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

Project Number: TA No. 7619-MON

FINAL REPORT

PART D: Volume - X of X

FINANCIAL ANALYSES

Prepared for

The Asian Development Bank

and

The Mongolian Ministry of Mineral Resources and Energy

Prepared by

e.Gen Consultants Ltd.

in association with

15 October 2013

CURRENCY EQUIVALENTS

(As of April 2013)

Currency Unit	–	Togrog (MNT)
$1.00	=	1,400 MNT

ABBREVIATIONS

ADB	–	Asian Development Bank
AuES	–	Altai-Uliastai Energy System
CES	–	Central Energy System
CHP	–	Combined Heat Power
CO_2	–	Carbon Dioxide
CPI	–	Consumer Price Index
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 Region Energy System

UNITS OF MEASURE

GCal	-	Gigacalorie (one million kilocalories)
GJ	-	Gigajoule (one thousand megajoules)
kWh	-	Kilowatt-hour
MWh	-	Megawatt-hour
MWel	-	Megawatt electric
MWth	-	Megawatt thermal

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 = 3.6 GJ = 1.52 steam tons/hour
1 TSC	=	7 Gcal = 29.3 GJ = 8.15 MWh

NOTE

In this report, “$” refers to US dollars.

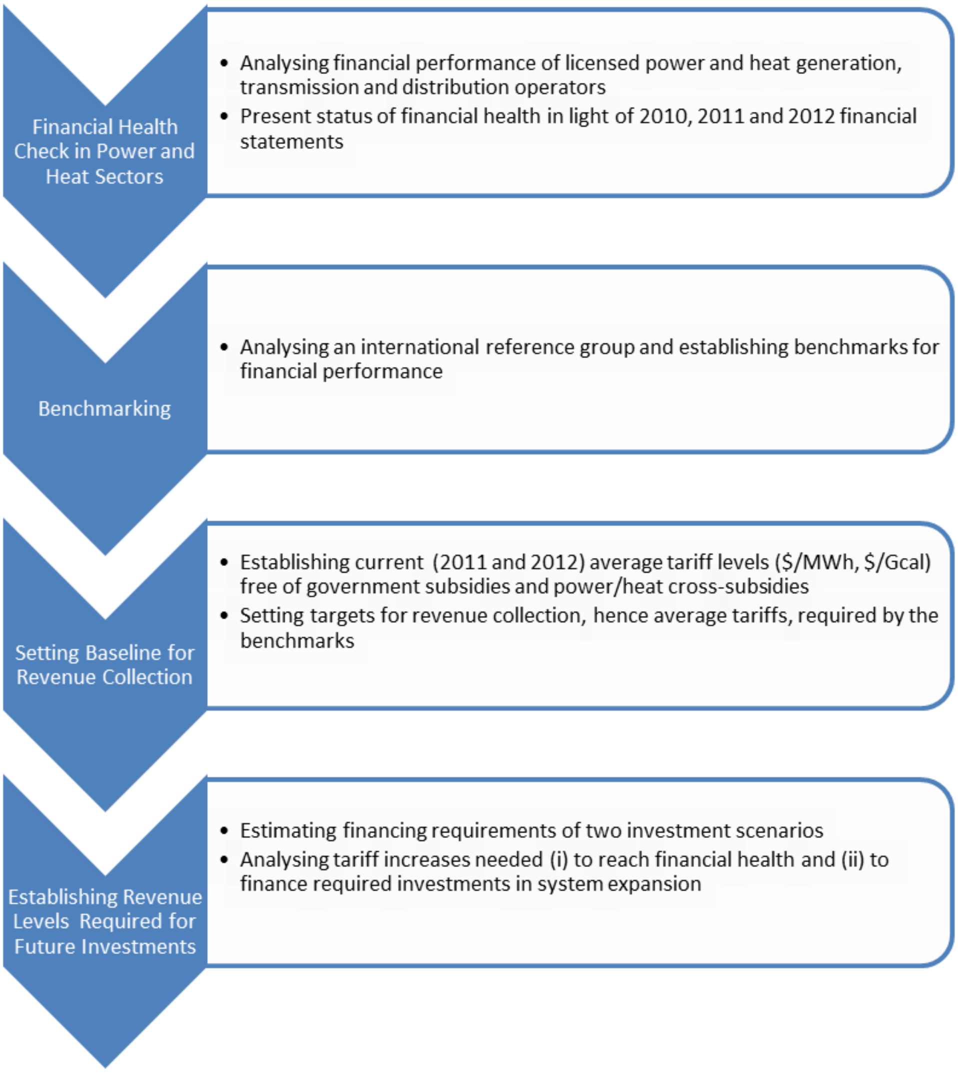
CONTENTS

I. FINANCING ENERGY INVESTMENTS

A. Introduction

1. The first part of this report seeks answers to the question of how Mongolia's energy consumers can finance the required improvements in the country's energy infrastructure. For this purpose the financial performance of the current licensed operators needs to be analysed and understood. Therefore, the first stages of the analysis will establish the level of tariff increases that are required to set the sector operators on healthy financial grounds. Today, the ability of sector operators to raise external financing is very low. Financial sustainability in the future is needed to enable higher level of self-financing and better access to debt financing. The next stages of the study then review future investment needs for system expansion, and estimate their consequent impacts to the level of revenue collection and tariffs.

Figure I-1: Methodology of Analysis



2. It is noted the energy sector legislation was reviewed in Volume I.

3. The second part of this report examines the impact of Foreign Direct Investment (FDI) on the macro-economy, therefore informing financing strategy.

II. FINANCIAL ASSESSMENT

B. Licensee Health Check

4. There are twenty-four (24) major licensed companies regulated by the Energy Regulatory Commission. Of these licensees, three are privately owned, one company is a joint venture, and three companies are owned by Aimag provincial Governments. The remaining licensees are state-owned. It is worth noting that the business activity of the non-state owned licensees is limited to electricity distribution and sales activities. None of the private or joint venture companies are involved in power generation or in the generation, transmission, distribution and sale of heat. Power transmission is carried out by state-owned JSCos, namely the National Electricity Transmission Network and Western Regional Energy System.

Table II-1: Major Licensees

Energy System	Sector	Company Name	Company ownership
UB	Energy generation	CHP2 SOJSC	State-owned JSC
	Energy generation	CHP3 SOJSC	State-owned JSC
	Energy generation	CHP4 SOJSC	State-owned JSC
	Energy generation	Nalaikh HS SOJSC	State-owned JSC
	Power transmission & imports	NETransNetwork SOJSC	State-owned JSC
	Power distribution & sales	UB EDN SOJSC	State-owned JSC
	Power distribution & sales	Nolgo LLC	Private LLC
	Power distribution & sales	Erchim Suljee LLC	Private LLC
	Power distribution & sales	JV UB Railway	Mongolian & Russian JV
	Heat distribution & sales	UB DHN SOJSC	State-owned JSC
CES	Energy generation	Darkhan CHP SOJSC	State-owned JSC
	Energy generation	Erdenet CHP SOJSC	State-owned JSC
	Energy generation	Baganuur HS SOJSC	State-owned JSC
	Power distribution & sales	Darkhan-Selenge EDN SC	Private JSC
	Power distribution & sales	Erdenet-Bulgan EDN SOJSC	State-owned JSC
	Power distribution & sales	Baganuur & South East Regional EDN SOJSC	State-owned JSC
	Power distribution & sales	Bayankhongor Erchim EDC LLC	Locally owned LLC
	Power distribution & sales	Khuvsgul Erchim LLC	Locally owned LLC
	Power distribution & sales	Erdenet-Amidral LLC	Locally owned LLC
	Heat distribution & sales	Darkhan DHN SOJSC	State-owned JSC
WRES	Power transmission & imports	WRES SOJSC	State-owned JSC
AuRES	Power distribution & sales	Altai Uliastai ES SOJSC	State-owned JSC
ERES	Energy generation	ERES SOJSC	State-owned JSC
	Power distribution & sales		
	Heat distribution & sales		

Energy System	Sector	Company Name	Company ownership
Dalanzadgad	Energy generation	Dalanzadgad SOJSC	State-owned JSC
	Power distribution & sales		
	Heat distribution & sales		

Note: due to its size, UB area has been considered as a separate "energy system", although officially it belongs to the Central Regional Energy System.

5. In addition to the major licensees regulated by the ERC and described above, there are more than hundred small rural licensees regulated by local regulatory commissions. These companies are mainly involved in the heat supply business. Due to unavailability of financial information on these rural licensees, a financial viability check was conducted only for the major energy licensees.

C. Methodology

6. The financial analysis of the major licensees was based on financial statements (balance sheets, income and cash flow statements) provided by the ERC. The financial statements were found to have been prepared according to the Mongolian GAAP and audited by an independent authorized auditor.

7. The Financial Statements of individual licensees engaged in power and / or heat generation and in electricity distribution and sales activities in Ulaanbaatar (UB) and the Central Regional Energy System (CRES) were consolidated into single statements. Analysis of other licensees was based on their original financial statements. The Financial Statements were converted to USD basis[1]. Financial analyses included analysis of the licensees' profitability, liquidity, solvency and capital adequacy for investments. Analysis techniques included ratios and common-size analysis.

8. The relative nature of a **ratio analysis** allows a comparison of licensees of different absolute size. The biggest benefit of ratio analysis can be achieved through comparison with ratios of peer companies or relevant benchmarks.

Profitability Ratios

1. Operating profit margin = Operating income / Revenue

   Measures operating profit after inclusion of all costs and expenditures

2. Net profit margin = Net Income / Revenue

   Measures overall profitability of the business. In case of Mongolia, Net Profit Margin reflects contribution of state subsidies to overall profitability of licensees business because subsidies are shown under Non-operative Income (Loss).

3. Return on Rate Base = Operating Income / Rate Base, where

   Rate Base = (Fixed assets - Depreciation) + (Current Assets – Current Liabilities)

   Measures return earned on its net fixed assets and working capital.

1. [1] Exchange Rate of 1 USD = 1400 MNT was used.

4. Return on Equity = Net Income / Average Total Equity

   Measures return earned on capital invested into business by its shareholders.

Liquidity Ratios

1. Current Ratio = Current Assets / Current Liabilities

   Measures company's ability to serve its sort-term liabilities.

2. Quick Ratio (Acid test) = (Cash + Sort-term marketable securities + Receivables) / Current Liabilities

   A more strict measure of company's ability to serve its sort-term liabilities based on the most liquid current assets

3. Cash Ratio = (Cash + Sort-term marketable securities) / Current Liabilities

   The strictest measure of a company's ability to serve its sort-term liabilities through cash and liquid marketable securities. Represents company's liquidity is a crisis situation.

4. Defence interval ratio = (Cash + Sort-term marketable securities + Receivables) / Daily Cash Expenditure, where

   Daily Cash Expenditure = (Costs of Goods Sold + Overhead Expenditures – Depreciation) / Number of Days in the Period

   Measures for how long time a company can cover its daily cash needs when using only its most liquid assets and without any additional cash inflows.

5. Days in receivables = Average Accounts Receivables x 360 / Revenue

   Measures average amount of days needed for recovering accounts receivable

6. Days in Accounts Payable = Average Accounts Payable / (Costs of Goods Sold / 360)

   Indicates average number of days a company takes to pay its suppliers.

7. Days in Inventory = Average Inventory / (Costs of Goods Sold / 360)

   Measures the average number of days it will take to sell an inventory.

Solvency and Capital Adequacy Ratios

1. Long-Term Debt to Equity = Long-term Debt / Total Equity

   Measures adequacy of long-term financing. The higher the ratio, the weaker is a company's solvency.

2. Debt to Capital= Total Debt / (Total Debt + Total Equity)

   Measures share of total liabilities in a company's the total capital. The higher the ratio, the weaker is a company's solvency.

3. Debt Service Coverage = (Net Income After Tax + Depreciation + Interest) / Debt Service

   Measures ability of a company to cover interest and principal payments with available revenues.

4. Times Interest Earned = (Earnings Before Tax + Interest Expenses) / Interest Expenses

   Measures the ability of a company to cover interest expenditures with EBIT

5. Self-financing Ratio = Net Cash from Operating Activities / Annual CAPEX

   Measures share of annual capital investments financed from internal cash sources.

9. **Common-size analysis** (CSA) is based on expression of financial data in relation to a certain financial statement item which is used as a base. In the given analysis, total assets were used as the base for balance sheet CSA, revenues as base for income statement CSA, and total cash inflows and total cash outflows for cash flow statement CSA.

D. Benchmarking

10. For **benchmarking** purposes, and broader performance comparison, three groups of energy companies were considered. The first group comprises two large energy utilities with good European presence originating from Nordic Europe (Finland, Sweden), the second group includes two energy utilities from Central and Eastern Europe (Czech Republic, Poland), the third group comprises two energy utilities located in Eastern Asia (South Korea, China). Brief information about selected utilities is presented below.

11. **Fortum Group** is the biggest energy utility in Finland. The company focuses on the Nordic and Baltic countries, Poland and Russia. Fortum's main business consists of production and distribution of electricity, heat and steam. The Group's generation assets are mainly based on hydropower, nuclear and gas, with a smaller share of coal and biomass-burning technologies. Fortum shares are listed on NASDAQ OMX Stock Exchange in Helsinki, the Finnish State holds 50.8% of the Group's shares.

12. **Vattenfall Group** is one of Europe's largest generators of electricity and the largest producer of heat and has assets in several European countries. In electricity and heat, Vattenfall works in generation, distribution and sales. Vattenfall is active in gas sales. The company also conducts energy trading and lignite mining. Europe-wide, most of Vattenfall's electricity comes from fossil fuels (52%) and nuclear power (25%), the rest is covered by hydropower and renewables. The parent company is fully owned by the Swedish Government, the Group shares are traded on exchanges.

13. **ČEZ Group** is the largest utility and biggest public company in Central and Eastern Europe. It is a conglomerate of 96 companies, 72 of them located in the Czech Republic. The Group is involved in power generation, trade and distribution, in heat generation, and in coal mining. The Czech Government is the largest (ca. 70% in December 2011) shareholder of the company, while the remaining part of stocks is listed on the Prague and Warsaw Stock Exchanges. The company uses diverse primary energy sources for energy generation, but its major part is based on coal.

14. **Polska Grupa Energetyczna (PGE Group**) is a majority state-owned (ca. 62% in March 2012) power company and the largest power producing company in Poland. Part of PGE stocks is listed on the Warsaw Stock Exchange. The PGE Group operates two large lignite mines and more than 40 power stations which are mainly fuelled by hard coal and lignite. The company consists of eight distribution system operator companies, eight electricity retail sales companies, an electricity wholesale company and enterprises operating in other industries (e.g. telecommunications).

15. **Korea Southern Power Ltd (KOSPO)** is a South-Korean state-owned energy utility which runs several thermal power plants (including CHP plants) and some wind power mills. Fuels include bituminous coal and LNG. All except one power plant owned by the company were built in 1997 or later.

16. **China Power Investment Corporation (CPI Group)** is one of the five largest state-owned

power producers in China. It is engaged in development, investment, construction, operation and management of power plants and power generation in 27 provinces in China and supplies ca. 10% of total China's electricity. The company is also involved in coal mining, aluminium production and logistics (railway and ports). Generation assets include hydropower, thermal power (mainly coal-based), nuclear power and renewable energy.

17. It can be seen that at least part of all selected utilities' generation assets is based on coal, although its significance as a primary energy source varies from case to case. All selected companies are involved into several energy sector business activities, and their financial statements represent aggregated reporting of the companies' performance. While it can be beneficial when comparing licensees performing several operating activities, it might give a biased picture for licensees involved into strictly one business area. It should be kept in mind that performance values for individual business sectors (power and heat generation, electricity distribution and sales, heat distribution and sales, power transmission) would slightly differ from the aggregated values. As an example, the table below presents ROA for different business segments of Fortum Group in 2012.

Table II-2: Fortum Group's RoNA in 2012

Power generation and trading (Nordic, CEE)	CHP generation, District Heating (Nordic, CEE)	CHP generation & sales in Russia	Electricity (Nordic)	Distribution
18.20 %	6.80 %	2.70 %		8.70 %

Source: Fortum Financials 2012

18. One of the Mongolian major licensees, UB DHN SOJSC, is a "hidden gem" among its peers. During the period of 2010 – 2012, it has had profitable and efficient operations and was one of the only two licensees who were profitable in 2012. For benchmarking purposes, UB DHN results for 2011 were selected for being included in the comparison group. The table below presents financial ratios calculated for the selected energy companies.

Table II-3: Performance Indicators Of Selected Energy Companies

	Fortum 2012	**Vattenfall 2012**	**CEZ 2012**	**PGE 2012**	**KOSPO 2011**	**CPI 2011**	**UB DHN 2011**
Net Profit Margin	24 %	10 %	19 %	7 %	1.2 %	0.3 %	2.8%
ROA	6.3 %	3.3 %	6.5 %	2.6 %	1.1 %	0.1 %	2.3%*
ROE	14.3 %	11.7 %	16.5 %	2.7 %	2.0 %	0.7 %	2.0%
Current ratio	108.9 %	128.3 %	118.7 %	336.8 %	125.1 %	36.5 %	730.9%
Quick ratio	92.7 %	77.5 %	94.3 %	172.0 %	94.1 %	17.7 %	673.1%
Days in Receivables	67	82	92	23	35	30	14
Days in Payables	182	96	278	16	36	65	0
Days in inventory	68	52	39	10	11	41	8
LT Debt to Equity	103 %	173.1 %	94.8 %	0.30 %	58.1 %	357.3 %	50.2%
Debt to Capital	56 %	70.6 %	56.6 %	3.6 %	44.4 %	85.8 %	34.5%
Self-financing ratio	97.2 %	97.4 %	120.7 %	-7140 %	50.8 %	33.7 %	175.1%

(*) Return on Rate Base (Rate Base being defined according to the Mongolian Methodology on Tariff Setting)

Source: Annual Financial Statements of the companies, Consultant analysis

19. As it can be seen from the above table, there is no "one truth" about performance indicators

of profitable energy utilities. Actual financial results vary from year to year and from company to company depending on local and global economic situation, company's strategy and, for some extent, also ownership structure.

20. It can be however seen that companies with a certain share of non-state ownership have better return on equity than fully public companies. To a large extent the same can be said about return on assets. More days in receivables, payables and inventory for bigger companies (Fortum, Vattenfall, CEZ) may indicate more sophisticated cash and inventory management practices employed in the Nordic, Central and Eastern European countries, as well as possible benefits of higher credit ratings enjoyed by economies of scale.

21. Bearing in mind that financial performance and viability of energy licensees in Mongolia cannot be changed dramatically within a short period of time, it is recommendable to establish two sets of benchmarks, short-to-mid-term, and mid-to-long-term. This should encourage realistic step-by-step approach to planning and development of the licensees operations.

22. Since there is a good example of achievable healthy financial performance inside Mongolia, the recommended short-to-mid-term performance benchmarks are based on UB DHN SOJSC performance. The mid-to-long-term benchmarks are based on financial performance of the considered Nordic and CEE energy utilities.

Table II-4: Financial Performance Benchmarks

	ST to MT	MT to LT
Net Profit Margin	2.5 %	10.0 %
ROA	2.3 %	4.5 %
ROE	2.0 %	8.0 %
Current ratio	200.0 %	150.0 %
Quick ratio	100.0 %	100.0 %
LT Debt to Equity	46.2 %	80.0 %
Debt to Capital	35.0 %	50.0 %
Self-financing ratio	50.0 %	100.0 %

23. It is worth to remember that the above benchmarks are indicative; some licensees already have better indicators (higher liquidity ratios and lower solvency ratios). In such cases, instead of being goals, the recommended benchmarks should be considered to be triggers for future financial performance follow-up and further business development and planning.

24. Since most of the licensees have rather small share of long-term liabilities in their capital structure, it is reasonable to use only ROE as a profitability benchmark. The State as major owner may be satisfied with a smaller return on equity. However, if in the future more private equity is involved e.g. through full or partial privatisation of public licensees, shareholders expectations of higher returns on equity will be very likely. Also, licensees might start to use higher financial leverage through larger involvement of debt financing. At that point, it would be useful to re-evaluate the level of the ROE benchmark and to introduce an additional benchmark for estimating efficiency of companies' capital, ROCE (Return on Capital Employed).

E. Results of Financial Analysis

1. Ulaanbaatar Regional Energy System

25. In the case of the **Energy Generation**, during the period 2010 – 2012, accounts receivables made ca. 3% of total assets; inventory was the biggest item among current assets (4.4 % of total assets in average). Share of current assets was ca. 10%. Non-current assets were

mainly consisting of fixed assets (in average 87.7% of total assets), construction in progress was close to zero. Share of current liabilities was rather low, slightly increasing to 4.6% of total assets in 2012. Total liabilities were under 50% of total business segment financing indicating its stable solvency.

26. Gross profit was negative during all the period of 2011 – 2012 indicating inadequate tariffs for energy producers. Indeed, all four companies included into this business segment were receiving subsidies in 2011 and two of them (CHP-2 and Nalaikh SOJSC) also in 2012. After deducting overheads and operating expenses, the business sector made 22%, 7.7% and 10.4% of loss in 2010, 2011 and 2012 respectively. After receiving state subsidies, the situation improved insignificantly, with net profit margin being positive (8%) in 2010, falling to a 1% loss in 2011 and a loss of around 9% in 2012.

27. Cash flows from operating activities were positive for the whole period, and the companies were active in investments (investments made up 63% and as much as 2,177% of operating cash flow in 2011 and 2012 respectively). In 2012, significant investments were financed with bank loans and state support.

Table II-5: UB Power and Heat Generation Business

	2011	2012
Total Sales, million MNT	187,949	206,913
Total Sales, '000 USD	134,249	147,795
Profitability		
Operating profit margin	-7.7 %	-10.4 %
Net profit margin	-0.9 %	-8.9 %
Return On Rate Base	-3.6 %	-5.7 %
ROE	-0.7 %	-6.9 %
Liquidity		
Current ratio	527.3 %	204.6 %
Quick ratio	241.3 %	76.9 %
Cash ratio	101.4 %	11.7 %
Defensive interval ratio	37	23
Days in Accounts Receivable	24	18
Days in Accounts Payable	12	22
Days in inventory	31	29
Solvency		
Long-Term LT Debt to Equity	44.4 %	44.6 %
Debt to Capital	32.2 %	34.1 %
Debt Service Coverage	< 0	< 0
Times Interest Earned	Na	< 0
Self-financing ratio	128.2 %	< 0

Note: Consolidated Income Statement does not include 2010 for CHP-4.

28. Despite negative operating and net profit margins, the business segment has good liquidity and solvency secured by low level of borrowings and by state equity financing. Weak profitability clearly influences the companies' ability of making significant capital investments without strong state support.

29. In **Electricity Distribution and Sales**, over the period 2010 to 2012, accounts receivables

made ca. 18% of total assets, while bad debts were a reducing share of current assets for almost 10% on average, bringing the share of current assets to ca. 17% of total assets. Non-current assets consist mainly of fixed assets (average share in total assets 63.5%), with construction in progress making up in average ca. 19%.

30. From 2010 to 2012, share of accounts payable was declining from 11.1% to only 3.2% of total assets producing positive effect on the business segment's liquidity. However, the share of other payables was increasing and offsetting most of the positive effect of decrease in accounts payable. The share of unearned revenues (mainly customer prepayments) increased from 2.6% in 2010 to almost 6% in 2012.

31. The share of long-term liabilities varied between 40% and 50% (but always less than 50%) of the total assets. However, total liabilities of the business segment were slightly exceeding own capital, although share of liabilities in total financing was decreasing from 64% in 2010 to ca. 56% in 2012 reflecting further improvement of the business sector solvency.

32. Gross profit of the business segment stayed positive during the whole period from 2010 to 2012. However, overhead operative expenses were exceeding gross profit margin making operating profit negative. Positive results from non-operating activities in 2010 and 2012 allowed the segment to have positive financial results during these years.

33. The business was generally profitable, and the State repatriated money, bringing net cash flow close to zero. In 2012, the State repatriation exceeded the operative cash flow of the business segment by 3%.

Table II-6: UB Electricity Distribution and Sales Business

	2011	2012
Total Sales, million MNT	129 591	154 367
Total Sales, 1,000 USD	92 565	110 262
Profitability		
Operating profit margin	-9.1 %	-0.4 %
Net profit margin	-8.4 %	0.2 %
Return On Rate Base	-19.8 %	-1.1 %
ROE	-33.5 %	0.7 %
Liquidity		
Current ratio	97.4 %	109.8 %
Quick ratio	123.5 %	131.2 %
Cash ratio	24.5 %	13.3 %
Defensive interval ratio	58	50
Days in receivables	46	41
Days in Accounts Payables	18	9
Days in inventory	10	11
Solvency		
Long-Term Debt to Equity ratio	118.6 %	92.3 %
Debt to Capital	62.8 %	55.9 %
Debt Service Coverage	< 0	501.2 %
Times Interest Earned	< 0	159.3 %
Self-financing ratio	na	142 061.9 %

Note: Consolidated financial statements do not include cash flow statements for Erchim Suljee

LLC, Nolgo LLC and UB Railways for 2011.

34. The business segment showed improvement of its liquidity from 2010 to 2012. The Current Ratio was lower than Quick Ratio due to significant share of bad debts within total current assets. Debt to equity ratios show that the business sector solvency is on appropriate level. Negative operating profitability may lead to problems with funding capital investments.

35. The assets of the **National Electricity Transmission Network SOJSC** almost fully (in average 93%) consist of fixed assets. Current liabilities are a very minor share, whereas total liabilities make up ca. 20% of total assets (average over 2010-2012), with strong increase of long-term debt (from 9.2% in 2010 to 23.1% in 2012). Thus the company is mainly financed with equity.

36. Gross profit was negative during all the period from 2010 to 2012, indicating inadequate tariffs for energy producers. Even after receiving state subsidies, the company made a loss. Non-operative income was rather high (23% of revenue) in 2010 but then decreased to 6% in 2011 and 2012. The company made net losses of 23%, 11% and 13% respectively in 2010, 2011 and 2012.

37. While both operating and investment cash flows were negative during 2010-2012, financing activities, cashflow was positive mainly due to state financing. This allowed total net cash flow to stay positive despite loss-making operations.

Table II-7: National Electricity Transmission Network

	2010	2011	2012
Total Sales, million MNT	10,794	15,291	17,694
Total Sales, 1,000 USD	7,710	10,922	12,638
Profitability			
Operating profit margin	-46.3 %	-17.4 %	-19.5 %
Net profit margin	-23.2 %	-11.0 %	-13.5 %
Return On Rate Base	-6.9 %	-2.5 %	-3.1 %
ROE	na	-2.3 %	-2.9 %
Liquidity			
Current ratio	278.4 %	566.5 %	376.7 %
Quick ratio	59.0 %	230.6 %	198.4 %
Cash ratio	35.3 %	227.4 %	138.0 %
Defensive interval ratio	16.12	44	64
Days in Receivables	na	1	1
Days in Payables	na	17	28
Days in inventory	na	45	51
Solvency			
LT Debt to Equity ratio	10.5 %	30.9 %	30.9 %
Debt to Capital	10.9 %	24.3 %	24.8 %
Debt Service Coverage	< 0	< 0	na
Times Interest Earned	na	na	na
Self-financing ratio	< 0	< 0	< 0

38. The transmission business has been significantly loss-making and required a strong

increase in share capital in 2012. Despite very good liquidity and solvency indicators, the business can continue only thanks to state financial support, both in terms of subsidies and equity. However, the company had to increase also its long-term borrowing.

39. In **Heat Distribution and Sales**, Total current assets (of which about half is cash) make ca. 10% of the total assets. Non-current assets consist mostly of net fixed assets (ca. 70% of total assets) and investments (ca. 20% of total assets). Current liabilities are very insignificant, while long-term liabilities made up 40% of total capital in 2010, decreasing to 31% in 2012. Thus the major source of capital of the company is its equity.

40. The company had positive results during the period of 2010 – 2012, although most (76%) of its profits in 2010 originated from non-operating income (mainly through realised FX gains). Share of non-operating income sharply dropped in 2011 but picked up and made 45% of EBT in 2012, this time mainly through gains from penalties and allowances. Such big influence of non-operating gains to the net profit is concerning since for business stability, it is important to earn most of profits through operating activities.

The company enjoyed positive cash flows from its operations during all years of the period in question, and in 2011 and 2012 used available cash resources for investment activities and repayment of its long-term debts.

Table II-8: UB District Heat Networks SOJSC

	2010	2011	2012
Total Sales, million MNT	43,369	43,338	47,686
Total Sales, 1,000 USD	30,978	30,956	34,062
Profitability			
Operating profit margin	2.2 %	4.1 %	0.8 %
Net profit margin	8.6 %	2.8 %	1.0 %
Return On Rate Base	1.2 %	2.3 %	0.5 %
ROE	na	2.0 %	0.8 %
Liquidity			
Current ratio	1844.5 %	730.9 %	841.0 %
Quick ratio	1641.1 %	673.1 %	663.7 %
Cash ratio	712.2 %	459.5 %	412.9 %
Defensive interval ratio	73.81	107	76
Days in receivables	na	14	11
Days in Accounts Payables	na	na	na
Days in inventory	na	8	6
Solvency			
Long-Term Debt to Equity ratio	69.2 %	50.2 %	45.9 %
Debt to Capital	41.2 %	34.5 %	32.4 %
Debt Service Coverage	na	na	na
Times Interest Earned	na	na	359.8 %
Self-financing ratio	na	175.1 %	105.8 %

41. The company has a healthy and attractive balance sheet, very significant liquidity and good solvency and thus can carry out needed capital investments and business development.

2. Central Regional Energy System

42. In **Energy Generation**, over the period 2010 – 2012, inventory made about half of current assets (ca. 3.5% of total assets), followed by accounts receivable and prepaid expenses (which made half of all current assets in 2012). Average share of current assets in total assets was ca. 10%. Non-current assets were mainly consisting of fixed assets, with its share declining from 92% in 2010 to 87.5% in 2012. Together with the work in progress being practically zero, it strongly indicates depletion of production assets and increasing threat of technical problems. Strong increase (from 0,1% in 2010 to 6.5% of total assets) of prepaid expenses (prepaid payments for purchase of equipment or contractual works) confirms that companies working in this business segment are facing sharp increase of repair and maintenance costs.

43. Current liabilities share in total assets was ca. 7% over the period in question, accounts payable making about half of them. Total liabilities equalled to ca. 8.8% of total assets, and its share was declining. Owner's capital is thus the major capital source of the business segment.

44. Gross profit was negative during all the period of 2011 – 2012 indicating inadequate tariffs for energy producers. All three companies included into this business segment were receiving subsidies in 2011 and 2012. However, the business segment was making net losses of ca. 3% and 17.6% in 2011 and 2012 respectively.

45. Cash flows from operating activities were negative for the whole period, and the companies were financed with state support and bank loans.

Table II-9: CRES Power and Heat Generation Business

	2011	2012
Total Sales, million MNT	35,436	40,442
Total Sales, 1,000 USD	25,311	28,887
Profitability		
Operating profit margin	-17.2 %	-26.0 %
Net profit margin	-2.9 %	-17.6 %
Return On Rate Base	-5.7 %	-9.7 %
ROE	-1.1 %	-7.2 %
Liquidity		
Current ratio	226.4 %	147.3 %
Quick ratio	43.9 %	26.8 %
Cash ratio	3.7 %	1.8 %
Defensive interval ratio	23	20
Days in receivables	25	19
Days in Accounts Payables	39	44
Days in inventory	34	31
Solvency		
Long-Term Debt to Equity ratio	9.5 %	9.5 %
Debt to Capital	13.4 %	16.4 %
Debt Service Coverage	< 0	< 0
Times Interest Earned	< 0	< 0
Self-financing ratio	na	na

46. The business segment is significantly loss-making. Its liquidity is also rather weak which is proved by decreasing quick ratio and very low cash ratio indicating that its current assets are locked in the least liquid segments (inventory and prepaid expenses). Strong solvency is secured by state equity backing. The business would not be possible without state support and subsidies.

47. In **Electricity Distribution and Sales**, current assets of the business segment made up ca. 17% of total assets. The largest categories were accounts receivable and prepaid expenses (increase from 1.2% 2010 to 9.4% in 2012). Cash share has been declining over time. Similar to the generation segment of the CRES, fixed assets made the largest portion of non-current assets, but this share was declining (from 85.4% in 2010 to 81.1.% in 2012. Together with significant increase in prepaid expenses, this signals accelerating depletion of fixed assets.

48. Share of current liabilities of the business segment was increasing from 10.3% in 2010 to 18.1% in 2012, mainly because of increasing share of unearned revenues (e.g. customers prepayments) which experience almost 9 times increase after 2010. Long-term liabilities never exceeded 2% of total assets, meaning that the companies in this business segment have been financed mostly through equity.

49. In 2010 – 2012, the business segment generated positive gross profit. However, revenues were not enough to cover operative overhead costs, resulting in negative net operating income in 2011 and 2012. Only one company in this segment received state support (in 2012), however non-operative income helped to make small profits in 2010 and 2011 so that net operating margin was close to zero. In 2012, the segment was loss-making.

50. Operative cash flows were positive in 2010 and 2011 but negative in 2012. Despite this, the companies were making investments during all the period of 2010 – 2012. Financing cash flows turned from being positive in 2010 and 2011 to negative in 2012, mainly due to loan repayments and share capital re-arrangements.

Table II-10: CRES Electricity Distribution and Sales Business

	2011	2012
Total Sales, million MNT	146,472	159,052
Total Sales, 1,000 USD	104,623	113,609
Profitability		
Operating profit margin	0.0 %	-3.3 %
Net profit margin	0.1 %	-3.2 %
Return On Rate Base	0.0 %	-4.9 %
ROE	0.2 %	-4.6 %
Liquidity		
Current ratio	118.6 %	98.0 %
Quick ratio	60.6 %	36.9 %
Cash ratio	26.1 %	5.8 %
Defensive interval ratio	33	21
Days in receivables	12	11
Days in Accounts Payables	13	17
Days in inventory	8	8
Solvency		
Long-Term Debt to Equity ratio	1.9 %	2.0 %
Debt to Capital	16.6 %	19.7 %
Debt Service Coverage	na	na
Times Interest Earned	na	< 0

Self-financing ratio	< 0	< 0

51. The sector showed slight profitability in 2010-2011 but was making losses in 2012. This was caused by inadequacy of tariffs and increasing operative costs (especially depreciation, maintenance and salary). General liquidity has been maintained on an appropriate level, but low quick and cash ratios indicate that most of current assets are increasingly being locked in least liquid forms. State equity financing helped to maintain solid liquidity levels and finance needed investments.

52. In **Heat Distribution and Sales**, share of current assets in total assets of the company was decreasing from 26% in 2010 to 9.4% in 2012, mainly because of the decrease in accounts receivable. Share of non-current assets was increasing from 71% to 90% due to increase in fixed assets. Share of current and especially long-term liabilities was decreasing all the time, bringing total liabilities from 27% in 2010 to only 9.6% in 2012. As a result, equity share in total company's capital was increasing, especially due to dramatic increase of paid-in capital in 2012.

53. Sales revenues were enough to cover costs of goods sold but were not sufficient to recover operating overheads, which substantially increased in 2012, mainly due to depreciation and other expenditures booked as "Other expenses". Positive results from non-operating activities (including subsidies) helped to achieve some positive results in 2010 and especially 2011 (net profit margin 8.6%), but was not enough to achieve the "break-even" in 2012.

54. Cash flows from operating activities were negative in 2011 and 2012, however the company was carrying out investments during the period 2010 – 2012. Financing was provided through long-term loans and state subsidies. Significant loan repayments in 2010 and 2011 made total cash flow of the company negative.

Table II-11: Darkhan DHN SOJSC

	2010	2011	2012
Total Sales, million MNT	4,311	4,744	5,009
Total Sales, 1,000 USD	3,079	3,389	3,578
Profitability			
Operating profit margin	-1.9 %	-2.1 %	-12.4 %
Net profit margin	0.2 %	8.6 %	-0.3 %
Return On Rate Base	-2.4 %	-2.3 %	-5.9 %
ROE	na	11.6 %	-0.2 %
Liquidity			
Current ratio	189.3 %	162.2 %	110.5 %
Quick ratio	146.2 %	111.7 %	60.3 %
Cash ratio	5.3 %	3.4 %	2.4 %
Defensive interval ratio	76.16	55	44
Days in receivables	na	55	44
Days in Accounts Payables	na	61	92
Days in inventory	na	35	50
Solvency			
Long-Term Debt to Equity ratio	18.4 %	7.3 %	1.2 %
Debt to Capital	27.1 %	18.1 %	9.6 %
Debt Service Coverage	na	na	36.8 %
Times Interest Earned	119.0 %	866.1 %	101.2 %

Self-financing ratio	< 0	< 0	< 0

55. The state subsidies helped to maintain positive profitability in 2010 and 2011 but were not enough for 2012. Tariffs and resulting revenues were not covering sales costs. Despite this, liquidity and solvency indicators were maintained on a good level. This was possible through subsidies and equity state financing. However, with some tariff adjustments the business would be able to achieve at least its break-even status.

3. Western Regional Energy System (WRES SOJSC)

56. The company has very small share of current assets in total assets (5.8% in average) mainly consisting of cash and accounts receivable. Practically all non-current assets consist of fixed assets. Average current liabilities account for ca. 2.6% and mainly consist or taxes payable and unearned revenues (received prepayments). Long-term liabilities make up ca. 56.1% of total company's capital. The rest of capital is financed with equity.

57. Sales revenues were not able to cover costs of goods sold clearly signalling strong inadequacy of tariffs. Operative losses were close to 50%. State support and other occasional non-operative gains reduced the losses, but were not able to recover significant part of the costs.

58. Cash flow from operating activities was negative during all the period of 2010 – 2012, leaving no way for serious investments. Strong financial cash flow was achieved with state financing, helping to bring the total net cash flow to the positive side.

Table II-12: WRES SOJSC

	2010	2011	2012
Total Sales, million MNT	3,315	4,239	4,990
Total Sales, 1,000 USD	2,368	3,028	3,564
Profitability			
Operating profit margin	-142.8 %	-147.7 %	-153.6 %
Net profit margin	-23.7 %	-33.3 %	-17.8 %
Return On Rate Base	-6.4 %	-8.2 %	-9.7 %
ROE	na	-4.5 %	-2.7 %
Liquidity			
Current ratio	169.8 %	155.4 %	464.0 %
Quick ratio	139.8 %	139.3 %	348.3 %
Cash ratio	49.8 %	69.1 %	179.2 %
Defensive interval ratio	120	149	127
Days in receivables	na	160	148
Days in Accounts Payables	na	3	3
Days in inventory	na	20	30
Solvency			
Long-Term Debt to Equity ratio	144.3 %	140.1 %	124.1 %
Debt to Capital	60.1 %	60.0 %	56.1 %
Debt Service Coverage	na	na	na
Times Interest Earned	na	na	na
Self-financing ratio	na	na	na

59. The company's activities have been extremely loss-making, even despite significant state subsidies. Liquidity was maintained on a good level, but solvency was weaker indicating that insufficient state financing was forcing the company to use long-term borrowing for continuing its operations.

4. Altai Uliastai Regional Energy System (Altai Uliastai ES SOJSC)

60. Share of current assets in total assets was declining during the period of 2010 – 2012 (from 16.7% to 3.7%), mainly due to decline in inventory. Both cash and accounts receivable peaked in 2011 (6.5% and 8.1% of total assets respectively), thereafter dropping sharply. Fixed assets share increased from 83% to 96%. Current liabilities peaked in 2011 due to sharp increase in unearned revenues, but then dropped to almost zero in 2012. Long-term liabilities were rather insignificant in 2010 and 2011 but increased sharply (41.4%) in 2012. Until 2012, equity was the major source of the company's capital.

61. Strong inadequacy of tariffs is seen in the gross loss (4 to almost 6 times more than sales revenues) during the whole observation period. Strong state support helped to almost completely cover total operating costs in 2010 and 2011, but significantly failed in doing so in 2012. Overall, the company's net result was negative during the period.

62. Despite negative cash flows from operating activities, the company was investing in long-term assets in 2010 and 2011. Financing cash flow was positive due to significant state funding, allowing for positive total net cash flow over the observation period.

Table II-13: Altai Uliastai ES SOJSC

	2010	2011	2012
Total Sales, million MNT	1,065	1,665	2,151
Total Sales, 1,000 USD	760	1,189	1,536
Profitability			
Operating profit margin	-587.5 %	-410.7 %	-406.7 %
Net profit margin	-15.4 %	-10.0 %	-83.1 %
Return On Rate Base	-50.3 %	-31.9 %	-8.4 %
ROE	na	-1.0 %	-4.3 %
Liquidity			
Current ratio	597.9 %	271.9 %	1967.9 %
Quick ratio	300.0 %	218.2 %	1530.0 %
Cash ratio	230.6 %	123.4 %	1471.2 %
Defensive interval ratio	57.17	227	117
Days in receivables	na	231	168
Days in Accounts Payables	na	18	6
Days in inventory	na	71	38
Solvency			
Long-Term Debt to Equity	5.9 %	3.4 %	70.8 %
Debt to Capital	8.2 %	11.5 %	41.5 %
Debt Service Coverage	na	Na	< 0
Times Interest Earned	na	Na	< 0
Self-financing ratio	< 0	< 0	na

63. Due to enormous losses, the company can continue its operations only with the state support. Liquidity and solvency indicators are on a very high level achieved through big cash and equity injection from the state.

5. Dalanzadgad Regional Energy System (Dalanzadgad SOJSC)

64. Share of current assets in total assets of the company peaked in 2011 (15.5.%) mainly due to increase in cash, prepaid expenses and inventory, but bounced to only 8.8% in 2012, inventory being the biggest part of current assets. Non-current assets were practically completely consisting of fixed assets. Current liabilities were rather high during the whole observation period (average 16.2% of total assets), decreasing in 2012. However they were clearly exceeding current assets thus weakening the company's liquidity. Long-term liabilities made in average 55% of total company's capital, with equity being ca. twice lower than long term debt, both in 2010 and 2011. Only in 2012 long term debt's and equity's shares became approximately equal. This indicates weaker solvency of the company.

65. Similar to AuRES, sales revenues were not recovering costs of goods sold, referring to insufficient energy tariffs. The company's net losses were 2.5 higher than its revenues during both 2011 and 2010, while 2010 had been only slightly better, when significant FX gains and state support helped to bring net results of the company to positive levels (net profit margin 7%). However, in 2011 and 2012 non-operative income (including state subsidies) was not able to cover losses.

66. Cash flow from operating activities was negative during the whole observation period,

leaving very little space for capital investments (realised in 2011 only), however financing cash flow was helping to achieve positive net cash flow during the whole period. Positive financing cash flows were secured through state funding, donations and interest and incentives income.

Table II-14: Dalanzadgad SOJSC

	2010	2011	2012
Total Sales, million MNT	1,577	1,435	1,399
Total Sales, 1,000 USD	1,127	1,025	999
Profitability			
Operating profit margin	-179.2 %	-268.9 %	-251.2 %
Net profit margin	7.0 %	-74.0 %	-87.1 %
Return On Rate Base	-26.8 %	-35.0 %	-32.3 %
ROE	na	-34.2 %	-30.2 %
Liquidity			
Current ratio	50.1 %	94.4 %	65.7 %
Quick ratio	24.6 %	40.2 %	10.4 %
Cash ratio	19.7 %	34.3 %	2.1 %
Defensive interval ratio	53.76	61	12
Days in receivables	na	31	32
Days in Accounts Payables	na	40	49
Days in inventory	na	36	51
Solvency			
Long-Term Debt to Equity ratio	232.6 %	263.2 %	117.3 %
Debt to Capital	75.9 %	77.0 %	59.7 %
Debt Service Coverage	na	na	na
Times Interest Earned	na	na	na
Self-financing ratio	na	< 0	na

67. The company is a significant loss-maker, with low liquidity and relatively low solvency. Its survival is highly dependent on state equity and cash financing.

6. Eastern Regional Energy System (ERES SOJSC)

68. Share of the company's current assets in total assets was stable and close to 2.5%. However, its' current assets almost fully consist of livestock (the company's side business), which might be not the most liquid asset in times of crisis. Fixed assets comprise 97.5 % of the total assets. The company has very small share of current liabilities (mostly comprises accounts payable) which explains its good current ratio. The company's share of long-term liabilities decreased from 44% in 2010 to only 28% in 2012. Most of the company's capital consists of equity.

69. Sales revenues could not fully recover costs of sales, thus making both gross and net operating results negative during 2010 – 2012. Results of non-operating activities were positive but could ensure positive net margin only for 2010. The rest of the period the company was making losses.

70. Cash flow from operating activities was negative during the whole period, with especially significant (78%) downside change in 2012. This left little space for investments which took place

only in 2010. Financial cash flow was positive all the time during 2010 – 2012, consisting of state financing and interest and incentives income.

Table II-15: ERES SOJSC

	2010	2011	2012
Total Sales, million MNT	7,357	9,145	11,250
Total Sales, 1,000 USD	5,255	6,532	8,035
Profitability			
Operating profit margin	-35.6 %	-33.2 %	-39.9 %
Net profit margin	9.5 %	-19.9 %	-18.3 %
Return On Rate Base	-5.9 %	-6.9 %	-10.2 %
ROE	na	-6.4 %	-6.5 %
Liquidity			
Current ratio	174.9 %	204.9 %	160.3 %
Quick ratio	23.3 %	19.2 %	21.0 %
Cash ratio	11.8 %	11.3 %	15.2 %
Defensive interval ratio	6	4	4
Days in receivables	na	2	1
Days in Accounts Payables	na	21	13
Days in inventory	na	39	28
Solvency			
Long-Term Debt to Equity ratio	80.5 %	41.6 %	40.2 %
Debt to Capital	45.4 %	30.3 %	29.8 %
Debt Service Coverage	na	na	na
Times Interest Earned	na	na	na
Self-financing ratio	< 0	na	na

71. The company was making relatively significant losses which were only partly covered by subsidies. Bearing in mind that most of current assets were kept in less liquid forms, the overall liquidity may be estimated as average. Solvency of the company was maintained on a rather good level achieved through increased state equity financing.

7. Findings

72. The results of the financial analysis show that all companies except the Ulaanbaatar district heating company have had very poor **profitability**. At the same time, almost all considered entities have had high level of **liquidity** and solvency. However, the liquidity indices do not mean good cash position but the liquidity level is mainly due to inventories. The least liquid segments in 2012 were the Dalanzadgad CHP and electricity distribution business in CRES.

73. High **solvency** levels are mainly explained by extensive government support and its participation in the companies' ownership. This allows companies to avoid using debt financing (in 2012, only two licensees, the WRES and the Dalanzadgad CHP, financed more than half of their needs through borrowings, but even in this case the share of debt was less than 60%).

74. During the period analysed in this study, only four business segments (UB and CRES electricity and heat distribution and sales) had tariffs which were covering sales costs, and only two licensees (UB DHN SOJSC, and CRES electricity distribution and sales segment) had tariffs

which were covering all operating costs. However, in 2012 this was no longer true for the CRES electricity distribution business.

75. Through the whole examination period, only one participant, UB DHN SOJSC, was running a profitable business. The next successful market participant, CRES electricity distribution segment, could not recover full costs in 2012, even though one of its companies received a subsidy.

76. The licensees' days in accounts payable and accounts receivable represent a relatively good payment discipline, the only exceptions are the AuES and WRES energy systems, which days in accounts receivable (168 and 148 respectively) indicate that the companies experience problems with collection of payments.

77. The debt service related ratios calculated on the basis of available financial statements do not allow making accurate conclusions because most of licensees did not have significant borrowings. On the other hand, losses from operative activities and optionality in the way the subsidies may be shown in financial statements adds additional challenges for reliable estimation of these ratios.

8. Analysis of Subsidies and Tariff Sufficiency

78. Every year, the ERC calculates subsidies and presents them the Ministry of Energy for further approval and inclusion in the state budget. The calculation of subsidies is based on previous year's operating losses. In most of cases, the ERC initiates the subsidies review, but it may also depend on how a licensee plans to cover its losses.

79. Subsidies are given only to state-owned companies. Locally-owned companies depend on the Aimags' governments. At present, local governments do not pay any subsidies to energy utilities. Private companies are not eligible for any state or regional support.

80. The subsidy receivers varies from year to year and depends on licensees' ability to recover costs based on their tariff revenues. After approval of the State budget for the next year, most of licensees agree subsidy financing schedules with the Ministry of Finance and Ministry of Energy. First money transfers may be done in January. Subsidies approved for a certain year are paid to the licensees during that year and are not transferrable to other years.

Table II-16: State Subsidies Received by Licensees, USD '000's

License	Company	2011	2012
P & H generation, power and heat distribution and sales	CHP2 SOJSC	771.4	350.0
	CHP3 SOJSC	2 128.6	0.0
	CHP4 SOJSC	2 670.0	0.0
P & H generation, heat distribution and sales	Darkhan CHP SOJSC	1 628.6	1 014.2
	Erdenet CHP SOJSC	1 628.6	350.0
Heat generation, distribution & sales	Nalaikh HS SOJSC	930.0	1 282.6
	Baganuur HS SOJSC	642.9	1 032.2
Heat distribution and sales	Darkhan DHN SOJSC	357.1	350.0
Power distribution and sales	Baganuur & SE REDN SOJSC	0.0	210.7
	Altai Uliastai ES SOJSC	5 699.3	4 836.6
Power transmission, import	NETransNetwork SOJSC	1 285.7	700.0
	WRES SOJSC	3 214.2	4 629.0

P & H generation, power and heat distribution and sales	ERES SOJSC	1 107.1	1 992.9
	Dalanzadgad SOJSC	1 285.7	1 575.0

Source: ERC of Mongolia

81. There are no strict rules on how subsidies are presented in financial statements, and as a result it is difficult to analyse financial performance of the companies. In income statements, subsidies are booked under non-operating income. In balance sheets, they are shown under various equity sub-categories. In cash flow statements, they are at least partly shown under the category "Financing from State".

82. When considering licensees' tariff and subsidies adequacy, it is worthwhile to look at several types of profit margins. A positive gross profit margin indicates that tariffs are sufficient for recovering sales costs. A positive operating profit margin indicates that the tariffs recover all operating costs (including overheads). A positive net profit margin indicates that tariffs secure full recovery of the company's costs. In the case of Mongolia, it is necessary to remember that the effect of subsidies, together with other non-operating cost items, is included in the net profit margin. In other words, if the gross and (or) operating margins are negative but the net profit margin is positive, it indicates that tariffs do not cover sales and (or) overhead operating costs, but also that subsidy payments are enough for full cost recovery of the company or sector. The following tables present gross profit margins for 2010 – 2012, positive margins are highlighted with yellow.

Table II-17: Gross Profit Margin of Energy Licensees in 2010 – 2012

	2010	2011	2012
CES HeatDist	52 %	53 %	53 %
UB HeatDist	27 %	29 %	26 %
CES ELDist	17 %	16 %	15 %
UB ELDist	11 %	3 %	13 %
ERES	-11 %	-4 %	-14 %
UB GEN	-17 %	-5 %	-8 %
UB Transmission	-33 %	-6 %	-5 %
CES GEN	-57 %	-12 %	-19 %
WRES	-106 %	-110 %	-120 %
Dalanzadgad	-155 %	-235 %	-211 %
AuES	-494 %	-223 %	-329 %

83. The table above proves that only four business segments (UB and CES electricity and heat distribution and sales) had tariffs which were covering sales costs.

Table II-18: Operating Profit Margin of Energy Licensees in 2010 – 2012

	2010	2011	2012
UB HeatDist	2.2 %	4.1 %	0.8 %
CES ELDist	0.8 %	0.0 %	-3.3 %
CES HeatDist	-1.9 %	-2.1 %	-12.4 %
UB ELDist	-2.8 %	-9.1 %	-0.4 %
UB GEN	-21.9 %	-7.7 %	-10.4 %
ERES	-35.6 %	-33.2 %	-39.9 %

	2010	2011	2012
UB Transmission	-46.3 %	-17.4 %	-19.5 %
CES GEN	-61.9 %	-17.2 %	-26.0 %
WRES	-142.8 %	-147.7 %	-153.6 %
Dalanzadgad	-179.2 %	-268.9 %	-251.2 %
AuES	-587.5 %	-410.7 %	-406.7 %

84. The table above proves that only two participants (UB DHN SOJSC, and CES electricity distribution and sales segment) had tariffs which were covering all operating costs. However, in 2012 this was not true for the CES electricity distribution business.

Table II-19: Net Profit Margin of Energy Licensees in 2010 – 2012

	2010	2011	2012
ERES	9.5 %	-19.9 %	-18.3 %
UB Heat Dist	8.6 %	2.8 %	1.0 %
Dalanzadgad	7.0 %	-74.0 %	-87.1 %
UB GEN	3.0 %	-0.9 %	-8.9 %
UB ELDist	3.0 %	-8.4 %	0.2 %
CES ELDist	1.2 %	0.1 %	-3.2 %
CES Heat Dist	0.2 %	8.6 %	-0.3 %
AuES	-15.4 %	-10.0 %	-83.1 %
CES GEN	-15.9 %	-2.9 %	-17.6 %
UB Transmission	-23.2 %	-11.0 %	-13.5 %
WRES	-23.7 %	-33.3 %	-17.8 %

85. The tables above show that through the whole period, only one participant, UB DHN SOJSC, was running a profitable business. The next successful market participant, CES electricity distribution segment, could not recover full costs in 2012, even though one of its companies received a subsidy.

86. UB electricity distribution segment made a net profit through non-operating activities. The other companies (UB generation, CES heat distribution, ERES and Dalanzadgad) had positive net results mainly in 2010 (some of them also in 2011 or 2012) with support of state subsidies. The other four business segments (AuRES electricity distribution, CES generation, UB power transmission and WRES power transmission) were getting subsidies inadequate for covering their costs.

87. Based on the above data it is possible to conclude the following:-

- Current tariff setting procedures is more favourable for heat and electricity distribution and sales business and is significantly disadvantageous for power transmission business
- State subsidies were sufficient for costs recovery only for some companies but became mostly insufficient after 2010.

88. On the other hand, according to the information available, tariffs of most of licensees were not reviewed since April 2011. Tariffs of several licensees have not been re-considered for even longer period (e.g. for WRES since May 2009, and for Erdenet CHP's heat since June 2008). This not only worsens financial performance of subsidies companies but also creates a threat for

healthy performance like UB DHN whose net profit margin although staying positive has been declining rather sharply.

89. It is recommendable to review tariffs on regular basis. However, if needed, licensees should have a right to initiate tariff review process also outside standard review schedule.

90. Tariffs for energy licensees should be based on full cost recovery, including operating costs and investment costs associated with expansion or upgrade of existing generation, transmission and distribution capacities and construction of new ones. There are several long-term solutions for ensuring financial viability of regulated natural monopolies:-

- Setting the tariffs equal to marginal cost. However, that price will not likely be high enough to cover the average cost of production. The answer is to provide a subsidy sufficient to compensate the firm.

- National ownership of the monopoly. One problem with this arrangement is that once a price is established, consumers are unwilling to accept price increases, even as factor costs increase. Politically, raising prices on products from government-owned enterprises is highly unpopular.

- Establishing a governmental entity that regulates an authorized monopoly. In such case, the regulator should ensure that regulated tariffs are equal to long-run average cost. This solution enables investors to receive a normal return for their risks. Under this approach, the regulator should determine the risk-related return and realistic long-run average cost of the regulated natural monopoly.

91. Tariff review methodology should have detailed description of components included into the tariff and clear guidelines and formulas used for calculations.

92. When tariffs are set equal to long-run average costs, in the longer run the licensees will not need any subsidies, and their financial performance will improve. However, higher tariffs would require re-consideration of tools for protecting vulnerable groups of population. For this purpose, it is recommended to develop comprehensive affordability criteria which may be reviewed whenever there are further improvements in living standards of the Mongolian population. These affordability criteria will be used for determining households who cannot afford payments for the utility services without state support.

93. Comprehensive rules for determining amount of subsidies for vulnerable households will be needed. Together with the abovementioned affordability criteria, these rules will ensure that only eligible utility services consumers get state (or regional) support, and this support is adequate. With time, when licensees financial health improves, the taxes they will pay to the state and regional budgets, as well as decreasing number of subsidies households (under the assumption of improving living standards of the population) will lead to more cash inflows and less expenditures for the state and regional budgets.

III. SHADOW TARIFFS

F. Full Cost Recovery

94. Retrospective estimation was carried out for wholesale electricity and heat tariffs for major licensees in terms of full cost recovery and possibilities to reach recommended short- and long-term benchmark targets for their operations in 2011 and 2012. Indicative results of this study can serve as a starting point for prospective tariff setting based on the full cost recovery principles and followed by improvements of the licensees' financial health in the future.

95. Since the results of the financial analysis highlighted that the main financial viability problem of the licensees is their low or negative profitability, the tariff estimation concentrated on the following aspects:-

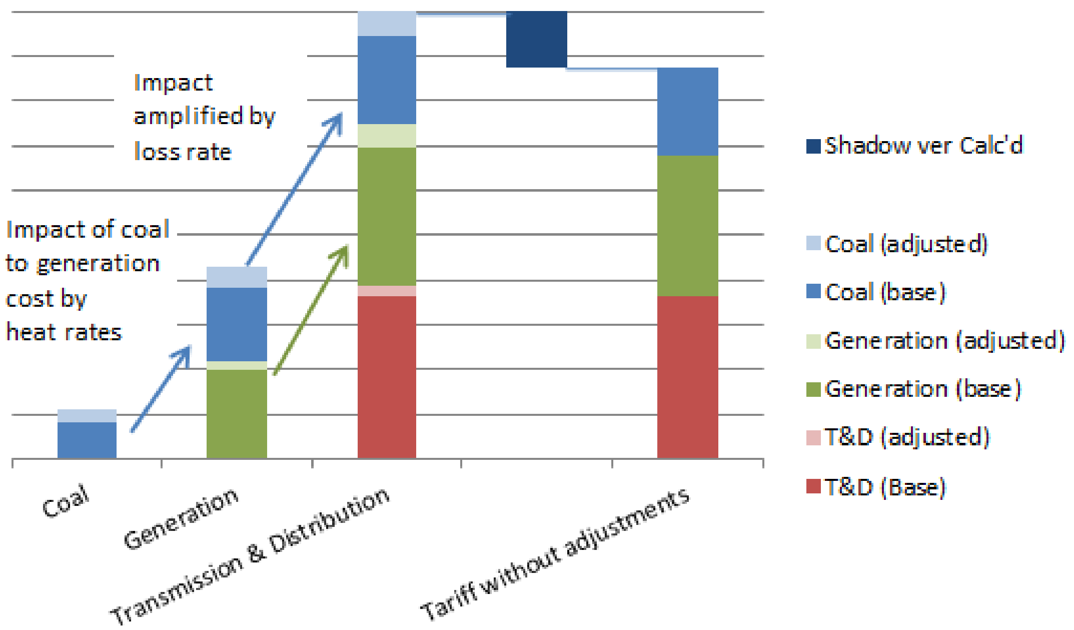
i. High-level estimate of actual unit production costs of operations is based on available financial statements of the licensees for 2011 and 2012

ii. Evaluation was done under assumption of no state subsidies in 2011 and 2012, and without cross-subsidizing of heat production for CHPs.

iii. Identification of tariff levels which would have allowed the major licensees to achieve proposed short- and long-term net profit margin targets (respectively 2.5% and 10%).

96. Due to inconsistent input data, two electricity distribution companies (Erchim suljee LLC and Nolgo LLC) were left out from the analysis. For the Dalanzadgad CHP and the Eastern Energy System, only evaluation of needed increase of the total revenue was done because of lack of data on costs and revenue allocation among power and heat generation and distribution activities.

Figure III-1: Cost Adjustment for the Tariff Analysis



97. Shadow tariffs for power and heat generation include shadow coal prices for the Baganuur

and Shivee Ovoo coal mines. For other mines, actual coal prices were used. Calculation of shadow tariffs for other parts of the value chain (power transmission and distribution, and heat distribution) incorporate influence of shadow prices and tariffs of the preceding value chain components.

98. The analysis was carried out under the following assumptions:

i. Electricity tariff is an average electricity price without separate calculation of capacity charges

ii. All generated electricity is bought by using same price equal to weighted average over domestic producers

iii. Fixed costs and variable costs not related to coal, domestically produced power and heat and electricity transmission are assumed to be same as in the initial financial statements for 2011 and 2012.

iv. Allocation of fuel consumption, variable costs and revenues between electricity and heat produced at CHP plants was done following the logic used for calculation of technical and economic indicators for energy producers in 2012 (the ERC data),

v. In accordance with the tariff setting methodology used by the ERC, allocation of fixed costs between electricity and heat produced at CHP plants was assumed to be 70% and 30% respectively.

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

i. Tariffs for electricity produced at CHPs could have been reduced still allowing to achieve 2.5% net profit margin target

ii. Tariffs for heat produced at CHPs would have significantly increased. This increase could be especially dramatic for older CHP plants and HOBs.

100. The above observations can be seen in the tables below. The incremental tariff growth rate (hereinafter Ratio) is calculated as

Ratio = [(Shadow tariff / Actual calculated tariff) – 1] x 100%

Table III-1: CHP Plant Electricity Tariffs, US cent/kWh

		Net profit margin 2.5%		Net profit margin 10%	
		2011	2012	2011	2012
CHP-2	Electricity tariff (calc'd)	5.79	6.10	5.79	6.10
	Electricity tariff (shadow)	5.06	6.28	5.64	7.00
	Ratio	-12.5 %	2.9 %	-2.5 %	14.7 %
CHP-3	Electricity tariff (calc'd)	5.18	5.61	5.18	5.61
	Electricity tariff (shadow)	4.89	5.18	5.46	5.78
	Ratio	-5.5 %	-7.6 %	5.5 %	3.1 %
CHP-4	Electricity tariff (calc'd)	2.71	2.76	2.71	2.76
	Electricity tariff (shadow)	2.54	2.79	2.83	3.12
	Ratio	-6.5 %	1.1 %	4.4 %	12.7 %
Darkhan CHP	Electricity tariff (calc'd)	5.60	5.60	5.60	5.60
	Electricity tariff (shadow)	4.49	5.36	5.01	5.97
	Ratio	-19.8 %	-4.4 %	-10.7 %	6.6 %

		Net profit margin 2.5%		Net profit margin 10%	
Erdenet CHP	Electricity tariff (calc'd)	7.23	8.12	7.23	8.12
	Electricity tariff (shadow)	6.98	7.85	7.78	8.75
	Ratio	-3.5 %	-3.4 %	7.6 %	7.8 %

Table III-2: CHP Plant Heat Tariffs, USD/Gcal

		Net profit margin 2.5%		Net profit margin 10%	
		2011	2012	2011	2012
CHP-2	Heat tariff (calc'd)	5.35	5.54	5.35	5.54
	Heat tariff (shadow)	14.82	18.04	16.52	20.12
	Ratio	177.1 %	225.9 %	208.9 %	263.4 %
CHP-3	Heat tariff (calc'd)	5.26	5.55	5.26	5.55
	Heat tariff (shadow)	12.49	12.85	13.94	14.33
	Ratio	137.5 %	131.4 %	165.1 %	158.2 %
CHP-4	Heat tariff (calc'd)	5.12	5.09	5.12	5.09
	Heat tariff (shadow)	10.34	11.15	11.54	12.43
	Ratio	102.0 %	118.9 %	125.5 %	144.0 %
Darkhan CHP	Heat tariff (calc'd)	3.57	3.66	3.57	3.66
	Heat tariff (shadow)	14.20	16.69	15.82	18.60
	Ratio	297.3 %	355.9 %	342.6 %	408.3 %
Erdenet CHP	Heat tariff (calc'd)	5.12	6.38	5.12	6.38
	Heat tariff (shadow)	11.15	13.63	12.42	15.19
	Ratio	117.5 %	113.7 %	142.5 %	138.2 %

101. With exception of WRES and AuES, electricity transmission and distribution tariffs would not have increased dramatically, as it can be seen from the following table.

Table III-3: T&D Tariffs, US cent/kWh

		Net profit margin 2.5%		Net profit margin 10%	
		2011	2012	2011	2012
NETN	Electricity transmission fee (calc'd)	0.28	0.31	0.28	0.31
	Electricity transmission fee (shadow)	0.36	0.41	0.41	0.47
	Ratio	29.2 %	31.7 %	48.9 %	51.5 %
UBEDN	Full electricity sales tariff (calc'd)	5.91	6.04	5.91	6.04
	Full electricity sales tariff (shadow)	6.51	7.16	7.86	8.66
	Ratio	10.3 %	18.5 %	33.1 %	43.3 %
DSEDN	Full electricity sales tariff (calc'd)	5.93	6.22	5.93	6.22
	Full electricity sales tariff (shadow)	6.23	7.52	7.49	9.00
	Ratio	5.0 %	21.0 %	26.2 %	44.7 %
BSEREDN	Full electricity sales tariff (calc'd)	6.28	6.53	6.28	6.53

		Net profit margin 2.5%		Net profit margin 10%	
	Full electricity sales tariff (shadow)	6.73	7.52	8.05	8.97
	Ratio	7.2 %	15.0 %	28.2 %	37.3 %
EBEDN	Full electricity sales tariff (calc'd)	6.44	6.83	6.44	6.83
	Full electricity sales tariff (shadow)	7.07	8.04	8.40	9.54
	Ratio	9.8 %	17.8 %	30.5 %	39.7 %

102. Heat distribution tariffs would have been affected more because of the more substantial increase in heat tariffs generated at domestic CHPs and HOBs. The table below shows the results of the analysis.

Table III-4: Heat Distribution Tariffs, USD/Gcal

		Net profit margin 2.5%		Net profit margin 10%	
		2011	2012	2011	2012
UB DHN	Heat distribution & sales tariff (calc'd)	6.95	7.15	6.95	7.15
	Heat distribution & sales tariff (shadow)	13.52	14.69	16.63	18.03
	Ratio	95 %	105 %	139 %	152 %
Darkhan DHN	Heat distribution & sales tariff (calc'd)	8.28	8.56	8.28	8.56
	Heat distribution & sales tariff (shadow)	21.08	25.09	25.59	30.45
	Ratio	154.7 %	193.3 %	209.2 %	255.9 %

103. Revenue increase for the Dalanzadgad CHP and the ERES needed for achieving short- and long-term profitability targets is presented in the table below. For achieving profitability targets, the ERES would need much smaller increase of tariffs compared to the Dalanzadgad CHP.

Table III-5: Dalanzadgad CHP & ERES Revenue Requirements

	Net profit margin 2.5%		Net profit margin 10%	
	2011	2012	2011	2012
Dalanzadgad CHP				
Needed increase in revenues	3.97	4.04	4.51	4.51
Total income, USD	4 068 925	4 035 779	4 535 263	4 505 288
ERES				
Needed increase in revenues	1.38	1.45	1.54	1.62
Total income, USD	9 014 657	11 635 239	10 053 302	12 977 149

104. An overall power and heat value chain tariff development is presented below, with electricity sector of the CES and heat sector of the City of Ulaanbaatar serving as examples.

Figure III-6: Electricity – Short-Term Benchmark Target

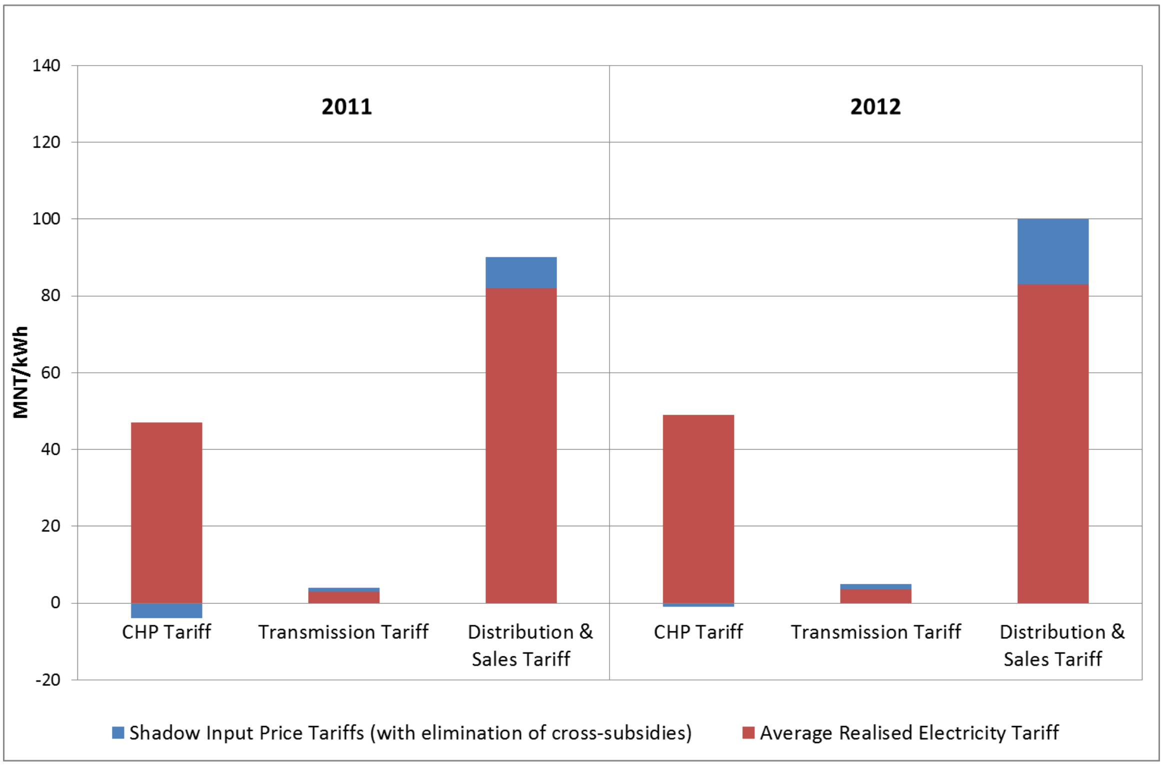


Figure III-7: Electricity – Long-Term Benchmark Target

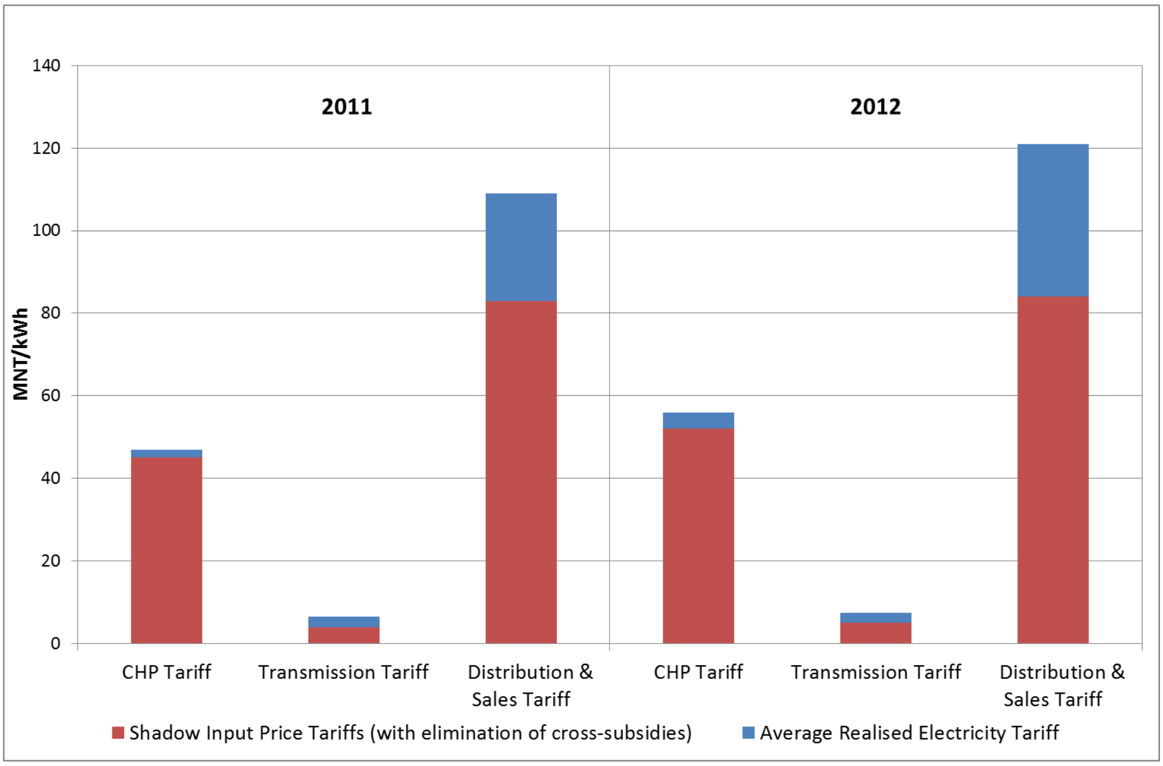


Figure III-8: Heat - Short-Term Benchmark Target

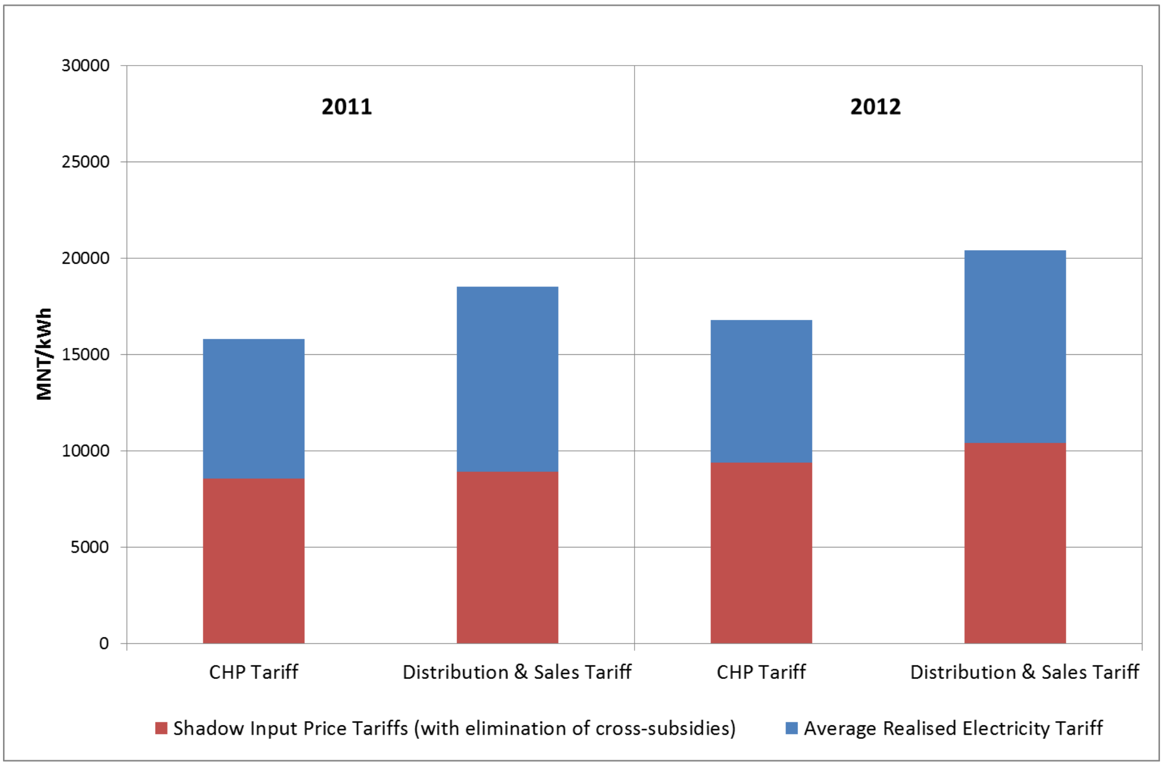
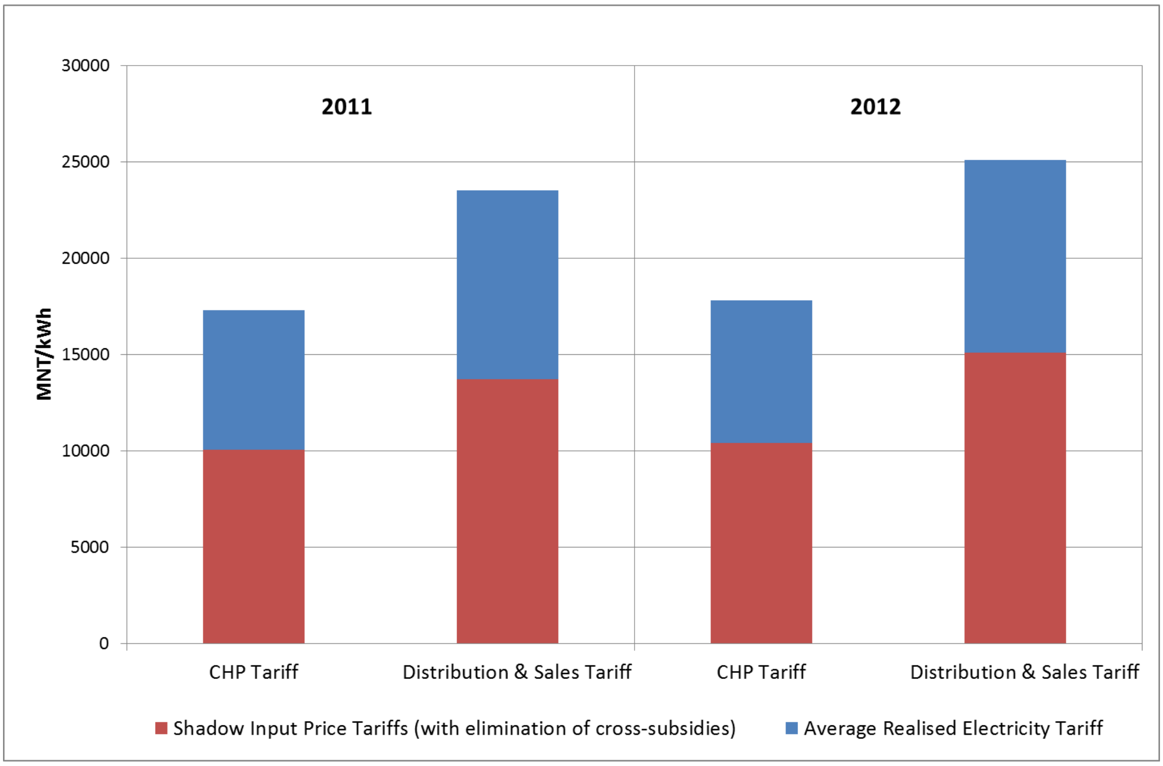


Figure III-9: Heat - Long-Term Benchmark Target

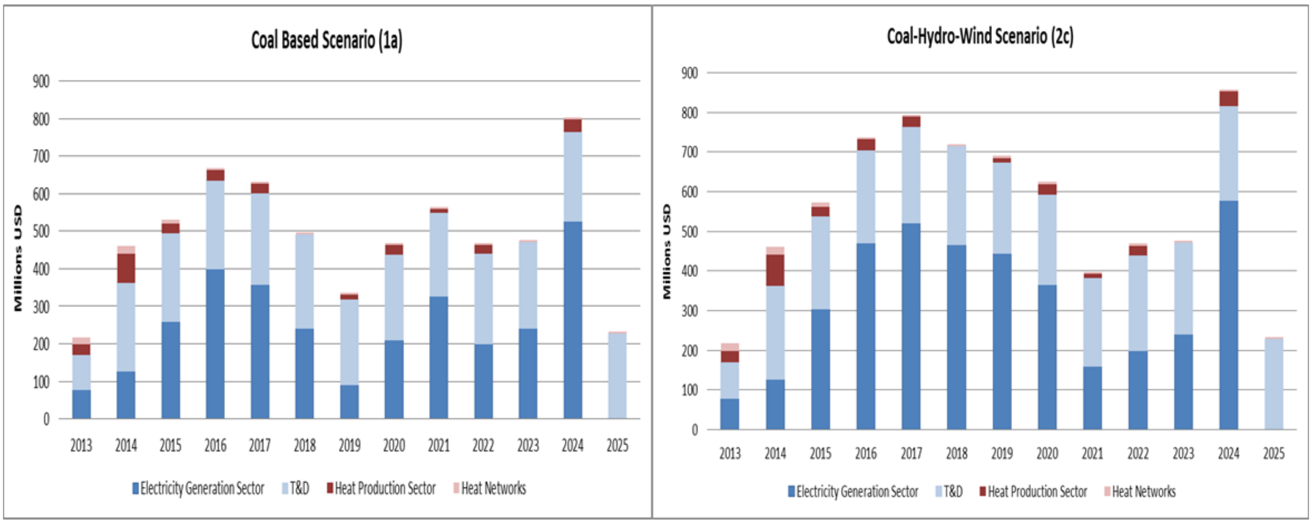


G. Financing Needs

105. This study has created a number of alternative energy system expansion scenarios for Mongolia. For the following tariff review, two scenarios have been selected for comparison. The first one is the coal-based Scenario 1a, which has the lowest upfront capital investment. The second is Scenario 2c, which includes Sheuren hydropower project. Scenario 2c ranks most favourably according to the multi-criteria decision making approach. The annual capital disbursements of the two scenarios are shown in the following figure.

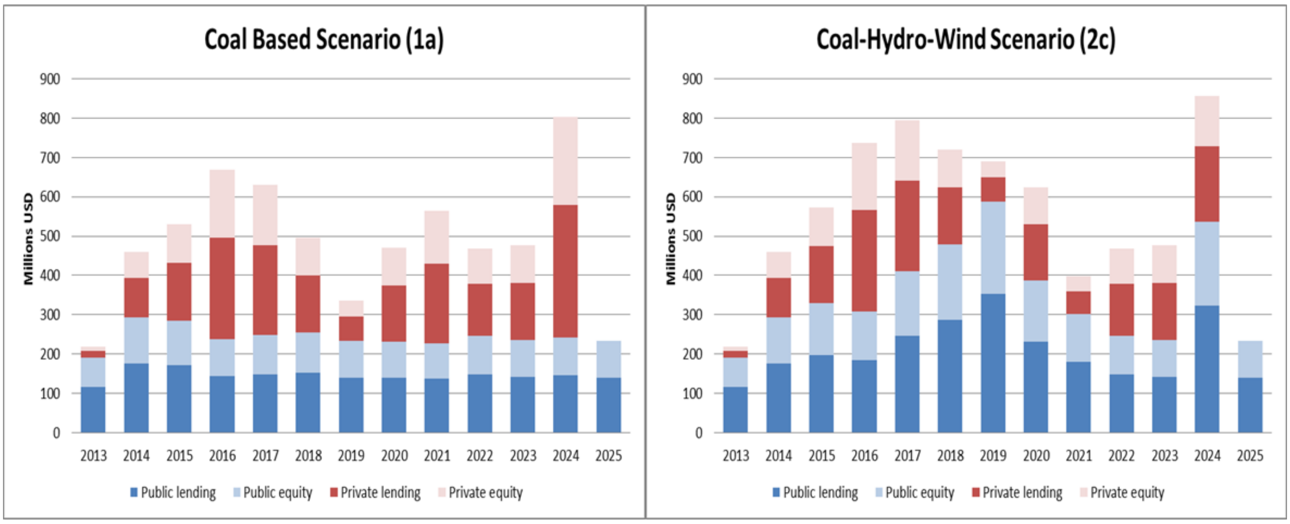
Figure III-10: Annual Disbursements for Investment in Energy Sector (2013-2025)

CES region



106. In the coal based scenario investments in power generation and transmission & distribution are almost equal in size. The first years are dominated by the new CHP plant to UB. The second scenario in characterized by the large investment in Sheuren hydropower plant and wind power. Sheuren's estimated construction time is six years, which causes high capital expenditure during periods when there are no corresponding revenues.

Figure III-11: Public and Private Financing of Expansion Programmes



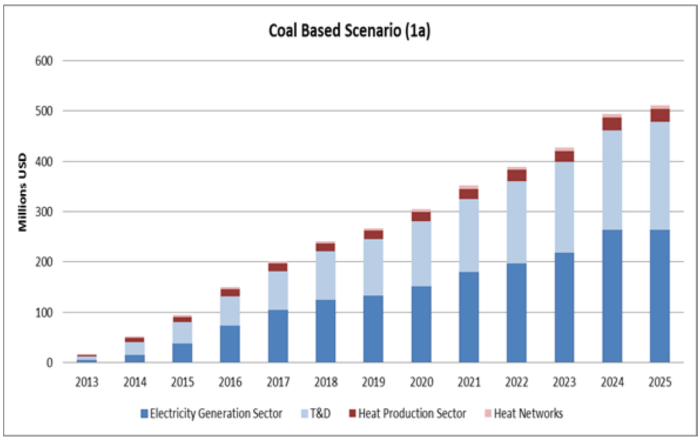
107. As Figure III-11 shows, Coal Based Scenario is more driven by the private sector (red

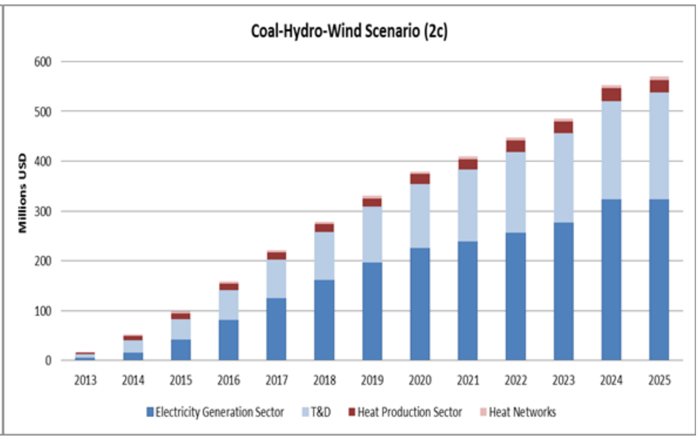
colours) and, on the other hand, the Sheuren hydropower plant in Scenario 2a sets high demands for the public sector (blue colours) to finance the expansion.

108. Whilst the annual capital disbursements occur during the planning period of this study, in reality most, if not all, projects will be financed by a mix of equity and credit. The financial cost will be distributed over several years beyond the planning period of this study. Therefore the annual capital requirements are annualized here assuming a harmonized capital structure of 60/40 (debt/equity) for all projects and WACC of 4 % for public projects and 6 % for PPP and private projects, and 20 years for the financial service period. In the analysis, all coal-based condensing and wind power plants were assumed to be sponsored by the private sector, whereas all CHP plants and hydropower by the public sector.

Figure III-12: Annualized Financial Cost of Investment in Energy Sector (2013-2025)

CES region





109. When the capital costs are annualized in the above mentioned way, the underlying assumption is that both the equity owners and lenders return requirements are satisfied. As to the existing assets, however, the financial health check revealed that they do not provide sufficient returns to the owner, i.e. the government. Therefore, the ultimately targeted financial self-sufficiency criterion for the sector requires that the tariffs enable the existing assets to not only cover their cost but to return sufficient profit.

110. The tariff analysis has three steps:-

i. Current tariffs. It is tested how much additional funding is required if the investment programme is implemented without any changes to the current tariff levels. The current tariff levels are calculated from 2012 income statement by dividing operational revenues (subsidies and non-operational items excluded) by sold energy.

ii. Benchmarks. Under this case, the tariffs are let to develop gradually towards such levels which fulfil the benchmarks set earlier in this study. The 2.5 % profitability target is set to be achieved by 2020, and the 10 % target by 2025.

iii. Full-cost recovery. This option includes that existing assets cover all of their operational costs but return no profit, whereas the new assets return profit and interest as per WACC. The full cost level for existing assets in established based on the 2012 income statements of the licensed companies.

111. It should be noted here that all above analysis is carried out by using real prices. This means that costs and revenues are expressed without consideration of inflation for both existing and new assets, and they are expressed in 2012 level.

Figure III-13: Funding Gap without Tariff Adjustments (Scenario 1a & 2c)

112. The current tariff levels, as the financial health check showed, are not sufficient for covering the total costs of existing assets. The analysis revealed that the operational expenses of the small CHP plants (with the exception of CHP4) were particularly high when comparing to international benchmarks. The calculated electricity tariffs were 61 $/MWh, 56.1 $/MWh, 56.0 $/MWh, 81.2 $/MWh for CHP2, CHP3, Darkhan and Erdenet respectively, whereas it was only 27.6 $/MWh for CHP4. One needs to take into account that these cost-based tariffs include hardly any capital costs, as the assets are largely fully depreciated.

113. The heat production tariffs were 5.54 $/GCal, 5.55 $/GCal, 3.66 $/GCal and 6.38 $/GCal for the same smaller CHPs whereas the heat tariff of CHP4 was 5.09 $/GCal. There is a substantial cross-subsidy in the average electricity generation tariff to reduce the heat tariff in the CES region. On average the electricity tariffs slightly exceed the costs but the heat tariffs are significantly below the costs. Therefore, as

114. Figure **III-13** shows, continuing under-pricing of heat would accrue a dramatic financing gap of over $ 1 billion by 2025.

115. The results of the tariff analysis are summarized in Table III-14. The adjusted tariffs represent the Benchmarking approach as described above. They are slightly lower in 2020 (2.5 %) than the Full Cost Tariffs, but in 2025 (10 %) their levels are roughly equal. The more expensive Scenario 2c shows a more significant difference between the adjusted current tariffs and the Full Cost Tariffs for 2025 when the 10% profit level is achieved.

Table III-14: Tariffs and Funding Gap with Various Tariff Adjustment Strategies

Scenario 1a	**Electricity**				
	2013	**2020**	**2025**	**Funding gap (m$)**	
Current tariffs ($/MWh)	67	67	65 *)	2760	
Adjusted current tariffs ($/MWh)	69	90	101	753	
Difference against current tariff	3 %	34 %	55 %	-73 %	
Full cost tariffs ($/MWh)	67	102	108	0	
Difference against current tariff	0 %	52 %	66 %	-100 %	
	Heat				**Total funding deficit (m$)**
Current tariffs ($/GCal)	8.3	8.3	8.3	1107	3867
Adjusted current tariffs ($/GCal)	9	18	20	310	1063
Difference against current tariff	8 %	117 %	141 %	-72 %	-73%
Full cost tariffs ($/GCal)	17	19	19	0	0
Difference against current tariff	105 %	129 %	129 %	-100 %	-100 %
Scenario 2a	**Electricity**				
Current tariffs ($/MWh)	67	67	65 *)	3,147	
Adjusted current tariffs ($/MWh)	69	90	101	1,140	
Difference against current tariff	3 %	34 %	55 %	-64 %	
Full cost tariffs ($/MWh)	67	113	111	0	
Difference against current tariff	0 %	67 %	71 %	-100 %	
	Heat				**Total funding deficit (m$)**
Current tariffs ($/GCal)	8.3	8.3	8.3	1107	4253
Adjusted current tariffs ($/GCal)	9	18	20	309	1449
Difference against current tariff	8 %	117 %	141 %	-72 %	-66 %
Full cost tariffs ($/GCal)	17	19	19	0	0

Difference against current tariff	105 %	129 %	129 %	-100 %	-100 %

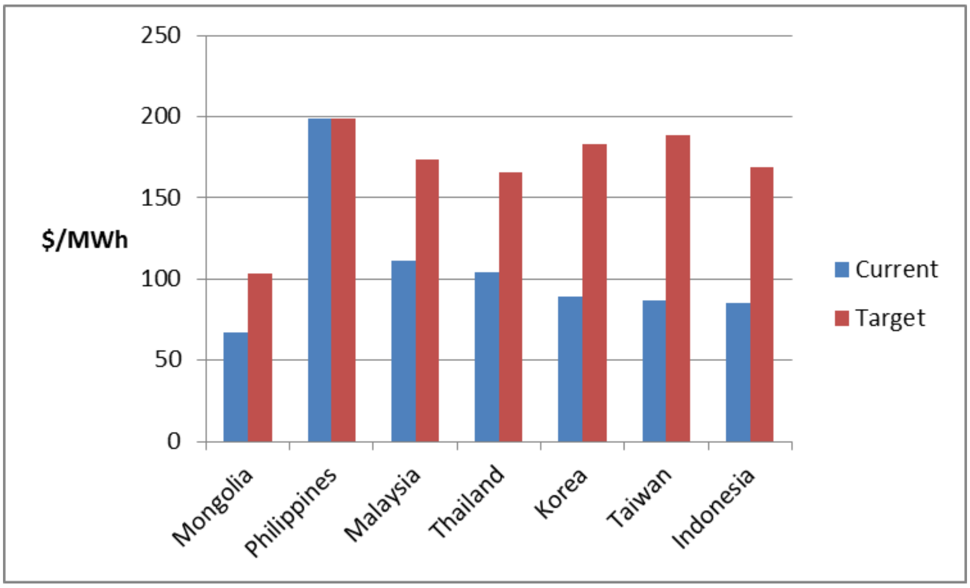
*) As a result of improved efficiency due to reduced T&D losses

116. The principle difference between the Full Cost Tariffs and Benchmark Tariffs is the higher pace of the tariff increase. The Full Cost Tariff is based on the idea that all costs of CAPEX and OPEX are covered each year by the tariff. Therefore, as soon as construction for the new investments starts, the tariff rises, which would need to occur commencing immediately after 2013. With Full Cost Tariffs electricity prices should increase 57 - 71 % from 2012 to 2025, depending on the selected expansion Scenario.

117. In 2012, residential consumption was about 20% of the total electricity demand in the country. Therefore it is believed that it is a realistic target to implement the Full Cost Tariffs needed by Scenario 2c. In the event vulnerable consumer groups, or the residential sector as a whole, would need to be saved from this growth, the other sectors can absorb the increase. Because the demand is mainly driven by productive sectors, and their share in overall consumption is high, their tariffs would need to 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 whole revenue loss caused by not increasing the residential tariffs.

118. Figure III-15 shows that the Mongolian electricity tariffs are relatively low even in comparison with the Philippines or Indonesia, where the GDP per capital figures are comparable to Mongolia. The targeted Full Cost Tariff would lift the Mongolian electricity tariff equal to the level of referenced other Asian countries. However, the source study states that the targeted LRMC based tariffs for all of the referenced countries exceeds 150 $/MWh.

Figure III-15: Mongolian Tariffs by International Comparison



Source: International Energy Consultants/MERALCO, June 2012; ERC Energy Statistics

119. The need to increase the heat tariffs is significantly higher than electricity tariffs. As the current tariffs average at around 8 $/GCal, the needed Full Cost Tariff is about 19 $/GCal. 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.

120. Increasing tariffs closer to financially sustainable levels would also have positive indirect consequences on the costs of borrowings, so that improving of financial health of the licensees

through transparent and adequate tariff regulation will have an overall positive impact through:

- Availability of own resources for capital investments (retained profit)
- Possibility to borrow on commercial basis instead of using governmental loans and thus reducing the Government's ability to finance investments in vital non-revenue making projects
- Reduction of borrowing costs due to improved credit rating
- Increase of tax collection from profitable licensees leading to availability of additional financial resources for the state and regional governments

121. Smaller projects in energy infrastructure development may be financed from own resources of well performing licensees combined with commercial loans from local banks. Financially less viable licensees would need government support in forms of direct equity financing, subsidies or grants. Larger projects would require loans from IFIs and the DMB, state participation (either through equity, quasi-equity or debt financing) and complex project finance arrangements like Public-Private Partnership.

122. If the Mongolian Government decides to fully or partly privatise some of the public licensees, it should develop transparent and stable rules and legislation framework which would define rights and obligations of the Mongolian State and the private investors.

H. Financing Sources for the Investment Plan

123. High demand on energy and other infrastructure requires well planned and coordinated infrastructure development policy. Prioritisation of energy projects is needed in order to define and develop sound financing policy. In Mongolia, energy projects are very dependent on mining industry because it has a very significant influence on demand on electricity and heat for actual mining, smelters, railway transportation, and development of new settlements for workers. Therefore it is important to have holistic picture of Mongolia's future development where energy sector development plans will be linked with mining industry and socio-economic development of the country.

124. Whenever possible, financing costs should be minimized by seeking the lowest cost selection through loans and equity attracted to the projects. Equity may be attracted either from investors or retained earnings. In case of companies controlled and financed by the State, it should be remembered that the governmental loans directed to state-owned enterprises increase the sovereign debt level and thus can have direct influence on financing of socially important project into non-revenue or low-revenue sectors. Therefore it is suggested to consider first other possibilities of financing preferably based on commercial basis and on improved financial health of licensees.

125. Possible sources of financing include own financial resources of licensees, public financing through sovereign debt from multilateral and bilateral lenders, private financing (commercial banks, multilateral debt and equity, listed and sponsor equity) and Private-Public Partnership (PPP) models.

126. The **equity investment** in a project represents the risk capital. Equity investors are the last in priority for repayment. Equity is typically advanced as the subscription of price for common or preferred stocks. Lenders look to the equity investments as providing a margin of safety. The appropriate debt-to-equity ratio for a given project is a matter of negotiation between the sponsors and senior lenders. If lenders are protected by various kinds of guarantees from third party sources, they are inclined to accept higher debt-to-equity ratios. However, unless the guarantees are available from very creditworthy guarantors, lenders will always require a substantial equity investment in a project.

127. **Quasi-equity** consists of subordinated loans and advances to a project. It is senior to equity capital but junior to senior debt and secured debt. Quasi-equity may be considered as equity by senior lenders for purpose of computing debt-to-equity ratios. A subordinated loan is often used by a sponsor to provide capital to a project which will support senior borrowings from third party lenders. Subordinated debt can sometimes be used for advances required by investors, sponsors or guarantors to cover construction costs over-runs or other payments necessary for maintaining debt-to-equity ratios, or other guaranteed payments.

128. Some lenders (e.g. the ADB) prefer that any loan by the government to the public utility would be subordinated and treated as quasi-equity capital. However, there might be certain restrictions or regulations from the government affecting ability to have its debt treated as quasi-equity.

129. Subordinate debt by a project sponsor has the following advantages over capital contributions:

- The borrowed amount will be repaid if the project is successful, without tax payments, whereas a repayment of capital is more complex from a corporate a tax point of view.
- Subordinate debt always has a specific schedule for interest payments and repayment of principal while dividends on shares are optional.
- The project company may have restrictions on dividend payments, which are not applicable to debt.
- A greater market exists for risk debt funds than for risk equity.
- The combination of subordinate debt with warrants of conversion rights enables a sponsor lender to influence the time the sponsor assumes control for tax and financial accounting purposes.
- Under regulating statutes such as anti-monopoly laws and laws regulating public utilities, participation in shareholders' equity may create problems which a subordinated loan will not create
- Interest paid on debt is deductible for income tax purposes
- A subordinated loan by a supplier in the form of subordinated trade credit for purchases from the supplier may provide a degree of subordination useful to the project in borrowing working capital, as well as providing a source of working capital
- An interested government agency sponsor that cannot take an equity position in a project for policy reasons, may be able to provide subordinated debt as seed capital to attract senior debt.

130. Most **commercial bank loans** will be in the form of senior debt. Such debt is first in priority of payment from the general revenues of the borrower in the even the borrower gets into financial difficulties. Secured senior debt holders have an advantage over unsecured senior debt holders. Secured loans are available to most projects where the assets securing the debt have value of collateral, i.e. these assets are marketable and can be easily converted into cash. The superior rights of a secured lender enable projects to borrow on a secured basis where other sources are not available.

131. A **Public-Private Partnership** (PPP) is a long-term contract between a government and a private equity under which the private company provides or otherwise contributes to the provision of a public service. PPPs typically have the following characteristics:

- Project revenue stream goes to a private company. Therefore, the agreement between the government and the private company transfers risk from the government to the private company

- The private company contributes with at least a limited investment in the project
- In addition to budget allocations, the government may make other contributions (in terms of land, assets, equity or debt finance, state guarantees, etc.)
- At the end of the PPP contract, the associated assets are transferred to government ownership. Depending on the PPP type and contract terms, this transfer may be done with or without compensation.

Due to a complex structure of PPP, its costs are usually higher compared to other types of financing.

132. According to the Feasibility Report for CHP5 prepared in frames of the project "Mongolia: Ulaanbaatar Low Carbon Energy Supply Project Using a Public-Private Partnership Model", the Government's objectives for entering into PPP contracts for the provision of public services and construction of energy infrastructure will vary from project to project but are seen to include:

- Transferring certain risks to the private sector which the private sector are better equipped to manage than the government is;
- Minimizing whole-of-life costs for infrastructure projects and thus reducing user tariffs or subsidy requirements over the long term;
- Expediting implementation and construction time
- Improving service quality.
- Innovation. The private sector should have access to bring better and more efficient technology and management methods.
- Providing an alternative source of finance, thus allowing government financing and borrowing to be diverted to other social projects and programs less suitable for a PPP approach.

133. If project financing requires substantial financial resources and involves sovereign borrowings, it is important to consider the influence of such financing on the government borrowing capacity. According to the IMF's Debt Sustainability Analysis Report from November 2012, Mongolia is at a low risk of debt distress in medium- to long-term. However, the IMF acknowledges existence of short-term risks related to expansionary policies which lead to overheating pressures and increase of Mongolia's vulnerability to a commodity price downturn, which remains a substantial risk in the current global environment.

134. The **Development Bank of Mongolia (DBM)** provides long-term financing for projects consistent with the Government Development Strategy. The bank issues loans for financing large-scale development projects and programmes approved by the Parliament on annual basis. Primary focus of financing is on infrastructure and industrial development. Energy is one of priority areas.

135. Within the current regulatory environment of Mongolia, the government is the ultimate guarantor in all power projects. This is because the PPA's for both public and private generating companies are concluded with the state-owned single-buyer (transmission licensee) and approved by ERC.

I. General Conclusions and Recommendations

136. Mongolian regulation and practice for tariff reviews has certain flaws, which should be addressed to enable adequate level of tariff based financing of future investments. This is more pressing now than before, because the country faces enormous investment needs in the energy sector.

137. Some of the issues to be addressed include the following:

i. The tariff review methodology is completely backward looking, based on past years performance, and does not take into consideration future investments.

ii. The allowed return on investment as calculated on depreciated assets does not provide returns which would be acceptable to any private project sponsors

iii. The WACC calculation method is not up-to-date and sufficiently reflective of on-the-ground financial realities in the country.

iv. The current subsidy system is based on compensating energy sector licensees' losses. This does not provide incentives for efficiency improvements.

v. In the event the regulated tariff adjustment method, whether cost-plus or RAB –based, is based on realistic assumptions, as to WACC and asset values, the cost escalation would be correctly reflected to the tariffs. The regulation allows tariff adjustments twice a year, or even more often when needed. However, in practice the tariffs are not reviewed frequently enough and do not follow the general cost increase of the country.

138. When return-on-invested-capital approach (usually referred to as Regulatory Asset Base or RAB) is used, it should take into account the following principles.

i. Stable energy supply to the customers at least costs and efficient utilization of production capacities;

ii. Full recovery of costs, which are strictly necessary for regulated activity, technical safety of the system and environmental protection;

iii. Efficient and profitable investments into development, modernization and reconstruction of facilities of energy systems.

139. The tariff calculation methodology should provide with detailed guidelines for evaluation of the regulated costs and the rate of return. If these are adequately set, the forward looking element can be established to the tariffs. The rate of return, which should reflect all of the above mentioned three aspects, should be defined using Weighted Average Cost of Capital (WACC) method, with clear guidance for its calculation and input data sources (such as for risk-free rate of return). The WACC calculation should take into account at least the country-specific risk, market premium, allowed structure of capital (equity vs. borrowings, etc.), and market beta coefficients used in the CAPM model. The values of these parameters should be specifically defined in the methodology. The cost of borrowed capital used in the WACC calculations must reflect the real rates accessible to power sector operators in the country. All the above parameters should be reviewed and updated on a regular basis (usually, annually) and according to transparent rules.

140. In Mongolian conditions, the tariffs of different operators could be regulated in different ways. For example, an adequate "costs plus" method could be used for existing generation facilities, where the asset are largely already depreciated. In this case:

A. The tariff should allow full cost recovery and advance inclusion of an adequate investment component

B. There should be stimulating measures for cost-efficiency, e.g. through

i. allowing the utilities to keep the achieved savings in their "costs" when applying for a new tariff during a certain period of time thus improving their general profitability and availability of financial resources

ii. set a tariff common for e.g. all power producers to be equal to the minimal acceptable level for the most expensive utility thus allowing more cost-efficient utilities to get the "efficiency premium" and use it for their investment activities and operating needs

141. The RAB method could be used for financing greenfield generation, transmission and

distribution facilities.

142. The current way of allocating subsidies should be critically reviewed. It is proposed to consider moving quickly out from subsidising energy sector operators to direct subsidization of vulnerable consumer groups. Comprehensive rules for determining amount of subsidies to vulnerable households will be needed. Clear, just and transparent affordability criteria should be established. With these the rules should ensure that only eligible utility services consumers get government support, and that this support is adequate. With time, when licensees' financial health improves, the taxes they would contribute to the government, as well as decreasing number of subsidized households under the assumption of improving living standards of population, will lead to more cash inflows and less expenditure for the government.

IV. FOREIGN DIRECT INVESTMENT

J. CGE Model

143. A Computable General Equilibrium model (CGE) has been applied to assess the impact of Foreign Direct Investment made in the heat and power sectors, as defined by the Energy Master Plan scenarios.

144. The CGE model attempts to answer the questions:-

1. What are the impacts of the EMP on the labour market?
2. How will the Mongolian economy improve?

145. Computable general equilibrium (CGE) models turn out to be particularly well-suited to address such questions. Given CGE model's popularity among policy makers, it should be noted that this type of CGE model has not often been applied to assess the impact of implementing an Energy Master Plan on the economy. One of the main advantages of applying these models is that they take account of the direct as well as the indirect effects of any policy measure implementation. This is due to their focus on multiple markets and their interactions.

146. The base year for the Social Accounting Matrix (SAM) has been take to be 2005, underlying the current calibration of the Mon-CGE model. The Mon-CGE model has been applied in a recursive dynamic way so that it is able to generate different scenarios. As such, the model has been calibrated to generate a benchmark scenario that refers to a 'Business-as-Usual' (BaU) situation.

147. The implementation of the EMP into the Mon-CGE model results in an alternative or counterfactual scenario. Comparing the latter scenario(s) with the BaU scenario allows for the assessment of the impact of implementing the EMP on the economy.

K. CGE Modelled Scenarios

148. The CGE model has been applied to three scenarios, namely Scenario 1a (coal expansion), 2c (mixed coal, hydro, wind) and 4 (heavy renewables).

SCENARIO 1 (ADB-MON-7619 EMP 1): This scenario is based on increased FDI according to a Coal-Based Expansion scenario (Scenario 1a)

149. In Table 11, the first column depicts a time series of total investments in the EleGasH2O production sector. The original series obtained from the Energy Master Plan was in millions of US$, hence we translated them into millions of Tugruk (mMNT) using the exchange rate of 1US$ = 1.435 MNT as used in the Energy Master Plan. From these total investments, depicted with T, we compute the part of foreign direct investments (FDI) and investments from domestic origin using an allocation of 90% of T being FDI and 10% of T being domestic investments.

Figure IV-1: CGE Input Scenario 1a

Scenario	ADB MON-7619 EMP 1a: Coal-based expansion			
T = total investments	T (in mMNT) = 1.435*T (in US$m)	FDI (90% * T)	Domestic (10% * T)	INDfactor x valIND(*)
2013	162.7	146.4	16.3	8.8
2014	438.0	394.2	43.8	22.9
2015	669.9	602.9	67.0	34.1
2016	978.2	880.4	97.8	48.3
2017	872.4	785.2	87.2	41.8
2018	346.7	312.0	34.7	16.1
2019	292.6	263.3	29.3	13.2
2020	682.6	614.3	68.3	30.0
2021	621.8	559.6	62.2	26.5
2022	642.0	577.8	64.2	26.6
2023	0.0	0.0	0.0	0.0
2024	917.2	825.5	91.7	35.8

Total investments, FDI, Domestic investments, and the calculated INDfactor in the EleGasH2O production sector, for the ADB MON-7619 EMP 1 scenario.

SCENARIO 2 (ADB-MON-7619 EMP 2) : This scenario is based on increased FDI according to a Mixed Hydro-Wind Expansion scenario.

150. In **Figure IV-2**, the first column depicts a time series of total investments in the EleGasH2O production sector. The original series obtained from the Energy Master Plan was in millions of US$, hence we translated them into millions of Tugruk (mMNT) using the exchange rate of 1US$ = 1.435 MNT as used in the Energy Master Plan. From these total investments, depicted with T, we compute the part of foreign direct investments (FDI) and investments from domestic origin using an allocation of 90% of T being FDI and 10% of T being domestic investments.

151. Notice that Robichaud et al. (2011) implement the FDI shocks as a multiple, 0.5, of va-lIND(EleGasH20',time,'bau') in the BaU scenario. We introduce a factor, INDfactor in Table 12, which denotes this multiple, and it is computed in such a way that the value FDI obtained in the Energy Masterplan according to Table 12, equals INDfactor times this valIND(EleGasH20',time,'bau') for each period 'time'. Column 4 enumerates the values

obtained for INDfactor for each period from 2013 until 2024.Based on the results of the tariff study it can be concluded that in many cases, as soon as tariffs reach the full cost recovery level, only slight further increase would be needed in order to achieve the short-term and even long-term profitability targets. Thus when considering major energy producers, heat distributors and the largest electricity transmission and distribution companies, the most significant increase from the full cost recovery level to the target profitability

Figure IV-2: CGE Input Scenario 2c

Scenario	ADB MON-7619 EMP 2c: Mixed hydro-wind expansion			
T = total investments	T (in mMNT) = 1.435*T (in US$m)	FDI (90% * T)	Domestic (10% * T)	INDfactor x valIND(*)
2013	162.7	146.4	16.3	8.8
2014	438.0	394.2	43.8	22.9
2015	731.7	658.5	73.2	34.1
2016	1077.1	969.4	107.7	48.3
2017	1107.5	996.7	110.7	41.8
2018	668.3	601.5	66.8	16.1
2019	800.9	720.8	80.1	13.2
2020	905.3	814.8	90.5	30.0
2021	380.9	342.8	38.1	26.5
2022	642.0	577.8	64.2	26.6
2023	346.7	312.0	34.7	0.0
2024	1340.1	1206.1	134.0	35.8

Total investments, FDI, Domestic investments, and the calculated INDfactor in the EleGasH2O production sector, for the ADB MON-7619 EMP 2 scenario.

SCENARIO 3 (ADB-MON-7619 EMP 3): This scenario is based on increased FDI according to a Heavy Renewables Expansion scenario.

152. In the table that follows the first column depicts a time series of total investments in the EleGasH2O production sector. The original series obtained from the Energy Master Plan was in millions of US$, hence we translated them into millions of Tugruk (mMNT) using the exchange rate of 1US$ = 1.435 MNT as used in the Energy Master Plan. From these total investments, depicted with T, we compute the part of foreign direct investments (FDI) and investments from domestic origin using an allocation of 90% of T being FDI and 10% of T being domestic

investments.

Figure IV-3: CGE Input EMP Scenario 4

Scenario	ADB MON-7619 EMP 4: Heavy Renewables expansion			
T = total investments	T (in mMNT) = 1.435*T (in US$m)	FDI (90% * T)	Domestic (10% * T)	INDfactor x valIND(*)
2013	162.7	146.4	16.3	8.8
2014	438.0	394.2	43.8	22.9
2015	669.9	602.9	67.0	34.1
2016	978.2	880.4	97.8	48.3
2017	872.4	785.2	87.2	41.8
2018	473.6	426.2	47.4	22.0
2019	715.5	644.0	71.6	32.3
2020	1105.6	995.0	110.6	48.5
2021	1044.8	940.3	104.5	44.5
2022	1065.0	958.5	106.5	44.0
2023	296.1	266.5	29.6	11.9
2024	917.2	825.5	91.7	35.8

Total investments, FDI, Domestic investments, and the calculated INDfactor in the EleGasH2O production sector, for the ADB MON-7619 EMP 2 scenario.

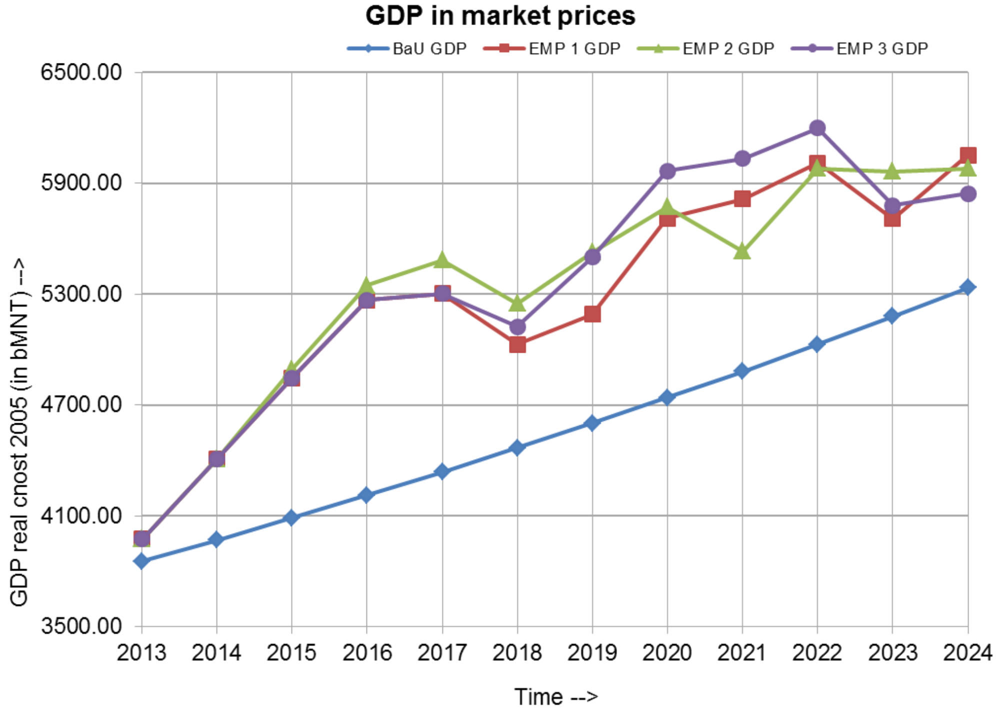
153. In the table that follows the first column depicts a time series of total investments in the EleGasH2O production sector. The original series obtained from the Energy Master Plan was in millions of US$, hence we translated them into millions of Tugruk (mMNT) using the exchange rate of 1US$ = 1.435 MNT as used in the Energy Master Plan. From these total investments, depicted with T, we compute the part of foreign direct investments (FDI) and investments from domestic origin using an allocation of 90% of T being FDI and 10% of T being domestic investments.

L. CGE Results

154. The results of the modelling show that in all cases there are positive effects of FDI on the Mongolian economy as measured by GDP.

155. The detailed model is provided as Appendix A.

Figure IV-4: CGE Input EMP Scenario 4



V. MON-CGE MODEL FORMULATION

Impact Assessments of Foreign Direct Investments (FDI) with the Mon-CGE Model.
by: Martin Ehrlich, Michael Emmerton, and Hans Kremers
THIS VERSION: 26 July 2013

PDF FILE