. In terms of hydro, flexible hydropower in the form of peaking run-of-river and storage hydro is preferred over run-of-river hydro capacity. This happens due to higher installation of renewable energy in the BBIN region, which attracts more hydro storage capacities in the region.
- **System Costs:** For Bhutan and Nepal, the capital cost requirement will increase to support higher hydro installation, but overall system cost will be reduced due to higher export earnings. For Bhutan, in the HCS scenario the system cost reduces by 10 times compared to the Base scenario. Whereas for Nepal, the system cost is reduced by 120 percent in the HCD compared to the Base scenario.

For Bangladesh and India:

- **Trade:** Bangladesh will be a net importer of power if there are no trade restrictions in place, as with no trade restrictions along with assumed RE&S costs decline, power import is the least costly option for Bangladesh. By 2050, more than 93 percent of demand is met through imports in the HCD scenario.
  India, from being a net importer of power in 2017, will emerge as a net exporter of power by 2050 with RE&S cost decline scenario. It imports power from Bhutan and Nepal and then exports it to Bangladesh.
- **Capacity Installation:** In Bangladesh, full solar potential (2.7 GW) and wind (0.6 GW) is utilised in the Base and HCD scenarios in 2050. The estimated solar and wind potential is quite old and it needs to be reassessed with cost decline and improved technology. The model choses coal-based capacity over electricity imports only when trade restrictions are put into place.
  In India, the full solar potential (749 GW) is utilised in the HCD scenario by 2050 and full wind potential (302 GW) is utilised in all scenarios by 2050. Apart from wind and solar, the full hydro potential of 145 GW is also utilized in all the scenario on the Indian side. The Government of India's target of 500 GW RE by 2030 is only met in the HCD scenario. This shows that for achieving higher RE targets, significant cost declines will be critical.
- **CO2 Reduction in Power Sector:** At country level, for Bangladesh, 97 percent of annual CO2 emission reduction is achieved in the HCD scenario compared to the Base by 2050 as 93 percent of the domestic demand is met through electricity imports. Whereas for India, 23 percent of the annual CO2 emission reduction is achieved in the HCD scenario compared to the Base in 2050 due to higher renewable and lower coal capacity installations.
- **System Costs:** For Bangladesh, the HCD scenario will help in achieving overall system cost reduction of 20 percent compared to the Base scenario due to higher volume of imports and lower domestically installed capacities. Whereas in India, the HCD scenario achieves overall system cost reduction of around 5 percent compared to the Base scenario.

5.2 Impact of RE&S cost decline and Political Energy Security (PES) on BBIN Trade

The scenarios discussed in the previous section show that electricity import from the BBIN region is a low-cost option for Bangladesh compared to domestic generation using imported fuel. However, owing to energy security and geo-politics in the region, electricity import dependence of 90% on other countries will not be politically accepted by any country in the region. Therefore, this scenario was constructed wherein the volume of annual power imports by Bangladesh, Nepal and Bhutan are restricted to 20 percent of their annual consumption demand for each year. This scenario will offer better insights into the implications of a trade restriction of 20% on Bangladesh's power system. Table 5.4 provides the variations for scenario construction among the key parameters.

Table 5.4 Key Variation for Scenario Construction

Scenario Abbreviation	RE & Storage cost decline	Political Energy Security Constraint of 20% on Energy imports	Higher RE potential Considered	Carbon Emission Reduction
LCD + PES	Lower	**Yes**	No	No
HCD + PES	Higher	**Yes**	No	No

5.2.1 Key results for Bhutan and Nepal (PES vs LCD/HCD)

a) Impact on Net Trade and Installed Capacities– Bhutan and Nepal

Both Bhutan and Nepal are power exporting countries which have negligible effect of Political Energy Security constraint of 20 percent import restriction as shown in Figure 5.15. Similarly, there is no change in the installed capacity of both Bhutan and Nepal as well.

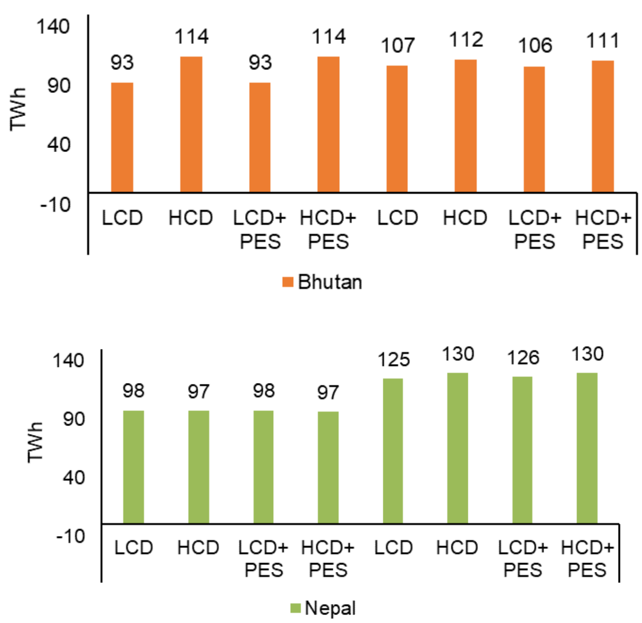
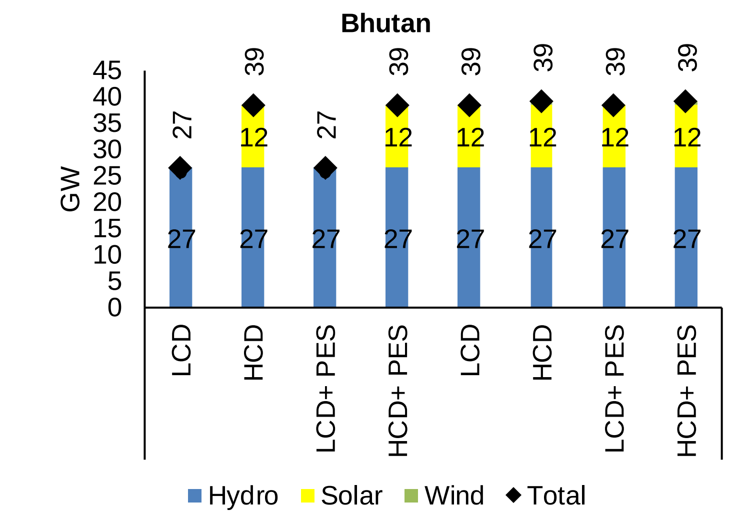


Figure 5.15 Net Trade* for Bhutan and Nepal in 2030 and 2050 for LCD, HCD, LCD-PES and HCD-PES Scenario (*Net Trade= Export – Import)



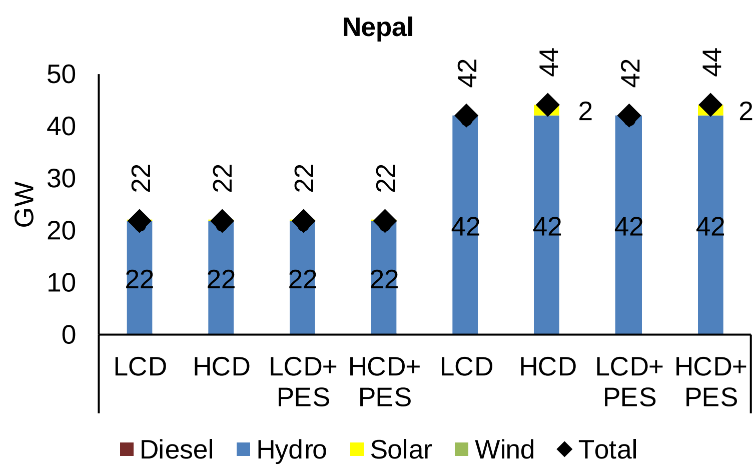


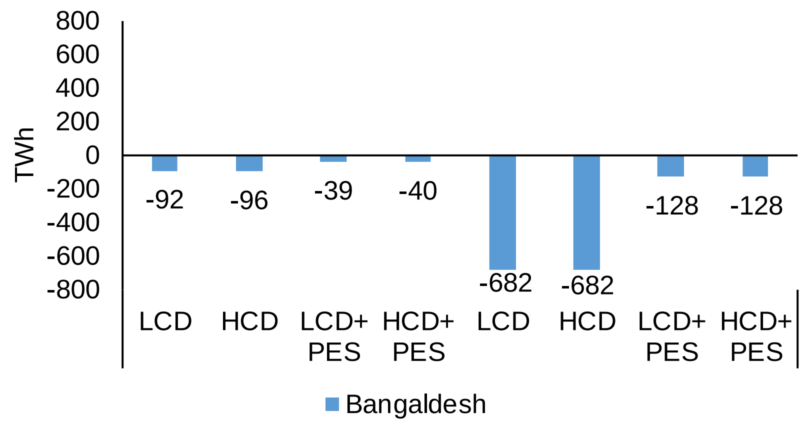
Figure 5.16 Installed Capacity mix for Bhutan and Nepal in 2030 and 2050 for LCD, HCD, LCD-PES and HCD-PES Scenario

5.2.2 Key results for Bangladesh and India (PES vs LCD/HCD)

a) Impact on Net Trade – Bangladesh and India

The political energy constraint will have major implications for Bangladesh and India's cross-border trade. Figure 5.17 shows that for Bangladesh, the net trade is negative in all the scenarios implying that it is a net importer. When the PES scenario is used, this negative net trade lowers from -682 to -128 TWh by 2050 due to constraints on import of power (limiting import to 20% of domestic demand) thus reducing imports by almost 81 percent in the LCD+PES/ HCD+PES compared to just the LCD/HCD scenario.

For India, the LCD and HCD scenario for 2050 will have positive net trade implying that India is a net exporter of power in the BBIN region. However, when the PES constraint is applied, the net trade becomes negative in the LCD+PES and HCD+PES scenarios. This is because the PES constraints reduce India's exports to Bangladesh and thus, India becomes a net importer of power from Bhutan and Nepal.



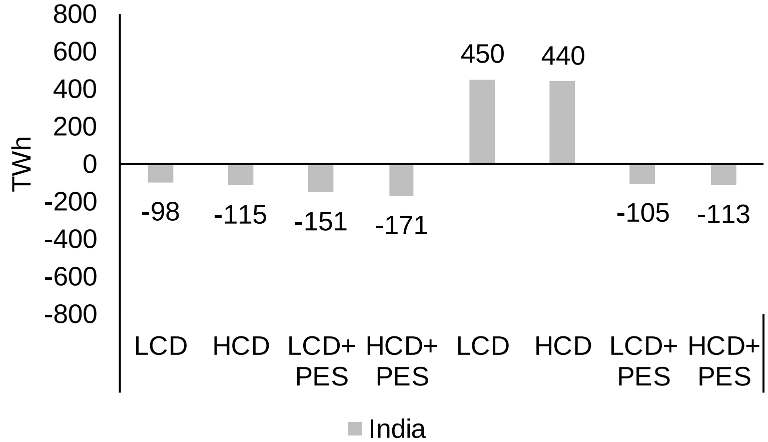


Figure 5.17 Net Trade* for Bangladesh and India in 2030 and 2050 for LCD, HCD, LCD-PES and HCD-PES Scenario

**Net Trade= Export - Import*

b) Impact on Installed Capacity – Bangladesh and India

The reduction in imports by Bangladesh will have implications for both Bangladesh and India. Figure 5.18 shows that in Bangladesh, there is an increase in domestic coal capacity for meeting demand under the PES scenarios because of the import constraints, which forces the model to increase its domestic power generation capacity to meet domestic demand. On the other hand, in India, there is a reduction in coal capacity and total capacity requirement due to the PES constraint in both the LCD+PES and the HCD+PES scenario because of lower exports to Bangladesh.

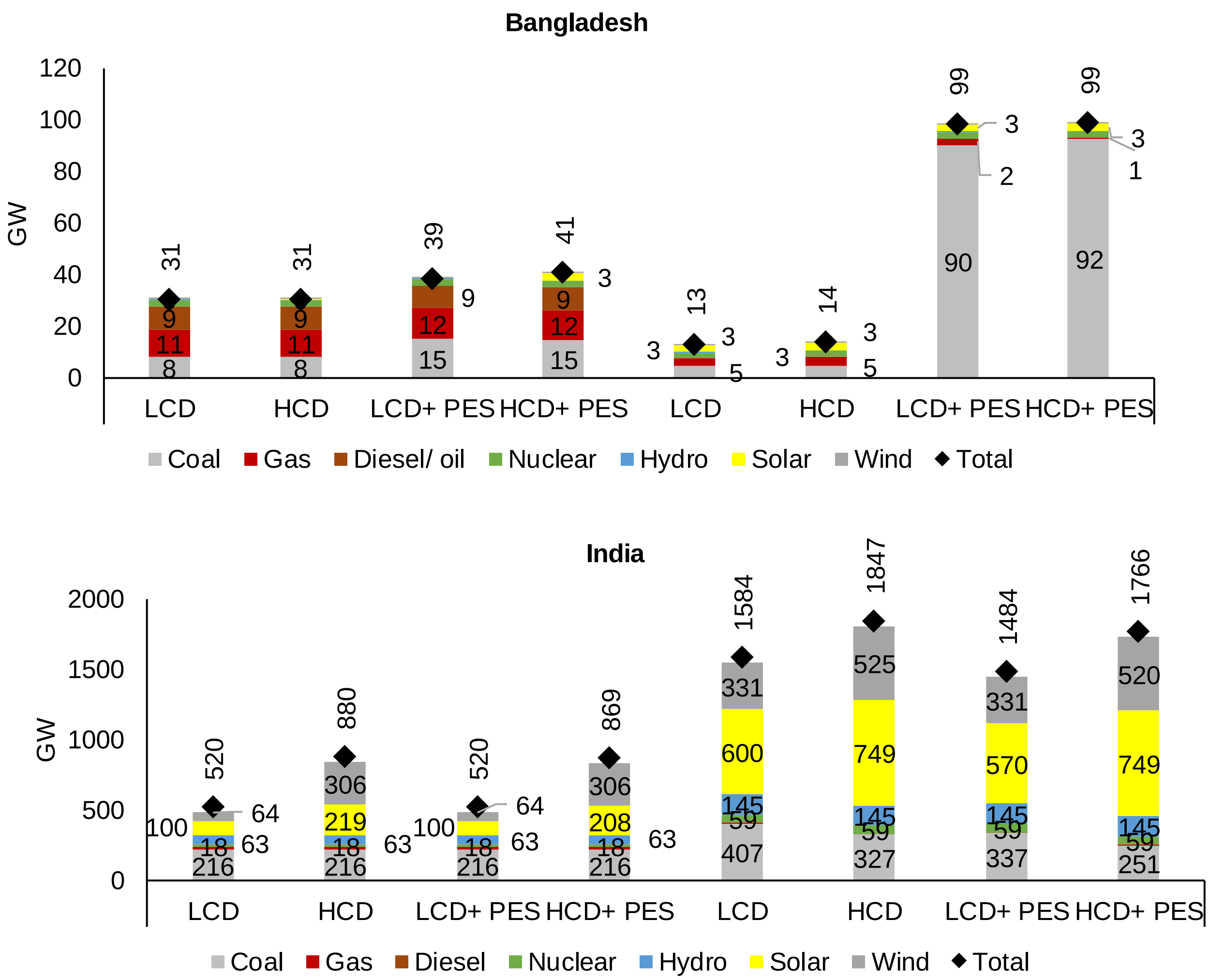


Figure 5.18 Installed Capacity mix for Bangladesh and India in 2030 and 2050 for LCD, HCD, LCD-PES and HCD-PES Scenario

c) Impact on Annual CO2 emissions – Bangladesh and India

With the PES constraint, Bangladesh will reduce its dependence on imported electricity. However, this will increase its requirement for producing electricity domestically. The limited RE potential and no constraint on carbon will lead to the higher installation of coal-based capacities within Bangladesh, which in turn will increase its power sector emissions as shown in Figure 5.19. This increase in annual emission in the LCD+PES/HCD+PES scenario will be around 66 percent of the LCD/HCD scenarios in 2030. By 2050, it will be more than 21 times the LCD/HCD scenario. This increase in annual emission from the power sector will also lead to an increase in CO2/kWh emission as shown in Figure 5.20. It is to be noted that CO2/kWh emission in the LCD+PES and the HCD+PES scenario (overlaps with each other in the figure) is higher than the HCD and LCD (overlaps with each other in the figure) scenarios.

For India, the situation is the opposite as a reduction in coal capacities under the LCD+PES/HCD+PES will reduce annual emission compared to the LCD/HCD scenario as shown in Figure 5.19. This annual emission reduction will CO2/kWh emission as shown in Figure 5.20. For further details on regional implications for CO2 reduction refer section 5.5 (d).

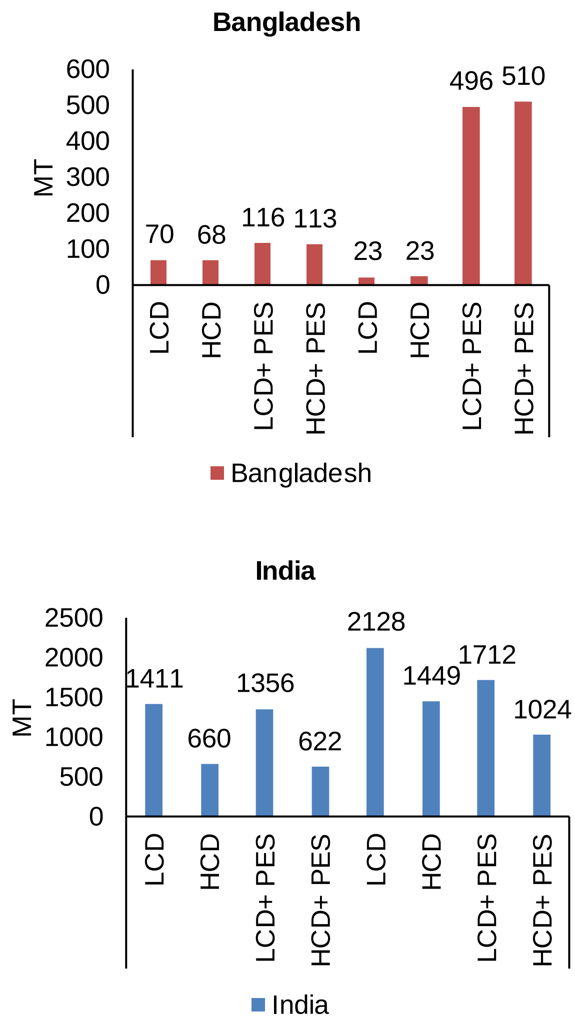


Figure 5.19 Annual CO2 emissions in the power sector in Bangladesh and India for Base, NC and HCD Scenario

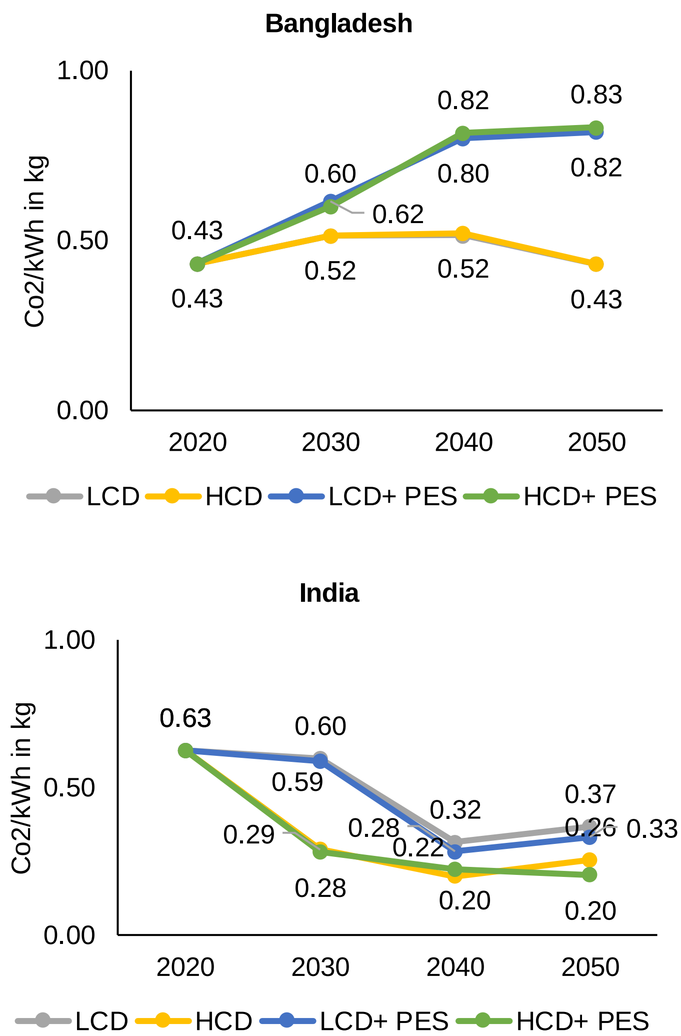


Figure 5.20 Annual CO2/kWh emissions in the power sector in Bangladesh and India for Base, NC and HCD Scenario

5.2.3 Impact on Discounted System Cost

For Bhutan, the PES constraint has a negligible effect in the LCD+PES scenario as this can be seen in Table 5.5. In the HCD+PES scenario, the total discounted system cost increases by 8 percent only keeping the value still negative, this is due to reduced revenues from exports an indicator of this effect can be observed in Table 5.6. Similarly, for Nepal, the PES constraint increases the total system cost by 3 percent in the LCD+PES compared to the LCD scenario and by 30 percent in the HCD+PES compared to the HCD scenario. Although the total cost increased in percentage terms, still it remains negative in value indicating that revenues from exports were higher than the total system cost thus making the objective function negative.

For Bangladesh, the LCD+PES will increase the cost by 9 percent compared to LCD and the HCD+PES scenario will increase it by 11 percent compared to the HCD scenario due to reduced imports and an increase in domestic installed capacities on the Bangladesh side. In cost terms, the PES scenario has a negligible impact on the total discounted system cost of India compared to the LCD/HCD scenario. Moreover, the regional cost is only increased by 1 percent due to the PES scenario constraint compared to the LCD/HCD scenario. This PES scenario has more implications for Bangladesh compared to other countries in the BBIN region.

Table 5.5 Discounted System cost (Objective Function) in Billion USD in 2015 prices for BBIN countries and region in LCD+PES, HCD+PES, LCD and HCD Scenario

Discounted System cost (Objective Function) in Billion USD in 2015 prices					
Scenario	**BBIN Region**	**India**	**Bangladesh**	**Nepal**	**Bhutan**
LCD	2619	2396	247	-5	-19
LCD+ PES	2640	2396	269	-5	-19
HCD	2487	2272	239	-5	-20
HCD+ PES	2513	2270	265	-3	-19
Change in system cost over LCD (Negatives represent % reduction and positive represent % increase over LCD)					
LCD+ PES	1%	0.005%	9%	3%	-0.04%
Change in system cost over HCD (Negatives represent % reduction and positive represent % increase over HCD)					
HCD+ PES	1%	-0.1%	11%	30%	8%

Table 5.6 Annual Average Marginal Net Trade Revenues in 2050 in Billion USD @ 2015 prices in LCD+PES, HCD+PES, LCD and HCD Scenario

(Net trade= Export – Imports)	India	Bangladesh	Nepal	Bhutan
LCD	16.1	-71.2	6.5	5.1
LCD+ PES	-9.2	-14.5	6.4	5.0
HCD	15.0	-71.0	6.0	5.3
HCD+ PES	-11.2	-14.1	5.9	5.2

5.2.4 Key Conclusions from PES scenario

The PES scenario is more relevant to Bangladesh as the electricity import dependence of 90% on other countries will not be politically accepted by any country due to energy security concerns and geopolitics in the region. The following are the key conclusions derived from the **PES scenario**:

For Bhutan and Nepal:

- **Trade and Installed Capacity:** Both Bhutan and Nepal are power exporting countries that have negligible effect of Political Energy Security constraint of 20 percent import restriction on their trade and installed capacity.
- **System Costs:** For Bhutan, in the HCD+PES scenario the total system cost increases by 8 percent compared to the HCD scenario due to reduced exports earnings. However, the total cost still remains negative indicating that exports revenues are higher than the total system costs.
  Similarly, for Nepal, in the HCD+PES scenario although the total cost number is negative it increases by 30 percent compared to the HCD scenario due to reduced exports earnings.

For Bangladesh and India:

- **Trade:** With the PES constraint, Bangladesh's net import of 682 TWh in the LCD/HCD scenario reduces to only 128 TWh under LCD+PES/HCD+PES scenario in 2050. Thus reducing imports by almost 81 percent in the LCD+PES/ HCD+PES compared to just the LCD/HCD scenario.
  For India, the PES constraint reduces India's exports to Bangladesh and thus, India becomes a net importer of power from Bhutan and Nepal.
- **Installed Capacity:** Compared to the LCD/HCD scenario, reduction in electricity imports under the PES scenario, forces the model to increase domestic coal capacity for meeting electricity demand.
  For India, due to the PES constraint, there is a reduction in coal capacity and total capacity requirement in both the LCD+PES and the HCD+PES scenario because of lower electricity exports to Bangladesh.
- **CO2 Emission Reduction in Power Sector:** For Bangladesh, the PES constraint will increase its requirement for producing electricity domestically. With limited RE potential and no constraint on carbon, the PES will lead to the higher installation of coal-based capacities within Bangladesh, which in turn will increase its power sector emissions. The increase in annual emissions in 2050 under the LCD+PES/HCD+PES scenario will be more than 21 times the LCD/HCD scenario.
  For India, the situation is the opposite as a reduction in coal capacities under the LCD+PES/HCD+PES will reduce annual emissions compared to the LCD/HCD scenario. For further details on regional implications for CO2 reduction refer section 5.5 (d).
- **System Costs:** For Bangladesh, the HCD+PES scenario will increase total system cost by 11 percent compared to the HCD scenario due to reduced imports and an increase in domestic installed capacities on the Bangladesh side.
  For India, the PES scenario has a negligible impact on the total system cost of India compared to the LCD/HCD scenario.

5.3 Impact of RE&S cost decline and High RE potential (HiRePo) on BBIN Trade

The current RE potential estimated in the BBIN region was estimated by individual country's agencies and many of them have been estimated decades back. With the change in technology and cost decline, we believe that these RE potential numbers need to be reassessed. Therefore, to capture the impact of higher RE potential on the regional trade we assumed a higher RE potential for all the countries than what is prescribed in the previous scenarios as shown in Table 3.1. Table 5.7 provides the variations for scenario construction among the key parameters.

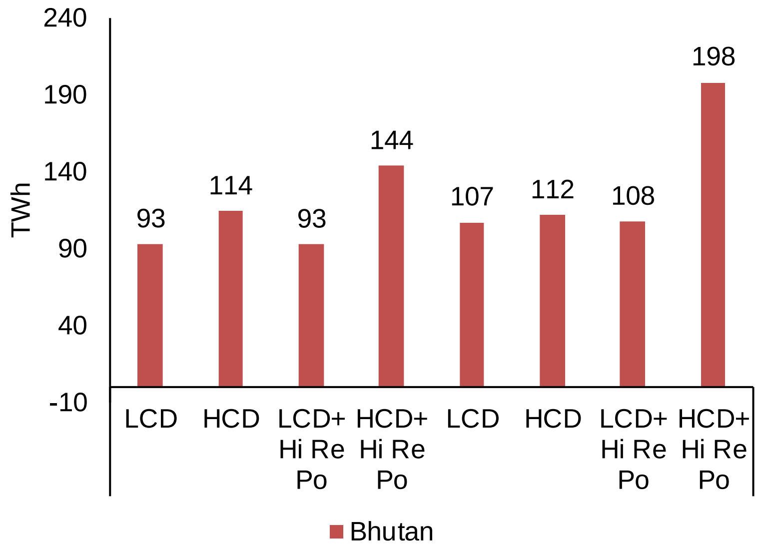
Table 5.9 Key Variation for Scenario Construction for LCD+HiRePo and HCD+HiRePo Scenario

Scenario Abbreviation	RE & Storage cost decline	Political Energy Security Constraint of 20% on Energy imports	Higher RE potential Considered	Carbon Emission Reduction
LCD + Hi Re Po	Lower	No	**Yes**	No
HCD + Hi Re Po	Higher	No	**Yes**	No

5.3.1 Key results for Bhutan and Nepal (HiRePo vs LCD/HCD)

a) Impact on Net Trade – Bhutan and Nepal

For Bhutan, Figure 5.21 shows an increase in net trade when comparing the LCD/HCD scenarios with the LCD+HiRePo and HCD+HiRePo scenarios. For the HCD+ Hi Re Po, there is a 77 percent increase in export compared to the HCD scenario in 2050 because of increased renewable (RE) potential from 13 GW to 63 GW and full utilisation of renewable (RE) potential. However, for Nepal, there is only 3-4% rise in exports when comparing the LCD and HCD scenarios with High RE Potential scenarios. This is due to the limited increase assumed in the RE potential for the HiRePo scenarios. In all scenarios, Nepal's RE Potential is assumed to be 2.5 GW and High RE scenario has a potential of 5.6 GW due to limitation in data availability.



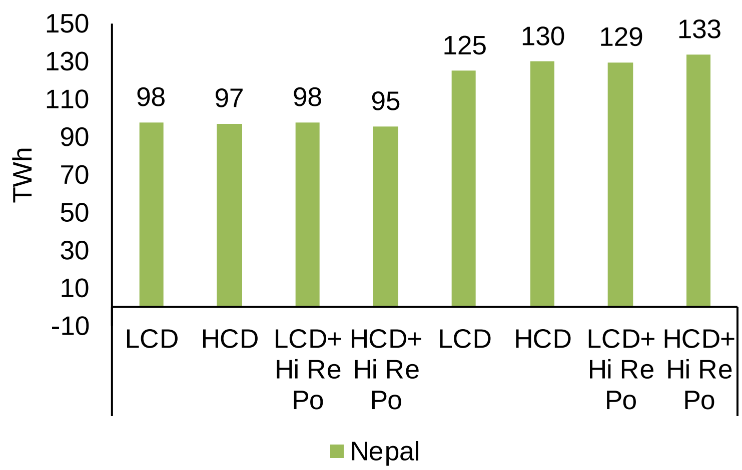
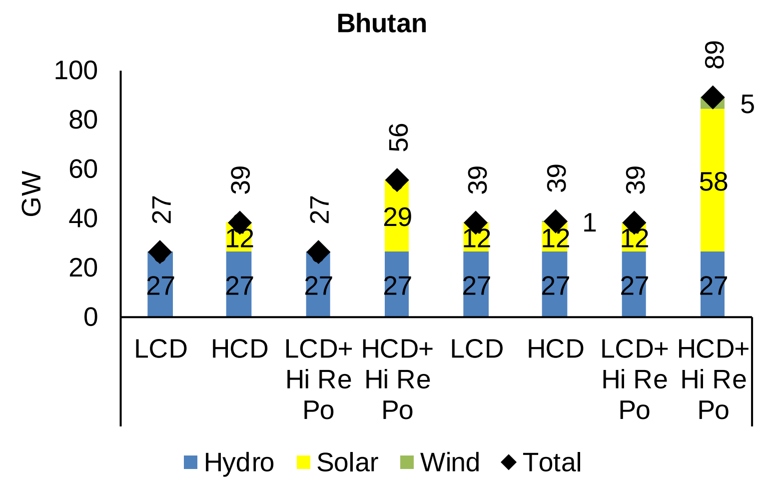


Figure 5.21: Impact on Net Trade for Bhutan and Nepal

b) Impact on Installed Capacity – Bhutan and Nepal

For Bhutan, the LCD scenario in 2030 and 2050 has the same capacity as the LCD+Hi Re Po scenario in 2030 and 2050 as shown in Figure 5.22. However, compared to HCD in 2030 and 2050 with HCD+HiRePo in 2030 and 2050, there is a surge in solar capacity installed in 2030 and 2050. In 2050, there is full utilisation of solar and wind potential due to the high-cost decline in renewable energy characterised by the HCD+HiRePo scenario. In Nepal, the LCD scenario and LCD+HiRePo have a similar installed capacity for 2030 and 2050. However, the HCD+HiRePo scenario in 2050 has full utilisation of solar potential and thus higher solar capacity in the scenario. If higher solar and wind potential are considered, trade volume will further increase from Bhutan and Nepal to India. The solar and wind potential in Nepal is underestimated and needs to be reassessed.



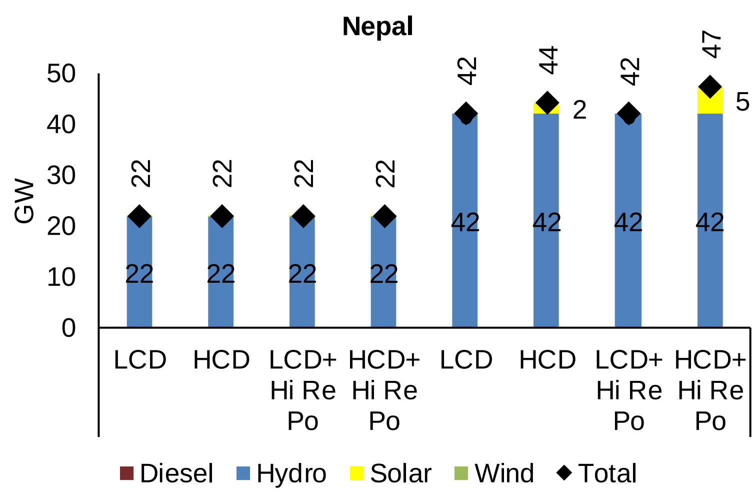
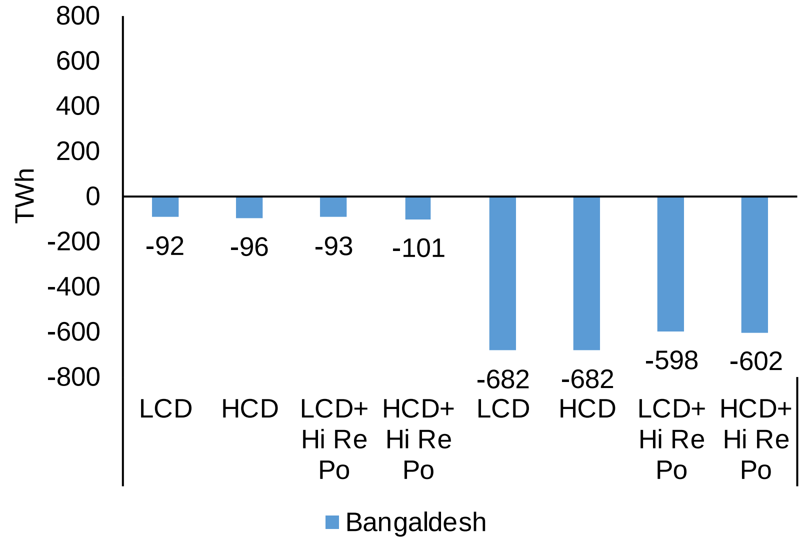


Figure 5.22 Installed Capacity mix for Bhutan and Nepal in 2030 and 2050 for LCD, HCD, LCD+HiRePo and HCD+HiRePo Scenario

5.3.2 Key results for Bangladesh and India (HiRePo vs LCD/HCD)

a) Impact on Net Trade – Bangladesh and India

The addition of high RE potential on Bangladesh's side will help Bangladesh in reducing its imports dependence as shown in Figure 5.23. Although the net trade remains negative (highlighting it's a net importer) even with High RE Potential, its total volume reduces due to higher domestic generation. In the HiRePo scenarios, Bangladesh has an RE Potential of 60 GW and this reduces the need for electricity imports from India by 11 percent compared to LCD/HCD scenarios. On the Indian side, net trade is negative in 2030 highlighting that it remains a net importer of electricity. Further by 2050, India's net trade under HiRePo scenarios remains positive as observed in the LCD/HCD scenario highlighting its position as a net exporter in the BBIN region, but net trade reduces due to a reduction in imports by Bangladesh.



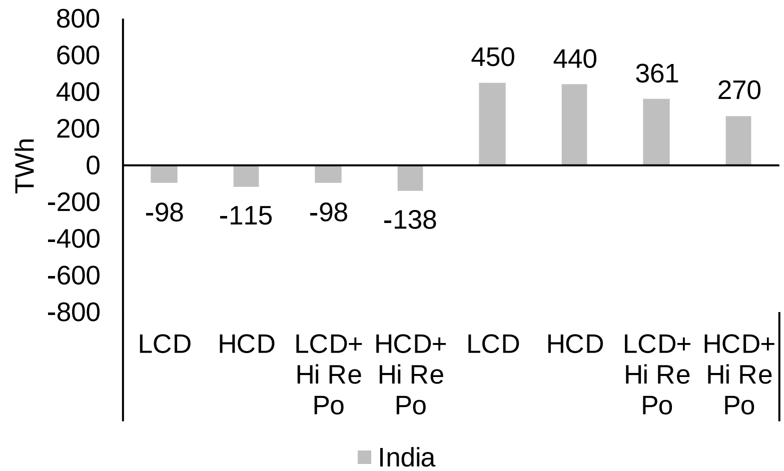
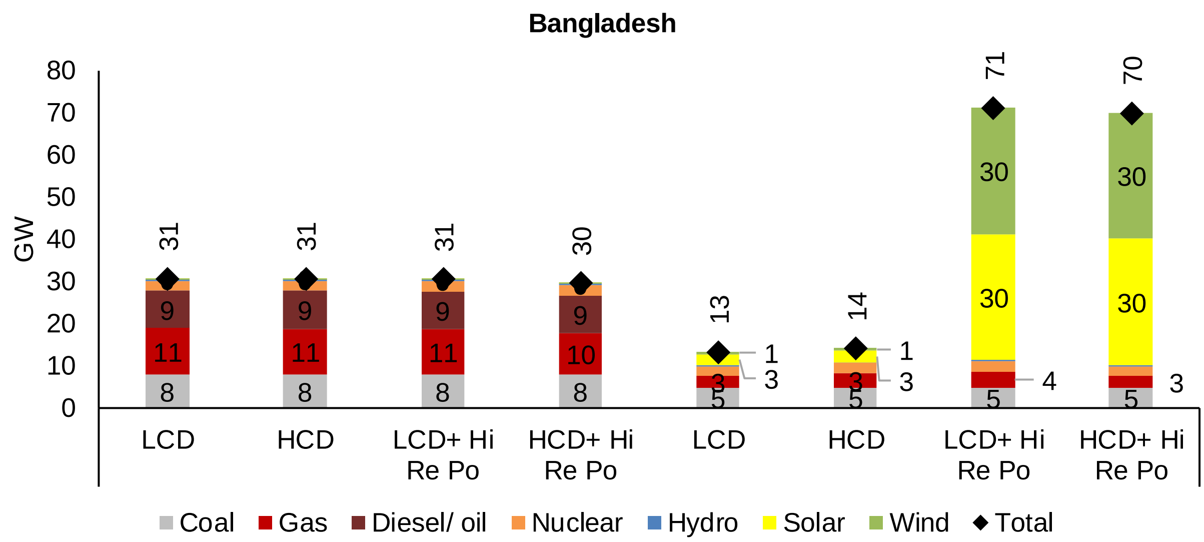


Figure 5.23: Net Trade for Bangladesh and India in 2030 and 2050 for LCD, HCD, LCD+HiRePo and HCD+HiRePo Scenario

b) Impact on Installed Capacity – Bangladesh and India

In 2050 for Bangladesh, there is full utilisation of RE potential in LCD + HiRePo and HCD+ HiRePo scenarios due to renewable energy being cheaper than imports as shown in Figure 5.24. The impact of high RE potential in 2030 is negligible due to planned coal and gas capacity and higher initial RE technologies in Bangladesh. In India, the wind is preferred over solar due to higher plant load factor (PLF) as well the possibility of power generation from wind in non-solar hours that supports peak demand. Due to this, there is full utilisation of wind potential in the LCD+HiRePo and HCD+HiRePo scenarios.



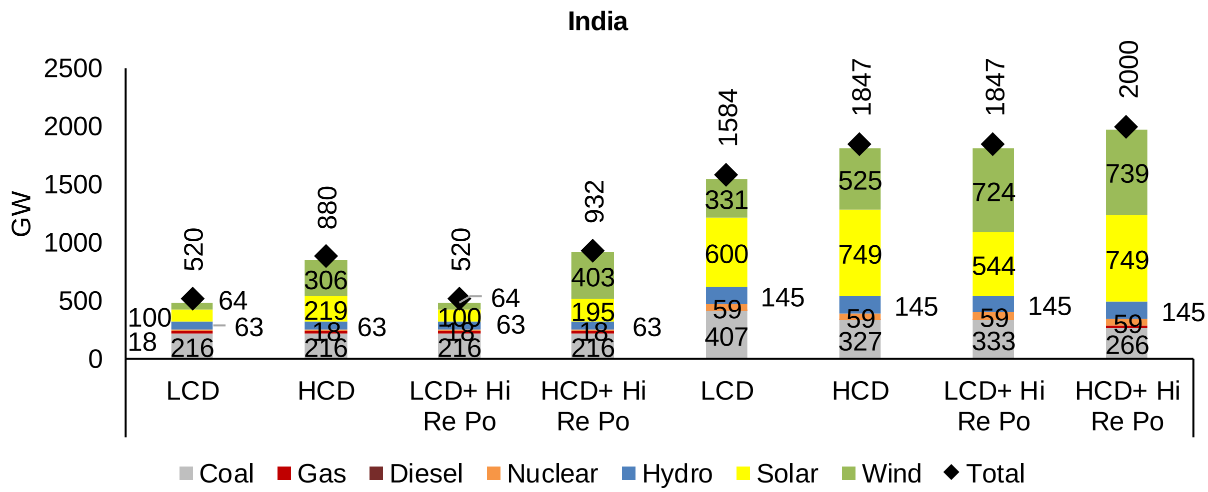


Figure 5.24: Installed Capacity mix for Bangladesh and India in 2030 and 2050 LCD, HCD, LCD+HiRePo and HCD+HiRePo Scenario

c) Impact on Annual CO2 emissions – Bangladesh and India

The higher RE potential helps in installing more RE capacities into the power system of each country leads to lower CO2 emissions. Figure 5.25 shows that in India, there is a reduction in annual CO2 emissions due to an increase in renewable capacity and a fall in installation of coal capacities. In 2030, the HCD+HiRePo scenario in India has 17% lower CO2 emissions compared to the HCD scenario. Further, in 2050 the LCD+HiRePo in India has 30% lower CO2 emissions compared to the LCD scenario, and the HCD+HiRePo has a 25% decrease in CO2 emissions compared to the HCD scenario. In Bangladesh, there is negligible change in annual CO2 emissions as there is no change in installed coal and gas capacities. An increase in generation from higher RE installation offsets the requirements for electricity imports. For further details on regional implications for CO2 reduction refer section 5.5 (d).

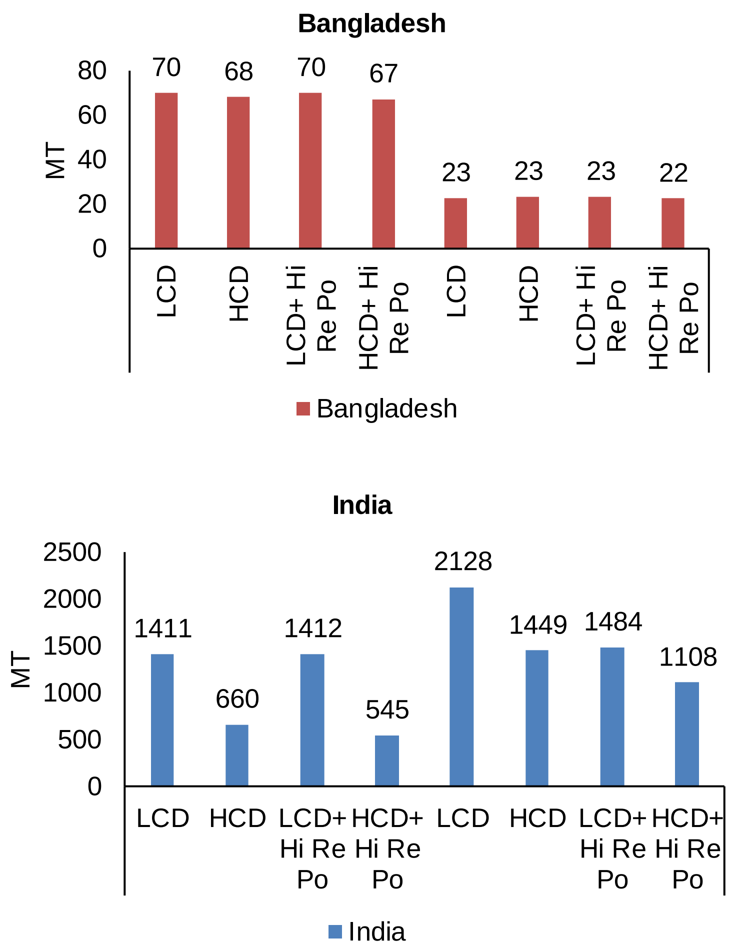
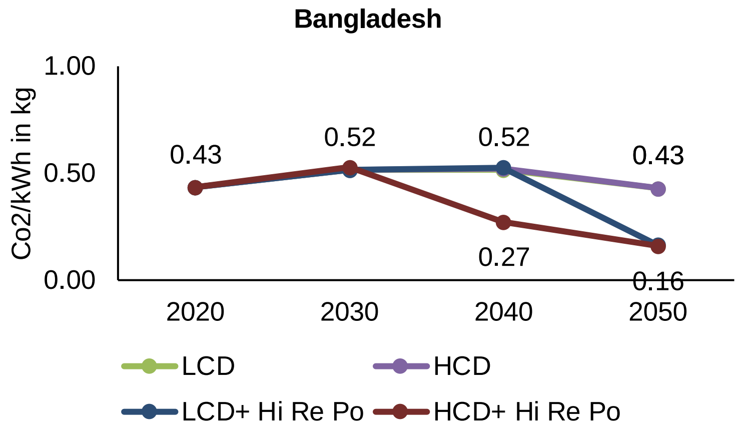


Figure 5.25 Annual CO2 emissions in the power sector in Bangladesh and India for LCD, HCD, LCD+HiRePo and HCD+HiRePo Scenario

For Bangladesh, CO2/kWh reduces for HCD+HiRePo and LCD+HiRePo because of an increase in generation from RE sources as shown in Figure 5.26 (LCD and HCD overlap in the figure). For India, the HCD+HiRePo scenario has a maximum reduction in terms of CO2/kWh due to higher installation and generation from wind capacities.



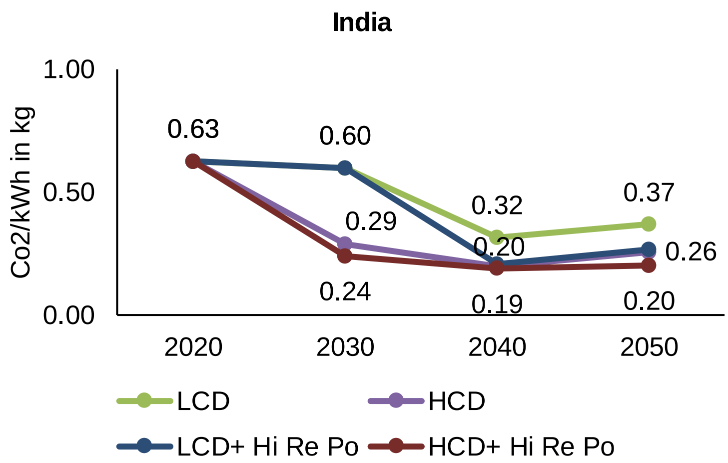


Figure 5.26 Annual CO2/kWh emissions in the power sector in Bangladesh and India for LCD, HCD, LCD+HiRePo and HCD+HiRePo Scenario

5.3.3 Impact on Discounted System Cost

For both Bhutan and Nepal, the total system cost in both the HiRePo scenarios will increase compared to the LCD/HCD scenario due to the increase in the installation of RE technologies. Although, their total system cost still remains negative highlighting export revenues are higher than total system costs except for Nepal in the HCD+HiRePo scenario as shown in Table 5.10. Further, revenue from exports doubles for Bhutan in 2050 under the HCD+HiRePo scenario due to 5 times increase in solar capacities compared to the HCD scenario as shown in Table 5.11.

In the case of both Bangladesh and India, total system cost reduces due to an increase in RE capacities which reduces import dependence for Bangladesh and coal capacity requirements for India. For the BBIN region, the HiRePo can reduce the regional system cost by 3 percent as shown in Table 5.11.

Table 5.10 Discounted System cost (Objective Function) in Billion USD in 2015 prices for BBIN countries and region in LCD, HCD, LCD+HiRePo and HCD+HiRePo Scenario

Discounted System cost (Objective Function) in Billion USD in 2015 prices					
	BBIN Region	**India**	**Bangladesh**	**Nepal**	**Bhutan**
LCD	2619	2396	247	-5	-19
LCD+ Hi Re Po	2577	2358	240	-2	-19
HCD	2487	2272	239	-5	-20
HCD+ Hi Re Po	2402	2195	225	1	-20
Change in system cost over LCD (negative represent % reduction and positive represent % increase over LCD)					
LCD+ Hi Re Po	-2%	-2%	-3%	54%	2%
Change in system cost over HCD (negative represent % reduction and positive represent % increase over HCD)					
HCD+ Hi Re Po	-3%	-3%	-6%	129%	3%

Table 5.11 Annual Average Marginal Net Trade Revenues in 2050 in Billion USD @ 2015 prices in LCD, HCD, LCD+HiRePo and HCD+HiRePo Scenario

(Net trade= Export – Imports)	India	Bangladesh	Nepal	Bhutan
LCD	16.1	-71.2	6.5	5.1
LCD+ Hi Re Po	12.4	-62.5	6.8	5.1
HCD	15.0	-71.0	6.0	5.3
HCD+ Hi Re Po	7.3	-62.5	6.0	9.3

5.3.4 Key Conclusions

Following are the key learnings from assuming higher RE potential for each country in the BBIN region in addition to the RE&S cost decline assumption:

For Bhutan and Nepal:

- **Trade:** Both for Bhutan and Nepal, HiRePo will help in increasing its export potential in the region through higher installation of RE technologies. For Bhutan in the HCD+ Hi Re Po, there is a 77 percent increase in export compared to the HCD scenario in 2050 because of increased renewable (RE) potential from 13 GW to 63 GW and full utilisation of renewable (RE) potential.
  For Nepal, there is only a 3-4% rise in exports when comparing the LCD and HCD scenarios with High RE Potential scenarios. This is due to the limited increase assumed in the RE potential for the HiRePo scenarios. Therefore, reassessment of RE potential in Nepal is required to increase its export potential.
- **Capacity Installation:** For both Bhutan and Nepal, a higher cost decline in RE&S technology along with high RE potential favour higher installation of RE capacities into the system.
- **System Costs:** For both Bhutan and Nepal system costs increase due to the installation of higher RE capacities but the overall total system cost remains negative highlighting export revenues are

higher than total system costs. Further, revenue from exports doubles for Bhutan in 2050 under the HCD+HiRePo scenario due to 5 times increase in solar capacities compared to the HCD scenario.

For Bangladesh and India:

- **Trade:** For Bangladesh, the addition of high RE potential on Bangladesh's side will help it in reducing its imports dependence on other countries. Although it remains a net importer but its total import volume reduces due to higher domestic generation.
  For India,
- **Installed Capacity:** For Bangladesh, by 2050 there is full utilisation of RE potential of 60 GW in both the LCD + HiRePo and HCD+ HiRePo scenarios due to renewable energy being cheaper than electricity imports.
  In India, with higher RE potential, in 2050 wind is preferred over solar due to the higher plant load factor (PLF) of wind plants as well the possibility of power generation from wind in non-solar hours that supports peak demand.
- **CO2 Emission Reduction in Power Sector:** Higher RE potential helps India to reduce its CO2 emissions from the power sector. However, in Bangladesh there is negligible change in annual CO2 emissions as there is no change in installed coal and gas capacities as an increase in generation from higher RE installation offsets the requirements for electricity imports.
- **System Costs:** For both Bangladesh and India, total system cost reduces due to an increase in RE capacities which reduces import dependence for Bangladesh and coal capacity requirements for India.

5.4 Impact of RE&S cost decline and carbon emission reduction scenario on BBIN Trade

To assess the impact of carbon constraint on BBIN regional power trade, we ran a scenario wherein we assumed power sector cumulative CO2 emission reduction of 50 percent on the Base scenario emissions from Bangladesh and India for the period 2015-50. The applicable cumulative reduction target under the CO-50 constraint for CO2 emissions is provided in Table 5.12. Table 5.13 provides the variations for scenario construction among the key parameters.

Table 5.12 CO2 Emission Constraint for Power Sector under CO-50 Constraint

Emission from Power Sector for 2012 to 2050 in GT		
Region	**Scenario**	
	BASE	**CO-50 Constraint**
India	63	31
Bangladesh	10	5

Table 5.13: Key Variation for Scenario Construction for LCD+CO-50 and HCD+CO-50 Scenario

Scenario Abbreviation	RE & Storage cost decline	Trade Restriction	Political Energy Security Constraint of 20% on Energy imports	Higher RE Potential Considered	Carbon Emission Reduction
Base	Lower	Yes	No	No	No
LCD	Lower	No	No	No	No
HCD	Higher	No	No	No	No
LCD + CO-50	Lower	No	No	No	Yes
HCD + CO-50	Higher	No	No	No	Yes

5.4.1 Key results for Bhutan and Nepal (CO-50 vs LCD/HCD)

a) Impact on Net Trade – Bhutan and Nepal

Both Bhutan and Nepal are hydropower exporting nations. The impact of the CO-50 constraint on Net Trade for Bhutan and Nepal is shown in Figure 5.27. The CO-50 Scenario will have a negligible impact on their power trade volumes. This is because installed capacity in Bhutan and Nepal is the same with full RE and hydropower potential utilisation.

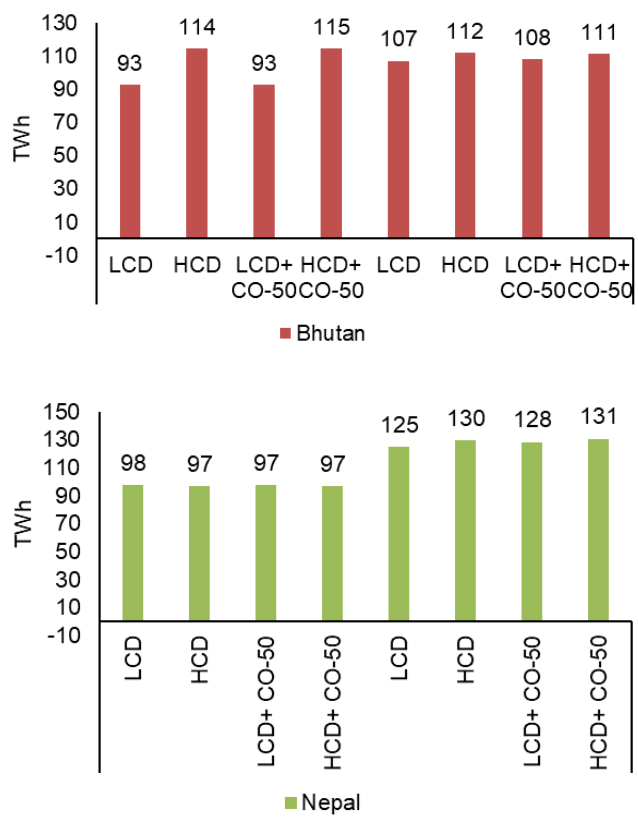
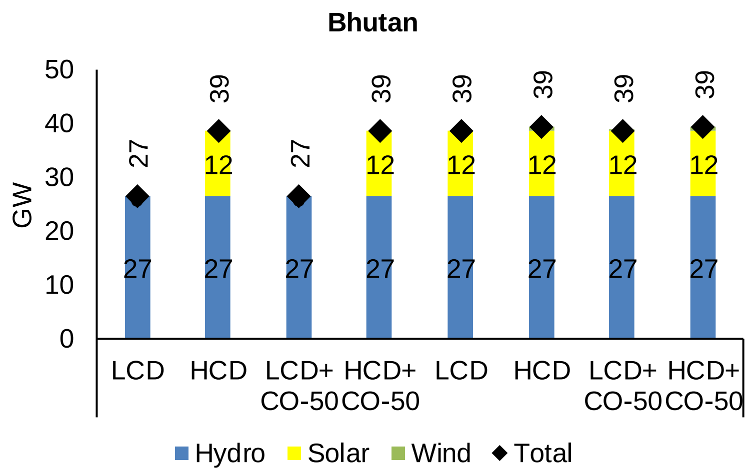


Figure 5.27 Net Trade for Bhutan and Nepal in 2030 and 2050 for LCD, HCD, LCD+CO-50 and HCD+CO-50 Scenario

b) Impact on Installed Capacity – Bhutan and Nepal

Figure 5.28 shows that for Bhutan and Nepal, there is negligible change in installed capacity in LCD+CO50 and HCD+ CO-50 scenarios compared to LCD/HCD Scenarios. This is because both Bhutan and Nepal are the major exporters of hydropower and RE power and their potentials are fully utilised by 2050.



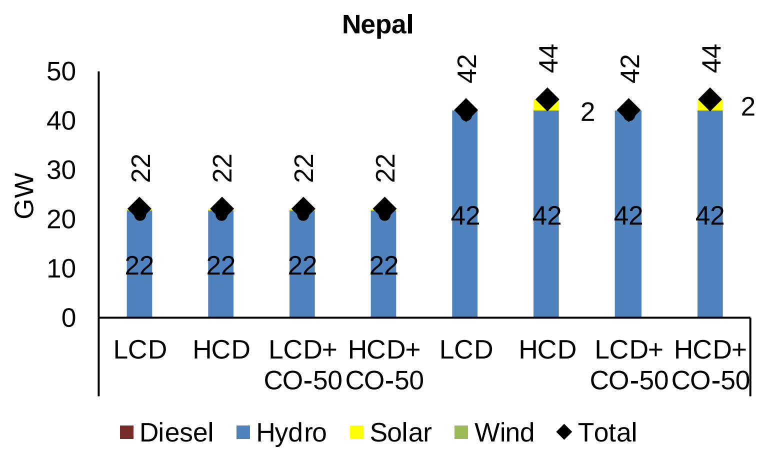


Figure 5.28 Installed Capacity mix for Bhutan and Nepal in 2030 and 2050 for LCD, HCD, LCD+CO-50 and HCD+CO-50 Scenario

5.4.2 Key results for Bangladesh and India (CO-50 vs LCD/HCD)

a) Impact on Net Trade – Bangladesh and India

The carbon reduction constraint will have implications for Bangladesh and India. Figure 5.29 shows that in 2030, there will be negligible changes in Bangladesh net trade under the LCD+CO-50 and HCD+CO-50 Scenario compared to the LCD/HCD scenario. Whereas in 2050, under the LCD+CO-50 scenario the net trade for Bangladesh reduces by half compared to the LCD scenario due to an increase in coal capacity installation within Bangladesh. Further for the HCD+CO-50 Scenario in 2050, the net trade for Bangladesh remains almost similar to the HCD scenario. Similarly, on the Indian side, a major reduction in net trade is observed in the LCD+CO-50 scenario for 2050 due to limitation on carbon emission and lower reduction in RE&S costs.

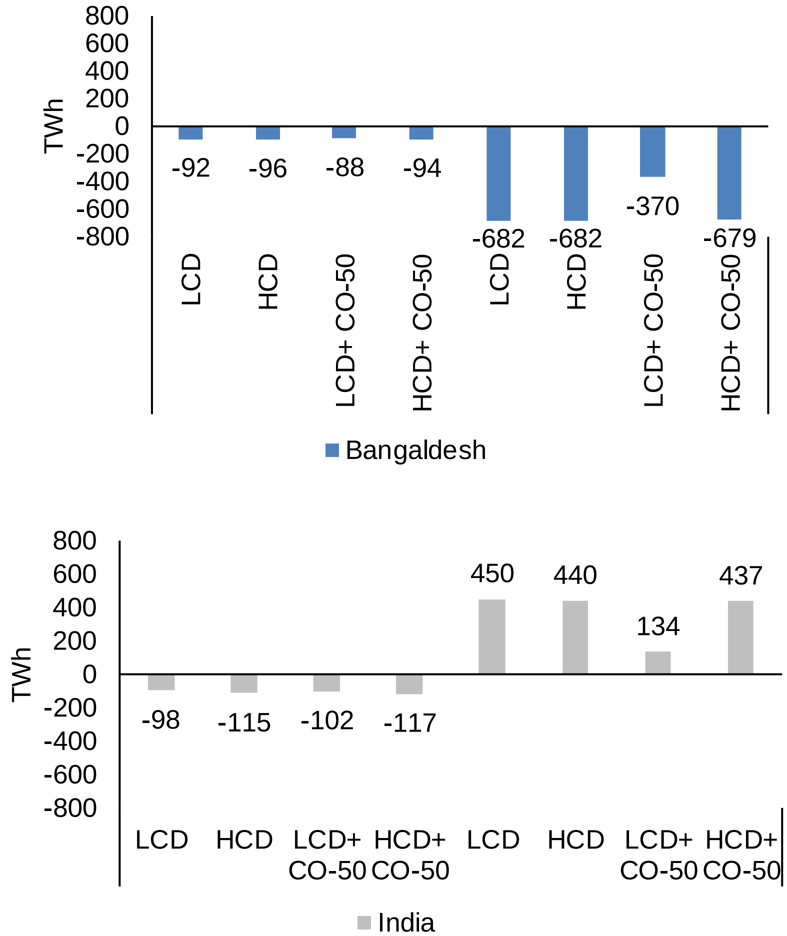
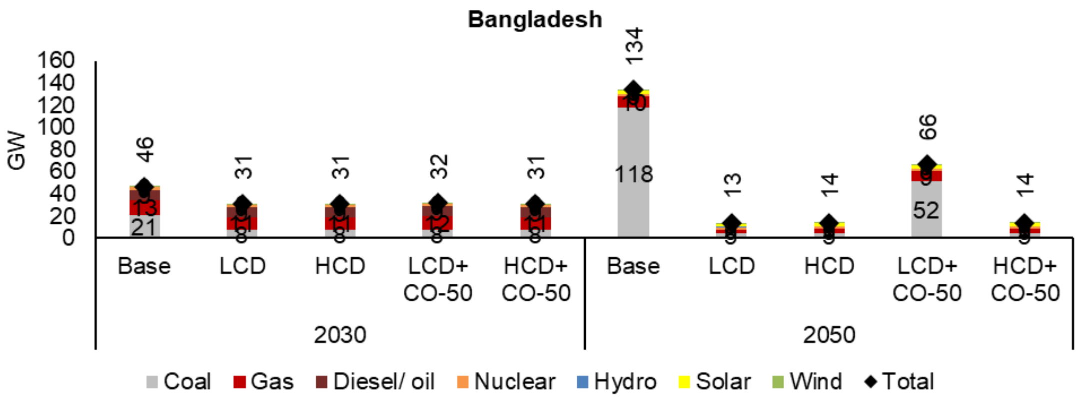


Figure 5.29 Net Trade for Bangladesh and India in 2030 and 2050 for LCD, HCD, LCD+CO-50 and HCD+CO-50 Scenario

b) Impact on Installed Capacity – Bangladesh and India

With CO-50 Constraint, Bangladesh coal capacity reduces in LCD+CO-50 and HCD+CO-50 Scenario compared to the Base both in 2030 and 2050 as shown in Figure 5.30. However, the model utilizes the emission budget on the Bangladesh side in 2050 to install coal capacities under the LCD+CO50 scenario to compensate for the reduction in electricity imports from India. Further, there is no change in installed capacity on the Bangladesh side in 2050 for the HCD+CO-50 scenario compared to the HCD scenario due to the higher installation of RE in the region.

On the Indian side, there is no change in installed coal capacities for 2030 but installed RE capacity increase for the LCD+CO-50 and HCD+CO-50 Scenario compared to the LCD/HCD scenario due to emission constraint. Further by 2050, installed coal capacities reduces on the India side by 10 percent in the LCD+CO-50 scenario and by 18 percent in the HCD+50 compared to the Base scenario. The reduction in coal capacities is met through an increase in the installation of solar capacity and wind capacities.



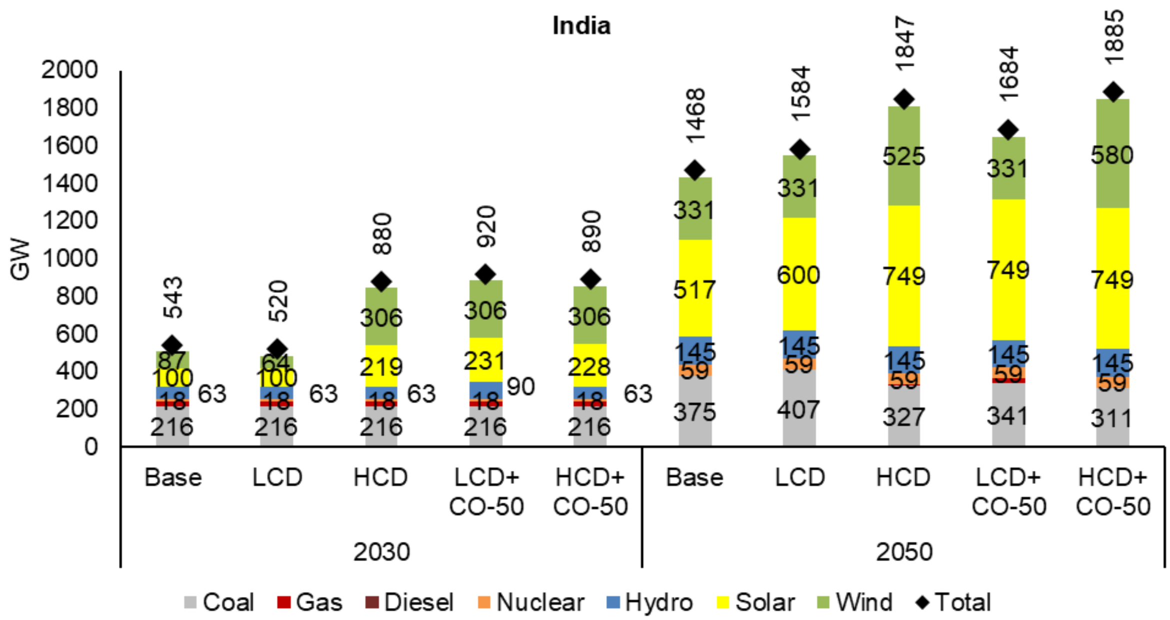
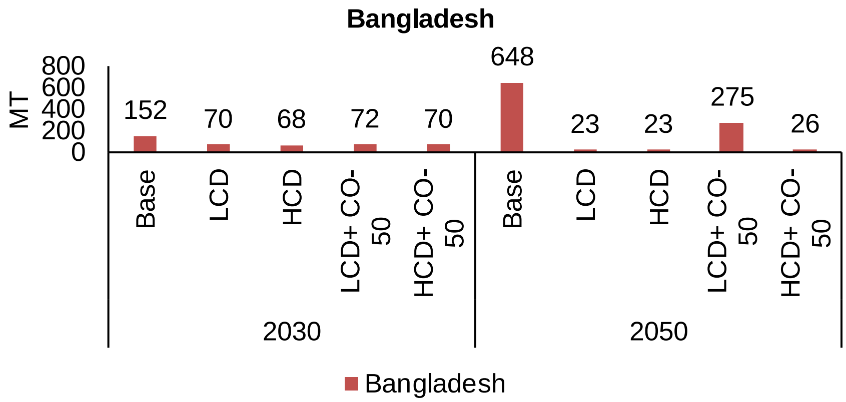


Figure 5.30 Installed Capacity mix for Bangladesh and India in 2030 and 2050 for LCD, HCD, LCD+CO-50 and HCD+CO-50 Scenario

c) Impact on Annual CO2 emissions – Bangladesh and India

For Bangladesh, compared to the Base scenario, the annual CO2 emissions will be lower in the LCD+CO-50 and HCD+CO-50 scenario in 2030 and 2050 as shown in Figure 5.29. Further, Bangladesh's emissions in the LCD+CO-50 scenario are 12 times higher than the LCD scenario due to a reduction in electricity imports from India and an increase in domestic coal capacity installation.

For India, the annual emissions in 2030 and 2050 are lower than the Base case in LCD+CO-50 and HCD+CO-50 Scenario. In the LCD+CO-50 scenario, the annual emission reduces by 62 percent in 2030 and by 13 percent in 2050 compared to Base. Similarly, in the HCD+CO-50 scenario, the annual emission reduces by 57 percent in 2030 and by 32 percent in 2050 compared to the Base scenario. For further details on regional implications for CO2 reduction refer section 5.5 (d).



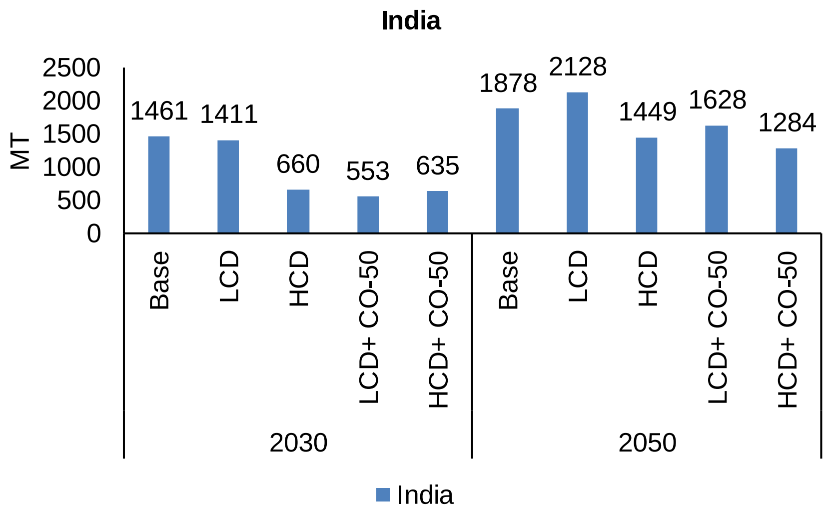
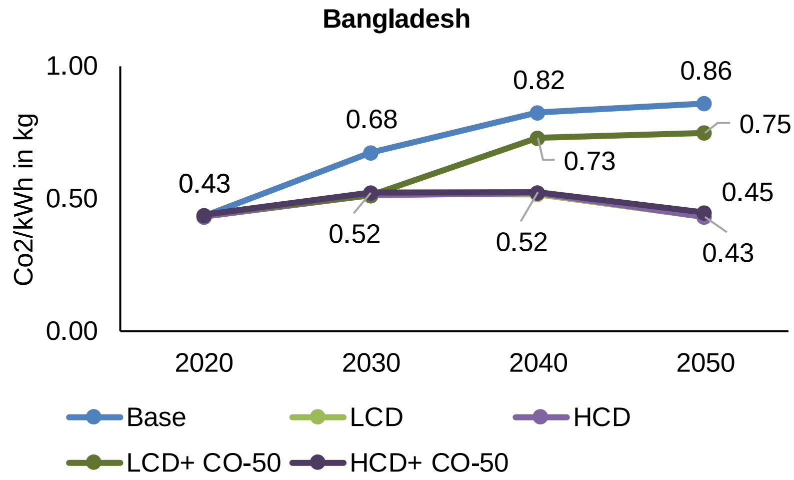


Figure 5.29 Annual CO2 emissions in the power sector in Bangladesh and India for LCD, HCD, LCD+CO-50 and HCD+CO-50 Scenario

Figure 5.67 shows in Bangladesh, there is a rise in the CO-50 scenario emissions compared to the LCD/HCD scenarios. For CO2/kWh, emissions for the HCD, HCD+CO-50 and LCD remain stagnant at 0.43 while for the LCD+CO-50 emissions rise from 0.43 to 0.75 kg of CO2/kWh.

The change in CO2/kWh for Bangladesh and India over the years is provided in Figure 5.30. For Bangladesh, the highest CO2/kWh over the years are for the Base scenario reaching 0.86 kg CO2/kWh by 2050 followed by the LCD+CO50 scenario with 0.75 kg CO2/kWh. The values for the LCD, HCD and HCD-CO50 overlap with each other and reach in the range of 0.43 to 0.45 kg CO2/kWh. For India, the highest values of CO2/kWh are for the Base and LCD scenario and the lowest is for the HCD+CO-50.



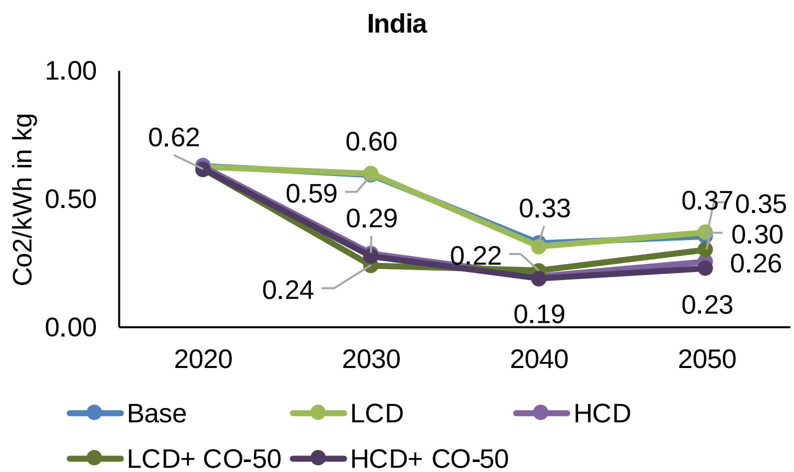


Figure 5.30 Annual CO2/kWh emissions in the power sector in Bangladesh and India for LCD, HCD, LCD+CO-50 and HCD+CO-50 Scenario

5.4.3 Impact on Discounted System Cost – Bangladesh, India, Nepal, Bhutan

With the CO-50 constraint, the system cost reduces for both Bhutan and Nepal as they earn higher revenues from exports in the LCD+CO-50 and HCD+CO-50 Scenario compared to the LCD/HCD scenario. Table 5.14 shows that for both Bhutan and Nepal, there is a negative system cost which means that their net trade revenue is higher than the total system cost. For Bhutan, system cost reduces by 56 percent under the LCD+CO-50 compared to the LCD scenario and by 16 percent under the HCD+CO-50 compared to the HCD scenario. Similarly, for Nepal, the system cost reduces by 5 times under the LCD+CO-50 compared to the LCD scenario and by 2 times under the HCD+CO-50 compared to the HCD scenario.

For Bangladesh, the CO-50 constraint increases the system cost by 9 percent under the LCD+CO-50 compared to the LCD scenario and by 4 percent under the HCD+CO-50 compared to the HCD scenario. Similarly, for India, the system cost increases by 1.6 percent under the LCD+CO-50 compared to the LCD scenario as shown in Table 5.14.

Table 5.14 Discounted System cost (Objective Function) in Billion USD in 2015 prices for BBIN countries and region in LCD, HCD, LCD+CO-50 and HCD+CO-50 Scenario

Discounted System cost (Objective Function) in Billion USD in 2015 prices					
	BBIN Region	**India**	**Bangladesh**	**Nepal**	**Bhutan**
LCD	2619	2396	247	-5	-19
LCD+ CO- 50	2654	2435	270	-21	-30
HCD	2487	2272	239	-5	-20
HCD+ CO- 50	2493	2277	248	-9	-23
Change in system cost over LCD (negative represent % reduction and positive represent % increase over LCD)					
LCD+ CO- 50	1%	1.6%	9%	-295%	-56%
Change in system cost over HCD (negative represent % reduction and positive represent % increase over HCD)					
HCD+ CO- 50	0.2%	0.2%	4%	-94%	-16%

5.4.3 Key Conclusions

Following are the key learnings from assuming power sector cumulative CO_2 emission reduction of 50 percent on the Base scenario emissions from Bangladesh and India for the period 2015-50:

For Bhutan and Nepal:

- **Trade and Installed Capacity:** For both Bhutan and Nepal, CO-50 Scenario will have a negligible impact on their power trade volumes as hydro and RE potential is fully utilised by 2050 in other scenarios as well.
- **System Costs:** For both Bhutan and Nepal, the CO-50 constraint on India and Bangladesh increases their overall electricity exports earnings. Therefore, for Bhutan, the total system cost reduces by 56 percent under the LCD+CO-50 scenario compared to the LCD scenario and reduces by 16 percent under the HCD+CO50 scenario compared to the HCD scenario.
  Similarly, for Nepal, the total system cost reduces by 5 times under the LCD+CO-50 compared to the LCD scenario and by 2 times under the HCD+CO-50 compared to the HCD scenario.

For Bangladesh and India:

- **Trade:** For Bangladesh, in the year 2050 under the LCD+CO-50 scenario the net trade reduces by half compared to the LCD scenario due to an increase in coal capacity installation within Bangladesh. Whereas for the HCD+CO50 scenario trade levels remains same as that of HCD scenario.
- **Installed Capacity:** For Bangladesh, the coal capacity installation increases in the LCD+CO50 scenario by 2050 due to a decrease in electricity imports from India. Further, there is no change in installed capacity on the Bangladesh side in 2050 for the HCD+CO-50 scenario compared to the HCD scenario due to the higher installation of RE in the region.
  For India, the installed coal capacities reduce and the RE capacity increased for the LCD+CO-50 and HCD+CO-50 Scenario compared to the LCD/HCD scenario due to emission constraint.
- **CO_2 Emission Reduction in Power Sector:** For Bangladesh, compared to the Base scenario the annual CO_2 emission from the power sector will be lower in both 2030 and 2050 for the LCD+CO-50

and HCD+CO-50 Scenario. However, it will increase by 12 times in the LCD+CO50 scenario compared to the LCD scenario due to a reduction in electricity imports from India and an increase in domestic coal capacity installation.

Similarly, for India, the annual CO2 emission from the power sector was lower than the Base scenario.

- **System Costs:** Overall system cost increase for both Bangladesh and India. For Bangladesh, the CO-50 constraint increases the total system cost by 9 percent under the LCD+CO-50 compared to the LCD scenario and by 4 percent under the HCD+CO-50 compared to the HCD scenario. Similarly, for India, the total system cost increases by 1.6 percent under the LCD+CO-50 compared to the LCD and remains almost same under the HCD+CO50 scenario compared to the HCD scenario.

5.5 Regional Implications of RE&S cost decline and other selected scenario on BBIN Trade

This section is a comparison of the various selected scenarios that were run on the IRADe's BBIN electricity Trade Model to highlight the regional implications of RE&S cost decline and key selected scenarios on the BBIN region as a whole. It will highlight regional net trade volumes, regional hydro potential utilisation, regional transmission capacity required between countries, system cost savings and regional CO2 savings. Table 5.15 provides the variations among the key parameters for scenario construction. Please note that we have not included the NC scenario in this comparison although it increases the CBET compared to the Base scenario as this increase in trade happens on the expense of higher coal consumption, increased CO2 emissions and increased regional system cost, which is not desirable. Further, the NC scenario is explained in the individual country sections as it helps to understand the concerns of Hydro rich nations (Bhutan and Nepal) around the utilization of hydro potential and change in type of hydro capacity preference with declining RE&S cost in the region.

Table 5.15 Key Variation for Scenario Construction for Base, HCD, HCD+PES, HCD+HiRePo and HCD+CO-50 Scenario

Scenario Abbreviation	RE & Storage cost decline	Trade Restriction	Political Energy Security Constraint of 20% on Energy imports	Higher RE Potential Considered	Carbon Emission Reduction
Base	Lower	**Yes**	No	No	No
HCD	Higher	No	No	No	No
HCD + PES	Higher	No	**Yes**	No	No
HCD + Hi Re Po	Higher	No	No	**Yes**	No
HCD + CO-50	Higher	No	No	No	**Yes**

a) Total Trade in BBIN region

The total power trade (Total trade = the summation of all exports within the region (or the sum of all imports within the region - as both numbers are the same)) within the BBIN region in 2019 was 13 TWh. This power trade can reach as high as 352 TWh and 986 TWh by 2030 and 2050 respectively under different scenarios as shown in Table 5.16. However, with the PES constraint, the trade potential is reduced to half and restricted to reach only 416 TWh by 2050. Figure 5.31 shows the trend in regional power trade (all exports) from the year 2020 to 2050 under different scenarios.

Table 5.16 BBIN Region Total Trade* in 2030 and 2050 for key selected scenarios

In TWh	2030	2050
Base	10	12
HCD	317	984
HCD + PES	263	416
HCD + Hi Re Po	352	976
HCD + CO-50	317	987

**Total Trade = summation of either all exports or imports in the region*

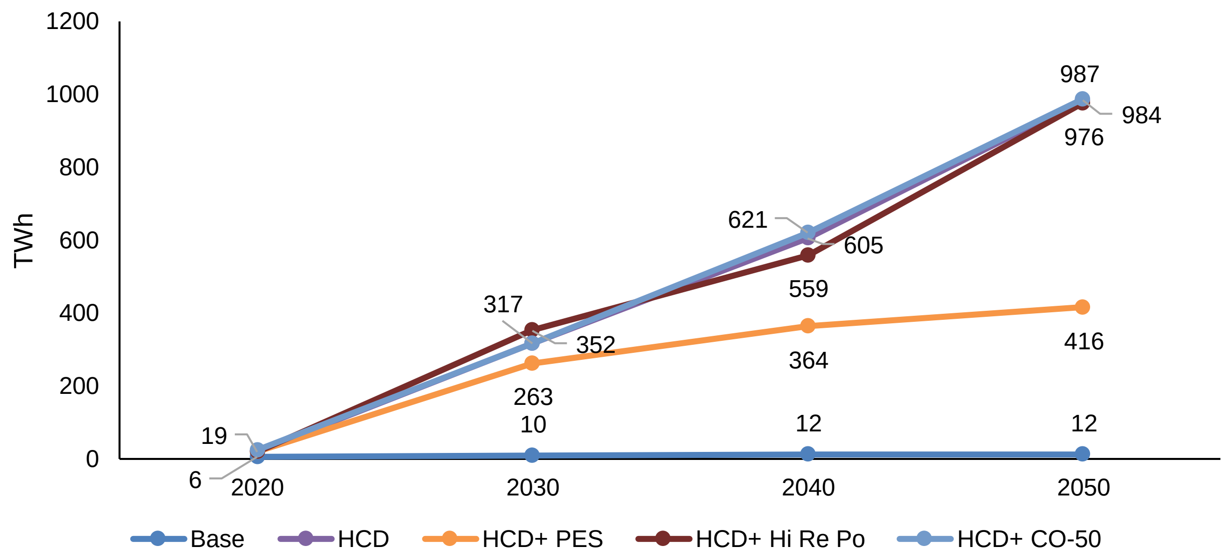


Figure 5.31 Regional Power Trade (all exports) from 2020 to 2050

b) Installed Capacity in BBIN region in 2030 and 2050

Table 5.17 shows the BBIN regional installed capacity in the year 2030 and 2050 under the five different scenarios. It is seen that renewable energy is the preferred technology in scenarios with cost decline in RE&S or high renewable potential. The share of regional RE capacity share in the total capacity in the year 2030 increases from 37 percent in the Base scenario to a highest of 62 percent in the HCD+HiRePo scenario and for other scenarios it remains close to 59 percent. Further, in the year 2050, the regional RE capacity share increases to as high as 75 percent in the HCD+HiRePo scenario and for other scenarios it remains close to 68 to 70 percent.

BBIN region and India witness a similar trend in terms of installed RE capacity which indicates that this surge in RE installed capacity is driven by India rather than the other three nations as India has the maximum potential for RE within the BBIN region as shown in Table 5.18. In the year 2050, the BBIN region has the potential to increase the installation of RE capacity in the range of 49 percent to 86 percent over the Base scenario capacities where trade is restricted to 2017 volumes. This further supports that cross-border trade among the BBIN nations will help in increasing the penetration of RE in the region.

Table 5.17 Installed capacity in BBIN region in 2030 and 2050 for selected scenario

in GW	2030					2050				
	Base	HCD	HCD+ PES	HCD+ Hi Re Po	HCD+ CO-50	Base	HCD	HCD+ PES	HCD+ Hi Re Po	HCD+ CO-50
Solar	100	231	223	224	240	522	766	766	842	766
Wind	87	306	306	403	306	332	526	521	773	581
Total Renewable	**225**	**573**	**565**	**642**	**583**	**891**	**1329**	**1325**	**1653**	**1384**
Coal	237	224	231	224	224	493	332	344	271	316
Gas	35	33	34	32	33	13	7	5	6	7
Nuclear	20	20	20	20	20	62	62	62	62	62
Hydro	74	112	112	112	112	174	214	214	214	214
Diesel	9	9	9	9	9	0	0	0	0	0
Total I.C.	**600**	**971**	**971**	**1039**	**981**	**1633**	**1944**	**1949**	**2206**	**1983**
RE share	37%	59%	58%	62%	59%	55%	68%	68%	75%	70%
Non- Fossil Share	53%	73%	72%	75%	73%	69%	83%	82%	87%	84%
Fossil Share	47%	27%	28%	25%	27%	31%	17%	18%	13%	16%

Table 5.18 Change in renewable capacity in BBIN region and India for selected scenarios over Base scenario in 2050

RE Installed Capacity by 2050 in GW		
	BBIN Region	**India**
Base in GW	891	885
% increase over Base		
HCD	49%	48%
HCD + PES	49%	48%
HCD + Hi Re Po	86%	72%
HCD + CO-50	55%	54%

An increase in RE capacities helps nations to reduce their dependence on Coal capacities. Table 5.19 shows the change in installed coal capacities for different scenarios over the Base for the year 2050. With trade and higher cost decline in RE&S technology, the BBIN region has the potential to reduce the installed coal capacities in the range of 33 to 45 percent compared to the Base scenario. On the country level, a major reduction in coal capacities on the Bangladesh side is overserved when there are no trade restrictions as electricity imports is a cheaper option over the domestic installation of coal capacities.

Table 5.19 Change in coal capacity in BBIN region for selected scenarios over Base scenario in 2050

Coal Installed Capacity by 2050 in GW			
	BBIN Region	**India**	**Bangladesh**
Base in GW	493	375	118
% Reduction over Base			
HCD	33%	13%	96%
HCD + PES	30%	33%	22%
HCD + Hi Re Po	45%	29%	96%
HCD + CO-50	36%	17%	96%

Apart from RE installation, with increasing RE share in the BBIN region, the installation of Hydro capacities also increases. Table 5.20 shows the hydro potential utilization in Bhutan, Nepal and India for the year 2050. It is observed that there is full utilisation of hydropower potential for these three countries. In the Base scenario, Bhutan utilises 10 GW out of 27 GW potential while Nepal utilises 19 GW out of 42 GW potential. However, in the other four scenarios, Nepal and Bhutan utilise the full potential of hydropower. For India, the hydropower potential of 145 GW is utilised fully in all five scenarios.

Table 5.20 Hydro capacity in Bhutan, Nepal and India in 2050

<table>
<tr><th>Hydro Installed Capacity by 2050 in GW</th><th>Bhutan
(Pot. assumed 27 GW)</th><th>Nepal
(Pot. assumed 42 GW)</th><th>India
(Pot. assumed 145 GW)</th></tr>
<tr><td>Base</td><td>10</td><td>19</td><td rowspan="5">145</td></tr>
<tr><td>HCD</td><td rowspan="4">27</td><td rowspan="4">42</td></tr>
<tr><td>HCD + PES</td></tr>
<tr><td>HCD + Hi Re Po</td></tr>
<tr><td>HCD + CO-50</td></tr>
</table>

c) Maximum Regional Transmission Capacity Requirement by 2050

The current regional transmission capacity among BBIN nations was close to 3.8 GW in the year 2020. To assess the future transmission capacity requirements between countries we have assumed the maximum hourly trade between two countries in a year as an indicator of transmission capacity required for that year. Table 5.21 shows the maximum regional transmission capacity requirement by 2050 under different scenarios. The maximum transmission capacity of 174 GW will be required in the BBIN region under the HCD+HiRePo scenario followed by the HCD and HCD+CO-50 scenario.

Table 5.21 Maximum Regional Transmission Capacity Requirement by 2050 for different scenarios

in GW	Bangladesh-India (Bangladesh's Imports)		Nepal- India (Nepal's Exports)		Bhutan- India (Bhutan's Exports)		Total Regional Transmission Capacity Requirement	
Scenarios	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
Base	7	11	0.1	6	2	8	9	25
HCD	29	112	17	28	18	28	65	168
HCD+ PES	15	78	17	28	18	28	51	134
HCD+ Hi Re Po	30	105	17	27	24	41	71	174
HCD+ CO-50	34	111	18	29	18	28	69	168

**Shows import in 2050 for Nepal*

d) CO2/kWh emissions in BBIN region

The regional BBIN CO2 emissions/kWh reduction is shown in Figure 5.60. For all scenarios, we see a reduction in CO2 emissions/kWh for the BBIN region compared to the Base scenario although each scenario has a different rate of reduction. The Base scenario reduces the slowest while the other four scenarios fall at a similarly fast rate. For the Base scenario, we see a reduction to 0.62 in 2030 while the other four scenarios reduce to the range of 0.23-0.28 in the year 2030. By 2050, in the Base scenario, we see a 30 percent reduction compared to 2020 whereas in the other four scenarios it reduces in the range of 60 to 70 percent. The highest reduction CO2/kWh is observed for the HCD+ HiRePo scenario as this scenario leads to the maximum installation of RE capacities in the region due to the twin advantage of the highest cost decline of RE&S technologies and availability of higher RE potential in the region.

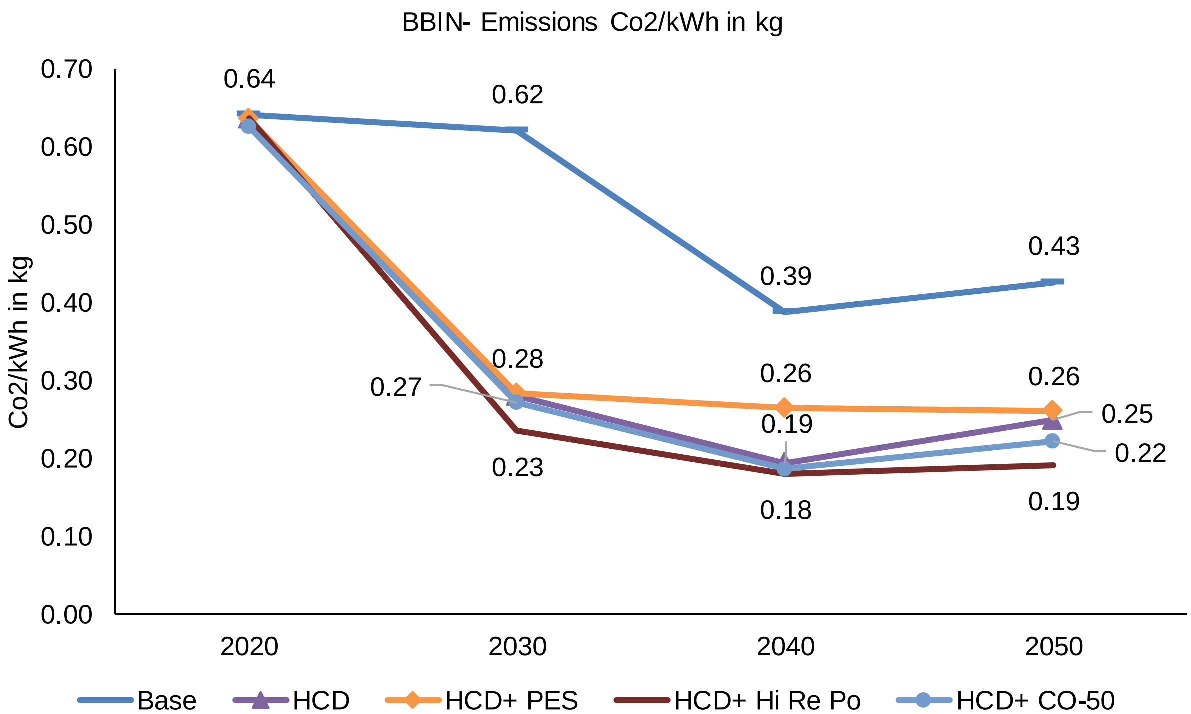
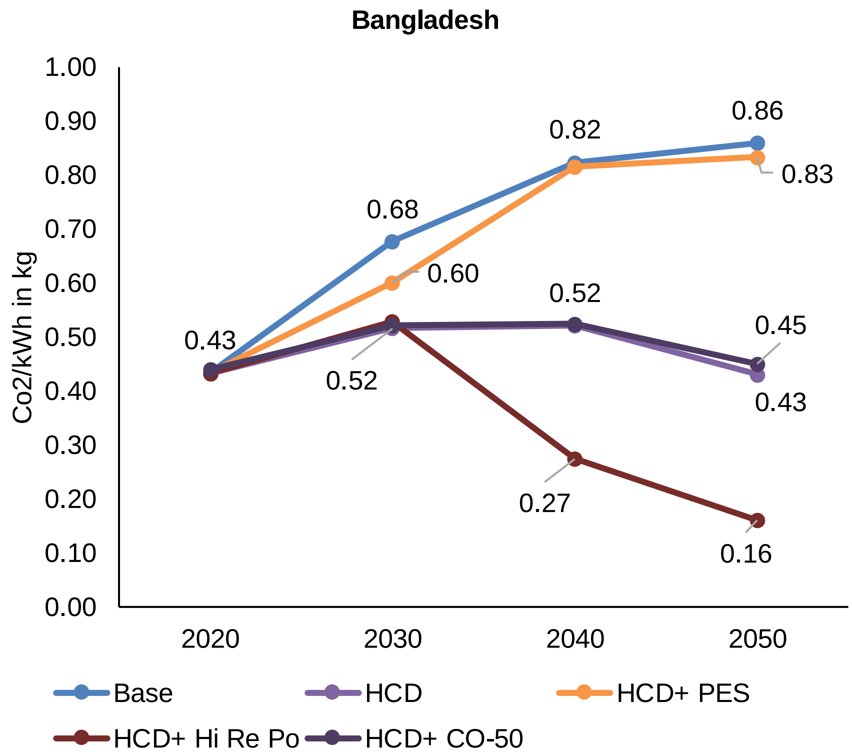


Figure 5.32 CO2/kWh emissions in BBIN region under various scenarios

The country-level CO2 emissions/kWh reduction for India and Bangladesh is shown in Figure 5.33. A similar trend is observed where the Base scenario falls slowest for India while the other four scenarios fall at a similar rate and converge to a range of 0.20-0.26 kg CO2/kWh in 2050. The Base scenario experiences a 45 percent drop in CO2/kWh while the other four scenarios experience roughly 65-68 percent decline compared to 2020.

For Bangladesh, CO2 emissions/kWh actually increase for the Base and HCD+PES scenarios though it falls for the HCD+Hi Re Po, HCD and HCD+CO-50 scenarios. The Co2 emissions/kWh rise in the Base scenario due to constraint on electricity imports forcing the model to install coal and gas-based capacities for meeting final demand. Similarly, in the HCD+PES scenario, there is a cap on power imports by Bangladesh thus increasing its CO2/kWh.



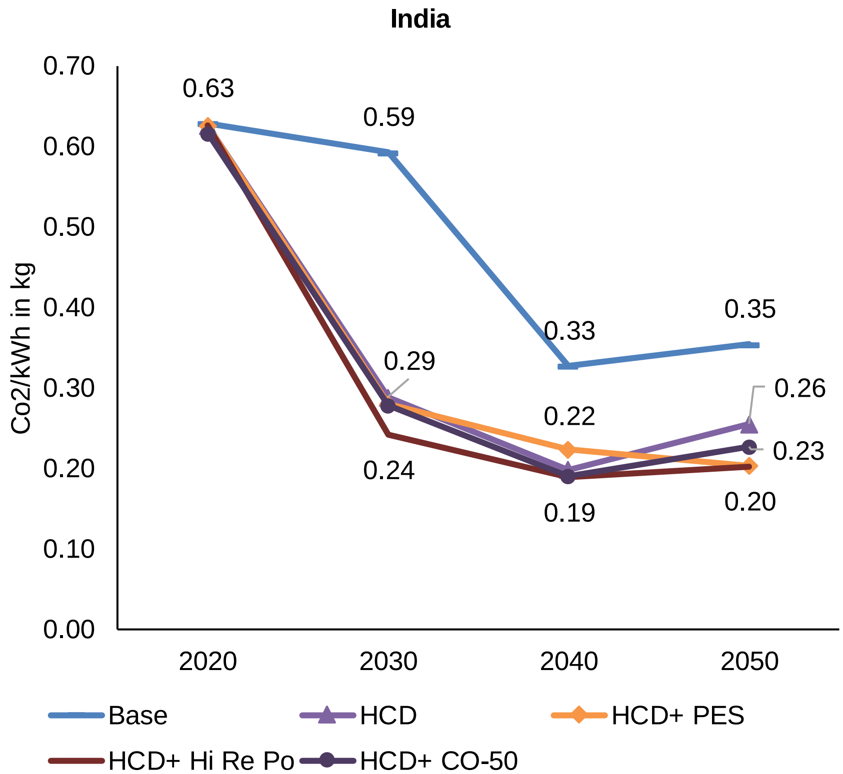


Figure 5.33 Annual CO2 emissions for Bangladesh and India under various scenarios

e) Discounted System Cost in BBIN region

In Table 5.21, the discounted system cost is shown in Billion USD at 2015 prices. We see a cost reduction compared to the Base scenario in all four scenarios for the BBIN region, India, Bangladesh, Nepal and Bhutan. This indicates that trade is better than a restricted or no-trade scenario. The system gains even with the PES constraint where imports are restricted to 20 percent of the consumption demand.

Table 5.21 Discounted System Cost for BBIN region and BBIN countries

Discounted System cost (Objective Function) in Billion USD @ 2015 prices					
	BBIN Region	**India**	**Bangladesh**	**Nepal**	**Bhutan**
Base	2714	2389	301	22	2
HCD	2487	2272	239	-5	-20
HCD + PES	2513	2270	265	-3	-19
HCD + Hi Re Po	2402	2195	225	1	-20
HCD + CO-50	2493	2277	248	-9	-23
Change in system cost over Base (negative represent % reduction and positive represent % increase over Base)					
HCD	-8%	-5%	-20%	-120%	-1068%
HCD + PES	-7%	-5%	-12%	-114%	-995%
HCD + Hi Re Po	-11%	-8%	-25%	-94%	-1037%
HCD + CO-50	-8%	-5%	-18%	-140%	-1224%

f) Key Learnings

Following are the key learnings for the BBIN region from this study:

- **Trade:** The total power trade (Total Trade = summation of all exports or imports in the region) in the BBIN region has the potential to increase from 13 TWh in 2019 to as high as 352 TWh and 986 TWh by 2030 and 2050 respectively under different scenarios. Even with Political Energy Constraint (20 percent electricity import bound), the trade can reach 416 TWh by 2050.
- **Installed Capacity:** In the Base scenario the regional RE installation reaches only 55 percent of the total installed capacity. Whereas the regional RE capacity share has the potential to increase to as high as 75 percent by 2050 under the HCD+HiRePo scenario and it may reach between 68 to 70 percent for other scenarios. This further supports that cross-border trade among the BBIN nations will help in increasing the penetration of RE in the region. The surge in regional RE capacities is driven by RE capacities installation in India as it has the maximum RE potential in the BBIN region.
  In the year 2050, with trade and higher cost decline in RE&S technology, the BBIN region has the potential to reduce the installed coal capacities in the range of 33 to 45 percent compared to the Base scenario.
- **Hydro Potential:** In the Base scenario, Bhutan utilises only 10 GW out of 27 GW hydropower potential while Nepal utilises only 19 GW out of 42 GW hydropower potential. However, in the other four scenarios with the possibility of regional trade and RE&S cost decline, the Nepal and Bhutan utilises their full hydro potential.
- **Regional Transmission Capacity:** The regional transmission capacities between the BBIN nations was close to 3.8 GW in the year 2020. This can increase to a maximum regional transmission capacity requirement of 174 GW by 2050 under the HCD+HiRePo scenario followed by 168 GW requirement in the HCD and HCD+CO-50 scenario.
- **CO2/kWh emissions:** The CO2/kWh emission from the power sector by 2050 is 0.43 kg in the Base scenario and it can be reduced by 40 to 55 percent under different scenarios.
- **System Cost**: In the HCD scenario, the region can save around 8 percent on the total discounted system cost (2015 to 2050) compared to the Base scenario, which will be close to 227 billion USD at 2015 prices. Further, under the HCD+HiRePo the region can save around 11 percent on the total discounted system cost i.e. close to 312 billion USD at 2015 prices.

5.6 Impact on Hourly Generation for BBIN Countries under Cost Decline Scenarios

This section provides insight into the operational behaviour of the generation system for each country for the year 2050 for a selected month.

a) Impact on Hourly Generation for India

The Base and HCD scenario hourly generation profile for a typical day in January month is shown in Figure 5.34. In January month, under the Base case, the system observes high solar generation and slight over generation in the middle of the daytime. During the daytime when solar generation is at peak, coal capacity backs down to 55 percent technical minimum. In non-solar generation hours i.e. early morning or evening hours, hydropower support is required by the system. Further, in the HCD scenario, there is Battery Energy Storage (BES) support requirement in the evening hours. The BES system is charged during the high solar generation hours in the afternoon. Excess generation in the system is trade to the region represented as Net Exports (negative values) in the figure below the X-axis.

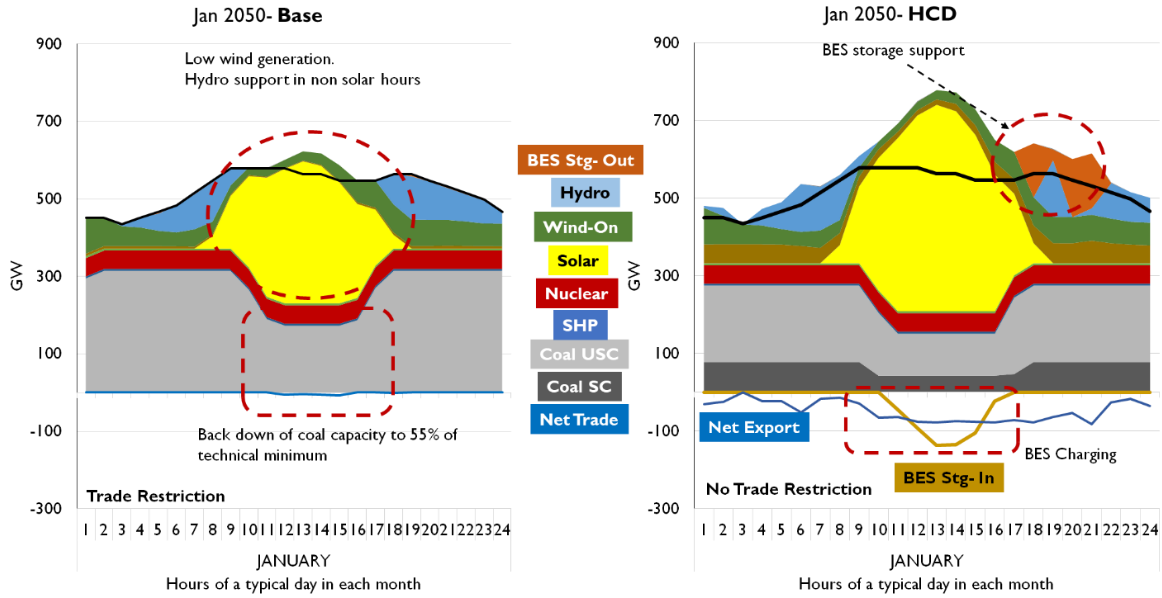


Figure 5.34 Impact of RE on hourly generation for India in January 2050 for Base and HCD Scenario

The September month is typical high wind and hydro generation month in India. Figure 5.21 shows that in September 2050 the Base scenario experiences higher wind generation and also there is a need to back down coal capacity to 55 percent of technical minimum during the daytime when solar generation is high. Further in the HCD scenario, for September month the wind generation is high and there is BES support taken by the system to manage peak evening demand.

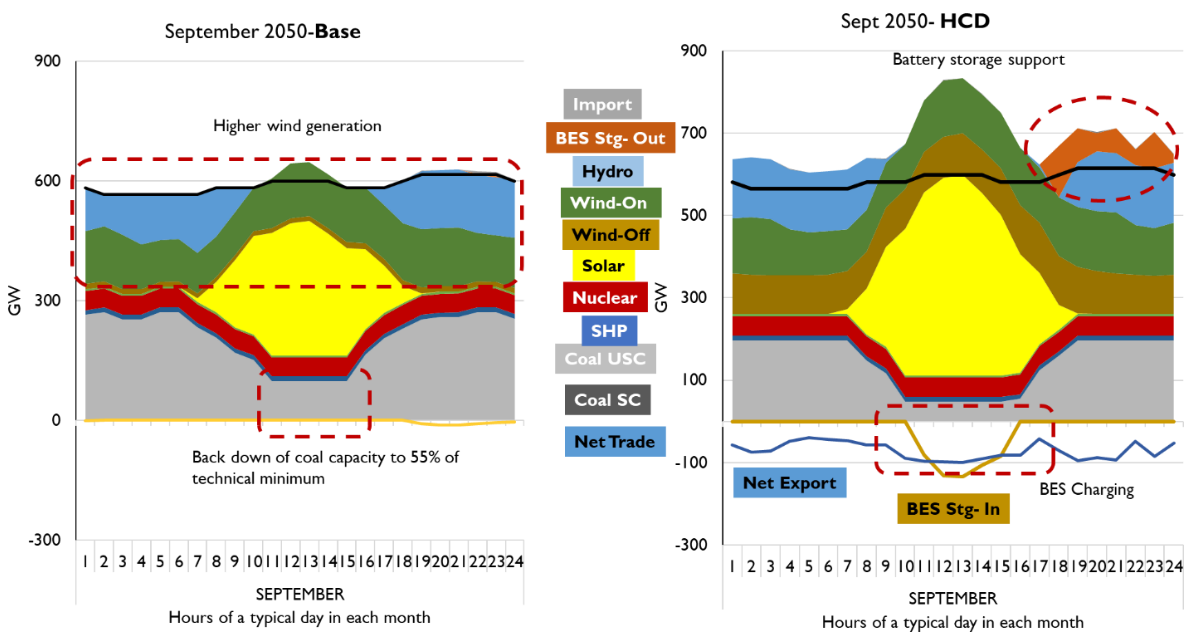


Figure 5.35 Impact of RE on hourly generation for India in September 2050 for Base and HCD Scenario

On the regional level, by 2050 India will be a net exporter of power to the region as it imports power from Bhutan and Nepal and exports it to Bangladesh. The hourly net trade of India for the year 2050 under the HCD, HCD+PES, HCD+HiRePo and HCD+CO-50 Scenario is shown in Figure 5.36.

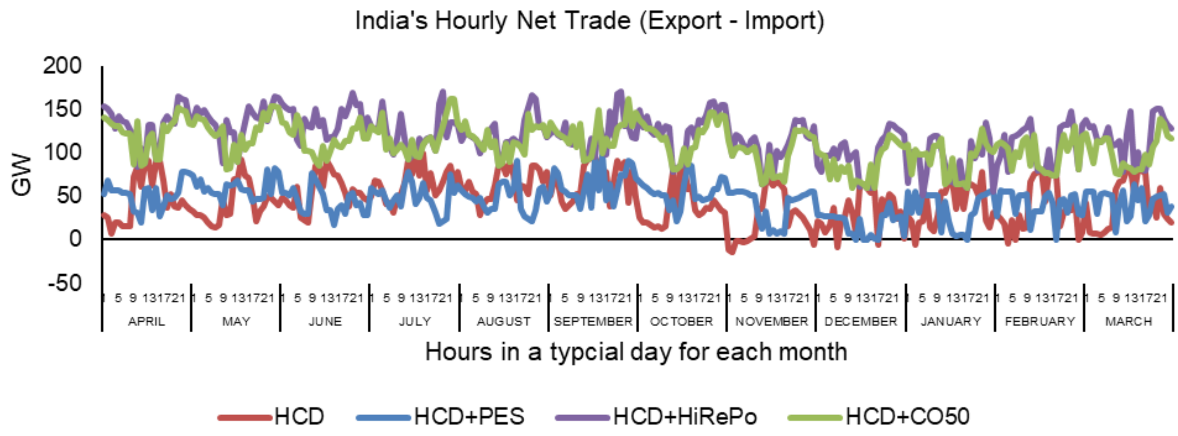


Figure 5.36 Indian Hourly Net Trade for 2050 for HCD, HCD+PES, HCD+HiRePo and HCD+CO-50 Scenario

b) Impact on Hourly Generation for Bangladesh

On the Bangladesh side, the impact on hourly generation will be significant. Figure 5.37 shows hourly generation for the Base and HCD scenario for September 2050. In the Base scenario, due to import restricted to 2017 volumes, the model installs huge coal capacities domestically. Further with no import restriction in the HCD scenario, the Bangladesh model imports huge volumes of electricity as it is cheaper than generating domestic electricity. Apart from electricity imports, the model uses the support of BES in late peak hours and charging of BES is observed during the daytime.

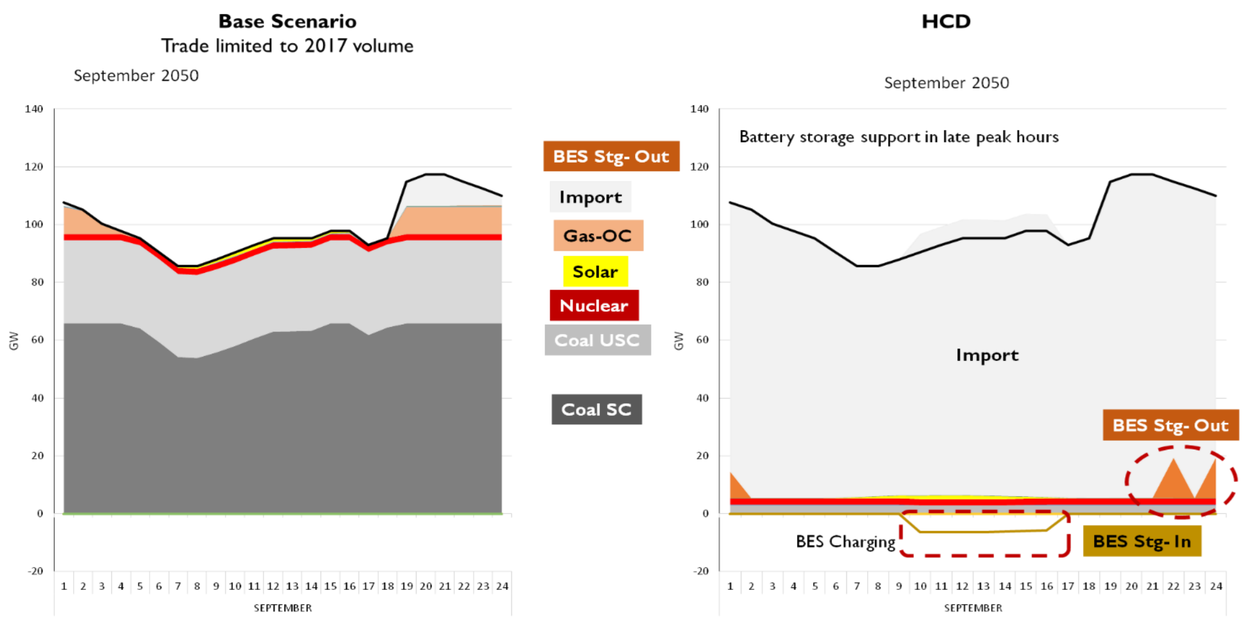


Figure 5.37 Bangladesh Hourly Generation in September 2050 for Base and HCD Scenario

c) Impact on Hourly Generation for Nepal

For Nepal, the hourly generation pattern for January month of year 2050 for the Base and HCD scenario is shown in Figure 5.38. In both the scenario, the model prefers pondage and storage-based hydro over ROR hydro capacities. In the Base scenario, due to limited trade restriction, the Nepal model installs only sufficient capacity to meets its domestic demand and further, it imports cheaper electricity during solar generation hours from the BBIN Region. In the HCD scenario, the Nepal model utilises full hydro potential and exports electricity to the BBIN region during non-solar generation hours. This indicates that hydro power is more utilized to support the power system in the BBIN region during non-solar generation hours.

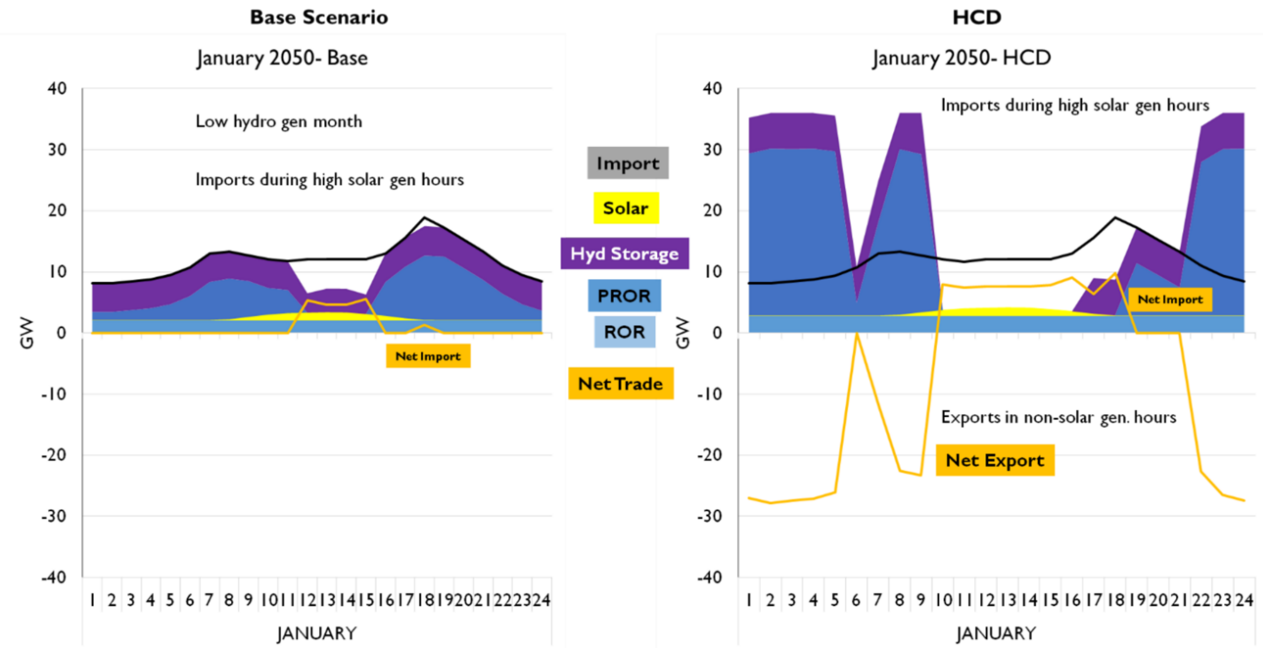


Figure 5.38 Nepal Hourly Generation in January 2050 for Base and HCD Scenario

d) Impact on Hourly Generation for Bhutan

Figure 5.39 shows Bhutan's hourly generation pattern for January month of the year 2050 under the Base and HCD scenario. In the Base scenario, the model on the Bhutan side only installs capacities to meet its demand (domestic demand of close to 1 GW in 2050) and to undertake electricity export within the trade restricted constraint. Due to this low demand and trade restriction, we observed some over-generation in the system on the Bhutan side. Further, in the HCD scenario, the model utilises both the hydropower potential as well as the solar potential to support electricity export from Bhutan. Electricity exports from Bhutan are primarily undertaken during non-solar generation hours as hydropower in installation in Bhutan is storage based. In addition to this, the model also uses BES system on the Bhutan side to supplement electricity exports to the BBIN region. The BES is charged during the daytime when solar generation in the system is high.

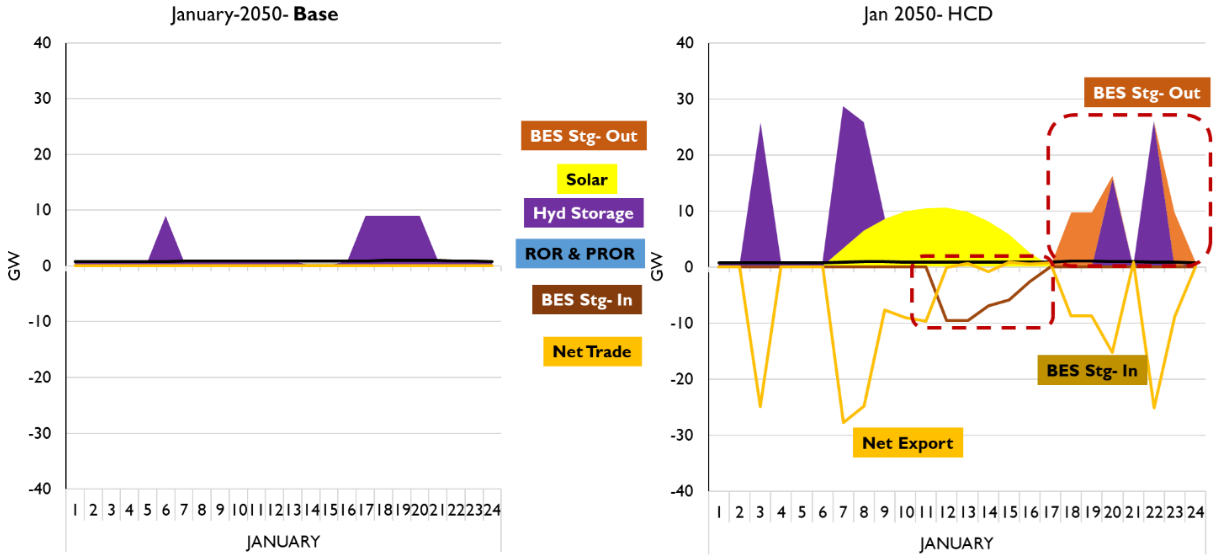


Figure 5.39 Bhutan Hourly Generation in January 2050 for Base and HCD Scenario

e) Key Learnings from Hourly Generation analysis

Following are the key learnings for each country based on the hourly generation analysis:

- **India:** By 2050, the share of RE capacities will increase thus increasing generation from both solar and wind installations into the system. The high solar generation during the daytime will force backing down of coal capacities to 55 percent technical minimum. Further, in non-solar generation hours i.e. early morning or evening hours, hydropower support is required by the system to meet the demand. In addition to this, the system will use BES in case where higher cost decline in RE&S technologies is observed. The BES system will be charged during the high solar generation hours (i.e. daytime) and stored electricity is used to support the system in peak demand hours (i.e. evening time). Flexibility in generation resources will be required with higher RE generation into the system.
- **Bangladesh:** The restriction on volumes of electricity imports will alter the choices of model for providing domestic generation in Bangladesh. By 2050, if trade restriction is in place then in the absence of carbon emission constraint and restricted RE potential assumption, the model will install significant coal capacities to manage demand. However, in case of no trade restriction, the model uses imported electricity to meet around 93 percent of its demand as electricity import is a least cost option. Further, if RE potential is assumed to be 60 GW along with RE&S cost decline, then this will help to offset some volumes of electricity imports. In addition to this, with high RE&S cost decline, the BES system can provide storage support in evening hours when demand is high and charging of the BES is undertaken in the high regional RE generation hours.
- **Nepal and Bhutan:** For both Bhutan and Nepal, the model prefers the installation of flexible hydro with storage possibilities so that it can support electricity exports at non-solar generation hours to the BBIN region. Further, with the RE&S cost decline, both hydro as well renewable potentials are fully utilised to support electricity exports.

Chapter 6. Key Messages and Way Forward

6.1 Key Messages

The study has multiple key messages for the region as a whole and also for the individual country. Following are the key messages for the BBIN region from this study:

BBIN Region:

a) **Higher Trade:** With cost decline in RE&S the regional electricity trade can reach from 13 TWh in 2019 to as high as 986 TWh by 2050. Even with a PES constraint (where electricity import in a year is restricted to 20 percent of domestic demand) the regional trade reaches 416 TWh by 2050.

b) **Time of Trade:** With higher RE capacities in the BBIN region, the time at which electricity trade is required will change. For instance, the hydro exporting nations such as Nepal and Bhutan will supply more electricity to the region in non-solar hours than solar generation hours.

c) **Hydro Potential**: Full hydro potential utilisation in Bhutan and Nepal is supported by regional trade and RE&S cost decline. Further, flexibility in hydropower generation will be a key element in deciding the utilisation of hydropower plants in the region.

d) **RE potential:** The RE potential in the region needs to be reassessed from time to time considering the technology development and cost declines as higher RE potential can bring more benefits to the region.

e) **RE installed capacity:** Share of RE capacities in the total installed capacities can go as high as 75 percent by 2050 under the HCD+HiRePo scenario which reaches only 55 percent in the Base scenario. This increase in RE capacity will help in reducing installed coal capacities in the region in the range of 33 to 45 percent compared to the Base scenario.

f) **Regional Transmission Capacity:** For supporting the above trade numbers, the regional transmission capacity needs to increase from 3.8 GW in 2020 to as high as 174 GW by 2050 under the HCD+HiRePo scenario.

g) **System Cost:** With RE&S cost decline, on the total discounted system cost (2015 to 2050) the region can save around 227 billion USD at 2015 prices in the HCD scenario and close to 312 Billion USD at 2015 prices in the HCD+HiRePo compared to the Base scenario.

Bhutan and Nepal:

Both Bhutan and Nepal will gain from RE&S cost decline in the region as the net trade increase from both the countries under various RE&S cost decline scenarios. Further, flexible hydro such as pondage-based ROR and storage-based hydropower plants will be more utilised in the region with increasing RE share in electricity generation as they can generate electricity in non-solar generation hours and during the winter season. In addition to this, RE&S cost decline will support the higher installation of both hydropower as well as RE capacities in both countries. Under most of the scenarios, the total discounted system cost for Bhutan and Nepal is negative indicating that their export earnings will be higher than total system costs.

Under the condition of only unrestricted trade and no RE&S cost decline, the trade levels reaches full potential for both Bhutan and Nepal with utilization of mostly ROR based hydro capacities. However, this leads to increase in regional system cost, coal consumption and emission at regional level which is not synchronous with the current dynamics of expected cost decline in RE&S and its implications on the preference of hydro capacity installation.

Bangladesh:

Bangladesh has to choose from regional power imports versus domestic generation using imported fuels as domestic fuel availability is limited. Therefore, under the RE&S cost decline scenarios, Bangladesh electricity imports can be as high as 93 percent of its domestic demand by 2050. Electricity imports from the BBIN region can help Bangladesh in reducing its total system costs by 20 percent (61 Billion USD at 2015 prices) and 25 percent (75 Billion USD at 2015 prices) under the HCD and HCD+HiRePo scenario respectively compared to the Base scenario.

India:

The RE&S cost decline will help India in achieving higher RE installed capacity as it has the highest RE potential within the BBIN region. With higher RE, the requirement for flexible hydropower generation will also increase. India can be a net exporter of power if power imports by Bangladesh is not restricted. With RE&S cost decline, on the total discounted system cost (2015 to 2050) India can save around 117 Billion USD at 2015 prices in the HCD scenario and 194 Billion USD at 2015 prices in the HCD+HiRePo compared to the Base scenario.

6.2 Way Forward

This study is one of its kind in the BBIN region that focuses on the implications of RE&S cost decline on the regional electricity trade. It is evident from the study that electricity trade in the region will increase further with RE&S cost decline along with bringing huge system cost savings and environmental benefits in terms of lower CO_2 emissions. To harness the full potential of electricity trade, the trade partners in the region need to develop harmonizing policies and trust among themselves to further accept their dependence on each other. The decision for electricity trade needs to be analysed from the economic and system planning level, and not just from the geopolitical level.

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Annexures

Annexure 1: Solar Energy

a) Solar Photovoltaic

Various renowned global REN research agencies like Fraunhofer, National Renewable Energy Laboratory (NREL), Energy Technology Reference Indicator (ETRI) and International Renewable Energy Agency (IRENA) have reviewed and forecasted the Capex of solar PV technologies from 2015 until 2050 and the projections are shown in Figure A1.

Fraunhofer has developed three long-term scenarios using assumptions on yearly market growth rates i.e. 5%, 7.5% and 10% per year after 2015, also an additional PV breakthrough scenario was suggested at the expert workshop that assumes a Compound Annual Growth Rate (CAGR) of 20% until 2020, 14% in the period of 2020 to 2030, 8% from 2030 to 2040 and 4% from 2040 to 2050. The percentage reduction in the Capex of SPV achieved through all the four scenarios are 48%, 54%, 59% and 64% respectively and the learning rates considered are 19%, 20.90% and 23% (Fraunhoffer, 2015).

Energy Technology Reference Indicator (ETRI) has reviewed three scenarios that are: (i) Ref, High and Low and the learning rates considered are 16%, 14%, 12%, 11% and 10%; the percentage reduction in Capex of solar PV projected for these scenarios is 53%, 36% and 33% respectively (ETRI, 2014).

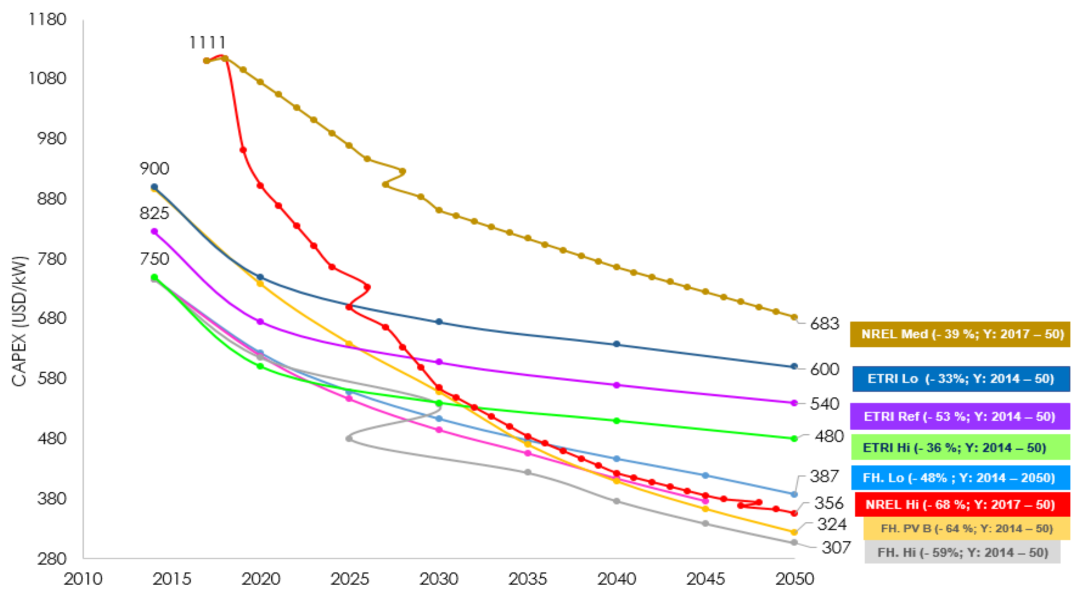


Figure A1 Projected Reduction of Capex for SPV Technology from 2014 until 2050

(PV B – PV Breakthrough; Lo – Low; Med - Medium; Hi – High)

Source: FH. – Fraunhoffer; NREL - National Renewable Energy Laboratory; ETRI- Energy Technology Reference Indicator; IRENA - International Renewable Energy Agency

NREL report has reviewed two scenarios i.e. High and Medium scenarios and the percentage reduction in Capex of SPV projected by the scenarios is 68% and 39% respectively. The Low scenario is based on low bound of literature projections of future Capex and O&M technology pathway analysis by NREL and the Medium scenario is based on median of literature projections of future Capex and O&M technology pathway analysis.

The solar PV module price in 14 countries for the year 2013 and 2019 has been shown in Figure A2; the percentage reduction in their prices has been highlighted in the figure; it is evident that the cost of modules has reduced across all the 14 countries due to economies of scale and technological improvements.

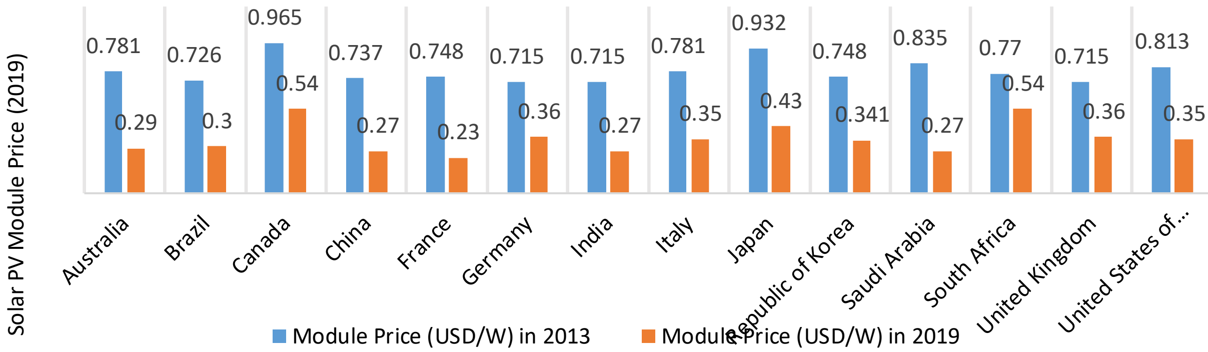


Figure A2 Solar PV Module Price (2019 USD/Watt) in 14 countries

Source: Renewable Power Generation Costs in 2019, IRENA

The LCOE of Solar PV technology for six countries namely China, France, Germany, Italy, Japan and the UK for the year 2010 to 2019 is shown in Figure A3; a decreasing trend is evident for all the countries with maximum reduction recorded for Italy due to significant reduction in module prices along with reduction in Balance of System (BoS) costs; the main challenge faced in the deployment of Solar PV in China has been the growing cost of RE subsidies and grid integration; however the RE policies in China are being modified in order to switch from feed-in-tariff (FIT) program to a quota system with green certificates along with the introduction of ambitious power market reforms, new transmission lines, and the expansion of distributed generation, thereby speeding up the deployment of PV in China (IBEF,2018).

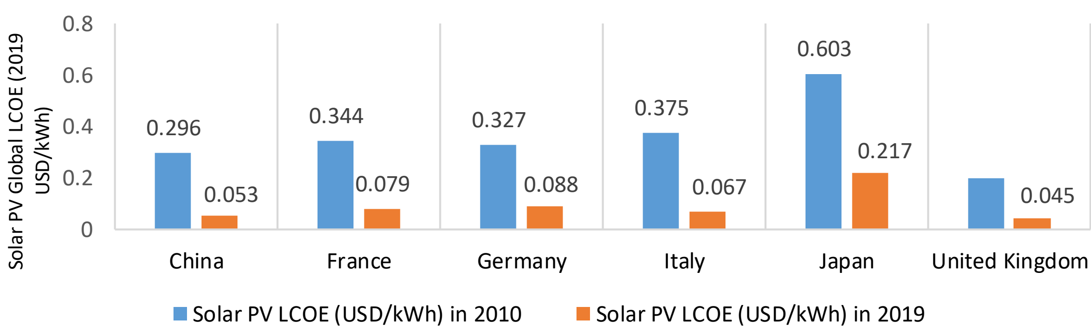


Figure A3 Country wise LCOE of Solar PV (2019 USD/kWh) - Percentage Difference 2010 – 2019

Source: Renewable Power Generation Costs in 2019, IRENA

b) Concentrated Solar Plant

Various renowned global REN research agencies like National Renewable Energy Laboratory (NREL) and Energy Technology Reference Indicator (ETRI) have reviewed and forecasted the Capex of CSP technologies from 2013 until 2050 and the projections are shown in Figure A4.

Energy Technology Reference Indicator (ETRI) has reviewed three scenarios that are: (i) Ref, High and Low with the learning rate of 10%; the percentage reduction in Capex of CSP projected for these scenarios is 39%, 37% and 42% respectively (ETRI, 2014).

The percentage reduction achieved by the two scenarios projected by NREL i.e. High and Medium is 66% and 50% respectively. The Low scenario is based on the low bound of literature projections of future CAPEX and O&M technology pathway analysis by NREL and the Medium scenario is based on the median of literature projections of future CAPEX and O&M technology pathway analysis.

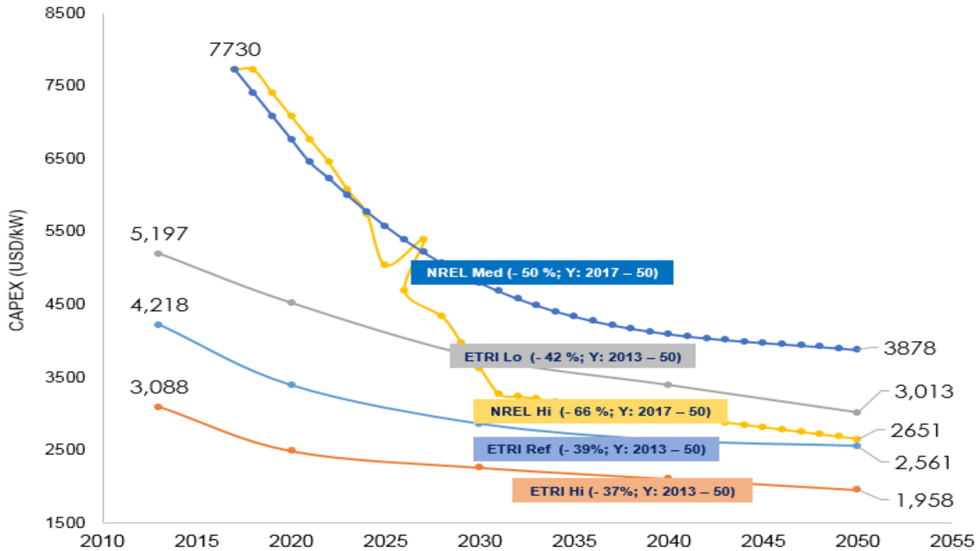


Figure A4 Projected Reduction of Capex for solar CSP Technology from 2013 until 2050

(Lo – Low; Med - Medium; Hi – High; Ref - Reference)

Source: NREL - National Renewable Energy Laboratory; ETRI- ETRI- Energy Technology Reference Indicator

Annexure 2: Wind Power

a) Onshore Wind

The reduction in total installed cost varies for each country and can be evident when large-scale commercial deployment starts. China, India and the United States have experienced the largest decline in total installed cost. In 2019, the average total installed cost for the country was around USD 1222/kW in China and USD 1054/kW in India (IRENA,2019). Figure A5 shows the total installed cost of onshore WPT in 11 countries in the year 2019 as compared to 2010. China has the lowest total installed cost for onshore WPT followed by Sweden and Spain in 2019.

Various renowned global REN research agencies like National Renewable Energy Laboratory (NREL) and Energy Technology Reference Indicator (ETRI) have reviewed and forecasted the Capex of onshore WPT technologies from 2013 until 2050 and the projections are shown in Figure A6.

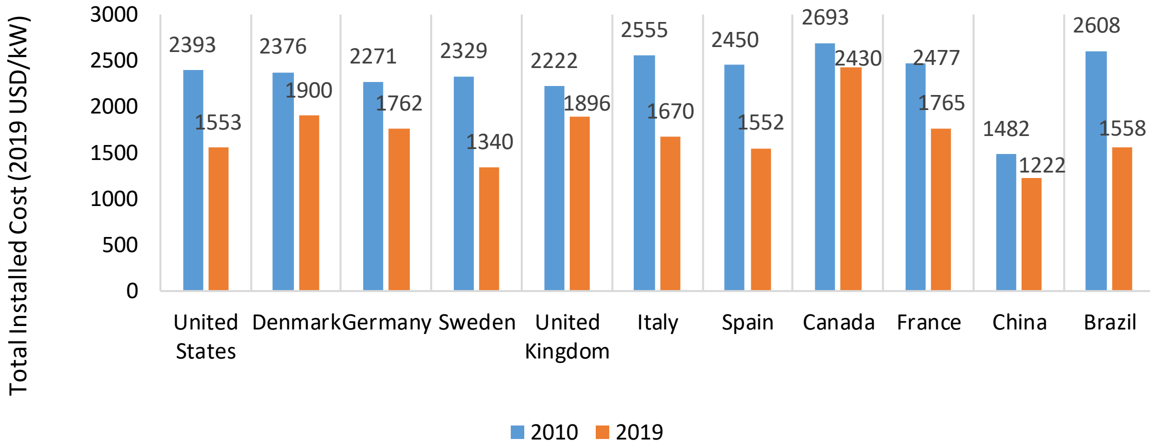


Figure A5 Onshore WPT Total Installed Cost (2019 USD/kW)

Source: Renewable Power Generation Costs in 2019, IRENA

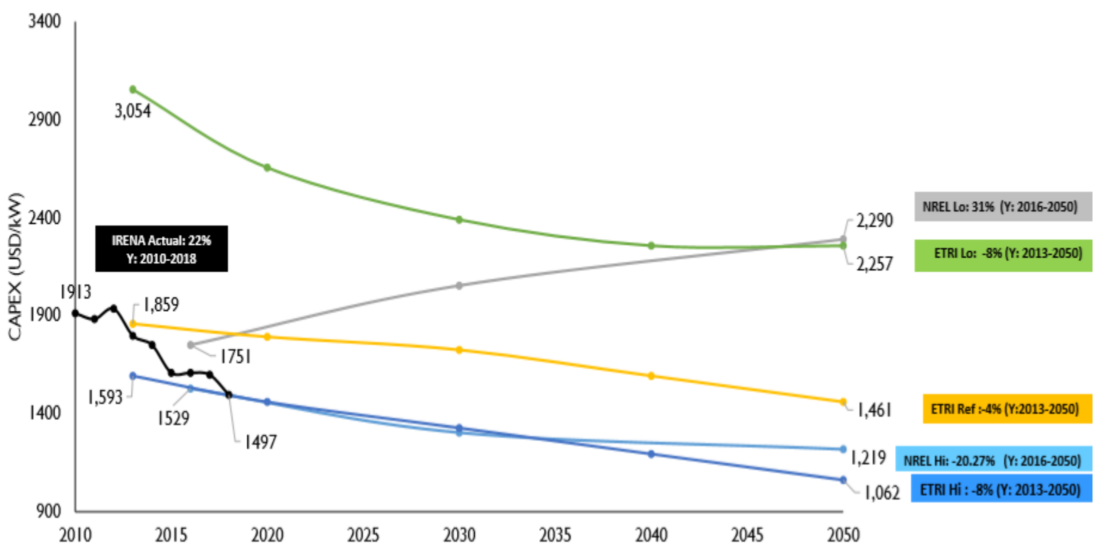


Figure A6 Onshore WPT Capex Projections (Lo – Low; Hi – High; Ref - Reference)

Source: NREL – National Renewable Energy Laboratory; ETRI – Energy Technology Reference Indicator

b) Offshore Wind

As per Energy Technology Reference Indicator (ETRI) projections for 2010-2050 (JRC, 2014), the offshore wind in spite of being a less mature technology as compared to onshore wind, a greater Capex reduction is expected until 2050 due to technological advancements resulting in an increased technical lifetime and maximum capacity factors. Also, as per DECC (Climate, 2011), future cost projections assume steel prices to remain constant in real terms and future cost projections apply central learning rates to high, medium and low costs. According to NREL, the assumptions taken for Capex projections of offshore wind power technology are based on estimates obtained from BVG (Valpy et al. 2017), (Hundleby et al. 2017)) for both fixed-bottom and floating offshore wind technologies. The factors considered by them are technology innovations such as larger rotors and taller towers that may increase energy capture at an identical geographical location without explicitly specifying tower height and rotor diameter changes. Moreover, for the low scenario they have assumed that there would be an increase in public and private investments along with R&D collaborations coupled with accelerated market growth will provide the necessary breakthroughs in reducing the Capex of offshore WPT.

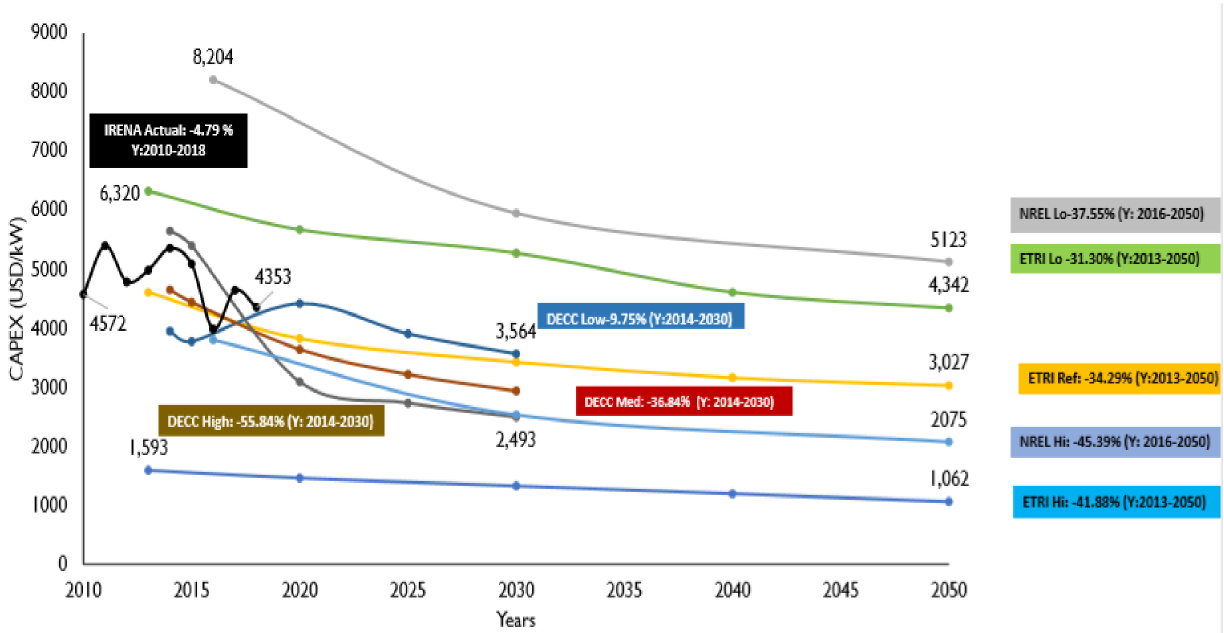


Figure A7 Offshore WPT Capex Projections (Lo – Low; Hi – High; Ref - Reference)

Source: DECC - Department of Energy and Climate Change; NREL - National Renewable Energy Laboratory; ETRI- Energy Technology Reference Indicator

Annexure 3: Storage Technologies

Storage technologies will play a crucial role in enabling the next phase of the energy transition by boosting solar and wind power generation; it will allow sharp decarbonisation in key segments of the energy market also will enable the growth of variable renewable energy (VRE) to substantial levels, as a result, the electricity system will require greater flexibility (The Year of Concentrating Solar Power, 2014, US Dept. of Energy). At very high shares of VRE, electricity will need to be stored over days, weeks or months. By providing these essential services, electricity storage can drive serious electricity decarbonisation and help transform the whole energy sector (IRENA, 2017).

Li-ion batteries are currently dominating the market, but a diverse blend of battery technologies is beginning to be deployed. Thermal energy storage using molten salt is also being widely used in connection with concentrated solar power (CSP) projects (ibid). Energy storage can integrate a large quantum of VRE and offer multiple services that can help stabilize and strengthen the grid (Electricity Storage and Renewables: Costs and Markets, IRENA). The traditional function of energy storage is to absorb energy during periods of an excess generation marked by low prices in order to release it back to the electricity system in times of scarcity or high prices. Storage facilities can be located with the consumer, with the generator or at the transmission or distribution grid level. Batteries have already been used for a variety of applications at a relatively small scale. Technology is still improving and will allow batteries to achieve a substantially larger scale and make them more suitable for frequency support and increase the speed of response (Chattopadhyay et al.).

Stationary battery storage is quickly establishing itself in an increasing number of markets, where the technology already supports the dissemination of solar, and will soon be crucial to ensure penetration of solar and wind technologies to the next level. The International Renewable Energy Agency (IRENA), analysing the effects of the energy transition until 2050 in a recent study for the G20, found that over 80% of the world's electricity could derive from renewable sources by that date. Solar photovoltaic (PV) and wind power would at that point account for 52% of total electricity generation. Electricity storage capacity can reduce constraints on the transmission network and can defer the need for major infrastructure investment. This also applies to the distribution, regardless of whether constraints reflect growth in renewables or a change in demand patterns. In the next section, we discuss the global Capex trend and projections for various energy storage units.

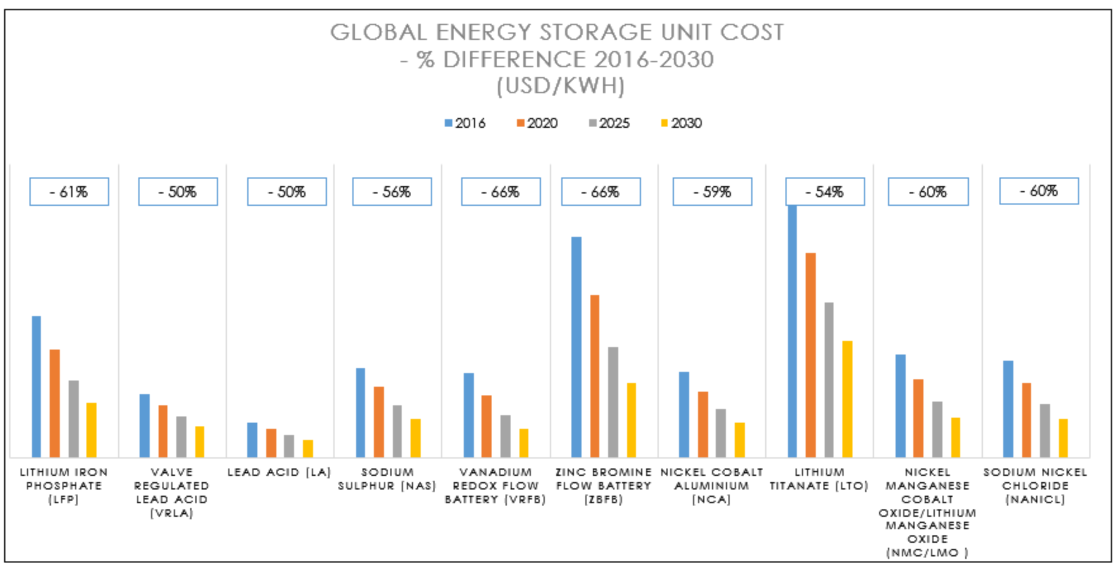


Figure A8 Global Energy Storage Unit Cost (USD/kWh) - % difference 2016-30

Source: Renewable Power Generation Costs in 2017, IRENA

a) Lithium Ion Battery Storage Capex Trend & Projections

Li-ion batteries are being foreseen as the primary candidate for electric vehicles (EVs) and residential renewable system applications as well. More than 500 MW of stationary Li-ion batteries were deployed worldwide by the year 2015, which further increased up to 1,629 MW by 2018. Their commercialization started in the early 1990s; Li-ion batteries are prevalent across a variety of industries due to their high specific energy, power, and performance. According to Bloomberg New Energy Finance New Energy Outlook (BNEF 2018), over 1,200 GW of additional Li-ion battery capacity is expected to be added by the year 2050. The Capex projections by various renowned global REN research agencies are given below:

ETRI 2014: The capital costs will see a decrease of 66 % between 2010 and 2020 and 14 % between 2020 and 2030. Also, costs between 2020 and 2030 will decrease at a slowing rate (79 %, which derives from (66 %-14 %)/66 %)) which concludes that some cost improvement is foreseen in these decades, but the improvement will be smaller each time. The same trend was applied to estimate costs improvement in the period 2030-2040 and 2040-2050. According to this methodology, costs would decrease by 3 % between 2030 and 2040 and by 1 % in the following decade. ETRI predicts storage costs of $124/kWh, $207/kWh, and $338/kWh in 2030 and $76/kWh, $156/kWh, and $258/kWh in 2050. All projections show a decline in Capex i.e. 10-52% by 2025, 21-67% reduction by 2030 and 31-80% reduction by 2050.

NREL 2018: Low, Mid, and High-cost projections were developed on a normalized basis relative to the published values. NREL predicts storage costs of $496/kW, $828/kW, and $1352/kW in 2030 and $304/kW, $624/kW, and $1032/kW in 2050. All projections show a decline in Capex, with cost reduction of 10-52% by 2025, 21-67% by 2030 and 31-80% reduction in Capex by 2050. NREL developed these projections after analysing over 25 publications that consider utility-scale storage costs.

USDE HydroWIRES 2018: Suitable multiple ranging from 0.65 for Li-ion battery systems to 0.85 for lead-acid battery systems were used to forecast 2025 prices from 2018 prices. An E/P ratio of 4 hours was used. The drop in Li-ion price was estimated to be 67%. Total project costs are estimated for a hypothetical 1 MW/4 MWh BESS.

For the year 2018, the total project cost ranged from 1570 $/kW to 2322 $/kW across the reviewed literature with a single value estimate of 1876 $/kW. And for the year 2025, the total project cost is expected to reduce to 1231 $/kW to 1676 $/kW across the reviewed literature with a single value estimate of 1446 $/kW.

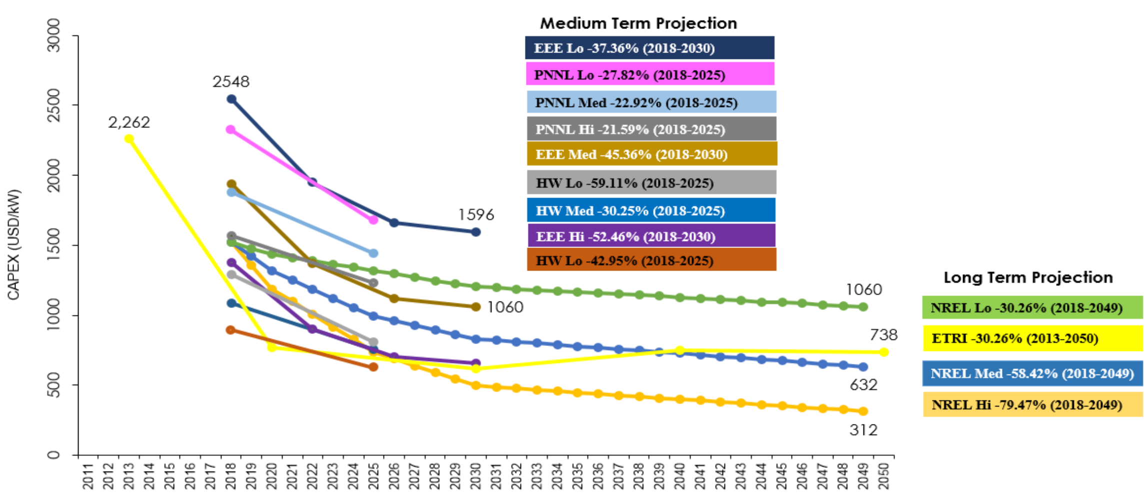


Figure A9: Lithium-ion Battery Storage Capex Trend & Projections (Lo – Low; Med – Medium; Hi – High)

Source: ETRI- Energy Technology Reference Indicator; HW - USDE HydroWIRES; NREL - National Renewable Energy Laboratory; PNNL- Pacific Northwest National Laboratory

b) Vanadium Redox Battery Storage Capex Trend & Projections

VRBs are capable of stepping from zero output to full output within a few milliseconds. They have high-efficiency levels, short-term response times and little maintenance needs during their lifetime. Their efficiency ranges from 70% to 80%. Most common VRB installations range from 50kW and 1MW. Commercial units range from 5kW and 250KW. Their technical complexity and relatively low energy density are the disadvantages, which makes them less competitive. Ongoing research may reduce stack costs by addressing individual components and/or by increasing the power density. The Capex projections by various renowned global REN research agencies are given below:

ETRI 2018: ETRI predicts storage costs of \$548/kWe, \$157/kWe, and \$383/kWe in 2030 and \$233/kWe, \$135/kWe, and \$330/kWe in 2050. All projections show a Capex decline of 41-73% by 2030 and 74-75% by 2050.

USDE HydroWIRES 2018: For the year 2018, the total project cost ranged from 1740\$/kW to 3808\$/kW across the reviewed literature with a single value estimate of 2220\$/kW. For the year 2025, the total project cost is expected to reduce to 1304\$/kW to 2572\$/kW across the reviewed literature with a single value estimate of 1572\$/kW.

PNNL 2012: The Capex of the system for the year 2012 was 1,111 \$/kW, PNNL estimates the same to be 775 \$/kW in 2020.

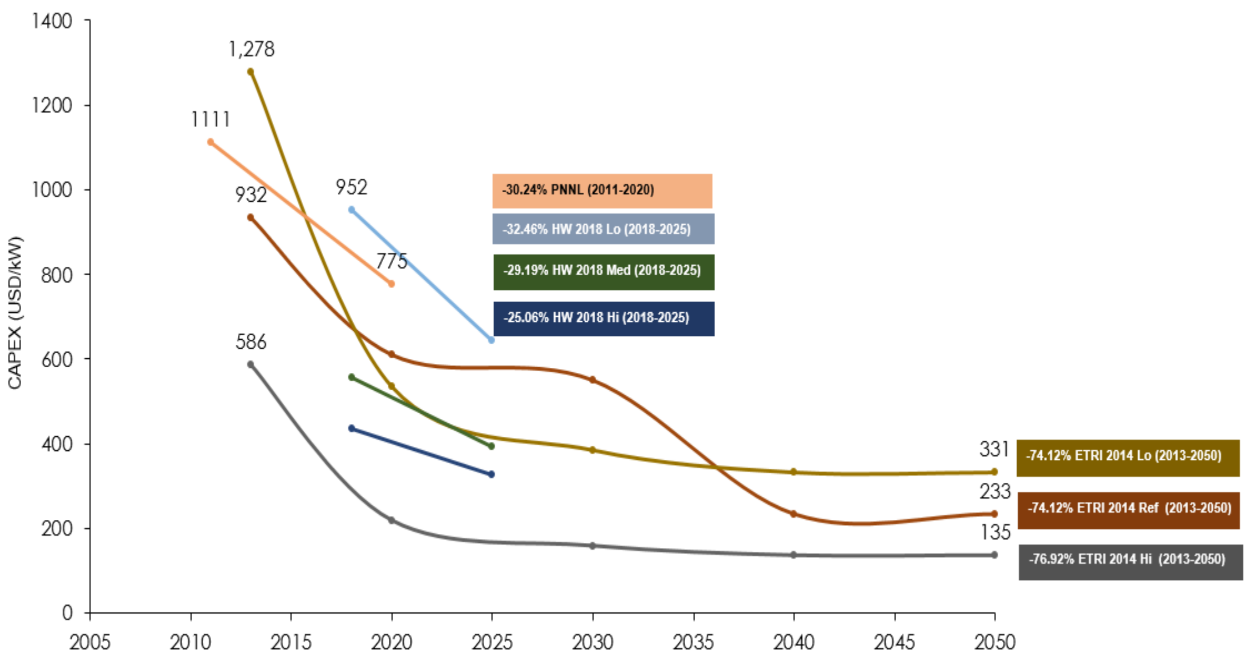


Figure A10: Vanadium Redox Battery Storage Capex Trend & Projections
(Lo – Low; Med – Medium; Hi – High; Ref - Reference)

Source: ETRI- Energy Technology Reference Indicator; HW - USDE HydroWIRES; NREL - National Renewable Energy Laboratory; PNNL- Pacific Northwest National Laboratory;

Annexure 4: Overview of Power Sector of BBIN countries

A4.1 **Bangladesh**

Bangladesh is one of the fastest growing economies in South Asia and aims to achieve 'middle-income country' status by 2021 and 'high-income country' status by 2041 (BPDB, 2019). Electricity is crucial for development, poverty eradication, sustainable growth and security of any country. Bangladesh's power sector is one of the fastest growing in South Asia and capacity growth has been tremendous in the last decade. Economic development has led to rising electricity demand and created a requirement to upgrade the power generation infrastructure. Bangladesh has extremely high electricity access of 97% and targets universal electricity access by 2021. Installation of solar home systems has significantly helped to enhance electricity access in Bangladesh.

A4.1.1 **Economy**:

Bangladesh is the eighth-most populous country in the world and one of the fastest growing economies. It shares a land border with India and Myanmar. Bangladesh's high GDP growth and per capita GDP growth seen in Figure A11 has placed it among the next eleven emerging market economies. In 2019, Bangladesh was the seventh fastest growing economy in the world with a growth rate of 8% (World Bank). Bangladesh's high GDP growth rate is driven by exports of readymade garments, remittances and the agricultural sector. Within exports, textiles, shipping and jute are the key sectors. Bangladesh also has sizeable reserves of natural gas and is Asia's seventh largest gas producer.

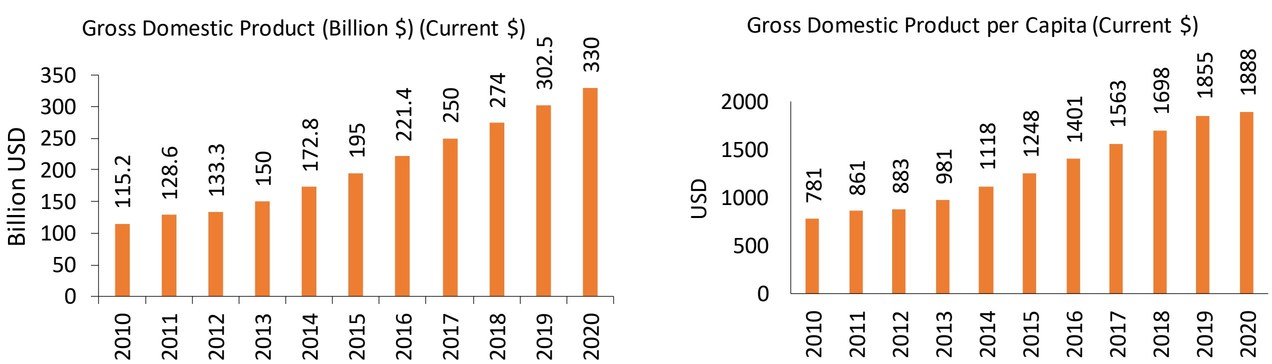


Figure A11: Bangladesh Gross Domestic Product (Billion $) (Current $) and Gross Domestic Product per Capita (Current $)

Data Source: World Bank

A4.1.2 **Current Status**:

The power sector in Bangladesh is predominantly dependent on natural gas and coal while renewable generation remains disproportionately low. Natural gas generated 53% of the electricity generation in 2019. The largest electricity consumers in the country are industrial and residential sectors followed by commercial and agriculture sectors. Electricity demand has been growing at a rate of 9-10% but this is expected to rise sharply. Electricity demand varies between day and night with maximum demand from 5 pm to 11 pm called 'peak period'.

The country has vast natural gas reserves, which are depleting fast. Other than this Bangladesh has some small coal and oil reserves which forces Bangladesh to import liquefied natural gas due to rising energy demand (Rupantarita Prakritik Gas Company Limited). Bangladesh targets to achieve universal electricity access by 2021. As of 2019, 97% of the population had access to electricity but per capita electricity consumption was among the lowest in the world. Moreover, the country is trying to reduce the demand and supply gap of electricity by massive additions of installed capacity. In 2019-20, capacity increased by 1773 MW and reached 20,383 MW. Presently, 43 new power plants with a capacity of 15,294 MW are under construction (BPDB, 2019). The Transmission & Distribution (T&D) losses also reduced from 12.4% in 2008 to 8.99% in 2020 (BPDB, 2020). In 2018, power sector emissions were 39 Mt CO_2 which constituted 47.5% of total greenhouse gas emissions (IEA, 2018).

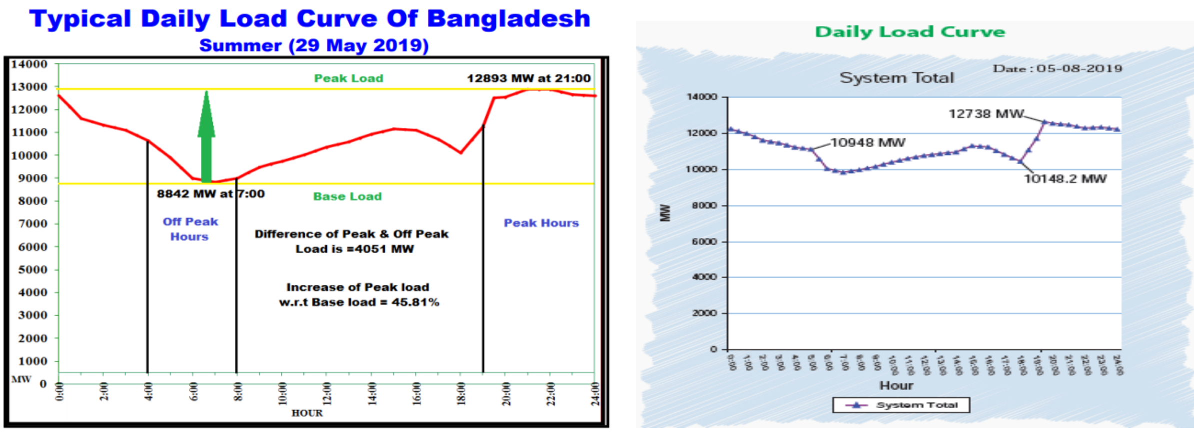


Figure A12: May and August Daily Load Curve of Bangladesh

(Data Source: Bangladesh Power Development Board)

Figure A12 shows the daily load curves for May and August. In 2019-20, installed capacity was 20,383 MW with 9717 MW public, 622 MW joint venture and 7332 MW independent power producer, 1301 MW rental power plant, 251 MW for rural electrification board and 1160 MW power import from India. Maximum peak generation was 12,738 MW which was 1.2% lower than in 2018-19. Trends in installed capacity from 2010 to 2019 are shown in Figure A13 and classified by technology type.

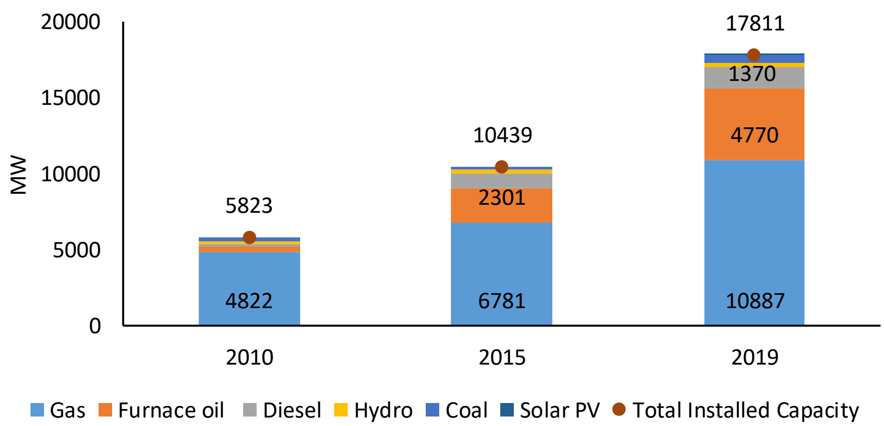


Figure A13: Bangladesh's Installed Capacity trend from 2010 to 2019

Bangladesh Power Sector – Future

Solar and wind will drive the clean energy transition and will constitute 50% and 40% of total renewable capacity respectively (SREDA,2019). The Power System Master Plan 2016 incorporates a long-term electricity generation plan with the projected capacity requirement of 30 GW against the demand of 27 GW in 2030 and capacity requirement of 57 GW against the demand of 51 GW in 2041. In 2041, 35% of electricity is to be generated from coal and 35% from natural gas. The plan aims to use coal (imported and indigenous), natural gas, nuclear, LNG and renewables along with imported power from neighbouring countries to provide a sustainable and secure power supply. In Figure A14 shows Bangladesh's electricity demand by 2041 as per the Power System Master Plan 2016, all the three scenarios assume similar GDP growth rate of 8-10% in the initial years although slightly higher GDP growth is assumed for High case as compared to other two cases.

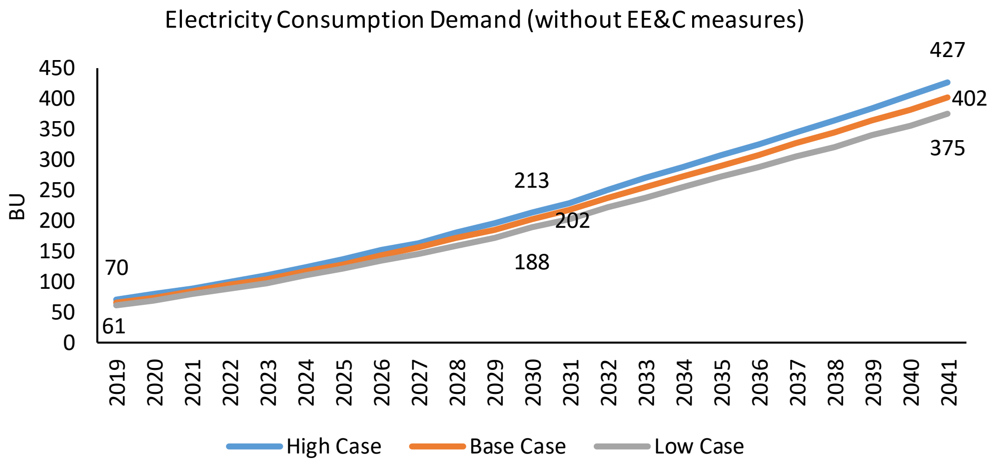


Figure A14: Bangladesh's Electricity demand till 2041 as per the Power System Master Plan 2016

Recently in June 2021, the government of Bangladesh cancelled the approval of 10 coal-based power plants as the progress of all the coal-based power plants was not satisfactory. Further, the government stressed on importance of importing hydropower from Nepal and Bhutan, increasing the use of LNG in power generation and planning to generate 40% of electricity from renewable energy by 2041[13].

Power Imports from India: Currently, Bangladesh imports 1200 MW of power from India and plans to import electricity from Nepal and Bhutan in the future. Electricity demand in Bangladesh is seasonal with demand reaching 12,000 MW in the summer and falling to 6000 MW in the winter. This is the opposite of the demand pattern in Bhutan and Nepal which facilitates power trade between peak and off-peak demand seasons. In 2019-20, Bangladesh imported 6168 GWh from India. It plans to import 340 MW from Tripura by 2021 and 1496 MW from Jharkhand by 2022 (BPDB, 2020).

Import of fossil fuels: Bangladesh has vast natural gas reserves of 12 trillion cubic feet but they are depleting fast and will run out of it by 2038, if no new exploration takes place (Centre for Policy Dialogue, 2019). Bangladesh's fossil fuel imports are projected to double to 32 million tonnes of oil equivalent (Mtoe) between 2020 and 2030 (Wood Mackenzie, 2020).

Bangladesh requires imported coal and LNG to have a reliable baseload capacity for power generation. The drastic rise in imported coal, LNG, High-Speed Diesel (HSD), and Furnace Oil (FO) has led to high import bills for the government and has crowded out investment in productive sectors along with hampering growth prospects for the country by creating a fiscal burden (Amin et al., 2018).

Quick rental power plants: Bangladesh was facing a huge power crisis in early 2000, and to resolve this quickly, the government prepared an emergency plan in 2009 which included installation of Quick Rental plants by Independent Power Producers (IPPs). These quick-rental plants need less time for construction, no investment from the government and provide a reliable baseload. The typical life of these plants is 3 to 15 years. With the introduction of quick-rental power plants, the country's installed capacity and generation increased but Bangladesh also faced problems.

Since these plants run on imported High-Speed Diesel and Furnace Oil, this added to the financial burden of the country. Apart from being emission-intensive and less efficient, these plants also increased electricity prices and T&D losses to around 12%. Thus, the government was advised to phase out these private rental power plants. This lowered subsidy and import burden along with reducing electricity prices. In 2019-20, the losses in the power sector were reduced due to lower usage of High-Speed Diesel (HSD), Heavy Fuel Oil (HFO) & electricity purchased from rental and quick rental power plants (Bangladesh Power Development

[13] https://mpemr.gov.bd/news/details/1837

Board, 2020). Though quick rental power plants are effective in the short-run, they are not sustainable in the long-term for economic growth and development.

Energy Security: With the Covid-19 pandemic, electricity demand is expected to fall temporarily leading to idle power plants and this overcapacity might be further augmented with the planned construction of coal and gas plants. With high fossil fuel import dependence, Bangladesh has an opportunity to transition toward indigenous renewable energy and invest to strengthen the power grid. This will help reduce system losses and improve energy security.

Renewable Energy Sector:

Installed capacity in Bangladesh's power sector has increased rapidly from 5 GW in 2010 to 23 GW in 2019 and is projected to reach 60 GW by 2041. However, renewable energy only constitutes 3% of generation in 2019 since Bangladesh is considered to have only limited renewable energy potential as land shortage to be a major constraint for wind and solar energy (PSMP, 2016). By boosting renewable capacity, Bangladesh can achieve cost-effectiveness, reduce greenhouse gas emissions, and create jobs along with improving human health. IRENA (2020) estimates 137,400 jobs have been created in Bangladesh due to solar PV installation, especially due to the 5.8 million decentralised solar home systems which make up 80% of solar capacity in the country. As of late, grid connected solar PV capacity has overtaken off-grid solar home systems (SREDA, 2020). According to a report by Low Emission Development Strategies Global Partnership (LEDS GP), renewable energy deployment in Bangladesh can reduce emissions by up to 20% by 2030.

Bangladesh has consistently failed to meet its renewable targets for 2015 and 2020 which were 5% and 10% generation respectively (Renewable Energy Policy, 2008). The target for 2020 was 10% renewable generation which implies 2337 MW of renewable capacity, but it stood only 268 MW in 2020 (SREDA). Recently in June 2021, Government of Bangladesh announced that they are planning to generate 40% of electricity from renewable energy by 2041[14]. Bangladesh is projected to import 5000 MW hydro from Nepal, Bhutan and North-east India by 2041.

In its updated Nationally Determined Contributions for the Paris Agreement, Bangladesh has pledged to reduce emissions by 15% by 2030 out of which 5% reduction is unconditional and 10% reduction depends on technological support and international funding. Solar and wind energy are to be the key focus for future capacity additions where solar will make up 50% and wind will constitute 40% of the total renewable capacity by 2021. The SREDA also targets to save 15% of total energy consumption by 2021.

Solar Energy (SE) Technologies

Out of all renewable sources, solar PV has the most potential in Bangladesh due to moderate level of solar radiation with a global horizontal irradiance of 4.5kWh/m^2 (National Solar Energy Roadmap). Long term average sunshine data shows that bright sunshine hours in the coastal regions of Bangladesh vary from 3 to 11 hours a day. The insolation varies from 3.8 kWh/m^2/day to 6.4 kWh/m^2/day. This indicates good potential for solar energy in the country. According to National Solar Energy Roadmap 2020, Bangladesh aims for 1700 MW utility scale solar PV and 250 MW rooftop solar PV by 2030. According to the Power System Master Plan 2016, Solar capacity is to reach 6000 MW by 2041. Cost of solar is declining rapidly in Bangladesh and in 2019, a new solar plant had a tariff of $65/MWh (IEEFA, 2020). Moreover, following the global trend of increasing utilisation of solar energy to power irrigation pumps, the Government of Bangladesh has initiated various projects to promote the use of solar irrigation pumps and has also introduced a scheme called solar home systems to provide electricity to households with no access to the grid.

The World Bank has called it the 'fastest growing solar home system program in the world' and has covered more than 6 million households till 2017. The first ever successful and commercial off-grid solar diesel mini-grid of Bangladesh was implemented in the year 2010 in the Sandwip Island. As of June 2020, there are 27 solar PV powered off-grid mini-grids having a capacity of 5.656 MWp with diesel generators as backup

[14] https://mpemr.gov.bd/news/details/1837

(National Solar Energy Roadmap, 2020). The biggest challenge faced by solar energy in Bangladesh is land shortage because it is an agricultural economy.

Wind Energy (WE) Technologies

Bangladesh has good wind potential in coastal areas and offshore islands where wind speeds are high. Wind potential is over 20,000 MW (National Solar Energy Roadmap, 2020). Average wind speed remains between 3 and 4.5 m/s from March to September and 1.7 to 2.3 m/s during the rest of the year. There is good potential for onshore and offshore wind farms. During summer and monsoons, the storm wind speeds during peak time may range from 200 to 300 km/h therefore wind turbines need to be sturdy to resist these high wind speeds. Wind plants offer opportunities for wind-powered pumps and electricity generation. Presently, there is only 2 MW of installed wind turbines at Feni and Kutubdia in Bangladesh.

Hydropower Technologies

Despite being a riverine country, Bangladesh has very limited hydropower potential due to its geography and topography. Bangladesh has been trying to import hydropower from Bhutan and Nepal with a transmission corridor through India. As of July 2020, Bangladesh has only 230 MW of hydropower capacity making it one of the lowest hydropower producers in Asia (International Hydropower Association, 2017).

A4.1.3. Key Challenges

- **Inefficient infrastructure**

Power shortages, high T&D losses, and low reliability of power supply are among the key challenges faced by the power sector. Most households receive an erratic supply of electricity and suffer frequent power outages. Bangladesh has failed to manage power loads efficiently which led to load shedding and disruption of economic activities. Power outages lead to a loss in industrial output worth $1 billion a year in Bangladesh (World Bank, 2017).

- **Land-use conflict**

If Bangladesh is to reduce dependence on expensive imported coal and LNG, mass deployment of wind and solar energy is required which needs large amounts of land. However, there is always a conflict of land use since Bangladesh is an agricultural economy.

Solution: Tough choices need to be made over land use if the country is to avoid a power system dominated by expensive, imported coal and LNG with high power tariffs and government subsidies. Bangladesh should set policy targets and create schemes where government, regulatory agencies, distribution companies and consumers can help facilitate rapid deployment of rooftop solar PV. Rooftop solar will help distribution companies by reducing peak demand during the daytime and decrease in T&D losses. Finally, it avoids investment in transmission and reduces dependence on grid power by proving a reliable source of long-term power for consumers (MNRE,2020).

A4.2 Bhutan

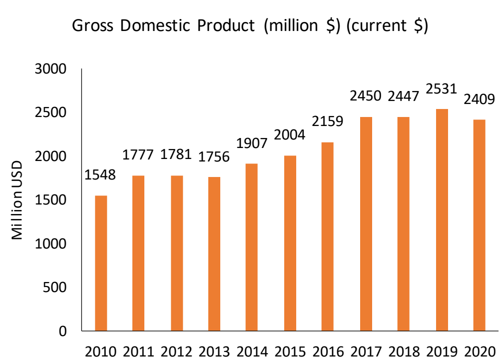
Bhutan is a landlocked country in South Asia located in the Eastern Himalayas. It is bordered by China to the north and west, and India to the south and east. The country's landscape ranges from sub-alpine Himalayan mountains to subtropical plains. The climate also varies with elevation, from subtropical in the south to temperate in the highlands, with year-round snow in the north.

Bhutan has aspired to grow sustainably and thus it prioritises the wellbeing of citizens and conservation of the environment, as indicated in the country's Gross National Happiness (GNH) approach. Bhutan is an environmental leader and a net carbon-negative country since it sequesters more carbon than it emits, due to substantial hydropower and 72% forest cover. In 2016, Bhutan emitted 2.2 million tonnes of CO_2 but the forests sequestered 4 million tonnes of CO_2 (IRENA, 2019).

A4.2.1 Economy: Bhutan is one of the smallest economies in South Asia but also one of the fastest-growing economies in the world (World Bank, 2019). Bhutan has shown remarkable economic performance in the last two decades. Figure A15 shows the growth in GDP and GDP per capita from 2010 to 2020. A large part of this economic performance has been supported by buoyant electricity exports to India.

Bhutan is a lower middle-income country and poverty has reduced by two-thirds from 2010 to 2019 (World Bank, 2019). The average annual growth of GDP has been 7.5% since the 1980s, making Bhutan one of the fastest growing economies in the world. Gross National Income (GNI) per capita is $3080 in 2018, which is three times the threshold for lower middle-income countries and only 10% lower than threshold for upper middle-income countries. Poverty has declined from 36% in 2007 to 12% in 2017 (World Bank, 2019). The main industries in Bhutan are hydropower, wood, cement and food products. In 2019, agriculture accounted for 16% of GDP while manufacturing constituted 36% of GDP and the service sector contributed 48% (National Statistics Bureau, 2020).

Bhutan maintains solid economic growth and macroeconomic stability. Hydropower construction and supportive fiscal and monetary policy have contributed to solid growth. Single-digit inflation, stable exchange rate and accumulating foreign exchange reserves have stabilised the country's economic progress. Bhutan's power sector provides a significant contribution to its national economy with 20% contribution to domestic revenue, 30-35% to export earnings and 13% of GDP in 2019 (National Statistics Bureau, 2020). As Bhutan's economy continues to grow and living standards improve, energy consumption and related environmental, resource, and economic challenges are set to increase. Balancing the objectives for growth and the aspirations for wellbeing and conservation will be an important challenge for the decision-makers of the country.



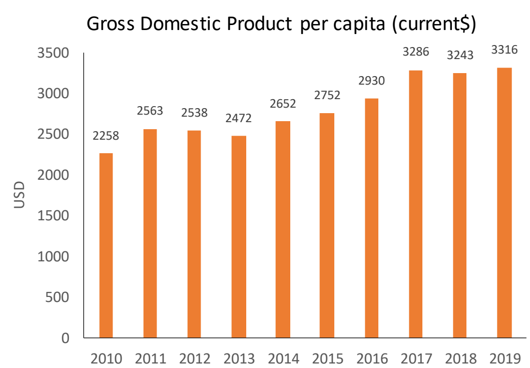


Figure A15 Gross Domestic Product (million $) and Gross Domestic Product per capita (current $)

Data Source: World Bank

A4.2.2 Current Status:

Electricity is the main source of lighting and cooking in Bhutan. It achieved the goal of 100% electricity access in 2016 from 61% in 2006, ahead of the universal electrification goal of 2020 (World Bank, 2016). Moreover, the per capita electricity consumption increased from 980 kWh in 2005 to 2988 kWh in 2019 Earlier, electricity generation was based on small diesel generating and micro hydro stations which provided a limited supply of electricity and this was supplemented by electricity imports from India. However, with large hydropower plants, Bhutan now meets its domestic demand and exports surplus electricity to India.

As of 2019, Bhutan has 2341 MW of installed power capacity constituting 2334 MW hydropower, 7 MW diesel and 0.6 MW of wind. Bhutan has seen great successes with developing its large hydropower projects through technical and financial assistance from India, however, little or no private sector participation with other forms of renewable energy has been evident as of now.

The daily load curve of Bhutan for the winter and summer months for the year 2019 is shown in Figure A16. The load curve shows a typical two peak curves morning and evening. In winters, the load is more than summer months since Bhutan is located in the cold Himalaya Mountain range, the demand for electricity for heating is high. A typical load curve in Bhutan has two peaks, morning and evening. The morning peak occurs between 7 am to 9 am and the evening peak between 6 pm to 9 pm. The total energy demand of Bhutan is expected to be 6,404.46MU with a peak demand of 1,150MW by 2040 (National Transmission Grid Master Plan of Bhutan, 2018).

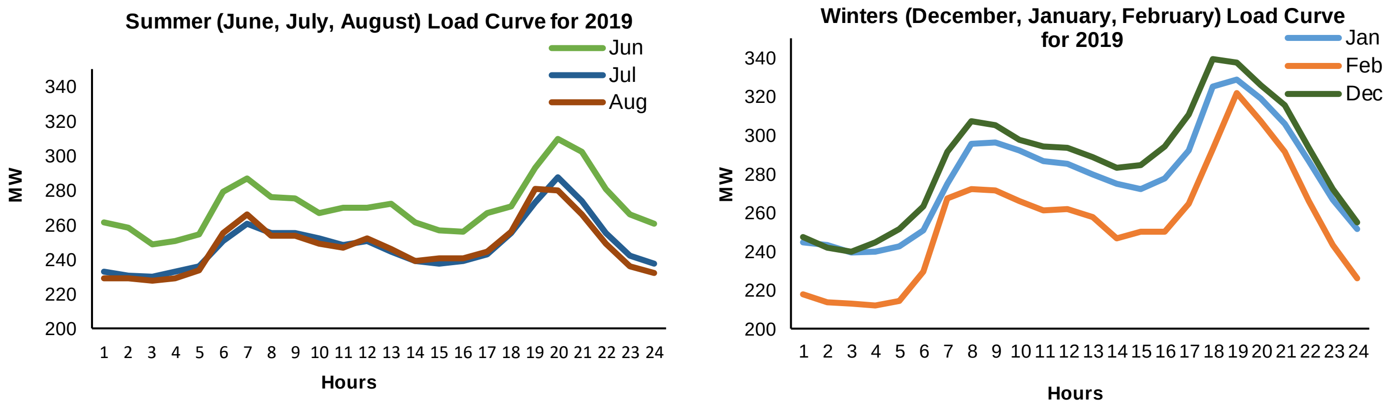


Figure A16: Bhutan's summer and Winter Load Curve for 2019

(Data Source: Bhutan Power System Operator Quarterly Report)

On the generation side, Bhutan's installed hydropower generation capacity in 2019 was 2.3 GW, representing only 8.8% of its techno-economic feasible hydropower potential of 27 GW although the theoretical potential of hydropower is 41 GW (DRE-MOEA, 2016b). As of 2019, medium, large and mega hydropower plants provide 98% of the hydropower capacity. The Tala Hydropower Plant provides 1020 MW while the Mangdechhu plant provides 720 MW (National Statistics Bureau, 2019). In 2019, electricity exports from Bhutan were 6146 GWh while imports were 96 GWh as shown in Figure A17. The T&D losses were 6% and peak system demand was 387 MW. Out of 8856 GWh of electricity generation, 6146 GWh was exported which is 70% of electricity generated (National Statistics Bureau, 2019).

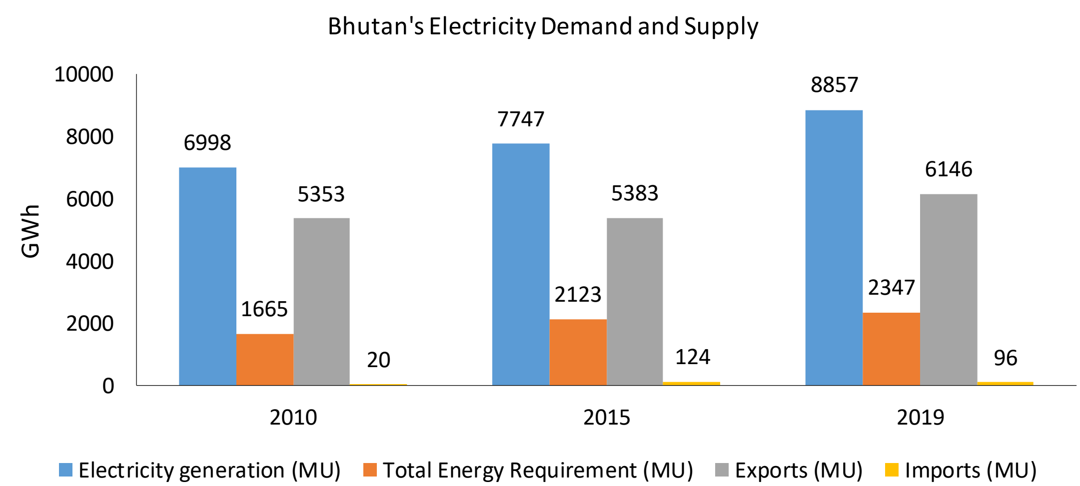


Figure A17: Bhutan's electricity demand and supply position (2010 – 2019)

Data Source: Statistical Yearbook of Bhutan 2020

Bhutan's power generation is mostly dependent on run-of-river (RoR) type hydropower plants, which are more susceptible to variation in rainfall patterns and the impacts of climate change. The winter season in Bhutan is drier than summer, due to lower average rainfall, which leads to reduced flow volume in the rivers and hence reduced hydropower generation (SARI/EI and IRADe, 2016). These seasonal variations can be observed from the monthly electricity generation profile of Druk Green Power Corporation (DGPC) as shown in Figure A18. Around 60 percent of the total generation from Druk Green Power Corporation hydro plants is generated from July to October, reflecting high seasonal variation in hydro generation.

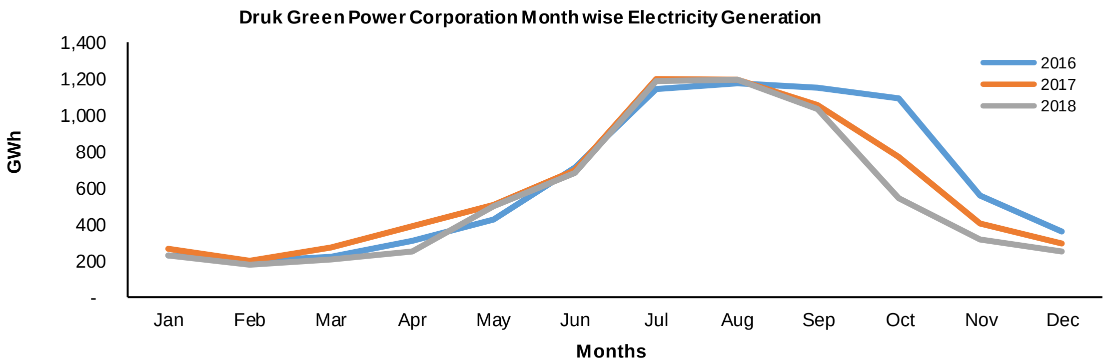


Figure A18: Druk Green Power Corporation Month wise Electricity Generation

Data Source: DGPC Annual Reports

Power Trade with India: Bhutan uses run-of-river hydropower with no water storage and therefore, rainfall variation has a direct impact on power generation. In the monsoon, Bhutan has surplus electricity which it exports, mainly to India but in the lean months from November to March when it faces power shortages, Bhutan imports power. A significant portion of total electricity generation is exported to India, which has increased from 1,460 GWh in 2000 to 6165 GWh in 2020 (Ministry of Power, 2020). In the winter, Bhutan imports electricity from India which was increased from 19 GWh in 2000 to 96 GWh in 2019.

Energy Security: Bhutan has vast hydropower resources; the country will continue to depend on them for meeting its electricity demand and for earning revenue by exporting power. Given that the country has no other major energy resource, barring some coal, the country will also continue to import fuels such as petrol, diesel, LPG, kerosene, and aviation turbine fuel for transport and other sectors of the economy, which exposes the country to volatility in international fuel markets. However, given the possible long-term impacts of climate change on water flows, vegetation, and forestry, the country needs to develop mitigation and adaptation programs to diversify its fuel mix and improve energy security. To address the energy security concerns, the focus areas identified include promoting the use of energy resources such as solar, wind, waste-to-energy, and biomass and biogas systems which could help diversify the fuel mix.

Renewable Energy Sector:

Bhutan's Second Nationally Determined Contributions (2021) targets 71 MW of solar and wind capacity by 2028. Even though Bhutan is blessed with good solar and wind potential, Bhutan only has 0.6 MW of installed wind capacity and negligible solar capacity (National Statistics Bureau, 2020). The Renewable Energy Master Plan (2017-2032) provided a long-term strategy to implement renewable energy technologies. It has identified 39 GW of feasible small hydropower, solar and wind potential across the country. The Sustainable Hydropower Development Policy (2021) aims to provide universal access to sustainable energy, ensure energy security, enhance cross border trade of electricity and ensure optimal use of water. It emphasises switching from run-of-river hydropower to pumped storage since seasonal variation in rainfall leads to power shortages. Pumped storage hydropower will also ensure energy and water security. Under the Alternative Renewable Energy Policy, medium-term targets for 2020-2028 are 71 MW of utility scale solar and wind energy, 300 rural households to have rooftop solar PV, 80 kW off-grid solar plant, to install 50 solar water heating systems of 1000 litres capacity/day in various public institutions & a 500 kW mini-hydel plant for the Lunana community (NDC, 2021).

Solar Energy Technologies

Bhutan's solar radiation ranges from 1600 to 2700 kWh/m^2/day which is better than nations like Germany or the UK which have significant share of solar generation in their power sector. With rising demand and threat to hydropower due to climate risks, solar PV can provide a sustainable and affordable source of energy and its potential has been estimated at 12 GW (IRENA, 2019).

With assistance from the Asian Development Bank, Bhutan is installing 180 kW solar plant in Rubessa in Wangdue Phodrang District. In the near future, Bhutan also targets 30 MW solar at Shingkhar, Bumthang and 17 MW at Sephu, Wangdue (NDC, 2021). Currently, there are about 1200 Solar rooftops (50 Wp per system with 60 AH battery storage) supplying power to the rural households which do not have access to the grid (Bhutan Ministry of Economic Affairs). The contribution of solar power to Bhutan's energy supply has been almost negligible compared to hydroelectricity but has been crucial as has been mainly used for rural electrification of remote areas where the extension of the grid electricity has been impossible due to prohibitive costs, climatic and environmental conditions.

Solar PV project costs range from 4 BTN/kWh to 16 BTN/kWh in 2018, whereas the hydro tariffs were in the range of 2.12 to 2.55 BTN.kWh. This makes small scale solar PV a feasible option to replace off-grid diesel and petrol generation sets which have costs around 17.4 BTN/kWh (IRENA, 2019). Bhutan's Alternative Renewable Energy Policy targets 5 MW solar PV and 3 MW solar heating capacity by 2025 and Bhutan's second NDC targets 47 MW solar PV by 2028 (NDC, 2021). To achieve the set target, rapid investments are needed to reach these levels by the target date.

Wind Energy Technologies

Wind energy in Bhutan is heavily influenced by seasonal monsoon and thus, wind speeds are high from November to April and low for the rest of the year. This coincides with seasonal variation in hydropower generation and thus, the peak months for wind are when hydro have lean months. This offers a phenomenal opportunity for Bhutan to diversity its power source by leveraging the seasonal complementarity between wind and hydro resources

The wind potential in Bhutan is 760 MW with the northern district of Wangdue accounting for 19% of the potential followed by the southern district constituting 10% (IRENA, 2019). Bhutan's Alternative Renewable Energy Policy targets 5 MW wind capacity by 2025 and the second NDC targets 24 MW wind by 2028 (NDC, 2021). Bhutan has installed 600 kW wind capacity at Rubessa in Wangdue (Bhutan Ministry of Economic Affairs, 2020).

At 50m hub height wind power densities are 200.96 W/m^2 for Tsirang, 103.57 W/m^2 for Wangdue Phodrang, 119.62 W/m^2 for Trashiyangtse, 129.75 W/m^2 for Tangmachu (Tenzin and Saini, 2019). The use of wind power is a leap forward for the renewable energy sector in Bhutan, but it does face few challenges. The first and major challenge is that the areas with high wind speeds are often located in high-altitude mountain tops and ridges above 3000 meters making them inaccessible to transport large wind turbine nacelles, blades and towers. As a result, installations are restricted to small wind turbines. Secondly, effective wind capacity installation requires proper road infrastructure, airports and built-up areas. Restricted areas like forests and national parks pose more challenges for transport and installation.

Role of Hydropower in the socio-economic development of Bhutan

Hydropower is of national strategic importance and the backbone of Bhutan's economy. With a techno-economic feasible potential of 27 GW and an installed capacity of 2335 MW, hydropower has brought immense socio-economic benefits by providing electricity in even the most remote parts and ensuring universal access to electricity. Tapping hydropower resources will be critical for Bhutan to meet rapidly growing electricity demand in a cost-effective and environmentally sustainable manner.

Hydropower in Bhutan has been supported financially and technically by India through agreements. Hydropower projects in Bhutan jointly benefit India and Bhutan by providing a reliable source of clean and cheap electricity to India and generating export revenue for Bhutan. Most of the new hydropower capacity in

Bhutan will be built with the purpose of export electricity to meet the growing demand in India (IHA, 2017). Under the Sustainable Hydropower Development Policy (2021), there are four hydropower projects under construction to be commissioned before 2030; Punatsangchuu – I (1200 MW), Punatsangchuu – II (1020 MW), Kholongchhu (600 MW) and Nikachhu (118 MW). In addition, Sankosh HEP (2585 MW), Dorjilung (1125 MW) and Nyera Amari (404 MW) are priority projects.

A4.2.3 Key Challenges

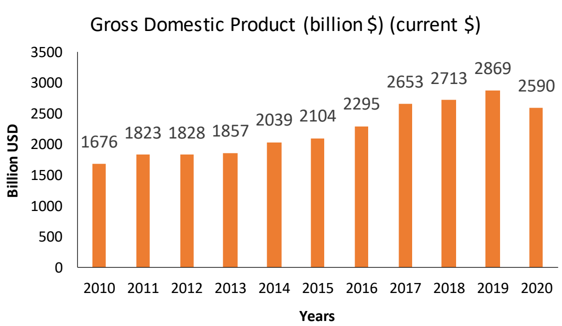
- **Seasonal variations -** The availability of hydropower is seasonal due to variation in rainfall and thus, Bhutan faces power shortages in lean months during the winter. Thus, an adequate level of firm power capacity must be developed through several hydropower projects with storage to minimize power shortages in the winter. Another option is to develop renewable energy like solar and wind to complement hydropower e.g. wind speeds are high during the lean hydro months. This will diversify the generation mix, reduce over-dependence on hydropower and mitigate hydrology risks. However, wind and solar potential in Bhutan face challenges like inaccessible locations, lack of transmission infrastructure, financial constraints and unreliable data and feasibility studies (ADB, 2014).
- **Grid extension difficult in remote areas** – Even though Bhutan achieved 100% electricity access in 2016, the mountainous terrain makes grid extension in remote rural areas difficult.. Bhutan lacks manpower and the resources to sustain off-grid renewable energy projects and thus depends on India for support to serve households by solar home systems and micro-hydropower systems.

A4.3 India

India is the second-most populous country in the world and also one of the fastest growing economies. It shares a land border with China, Pakistan, Nepal, Bhutan, Afghanistan, Bangladesh and Myanmar. India plays an important role in the global energy scenario. Rapid economic growth, urbanization, industrialisation and a burgeoning population have doubled energy consumption since 2000 but 80% of demand continues to be met by coal, oil and solid biomass. There are large inequalities across states and between rural and urban areas resulting in indicators like per capita emissions and electricity consumption being less than half the world average. Affordability, reliability and sustainability of energy are key issues faced by consumers.

A4.3.1 Economy

India's high growth rate of GDP and per capita GDP has placed it among the fastest-growing economies in the world. India is the fifth-largest economy in the world in terms of nominal GDP and the third-largest in purchasing power parity (IMF,2020). From 2014 to 2018, India has remained the world's fastest growing major economy, surpassing China. Key export-oriented sectors for India include petroleum, jewellery and medicines. Figure A19 provide trends in development of GDP and GDP per capita for India from 2010 to 2020.



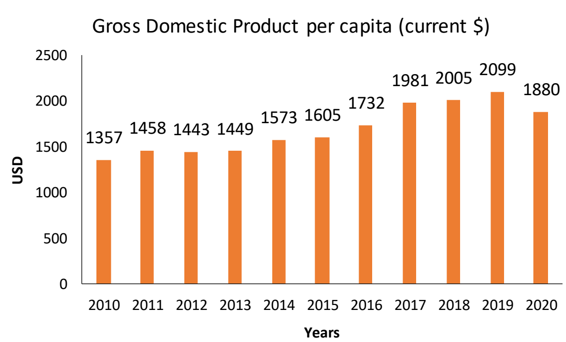


Figure A19: Gross Domestic Product (Billion $) and Gross Domestic Product per capita (current $)

Data Source: World Ban

A4.3.2 Current Status

India has a tremendously high electricity access of 96.7% and the per capita electricity consumption has reached 1208 kWh/year in 2020 (IEA,2020; CEA,2020). India's power sector is dominated by fossil fuels, mainly coal which contributes more than half of overall electricity generation (CEA,2020). Coal has hindered India's diversification of generation by accounting for the largest single fuel in the electricity mix. In terms of renewables, India is looking to have mass deployment in the future. Solar energy has expanded in recent years due to declining costs and better infrastructure.

India is the third largest producer and consumer of electricity and is also the third largest emitter of CO_2 emissions in the world (CEA,2020). India has the fifth-largest power producing capacity in the world, third-largest solar capacity and fifth-largest wind and hydropower capacity (MOEFCC). India has a wide range of policies aimed at clean and sustainable energy. With growing electricity demand, India needs to provide reliable, affordable, secure and sustainable electricity which requires diversification of generation mix. India has now moved from being a power deficit country to a power surplus country. In 2019-20, India had a peak demand of 183,804 MW and the peak demand met was 182,533 MW (Ministry of Power,2020). Typical daily load variation in demand at all India levels is shown in Figure A20. The load curve shows a typical two peak curves morning and evening peak.

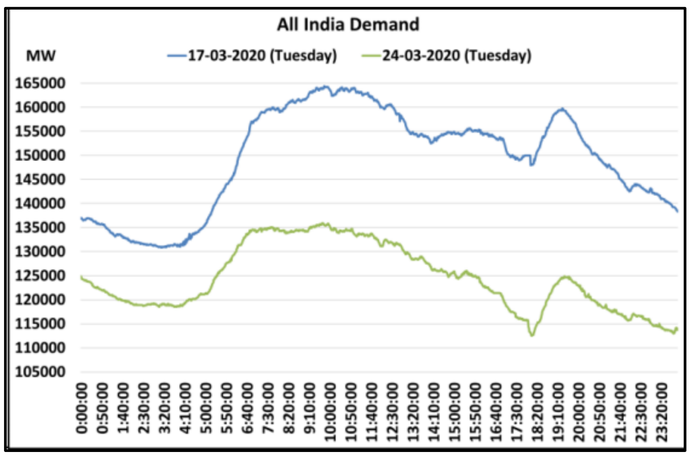


Figure A20: March 2020 Load curve for India

Data Source: Power System Operation Corporation Limited

In terms of capacity, by March 2020, India's total installed capacity was 375 GW constituting 104 GW from the states, 177 GW from private sector and 94 GW from the central sector. The trend in technology-wise installed capacity from 2002 to 2020 is shown in Figure A21.

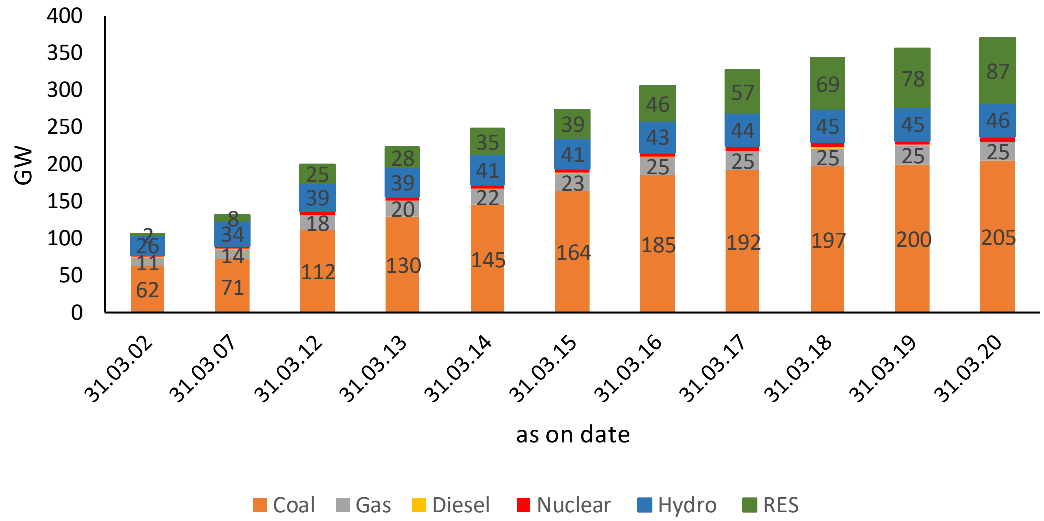


Figure A21 India's Installed Capacity trend from 2002 to 2020

Data Source: Central Electricity Authority

Power Trading by India: Presently, India exports electricity to Nepal, Bangladesh and Myanmar, while India imports power from Bhutan. However, sometimes India also exports power to Bhutan during lean hydro season. As mentioned above, India has significant power trade with Nepal, Bhutan and Bangladesh. India has signed a Memorandum of Understanding (MoU) with Bhutan, Bangladesh, Nepal and Myanmar to improve power connectivity. The current bilateral power trading arrangement for electricity helps to facilitate regional power trade and meet the requirement of power in each country, leading to greater energy security for the South Asian region. Power export volumes from India have increased at a CAGR of 61.83% from 2008-09 to 2017-18 whereas electricity imports have declined at a CAGR of 0.5% during the same period. Export of electricity has increased from 58 GWh in 2008-09 to 7203 GWh in 2017-18. The gross import of electricity remains in the range of 5000 to 6000 GWh. Currently, Nepal, Bhutan and Bangladesh do not use the Indian Transmission Grid to trade power between themselves.

Import of fossil fuels: The import of coal has been rising along with imports of crude oil and natural gas. The average quality of coal found in India is low. The power sector in India is the major consumer of low-quality non-coking coal. Whereas high quality coking coal is used in the iron and steel production, this coking coal is partly produced in India and the rest of it is imported from Australia, Indonesia and South Africa. Due to logistic and fuel availability constraints, imported non-coking coal is also utilized for power generation and by other industries.

Energy Security: India aims to become a global leader in energy to fuel its energy needs for providing infrastructure, skill development, and employment generation. However, India's energy future continues to be tied with sharp fluctuations in crude oil prices. India has made energy security a priority by creating a single national power system and major investment in installing power generation capacities. India's power system is being transformed with a higher share of renewables and the power system is becoming flexible. India has facilitated greater interconnection across the country and is promoting affordable battery storage. The government is also striving for electricity market reforms. With limited oil reserves compared to domestic demand, India's oil import dependency will rise significantly in the coming years.

Renewable Energy Sector: India's renewable energy expansion plan is the largest and most ambitious in the world (IRENA,2017). Due to rapidly declining costs, there has been mass-uptake of renewable energy like wind, solar PV, and small hydropower which are set to be more cost-effective than a coal-fired generation (IEA, 2020). Apart from falling costs, renewable energy helps to reduce fossil fuel import dependence and reduces risk from price volatility. It also helps to increase access to energy and reduce carbon emissions. As of December 2020, India's renewable capacity stands at 136.8 GW (including large hydro) out of a total of 375.3 GW which is 36.5% of the total generation capacity (CEA,2020). The country targets 40% non-fossil installed capacity by 2030 and has ambitious renewable targets of 175 GW by 2022 and 450 GW by 2030 (MNRE,2020). In 2019, India ranked fourth most attractive renewable energy market in the world and is expected to be the largest contributor to a renewable upswing in 2021 India's annual renewable additions will double from 2020 since a large number of auctioned wind and solar PV projects will become operational, and its renewable energy market has attracted FDI inflow of $9.5 billion between April 2000 and June 2020 (IRENA, 2017; IBEF, 2020).

Solar Energy (SE) Technologies

India has abundant sunlight which means a vast solar energy potential. Around 1000 TWh of energy per year is incident on India's land area with most parts receiving 4-7 kWh/square m per day. From an energy security perspective, solar is the most secure source of energy due to its abundance and low-cost. National Institute of Solar Energy has assessed India's solar potential to be 748 GW assuming 3% of wasteland is covered with solar PV. Solar energy holds a key position in India's National Action Plan on Climate Change with programs like National Solar Mission. The Mission targets 100 GW solar by 2022 and recently, India has achieved 5th position in solar deployment surpassing Italy (MNRE,2020). Solar capacity has increased by more than 11 times in the last five years from 3.7 GW in March 2015 to 34 GW as of March 2020 (CEA,2020). Presently, solar tariff in India is very competitive and has achieved grid parity.

Wind Energy (WE) Technologies

India's wind energy sector is spearheaded by indigenous wind power plants. It has the fourth largest wind capacity in the world with an installed capacity of 38 GW as of December 2020 and the government plans to promote wind power projects by providing investment incentives to the private sector Almost 97% of wind potential is concentrated in seven states- Gujarat, Karnataka, Maharashtra, Andhra Pradesh, Tamil Nadu, Madhya Pradesh, and Rajasthan. Wind power has seen steady growth over the last three decades and this is driven by incentives like accelerated depreciation and generation-based payments along with attractive feed-in-tariffs. India has a target of 60 GW wind-onshore installed capacity by 2022. India's current wind-onshore potential is estimated at 302 GW at 100 metres (MNRE,2020).

Hydropower Technologies

India has around 100 hydropower plants above 25 MW and surpassed Japan to become the fifth largest country in the world for potential hydropower capacity, surpassing 50 GW (IHA). Large and small hydro plants contribute more than 15% to electricity generation in 2019-20 (CEA,2020). Before 2019, hydropower projects larger than 25 MW were not considered renewable but in 2019, large hydropower projects were classified as a renewable source of energy and eligible to benefit from renewable purchase obligations. Hydropower is essential for India to increase the share of renewable generation in electricity. As per India's Nationally Determined Contribution, India is to have 40% non-fossil fuel capacity by 2030 and thus, hydropower will play a key role in meeting this Paris Agreement goal. Further, India plans to install 70,000 MW of hydropower generation capacity by 2030. Currently, it has 13,000 MW of hydropower plants under construction and 8000 MW in the pipeline. The estimated hydropower potential is 145,000 MW at a 60% plant load factor. Till now, only 26% of hydropower potential has been exploited (MNRE,2020).

A4.3.3 Key Challenges

India's power sector has undergone a massive transformation due to government reforms. These reforms have created a single national power grid, very high electricity access and higher renewable integration (IEA,2020). After years of power deficit, India is now a power surplus country due to investment in power generation capacity especially by the private sector which owns more than 45% of installed capacity (CEA,2020). For India to make its power grid larger than the size of Europe's grid of 27 countries and to achieve the 450 GW renewable target, the power sector needs to be physically and financially resilient to stimulate investment and transition to clean energy. With the Covid-19 pandemic, India's electricity demand dropped 28% by the end of March 2020 and as a result, thermal power plants were running at low capacity but the share of renewables was rising consistently due to 'must-run' status (IEA,2020). India's state-owned power distribution companies were financially stressed even before the Covid-19 pandemic but during the pandemic, their revenue dropped drastically and state government payments were reduced.

Poor financial health

Power generation companies have invested huge amounts of money to set up thermal power plants. Low plant load factors impact revenue generation capability. Low capacity factors are due to overestimation of electricity demand and lack of adequate coal linkages. The electricity demand has grown at a slower pace than expected due to lower economic growth. This has led to a low plant load factor for coal power plants. Generation companies are financially stressed due to non-performing assets. Distribution companies are facing a financial crisis because electricity is a concurrent subject in the Indian constitution and most of the distribution companies are owned by state governments. The price of electricity is controlled by the state, especially during elections and thus distribution companies have to purchase electricity from spot markets and this discrepancy reflects in their balance sheets.

Tariff

Electricity tariffs are higher in the industrial and commercial sector, and this subsidises electricity for residential and agricultural sector who pay lower tariffs. However, electricity demand fell for the commercial and industrial sector during the pandemic but rose in the residential sector. Higher than expected aggregate technical and commercial losses have exerted additional pressure. Delayed payments or delinquencies from end-users have further strained the balance sheets of DISCOMS. Inevitably, stakeholders across the value chain—power generating companies, fuel suppliers etc. are also impacted.

A4.4 Nepal

Nepal is a middle-sized country in South Asia with a population of about 30 million (National Planning Commission, June 2020). The country has undergone major transformations related to social, economic and political spheres over the last few decades. The country went through a decade-long conflict starting from the mid-1990s, followed by another decade of political transition. Nepal is now on the path of peace, prosperity, stability, inclusive development and economic changes. The country is richly endowed with renewable energy resources, comprising hydropower, solar, biogas, and various forms of biomass energy. It has rich reserves of fuelwood, no proven petroleum reserves and very limited coal reserves. The country imports fossil fuels from India making it highly vulnerable to international price fluctuations.

A4.4.1 Economy:

Nepal is a small and developing economy, landlocked between two rapidly changing countries of India and China. However, Nepal remains one of the poorest countries in the world and still copes with long periods of political insurgency which ended in 2006. Nepal's GDP growth rate was lower than 4% per annum till 2016 and has risen since then to an average of 6.5% per annum. The slow growth from 2006 to 2016 is partially attributed to electricity shortages which stem from chronic underinvestment in the power sector. This in turn is caused by political instability owing to the frequent change in political leadership (Surendra et al., 2011). Around 5 million Nepalis work abroad as migrant labourers and contribute to the economy by remittances which make up 24% of the gross domestic product in 2020. Due to abandonment of farming areas, the contribution of agriculture to GDP has gone down from 69% in 1975 to 23% in 2020 (World Bank, 2020).

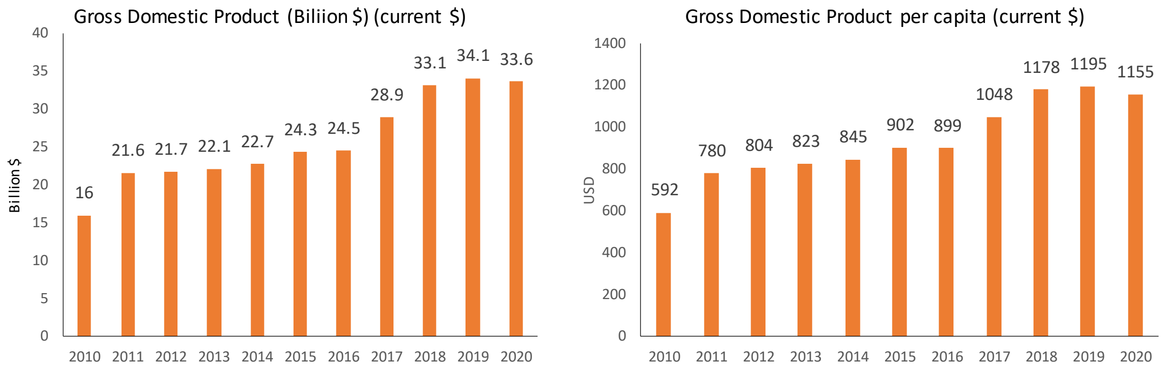


Figure *A*22: Gross Domestic Product (Billion $) and Gross Domestic Product per capita (current $)

(Data Source: World Bank)

Figure A22 presents the growth in GDP and GDP per capita from 2010 to 2020. The growth rate of GDP from 2018 to 2019 was 6.65%. Nepal's GDP has grown at a slow pace of less than 4% from 2010 to 2016 and has increased from 2016 to 2019 to grow at an average rate of 6.5% per annum (World Bank, 2020). The major political upheavals of 2008 in Nepal overthrew the 240-year-old monarchical system with the establishment of the Federal Democratic Republic (FDR) in 2015. Accordingly, Nepal's 75 districts were realigned to 77 districts and Nepal is divided into 7 provinces, 753 local units, and 6,743 hamlets (wards). The government aims to create jobs through sustainable land management in each province. Unemployment in Nepal has remained low throughout, with 1.5% in 2005 and 2.8% in 2019 (World Bank, 2019).

A4.4.2 Power Sector Current Status

Almost all of the electricity generated in Nepal comes from hydropower. Most of the energy supply is from biofuels and waste as 21 million people still rely on traditional biomass for cooking. In 2000, only 19% of people had access to electricity but with remarkable efforts from the government, 89% of the population has access to electricity in 2019 (World Bank, 2019).

At household level, only 60% of households are connected to the grid, 10% by community rural electrification schemes, 18% by off-grid electrification schemes and 7% by stand-alone solar systems. Nepal had a per capita electricity consumption of 245 kWh in 2019, which is one of the lowest in the world. The fundamental reason is inadequate access to reliable, affordable, and sustainable electricity. About 79% of the population lives in rural areas and many remote villages are not connected to the national grid. Even when the national grid is available, natural disasters like earthquakes and storms lead to power outages.

In 2019-20, Nepal Electricity Authority's hydropower plants generated a total of 3021 GWh which is an increase of 18.5% over the generation in 2018-19. The total power purchases from Independent Power Producers (IPPs) was 2991 GWh in 2019-20. Energy imported from India was 1729 GWh. Out of total available energy, NEA's generation was 39%, Indian imports and domestic IPP's constituted 22% and 38% respectively. Total energy consumption in 2019-20 was 6422 GWh against 6303 GWh in 2018-19. Nepal is committed to support initiatives of SDGs by improving access to efficient and clean energy sources. However, due to lack of access to clean energy and low incomes, rural residents rely heavily on locally available traditional fuels like fuelwood and biogas. Currently, petroleum is the second largest source of energy after fuelwood. This dependence on imported fossil fuels leaves the country vulnerable to international price fluctuations.

In 2019-20, total installed capacity in Nepal stands at 1332 MW with a peak demand of 1408 MW. Of this, Nepal Electricity Authority owns 636 MW while independent power producers own 696 MW (Nepal Electricity Authority, 2020). Electricity generation capacity in Nepal is rapidly increasing. A total of 943 MW is under construction and 3219 MW is being planned and proposed. The Upper Tamakoshi Hydropower Project under construction has a capacity of 456 MW and the Upper Arun HEP has a capacity of 1061 MW which is still being planned. By 2030, electricity demand will more than double under a 5% GDP growth rate and almost quadruples under a 10% GDP growth rate. In the high-growth scenario (10% GDP growth rate), the manufacturing sector foresees a maximum increase in demand, however under all scenarios, the domestic demand is set to be one of the largest components of electricity consumption in the country (Electricity Demand Forecast Report (2015-2040), January 2017).

In the past electricity prices in the country had been kept too low, rather below cost-recovery levels due to the absence of an adequate independent regulatory system. However, by the year 2018, the operational expenses were brought under control, load-shedding was ended, and financial reforms were implemented that led to an operating profit by NEA (Nepal: Electricity Grid Modernization, November, 2020). The country is a net importer of electricity even though it has significant hydropower potential. Based on the water resources availability, Nepal's technical potential for hydropower has been estimated to be **83 gigawatts** (GW), out of which about 42 GW is considered economically viable.

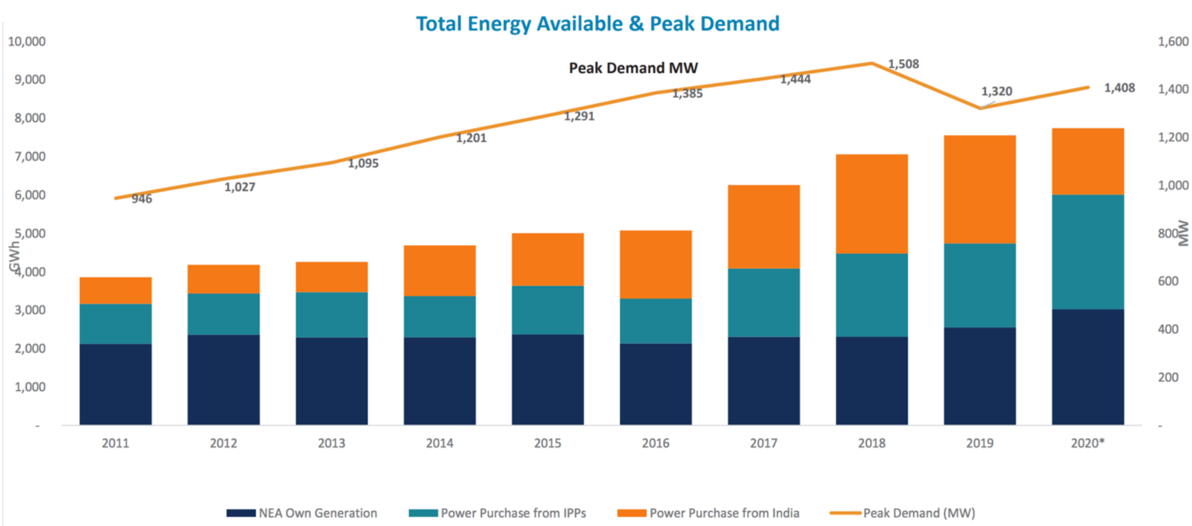


Figure A23 Total Energy Available and Peak Demand

(Data Source: Nepal Electricity Authority Annual Report)

Figure A23 presents the generation, imports, and peak demand for Nepal from 2011 to 2020. The current peak load demand is 1408 MW which is expected to rise to 2379 MW by 2022 and 4280 MW by 2030 in a business-as-usual scenario. However, the peak electricity demand will reach 2,744 MW by 2022 and 5,371 MW by 2030 if there is reliable electricity for 24 hours per day (ADB, March 2017).

Power Imports from India- The power production from Nepal hydropower plants falls sharply between mid-December and mid-January when the water levels in the rivers recede, prompting NEA to import electricity. Power imports from India have been rising rapidly over the years. In 2011, power imports constituted 18% of total available electricity and in 2020, power imports from India make up 22% of total electricity availability (Nepal Electricity Authority, 2020). The 456 MW Upper Tamakoshi Hydropower Project is Nepal’s largest hydro project and as of July 2021, it has started generating power and is paving the way for Nepal to become a power surplus country capable of exporting electricity. At the inauguration, the first unit of 76 MW came into operation with remaining five units coming into operation gradually.

Energy Security– The energy sector plays a very important role in economic development and evidence shows that expanding the electricity sector contributes to economic growth in many countries. Nepal's electricity sector is underperforming with inadequate and unreliable supply of poor-quality electricity. Energy security signifies protecting the nation against possible threats to the national energy system in the present and future. Nepal's energy system is threatened by two factors. The first is climate change which may alter the energy system and reduce or interrupt the energy supply. The second is the possible high costs of imported fossil fuels and a subsequent supply constraint. Nepal is an agriculture dominant economy, and the energy crisis has forced the manufacturing sector to operate at only 58% of its available capacity.

Nepal should aim to have an uninterrupted and smooth supply of energy that is affordable, reliable, and accessible. Energy security can be achieved by ensuring sustainable energy supply, promoting clean energy, and promoting cross-border electricity trade. Nepal needs to diversify its energy mix to include more renewable sources like solar, wind, etc.. In hydropower, Nepal should include pumped storage rather than only depend on run-of-river hydro plants. Hydropower development has been successful in Nepal by contributing to meeting both water and energy needs. Hydropower with a storage reservoir is the most flexible energy technology in terms of power generation; it can generate power exactly when it is needed, providing back-up for intermittent sources such as wind power and allowing thermal plants to operate at their best efficiency, thus further reducing greenhouse gas emissions.

Renewable Energy Sector:

Nepal is among the top 20 countries with the highest rates of electricity access to off-grid solar or hydro mini/micro grids. For households in remote areas, the only viable option is off-grid solar where small hydro cannot be developed. The operational and maintenance costs of diesel generators are too high and biogas technology does not work satisfactorily at high altitudes and cold weather. Small hydro turbines need specific topological conditions which are not prevalent in remote villages. Off-grid technologies can be created using local mini-grids based on solar and micro-hydro. Homes can also be fitted with solar home systems for household consumption.

Solar Energy (SE) Technologies

Nepal is located at a latitude of 26–30° north latitude, with the sun shining for >300 days per year. It has relatively high insolation of an average of ~17 megajoules per m^2 per day (1.7 TWh per km^2 per year) and national average sunshine hours of 6.8 per day. This makes Nepal a country with moderately high solar potential. All parts of the country are reasonably favourable for solar energy. Nepal receives an average of 3.6–6.2 kWh/m^2/day of solar radiation, up to approximately 300 days of sun a year (Lohani and Blakers, 2021). As per the current estimates, the solar potential in Nepal is 2100 MW but it is mostly untapped due to over-dependence on hydropower as the only renewable source of energy. Solar energy in Nepal is used mainly for lighting in households not connected to the grid but solar energy is also spreading to urban areas. Solar power has helped to power hospitals and clinics in rural Nepal and has replaced diesel generators (Gray, 2016).

While technology cost for solar energy has been declining worldwide, higher import costs of solar photovoltaic (PV) panels and associated storage systems, transportation costs, storage costs and installation costs make access to solar technology in Nepal expensive. Therefore, the average cost of production of solar energy is very high in Nepal when compared to the other sources of energy production. In addition, the solar energy industry is presently dependent on the government subsidy for covering the higher initial investment required to set up the solar energy system. Hence the solar energy segment in Nepal still has a long way to go in terms of achieving commercial scalability and competitiveness vis-a-vis other forms of energy. However, reducing generation costs by addressing the challenges mentioned earlier can pave the way for realizing solar energy's potential in Nepal.

Wind Energy (WE) Technologies

Nepal's tall and windy mountains are suitable for wind turbines and Nepal has a commercially viable wind potential of 448 MW. According to the Solar and Wind Energy Resource Assessment, Nepal has a potential area of 6074 sq. km with wind power density higher than 300 W/m^2. From the total area of 6074 square kilometres, only 10% has been analysed and it was found that 3000 MW of electricity can be generated from wind energy itself, with an installed capacity of 5 MW/square km. However, the current utilisation of wind is negligible because the entire focus of renewable energy is on hydropower. At the same time, Nepal has limited potential for large-scale wind deployment as compared to hydropower potential (Poudyal et al., 2019).

By 2030, Nepal targets 15,000 MW of renewable energy out of which only 5-10% will be from solar, wind, and small hydro while most of the generation is to be from large hydropower (NDC, 2021). Of this target, only 5% is unconditional while the 10% reduction is conditional on technical and financial aid from developed nations.

Despite the huge potential, there are a few challenges for the development of wind energy in Nepal. The main challenge is the transportation of large turbines over challenging topography to reach areas with high potential. Further, land acquisition for electricity projects, transmission lines, and substations are very difficult and costly. The country has high wind energy potential, if the electricity could be generated by erecting towers in the hilltops where wind blows at high speed such as Thini and Kagbeni of Mustang, Palpa, Ramechhap, Nagarkot, Pyuthan, Makwanpur, it would certainly aid in power supply in the country (Asia Wind Energy Association).

A4.4.3 Key Challenges

The following key challenges are being faced by the power sector of Nepal:

- **High rate of sedimentation** in most of the hydropower plants in the Himalayan rivers primarily decrease the life of the reservoir and cause excessive erosion resulting in a reduction in the efficiency and life of the turbine and its components in both storage and non-storage-based hydropower plants. The best way to mitigate this risk is through sediment monitoring and implementing necessary counter measures to protect the reservoir from sedimentation like watershed management, construction of sediment traps, structures, and management of the sediment within the reservoir and watershed.
- **Lack of mobilization of credit and high dependence on subsidy** is hampering the expected promotion of RETs.
- **Lack of adequate hydrologic data**, the country should invest in data collection and quality control as a large investment depends on it.
- **Difficult terrain with dispersed settlement**, long transmission lines are required and the costs of connection to national or regional grids could be manifolds higher. The only way to mitigate this risk is by promoting micro hydropower (with low cost) in such areas.
- **Local government units made responsible for electricity supply,** which is not necessarily commensurate with their capacity and capabilities to implement them.
- **Lack of strong institutions**, such as a regulator (only recently appointed) and clear policies (the electricity act has been submitted three times so far but has still not been passed), has been a challenge for progress in the sector. As a result, issues around trading, foreign exchange risk for investors, and the licensing regime remain unaddressed.
- **Stringent environmental concerns** like verification, monitoring, quality assurance, and testing against standards incur large financial costs, and are a hindrance to hydropower development in Nepal and delays that need to be streamlined.
- **Undeveloped infrastructure** like access roads and transmission networks is a challenge for hydropower development in Nepal. The isolated load dispatch centres that are not connected to national grid centre are a cause of concern for the hydropower developers as they result in incurring additional costs for developing the transmission line networks.
- **Lack of 'due diligence' capability in financial intermediaries (FIs) - The** hydropower sector is multi-disciplinary involving civil, electrical, mechanical engineers along with hydrology, geology, hydro morphology experts as well. In order to invest in hydropower, one needs to have in-house expertise in all these disciplines which FIs in Nepal lack and hence they don't show interest in investing in hydropower because of not having necessary 'due diligence' capability.

Annexure 5: Technical and Economic Assumptions for Power Generation Technologies for BBIN region

Country	**India**	**India**	**India**	**Bangladesh**	**Bangladesh**	**Bangladesh**	**India**	**India**	**Bangladesh**	**India**
Power Generation Technology	**Coal (Sub)**	**Coal (SC)**	**Coal (USC)**	**Coal (Sub) PP**	**Coal (SC) PP**	**Coal (USC) PP**	**Gas (OC)**	**Gas (CC)**	**Gas (OC)**	**Gas(CC)**
Technology Data										
Net Thermal Efficiency	0.33	0.35	0.41	0.35	0.37	0.43	0.29	0.42	0.39	0.57
Fuel Type	Domestic & Imported Coal	Domestic & Imported Coal	Domestic & Imported Coal	Coal	Coal	Coal	Domestic & Imported Gas	Domestic & Imported Gas	Gas	Gas
Annual Availability Factor	< 80	< 80	< 80	<.80	<.80	<.80	< 80	<80	<90	<85
Operational Life Time (Year)	25	25	25	30	30	30	25	25	20	25
Construction Period (Year)	4	4	4	4	5	5	2	2	2	3
Economic Data										
Overnight Cost ($/kW)	1012	1118	1291	1038	1038	1400	530	620	899	667
Fixed O&M Cost ($/kW/year)	23	26	39	24	25	39	11	25	30	30

Country	**India**	**India**	**Bangladesh**	**India**	**Nepal**	**Nepal**	**Nepal**	**Bhutan**	**Bhutan**
Power Generation Technology	**Nuclear (LWR)**	**Nuclear (PHWR)**	**Nuclear PP**	**Hydro**	**ROR**	**Pondage ROR**	**STG**	**ROR with Pondage**	**STG**
Technology Data									
Net Thermal Efficiency									
Fuel Type									
Annual Availability Factor	<80	<80	<90	0.387	0.66	0.55	0.41	0.48	0.36
Operational Life Time (Year)	30	30	60	35	40	40	40	40	40
Construction Period (Year)	6	6	8	8	6	6	6	8	8
Economic Data									
Overnight Cost ($/kW)	4500	1778	5000	1667	1602	1562	2025	1216	974
Fixed O&M Cost ($/kW/year)	112	44	78	42	48	47	51	30	24