MINISTRY OF INDUSTRY AND TRADE
INSTITUTE OF ENERGY

Global Energy Alliance
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GEAPP

STUDY ON RENEWABLE ENERGY

SCALE UP TO REPLACE COAL IN THE NORTHERN REGION OF VIETNAM

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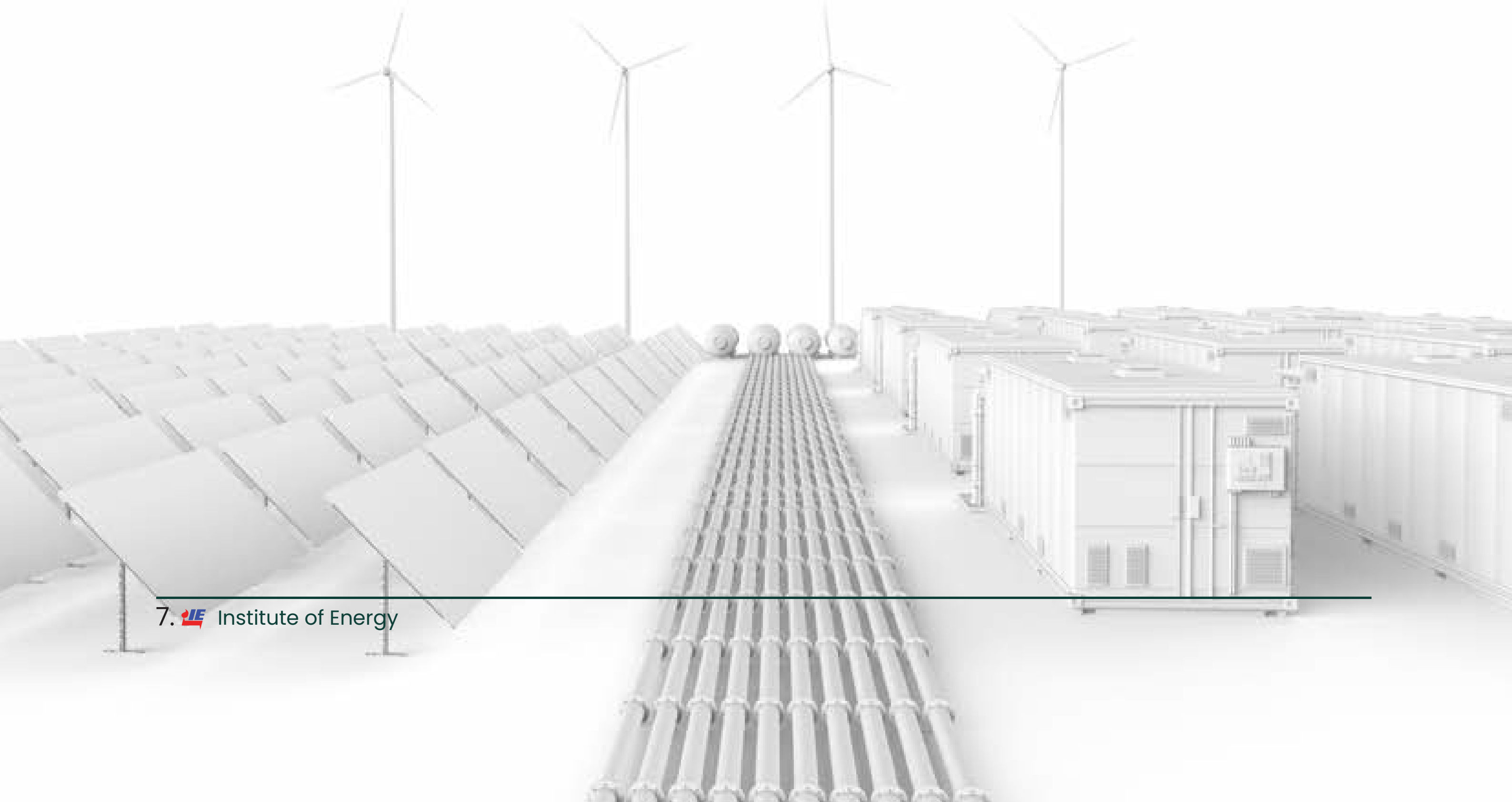

ABBREVIATIONS

EIRR	Economic Internal Rate of Return
EVN	Vietnam Electricity
FIRR	Financial Internal Rate of Return
FIT	Feed-In Tariff
HPP	Hydro Power Plant
MOIT	Ministry of Industry and Trade
NPV	Net Present Value
OWF	Offshore Wind Farm
PDP	Vietnam Power Development Master Plan
PSPP	Pump Storage Power Plant
PVN	Vietnam Oil and Gas Group
SPP	Solar Power Plant
TPP	Thermal Power Plant
WPP	Wind Power Plant

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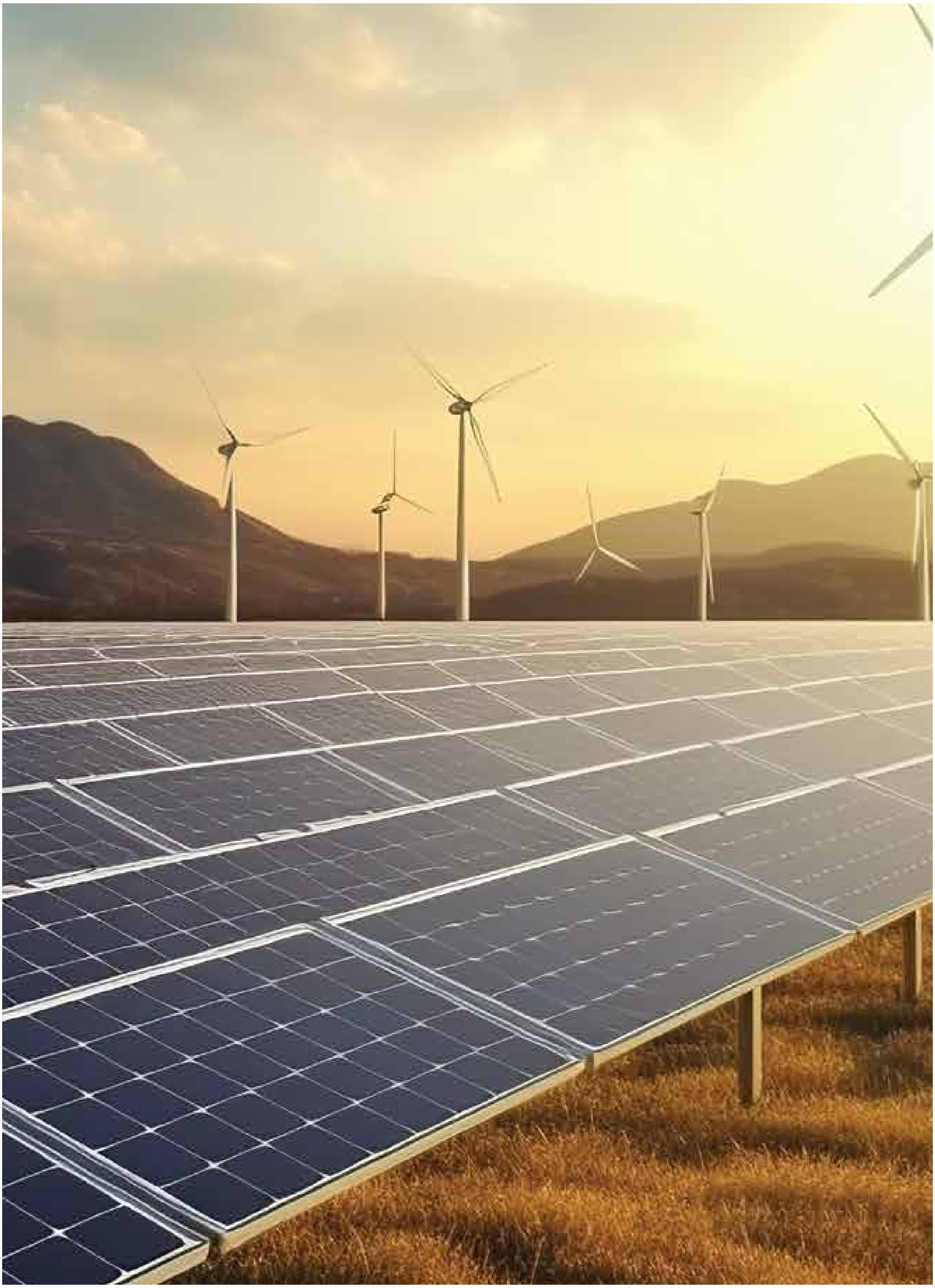


1. ASSESS THE CHALLENGES IN ELECTRICITY SUPPLY TO THE NORTH IN THE ROADMAP TOWARDS VIETNAM'S NET ZERO 2050 COMMITMENT

1.1. Current status and development plan of Vietnam power system

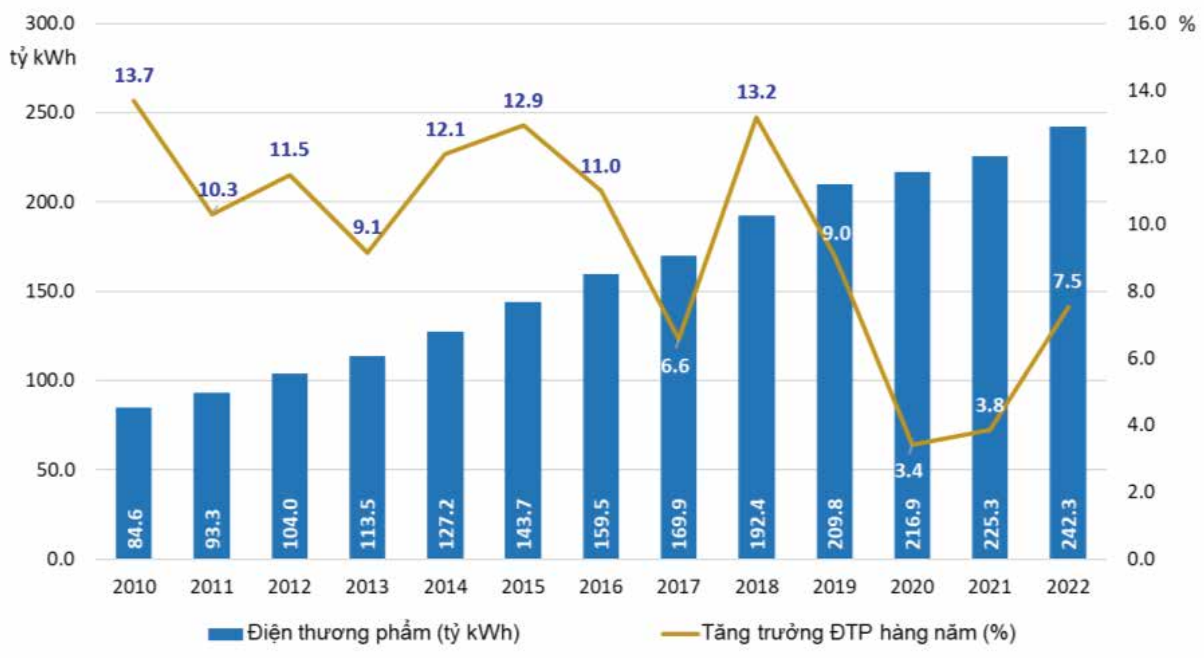
1.1.1. Current status of Vietnam power system

1.1.1.1. Status of Electricity Consumption

Vietnam's electricity consumption in recent years has regularly grown at a high rate to meet the needs of socio-economic development. Statistics on the growth of national commercial electricity output in the period 2011 - 2022 are illustrated in Figure 1-1. During this period, the national commercial electricity output increased more than 2.5 times from 85.7 billion kWh in 2010 to 242.3 billion kWh in 2022 with an average growth rate of about 9.2% per year.

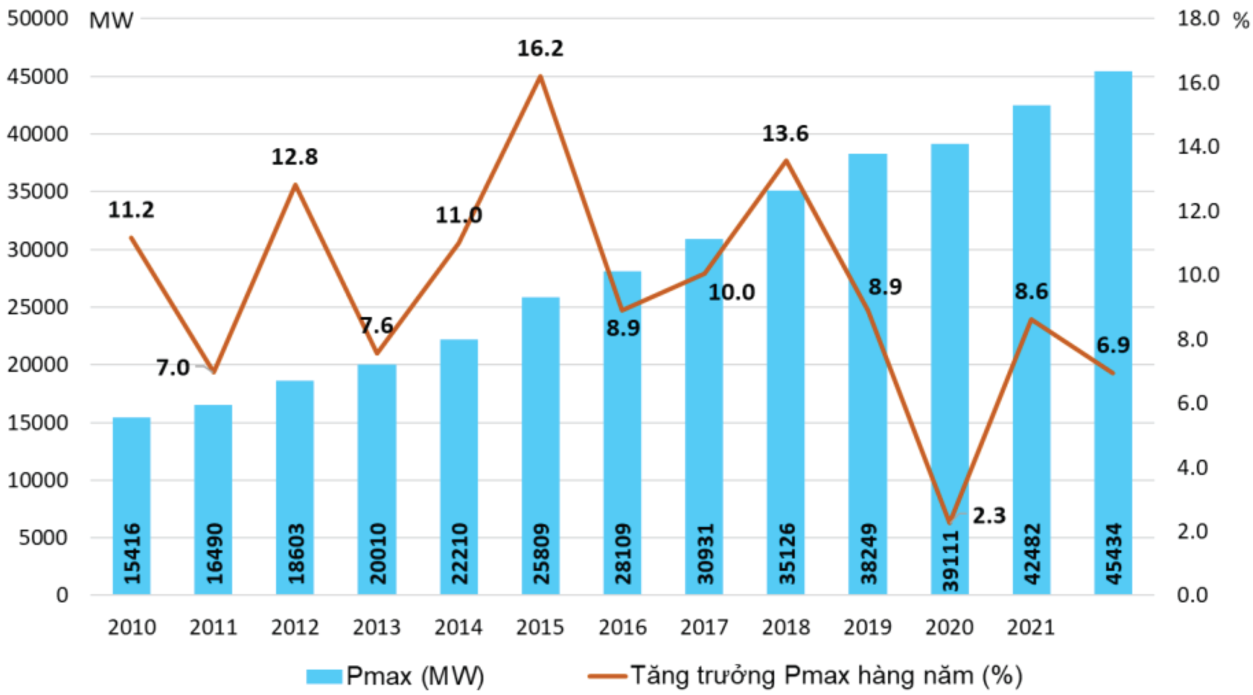
In the years 2020 - 2021, due to the impact of the COVID-19 epidemic, the national commercial electricity output growth slowed down, increasing by about 3-4% each year compared to the previous year. In 2022, Vietnam's economy entered the post-pandemic recovery phase, commercial electricity increased by 7.5% compared to 2021.

Figure 1-1 National sale electricity in the period of 2011-2022



Similar to sale electricity, the peak load of the power system in the period of 2011 - 2022 also grew rapidly with an average rate of about 9.9% per year from more than 16000 MW in 2011 to over 45400 MW in 2022. Due to the impact of the COVID-19 pandemic, peak load in 2020 only increased by about 2.3% compared to 2019. In 2021, due to the hot weather situation occurring in the North and Central from May to August, the demand for electricity increased dramatically. The national peak load in 2021 reached nearly 42482 MW, recorded on June 21, 2021, an increase of 8.6% compared to 2020. In 2022, peak load capacity continued to increase especially in the North, the Pmax reached about 45400 MW at the beginning of July 2022.

Figure 1-2 Peak load of VietNam in the period 2011-2022



1.1.1.2. Power Generation

Installed Capacity:

Total installed capacity of power sources in the period 2011 - 2022 is presented in Table 1-1 and illustrated in Figure 1-3. During this period, the total installed capacity of power sources in the system has more than tripled from about 23 GW to 78 GW, with an average growth rate of about 13% per year. Before 2019, Vietnam's electricity sources were mostly traditional power plants such as coal-fired thermal power, gas-fired thermal power, and hydropower. From 2019 onwards, due to the Government's mechanisms to encourage renewable energy development, solar and wind power sources have developed significantly. By 2021, Vietnam's electricity system will have over 16 GW of solar power (including rooftop solar power) and 4 GW of wind power.

In 2022, several coal-fired, hydropower, solar, and wind power plants will be put into operation. However, there are quite a few unavailable sources including the Thai Binh II power plant, 150 MW of solar power, and 933 MW of wind power in 2022.

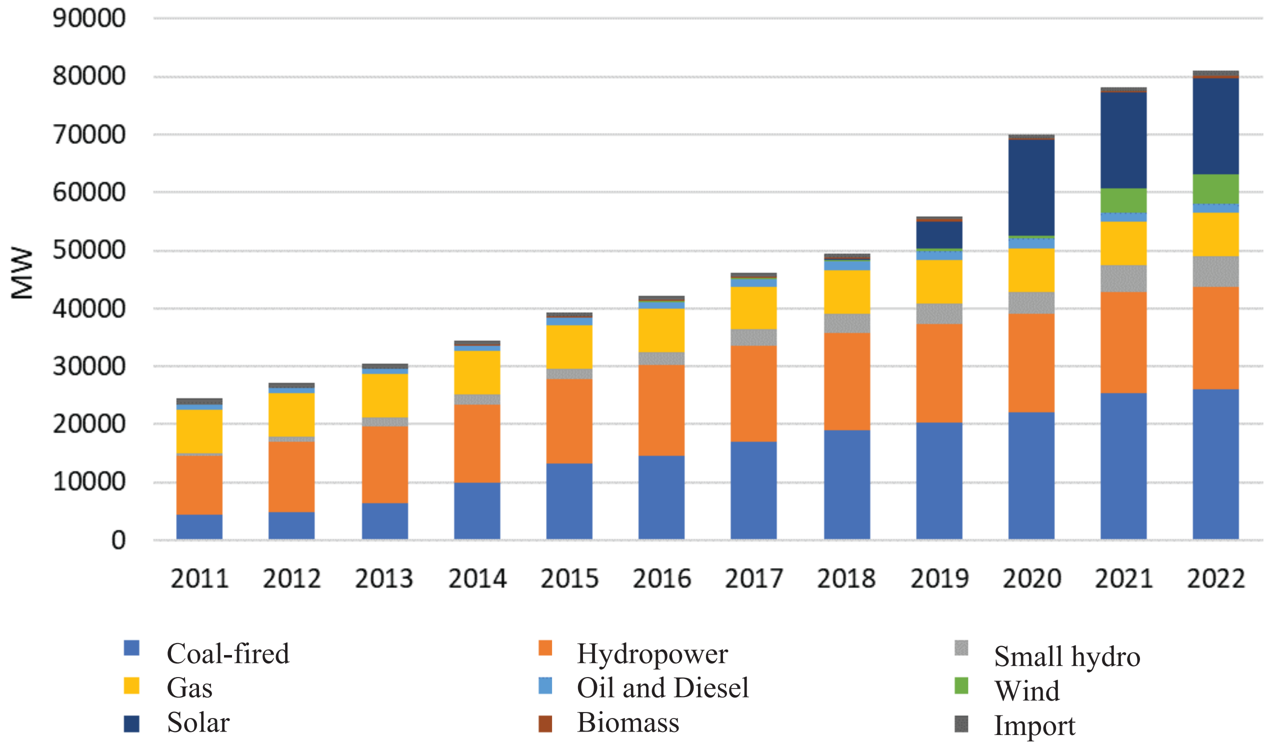
Table 1 1 National installed capacity of power sources in the period of 2011 - 2022 (Unit: MW)

Category/Year	2011	2016	2017	2018	2019	2020	2021	2022
Coal-fired Thermal Power	4451	14595	17089	18944	20267	22077	25397	26087
Large Hydropower	10100	15753	16497	16848	16958	16972	17493	17703
Small Hydropower	475	2083	2749	3322	3674	3887	4618	5296
Gas Turbines	7434	7446	7446	7446	7446	7446	7446	7398
Gas + Oil + Diesel	912	1242	1242	1624	1624	1624	1624	1627
Wind Power	0	104	158	243	377	538	4126	5059
Solar Power	0	0	0	86	4696	16564	16564	16568
Biomass Power	49	199	230	325	325	325	325	395
Import	0	540	540	572	572	572	572	942
Installed Capacity	**23421**	**41962**	**45951**	**49410**	**55939**	**70005**	**78165**	**81075**

Hydropower sources (including small hydropower) have been almost fully exploited, and their proportion in the national electricity structure has been gradually decreasing. By 2021, hydropower will only account for about 28% of the nation’s electricity structure. Meanwhile, coal-fired thermal power still accounts for over 30% because many power plants were put into operation in this period, such as Mong Duong 1, Vinh Tan, and Duyen Hai.

With outstanding growth in recent years, the proportion of solar and wind power sources has gone from almost 0% in 2018 to 21% and 25%, respectively, in 2020, 2021, and continuing to maintain the above rate in 2022. Gas turbine power has not been added in the last 10 years. As a result, the share of this type of power source decreased from 32% in 2011 to 9% in 2021. Other types of sources currently account for a small proportion of the national power structure.

Figure 1-3 Total installed capacity of power sources in 2011 – 2022



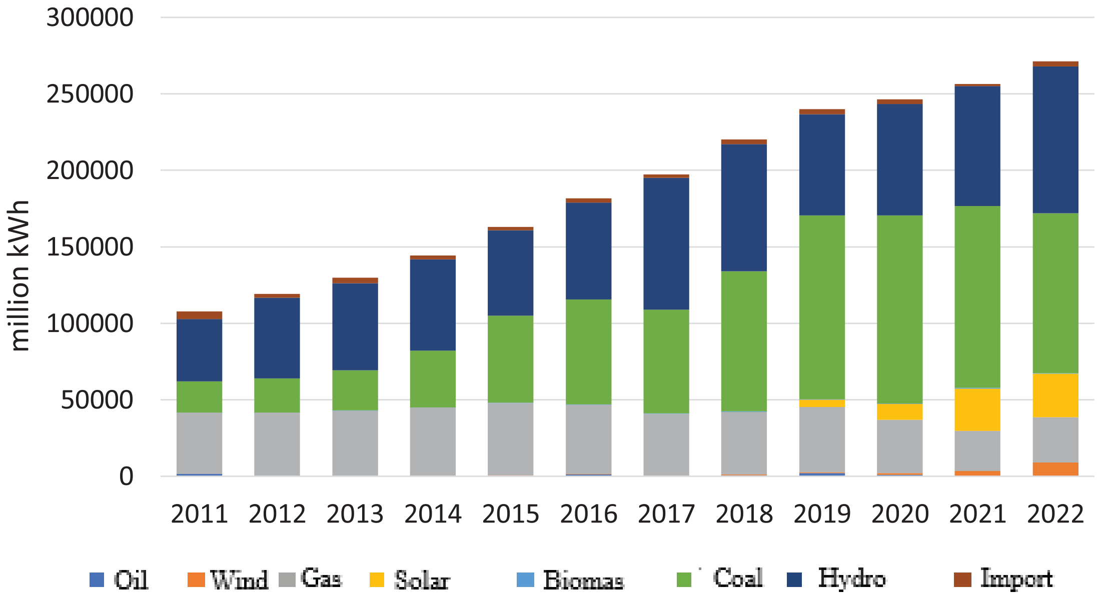
Electricity Production:

Vietnam electricity production growth in the period 2011 - 2022 is presented in Table 1-2 and illustrated in Figure 1-4. During this period, national electricity production grew by an average of 8.9% per year from about 108 billion kWh in 2011 to nearly 271 billion kWh in 2022. In 2 years, 2020 - 2021, due to the impact of the COVID-19 pandemic, electricity production only increased by 3% and 5%, respectively.

Table 1-2 National electricity production in the period 2011 - 2022 (Unit: GWh)

Category/Year	2011	2016	2017	2018	2019	2020	2021	2022
Coal-fired Thermal Power	20226	68779	68132	91654	20267	120158	123177	104541
Hydropower	40856	63491	85940	83081	66117	72892	78553	95929
Gas turbine + Gas	40285	45365	40347	40701	42507	34802	26312	29410
Solar Power	0	0	0	22	4819	10263	27791	28397
Wind Power	0	0	0	487	724	982	3344	9090
Biomass	72	122	208	488	350	340	321	378
Oil, Diesel	2204	1182	150	751	2114	1063	7	78
Import	4959	2736	2361	3124	3316	3067	1403	3279
Total electricity production	**108602**	**181675**	**197138**	**220308**	**240105**	**24658**	**25673**	**271102**

Figure 1-4 Electricity production growth in the period 2011 – 2022



shortage of electricity, having to receive electricity from the Central through the inter-regional transmission grid. Meanwhile, the Central region has excess electricity due to low local load.

In the North in the years before 2021, electricity production could meet the electricity demand of the whole region. However, in 2021 - 2022, the North encountered a shortage of electricity and had to receive electricity from the Central. This is shown in the inter-regional transmission trend illustrated in the figures below.

Figure 1-5 Inter-regional transmission trends in 2016 – 2022

1.1.1.5. Status of the Transmission Grid

Vietnam's transmission grid is regulated with voltage levels of 220 kV or higher. The total volume of 500 - 220 kV transmission lines and substations in 2019 - 2022 across the system is listed in the table below.

Table 1-3 Volume of transmission lines and substations, 2019 – 2022

Year	2019		2020		2021		2022	
Volume	**km**	**MVA**	**km**	**MVA**	**km**	**MVA**	**km**	**MVA**
500kV	8496	34050	8510	42900	9008	47100	10152	49500
220kV	18391	62236	18477	67824	19145	70464	19567	72848
Total	**26887**	**96286**	**27615**	**110724**	**28153**	**117564**	**29719**	**122348**

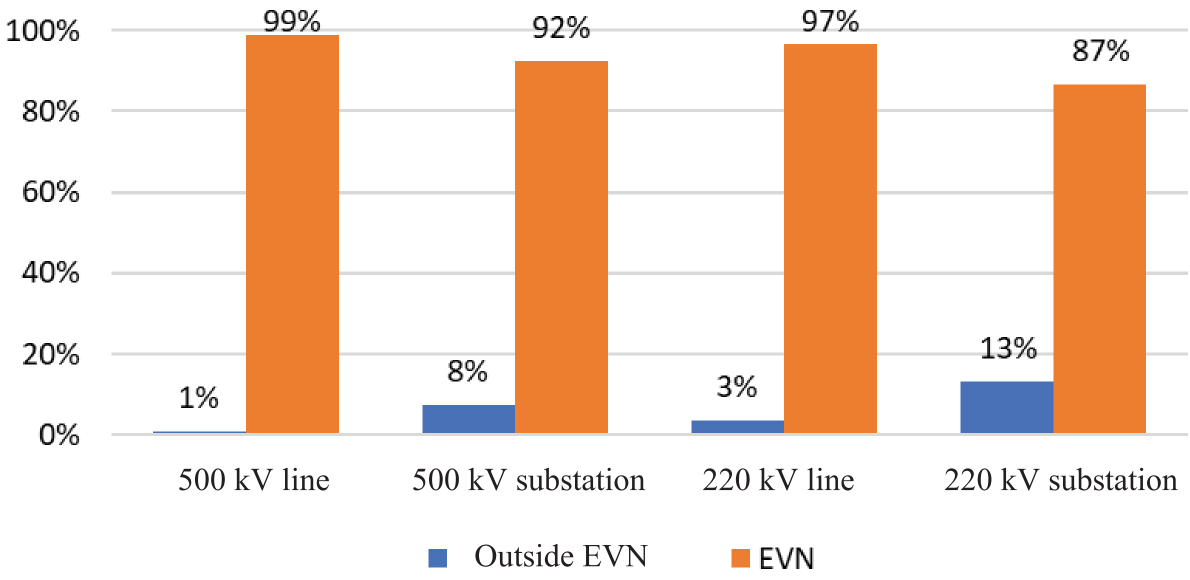
Between 2016 and 2022, the volume of 500 kV lines and substations grew by an average of 4.2% per year and 12.5% per year, respectively. The transmission line volume and substation capacity of 220 kV achieved average growth rates of 2.9% and 9.4% in the same period. In 2021 - 2022, several important regional-crossing 500 kV TL were put into operation, such as 500 kV Pleiku 2 - Chon Thanh, Doc Soi- Pleiku 2, and Quang Trach - Doc Soi.

According to Decision No. 168/QD-TTg dated 07/02/2017 of the Prime Minister, the power transmission grid will be managed and operated by the National Power Transmission Corporation (EVNNPT) in the form of a limited liability company represented by EVN holding 100% charter capital. By 2022, besides the power transmission grid invested by EVNNPT and other units of EVN (such as Power Management Board 1, 2, EVNHCMPC, EVNHNPC), there are also about 1-3% and 8-13% of the volume of 500 - 220 kV and 500 - 220 kV MBA invested and operated by private units.

Table 1-4 Structure of national transmission grid owners, 2022

Owner	500 kV TL (km)	500 kV Substation (MVA)	220 kV TL (km)	220 kV Substation (MVA)
Transmission grid volume				
EVN	10058	45750	18886	63263
Outside EVN	94	3750	681	9585
Percentage (%)				
EVN	99%	92%	97%	87%
Outside EVN	1%	8%	3%	13%

Figure 1-6 Nationwide transmission grid ownership structure in 2022



Currently, EVN still plays a major role in investment, construction, management, and operation of transmission grids, especially 500 kV power grids. The proportion of transmission infrastructure owned by EVN accounts for 97-99% with 500 - 220 kV substations and 87-92% with 500 - 220 kV substations.

In January 2022, the XV National Assembly of Vietnam passed Law No. 03/2022/QH15 amending and supplementing a number of Laws, including the Law on Electricity. This law allows all economic sectors to participate in investment in the construction of power transmission grids on the basis of ensuring national defense and security and according to electricity development planning, power generation activities, power distribution, wholesale,

wholesale, electricity retail and electricity specialized consultancy. The Ministry of Industry and Trade and other state management agencies are developing a system of documents under the law to guide the implementation of socialization in transmission grid investment. In the future, after the legal corridor is consolidated, the appropriately calculated electricity price and transmission price mechanism will gradually promote socialization, attract money from other sectors to develop the power transmission grid, and reduce investment pressure for EVN and EVNNPT.

1.1.2. National Demand Forecast

During the period of 2011 - 2020, the growth rate of sale electricity nationwide tended to decrease due to the shift in the structure of electricity consumption and the shift of sectors in the national economy. In addition, due to the impact of the COVID-19 epidemic, commercial electricity growth in 2020 reached 3.36%, while the average growth rate in the period of 2011 - 2019 was 10.5% per year. The growth rate of commercial electricity in the period of 2011 - 2020 reached 9.7% per year. The ratio of commercial electricity elasticity/GDP in the period of five years (2011 - 2015) and (2016 - 2020) is 1.86 and 1.44 times, respectively.

During the period of 2011 - 2020, the growth rate of commercial sale electricity nationwide tended to decrease due to the shift in the structure of electricity consumption and the shift of sectors in the national economy. In addition, due to the impact of the COVID-19 epidemic, commercial electricity growth in 2020 reached 3.36%, while the average growth rate in the period of 2011 - 2019 was 10.5% per year. The growth rate of commercial electricity in the period of 2011 - 2020 reached 9.7% per year. The ratio of commercial electricity elasticity/GDP in the period of five years (2011 - 2015) and (2016 - 2020) is 1.86 and 1.44 times, respectively.

The results of the demand forecast in PDP8 are implemented on the basis of the objectives of Resolution No.81/2023/QH15 of the National Assembly on the National Master Plan for the period 2021 - 2030, vision to 2050.

The main results are as follows:

- The sale electricity of the electricity system in 2030 is expected to reach about 505 billion kWh, with an average growth rate of 8.8% per year in the period of 2021 - 2030. The commercial electricity of the electricity system in 2050 is expected to be from 1,114 billion kWh to 1,254 billion kWh, with an average growth rate of 4.0%/year to 4.7%/year in the period of 2031 - 2050.

- The electricity production of electricity systems in 2030 is expected to reach about 567 billion kWh, with an average growth rate of 8.7% per year in the period of 2021 - 2030. The electricity production of electricity systems in 2050 is expected to be from 1,224 billion kWh to 1,378 billion kWh, with an average growth rate of 3.9%/year to 4.5%/year in the period of 2031 - 2050 from.

- The maximum capacity of the Pmax power system in 2030 is expected to be about 90,500 MW, with an average growth rate in the period of

- 2021 - 2030 of 8.9%/year. The maximum capacity Pmax power system in 2050 is expected to be from 185,000 MW to 208,600 MW, with an average growth rate of 3.6%/year to 4.3%/year in the period of 2031 - 2050.

- The commercial sale electricity elasticity coefficient/GDP is expected to reach about 1.30 times in the period of 2021 - 2025; 1.22 times between 2026 and 2030; 0.96 times between 2031 and 2035; 0.68 times between 2036 and 2040; decrease to 0.47 times in the period 2041 - 2045 and 0.37 times in the period 2046 - 2050.

According to the forecast results, the average annual growth of electricity demand in two scenarios in the periods of 2021 - 2030 is 8.8%/year. Compared to the growth of electricity demand in the period of 2011 - 2020 of 9.9%/year (electricity load in 2020 decreased due to the impact of the COVID-19 pandemic), the increase in electricity demand was significantly lower. In the period of 2031 - 2050, the growth rate of electricity demand will be affected by two trends: the downward trend due to more efficient electricity use and the upward trend due to electrification (increasing electricity-using equipment/vehicles to reduce emissions). The average increase in commercial electricity in the period of 2031 - 2050 is from 4.0% to 4.7%/year.

The forecast results of electricity demand in the period of 2021 - 2050 of the updated load forecast scenarios reflect the socio-economic development orientation set out in Resolution 81, especially the targets of GDP growth and national GDP restructuring. At the same time, it is in line with the orientation and requirements to improve Vietnam's electricity efficiency in the future.

1.1.3. National Power Source Development Plan

The first period of 2022 has taken place in the context of geopolitical and geo-economic fluctuations in the world, the trend of shifting to green and clean energy sources after COP26, and the rapid development of science and technology. In line with Vietnam's message at COP 26 (achieve net zero emissions by 2050), the PDP8 has launched scenarios to meet this net zero commitment by 2050.

According to PDP8, Vietnam's installed capacity of power sources by 2050 is presented in

Table 1-5 Vietnam's installed capacity of power sources by types to 2050

Target/Year	2025(*)	2030(*)	2035	2040	2045	2050
Peak Demand (Pmax)	**59.318**	**90.512**	**124.857**	**159.039**	**187.496**	**208.555**
Total Installed Capacity	**97.234**	**150.489**	**242.159**	**354.089**	**470.712**	**573.129**
Coal	28.757	30.127	23.137	15.337	3.635	0
Coal and Biomass/Ammonia	0	0	6.990	14.790	18.642	0
Coal completely switched to Biomass/Ammonia	0	0	0	0	6.990	25.632
Domestic Gas CCGT, switch to LNG	7.076	14.930	7.900	7.900	7.900	7.900
LNG and Hydrogen	0	0	7.030	7.030	0	0
Fully Hydrogen	0	0	0	0	7.030	7.030
New LNG CCGT	2.700	22.400	22.700	12.200	0	0
LNG and Hydrogen	0	0	2.700	13.200	21.900	4.500
Fully Hydrogen	0	0	0	0	3.500	20.900
Flexible CFPP	0	300	9.000	23.100	33.900	46.200
Oil and Diesel	1.221	0	0	0	0	0
Hydropower (including small hydro)	26.795	29.346	33.654	34.414	35.139	36.016
Onshore, nearshore Wind Power	13.416	21.880	30.400	46.100	62.250	77.050
Offshore Wind Power	0	6.000	18.000	45.500	79.500	91.500
Solar Power	10.136	12.836	56.866	94.866	135.824	189.294
Biomass, Garbage-fired and other Renewable energy	1.180	2.270	3.290	4.960	5.210	6.015
PSPP and Battery Storage	50	2.700	9.450	19.950	33.750	45.550
Import	4.453	5.000	7.742	10.242	11.042	11.042
Cogeneration	*1.450*	*2.700*	*3.300*	*4.500*	*4.500*	*4.500*

(*): Excluding existing rooftop solar sources.

The installed capacity structure has changed in the direction of gradually reducing the proportion of coal-fired thermal power. During this period, no new coal-fired thermal power plants will be developed besides those that are already in the implementation process (expected COD in 2025). The proportion of coal-fired thermal power will decrease from 30% in 2020 to 21% in 2030. By 2050, all coal-fired thermal power plants (25632 MW) will completely switch fuel to biomass and ammonia.

The proportion of domestic gas power plants will reach about 10% of the total installed capacity of the country by 2030. The proportion of LNG-fired power plants will increase from 0% now to 16% by 2030. By 2050, all gas-fired thermal power plants will completely switch fuel to hydrogen.

The proportion of hydropower will decrease because it is now fully exploited. Wind and solar power sources will be strongly developed in the future with an increasing proportion. The proportion of renewable energy capacity (except hydropower) will increase from 25% in 2020 to 35% by 2030. During the period of 2031 - 2050, renewable energy will continue to be developed, increasing capacity proportion to 68% and the electricity proportion to 63% by 2050.

1.1.4. National Power Transmission Grid Development Plan

By 2025:

In the period up to 2025, it is necessary to continue developing inter-regional transmission 500 kV transmission lines to increase the efficiency of power system operation. This will help evacuate the electricity from renewable energy sources and increase the transmission capacity, ensuring electricity supply for the socio-economic development of northern and southern load centers.

On the Center Central - North Central - North interface, it is necessary to ensure the progress of Quang Trach – Quynh Luu – Thanh Hoa – Nam Dinh – Pho Noi 500 kV transmission line. This project is being implemented and plays an important role in ensuring Northern power supply and limiting congestion on the North Central - North interface. After the above-mentioned lines are put into operation, there will be 04 circuits of a 500 kV transmission line in the Center Central - North Central - North interface.

On the Central Highlands - Southern and South Central – Southern interface, it is necessary to implement 500 kV transmission lines such as the 500 kV Krong Buk - Tay Ninh 1 (Highlands - South) and Ninh Son - Chon Thanh (South Central - South), bringing the total number of 500 kV transmission lines linking from the Highlands and South Central to the Southern to 12 circuits. These lines will support the evacuating of regional renewable energy capacity, while contributing to ensuring power supply for the Southern load center.

On the Southwest - Southeast interface, in the period to 2025, it is necessary to pay attention to Song Hau - Duc Hoa 500 kV transmission line. This is a line connecting Song Hau CFPP, which is under construction.

In addition to the 500 kV inter-regional transmission lines, transmission grid projects connecting power sources, releasing hydropower capacity, and importing electricity also play an important role, especially in the situation of slow deployment of many thermal power sources and the risk of shortage of power supply capacity for the North. Specifically, some notable projects are the Van Phong – Vinh Tan 500 kV transmission line connecting Van Phong coal-fired thermal power plant, 500 kV and 220 kV lines connecting Nhon Trach 3,4 CCGT, Lao Cai 500 kV substation and Lao Cai – Vinh Yen 500 kV transmission line, 220 kV TL and substation projects in the Northwest region to evacuate hydropower, Lao Bao 500 kV substation and connection lines to evacuate renewable energy, and 500-220 kV lines importing electricity from Laos such as Monsoon - Thanh My 500 kV TL, Nam Mo – Tuong Duong 220 kV TL, Nam Sum - Nong Cong 220 kV TL, Nam E-Moun - Dak Ooc 220 kV TLand Nam Kong 3 – Bo Y 220 kV TL.

From 2026 to 2030:

In this period, inter-regional transmission capacity will be strengthened, especially the North Central – Northern and South Central - Southern interfaces. The inter-regional links to 2030 are expected as follows:

- North Central – North: Including 05 circuits of 500 kV transmission line, specifically: 01 existing Vung Ang – Nho Quan circuit, building 01 new double-circuit transmission line Quang Trach – Quynh Luu – Thanh Hoa – Nam Dinh (2021 - 2025), and upgrading Vung Ang – Nghi Son – Nho Quan circuit into a double circuit transmission line (2026 - 2030). In case of high development of LNG power sources in the North Central region, consider building a new 500 kV double-circuit transmission line to transmit LNG power capacity from North Central to the North.

- Center Central – North Central: including 04 circuits of 500 kV transmission lines, specifically: 2 single circuits Da Nang – Vung Ang and 1 double circuit Doc Soi – Quang Tri – Quang Trach (2022).

- Highlands – Center Central: Including 5 circuits of 500 kV transmission lines, including existing single-circuit Pleiku – Doc Soi and Pleiku 2 – Doc Soi and upgrading the Pleiku – Thanh My single-circuit 500 kV line into double circuit (2026 - 2030).

- South Central – Highlands: Includes 3 circuits 500 kV transmission lines: existing single circuit Pleiku – Di Linh and double-circuit Krong Buk – Binh Dinh.

- South Central – South: Including 7 circuits of 500 kV transmission lines. Specifically: the existing single circuit Di Linh – Tan Dinh TL, 2 double-circuit of the existing 500 kV Vinh Tan – Dong Nai – Song May TL, and the new double-circuit 500 kV Ninh Son – Chon Thanh TL. In case of LNG Ca Na development, build a new double-circuit 500 kV line from South Central to Southern Vietnam.

- Highlands – South: Including 5 circuits of 500 kV transmission lines: the existing double-circuit Pleiku – Chon Thanh TL, the existing single circuit Dak Nong – Tan Dinh TL, and the double-circuit Krong Buk – Tay Ninh 1.

In addition to the above-mentioned 500 kV transmission works, notable intra-regional 500 kV transmission line projects in this period can be mentioned: Tay Ha Noi – Vinh Yen 500 kV TL, Da Nang – Doc Soi 500 kV and Thot Not – Duc Hoa 500 kV transmission line linking the Southwest - Southeast. The transmission lines connecting and releasing thermal power, LNG, and wind power sources will be carried out synchronously, corresponding to the power development plan in each scenario.

From 2031 to 2050:

After 2030, consider building HVDC power transmission systems with a total capacity of 20,000 MW to 30,000 MW depending on each scenario.

In the base scenario:

- Consider building a new Center Central - North HVDC transmission line, with a capacity of 10,000 MW, a length of more than 1,000 km.
- Consider building a new South Central - North HVDC transmission line, with a capacity of 10,000 MW, a length of more than 1,500 km.

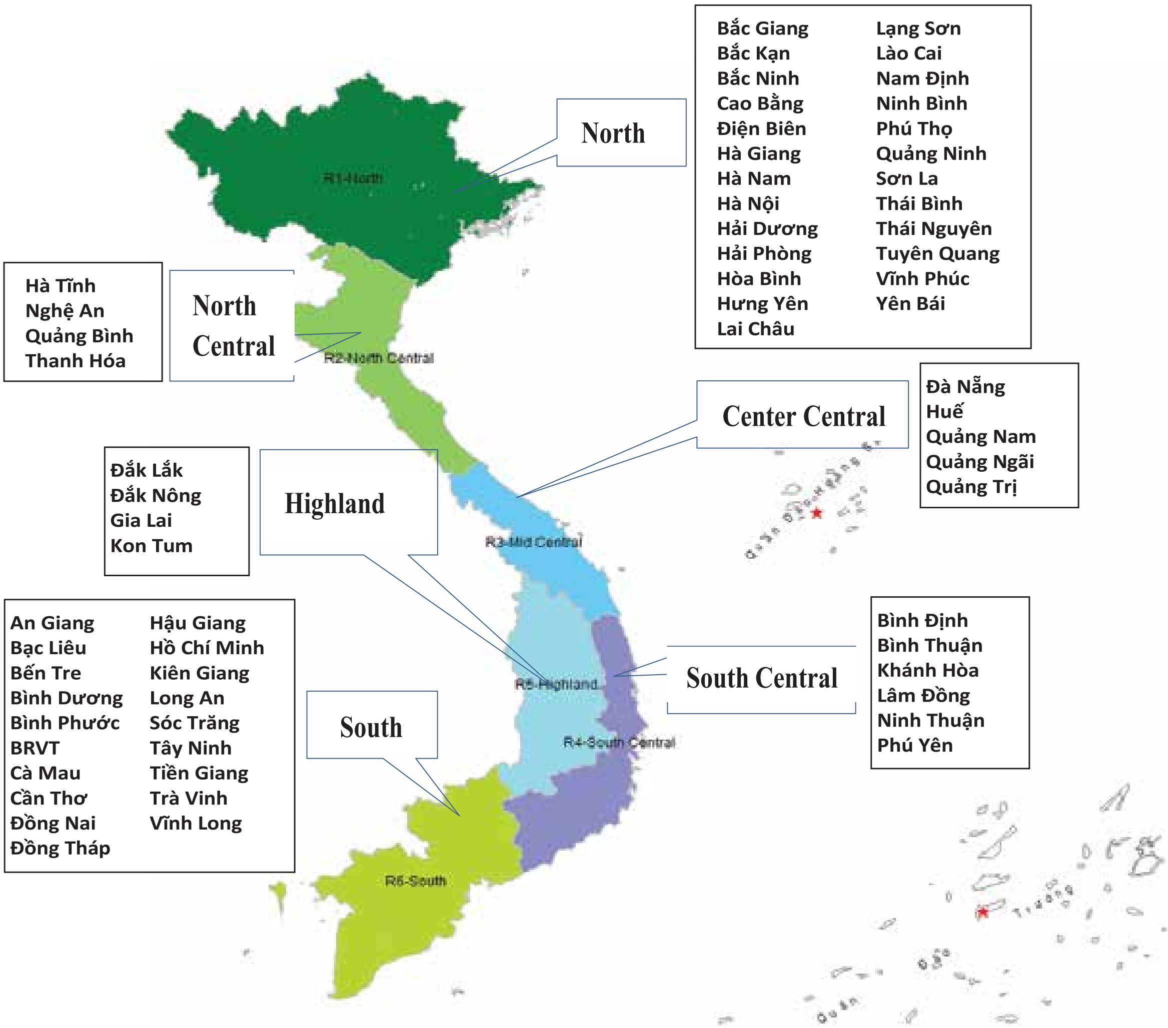
In the base scenario:

- Consider building a new Center Central - North HVDC transmission line, with a capacity of 10,000 MW, a length of more than 1,000 km.
- Consider building a new South Central - North HVDC transmission line, with a capacity of 10,000 MW, a length of more than 1,500 km.
- Consider building a new South Central - North HVDC transmission line, with a capacity of 10,000 MW, a length of more than 1,500 km.

1.2. Current Status of Northern Power System

The scope of the study covers 29 provinces/cities in the North and North Central regions as follows: Lai Chau, Son La, Dien Bien, Hoa Binh, Yen Bai, Lao Cai, Cao Bang, Bac Kan, Thai Nguyen, Ha Giang, Hai Phong, Quang Ninh, Bac Giang, Lang Son, Hanoi, Tuyen Quang, Phu Tho, Vinh Phuc, Bac Ninh, Hung Yen, Hai Duong, Ha Nam, Nam Dinh, Thai Binh, Ninh Binh, Thanh Hoa, Nghe An, Ha Tinh and Quang Binh.

Figure 1-7 Zoning of Vietnam's power system according to PDP VIII



1.2.1. Current status of electricity consumption

Electricity consumption in the North accounts for nearly 50% of the total electricity consumption of the country. Pmax in the North has started to surpass Pmax in the South since 2015 and has continued to increase in recent years. However, in terms of sale electricity, the North's electricity consumption will only exceed the South's from 2021.

Table 1-6 Electricity consumption of the North in the period 2010 – 2022

No	Item	2010	2015	2016	2017	2018	2019	2020	2021	2022
1	Sale electricity (GWh)	33223	59719	67438	74590	83181	90654	95875	103574	109858
2	Growth rate (%)	13.9%	13.7%	12.9%	10.6%	11.5%	9.0%	5.8%	8.0%	6.1%
3	Pmax (MW)	7321	11900	13197	15000	16539	17947	18894	20850	23421
4	Growth rate (%)	9.1%	10.6%	10.9%	13.7%	10.3%	8.5%	5.3%	10.4%	12.3%

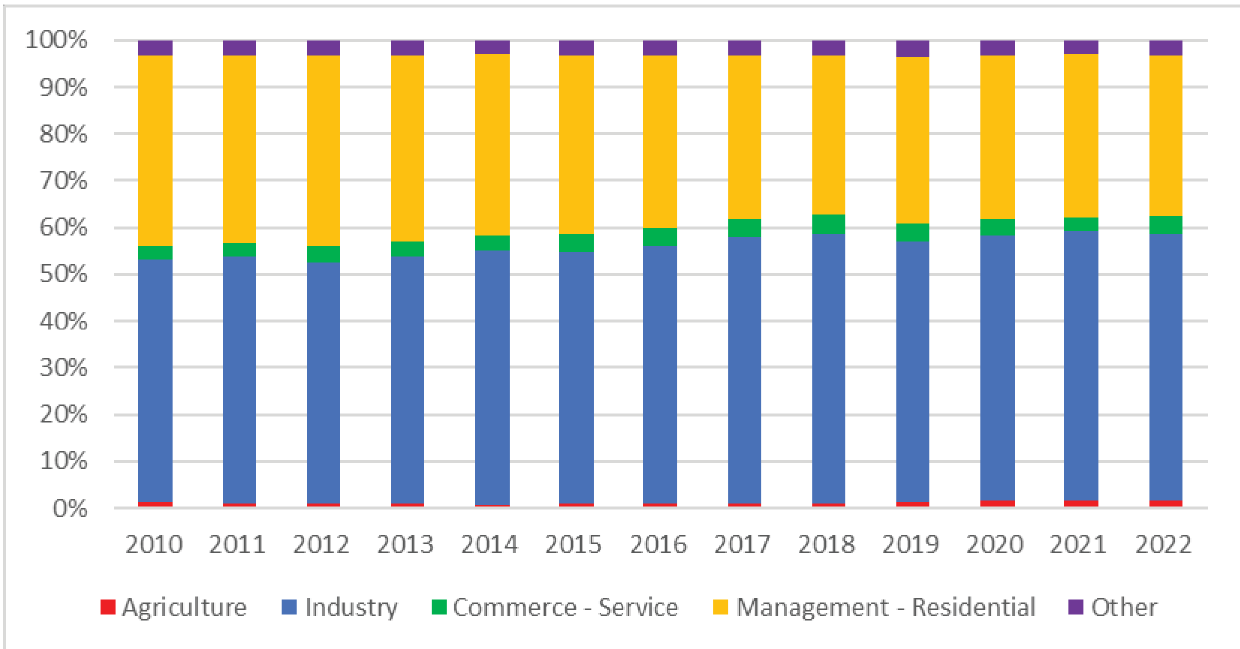
Figure 1-8 Sale electricity of the North in 2022

According to statistics for the period 2010 - 2022, Pmax in the North has a high growth rate, reaching an average of 10.2%/year. Pmax in the North in 2022 is more than 23 GW, 3 times higher than 2010. Meanwhile, the sale electricity of the North in 2022 will reach about 109 billion kWh, 3.3 times higher than that of 2010.

With its position as the economic locomotive of the Northern region, Hanoi has the largest sale electricity output in 2022, at 22 billion kWh. Next are the provinces/cities that have developed many large industrial parks such as Bac Ninh, Hai Phong, Hai Duong, Thanh Hoa, and Quang Ninh. In contrast, mountainous provinces such as Lai Chau, Dien Bien and Bac Kan have low electricity consumption. It can be seen that the level of electricity consumption of the provinces/cities in the Northern region is not uniform, with the difference in sale electricity output between the largest and the smallest provinces about nearly 100 times.

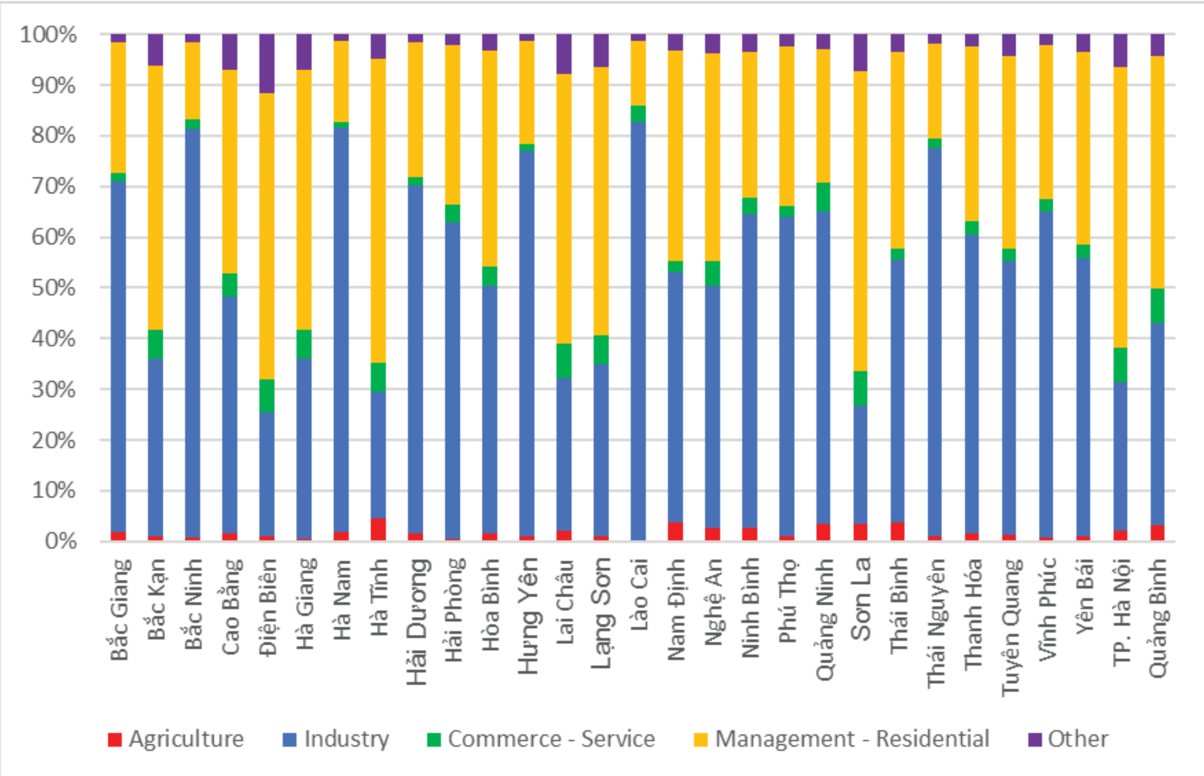
Regarding the structure of electricity consumption, there was no significant structural change in the last 13 years. Industrial load maintains the largest proportion in the period 2010 - 2022 along with the following components of Management - Residential and Commerce - Service. The proportion of electricity used for Agriculture, Commerce - Services and Other tends to increase while the proportion of electricity used for Management - Residential gradually decreases. The proportion of electricity for Industry increases from 52% in 2010 to 57% in 2022. Electricity for Management - Residential accounts for a large proportion (nearly 40%), so the daily load graph of the North has 2 sharp peaks in the morning and evening. Figure 1-9 shows the electricity consumption structure of the North in the period 2010 - 2022.

Figure 1-9 Electricity consumption structure of the North in the period 2010 - 2022



Depending on the economic development orientation of each province, the proportion of electricity consumption structure according to 5 economic sectors in different provinces. The group of industrial provinces with the largest proportion of industrial electricity consumption includes: Bac Giang, Bac Ninh, Hai Duong, Hai Phong, Hung Yen, Quang Ninh, and Thai Nguyen. Lao Cai province has large mineral reserves, focusing on the mining industry, so the proportion of electricity consumed by the sub-industry accounts for over 70%. The provinces of the Red River Delta have large rice-growing areas such as Thai Binh, Hanoi, Hai Duong, Vinh Phuc, Bac Giang, Nam Dinh, Ha Tinh, etc. However, the proportion of electricity consumed by the agricultural sector is small, less than 5%. This can also be explained by the fact that agricultural activities usually consume less electricity. In addition, the component of Management - Residential consumption accounts for the largest proportion in developed provinces/cities such as Hanoi or less developed provinces/cities such as Dien Bien, Ha Giang, Ha Tinh, Lai Chau, Lang Son, Son La.

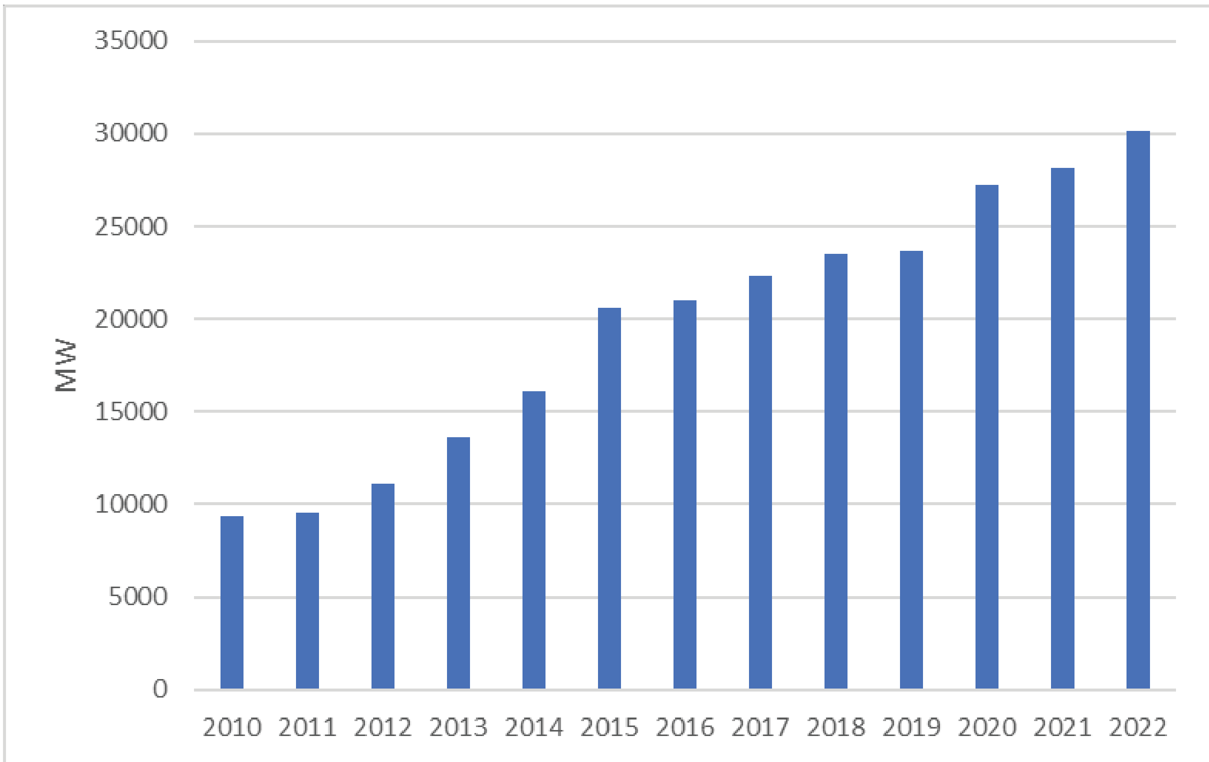
Figure 1-10 Structure of electricity consumption of Northern provinces/cities in 2022



1.2.2. Analysis of the Situation of Power Generation Development in the North in the Period 2010 – 2022

In the past, when Vietnam focused on developing traditional power sources such as hydro power and coal-fired power, the North always played the position of a large power source center with a high reserve capacity of power. However, in recent years, demand in the North has tended to grow rapidly while not many new power sources have been put into operation. Power is much lower than the rated capacity. The growth rate of the capacity of the Northern electricity source in the period 2010 - 2022 reached an average of 10.6%/year, while the growth rate of load reached about 10.2%/year. The growth of the installed capacity of the North in the 2010 - 2022 period is shown in Figure 1-11

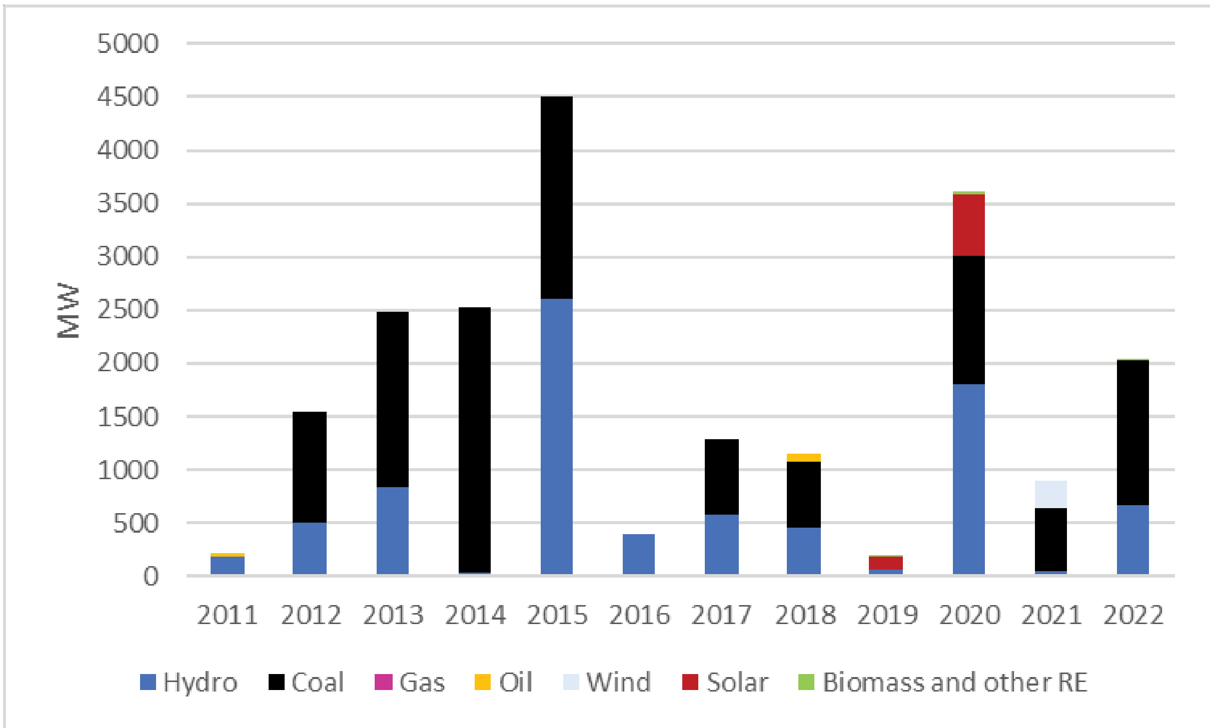
Figure 1-11 Installed capacity of the North in the period 2010 - 2022



In 2022, the total installed capacity of the North will reachis over 30 GW. This includes about 14 GW of hydro power, 15 GW of coal-fired power, the rest are wind, solar, biomass and other renewable energy sources. In the period 2010 - 2022, the total installed capacity of the North will increases by about 21 GW. Within 13 years, installed capacity increased more than 3 times, from 9 GW in 2020 to 30 GW in 2022.

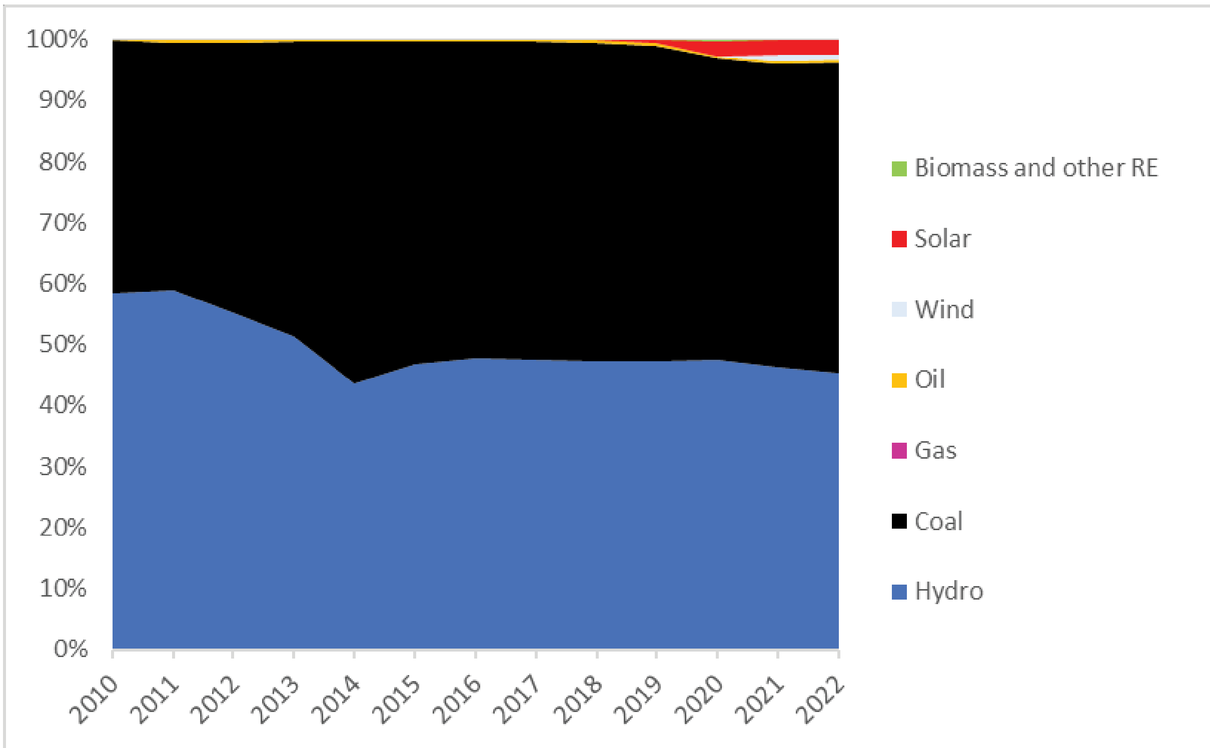
The power sources put into operation in the period 2010 - 2022 in the North are mainly hydropower (about 8 GW) and coal-fired power (about 11.5 GW). In particular, a series of coal-fired power plants with large capacity using domestic coal at the Northeast coal mine have come into operation, such as Hai Phong II thermal power plant (600 MW), Mong Duong I power plant (1120 MW), Mong Duong thermal power plant, Duong II (1245 MW), Thang Long Thermal Power Plant (620 MW), Thai Binh I Thermal Power Plant (706 MW), etc. Although Vietnam has issued a mechanism to encourage FIT prices for wind and solar power sources for 5 years, the North has almost no large wind and solar power projects coming into operation because the potential is not as good as the Central and the South regions. The additional solar power capacity is mainly rooftop solar power. Power capacity increases over the years according to each type shown in Figure 1-12

Figure 1-12 Power source capacity increases year by year by type



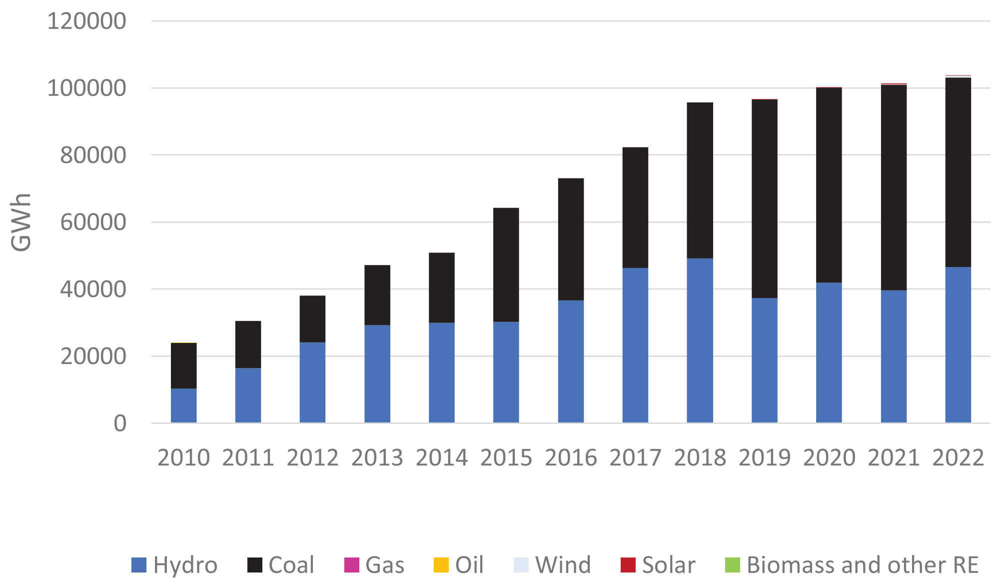
Regarding the structure of power source capacity, no significant shift was recorded in the period 2010 - 2022. Hydropower and coal-fired power always hold the largest proportion. The proportion of hydropower sources will decrease from 58% in 2010 to 45% in 2022 as the potential has been gradually exploited. In contrast, the proportion of coal-fired power sources will increase from 41% in 2010 to 51% in 2022. The North has no gas turbine plants because there are no domestic gas fields in the region. Wind, solar, biomass, and other renewable energy sources account for less than 5% of the total installed capacity of the whole region.

Figure 1-13 Structure of the installation capacity of the Northern power source in the period 2010 – 2022



In the period 2010 - 2022, the growth rate of electricity production in the North reached an average of 13.4%/year. In which, in the period 2010 - 2017, electricity production increased rapidly, reaching an average of 19.6%/year. In the period of 2018 - 2022, the speed of electricity production slowed down with an increase of 5% per year. Hydro power and coal-fired power are the two main power sources in the North, with the same proportion of electricity produced.

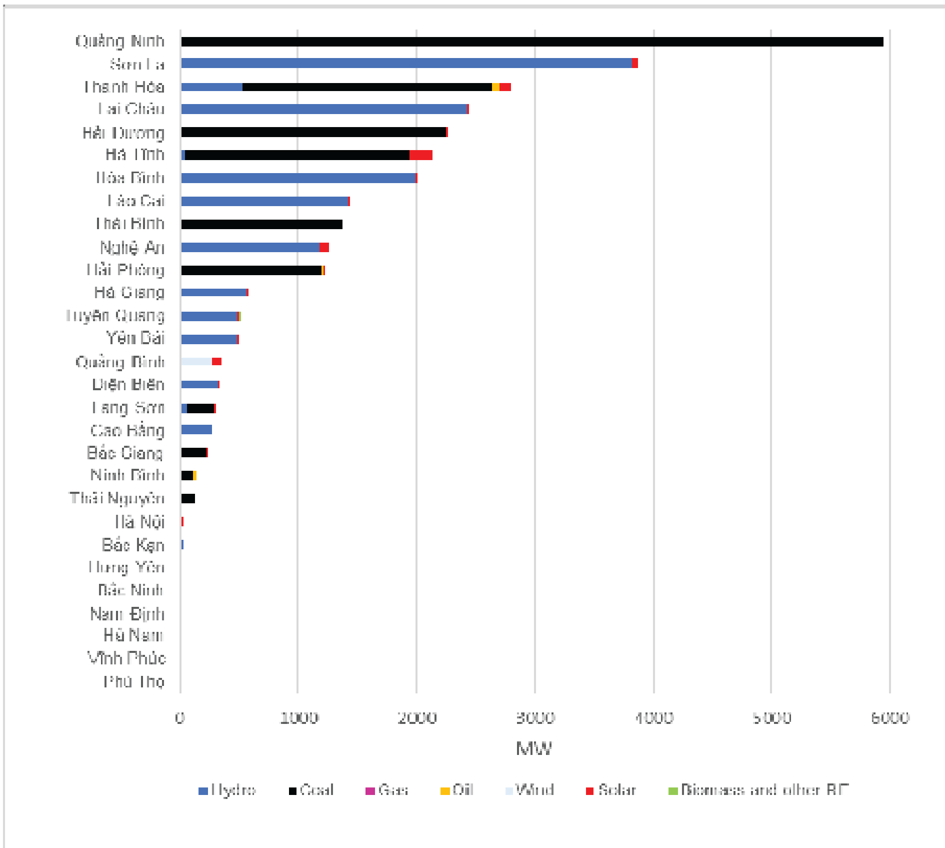
Figure 1-14 Output of electricity for production of various types of power sources in the North in the period 2010 – 2022



Currently, the installed capacity of Quang Ninh province is the largest in the North, reaching nearly 6 GW (accounting for 20%) because this is an area with many large domestic coal-fired power plants, such as Quang Ninh TPP, Mong Duong I & II TPP, Thang Long TPP, Uong Bi TPP, etc. Next is Son La province with Son La hydro power plant (capacity of 3200 MW), the largest hydropower plant in the country. On the contrary, some provinces/cities in the Red River Delta region do not have large power plants, only developing a small amount of rooftop solar power capacity, needing to depend on power supply of power system grid, such as Hanoi, Phu Tho, Vinh Phuc, Ha Nam, Nam Dinh, Bac Ninh, and Hung Yen.

The development of power sources depends heavily on the natural and topographical conditions of the area. In the North, the Northeast and Northwest regions have markedly different characteristics, suitable for the development of different types of power sources. Coal-fired thermal power plants mainly use domestic coal, located in the Northeastern provinces/cities such as Quang Ninh, Hai Phong, Bac Giang, etc. Hydropower focuses on development in the Northwest region because this is an area with high terrain, strongly dissected along with many large rivers, which are favorable conditions for building dams to store water. Large hydropower plants are built mainly in the Da river basin such as Hoa Binh hydropower plant, Son La hydropower plant, Lai Chau hydropower plant, etc. Small hydropower plants are built mainly in Ha Giang, Lao Cai, Lai Chau, and Dien Bien provinces.

Figure 1-15 Structure of installed capacity by provinces/cities in 2022



1.2.3. Analysis of the Development of the Power Grid in the North in the Period 2010 – 2022

The Northern part of the 500 - 220 kV transmission grid is currently managed and operated by Power Transmission Company 1 (PTC1) of the National Power Transmission Corporation (EVNNPT).

By the end of 2022, the total capacity of 500 kV substations in the North reached 17850 MVA (accounting for 36% of the national volume) and the total capacity of 220 kV substations reached 30991 MVA (accounting for 43% of the national volume). In terms of transmission line length, the Northern power grid has about 3296 km of 500 kV transmission lines and 7607 km of 220 kV lines. The 500 kV lines play the role of linking the regions while the 220 kV lines perform the task of inter-provincial and intra-provincial connections.

The capacity of substations as well as the length of lines have grown strongly in the period 2010 - 2022. The growth rate of 500 kV substations has averaged 16%/year. However, in the last 5 years, the growth of 500 kV substation capacity has tended to slow down, reaching only about 10% per year. With 500 kV lines, the average growth rate is 6.2%/year in the period 2011 - 2022. From 2018 to 2021, no new 500 kV lines in the North will come into operation. At the voltage level of 220 kV, the growth rates of substations and lines will reach 13.1%/year and 4.5%/year respectively in the period 2010 - 2022. Details of growth of 500 kV and 220 kV power grids in the period 2010 – 2022 is shown in Figure 1-16 and Figure 1-17

Figure 1-16 Volume of 500-220 kV substation in the period 2010 – 2022

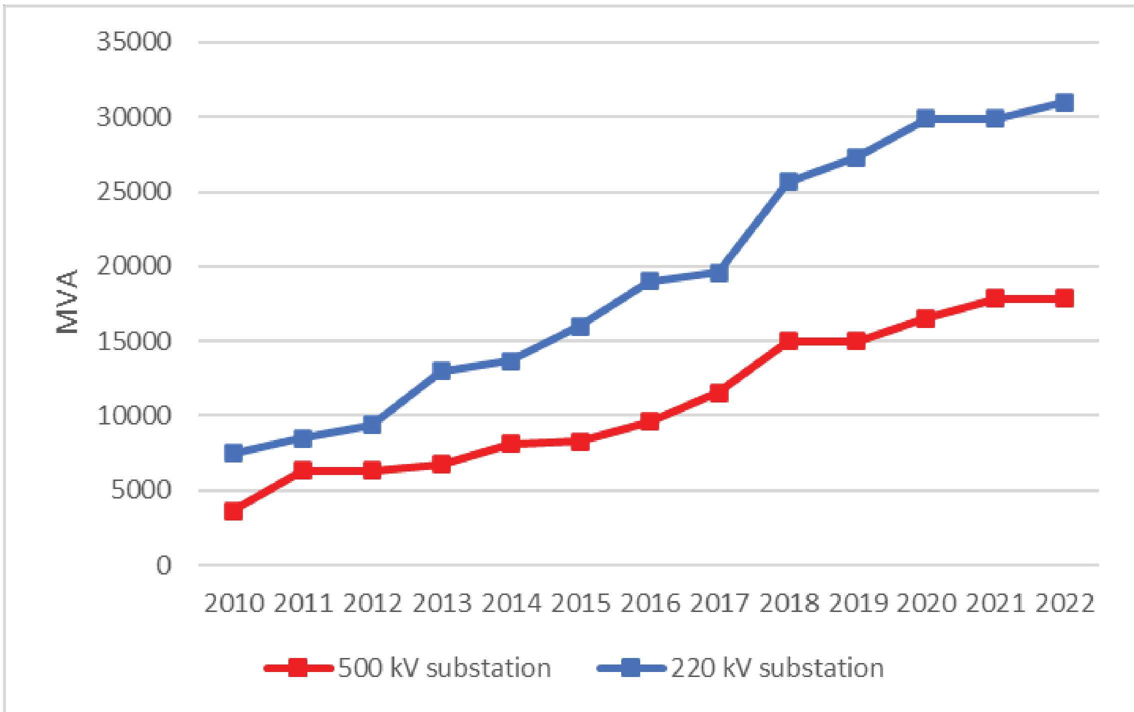
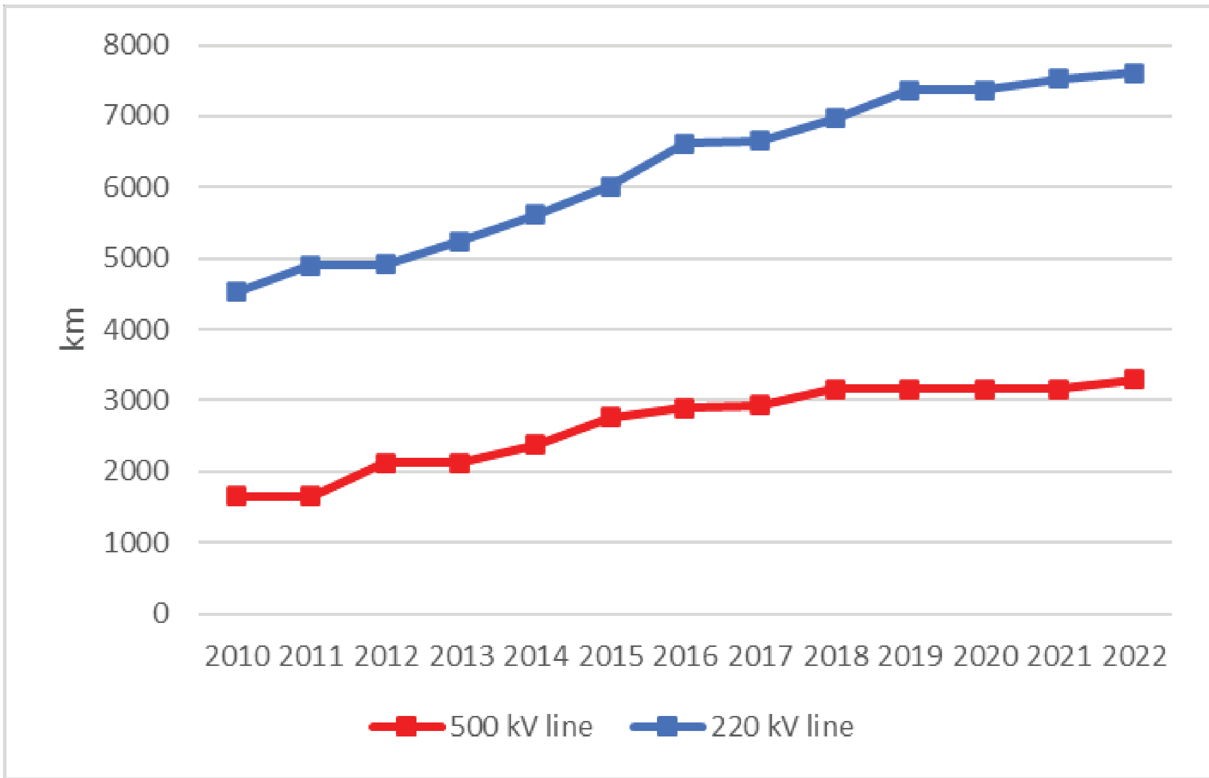


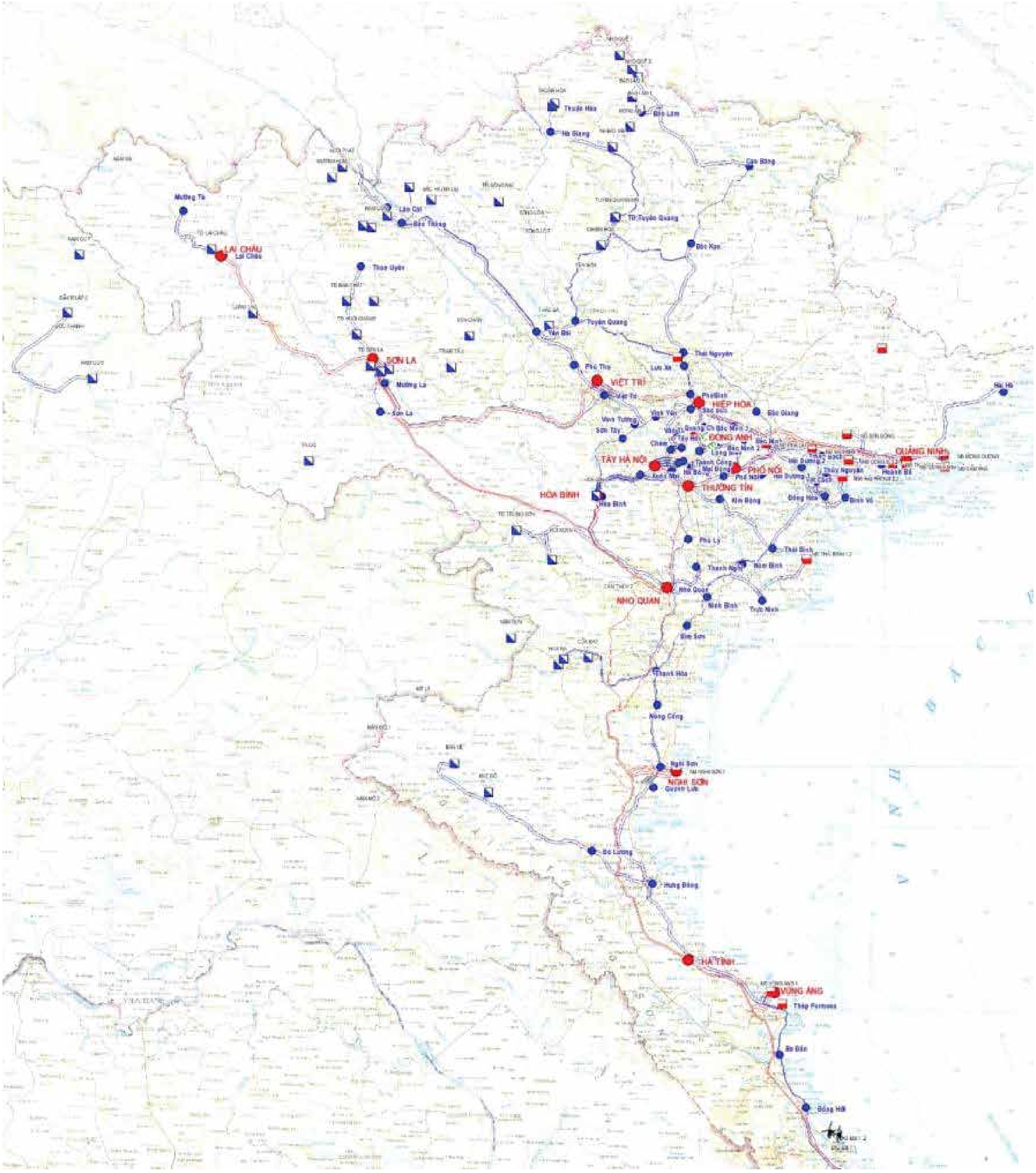
Figure 1-17 Volume of 500-220 kV line in the period 2010 - 2022



The volume of investment in construction of 500 - 220 kV power grids compared with the PDP VII Revised is quite high, but there are still some projects behind schedule. The main reason is due to financial difficulties of the investor and problems with technical construction solutions. In addition, the work of compensation for site clearance also faced many difficulties. High-voltage line works pass through many localities, the policy of compensation and support for each locality is different. In recent years, many households have built temporary houses with a large area in the foundation locations and corridors to profit from compensation, affecting the progress of projects. According to statistics in PDP VIII, the completion rate of 500 kV substations, 500 kV lines, 220 kV substations, and 220 kV lines in the North under PDP VII Revised for the 2016 - 2020 period will reached about 88%, 56%, 88% and 64%, respectively.

The current grid map of the Northern region is shown in Figure 1-18

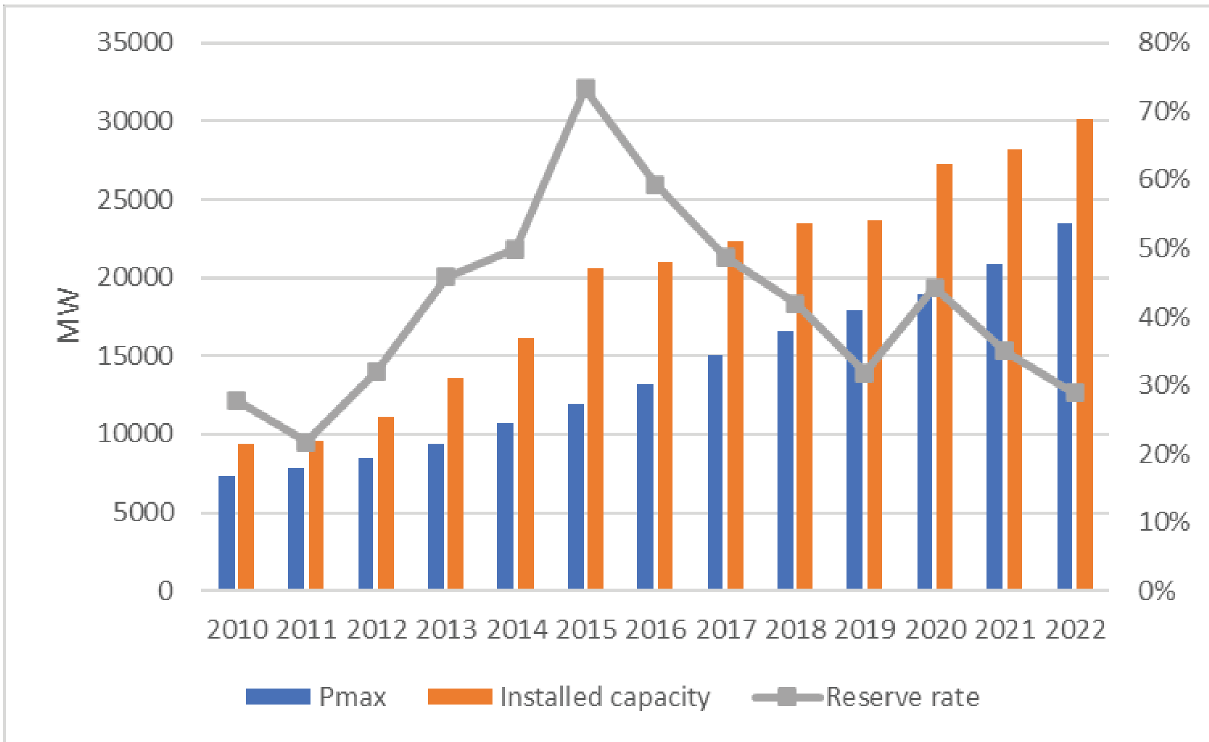
Figure 1-18 Current 500 - 220 kV grid map in the North



1.2.4. Analysis of the Current Situation of Electricity Supply to the North

In the period 2010 - 2022, the North maintains a relatively good capacity reserve ratio (over 25%). Especially in the period of 2013 - 2017, the capacity reserve rate of the North has always reached over 45%. In fact, there have been a series of large coal-fired power plants put into operation during this period, such as Hai Phong 1 & 2 TPP (1200 MW), Mong Duong I TPP (1120 MW), Mong Duong II TPP (1245 MW), Nghi Son I TPP (708 MW), Vung Ang I TPP (1245 MW), etc., contributing to ensure power supply for the Northern region- one of the two major load centers of the country. Besides, hydropower continues to be exploited in the North (mainly in the Northwest), in which energizing and commercial operation of a number of large hydropower plants, such as Lai Chau HPP (1200 MW), Huoi Quang HPP (520 MW), Ban Chat HPP (220 MW), Trung Son HPP (260 MW), etc. However, in the period after 2018, the capacity reserve ratio of the North began to gradually decrease from 42% in 2018 to 28.9% in 2020.

Figure 1-19 Demand – supply balance in the North in the period 2010 - 2022

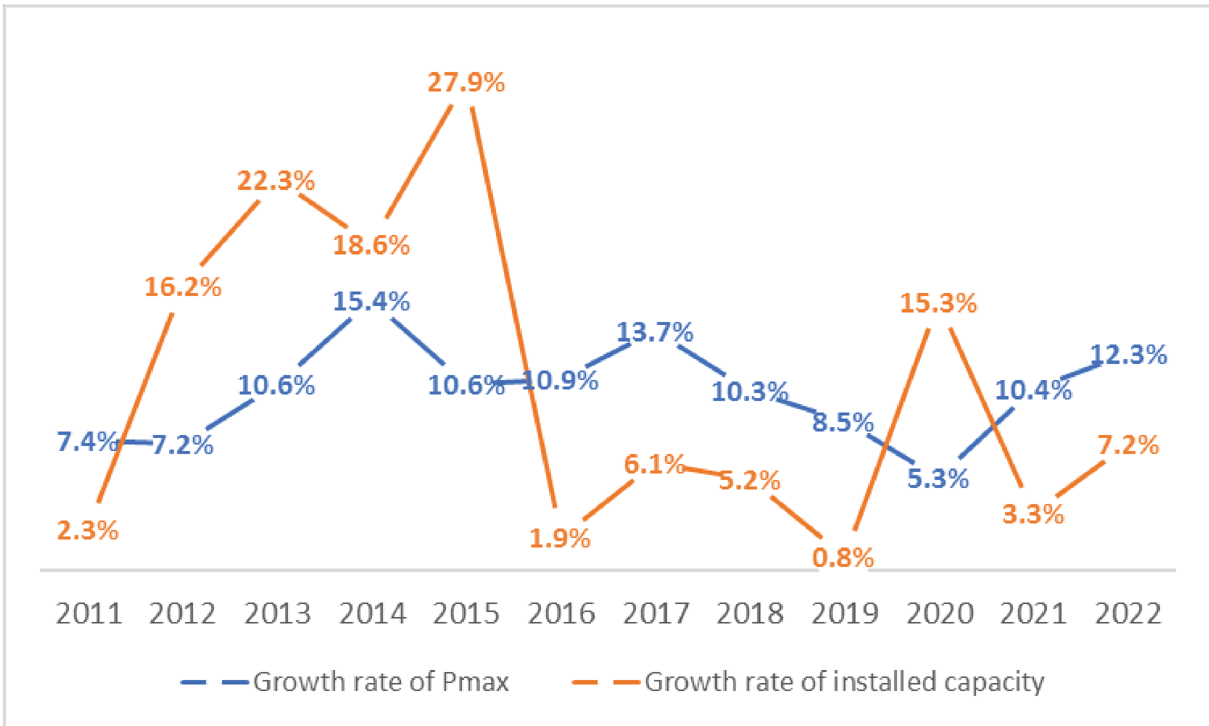


Despite the large capacity reserve ratio, the available capacity of the Northern power sources sometimes cannot reach the rated capacity, leading to power shortage during the summer peak. In 2021 and 2022, there will be some time when the Northern power system has a shortage of power, requiring curtailment of the demand (DR). This situation mainly occurs in the summer months (around May, June, July) when the demand is high while a number of hydropower and coal-fired power plants do not generate capacity due to inadequate technical conditions.

Some of the causes leading to the failure of power supply to the North at some times in recent years can be analyzed in detail as follows:

Firstly, the demand in the North has a high growth rate while the power source in recent times has not developed much. The growth rate of Pmax in the North reaches an average of 10.2%/year while the growth rate of power sources in the North reaches an average of 10.6%/year in the period 2010 - 2022. Many coal-fired thermal power plants are planned to operate in the period up to 2020 according to the PDP VII Revised, but have not been put into operation so far, such as Thai Binh II TPP (there is one 600 MW unit not yet in commercial operation), Cong Thanh TPP (600MW), Na Duong TPP (110 MW), and Cam Pha III TPP (220 MW) stopped being deployed. The lack of power supply in the North is mainly due to the lack of capacity to meet Pmax, especially during the daytime in the summer months such as May, June, July, when the demand for electricity for cooling equipment increases. According to statistics, from 2015, Pmax of the North began to surpass the South.

Figure 1-20 Comparing the growth rate of demand and supply in the North in the period 2011 – 2022

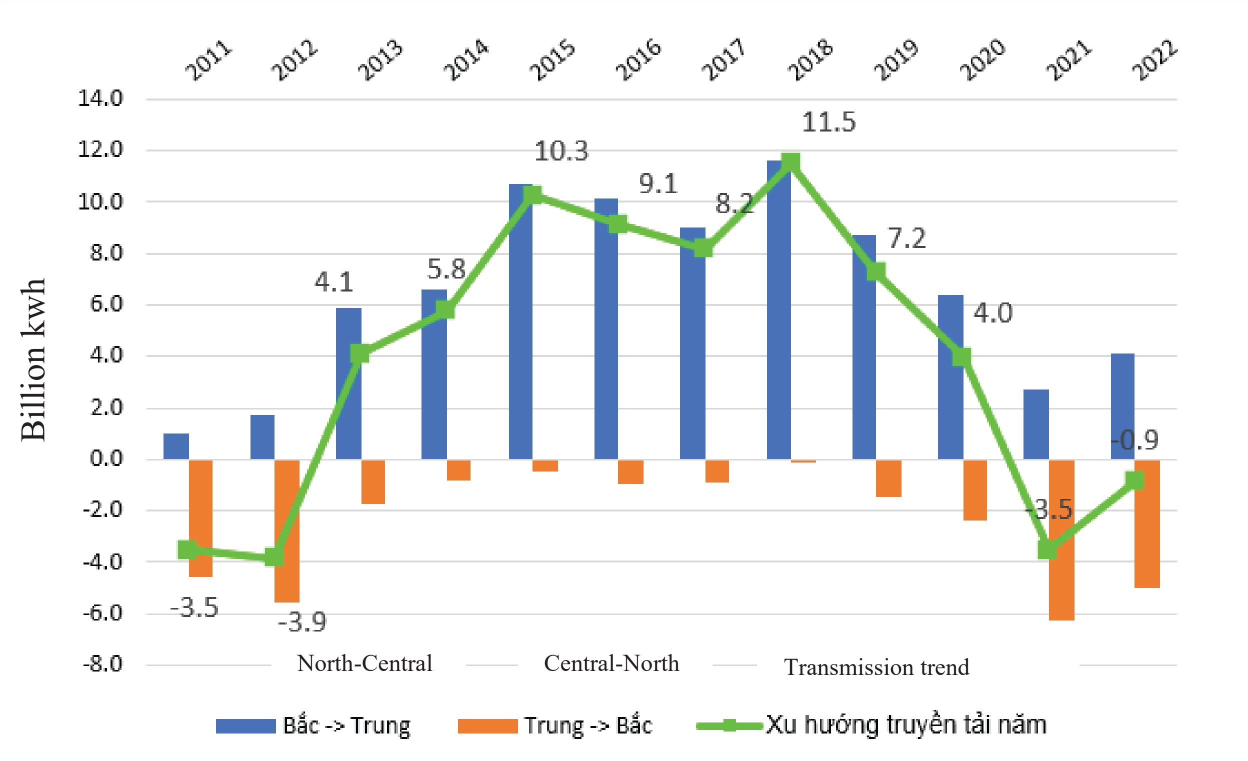


Secondly, the power structure of the North is not diversified, mainly developing hydro power and coal-fired power. The proportion of hydro power capacity in the North is large, accounting for 45% of the total installed capacity of the whole region, so the power supply capacity depends heavily on the hydrological situation. Typically, in 2023, the year of El Nino, the amount of water entering the reservoirs decreased, leading to many hydropower plants being unable to operate in the dry season because the reservoir's water level was below the dead water level. While renewable energy sources such as wind power and solar power flourished in the years 2019 - 2021 in the Central and Southern regions, thanks to the Government's FIT price incentive mechanism, the North has almost no large wind and solar power projects coming into operation, except for a few projects in the North Central region.

Thirdly, many power plants in the North have an available capacity that is not equal to the rated capacity due to technical limitations or problems that cannot coincide with the peak load time of the year. Pmax of the North usually falls around June and July, when the temperature rises, leading to an increase in electricity demand for cooling devices. For hydro power sources, this is just the beginning of the rainy season, and the amount of water entering the reservoirs is not much. In some dry years, the reservoirs have not accumulated enough water to be able to operate. This will reduce the generating output of hydropower sources. For thermal power sources, the ambient temperature is too high, which affects the cooling water temperature, leading to a decrease in the output of units. Some thermal power units in the North have been operating for a long time with outdated technology and reduced efficiency and cannot ensure continuous operation for a long time.

Besides self-sufficient power supply by regional power sources, the North is also supplied with electricity from the Central and the South through the inter-regional transmission line system. In the period 2011 - 2015, especially the years 2014 - 2015, which are the last years of this period, the North has been supplemented with many new power sources and exploited more efficiently than hydropower plants, while power projects in the South are still behind schedule, so the trend of power transmission is mainly in the North - Central and Central - South directions. However, in the period of 2021 - 2022, when the Central and South regions have been added with an additional amount of source capacity, especially from renewable energy sources, along with the relatively fast growth of demand in the Northern power system, the power transmission trend has changed. The main power transmission trend in 2022 is from the Central to the North and the South. In some times of local heat, electricity demand in the North increases, while in the South, solar power sources generate maximum output, electricity will be transmitted from the Central and South to the North. The transmission output in the North-Central direction decreased sharply from 6.2 billion kWh in 2020 to more than 2.7 billion kWh in 2021 and 4.1 billion kWh in 2022. In contrast, the transmission output in the direction from the Central to the North tends to increase from 2.3 billion kWh in 2020 to nearly 6.3 billion kWh in 2021 and 5 billion kWh in 2022. This shows that the North's ability to meet the demand and supply balance has gradually decreased.

Figure 1-21 Transmission output of North – Central in the period 2011 - 2022



In 2023, to enhance power supply to the North, EVN has increased the transmission limit of the North-Central transmission lines from 2100 - 2200 MW to 2400 - 2500 MW in the short term. At some hours there is a risk of local capacity shortage.

Therefore, it can be seen that the North is facing the risk of not ensuring electricity supply in the short term. In fact, there have been times when the load in the North had to reduce capacityoutput. Therefore, the study of solutions to save energy as well as ensure rapid increase of power supply is absolutely necessary for the Northern region.

1.3. Power System Development Plan in the North in the Period Up To 2050

1.3.1. Regional Demand Forecast

The demand forecast for the northern provinces/cities in the period up to 2035 is taken according to the provincial power development plan, which is adjusted and updated according to the high demand scenario in the PDP VIII. In particular, the demand in the North will grow rapidly in the next period with an average growth rate of 9.9%/year in the period 2021 - 2025 and decrease to 8.9%/year in the period 2026 - 2030 and 6.8% in the period 2031 - 2035. The regional Pmax is forecasted to reach more than 30 GW in 2025, more than 46 GW in 2030 and more than 64 GW in 2035. Therefore, within the next 13 years, the demand in the North is forecasted to increase 3 times compared to 2022, placing a heavy burden on regional power supply, especially in the context that the North does not have much potential for developing different types of power sources.

Details of the forecasted demand growth for the 29 northern provinces/cities in the period 2021 - 2035 are shown in Figure 1-22, Figure 1-23F, Figure 1-24, Figure 1-25, and Figure 1-26.

Figure 1-22 Demand forecast in the Northwest and Northern mountainous areas in the period of 2021 - 2035

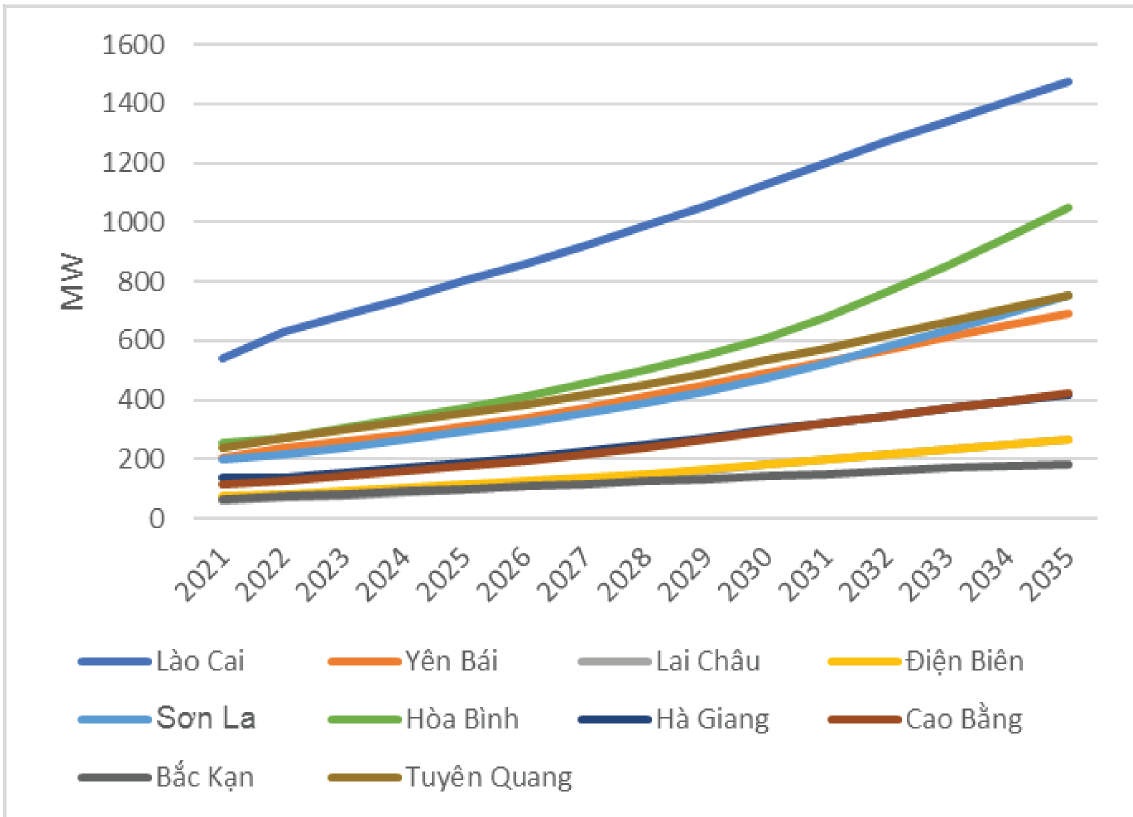


Figure 1-23 Demand forecast in the Northeast region in the period of 2021 - 2035

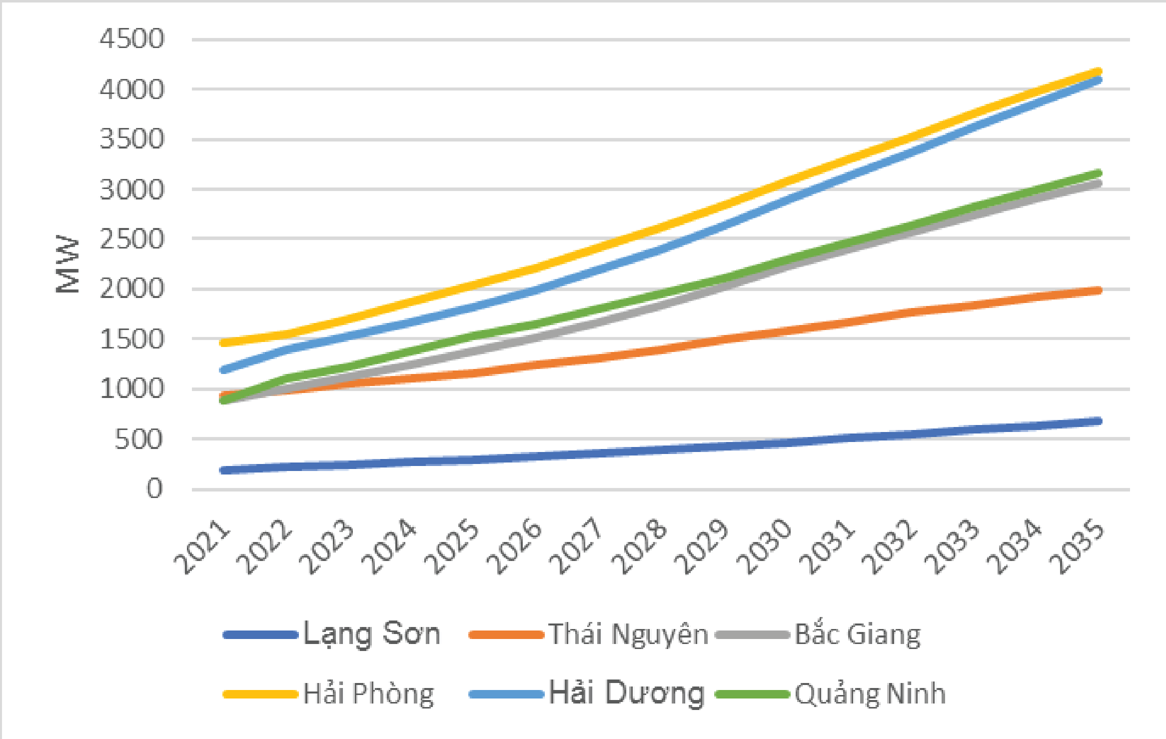


Figure 1-24 Demand forecast in Hanoi and surrounding areas in the period of 2021 - 2035

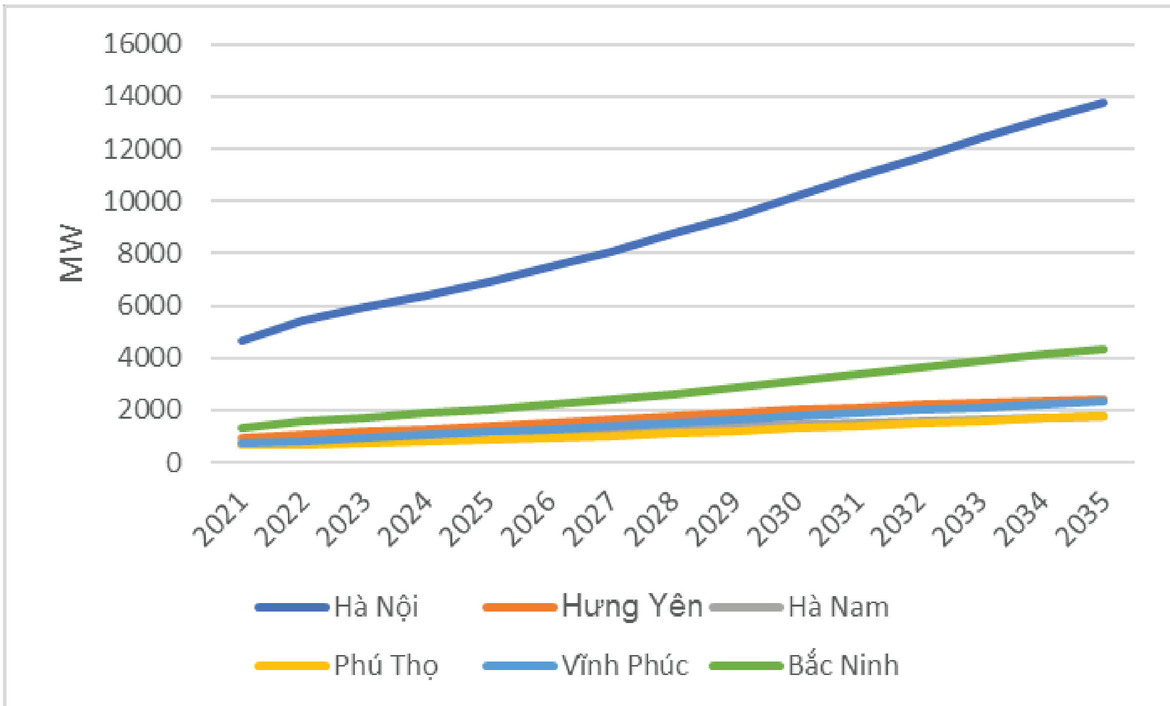


Figure 1-25 Demand forecast in the South of Hanoi area in the period of 2021 - 2035

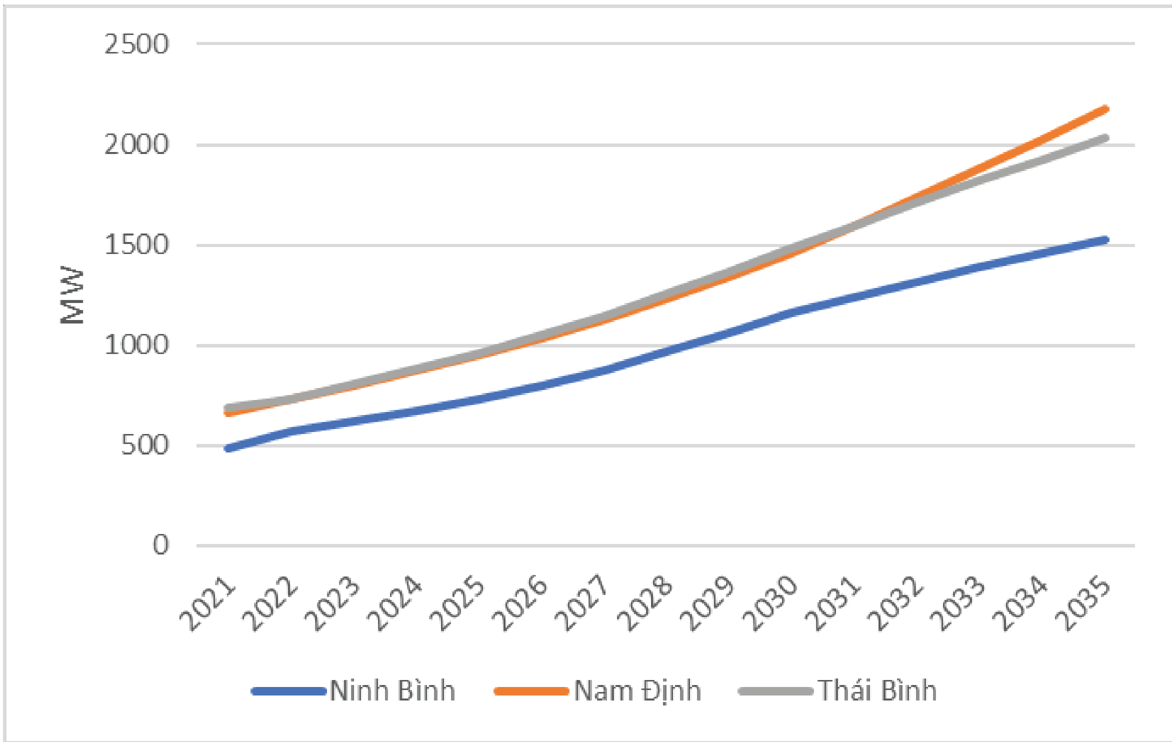
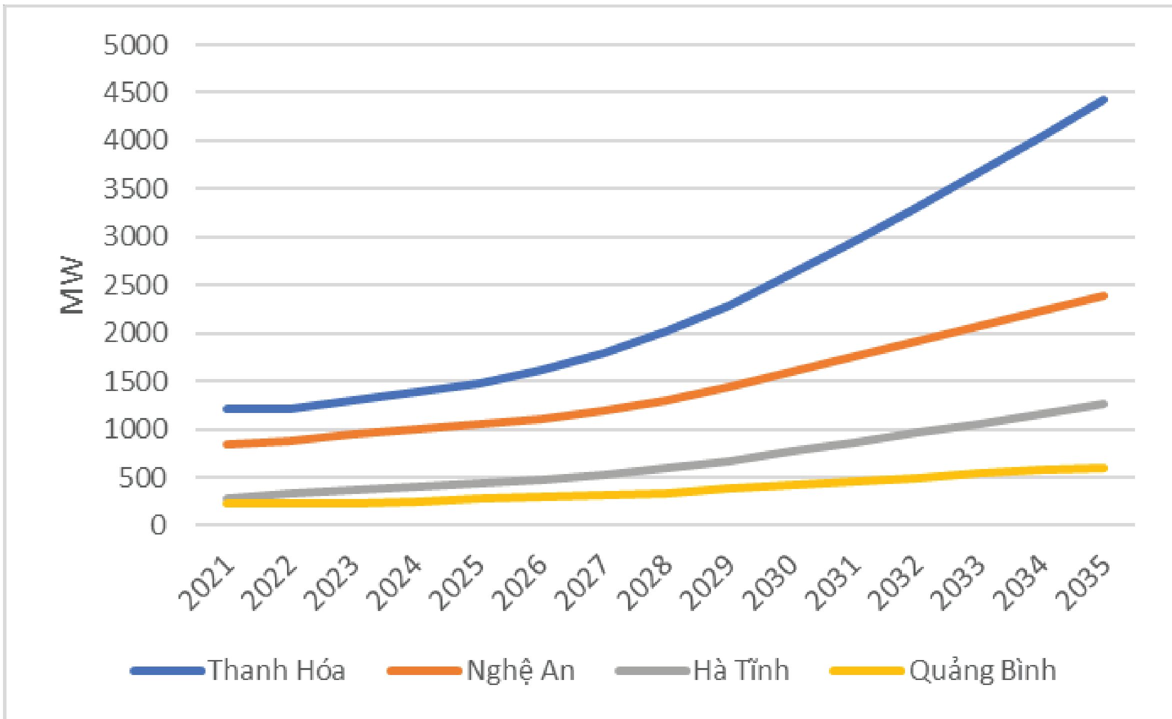


Figure 1-26 Demand forecast in the North Central in the period of 2021-2035



In general, Pmax of all provinces/cities has an upward trend in the period 2021 - 2030, corresponding to the development trend of national and regional demand. However, the demand growth rate will gradually decrease over time. The highest growth rates in the region belong to Hoa Binh, Lai Chau, and Ha Tinh provinces, with an average growth rate of 11.1%/year. Next are the provinces of Son La, Thanh Hoa, and Cao Bang. Some developed provinces/cities have high electricity consumption but only the growth rate Pmax is at the average level of the region such as Hanoi, Hai Duong, Hai Phong, Quang Ninh. The load growth rate of the Northern provinces/cities is relatively uniform, ranging from 7.5% to 11%. In the case of Thai Nguyen province, it only develops at a rate of about 5.8% in the period 2021 - 2030. Provincial Pmax data will be an important input to simulate the load flow of the power system.

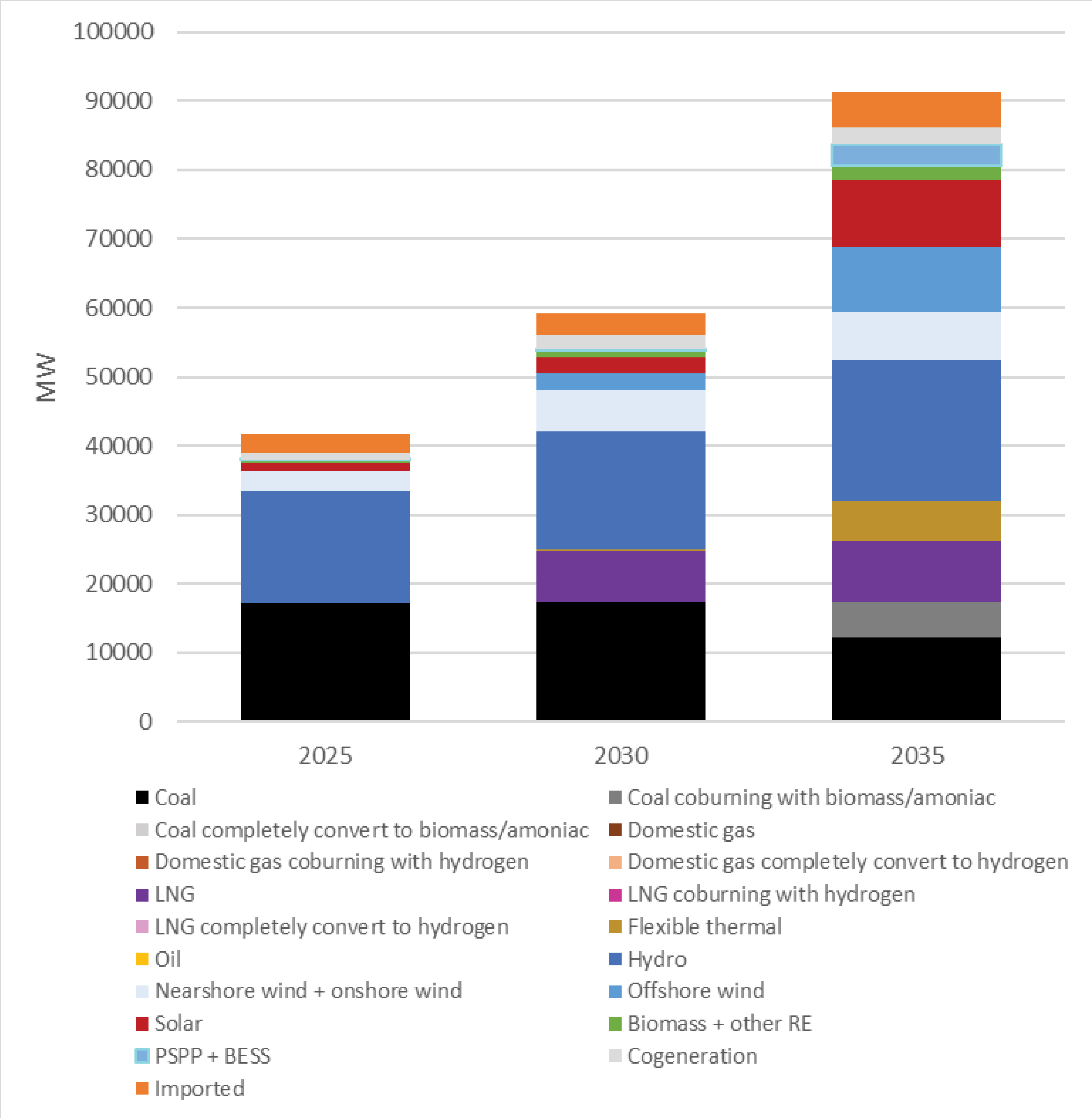
Regarding electricity consumption, the whole North continued to grow at an average rate of 8.4%/year. By 2035, the total electricity consumption of the North will reach about 320 billion kWh. In which, Hanoi maintains the largest consumption volume in the region, up to about 70 billion kWh (accounting for about 22% of the whole region). The provinces of Hoa Binh, Lai Chau and Ha Tinh had the highest average growth rates in the region, reaching 11.0%, 11.2%, and 10.8%, respectively.

1.3.2. Regional Power Source Development Plan

As mentioned in the previous section, demand is forecasted to continue to grow at a high rate in the coming period. Therefore, in the coming period, the installed capacity of the North's power source must constantly expand and develop in line with the growth rate of demand.

According to PDP VIII, in the period of 2021 - 2035, the total installed capacity in the North needs to increase by about 64 GW. The average growth rate of power sources is about 9%/year. Total installed capacity will reach over 59 GW in 2030 and 91 GW in 2035. In which, coal power will gradually reduce its proportion from 45% in 2022 to 19% in 2035; LNG gas sources increase from 0% at present to 13% in 2030 and 10% in 2035; Hydropower will reduce its share from 45% in 2022 to 22% in 2035; Renewable energy sources will increase from 4% in 2022 to 31% in 2035. After 2030, following the orientation of energy transition in PDP VIII, thermal power sources in the North will begin to switch to burning with biomass/ammonia at the rate of 20%, gradually increasing the rate towards the goal of not using coal fuel for electricity production by 2050. The installed capacity of power sources in the North will be shown in Figure 1-27

Figure 1-27 Installed capacity by types in the North in 2025, 2030 and 2035



Due to the lack of local consensus, a number of coal-fired power plants in the North already included in the PDP VII Revised had to be stopped, such as Cam Pha III, Hai Phong III, and Quang Ninh III. In addition, due to the trend of energy transition as well as the commitments of Vietnam and other countries around the world on greenhouse gas reduction, many coal-fired power projects being implemented are having difficulty in arranging capital, such as Nam Dinh I and Cong Thanh thermal power plants. For these projects, the Ministry of Industry and Trade will work with investors. If they cannot be implemented until June 2024, they must consider terminating in accordance with the law. Instead, PDP VIII proposes to develop about 7.5 GW of LNG-using renewable energy resources, including Quang Ninh LNG plants (1500 MW), Thai Binh LNG (1500 MW), Nghi Son LNG (1500 MW), Quang Trach II LNG (1500 MW), and Quynh Lap/Nghi Son LNG (1500 MW). However, until now, many LNG projects have not been implemented due to problems in price negotiation (no price bracket), LNG import mechanism, and operation management mechanism of the whole Gas - Power chain. The feasible progress to operate an LNG power plant in the North will be the earliest in the period 2027 - 2028.

Regarding to renewable energy sources, Decision 500/QD-TTg, dated May 15, 2023 only approves the total capacity of offshore wind power, onshore/near-shore wind power, solar power, small hydro power, biomass power and waste power in the period 2021 - 2030 and 2031 - 2050 nationwide. Report of PDP VIII has calculated the capacity of various types of power sources by region on the basis of minimizing total system costs, ensuring the development of power sources in accordance with geographical potential while balancing supply and demand within the region, and minimizing long distance transmission. The total capacity of onshore/nearshore wind power, offshore wind power, solar power, biomass power, waste power, and hydropower proposed for development in the North is stated in Table 1-7.

Table 1-7 Cumulative capacity of onshore/nearshore wind power, solar power, biomass power and waste power, hydropower in the North (MW)

Year	2030	2050
Onshore and nearshore wind power	3016 – 6016	12550 - 15550
Offshore wind power	1000 - 2500	22000 - 23000
Solar power	1865 - 2165	63048 - 65348
Hydro power	16531 - 16931	22482
Biomass and waste power	1920	2779

Detailed capacity of renewable energy sources by province/city will be clarified in the Implementation Plan.

1.3.3. Regional Power Transmission Grid Development Plan

The plans for new construction and renovation of the power grids of the northern provinces/cities are updated on the following bases:

- Decision No. 500/QD-TTg, dated May 15, 2023, approving the power development master plan for the period 2021-2030, with a vision to 2050.

- Draft plan for investment and development of the national power transmission grid in 2024 with a vision to 2028.

According to PDP VIII, period up to 2030, the North will new build about 33.5 GW of 500 kV transformer, 46.5 GW of 220 kV transformer, 4000 km of 500 kV transmission line, 8000 km of 220 kV transmission line; upgrade about 15.5 GW of 500 kV transformer, 16.5 GW of 220 kV transformer, 600 km of 500 kV transmission line, 4000 km of 220 kV transmission line. Detail transmission grid projects in the North in the period up to 2030 shown in Annex 3.

1.4. Assessing Challenges in Ensuring Electricity Supply for the North on Vietnam's Roadmap to Implement Net Zero Commitment in 2050

Vietnam has geographical features stretching and narrowing in the north-south direction, different natural conditions, and uneven socio-economic development among regions. The natural, economic, and social characteristics lead to the Vietnamese power system having a spatially unbalanced distribution of power sources and loads: the main power sources such as hydropower (concentrated in the Northwest and Highlands) and thermal power (mainly in the Northeast, South Central and Southern regions) must be transmitted far to load centers such as Hanoi and Ho Chi Minh City. The backbone transmission grid has a large length, stretching nearly 2,000 km. In recent years, while the demand continues to grow at a high rate, the North faces the risk of not being able to meet the peak load due to capacity decline at some power plants. Considering the long-term future, the North's ability to develop resources is limited. The hydro power potential of the North has been almost fully exploited. The region does not have many favorable natural conditions for the development of wind and solar power such as the Central and the South.

Some challenges in ensuring electricity supply to the North in the long term include:

1. The demand growth rate of the North is forecasted to be relatively high

According to demand statistics for the period 2010 - 2022, Pmax in the North has a high growth rate, reaching an average of 10.2%/year. Pmax in the North in 2022 is estimated at more than 23 GW, 3 times higher than in 2010. Meanwhile, the North's sale electricity consumption in 2022 will reach about 109 billion kWh, 3.3 times higher than that in 2010. According to the demand forecast of PDP VIII, the electricity consumption in the North will reach about 219 billion kWh in 2030 and 506 billion kWh in 2050 in the base demand scenario, about 220 billion kWh in 2030, and 574 billion kWh in 2050 in the high demand scenario. In which, by 2030, the proportion of electricity consumed by the North will account for about 44% of the electricity consumed in the country and will increase to 46% by 2050. The growth rate of sale electricity in the North will reach about 9.34% - 9.36% in the period 2021 - 2025, 8.81% - 8.83% in the period 2026 - 2030, 6.56% - 7.54% in the period 2031 - 2035, 4.68% - 5.4% in the period 2036 - 2040, 3.29% - 3.78% in the period 2041 - 2045, and 2.59% - 2.98% in the period 2046 - 2050.

One of the biggest differences in the demand forecast of PDP VIII compared with PDP VII Revised is the change in proportion of electricity demand between the South and the North. According to PDP VIII, the proportion of sale electricity sold in the North will gradually increase from 42.4% in 2020 to 45% in 2050 while the proportion in the South will decrease from 47.4% in 2020 to 45.0% in 2050. The reason is that the North tends to attract many investors to set up large production plants and industrial parks are forecast to develop much more widely. According to estimates by Fitch Solutions, about 65% of foreign electronic enterprises plan to set up production bases in the North, 30% in the South and a small percentage in the central provinces. The northern provinces have advantages of strategic location adjacent to China, convenient transportation, and lower industrial land price. The provinces/cities with many large industrial parks in the North include: Hai Phong, Bac Ninh, Bac Giang, Thai Nguyen, Ha Nam, etc.

2. The structure of power sources is less diversified, heavily dependent on hydropower

Due to its geographical characteristics, the North is suitable for developing hydroelectric and coal-fired power sources. Hydropower is suitable for development in the Northwest region because this is an area with high terrain, strongly dissected along with many large rivers, which are favorable conditions for building dams. Meanwhile, the Northeast region (mainly in Quang Ninh province) has many large coal mines, which are an abundant supply for domestic coal-fired power plants. In fact, these two types of power sources are accounting for the largest proportion in the North currently, with the proportion of hydropower about 45%, and coal-fired power about 51%. Other power sources account for less than 5%.
The potential of large hydropower sources has been almost fully exploited. The North has about 5.6 GW of potential small hydropower that has not yet been put into operation. However, the deployment of small hydropower sources faces many obstacles and difficulties in construction because the plants are often located in remote areas and traffic is underdeveloped. Many projects have affected the natural forest system, caused landslides due to the opening of public roads, affected the downstream areas, aquatic systems, and have low economic efficiency. The Ministry of Industry and Trade has written to request provinces and cities to suspend small hydropower projects already in the planning but not yet invested in construction; only implemented after the assessment results ensure that there is no major or negative impact on the environment and no major impact on the population, does not occupy natural forest land and is economically viable. Therefore, the feasibility of deploying small hydro power sources is still uncertain. The structure of the North's hydropower is relatively large, so the North's power supply depends heavily on the annual hydrological situation. Typically, in 2023, the year of El Nino, the amount of water entering the reservoirs decreased, leading to many hydropower plants unable to operate in the dry season because the reservoir's water level was below the dead water level. The dry season often has many potential risks of power shortage due to low available capacity of hydropower and limited alternative power sources.

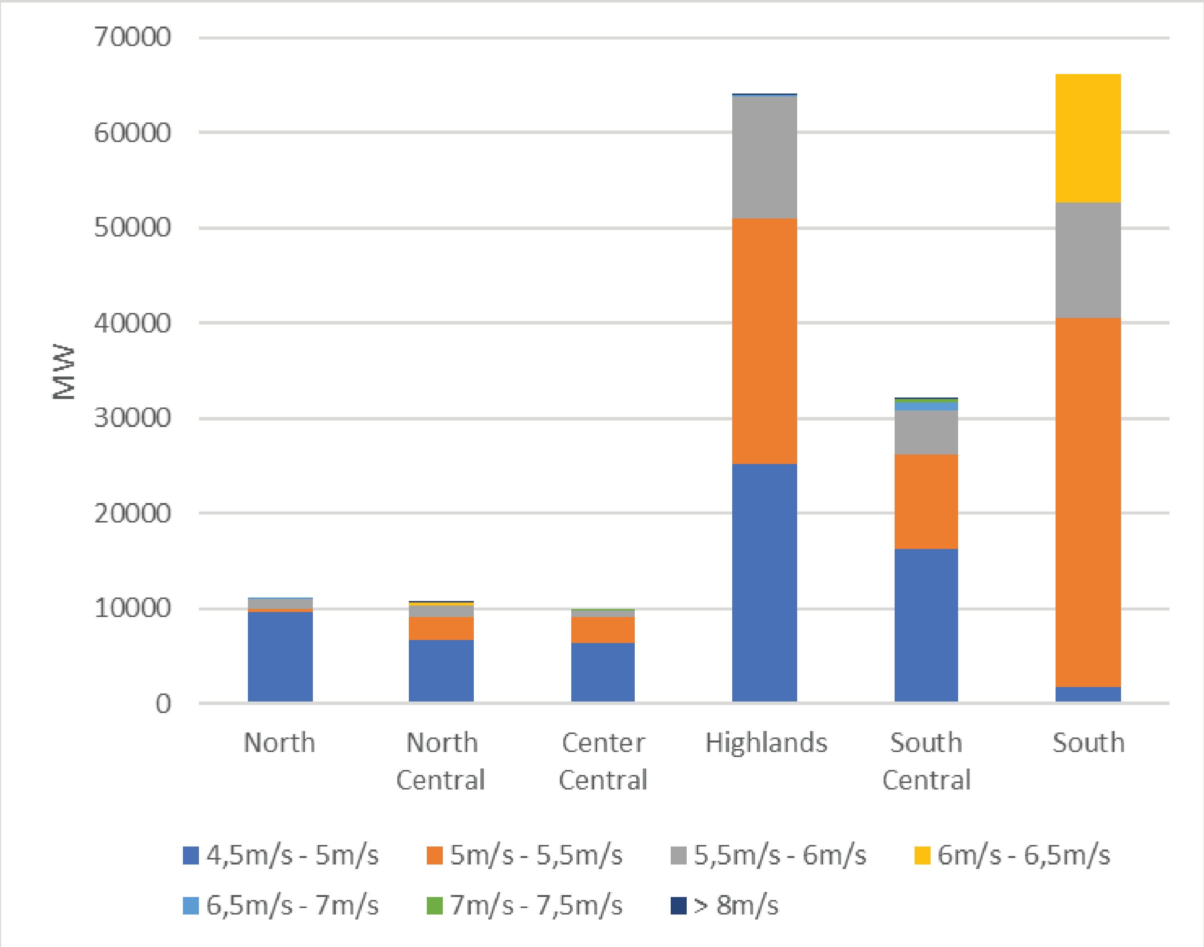
For coal-fired power sources, the total output of domestic coal that can be supplied for electricity in 2020 is about 35 million tons, about 36.3 million tons in 2025, about 39.8 million tons in 2030, about 39.5 million tons in 2035. According to the coal mining plan for the period after 2035, the scale of domestic coal supply for electricity is limited to a maximum of 39.5 million tons/year for the period 2035 - 2045. At this scale, domestic coal can only supply nearly 14 GW of existing domestic coal-fired power plants. New coal-fired power plants in the North, to the coal mining plan for the period after 2035, the scale of domestic coal supply for electricity is limited to a maximum of 39.5 million tons/year for the period 2035 - 2045. At this scale, domestic coal can only supply nearly 14 GW of existing domestic coal-fired power plants. New coal-fired power plants in the North, such as Thai Binh 2 and Hai Duong must use mixed coal, most of which is imported coal. Therefore, the possibility of developing coal-fired power plants in the North in the future is almost non-existent, especially in the context of Vietnam's commitment to achieve net zero emissions by 2050.

According to PDP VIII, in the future, the North's power source structure tends to diversify with the new development of LNG, solar power, onshore/nearshore wind power and offshore wind power. The ability to develop wind power and solar power in the North is much lower than that in the Central and the South because heat radiation and wind speed are not as good. In addition, the North will be planned to develop about 7.5 GW of LNG power plant using LNG, including Quang Ninh LNG plants (1500 MW), Thai Binh LNG (1500 MW), Nghi Son LNG (1500 MW), Quang Trach II LNG (1500 MW), and Quynh Lap/Nghi Son LNG (1500 MW) by 2030. However, until now, many LNG projects have not been implemented due to problems in price negotiation (no price bracket), LNG import mechanism, and operation management mechanism of the whole Gas - Power chain. In addition, the development of 2500 MW of offshore wind power in the North in the period up to 2030 is also assessed to face many difficulties due to legal problems, time to prepare survey, investment, training design and operation staff, etc., which is relatively urgent because from now to 2030 there are only about 7 6 years left.

3. Renewable energy potential of the North is not high when compared to the Central and South regions

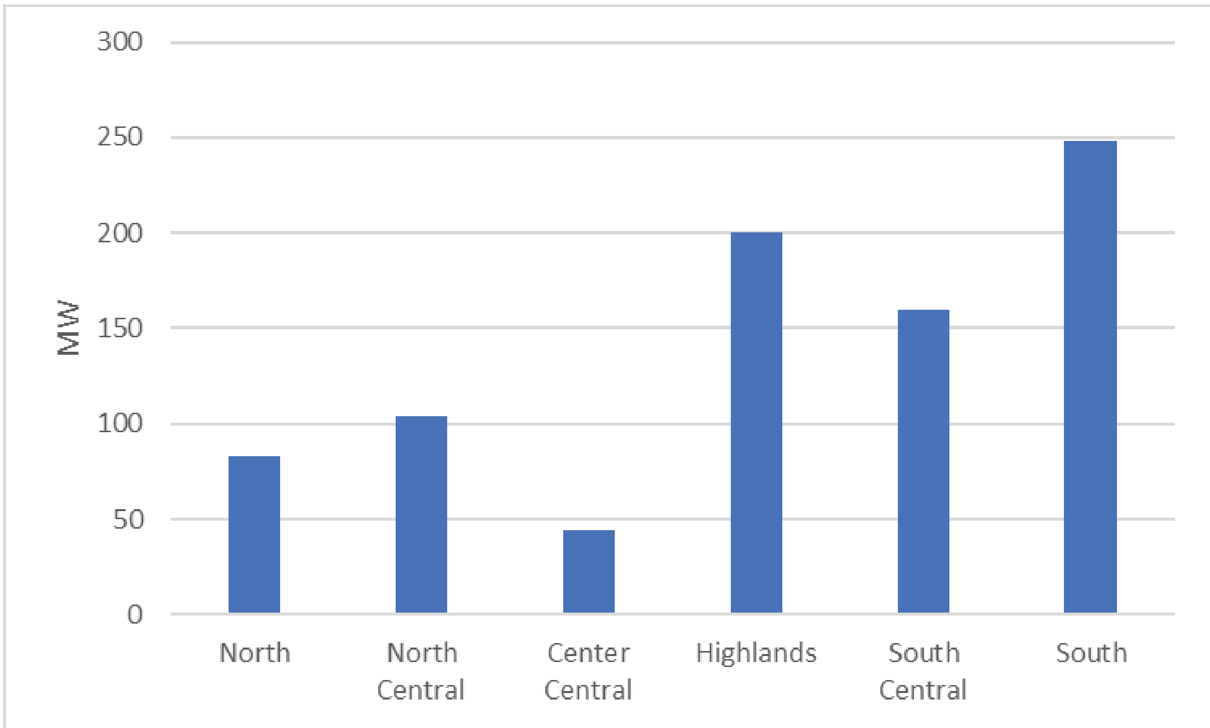
After Vietnam's commitment to achieve net zero emissions by 2050 at COP26, the energy transition trend in the power sector is strongly and clearly oriented, which has been concretized in PDP VIII. Accordingly, the proportion of electricity produced from renewable energy sources will reach about 30.9 - 39.2% in 2030 and aim to increase to 67.5 - 71.5% in 2050. However, the potential for renewable energy (wind power and solar power) is good mainly in the South Central, Highlands, and Southwest regions, which are areas with relatively low loads. The northern area is assessed to have solar radiation and wind speed not as good as the above areas. Specifically, the full load hour (FLH) of solar power sources in the North is only about 1400 h on average, while the average FLH of the South Central and Highland regions is up to 1900 h. In addition, the provinces with great potential for solar power development in the North, mainly in the Northwest, such as Son La, Lai Chau, and Dien Bien have relatively steep terrain, which is not suitable for installing solar panels in large quantities. With onshore and nearshore wind power sources, good wind areas in the North such as Lang Son and Son La have an average wind speed of about 5.5 - 6m/s, while the South Central and the Highlands have an average wind speed of about 6 - 7m/s, the Southwest has an average wind speed of about 6 - 6.5m/s. With offshore wind power, the average wind speed of potential sites in the North is about 7.3m/s while in the South, it is about 8.1m/s. Solar radiation and wind speed characteristics lead to the levelized cost (LCOE) of solar and wind power sources in the North not being as competitive as the Central and the South.

Figure 1-28 Technical potential of wind power on land by regions



Source: PDP VIII

Figure 1-29 Technical potential of solar farm by regions



Source: PDP VIII

4. A large amount of coal-fired power capacity will be decommissioned in the period up to 2050

Because the Northeast region has many coal mines with large reserves (Quang Ninh province), the North has developed many large coal-fired power sources such as Quang Ninh Thermal Power Plant (1200 MW), Hai Phong Thermal Power Plant (1200 MW), Thang Long Thermal Power Plant (620 MW), Mong Duong I Thermal Power Plant (1120 MW), Mong Duong II Thermal Power Plant (1245 MW), etc. By the end of 2022, the total coal thermal power installed capacity of the North will reached about 15 GW.

Compared to PDP VII Revised approved in 2016, up to now, a number of coal-fired power plants in the North have had to stop deploying, such as Cam Pha III, Hai Phong III, and Quang Ninh III due to lack of local consensus. In addition, due to the trend of energy transition as well as the commitments of Vietnam and other countries around the world on greenhouse gas reduction, many implementing coal-fired power projects have difficulty in arranging capital, such as Nam Dinh I and Cong Thanh thermal power plants. For these projects, the Ministry of Industry and Trade will work with investors. If they cannot be implemented until June 2024, they must consider terminating in accordance with the law. Total installed capacity of coal-fired power of the whole country by 2030 is estimated at 30 GW, of which about 20 GW in the North. To compensate for the reduced capacity of coal-fired power plants, PDP VIII has proposed to develop an additional 7.5 GW of LNG thermal power by 2030, and at the same time accelerate the development of more solar power, onshore/near-shore wind power, and offshore wind power.

According to the government's energy transition orientation stated in the National Strategy on Climate Change approved by the Prime Minister in Decision 896/QD-TTg dated July 26, 2022, Vietnam will not develop more new coal-fired power sources after 2030. PDP VIII also orients the fuel conversion roadmap for coal-fired power sources. Accordingly, converting fuel to biomass and ammonia with power plants that have been in operation for 20 years when the price is suitable, shutting down power plants with a lifetime of more than 40 years if fuel conversion is not possible, orientation to 2050 no longer use coal for power generation, and completely switching fuels to biomass and ammonia. However, at present, the fuel conversion option for coal-fired power plants has only been studied at a very preliminary level. Many opinions are concerned about the uncertain supply of biomass fuel and ammonia as an alternative to coal-fired power plants with large capacity. In case coal-fired power plants cannot convert fuel but have to stop operating in 2050 to ensure Vietnam's commitment to net zero, a large amount of green capacity is needed in the North to replace them.

5. It is necessary to build a long distance power transmission system to supply electricity to the North

As analyzed in the previous sections, while the Northern load is forecasted to grow rapidly in the future, the ability to develop different types of power sources in the North is still uncertain. Therefore, one of the other solutions to ensure electricity supply for the North is to strengthen the transmission capacity between the Central and the North. However, in reality, it is very difficult to build more inter-regional transmission lines, especially when passing through provinces with narrow widths, such as Quang Binh, Quang Tri, Thua Thien - Hue. PDP VIII has oriented the arrangement of power sources to ensure the maximum balance of regional power - transmission, limit transmission far away, not building more inter-regional power transmission lines in the period of 2021 - 2030, minimizing investment in new transmission lines (except for those that are in the process of being built), and minimizing the construction of new inter-regional power transmission lines in the period 2031 - 2045.

According to the long-distance transmission plan by HVDC in PDP VIII, it is planned to develop two independent HVDC systems: 10,000 MW in Center Central - North 800 kV HVDC, 1000 km in length and 12,000 MW in South Central - North 800 kV HVDC, 1,300 km in length in the period after 2035.

However, the development of HVDC systems on a large scale (10 - 12 GW), high voltage (800 kV) takes a lot of time to research and develop to build a system of criteria and specialized regulations. In-depth technical aspects also need to be further studied, such as the effect of HVDC systems on power system stability, short-circuit current, voltage, and power supply reliability. Although the solution of using HVDC submarine cable under the sea has a much higher investment cost than building an overhead line, it also needs to be considered due to its advantages in terms of saving time for site clearance and saving land.

1.5. The Opportunities in Implementing Energy Transition in the North

In addition to the challenges that may be faced in ensuring power supply for the North on the roadmap to implementing Vietnam's net zero commitment analyzed in the previous section, opportunities for the North to implement energy transition, specifically the replacement of coal thermal power sources with renewable energy and clean power sources as follows.

Firstly, the production cost of various types of renewable energy sources is becoming cheaper and cheaper, with the development of science and technology supporting the development of wind and solar power in areas with lower potential at cheaper costs and higher performance. Some actual projects surveyed in mountainous terrain areas, such as Son La, Dien Bien, Lang Son, etc. show that there is still the possibility of developing wind power and solar power.

Secondly, energy transition from fossil fuels to renewable fuels is an inevitable global trend, supported by many countries around the world. Even in Vietnam, awareness of environmental protection and greenhouse gas emissions reduction has also been raised and unified by local authorities as well as people. Many coal-fired power projects included in PDP VII Revised cannot be implemented, such as Hai Phong 3 Thermal Power Plant and Quang Ninh 3 Thermal Power Plant due to not receiving local consent owing to concerns about environmental issues. Instead, renewable energy projects that use clean fuels, do not emit greenhouse gasses, and do not violate environmental issues are supported, creating conditions to attract investment and implementation.

Thirdly, there is the ability to take advantage of support and financial capital from the international community. Capital sources to implement energy transition are the biggest challenge for Vietnam. Groups of developed countries and international organizations have initially taken specific actions to support Vietnam by committing to support financial capital (eg JETP, AZEC, ...).

Fourthly, the need to buy green electricity from international corporations with commitments to sustainable development goals and the use of renewable energy in the North is very large. With the goal of producing carbon-neutral products (not generating CO2 emissions in all stages from raw material exploitation, production to transportation, and product use), international corporations are ready to invest in renewable energy sources to produce electricity for manufacturing plants. Building renewable energy sources near industrial parks in the North will be more convenient than having to transmit electricity from renewable energy sources in the Central and South regions.

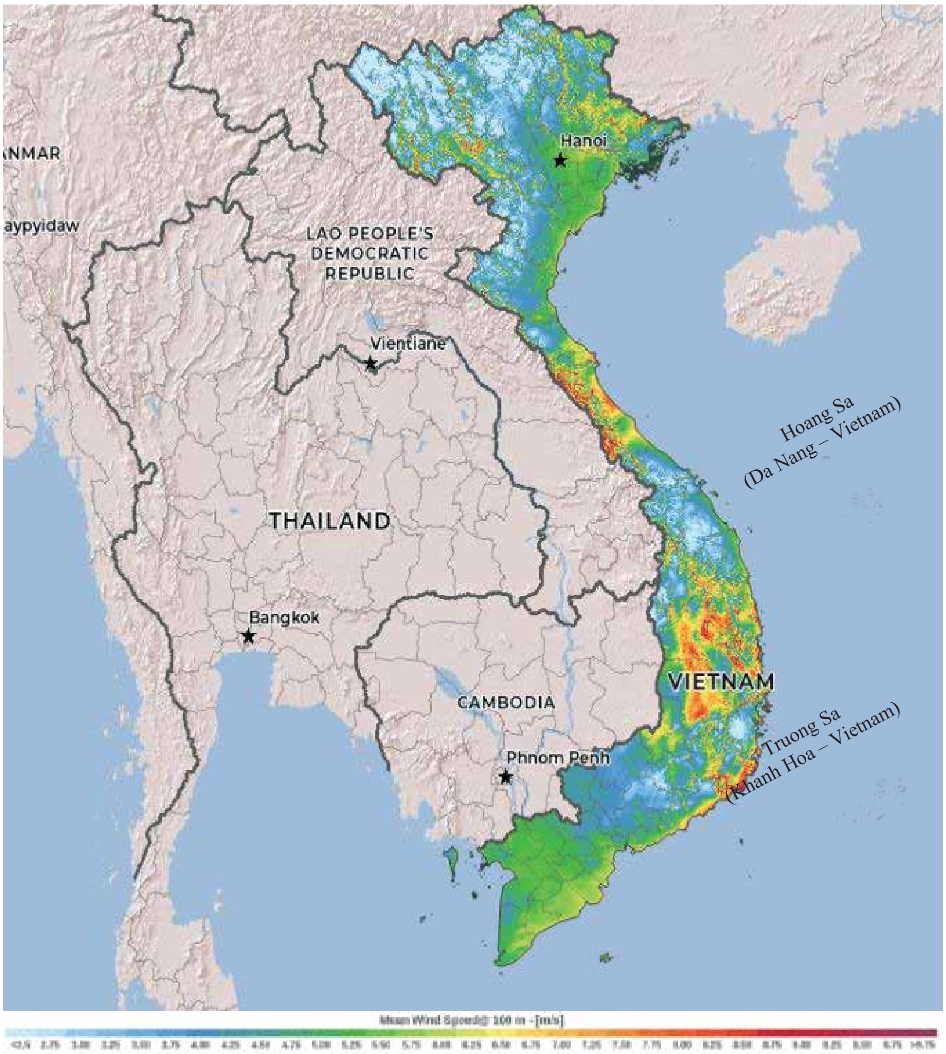
2. EVALUATION AND ANALYSIS: THE POTENTIAL OF RENEWABLE ENERGY SOURCES FOR ELECTRICITY PRODUCTION IN THE NORTH

2.1. Evaluation and Analysis Wind Power Potential in the North

2.1.1. Evaluation and Analysis: Onshore Wind Power Potential

Vietnam is located in the tropical monsoon climate zone, with a coastline stretching over 3,000 km, so the potential for wind energy development in Vietnam is extremely large. According to the World Bank's assessment, Vietnam is the country with the greatest wind potential among the four countries in the region, with more than 39% of Vietnam's total area estimated to have an average annual wind speed greater than 6m/s at an altitude of 65 m, equivalent to a capacity of 512 GW.

Figure 2-1 Wind resource in mainland Viet Nam, 100m height [1]



The technical potential of onshore wind power nationwide used in the report is taken from the calculation results in PDP VIII. [2]

Technical potential is determined based on theoretical potential with current status and land use planning. Types of land that are not suitable for wind power development planning will be eliminated, such as:

- Residential land and institutional land
- Security and defense area
- Industrial parks and production and business establishments
- Transportation infrastructure area, including airways, railways, roads, waterways, and other transportation works
- Archaeological and historical relics, cultural and religious sites, sensitive ecological areas, and nature conservation areas
- At least 300 m away from residential areas
- Affecting radio waves and electronic telecommunications of residential areas and surrounding buildings.

The exclusion zone and buffer zone are determined based on reference to wind power planning guidance documents (from GIZ) and a number of provincial wind power plans that have been implemented. The exclusion zone is defined as an area with planned land use functions that are not suitable for "living with" wind power. The buffer zone is an area with a minimum width so that the wind power area does not affect the exclusion zone.

Table 2-1 Regulating buffer zone distances and exclusion zones

No	Exclusion zones according to land use planning functions	Buffer zone (m)
1	Slope Altitude excluded	> 30° > 2000
2	Original areas (points and zones) and buffer zones	1000
3	Urban areas and buffer zones	1000
4	Rural areas, population density and buffer zones	500
5	Coastline, water surface (ponds, lakes, rivers, streams...) and buffer zones	100
6	National highways, railways, sea routes and buffer zones	250
7	Forest with coverage > 15% and buffer zone	100
8	Remove areas	1000

Based on stacking map layers to eliminate areas with theoretical potential but not suitable for wind power development, the project calculates that the total technical potential for the whole country can reach about 221 GW. If we exclude the range of low-speed wind ≤ 5.5 m/s, which is considered unfeasible with the current level of science and technology, the technical potential of wind power on land is about 57 GW. Onshore wind power technical potential by provinces/cities in the North is shown in the following table:

Table 2-2 Onshore wind power technical potential by provinces/cities in the North

No	City/Province	Technical potential (MW)							
		4.5 - 5	5 - 5.5	5.5 - 6	6 - 6.5	6.5 - 7	7 - 7.5	>7.5	Total
I	**North**	9,656	2,650	1,087	38	15	-	-	**13,446**
II	**North Central**	6,691	2,505	1,103	382	28	-	8	**10,717**

The total technical potential of onshore wind power in the North reaches about 24 GW, of which the North is about 13 GW and the North Central is about 11 GW.

The results of assessing onshore wind power potential show that the natural characteristics of the North are mainly suitable for developing low wind power (4.5-5.5m/s) and medium wind power (5.5 - 6m/s). High wind power areas (> 6m/s) are only available in some Northern provinces such as Quang Ninh, Lang Son, and North Central provinces. If considering the total potential at all wind speeds, Lang Son is the province with the best technical potential (about 6.5 GW), followed by Quang Binh (about 5.9 GW), Ha Tinh (about 2.9 GW), and Quang Ninh (about 2.4 GW).

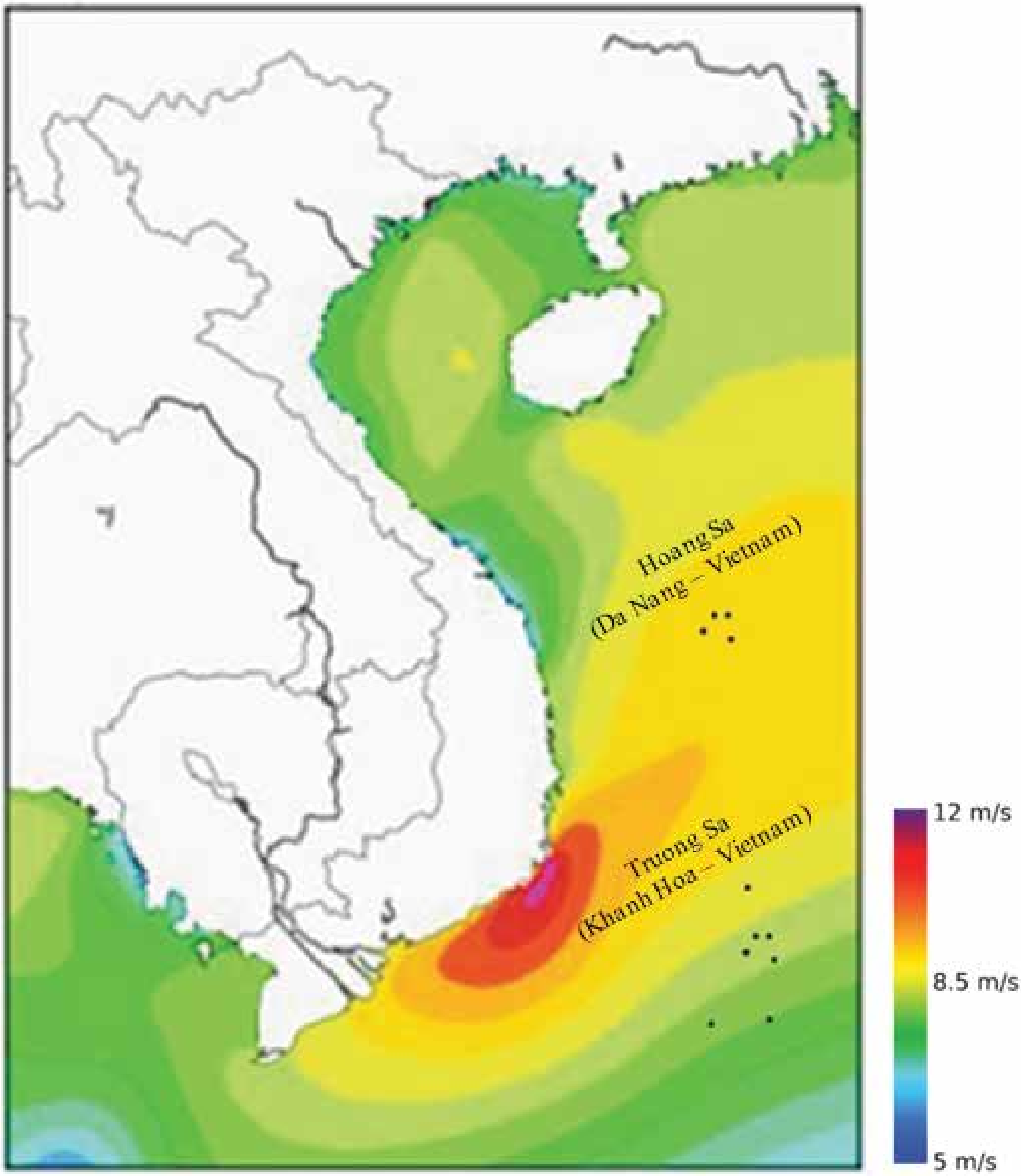
In general, compared to the Central and South regions, the ability to develop onshore wind power in the North is less competitive but there is still room for development in the North Central region and some Northern provinces, such as Lang Son, Quang Ninh, Son La, Cao Bang, and Bac Kan.

2.1.2. Evaluation and Analysis: Offshore Wind Power Potential

According to assessments, Vietnam is a country with great offshore wind potential. However, up to now, the whole country has not had an approved offshore wind power project, although there have been many reports assessing Vietnam's offshore wind energy potential supported by domestic and foreign organizations, for example:

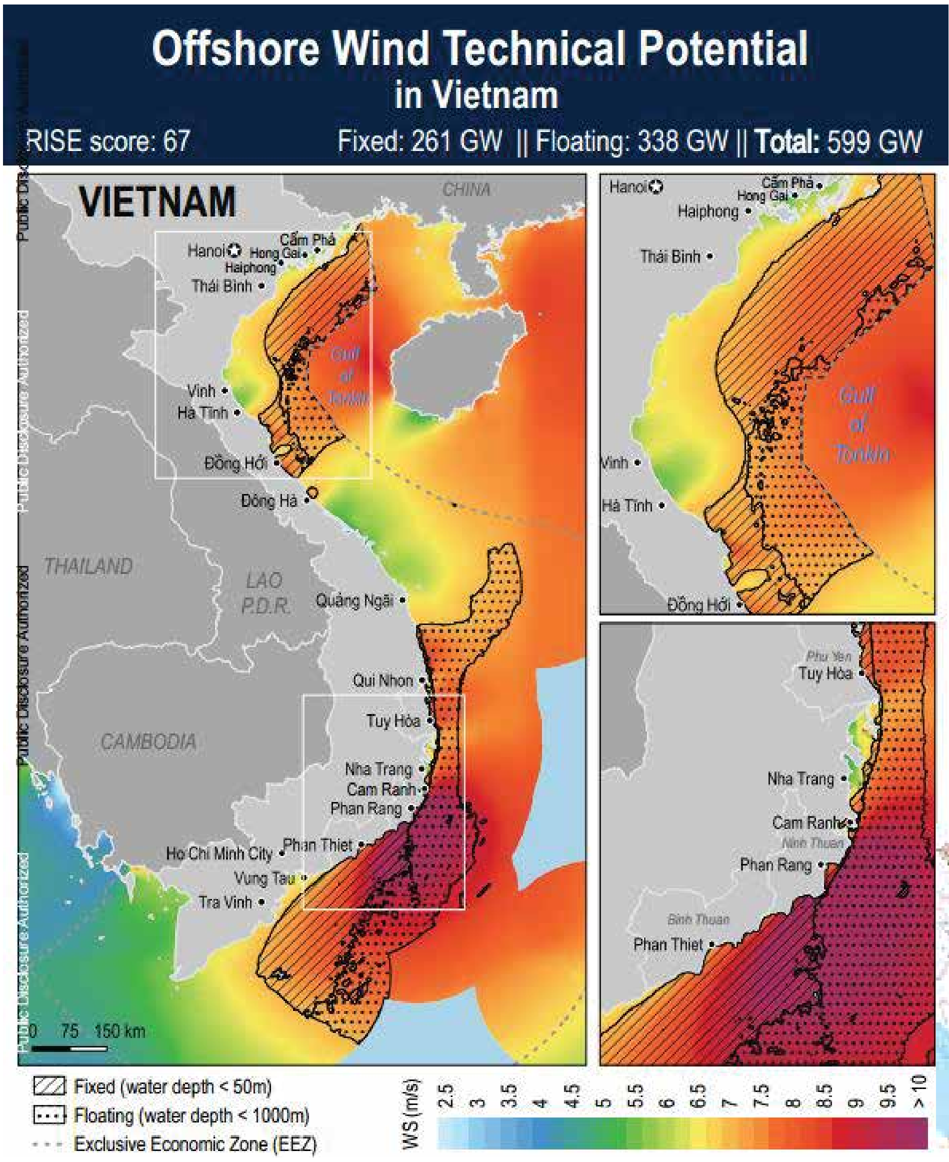
1. Research by a domestic research group titled "Research on Vietnam's Offshore Wind Potential, Considering the Scope of Hoang Sa and Truong Sa Island" [3] reviews the potential for OWF in the sea, considering the entire 200 nautical mile exclusive economic zone and Vietnam's Hoang Sa and Truong Sa islands. The results show a huge potential to develop OWF with over 6,000 GW.

Figure 2-2 Potential of Vietnam offshore wind assessment according to research by a group of domestic authors



2. Report assessing offshore wind power potential of countries including Vietnam was published by the Energy Sector Management Assistance Program (ESMAP) of the World Bank Group in October 2019 [4]. Vietnam's total OWF potential is 475 GW, including 261 GW of fixed foundation OWF and 214 GW of floating foundation OWF, within a range of up to 200 km from shore. In the updated January 2021 version of the report [5], the theoretical and technical potential of offshore wind power is 600 GW. Potential areas are concentrated in the offshore areas of Ninh Thuan and Binh Thuan provinces (South) and Quang Ninh - Hai Phong - Thai Binh (North).

Figure 2-3 Vietnam offshore wind potential map according to ESMAP



3. C2 Wind offshore wind potential review report "Vietnam Offshore Wind- Country screening and Site selection" [6], published in 2020. This is a report supporting the Ministry of Industry and Trade in developing PDP from the Denmark government.

C2 Wind and DEA (Denmark) have supported the Ministry of Industry and Trade to evaluate the technical potential and rank the technical potential locations of offshore wind power in Vietnam. Accordingly, Vietnam has a large potential for wind resources at sea, but to evaluate the technical feasibility of construction, it is necessary to base on a number of exclusion criteria, such as navigation channels, conservation areas prohibited from exploitation, oil and gas exploitation mines, distance to shore from 5 - 100 km, areas of harsh storms and earthquakes, and undersea cables.

The selection of technical potential is only within 5-100 km from shore for the following reasons:

- Experience from offshore wind farms in Europe indicates that at distances to land less than 5 km, visual impacts can become a problem and can lead to public opposition.

- Distances greater than 100 km will lead to high additional costs related to connection and operation and maintenance. The construction of 500 kV marine cables for long-term transmission is currently not built in the world.

Based on the assessment of the technical potential of offshore wind power according to the above exclusion criteria, C2Wind has selected 24 potential locations with a total capacity of 160 GW.

Figure 2-4 Vietnam's offshore wind power technical potential areas were identified by C2WIND

These include 5 fixed foundation offshore wind power areas (seabed depth ≤ 50m) with a total capacity of about 103 GW, and 3 floating foundation offshore wind power areas (seabed depth 50 m - 1000 m) with a total capacity of about 57 GW. In particular, the North has 5 potential areas for offshore wind power development in the coastal areas of Quang Ninh, Hai Phong, Thai Binh, Nam Dinh (North) and Ha Tinh, Quang Binh (North Central).

In general, nationwide offshore wind speed maps show that the Northern region has lower wind speeds than the South Central and Southern regions. However, in the North, there is still potential to develop offshore wind power in the sea of Quang Ninh, Hai Phong, and Thai Binh provinces.

2.2. **Evaluation and Analysis: Solar Power Potential in the North**

The project conducts calculations to update solar power technical potential not only in the North but nationwide. Compared to the solar power potential in PDP VIII, the project updates some information:

- Update land use planning of provinces/cities according to Resolution No. 39/2021/QH15 of the National Assembly, dated November 13, 2021, on national land use planning for the period 2021 - 2030, vision to 2050, 5-year national land use plan 2021 - 2025, Decision No. 326/QD-TTg of the Prime Minister, dated March 9, 2022, on allocation of national land use planning targets for the period 2021 - 2030, vision to 2050, national land use plan 5 years 2021-2025. PDP VIII has calculated the potential of concentrated solar power based on the land use planning of the provinces approved since 2015. Accordingly, the remaining unused land area is quite large. However, currently the land use planning of the provinces and the whole country has been updated, in which the area of forestry land is increasing and the area of unused land is decreasing.

- Update on the potential of rooftop solar power placed on the roofs of public buildings (schools, hospitals, administrative offices, etc.) and industrial parks, due to the potential of rooftop solar power in the PDP VIII is only calculated for potential installations on residential roofs.

Solar power technical potential is calculated according to the following principles:

- Calculate land use needs and subtract the land fund for the scale of existing land solar power sources and the planned additional capacity located in the energy land area.

- The scale of land solar power potential for further construction will be calculated on the remaining land area until 2030 in the province's land use planning.

- Overlay the land use planning map of the provinces onto GEBCO's topographic map to calculate the available area for installing land solar power on the remaining land area. Areas suitable for installing concentrated solar power will have an average slope of 30% or less.

● Technical potential of land solar power (MW) = Available area for installing land solar power (ha) x Land use coefficient (1.1 MW/ha).

● Technical potential of industrial park rooftop solar power (MW) = Industrial park land area (ha) x Roof area coefficient (0.275) x Usage coefficient (1 MW/ha).

● Technical potential of rooftop solar power at public construction = Land area for public construction (ha) x Roof area coefficient (0.25) x Usage coefficient (1 MW/ ha).

● Technical potential of residential rooftop solar power is taken according to PDP VIII.

● Technical potential of floating solar power is taken according to PDP VIII.

Summary of technical potential of various types of solar power by provinces/cities in the North is shown in the following table.

Table 2-2 Technical potential of solar power in the North

No	Province/City	Technical potential of rooftop solar power for public constructions and industrial parks (MW)	Technical potential of residential rooftop solar power (MW)	Technical potential of floating solar power (MW)	Technical potential of land solar power (MW)
I	North	33225	11254	16737	56492
II	North Central	8986	5542	8895	17830

The total potential for solar power of all types in the North and North Central regions is 56 GW and 18 GW, respectively.

2.3. Biomass and MSW Power Potential in the North

2.3.1. Biomass Power Potential

Biomass power potential is taken from PDP VIII [2].

The assessment of biomass resources is carried out including current assessment and future forecast. While the assessment of the current situation is largely based on statistical and inventory data sources, the assessment for future years such as 2030 is mainly based on planning data and development plans stated in the decision approved by national or sectoral and local levels that are directly or indirectly related to biomass supply and demand.

The methodology for assessing the theoretical potential of biomass resources in the future will begin with a review of land use planning and land use changes for each type of agricultural land and forestry land, such as rice land area in 2025 - 2030. Next is crop productivity (such as tons of rice/ha and tons of sugarcane/ha), natural forest land, planted forest land, scattered crops, perennial industrial crops, regulations related to conservation, sustainable development, biodiversity, land and water resource protection, as well as social issues and environmental protection (such as reducing greenhouse gas emissions).

The calculation of the theoretical potential of future biomass resources will also be carried out as calculated for the current status year. Input data are data at the year of calculation. In some cases where there is no data (such as land use data until 2035 or forest inventory for future years), necessary assumptions will be made with clear evidence and transparency based on available documents, accompanied by analysis based on impact factors.

For the assessment of future technical potential, it will be based on not only 3 influence factors as in the assessment for the base year but also , two new factors: improving infrastructure (For example: Easier access to sources at lower costs,..) and applying technical advances in biomass production and processing (For example: rice harvesters with straw rolling units such as developed countries in Europe have used it...)

Technical potential of biomass resources is defined as part of the theoretical potential when considering and taking into account limitations in exploitation, accessibility, and collection techniques of biomass resources. The collection coefficient depends on the above limits according to the type of biomass and each mining location/area.

After excluding biomass sources for other essential uses, unconcentrated biomass sources and taking into account the ability to attract wood resources for producting domestic electricity, the estimated biomass power potential until 2030 in the North is shown in the table below.

Table 2-3 Technical potential of biomass energy sources

No	Region	Capacity (MW)
I	North	1790
II	North Central	700

Note: (*) Including cogeneration power plants using existing sugarcane bagasse with a total capacity of up to 500 MW

Compared to the draft National Biomass Development and Utilization Plan prepared by the Institute of Energy in 2017, PDP VIII has adjusted the technical potential for electricity production from rice straw to decrease, due to the current use of rice straw for other higher purposes.

Calculation results show that without considering price competition for other uses, the biomass potential for electricity production in the North is estimated to reach about 2.5 GW by 2030.

2.3.2. Municipal Solid Waste Power Potential

Municipal solid waste power potential is taken from PDP VIII [2].

The theoretical potential is assessed on the basis of forecasting the amount of household solid waste based on the local population, combined with forecasting the total amount of solid waste of each locality in decisions of the Government and localities.

Technical potential is assessed based on the planning of treatment areas, technology, electrical connection infrastructure, and operational water supply. The most important technical evaluation criteria is the installed capacity level to achieve economic efficiency.

Commercial potential is assessed based on total investment, loan capital, equipment supply ability, and electricity price.

The theoretical potential for the years 2020, 2025, and 2030 is calculated based on the total amount of solid waste each province and city has in the decisions approving solid waste management planning. Provinces and cities that do not have data will be supplemented based on the report "Mid-Term Population and Housing Survey April 1, 2014 - Main Results" by the General Statistics Office, issued in September 2015 combined with Vietnam Construction Standards - Construction Planning (QCXDVN 01:2008/BXD) regulating the amount of solid waste generated by each type of urban area.

Summary of theoretical potential until 2030 is shown in the following table:

Table 2-4 Summary of theoretical potential until 2030

No	Region	Theoretical potential (MW)		
		2020	2025	2030
I	North	1100.92	1423.11	1849.14

Technical potential is assessed based on planning of treatment areas, technology, electrical connection infrastructure, and operational water supply. The most important technical evaluation criteria is the installed capacity level to achieve economic efficiency.

Criteria for evaluating the technical potential of power generation using MSW are as follows:

- Based on the capacity of solid waste treatment areas extracted from approval decisions and reports on solid waste management planning at all levels.

- Prioritize the use of conventional solid waste as a fuel source for power plants with a burning rate of about 85%.

- The solid waste generation plant located in the solid waste treatment area must be consistent with the local solid waste treatment area management and planning.

- The site must have adequate infrastructure including roads.

- Water supply and drainage lines.

- Electricity supply line.

- Solid waste must be preliminarily classified and dried before being used as fuel and sent to the incinerator.

● Ensure environmental conditions during construction and operation.

Summary of technical potential until 2030 is shown in the following table:

Table 2-5 Summary technical potential of MSW

No	Region	Capacity (MW)
I	North	470.50
II	North Central	95.51

Source: Draft National Solid Waste Power Development Plan to 2025, vision to 2035 (PECC4) and updated supply data from localities.

By the end of 2022, the total capacity of biomass and waste power in operation is about 87 MW, including Soc Son (60 MW), Nam Son (1.93 MW), and Tuyen Quang sugarcane (25 MW). The total capacity of biomass and waste power projects under construction and feasible for operation by 2025 will reach about 340 MW in the North and 81 MW in the North Central. The technical potential of biomass power and waste power in the North by 2030 is about 2.5 GW and 0.6 GW, respectively.

2.4. Small Hydropower Potential in the North

According to regulations, small hydropower sources are defined as hydropower sources with a capacity of ≤ 30 MW. For assessing small hydropower potential (1-30 MW), two approaches are considered:

- Theoretical potential: Is the potential energy of the water flow in the river from upstream to the river mouth.

- Economic-technical potential: Energy that can be exploited technically and is economically useful.

Small hydropower potential is concentrated in the Northern mountainous areas, the South Central region, and the Highlands.

Table 2-6 Summary of capacity of small hydropower sources that are already in operation, have been approved but have not yet been put into operation, and have potential

No	Region	Operated (MW)	Approved to plan but not operate (MW)	Additional potential (MW)	Potential from irrigation reservoirs (MW)	Total small hydro potential (MW)
1	North	2996	3510	995	55	7556
2	North Central	383	366	185	73	1007
	Total	**3379**	**3876**	**1180**	**128**	**8563**

Actual implementation shows that small hydropower sources face many obstacles and difficulties in construction because power plants are often located in remote areas with underdeveloped transportation. Many projects have an impact on the natural forest system, landslides due to the opening of service roads, affecting downstream areas and aquatic systems, and have low economic efficiency. The Ministry of Industry and Trade has issued a document requesting provinces and cities to temporarily suspend small hydroelectric projects that have been planned but not yet been invested in construction; only deploying them after receiving assessment results. This is being done for economic efficiency, minimising major or negative impacts on the population and environment, and preventing appropriation of natural forest land.Therefore, the feasibility of deploying small hydropower sources is still uncertain.

3. PROPOSE POWER SOURCE DEVELOPMENT PLAN TO REPLACE COAL THERMAL POWER PLANTS IN THE NORTHERN

3.1. Methodology and Input Assumption

3.1.1. Methodology

Proposing a power source development program plan according to scenarios of stopping operation of Northern coal power plants is proposed according to the following steps:

+ **Step 1:** Determine the roadmap to reduce CO2 emissions of the power sector according to PDP VIII- Case of low emission and case of high emission.

+ **Step 2:** Propose scenarios for the closure time of coal-fired power plants in the North-Closing after 30 years of life, closing after 40 years of life.

+ **Step 3:** Determine investment costs for converting Northern coal-fired power plants according to the PDP VIII scenario and scenarios for closing Northern coal-fired thermal power plants.

+ **Step 4:** Calculate the power source development structure to meet demand according to scenarios of closing coal-fired power plants using the power source development planning model at minimum cost while ensuring CO2 emission reduction program according to the orientation of PDP VIII. Determine the scale of power sources that need to be increased compared to PDP VIII according to the scenarios for closing coal power plants in the North.

+ **Step 5:** Determine the cost of the entire electricity system according to calculation scenarios. Compare power system costs between scenarios and evaluate calculated power source development scenarios compared to PDP VIII.

3.1.2. Modeling Tool

The project uses the PLEXOS model to calculate capacity expansion of various types of power sources in the future.

The PLEXOS model calculates the mobilization of power source hourly with the 8760-hour load chart of each region or each 220 kV substation according to the criteria for minimizing the cost of the entire power system. With 4 modules (PASA, LT, MT, and ST), the PLEXOS model can calculate the expansion of power source and grid capacity in long-term planning and can also calculate power source mobilization when the scale of the projects is available and operate the electricity market according to each transaction cycle. The PLEXOS model can simulate to calculate optimal mobilization of both 500 kV and 220 kV transmission grids according to the principle of nodal marginal price market.

PLEXOS is currently being used in 47 countries around the world, including some large countries such as the US, Australia, and the UK.

The power system's production costs are calculated and optimized in power source mobilization, including fuel costs, operation and maintenance costs, external costs of various types of emissions, transmission costs, and electricity shortage costs.

The investment cost of each project will be calculated by the model over the entire life of the project according to regular payments and a constant interest rate (10%/year).

Constraints on power system operation that are simulated include:

- Ensuring the dispatching and operating ability of thermal power plants when integrating wind and solar power. Meet the operational constraints of various types of technology, including performance, converted maximum power generation hours, unit mobilization parameters, emission target, hydroelectric reservoir parameters, and wind speed and 8760h solar power capacity chart by region and province.

- Meet constraints on capacity of the power grid, such as constraints on the ability to provide ancillary services, constraints to ensure technical standards and power system operating standards, constraints on regulation and operation of hydropower plants according to inter and single-lake operating procedures, constraints on primary fuel supply, and fuel consumption.
Meet 8760h load charts of each region.

- Limit the supply of domestic coal and domestic gas according to the ability to exploit domestic primary energy sources for electricity production.

- Meet CO_2 emission level of Vietnam's power system according to the high load scenario of PDP VIII.

Vietnam's power system is divided into 6 regions linked together through 7 transmission interfaces: North - North Central, North Central – Center Central, Center Central - Highlands, Highlands - South Central, Center Central - South Central, South Central - South, Highlands - South. Power plants will be mobilized to meet the load of 6 regions, taking into account limitations on inter-regional transmission lines.

3.1.3. Input Assumptions

a) Technical and economic parameters of different types of technology

Economic - Technical parameters of various types of technology, including investment costs, O&M costs, performance, unit mobilization parameters, and emission coefficients are taken according to the documents:

- Main report of the National Power Development Plan for the period 2021-2030, vision to 2050 [2].

- Vietnam technology catalog on power generation 2023, developed by the Electricity and Renewable Energy Authority and the Danish Energy Agency within the framework of the cooperation program in the energy field between the two Governments of Vietnam and Denmark [7].

Technical and economic parameters are included in the detailed simulation model for each type of technology and each stage, and are important inputs that determine the accuracy of the results. These parameters were developed with the support of Danish experts and have been widely reviewed and accepted by experts in the energy industry during the development of the Vietnam Technology Catalog as well as PDP VIII.

All costs are converted to 2020 USD, excluding annual price inflation.

b) Forecasting thermal power plant parameters when extending life and converting fuel

Table 3-1 Assumptions on thermal power plant parameters when extending lifespan

Item	Coal	Gas	Oil
Lifetime extending cost (MUSD/MW)	+0.26	+0.42	+0.3
O&M cost	+3%	+3%	+3%
Efficiency decrease when lifetime extending	-1%	-1%	-1%
Number year of lifetime extending	20	20	20

Source: Cost of Capacity for Calibration of the Belgian Capacity Remuneration Mechanism (CRM) - Fichtner- 2020, Page 85. Vietnam Technology Catalog 2023.

Note: Lifetime extending cost will be spread out over 20 years.

Table 3-2 Assumptions on thermal power plant parameters when converting fuel

No	Technology	% cofiring	Renovation cost (kUSD/MW)	O&M cost	Efficiency	PM2.5	SO2	NOx
I	**Coal- biomass cofiring**							
	Coal-biomass 20% (CFB)	20%	45	+3%	+0%	-10%	-10%	-5%
	Coal-biomass 50% (CFB)	50%	114	+4%	-1%	-40%	-40%	-15%
	Coal-biomass 100% (CFB)	100%	227	+5%	-1%	-70%	-70%	-30%
II	**Coal-Amoniac cofiring**							
	Coal-Amoniac 20% (PC)	20%	167	+5%	-1%	-20%	-20%	+30%
	Coal-Amoniac 50% (PC)	50%	246	+7%	-1%	-50%	-50%	+40%
	Coal-Amoniac 100% (PC)	100%	379	+10%	-2%	-100%	-100%	+50%
III	**Gas-hydro cofiring**							
	Gas-hydro 20%	20%	54	+3%	+0%	-20%	-20%	+20%
	Gas-hydro 50%	50%	77	+4%	+0%	-50%	-50%	+30%
	Gas-hydro 100%	100%	190	+5%	+0%	-100%	-100%	+40%

Source: Vietnam Technology Catalog 2023 for Power Generation. (+) is an increase compared to the original (-) is reduced compared to the original

Renovation costs according to levels are the accumulated costs from the unrenovated period.

c) Forecasting the cost of closing a thermal power plant at the end of economic life

The cost of closing a thermal power plant includes:

- Payments to equity investors, creditors, and the workforce affected by plant shutdowns. At the end of economic life, the shutdown only requires consideration of unemployment payments to the workforce.

- Plant overhead and O&M costs during the preparation period for shutdown.
Cost of dismantling equipment and cleaning coal storage area.

- Cost of cleaning coal combustion residue (slag dump) and soil environmental treatment (such as asbestos and hazardous substances).

- The assumed cost of closing a thermal power plant is referred to in the following documents- 'Decommissioning US Power Plants: Decisions, Costs, and Key Issues', 'RFF's 2017 Annual Report', 'Coal Plant Repurposing for Ageing Coal Fleets in Developing Countries (World Bank)', and World Economic Forum's article '4 Key Steps to Decommissioning Coal-Fired Power Plants'. Assumptions and calculations of power plant closure costs according to closure scenarios are presented in detail in section 3.4. Chapter 3.

d) Primary fuel prices for electricity production forecast

Fuel costs for electricity production are taken according to forecasts in PDP VIII.

Table 3-3 Forecasting primary fuel prices for Vietnamese power plants

Fuel	Heat rate	2025	2030	2035	2040	2045	2050
Domestic coal (USD/tons)	5000 (Kcal/kg)	72	74	76	78	80	82
Imported coal (USD/ tons)	6000 (Kcal/kg)	140	105	105	105	105	105
LNG (USD/million BTU)	(41MJ/m^3- HHV; 36.5MJ/m3-LHV)	14	11.8	11.8	11.9	11.9	11.9
Green Hydrogen (USD/kg)	120 MJ/kg	4.2	3	2.8	2.6	2.4	2.2
Green Amoniac (USD/kg)	18.6 MJ/kg	0.72	0.5	0.46	0.42	0.38	0.35
Uranium (USD/GJ)	28000 GJ/kg	4.86	4.86	4.86	4.86	4.86	4.86
Biomass (USD/ton)	3000 Kcal/kg	70	80	80	80	80	80
Gas Block B (USD/ million BTU) - Hydrocarbon	(41MJ/m^3- HHV; 36.5MJ/m3-LHV)	11.98	11.98	11.98	11.98	11.98	11.98
Gas Blue Whale (USD/ million BTU) - Hydrocarbon	(41MJ/m^3- HHV; 36.5MJ/m3-LHV)	9.71	9.71	9.71	9.71	9.71	9.71

Source: PDP VIII – April 2023. Prices refer to 2020, excluding price inflation.

e) External cost forecast

External costs in the project are calculated as costs affecting human health or medical costs.

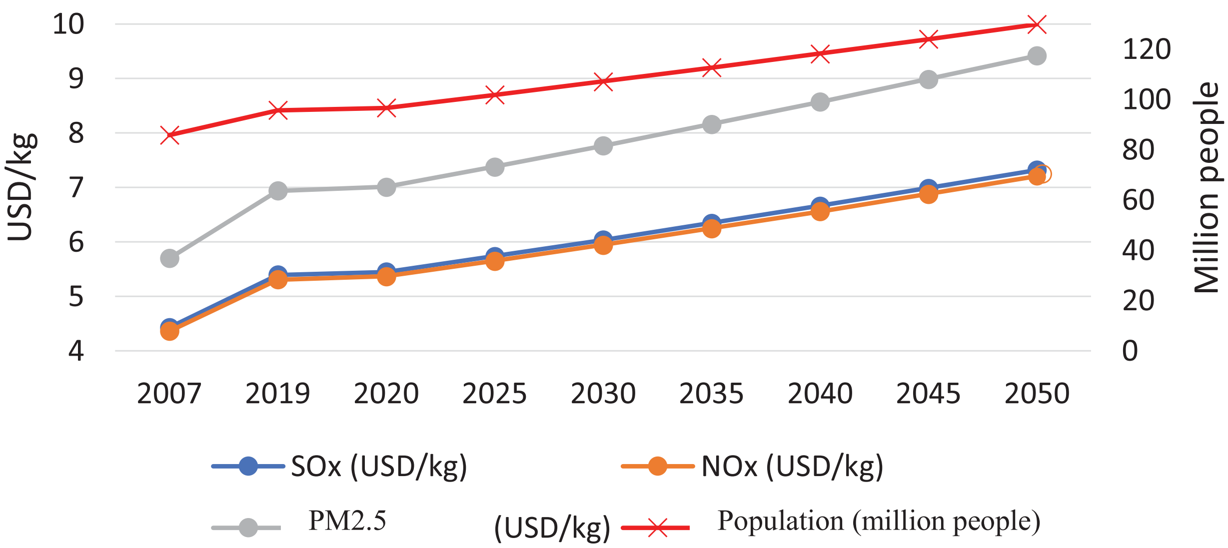
The study is based on documents calculating the external costs of various types of emissions for Vietnam from international organizations, such as “Valuation of Some Environmental Costs Within the GMS Energy Sector Strategy" by Måns Nilsson, report to the Asian Development Bank; January 25, 2007 MS document “Getting Energy Prices Right – From Principle to Practice” published by the World Monetary Fund in 2014. The EU Technical Assistance Program for Sustainable Energy supports the Department of Electricity and Energy renewable energy to carry out a strategic environmental assessment in 2020. Although the costs of Sox, NOx, and PM2.5 from the above three information sources were proposed at different times, the net present values (according to the population growth rates) are similar.

The study estimates the external costs of SOx, NOx, and PM2.5 emissions as follows (forecasted future prices will increase according to Vietnam's population growth rate):

Source: Valuation of some environmental costs within the GMS Energy Sector Strategy – ADB, 2007, and Getting Energy Prices Right – from principle to practice – IMF, 2014

EU technical assistance program for sustainable energy supports the Electricity and Renewable Energy Authority to carry out strategic environmental assessments, 2020.

Figure 3-1 External cost forecast in Vietnam



For the external cost of CO2, the study only considers the national damage aspect. According to the EU Technical Assistance Program, the national damage cost of CO2 for developing countries is less than 1 USD /ton, for Vietnam it is about 0.4 USD/ton. Therefore, the study is expected to take the health cost of CO2 as 0.4 USD/ton. The health cost of CO2 in the following years during the planning period will be assumed to be maintained at 0.4 USD/ton.

Regarding the cost of processing solar panels at the end of the project, the study refers to End-of-life management for Solar PV panels - IRENA, 6/2016. Accordingly, the expected cost of processing solar panels at the end of the project is 200 Euro/ton (equivalent to 0.0206 MUSD/MW). This cost will be included in the investment cost for solar power.

The cost of handling chemicals used in Lithium-Ion batteries at the end of the project life is 5000 USD/ton (according to information provided by the National Argonne Lab, USA).

The land cost will be calculated in addition to the cost of renewable energy with large land use, such as a solar farm. The land cost is taken based on decisions of the People's Committees of the provinces on the land price.

3.2. Evaluate the CO2 Emission Reduction Roadmap of the Power Sector and the Energy Transition Roadmap of Coal-Fired Power Plants in PDP VIII. Select CO2 Emission Roadmap for Calculations in the Study

3.2.1. Assess the Relationship between the Power Source Development Program and National Goals on Reducing Greenhouse Gas (GHG) Emissions.

According to the Master Energy Plan for the period 2021-2030 with consideration to 2050, the proportion of GHG emissions of the electricity production sub-sector in the energy industry in 2020 will reach about 42%. The proportion of the electricity production sub-sector compared to the whole country reached about 28%. By 2030, this proportion will be 56% in the energy sector and 48% in national emissions, respectively. Specifically, see the following tables:

Table 3-4 National and sectoral emissions. Unit: Million tons of CO2eq

Item/Year	2020	2025	2030	2035	2040	2045	2050
Emission according to BAU	**513.3**	**716.5**	**928.0**	**1,096.0**	**1,252.5**	**1,396.7**	**1,519.3**
Energy Sector	247.0	394.1	457.2	495.3	408.2	261.3	101.0
Agriculture Sector	88.3	75.3	63.9	62.2	63.8	61.5	56.4
LULUCF Sector	-45.9	-65.6	-95.3	-112.4	-134.0	-149.6	-185.2
Waste Sector	30.6	22.91	18.2	15.9	13.3	10.64	7.8
IP Sector	67.3	91.9	86.5	78.1	68.0	50.0	20.0
Total emission	**387.3**	**518.6**	**530.5**	**539.1**	**419.3**	**233.8**	**0.0**

Source: National Strategy Report on Climate Change for the period up to 2050

Table 3-5 Emissions of the power generation sub-sector in the energy sector – High demand scenario. Unit: Million tons of CO2

Fuel	2020	2025	2030	2035	2040	2045	2050
Coal	84.2	72.3	77.8	75.9	66	51.5	13.4
Gas	3.5	4	7.4	10.8	15.9	22	31.6
Oil	54.6	75.3	89.1	92.4	85.9	69.5	17.2
Energy exploitation	15.8	15.2	23.1	18.4	14.6	13.5	12.5
Power production	115	155	221	226	182	107	27
Total emission	**273.1**	**321.8**	**418.4**	**423.5**	**364.4**	**263.5**	**101.7**
Carbon capture					*1*	*3*	*8*
Net CO2 emissions	**273.1**	**321.8**	**418.4**	**423.5**	**363.4**	**260.5**	**93.7**

Source: Energy master plan for the period 2021-2030 with consideration to 2050

Currently, the biggest goal of the national power development program that must be followed is to implement Vietnam's Net Zero Declaration by 2050 at the COP26 Conference.

According to the National Strategy on Climate Change for the period up to 2050 approved by the Prime Minister in Decision No. 896/QD-TTg dated July 26, 2022, to achieve the net zero emissions target in . By 2050, the energy sector (including sub-sectors: electricity production, transportation, energy exploitation, commerce, and residential) is allowed to emit a maximum of 457 million tons of greenhouse gasses (CO2eq) in 2030 and 101 million tons in 2050.

According to the draft National Energy Master Plan for the period 2021-2030, with a vision to 2050, to meet the National Strategy on Climate Change, the maximum allowable CO2 emissions of the power generation industry is about 240 million tons in 2030 and about 30 million tons in 2050.

Emissions of 30 million tons of CO2eq in 2050 for the power generation industry are only enough to cover emissions from about 8 GW of domestic gas power sources (Blue Whale, Block B, or Ken Bau gas in the future). Due to the priority of using all domestic gas resources, the electricity industry needs solutions to reduce CO2 emissions of coal-fired power plants and LNG thermal power plants to "0" by 2050.

Energy exploitation and transportation have been separately calculated for GHG emissions in the structure of energy sub-sectors. Therefore, the power source development program of PDP VIII only calculates GHG emissions from electricity production.

3.2.2. Analysis of CO_2 Emission Reduction Roadmap and Energy Conversion Roadmap of Coal-Fired Power Plants according to the National Power Source Development Scenario in PDP VIII

According to the Decision approving QHD VIII No. 500/QD-TTg dated May 15, 2023, the target for reducing CO_2 emissions has been set as follows: "Controlling greenhouse gas emissions from electricity production to about 204 - 254 million tons in 2030 and about 27 - 31 million tons in 2050. Aiming to reach a peak emission level of no more than 170 million tons in 2030, provided that commitments under JETP are fully implemented by international partners."

ThusTherefore, the CO_2 emission reduction roadmap of PDP VIII will have 2 cases: High emission case and Low emission case.

High Emission Case

With the principle of "dynamic" and "open", PDP VIII has built 3 scenarios for power source development that cover possible cases in investment in power source development during the planning period. The scale of power sources proposed for development will be within the lower and upper bounds of the scenarios. This helps avoid legal risks and the risk of not being able to implement the entire planned power source scale, while at the same time being proactive in managing power source development. The power source development program of PDP VIII has proposed the following 3 power source development scenarios:

Scenario 1 - PDP VIII: Power sSource development program according to the base demand scenario. In caseIn this scenario, there are 6,800 MW of risky coal thermal power projects (Nam Dinh thermal power plant, Cong Thanh thermal power plant, Quang Tri thermal power plant, Vinh Tan III thermal power plant, and Song Hau II thermal power plant). Scenario 1 is considered the lower bound of the demand forecast as well as the power source development program.

Scenario 2 - PDP VIII: Developing power sources according to high load and not implementing the coal thermal power projects that are having difficulty arranging capital (6,800MW).

Scenario 3 - PDP VIII: Starting from Scenario 2 and considering an additional reserve of about 15% of the additional installed power capacity in the period 2021 - 2030 of Scenario 2 (according to Notice No. 308/TB- VPCP dated November 9, 2021 and practice of power source construction in previous periods). This scenario provides information for management levels to ensure power supply in case of delay in power sources. This is the upper limit of power source development.

Of the three scenarios of PDP VIII, Scenario 1 with 6,800 MW of risky coal thermal power plants will not be feasible, because these coal power plants currently cannot arrange investment capital. Scenario 3 is a scenario that accelerates power supply from 2035 to 2030 in Scenario 2 and is a scenario with excess land compared to forecast load demand, used to manage the implementation of electricity planning. Calculation according to Scenario 3 will not accurately reflect the operation of thermal power sources according to forecast load demand. Therefore, the study does not select Scenario 1 and Scenario 3 to calculate the national CO_2 emission reduction roadmap of the electricity sector.

Scenario 2, without 6800 MW of risky coal thermal power, is more feasible and was selected as the base scenario for calculation in the project. The demand in base scenario and high scenario in the period up to 2030 is the same. After 2030, along with the strong transition to using electricity by industries and transport sectors to reduce CO_2 emissions and achieving the net zero commitments by 2050, the load demand scenario will be more feasible than the base demand scenario. Therefore, choosing to calculate the national CO_2 emission reduction roadmap according to Scenario 2 - high load is completely appropriate.

Balance the capacity of the North's power source according to the power source development roadmap of PDP VIII in case of high emissions as follows:

Table 3-6 Balancing installed capacity of power sources in the North - PDP VIII - Case of high emissions

Item/Year	2025	2030	2035	2040	2045	2050
TOTAL DEMAND OF THE NORTH	**25368**	**37668**	**52516**	**66168**	**77084**	**86743**
Installed capacity	**31431**	**40860**	**72172**	**100632**	**132122**	**166205**
Medium and large hydro	9356	9397	10177	10687	11087	11087
PSPP	50	300	3150	7350	13350	20350
Small hydro	4866	5284	7398	7598	7598	8475
Onshore+nearshore wind	1616	3616	4450	5450	7150	9150
Offshore wind	0	2000	9500	13500	16000	18000
Solar	256	1256	8190	17090	31790	47490
Biomass and other RE	410	960	1760	2110	2110	2161
Import from China	700	700	700	700	700	700
Import from Laos	1272	1272	3272	3272	3272	3272
Domestic coal	12606	12176	8651	6115	4205	0
Coal co firing biomass	0	0	2925	3545	620	0
Coal convert to 100% biomass	0	0	0	0	2925	4305
Coal co firing ammonia	0	0	600	2516	3116	0
Coal convert to 100% ammonia	0	0	0	0	600	3716
CCGT using LNG	0	3000	4500	1500	0	0
LNG co firing hydrogen	0	0	0	3000	4500	1500
LNG convert to 100% hydrogen	0	0	0	0	0	3000
Flexible thermal	0	300	5700	13800	20700	30600
Cogeneration	299	599	1199	2399	2399	2399
TOTAL DEMAND OF THE NORTH CENTRAL	**3969**	**6199**	**9450**	**12912**	**16203**	**19535**
Installed capacity	**9027**	**16512**	**20023**	**26523**	**39016**	**48589**
Medium and large hydro	1655	1750	2000	2000	2000	2000
Small hydro	500	500	870	920	920	920
Onshore+nearshore wind	1200	1700	2500	3900	5900	6400
Offshore wind	0	0	0	0	5000	5000
Solar	909	909	1500	4400	8858	17858
Biomass and other RE	60	160	160	310	460	618
Import from Laos	770	1178	1178	3178	3978	3978
Domestic coal	1953	1953	0	0	0	0
Imported coal	1330	4062	4062	4062	2732	0
Coal co firing ammonia	0	0	1953	1953	1330	0
Coal convert to 100% ammonia	0	0	0	0	2038	6015
CCGT using LNG	0	3000	4500	3000	0	0
LNG co firing hydrogen	0	0	0	1500	4500	3000
LNG convert to 100% hydrogen	0	0	0	0	0	1500
Cogeneration	650	1300	1300	1300	1300	1300

In the power source development scenarios of PDP VIII, the energy conversion roadmap for coal-fired power plants is selected to combine closing low-performance plants that have been operating for a long time and converting fuel for newly built factories (not yet reaching 40 years of life by 2050). As follows:

- Coal thermal power sources increase from 20 GW in 2020 to 31 GW in 2030 and decrease to zero in 2050.

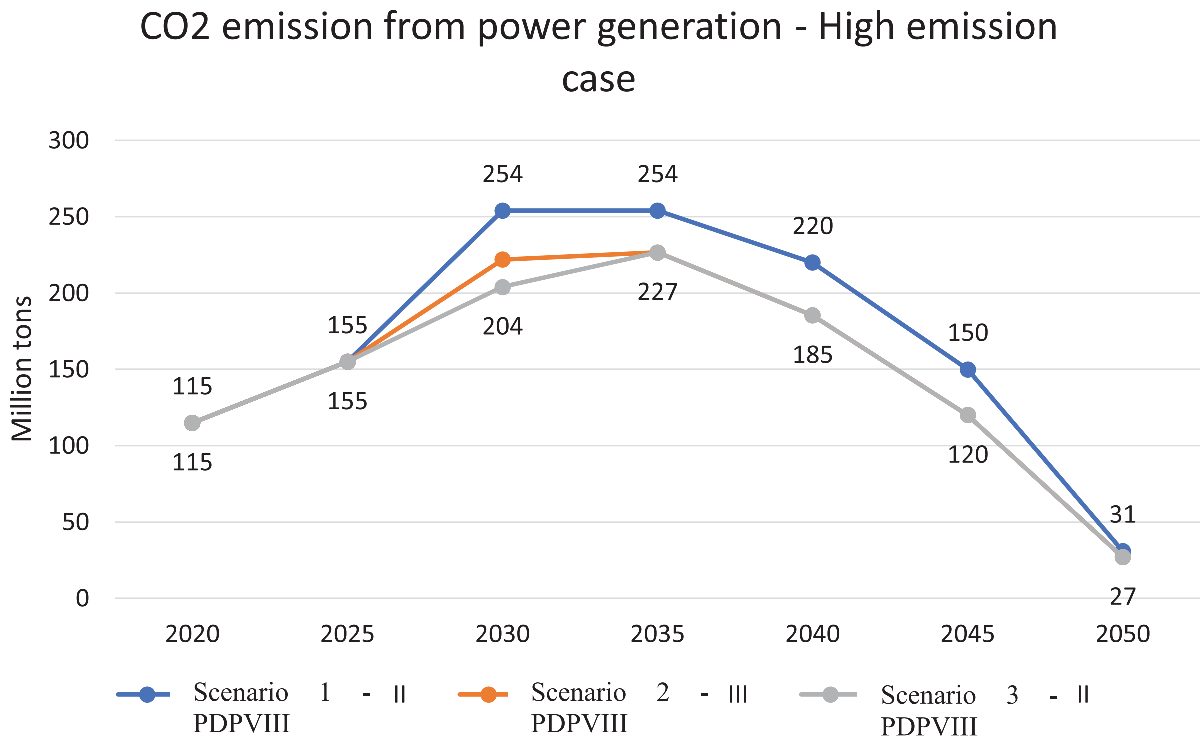
● Coal thermal power sources will stop operating after 40 years of operation if fuel is not converted. Decision 500/QD-TTg approving PDP VIII does not clearly state the plants that have stopped operating, however, the scale of coal thermal power plants that have stopped operating is shown in the total coal thermal power capacity before and after fuel conversion. Total coal power capacity in 2022 is 24.9GW, under construction capacity is 5.8GW, by 2030 the total capacity is 30.1-36.9GW (with and without 6.8GW of risky coal), and by 2050, the total capacity converted to new fuels (biomass, ammonia) will be 25.6-32.4GW. Thus, in the period up to 2030 there will be about 0.6GW and in the period 2031-2050 there will be about 4.5GW of coal thermal power out of operation. (Note: Statistics on coal thermal power capacity in Decision 500/QD-TTg only calculate even grams of capacity with typical power units such as 300MW, 500MW, and 600MW. Therefore, coal thermal power capacity in the balance tables of the project, with full installed capacity, will be higher than Decision 500/QD-TTg.)

● After 2030, coal-fired power sources that do not stop operating will burn biomass or ammonia. By 2050, coal-fired power sources will completely switch to burning biomass/ammonia with an installed capacity of 26 GW. Coal-fired power sources using CFB furnaces (about 4GW) will be converted to biomass combustion due to the favorable conditions of CFB furnaces, combined with the limitation of biomass potential in Vietnam. PC furnace plants will convert to combustion with ammonia with a total scale of 22GW.

For gas turbine sources using LNG, it they will not be considered to stop operating but must have to convert fuel to hydrogen gradually. In direction of PDP VIII, they are, expected to start burning cofiring after 10 years of operation, and completely switch to burning hydrogen after the next 10 years.

With the energy transition roadmap of coal and gas thermal power plants as above in PDP VIII, CO2 emissions from the national power system of scenarios 1-3- PDP VIII will reach 204-254 million tons in 2030, peaking in 2035 at about 226-254 million tons, then gradually decreasing to 27-31 million tons in 2050. Thus, CO2 emissions in 2050 in electricity production have reached the goal of the climate change strategy and achieving the net zero commitments of COP26.

Figure 3-2 CO2 emission path in national electricity production according to 3 power source development scenarios of PDP VIII – normal year



b. Low Emission Case

The energy conversion roadmap of coal and gas thermal power plants is similar to the case of high emissions calculated in PDP VIII. Along with the roadmap for CO2 emissions to peak at 170 million tons in 2030, then gradually decrease to about 27 million tons in 2050, the project uses the PLEXOS model to calculate the expansion of national power capacity in the period up to 2050 according to the principle of minimizing total system cost.

With the roadmap to reduce CO2 emissions of the national electricity industry according to the low emission case of PDP VIII, it is expected to be as follows:

Table 3-7 National CO2 emissions in PDP VIII – High load scenario – Low emission case

Year	2025	2030	2035	2040	2045	2050
CO2 emission (million tons)	155	170	169	145	100	27

Balance the installed power capacity of the North according to the power source development roadmap of PDP VIII - low emission case as follows:

Table 3-8 Balancing installed capacity of power sources in the North - PDP VIII - Case of low emissions

Item/Year	2025	2030	2035	2040	2045	2050
TOTAL DEMAND OF THE NORTH	**25368**	**37668**	**52516**	**66168**	**77084**	**86743**
Installed capacity	**30620**	**52649**	**94101**	**122551**	**150021**	**172914**
Medium and large hydro	9356	9397	9517	9517	9917	9917
PSPP	300	2700	6450	10950	16950	23950
Small hydro	4866	5284	7798	7998	8078	8555
Onshore+nearshore wind	1616	3816	4650	5650	7150	9150
Offshore wind	0	5000	14000	18000	18000	18000
Solar	256	6756	18690	27090	41290	47490
Biomass and other RE	410	1460	1860	2110	2110	2161
Import from China	700	700	700	700	700	700
Import from Laos	1272	1272	3272	3272	3272	3272
Domestic coal	11545	11765	8405	6005	3335	0
Coal cofiring biomass	0	0	2760	3360	1360	0
Coal convert to 100% biomass	0	0	0	0	2760	4120
Coal co firing ammonia	0	0	600	2400	3000	0
Coal convert to 100% ammonia	0	0	0	0	600	3600
CCGT using LNG	0	3000	3000	0	0	0
LNG co firing hydrogen	0	0	0	3000	3000	0
LNG convert to 100% hydrogen	0	0	0	0	0	3000
Flexible thermal	0	900	11200	20100	26100	36600
Cogeneration	299	599	1199	2399	2399	2399
TOTAL DEMAND OF THE NORTH CENTRAL	**3969**	**6199**	**9450**	**12912**	**16203**	**19535**
Installed capacity	**10674**	**17327**	**27406**	**34336**	**45594**	**49094**
Medium and large hydro	1655	1750	1880	1880	1880	1880
Small hydro	500	500	900	1030	1030	1030
Onshore+nearshore wind	1200	2200	3000	3900	5900	6400
Offshore wind	0	0	0	0	5000	5000
Solar	909	4409	13000	16900	20358	23358
Biomass and other RE	60	460	618	618	618	618
Import from Laos	770	1178	1178	3178	3978	3978
Domestic coal	1800	1800	0	0	0	0
Imported coal	3130	3730	3730	3730	0	0
Coal co firing ammonia	0	0	1800	1800	3730	0
Coal convert to 100% ammonia	0	0	0	0	1800	5530
Cogeneration	650	1300	1300	1300	1300	1300

Compared to the high emission case, to reach peak CO2 emissions of 170 million tons in 2030, the system will have to reduce the development of LNG power sources

sources and increase the development of wind, solar power sources, flexible thermal power sources, and storage as follows:

In 2030: The system will reduce 6900MW of CCGT using LNG, increase 1600 MW of flexible solar power, 6300MW of onshore and nearshore wind power, 8000MW of offshore wind power, 18800 MW of solar power, 1844 MW of biomass power, and 4800 MW of storage power.

In 2050: The system will reduce 15,200 MW CCGT using LNG convert to hydrogen, increase 10,800 MW of flexible thermal power sources, 1,200 MW of onshore wind power, 12,500 MW of solar power, and 7,500 MW of storage sources.

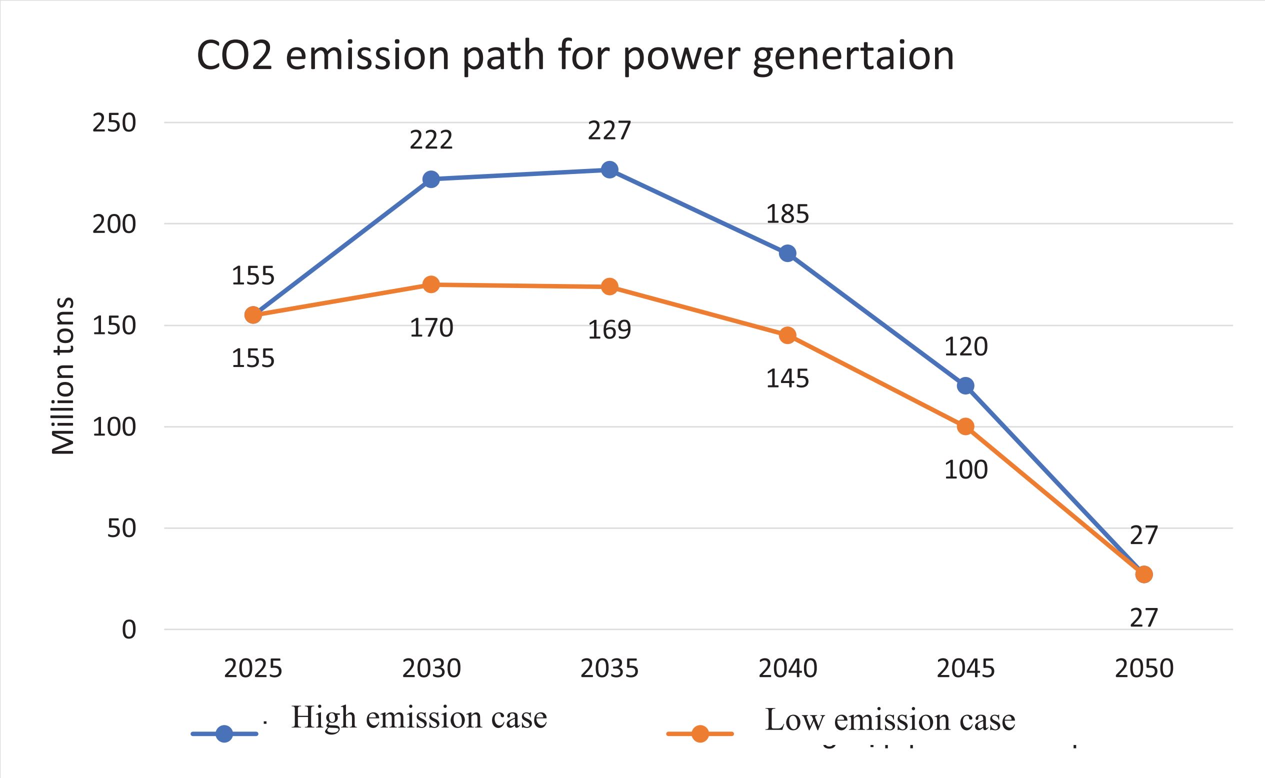
In the case of low emissions, CCGT using LNG in the North Central, Central, and South Central regions will not be developed, the system only has 10,200MW of LNG power source (including LNG Nhon Trach 3&4 - 1500MW, LNG Hiep Phuoc I - 1200MW, LNG Son My I&II - 4500MW, LNG Quang Ninh - 1500MW, and LNG Thai Binh - 1500MW).

3.2.2. Select a National CO2 Emission Path for Coal Power Plant Closure Scenarios in the North

According to the analysis in the above section, the study selects a high load scenario to calculate the national power source structure according to scenarios of closing coal power plants in the North.

The CO2 emission path will be selected in accordance with the CO2 emission roadmap of PDP VIII according to high emission cases and low emission cases as described in the above section. This will be the upper limit on CO2 emissions in the project's calculation scenarios. Specifically, see the following chart:

Figure 3-3 CO2 emission path of national power generation sources according to 2 cases of low emission and high emission expected in the project – Normal year



The carbon market in Vietnam is expected to operate in 2028 and will operate according to carbon quotas and carbon credits. Carbon quotas will be assigned to each enterprise each year. Therefore, the project's options for closing the Northern Coal Power Plant are calculated with the same emission level, consistent with the general emission path of the electricity industry as stated in Decision 500/QD-TTg.

3.3. Proposing Scenarios for Closing Coal-Fired Power Plants in the North

The study proposes scenarios for closing coal-fired power plants in the North as follows:

Scenario 1: Closing coal-fired power plants in the North after 30 years of operation. By 2050, coal-fired power plants that have not been in operation for 30 years will still have to close by 2050.

Scenario 2: Closing coal-fired power plants in the North after 40 years of operation. By 2050, coal-fired power plants that have not been in operation for 40 years will still have to close by 2050.

List of coal-fired power plants in the North and their closure time according to the scenarios are shown in the following table:

Table 3-9 List of Northern coal-fired power plants and closure times according to different closure scenarios

No	Power plant	Installed capacity (MW)	Operation year	Owner	Expected year of closure	
					Scenario 1	Scenario 2
1	Hai Phong 1	600	2009	EVNGENCO 2	2039	2049
2	Hai Phong 2	600	2013	EVNGENCO 2	2043	2050
3	Pha Lai 1	440	1983	EVNGENCO 2	2029	2029
4	Pha Lai 2	600	2002	EVNGENCO 2	2032	2042
5	Thai Binh 1	100	2017	EVNGENCO 3	2047	2050
6	Ninh Binh	1120	1974	EVNGENCO 3	2029	2029
7	Mong Duong 1	1245	2015	EVNGENCO 3	2044	2050
8	Quang Ninh 1	600	2009	EVNGENCO 1	2039	2049
9	Quang Ninh 2	600	2012	EVNGENCO 1	2042	2050
10	Uong Bi extend 1	300	2009	EVNGENCO 1	2039	2049
11	Uong Bi extend 2	330	2013	EVNGENCO 1	2043	2050
12	Cam Pha	680	2009	TKV	2039	2049
13	Mao Khe	440	2012	TKV	2042	2050
14	Son Dong	220	2008	TKV	2038	2048
15	Cao Ngan	115	2006	TKV	2036	2046
16	Na Duong 1	110	2004	TKV	2034	2044
17	Na Duong 2	110	2026	TKV	2050	2050
18	Hai Duong	1210	2020	BOT	2050	2050
19	Mong Duong 2	620	2014	BOT	2048	2050
20	Thang Long	120	2018	IPP	2044	2050
21	An Khanh 1	650	2014	IPP	2050	2050
22	An Khanh Bac Giang	706	2026	IPP	2047	2050
23	Thai Binh 2	1200	2022	PVN	2050	2050
24	Nghi Son 1	708	2013	EVNGENCO 1	2043	2050
25	Vung Ang 1	1330	2013	PVN	2050	2050
26	Nghi Son 2	1245	2021	BOT	2043	2050
27	Vung Ang II	1330	2026	BOT	2050	2050
28	Quang Trach I	1402	2026	EVN	2050	2050

Ninh Binh and Pha Lai 1 thermal power plants, although they have been in operation for many years, still have to operate in the short term due to the risk of power shortage in the North in the coming years. The earliest closure time according to assessment is around 2029. The above two scenarios for closing thermal power plants will be calculated with 2 cases: Low emission and High emission.

Scenarios for closing coal-fired power plants in the North will be calculated and compared with scenario 0 (KB0), which is the PDP VIII scenario. Scenario 0 would combine closing low-efficiency coal-fired power plants after 40 years of operation and converting to biomass and ammonia for newer coal-fired power plants. Summary of coal thermal power capacity in the North (including combustion and conversion to other fuels) according to the following scenarios:

Table 3-10 Total coal thermal power capacity in the North (including combustion and conversion to other fuels) according to calculation scenarios. Unit: MW

Scenario/Year	2025	2030	2035	2040	2045	2050
Scenario 0- PDP VIII	15889	18191	18191	18191	17566	14036
Scenario 1 – closed after 30 years of operation	15889	18191	17481	14966	8558	0
Scenario 2 – closed after 40 years of operation	15889	18191	18191	18191	17481	0

Thermal power capacity of Scenario 1 and Scenario 2 will be 14GW in 2050, lower than Scenario 0. Therefore, in Scenario 1 and Scenario 2, the system will have to invest in additional renewable energy sources, storage, and flexible thermal power sources to ensure security of power supply for the system and CO2 emissions to reach the same level compared to scenario 0.

3.4. Preliminary Estimate of the Cost of Closing Coal-Fired Thermal Power Plants in the North according to Scenarios

In both calculated closure scenarios, some factories will have to close by 2050 before the end of their economic life (30 years). Because coal-fired power plants in Vietnam are charged electricity prices, the investment costs are calculated over a 30-year life span. So for power plants that have not yet completed 30 years of life, the capital cost will still remain and the remaining amount is calculated according to the PMT financial function for the remaining years (assuming the loan in power plants investment is paid over 30 years with an annual interest rate of 10%/year). For power plants that have reached the end of their economic life, the investment capital costs have been paid off, so there will be no capital costs paid to the investor.

Based on the current unemployment support regime in Vietnam, the unemployment benefit costs for the workforce is about 60% of the salary for 12 months. It is estimated that the average salary of workers at coal-fired power plants (converted to 2020) is about 20 million VND/month.

Other costs refer to documents: Coal plant repurposing for aging coal fleets in developing countries (World Bank) and document Just transition of coal-based power plants in India for coal power plants in India. As follows:

- O&M costs, insurance, taxes, security, electricity(plant overhead cost): 0.028 million USD/MW.

- Dismantling cost: 0.005 million USD/MW.

- Cost of cleaning the slag dump area: 0.016 million USD/MW.

- Cost of cleaning coal storage area: 0.003 million USD/MW.

The results of calculating decommissioning costs for Scenarios 1 and 2 are as follows:

Table 3-11 Preliminary estimate of decommissioning costs of Northern coal-fired power plants in the period to 2050 according to scenarios

No	Power plant	Installed capacity (MW)	Cost of paying remaining equity (million USD)	Unemployment support (million USD)	Plant overhead and O&M costs must be paid during the preparation period for stopping operations (million USD)	Cost of cleaning slag dump (million USD)	Cost of dismantling and cleaning coal storage area (million USD)	Total cost of closing the power plant (million USD)
1	Hai Phong 1	600	0	3	16.8	9.6	4.8	34
2	Hai Phong 2	600	0	3	16.8	9.6	4.8	34
3	Pha Lai 1	440	0	1	12.3	7.0	3.5	24
4	Pha Lai 2	600	0	4	16.8	9.6	4.8	35
5	Ninh Binh	100	0	2	2.8	1.6	0.8	8
6	Mong Duong 1	1120	0	2	31.4	17.9	9.0	61
7	Mong Duong 2	1245	0	2	34.9	19.9	10.0	66
8	Quang Ninh 1	600	0	3	16.8	9.6	4.8	34
9	Quang Ninh 2	600	0	3	16.8	9.6	4.8	34
10	Uong Bi extend 1	300	0	2	8.4	4.8	2.4	18
11	Uong Bi extend 2	330	0	2	9.2	5.3	2.6	20
12	Cam Pha	680	0	2	19.0	10.9	5.4	38
13	Mao Khe	440	0	2	12.3	7.0	3.5	25
14	Son Dong	220	0	2	6.2	3.5	1.8	13
15	Cao Ngan	115	0	2	3.2	1.8	0.9	8
16	Na Duong 1	110	0	1	3.2	1.8	0.9	7
17	Na Duong 2	110	105	1	3.1	1.8	0.9	112
18	Hai Duong	1210	0	4	33.9	19.4	9.7	67
19	Thang Long	620	0	2	17.4	9.9	5.0	35
20	An Khanh 1	120	0	2	3.4	1.9	1.0	8
21	An Khanh Bac Giang	650	621	2	18.2	10.4	5.2	656
22	Thai Binh 1	706	0	2	19.8	11.3	5.6	39
23	Thai Binh 2	1200	420	2	33.6	19.2	9.6	484
24	Nghi Son 1	708	0	3	19.8	11.3	5.7	39
25	Nghi Son 2	1330	226	2	37.2	21.3	10.6	297
26	Vung Ang 1	1245	0	2	34.9	19.9	10.0	67
27	Vung Ang II	1330	1608	2	37.2	21.3	10.6	1679
28	Quang Trach I	1402	1695	2	39.3	22.4	11.2	1770
	Total	**18731**	**4675**	**63**	**525**	**300**	**150**	**5712**

In addition to decommissioning costs, for Scenario 2, additional costs for extending the life of coal-fired power plants must be added after 30 years of operation.

Scenarios for closing coal power plants will be compared with the roadmap for converting power plants according to PDP VIII. According to the energy transition roadmap of PDP VIII, Northern coal-fired power plants will stop operating some low-performance plants when their lifespan reaches 40 years and convert fuel to biomass and ammonia. In the coal-fired power plant conversion scenario of PDP VIII, the North will have about 5GW of coal-fired power plants decommissioned. These are plants that have been operating for a long time and have low efficiency. The project estimates investment and renovation costs to convert fuel and stop operating a number of plants with a lifespan of 40 years before 2050 according to the roadmap of PDP VIII as follows:

Table 3-12 Preliminary estimate of energy transition costs of Northern coal-fired power plants in the period to 2050 according to the roadmap of PDP VIII (Scenario 0- PDP VIII)

No	Power plant	Installed capacity (MW)	Decommission year	Year begins with new fuel	Year of switching to completely burning new fuel	Cost of closing the power plant (million USD)	Investment capital to renovate and convert energy (million USD)		Cost to lifetime expanding (million USD)
							50%	100%	
1	Hai Phong 1	600	2049			34			78
2	Hai Phong 2	600		2035	2045		148	80	31
3	Pha Lai 1	440	2028			24			
4	Pha Lai 2	600	2042			35			78
6	Ninh Binh	100	2028			8			
7	Mong Duong 1	1120		2035	2045		276	149	73
19	Mong Duong 2	1245		2034	2044		306	166	81
8	Quang Ninh 1	600	2049			34			78
9	Quang Ninh 2	600	2049			34			78
10	Uong Bi extend 1	300	2049			18			39
11	Uong Bi extend 2	330	2049			20			43
12	Cam Pha	680	2049			38			88
13	Mao Khe	440		2032	2042		108	59	57
14	Son Dong	220	2048			13			29
15	Cao Ngan	115	2046			8			15
16	Na Duong 1	110	2044			7			15
17	Na Duong 2	110		2046	2050		27	15	
18	Hai Duong	1210		2040	2050		298	161	
20	Thang Long	620		2038	2048		153	82	81
21	An Khanh 1	120		2034	2044		30	16	8
22	An Khanh Bac Giang	650		2046	2050		160	86	
5	Thai Binh 1	706		2038	2048		174	94	46
23	Thai Binh 2	1200		2042	2050		295	160	
24	Nghi Son 1	708		2033	2043		174	94	92
26	Nghi Son 2	1330		2041	2050		327	177	
25	Vung Ang 1	1245		2033	2043		306	166	162
27	Vung Ang II	1330		2046	2050		327	177	
28	Quang Trach I	1402		2046	2050		345	186	
	Total	**18731**				**273**	**3453**	**1867**	**1171**

Summary of investment costs for coal-fired power plants according to the following calculation scenarios:

Table 3-13 Summary of investment costs for Northern coal-fired power plants according to scenarios

No	Item	Scenario 0 – PDP VIII	Scenario 1	Scenario 2
1	Cost of closing the power plant (million USD)	272	5712	5712
2	Cost to renovate and convert fuel (million USD)	5320		
3	Cost to lifetime expanding (million USD)	1171		1171
	Total cost for conversion thermal power plants	**6763**	**5712**	**6883**

3.5. Calculate the Structure of Power Source Development according to Scenarios of Closing Coal-Fired Power Plants in the North

3.5.1. High Emission Case

Scenario 1 – Northern coal power plant stops operating after 30 years of life, or 2050 if less than 30 years – High emission case

Due to the reduction of coal thermal power capacity in the North, renewable energy sources (wind, solar), flexible thermal power sources, and storage batteries in the North will be developed to compensate for coal thermal power capacity stopping operating. Calculation results show that power sources only change in the Northern region. Specifically, the installed capacity of the Northern power source according to Scenario 1 is as follows:

Table 3-14 Balancing the capacity of power sources in the North - Scenario 1 - High emission case. Unit: MW

Item/Year	2025	2030	2035	2040	2045	2050
TOTAL DEMAND OF THE NORTH	**25368**	**37668**	**52516**	**66168**	**77084**	**86743**
Installed capacity	**31431**	**40860**	**82062**	**109807**	**135452**	**171484**
Medium and large hydro	9356	9397	10177	10687	11087	11087
PSPP	50	300	3450	7950	15450	24550
Small hydro	4866	5284	7398	7598	7598	8475
Onshore+nearshore wind	1616	3616	4450	5450	7150	9150
Offshore wind	0	2000	9500	13500	16000	19000
Solar	256	1256	18190	26590	33790	49490
Biomass and other RE	410	960	1760	2110	2110	2161
Import from China	700	700	700	700	700	700
Import from Laos	1272	1272	3272	3272	3272	3272
Domestic coal	12606	12176	11466	8951	4496	0
CCGT using LNG	0	3000	4500	1500	0	0
LNG co firing hydrogen	0	0	0	3000	4500	1500
LNG convert to 100% hydrogen	0	0	0	0	0	3000
Flexible thermal	0	300	6000	16100	26900	36700
Cogeneration	299	599	1199	2399	2399	2399
TOTAL DEMAND OF THE NORTH CENTRAL	**3969**	**6199**	**9450**	**12912**	**16203**	**19535**
Installed capacity	**9027**	**16512**	**25523**	**35023**	**39978**	**47574**
Medium and large hydro	1655	1750	2000	2000	2000	2000
Small hydro	500	500	870	920	920	920
Onshore+nearshore wind	1200	1700	3000	4400	5900	6400

Item/Year	2025	2030	2035	2040	2045	2050
Offshore wind	0	0	1000	3000	5000	6000
Solar	909	909	5500	9400	11858	17858
Biomass and other RE	60	160	160	310	460	618
Import from Laos	770	1178	1178	3178	3978	3978
Domestic coal	1953	1953	1953	1953	0	0
Imported coal	1330	4062	4062	4062	4062	0
CCGT using LNG	0	3000	4500	3000	0	0
LNG co firing hydrogen	0	0	0	1500	4500	3000
LNG convert to 100% hydrogen	0	0	0	0	0	1500
Cogeneration	650	1300	1300	1300	1300	1300
Flexible thermal	0	0	0	0	0	4000

Table 3-15 Difference in installed capacity of power source of Scenario 1 compared to Scenario 0 (PDP VIII) - Case of high emissions. Unit: MW

Year	2035	2040	2045	2050
Difference in installed capacity (Scenario 1 – Scenario 0)	**15390**	**17675**	**4292**	**4264**
Domestic coal	4768	4789	291	0
Imported coal	0	0	1330	0
Coal co firing biomass	-2925	-3545	-620	0
Coal convert to 100% biomass	0	0	-2925	-4305
Coal co firing ammonia	-2553	-4469	-4446	0
Coal convert to 100% ammonia	0	0	-2638	-9731
Flexible thermal using hydrogen	300	2300	6200	10100
Onshore+nearshore wind	500	500	0	0
Offshore wind	1000	3000	0	2000
Sola	14000	14500	5000	2000
PSPP+baterry	300	600	2100	4200

Scenario 2 – Northern coal power plant stops operating after 40 years of life, or 2050 if less than 40 years – High emission case

Table 3-16 Balancing the capacity of power sources in the North - Scenario 2 - High emission case.
Unit: MW

Item/Year	2025	2030	2035	2040	2045	2050
TOTAL DEMAND OF THE NORTH	**25368**	**37668**	**52516**	**66168**	**77084**	**86743**
Installed capacity	**31431**	**40860**	**82172**	**113732**	**150822**	**171484**
Medium and large hydro	9356	9397	10177	10687	11087	11087
PSPP	50	300	3450	8850	17550	24550
Small hydro	4866	5284	7398	7598	7598	8475
Onshore+nearshore wind	1616	3616	4450	6950	9150	9150
Offshore wind	0	2000	9500	14000	19000	19000
Solar	256	1256	18190	29590	41790	49490
Biomass and other RE	410	960	1760	2110	2110	2161
Import from China	700	700	700	700	700	700
Import from Laos	1272	1272	3272	3272	3272	3272
Domestic coal	12606	12176	12176	12176	11466	0
CCGT using LNG	0	3000	4500	1500	0	0
LNG co firing hydrogen	0	0	0	3000	4500	1500
LNG convert to 100% hydrogen	0	0	0	0	0	3000
Flexible thermal	0	300	5400	10900	20200	36700
Cogeneration	299	599	1199	2399	2399	2399
TOTAL DEMAND OF THE NORTH CENTRAL	**3969**	**6199**	**9450**	**12912**	**16203**	**19535**
Installed capacity	**9027**	**16512**	**25523**	**37123**	**43931**	**47574**
Medium and large hydro	1655	1750	2000	2000	2000	2000
Small hydro	500	500	870	920	920	920
Onshore+nearshore wind	1200	1700	3000	5000	5900	6400
Offshore wind	0	0	1000	4000	5000	6000
Solar	909	909	5500	9900	13858	17858
Biomass and other RE	60	160	160	310	460	618
Import from Laos	770	1178	1178	3178	3978	3978
Domestic coal	1953	1953	1953	1953	1953	0
Imported coal	1330	4062	4062	4062	4062	0
CCGT using LNG	0	3000	4500	3000	0	0
LNG co firing hydrogen	0	0	0	1500	4500	3000
LNG convert to 100% hydrogen	0	0	0	0	0	1500
Cogeneration	650	1300	1300	1300	1300	1300
Flexible thermal	0	0	0	0	0	4000

Table 3-17 Difference in installed capacity of power source of Scenario 2 compared to Scenario 0 (PDP VIII) - Case of high emissions. Unit: MW

Year	**2035**	**2040**	**2045**	**2050**
Difference in installed capacity (Scenario 2 – Scenario 0)	**15500**	**23700**	**23615**	**4264**
Domestic coal	5478	8014	9214	0
Imported coal	0	0	1330	0
Coal co firing biomass	-2925	-3545	-620	0
Coal convert to 100% biomass	0	0	-2925	-4305
Coal co firing ammonia	-2553	-4469	-4446	0
Coal convert to 100% ammonia	0	0	-2638	-9731
Flexible thermal using hydrogen	-300	-2900	-500	10100
Onshore+nearshore wind	500	2600	2000	0
Offshore wind	1000	4500	3000	2000
Sola	14000	18000	15000	2000
PSPP+baterry	300	1500	4200	4200

3.5.2. Low Emission Case

Scenario 1 – Northern coal power plant stops operating after 30 years of life, or 2050 if less than 30 years – Low emission case

Table 3-18 Balancing the capacity of power sources in the North - Scenario 1 - Low emission case.
Unit: MW

Item/Year	2025	2030	2035	2040	2045	2050
TOTAL DEMAND OF THE NORTH	**25368**	**37668**	**52516**	**66168**	**77084**	**86743**
Installed capacity	**30620**	**52649**	**101991**	**133506**	**158426**	**179394**
Medium and large hydro	9356	9397	9517	9517	9917	9917
PSPP	300	2700	6750	11550	19050	28150
Small hydro	4866	5284	7798	7998	8078	8555
Onshore+nearshore wind	1616	3816	6150	7150	8150	9150
Offshore wind	0	5000	14000	18000	19000	19000
Solar	256	6756	25190	37090	46290	50490
Biomass and other RE	410	1460	1860	2110	2110	2161
Import from China	700	700	700	700	700	700
Import from Laos	1272	1272	3272	3272	3272	3272
Domestic coal	11545	11765	11055	8620	4360	0
CCGT using LNG	0	3000	3000	0	0	0
LNG co firing hydrogen	0	0	0	3000	3000	0
LNG convert to 100% hydrogen	0	0	0	0	0	3000
Flexible thermal	0	900	11500	22100	32100	42600
Cogeneration	299	599	1199	2399	2399	2399
TOTAL DEMAND OF THE NORTH CENTRAL	**3969**	**6199**	**9450**	**12912**	**16203**	**19535**
Installed capacity	**10674**	**17327**	**28806**	**39336**	**45294**	**48564**
Medium and large hydro	1655	1750	1880	1880	1880	1880
Small hydro	500	500	900	1030	1030	1030
Onshore+nearshore wind	1200	2200	3400	4900	6400	6400
Offshore wind	0	0	1000	4000	6000	6000
Solar	909	4409	13000	16900	20358	23358
Biomass and other RE	60	460	618	618	618	618
Import from Laos	770	1178	1178	3178	3978	3978
Domestic coal	1800	1800	1800	1800	0	0
Imported coal	3130	3730	3730	3730	3730	0
Cogeneration	650	1300	1300	1300	1300	1300
Flexible thermal	0	0	0	0	0	4000

Table 3-19 Difference in installed capacity of power source of Scenario 1 compared to Scenario 0 (PDP VIII) - Case of low emissions. Unit: MW

Year	2035	2040	2045	2050
Difference in installed capacity (Scenario 1 – Scenario 0)	**9290**	**15955**	**8105**	**5950**
Domestic coal	4450	4415	1025	0
Imported coal	0	0	3730	0
Coal co firing biomass	-2760	-3360	-1360	0
Coal convert to 100% biomass	0	0	-2760	-4120
Coal co firing ammonia	-2400	-4200	-6730	0
Coal convert to 100% ammonia	0	0	-2400	-9130
Flexible thermal using hydrogen	300	2000	6000	10000
Onshore+nearshore wind	1900	2500	1500	0
Offshore wind	1000	4000	2000	2000
Sola	6500	10000	5000	3000
PSPP+baterry	300	600	2100	4200

Scenario 2 – Northern coal power plant stops operating after 40 years of life, or 2050 if less than 40 years – Low emission case

Table 3-20 Balancing the capacity of power sources in the North - Scenario 2 - Low emission case. Unit: MW

Item/Year	2025	2030	2035	2040	2045	2050
TOTAL DEMAND OF THE NORTH	**25368**	**37668**	**52516**	**66168**	**77084**	**86743**
Installed capacity	**30620**	**52649**	**101801**	**133851**	**160321**	**179394**
Medium and large hydro	9356	9397	9517	9517	9917	9917
PSPP	300	2700	6750	11550	19650	28150
Small hydro	4866	5284	7798	7998	8078	8555
Onshore+nearshore wind	1616	3816	6150	7150	8150	9150
Offshore wind	0	5000	14000	18000	19000	19000
Solar	256	6756	25190	37090	46290	50490
Biomass and other RE	410	1460	1860	2110	2110	2161
Import from China	700	700	700	700	700	700
Import from Laos	1272	1272	3272	3272	3272	3272
Domestic coal	11545	11765	11165	11165	11055	0
CCGT using LNG	0	3000	3000	0	0	0
LNG co firing hydrogen	0	0	0	3000	3000	0
LNG convert to 100% hydrogen	0	0	0	0	0	3000
Flexible thermal	0	900	11200	19900	26700	42600
Cogeneration	299	599	1199	2399	2399	2399
TOTAL DEMAND OF THE NORTH CENTRAL	**3969**	**6199**	**9450**	**12912**	**16203**	**19535**

Installed capacity	10674	17327	28806	39336	47094	48564
Medium and large hydro	1655	1750	1880	1880	1880	1880
Small hydro	500	500	900	1030	1030	1030
Onshore+nearshore wind	1200	2200	3400	4900	6400	6400
Offshore wind	0	0	1000	4000	6000	6000
Solar	909	4409	13000	16900	20358	23358
Biomass and other RE	60	460	618	618	618	618
Import from Laos	770	1178	1178	3178	3978	3978
Domestic coal	1800	1800	1800	1800	1800	0
Imported coal	3130	3730	3730	3730	3730	0
Cogeneration	650	1300	1300	1300	1300	1300
Flexible thermal	0	0	0	0	0	4000

Table 3-21 Difference in installed capacity of power source of Scenario 2 compared to Scenario 0 (PDP VIII) - Case of low emissions. Unit: MW

Year	2035	2040	2045	2050
Difference in installed capacity (Scenario 2 – Scenario 0)	**9100**	**16300**	**11800**	**5950**
Domestic coal	4560	6960	9520	0
Imported coal	0	0	3730	0
Coal co firing biomass	-2760	-3360	-1360	0
Coal convert to 100% biomass	0	0	-2760	-4120
Coal co firing ammonia	-2400	-4200	-6730	0
Coal convert to 100% ammonia	0	0	-2400	-9130
Flexible thermal using hydrogen	0	-200	600	10000
Onshore+nearshore wind	1900	2500	1500	0
Offshore wind	1000	4000	2000	2000
Sola	6500	10000	5000	3000
PSPP+baterry	300	600	2700	4200

3.6. Compare Scenarios for Closing Coal-Fired Thermal Power Plants in the North with PDP VIII

a. Installed Capacity

Calculations of expanding power capacity in scenarios for closing coal-fired power plants in the North show that when closing coal-fired power plants without converting fuel, the system will have to invest in additional renewable energy (wind, solar), flexible thermal power sources, and storage batteries to meet demand. In the period up to 2030, because PDP VIII also plans to stop operating Ninh Binh and Pha Lai 1 thermal power plants, the scale of power sources up to 2030 in the scenarios for closing coal power plants in the North remains unchanged compared to PDP VIII. In the period 2031 - 2050, the scale of wind, solar, and flexible storage power sources in all years is higher than in PDP VIII. By 2050, the system will have to invest an additional 10.1GW of flexible hydrogen power sources, 2GW of offshore wind power sources, 2 - 3GW of solar power sources, and about 4.2GW of pumped storage hydropower sources, compared to PDP VIII, to meet demand in 2050 when the Northern coal power plant is closed.

b. Investment Cost for Power Sources

Table 3-22 Difference in investment costs for energy conversion of Northern coal-fired thermal power plants in the period 2031-2050 according to scenarios - High emission case.
Unit: Million USD

Item	Scenario 0	Scenario 1	Scenario 2
Investment cost for energy conversion of thermal power plants	6762	5712	6882
Investment cost in additional renewable energy sources, flexible sources, and pumped storage hydropower compared to scenario 0		14472	14472
Total investment costs	**6762**	**20184**	**21354**
Total investment costs increased compared to scenario 0 (million USD)		***13421***	***14592***

Table 3-23 Difference in investment costs for energy conversion of Northern coal-fired thermal power plants in the period 2031-2050 according to scenarios - Low emission case.
Unit: Million USD

Item	Scenario 0	Scenario 1	Scenario 2
Investment cost for energy conversion of thermal power plants	6762	5712	6882
Investment cost in additional renewable energy sources, flexible sources and pumped storage hydropower compared to scenario 0		15098	15098
Total investment costs	**6762**	**20810**	**21980**
Total investment costs increased compared to scenario 0 (million USD)		***14047***	***15218***

Two scenarios for closing thermal power plants have higher investment costs for energy transition than PDP VIII, due to the need to invest in additional renewable energy sources, energy storage sources, storage sources, and costs for closing thermal power plants. The investment costs for renewable energy sources are mainly focused on the early periods of 2031 - 2035 and 2036 - 2040 due to the model choosing to promote renewable energy sources early to reduce CO2 emissions in scenarios without fuel conversion. Scenario 1 will require mobilizing investment capital for flexible thermal power sources earlier than Scenario 2.

c. Inter-Regional Transmission Grid

Calculation results of transmitted power on interface according to the following scenarios:

Table 3-24 Electricity transmitted on interface according to scenarios - high emission cases. Unit: Billion kWh

Interface/Year	2025	2030	2035	2040	2045	2050
1. Scenario 0						
Central => North	1.4	11.2	24.4	46.4	55.3	49.6
North => Central	8.7	0.7	0.1	0.0	0.0	0.0
Central => South	22.7	32.3	21.4	0.9	0.4	1.0
South => Central	0.6	3.9	8.5	4.0	3.6	0.9
South => North	0.0	0.0	11.5	54.2	87.7	103.7
2. Scenario 1						
Central => North	1.4	11.2	13.1	40.7	56.1	50.0
North => Central	8.7	0.7	2.1	0.0	0.0	0.0
Central => South	22.7	32.3	30.2	2.2	0.5	1.1
South => Central	0.6	3.9	3.6	2.2	4.3	1.0
South => North	0.0	0.0	6.6	43.5	95.0	102.9
3. Scenario 2						
Central => North	1.8	22.2	23.4	39.2	51.2	50.0
North => Central	2.6	0.0	0.2	0.0	0.0	0.0
Central => South	16.6	25.5	22.3	2.8	0.5	1.1
South => Central	0.7	4.1	7.7	1.9	1.8	1.0
South => North	0.0	0.0	10.7	40.9	72.9	103.0

Table 3-25 Electricity transmitted on interface according to scenarios - low emission cases.
Unit: Billion kWh

Interface/Year	2025	2030	2035	2040	2045	2050
1. Scenario 0						
Central => North	3.9	21.7	23.6	42.4	54.3	58.3
North => Central	3.6	0.3	0.7	0.0	0.0	0.0
Central => South	15.3	14.3	18.7	3.4	2.9	4.0
South => Central	1.1	1.2	11.8	1.2	1.3	3.1
South => North	0.0	0.0	14.8	46.8	60.2	73.5
2. Scenario 1						
Central => North	3.9	21.7	19.2	39.3	54.7	58.0
North => Central	3.6	0.3	1.3	0.2	0.0	0.0
Central => South	15.3	14.3	21.1	5.2	2.2	4.7
South => Central	1.1	1.2	7.7	1.1	2.2	3.5
South => North	0.0	0.0	10.7	35.6	58.0	67.9
3. Scenario 2						
Central => North	4.2	21.7	19.0	36.9	51.7	58.0
North => Central	3.3	0.3	1.3	0.6	0.0	0.0
Central => South	14.8	14.3	21.3	7.0	4.0	4.7
South => Central	1.1	1.2	7.6	1.5	0.8	3.5
South => North	0.0	0.0	10.6	29.5	48.2	67.9

In general, power transmission on an inter-regional grid does not change much between scenarios in 2050. Transmission output only changes mainly between 2035 - 2045. For Scenario 2, stopping operation of coal-fired thermal power plants in the North after 40 years of operation, the inter-regional transmission output from the South to the North is about 5 - 15 billion kWh lower in the period 2035 - 2045. However, with the scale of transmission load of Scenario 2, the transmission grid construction volume of Scenario 0, 1, and 2 will be the same for each emission case.

d. CO2 Emission

Table 3-26 CO2 emission in scenarios

Year	2025	2030	2035	2040	2045	2050
1. High emission case						
Scenario 0	155	222	227	185	115	27
Scenario 1	155	222	227	185	115	27
Scenario 2	155	222	225	180	120	27
2. Low emission case						
Scenario 0	155	170	169	144	99	26
Scenario 1	155	170	169	144	99	26
Scenario 2	155	170	169	144	100	26

CO2 emissions of all scenarios are within the limits set according to the roadmap of PDP8.

e. Total System Cost

The results of calculating electrical system costs from the PLEXOS model of the scenarios are as follows:

Table 3-27 Power system costs of calculation scenarios – high emission case

Year	2021	2030	2035	2040	2045	2050	2021-2050
Power generation (GWh)	268555	566992	800874	1022744	1208046	1378520	
1. Scenario 0 (million USD)							
Investment costs (capital and depreciation)	10403	17064	28175	37684	47092	45763	879673
O&M cost	2446	6496	9815	13931	16776	18882	311856
Fuel cost	6959	18220	25550	33129	42155	56107	806713
Inter-regional transmission cost	492	1183	1302	2493	3359	3561	54699
Energy shortage cost	0	0	0	0	0	0	0
Emission cost	0	0	4584	3534	2344	1746	68454
Total system cost (million USD)	**20299**	**42963**	**69425**	**90771**	**111726**	**126059**	**2121395**
Average electricity production cost (cent/kWh)	**7.6**	**7.6**	**8.7**	**8.9**	**9.2**	**9.1**	
NPV of total system cost in the period 2021-2050 (million USD)	**433922**						
2. Scenario 1 (million USD)							
Investment costs (capital and depreciation)	10404	17064	30364	40184	46517	51050	903063
O&M cost	2446	6496	9878	13778	16540	18734	309805
Fuel cost	6959	18220	23746	31126	42673	54964	787157
Inter-regional transmission cost	492	1183	1241	2324	3541	3607	54720
Energy shortage cost	0	0	0	0	0	0	0
Emission cost	0	0	4860	3774	2225	1776	70599
Total system cost (million USD)	**20301**	**42963**	**70089**	**91185**	**111496**	**130131**	**2125344**
Average electricity production cost (cent/kWh)	**7.6**	**7.6**	**8.8**	**8.9**	**9.2**	**9.4**	
NPV of total system cost in the period 2021-2050 (million USD)	**434742**						
3. Scenario 2 (million USD)							
Investment costs (capital and depreciation)	10404	17064	30271	41432	48683	51062	910199
O&M cost	2446	6496	9916	13786	16703	18734	313749
Fuel cost	6959	18220	22996	29894	38523	54944	758792
Inter-regional transmission cost	492	1183	1196	2130	3030	3610	50654
Energy shortage cost	0	0	0	0	0	0	0
Emission cost	0	0	4876	3981	3231	1809	77413
Total system cost (million USD)	**20301**	**42963**	**69255**	**91223**	**110171**	**130158**	**2110807**
Average electricity production cost (cent/kWh)	**7.6**	**7.6**	**8.6**	**8.9**	**9.1**	**9.4**	
NPV of total system cost in the period 2021-2050 (million USD)	**433298**						

Note: Assume emission costs (NOx, SOx, dust, CO2) are calculated from 2031, costs are converted to 2020, discount factor is 10%

Table 3-28 Power system costs of calculation scenarios – low emission case

Year	2021	2030	2035	2040	2045	2050	2021-2050
Power generation (GWh)	268555	566992	800874	1022744	1208046	1378520	
1. Scenario 0 (million USD)							
Investment costs (capital and depreciation)	10403	24352	37734	42057	43919	38786	954357
O&M cost	2446	6782	10642	14123	17149	18990	320964
Fuel cost	6857	16001	18018	25940	37008	55396	681583
Inter-regional transmission cost	316	736	1406	2369	2841	3093	47976
Energy shortage cost	0	0	0	0	0	0	6
Emission cost	0	0	3614	3173	2155	1946	59651
Total system cost (million USD)	**20021**	**47870**	**71413**	**87663**	**103072**	**118210**	**2064538**
Average electricity production cost (cent/kWh)	**7.5**	**8.4**	**8.9**	**8.6**	**8.5**	**8.6**	
NPV of total system cost in the period 2021-2050 (million USD)	**434790**						
2. Scenario 1 (million USD)							
Investment costs (capital and depreciation)	10404	24352	39277	44907	44405	43936	982245
O&M cost	2446	6782	10646	14078	17059	18773	319590
Fuel cost	6857	16001	16860	23422	36227	55087	660750
Inter-regional transmission cost	316	736	1304	2187	2808	3001	46561
Energy shortage cost	0	0	0	0	0	0	6
Emission cost	0	0	3702	3256	2022	1879	60119
Total system cost (million USD)	**20023**	**47870**	**71788**	**87851**	**102521**	**122676**	**2069271**
Average electricity production cost (cent/kWh)	**7.5**	**8.4**	**9.0**	**8.6**	**8.5**	**8.9**	
NPV of total system cost in the period 2021-2050 (million USD)	**435388**						
3. Scenario 2 (million USD)							
Investment costs (capital and depreciation)	10403	24352	39241	44796	45220	44838	982738
O&M cost	2446	6782	10641	14007	16949	18773	320307
Fuel cost	6857	16001	16809	23236	34257	55087	641308
Inter-regional transmission cost	316	736	1301	2054	2633	3001	44868
Energy shortage cost	0	0	0	0	0	0	6
Emission cost	0	0	3706	3545	3137	1807	67446
Total system cost (million USD)	**20021**	**47870**	**71698**	**87639**	**102196**	**123506**	**2056672**
Average electricity production cost (cent/kWh)	**7.5**	**8.4**	**9.0**	**8.6**	**8.5**	**9.0**	
NPV of total system cost in the period 2021-2050 (million USD)	**434242**						

Note: Assume emission costs (NOx, SOx, dust, CO2) are calculated from 2031, costs are converted to 2020, discount factor is 10%

Calculation results show that in the cases of high and low emissions, Scenario 1 (stop operation after 30 years of operation) always has the highest present value of the total system cost for the period 2021 - 2050, followed by Scenario 0, and finally Scenario 2. Scenario 1 has high fuel costs due to having to replace backup coal thermal power sources with flexible thermal power sources running on expensive hydrogen gas in the period 2040 - 2050. Stopping coal-fired power plants early and investing in more flexible thermal power sources running on hydrogen gas will increase fuel costs for the entire system. In the following stages, due to the requirement to ensure a roadmap to reduce CO_2 emissions, the coal-fired power source in Scenario 2 almost only serves as a backup source, with very low operating hours.

Scenario 2 has the lowest total system cost in the period to 2050, however the average electricity production cost in 2050 is higher than scenarios 0 and 1. This is due to many power plants shutdowns in 2050, causing investment costs for decommissioning to be higher than other scenarios in 2050.

Comparing decommissioning under Scenario 1 and decommissioning under Scenario 2, the study proposes to choose decommissioning under Scenario 2 to reduce system costs in the period to 2050 as well as reducing pressure of early investment in alternative power sources.

3.7. Conclusion on the Scenario of Closing Coal-Fired Power Plants in the North

With the assumption that CO2 emission quotas are guaranteed as in the roadmap to reduce CO2 emissions of PDP VIII, in order to close all coal-fired power plants in the North, the power system will need to invest earlier and more renewable energy power sources, flexible power sources, and storage sources compared to the power source investment volume of PDP VIII. To close coal power plants in the North, investment costs of about 21-22 billion USD are needed in the period 2031-2050. The cost of power investment in the period 2031-2050 in the scenario of closing the Northern coal power plant will increase by 14-15 billion USD compared to PDP VIII.

The investment in the inter-regional power transmission grid will remain the same as PDP VIII in the scenarios of coal-fired thermal power closure in the North.

The scenario of closing the Northern coal-fired power plant after 30 years of operation will make the total operating costs for the period 2031 - 2050 larger than the operating costs of PDP VIII. While the scenario of closing the Northern coal power plant after 40 years of operation, the total system cost in the period to 2050 is the lowest. However, the average electricity production cost in 2050 is higher than PDP VIII and the scenario closed after 30 years of operation. Therefore, the study proposes that if selecting to close coal-fired power plants, it should be considered closing after 40 years of operation to reduce pressure on early investment in power sources and reduce power system costs throughout the planning period.

Therefore, if there is about 22 billion USD invested to finance the closure of the Northern coal power plant, the option of closing the plant to implement net zero can be chosen instead of the fuel conversion roadmap in PDP VIII. Expected closing year is as follows:

Table 3-29 Expected year to close Northern coal power plants according to the selected scenario

No	Power plant	Installed capacity (MW)	Operated year	Expected year to close
1	Hai Phong 1	600	2009	2049
2	Hai Phong 2	600	2013	2050
3	Pha Lai 1	440	1983	2029
4	Pha Lai 2	600	2002	2042
5	Ninh Binh	100	1974	2029
6	Mong Duong 1	1120	2015	2050
7	Mong Duong 2	1245	2014	2050
8	Quang Ninh 1	600	2009	2049
9	Quang Ninh 2	600	2012	2050
10	Uong Bi extend 1	300	2009	2049
11	Uong Bi extend 2	330	2013	2050
12	Cam Pha	680	2009	2049
13	Mao Khe	440	2012	2050
14	Son Dong	220	2008	2048
15	Cao Ngan	110	2006	2046
16	Na Duong 1	115	2004	2044
17	Na Duong 2	110	2026	2050
18	Hai Duong	1210	2020	2050
19	Thang Long	620	2018	2050
20	An Khanh 1	120	2014	2050
21	An Khanh Bac Giang	650	2026	2050
22	Thai Binh 1	706	2017	2050
23	Thai Binh 2	1200	2022	2050
24	Nghi Son 1	708	2013	2050
25	Nghi Son 2	1330	2021	2050
26	Vung Ang 1	1245	2013	2050
27	Vung Ang II	1330	2026	2050
28	Quang Trach I	1402	2026	2050
	Total	**18731**		

The above closure plan will not affect the scale of the national power source in the period up to 2030 compared to PDP VIII.

In the period up to 2035, the scale of the Northern power source needs to be accelerated from 2040 of PDP VIII to 2035 as follows:

- High emission case: Increase 500 MW onshore wind power, 1000 MW offshore wind power, 14000 MW solar power source, and 300MW storage power source, with a 300MW decrease in flexible power source.

- Low emission case: Increase 1900MW of onshore wind power, 1000MW of offshore wind power, 6500 MW of solar power, and 300MW of storage power.

In the period up to 2050, the scale of power sources in the North needs to be supplemented compared to PDP VIII as follows:

- High emissions case: Increase 2000 MW of offshore wind power, 2000MW of solar power, 4200 MW of storage power, and 10100MW of flexible thermal power using hydrogen.

- Low emission case: Increase 2000 MW of offshore wind power, 3000MW of solar power, 4200 MW of storage power, and 10000 flexible thermal power sources using hydrogen.

Therefore, to transition energy, it is possible to consider closing coal-fired power plants, especially those that have been operating for a long time and have low efficiency. However, when the coal-fired thermal power plants stop operating, the system must still supplement backup power sources such as flexible power sources and storage batteries to ensure power supply security. The locations of coal power plants that have stopped operating have convenient connection infrastructure and are located in load center areas. Therefore, it is recommended that the People's Committees of provinces and cities create conditions to continue maintaining land used for new backup power sources at the locations of power plants that have stopped operating, to reduce investment costs, thereby reducing electricity price for the people.

4. RESEARCH AND PROPOSE THE BACKBONE TRANSMISSION GRID IN THE NORTH ACCORDING TO SELECTED ENERGY TRANSITION SCENARIO

4.1. Methodology

Similar to PDP VIII, to calculate the optimal power source structure for each region (Chapter 3), the study divides Vietnam's power system into 6 regions, including North, North Central, Center Central, Highlands, South Central, and South. In particular, the scope of study is the North, including the North and North Central regions. The results of power source dispatching calculations will indicate power transmission between regions.

In the design of the backbone transmission grid, to clarify the transmission characteristics, based on the natural geographical conditions and the ability to supply and consume electricity in the North, the study divides the North into 5 sub-regions: Northwest and Northern mountainous provinces include Lao Cai, Yen Bai, Lai Chau, Dien Bien, Son La, Hoa Binh, Ha Giang, Cao Bang, Bac Kan, Tuyen and Quang; The Northeast includes Lang Son, Thai Nguyen, Bac Giang, Hai Phong, Hai Duong, and Quang Ninh; Hanoi City and surrounding areas include Hanoi, Hung Yen, Ha Nam, Phu Tho, Vinh Phuc, and Bac Ninh; Southern Hanoi includes Ninh Binh, Nam Dinh, and Thai Binh; The North Central includes Thanh Hoa, Nghe An, Ha Tinh, and Quang Binh.

Definition of backbone transmission grid works to evacuate power sources:

With the role of evacuation power source capacity, the study calculates and designs the backbone transmission network including 500-220 kV substations and transmission lines that play an important role in connecting and evacuating power sources (thermal power, hydro power, and renewable energy) and ensuring inter-regional transmission (transmission of power from one area to another due to the characteristics of supply-demand distribution). Specifically includes:

- 500 kV inter-regional transmission line.

- 500 kV substation and line on the main axis evacuate power source capacity (thermal power, hydropower, renewable energy).

- 220 kV substation and line on the main axis evacuate power source capacity (thermal power, hydropower, renewable energy).

The methodology for designing the backbone transmission grid to connect and evacuate power sources according to proposed power development scenarios in the period up to 2030, with an orientation to 2050 includes the following steps:

Step 1: Collect data information, prepare to build a calculation model

It is expected that the data to be collected includes the following main contents (but not limited to):

- Data on the current status of Vietnam's power sources and grid.

- Updated information on possible operation progress of various types of power sources (Collected from the Ministry of Industry and Trade, provinces/cities, investors).

- Updated information on possible operation progress of 500 kV and 220 kV transmission grid projects (Collected from EVN).

The scope of power grid calculation in the study includes the nationwide 500 kV and 220 kV power transmission system. The calculation model includes main input parameters such as load forecast, power source development program, and initial power grid development program built on the basis of PDP VIII. Then, based on the power source development program proposed in Chapter 3, main transmission grid projects are proposed to evacuate power source capacity to meet Vietnam's technical standards.

Step 2: Calculate inter-regional transmission limits according to the power grid development program approved in PDP VIII

As presented in Step 1, the study will originate from analyzing the ability to integrate power sources on the initial basis of the power grid approved under PDP VIII. The purpose of this calculation is to check whether the inter-regional power grid according to PDP VIII meets the capacity of power sources according to the new source development plan proposed for the North. If the capacity is not met, proposals will be made to renovate and build new inter-regional power grids.

Step 3: Calculate regional power balance

The study will calculate regional supply-demand balance to evaluate the correlation between load growth and source development of each region. To do this, it is necessary to accurately update load forecasts for each province/city and development plans for each type of power source for each province/city. For large power sources, such as thermal power and medium and large hydropower, there is a detailed project list in Decision No. 500/QD-TTg. The feasibility progress for operation is updated according to the Implementation Plan of PDP VIII. For types of renewable energy power sources, such as onshore wind power, biomass power, waste power, and small hydropower, the study will calculate the capacity of these types of sources by sub-region based on the regional scale of the power source development program in Chapter 3.

The power balance results will provide preliminary assessments of transmission direction between sub-regions.

Step 4: Calculate the design of the backbone transmission grid to evacuate power sources

Based on the results of demand forecasting and power source development scenarios, the project will calculate and design the backbone 500-220 kV transmission grid to meet the requirements for evacuating power source capacity. The power grid development plan is selected according to the principle of minimum cost, taking into account the possibility of practical implementation, and at the same time, meeting the criteria for transmission grid development. The study focuses on considering transmission grid design in the period up to 2030. The period after 2030 is for orientation only.

- For inter-regional transmission grids: Compare the results of calculating inter-regional transmission output in power source development scenarios with PDP VIII to consider the necessity of additional inter-regional transmission grid projects.

- For intra-regional transmission grids: Based on the capacity of different types of power sources changing in power source development scenarios compared to PDP VIII.

Step 5: Simulate to check the operating ability of the power system, check the ability to meet the technical requirements of selected option in 2030

The report conducts simulations to check the operating ability of the electrical system in normal operating mode and N-1 incident, thereby proposing adjustments and additions to the electrical grid if necessary. The calculation scope is 2030 because the transmission grid configuration approved in Decision 500/QD-TTg dated May 15, 2030 only extends to 2030. Transmission grid projects in the period after 2030 are only for orientation and have no clear legal basis.

- Use the PSS/E model to calculate and check the power flow on the power system, identify nodes with voltage or transmission capacity exceeding the allowed limit. In addition, PSS/E is also used to evaluate the level of violation of criteria for safe operation of the power system (analyzing the ability to meet N-1 criteria).

- Based on the results of analytical calculations, the study proposes that main transmission grid projects need to be newly built or renovated to evacuate power sources, avoid congestion and overload, and ensure safe and reliable operation for the system.

Step 6: Summarize the volume of new construction and renovation of transmission grids to connect and evacuate power sources in the period up to 2030, with an orientation to 2050 corresponding to scenarios on power source development

Based on the new construction and renovation of power transmission grids proposed in Step 5 and Step 6, summarize the volume of new construction and renovation of power transmission grids in the period up to 2030, with a vision toward 2050 to respond to scenarios on power source development. The study will focus on the volume of new projects compared to the power grid development program in PDP VIII.

The power transmission grid is designed to correspond to two power source development options proposed in Chapter 3: High emission case (temporarily called Scenario 2A) and Low emission case (temporarily called Scenario 2B).

4.2. Calculate Inter-Regional Transmission Limits according to the Approved Power Grid Development Plan

❖ Transmission Limit Calculation Method

Transmission power limits across each regional link slice is calculated as follows:

- Determine the list of 500-220 kV lines through transmission slices of interest according to the approved grid development plan.

- Simulation of placing additional power sources at locations that are favorable for capacity evacuation in the area that needs to evacuate power, while increasing the load in the area receiving the capacity. Perform calculation of power flow on the power system in normal working modes (N-0) and 01 element fault (N-1) on the transmission grid.

- Increase power and load capacity until overload begins to occur on the transmission slice of interest corresponding to the calculation modes N-0 and N-1, or the system voltage instability.

- The limit of transmission capacity through the slice will be the total capacity on the 500-220 kV lines in the slice, at the increased capacity level before overload or instability occurs.

❖ Transmission trends between regions of the North:

According to the calculation results of power source dispatching corresponding to the two power source development scenarios proposed in Chapter 3, the amount of power transmitted from the South and Central to the North has continuously increased over the years. Accordingly, the North must receive about 22 - 27 billion kWh from the Central region in 2030. In 2050, in addition to receiving about 50 billion kWh from the Central region in the case of high emissions and 58 billion kWh in the case of low emissions through the alternating current transmission line system, the North must receive about 68 - 103 billion kWh from the South through the direct current transmission line system (HVDC).

The results of power transmission between regions of the North are calculated from the power dispatching program as follows:

Table 4-1 Inter-regional electricity transmission in the period until 2050 in the North - Scenario 2A

Unit: billion kWh

Interface/Year	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
North Central => North	3.1	34.7	38.5	34.7	24.3	17.6
North Central => Center Central	2.6	0.0	0.2	0.0	0.0	0.0
Center Central => North Central	1.8	22.2	23.4	18.2	18.2	19.8
Center Central => North				21.0	33.0	30.2
South Central => North			10.7	40.9	72.9	103.0

Table 4-2 Inter-regional electricity transmission in the period until 2050 in the North - Scenario 2B

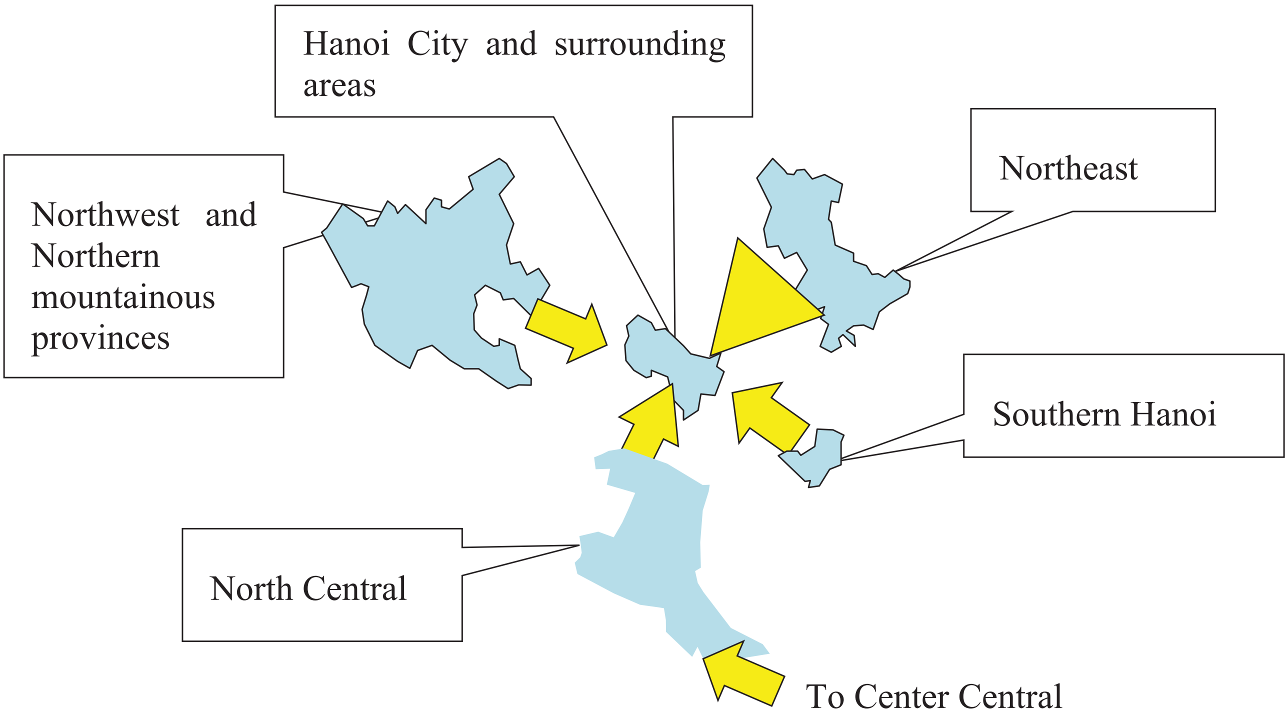
Unit: billion kWh

Interface/Year	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
North Central => North	8.0	26.8	33.1	32.4	28.5	17.1
North Central => Center Central	3.3	0.3	1.3	0.6	0.0	0.0
Center Central => North Central	4.2	21.7	19.0	16.3	18.0	33.7
Center Central => North				20.5	33.7	24.3
South Central => North			10.6	29.5	48.2	67.9

Calculation results show that due to large demand, the North receives a large amount of electricity from the North Central, Center Central, and South Central regions. In particular, the North Central - North and North Central - Center Central links are AC links and the Center Central - North and South Central - North links are DC links.

At the sub-region level, Hanoi and surrounding areas are the load centers of the North but do not have the potential to develop large power sources, so it must receive power from other sub-regions. The dominant transmission direction among the 5 northern sub-regions is shown in the following figure:

Figure 4-2 Main transmission direction among 5 Northern sub-regions



Because transmission grid projects are only clarified in the period up to 2030, the project only calculates capacity transmission limits between regions in the period up to 2030. The period after 2030 will be based on calculations of inter-regional transmission power to propose power grid projects.

Transmission capacity limits on slices for the period up to 2030 according to PDP VIII are as follows:

Table 4-3 Transmission capacity on Northern interfaces according to the PDP VIII

No	Interface	Year 2030
	Inter-regional	
1	North Central - North	15175
	Inter-sub regional	
1	North Central - Hanoi City and surrounding	3314
2	Southern Hanoi - Hanoi City and surrounding	4585
3	Northeast - Hanoi City and surrounding	9361
4	Northwest and Northern mountainous provinces - Hanoi City and surrounding	11262

4.3. Calculate Capacity of Renewable Energy Sources by Sub-Region

4.3.1. Methodology

To design the backbone transmission grid, in addition to determining transmission trends between sub-regions, it is necessary to determine the relative locations of power delivery and receiving points, i.e. power source centers and load centers. In particular, determining the relative location of power sources is a necessary condition for designing the power grid to evacuate power source capacity. The scope of the study will focus on designing the power grid to evacuate power source capacity. The part of the power grid supplying power to the load will be inherited according to PDP VIII.

As stated in the previous section, for large power sources, such as coal thermal power, gas thermal power, medium and large hydropower, there is a detailed project list in Decision No. 500/QD-TTg, source development program. The power proposed in Chapter 3 still closely follows PDP VIII. In this study, we only reviews the operating progress of these types of sources based on Implementation Plan of PDP VIII, the position is relatively clear.

However, for renewable energy sources with a small installed capacity, such as wind power, solar power, biomass power, waste, and small hydropower, detailed location determination of each project is difficult. Therefore, to proceed with power grid design, the project only determines the relative locations of these types of sources according to sub-regional clusters. This method still ensures accuracy in the design of the backbone power grid, because in reality, in each area with favorable characteristics for developing renewable energy sources, substations that collect the capacity of many projects are often placed and connected to the

The methodology for calculating capacity of renewable energy sources by sub-region in the North is similar to that in the Implementation Plan of PDP VIII. Among them, the main requirements include:

●Ensuring compliance with the capacity scale of each type of power source by region based on the results of calculating the power source structure of the power source development scenario proposed in Chapter 3.

●Prioritizing projects that have been approved for additional planning, have been granted investment policies, and have deployed and completed construction compared to projects proposed for new research.

Specifically, the basis for calculating types of power sources by sub-region is as follows:

●Solar power: Calculate the capacity of rooftop solar power and concentrated solar power of each sub-region according to the available area of the industrial park and the typical levelized cost of electricity production (LCOE) of the potential sub-region.

●Onshore/near-shore wind power: Calculate the onshore/near-shore wind power capacity of each sub-region according to the typical levelized cost of electricity production (LCOE) of the potential sub-region.

●Offshore wind power: Calculate the offshore wind power capacity of each region according to the typical levelized cost of electricity production (LCOE) of the potential area at sea.

●Biomass power and waste power: Priority is given to developing waste power. The capacity of each sub-region is calculated according to population size, industrial park, and technical potential. The biomass power capacity of each sub-region is calculated according to technical potential.

●Small hydro power: Calculate the small hydro power capacity of each sub-region according to the small hydro power capacity supplemented with new planning and proposals of the localities.

Levelized Cost of Energy (LCOE) is the net present value for each unit of electricity generated over the life of a power plant, calculated as total lifetime costs divided by total production energy generated during that period of time. Total costs include initial investment capital, operation and maintenance costs and fuel costs.

LCOE is calculated as follows:

$$LCOE = \frac{Sum\ of\ cost\ of\ electricity\ over\ lifetime}{Sum\ of\ electricity\ produced\ over\ lifetime} = \frac{\sum_{=1}^{n} \frac{I_t+M_t+F_t}{(1+}}{}$$

Note:

I_t : Investment cost in year t

M_t : O&M cost in year t

F_t : Fuel cost in year t

E_t : Electricity produced in year t

r : Discount rate

n : Lifetime

4.3.2. Calculating Capacity of Renewable Energy Sources by Sub-Region in the North

Renewable energy source capacity by regions in two source development scenarios according to high emission and low emission cases is as follows:

Table 4-4 Scale of renewable energy source by regions according to 2 scenarios of power source development

Power generation	Unit	Scenario 2A		Scenario 2B	
		2030	Orientation in 2050	2030	Orientation in 2050
North					
Onshore/nearshore wind	MW	3616	9150	3816	9150
Offshore wind	MW	2000	19000	5000	19000
Solar	MW	1256	49490	6756	50490
Biomass and MSW	MW	960	2161	1460	2161
Small hydro	MW	5284	8475	5284	8555
North Central					
Onshore/nearshore wind	MW	1700	6400	2200	6400
Offshore wind	MW	0	6000	0	6000
Solar	MW	909	17858	4409	23358
Biomass and MSW	MW	160	618	460	618
Small hydro	MW	500	920	500	1030

The results of the scale of renewable energy source capacity in the North and North Central regions as shown in Table 4.4 are extracted from the results of calculating the power source structure presented in Chapter 3. However, as stated in the previous section, to design a transmission grid development plan, the study will calculate the scale of the North's renewable energy source capacity to a smaller extent, according to 5 proposed sub-regions including Northwest and Northern mountainous areas, Northeast, Hanoi city and surrounding areas, South Hanoi, and North Central. Details are shown in the following tables:

Table 4-5 Scale of renewable energy source by 5 sub-regions – Scenario 2A

Unit: billion kWh

No	Subregion/Power generation	Onshore/near shore wind	Offshore wind	Solar	Biomass and MSW	Small hydro
	Period up to 2030	**5316**	**2000**	**2165**	**1120**	**5784**
1	Northwest and Northern mountainous	1179	0	264	383	5192
2	Northeast	2367	1500	459	245	89
3	Hanoi city and surrounding areas	0	0	416	277	3
4	South Hanoi	70	500	117	55	0
5	North Central	1700	0	909	160	500
	Orientation to 2050	**15550**	**25000**	**67348**	**2743**	**9395**
1	Northwest and Northern mountainous	4602	0	12483	835	8258
2	Northeast	4478	12000	13475	585	202
3	Hanoi city and surrounding areas	0	0	16684	574	14
4	South Hanoi	70	7000	6848	131	0
5	North Central	6400	6000	17858	618	920

Table 4-6 Scale of renewable energy source by 5 sub-regions – Scenario 2B

Unit: billion kWh

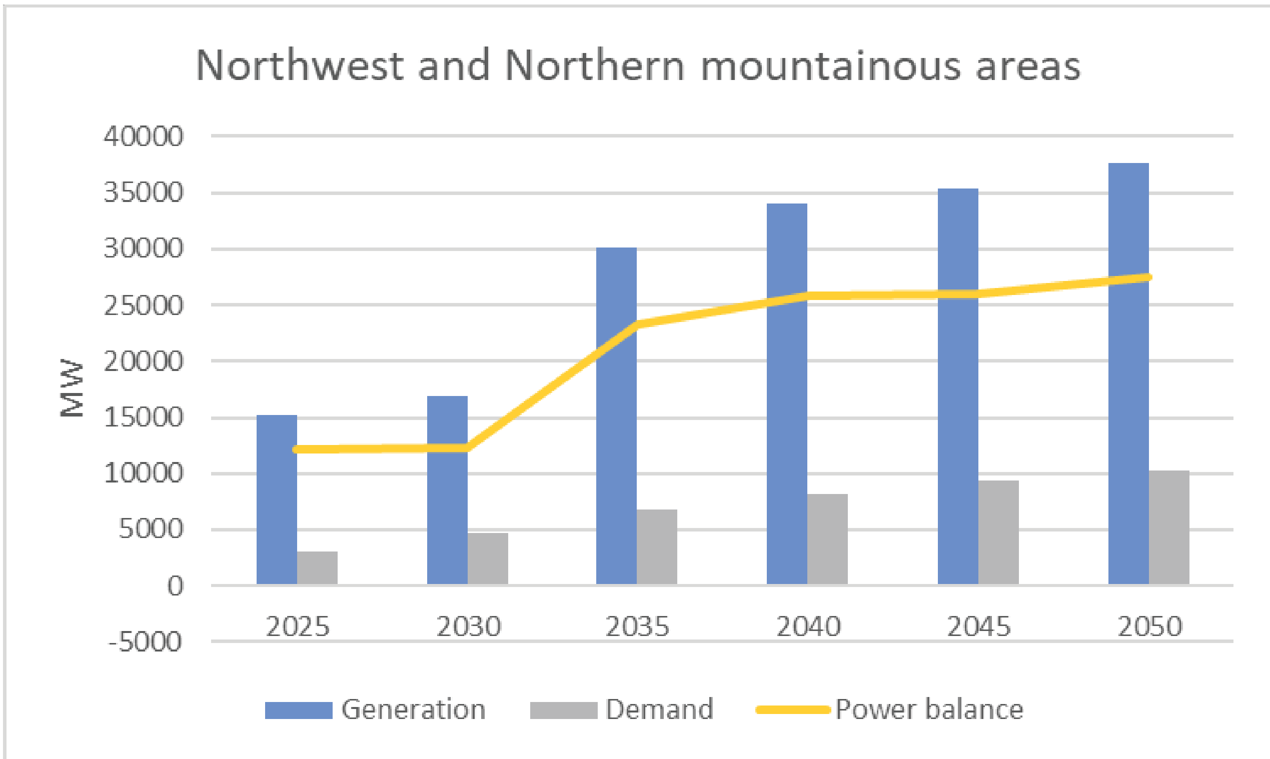
No	Subregion/Power generation	Onshore/near shore wind	Offshore wind	Solar	Biomass and MSW	Small hydro
	Period up to 2030	**6016**	**5000**	**11165**	**1920**	**5784**
1	Northwest and Northern mountainous	1229	0	1177	765	5192
2	Northeast	2517	3000	2730	344	89
3	Hanoi city and surrounding areas	0	0	2258	295	3
4	South Hanoi	70	2000	590	55	0
5	North Central	2200	0	4409	460	500
	Orientation to 2050	**15550**	**25000**	**73848**	**2743**	**9585**
1	Northwest and Northern mountainous	4602	0	14829	1107	8336
2	Northeast	4478	12000	11778	521	204
3	Hanoi city and surrounding areas	0	0	15560	413	15
4	South Hanoi	70	7000	8323	83	0
5	North Central	6400	6000	23358	618	1030

4.4. Sub-Regional Power Balance

4.4.1. Sub-Regional Power Balance – Scenario 2A

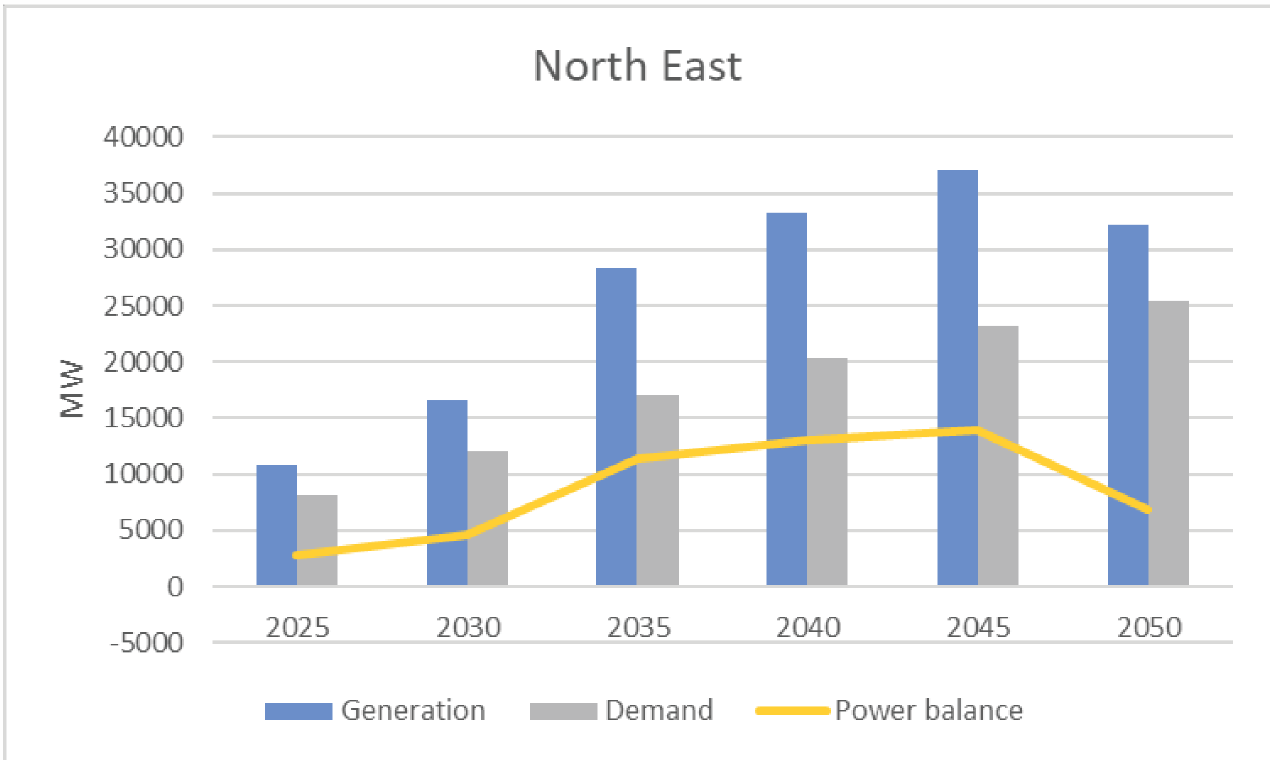
To determine transmission trends and the amount of excess or insufficient capacity that needs to be transmitted or received, the study balances the capacity of each sub-region. The power balance results are shown in the following charts.

Figure 4-3 Power balance in Northwest and Northern mountainous area – Scenario 2A



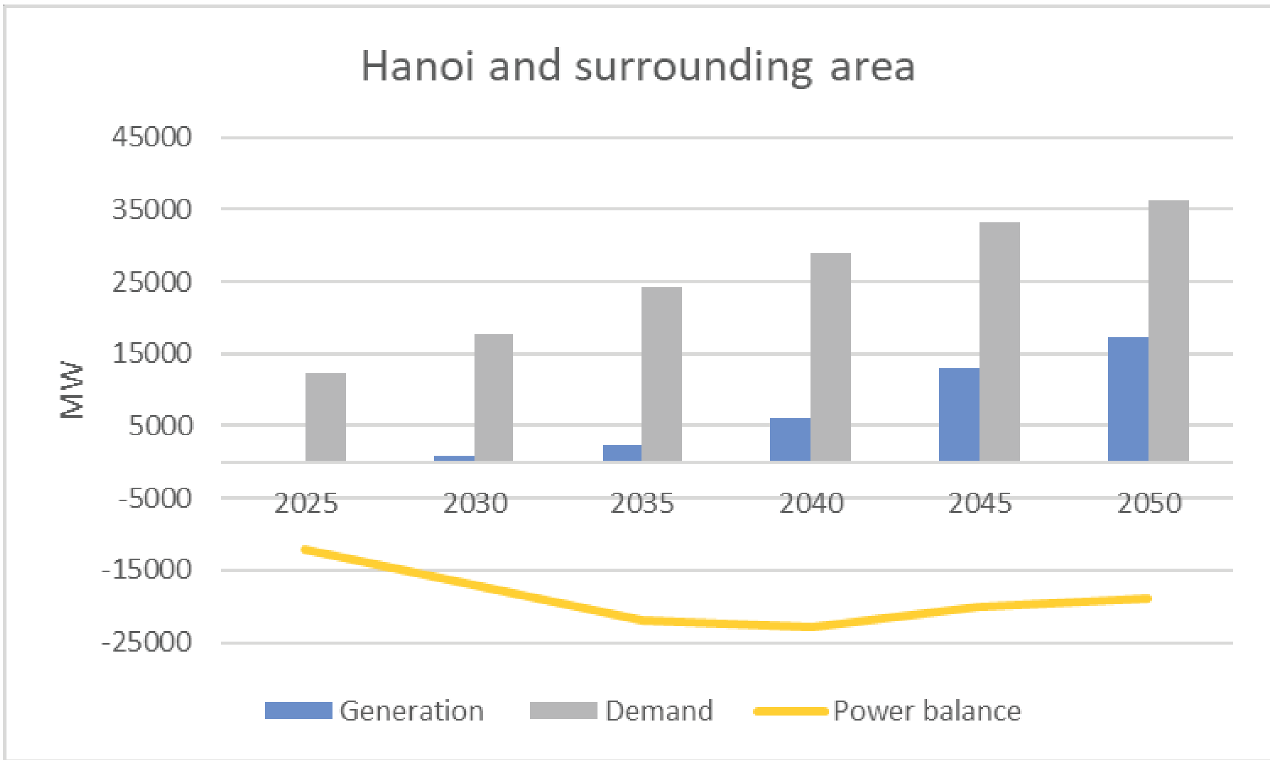
The Northwest and Northern mountainous provinces are one of the hydropower centers of the country, with many large hydropower sources such as Son La, Lai Chau, and Hoa Binh, and other small and medium hydropower sources. Some provinces with good wind potential such as Son La, Dien Bien, and Yen Bai or good solar power potential, such as Dien Bien should also be given priority for development. Meanwhile, the local load of the provinces in this subregion is not high. In the period to 2030, the sub-region will surplus about 12 GW of capacity transmitting to the Hanoi load center through the 500 kV power grid system. The sub-region's excess capacity will continue to increase to about 27 GW in the period to 2050.

Figure 4-4 Power balance in Northeast – Scenario 2A



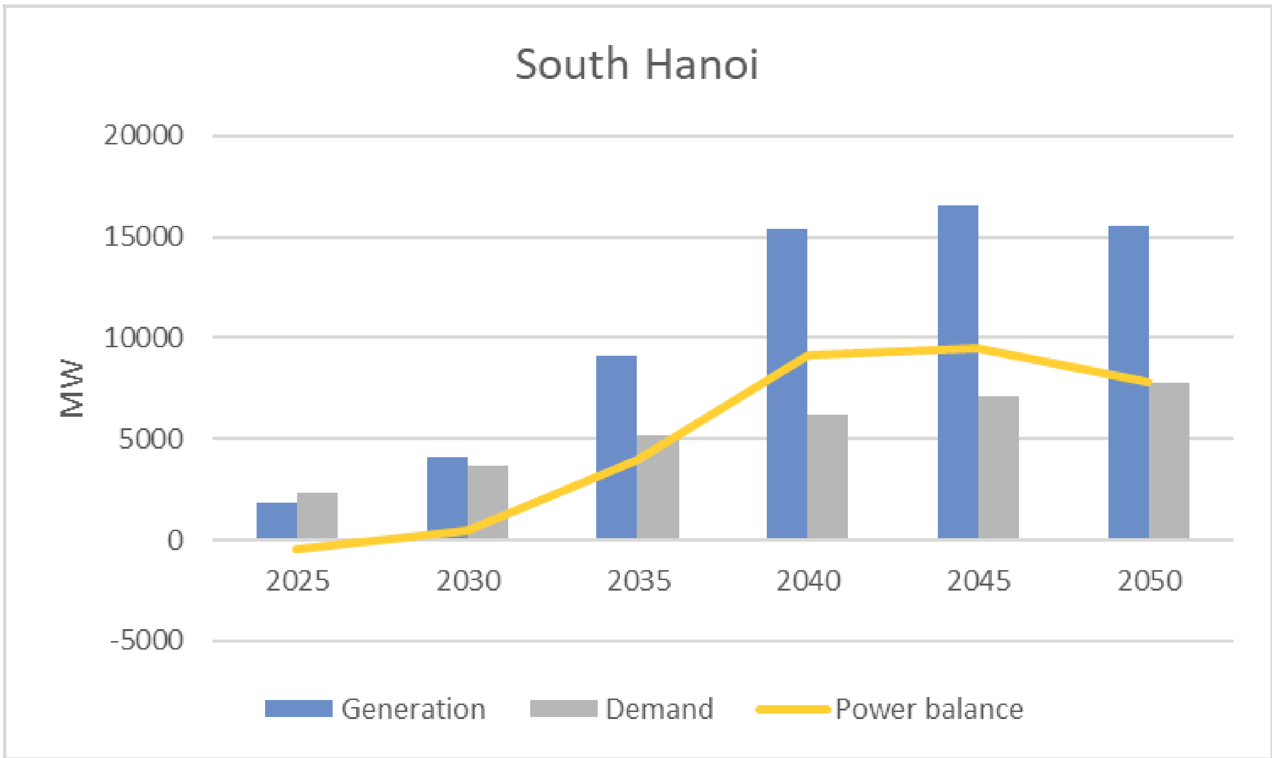
The Northeast region is home to many thermal power centers with large capacities, such as Hai Phong thermal power, Quang Ninh thermal power, Thang Long thermal power, and Hai Duong thermal power. Besides, the areas of Lang Son and Thai Nguyen, Bac Giang and Quang Ninh also have good potential for developing onshore wind power. With the development of many industrial parks, this area has relatively high load demand, being one of the major load centers in the North besides Hanoi City and surrounding areas. The capacity and power of regional power sources both meet local load needs and transmit power to other areas. The sub-region's excess capacity is estimated to reach about 4.5 GW in 2030 and increase to nearly 7 GW in 2050.

Figure 4-5 Power balance in Hanoi and surrounding area – Scenario 2A



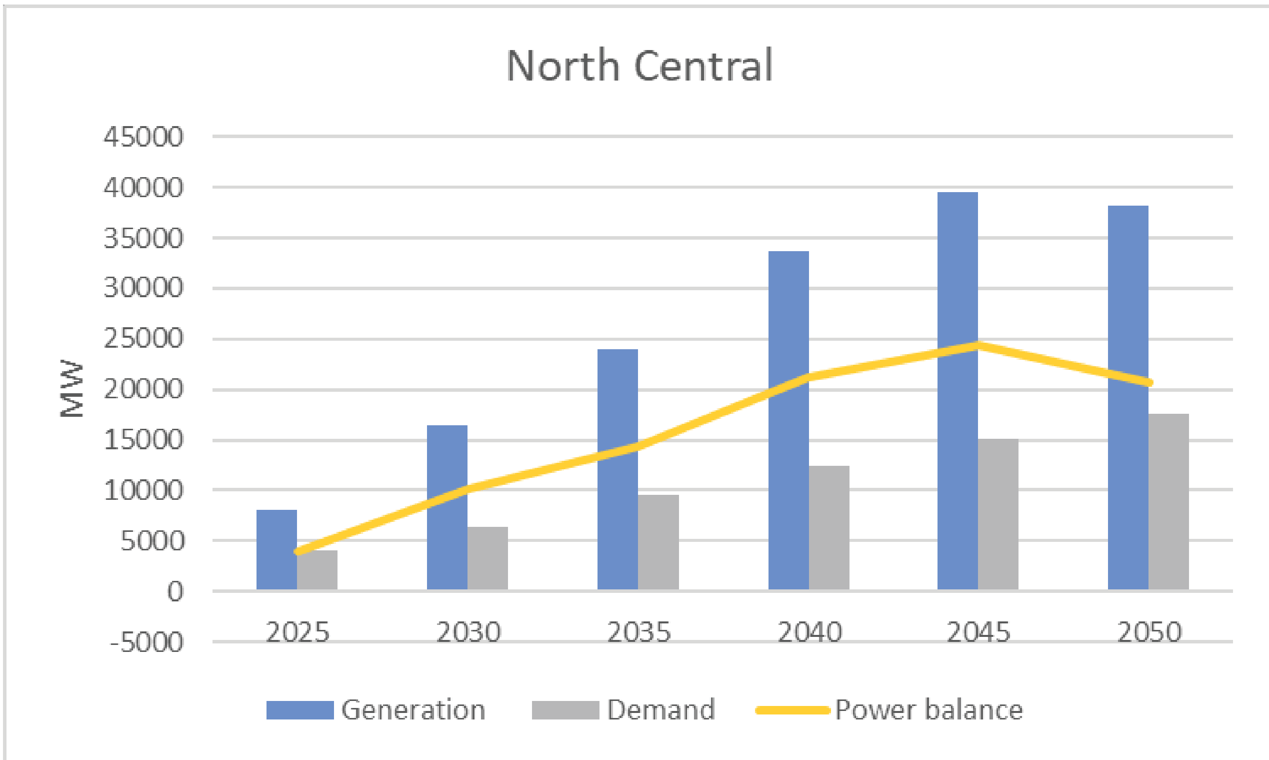
Hanoi City and surrounding areas are the economic - cultural - social center of the North with very high load density and scale. This sub-region also has very few local power sources, mainly receiving power from other areas through the transmission line system. Sub-Regional load depends heavily on power supply from the national power system through the 500 kV and 220 kV transmission line system. The sub-regional shortfall is about 17 GW in 2030 and increases to about 19 GW in 2050.

Figure 4-6 Power balance in South Hanoi – Scenario 2A



The South Hanoi area is a buffer zone between Hanoi's load center and the Northeast and North Central, so it plays an important role in connecting the Northern power grid. Regarding the source development scenario, in the period to 2030, the South Hanoi area is expected to develop more coal-fired power sources and LNG gas-fired power sources. However, major power sources are mainly concentrated in Thai Binh province (Thai Binh II and Thai Binh LNG). In 2030, the sub-region will have a surplus of about 400 MW. Oriented to 2050, the sub-region has a surplus of nearly 8 GW of power sources.

Figure 4-7 Power balance in North Central – Scenario 2A



The North Central is an important link between the Northern and Central power systems. This area has a lot of potential for developing hydropower, buying electricity from Laos, renewable energy sources, as well as developing large coal-fired and gas-fired power sources, thanks to the deep-water port system, convenient for receiving fuel. The sub-region is expected to have a surplus of about 10 GW by 2030 and about 21 GW by 2050. This amount of capacity will be transmitted to the Hanoi load center and surrounding areas, however, it should be noted that transmission limits on the North Central - North region are relatively limited and it is difficult to implement improvement measures.

From the picture of regional capacity balance, some comments can be drawn as follows:

- Load sub-region must receive electricity from other areas including Hanoi City and surrounding areas.

- Power source centers with a large amount of excess capacity requiring strengthening of power capacity evacuation lines include Northwest and Northern mountainous areas, and Northeast and North Central sub-regions.

- Some sub-region with power source structures with a high proportion of hydroelectric power such as the Northwest and Northern mountainous areas and North Central need to pay attention to the influence of seasonal factors that change the generating capacity of hydroelectric sources in the region. This can change the flow of capacity, putting pressure on the transmission system.

● Areas developing large thermal power centers such as the Northeast and North Central sub-region need to ensure the design of power grids to evacuate capacity according to N-1 criteria.

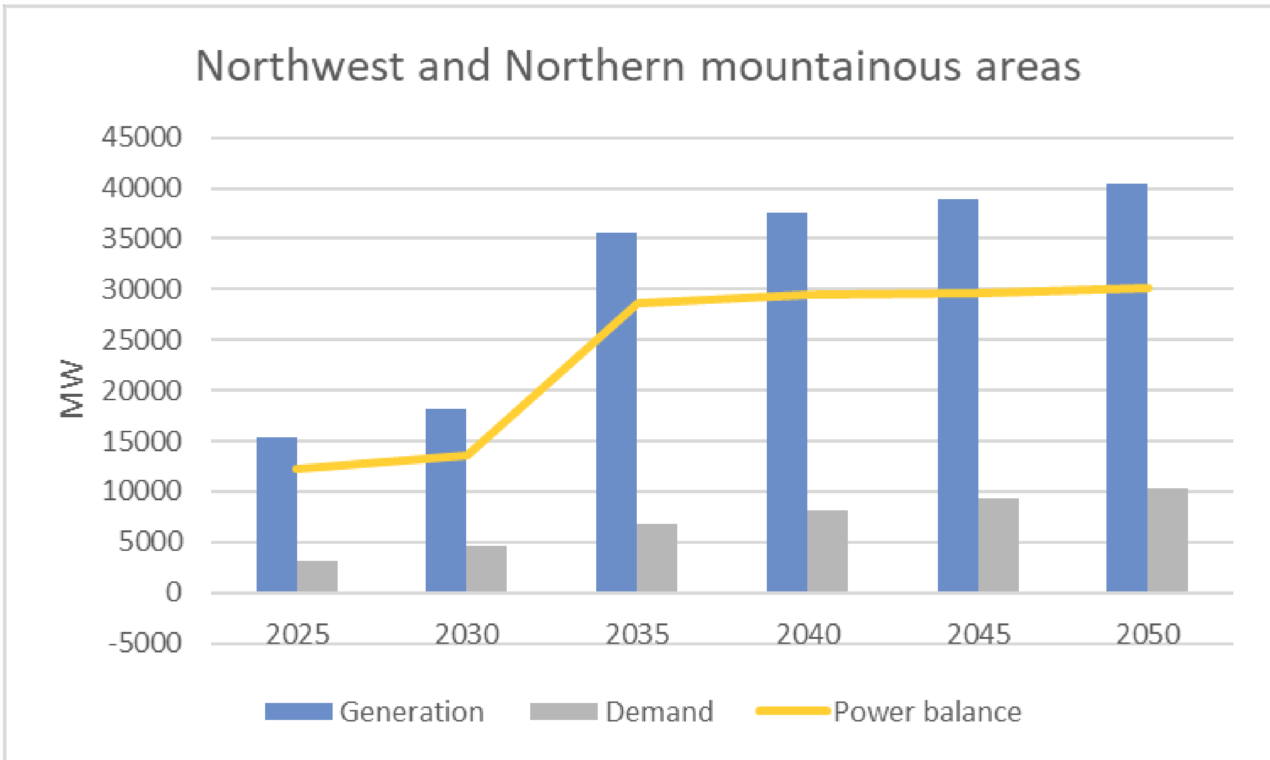
● The power grid to evacuate the capacity of wind and solar power sources in areas with potential to develop this type of source, such as the Northwest and Northern mountainous areas, North Central, etc. can be designed according to flexible N-1 criterion. For transmission lines of renewable energy power clusters, when one power circuit fails, the remaining circuits are only allowed to operate at 100% load, the excess renewable energy power capacity will be curtailed. If the amount of renewable energy capacity that must be curtailed is lower than the amount of rotating spare capacity of the power system, the system is considered to meet the flexible N-1 criterion. When viewed from the perspective of evacuation the capacity of the renewable energy source cluster, this power grid can only meet the N-0 criterion (ie, when there is no element failure, the power grid is guaranteed to transmit the full capacity of the renewable energy source).

● Areas that develop a large proportion of solar power need to pay attention to the fact that capacity trends and transmission trends will change greatly between daytime (solar power generating maximum capacity) and night time (solar does not generate).

4.4.2. Sub-Regional Power Balance – Scenario 2B

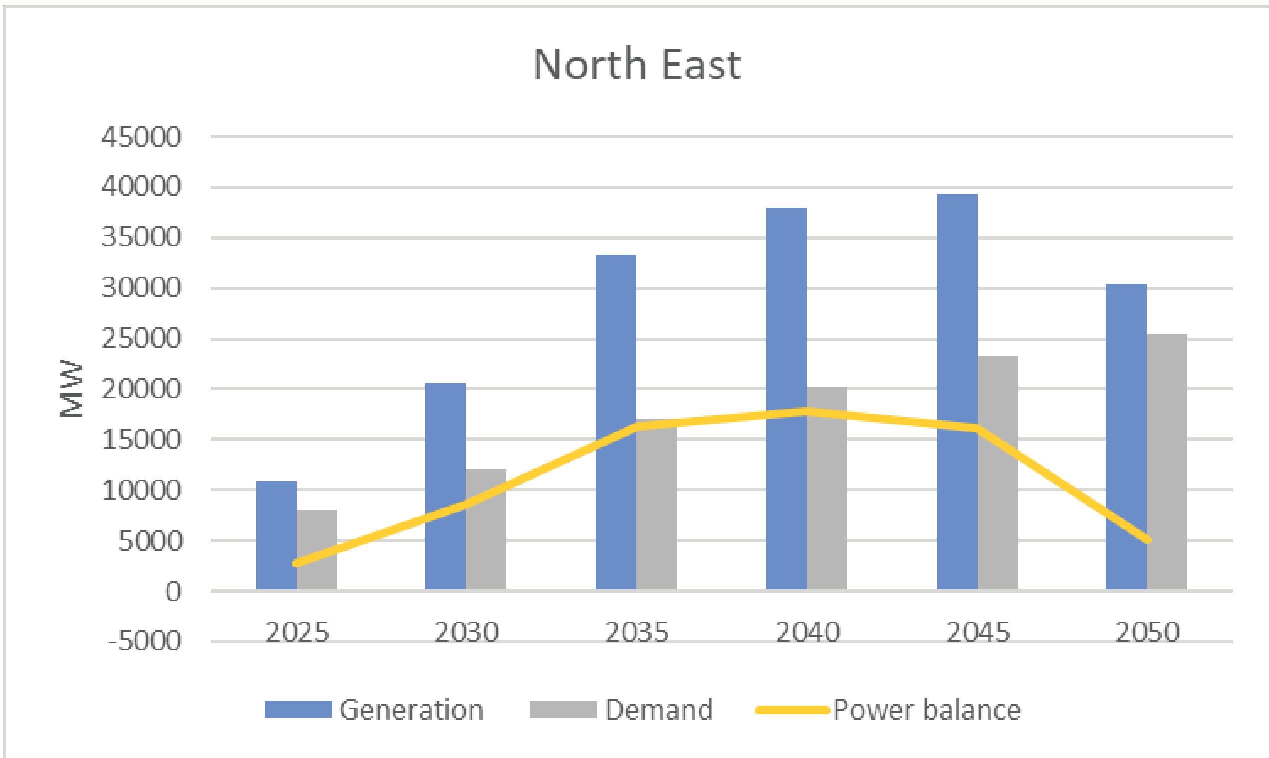
Similarly, the study calculates the supply-demand balance by sub-region in the case of low emissions according to the JETP target (Scenario 2B). Compared to Scenario 2A, Scenario 2B reduces the scale of LNG thermal power source capacity, instead increasing renewable energy sources such as solar power, wind power, offshore wind power, especially in the period to 2030. The power balance is shown in the following diagrams.

Figure 4-8 Power balance in Northwest and Northern mountainous area – Scenario 2B



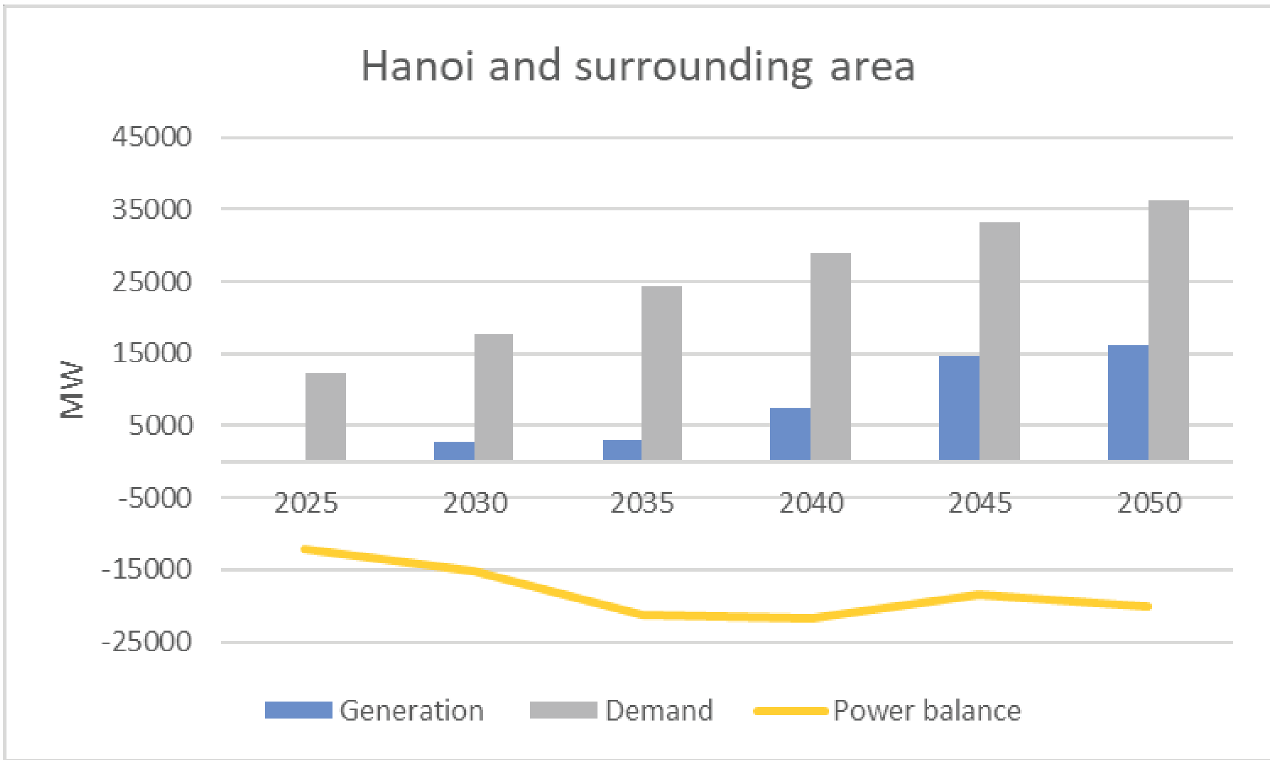
Due to the advantage of developing many small hydropower sources, wind power and solar power, but the load is relatively low, the Northwest sub-region has a large amount of excess capacity, reaching about 14 GW in the period to 2030 and 30GW period up to 2050. Because scenario 2B promotes the development of renewable energy sources more than scenario 2A, the amount of surplus capacity in potential sub-region such as the Northwest will also be larger, requiring careful research on capacity evacuation solutions. The Northwest subregion is connected to the Hanoi load center and its surroundings by a 500 kV line system, convenient for capacity exchange.

Figure 4-9 Power balance in North East – Scenario 2B



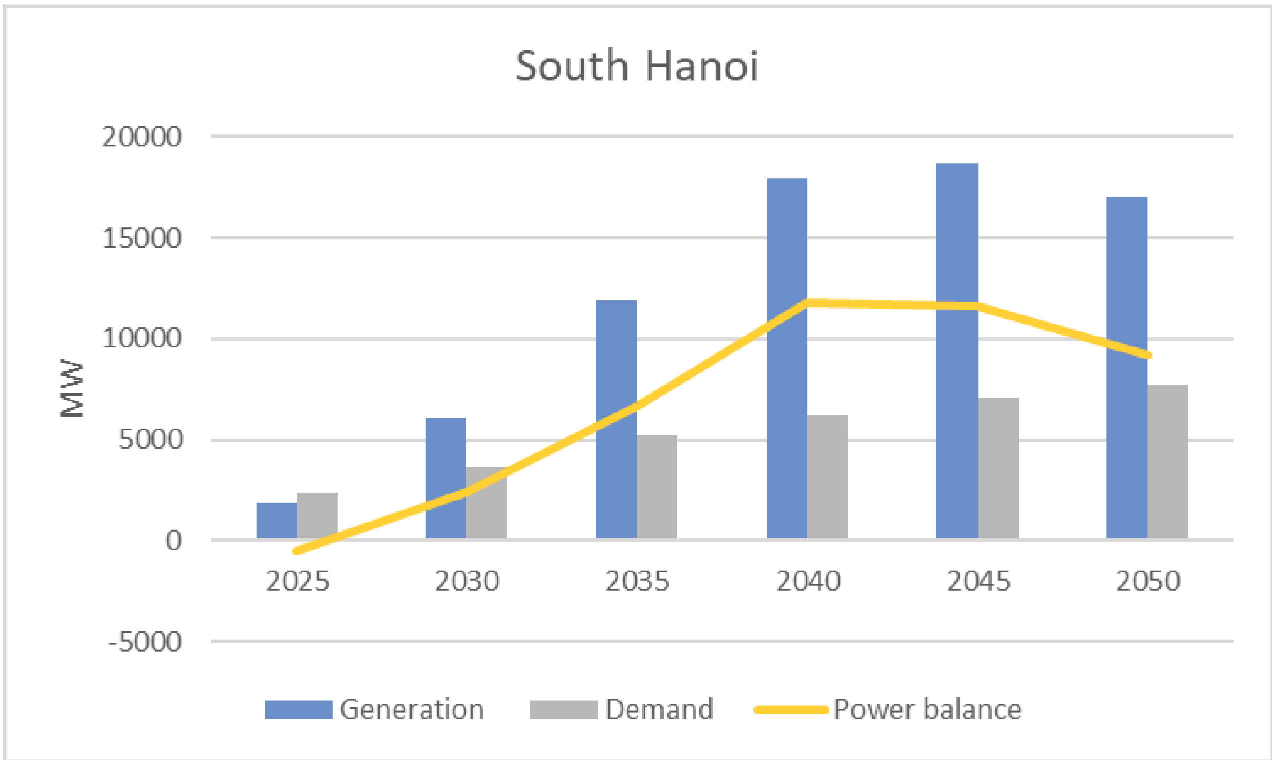
As for the Northeast sub-region, due to the current situation of many large coal-fired thermal power centers, this is also considered one of the major power source centers of the North. In the period to 2030, the region is expected to have a surplus of about 8.5 GW, gradually increasing in the period 2031-2045 and decreasing to a surplus of about 5 GW by 2050. Besides developing coal-fired power sources, the sub-region has potential for developing large-scale offshore wind power in Quang Ninh and Hai Phong.

Figure 4-10 Power balance in Hanoi and surrounding area – Scenario 2B



Similar to Scenario 2A, in Scenario 2B, Hanoi City and surrounding areas are the largest load centers in the North but do not develop many power sources. This subregion is close to receiving electricity from all other sub-regions, with a capacity shortage of about 15 GW in the period to 2030 and 20 GW in the period until 2050.

Figure 4-11 Power balance in South Hanoi – Scenario 2B



In the period up to 2025, the power source in the South of Hanoi area will basically meet local load, thanks to the appearance of Thai Binh 2 thermal power plant (2x600 MW), expected to be energized in 2023. In the period up to 2030, Due to the proposal to develop about 2 GW of offshore wind power in the area, the power capacity will be surplus compared to the regional load of about 2.4 GW. However, OWF sources with large capacity scales are often proposed to be connected to the 500 kV system power grid, so the sub-regional supply-demand balance in the period up to 2030 is relatively balanced. The sub-region's excess capacity will increase in the period 2031-2050 and will be around 9 GW in 2050.

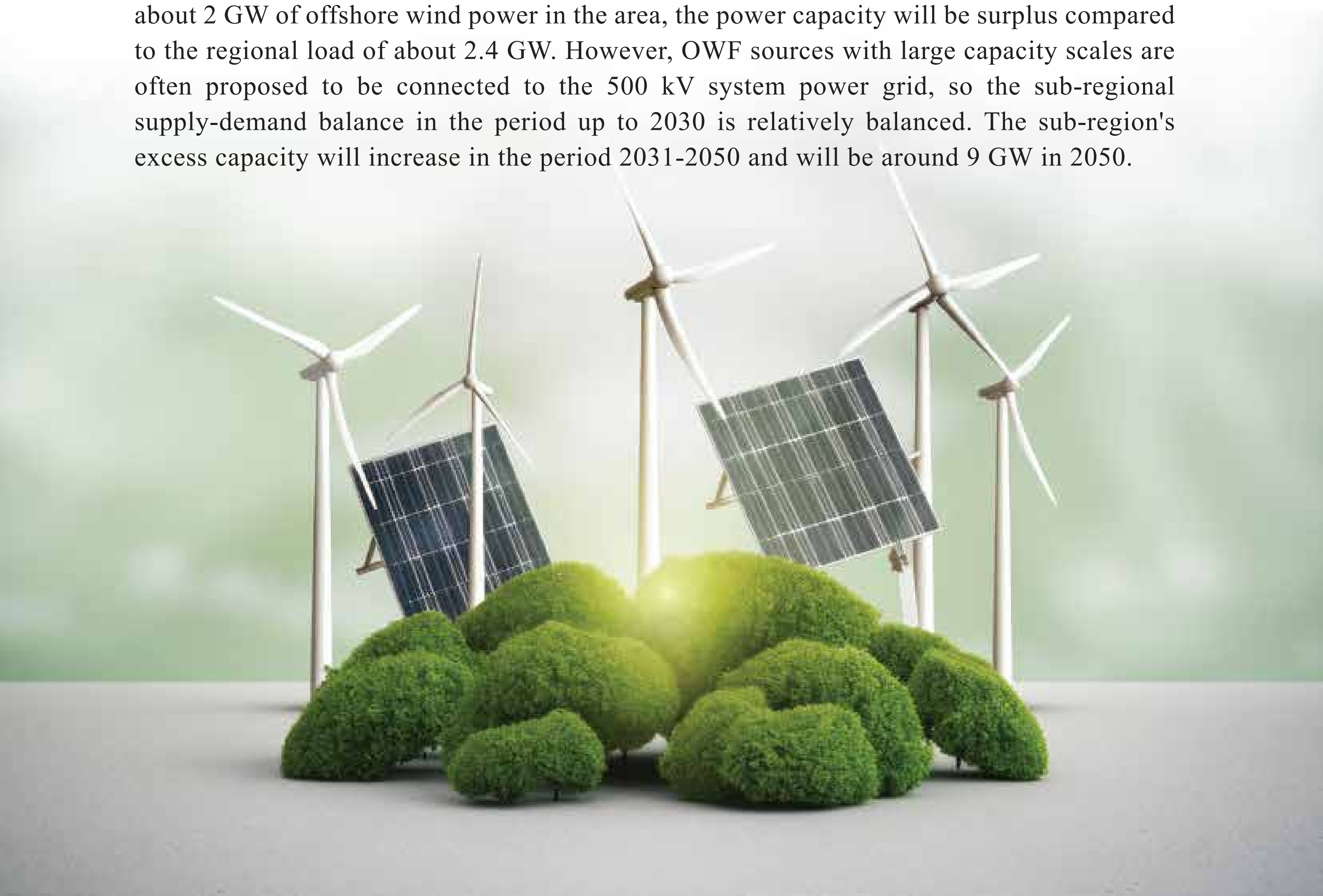
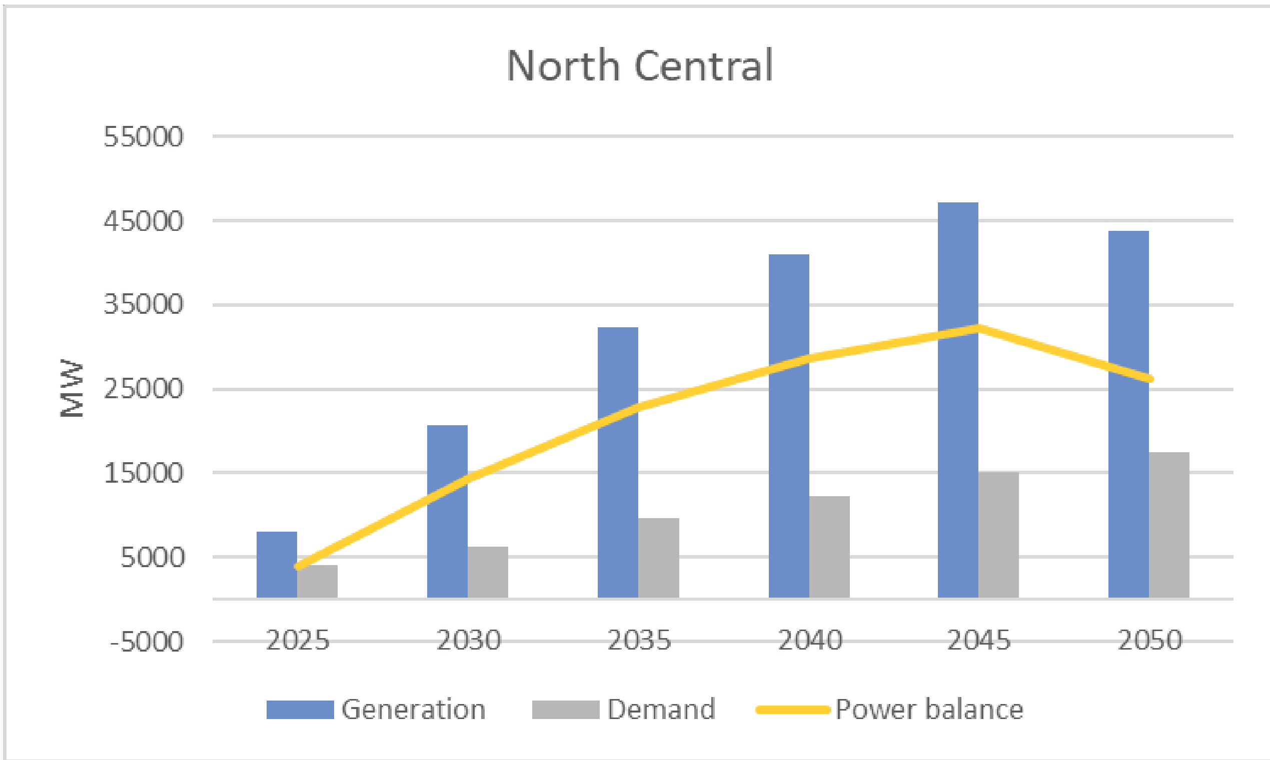


Figure 4-12 Power balance in North Central – Scenario 2B



In the period to 2030, the North Central sub-region is proposed to add a number of thermal power sources including: Vung Ang II thermal power plant, Quang Trach I thermal power plant. Compared to Scenario 2A, LNG sources are limited in development, no LNG Nghi Son, Quang Trach II. Instead, there will be solar power (including rooftop solar power) with a scale of about 4.4 GW by 2030. The sub-region's surplus power capacity is expected to be about 14 GW by 2030 and increase to 26 GW by 2050.

Therefore, compared to Scenario 2A, renewable energy sources are more developed in Scenario 2B, leading to areas with high potential for developing renewable energy, such as the Northwest and Northern mountainous areas and the North Central and Northeast sub-regions, which will increase the amount of excess capacity.

4.5. Proposing Plan to Develop the Northern Power Transmission Grid according to the Selected Energy Transition Scenario

4.5.1. Scenario 2A

4.5.1.1. Plan to Develop Inter-Area Power Transmission Grid

Inter-area transmission power output compared between the power source development scenario according to PDP VIII and the scenario proposed in chapter 3 is as follows:

Table 4-7 Compare inter-area transmission power output between Scenario 2A and Scenario 0A

Interface/Year	2025	2030	2035	2040	2045	2050
Scenario PDP VIII (Scenario 0A)						
Central => North	1.4	11.2	24.4	46.4	55.3	49.6
North => Central	8.7	0.7	0.1	0	0	0
Central => South	22.7	32.3	21.4	0.9	0.4	1
South => Central	0.6	3.9	8.5	4	3.6	0.9
South => North	0	0	11.5	54.2	87.7	103.7
Proposed Scenario (Scenario 2A)						
Central => North	1.8	22.2	23.4	39.2	51.2	50
North => Central	2.6	0	0.2	0	0	0
Central => South	16.6	25.5	22.3	2.8	0.5	1.1
South => Central	0.7	4.1	7.7	1.9	1.8	1
South => North	0	0	10.7	40.9	72.9	103
Difference between Scenario 2A and 0A						
Central => North	0.4	11	-1	-7.2	-4.1	0.4
North => Central	-6.1	-0.7	0.1	0	0	0
Central => South	-6.1	-6.8	0.9	1.9	0.1	0.1
South => Central	0.1	0.2	-0.8	-2.1	-1.8	0.1
South => North	0	0	-0.8	-13.3	-14.8	-0.7

❖ Period Up To 2030

In the period up to 2030, electricity tends to be transmitted from the Central region to the North in the context that thermal power sources in the North continue to lag behind schedule and reserve capacity declines. Accordingly, transmission on the North - Central interface and North Central - North interface will continue to increase. Transmission capacity in the direction from the North - Central region will appear less, mainly during the off-peak flood season, to release the capacity of hydro power and small hydropower sources.

The emergence of renewable energy sources in the Central and Southern regions, as well as the rapid growth of load in the North in the period 2019-2021 has led to a change in inter-area transmission trends. The transmission direction from the Central region to the North becomes the main transmission trend, replacing the North-Central transmission direction. The peak heat wave in 2021-2022 was recorded many times when the North-Central transmission line operated with a capacity of 1800-2000 MW, close to the transmission limit.

In the period to 2030, the North will add about 10,000 MW of power source. Notable sources are Thai Binh 2, An Khanh - Bac Giang, Quang Trach I (1403 MW), Vung Ang 2, Hoa Binh extend, and Yen Son thermal power sources. Meanwhile, the load in the North is expected to grow about 11,000 MW. Capacity reserves in the North decreased from about 35% to 20%, if considering renewable energy sources, and 32% to 18%, if not considering renewable energy sources. Thus, in the period 2023-2030, the North-Central power transmission grid will operate increasingly stressed to ensure electricity supply to the North.

During this period, Central => North is the main transmission trend on the interface. Central-North transmission power in 2030 in scenario 2A could increase to over 22 billion kWh. According to PDP VIII, by 2030, the Central-North interregional interface is expected to have 4 500 kV line circuits with a load capacity of about 4,500 MW. With the transmission power output calculated according to scenario 2A, it is found that there is no need to build new lines compared to PDP VIII. However, it should be noted that this is a high transmission level and needs to be taken into account during operation.

❖ Orientation to 2050

According to PDP VIII, in addition to the AC power transmission system expected to be built by 2030 inherited from PDP VII, in the period after 2030, consider building an ultra-high voltage DC power transmission system as follows:

- Consider building a new HVDC line from the Center Central region to the North (between the Central and Northern regions), with a capacity of 10,000 MW and a length of more than 1,000 km.

- Consider building a new HVDC line in the South Central - North region (between South and North regions), capacity of 10,000 MW, length of more than 1,500 km.

- Consider building the second of a new HVDC line in the South Central - North region (between South and North regions), capacity of 10,000 MW, length of more than 1,500 km.

In general, power transmission on inter-area links does not change much between the two scenarios. Transmission output will only change mainly between 2040-2045 at the South-North interface. In particular, the South-North transmission output (one-way transmission system) will decrease by about 13 billion kWh - 15 billion kWh in the period 2040-2045 compared to PDP VIII. However, this level of reduction is not enough to reduce the volume of inter-area line construction compared to PDP 8 because it is estimated that the South - North interface will still have to transmit about 8.5 GW in 2040 and 15 GW in 2050, respectively (assuming transmission Tmax is 5000 h/year). By 2050, the inter-area power transmission output between the two scenarios in 2050 is nearly equivalent. Therefore, the volume of construction of the inter-area power transmission grid in the proposed source scenario does not change compared to PDP VIII.

4.5.1.2. Plan to Develop Inter-Regional Power Transmission Grid

❖ Period to 2030

In the period up to 2030, the North Central - Northern interface is the "bottleneck" on the inter-regional power transmission grid. According to PDP VIII, it is expected that in the period to 2025, the 500 kV North Central - North transmission interface will still only include two 500 kV circuits Ha Tinh - Nghi Son - Nho Quan with a transmission limit of about 2400 MW. It is expected that in 2026-2027, the interface will be added with two additional 500 kV circuits in Quang Trach - Quynh Luu - Thanh Hoa - Nam Dinh, increasing the transmission limit on this interface to about 5400 MW. In the period to 2030, the North Central - Northern interface will be supplemented with 2 more 500 kV line LNG Nghi Son - Hung Yen circuits and the old circuit 1.2 will be renovated, increasing the transmission limit on this inter-regional interface to about 10 GW.

The results of calculating transmission output on the North Central - Northern interface in Scenario 2A are not much different from Scenario 0A. Accordingly, the power transmission output in 2030 will reach about 35 billion kWh, still ensuring transmission with the planned power grid configuration according to PDP VIII.

❖ Orientation to 2050

Power transmission output on the North Central - North interface will peak in 2035 (about 39 billion kWh). However, this transmission output is still lower than the 0A Scenario (about 49 billion kWh). Therefore, for the new proposed power source development program, there is no need to implement measures to build/renovate the inter-regional interface between the North Central and North regions compared to PDP VIII.

4.5.1.3. The Transmission Grid Evacuation Power Sources in the Northwest and Northern mountainous Area

a. Period Up To 2030

❖ Hydropower Evacuation:

The Northwest and Northern mountainous areas have many hydroelectric sources, while the local load is not high. The surplus power capacity of the Northwest region (~8000 MW) is transmitted to the load center of Hanoi and the Red River Delta. In particular, the Hoa Binh Hydropower Plant and small hydropower plants (~2000 MW) are being transmitted through 1 500 kV circuit, 9 220 kV circuits. About 6,000 MW of hydroelectric power in the remaining provinces (Lao Cai, Lai Chau, Yen Bai, Dien Bien, and Son La) is transmitted through 5 of 500 kV circuits and 3 of 220 kV circuits, with times when full load occurs during the flood season. Northern mountainous provinces have their power capacity evacuated through the 220 kV power grid to Yen Bai and Thai Nguyen.

In the coming period, the above area will continue to develop more hydroelectric sources and can increase electricity imports from China in the direction of Lao Cai and Ha Giang. This leads to the need to renovate and upgrade the power transmission grid. To ensure the release of capacity from power sources, on December 17, 2019, the Prime Minister issued Decision No. 1698/TTg-CN on adjusting and supplementing the planning of power grid projects to evacuate the hydropower capacity of the Northwest subregion and neighboring regions. These projects are also included in the list of power grids that need investment and construction in the period up to 2030 of PDP VIII. Some notable projects expected to operate in 2023-2025 are as follows:

Table 4-8 New construction and renovation of 500 - 220 kV substations and transmission lines to evacuate of Northwest hydropower capacity in the period up to 2025 (approved by PDP VII and PDP VIII)

No	Transmission Work	Voltage (kV)	Type			Ref
A	**500 - 220 kV Substation**		**Transformer**	**x**	**MVA**	
1	Upgrade Lai Chau	500	2	x	900	Document 1689
2	Lao Cai	500	2	x	900	Document 1689
3	Pac Ma	220	2	x	250	Document 1689
4	Bat Xat	220	2	x	250	Document 1689
5	Nghia Lo	220	1	x	250	Document 1689
6	Phong Tho	220	2	x	250	Document 1689
B	**500 - 220 kV Line**		**Circuit**	**x**	**km**	
1	Lao Cai – Vinh Yen	500	2	x	223	Document 1689
2	Lao Cai – Bao Thang	220	2	x	18	Document 1689
3	Pac Ma – Muong Te	220	2	x	36	Document 1689
4	Bat Xat – Bao Thang/ 500kV Lao Cai	220	2	x	40	Document 1689
5	Than Uyen – 500 kV Lao Cai	220	2	x	70	Document 1689
6	Phong Tho – Than Uyen	220	2	x	65	Document 1689

In the period 2026-2030, hydroelectric power potential is expected to continue being exploited in the Northwest region and northern mountainous provinces. To evacuate the power source, Decision No. 500/QD-TTg approves the renovation and construction of a number of power transmission grid projects as follows:

- Construction of 220 kV Bac Ha and Van Ban substations and connection lines to collect small hydropower capacity and reduce load on the 110 kV power grid.

- Increasing the capacity of Bac Quang 220kV substation to evacuate small hydropower capacity.

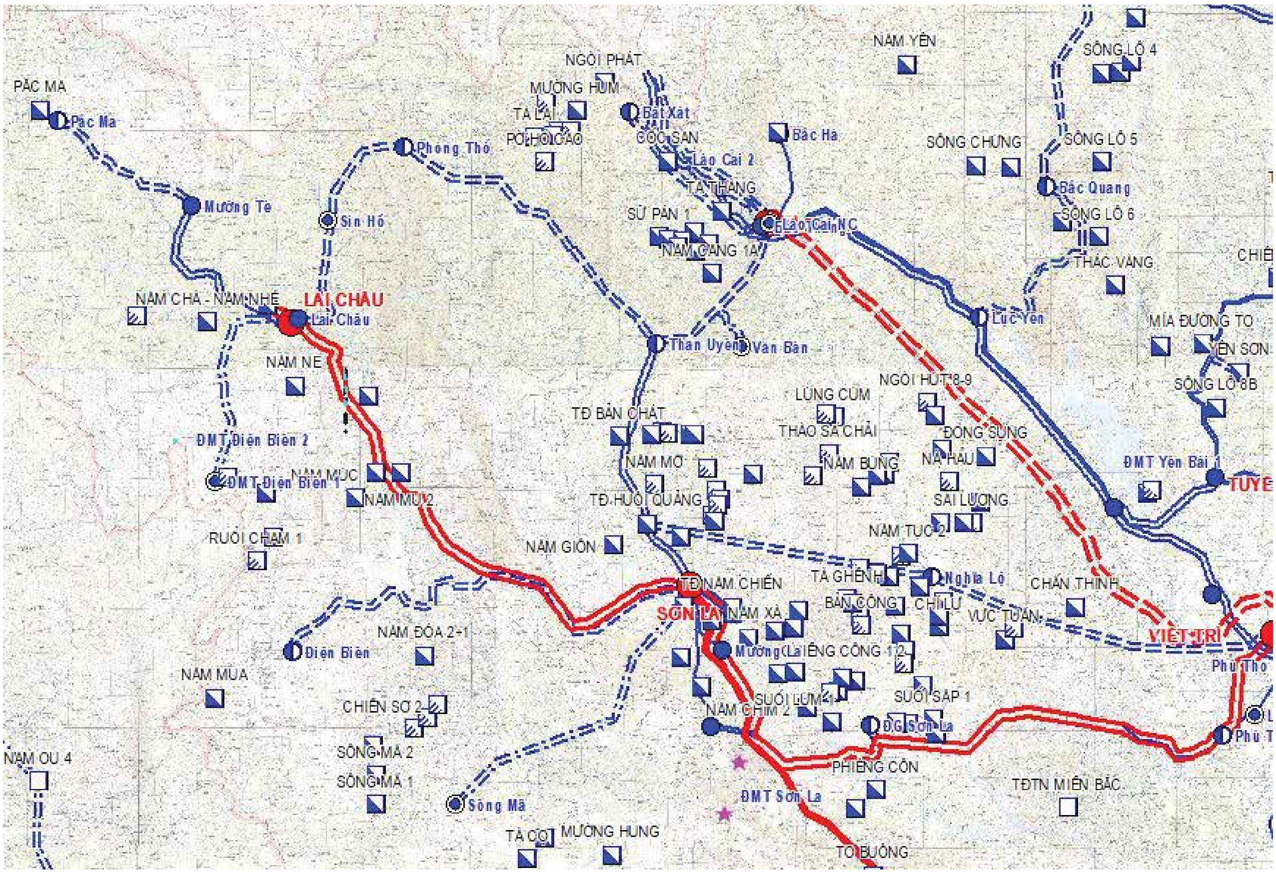
- Construction of 220kV Song Ma substation and 220kV Song Ma - Son La 500kV transmission line, combining the capacity of Son La province's power plant.

● Construction of Sin Ho 220kV substation with transition connection on 2 220kV Phong Tho - Than Uyen circuits to evacuate hydroelectric power.

● Construction of the 220kV Muong Te - Sin Ho transmission line to improve the ability to evacuate the power generation capacity in Muong Te district, Lai Chau province, ensuring N-1.

● Increase capacity of 220kV Pac Ma and Phong Tho substations, reserve for development of small hydropower sources, ensure N-1.
Develop 220 kV grid in Son La and Dien Bien areas to exploit renewable energy sources.

Figure 4-13 Transmission work to evacuate hydropower capacity in the Northwest



Currently, EVN is planning to deploy a number of expanded hydropower projects to increase the flexibility of power system operations and improve the ability to integrate renewable energy sources. The Northwest and Northern mountainous regions propose to develop the projects of Tuyen Quang extend Hydropower Plant (120 MW) and Thai An extend Hydropower Plant (60 MW) in the period up to 2030. These projects are in the list of potential hydroelectric power sources in PDP VIII (Appendix III).

In addition, Bac Yen district of Son La province has the potential to develop small hydropower and wind power. Among them, the Suoi Sap 2A power plant cluster has been approved by the Prime Minister according to Document No. 136/TTg-CN dated January 29, 2021. Suoi Sap 2A 220 kV substation connects transit on Son La - Viet Tri 220 kV line. This line was completely converted into a thermal conductor in March 2023, increasing the release of planned power sources.

❖ Import from China:

In addition to the task of hydropower transmission, the above projects are also the basis for increasing electricity purchases from China. Currently, the ability to buy more electricity from China is limited by the transmission capacity of existing 220 kV lines from Lao Cai 220 kV substation and Ha Giang 220 kV substation. However, the appearance of the above-mentioned Northwest small hydroelectric power transmission projects will enhance transmission capacity to the Northern load center, thereby opening up the possibility of increasing electricity purchases from China, applying to cope with the scenario of power shortage in the near future. Currently, EVN has assigned EVNNPT to research and invest in 220 kV lines according to increased electricity purchases from China, including:

- Hang on the second circuit of Malungtang - Ha Giang 220 kV line (30 km, ACSR - 2x330).

- New construction of Bac Quang - China line (2x83 km, ACSR - 2x500).

- Construction of 220 kV Lao Cai 500 kV transmission line - China (2x40 km, ACSR - 2x330).

- Construction 2 of 220 kV Back - to - Back stations at the border of Lao Cai and Ha Giang, purchase about 1000 MW of capacity from these directions.

This option has the advantage of fast implementation progress, meeting capacity and electricity needs. However, before energizing the 220 kV Back-To-Back station, purchasing AC power with large capacity and seasonal demand changes is both difficult in contractual agreements with the Chinese side. It can easily cause problems such as complexities in operation. Since the two power grids are not synchronised, it is necessary to separate the grid according to seasons and load changes. Furthermore, the additional 2000 MW purchased from China has the potential to overload the 220 kV power grid in N-1 fault modes. Additional power transmission grid projects are needed to ensure the release of China's electricity purchasing capacity. Some projects approved in PDP VIII are as follows:

● Renovating and increasing the load capacity of the 220 kV Ha Giang - Bac Me transmission line and the 220 kV Ha Giang - Thai Nguyen transmission line.

● Renovating and increasing the load capacity of the 220 kV transmission line Thai Nguyen - Luu Xa - Phu Binh.

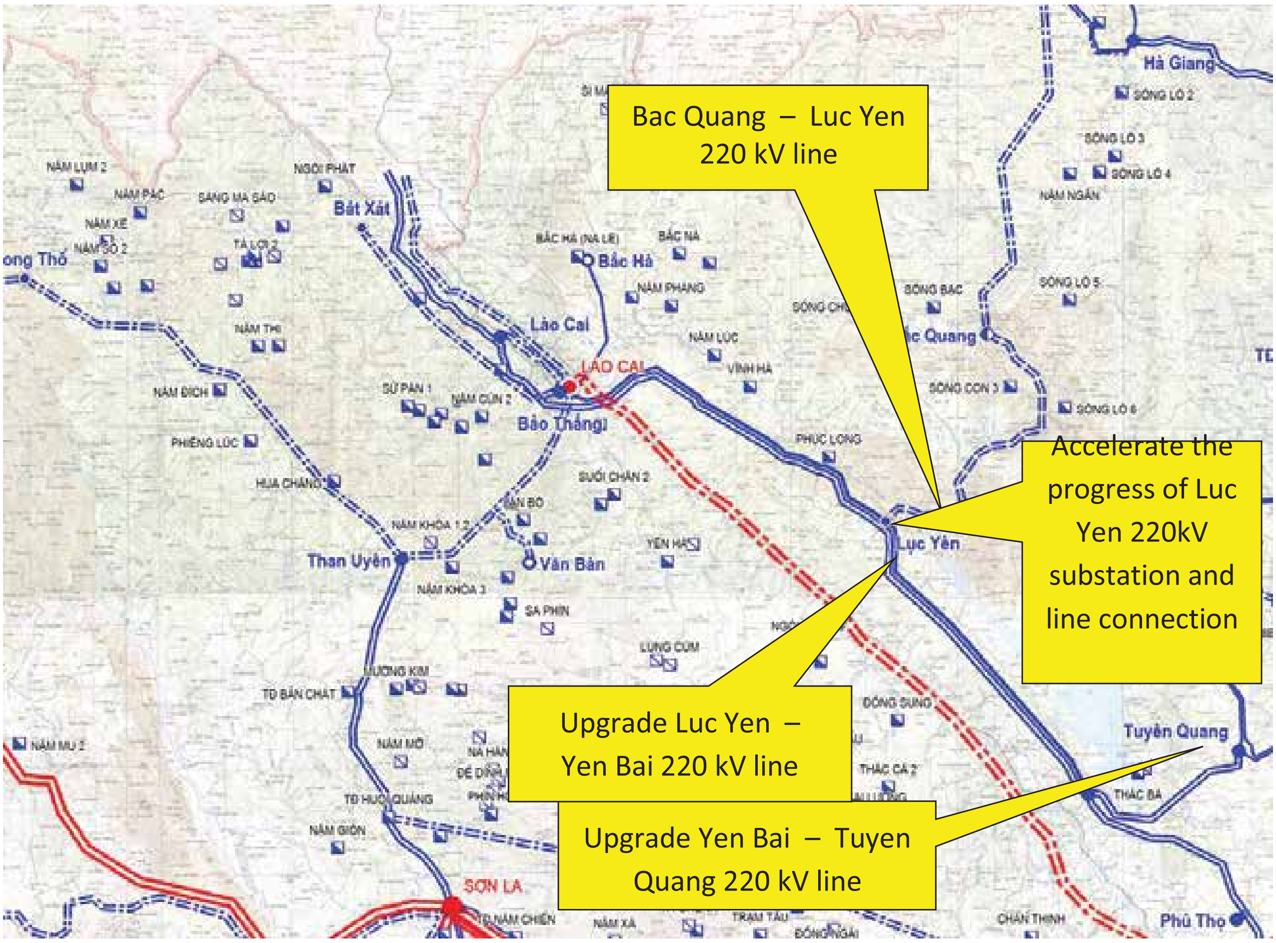
● Renovating and increasing the load capacity of 220 kV transmission line Yen Bai - Tuyen Quang.

● Renovating and increasing the load capacity of 220 kV transmission line Luc Yen - Yen Bai transmission line.

● Renovating and increasing the load capacity of 220 kV transmission line Yen Bai – Viet Tri.

● Upgrading the Lao Cai 500 kV substation to 3x900 MVA.

Figure 4-14 Proposed projects to evacuate Chinese electricity purchasing capacity



b. Orientation to 2050

In the period 2031 - 2050, the sub-region will continue to develop renewable energy sources, especially onshore wind power sources, solar power, and small hydropower.

To enhance the ability to evacuate the capacity of solar power sources and renewable energy sources in the Northwest region and ensure N-1 operating conditions, it is necessary to consider building an additional 500 kV Than Uyen substation and associated 500 kV lines, such as Lai Chau - Dien Bien, Than Uyen - Lao Cai and Lai Chau - Than Uyen. When these projects are put into operation, they will help reduce the load on the 220 kV power grid, and at the same time create a 500 kV loop circuit to ensure operation in the event of an N-1 incident on dual circuit 500 kV lines, such as Lai Chau - Son La, Lao Cai - Vinh Yen, Son La - Northern PSPP.

To evacuate the capacity of onshore wind power sources and regional solar power, it is necessary to build 500 kV and 220 kV substations to gather capacity. Provinces/cities with large-scale renewable energy capacity development that need to consider building 500 kV substations to evacuate capacity include Son La, Lai Chau, Dien Bien, Bac Kan, and Hoa Binh. Compared to PDP VIII (Scenario 0A), because renewable energy sources in Scenario 2A will develop earlier in the period up to 2035 and 2040, it is necessary to speed up the operation progress of gathering substation and connection lines, synchronized with the pace of regional renewable energy development.

4.5.1.4. The Transmission Grid Evacuate Power Sources in Northeast

a. Period Up To 2030

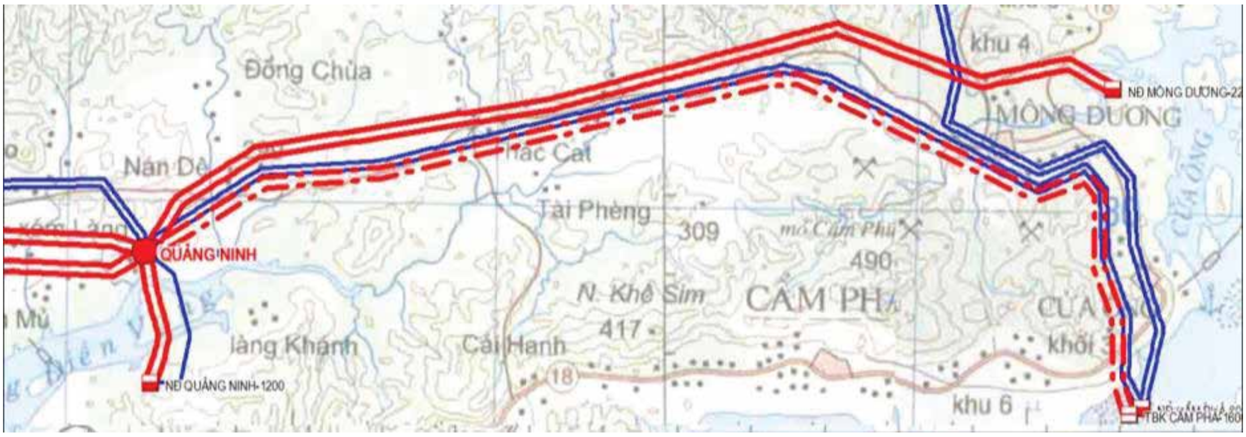
❖ An Khanh - Bac Giang Coal-Fired Thermal Power Plant (650 MW):

An Khanh - Bac Giang thermal power plant has an initial capacity of 50 MW, adjusted to increase the capacity to 650 MW according to document No. 1777/TTg-KN dated October 11, 2016 of the Prime Minister. According to PDP VIII, the plant is expected to be transitionally connected on two 220 kV circuits in Bac Giang - Lang Son. In addition, the project of circuit 2 of the 220kV power transmission line in Pha Lai - Bac Giang also needs to ensure progress to evacuate the regional power source.

❖ LNG Quang Ninh (1500 MW):

According to PDP VIII, in the period up to 2030, the Northeast region will further develop the Quang Ninh LNG Power Plant (1,500 MW), expected to be connected through the 500 kV double-circuit transmission line LNG Quang Ninh - Quang Ninh.

Figure 4-15 Connection alternative of LNG Quang Ninh



❖ Onshore Wind Evacuation:

The Northeast region has good potential for developing onshore wind power in the provinces of Quang Ninh, Lang Son, Bac Giang, and Thai Nguyen. In particular, Lang Son province is assessed to have good wind speed, with the expectation of developing many onshore wind power projects in the period up to 2030. To evacuate the capacity of onshore wind power sources in Lang Son and Bac Giang provinces, it is necessary to build a Lang Son 500 kV substation with transitional connection on two circuits of OWF 2 - Thai Nguyen 500 kV line.

❖ Offshore Wind Evacuation:

The Northern region will have about 3,000 MW of electricity generation in the period up to 2030. Areas with great development potential include Quang Ninh, Hai Phong, Thai Binh, and Nam Dinh. In case of developing OWF in Hai Phong - Quang Ninh waters, it is necessary to build 220 kV onshore substations to collect OWF capacity and connect to Hai Ha, Do Son 220 kV substations and Hai Phong, Thai Nguyen 500 kV substations.

b. Orientation to 2050

❖ Onshore Wind Evacuation:

In the period after 2030, the Northeast sub-region will continue to develop more capacity of onshore wind power sources, especially in Quang Ninh and Lang Son provinces. For Lang Son province, in addition to increasing the capacity of Lang Son 500 kV substation according to the scale of regional wind power development, it is necessary to build about 2-3 additional 220 kV substations in convenient locations to collect wind power source capacity. For Quang Ninh province, due to the limited capacity of the regional 220 kV power grid, it is necessary to take advantage of the Hai Ha 500 kV substation to evacuate wind power capacity and upgrade this substation in sync with the local development.

❖ Offshore Wind Evacuation:

According to Scenario 2A's power source development program, it is expected to develop about 19 GW of OWF sources in the North by 2050. Of which, areas with good offshore wind power potential are considered for development in the North East, including Quang Ninh and Hai Phong. In each province/city, it is necessary to consider placing 1-2 of 500 kV onshore substations to collect offshore wind power capacity and connect to the National power system. Part of the capacity of OWF in the North will directly supply electricity to the load, reducing the load for the regional 500 kV substation.

4.5.1.5. The Transmission Grid Evacuating Power Sources in Hanoi City and Surrounding Area

Hanoi City and surrounding areas do not have the potential to develop power sources (except for rooftop solar power), so there is no need to add transmission grid connection projects to evacuate power source capacity. Rooftop solar power sources are distributed and scattered, which will contribute to reducing the burden of transmitting power to this load center area. Regarding the transmission grid supplying power to the load, new construction and renovation projects will be inherited according to PDP VIII, which are not presented here as they are not the focus of this study.

4.5.1.6. The Transmission Grid Evacuation Power Sources in South Hanoi

a. Period Up To 2030

In the period to 2030, the sub-region is expected to have the Thai Binh LNG Power Plant, develop offshore wind power, and increase electricity imports from Laos. The connection alternative for these power sources are as follows:

❖ LNG Thai Binh (1500 MW):

The Thai Binh LNG connection plan approved in PDP VIII is as follows:

- Construction of a 220 kV double circuit line LNG Thai Binh - Truc Ninh.
- Construction of a 220 kV double-circuit line LNG Thai Binh - Tien Lang.

❖ Offshore Wind Evacuation:

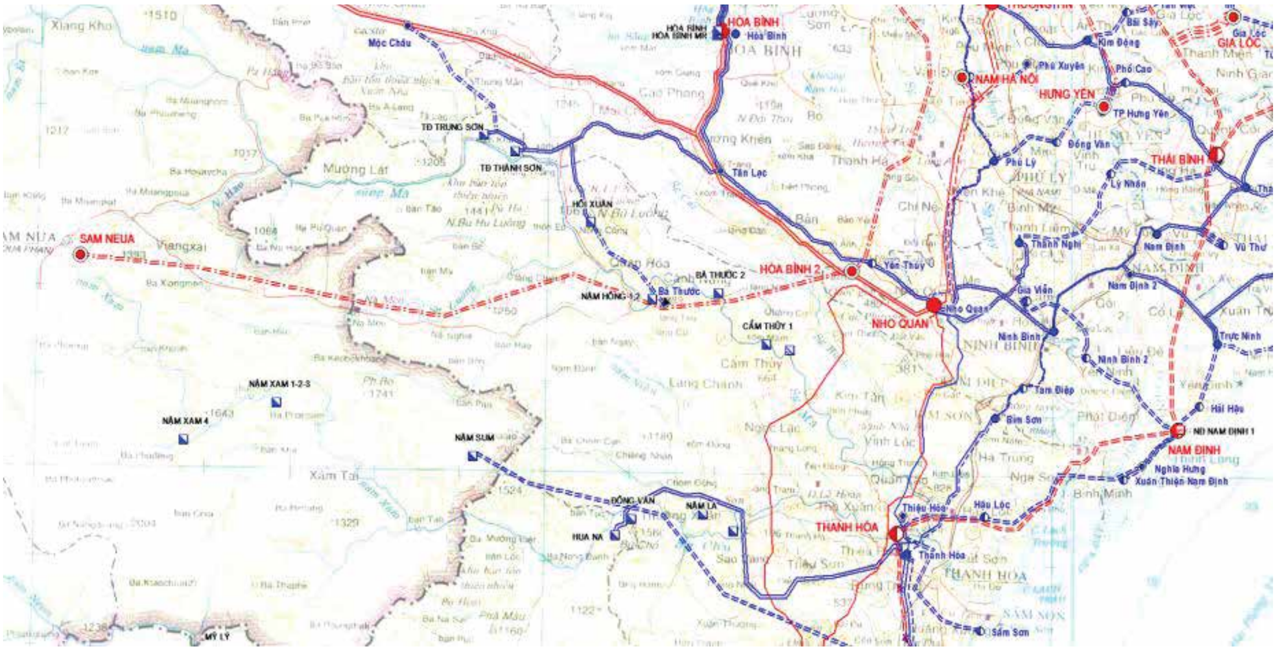
The Northern region will develop about 3,000 MW of OWF in the period up to 2030. In case of developing Northern OWF in the South of Hanoi, it is necessary to build an OWF collection substation connected to the Thai Binh 500 kV substation.

❖ Import from Laos:

PDP VIII proposes to build the 500 kV Hoa Binh 2 switching station and the 500 kV Sam Neua - Hoa Binh 2 transmission line to import electricity from the Northern Laos region to Vietnam. Hoa Binh 2 500 kV switching station is connected to transit on a 500 kV Nho Quan - Ha Tinh circuit. In case of increasing electricity purchases using the above lines, it is necessary to consider building an additional 500 kV Hoa Binh 2 - Tay Hanoi line to evacuate the capacity of these power sources.

The North Central - North interface will often carry high loads after 2025, leading to the need to improve transmission capacity. In addition to building new lines to evacuate capacity directly from sources such as Nghi Son - Long Bien LNG, PDP VIII plans to renovate an existing circuit of the 500 kV Vung Ang - Nho Quan transmission line into a dual circuit. However, the renovation of the 500kV Vung Ang - Nho Quan transmission line may encounter difficulties during implementation due to the limited land fund around the 500kV Nho Quan substation. Therefore, it is possible to consider transferring the connection to the 500 kV Hoa Binh 2 switching station.

Figure 4-16 Hoa Binh 2 500 kV switching station and Hoa Binh 2 – Tay Ha Noi 500 kV line



b. Orientation to 2050

❖ Onshore Wind Evacuation:

According to Scenario 2A's power source development program, it is expected to develop about 19 GW of OWF sources in the North by 2050. In particular, areas with good offshore wind power potential are considered for development in the South of Hanoi, including Thai Binh and Nam Dinh. In each province/city, it is necessary to consider placing a 500 kV onshore substation to collect offshore wind power capacity and connect it to the national power system. Part of the capacity of OWF in the North will directly supply electricity to the load, reducing the load for the regional 500 kV substation.

4.5.1.7. The Transmission Grid Evacuation Power Sources in North Central

a. Period Up To 2030

In the period up to 2030, the North Central sub-region continues to develop power sources approved under PDP VII, such as Hoi Xuan, Ban Uon, My Ly, Nam Mo, Vung Ang II, and the Quang Trach I thermal power plants. In addition, the Quang Trach II thermal power plant has been approved to convert to LNG. In particular, the Cong Thanh thermal power plant is a risky project, likely to be eliminated if the investor cannot implement it.

❖ Nghi Son II Coal-Fired Thermal Power Plant:

To enhance the ability to evacuate the capacity of Nghi Son II thermal power plant, PDP VIII has planned a number of projects as follows:

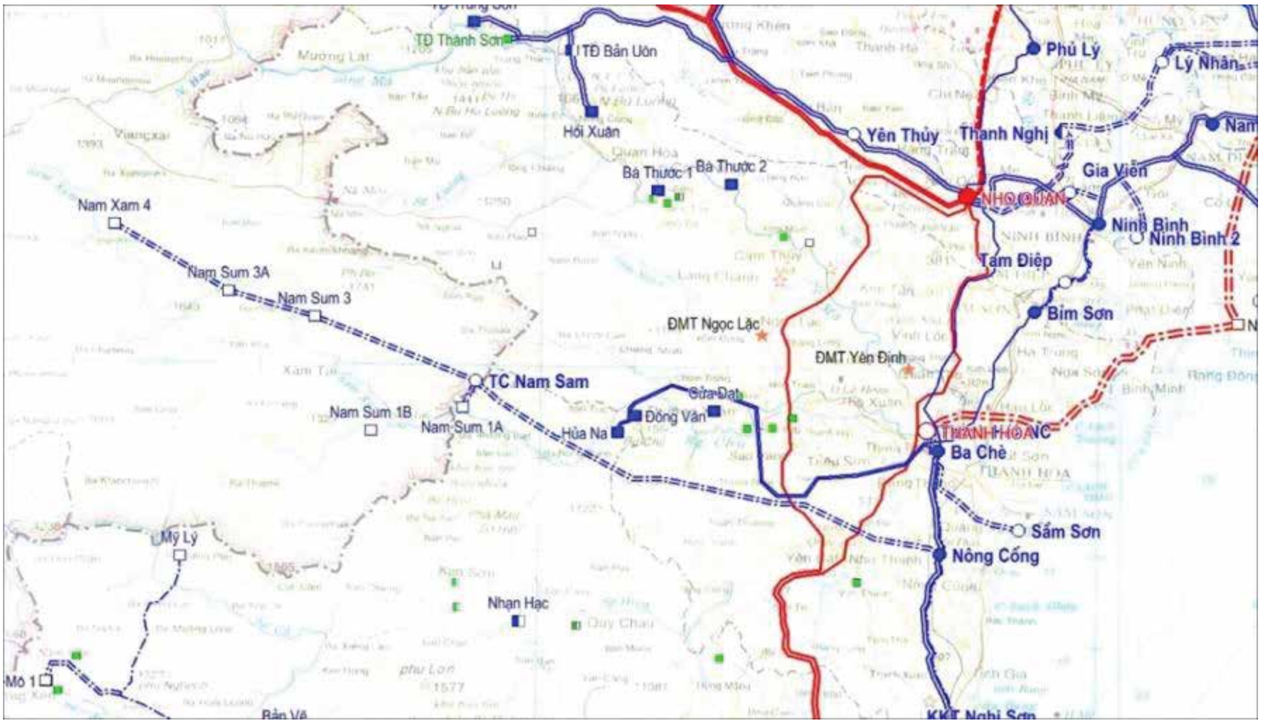
● Construction of a 220 kV Nghi Son thermal power transmission line - Nong Cong - Quynh Luu branch: Converting Nong Cong - Nghi Son and Nghi Son - Quynh Luu connections to Nong Cong - Quynh Luu, replacing the 220 kV line Nghi Son TPP transit on Nghi Son – Vinh.

● Renovating and increasing the load capacity of Nong Cong - 500 kV Thanh Hoa.

❖ Import from Laos:

Nam Sum HPP cluster (Laos) has a total capacity of 265 MW, expected to connect to the Vietnamese power grid via a dual-circuit 220 kV line to the Nong Cong 220 kV substation. The policy of importing electricity and connection plans for the Nam Sum power plant cluster were approved by the Prime Minister in document No. 1889/TTg-CN dated December 27, 2018. These projects are also in accordance with Decision No. 500/QD-TTg approving PDP VIII.

Figure 4-17 Connection map of Nam Sum HPP cluster (Laos)



The Nam Mo HPP cluster was approved for the policy of importing electricity according to document No. 1490/TTg-CN of the Prime Minister. Accordingly, the Nam Mo power plant cluster includes 11 plants with a total capacity of 505 MW, expected to be connected to the Tuong Duong 220 kV substation via a 45 km long double-circuit 220 kV line. At the same time, when the power plants in the Nam Mo power plant cluster gradually come into operation, it is necessary to build additional double-circuit 220 kV lines Tuong Duong - Do Luong, Do Luong - Nam Cam to ensure transmission capacity. At the same time, it is necessary to consider increasing the load capacity of the 220 kV Hung Dong - Quynh Luu - Nghi Son transmission line to ensure operation.

Figure 4-18 Connection map of Nam Mo HPP cluster (Laos)

❖ Evacuating Renewable Energy Sources:

The North Central sub-region is planned to develop more wind power in the period up to 2030. To ensure the evacuation of renewable energy, it is necessary to renovate and increase the load capacity of 220 kV lines Ha Tinh - Hung Dong AND Hung Dong - Quynh Luu - Nghi Son. These are important main axes, affecting the ability to evacuate capacity of many renewable energy projects in the region.

❖ Evacuating LNG Power Plants:

The North Central sub-region plans to develop Nghi Son and Quang Trach II LNG thermal power sources in the period 2026-2030 with a scale of about 1,500 MW per location. The plants' electricity is transmitted to the North. To ensure the evacuation of Nghi Son LNG capacity while enhancing transmission capacity in the North Central - North, it is necessary to build the LNG Nghi Son - Long Bien 500 kV transmission line.

b. Orientation to 2050

❖ Evacuating Wind and Solar Power:

In the period after 2030, the North Central sub-region will continue to strongly develop renewable energy sources. With the large capacity scale of onshore wind and solar power sources as proposed in Scenario 2A, in the period to 2050, each province in the region needs to build at least 1 of 500 kV substations to collect power source capacity. In case of developing many small and medium-sized projects in a geographical area, building a 220 kV gathering substation to evacuate renewable energy source capacity can be considered.

❖ Evacuating Small Hydropower and Import from Laos

Considering building an additional 220kV Tuong Duong - Quy Hop line to consolidate the capacity of hydroelectric sources and increase electricity imports from Laos. With the 220 kV line connecting Tuong Duong - Quy Hop - Quynh Luu 500 kV substations, it is expected that this area can receive about 200 - 300 MW of additional power source.

Building new 500 kV lines linking Laos - North Central can be considered to increase Laos electricity imports in the period up to 2050. Research plans to connect the power grid through a back-to-back system.

❖ Evacuating Offshore Wind Power

According to the power source development program at Scenario 2A, about 6 GW of OWF source is expected to develop in the North Central region by 2050. Areas with great potential are in the coastal areas of Thanh Hoa and Ha Tinh provinces. In the period up to 2035, it is necessary to develop North Central Region OWF collection stations and connection lines in these two localities. With the large capacity scale of OWF projects, priority is given to connection to the national electricity system at the voltage level of 500 kV.

4.5.2. Scenario 2B

4.5.1.1. Plan to Develop Inter-Area and Inter-Regional Power Transmission Grid

Inter-area and inter-regional transmission power output in Scenario 2B is as follows:

Table 4-9 Inter-area transmission power output in Scenario 2B

Unit: billion kWh

Interface/Year	2025	2030	2035	2040	2045	2050
Scenario 2B						
Central => North	4.2	21.7	19.0	36.9	51.7	58.0
North => Central	3.3	0.3	1.3	0.6	0.0	0.0
Central => South	14.8	14.3	21.3	7.0	4.0	4.7
South => Central	1.1	1.2	7.6	1.5	0.8	3.5
South => North	0.0	0.0	10.6	29.5	48.2	67.9

Table 4-10 Inter-regional transmission power output in Scenario 2B

Unit: billion kWh

Interface/Year	2025	2030	2035	2040	2045	2050
North Central => North	8.0	26.8	33.1	32.4	28.5	17.1
North Central => Center Central	3.3	0.3	1.3	0.6	0.0	0.0
Center Central => North Central	4.2	21.7	19.0	16.3	18.0	33.7
Center Central => North				20.5	33.7	24.3
South Central => North			10.6	29.5	48.2	67.9

The calculation results of inter-area and inter-regional transmission output in Scenario 2B are not much different from Scenario 2A. Therefore, the inter-regional transmission network configuration of Scenario 2B is similar to Scenario 2A as detailed in sections 4.5.1.1 and 4.5.1.2.

4.5.2.2. Transmission Grid Power Sources Evacuation in the Northwest and Northern Mountainous Area

a. Period Up To 2030

❖ Evacuating RE Sources:

Scenario 2B proposes to further develop about 50 MW of onshore wind power, 900 MW of solar power, and 400 MW of biomass - waste power in the Northwest and Northern mountainous provinces. To evacuate the increased power capacity, the report proposes a number of projects in addition to the proposed transmission grid projects at Scenario 2A, as follows:

- Accelerating the construction of the 500 kV Yen Bai substation and the 500 kV Yen Bai transit on Lao Cai - Vinh Yen.

- Accelerating the construction of the 500 kV Dien Bien substation and the Dien Bien - Lai Chau 500 kV line.

- Accelerating the 220 kV substations gathering renewable energy in Dien Bien and Yen Bai.

b. Orientation in 2050

To evacuate the increased capacity of regional solar power sources, it is necessary to add a number of transmission grid projects as follows:

- Construction of the 500 kV Lai Chau RE substation and the Lai Chau RE - Vinh Yen 500 kV line.

- Increasing the capacity of the 500 kV Son La RE substation and the 220 kV Son La RE substations 1, 2, and 3, suitable for the scale of renewable energy capacity developed in the region.

- Increasing the capacity of the 500kV Hoa Binh 2 substation and the 220kV Hoa Binh RE substations, consistent with the scale of renewable energy capacity developed in the region.

4.5.2.3. The Transmission Grid Power Sources Evacuation in the Northeast

a. Period Up To 2030

❖ Evacuating Offshore Wind:

Because Scenario 2B will develop up to 3 GW of OWF in the Northeast in the period to 2030, it is necessary to accelerate the construction of the 500 kV Northern 4 substation in Hai Phong city area and complete the 500 kV Hai Phong – Northern 1 - Northern 4 – Bac Giang in the period up to 2030.

b. Orientation to 2050

Scenario 2B does not increase the scale of power source capacity in the Northeast region in the period to 2050 compared to Scenario 2A, so there is no need to add additional transmission grid projects to evacuate power source capacity.

4.5.2.4. The Transmission Grid Power Source Evacuation in Hanoi City and Surrounding area

Hanoi City and surrounding areas do not have much potential for developing renewable energy sources, so no additional need to add more power grid projects to evacuate power capacity compared to Scenario 2A and PDP VIII.

4.5.2.5. Transmission Grid Power Source Evacuation in South Hanoi

a. Period Up To 2030

❖ Evacuating Offshore Wind Power:

Because Scenario 2B will develop an additional 1.5 GW of OWF in the Northeast in the period to 2030, it is necessary to quickly increase the capacity of the 500kV Northern 2 substation in sync with the scale of OWF development capacity in the region.

b. Orientation to 2050

To evacuate the increased capacity of regional solar power sources, it is necessary to add a number of transmission grid projects as follows:

- Additional 220kV solar power gathering substations in Ninh Binh and Nam Dinh provinces and connection lines.

4.5.2.6. The Transmission Grid Evacuate Power Sources in North Central

a. Period Up To 2030

❖ Evacuating RE Sources:

Scenario 2B proposes to further develop about 500 MW of onshore wind power, 3500 MW of solar power, and 300 MW of biomass - waste power in the North Central region. To evacuate the increased power capacity, the study proposes a number of projects in addition to the proposed transmission grid projects at scenario 2A, as follows:

- Accelerating the construction of the 500 kV Ha Tinh RE substation and connection lines.

- Construction of the Quang Binh 500kV substation with a capacity scale suitable to the scale of onshore power station development in the region.

- Accelerating the 220kV substations that collect renewable energy in Ha Tinh and Quang Binh.

- Although scenario 2B does not develop Nghi Son LNG and Quynh Lap LNG, it is still necessary to build 2 circuits of a 500 kV line from the 500 kV substation gathering RE gathering substation in Thanh Hoa/Nghe , an area directly to Hanoi.

b. Orientation to 2050

To evacuate the increased capacity of regional solar power sources, it is necessary to add a number of transmission grid projects as follows:

- Constructing about 2 additional 500 kV substations to collect solar power capacity in the area and connect to the National Power System.

4.6. Check the Load Flow of the Northern Power System After Implementing Proposed Solutions by 2030

To check the ability to evacuate the capacity of the Northern power source according to the transmission grid development plan proposed in Section 4.5, research and calculate the capacity trend of Vietnam's power grid in the period to 2030. The center evaluates the load carrying capacity of transmission lines and substations and the voltage on bus bars to propose improvement measures if there are violations of technical conditions. Because Decision No. 500/QD-TTg dated May 15, 2023 approving PDP VIII only clearly states the list of power transmission grid projects in the period up to 2030, the power grid structure after 2030 is only directional and there is not enough legal basis to perform detailed load flow calculations. The study will calculate and check the technical conditions of transmission grid elements in normal operating mode (N-0) and 1-element fault mode (N-1) according to Vietnamese regulations. With the characteristics of the Northern region developing many hydroelectric sources, seasonal characteristics greatly affect the power system operating mode. Typical calculation modes performed in this section include Peak Load Mode in rainy season (maximum load, hydropower generates maximum capacity, thermal power generates about 70% of installed capacity) and Peak Load Mode in dry season (maximum load, hydropower generates about 50% of installed capacity, the thermoelectric generator generates maximum capacity).

To calculate the power grid capacity flow, the study uses the system analysis program PSS/E (Power System Simulator for Engineer) written by PTI Company (USA) and transferred by Vietnam Electricity Group. This is a very effective program in calculating the working modes of the power system (steady mode, unbalanced working mode, short circuit, and stability calculation) and is widely used on the Internet world. For testing N-1 faults, the study uses a calculation module written in Python to test all N-1 fault cases on 500 kV and 220 kV grids in the regimes of interest, different for each region. It only scans N-1 incidents of line branches and transmission transformers, excluding generator set incidents and busbar incidents. The calculation program will classify N-1 incidents depending on the overload level on the elements of the transmission grid:

- Serious incidents (overload < 10%);
- Extremely serious incidents (overload 10% ÷ 20%);
- Emergency incidents (overload > 20%).

❖ Peak Load Mode, Rainy Season in 2030:

The rainy season in the North starts in May and lasts until October.

With the North Central - Northern inter-regional transmission segment, after the 500 kV Quang Trach - Thanh Hoa - Nam Dinh - Pho Noi line is energized and put into operation (expected in 2026), the transmission capacity on the interface will significantly improve. In addition, PDP VIII has approved the construction of the 500kV Nghi Son - Long Bien LNG transmission line (synchronized with the Nghi Son LNG project) and the renovation of an existing 500kV Nghi Son - Nho Quan circuit in the period to 2030, upgrading the total interface size to 7 of 500 kV circuits, ensuring N-1 criteria. However, these lines have a large length, go through many provinces, are only at the planning stage, and have not yet prepared a feasibility study report. Therefore, the progress towards operation is still uncertain.

In case 2030 still maintains the scale of 4 500 kV circuits on the North Central - Northern transmission interface, it will not ensure operation when an N-1 incident occurs on the 500 kV Nghi Son - Nho Quan section (overload level can be up to 25%). At that time, the power source capacity must be cut too large, not meeting the system's requirements. This line becomes a "bottleneck" limiting the ability to transmit inter-regionally and supply power to the Northern load center. Therefore, it is necessary to add additional 500 kV transmission infrastructure on the North Central - Northern interface in the period up to 2030 to ensure power supply to the North.

Under normal operating conditions (N-0), some Northern power grid elements have a high load of over 75% that requires attention such as:

- The 220 kV double circuit line Nghia Lo - Phu Tho 3.

- The 220 kV line Trang Bach - Khe Than - Quang Ninh 1 is fully loaded due to releasing the power of onshore power in Quang Ninh province.

- The 220 kV double circuit line Dien Bien - Son La, 220 kV line Son La 1 - Suoi Sap 2A - Phu Yen due to releasing renewable energy capacity in Dien Bien, Son La area.

- The 220 kV line Trung Son hydropower plant - Thanh Son hydropower plant.

- The 220 kV line Ban Ve - Tuong Duong.

It can be seen that the Northern power grid elements carry high loads in normal operating mode related to capacity release of small hydropower sources (Northwestern region), wind power, and solar power. However, no cases of overload were recorded. Thus, the Northern power transmission grid ensures technical conditions under normal operating conditions (N-0).

Calculate N-1 for the Northern transmission grid (only scanning transmission lines and transformer branches, excluding generator set failures and bus bar failures) in the rainy season regimes of 2030. Some N-1 events that need attention are as follows:

- The Lao Cai - Van Ban 220 kV line incident.
- The Van Ban - Than Uyen 220 kV line incident.
- The Phu Tho 2 - Viet Tri 220 kV line incident.
- The Do Luong - Khe Bo hydropower plant 220 kV line incident.

N-1 incidents cause fullness and overload on the transmission grid mainly in the Northwest region during a mode of high mobilization of hydroelectric and renewable energy sources. To overcome it, it is necessary to properly mobilize the region's power sources. Thus, the Northern power transmission grid basically ensures technical conditions under N-1 incident operating conditions without implementing renovation measures.

❖ Peak Load Mode, Dry Season in 2030:

The dry season in the North takes place from January to April and the last two months of the year.

With the North Central - North interface, after the 500 kV Quang Trach - Thanh Hoa - Nam Dinh - Pho Noi operating (expected in 2026), the transmission capacity on the interface will be significantly improved. In addition, PDP VIII has approved the construction of Nghi Son - Long Bien LNG 500 kV transmission line (synchronized with the Nghi Son LNG power plant) and the renovation of an existing Nghi Son - Nho Quan 500kV line in the period to 2030. The interface will have 7 of 500 kV circuits, ensuring N-1 criteria. However, these lines have a large length, go through many provinces and are only at the planning stage, and have not yet prepared a feasibility study report. Therefore, the operation progress is still uncertain.

Under normal operating conditions (N-0), some Northern power grid elements have a high load of over 75% that require attention, such as:

● The Trang Bach - Khe Than - Quang Ninh 1 220 kV line, Cam Pha - Quang Ninh 220 kV line are full load due to evacuate power generation capacity onshore wind of Quang Ninh province.

● Hung Dong – Ha Tinh 220 kV line.

During the peak load regime in the dry season of 2030, the Northern power grid did not record any overload incidents. Northern power grid elements carry high loads in normal operating mode related to capacity release of small hydropower sources (Northwestern region), wind power, and solar power. Lines and substations related to the release of thermal power source capacity carry normal loads.

Calculate N-1 for the Northern transmission grid (only scanning transmission lines and transformer branches, excluding generator set failures and bus bar failures) in the rainy season regimes of 2030. In general, The Northern power transmission grid basically ensures technical conditions under N-1 incident operating conditions without implementing renovation measures. Except for the case of a fault in one circuit of the Ba Che - 500 kV Thanh Hoa 220 kV line, which can cause overload to the remaining circuit due to high Central - North transmission.

4.7. Summary of Investment Volume in the Northern Transmission Grid according to the Selected Energy Transition Scenario

4.7.1. Investment Volume of Northern Transmission Grid according to Scenario 2A

Summary of investment volume in the Northern transmission network according to scenario 2A is shown in Table 4-11 In order not to lose generality, the study summarizes the amount of investment in the transmission grid, both evacuation power sources and supplying load power. In particular, the main transmission grid releases power sources based on the proposals in sections 4.5 and 4.6. The transmission grid supplies load according to PDP VIII.

Table 4-11 Summary of investment volume in the Northern transmission grid – Scenario 2A

	Unit	Period 2023-2030	Orientation in period 2031-2050
Substation			
500 kV			
New build	MVA	32400	153900
Renovation	MVA	11550	68709
220 kV			
New build	MVA	45388	98750
Renovation	MVA	14312	60250
Line			
500 kV			
New build	km	5271	4726
Renovation	km	720	857
220 kV			
New build	km	8002	4739
Renovation	km	2502	280

To carry out energy transition in the North, it is necessary to build a large power transmission grid in addition to investing in renewable energy sources to replace coal thermal power. In particular, the volume of transmission grid releasing power source capacity accounts for about 22% (for substations) and 35% (for lines) in the period 2023 - 2030 and about 42% (for substations) and 40% (for lines) in the period 2031 - 2050. Thus, in the later stages, the amount of power transmission grid evacuation power source capacity will account for a larger proportion because the renewable energy source capacity that needs to be invested to meet the demand is larger than that of traditional power sources.

4.7.2. Investment Volume of Northern Transmission Grid according to Scenario 2A

Summary of investment volume in the Northern transmission network according to Scenario 2B shown in Table 4-12

Table 4-12 Summary of investment volume in the Northern transmission grid – Scenario 2B

	Unit	Period 2023-2030	Orientation in period 2031-2050
Substation			
500 kV			
New build	MVA	36900	153900
Renovation	MVA	11550	73200
220 kV			
New build	MVA	46638	99750
Renovation	MVA	14312	61250
Line			
500 kV			
New build	km	6027	4570
Renovation	km	740	837
220 kV			
New build	km	7884	4803
Renovation	km	2502	280

Compared to Scenario 2A, Scenario 2B requires investment in a larger transmission grid volume. In particular, the investment volume of new and renovated power grid projects in Scenario 2B is larger than Scenario 2A, about 9000MVA of 500kV transformer, 3250 MVA of 220kV transformer, 600 km of 500 kV lines, and 120 km of 220 kV lines.

5. INVESTMENT COST

5.1. Input Assumption

❖ Investment Cost of Power Generation:

Investment rates of various types of power sources are referenced in the following documents:

- Main report of the National Power Development Plan for the period 2021-2030, vision to 2050 [2].

- Vietnam technology catalog on Power Generation 2023, developed by the Electricity and Renewable Energy Authority and the Danish Energy Agency within the framework of the cooperation program in the energy field between the two Governments of Vietnam and Denmark [7].

In particular, investment costs in the Technology Catalog do not include administrative cost, consulting cost, project management cost, site preparation cost, and taxes and interest during

❖ Investment Cost of Transmission Grid:

Investment rate of transmission grid projects is referenced according to the Main report of the National Power Development Plan for the period 2021-2030, vision to 2050 [2]. Investment cost for the construction of 500 kV and 220 kV power grid projects includes costs of construction, procurement and installation of equipment, reserve costs, and taxes. Costs for a number of other activities have also been included, such as project management costs, construction investment consulting costs (includes costs of survey, investment project planning, design, technical design verification, estimate verification, bidding documents preparation, construction supervision, and equipment installation), and other costs (e-commerce verification, clearance of bombs, mines, and explosives on construction sites, construction insurance, fees and charges of all kinds, land rental or payment of land use rights, interest Bank loan from the investor, acceptance, energization, handover, production preparation, audit, and the verification and approval of settlement).

The investment cost for construction of 500 kV and 220 kV power grid projects does not include: (1) Site clearance compensation costs (2) Special reinforcement of building foundations, such as using special foundation structure solutions for works on soft ground, areas where crossing poles with large clearances must be arranged (electric transmission line works), and anti-corrosion solution when the building's foundation is located in an area with chemical corrosion phenomenon (3) International quality inspection and construction deformation monitoring (if any) (4) Inspection and certification of conformity in quality of construction works and (5) Cost of hiring foreign consultants.

❖ **USD/VND exchange rate: Based on the State Bank's foreign exchange rate on December 4, 2023, 1 US dollar = 23,923 VND.**

5.2. Investment Cost Needs in the North according to Scenario 2A

5.2.1. Investment Cost for Power Generation in the North according to Scenario 2A

Investment cost for power generation in the North according to scenario 2A is summarized in the Table below:

Table 5-1 Investment cost of power generation in the North – Scenario 2A

Power Generation/Period	Unit	Period 2023-2030	Orientation period 2031-2050
Coal	Million USD	14982	0
LNG	Million USD	4650	2175
LNG co firing hydrogen	Million USD	0	486
LNG convert to 100% hydrogen	Million USD	0	855
Medium and large hydro	Million USD	2109	2910
Small hydro	Million USD	3309	4875
Onshore/nearshore wind	Million USD	9648	15437
Offshore wind	Million USD	5820	53780
Solar	Million USD	1432	69469
Biomass+other RE	Million USD	2058	3139
Flexible thermal	Million USD	222	26684
PSPP+battery	Million USD	177	5547

The total investment capital of Northern power sources in the period 2023 - 2030 will be 44.4 billion USD, equivalent to an average investment of approximately 5.6 billion USD per year during this period.

The total investment capital of the Northern power source oriented for the period 2031 - 2050 is 185.4 billion USD, equivalent to an average investment of approximately 9.27 billion USD per year during this period.

Although the volume of renewable energy sources that must be invested in the period after 2030 is very large, the investment rate of these types of sources decreases significantly over time, competing well with traditional power sources. Besides, the operating costs of renewable energy sources such as wind power and solar power are also smaller due to no fuel costs.

In addition to the investment cost to build new types of power sources, Scenario 2A also has to spend about 6.9 billion USD on investment costs energy transition of coal-fired power plants. This cost includes equity payment costs, unemployment support costs for employees, operating and maintenance costs during the preparation period, costs for cleaning the slag dump, and dismantling costs.

5.2.2. Investment Cost for Transmission Grid in the North according to Scenario 2A

The investment capital needed for the transmission grid in the North according to scenario 2A is calculated based on the volume of transmission grid investment proposed in section 4.7. Summary of investment capital needs for the power transmission grid in the North according to scenario 2A according to the period is presented in the following table:

Table 5-2 Investment cost of transmission grid in the North – Scenario 2A

	Unit	Period 2023-2030	Orientation period 2031-2050
Transmission grid	Billion VNĐ	190347	368089
	Billion USD	8.0	15.4

Investment cost for the power transmission grid in the North is estimated at about 8 billion USD in the period 2023 - 2030 and about 15.4 billion USD in the period 2031 - 2050. Thus, the investment cost needed for the Northern power transmission grid is estimated to average about 1 billion USD/year in the period 2023 - 2030 and about 0.8 billion USD/year in the period 2031 - 2050.

5.3. Investment Cost Needs in the North according to Scenario 2B

5.3.1. Investment Cost for Power Generation in the North according to Scenario 2B

The need for investment cost in power generation in the North according to Scenario 2B is summarized in the following table:

Table 5-3 Investment cost of power generation in the North – Scenario 2B

Power Generation/Period	Unit	Period 2023-2030	Orientation Period 2031-2050
Coal	Million USD	12487	0
LNG	Million USD	1860	0
LNG co firing hydrogen	Million USD	0	162
LNG convert to 100% hydrogen	Million USD	0	570
Medium and large hydro	Million USD	2109	975
Small hydro	Million USD	3243	5131
Onshore/nearshore wind	Million USD	10881	14347
Offshore wind	Million USD	14550	48000
Solar	Million USD	9631	76118
Biomass+other RE	Million USD	3666	1625
Flexible thermal	Million USD	666	30465
PSPP+battery	Million USD	1593	5937

The total investment cost of Northern power sources in the period 2023 - 2030 in Scenario 2B will be 60.7 billion USD (about 16.3 billion USD higher than Scenario 2A), corresponding to an average investment of approximately 7.6 billion USD per year during this period.

The total investment cost of Northern power sources oriented for the period 2031 - 2050 in Scenario 2B is 183.3 billion USD, corresponding to an average investment of approximately 9.17 billion USD per year during this period.
To promote the reduction of CO2 emissions to peak in 2030, the period 2023-2030 will have to increase investment in renewable energy sources, leading to relatively large investment costs for power sources.

In addition to the investment cost to build new types of power sources, Scenario 2B also has to spend about 6.9 billion USD on investment costs energy transition of coal-fired power plants. This cost includes equity payment costs, unemployment support costs for employees, operating and maintenance costs during the preparation period, costs for cleaning the slag dump, and dismantling costs.

5.3.2. Investment Cost for Transmission Grid in the North according to Scenario 2B

Summary of investment cost needs for the power transmission grid in the North according to scenario 2B according to the period is presented in the following table:

Table 5-4 Investment cost of transmission grid in the North – Scenario 2B

	Unit	**Period 2023-2030**	**Orientation period 2031-2050**
Transmission grid	Billion VNĐ	203545	368479
	Billion USD	8.5	15.5

For Scenario 2B, investment cost for the power transmission grid in the North is estimated at about 8.5 billion USD in the period 2023 - 2030 (about 0.5 billion USD higher than Scenario 2A) and about 15.5 billion USD in the period 2031 - 2050 (about 0.1 billion USD higher in Scenario 2A). Therefore, the investment cost needed for the Northern power transmission grid is estimated to average about 1.1 billion USD/year in the period 2023 - 2030 and about 0.8 billion USD/year in the period 2031 - 2050.

6. MECHANISM AND POLICY TO IMPLEMENT ENERGY TRANSITION IN THE NORTH

6.1. Current Status of Mechanisms and Policies to Encourage Renewable Energy Development in Vietnam

6.1.1. Policy Guidelines of the Government of Vietnam on the Goal of Developing Renewable Energy

Renewable energy is a new industry that has developed in Vietnam in the past 5 years. In the context of countries around the world committing to reducing greenhouse gasses and shifting from using fossil energy to renewable energy, Vietnam cannot stand outside the trend. In terms of the potential for developing power sources in Vietnam, while coal-fired thermal power sources are at risk of causing pollution, hydroelectric power has been exploited to the limit, nuclear power still has safety concerns, research and supplementation is needed. Supplementing and gradually replacing thermal and hydroelectric sources with renewable energy from wind, solar, and biomass is an inevitable trend. In terms of policy guidelines, the Government of Vietnam has set the goal of developing renewable energy in the following documents:

- Vietnam's renewable energy development strategy for the period up to 2030 with a view to 2050: Approved by the Prime Minister in Decision No. 2068/QD-TTg dated November 25, 2015, which sets out the electricity ratio production from renewable energy (including both large and small hydropower) in the country's total electricity production to reach 38% by 2020, 32% in 2030, and 43% in 2050

- Resolution 55-NQ/TW on Orientation of Vietnam's National Energy Development Strategy to 2030, vision to 2045 dated February 11, 2020 of the Politburo: Regulating the proportion of renewable energy sources generation in the total primary energy supply reaches 15-20% in 2030 and 25-30% in 2045, respectively. The proportion of renewable energy in the total electricity produced nationwide is about 30% in 2030 and 40% in 2045. In particular, specific tasks and solutions on renewable energy are given as follows:

"Building breakthrough mechanisms and policies to encourage and promote strong development of energy sources renewable energy to maximally replace fossil energy sources".

- National strategy on climate change for the period up to 2050: Approved by the Prime Minister in Decision No. 896/QD-TTg dated July 26, 2022. Accordingly, the proportion of renewable energy sources including hydropower, wind power, *solar power, and biomass will* account for at least 33% of total electricity generation by 2030. By 2050, the proportion of renewable energy sources will account for at least 55% of total electricity generation.

- Political declaration establishing the Just Energy Transition Partnership (JETP): Vietnam strives to control peak emissions to no more than 170 million tons and aims to achieve a renewable energy ratio of 47% by 2030, provided that commitments under JETP are fully and substantially implemented by international partners.

- National power development plan for the period 2021-2030, vision to 2050 (PDP VIII): Approved by the Prime Minister in Decision No. 500/QD-TTg dated May 15, 2023. PDP VIII plans to develop power sources and transmission grids at voltage levels of 220 kV or higher in the territory of Vietnam in the period 2021 - 2030, with a vision to 2050, including works connecting power grids with neighboring countries. PDP VIII has complied with the current policies of the Party and Government on the goal of developing renewable energy with the specific goal of strongly developing renewable energy sources for electricity production, reaching a rate of about 30.9 - 39.2% by 2030 and up to 67.5 - 71.5%, oriented to 2050.

The Government's policies have set relatively clear and specific goals for Vietnam's renewable energy development targets for the period to 2030, with a vision to 2050. In particular, under the conditions Vietnam receives international support and assistance in technology development, finance, etc., with a larger ambitious goal of developing renewable energy. This shows that Vietnam is not outside the world's development trend in focusing on green and sustainable energy development, especially with its commitment to achieving net zero emissions by 2050 at the COP26 conference.

6.1.2. Mechanisms to Encourage Electricity Purchase Prices from Renewable Energy in Vietnam

To realize the goal of developing renewable energy, the Government of Vietnam has issued mechanisms to encourage electricity purchase prices from various types of renewable energy, including small hydropower, wind power, solar power, and biomass electricity. Most incentive mechanisms are in the form of fixed electricity purchase prices (Feed in tariff - FIT). Practical experience in the world also shows that in the first phase of encouraging renewable energy development, the FIT price mechanism should be applied, then gradually switching to a bidding mechanism or letting renewable energy plants participate on the free electricity market.

Mechanisms to encourage electricity purchase prices from renewable energy that have been issued in Vietnam, include:

- Decision No. 37/2011/QD-TTg dated June 29, 2011, amended and supplemented according to Decision No. 39/2018/QD-TTg dated September 10, 2018 of the Prime Minister on support mechanism developing wind power projects in Vietnam.

- Decision No. 24/2014/QD-TTg dated March 24, 2014, amended and supplemented according to Decision No. 08/2020/QD-TTg dated March 5, 2020 of the Prime Minister on support mechanism developing biomass power projects in Vietnam.

- Decision No. 11/2017/QD-TTg dated April 11, 2017, amended and supplemented according to Decision No. 02/2019/QD-TTg dated January 8, 2019 of the Prime Minister on incentive mechanism of solar power development in Vietnam; Decision No. 13/2020/QD-TTg dated April 6, 2020 on the mechanism to encourage solar power development in Vietnam.

- Circular No. 16/2017/TT-BCT dated September 12, 2017, amended and supplemented according to Circular No. 05/2019/TT-BCT dated March 11, 2019 of the Ministry of Industry and Trade regulating development project and sample Power Purchase Agreement applicable to solar power projects.

And a number of other Circulars and Decisions.

Specifically, with regards to solar power:

Decision No. 11/2017/QD-TTg of the Prime Minister dated April 11, 2017 on the incentive mechanism for the developingment of solar power projects in Vietnam regulates FIT electricity purchase prices for solar power projects is as 9.35 Uscent/kWh with a power purchase contract term of 20 years from the date of commercial operation. In addition, solar power projects also enjoy investment capital and tax incentives such as import tax exemption and corporate income tax exemption and reduction. Land incentives such as exemption or reduction of land use fees, land rent, and water surface rent are facilitated by the People's Committees of the provinces to arrange land funds. This decision is valid until June 30, 2019.

Decision No. 13/2020/QD-TTg of the Prime Minister dated April 6, 2020 on the incentive mechanism for developing solar power projects in Vietnam replacing Decision No. 11/2017/QD-TTg. Accordingly, the FIT price to buy new electricity for ground-mounted solar power projects is 7.09 US cent/kWh, floating solar power is 7.69 US cent/kWh, and rooftop solar power is 8.38 US cent/kWh for projects that have been approved by the agency on investment policies before November 23, 2019 and have a commercial operation date of the project or part of the project in the period from July 1, 2019 to December 31, 2020.

Preferential prices apply for 20 years from the date of commercial operation of the project. Particularly for Ninh Thuan province, the encourage FIT (9.35 Uscent/kWh) will be applied for grid-connected solar power projects is included in the electricity development planning and having commercial operation date before January 1, 2021 with a total accumulated capacity not exceeding 2,000 MW.

With Wind Power:

Decision No. 37/2011/QD-TTg of the Prime Minister dated June 29, 2011 on the mechanism to support the development of wind power projects in Vietnam. Wind power projects are given incentives to buy electricity at a fixed price of 7.8 US cent/kWh and apply for 20 years from the date of commercial operation. The State supports electricity prices for the Electricity Buyer (EVN) for the entire electricity output purchased from wind power plants at about 1.0 US cent/kWh through the Vietnam Environmental Protection Fund. In addition, wind power projects enjoy investment capital and tax incentives such as import tax exemption and corporate income tax exemption and reduction. In addition, land incentives such as exemption or reduction of land use fees, land rent, and land allocation are provided by the People's Committee when the project is planned and approved by competent authorities.

Decision No. 39/2018/QD-TTg of the Prime Minister dated September 10, 2018 amending and supplementing a number of articles of Decision No. 37/2011/QD-TTG dated June 29, 2011 of the Prime Minister on mechanisms to support the development of wind power projects in Vietnam. Accordingly, the revised FIT power purchase price for onshore wind power projects is 8.5 Uscent/kWh and for offshore wind power projects is 9.8 Uscent/kWh, applicable for 20 years from the date of commercial operation. Preferential electricity purchase prices only apply to wind power projects with commercial operation dates before November 1, 2021.

With Biomass Power:

Decision No. 24/2014/QD-TTg dated March 24, 2014 on the mechanism to support the development of biomass power projects in Vietnam regulates the electricity selling price at the delivery point for cogeneration heat projects - electricity using biomass energy is 1,220 VND/kWh (not including value added tax, equivalent to 5.8 UScent/kWh); Electricity selling prices for power source projects using biomass energy to generate electricity, but not heat-electricity cogeneration projects, apply according to the avoided cost tariff applicable to biomass power projects.

Decision No. 08/2020/QD-TTg dated March 5, 2020 amending and supplementing Decision No. 24/2014/QD-TTg dated March 24, 2014. Accordingly, for heat and electricity cogeneration projects: The electricity purchase price schedule at the delivery point is 1,634 VND/kWh, equivalent to 7.03 UScent/kWh, according to the exchange rate calculated according to the central exchange rate of Vietnam Dong with US Dollar announced by the State Bank of Vietnam on February 21, 2020. For projects other than heat and electricity cogeneration projects: the electricity purchase price schedule at the delivery point is 1,968 VND/kWh, equivalent to 8.47 UScent/kWh, according to the exchange rate calculated according to the central exchange rate of Vietnam Dong with US Dollar was announced by the State Bank of Vietnam on February 21, 2020. This decision is still valid to this day.

The FIT electricity price mechanism is a support tool for electricity producers from renewable energy sources, encouraged by long-term fixed price electricity purchase contracts for investors producing electricity from renewable energy sources. Purchase obligations and guaranteed access to the grid will increase investor safety. Therefore, this mechanism enhances the competitiveness of renewable energy compared to traditional forms of energy.

6.1.3. Direct Power Purchase Agreement (DPPA) – Draft Version

Direct Power Purchase Agreement (DPPA) is a mechanism that allows direct power purchase and sale agreements between power generating units (seller) and electricity customers (buyer). The DPPA mechanism is expressed in the form of a long-term bilateral contract with price and contract term agreed upon by both parties.

In the first quarter of 2021, the Ministry of Industry and Trade developed a Draft Circular stipulating the pilot implementation of the DPPA mechanism, organized consultations with relevant agencies and units in writing, and posted the content. The Draft Circular is posted on the Government Portal and the Ministry of Industry and Trade for public comments. In which, the pilot phase of the DPPA mechanism applies to renewable energy generators and large electricity users. Subjects of application of this Circular are wind and solar power sources with an installed capacity of more than 30 MW already included in the power development plan approved by the competent authority and the customers purchasing electricity for industrial production at 22 kV voltage level and above. According to the draft DPPA between renewable energy generators and electricity users, renewable energy plants will sign contracts to sell electricity directly to customers in the form of Contract For Difference (CFD). At the same time, renewable energy plants will sign contracts with EVN to participate in the spot electricity market. Renewable energy plants will be paid for their output at the spot market price and the difference between the DPPA contract price with the customer and the spot market price (if any) from the customer. On the customer side, electricity will be purchased through the Power Corporations, which are responsible for purchasing electricity from the spot market. The price paid by customers to the Power Corporations includes the cost of electricity and the cost of DPPA services. In which, the cost of DPPA services includes transmission costs, distribution costs, power system and market operating costs, and ancillary service costs. Similarly, in addition to the spot market price of electricity, customers will have to pay the difference directly to the plant if the DPPA price is greater than the spot market price or receive the difference back from the plant if the DPPA price is less than the spot market price.

On October 29, 2021, the Ministry of Industry and Trade issued Document No. 94/BC-BCT to the Prime Minister, reporting on the implementation of regulations on the pilot implementation of the DPPA mechanism between generators and from renewable energy with large electricity users. In this draft mechanism, the Ministry of Industry and Trade proposes to choose a financial DPPA mechanism model, in which electricity customers still buy electricity from the Electricity Corporation at the current retail price of electricity. Electricity users: (i) Maintain purchase of electricity from the Electricity Corporation at current retail prices and (ii) Directly agree and sign with the power generation unit a Difference Contract (CfD contract) with the price and electricity output agreed upon by both Parties for future transaction cycles. The Electricity users will pay the difference between the agreed contract price and the spot market price for the electricity output committed in the contract. Generating units: (i) Sign a power purchase agreement with Vietnam Electricity to sell all electricity on the spot market, receive revenue at the spot market price and (ii) Sign the Contract for Difference with customers using electricity with the above transaction principles. The Electricity of Vietnam Group has the duty to pay the generating unit at the spot market price of electricity for the entire electricity output generated into the system in accordance with the electricity market regulations. The Electricity Corporation maintains its current role, buying electricity from EVN at the internal wholesale price and selling electricity to customers at the current retail price.

In October 2023, the Ministry of Industry and Trade continued to review and propose a model for implementing the DPPA mechanism. Specifically:

Case 1: The case between a renewable energy generating unit buying and selling electricity directly with a large customer via a private line. Through review, Vietnam's current legal regulations have been fully adjusted in legal documents for units to implement (Circular No. 21/2020/TT-BCT dated September 9/ 2020 of the Ministry of Industry and Trade regulating the order and procedures for granting electricity activity licenses).

Case 2: In case the unit generating electricity from renewable energy sells electricity to large end-users through the national grid. In this model, purchasing and selling relationships between units are carried out according to transaction principles:. The generating unit participates in the electricity market and connects to the national grid, offering to sell electricity output into the competitive wholesale electricity market, receiving revenue from the electricity market at the spot market price.

Large customers buy electricity from electricity retailers and pay electricity retailers according to the electricity spot market price plus service prices. Large customers and power generation units sign a forward contract for difference (derivative financial contract). Accordingly, the payments of large customers and electricity generating units are reflected in the electricity market price. However, in order to implement this model, according to the Ministry of Industry and Trade, it is necessary to adjust and issue additional legal regulations to guide the calculation of electricity distribution prices, dispatch price to operate the power system, operating power market transaction, price of electrical system support services and other payment costs, and sample power purchase contracts(between power generation units and large customers and between power generation units and Vietnam Electricity Group/National Power System Dispatch Center). The development and promulgation of these types of documents is a prerequisite to ensure that the retail price for each major customer accurately and fully reflects costs, avoids loss of state assets, and ensures fair trade between FDI enterprises and other customers. Therefore, the time to apply the model depends on the progress of developing, amending, and taking effect of these documents.

Currently, the pilot DPPA mechanism between renewable energy power producers and large electricity users is still being studied and considered by the Ministry of Industry and Trade and the Government. The DPPA mechanism issued in the future promises to open up many benefits for participating parties, specifically:

- For electricity users (groups and companies that have a need to use a large amount of electricity for production and business activities) participating in the DPPA mechanism: On the one hand, it meets global commitments on renewable energy use and sustainable development. On the other hand, it ensures long-term energy supply and minimizes the risk of energy costs in the future because the electricity purchase price can be negotiated and fixed.

- For investors developing projects participating in the DPPA mechanism: Achieve stable/predictable long-term revenue due to a large portion or all of the electricity produced being reliably purchased by a highly reputable customer with a fixed long-term electricity price. By reaching long-term agreements with a highly reputable customer (usually large corporations/companies with strong financial potential), project developers can reduce the risk of project financial risks and easier access to limited financial resources to undertake project development. Although currently, in many markets project developers can choose to enter into long-term contracts with electricity units, the DPPA mechanism is still being applied more and more widely as it can lead to more diverse interests/agreements. For example, DPPA contracts offer a better fixed price/floor price for a project than the current market price.

- For the economy: The DPPA mechanism brings a number of specific benefits to the economy such as (i) Attracting foreign direct investment (FDI) from international corporations with commitment to targets for sustainable development and the use of renewable energy(enterprises participating in groups RE-100 and REBA, such as Apple, Google, Nike, Heineken, and H&M); (ii) Enhance renewable energy power generation capacity by creating strong incentives to encourage investors to participate in the development of renewable energy power sources (iii) Reducing financial pressure on the Government/State corporation by investing in the development of new renewable energy power sources or providing subsidies through the FIT pricing mechanism (iv) Enable more equitable distribution of electricity for economic growth purposes.

6.2. Propose Mechanisms and Policies to Implement Energy Transition in the North

6.2.1.1. Group of Investment Mechanism

6.2.1.1. Bidding Mechanism for Selecting Projects and Power Project Investors

According to the current legal regulations, the selection of investors to implement power projects will have to be done through investor selection bidding. However, there are currently no specific instructions for the implementation of power projects in the period 2021-2025, especially projects that are currently preparing PreFS and FS but have not been approved by competent authorities. Therefore, it is recommended that the Ministry of Industry and Trade soon issue a bidding mechanism and unify specific regulations in the principles of selecting and identifying investors to avoid affecting the progress of power projects currently in the development stage.

The Ministry of Industry and Trade is the agency in charge that coordinates with relevant ministries and branches in building a bidding mechanism to select investors to carry out power projects. Bidding to select investors to implement projects needs to be oriented on the basis of ensuring competition, transparency, and creating conditions for all economic sectors to participate in energy development. However, it is necessary to ensure that the State still plays the leading role, ensuring national energy security in accordance with the Politburo's direction in Resolution 55-NQ/TW.

- Based on the list of approved planning implementation plans, the bidding organization will select the location and scale of construction of electrical works to bid for investor selection.

- Develop a bidding mechanism to select investment projects in the field of renewable energy electricity to select projects with reasonable and effective electricity prices, avoiding major impacts on the average cost of the entire system.

- The bidding process and investor selection will be based on the Bidding Law.

- The contractors' capacity criteria are checked in terms of both financial and technical capacity.

- It is necessary to build the capacity of government agencies in organizing bidding and selecting investors.

- There should be sanctions against investors and localities that do not implement power projects according to progress commitments in accordance with the provisions of law.

6.2.1.2. Mechanisms and Policies for Piloting Large and New Power Projects

The project recommends that the Government and competent agencies consider promulgating mechanisms and policies to allow the electricity industry to pilot a number of projects/fields that are not included in current regulations to ensure system operation. Electricity, promptly supplementing power sources, limits the risk of power shortages in the period from now to 2030. Specifically, as follows:

❖ Pilot Offshore Wind Power:

Offshore wind power is a new type of power source with high technical requirements in construction and operation and large investment capital. In addition, the issue of exploiting offshore wind power is relatively complicated due to its involvement in the national security area. The Government has requested the Ministry of Industry and Trade to quickly research and complete the pilot mechanism to assign corporations and State corporations in developing offshore wind power.

Proposed implementation methods are as follows:

- The Government approved the implementation plan of PDP VIII with the allocation of capacity scale and development area of OWF. In particular, there is content assigned to EVN and domestic enterprises that are qualified to pilot the OWF project.

- The Ministry of Industry and Trade promulgates the electricity generation price frame for offshore wind power plants and adjusts the price frame annually according to the actual implementation of power purchase contracts and the situation of offshore wind power development.

- The Government approved the National Marine Spatial Plan and amended Decree 11/2021/ND-CP. Ministries and departments issue regulations and implementation instructions related to offshore wind power development.

- Based on pilot project proposals from state-owned enterprises and other domestic enterprises, the Ministry of Industry and Trade synthesizes and evaluates the appropriate pilot scale, building a list of pilot projects. The project section collects opinions from relevant ministries, branches, and localities, and proposes the Government to approve and assign the investor to pilot the OWF project. The evaluation of pilot assignment to domestic enterprises includes the following criteria: investor capacity and experience, project development scale and location, connection plan, financial mobilization plan, localization capabilities, and proposed electricity price of the project.

- The Ministry of Industry and Trade reviews the development of offshore wind power sources and synchronous power transmission infrastructure every year, and reports to the Prime Minister to adjust the plan (if necessary) to meet practical requirements.

However, to develop offshore wind power, Vietnam is facing many difficulties and challenges. Typically, the legal framework for this field is lacking, the project has a large investment scale, is complex in terms of techniques - technology and investment processes-procedures, and is related to many other fields, such as security, national defense, oil and gas, maritime, and fisheries industries. The investment process to develop an offshore wind farm can last many years (including project development stages, construction preparation, construction, and trial run). Therefore, an appropriate legal framework is needed (including strategic vision, maritime space handover, grid connection, tax incentives, and incentives for supply chain development).

❖ Pilot Battery Energy Storage System (BESS):

Currently, a number of organizations, such as the Asian Development Bank (ADB) and the US Consulate General,… propose to implement a pilot battery storage system project to explore the exploitation of other applications and benefits of integrating BESS into the power transmission network, and provide a pilot case for research, develop legal regulations for the BESS system.

BESS is a type of investment that has not yet appeared in Vietnam, so there is no policy on electricity selling prices according to peak and off-peak hours or the differential price between renewable energy electricity and electricity from renewable energy combined with BESS. Current regulations do not mention energy storage technology, so it is necessary to adjust and supplement to allow these technologies to participate in the operation of the electricity system and electricity market.

In power systems with a high proportion of renewable energy, developing energy storage systems is an inevitable trend to ensure safe and stable operation of the system. With the perspective of developing Vietnam's power system in the coming years, a balanced power source across regions based on local consumption needs must be developed. This will reduce the need for inter-regional transmission and losses and increase the operating efficiency of the electrical system. To achieve the goal of reducing net emissions to "zero" by 2050, energy policy needs to promote different economic sectors to invest in energy storage systems at many different scales. Therefore, it is recommended that the authorities need to soon issue investment, operation, and price mechanisms for various types of energy storage in the power system.

6.2.1.3. Mechanism for Socialization of Power Transmission Grid

Before Law No. 03/2022/QH15 was enacted, the electricity development investment policy was stipulated in Clause 2, Article 4, Electricity Law No. 28/2004/QH11 as follows: "…attracting all sectors economic activities participating in electricity generation, electricity distribution, electricity wholesale, electricity retail, and specialized electricity consulting. The State has a monopoly on transmission and dispatching of the national power system and the construction and operation of large power plants, which have particularly important socio-economic, national defense, and security implications."

From March 1, 2022, Law No. 03/2022/QH15 takes effect, the electricity development investment policy is amended and supplemented in Clause 1, Article 6, Law No. 03/2022/QH15 as follows: " ...attract all economic sectors to participate in investment activities to build power transmission grids on the basis of ensuring national defense and security and according to electricity development planning, electricity generation, electricity distribution, and wholesale activities electricity, electricity retail and specialized electricity consulting. Non-state economic sectors are allowed to operate the power transmission grid they invested in and built."

Therefore, there is a big change in investment policy for electricity development in the future. In particular, non-state economic sectors can invest in building and operating power transmission grids, instead of the state having a monopoly on power transmission as before. This policy will affect the process of selecting investors for power transmission grid projects, encourage many different resources to participate in developing power transmission grids, and reduce investment pressure on state units. However, Law 03/2022/QH15 does not clearly state which power grid projects non-state economic sectors can invest in and build.

Allowing the socialization of investment in power transmission grids will contribute to ensuring the proactive progress of investment in construction of synchronous connection works of power plants (especially renewable energy power plants), reducing the burden on investment for the state. Proposing a number of mechanism contents as follows:

● Power transmission projects and power source clusters will be socialized for investment. The costs of these transmission projects will be equitably divided among all parties connected to the transmission project based on their influence and interests in the transmission project. It is necessary to develop a mechanism to allocate costs to all parties connected to the transmission project and to be fair. Cost allocation also needs to create incentives for transmission investment.

● To synchronize the power source and the power grid, consider building a mechanism to transfer investment in the power plant's synchronous power grid to power plant investors. The power plant's synchronous power grid will be invested and managed by the investor, and the cost will be accounted for in the electricity selling price of the power plant project. This will encourage investors to evaluate project effectiveness overall, choosing locations that are convenient for connection or areas that are not congested.

● The State needs a monopoly in both investment and operational management for the national electricity transmission system, which is the backbone and lifeblood of the National Electricity System. National power transmission grid projects (including backbone transmission grids and inter-regional connections serving power supply to loads) will be invested by EVN/EVNNPT.

● The process of investment, construction, and operation management of transmission projects must comply with strict and strict standards, processes and regulations to ensure quality, uniformity of equipment and coupling. connection... and ensure safety, stability, and reliability during the operation management process. Regulations are included in the Electricity Law for participating parties to comply with.

● Regarding asset management: power transmission grids invested by investors other than EVN will be the property of the investors, assets will not be handed over to EVN/EVNNPT.

● Regarding the management and operation of the power transmission grid system (in addition to the privately invested power transmission grid), EVNNPT will be responsible for management and operation. In which, EVNNPT can sign operating contracts for investors for power transmission grid projects invested by investors other than EVN.

In addition, it is necessary to consider having a mechanism to encourage private investment: (i) Self-invest in the connection grid (to the connection point) deep into the large load areas of the power system, without affecting backbone transmission lines of the power system; (ii) Self-hire available auxiliary services in the power system/ self-invest or rent services of energy storage sources to meet the need to regulate the power generation capacity of the plant, without affecting the power system.

It is necessary to soon complete the legal framework for the mechanism of socialization of investment in power transmission grids. It clarifies the provisions of the Electricity Law on State monopoly in transmission activities. Investment costs for power grids made by private investors must be controlled. The party receiving the power grid transfer must be able to control the quality of the projects being handed over. Mechanism for handing over the transmission grid to the electricity industry for management: there needs to be clear regulations on project handover methods, asset value, profit sharing mechanism...

6.2.1.4. Mechanism to Encourage Investment in Self-Consumed Solar Power Sources

According to Decision No. 500/QD-TTg dated May 15, 2023, approving PDP VIII with the goal of rooftop solar: "Strive to have 50% of office buildings and 50% of residential houses using self-produced and self-consumed rooftop solar power by 2030 (serves local consumption, does not sell electricity to the national electricity system). Regarding power source development plans: "Prioritize and have breakthrough policies to promote the development of solar power on people's rooftops and construction roofs, especially in areas at risk of electricity shortages like the North." and self-produced and self-consumed solar power. From now to 2030, the capacity of these types of power sources is estimated to increase by 2,600 MW. This type of power source is prioritized for unlimited capacity development, on the condition that the price is reasonable and takes advantage of the existing power grid, without having to be upgraded."

To realize the Government's goals of developing self-consumed power sources, the following contents are proposed:

- Currently, the law on electricity does not have regulations on self-consumed power sources, causing difficulties in implementation. Proposal to include a detailed definition of "self-consumed power sources" in the program to develop the Electricity Law (amended) to create a legal corridor for practical application and easy management, inspection, and supervision..

- Allowing rooftop solar power to be connected to the power system (connected behind the meter) without having to make a connection agreement with the power company because previously, when connecting during the process of supplying and using electricity, users have made connections according to regulations on distribution power systems with the condition that they do not transmit to the National grid (equipped with equipment to control the power transmitted to the grid)

- Self-consumed solar power not linked to the national grid is encouraged to develop and is allowed to sell electricity to organizations and individuals not affiliated with EVN according to the provisions of law.

- Encourage organizations and individuals to install rooftop solar power with energy storage batteries, and initially consider subsidizing storage batteries.

- Organizations and individuals installing rooftop solar power shall implement preferential policies on taxes, fees, and charges, according to the provisions of law on taxes, fees, and charges.

- For rooftop solar power sources linked to the electrical system, it is necessary to ensure compliance with strict regulations on connection requirements issued by EVN and must be equipped with equipment to control the amount of capacity broadcast to the net. During the operation management process, EVN is allowed to request organizations and individuals install rooftop solar power to adjust generating capacity or disconnect from the power grid in case it affects grid operation.

- Organizations and individuals investing, installing, and using rooftop solar power must ensure efficiency and requirements on electrical safety, construction safety, environment, and fire and explosion prevention according to current regulations.

6.2.1.5. Mechanism to Encourage Energy Saving and Demand Side Management

- Reviewing, amending, supplementing, and systematizing legal documents on economical and efficient use of energy; Researching and developing technical guidelines on economical and efficient use of energy; Researching and building an energy saving certification system for economical and efficient energy use solutions.

- Technical and financial support to promote investment, production, and business projects on economical and efficient use of energy for activities: production, manufacturing, renovation, and market transformation of equipment, machinery, production lines, public lighting, energy saving in households, etc.

- Financial incentive mechanisms need to be built based on the avoided costs of deflation of peak power plants. Research the electricity price mechanism and implement content on load adjustment through the electricity price mechanism. Customers who participate in demand control will receive financial incentives. Evaluation of different financial incentives for different customer groups (industry, commercial buildings, etc.) should be conducted through more detailed customer surveys on electricity consumption regimes, production characteristics and the ability to change production methods, characteristics of electricity-using technologies, costs of damage due to power supply interruption, etc. From there, a specific level of financial incentives for each customer group.

- Designing the retail electricity market allows groups of electricity customers to participate in bidding for acts of reducing electricity demand or shifting electrical equipment usage hours to off-peak hours.

- Equip the power system with smart control devices and advanced infrastructure to be suitable and ready to manage customers participating in demand side management.

6.2.1.6. Mechanism to Encourage Research and Testing of New Green Technologies

- Building funds to support research on technical standards, operations, and energy technologies that support green energy transition in Vietnam, such as carbon capture and storage system (CCS) and co firing biomass and hydrogen for thermal power plants.

- Strengthening international cooperation in training and capacity building in the design and use of new technologies.

- Assigning businesses with economic potential to research and implement a number of pilot projects on installing carbon capture and storage systems (CCS) for coal-fired power plants.

- Hydrogen is expected to be a fuel source in the future thanks to its green, clean, and carbon-free nature. Therefore, it is necessary to encourage research and autonomy in domestic hydrogen production technology to ensure fuel supply and avoid dependence on imported fuel.

6.2.2. Group of Financial and Capital Mobilization Mechanisms

6.2.2.1. Direct Electricity Trading Mechanism between Renewable Energy Generators and Electricity Customers (DPPA)

The DPPA mechanism allows electricity customers with commitments or goals to use clean energy and sustainable development (typically industrial or commercial customers) to access and buy electricity directly from units. Renewable energy generation through a long-term bilateral contract with price and contract term is agreed upon by both parties. To encourage the development of renewable energy sources, it is recommended to soon issue a direct power purchase and sale mechanism (DPPA) as a basis for units to implement.

6.2.2.2. Mechanism on Renewable Energy Portfolio Standard, Renewable Energy Certificates

The mechanism on renewable energy ratio standards can stipulate a prescribed proportion of renewable energy that must be produced by large-scale electricity producers and large electricity users.. Based on the Renewable Energy Development Strategy (Decision No. 2068/QD-TTg), this rate will not be less than 10% in 2030, and not less than 20% in 2050.

Renewable energy certificates (RECs) are trading tools used to meet voluntary renewable energy consumption targets or comply with renewable energy policy requirements. A REC unit is created when a renewable energy source generates one Megawatt hour (MWh) of electricity and sends it to the grid. Corporations, companies, non-profit organizations, or individuals anywhere can buy RECs if they do not generate enough renewable energy themselves. The benefit of RECs buyers is to use renewable energy without installing high-cost equipment such as solar panels or wind farms. They will enhance their competitive brand through supporting clean energy.

Electricity generated from the following sources will be eligible for RECs certificates: solar, wind, hydropower, biomass, biogas, and waste. The value of renewable energy certificates will be different for each power plant, depending on the type of technology, project location, and the time of certificate registration. The Ministry of Industry and Trade will be the unit issuing renewable energy certificates. Renewable energy certificate payment transactions will also be through the competitive electricity market.

6.2.2.3. Mechanism to Support Loans and Mobilize Foreign Capital

- Considering the special preferential loan support mechanism for key power plant and power grid projects to ensure that the project can arrange capital on schedule and ensure the operation plan according to planning.

- Although offshore wind power is related to national security issues, this type of source requires large investment capital, so it is recommended to consider allowing foreign investors to enter into joint ventures with domestic enterprises, with conditions ensuring commitments on confidentiality and respect for Vietnam's territorial sovereignty.

- Diversifying capital sources and forms of capital mobilization, effectively attracting domestic and foreign capital sources to develop electricity, and ensuring national defense, security, and competition in the electricity market. Strengthen calling and effective use of international support commitments (eg JETP, AZEC), green credit sources, climate credits, and green bonds.

6.2.3. Group of Management Mechanism

6.2.3.1. Mechanism for Managing Environmental Indicators of Power Plants

- To realize Vietnam's emission reduction commitment roadmap, it is necessary to issue detailed and strict targets on CO2, SO2, Nox, dust emissions, factory performance, etc. for each type of house and electric machine. Consider adjusting targets over 5-10 years to align with Vietnam's emissions reduction roadmap, aiming to achieve net zero emissions by 2050.

- Regularly monitor and periodically check the actual emission levels of power plants. Require all thermal power plants to be equipped with automatic emissions/waste monitoring systems and ensure that. There are strict sanctions for violations.

- Require all thermal power plants to be equipped with decarbonization equipment by 2050.

- Complete financial tools (environmental protection fees) for emissions in electricity production to create conditions for clean electricity production types (natural gas, LNG, hydrogen.) to compete with coal-fired power in the electricity market (Currently, coal power plants are required to install SO2, NOx and PM control equipment, but do not have to pay for emissions, so gas-fired power plants It will be difficult to compete with coal plants). Solutions to reduce emissions in electricity production need to be chosen in accordance with the development of the economy, maintaining harmonious development between fossil fuel sources to ensure energy security and do not increase electricity prices too high, but still ensure committed emission reduction targets.

- According to the Law on Environmental Protection No. 72/2020/QH14 dated November 17, 2020, Vietnam will organize and develop the domestic carbon market. Reducing greenhouse gas emissions through carbon finance is considered a catalyst to promote the development of renewable energy sources. This is also one of the important solutions contributing to Vietnam's goal of achieving net zero emissions by 2050.

- It is necessary to consider supplementing the Electricity Law on the mechanism to add emission costs in scheduling power source dispatching calculated by the market operator and system operator. It is necessary to calculate annual emissions valuation to incorporate into market regulations (expected to be issued by the Ministry of Natural Resources and Environment).

6.2.3.2. Support Mechanism for Coal-Fired Power Plants to Stop Deployment/Close Early

- Call for and effectively use international financial support sources during Vietnam's energy transition process, such as JETP, to compensate coal-fired power plants for stopping deployment or closing early. However, determining appropriate compensation costs is relatively complicated and needs to be established with clear targets.

- Developing a mechanism to support coal-fired power plants to equip additional decarbonization equipment or convert to other types of plants such as battery storage, flexible thermal power, renewable energy, etc.

- Developing a mechanism to support training for industry change or workplace change for employees in closed coal-fired power plants, ensuring social security for workers. Currently, the majority of coal-fired power plants are owned by EVN and PVN, so appropriate measures to transfer human resources can be considered when closing plants.

6.2.3.3. Complete the Mechanism to Build a Competitive Electricity Market

- Ensuring the construction of a fair electricity market where electricity prices reflect true costs, and avoiding cross-subsidy mechanisms.

- Developing a mechanism to encourage power plants to improve flexible operation capabilities to ensure the ability to operate highly integrated power systems with renewable energy sources. Regulations on flexibility need to be included in the Electricity Law so that investors can have the basis for implementing new power plants.

- Developing a mechanism to encourage existing thermal power plants to add equipment to increase flexibility and be ready to provide flexibility according to dispatching signals of the power system dispatcher:

To integrate renewable energy sources well, in the coming period, newly built and renovated thermal power plants (coal thermal power, CCGT) must be selected with new technological equipment to increase flexibility (more flexible unit commitment parameters such as minimum stable load and higher ramp rate). For systems that develop a lot of renewable energy, focusing on increasing the flexibility of thermal power plants will have higher system-wide economic efficiency than focusing on choosing high efficiency for thermal power plants. However, when the electricity market is not fully developed, this will affect the financial situation of thermal power plants, because they always have to reserve capacity for wind and solar power, but are not allowed to generate at high efficiency levels, the number of Tmax generation hours per year will be lower.

Therefore, flexibility standards need to be included in supply contracts as an additional criterion to develop a competitive market for flexibility. The electricity tariff for existing thermal power plants will be revised in accordance with the costs incurred to increase flexibility. Costs include:

+ Capital Expenditure (CAPEX): This is a one-time expenditure incurred in installing various equipment required to make the plant capable of operating at low loads and enhancing ramp-up/down capacity load.

+ Operating Expenses (OPEX): This is the recurring cost of operating flexibly due to factors such as increased O&M costs and reduced efficiency.

- Coal and gas thermal power plants will need to operate more flexibly in a highly integrated renewable energy power system (reduced operating hours in comparison to traditional power system)). It is necessary to have incentives on capacity price mechanisms and ancillary service prices to ensure economic and financial targets of gas power plants. At the same time, in the future, it is necessary to avoid signing electricity purchase contracts that stipulate annual electricity output.

- Develop a mechanism to encourage investment in flexible power sources (ICE, SCGT, thermal power plants, storage batteries):

The current market structure and current legal framework do not support investment in building flexible sources such as ICE (Internal Combustion Engines), single cycle gas turbines, pumped storage hydropower, and storage batteries. These projects are currently very difficult to prove investment efficiency in order to mobilize capital for construction. Therefore, it is necessary to build new market mechanisms and tariff structures to encourage the development of flexible sources. While the market is not yet complete, it is necessary to build a mechanism to support capacity prices and electricity prices for flexible power sources to promote this type.

PSPP and storage batteries should be generally understood as a semi-regulated activity, with the main goal of ensuring flexibility in the power system while ensuring security of supply. Due to the "semi-regulated" nature of storage, pumped storage resources should be owned by a separate entity, a "storage system operator".

● In addition, it is necessary to consider adding the following mechanisms in building the ancillary services market to fully recover costs and encourage the private sector to invest: mechanism to develop public ancillary services power, voltage control; Mechanism for auxiliary services to compensate the generator set to increase system inertia and Short Circuit Ratio for power grids with centralized connection of renewable energy sources;

mechanism to bind capacity forecasting responsibilities and penalties for renewable energy sources when causing a burden for capacity reserve arrangements in the system, or to improve forecast quality.

- To be able to flexibly dispatch hydropower sources, consider building a mechanism that allows flexible adjustment of hydropower reservoir exploitation in the context of high penetration of renewable energy.

7. CONCLUSIONS AND

7.1. Conclusions

In the context of countries around the world joining hands to protect the environment, gradually shifting from using fossil fuels to green fuels, although Vietnam is a developing country, it is not outside the trend, making a strong commitment to cutting emissions. At the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change (COP26), the Government of Vietnam committed to achieving net zero emissions by 2050. Immediately after COP26, Vietnam has urgently concretized and immediately started implementing its commitments to the international community. Notably, the completion of the National Power Development Plan for the period 2021-2030, with a vision to 2050; develop a Project on tasks and solutions to implement the results of COP26 Conference; National Strategy on climate change for the period up to 2050; Action program on green energy conversion, reducing carbon and methane emissions of the transportation sector; National action plan on green growth for the period 2021-2030; Action plan to reduce methane emissions until 2030.

For the power sector, the National Power Development Plan for the period 2021-2030, with a vision to 2050, was approved by the Prime Minister in Decision No. 500/QD-TTg dated May 15, 2023. Accordingly, this National Power Development Plan has made breakthroughs in realizing Vietnam's commitment to green energy transition: (i) Strongly developing renewable energy sources to serve electricity production, reaching a rate of about 30.9 - 39.2% by 2030, aiming for a renewable energy rate of 47% provided that commitments under the Political Declaration establishing the Transition Partnership Fair Energy Exchange (JETP) with Vietnam is fully and practically implemented by international partners. By 2050, the proportion of renewable energy will reach 67.5 - 71.5%; (ii) Control greenhouse gas emissions from electricity production to about 204 - 254 million tons in 2030 and about 27 - 31 million tons in 2050. Aim to reach peak emissions of no more than 170 million tons in 2030. 2030 on condition that commitments under JETP are fully and substantially implemented by international partners; (iii) Orientation for converting fuel to biomass and ammonia with coal-fired power plants that have been in operation for 20 years when the price is appropriate. Stop operating plants with a lifespan of over 40 years if fuel conversion is not possible. Orientation for 2050 is to no longer use coal to generate electricity. Thus, for current and existing coal-fired power plants in PDP VII, PDP VIII orients a roadmap for gradually converting to greener, cleaner fuels such as biomass or ammonia, with a gradually increasing co-firing ratio and aim for a complete fuel switch before 2050.

Because the Northeast region has many coal mines with large reserves (Quang Ninh province), the North has developed many large coal-fired power sources such as Quang Ninh Thermal Power Plant (1200 MW), Hai Phong Thermal Power Plant (1200 MW), Thang Long Thermal Power Plant (620 MW), Mong Duong I Thermal Power Plant (1120 MW), Mong Duong II Thermal Power Plant (1245 MW), etc. By the end of 2022, the total coal thermal power installed capacity of the North will reach about 15 GW.

Compared to PDP VII Revised approved in 2016, up to now, a number of coal-fired power plants in the North have had to stop deploying such as Cam Pha III, Hai Phong III and Quang Ninh III due to lack of local consensus. In addition, due to the trend of energy transition as well as the commitments of Vietnam and other countries around the world on greenhouse gas reduction, many implementing coal-fired power projects have difficulty in arranging capital such as Nam Dinh I and Cong Thanh thermal power plants. For these projects, the Ministry of Industry and Trade will work with investors. If they cannot be implemented until June 2024, they must consider terminating in accordance with the law. Total installed capacity of coal-fired power of the whole country by 2030 is estimated at 30 GW, of which about 20 GW in the North. To compensate for the reduced capacity of coal-fired power plants, PDP VIII has proposed to develop an additional 7.5 GW of LNG thermal power by 2030, and at the same time accelerate the development of more solar power, onshore/near-shore wind power and offshore wind power.

According to the Government's energy transition orientation stated in the National Strategy on Climate Change approved by the Prime Minister in Decision 896/QD-TTg dated July 26, 2022, Vietnam will not develop more new coal-fired power sources after 2030. PDP VIII also orients the fuel conversion roadmap for coal-fired power sources. Accordingly, converting fuel to biomass and ammonia with power plants that have been in operation for 20 years when the price is suitable; shutting down power plants with a lifetime of more than 40 years if fuel conversion is not possible; orientation to 2050 no longer use coal for power generation, completely switching fuels to biomass and ammonia. However, at present, the fuel conversion option for coal-fired power plants has only been studied at a very preliminary level. Many opinions are concerned about the uncertain supply of biomass fuel and ammonia as an alternative to coal-fired power plants with large capacity. In case coal-fired power plants cannot convert fuel but have to stop operating in 2050 to ensure Vietnam's commitment to Net zero, a large amount of green capacity is needed in the North to replace them.

This study will research and calculate the roadmap for developing power generation in the case of stopping coal power plants in the North. In accordance with the green development orientation of the energy industry, renewable energy sources will be expected to gradually replace fossil fuels, especially coal. The main results of the study include:

❖ Regarding the Power Source Development Program

The study calculated and compared the power source development program to replace coal-fired power plants in the North according to the following scenarios:

- Scenario 0: Fuel conversion for Northern coal-fired power plants according to the roadmap of PDP VIII.

- Scenario 1: Closing coal-fired power plants in the North after 30 years of operation. By 2050, power plants that have not been in operation for 30 years will still have to close by 2050.

- Scenario 2: Closing coal-fired power plants in the North after 40 years of operation. By 2050, power plants that have not been in operation for 40 years will still have to close by 2050.

Each group of scenarios will be calculated for the high emission case (corresponding to the emission level of 204 - 254 million tons of CO2 in 2030) and the low emission case (corresponding to the emission level of 170 million tons of CO2 in 2030).

In the calculations, the study provides preliminary estimates of the costs to close a coal-fired power plant in addition to the basic costs of electricity production technologies. These costs include equity payment costs, unemployment support costs for employees, operating and maintenance costs during the preparation period, slag dump cleaning costs, dismantling fees, etc. In addition, coal-fired power plants that operate for more than 30 years (the average economic life), must pay a cost to extend their life. This ensures plant recovery to near original state in terms of availability, performance, operating characteristics, and operating and maintenance costs.

After comparing the calculation results between the scenarios, the study proposes to choose Scenario 2 in both high and low emission cases for the following reasons:

- There is no volume of investment in inter-regional power transmission grids.

- The plan to close coal-fired power plants under Scenario 2 will not affect the scale of the national power source in the period up to 2030 compared to PDP VIII.

- Net present value (NPV) of system costs for the period 2021-2050 (including investment costs, operating and maintenance costs, fuel costs, inter-regional transmission costs, power shortage costs, and emission costs) is the lowest among the scenarios.

With the assumption that CO2 emission quotas are guaranteed as in the roadmap to reduce CO2 emissions of PDP VIII, in order to close all coal-fired power plants in the North, the power system will need to invest earlier and more in renewable energy power sources, flexible power sources, and storage sources compared to the power source investment volume of PDP VIII. In the period up to 2035, the scale of the Northern power source needs to be accelerated from 2040 of PDP VIII to 2035 as follows:

- High emission case: Increase 500 MW onshore wind power, 1000 MW offshore wind power, 14000 MW solar power source, and 300MW storage power source, and decrease 300MW in flexible power source.

- Low emission case: Increase 1900MW of onshore wind power, 1000MW of offshore wind power, 6500 MW of solar power, and 300MW of storage power.

In the period up to 2050, the scale of power sources in the North needs to be supplemented compared to PDP VIII as follows:

- High emissions case: Increase 2000 MW offshore wind power, 2000MW solar power generation, 4200 MW storage power generation, and 10,100MW flexible hydrogen thermal power generation.

- Low emission case: Increase 2000 MW offshore wind power, 3000MW solar power, 4200 MW storage power and 10,000 flexible hydrogen thermal power generation.

❖ Regarding the Backbone Transmission Grid Development Program

Corresponding to the two proposed power source development scenarios in the case of high emission and the case of low emission, there is no increase in the amount of investment in inter-regional power transmission grid compared to PDP VIII.

In case of high emissions: The volume of investment in new construction and renovation of transmission grid projects is about 43,950 MVA of 500 kV transformer, 59,700 MVA of 220 kV transformer, 5,991 km of 500 kV line, 10,330 km of 220 kV line in the period of 2023 - 2030, about 222,609 MVA of 500 kV transformer, 159,000 MVA of 220 kV transformer, 5,583 km of 500 kV line, and 5,019 km of 220 kV line in the period 2031 - 2050.

In case of low emissions: The volume of investment in new construction and renovation of transmission grid projects is about 48,450 MVA of 500 kV transformer, 60,950 MVA of 220 kV transformer, 6767 km of 500 kV line, 10,386km of 220 kV line in the period of 2023 - 2030, about 227,100 MVA of 500 kV transformer, 161,000 MVA of 220 kV transformer, 5,407 km of 500 kV line, and 5,083 km of 220 kV line in the period 2031 - 2050.

❖ Investment Cost Need:

High Emission Case:
The total investment capital of Northern power sources in the period 2023 - 2030 will be 44.4 billion USD, equivalent to an average investment of approximately 5.6 billion USD per year during this period.

The total investment capital of the Northern power source oriented for the period 2031 - 2050 is 185.4 billion USD, equivalent to an average investment of approximately 9.27 billion USD per year during this period.

Although the volume of renewable energy sources that must be invested in the period after 2030 is very large, the investment rate of these types of sources decreases significantly over time, competing well with traditional power sources. Besides, the operating costs of renewable energy sources such as wind power and solar power are also smaller due to no fuel costs.

In addition to the investment cost to build new types of power sources, Scenario 2A also has to spend about 6.9 billion USD on investment costs energy transition of coal-fired power plants. This cost includes equity payment costs, unemployment support costs for employees, operating and maintenance costs during the preparation period, costs for cleaning the slag dump, and dismantling costs.

Investment cost for the power transmission grid in the North is estimated at about 8 billion USD in the period 2023-2030 and about 15.4 billion USD in the period 2031-2050. Therefore, the investment cost needed for the Northern power transmission grid is estimated to average about 1 billion USD/year in the period 2023-2030 and about 0.8 billion USD/year in the period 2031-2050.

Low emission case:
The total investment cost of Northern power sources in the period 2023 - 2030 in Scenario 2B will be 60.7 billion USD (about 16.3 billion USD higher than Scenario 2A), corresponding to an average investment of approximately 7.6 billion USD per year during this period.

The total investment cost of Northern power sources oriented for the period 2031 - 2050 in Scenario 2B is 183.3 billion USD, corresponding to an average investment of approximately 9.17 billion USD per year during this period.

To promote the reduction of CO_2 emissions to peak in 2030, the period 2023-2030 will have to increase investment in renewable energy sources, leading to relatively large investment costs for power sources.

In addition to the investment cost to build new types of power sources, Scenario 2B also has to spend about 6.9 billion USD on investment costs energy transition of coal-fired power plants. This cost includes equity payment costs, unemployment support costs for employees, operating and maintenance costs during the preparation period, costs for cleaning the slag dump, and costs of dismantling.

For scenario 2B, investment cost for the power transmission grid in the North is estimated at about 8.5 billion USD in the period 2023-2030 (about 0.5 billion USD higher than scenario 2A) and about 15.5 billion USD in the period 2031-2050 (about 0.1 billion USD higher in scenario 2A). Therefore, the investment cost needed for the Northern power transmission grid is estimated to average about 1.1 billion USD/year in the period 2023-2030 and about 0.8 billion USD/year in the period 2031-2050.

7.2. Recommendations

Through the analysis and calculations of the study, the implementation team has a number of recommendations as follows:

● It is recommended that coal-fired power plants in the North in general and the country in particular need to carry out systematic and detailed studies on the roadmap to stop using coal fuel because the current PDP VIII only provides a general roadmap. The roadmap to stop using coal fuel will depend on geographical location, project characteristics, etc. and is not the same for individual projects.

● To realize Vietnam's emission reduction commitment roadmap, it is necessary to issue detailed and strict targets on CO2, SO2, Nox, dust emissions, factory performance, etc. for each type of power plant. Considering adjusting targets in about 5-10 years to be consistent with Vietnam's emissions reduction roadmap, aiming to achieve net zero emissions by 2050. At the same time, regularly monitoring the actual emission levels of factories.; Further, requiring all thermal power plants to be equipped with automatic emissions/waste monitoring systems and instituting strict sanctions for violations. The experience of developed countries in the world, such as the UK and Germany, shows that the main driving force in energy transition at coal-fired power plants is to ensure compliance with strict regulations on Government environment.

● Currently, data on the cost of closing coal-fired power plants is limited. The study has only stopped at a preliminary estimate according to references around the world. Social costs have characteristics associated with the culture and policies of countries. Therefore, it is recommended that there should be more in-depth studies and surveys to accurately assess the costs of closing coal-fired power plants in Vietnam, ensuring accuracy, completeness, and widespread acceptance.

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ANNEX 1: NATIONAL DEMAND FORECAST

Table 1 Forecast of national electricity load demand according to scenarios up to 2050

STT	Scenario/year	Unit	2020	2025	2030	2035	2040	2045	2050
I	**Commercial Electricity**								
	Base Scenario	Bil kWh	217	335	505	686	853	991	1114
	High Scenario	Bil kWh	217	335	505	718	922	1097	1255
II	**Electricity produced and imported**								
	Base Scenario	Bil kWh	247	378	567	766	946	1092	1224
	High Scenario	Bil kWh	247	378	567	801	1023	1208	1379
III	**Pmax**								
	Base Scenario	GW	39	59	91	119	147	170	185
	High Scenario	GW	39	59	91	125	159	188	209

Table 2 National sale electricity growth rate in scenarios

Scenario	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Base Scenario	9.1%	8.6%	6.3%	4.4%	3.1%	2.4%
High Scenario	9.1%	8.6%	7.3%	5.1%	3.5%	2.7%

ANNEX 2: LIST OF LARGE POWER SOURCES PRIORITIZED FOR INVESTMENT AND DEVELOPMENT IN THE NORTH

Table 3 List of large power sources prioritized for investment and development in the North

No	Power plant	Capacity (MW)	Type	Province/City	Progress according to PDP VIII
1	TPP Na Duong II	110	Coal	Lang Son	2021-2030
2	TPP An Khanh - Bac Giang	650	Coal	Bac Giang	2021-2030
3	TPP Vung Ang II	1330	Coal	Ha Tinh	2021-2030
4	TPP Quang Trach I	1403	Coal	Quang Binh	2021-2030
5	TPP cogeneration Hai Ha 1	300	Cogeneration	Quang Ninh	2021-2030
6	TPP cogeneration Hai Ha 2	600	Cogeneration	Quang Ninh	2031-2035
7	TPP cogeneration Hai Ha 3	600	Cogeneration	Quang Ninh	2031-2035
8	TPP cogeneration Hai Ha 4	600	Cogeneration	Quang Ninh	2031-2035
9	TPP cogeneration Duc Giang	100	Cogeneration	Lao Cai	2021-2030
10	Formosa HT2	650	Cogeneration	Ha Tinh	2021-2030
11	LNG Quang Ninh	1500	LNG	Quang Ninh	2021-2030
12	LNG Thai Binh	1500	LNG	Thai Binh	2021-2030
13	LNG Nghi Son	1500	LNG	Thanh Hoa	2021-2030
14	LNG Quang Trach II	1500	LNG	Quang Binh	2021-2030
15	LNG Quynh Lap/Nghi Son	1500	LNG	Nghe An/Thanh Hoa	2021-2030
16	HPP Hoa Binh extended	480	Hydro	Hoa Binh	2021-2030
17	HPP Long Tao	44	Hydro	Dien Bien	2021-2030
18	HPP Yen Son	90	Hydro	Tuyen Quang	2021-2030
19	HPP Song Lo 6	60	Hydro	Ha Giang	2021-2030
20	HPP Song Lo 7	36	Hydro	Ha Giang	2021-2030
21	HPP Pac Ma	160	Hydro	Lai Chau	2021-2030
22	HPP Nam Cum 1,4,5	95,8	Hydro	Lai Chau	2021-2030
23	HPP Nam Cum 2,3,6	79,5	Hydro	Lai Chau	2021-2030

No	Power plant	Capacity (MW)	Type	Province/City	Progress according to PDP VIII
24	HPP Thanh Son	40	Hydro	Thanh Hoa	2021-2030
25	HPP Cam Thuy 2	38	Hydro	Thanh Hoa	2021-2030
26	HPP Suoi Sap 2A	49,6	Hydro	Son La	2021-2030
27	HPP Hoi Xuan	102	Hydro	Thanh Hoa	2021-2030
28	HPP Song Hieu (Ban Mong)	45	Hydro	Nghe An	2021-2030
29	HPP My Ly	120	Hydro	Nghe An	2021-2030
30	HPP Nam Mo 1 (Viet Nam)	51	Hydro	Nghe An	2021-2030

ANNEX 3: LIST OF TRANSMISSION LINE AND SUBSTATION IN THE NORTH IN THE PERIOD UP TO 2030

Table 4 List of 500 kV substation in the North in the period up to 2030

No	Substation	Capacity (MVA)	Note
1	Tay Ha Noi	1800	Upgrade
2	Long Bien	1800	New build
3	Son Tay	900	New build
4	Dan Phuong	1800	New build
5	Nam Ha Noi	900	New build
6	Hai Phong	1800	New build
7	Gia Loc	900	New build
8	Pho Noi	1800	New build
9	Hung Yen	900	New build
10	Nam Dinh	2700	New build
11	Thai Binh	1.200	New build
12	Nho Quan	1800	Upgrade
13	Hoa Binh 2	Switch station	New build
14	Lao Cai	2700	New build
15	Thai Nguyen	900	New build
16	Viet Tri	1800	Upgrade
17	Vinh Yen	1800	New build
18	Bac Giang	900	New build
19	Yen The	900	New build
20	Bac Ninh	1800	New build
21	Quang Ninh	1.200	Upgrade
22	Lai Chau	2700	Upgrade
23	Son La	2700	Upgrade
24	Hoa Binh	1800	Upgrade
25	Thanh Hoa	1800	New build
26	Nghi Son	1800	Upgrade
27	Nam Cam		500 kV switch station, connecting transit on 01 circuit of 500 kV Vung Ang - Nho Quan transmission line (new)
28	Quynh Luu	1800	New build
29	Bac Bo 1 (*)	1800	New build
30	Bac Bo 2 (*)	1800	New build
31	Bac Bo 3 (*)	900	New build

No	Substation	Capacity (MVA)	Note
32	Lang Son (*)	1800	New build
33	Provision for arising 500kV substations for new construction, renovation and capacity improvement	1800	Provision for demand growth and power source development

Table 5 List of 500 kV liness in the North in the period up to 2030

No	Line	No of circuit	x	km
1	Tay Ha Noi - Thuong Tin	2	x	40
2	Second circuit of Nho Quan - Thuong Tin	1	x	75
3	Hai Phong - Thai Binh	2	x	35
4	TPP Nam Dinh I - Pho Noi	2	x	123
5	TPP Nam Dinh I - Thanh Hoa	2	x	73
6	Thai Binh transit on TPP Nam Dinh I - Pho Noi	4	x	2
7	Lao Cai - Vinh Yen	2	x	210
8	Vinh Yen transit on Son La - Hiep Hoa and Viet Tri - Hiep Hoa	4	x	5
9	Bac Ninh transit on Dong Anh - Pho Noi	2	x	3
10	Connecting HPP Hoa Binh extended	2	x	2
11	Thanh Hoa transit on Nho Quan - Ha Tinh	2	x	5
12	TPP Cong Thanh transit on Nghi Son - Nho Quan	2	x	5
13	Quynh Luu - Thanh Hoa	2	x	91
14	Quang Trach - Quynh Luu	2	x	226
15	Vung Ang transit on Ha Tinh - Da Nang (3, 4 circuit)	2	x	16
16	Vung Ang - Quang Trach	2	x	33
17	Long Bien transit on Pho Noi - Thuong Tin	2	x	5
18	Tay Ha Noi - Vinh Yen	2	x	44
19	Nam Ha Noi transit on Nho Quan - Thuong Tin	4	x	5
20	Dan Phuong transit on Tay Ha Noi - Vinh Yen	4	x	5
21	Son Tay - Dan Phuong	2	x	20
22	Gia Loc transit on Thai Binh - Pho Noi	4	x	13
23	Hung Yen transit on LNG Nghi Son - Long Bien	4	x	5

No	Line	No of circuit	x	km
24	Hoa Binh 2 transit on Hoa Binh - Nho Quan	4	x	5
25	Sam Nuea - Hoa Binh 2	2	x	110
26	Hoa Binh 2 - Tay Ha Noi	2	x	80
27	Lang Son transit on Bac Bo 3 - Thai Nguyen (*)	4	x	5
28	Hiep Hoa - Thai Nguyen	2	x	34
29	Bac Giang - Bac Ninh	2	x	40
30	Bac Giang transit on Quang Ninh - Hiep Hoa	4	x	5
31	Yen The transit on Bac Bo 3 - Thai Nguyen	4	x	10
32	LNG Quang Ninh I - Quang Ninh	2	x	30
33	Upgrade Vung Ang - Nho Quan (first circuit)	2	x	360
34	Nam Cam transit on Vung Ang - Nho Quan	2	x	12
35	LNG Quang Trach II - Quang Trach	2	x	1
36	Bac Bo 1 - Hai Phong (*)	2	x	25
37	Bac Bo 3 - Thai Nguyen (*)	2	x	250
38	Bac Bo 2 - Thai Binh (*)	2	x	50
39	LNG Nghi Son - Long Bien	2	x	212
40	LNG Nghi Son - LNG Quynh Lap	2	x	25
41	Connecting LNG North (Quynh Lap/Nghi Son)	40		
	Provision for arising 500kV transmission line renovation and new construction	400		

Table 6 List of 220 kV substation in the North in the period up to 2030

No	Substation	Capacity (MVA)	Note
1	Van Tri	750	Upgrade
2	Tay Ha Noi	750	Upgrade
3	Long Bien	750	Upgrade
4	Thanh Xuan	750	New build
5	Dai Mo (My Dinh)	750	New build
6	Hoa Lac	500	New build
7	Me Linh	500	New build
8	Van Dien	750	New build
9	Long Bien 2 (Gia Lam)	750	New build
10	Soc Son 2	500	New build

No	Substation	Capacity (MVA)	Note
11	Phu Xuyen	500	New build
12	Hoa Lac 2	500	New build
13	Dan Phuong	500	New build
14	Chuong My	250	New build
15	Cau Giay	500	New build
16	Hai Ba Trung	500	New build
17	Ung Hoa	500	New build
18	Vat Cach	500	Upgrade
19	ND Hai Phong	500	Upgrade
20	Thuy Nguyen	500	Upgrade
21	Duong Kinh	500	New build
22	An Lao	500	New build
23	Cat Hai	500	New build
24	Dai Ban	250	New build
25	Do Son	250	New build
26	Tien Lang	250	New build
27	Gia Loc	500	New build
28	Tan Viet	500	New build
29	TPP Pha Lai	750	Upgrade
30	Thanh Ha	250	New build
31	TPP Hai Duong	500	Upgrade
32	Tu Ky	250	New build
33	Nhi Chieu	250	New build
34	Yen My	500	New build
35	Pho Noi 500 kV	500	New build
36	Pho Cao	500	New build
37	Bai Say	500	New build
38	Hung Yen (TP Hung Yen)	250	New build
39	Van Giang	250	New build
40	Dong Van	500	New build
41	Ly Nhan	500	New build
42	Hai Hau	500	New build
43	Nam Dinh 3	750	New build
44	Nam Dinh 2	250	New build
45	Nghia Hung	250	New build

No	Substation	Capacity (MVA)	Note
46	Thai Thuy	500	Upgrade
47	Vu Thu	500	New build
48	Quynh Phu	250	New build
49	Thai Binh 500 kV	250	New build
50	Nho Quan 500 kV	500	Upgrade
51	Ninh Binh 2	500	New build
52	Tam Diep	250	New build
53	Gia Vien	500	New build
54	Bac Quang	500	New build
55	Ha Giang	375	Upgrade
56	Cao Bang	500	Upgrade
57	Bat Xat	500	New build
58	Lao Cai 500 kV	500	New build
59	Van Ban	250	New build
60	Bac Ha	250	New build
61	Bac Kan	375	Upgrade
62	Dong Mo	250	New build
63	Lang Son	500	New build
64	Lang Son 1 (*)	500	New build
65	Lang Son 2 (*)	500	New build
66	Tuyen Quang	500	Upgrade
67	Nghia Lo	250	New build
68	Luc Yen	250	New build
69	Yen Bai	500	Upgrade
70	Luu Xa	500	Upgrade
71	Song Cong	250	New build
72	Phu Binh 2	750	New build
73	Dai Tu	250	New build
74	Bac Giang 1 (*)	500	New build
75	Viet Tri 500 kV	500	New build
76	Phu Tho 2	500	New build
77	Phu Tho 3	250	New build
78	Vinh Tuong	500	Upgrade
79	Ba Thien	500	New build
80	Phuc Yen	250	New build

No	Substation	Capacity (MVA)	Note
81	Chan Hung	250	New build
82	Tam Duong	500	New build
83	Yen Dung	500	New build
84	Lang Giang	500	New build
85	Hiep Hoa 2	250	New build
86	Bac Giang 500 kV	250	New build
87	Viet Yen	250	New build
88	Tan Yen	250	New build
89	Bac Ninh 6	500	New build
90	Bac Ninh 4	500	New build
91	Bac Ninh 500 kV	500	New build
92	Bac Ninh 7	250	New build
93	Bac Ninh 5	500	New build
94	Trang Bach	500	Upgrade
95	Hoanh Bo	500	Upgrade
96	Quang Ninh 500 kV	500	Upgrade
97	Hai Ha	500	Upgrade
98	Yen Hung	750	New build
99	Cong Hoa	250	New build
100	Khe Than	126	New build
101	Mong Cai	250	New build
102	Cam Pha	500	Upgrade
103	Nam Hoa	500	New build
104	KCN Hai Ha	500	New build
105	Quang Ninh 1 (*)	500	New build
106	Muong Te	750	Upgrade
107	Than Uyen	750	Upgrade
108	Sin Ho	250	New build
109	Phong Tho	750	New build
110	Pac Ma	750	New build
111	Dien Bien	500	New build
112	Dien Bien 1 (*)	500	New build
113	Muong La	500	Upgrade
114	Suoi Sap 2A	200	New build
115	Phu Yen	375	New build

No	Substation	Capacity (MVA)	Note
116	Moc Chau	250	New build
117	Song Ma	250	New build
118	Son La 1 (*)	500	New build
119	Yen Thuy	250	New build
120	Hoa Binh	500	Upgrade
121	Tan Lac	250	New build
122	Bim Son	500	Upgrade
123	Nong Cong	500	Upgrade
124	KKT Nghi Son	750	New build
125	Tinh Gia	500	New build
126	Sam Son	500	New build
127	Hau Loc	500	New build
128	Thieu Hoa	250	New build
129	Ba Thuoc	250	New build
130	Thanh Hoa 1 (*)	250	New build
131	Dong Vang	500	New build
132	Thieu Yen	250	New build
133	Tuong Duong	250	New build
134	Nam Cam	500	New build
135	Quy Hop	250	New build
136	Do Luong	500	Upgrade
137	Ha Tinh	500	Upgrade
138	Vung Ang	500	New build
139	Vung Ang 2	500	New build
140	Can Loc	250	New build
141	Nghi Son 2	500	New build
142	Ha Tinh 1 (*)	500	New build
143	Provision for generating new 220kV substations, renovating and increasing capacity	2.000	Provision for load growth and power source development

Table 7 List of 220 kV substation in the North in the period up to 2030

No	Line	No of circuit x km		
1	Van Dien transit on Ha Dong - Thuong Tin	4	x	4
2	Tay Ha Noi - Thanh Xuan	4	x	16
3	500 kV Dong Anh - Van Tri	2	x	13
4	Upgrade Hoa Binh - Chem	1	x	74
5	Upgrade Ha Dong - Chem	1	x	16
6	Dai Mo (My Dinh) transit on Tay Ha Noi - Thanh Xuan	4	x	2
7	Me Linh transit on Soc Son - Van Tri	2	x	2
8	500 kV Tay Ha Noi - Hoa Lac	2	x	14
9	Ung Hoa transit on Ha Dong - Phu Ly	2	x	4
10	Second circuit of Ha Dong - Ung Hoa - Phu Ly	2	x	40
11	Upgrade Hiep Hoa - Soc Son	2	x	10
12	Upgrade Ha Dong - Thuong Tin	2	x	16
13	Upgrade 220 kV Son Tay - Vinh Yen	2	x	30
14	Long Bien - Mai Dong	2	x	16
15	Long Bien 2 transit on Mai Dong - Long Bien	4	x	3
16	Upgrade Thuong Tin - Pho Noi	2	x	33
17	Upgrade Xuan Mai - Ha Dong	1	x	25
18	Upgrade Van Tri - Tay Ho - Chem	2	x	20
19	An Lao transit on Dong Hoa - Thai Binh	4	x	2
20	Cat Hai - Dinh Vu	2	x	12
21	Duong Kinh transit on Dong Hoa - Dinh Vu	4	x	3
22	Nam Hoa - Cat Hai	2	x	12
23	TPP Hai Duong - Pho Noi 500 kV	2	x	60
24	Gia Loc transit on TPP Hai Duong - Pho Noi	4	x	5
25	Bai Say - Kim Dong	2	x	12
26	500 kV Hai Phong - Gia Loc	2	x	35
27	Thanh Ha transit on 500 kV Hai Phong - Gia Loc	2	x	7
28	Tan Viet (Binh Giang) transit on Gia Loc - Pho Noi	4	x	3
29	Yen My transit on Pho Noi 500kV - Thuong Tin 500 kV	2	x	2
30	Pho Cao transit on Thai Binh - Kim Dong	4	x	1
31	Second circuit of Nho Quan - Phu Ly	2	x	27
32	Ly Nhan transit on Thanh Nghi - Thai Binh	4	x	2
33	Dong Van - Phu Ly	2	x	15
34	TPP Nam Dinh 500 kV - Ninh Binh 2	2	x	30
35	Hai Hau - Truc Ninh	2	x	16

No	Line	No of circuit x km		
36	TPP Nam Dinh 500 kV - Hai Hau	2	x	10
37	TPP Nam Dinh 500 kV - Hau Loc	2	x	48
38	TPP Nam Dinh 500 kV - Nam Dinh 3	2	x	18
39	Vu Thu transit on Thai Binh - Nam Dinh and Thai Binh - Ninh Binh	4	x	2
40	Upgrade Dong Hoa - Thai Binh	2	x	53
41	Thai Binh 500kV - Thanh Nghi	2	x	60
42	Thai Binh 500 kV transit on Thai Binh - Kim Dong	4	x	5
43	Tam Diep transit on Bim Son - Ninh Binh	4	x	5
44	Gia Vien transit on Nho Quan 500 kV - Ninh Binh	4	x	2
45	Gia Vien - Nam Dinh	2	x	7
46	Upgrade Nho Quan 500kV - Ninh Binh	2	x	26
47	Upgrade Tam Diep - Gia Vien - Bim Son	2	x	34
48	Ninh Binh 2 transit on Ninh Binh - Thai Binh	2	x	19
49	Bac Quang transit on Bao Thang - Yen Bai (Bac Quang - Luc Yen)	2	x	43
50	Upgrade Ha Giang - Viet Nam border - Trung Quoc	1	x	30
51	Bac Quang - Viet Nam border - Trung Quoc	2	x	55
52	Upgrade Ha Giang transit on HPP Bac Me va Ha Giang - Thai Nguyen	42	+	51
53	Upgrade Cao Bang - Bac Kan	1	x	71
54	Lao Cai - Bao Thang	2	x	18
55	Connecting 500 kV Lao Cai	4	x	5
56	Bat Xat - 500 kV Lao Cai	2	x	42
57	Than Uyen - 500 kV Lao Cai	2	x	65
58	500 kV Lao Cai - Viet Nam border - Trung Quoc	2	x	40
59	HPP Bac Ha - 500 kV Lao Cai	1	x	5
60	Bac Giang - Lang Son	2	x	102
61	Dong Mo transit on Bac Giang - Lang Son	4	x	3
62	HPP Yen Son transit on HPP Tuyen Quang - Tuyen Quang	2	x	8
63	Upgrade Yen Bai - Viet Tri	2	x	67
64	Huoi Quang - Nghia Lo	2	x	103
65	Nghia Lo - Viet Tri (500 kV Viet Tri)	2	x	93
66	Luc Yen transit on Lao Cai - Yen Bai	4	x	5
67	Bac Quang - Luc Yen	2	x	1
68	Upgrade Yen Bai - Tuyen Quang	2	x	36
69	Upgrade Luc Yen - Yen Bai	2	x	58
70	500 kV Hiep Hoa - Phu Binh 2	2	x	14

No	Line	No of circuit x km		
71	Song Cong transit on Tuyen Quang - Phu Binh	2	x	2
72	Phu Binh 2 transit on Thai Nguyen - Bac Giang	2	x	13
73	Upgrade Hiep Hoa - Phu Binh	1	x	10
74	Upgrade Thai Nguyen - Luu Xa - Phu Binh	1	x	30
75	500 kV Viet Tri - Viet Tri	2	x	10
76	Upgrade 500kV Viet Tri - Vinh Tuong	1	x	27
77	Upgrade 500 kV Viet Tri - Vinh Yen	1	x	36
78	500 kV Viet Tri - Ba Thien (500 kV Vinh Yen)	2	x	43
79	Phu Tho 2 transit on Son La - Viet Tri	2	x	1
80	Ba Thien (Vinh Yen 500 kV) transit on Vinh Yen - Soc Son	2	x	13
81	Tam Duong tran sit on 500 kV Viet Tri - Ba Thien (500 kV Vinh Yen)	4	x	2
82	Vinh Yen 500 kV - Me Linh	2	x	25
83	Me Linh transit on Soc Son -Van Tri (circuit 2)	2	x	2
84	Vinh Tuong - Vinh Yen	2	x	8
85	Second circuit of Pha Lai - Bac Giang	2	x	27
86	Connecting An Khanh Bac Giang	4	x	14
87	Lang Giang transit on Bac Giang - Thai Nguyen	2	x	2
88	Yen Dung transit on TPP Pha Lai - Quang Chau	2	x	2
89	Bac Ninh 4 - Dong Anh	2	x	11
90	Bac Ninh 5 transit on Bac Ninh 500 kV - Pho Noi	2	x	4
91	Bac Ninh 6 transit on Pha Lai - 500kV Pho Noi	2	x	3
92	Bac Ninh 500 kV transit on Bac Ninh 2 - Pho Noi	4	x	3
93	Bac Ninh 500 kV - Bac Ninh 4	2	x	13
94	Khe Than transit on Trang Bach - Hoanh Bo	2	x	2
95	Cong Hoa transit on Cam Pha - Hai Ha	2	x	2
96	Yen Hung transit on TPP Uong Bi - Trang Bach	2	x	12
97	Yen Hung - Nam Hoa	2	x	30
98	Hai Ha - Mong Cai	2	x	40
99	Phong Tho - Than Uyen	2	x	65
100	Muong Te - Lai Chau	2	x	50
101	Pac Ma - Muong Te	2	x	36
102	Nam Ou 7 - Lai Chau	2	x	65
103	Nam Ou 5 - Dien Bien	2	x	22
104	Upgrade Son La - Viet Tri	1	x	167
105	500 kV Son La - Dien Bien	2	x	133
106	Upgrade 500 kV Son La - Son La	1	x	41

No	Line	No of circuit x km		
107	Upgrade 500 kV Son La - Muong La	1	x	21
108	Upgrade Muong La - Son La	1	x	32
109	Suoi Sap 2A - Re Son La - Viet Tri	2	x	5
110	Phu Yen transit on Son La - Viet Tri	2	x	7
111	Yen Thuy transit on Hoa Binh - Nho Quan	2	x	2
112	KKT Nghi Son transit on Nghi Son - TPP Nghi Son	4	x	2
113	Nghi Son 2 transit on TPP Nghi Son - Nong Cong	4	x	2
114	Thanh Hoa 500 kV - Sam Son	2	x	36
115	500 kV Thanh Hoa transit on Nong Cong - Thanh Hoa	4	x	7
116	500 kV Thanh Hoa - Hau Loc	2	x	35
117	Thanh Hoa 500kV - Bim Son	1	x	36
118	HPP Nam Sum (Lao) - Nong Cong	2	x	129
119	The third circuit of Thanh Hoa - Nghi Son - Quynh Luu	1	x	83
120	Upgrade Nong Cong - 500 kV Thanh Hoa	2	x	26
121	TPP Nghi Son transit on Nong Cong - Quynh Luu	2	x	10
122	Nong Cong - Nghi Son connect to TPP Nghi Son	2	x	42
123	Tinh Gia transit on Nong Cong - Nghi Son	2	x	8
124	My Ly - Ban Ve	1	x	72
125	Dong Vang transit on TPP Nghi Son - Nong Cong	4	x	4
126	Nam Cam transit on Quynh Luu - Hung Dong	4	x	3
127	Quy Hop - Quynh Luu 500 kV	2	x	62
128	Connecting 500 kV Quynh Luu	4	x	5
129	Do Luong - Nam Cam	2	x	32
130	Upgrade Hung Dong - Quynh Luu - Nghi Son	2	x	100
131	Nam Mo 2 (Lao) - Tuong Duong	2	x	77
132	Tuong Duong - Do Luong	2	x	100
133	Tuong Duong transit on HPP Ban Ve - Do Luong	2	x	3
134	Vung Ang - 500kV TPP Vung Ang	2	x	13
135	Vung Ang 2 transit on Vung Ang - 500 kV TPP Vung Ang	2	x	2
136	Upgrade Ha Tinh - Hung Dong	2(3)	x	66
137	500 kV Dan Phuong - Me Linh	2	x	15
138	Connecting 500 kV Dan Phuong	4	x	11
139	Soc Son 2 transit on Hiep Hoa - Dong Anh	2	x	3
140	500 kV Son Tay - Hoa Lac 2	2	x	15
141	500 kV Son Tay - Hoa Lac	2	x	12
142	500 kV Son Tay transit on Son Tay - Vinh Yen	4	x	5
143	Dan Phuong 500 kV - Cau Giay	2	x	20

No	Line	No of circuit x km		
144	Hai Ba Trung - Thanh Cong	2	x	5
145	Hai Ba Trung - Mai Dong	2	x	3
146	Chuong My transit on Hoa Binh - Ha Dong	2	x	2
147	Nam Ha Noi 500 kV - Phu Xuyen	2	x	15
148	Connecting 500 kV Nam Ha Noi	2	x	15
149	Long Bien 500 kV transit on Long Bien 2 - Mai Dong	4	x	10
150	Hai Phong 500 kV - Duong Kinh	2	x	8
151	Hai Phong 500 kV - Tien Lang	2	x	14
152	Bac Bo 1 - Do Son	2	x	10
153	Bac Bo 3 - Hai Ha	2	x	20
154	Do Son - Duong Kinh	2	x	8
155	Dai Ban transit on Hai Duong 2 - Duong Kinh	4	x	2
156	Nhi Chieu transit on Mao Khe - Hai Duong 2	4	x	2
157	Tu Ky transit on 500 kV Hai Phong - Gia Loc	4	x	4
158	Gia Loc 500 kV transit on Gia Loc - Hai Phong 500 kV	4	x	5
159	Hung Yen 500 kV - Dong Van	2	x	14
160	Van Giang transit on Long Bien 500 kV - Thuong Tin 500 kV	4	x	2
161	Hung Yen 500 kV (TP Hung Yen) transit on Kim Dong - Pho Cao	4	x	5
162	Nam Dinh 2 transit on Truc Ninh - Ninh Binh and Truc Ninh - Nam Dinh	2	x	2
163	LNG Thai Binh - Tien Lang	2	x	56
164	LNG Thai Binh - Truc Ninh	2	x	50
165	Nghia Hung transit on TPP Nam Dinh 500kV - Hau Loc	4	x	2
166	Quynh Phu transit on Thai Binh - Dong Hoa	4	x	2
167	Cao Bang - Lang Son	2	x	120
168	Bao Lam - Bac Me	2	x	30
169	Van Ban transit on Than Uyen - Lao Cai 500 kV	4	x	10
170	Lang Son 1 - Dong Mo (*)	2	x	60
171	Lang Son 2 - Lang Son 1 500kV (*)	2	x	20
172	Hiep Hoa 2 transit on Hiep Hoa 500kV - Phu Binh 2	4	x	5
173	500 kV Thai Nguyen transit on Malutang - Thai Nguyen	2	x	12
174	500 kV Thai Nguyen transit on Tuyen Quang (TBA) - Phu Binh	2	x	12
175	500 kV Thai Nguyen transit on Luu Xa - Phu Binh	2	x	9
176	Dai Tu transit on Ha Giang - Thai Nguyen 500 kV and Tuyen Quang - Thai Nguyen 500 kV	4	x	2
177	Phu Tho 3 transit on Nghia Lo - 500 kV Viet Tri	4	x	5

No	Line	No of circuit x km		
178	Bac Giang 500kV transit on TPP An Khanh Bac Giang - Lang Son	4	x	8
179	Connecting 500 kV Yen The	4	x	4
180	Yen The 500 kV - Viet Yen	2	x	25
181	Tan Yen transit on Yen The - Viet Yen	4	x	5
182	Phuc Yen transit on 500 kV Vinh Yen - 220 kV Vinh Yen	2	x	2
183	Chan Hung transit on 500 kV Viet Tri - 220kV Vinh Yen	2	x	2
184	Bac Giang 1 - Lang Son 1 (*)	2	x	35
185	Dong Mo - Son Dong	2	x	60
186	Bac Ninh 7 transit on 500 kV Dong Anh - Bac Ninh 4	4	x	2
187	Bac Ninh 500 kV - Bac Ninh	2	x	10
188	KCN Hai Ha - Hai Ha	2	x	10
189	Upgrade Quang Ninh - Hoanh Bo	2	x	20
190	Quang Ninh 1 transit on Hoanh Bo - TPP Son Dong and Hoanh Bo - Trang Bach (*)	4	x	5
191	Lai Chau 500 kV - Phong Tho	2	x	60
192	Sin Ho transit on Lai Chau 500 kV - Phong Tho	4	x	5
193	Muong Te - Sin Ho	2	x	35
194	Dien Bien 1 - Dien Bien (*)	2	x	23
195	Dien Bien 1 - Lai Chau (*)	2	x	52
196	Moc Chau - HPP Trung Son	2	x	35
197	Song Ma - Son La 500 kV	2	x	83
198	Son La 1 transit on Son La - Suoi Sap 2A (*)	2	x	4
199	Connecting Tan Lac	6	x	5
200	Thieu Hoa - Thanh Hoa 500 kV	2	x	5
201	Thieu Hoa - Thieu Yen	2	x	25
202	HPP Hoi Xuan - Ba Thuoc	2	x	30
203	Thanh Hoa 1 transit on Nghi Son - Nong Cong (*)	4	x	2
204	Tuong Duong - Quy Hop	2	x	80
205	HPP Nam Mo 1 transit on My Ly - Ban Ve	2	x	18
206	Can Loc transit on Ha Tinh - Hung Dong	4	x	2
207	Ha Tinh 1 transit on Vung Ang - Ha Tinh (*)	4	x	4
208	Provision for arising of 220 kV line for renovation and new construction	350		

(*) The progress, size and location of the substations and transmission lines will be accurate during the formulation of the Implementation Plan, depending on the potential for source development and the actual configuration of the power grid.