ADB

Technical Assistance Consultant's Report

Project Number: 43079
September 2013

Mongolia: Updating the Energy Sector Development Plan

(Financed by the Japan Fund for Poverty Reduction)

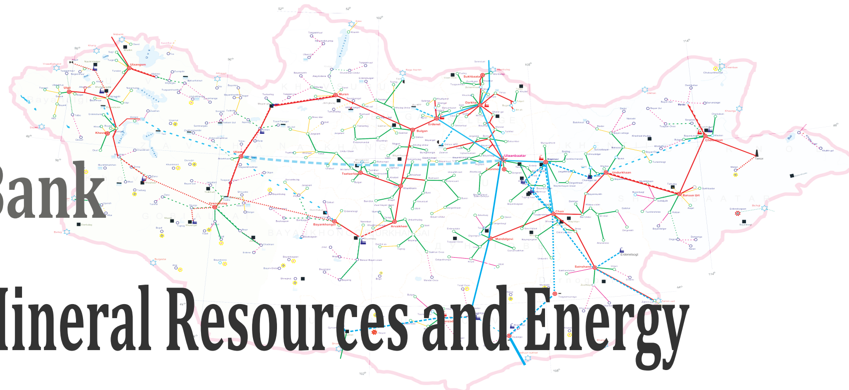
Prepared by E. Gen Consultants Ltd. Bangladesh in association with MVV decon GmbH, Germany, and Mon-Energy Consult, Mongolia

For Ministry of Energy, Mongolia

Asian Development Bank

Updating Energy Sector Development Plan

EXECUTIVE SUMMARY



Prepared for

The Asian Development Bank

and

The Mongolian Ministry of Mineral Resources and Energy

Prepared by

e • gen

empowering people

in association with

MONENERGY consult

September 2013

CURRENCY EQUIVALENTS

(As of June 2013)

Currency Unit	–	Tugrik (MNT)
USD 1.00	=	1,435 MNT
EUR 1.00	=	1,880 MNT
USD 1.00	=	0.759 EUR

ABBREVIATIONS

ADB	–	Asian Development Bank
AuES	–	Altai-Uliastai Energy System
CES	–	Central Energy System
CFB	–	Circulating Fluidized Bed
CHP	–	Combined Heat Power
CO_2	–	Carbon Dioxide
CPI	–	Consumer Price Index
EA	–	Energy Authority
EHV	–	Extra High Voltage
ERES	–	Eastern Energy System
EUR	–	European currency unit EURO
GHG	–	Greenhouse Gases
HOB	–	Heat Only Boilers
IDC	–	Interest during construction
LCOE	–	Levelized Cost of Energy
MoE	–	Ministry of Energy
MNT	–	Mongolian Tugrik
NOx	–	Nitrogen Oxides
O&M	–	Operation and Maintenance
PPA	–	Power Purchase Agreement
PV	–	Photovoltaic
SOx	–	Sulfur Oxides
USD	–	United States Dollars
VAT	–	Value Added Tax
WACC	–	Weighted Average Cost of Capital
WRES	–	Western Energy System

UNITS OF MEASURE

GCal	-	Gigacalorie (one million kilocalories)
GJ	-	Gigajoule (one thousand megajoules)
kJ	-	Kilojoule
kWh	-	Kilowatt-hour
MWh	-	Megawatt-hour
MWel	-	Megawatt electric
MWth	-	Megawatt thermal
PJ	-	Petajoule
TSC (TPU)	-	Tons of standard coal
TJ	-	Terajoule

WEIGHTS AND MEASURES

GW (giga watt)	–	1,000,000,000 calories
GJ (giga joules)	–	1,000,000,000 joules
GW (giga watt)	–	1,000,000,000 watts
kVA (kilovolt-ampere)	–	1,000 volt-amperes
kW (kilowatt)	–	1,000 watts
kWh (kilowatt-hour)	–	1,000 watts-hour
MW (megawatt)	–	1,000,000 watts
W (watt)	–	unit of active power

CONVERSION FACTORS

1 GCal	=	4.19 GJ
1 BTU	=	1.05506 kJ
1 Gcal	=	1.1615 MWh = 4.19 GJ = 1.75 steam tons/hour
1 GJ	=	0.278 MWh = 0.239 Gcal = 0.42 steam tons/hour
1 MW	=	0.86 Gcal/hour = 3.6 GJ = 1.52 steam tons/hour
1 TSC	=	7 Gcal = 29.3 GJ = 8.15 MWh

I. INTRODUCTION

A. Energy Masterplan

1. The Energy Masterplan is organized as an Executive Summary with three parts A, B and C comprising a total of 10 volumes. Part A deals with past performance, current situation and demand projections to the end of the planning horizon, Part B deals with expansion plans, and Part C deals with implementation issues. The detailed structure of the Energy Masterplan is as follows:-

Executive Summary

PART A

Volume I: Energy Sector Policy Review

Volume II: Economic Scenarios

Volume III: Electricity Forecasts

Volume IV: Heat Forecasts

PART B

Volume V: Primary & Secondary Energy

Volume VI: CES Expansion Plan

Volume VII: Aimag Heat Expansion Plan

Volume VIII: Small Energy System Expansion Plan

Volume IX: Transmission Expansion Plan

PART C

Volume X: Financial Analyses

B. Contents of Executive Summary

Section I This Introduction

Section II Heat Forecasts

Section III Electricity Forecasts

Section IV Expansion Plan

Section V Finance Considerations

Section VI Policy Note

Section VII Investment Long List

II. HEAT FORECASTS

C. UB Heat Demand

1. Heat production determines the amount of cogeneration and condensing power that can be generated by each power plant. In the case of space heat, the heat production is determined by outdoor temperature relative to a target indoor temperature, accordingly space heat is a variable quantity. Hot tap water is a relatively constant quantity throughout the year. Heat losses are also a relatively constant quantity.

2. The heat production requirement has been modelled based on temperature records, according to heat degree day concept, to which has been added hot tap water, steam and heat losses as constant quantities. In the latter case it has been assumed that these quantities grow throughout the planning horizon, according to the forecast change in drivers, notably the population driver.

3. The 'must run' cogeneration power and net available condensing power was determined according to the 'turbine' curves of each thermal power plant. In the interconnected CES, the available power has been determined separately for CHP2, CHP3, CHP4, Darkhan, Erdenet CHPs and for the future CHP5.

4. Cogeneration power is highest in the winter months, from November to February, and lowest in the summer. In the summer period, the CHPs mainly produce inefficient condensing power. It should be noted that the summer heat and power production reduces the average annual efficiency of the CHPs. The efficiency in the winter months is closer to typical CHP efficiencies observed in other countries.

D. UB City Heat Capacity Expansion

5. Two heat capacity expansion scenarios are envisaged. Scenario 1 is based on a CHP expansion strategy using standard blocks of capacity of 168 GCal / hour. Scenario 2 is based on a large Heat Only Boiler (HOB) strategy.

6. The modelled heat capacity expansion is shown in Table 1:-

Table 1: Scenario 1 – Capacity Expansion Plan

	Forecast Deficit	New Capacity	Avail Capacity	New Deficit	Reserve Margin	
	Gcal/hr	Gcal/hr	Gcal/hr	Gcal/hr	%	
2013	9	-	1,585	9	1%	-
2014	(44)	-	1,585	(44)	-3%	-
2015	(98)	300	1,885	202	12%	+HOB300
2016	(154)	180	2,065	326	19%	+PP#4 ext180
2017	(212)	-	2,065	268	15%	-
2018	(271)	336	2,401	545	29%	+CHPX336
2019	(333)	-	2,401	483	25%	-
2020	(397)	-	2,401	419	21%	-
2021	(463)	168	2,569	521	25%	+CHPX168
2022	(531)	-	2,569	453	21%	-
2023	(601)	168	2,737	551	25%	+CHPX168

	Forecast Deficit	New Capacity	Avail Capacity	New Deficit	Reserve Margin	
	Gcal/hr	Gcal/hr	Gcal/hr	Gcal/hr	%	
2024	(674)	-	2,737	478	21%	-
2025	(749)	168	2,905	571	24%	+CHPX168

Source: Consultant's analyses

7. The modelled heat capacity expansion for Scenario 2 is shown in the following table:-

Table 2: Scenario 2 – Capacity Expansion Plan

	Forecast Deficit	New Capacity	Avail Capacity	New Deficit	Reserve Margin	
	Gcal/hr	Gcal/hr	Gcal/hr	Gcal/hr	%	
2013	9	-	1,585	9	1%	-
2014	(44)	-	1,585	(44)	-3%	-
2015	(98)	300	1,885	202	12%	+HOB300
2016	(154)	180	2,065	326	19%	+PP#4 ext180
2017	(212)	-	2,065	268	15%	-
2018	(271)	300	2,365	509	27%	+HOB300
2019	(333)	-	2,365	447	23%	-
2020	(397)	-	2,365	383	19%	-
2021	(463)	300	2,665	617	30%	+HOB300
2022	(531)	-	2,665	549	26%	-
2023	(601)	-	2,665	479	22%	-
2024	(674)	300	2,965	706	31%	+HOB300
2025	(749)	-	2,965	631	27%	-

Source: Consultant's analyses

8. As HOBs do not produce electrical power, Scenario 2 also requires conventional coal-fired power plants to meet power demand.

E. Heat Allocation to Heat Plants

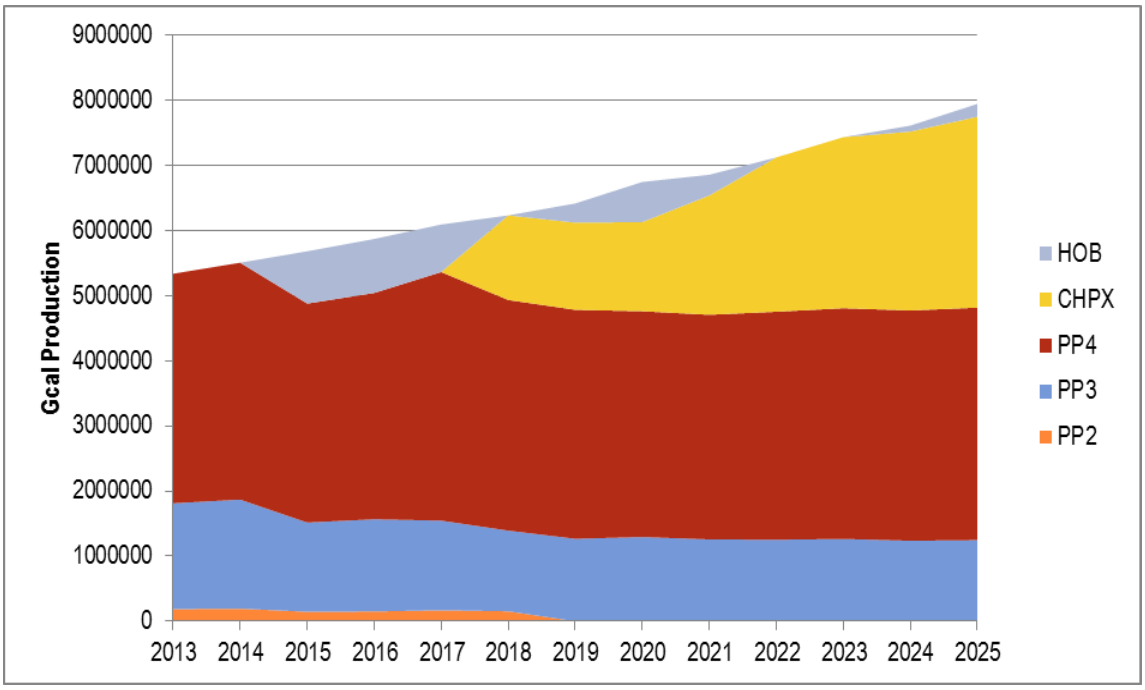
9. In the case of a heat production system, the CHPs and HOBs will produce the heat demanded by the Districts they supply individually, according to the routing of their associated heat transmission pipelines and location of heat exchangers.

10. In UB, the heat production does not match neatly to Districts or sub-Districts. Over time the share of total heat production of each CHP and HOB will change according to CHP retirements and demographics, the latter measured in terms of new household connections. In addition hydraulic considerations limit the areas that can be served by the heat transmission network.

11. For the purpose of modelling heat capacity expansion it has been assumed that CHP2 will be retired in 2017. It is assumed that a 300 GCal/h HOB (Amgalan) will be required and is committed to supply heat demand in the eastern part of UB. These assumptions are common to both scenarios.

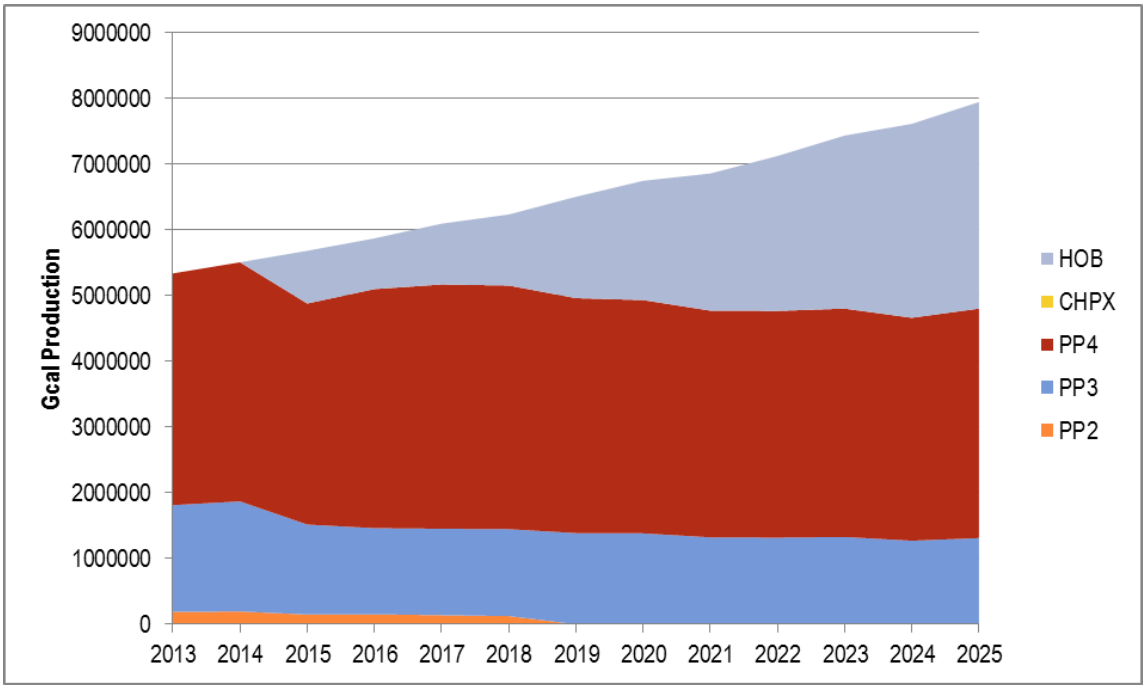
12. The following charts provide the heat production assumptions for Scenarios 1 and 2. The detailed report includes the production assumptions by District.

Figure 3: Scenario 1 – Modelled Heat Allocation for CHP Strategy



Source: Consultant's analyses

Figure 4: Scenario 2 – Modelled Heat Allocation for HOB Strategy



Source: Consultant's analyses

F. Aimag Heat Forecast

13. Aimag heat forecasts were determined from data gathered from the licensed operators.

Table 5: Aimag Heating Systems – 2025

Aimag Center	Heat Intensity	Max Demand	Rated Capacity	Downstream Capacity Loss		Annual Production	Peak utilization	Coal price	Distance to coal
	MW/km	Gcal/h	Gcal/h	%	Gcal/h	Gcal/a	h/a	MNT/ton	km
Baruun-Urt	2.16	12.3	13.1	6%	0.8	39,740	3,037	14,400	35
Bayankhongor	1.82	13.0	13.8	6%	0.8	42,399	3,066	12,727	90
Bulgan	1.38	8.7	9.2	6%	0.6	30,484	3,304	26,500	758
Zuunmod	4.63	45.4	48.3	6%	2.9	100,155	2,072	36,194	45
Mandalgov	0.85	11.1	11.8	6%	0.7	23,780	2,010	34,847	300
Muren	3.36	31.5	33.5	6%	2.0	102,213	3,050	70,401	217
Ulgii	3.30	18.8	20.0	6%	1.2	41,865	2,096	19,500	140
Ondorhaan	2.33	19.3	20.5	6%	1.2	44,091	2,153	23,742	59
Sainshand	2.11	21.4	22.8	6%	1.4	42,504	1,866	16,430	220
Suhbaatar	1.47	28.9	30.7	6%	1.8	68,161	2,218	27,816	630
Ulaangom	5.06	48.8	51.9	6%	3.1	120,138	2,316	29,770	90
Uliastai	1.29	18.4	19.5	6%	1.2	47,586	2,435	24,400	140
Hovd	3.23	25.0	26.6	6%	1.6	51,314	1,929	12,910	196
Tsetserleg	2.86	13.0	13.9	6%	0.8	33,132	2,388	35,000	402
Choir	2.29	10.8	11.5	6%	0.7	20,567	1,786	13,960	35
Nailakh	16.58	125.6	133.6	6%	8.0	388,186	2,905	-	-
Baganuur	10.06	188.9	201.0	6%	12.1	281,053	1,399	-	-
Choibalsan	1.24	76.2	81.1	6%	4.9	169,314	2,089	-	-
Dalanzadgad	0.36	7.3	7.8	6%	0.5	14,487	1,865	-	-
Sum		**785.0**	**835.1**		**50.1**	**1,790,958**		**442,197**	
Average	**3.33**	**37.4**	**39.8**	**6%**	**2.4**	**85,284**	**2,280**	**21,057**	**176**

Source: Consultant's analyses

III. ELECTRICITY FORECASTS

G. Demand Growth Scenarios

14. Electricity load forecasts are based on the following scenarios:-

1. A Low or 'organic' forecast – this forecast includes growth associated with existing domestic, commercial and industrial consumers. The growth has been modelled using an end-use model applied on individual Aimag and Energy Region basis.
2. A Medium or 'bear' industrial forecast – this forecast includes an industrial growth forecast added to the organic forecast; it is assumed that industrial development takes place over a 30 year period (from 2013) centred in three industrial zones – Northern zone (Erdenet / Darkhan), Central zone (Choir / Sainshand) and Southern zone (Dalanzadgad / TT / OT area).
3. A High or 'bull' industrial forecast – this forecast assumes that the industrial development described above takes place over a 20 year period in accordance with mineral and minerals processing expectations.

15. Load forecasts are presented as forecasts of consumer demand, not production of power plants. Production forecasts have also been prepared incorporating forecasts of station losses and T&D losses.

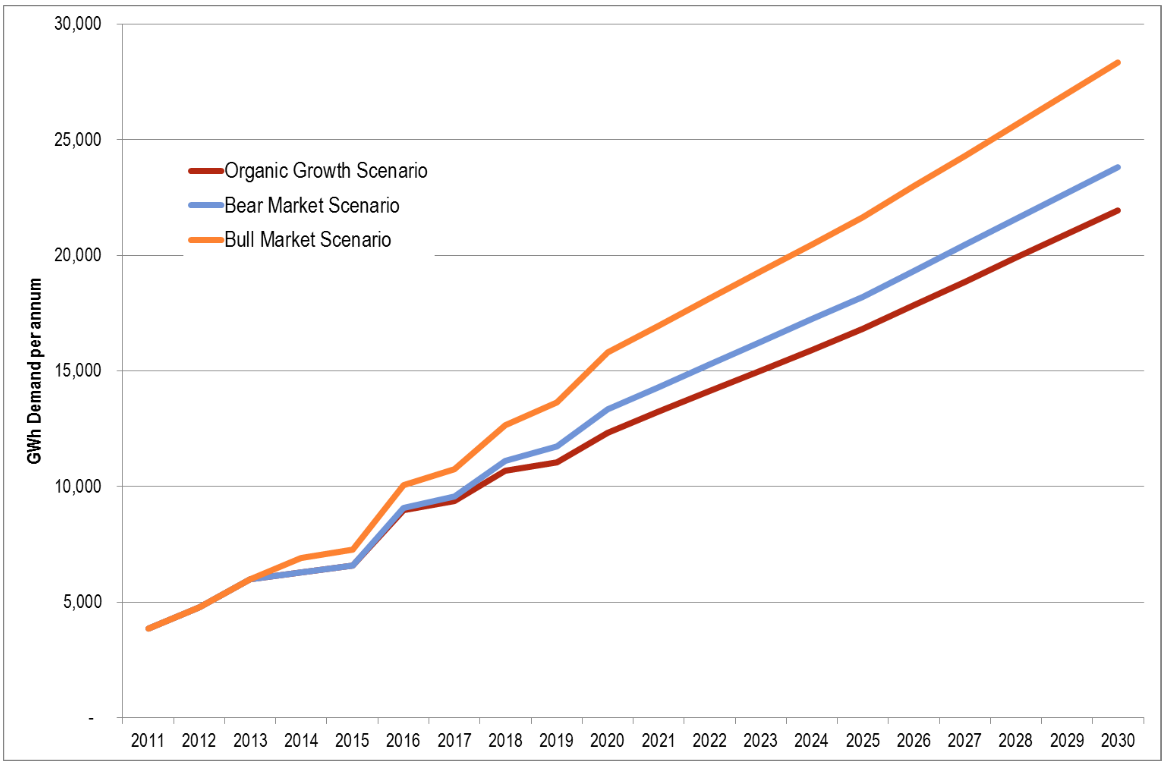
16. Total losses in the Mongolian power system are currently high, of the order of 35%. New plant will result in a reduction of losses. Production forecasts in 2025 can be estimated by adding 20%.

17. Load forecasts are based on the assumption that demand is realized when industrial facilities commence operation. This means that in the early years of the industrial zone growth forecast, demand growth is low. It will take some three to four years from today to establish major industrial facilities, e.g. an oil refinery. This explains why demand growth in the early years is forecast to be low.

H. Whole of Mongolia Electricity Forecasts

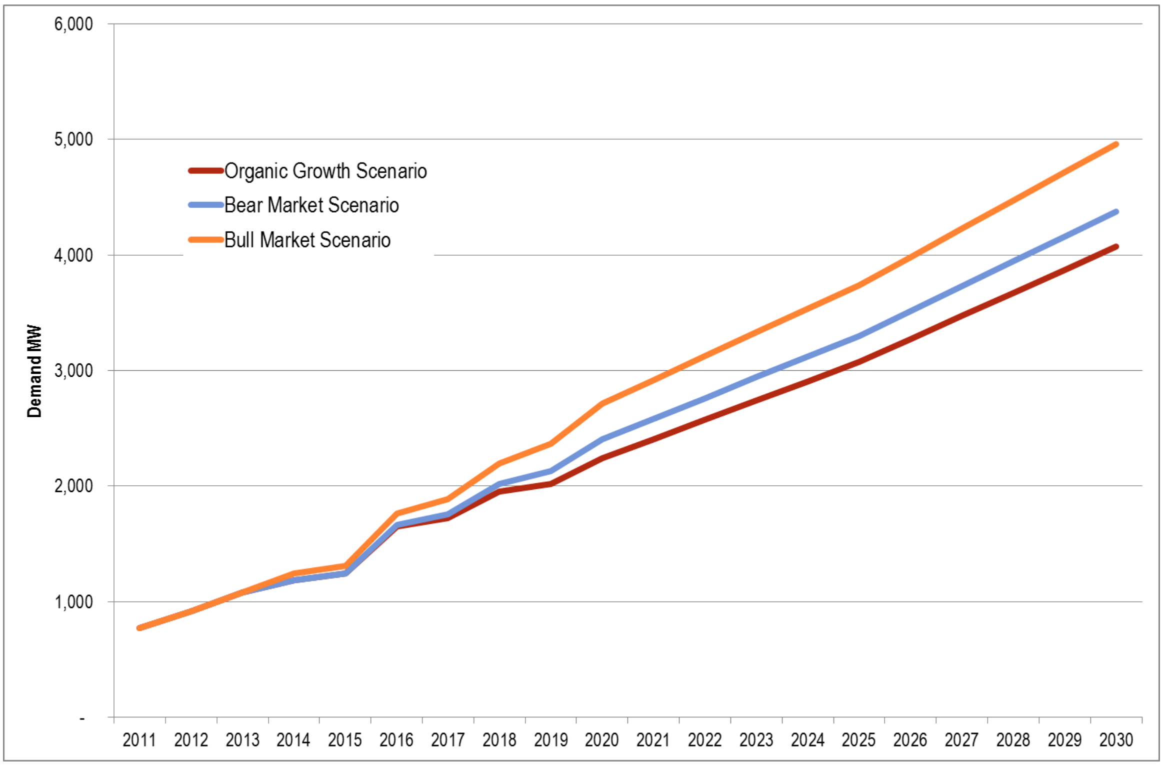
18. The following forecast for whole of Mongolia and includes Oyu Tolgoi and Tavan Tolgoi as loads as well as other known spot loads.

Figure 6: Electricity Consumption Forecast (GWh)



Source: Consultant's analyses

Figure 7: Electricity Demand Forecast (MW)



Source: Consultant's analyses

19. The compound annual growth rates are Low (9.3%), Medium (9.8%) and High (10.5%). The growth rates are high by international standards, although consistent with forecasts in developing countries that are pursuing an industrialization strategy and where the industrial base is low. The growth rates can be seen to be impacted significantly by Oyu Tolgoi and Tavan Tolgoi mines in 2016.

20. The average MW additions for the medium growth forecasts can be understood as two 150MW blocks of power every two years for the next 20 years. The growth can also be understood in terms of kWh / capita growth.

Table 8: kWh / Capita Growth

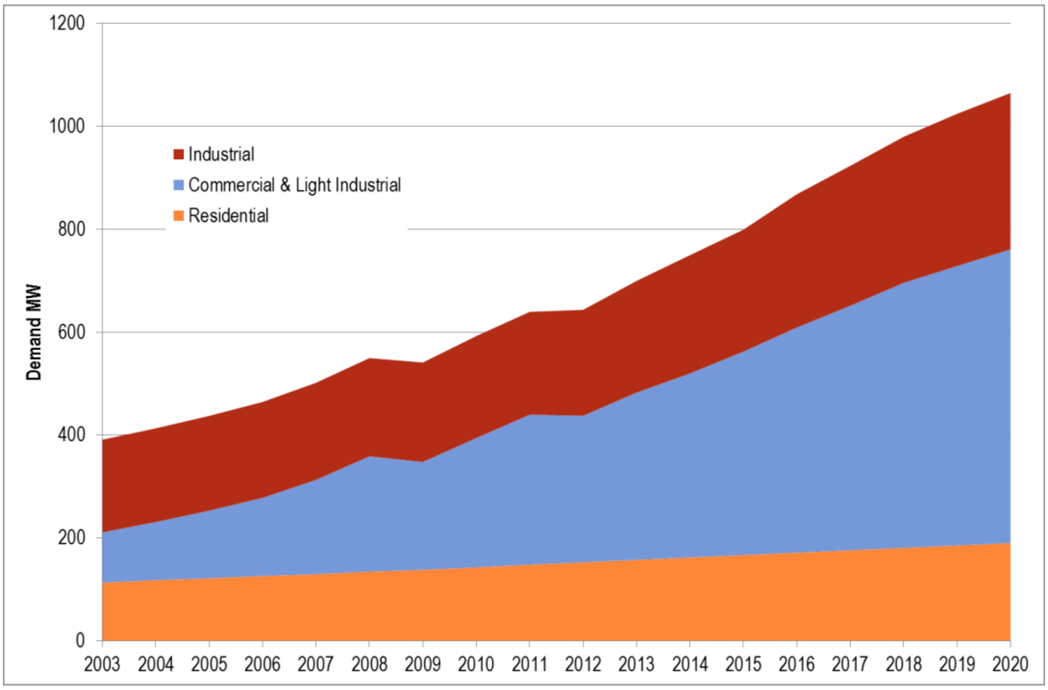
	kWh per Capita		
	Low	Medium	High
2012	1,739	1,739	1,739
2015	2,269	2,272	2,503
2020	3,914	4,232	5,015
2025	4,994	5,408	6,425
2030	6,172	6,692	7,959

Source: Consultant's analyses

I. Electricity Forecasts of the Energy Systems

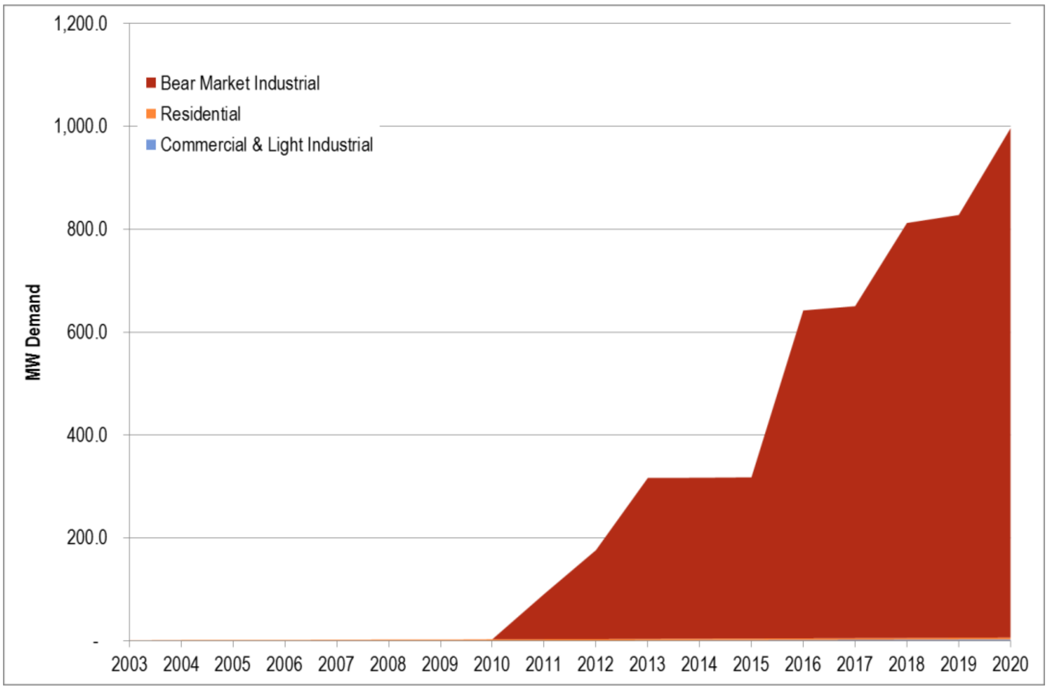
21. The demand forecasts for the Energy Systems follow. The details are provided in Volume III.

Figure 9: CES Demand Forecast (MW)



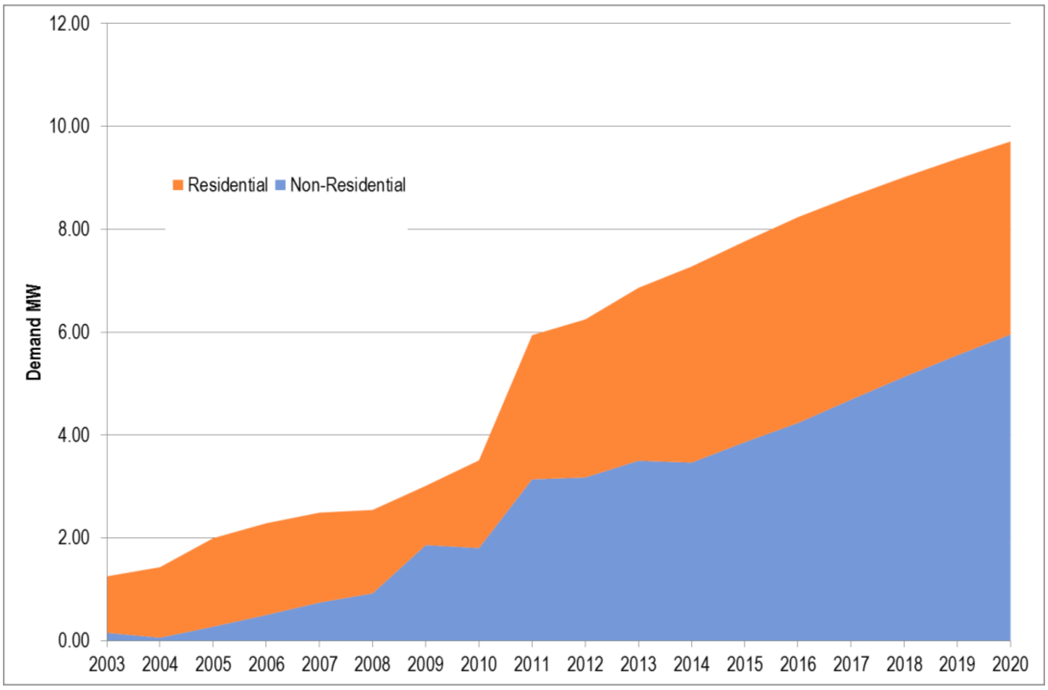
Source: Consultant's analyses

Figure 10: South Gobi Demand Forecast (MW) (including OT, TT)



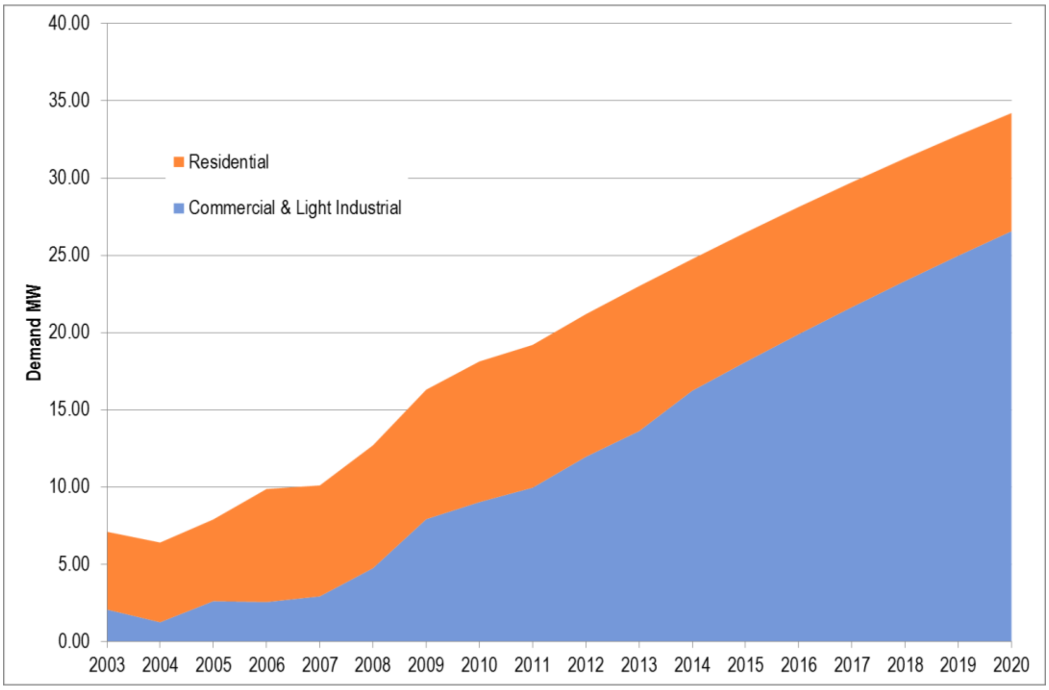
Source: Consultant's analyses

Figure 11: AuES Demand Forecast (MW)



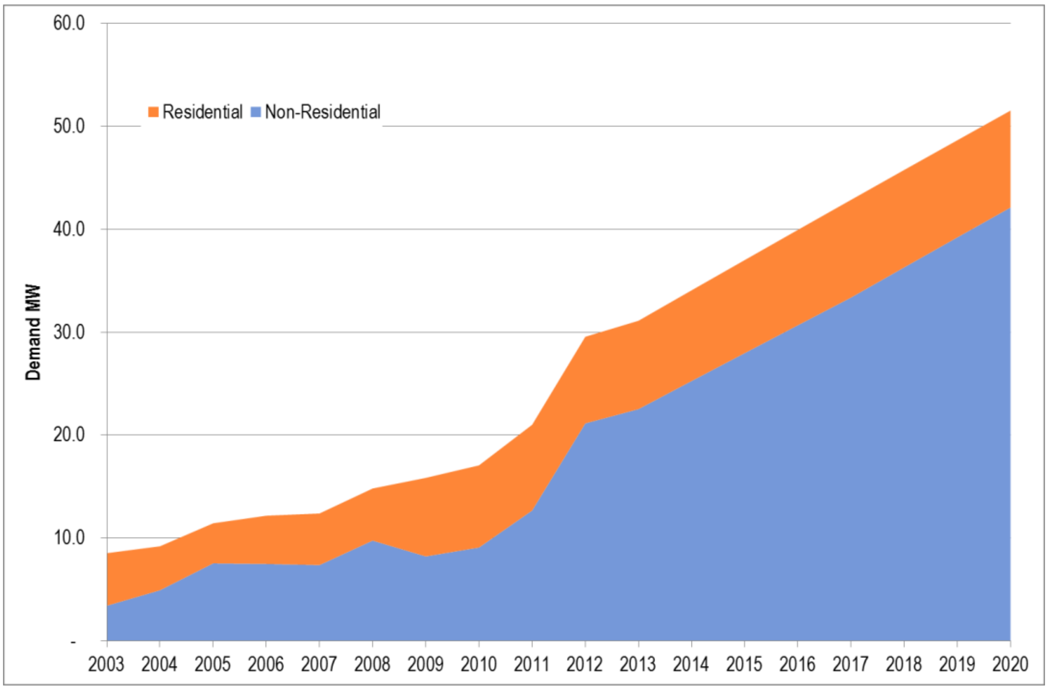
Source: Consultant's analyses

Figure 12: ERES Demand Forecast (MW)



Source: Consultant's analyses

Figure 13: WRES Demand Forecast (MW)



Source: Consultant's analyses

IV. EXPANSION PLAN

J. Central Energy System (CES)

22. The Central Energy System is by far the largest Energy System and the most complex. The TA Consultant has expended considerable effort to model the CES system accurately, on year-to-year basis for the planning horizon 2013 to 2025. An expansion plan has been formulated against a low or 'organic' electricity compound annual growth rate of 8%. The plan includes committed plants, namely CHP5, expansion of CHP 4, refurbishment of CHP 3, expansion of the Darkhan Thermal Power Plant and the 50 MW Newcom wind farm. It is proposed that new capacity needs are met as follows – addition of 750 MW of new CHP power by 2025, addition of Sheuren Hydropower plant (design capacity of 390 MW, operated year round at 170MW on energy basis) commencing operation in 2021, coal-fired condensing power plants starting at 300 MW in 2018 and increasing to 600 MW by 2025, and grid connected wind power commencing at 50 MW in 2014 and increasing to 400 MW by 2025. The planting schedule follows:-

Figure 14: CES Expansion Plan (Scenario 2c)

	Existing	New CHP	Coal	Hydro	Wind	Solar PV	Import	Total	Total System
	MW	MW	MW	MW	MW	MW	MW	MW	MW
2013	775	0	0	0	0	0	119	0	893
2014	775	0	0	0	50	0	175	50	1,000
2015	775	0	0	0	50	0	175	50	1,000
2016	879	0	0	0	50	0	175	50	1,104
2017	879	0	0	0	50	0	175	50	1,104
2018	879	300	300	0	50	0	132	650	1,661
2019	860	300	450	0	50	0	0	800	1,660
2020	860	300	450	0	150	0	0	900	1,760
2021	860	450	450	170	150	0	0	1220	2,079
2022	860	450	450	170	200	0	0	1270	2,129
2023	860	600	450	170	200	0	0	1420	2,279
2024	860	600	600	170	200	0	0	1570	2,429
2025	860	750	600	170	400	0	0	1920	2,779

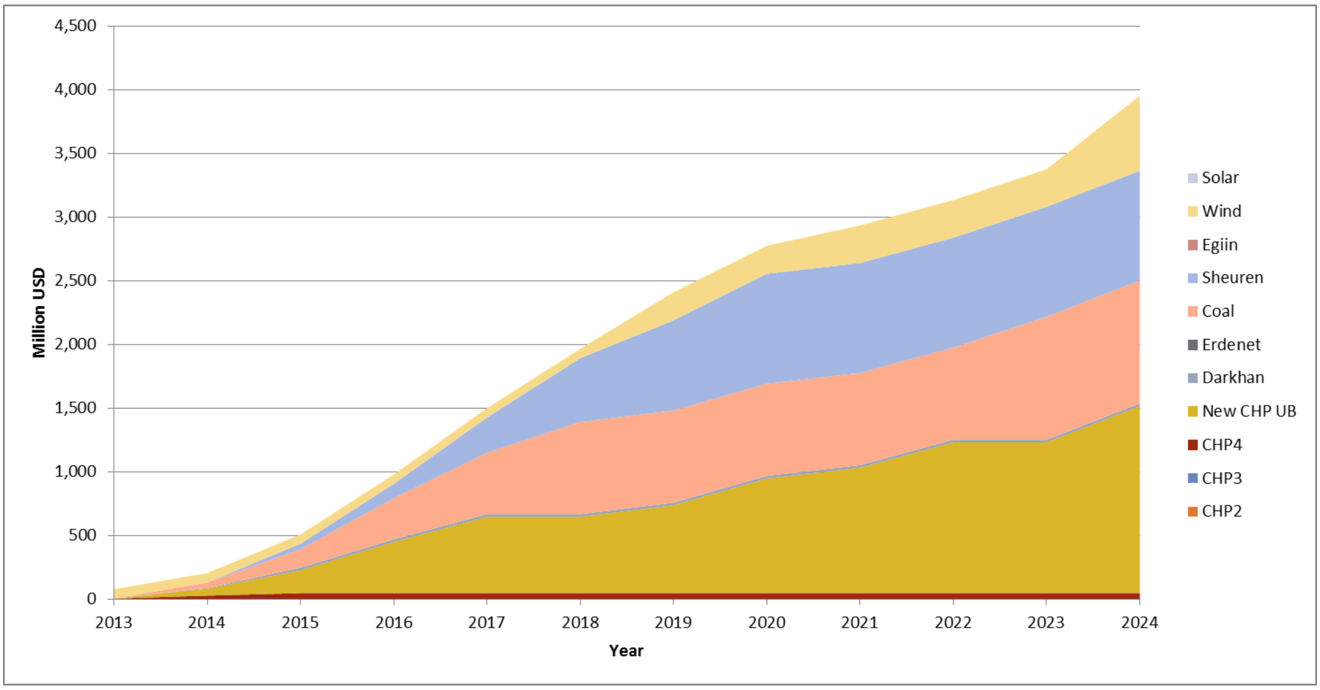
Source: Consultant's analyses

23. **It has been determined that for the period 2013 to 2025 the Central Energy System requires a capital investment of $300 million for heat supply expansion in Ulaanbaatar, and $4 billion for electricity supply expansion.**

24. The annual capital investment profiles for this plan are shown in Figures 15 to 18. The CES expansion plan is developed in Volume VI. The power expansion plan and grid integration

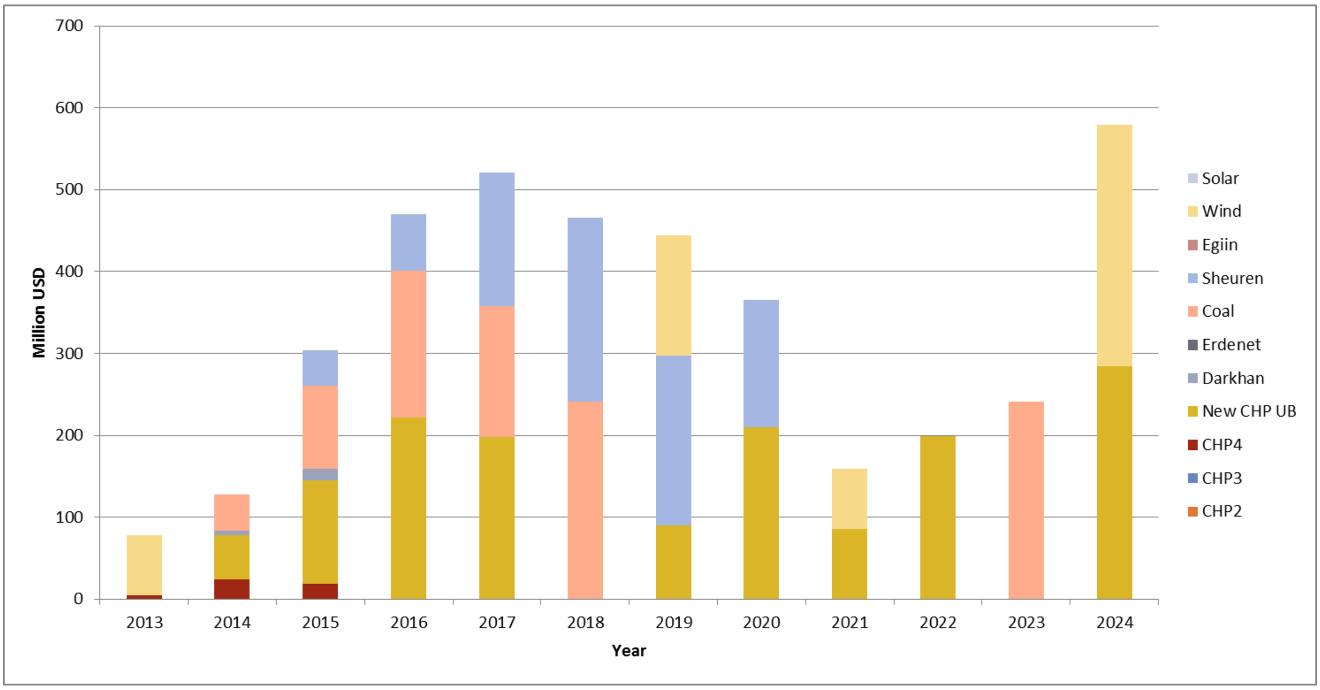
plan is discussed in detail in Volume IX.

Figure 15: Cumulative Capex Requirement of CES Power Sector (Scenario Plan 2c)



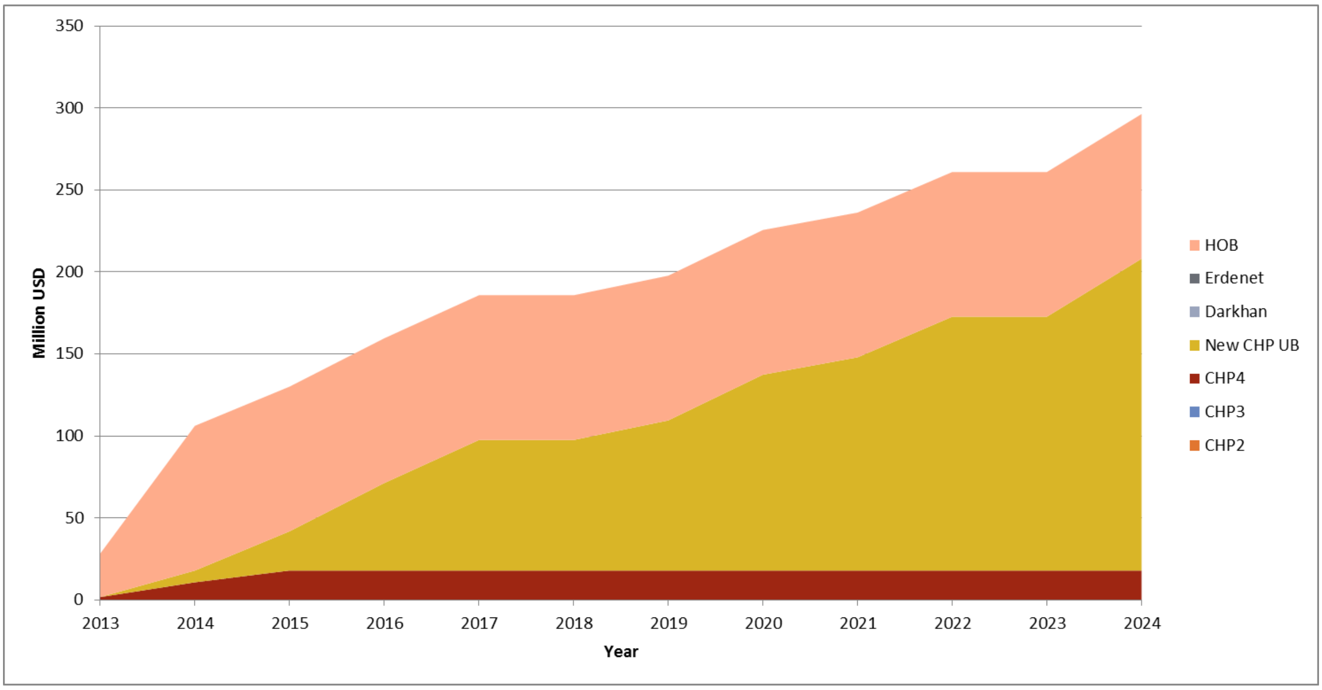
Source: Consultant's analyses

Figure 16: Annual Capex Requirement of CES Power Sector (Scenario Plan 2c)



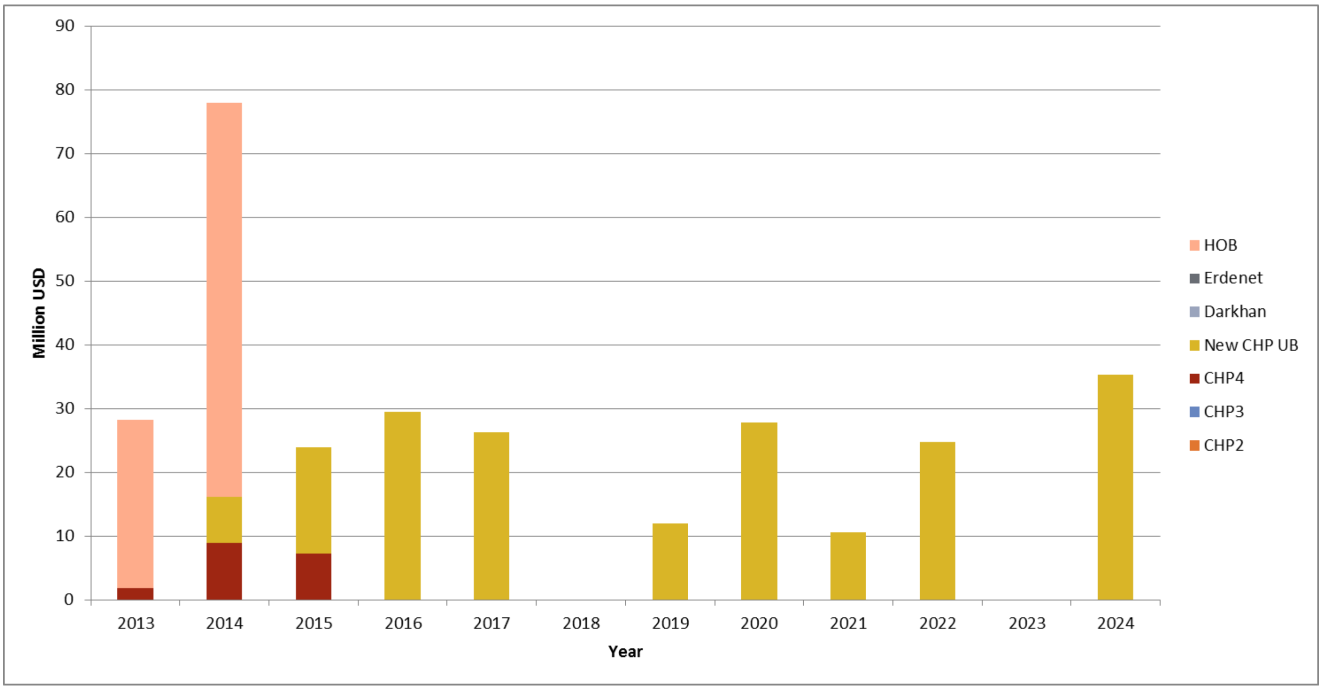
Source: Consultant's analyses

Figure 17: Cumulative Capex Requirement of CES Heat Sector (Scenario Plan 2c)



Source: Consultant's analyses

Figure 18: Annual Capex Requirement of CES Heat Sector (Scenario Plan 2c)



Source: Consultant's analyses

25. To this electricity and heat generation expansion estimate must be added $52 million for expansion and refurbishment of the heat transmission network in Ulaanbaatar.

26. Expansion plans for medium and high growth scenarios have also been developed. For these scenarios the demand in excess of the low growth demand is planned to be met with coal-fired condensing power plants offering low cost and high reliability power to industrial centers.

K. Dalanzadgad / South Gobi Energy System

27. The development of the power plants intended to supply Tavan Tolgoi and Oyu Tolgoi is understood to have stalled for various commercial reasons. In principle these plants are needed to supply between 900 to 1200 MW within the next five years. Without such investment and associated mining activity, the Government stands to lose a significant share of taxes and royalties due to reduced turnover of the companies. This supply capacity will cover the two mines power needs, as well as other small mines in the area. The plant potentially covers electricity needs from Dalanzadgad to Nariin Sukhait. It will also allow for dismantling of the cross-border transmission line entering Mongolia from Inner Mongolia and supplying Oyu Tolgoi. **The investment need for the period 2013 to 2025 is potentially as high as $2 billion to establish up to 1200 MW of capacity in the South Gobi.** The electricity expansion plan for the South Gobi area is discussed in detail in Volume VIII.

28. The timing of investment is largely a commercial matter wherein the market for gold, silver and metallurgical coal will determine the rate at which mine development proceeds and power needs grow. Accordingly the Consultant is not able to accurately fix the disbursement of capital profile for this power plant development. However a potential expansion plan has been developed based on an understanding of the development schedules of Tavan Tolgoi and Oyu Tolgoi.

Figure 19: South Gobi Expansion Plan

Asset	Capacity	Year
Tavan Tolgoi units 1 – 3	450MW	2018
Tavan Tolgoi unit no. 4	+150MW	2020
Tavan Tolgoi unit no. 5	+150MW	2022
Tavan Tolgoi - Oyu Tolgoi 220kV	25MW	2016
Tavan Tologi – Dalanzadgad – Nariin Suhkait 110kV line	50-100MW	2018

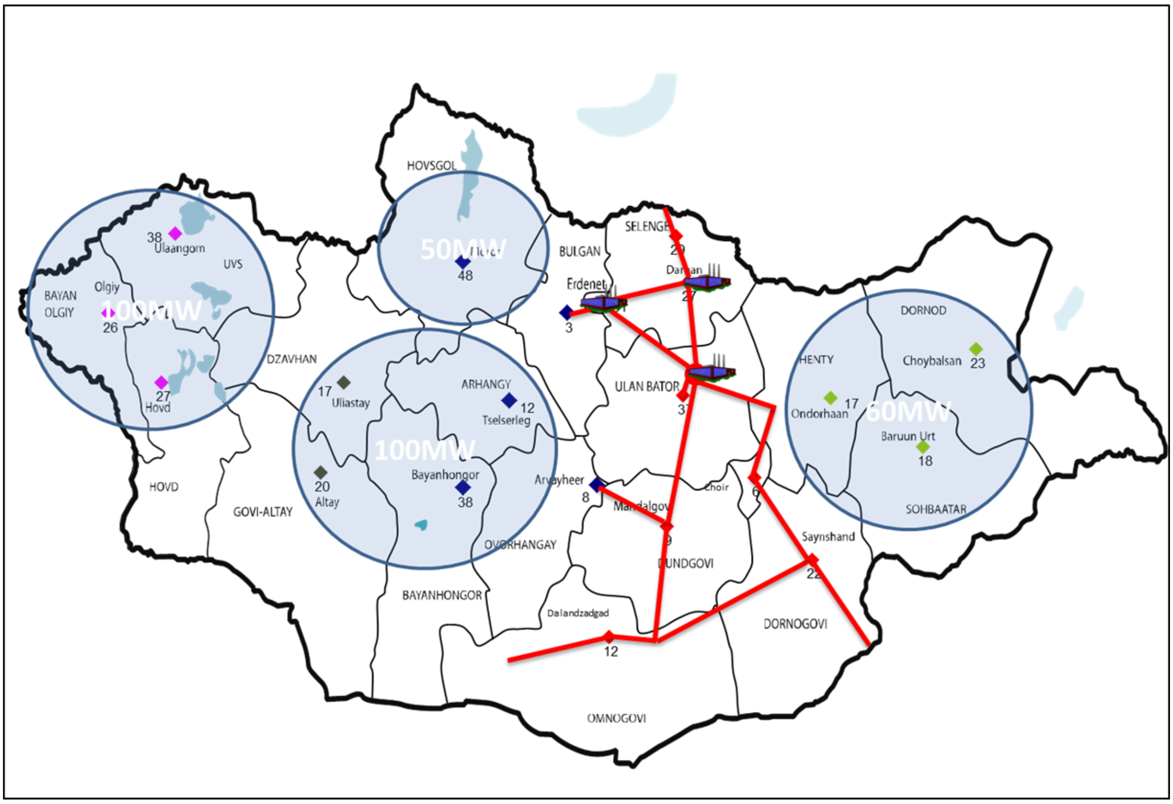
Source: Consultant's analyses

L. Eastern, Western & Altai-Uliastai Energy Systems

29. The development of the areas served by these Energy Systems is affected greatly by the pace of mining development, and by the development of the livestock industry. The high growth forecast would see the total load of these areas grow to around 450 MW by 2025.

30. The low end growth rate is substantially less than 450 MW, around 310 MW as shown in Figure 20. Accordingly the actual economic development must be monitored closely. It is to be expected that the developers of facilities that present as large spot loads, such as gasoline and livestock processing factories, will understand the need to engage with the local electricity distribution company or the MoE to plan for electricity needs. In this regard gathering market intelligence on ongoing basis will identify the total pool of development activity, determine expansion timing, and support expansion plan adjustment.

Figure 20: Load Centres – 2025 (Low Growth)



Source: Consultant's analyses

31. **For AuES, ERES and WRES, the total investment need for the period 2013 to 2025 could be as high as $750 million, needed to establish 450 MW of new capacity in these regional areas.** The electricity expansion plan for the small energy systems is discussed in detail in Volume VIII.

Figure 21: AuES Expansion Plan

Asset	Capacity	Year
Mogoin Gol Coal no. 1	25MW	2018
Mogoin Gol Coal no. 2	25MW	2018
Mogoin Gol Coal no. 3 (Muren)	25MW	2018
Mogoin Gol Coal no. 4	25MW	2022
Mogoin Gol Coal no. 5	25MW	2025
Mogoin Gol Coal no. 6 (Muren)	25MW	2025
220kV Interconnector – Mogoin Gol to Ulaangom	25MW	2018
220kV Interconnector – Mogoin Gol to Erdenet via Muren	25MW	2025
220kV line – Mogoin Gol to Altai via Uliastai	50MW	2023

Asset	Capacity	Year
110kV line – Altai to Bayankhongor	25MW	2023
220kV line – Mogoin Gol to Bayankhongor	50MW	2025

Source: Consultant's analyses

Figure 22: ERES Expansion Plan

Asset	Capacity	Year
Choibalsan CHP	3 x 10MW	2018
Baganuur / Chandgana no 1	25MW	2018
Baganuur / Chandgana no 2	25MW	2025
220kV Interconnector – Banganuur / Chandgana to Ondorhaan	25MW	2018
110kV line – Ondorhaan to Baruun-Urt	25MW	2025
110kV line – Baruun-Urt to Choibalsan	25MW	2025

Source: Consultant's analyses

Figure 23: WRES Expansion Plan

Asset	Capacity	Year
Power plant unit no. 1	25MW	2018
Power plant unit no. 2	25MW	2018
Power plant unit no. 3	25MW	2022
Power plant unit no. 4	25MW	2025
110kV line – Ulaangom to Ulgii	25MW	2018
110kV line – Ulgii to Khovd	25MW	2018
110kV line – Khovd to Ulaangom	25MW	2022

Source: Consultant's analyses

M. Aimag Heating

32. The Aimag town centre heating systems, comprising HOB's and piped heating networks are in need of replacement. The Energy Masterplan update evaluated the heating systems of all of the Aimag centres, and those of Nailakh, Baganuur and Bagakhangai. The technical life has been exceeded in most all cases. An economic evaluation based on expected heat demand in 2025 indicates that 7 population centres have sufficient heat intensity to justify upgrade to a CHP plant.

33. **The investment need for the period 2013 to 2025 is estimated to be $258 million.** This level of investment is modest considering the economic benefits and could be expected to attract development bank funding on social and environmental grounds.

The Aimag heating expansion plan is discussed in detail in Volume VII.

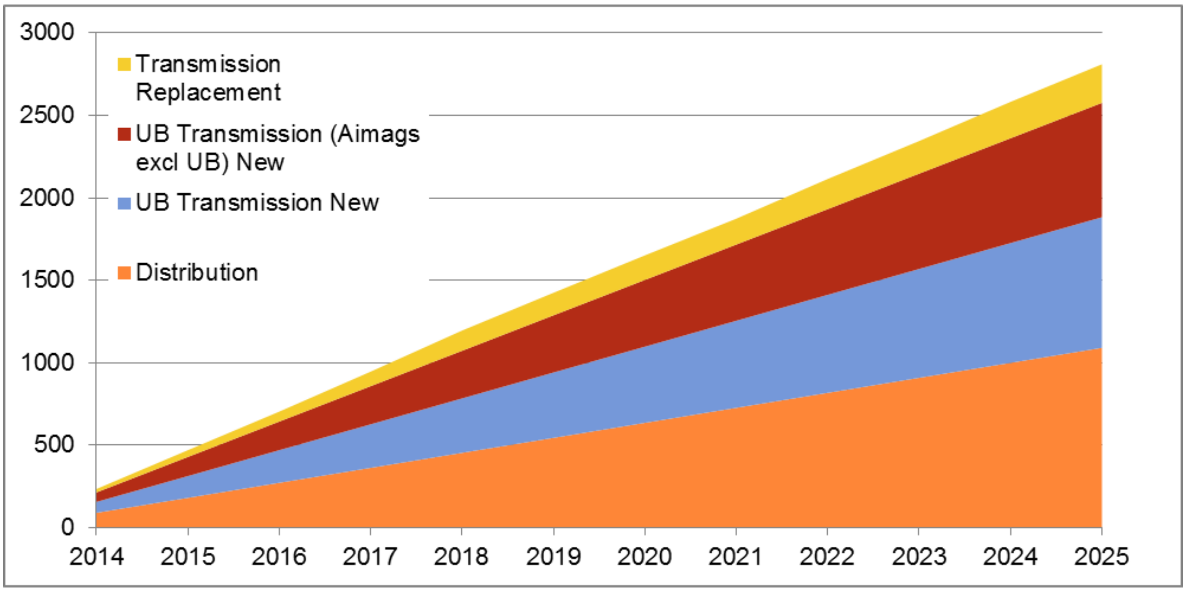
N. Electricity Transmission & Distribution

34. The electricity transmission investment requirement relates to new capacity expansion and replacement of aging assets. Capacity expansion has been modelled based on a low load growth scenario, with demand utilization functioning as the driver of investment, i.e. as demand utilization increases the trigger for investment is reached when reliability can no longer be met under first contingency conditions. Transmission asset replacement needs were determined based on the age profiles of transmission assets.

35. Distribution network replacement needs were set equal to anticipated expenditure to meet electricity demand growth.

36. **The investment need for the period 2013 to 2025 is estimated to be $2.8 billion.** The grid integration plan is discussed in Volume VIII. The power expansion plan and grid integration plan is discussed in detail in Volume IX.

Figure 24: Cumulative Capex Requirement for T&D



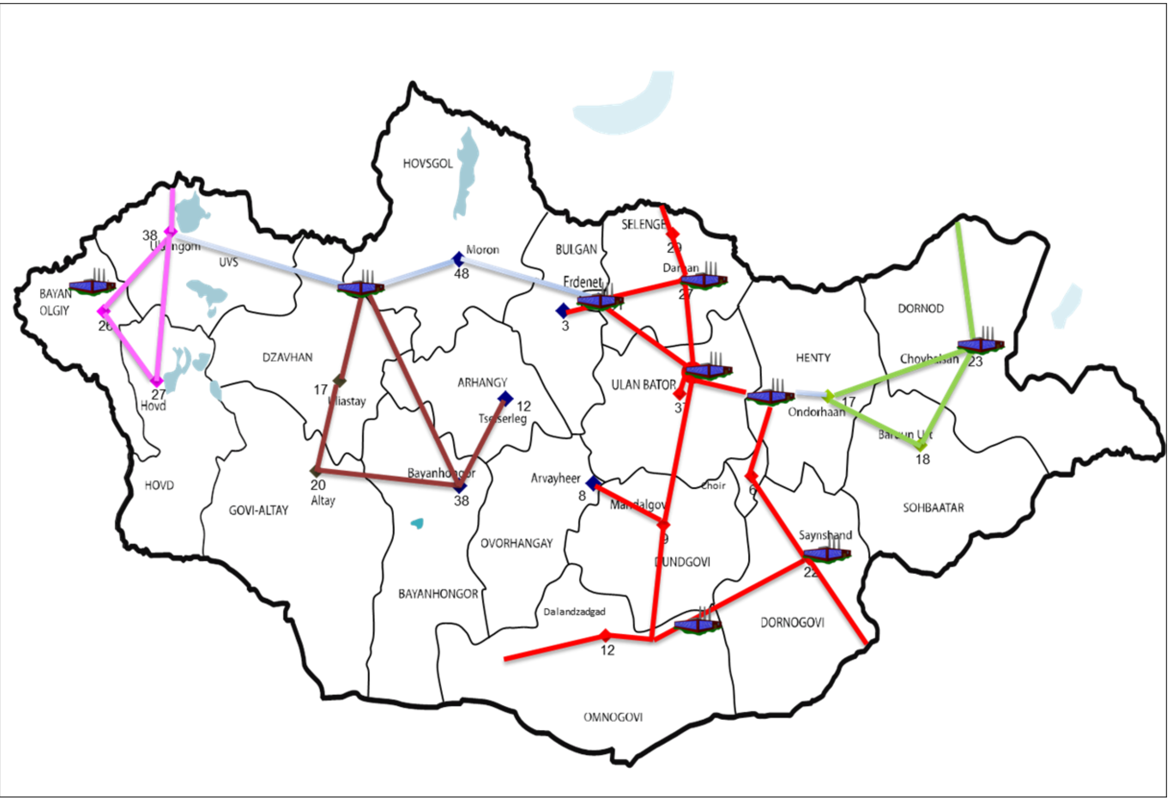
Source: Consultant's analyses

O. Integrated Energy System

37. The 2025 load forecasts for Mongolia's Aimag centres, and associated load centres are shown in Figure 20 above.

38. As these load centres are separated by large distances and the loads are not particularly high in MW terms, from the perspective of adequacy and security of supply each load centre should be supplied from a local 110kV or 220kV grid. Furthermore each load centre would be linked by 220kV interconnectors capable of bi-directional delivery of power. It is not envisaged that power transfers into the Central Energy System (CES) would be a feature of this arrangement, since the security of the CES should not be compromised in any way by small Energy Systems. A proposed arrangement is shown in Figure 25; power plants are shown sited at local coal basins. A hydropower plant built on the Sheuren river system is included in the future vision of the Integrated Electricity System, i.e. the CES expansion plan is included.

Figure 25: Vision – Integrated Electricity System – 2025



Source: Consultant's analyses

39. The power plants required to supply the load centres would be sized to supply the load centre, in one case with a local 25% reserve margin, in other cases the reserve margin can be provided by transfer from adjacent regions or potentially from Russia. The maximum size of power plant units must be commensurate with the need to maintain adequate voltage stability under load rejection or fault conditions, to perform power plant maintenance, to cope with forced outages, and to provide power on emergency basis to an adjacent Energy System. In practice these conditions could be met with units of minimum 25 MW each. Interconnection to the CES and Russia would make the small Energy Systems 'stiffer' or more tolerant of loss of a 25 MW unit, however the final arrangements and sizing would require detailed feasibility study. However, in principle this overall supply strategy would guarantee a high level of security on the most economical basis across widely dispersed load centres. The local 220kV grid arrangement would provide for a high level of reliability, with an estimated annual loss of load probability due to grid issues at less than 0.1%. Overall the loss of load probability would be no worse than 0.342%, a typical target for developing countries. Further detail of the grid expansion plan is provided in Volume VIII.

V. FINANCE CONSIDERATIONS

P. Tariff Insufficiency

40. It is an accepted fact around the world that private sector participation in energy markets requires that tariffs support full cost recovery, allowing for reasonable returns on capital and reasonable profits. In the coming decade Mongolia has a considerable need for capital investment in infrastructure, not limited to energy infrastructure. Where tariffs involve subsidy (or losses) it will hamper the involvement of the private sector with or without sovereign guarantees.

41. The Energy Master Plan defines the long-run cost of the power and heat supply sectors based on a rigorous determination of investment needs to 2025. The plan provides a reference against which long term tariff strategies can be developed within the context of an objective of achieving full cost recovery. The rate of achievement of full cost recovery must be affordable for consumers.

42. A financial viability check has been undertaken for the heat and power sectors by energy region and sector. Financial analysis of the licensees was based on financial statements (balance sheets, income and cash flow statements) obtained from the Electricity Regulatory Commission. Financial statements of individual licensed operators serving Ulaanbaatar (UB) and the Central Regional Energy System (CRES) were consolidated into single statements. Analysis of other licensee performance was based on their original financial statements. The result of the financial analysis shows that all companies except the Ulaanbaatar district heating company have had poor profitability in recent years. Only four business sectors (UB and CRES electricity and heat distribution and sales) had approved tariffs covering the full cost of sales, and only two participants (UB DHN SOJSC, and CRES electricity distribution and sales segment) had tariffs which were covering total operating costs.

43. Since the results of the financial analysis highlights that the main financial viability problem of the licensees is their low or negative profitability, the Consultants carried out a retrospective estimation of wholesale electricity and heat tariffs of major licensees, with a view to establish a shadow tariff that would have recovered full costs and achieved reasonable profit levels in 2011 and 2012.

44. The tariff study has shown that for 2011 and 2012, the biggest change in tariffs would have been caused by abolishing heat and power cross-subsidies at the CHP plants. This would have had two effects:-

1. Tariffs for electricity produced at CHPs could have been reduced still allowing to achieve 2.5% net profit margin target; and
2. Tariffs for heat produced at CHPs would have significantly increased. This increase would be especially dramatic for the older CHP plants and HOBs.

45. With exception of WRES and AuES, electricity transmission and distribution tariffs would not have increased greatly.

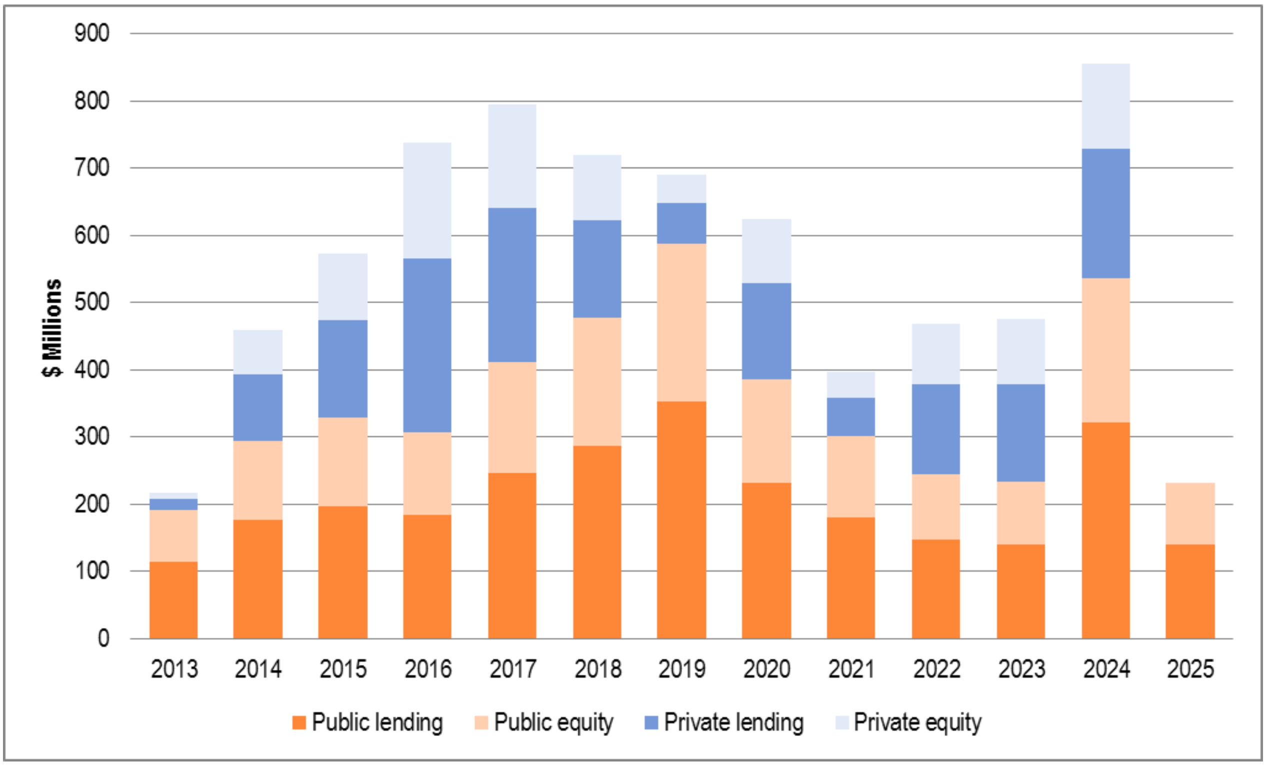
46. It is clear that tariff rationalization will be necessary if private sector investment is to increase, and if the necessary sustaining capital investment is to be made by the currently licensed operators.

Q. Finance Sources

47. The sources of capital investment are likely to vary according to the nature of the investment plan, e.g. it is likely that the Government will need to play a greater role in the financing

of a hydropower plant, than in the case of a coal-fired plant which could be readily developed as a merchant plant. One possible scenario for the sources of finance for the recommended CES expansion plan follows:-

Figure 26: CES Expansion Plan by Finance Source (Scenario 2c)



Source: Consultant's analyses

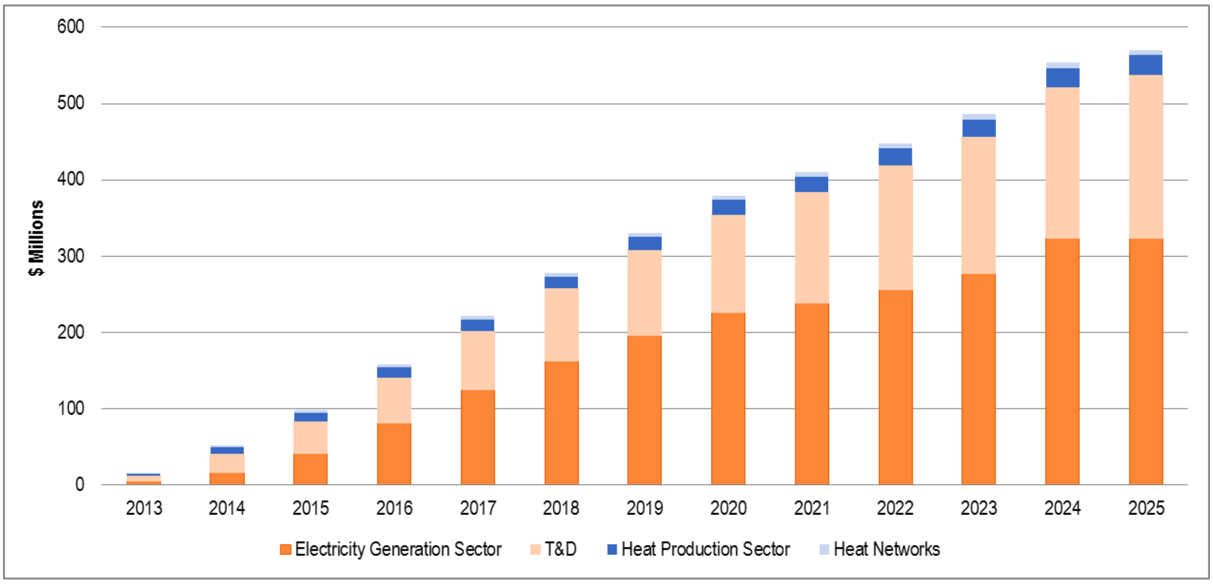
48. In this expansion plan view all coal-based condensing power plants, new HOBs and the new CHP plant in Ulaanbaatar are assumed to be sponsored by the private sector, and all old CHP plants, new wind power and hydropower by the public sector.

R. Forward Tariff Path

49. An analysis of the CES tariffs has been undertaken, allowing for the impact of future capital investment. The existing tariffs allow include hardly any cost to capital, as the assets are largely fully depreciated. Forward –looking tariffs must allow for capital investment.

50. Whilst annual capital disbursements will occur throughout the expansion period, in reality most, if not all, projects will be financed by a mix of equity and debt, and the financial cost will be distributed over several years beyond the planning horizon. Assuming the financing sources shown in Figure 26, annual capital requirements are shown in Figure 27. The calculation of the annualized capital costs assumes a harmonized capital structure of 60/40 (debt/equity) for all projects, a real WACC of 4% for public projects and 6% for PPP and private projects, and 20 years for the financial service period.

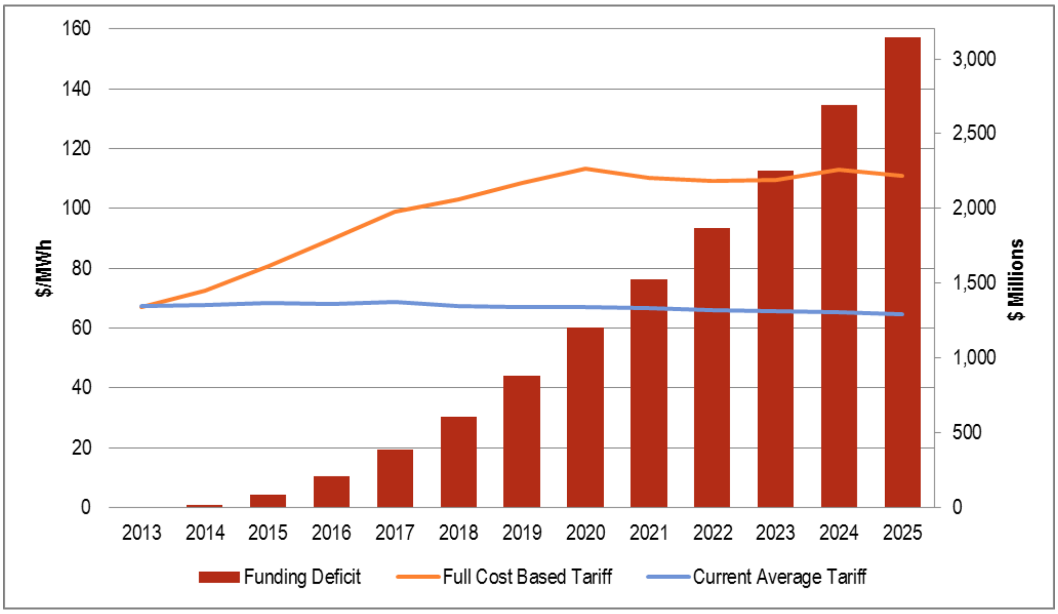
Figure 27: Annualized Investment for CES Expansion Plan (Scenario 2c)



Source: Consultant's analyses

51. The Full Cost Tariffs shown in Figure 28 and Figure 29 are based on the objective that the full Capex and Opex expenditure is covered each year by the tariff. The tariffs are calculated under assumption of achieving the net profit margin of 2.5% by 2020, and of 10% by 2025. The calculations are based on the real prices and forex rates of 2012. As soon as construction of new assets commences an immediate tariff rise is needed. If tariffs do not rise, the funding deficit columns shown in these figures will develop over time. Obviously partial rises will lead to partial deficits.

Figure 28: Full Cost-Based Electricity Tariff vs. Funding Deficit



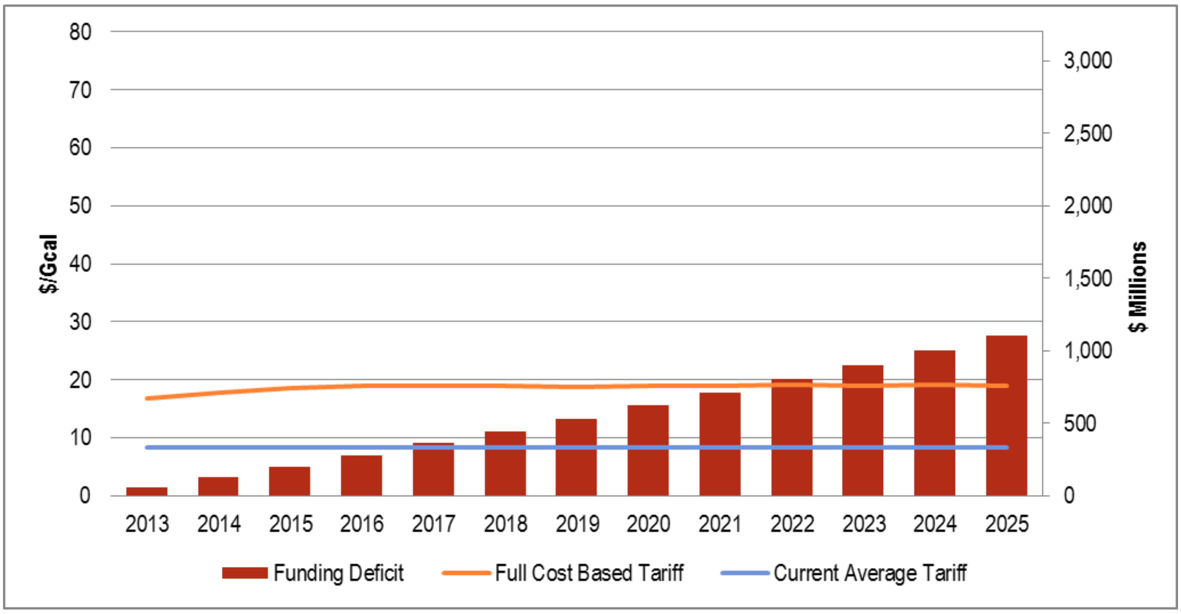
Source: Consultant's analyses

52. In 2012, residential electricity consumption was around 20% of the total electricity demand. In the event that vulnerable consumer groups, or the residential sector as a whole, would need to

be shielded from a pass through of the full cost tariffs, other sectors could absorb the increase. This is fair and equitable because the demand is mainly driven by the commercial and industrial sectors, their share in overall consumption is high, and tariffs would need only be increased by another 10% (or even less in case of a bullish growth of industrial demand) in real terms by 2025 to cover the revenue loss incurred if residential tariffs were not increased.

53. The needed increase in heat tariffs is significantly greater than the increase needed for electricity tariffs. The current tariffs average at around 8 $/ gigacalorie (GCal), the needed Full Cost Tariff is about 19 $/ GCal.

Figure 29: Full Cost-Based Heat Tariff vs. Funding Deficit



Source: Consultant's analyses

54. The share of residential consumption in heating demand is substantially higher than in case of electricity demand. Therefore, the social consequences of tariff increases are more severe. On the other hand, the stratum affected by such increase would not be the poorest, as people living in the district heated apartment buildings of cities and Aimag centres represent on average basis higher income groups than the population as a whole.

VI. POLICY NOTE

S. Sector Background, Policies & Institutions

55. **Coal dominant energy structure.** Coal is a dominant source both in primary energy (70% for Mongolia, 66% for the PRC and 22% for Japan) and secondary energy - electricity and heat generation (over 95%). There is no natural gas available in Mongolia and all refined oil is imported mainly from Russia with some minor import from the People's Republic of China (PRC), and South Korea.

56. **High energy intensity.** Energy intensity is more than two times higher than in Organisation for Economic Co-operation and Development (OECD) countries, but comparable to Kazakhstan, due to energy intensive industrial structure (mining industries) and cold climate condition (long heating season).

57. **Heat driven energy economy.** The demand for heating is over two times that of electricity due to climatic condition (8 months of heating season – winter temperatures fall in the range below minus 20ºC to minus 40ºC). Because of this, combined heat and power (CHP) plant is the most suitable, efficient, and economical choice to provide electricity and heat in Mongolia, notably in Ulaanbaatar where the population density is high. In Ulaanbaatar and most Aimag centres, it is economical to employ district heating systems to distribute heat. Heat access is a matter of human survival for Mongolia's citizens.

58. **Aging heat and power plants.** The existing facilities for providing heating and electricity (power plants and transmission and distribution lines) are energy inefficient and vulnerable since this infrastructure dates to the Soviet era. Two out of three CHP plants (number 2 and 3) in Ulaanbaatar have been operating for over 40 years, and the largest CHP plant number 4 in Ulaanbaatar has operated for more than 25 years.

59. **Potential supply crisis.** Electricity and heating demand has almost doubled in the last decade due to mining developments and urbanization of Ulaanbaatar, and is expected to grow at the rate of 8 to 10% by 2020. However, no major investments have been made to date to meet the growing demand; as a result , which results in almost zero reserve margin of electricity and heat supplies is almost zero. If no capacity additions are made, an electricity and heat supply crisis may happen in the near future.

60. **Rich renewable resources.** Mongolia has a very high development potential in renewable sources (solar, wind and hydro). A Mongolian private company successfully commissioned a 50 megawatt wind farm in Salkhit in 2013, which is the first megawatt scale grid connected wind farm in Mongolia. However, due to the intermittent nature of wind, development of dispatchable backing sources (hydropower plant) is required to support further development.

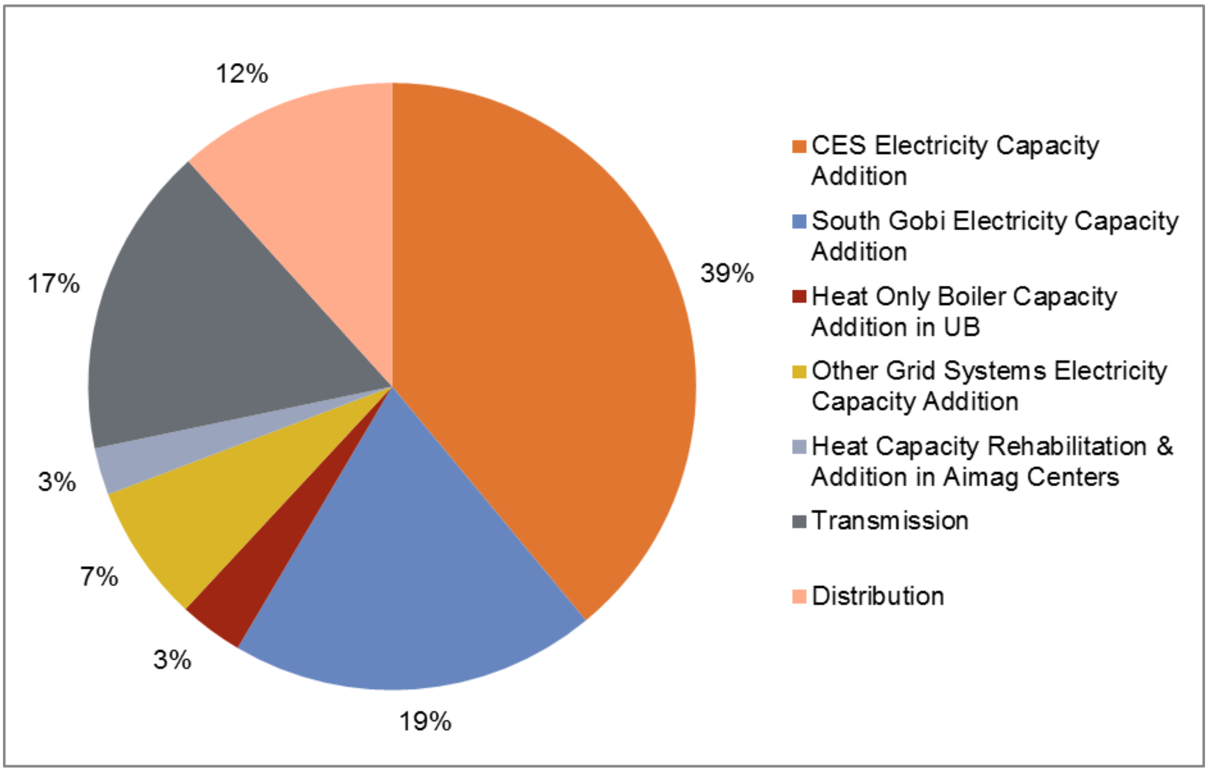
61. **Aging heating facilities in rural area.** Coal based heating facilities in Aimag and Soum centers are old and inefficient and mostly beyond refurbishment. Urgent replacement of heating facilities is needed to provide reliable and efficient heating services to the citizens. Also, renewable energy integration in coal fired based district heating system in rural remote areas can be considered depending on the availability of land and high solar irradiation.

62. **Central electricity system operation.** In Mongolia combined heat and power plants operate most efficiently in winter at the time of peak heat demand. It happens that in the central electricity system the peak electricity demand also occurs in winter and is met by combined heat and power plants. This means that in Mongolia a hydropower plant will not be required to supply peak demand in winter, instead it is economical to use a hydropower plant, particularly in summer, but also as a baseload power plant operating year round.

63. **Integrated energy system.** The Government has a vision to interconnect the currently independent energy grid systems operating in the country. Recently the Dalanzadgad area was connected to Ulaanbaatar via Mandalgovi at 220kV, establishing integrated central and southern grids. The eastern and western grids are currently supplied by Russia. Integration of these grids to the central grid will increase energy independence and offers the potential to improve energy security in an economical manner through cross-grid sharing of energy resources.

64. **Large investment needs.** It is estimated that $10.26 billion of investment is required by 2025 (or $840 million per year), comprising of which (i) $4.0 billion for CES electricity and combined heat and power capacity addition, (ii) $0.35 billion for heat only boiler capacity addition in Ulaanbaatar, (iii) $2.0 billion for electricity capacity addition in South Gobi Region, (iv) $0.75 billion for electricity capacity addition in the other grid systems, (v) $0.26 billion for heat capacity rehabilitation and addition in Aimag centers, (vi) $1.7 billion for transmission, and (viii) $1.1 billion for distribution.

Figure 30: Estimated Investment Requirements by 2025 by %



Source: Consultant's analyses

65. **Reasonable policies and institutional framework.** Mongolia has transformed to the modern energy market system (single buyer market model) unlike other central Asian counties. There is also a provision of bilateral contract between power producers and end users. However, this provision is limited to use for power supply project to the coal mines. Consumer tariffs are regulated and have been adjusted recurrently to keep pace with domestic inflation. However, tariffs remain below level of full cost recovery, which has led to state subsidies to sector operators and cross-subsidies between electricity and heat consumer segments. National Renewable Energy program (2005) set the renewable energy production target at 20 to 25 % in 2020, and Renewable Energy Law (2007) sets reasonable feed-in-tariffs to accelerate investment. A Renewable energy fund has been established under the law for supporting research and development and rural electrification, but the fund needs to be populated.

T. Policy Recommendations

66. **Renew urgently the critical heat and power infrastructure.** Investment for expansion and modernization of the electricity facilities in central energy system and heating facilities in Ulaanbaatar, where 90% of heat and electricity produced in Mongolia is the top priority to sustain people's life and economic activities, and to reduce urban air pollution in Ulaanbaatar. By renewing the facilities, it will (i) bring supply side energy efficiency gain of up to 30% in combined heat and power stations, and up to 50% efficiency gain in electrical transmission and distribution networks, and (ii) guarantee to provide reliable heat and power services.

67. **Aimag heat supplies.** Renew the aged heating plants and district heating networks in the Aimags, to provide adequate and reliable heating and hot tap water supplies. This will have the effect of encouraging residents to refrain from moving to the larger population centres. New heating systems will see improved efficiency, reduced air pollution and great improvements to the current working conditions in many of the smaller heat plants.

68. **Develop regulating power supply plant(s).** Develop a large hydro power plant(s) on the Sheuren river system as an effective measure to (i) provide low cost electricity in summer months, to reduce import from Russia during the peak hours, and (ii) to support scaling up wind power development. The link to Russia can be maintained to meet supply needs under emergency conditions.

69. **Introduce grid-connected wind farm capacity.** The grid-connected wind farm capacity defined by the planting schedule of Scenario 2c (refer Volume VI) will ensure that the renewable energy contribution averages 20% on energy base during the years 2020 to 2025.

70. **Develop a secure integrated energy system.** Establish four energy grids linked by transmission line interconnectors capable of providing back-up supply between adjacent grids under conditions of first contingency supply loss. In the case of the central energy system, long-term development will focus on securing the bulk power supplies to the industrial centres of Darkhan, Erdenet, Ulaanbaatar, Tavan Tolgoi / Oyu Tolgoi and Sainshand Industrial Park. Outside of the central energy system, the three smaller energy grids will each connect three Aimag centres in a ring configuration, each ring supplied by local power generation capacity.

71. **Remove subsidies and increase electricity and heating tariffs.** A 70% tariff increase for electricity and 130% for heat is advised to achieve full cost recovery, to maintain the financial health of heat and power companies, to ensure investments in system expansion and attract private sector participation. Subsidies provided to energy sector companies should be replaced by channelling financial support directly to vulnerable consumer groups to mitigate the impacts of tariff increases.

VII. MONGOLIA - LONG LIST (2014 to 2025)

	Sector	Initiative	By	$ mill	Comment
5 - Year Plan:	**2014 TO 2018**				
1	UB Heat Transmission	Construct new Ø1200 pipe line, main line No 10 from CHP-4	2014	5.8	
2	UB Heat Transmission	Construct new main pipe line for heating from CHP-4 to Yarmag direction	2015	7.7	
3	UB Heat Transmission	Improve reliability heat supply for Zaisan consumers	2014	3.9	
4	UB Heat Transmission	Extend capacity of 5а, 10в,10г,10д heat mail pipe lines from CHP-3	2015	23.1	
5	UB Heat Transmission	Extend capacity of district heating system in UB	2014	11.5	
6	CES / UB Heat & Power	Construct 300GCal/h HOB at Amgalan	2014	88.2	
7	CES / UB Heat & Power	Construct 300MWe CHP5 (Units 1 and 2)	2018	600.0	
8	CES / UB Heat & Power	Construct 300MW (2 X 150MW) coal plant (to East at Baganuur / Chandgana or south UB)	2018	483.0	
18	Power Transmission	Replace power transformers - 110kV (24 off, 230MVA total) and 220kV (5 off, 438MVA total)	2018	36.3	
21	Power Transmission	Replace transmission lines - 110kV (970km total)	2018	60.0	
24	Power Transmission	Replace circuit breakers - 35kV (34 off) and 110kV (23 off)	2018	8.8	
27	Power Transmission	New Power Transformers - 220kV (320MVA total)	2018	16.2	

	Sector	Initiative	By	$ mill	Comment
28	Power Transmission	New Transmission Lines - 220kV (460 km)	2018	90.0	
29	Power Transmission	New circuit breakers - 220kV (12 off)	2018	6.4	
36	Power Transmission	New Power Transformers - 110kV (420MVA total)	2018	25.9	
37	Power Transmission	New Transmission Lines - 110kV (1,092 km)	2018	87.3	
38	Power Transmission	New circuit breakers - 110kV (53 off)	2018	14.1	
45	Power Transmission	New Power Transformers - 35kV (626MVA total)	2018	45.0	
46	Power Transmission	New Transmission Lines - 35kV (1,676 km)	2018	46.9	
47	Power Transmission	New circuit breakers - 35kV (186 off)	2018	15.5	
54	Aimag Heat	Extension & rehabilitation of heating supply in Uvs (CHP), Khuvsgul (CHP), Selenge (Small Boilers), Bulgan (HOB), Bayankhongor (HOB), Uvurkhangai (Small Boilers), Sukhbaatar (Small Boilers), Zavkhan (CHP), Gobi-Altai (CHP), Dornogobi (CHP), Dundgobi (Small Boilers), Khovd (CHP), Khentee (CHP), Tuv (CHP), Arkhangai (HOB),Khovd (CHP), Dalanzadgad (Small Boilers), Gobi-Sumber (HOB), Nailakh (CHP), Baganuur (CHP), Choibalsan(CHP), Bayan-Ulgii (CHP)	2016	258.3	
55	Altai Uliastai Energy Region Power	Mogoin Gol Coal no. 1 25MW unit	2018	50.0	
56	Altai Uliastai Energy Region Power	Mogoin Gol Coal no. 2 25MW unit	2018	50.0	
57	Altai Uliastai Energy Region Power	Mogoin Gol Coal no. 3 (Muren) 25MW unit	2018	50.0	
61	Altai Uliastai Energy Region Power Transmission	220kV Interconnector – Mogoin Gol to Ulaangom; 25MW capacity	2018		Included in Item 28
66	Eastern Energy Region System Heat	Choibalsan CHP 3 x 10MWe	2018		Included under Item 54

	Sector	Initiative	By	$ mill	Comment
	& Power				
67	Eastern Energy Region System Power	Baganuur / Chandgana no 1 25MW unit	2018	50.0	
69	Eastern Energy Region System Transmission	220kV Interconnector – Banganuur / Chandgana to Ondorhaan; 25MW capacity, 580km	2018		Included in Item 28 ($60m)
72	Western Region Energy System Power	Power plant no. 1 25MW unit	2018	50.0	
73	Western Region Energy System Power	Power plant no. 2 25MW unit	2018	50.0	
76	Western Region Energy System Transmission	110kV line – Ulaangom to Ulgii; 25MW capacity	2018		Included in Item 37
77	Western Region Energy System Transmission	110kV line – Ulgii to Khovd; 25MW capacity	2018		Included in Item 38
79	South Gobi Energy System Power	Tavan Tolgoi units 1 – 3 (3 x 150MW)	2018	900.0	
82	South Gobi Energy System Power	Tavan Tolgoi - Oyu Tolgoi 220kV; 25MW capacity	2016	50.0	
83	South Gobi Energy System Power	Tavan Tologi – Dalanzadgad – Nariin Suhkait 110kV line; 100MW capacity	2018		Included in Item 37

	Sector	Initiative	By	$ mill	Comment
	Transmission				
84	Power Distribution	New Line Transformers ; 6 - 10kV (940MVA total)	2018	73.0	
85	Power Distribution	New LV Lines ; 6 - 10kV (1,860km)	2018	32.0	
90	Power Distribution	New Low Voltage Systems (1,400km)	2018	14.3	
5 - Year Plan:	**2019 TO 2023**				
9	CES / UB Heat & Power	Construct coal plant (150MWe)	2019	282.0	
10	CES / UB Heat & Power	Construct CHP5 Unit 3	2021	300.0	
11	CES / UB Heat & Power	Construct CHP5 Unit 4	2023	284.0	
13	CES / UB Heat & Power	Construct CHP5 Unit 5	2025	284.0	
14	CES / UB Heat & Power	Construct 100MW windfarm (2 x 50MW)	2020	147.0	
15	CES / UB Heat & Power	Construct 390MW Sheuren HPP	2021	862.0	
16	CES / UB Heat & Power	Construct 50MW windfarm (1 x 50MW)	2022	74.0	
19	Power Transmission	Replace power transformers - 110kV (4 off, 26MVA total) and 220kV (2 off, 250MVA total)	2023	14.1	
22	Power Transmission	Replace transmission lines - 110kV (515km total)	2023	32.0	
25	Power Transmission	Replace circuit breakers - 35kV (25 off) and 110kV (35 off)	2023	11.2	
30	Power Transmission	New Power Transformers - 220kV (270MVA total)	2023	13.5	
31	Power Transmission	New Transmission Lines - 220kV (382 km)	2023	74.4	

	Sector	Initiative	By	$ mill	Comment
32	Power Transmission	New circuit breakers - 220kV (8 off)	2023	5.4	
39	Power Transmission	New Power Transformers - 110kV (348MVA total)	2023	21.5	
40	Power Transmission	New Transmission Lines - 110kV (910 km)	2023	72.8	
41	Power Transmission	New circuit breakers - 110kV (44 off)	2023	11.7	
48	Power Transmission	New Power Transformers - 35kV (521MVA total)	2023	37.5	
49	Power Transmission	New Transmission Lines - 35kV (1,396km)	2023	13.9	
50	Power Transmission	New circuit breakers - 35kV (155 off)	2023	12.9	
58	Altai Uliastai Energy Region Power	Mogoin Gol Coal no. 4 25MW unit	2022	50.0	
63	Altai Uliastai Energy Region Power Transmission	220kV line – Mogoin Gol to Altai via Uliastai; 50MW capacity	2023		Included in Item 31
64	Altai Uliastai Energy Region Power Transmission	110kV line – Altai to Bayankhongor; 25MW capacity	2023		Included in Item 40
74	Western Region Energy System Power	Power plant no. 3 25MW unit	2022	50.0	
78	Western Region Energy System Transmission	110kV line – Khovd to Ulaangom; 25MW capacity	2022		Included in Item 40
80	South Gobi Energy System Power	Tavan Tolgoi unit no. 4 (150MW)	2020	300.0	
81	South Gobi Energy System Power	Tavan Tolgoi unit no. 5 (150MW)	2022	300.0	

	Sector	Initiative	By	$ mill	Comment
86	Power Distribution	New Line Transformers ; 6 - 10kV (780MVA total)	2023	61.0	
87	Power Distribution	New LV Lines ; 6 - 10kV (1,550km)	2023	26.0	
91	Power Distribution	New Low Voltage Systems (1,200km)	2023	11.9	
5 - Year Plan:	**2024 TO 2028**				
12	CES / UB Heat & Power	Construct coal plant (150MWe)	2024	282.0	
17	CES / UB Heat & Power	Construct 200MW wind farm (4 x 50MW)	2025	295.0	
20	Power Transmission	Replace power transformers - 110kV (10 off, 135MVA total) and 220kV (4 off, 190MVA total)	2025	17.8	
23	Power Transmission	Replace transmission lines - 110kV (107km total)	2025	6.7	
26	Power Transmission	Replace circuit breakers - 35kV (10 off) and 110kV (79 off)	2025	21.4	
33	Power Transmission	New Power Transformers - 220kV (108MVA total)	2025	5.4	
34	Power Transmission	New Transmission Lines - 220kV (153 km)	2025	29.8	
35	Power Transmission	New circuit breakers - 220kV (3 off)	2025	2.1	
42	Power Transmission	New Power Transformers - 110kV (140MVA total)	2025	8.6	
43	Power Transmission	New Transmission Lines - 110kV (364 km)	2025	29.1	
44	Power Transmission	New circuit breakers - 110kV (18 off)	2025	4.7	
51	Power Transmission	New Power Transformers - 35kV (209MVA total)	2025	15.0	
52	Power Transmission	New Transmission Lines - 35kV (560 km)	2025	15.6	
53	Power Transmission	New circuit breakers - 35kV (62 off)	2025	5.2	
59	Altai Uliastai Energy Region Power	Mogoin Gol Coal no. 5 25MW unit	2025	50.0	
60	Altai Uliastai Energy Region Power	Mogoin Gol Coal no. 6 (Muren) 25MW unit	2025	50.0	

	Sector	Initiative	By	$ mill	Comment
62	Altai Uliastai Energy Region Power Transmission	220kV Interconnector – Mogoin Gol to Erdenet via Muren; 25MW capacity	2025		Included in Item 34
65	Altai Uliastai Energy Region Power Transmission	220kV line – Mogoin Gol to Bayankhongor; 50MW capacity	2025		Included in Item 34
68	Eastern Energy Region System Power	Baganuur / Chandgana no 2 25MW unit	2025	50.0	
70	Eastern Energy Region System Transmission	110kV line – Ondorhaan to Baruun-Urt; 25MW capacity	2025		Included in Item 96
71	Eastern Energy Region System Transmission	110kV line – Baruun-Urt to Choibalsan; 25MW capacity	2025		Included in Item 96
75	Western Region Energy System Power	Power plant no. 4 25MW unit	2025	50.0	
88	Power Distribution	New Line Transformers ; 6 - 10kV (300MVA total)	2025	24.0	
89	Power Distribution	New LV Lines ; 6 - 10kV (600km)	2025	11.0	
92	Power Distribution	New Low Voltage Systems (500km)	2025	4.8	