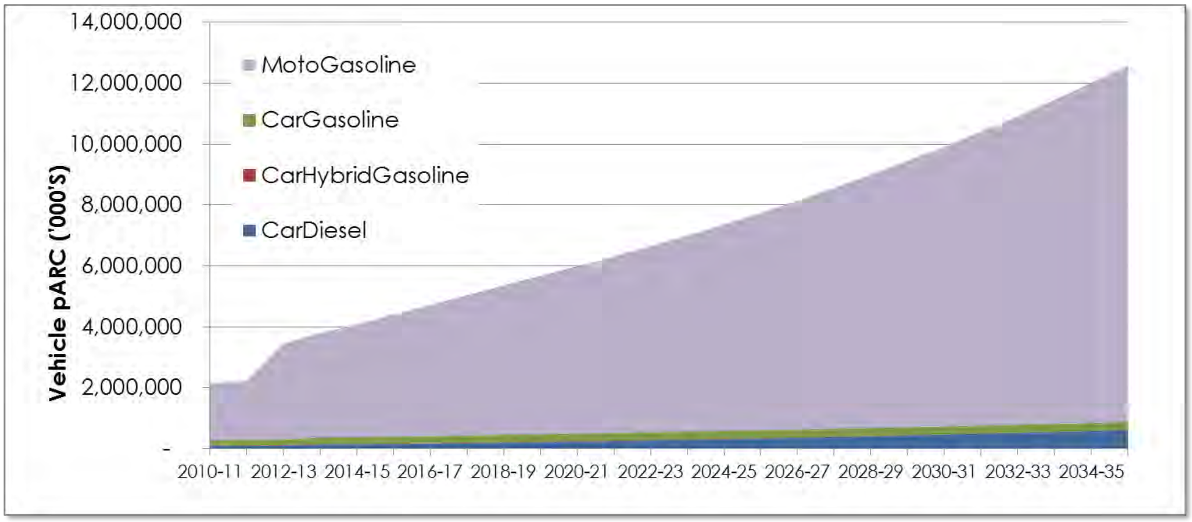
Table III-9: Vehicle PARC

	Reference						
	2012	2015	2018	2021	2024	2027	2030
Passenger car	298,861	527,670	602,653	194,234	769,640	862,448	961,958
Motorcycle	3,153,201	4,012,298	4,907,778	5,799,181	6,779,526	7,907,553	9,186,215
Bus	21,051	29,279	32,464	35,728	39,070	42,490	45,986
Heavy Commercial Vehicle	41,075	51,024	54,882	60,401	67,994	78,195	92,163
Light Commercial Vehicle	53,730	63,907	70,303	76,671	83,673	91,731	100,864
3 Wheel, Trawlergi	72,119	99,443	117,745	139,542	165,503	196,423	233,249
Total	3,640,037	4,783,622	5,785,826	6,305,756	7,905,406	9,178,840	10,620,436

	Alternative Case						
	2012	2015	2018	2021	2024	2027	2030
Passenger car	298,861	527,670	602,653	194,234	769,640	862,448	961,935
Motorcycle	3,153,201	4,012,298	4,907,778	5,799,181	6,779,526	7,907,553	9,186,215
Bus	21,051	29,279	32,464	35,728	39,070	42,490	45,986
Heavy Commercial Vehicle	41,075	51,024	54,882	60,401	67,994	78,195	92,163
Light Commercial Vehicle	53,730	63,907	70,303	76,671	83,673	91,731	100,864
3 Wheel, Trawlergi	72,119	99,443	117,745	139,542	165,503	196,423	233,249
Total	3,640,037	4,783,622	5,785,826	6,305,756	7,905,406	9,178,840	10,620,413

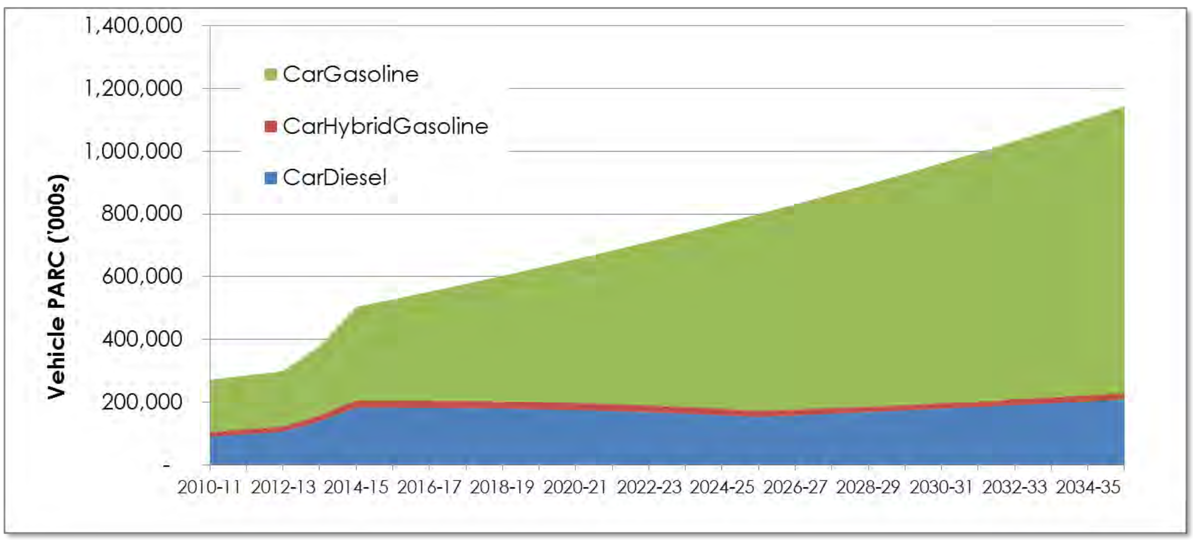
Source: Consultant

Figure III-10: Vehicle PARC (All Passenger Vehicles)



Source: Consultant

Figure III-11: Vehicle PARC (excluding motorcycles)



Source: Consultant

Table III-12: Average Passenger Vehicle Fuel Economy (litres per 100km)

	Reference							Alternative Case						
	2012	2015	2018	2021	2024	2027	2030	2012	2015	2018	2021	2024	2027	2030
Gasoline cars	16.9	18.0	18.1	18.1	18.0	17.7	17.1	16.9	18.0	18.0	18.1	18.0	17.7	17.1
CNG cars*	10.7	10.6	9.9	9.4	8.8	7.9	8.0	10.7	10.6	9.9	9.4	8.8	7.9	6.4
Diesel cars	18.0	18.3	17.4	16.6	15.0	14.9	15.1	18.0	18.3	17.4	16.6	15.0	14.9	15.1
Gasoline motos	4.4	4.4	4.3	4.4	4.4	4.4	4.4	4.4	4.4	4.3	4.4	4.4	4.4	4.4
Diesel bus	21.8	21.6	21.4	20.8	20.3	21.3	21.3	21.8	21.6	21.3	20.6	20.1	21.1	21.1

Source: Consultant

Table III-13: Average Freight Vehicle Fuel Economy (litres per 100km)

	Reference							Alternative Case						
	2012	2015	2018	2021	2024	2027	2030	2012	2015	2018	2021	2024	2027	2030
Diesel HCV	19.5	19.6	19.5	18.9	19.8	18.96	18.6	19.5	19.6	19.4	18.8	19.7	18.8	18.5
Diesel LCV	12.4	12.1	12.0	12.0	12.0	11.78	11.8	12.4	12.1	12.0	12.0	12.0	11.7	11.7
Gasoline LCV	12.5	12.3	12.2	12.2	12.3	12.13	12.1	12.5	12.3	12.2	12.2	12.3	12.1	12.1

Source: Consultant

Table III-14: Total Fuel Sales Projection

	Reference						
	2012	2015	2018	2021	2024	2027	2030
Gasoline (IG - 000's)	138,568	262,495	313,401	373,072	437,381	485,485	519,767
Bioethanol (IG - 000's)	-	-	-	-	-	-	-
Diesel (IG - 000's)	192,351	283,269	268,451	259,578	264,090	291,511	338,510
Natural Gas (cub m - 000's)	37,326	52,971	43,164	35,197	27,509	19,751	20,839
Jet Fuel (IG '000s)	9,211	9,250	14,800	20,350	25,900	31,450	37,000
	Alternative Case						
	2012	2015	2018	2021	2024	2027	2030
Gasoline (IG - 000's)	138,568	262,451	313,243	335,738	382,597	413,114	437,354
Bioethanol (IG - 000's)	-	-	-	37,082	54,487	72,024	84,832
Diesel (IG - 000's)	192,350	283,137	267,838	258,468	262,703	290,054	337,020
Natural Gas (cub m - 000's)	37,325	52,969	43,154	35,156	27,439	19,655	11,409
Jet Fuel (IG '000s)	9,211	9,250	14,800	20,350	25,900	31,450	37,000

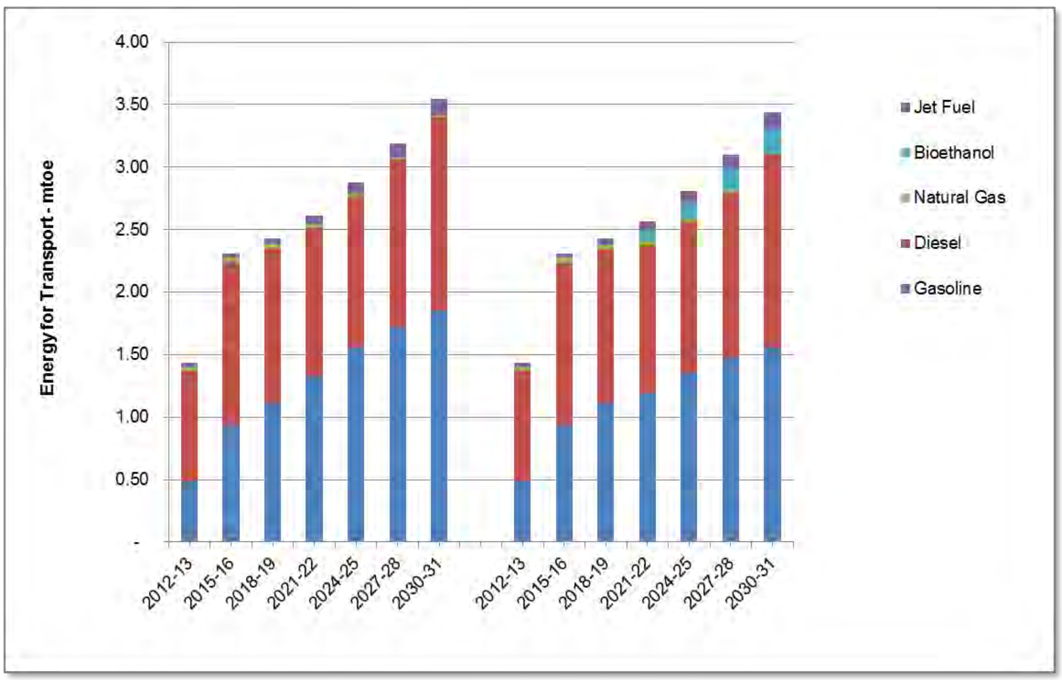
Source: Consultant

Table III-15: Energy for Transport (mtoe)

	Reference							Alternative Case						
	2012	2015	2018	2021	2024	2027	2030	2012	2015	2018	2021	2024	2027	2030
Gasoline	0.49	0.93	1.11	1.33	1.56	1.73	1.85	0.49	0.93	1.11	1.19	1.36	1.47	1.55
Bioethanol	-	-	-	-	-	-	-	-	-	-	0.09	0.13	0.17	0.21
Diesel	0.88	1.30	1.23	1.19	1.21	1.33	1.55	0.88	1.30	1.23	1.18	1.20	1.33	1.54
Natural Gas	0.03	0.05	0.04	0.03	0.02	0.02	0.02	0.03	0.05	0.04	0.03	0.02	0.02	0.01
Jet Fuel (ATF)	0.03	0.03	0.05	0.07	0.09	0.11	0.13	0.03	0.03	0.05	0.07	0.09	0.11	0.13
Total	1.44	2.31	2.43	2.61	2.88	3.18	3.54	1.44	2.31	2.43	2.57	2.81	3.09	3.44

Source: Consultant

Figure III-16: Energy for Transport



Source: Consultant

Table III-17: CO2 Emissions (mtons)

	Reference							Alternative Case						
	2012	2015	2018	2021	2024	2027	2030	2012	2015	2018	2021	2024	2027	2030
Passenger cars	1.57	2.89	3.13	3.43	3.78	4.20	4.66	1.57	2.89		3.20	3.51	3.89	3.99
Public bus	0.34	0.51	0.53	0.57	0.60	0.65	0.70	0.34	0.51	0.53	0.57	0.60	0.65	0.70
Freight	1.74	2.14	2.22	2.41	2.73	3.17	3.77	1.74	2.14	2.22	2.41	2.73	3.17	3.77
Total	3.65	5.60	5.95	6.48	7.19	8.10	9.23	3.65	5.53	2.75	6.17	6.84	7.71	8.46

Table III-18: CO2 Intensity

	Reference							Alternative Case						
	2012	2015	2018	2021	2024	2027	2030	2012	2015	2018	2021	2024	2027	2030
Passenger cars (g CO2 per p-km)	92	112	107	104	103	103	103	92	112	107	98	96	96	89
Freight (g CO2 per ton-km)	274	319	306	301	302	306	310	274	319	306	301	302	306	310

Source: Consultant

Project Number: TA No. 8356-MYA

FINAL REPORT

ENERGY FORECASTS

HOUSEHOLD SECTOR

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

IES
Intelligent Energy Systems

in association with

MMIC
MYANMAR
INTERNATIONAL
CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
CSO	–	Central Statistics Organisation
FES	–	Fuel Efficient Stove
GDP	–	Gross Domestic Product
GoM	–	Government of the Republic of the Union of Myanmar
MoE	–	Ministry of Energy

UNITS OF MEASURE

toe	–	tons of oil equivalent
ton	–	metric ton
kg	–	kilogram
KJ	–	kilojoule
ks	–	Kyat
MJ	–	megajoule

WEIGHTS AND MEASURES

ktoe	–	1000 toe
MJ	–	1000 kilojoue
kg	–	1000 gram
KJ	–	1000 joule
ton	–	1000 kg

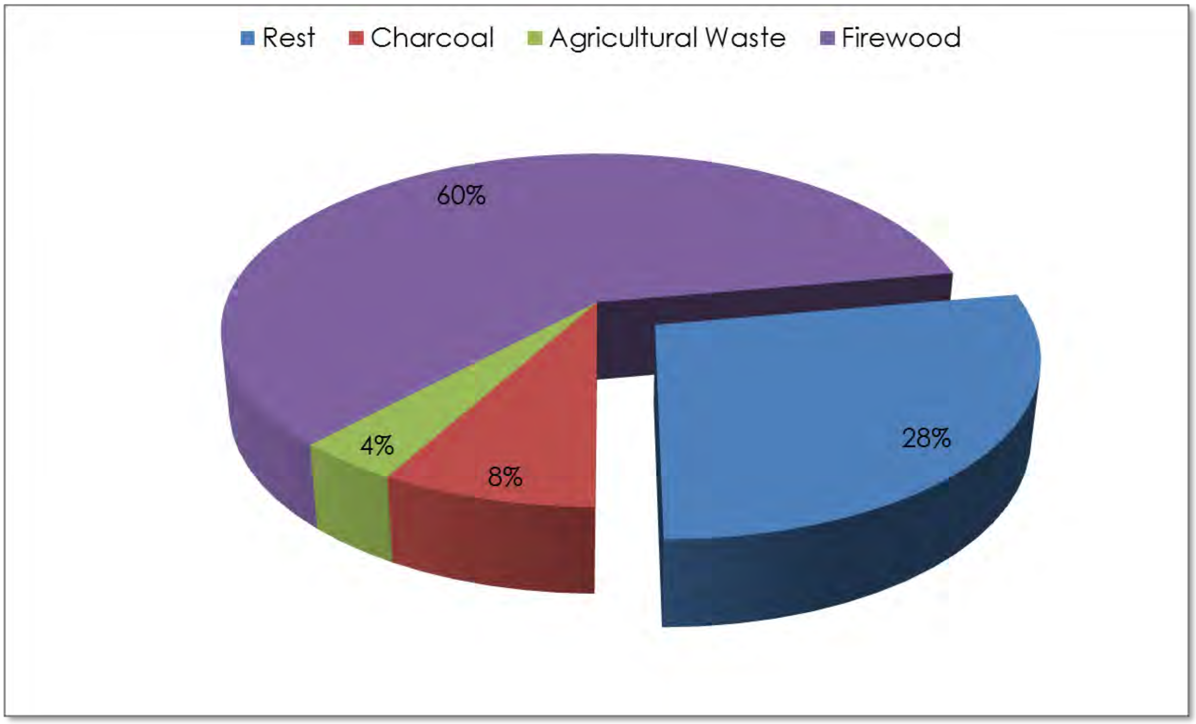
CONTENTS

I. SUMMARY

A. Introduction

1. Household energy accounts for by far the largest consumption of energy in Myanmar due to the large rural population and the daily cooking cycle. Cooking relies on woody biomass as the most important national energy source. In 2013, cooking demand met by biomass sources— firewood, charcoal, agricultural waste, wood waste, and animal dung—amounted to around 72% of total final energy consumed.

Figure I-1: Cooking Fuels: 2013-14

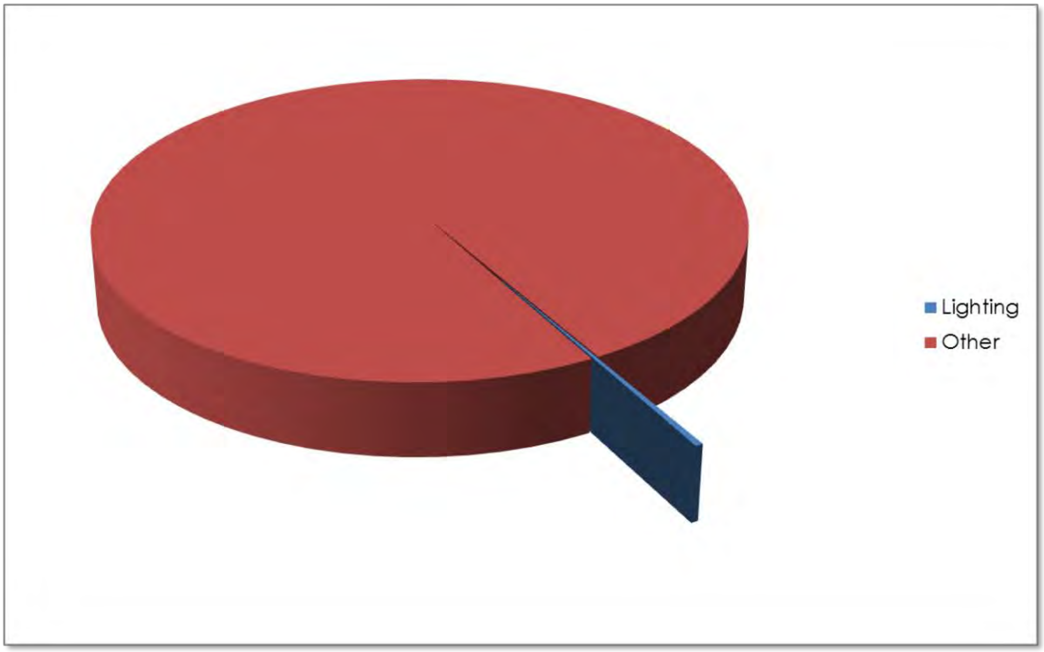


Sources: Consultant

2. In Yangon and urban Mandalay commercial fuels are in use for cooking; electricity, LPGas and charcoal are in common use. Outside of these urban areas, traditional fuels are mainly used along with electricity where it is available.

3. Rural household lighting accounts for a relatively low consumption of the total household energy consumption at less than 1%. Energy used for household cooking dominates household energy consumption. The demand for lighting services is met by on-grid and off-grid sources—by candles, wick lamps, fluorescent bulbs, LED / battery lighting systems, and solar lighting systems. Households without access to electricity, and those with the lowest incomes, rely mainly on candles, oil wick lamps and LED DC lighting.

Figure I-2: Lighting Energy Use: 2012



Sources: Consultant

4. The use of non-commercial fuels in the villages occurs because rural villagers have a very low and sporadic cash income and this poses two problems:-

(i) It limits their fuel options

Poor villagers are able to buy only small amounts of fuel when money is available to do so. This means that fuels that can be purchased in small amounts at low cost will be most viable. It also means that the cheapest fuel will usually be sought, regardless of the harmful health effects that come with the burning of woody biomass.

(ii) There is a limited expendable income to buy appliances

Energy using appliances often require significant capital outlay relative to the household income. A particular consequence is that if electricity or LPGas becomes available, many households will not be able to use these fuels for cooking because of a lack of electrical appliances.

5. Compared to wealthier, electrified households, low income households (mainly rural but also many peri-urban) suffer high levels of harmful emissions by burning wood, woody biomass, charcoal, diesel oil and paraffin. Emissions from these fuels are highly concentrated and slow moving. The use of open fires in the household can also be the cause of accidents that result in injury or death. Electricity and gas are relatively cleans fuel for households, notwithstanding that gas is more hazardous than electricity.

6. Long-term planning requires an accurate depiction of the current household demand for energy on which to base projections of future demand. The EMP household survey, conducted throughout 2014, has provided household end-use data suitable for establishing baseline energy use in 2014.

7. An important planning issue is the potential for fuel substitution over the long-term. The ADB

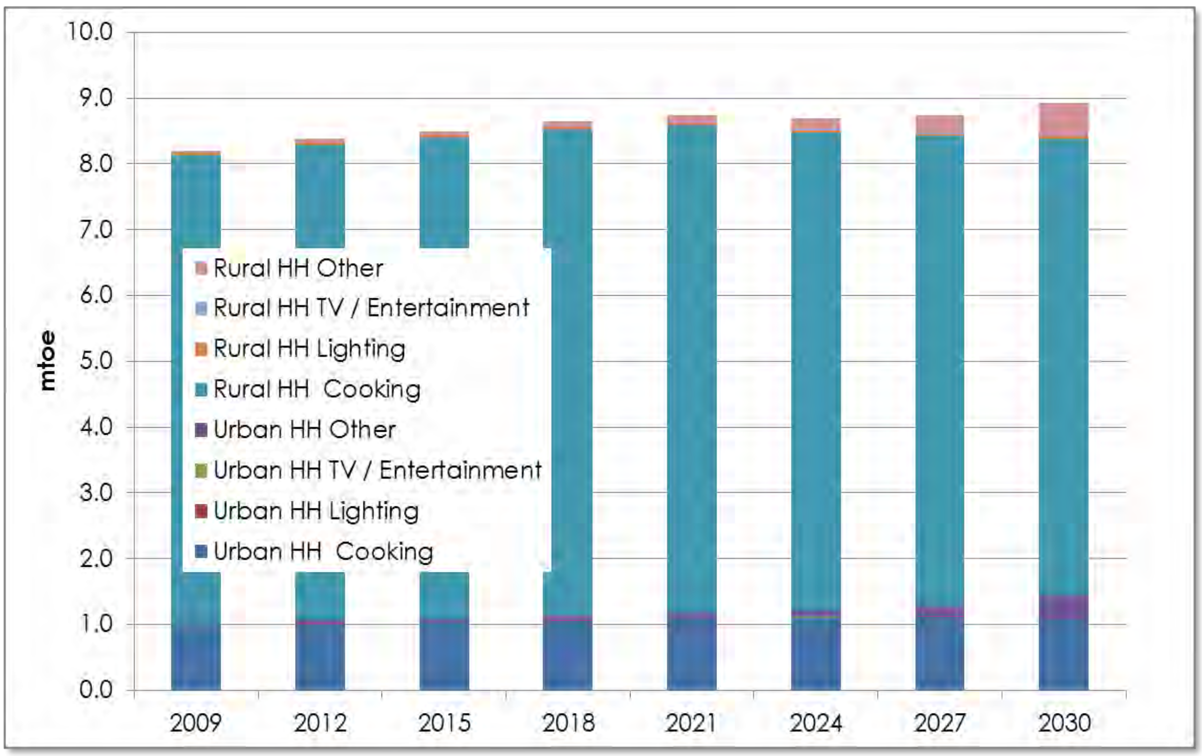
supports a 100% rural electrification program and household energy demand has been projected with the programme in mind. In the case of cooking, electricity access would provide an opportunity for the use of rice cookers. In the case of lighting, electricity access would allow households to switch from candles, diesel oil lamps and battery lighting to electric lights. Care has been taken to ensure that the household electricity use projected in this household sector report, is fully consistent with the State/Region 'top-down' electricity forecasts developed from historical electricity sales data.

B. Household Sector Final Energy Consumption Forecasts

8. The EMP household survey has revealed that the patterns of fuel use for cooking divide into a 'Yangon Division / urban Mandalay' and 'Other' segmentation. For consistency the same segmentation has been used for lighting, TV/entertainment and other energy consumption (cooling services). These segments are hereafter referred to as the 'Urban' and 'Rural' segments.

9. The household sector energy projections are provided as Figure I-3 . The details are given in Table I-4.

Figure I-3: Final Energy Consumption by Household Segment



Sources: Consultant

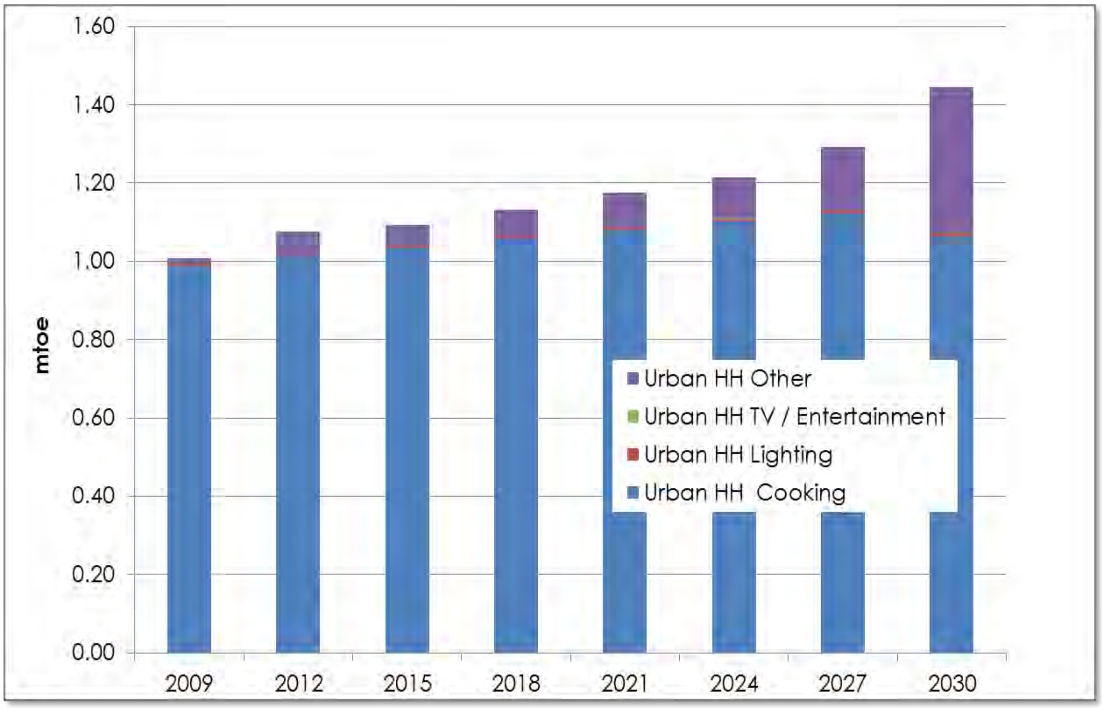
10. Figure I-5 and Figure I-6 provide separate views of final energy consumption for Urban households and Rural households respectively. Table I-7 provides the final energy consumption for electricity only. Table I-8 provides the final energy consumption on a toe per household basis. The toe per capita estimates are consistent with international benchmarks. Figure I-9 to Figure I-15 provide the projections of household fuel carrier consumption (in physical terms).

Table I-4: Household Sector (mtoe)

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR	Comment
Urban HH Cooking	0.9885	1.0121	1.0358	1.0594	1.0819	1.1019	1.1220	1.0651	0.2%	Use of commercial fuels continues
Urban HH Lighting	0.0040	0.0043	0.0046	0.0049	0.0052	0.0059	0.0065	0.0070	2.8%	Candles and wick lamps replaced
Urban HH TV / Entertainment	0.0002	0.0003	0.0005	0.0008	0.0010	0.0013	0.0017	0.0021	9.4%	Leisure hours increasing
Urban HH Other	0.0163	0.0585	0.0519	0.0674	0.0877	0.1050	0.1632	0.3699	13.1%	Air-conditioning, refrigeration, fans, other
Urban HH Total	*1.0090*	*1.0752*	*1.0928*	*1.1325*	*1.1757*	*1.2141*	*1.2934*	*1.4441*	*1.9%*	Increase in line with population rise
Rural HH Cooking	7.1287	7.2167	7.3046	7.3925	7.4056	7.2689	7.1323	6.9382	-0.3%	Firewood displaced by electricity
Rural HH Lighting	0.0239	0.0246	0.0253	0.0260	0.0267	0.0267	0.0266	0.0255	0.1%	Candles and wick lamps replaced
Rural HH TV / Entertainment	0.0009	0.0010	0.0020	0.0030	0.0040	0.0050	0.0060	0.0076	8.8%	Leisure hours increasing
Rural HH Other	0.0297	0.0682	0.0705	0.0941	0.1281	0.1762	0.2735	0.5037	13.1%	Refrigeration, fans, other, cottage industry
Rural HH Total	*7.1832*	*7.3105*	*7.4024*	*7.5156*	*7.5644*	*7.4767*	*7.4384*	*7.4751*	*0.1%*	Efficiency with increased population
Total Urban & Rural	*8.1923*	*8.3857*	*8.4952*	*8.6481*	*8.7401*	*8.6909*	*8.7318*	*8.9192*	*0.3%*	Energy efficiency with increasing population
% Electricity	1.8%	3.4%	4.0%	5.1%	6.6%	8.8%	12.0%	16.4%		

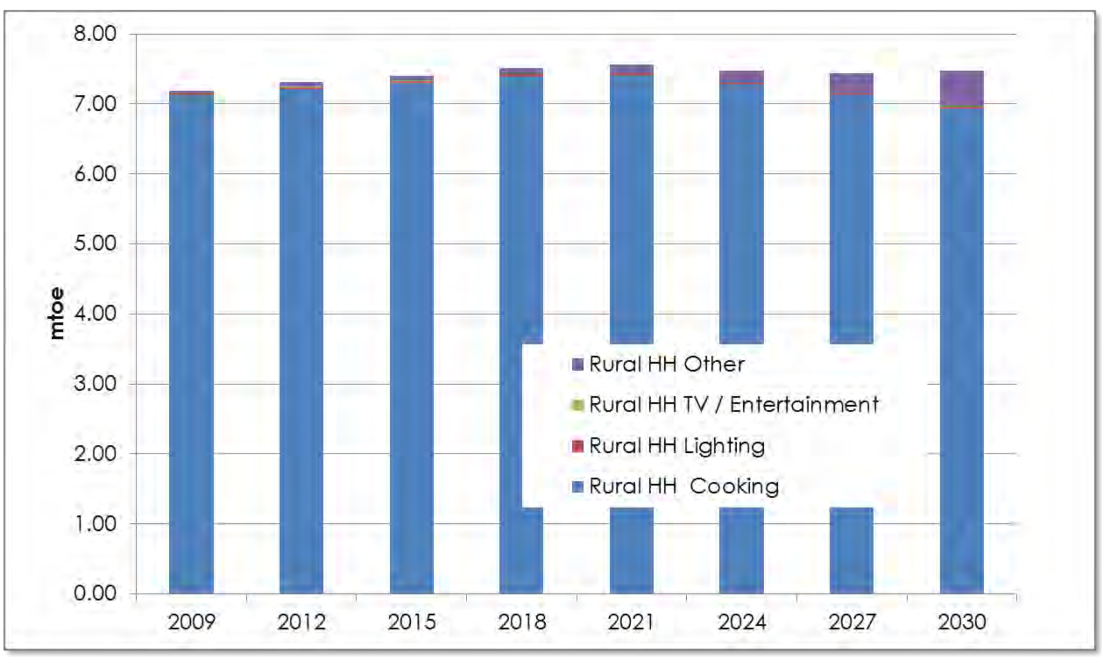
Sources: Consultant

Figure I-5: Urban Household Sector (mtoe)



Sources: Consultant

Figure I-6: Rural Household Sector (mtoe)



Sources: Consultant

Table I-7: Household Sector Electricity Only (mtoe)

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR
Urban HH Cooking	0.0662	0.0905	0.1148	0.1391	0.1768	0.2414	0.3060	0.2905	6.2%
Urban HH Lighting	0.0016	0.0019	0.0021	0.0024	0.0027	0.0037	0.0047	0.0055	6.3%
Urban HH TV / Entertainment	0.0002	0.0003	0.0005	0.0008	0.0010	0.0013	0.0017	0.0021	9.4%
Urban HH Other	0.0163	0.0585	0.0519	0.0674	0.0877	0.1050	0.1632	0.3699	13.1%
Urban HH Total	*0.0844*	*0.1512*	*0.1694*	*0.2097*	*0.2682*	*0.3514*	*0.4755*	*0.6680*	*9.1%*
Rural HH Cooking	0.0285	0.0612	0.0940	0.1267	0.1673	0.2235	0.2798	0.2721	7.1%
Rural HH Lighting	0.0052	0.0057	0.0062	0.0067	0.0072	0.0091	0.0111	0.0128	4.9%
Rural HH TV / Entertainment	0.0009	0.0010	0.0020	0.0030	0.0040	0.0050	0.0060	0.0076	8.8%
Rural HH Other	0.0297	0.0682	0.0705	0.0941	0.1281	0.1762	0.2735	0.5037	13.1%
Rural HH Total	*0.0643*	*0.1362*	*0.1727*	*0.2305*	*0.3066*	*0.4138*	*0.5703*	*0.7964*	*10.2%*
Total Urban & Rural	*0.1488*	*0.2874*	*0.3421*	*0.4402*	*0.5747*	*0.7652*	*1.0458*	*1.4644*	*9.7%*

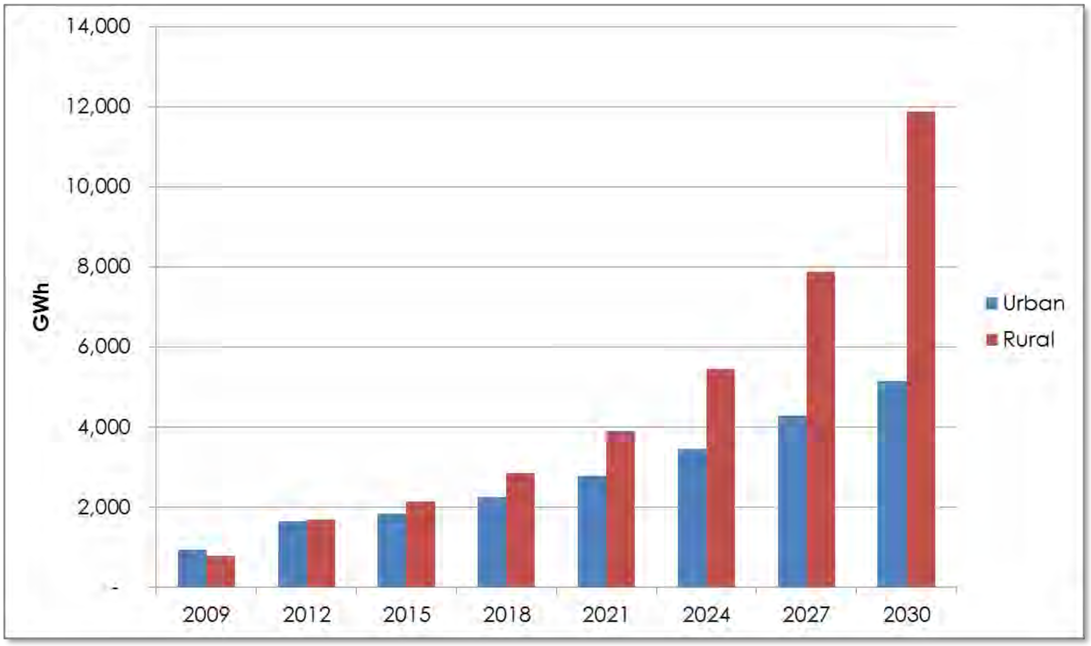
Sources: Consultant

Table I-8: Household Sector Energy (toe per household)

	2009	2012	2015	2018	2021	2024	2027	2030
Urban HH Cooking	0.5196	0.5162	0.4849	0.4552	0.4266	0.3988	0.3727	0.3247
Urban HH Lighting	0.0021	0.0022	0.0021	0.0021	0.0020	0.0021	0.0022	0.0021
Urban HH TV / Entertainment	0.0001	0.0001	0.0002	0.0003	0.0004	0.0005	0.0005	0.0006
Urban HH Other	0.0086	0.0299	0.0243	0.0290	0.0346	0.0380	0.0542	0.1128
Urban HH Total	*0.5304*	*0.5484*	*0.5116*	*0.4866*	*0.4636*	*0.4394*	*0.4296*	*0.4403*
Rural HH Cooking	0.6156	0.6047	0.5941	0.5835	0.5674	0.5405	0.5148	0.4860
Rural HH Lighting	0.0021	0.0021	0.0021	0.0021	0.0020	0.0020	0.0019	0.0018
Rural HH TV / Entertainment	0.0001	0.0001	0.0002	0.0002	0.0003	0.0004	0.0004	0.0005
Rural HH Other	0.0026	0.0057	0.0057	0.0074	0.0098	0.0131	0.0197	0.0353
Rural HH Total	*0.6203*	*0.6126*	*0.6020*	*0.5933*	*0.5796*	*0.5560*	*0.5369*	*0.5237*
Average Urban & Rural (wtd)	*0.6076*	*0.6035*	*0.5886*	*0.5767*	*0.5607*	*0.5361*	*0.5177*	*0.5081*

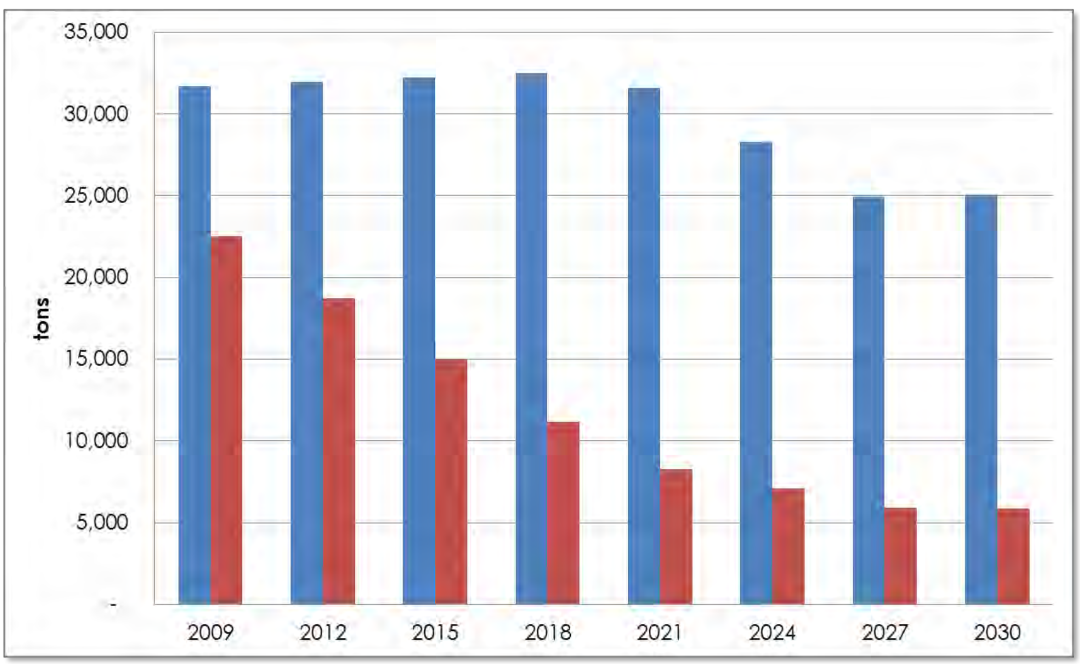
Sources: Consultant

Figure I-9: Household Sector – Electricity (GWh)



Sources: Consultant

Figure I-10: Household Sector – LPG (tons)

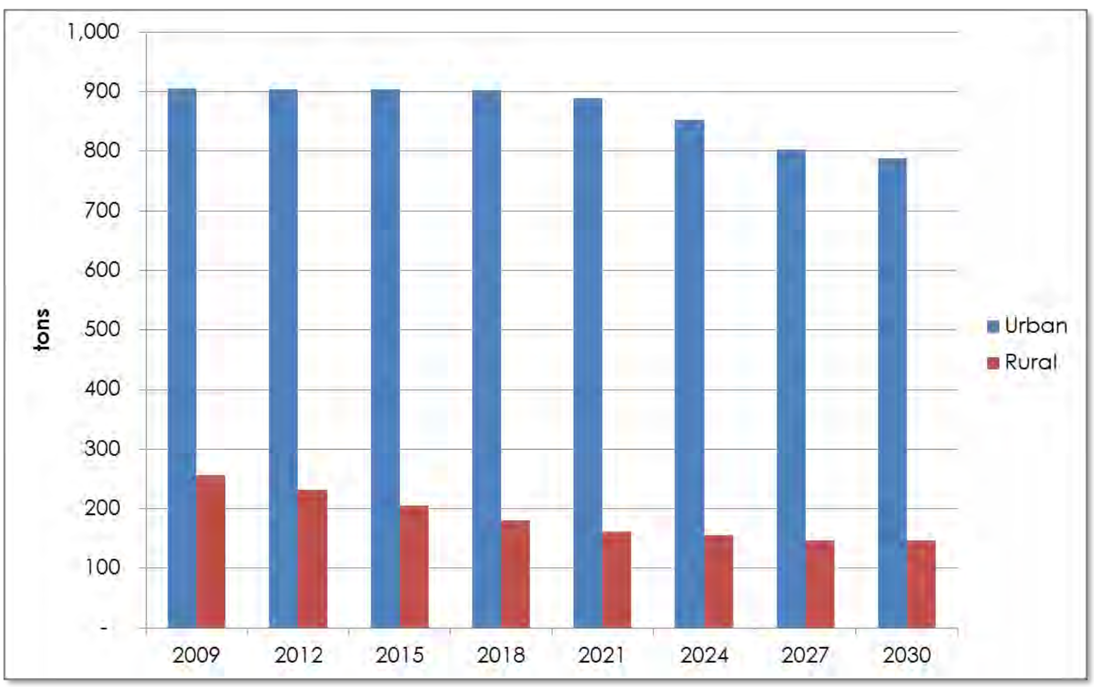


Sources: Consultant

Figure I-11: Household Sector – Firewood (tons)

Sources: Consultant

Figure I-12: Household Sector – Biomass (tons)

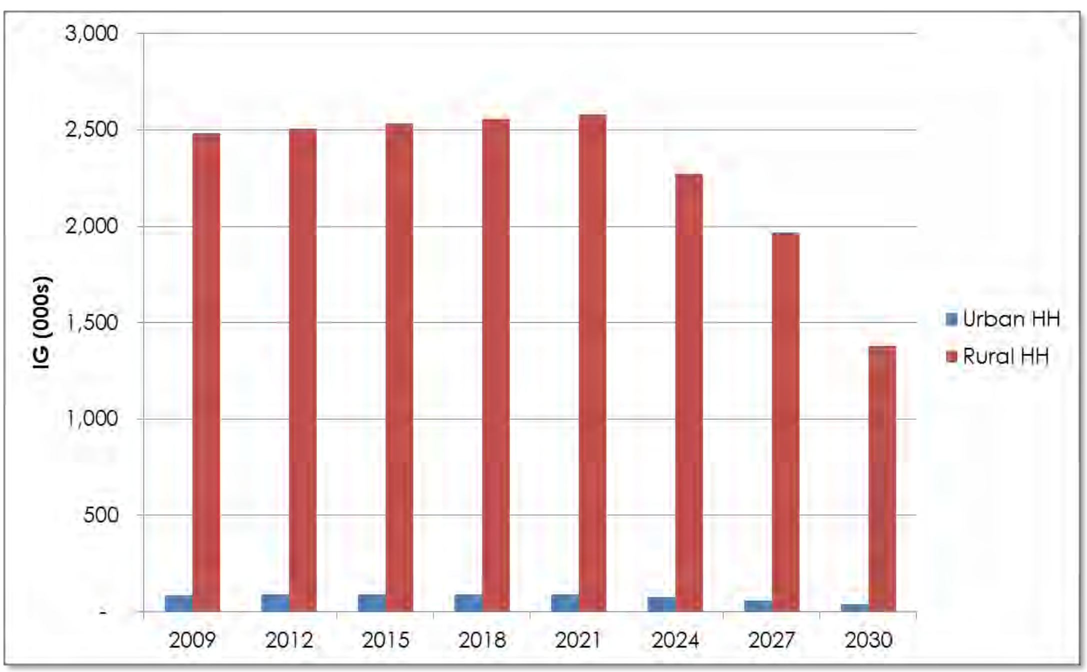


Sources: ADB, Consultant

Figure I-13: Household Sector – Charcoal (tons)

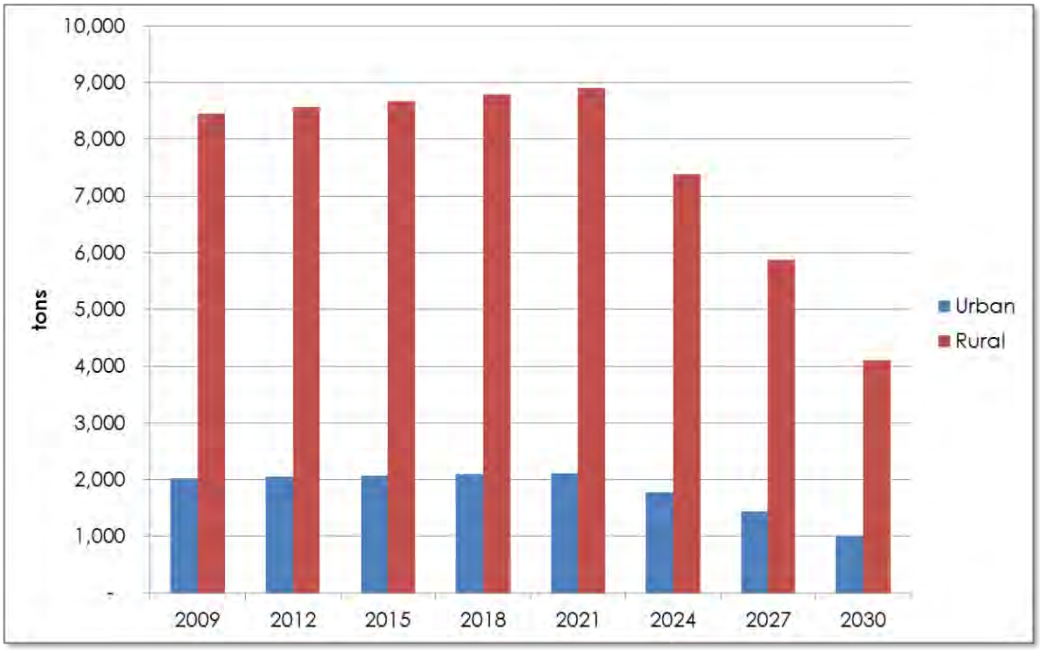
Sources: Consultant

Figure I-14: Household Sector – Diesel Oil (IG 000s)



Sources: Consultant

Figure I-15: Household Sector – Paraffin Wax (tons)



Sources: Consultant

II. PLANNING CONSIDERATIONS

C. EMP HH Survey

11. The data concerning household energy use for cooking and heating water has been sparse until recent years. MercyCorps has undertaken surveys of rural households that provide insights into the patterns of energy use for household cooking, water heating and lighting. The focus of the MercyCorps studies was on the use and barriers to the introduction of fuel efficient stoves (FES). A survey of food security was conducted in 2012 by the Livelihoods for Food Security Trust (LIFT). The survey covered 4,000 rural households in poverty-stricken areas and captured high level information concerning fuel use for cooking by fuel zone and by income decile.

12. Whilst previous surveys provide a useful starting point for energy planning, the LIFT survey did not extend to end-use patterns or urban households, and so a household survey was designed and conducted under the aegis of the Energy Masterplan. The design of the EMP household survey was shaped by the insights gained from the LIFT survey but has specifically tackled the question of household end-use.

13. The EMP HH survey revealed that the fuels used for cooking are predominantly commercial fuels in the Yangon Division and the urban area of Mandalay. Outside of these areas, cooking fuel use was found to be fairly uniform and predominantly fuel wood. Fuel wood includes fire wood and woody biomass in the form of agricultural waste used mainly as a supplementary fuel. On a dry weight basis, agricultural waste accounts for around 7% of the wood fuel used for cooking by rural households. These fuel use patterns are revealed by 'fuel heatmaps' developed from the HH survey data:-

Figure II-1: Yangon Division – Cooking Appliance Use by Surveyed Towns

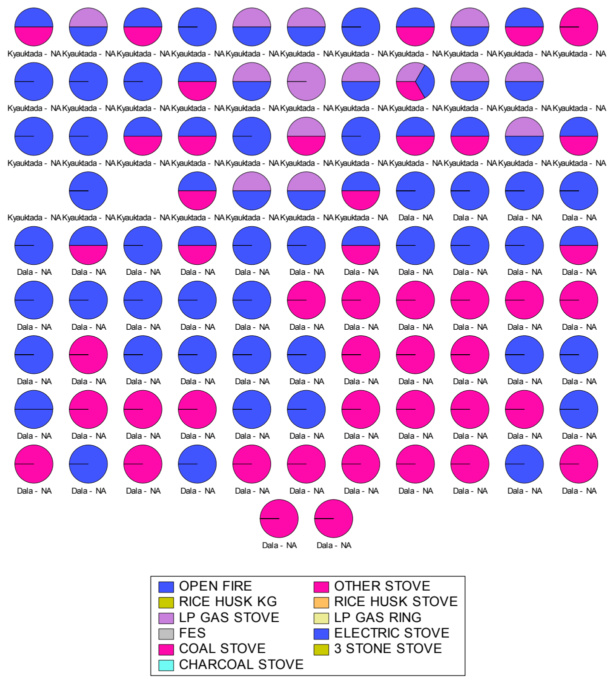
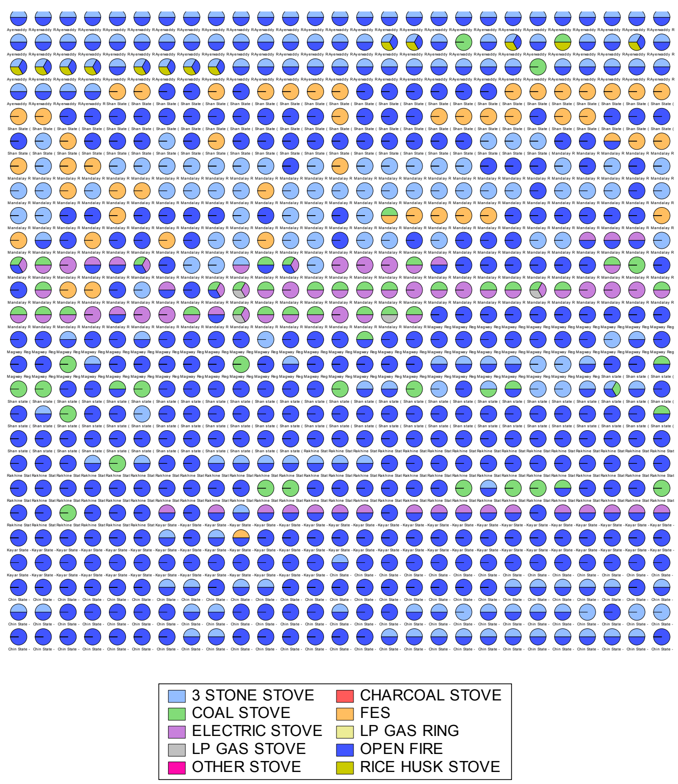


Figure II-2: Outside Yangon – Cooking Appliance by State / District Towns



Sources: EMP HH Survey

14. The heat maps provide a striking illustration of the difference between the cooking habits of Yangon and urban Mandalay residents and residents elsewhere in Myanmar. The colours represent a different cooking technology / fuel and from the difference in colours it can be seen that there is a vast difference between urban and rural cooking habits. It is apparent from Figure II-1 that electricity, LPGas and charcoal are the dominant fuels in the Yangon Division where households are relatively affluent and commercial fuels are available. Moveover, Figure II-2 shows that electricity, LPGas and charcoal are also the dominant fuels in urban Mandalay. Outside of urban Mandalay the pattern of end-use is fairly homogenous; open fires were found to be the most common means used for cooking. These patterns of fuel use for cooking mean that it is logical to segment fuel estimates for cooking according to a 'Yangon Division / urban Mandalay' and 'Other' split. Hereafter these segments are referred to as the 'Urban' and 'Rural' segments.

D. Fuel Zone Population

15. The energy consumption estimate for the household sector is significantly affected by the demographic of the population because the available fuels for cooking vary according to the temperate zones of the country. A spread of the household population is shown in Figure II-8 below, characterized by agricultural zones1. These agricultural zones coincide with 'fuel zones' defined in the LIFT study as the 'hilly zone', the 'dry zone' and the 'coastal/ delta' zone. LIFT also defined a 'Giri zone' as a zone that has a unique fuel status due to the long lasting effects of cyclone Nargis. The hilly zone corresponds to the yellow shaded areas in Figure II-8, the dry zone to the green shaded area, and the coastal/delta zone to the brown shaded areas. The Giri zone is the smaller of the two brown-shaded areas to the north-west. The household population breakdown is shown in Table II-3, segmented by the fuel zones.

Table II-3: Estimated Population by Fuel Zone (millions)

	Total	Rural	Urban
Hilly	15.7	15.7	0
Dry	21.4	19.9	1.5
Delta/Coastal	22.5	15.3	7.2
Giri	1.5	1.5	0
Total	61.1	52.5	8.6

Sources: ADB, USAID, Consultant

16. The fuel zone population and income data from the LIFT study of 2012 (4,000 household sample) supports an estimate of the population by fuel zone and income for both Urban and Rural areas.

Table II-4: Estimated Urban Population by Fuel Zone & Income Deciles: 2012

	Hilly	Dry	Delta/Coastal	Giri
Less than Ks 25,000	-	40,560	152,770	-
Ks 25,001-50,000	-	99,331	694,594	-

[1] "A Strategic Agricultural Sector and Food Security Diagnostic for Myanmar prepared for prepared for USAID/Burma by the University of Michigan and the Myanmar Development Resource Institute's Center for Economic and Social Development"; July 2013

	Hilly	Dry	Delta/Coastal	Giri
Ks 50,001-75,000	-	80,293	346,278	-
Ks 75,001-100,000	-	58,357	179,250	-
Ks 100,001-150,000	-	23,591	128,327	-
Ks 150,001-200,000	-	13,658	50,923	-
Ks 200,001-250,000	-	4,139	20,369	-
Ks 250,001-300,000	-	4,553	18,332	-
Over Ks 300,000	-	6,622	38,702	-
Total	-	331,104	1,629,545	-

Sources: Consultant

Table II-5: Estimated Rural Population by Fuel Zone & Income Deciles: 2012

	Hilly	Dry	Delta/Coastal	Giri
Less than Ks 25,000	513,387	555,085	326,151	65,665
Ks 25,001-50,000	1,374,985	1,359,392	1,482,899	123,937
Ks 50,001-75,000	785,706	1,098,842	739,275	76,972
Ks 75,001-100,000	410,710	798,643	382,684	56,533
Ks 100,001-150,000	232,140	322,856	273,967	19,569
Ks 150,001-200,000	124,999	186,916	108,717	2,609
Ks 200,001-250,000	49,107	56,641	43,487	1,305
Ks 250,001-300,000	44,642	62,305	39,138	-
Over Ks 300,000	40,178	90,626	82,625	1,305
Total	3,575,855	4,531,308	3,478,943	347,894

Sources: Consultant

E. Fuel Substitution

17. Fuel substitution is driven by economic considerations. A comparison of the fuel costs of different cooking fuels reveals that on average basis the lowest energy cost fuel is biogas, followed by firewood and electricity[2]. Charcoal and LPGas are currently considerably more expensive.

2 The electricity tariff rate is taken from the World Bank National Electrification Plan report; 7 July 2014.

Table II-6: Cooking Fuel Economic Comparison

Fuel	Wood vs Grid	Charcoal	Biogas	LP Gas	Grid	Private Gen
Unit of Sale	kg	kg	kg	kg	kWh	kWh
End Use	cooking	cooking	cooking	cooking	Elec	Elec
Price (kyat)	55	150	186	1280	40	50
Gross Energy Content (MJ)	15	27	43	49	3.6	3.6
Conversion	30%	30%	78%	78%	90%	90%
Useful Energy Cost (kyat/kWh)	44	67	20	121	44	55
Useful Energy Cost (USD/ kWh)	0.046	0.07	0.02	0.13	0.046	0.06

Sources: Consultant

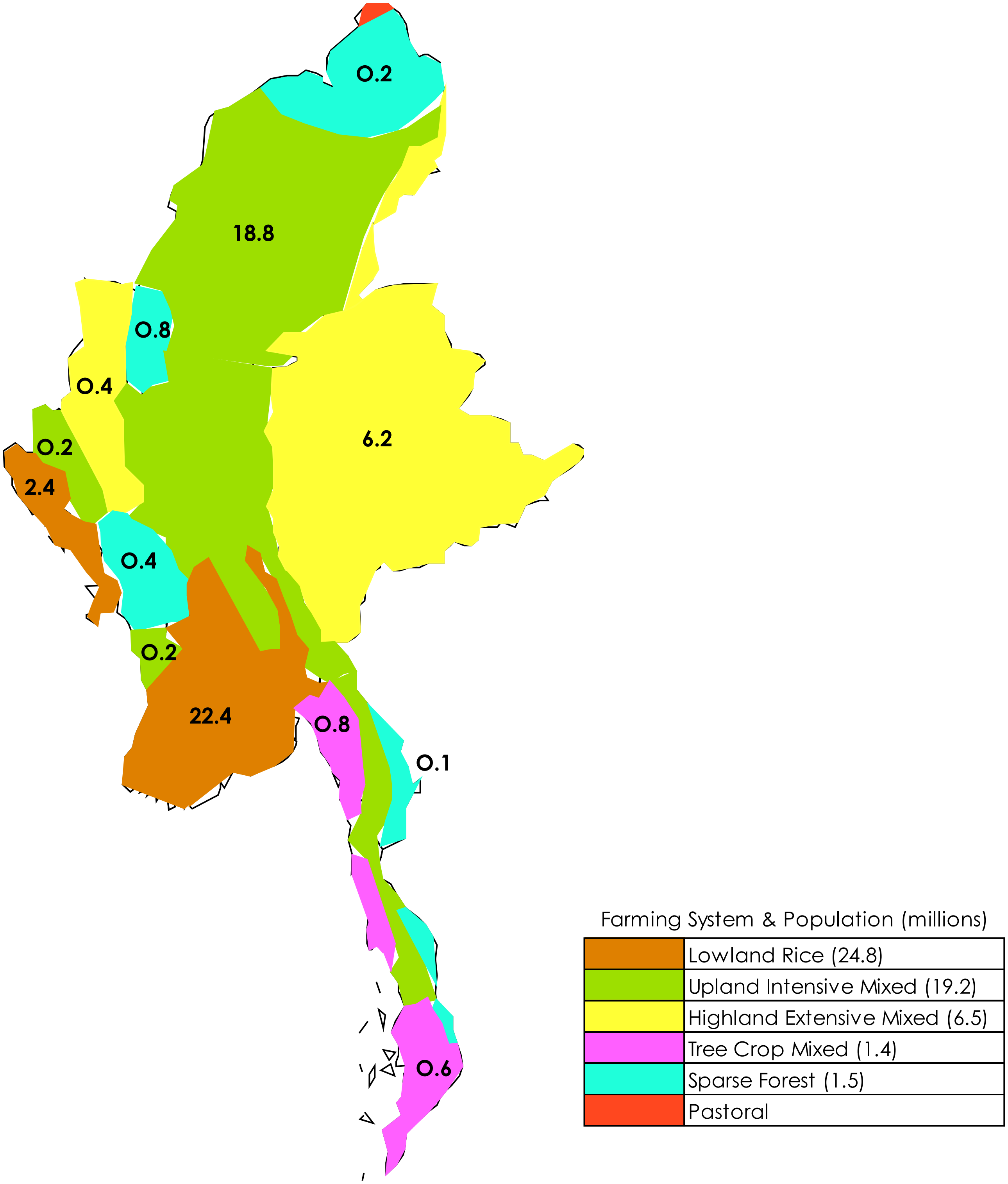
18. In the case of lighting, grid electricity is clearly the most economic choice if grid access is available. The relative attractiveness of electricity means that significant weight should be given to fuel substitution by electricity, consistent with a 100% national electrification plan.

Table II-7: Lighting Energy Economic Comparison

Fuel	Grid	Private Gen	Diesel	Car Batts	Candles	Dry Batteries	Solar PV
Unit of Sale	kWh	kWh	litre	80Ah	pkt	2 x D	kWh
End Use	Elec	Elec	lighting	lighting	lighting	lighting	lighting
Price (kyat)	40	50	1300	133	150	25	150
Gross Energy Content (MJ)	3.6	3.6	45	2.8	20.7	0.04	n.a.
Conversion	90%	90%	11%	100%	2%	100%	n.a.
Useful Energy Cost (kyat/kWh)	44	55	945	171	1304	2250	150
Useful Energy Cost (USD/ kWh)	0.046	0.06	0.98	0.18	1.36	2.34	0.16

Sources: Consultant

Figure II-8: Myanmar's Rural Population by Agriculture (Fuel) Zone



Sources: ADB, Myanmar CSO, USAID/MDRI/CESD

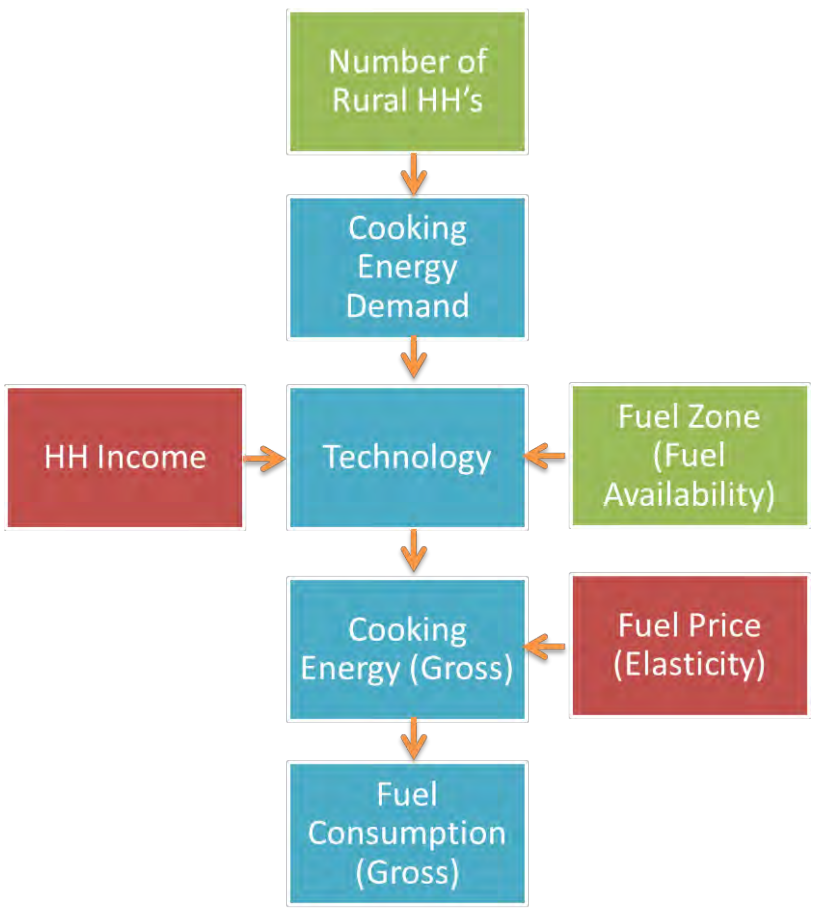
III. RURAL HOUSEHOLD COOKING

F. Cooking Energy Model

19. The modelling of household cooking energy demand depends on a variety of assumptions. The key assumptions are the quantities of fuels used in the daily cooking cycle today, and into the future; the calorific values of fuels in use or expected to be in use; the penetration of cooking appliances according to household income deciles; and the efficiencies of energy conversion by the technologies (useful to final energy).

20. A schematic representation of a household cooking model is shown in Figure III-1. Cost factors influencing energy consumption are shown (red boxes). Inputs of the model are based on the abovementioned assumptions (green boxes). The outputs of the model (blue boxes) are computed by the model algorithms.

Figure III-1: Rural HH Cooking Energy Model Structure



Sources: Consultant

21. To apply the household cooking model requires a cooking appliance classification as shown in Table III-2.

Table III-2: Cooking Appliances & Fuel Type

Item	Cooking Appliance	Fuel Type
1	Open Fire / 3 stone stove	Woody biomass
2	Fuel Efficient Stove	Woody biomass
3	Charcoal Stove	Charcoal
4	Rice Husk Stove	Rice Husks
5	Electric Stove	Electricity
6	Gas Ring	LPG

22. The cooking model requires an inventory of cooking appliances. The Energy Masterplan household survey results were used to establish such an inventory for Urban and Rural areas. These results were then combined with LIFT household survey results to develop estimates of the inventory by income deciles and by fuel zone. Table III-3 and Table III-4 shows the inventory as at 2012, according to the % of common appliances over the total inventory population.

Table III-3: Urban HH Cooking Appliance Inventory by Income (% basis)

Income Decile	Hilly	Dry	Delta/Coastal	Giri
3 stone / open fire		62%	73%	
FES		8%	0%	
Charcoal Stove		12%	12%	
Rice Husk Stove		0%	3%	
Electric		18%	12%	

Table III-4: Rural HH Cooking Appliance Inventory by Income (% basis)

Income Decile	Hilly	Dry	Delta/Coastal	Giri
3 stone / open fire	85%	62%	73%	73%
FES	7%	8%	0%	0%
Charcoal Stove	3%	12%	12%	12%
Rice Husk Stove	0%	0%	3%	3%
Electric	5%	18%	12%	12%

Sources: Consultant' analysis

23. The cooking model also requires knowledge of the daily cooking cycle fuel / energy use. The EMP household survey was used to determine the daily cooking cycle fuel use for Urban and Rural households in 2014. The amount of fuel used for cooking was reported by households in each fuel zone and found to vary between the fuel zones as shown in Table III-5 and Table III-6 respectively.

Table III-5: Urban HH Annual Cook Cycle by Fuel Type

		3 stone / open fire	FES	Charcoal Stove	Rice Husk Stove	Electric	LPG Stove
Hilly	dry mton	-	-	-	-	-	
	MJ	-	-	-	-	-	
Dry	dry mton	2.04	1.43	0.52	0.61	614.41	768
	MJ	31,249	42,891	7,121	2,199	9,400	76,800
Delta / Coastal / Giri	dry mton	1.50	1.05	1.20	0.61	737.29	768
	MJ	22,950	31,500	16,497	2,199	11,281	76,800

Table III-6: Rural HH Annual Cook Cycle by Main Fuel Type

		3 stone / open fire	FES	Charcoal Stove	Rice Husk Stove	Electric	LPG Stove
Hilly	dry mton	1.64	1.15	0.26	0.61	224.00	365
	MJ	25,153	34,524	3,643	2,199	3,427	36,500
Dry	dry mton	2.40	1.68	0.52	0.61	224.00	365
	MJ	36,720	50,400	7,121	2,199	3,427	36,500
Delta / Coastal / Giri	dry mton	1.02	0.71	0.26	0.61	224.00	365
	MJ	15,606	21,420	3,643	2,199	3,427	36,500

Sources: EMP HH Survey, Consultant

24. The energy estimates (MJ) appearing in these tables were based on the gross calorific values of cooking fuels as listed in Table III-7.

Table III-7: Gross Calorific Values of Energy Carriers

Fuel wood		
3 stone stove (firewood)	15.3	MJ / kg
FES (firewood)	15.3	MJ / kg
Charcoal	30	MJ / kg
Agricultural Residue		
Pigeon Pea Stalk	18.6	MJ / kg
Cotton Stalk	18.1	MJ / kg
Sesame Stalk	19.1	MJ / kg
Coconut or Palm leaves	18.3	MJ / kg
Rice Husk	13.8	MJ / kg
Sawdust	18.1	MJ / kg
Bamboo	19.5	MJ / kg
Other		
LPG Gas	100	MJ / m3
Biogas (digester)	24.9	MJ / m3
Electricity	3.6	MJ/ kWh

Sources: UK Digest of Energy Statistics, Agriculture Research Institutes

G. Cooking Energy Demand Model Calibration

25. The assumptions outlined in the preceding section, along with population estimates, were used to generate baseline cooking fuel and energy use estimates by fuel zone and by income decile. Fuel stacks were developed on energy consumption basis to test the validity of the model.

26. Figure III-9 shows that the penetration of commercial fuels in the higher income deciles in the urban areas is significant compared to the penetration in rural areas that is shown in Figure III-10.

27. The cooking energy measured in toe per household is 0.52 per Urban household and 0.60 per Rural household. These figures show the expected relative difference and compare well to international benchmarks for rural cooking energy consumption.

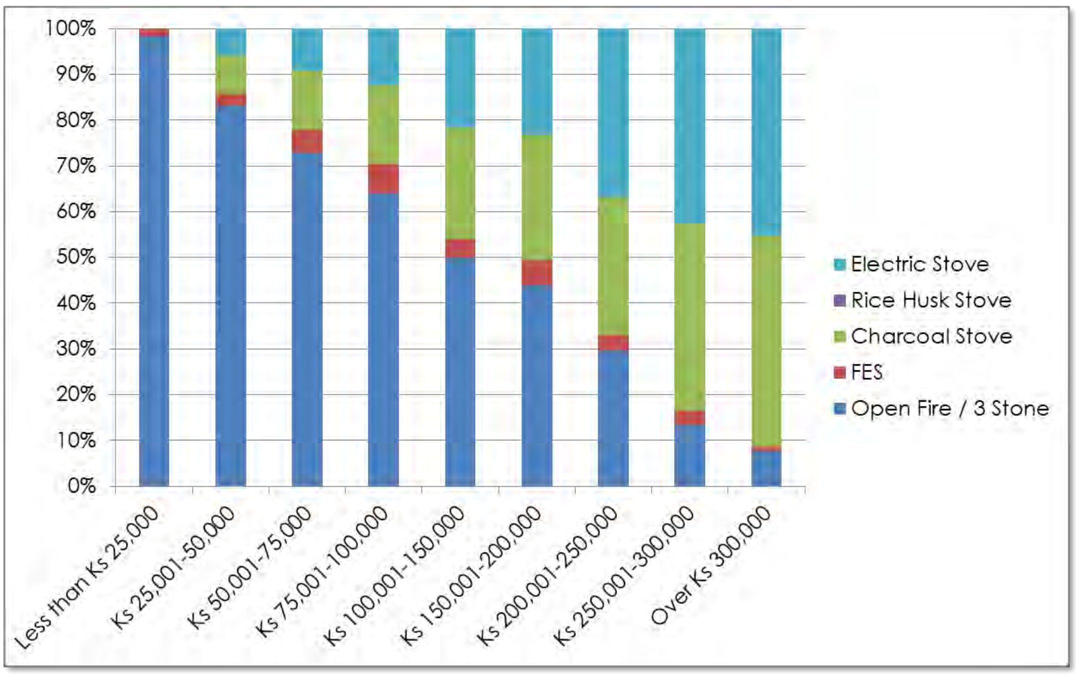
28. Estimates of the household cooking final energy consumption (FEC) in 2012-13 are given in the following table:

Table III-8: Household Cooking FEC by Fuel Zone: 2012-13

	Urban	Rural
	ktoe	ktoe
Hilly Zone	-	2,203
Dry Zone	242	3,714
Coastal/Delta Zone	770	1,178
Giri Zone	-	122
Total	1,012	7,217

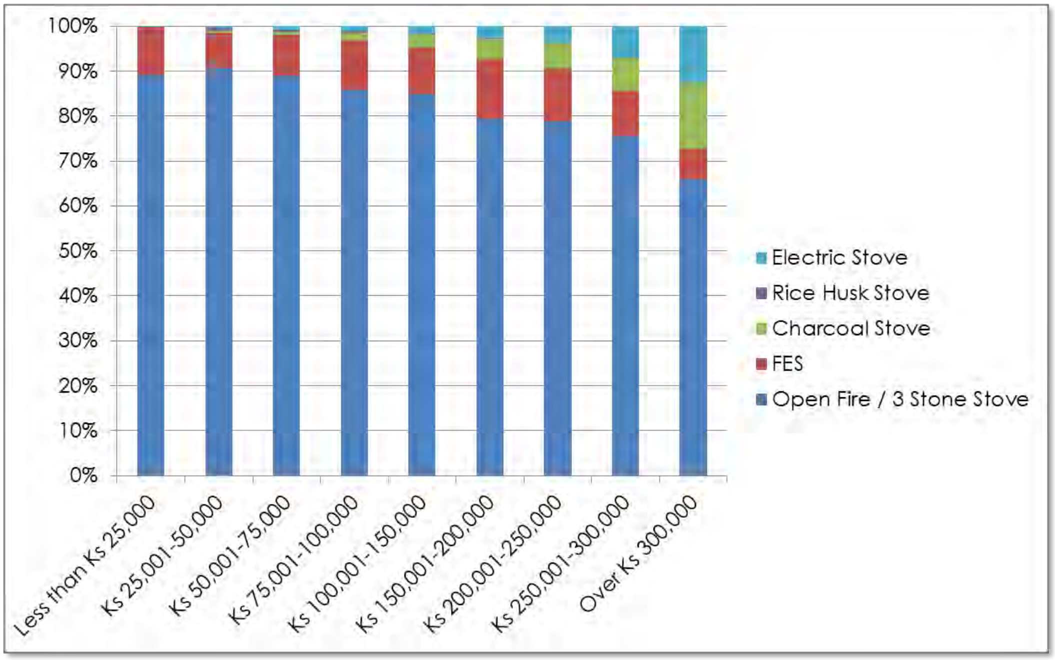
Sources: Consultant

Figure III-9: Urban HH Cooking Fuel Stack (% Energy Use)



Sources: Consultant

Figure III-10: Rural HH Cooking Fuel Stack (% Energy Use)



Sources: Consultant

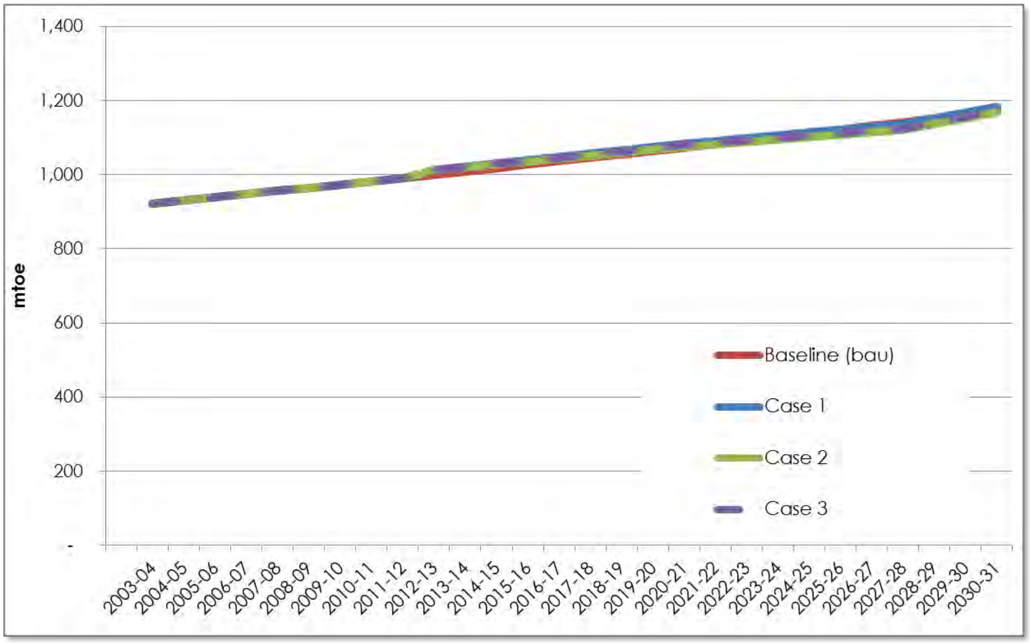
H. Final Energy Consumption Projections for HH Cooking

29. The projection of the final energy consumption for household cooking was made from the baseline year of 2012-13. The projections take into account the rate at which household income increases over time, the change in population and the impact of grid electrification. More specifically assumptions common to all planning cases were 1) the rate of income growth was assumed to be 4% real on long-term basis, and 2) the population growth was assumed at a fixed rate of 1% per annum.

30. A reference case assumed no change to the basic pattern of cooking fuel and appliance use, i.e. electricity grid subscription was taken to grow at the historical rate. Three cases were modelled according to national rural electrification targets as follows:-

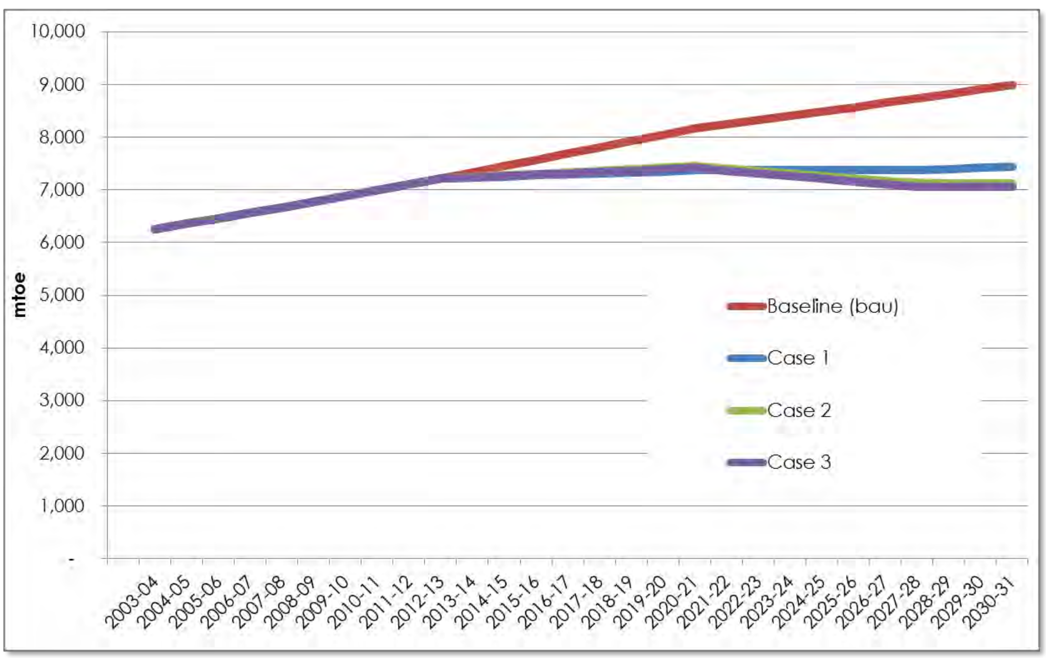
1. Assumption 81% grid electrification is reached by 2030;
2. Assumption 87% grid electrification is reached by 2030; and
3. Assumption 96% grid electrification is reached by 2030.

Figure III-11: Urban HH Cooking Final Energy Use



Sources: Consultant

Figure III-12: Rural HH Cooking Final Energy Use



Sources: Consultant

31. The HH cooking model demonstrates that the Urban household projections are not greatly affected by electrification. This is to be expected as electrification is already advanced in the Urban area. The final energy consumption grows in line with the population. The Rural household projections show a reduction in energy consumption compared to a business as usual case. The difference in electrification between each case is not so marked that there is a substantial difference in energy efficiency between the cases.

Table III-13: HH Cooking FEC Projections (mtoe) (Case 2)

	2012	2015	2018	2021	2024	2027	2030	CAGR
3 stone	6.701	6.742	6.783	6.746	6.554	6.362	6.173	-0.6%
FES	0.668	0.692	0.716	0.726	0.706	0.686	0.667	-0.2%
Charcoal Stove	0.194	0.187	0.180	0.173	0.163	0.153	0.146	-1.6%
Rice Husk Stove	0.025	0.017	0.010	0.006	0.006	0.005	0.005	-8.0%
Electric Stove	0.152	0.209	0.266	0.344	0.465	0.586	0.563	6.6%
LPG Stove	0.042	0.037	0.032	0.028	0.025	0.021	0.020	-4.0%
Biogas Stove	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0%
Pigeon Pea Stalk	0.217	0.221	0.224	0.225	0.219	0.213	0.207	-0.4%
Cotton Stalk	0.043	0.043	0.044	0.044	0.043	0.042	0.041	-0.4%
Sesame Stalk	0.117	0.119	0.121	0.121	0.118	0.115	0.112	-0.4%
Coconut or Palm leaves	0.053	0.054	0.055	0.055	0.054	0.052	0.051	-0.4%
Sawdust	0.006	0.007	0.007	0.007	0.007	0.006	0.006	-0.4%
Bamboo	0.012	0.012	0.012	0.012	0.012	0.012	0.011	-0.4%
Total	8.229	8.340	8.452	8.487	8.371	8.254	8.003	-0.3%

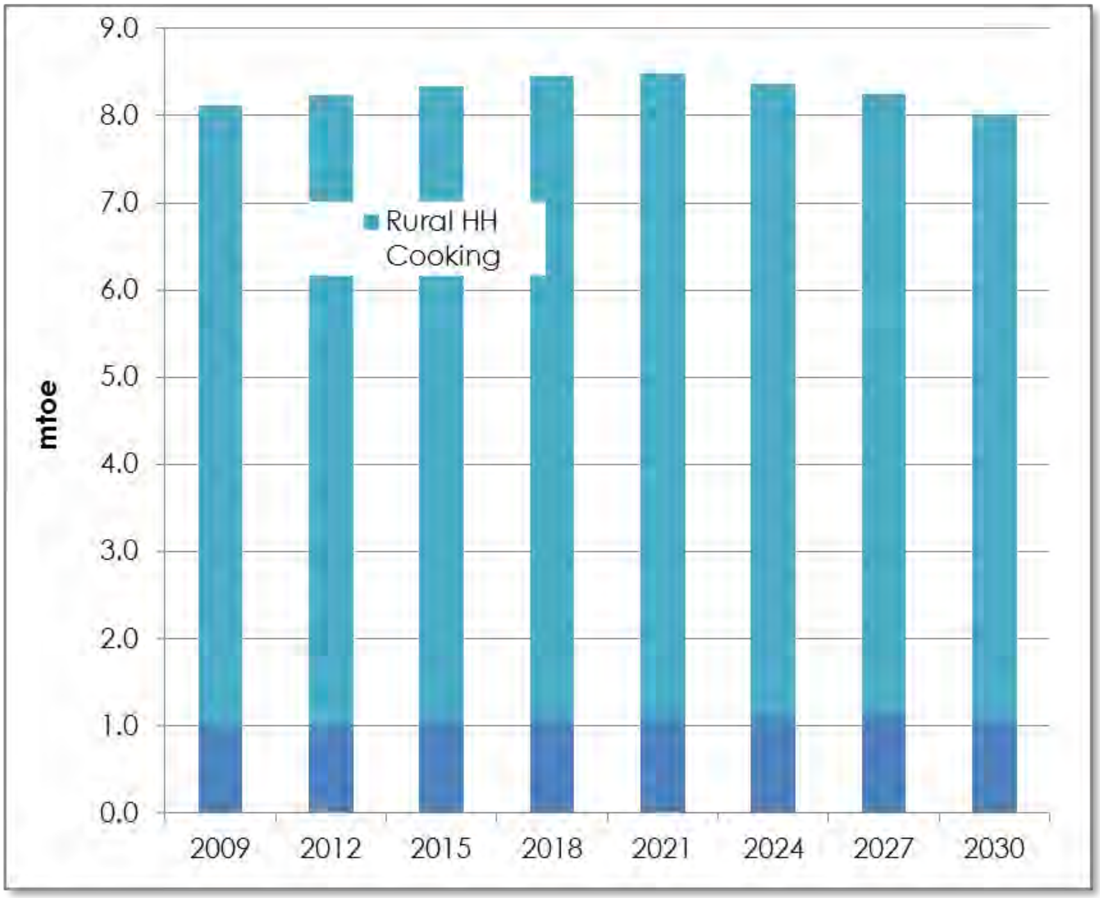
Sources: Consultant

Table III-14: Cooking Fuel Carrier Projections (physical) (Case 2)

		2012	2015	2018	2021	2024	2027	2030	CAGR
3 stone	tons	2,034,814	2,027,474	1,995,111	1,912,701	1,802,822	1,767,864	1,732,905	-1.0%
FES	tons	52,160	52,563	52,503	51,517	50,203	50,160	50,116	-0.3%
Charcoal Stove	tons	363,590	368,649	365,336	345,282	318,542	315,475	312,407	-1.1%
Rice Husk Stove	tons	204	122	67	65	63	61	60	-4.8%
Electric Stove	GWh	573	730	931	1,221	1,608	1,898	2,187	7.3%
LPG Stove	mcm	15	14	12	11	9	9	9	-2.8%
Biogas Stove	tons	0	0	0	0	0	0	0	0.0%
Pigeon Pea Stalk	tons	13,811	13,834	13,757	13,478	13,106	13,047	12,987	-0.4%
Cotton Stalk	tons	2,786	2,791	2,776	2,719	2,644	2,632	2,620	-0.4%
Sesame Stalk	tons	7,269	7,281	7,240	7,094	6,898	6,867	6,835	-0.4%
Coconut / Palm	tons	3,453	3,459	3,439	3,370	3,277	3,262	3,247	-0.4%
Sawdust	tons	424	425	422	414	402	401	399	-0.4%
Bamboo	tons	727	728	724	709	690	687	684	-0.4%

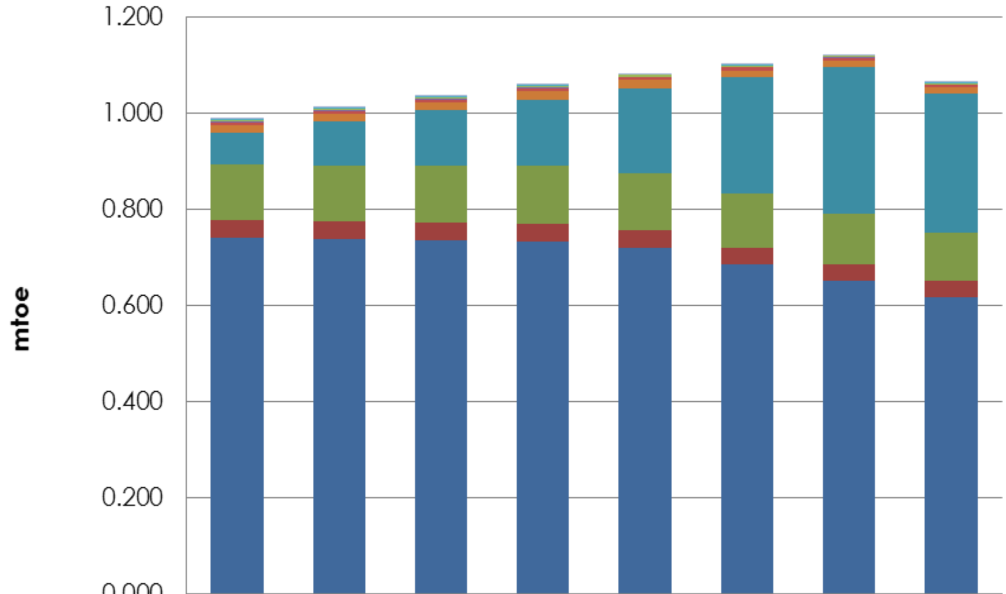
Sources: Consultant

Figure III-15: Final Energy Use Projections for Household Cooking (Case 2)



Sources: ADB Consultant

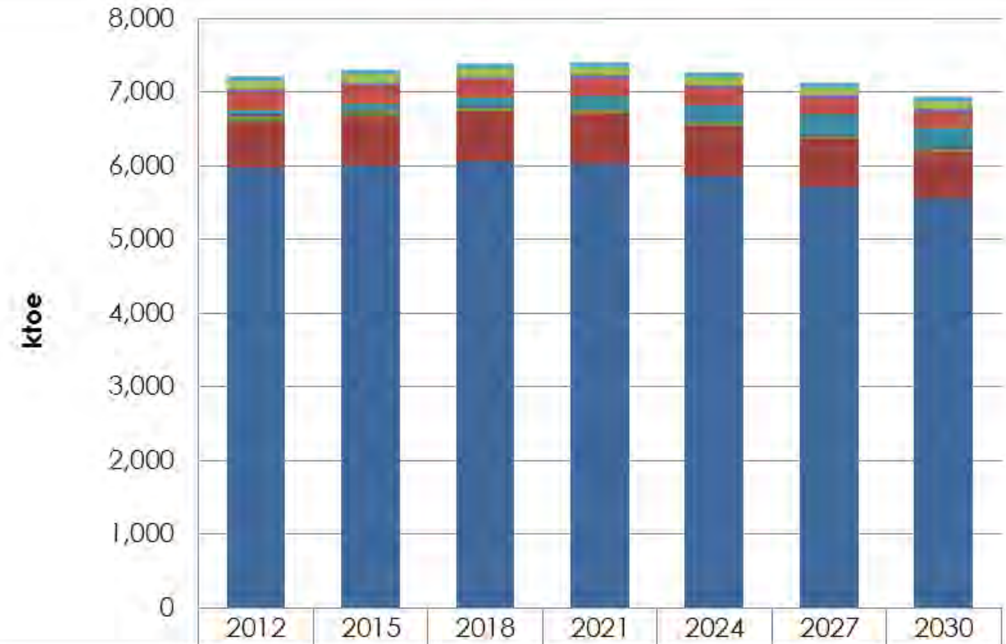
Figure III-16: Urban HH Cooking Energy Carrier Projections to 2030 (Case 2)



	2009	2012	2015	2018	2021	2024	2027	2030
Bamboo	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sawdust	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Coconut or Palm leaves	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Sesame Stalk	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Cotton Stalk	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Pigeon Pea Stalk	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005
Biogas Stove	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LPG Stove	0.017	0.017	0.018	0.018	0.017	0.015	0.014	0.013
Electric Stove	0.066	0.091	0.115	0.139	0.177	0.241	0.306	0.291
Rice Husk Stove	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Charcoal Stove	0.116	0.118	0.119	0.121	0.120	0.112	0.105	0.099
FES	0.036	0.036	0.037	0.037	0.037	0.036	0.035	0.033
3 stone	0.741	0.738	0.735	0.733	0.719	0.685	0.651	0.618

Sources: Consultant

Figure III-17: Rural HH Cooking Energy Carrier Projections to 2030 (Case 2)



	2012	2015	2018	2021	2024	2027	2030
Bamboo	11.6	11.8	12.0	12.1	11.8	11.5	11.1
Sawdust	6.3	6.4	6.5	6.5	6.4	6.2	6.0
Coconut or Palm leaves	51.9	52.8	53.7	53.8	52.5	51.1	49.7
Sesame Stalk	114.1	116.0	118.0	118.3	115.3	112.3	109.2
Cotton Stalk	41.4	42.2	42.9	43.0	41.9	40.8	39.7
Pigeon Pea Stalk	211.1	214.7	218.4	218.9	213.3	207.7	202.1
Biogas Stove	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LPG Stove	24.2	19.4	14.5	10.7	9.2	7.7	7.5
Electric Stove	61.2	94.0	126.7	167.3	223.5	279.8	272.1
Rice Husk Stove	24.5	17.5	10.5	5.7	5.6	5.4	5.3
Charcoal Stove	75.9	67.6	59.3	52.9	50.6	48.2	46.9
FES	631.4	655.4	679.4	689.1	670.1	651.1	633.4
3 stone	5,962.8	6,006.7	6,050.6	6,027.2	5,868.9	5,710.6	5,555.2

Sources: Consultant

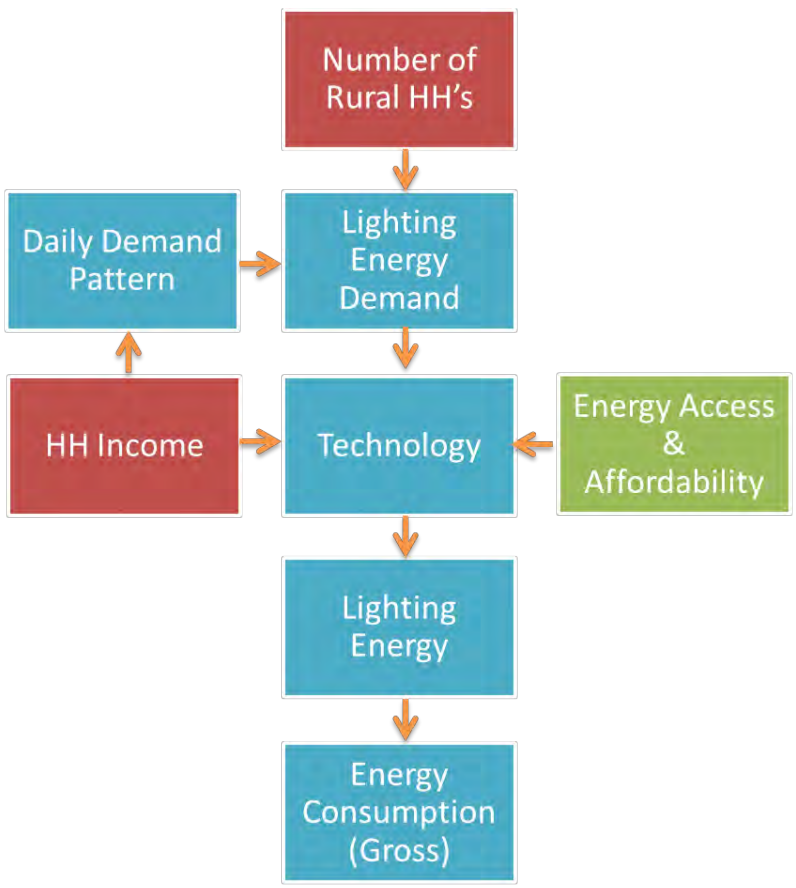
IV. HOUSEHOLD LIGHTING

I. Lighting Energy Model

32. Several distinct elements are included in the rural household lighting model used for energy demand planning. These are the fuels known to be available and in use today or expected to be in use in the future, the calorific values of said fuels, the lighting technologies, the energy used by technology, rural household income deciles by fuel zone and by population, the rural household populations by fuel zone and the average family size. Furthermore where technologies / fuels are known to be absent from a particular fuel zone, and likely to remain so, they are excluded from the model for that zone.

33. A schematic representation of the rural household lighting model and its inputs (green boxes) is shown in Figure IV-1. Factors influencing energy consumption are shown as drivers (red boxes). The outputs of the model (blue boxes) are computed by the model algorithms.

Figure IV-1: Household Lighting Energy Model Structure



Sources: International Planning Agencies, ADB Consultant

34. To apply the household cooking model requires a cooking appliance classification as shown in Table IV-2.

Table IV-2: Lighting Appliance

Item	Cooking Technology	Energy Supply	Model ID*
1	Battery / LED 1W	Battery	BL
2	Candle	Paraffin	C
3	Compact Fluorescent 20W	Electricity	CFL
4	Wick Lamp	Diesel	D
5	Fluorescent 10W	Electricity	F
6	Incandescent 20W	Electricity	I
7	Wick Lamp	Paraffin	P
8	Solar Battery Lantern 15W	Sun / Battery	SHS1
9	Solar Battery Lantern 20W	Sun / Battery	SHS2
* These technology IDs are used in all charts and tables			

Sources: Consultant

35. The lighting model requires an inventory of cooking appliances. The Energy Masterplan household survey results were used to establish such an inventory for Urban and Rural areas. These results were then combined with LIFT household survey results to develop estimates of the inventory by income deciles and by fuel zone. Table IV-3 and Table IV-4 shows the inventory as at 2012, according to the % of common appliances over the total inventory population.

Table IV-3: Urban Lighting Appliance Counts

	Electric Lights			Lamp	Candles	Others
	Fluoro	Incandescent	CFL	Diesel Oil	Paraffin	Battery LED
Less than Ks 25,000	24,028	5,875	5,875	2,853	72,750	11,395
Ks 25,001-50,000	130,149	35,597	44,496	10,671	280,513	46,712
Ks 50,001-75,000	100,911	31,054	44,362	7,845	167,649	29,717
Ks 75,001-100,000	86,300	29,204	45,632	5,314	98,097	15,036
Ks 100,001-150,000	62,644	22,147	36,912	2,078	68,407	10,807
Ks 150,001-200,000	35,805	13,210	25,686	1,337	12,047	5,217
Ks 200,001-250,000	15,531	6,631	13,262	573	4,821	897
Ks 250,001-300,000	10,650	5,231	10,700	390	6,461	2,418
Over Ks 300,000	30,724	17,599	35,931	434	137,807	1,515
	496,743	166,548	262,856	31,497	848,551	123,714

Source: EMP HH Survey, LIFT 2012

Table IV-4: Rural Lighting Appliance Counts

	Electric Lights			Lamp	Candles	Others
	Fluoro	Incandescent	CFL	Diesel Oil	Paraffin	Battery LED
Less than Ks 25,000	73,367	40,267	32,467	130,289	391,806	150,448
Ks 25,001-50,000	281,062	127,855	102,168	456,426	1,025,784	417,195
Ks 50,001-75,000	243,659	130,679	97,994	190,911	732,140	278,715
Ks 75,001-100,000	219,014	118,142	92,901	86,423	476,670	138,699
Ks 100,001-150,000	124,114	63,752	44,950	38,698	269,695	69,548
Ks 150,001-200,000	88,709	52,490	35,445	16,355	61,030	38,519
Ks 200,001-250,000	39,256	24,271	14,306	8,456	21,378	6,003
Ks 250,001-300,000	30,693	18,533	11,111	4,811	27,915	15,364
Over Ks 300,000	72,083	32,213	21,162	5,752	399,659	6,528
	1,171,958	608,200	452,505	938,121	3,406,078	1,121,021

Source: EMP HH Survey, LIFT 2012

36. The Energy Masterplan household survey results were used to establish the hours of use of lighting appliances in Urban and Rural areas. Again the results were then combined with LIFT household survey results to develop estimates of the daily hours of use of lighting by income deciles.

Table IV-5: Household Lighting Appliance Daily Hours of Use

Income Decile	Hours of Use per Day
Less than Ks 25,000	2.76
Ks 25,001-50,000	3.25
Ks 50,001-75,000	3.43
Ks 75,001-100,000	3.51
Ks 100,001-150,000	4.04
Ks 150,001-200,000	4.32
Ks 200,001-250,000	4.51
Ks 250,001-300,000	5.25
Over Ks 300,000	5.75

Source: EMP HH Survey

37. The power and consumption of energy carriers supplying lighting are provided in Table IV-6.

Table IV-6: Power / Consumption of Energy Carriers

Fuel / Technology Characteristics				
BL	1	Watt	3600	kJ per kWh
C	2.25	gms per hour	42.0	kJ per gram
CFL	20	Watt	3600	kJ per kWh
D	10	ml per hour	38.0	kJ per ml
F	10	Watt	3600	kJ per kWh
I	20	Watt	3600	kJ per kWh
P	10	ml per hour	37.2	kJ per ml
SHS1	15	Watts	3600	kJ per kWh
SHS2	20	Watts	3600	kJ per kWh

Sources: UK Digest of Energy Statistics, Agriculture Research Institutes

J. Lighting Energy Demand Model Calibration

38. The assumptions outlined in the preceding section, along with population estimates, were used to generate baseline cooking fuel and energy use estimates by fuel zone and by income decile. Fuel stacks were developed on energy consumption basis to test the validity of the model.

39. Figure IV-8 shows that the penetration of commercial fuels in the higher income deciles in the urban areas is far more significant compared to the penetration in rural areas that is shown in Figure IV-9.

40. The lighting energy measured in toe per household is 0.0021 per Urban household and 0.0022 per Rural household. As a result of energy poverty, the total lighting energy consumption in 2012-13 is most certainly insufficient to meet a minimum level of illumination required for task-based lighting such as reading. A typical Western standard for illumination for reading is 300 lux, whereas the average illumination level in the majority of Myanmar rural households is of the order of 10 lux. As a matter of energy policy the target demand for lighting services should be set according to a minimum standard of illumination. A suitable long-term intermediate illumination target for rural households in Myanmar is 160 lux. This level of illumination can be met with a 1 watt LED lamp fitted with a polycarbonate lens or by grid-connected lighting.

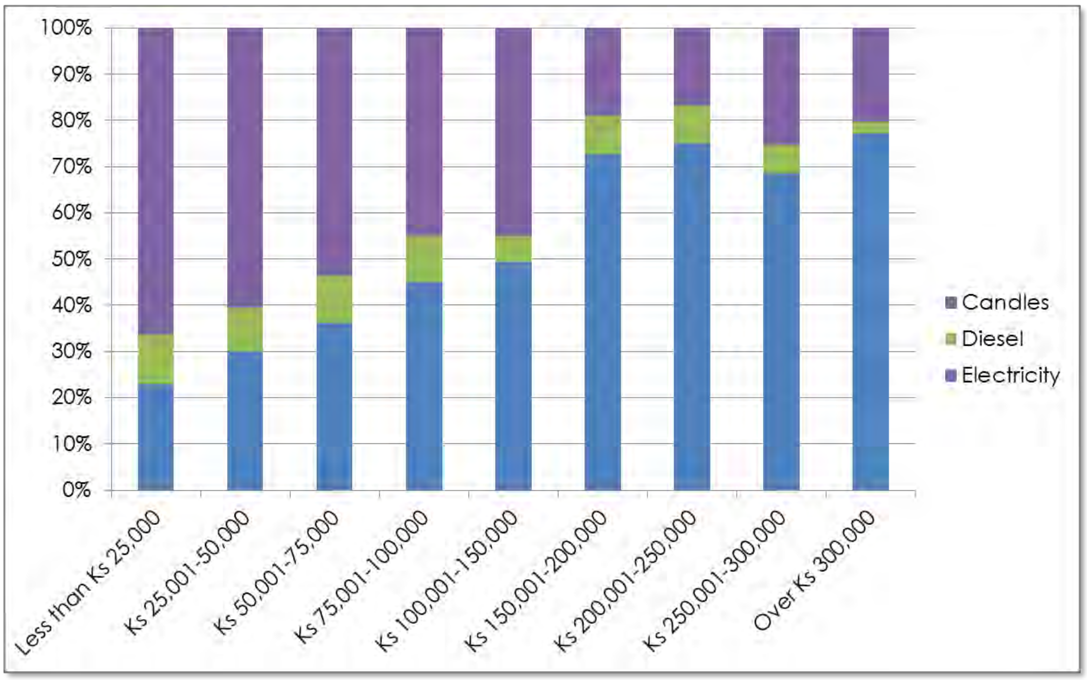
41. Estimates of the household lighting final energy consumption (FEC) in 2012-13 are given in the following table:-

Table IV-7: HH Lighting Final Energy Use by Fuel Zone

	Urban	Rural
	ktoe	ktoe
Hilly Zone	-	7.5
Dry Zone	0.9	8.2
Coastal/Delta Zone	3.3	8.9
Total	4.3	24.6

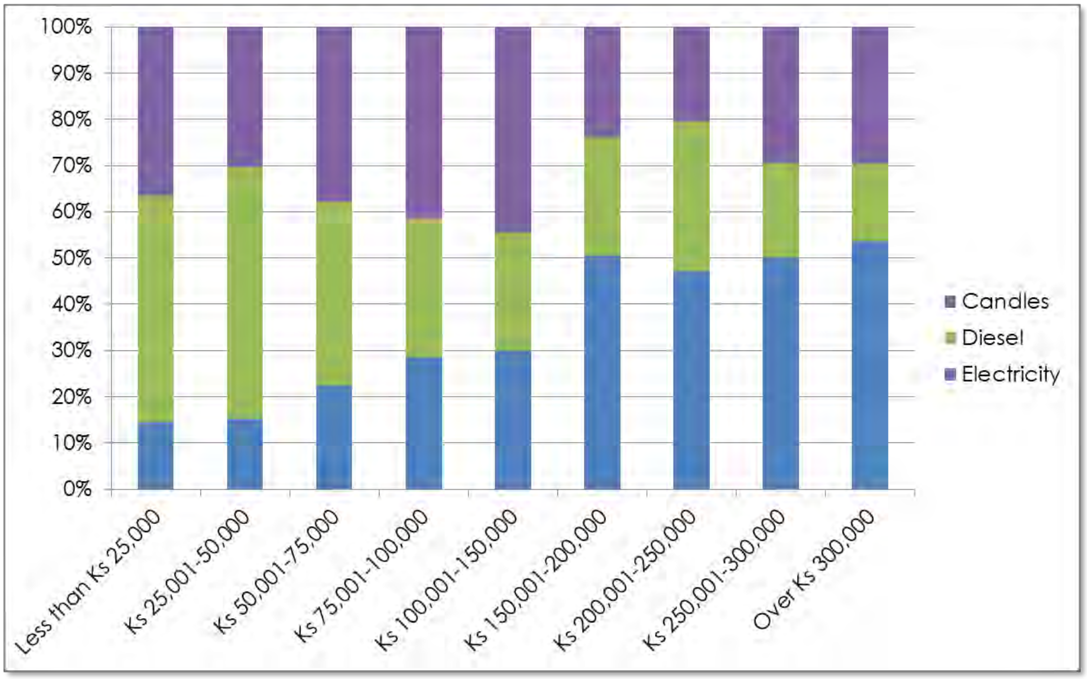
Sources: Consultant

Figure IV-8: Modelled Urban HH Lighting Fuel Stack (Final Energy)



Sources: Consultant

Figure IV-9: Modelled Rural HH Lighting Fuel Stack (Final Energy)



Sources: Consultant

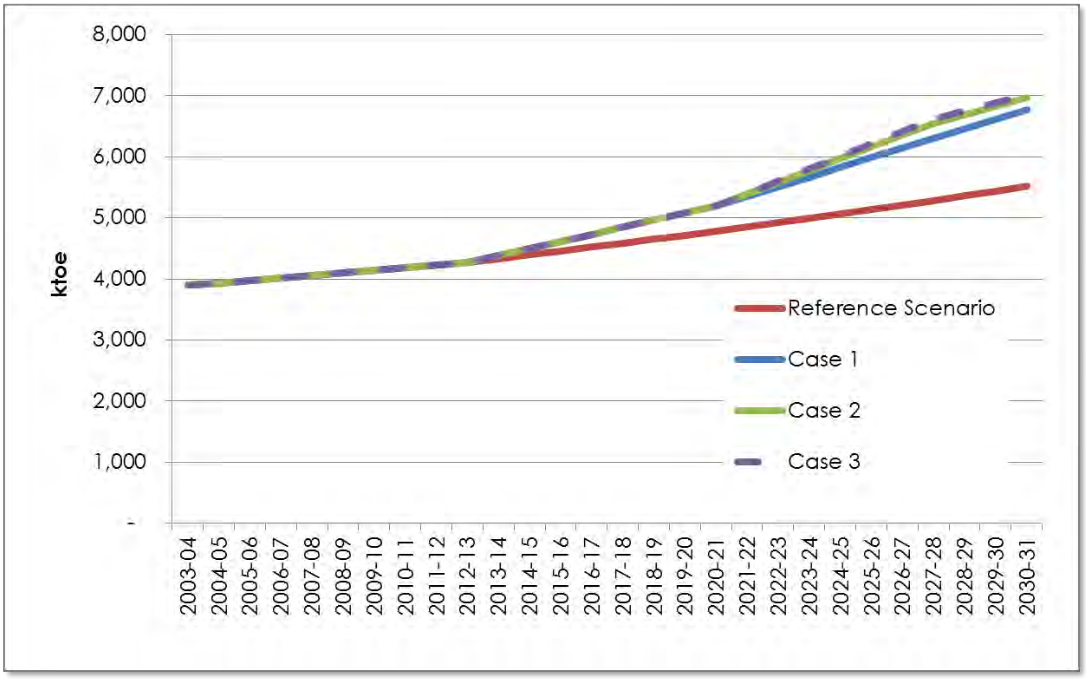
K. Final Energy Consumption Projections for HH Lighting

42. The projection of the final energy consumption for household lighting was made from the baseline year of 2012-13. The projections take into account the rate at which household income increases over time, the change in population and the impact of grid electrification. More specifically assumptions common to all planning cases were 1) the rate of income growth was assumed to be 4% real on long-term basis, and 2) the population growth was assumed at a fixed rate of 1% per annum.

43. A reference case assumed no change to the basic pattern of lighting fuel and appliance use, i.e. electricity grid subscription was taken to grow at the historical rate. Three alternative cases were also defined according to national rural electrification targets as follows:-

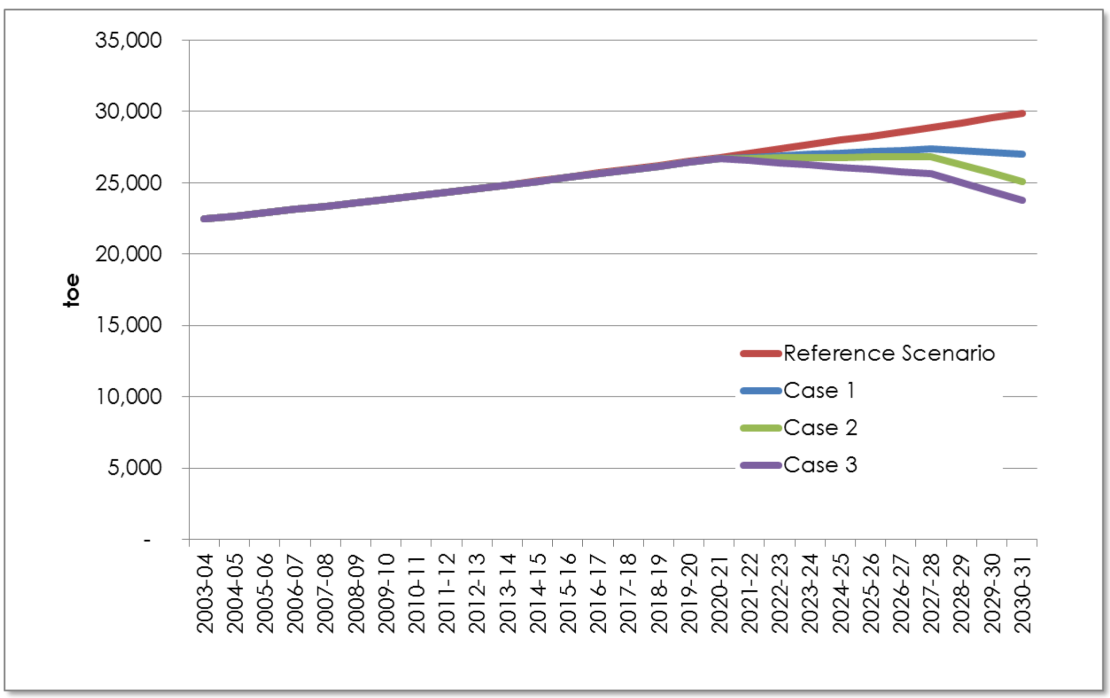
1. Assumption 81% grid electrification is reached by 2030;
2. Assumption 87% grid electrification is reached by 2030; and
3. Assumption 96% grid electrification is reached by 2030.

Figure IV-10: Urban HH Lighting Final Energy Use



Sources: Consultant

Figure IV-11: Rural HH Lighting Final Energy Use



Sources: Consultant

44. The Urban lighting cases 1 to 3 show an increased energy consumption trajectory compared to the business as usual case. This is due to an accelerated electrification rate and population growth. The energy efficiency of lighting in the Rural sector improves as candles and oil lamps are replaced by grid lighting. The greater the extent of rural electrification, the greater the extent of the efficiency gain, despite the increasing population.

Table IV-12: Urban HH Lighting FEC Projections (mtoe) (Case 2)

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR
Electricity	0.00160	0.00185	0.00214	0.00243	0.00271	0.00368	0.00465	0.00553	6.3%
Diesel	0.00036	0.00036	0.00037	0.00037	0.00037	0.00033	0.00029	0.00021	-3.9%
Candles	0.00203	0.00205	0.00207	0.00209	0.00211	0.00186	0.00161	0.00124	-3.4%
Total	0.0040	0.0043	0.0046	0.0049	0.0052	0.0059	0.0065	0.0070	2.8%

Sources: Consultant

Table IV-13: Rural HH Lighting FEC Projections (mtoe) (Case 2)

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR
Electricity	0.0052	0.0057	0.00618	0.00668	0.00717	0.00912	0.01106	0.01284	4.9%
Diesel	0.0102	0.0103	0.01042	0.01052	0.01062	0.00983	0.00905	0.00730	-2.4%
Candles	0.0085	0.0086	0.00868	0.00879	0.00890	0.00770	0.00650	0.00538	-3.2%
Total	0.0239	0.0246	0.0253	0.0260	0.0267	0.0267	0.0266	0.0255	0.1%

Sources: Consultant

Table IV-14: Urban Lighting Fuel Carrier Projections (physical) (Case 2)

		2012	2015	2018	2021	2024	2027	2030	CAGR
Electricity	GWh	21.6	25.0	28.3	31.6	43.0	54.3	64.5	6.3%
Diesel	litres	399,382	404,126	408,870	413,614	364,797	315,980	227,724	-3.8%
Candles	tons	2,050	2,070	2,090	2,110	1,861	1,611	1,241	-3.4%

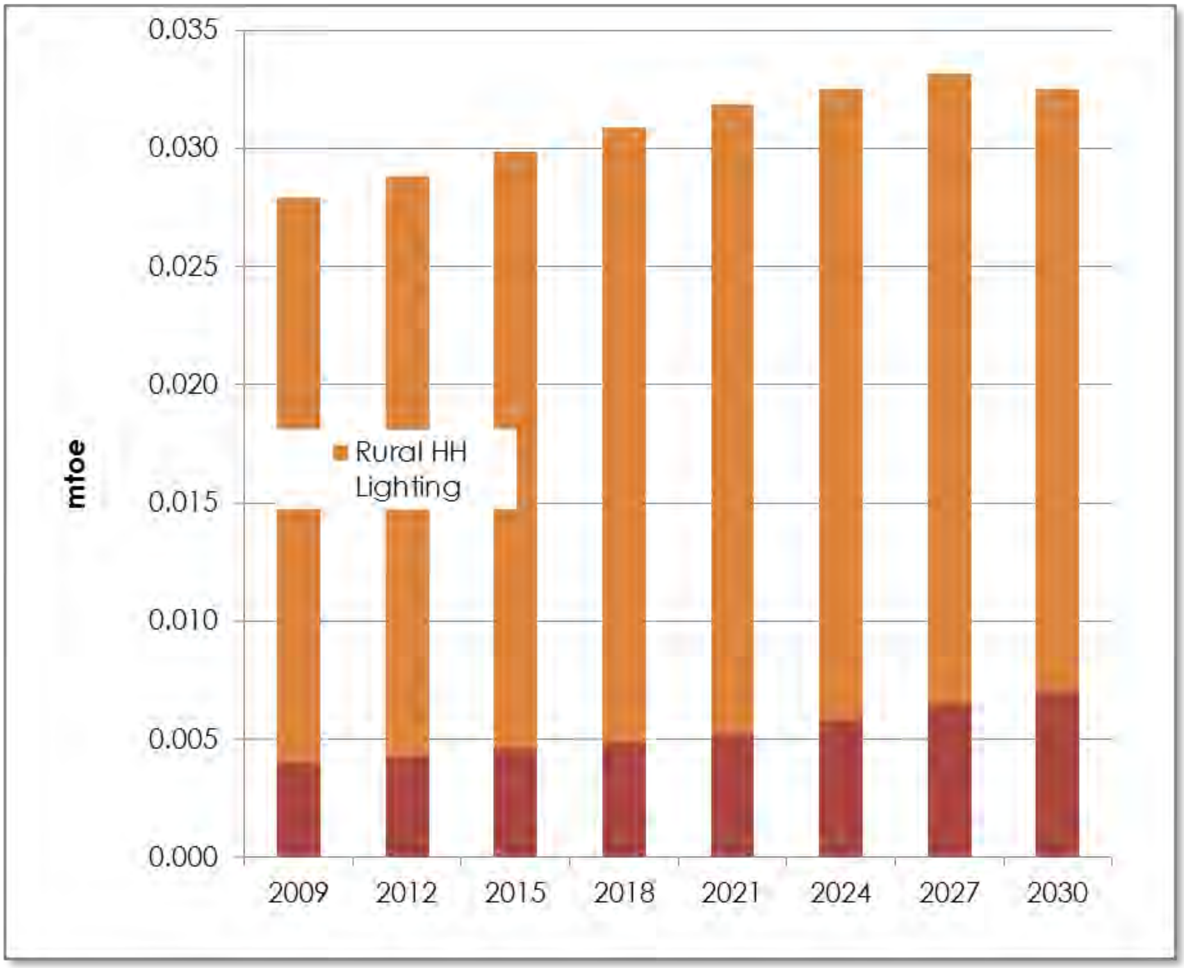
Sources: Consultant

Table IV-15: Rural Lighting Fuel Carrier Projections (physical) (Case 2)

		2012	2015	2018	2021	2024	2027	2030	CAGR
Electricity	GWh	66.4	72.1	77.9	83.7	106.4	129.1	149.9	4.9%
Diesel	litres	11,404,846	11,515,774	11,626,703	11,737,632	10,869,991	10,002,351	8,063,712	-2.4%
Candles	tons	8,565.2	8,678.4	8,791.7	8,905.0	7,702.7	6,500.4	5,381.2	-3.2%

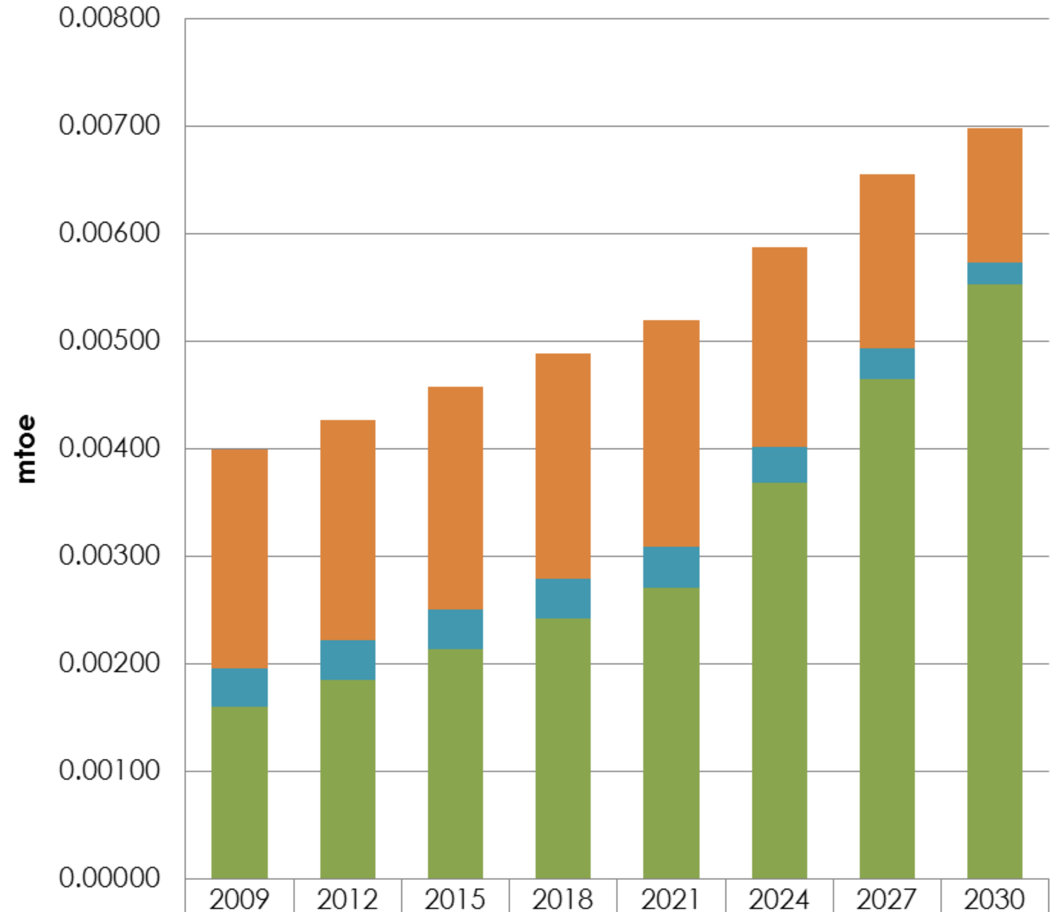
Sources: Consultant

Figure IV-16: Final Energy Use Projections for Household HH Lighting (Case 2)



Sources: ADB Consultant

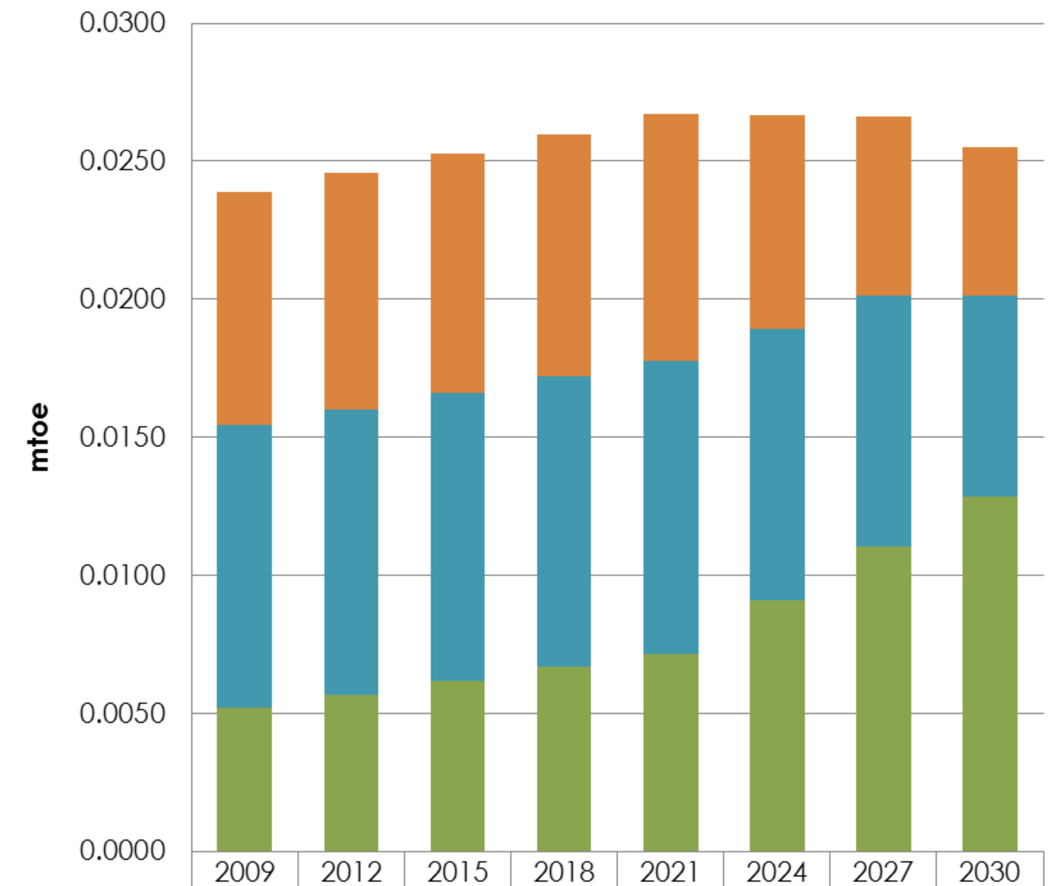
Figure IV-17: Urban HH Lighting Energy Carrier Projections to 2030 (Case 2)



	2009	2012	2015	2018	2021	2024	2027	2030
Candles	0.00203	0.00205	0.00207	0.00209	0.00211	0.00186	0.00161	0.00124
Diesel	0.00036	0.00036	0.00037	0.00037	0.00037	0.00033	0.00029	0.00021
Electricity	0.00160	0.00185	0.00214	0.00243	0.00271	0.00368	0.00465	0.00553

Sources: Consultant

Figure IV-18: Rural HH Lighting Energy Carrier Projections to 2030 (Case 2)



	2009	2012	2015	2018	2021	2024	2027	2030
Candles	0.0085	0.0086	0.0086	0.0087	0.0089	0.0077	0.0065	0.0053
Diesel	0.0102	0.0103	0.0104	0.0105	0.0106	0.0098	0.0090	0.0073
Electricity	0.0052	0.0057	0.0061	0.0066	0.0071	0.0091	0.0110	0.0128

Sources: Consultant

V. OTHER HOUSEHOLD ENERGY USE

L. Introduction

45. Other household energy use falls into two categories – TV / entertainment and Cooling Services. TV / Entertainment end-use has been modelled using a similar approach to that used for household lighting. Cooling services includes cooling fans, air-conditioning and refrigeration. Due to paucity of data, cooling service end-use has been modelled as a net energy consumption where the net represents the difference between the total residential electricity consumption reported by YESB and ESE, and the total residential electricity use estimated for cooking, lighting and TV / entertainment. In this way there is consistency maintained between the 'bottom-up' electricity end-use estimates and the top-down electricity sales. The net energy consumption is validated by computing the equivalent cooling service given by the average net electricity consumption per Urban and Rural household, and by comparison of the toe per household between segments and across segments, particularly between lighting and cooling services.

M. TV / Entertainment

46. The estimate of energy consumption of TV / Entertainment category requires an inventory of appliances. The Energy Masterplan household survey results were used to establish such an inventory for Urban and Rural areas. These results were then combined with LIFT household survey results to develop estimates of the inventory by income deciles and by fuel zone. Table IV-3 shows the inventory as at 2012, according to the % of common appliances over the total inventory population.

Table V-1: TV / Entertainment Appliance Counts

	Urban	Rural
Less than Ks 25,000	81,376	14,798
Ks 25,001-50,000	87,935	20,622
Ks 50,001-75,000	129,751	27,628
Ks 75,001-100,000	141,177	19,595
Ks 100,001-150,000	240,045	22,629
Ks 150,001-200,000	156,638	41,880
Ks 200,001-250,000	315,360	53,136
Ks 250,001-300,000	291,834	67,523
Over Ks 300,000	300,001	63,614
	1,744,116	331,426

Source: EMP HH Survey, LIFT 2012

47. The Energy Masterplan household survey results were used to establish the hours spent watching TV (on appliance basis) in Urban and Rural areas. Again the results were combined with LIFT household survey results to develop estimates of the daily hours of use of lighting by income deciles.

Table V-2: Household Lighting Appliance Daily Hours of Use

Income Decile	Hours of Use per Day
Less than Ks 25,000	1.5
Ks 25,001-50,000	2
Ks 50,001-75,000	2.5
Ks 75,001-100,000	2.5
Ks 100,001-150,000	3
Ks 150,001-200,000	3
Ks 200,001-250,000	3
Ks 250,001-300,000	3
Over Ks 300,000	3

Source: EMP HH Survey

48. The power rating of a typical TV / entertainment system was determined to be 80W. Estimates of the household lighting final energy consumption (FEC) in 2012-13 are given in the following table:-

Table V-3: Final Energy Use by Fuel Zone

	Urban	Rural
	GWh	GWh
Hilly Zone	-	5.415
Dry Zone	0.466	4.899
Coastal/Delta Zone	2.686	12.088
Total	3.152	22.402

Sources: Consultant

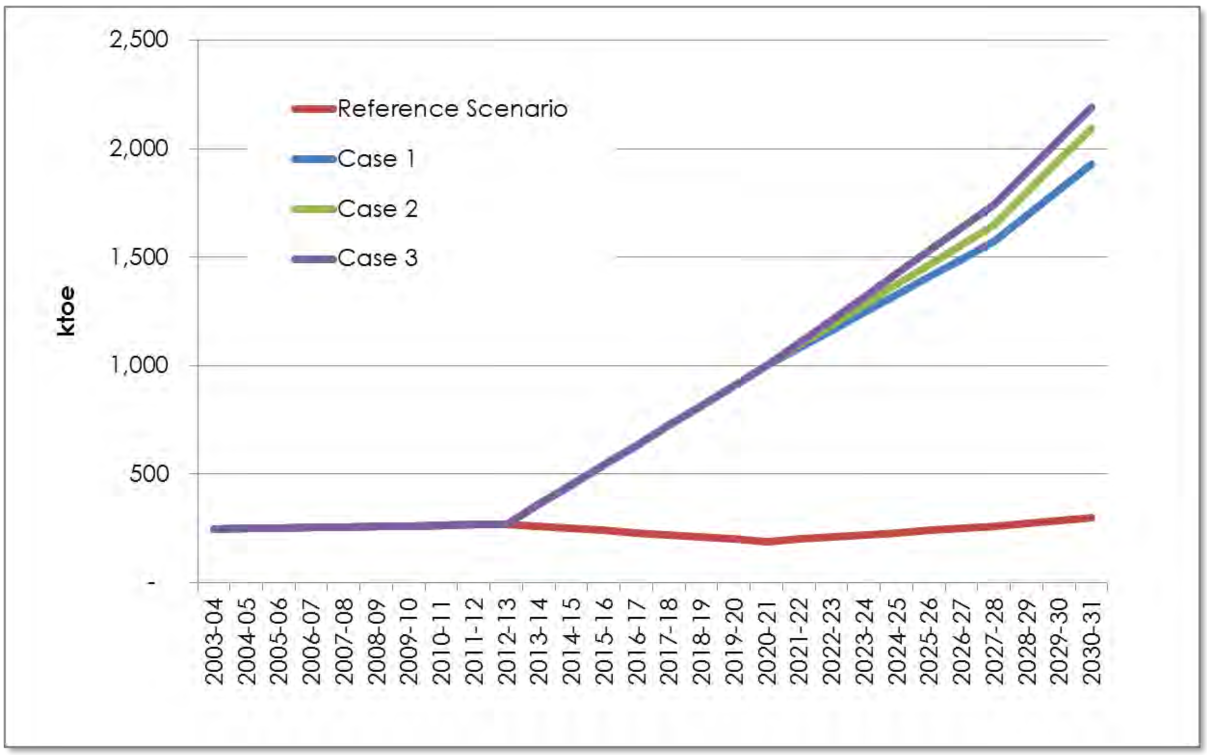
N. Final Energy Consumption Projections for HH Lighting

49. The projection of the final energy consumption for household lighting was made from the baseline year of 2012-13. The projections take into account the rate at which household income increases over time, the change in population and the impact of grid electrification. More specifically assumptions common to all planning cases were 1) the rate of income growth was assumed to be 4% real on long-term basis, and 2) the population growth was assumed at a fixed rate of 1% per annum.

50. A reference case assumed no change to the basic pattern of lighting fuel and appliance use, i.e. electricity grid subscription was taken to grow at the historical rate. Three alternative cases were also defined according to national rural electrification targets as follows:-

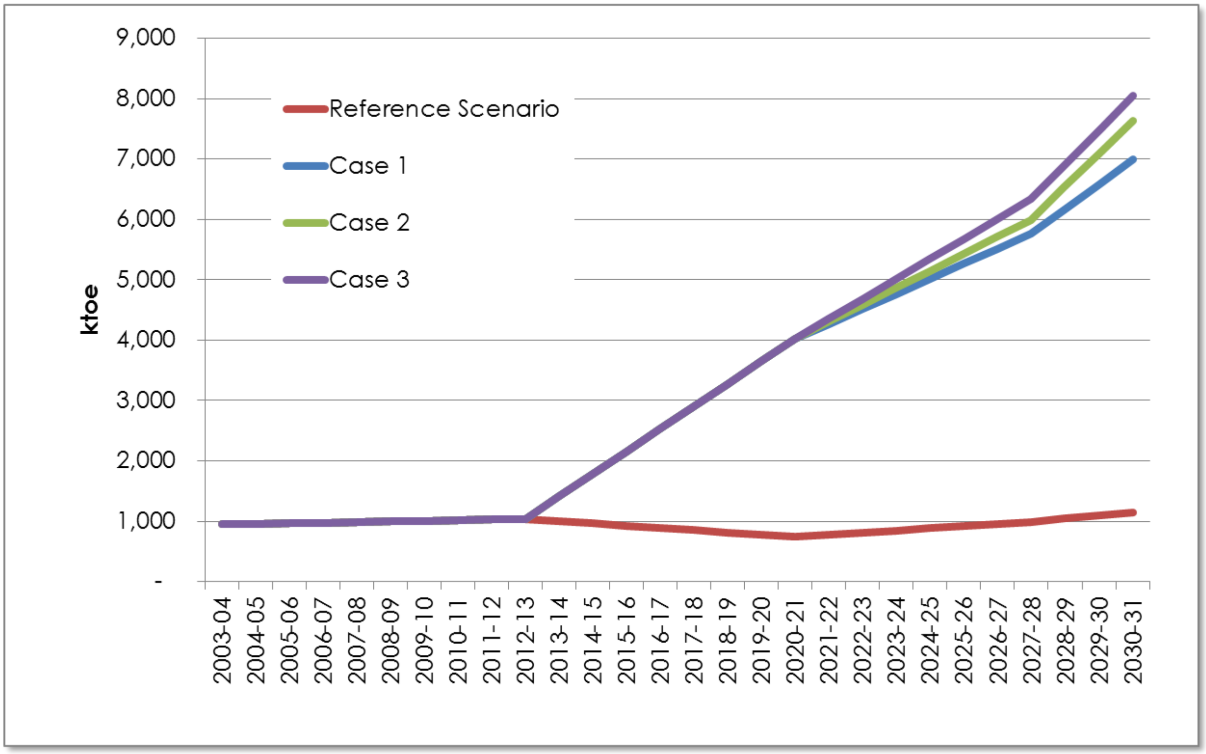
1. Assumption 81% grid electrification is reached by 2030;
2. Assumption 87% grid electrification is reached by 2030; and
3. Assumption 96% grid electrification is reached by 2030.

Figure V-4: Urban HH TV / Entertainment Final Energy Use



Sources: Consultant

Figure V-5: Rural HH TV / Entertainment Final Energy Use



Sources: Consultant

51. The Urban and Rural cases 1 to 3 show an increased energy consumption trajectory compared to the business as usual case. This is due to an accelerated electrification rate and population growth.

Table V-6: Urban HH TV / Ent FEC Projections (mtoe) (Case 2)

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR
Electricity mtoe	0.00023	0.00027	0.00051	0.00076	0.00100	0.00133	0.00165	0.00209	9.4%
Electricity GWh	5.1	6.0	8.8	11.7	15.5	19.3	24.4	29.5	8.1%

Sources: Consultant

Table V-7: Rural HH TV / Ent FEC Projections (mtoe) (Case 2)

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR
Electricity mtoe	0.0009	0.0010	0.0020	0.0030	0.0040	0.0050	0.0060	0.0076	8.8%
Electricity GWh	10.3	12.1	23.7	35.3	46.9	58.4	69.9	89.1	8.8%

Sources: Consultant

O. Other Energy Consumption Projections (Cooling Services)

52. The electricity sales consumption data reported by YESB and ESE were reconciled to the total electricity consumption estimates for household cooking, lighting and TV / Entertainment in 2012-13. The reconciliations were carried out separately for Urban and for Rural segments. The net energy estimate and forecasts for the 'Other' energy category are provided in the following tables. The toe per household for the Other category (average basis) is of the same order as for lighting in the Rural segment suggesting that the predominant form of cooling is electric fans. In the Urban segment the toe per household for the Other category is a factor of four greater. These comparisons are a reasonable validation of the estimates. The forecast shows a convergence between the Urban and Rural segments as rural electrification proceeds to a 100% target.

Table V-8: Household Sector Electricity Only (mtoe)

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR
Urban HH Other	0.0163	0.0585	0.0519	0.0674	0.0877	0.1050	0.1632	0.3699	13.1%
Rural HH Other	0.0297	0.0682	0.0705	0.0941	0.1281	0.1762	0.2735	0.5037	13.1%

Sources: Consultant

Table V-9: Household Sector Energy (toe per household)

	2009	2012	2015	2018	2021	2024	2027	2030
Urban HH Other	0.0086	0.0299	0.0243	0.0290	0.0346	0.0380	0.0542	0.1128
Rural HH Other	0.0026	0.0057	0.0057	0.0074	0.0098	0.0131	0.0197	0.0353

Sources: Consultant

Project Number: TA No. 8356-MYA

FINAL REPORT

MYANMAR ENERGY MASTER PLAN

LONG-TERM OPTIMAL FUEL MIX

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

Intelligent Energy Systems

in association with

MYANMAR INTERNATIONAL CONSULTANTS

Project Number: TA No. 8356-MYA

FINAL REPORT

CONSOLIDATED DEMAND FORECASTS

(BIOMASS, LIQUID FUELS, ELECTRICITY)

Prepared for

The Asian Development Bank

and

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Prepared by

IES
Intelligent Energy Systems

in association with

MMIC
MYANMAR
INTERNATIONAL
CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
CSO	–	Central Statistics Organisation
ESE	–	Electricity Supply Enterprise
FEC	–	Final Energy Consumption
GDP	–	Gross Domestic Product
GoM	–	Government of the Republic of the Union of Myanmar
MoE	–	Ministry of Energy
YESC	–	Yangon Electricity Supply Corporation

UNITS OF MEASURE

IG	–	Imperial Gallon
km	–	Kilometre
l	–	Litre
mtoe	–	Million tons of oil equivalent
Passenger-km	–	Passenger-Kilometre
Ton-km	–	Metric Ton-Kilometre

CONVERSION FACTORS

1 litre	=	0.22 Imperial Gallon
1 km	=	0.62137 mile

NOTE

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

CONTENTS

I. SUMMARY

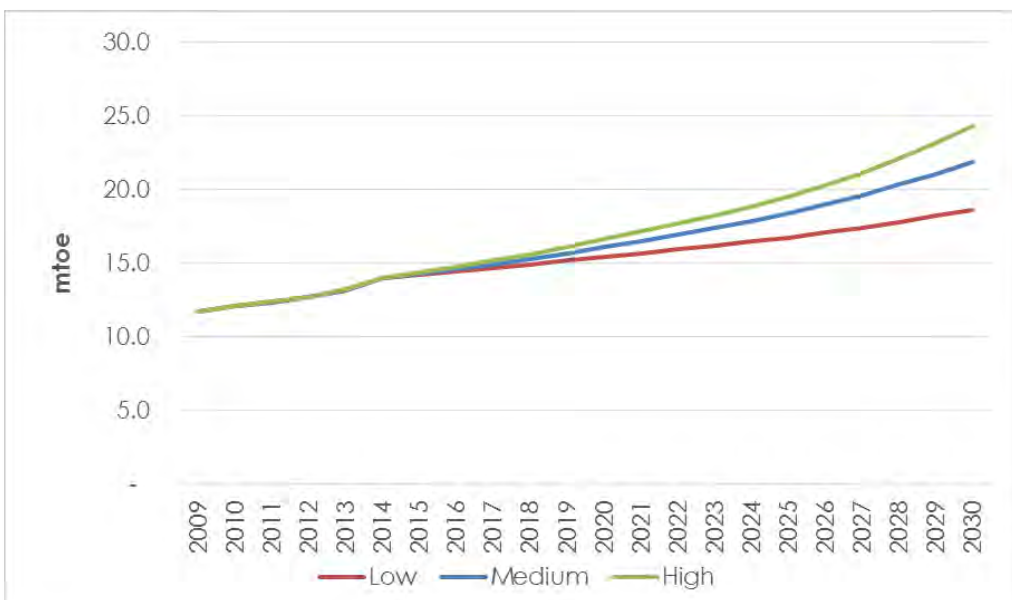
A. Introduction

1. This summary report presents the aggregate demand projections for biomass, solid fuels, liquid fuels and electricity for Myanmar. The demand projection for biomass is given according to the forecasts developed for household and economic sectors using firewood, charcoal and woody biomass. Solid fuel is primarily coal and is an aggregation of the forecasts for the energy-intensive and SME industry sectors. Liquid fuel forecasts represent an aggregation of demands of the economic and household sectors. In the case of electricity the demand projections are presented in this report as 'top-down' forecasts for Yangon Division and the fourteen States and Regions that collectively make up the countryside areas of Myanmar. Residential, commercial, light industry and heavy industry electricity consumption energy forecasts have been forecast separately. A reconciliation process was undertaken to ensure that the aggregated electricity consumption forecast is fully consistent with the individual electricity consumption forecasts presented in the Agriculture, Industry, Commerce & Public Services and Household sector reports of this Energy Masterplan.

B. Final Energy Consumption Projection for Myanmar

2. The aggregate final energy consumption (FEC) forecast for Myanmar is given in Figure I-1. In the case of the medium growth final energy consumption is forecast to rise at a compound annual growth rate of 3.0% from 2012 to 2030, from 12.7 mtoe to 21.9 mtoe.

Figure I-1: Myanmar: Final Energy Consumption Projection to 2030

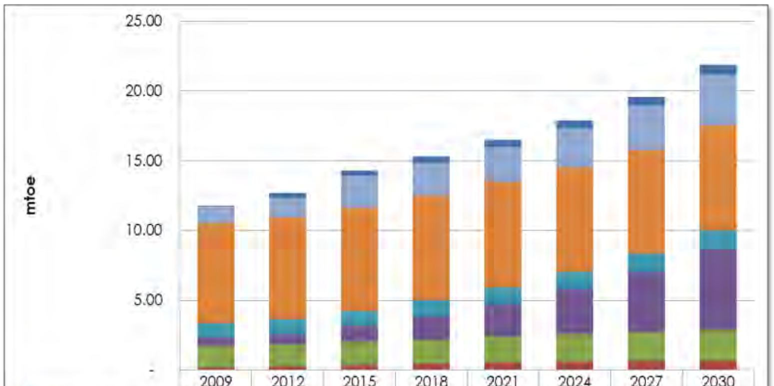


Source: Consultants' analysis

3. The low, medium and high growth cases in Figure I-1 correspond to a) GDP growth of 4.8%, 7.1% and 9.5% respectively, and b) electrification ratios of 80%, 87% and 86% respectively.

4. Figure I-2 to Figure I-5 provide a detailed breakdown of FEC for the medium demand growth forecast by sector and by energy carrier. Given the dominance of household cooking energy consumption, Figure I-4 shows the FEC projection without the household sector.

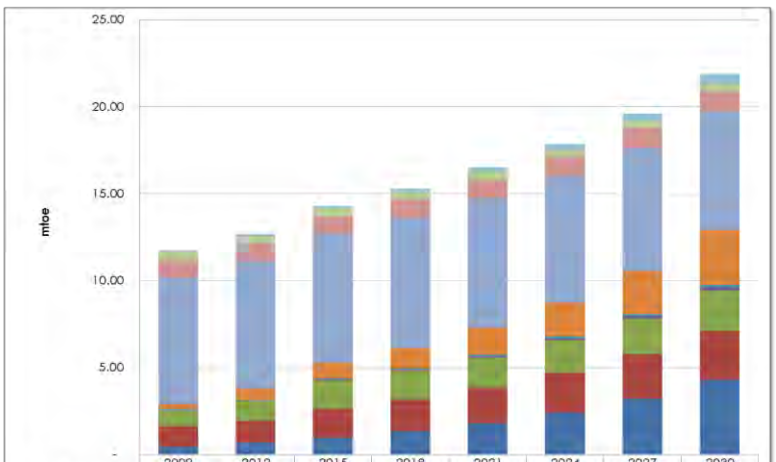
Figure I-2: Myanmar: Final Energy Consumption Projection (Medium)



	2009	2012	2015	2018	2021	2024	2027	2030
Non-Energy	0.01	0.31	0.37	0.44	0.51	0.57	0.64	0.70
Transport	1.22	1.44	2.28	2.34	2.52	2.81	3.19	3.68
Residential - Rural	7.18	7.31	7.40	7.52	7.56	7.48	7.44	7.48
Residential - Urban	1.01	1.08	1.09	1.13	1.18	1.21	1.29	1.44
Industry	0.59	0.70	1.15	1.69	2.38	3.25	4.34	5.70
Commercial	1.54	1.59	1.65	1.74	1.84	1.95	2.09	2.25
Agriculture	0.19	0.25	0.34	0.43	0.52	0.60	0.62	0.63

Source: Consultants' analysis

Figure I-3: Myanmar: FEC Projection by Energy Carrier (medium)

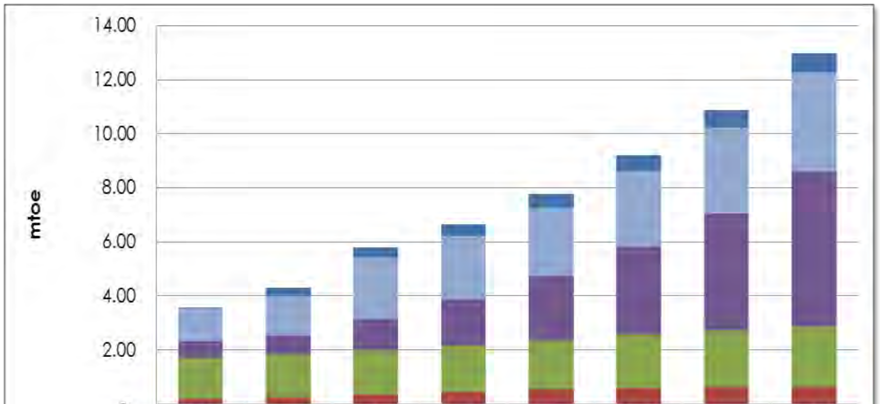


	2009	2012	2015	2018	2021	2024	2027	2030
Coal	0.10	0.07	0.11	0.16	0.23	0.31	0.42	0.55
Paraffin	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Woody Biomass	0.47	0.47	0.47	0.47	0.47	0.46	0.45	0.43
Charcoal	0.97	0.98	1.00	1.02	1.05	1.08	1.11	1.16
Firewood	7.30	7.37	7.43	7.50	7.47	7.26	7.05	6.84
Gas	0.29	0.63	0.89	1.18	1.54	1.97	2.50	3.15
ATF	0.03	0.03	0.03	0.05	0.07	0.09	0.11	0.13
Furnace Oil	0.04	0.03	0.04	0.06	0.08	0.11	0.15	0.20
HSD	0.93	1.16	1.67	1.68	1.75	1.89	2.05	2.30
Motor Spirit	1.17	1.23	1.67	1.83	2.04	2.29	2.55	2.83
Electricity	0.43	0.70	0.96	1.33	1.80	2.41	3.21	4.29

Source: Consultants' analysis

5. The FEC forecast, excluding the household sector is given as Figure I-4. Energy is forecast to rise at a compound annual growth rate of 6.2% from 2012 to 2030, from 4.3 mtoe to 13.0 mtoe.

Figure I-4: Myanmar: FEC Projection (excluding HH's, medium)

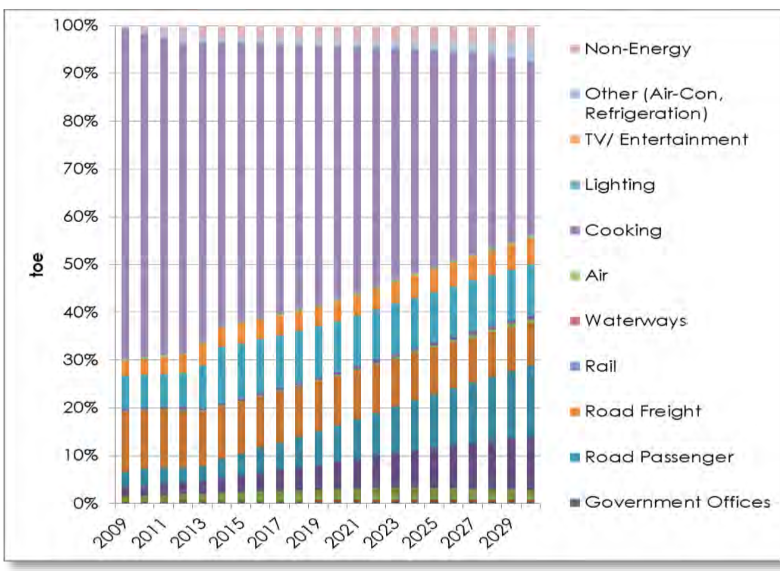


	2009	2012	2015	2018	2021	2024	2027	2030
Non-Energy	0.01	0.31	0.37	0.44	0.51	0.57	0.64	0.70
Transport	1.22	1.44	2.28	2.34	2.52	2.81	3.19	3.68
Industry	0.59	0.70	1.15	1.69	2.38	3.25	4.34	5.70
Commercial	1.54	1.59	1.65	1.74	1.84	1.95	2.09	2.25
Agriculture	0.19	0.25	0.34	0.43	0.52	0.60	0.62	0.63

Source: Consultants' analysis

6. The FEC forecast is given by sub-sector contributions as follows, illustrating the dominance of household cooking but also the reduction assuming an electrification ratio of 87% by 2030.

Figure I-5: Myanmar: FEC Projection Contribution by Sub-Sectors (medium)



Source: Consultants' analysis

C. Energy Intensity & Elasticity Projection for Myanmar

7. The energy intensity projection for Myanmar is given as Figure I-6; this projection includes only the economic sectors, the household sector is excluded, and the projection is for the medium GDP growth scenario. The elasticity of electricity consumption is given as Figure I-7.

Figure I-6: Myanmar: Energy Intensity Projection

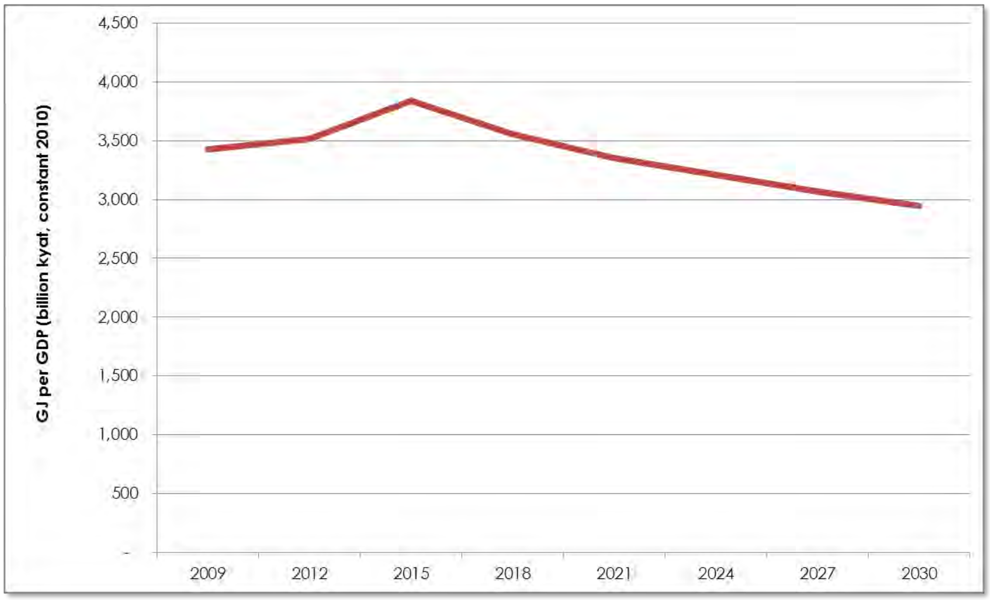
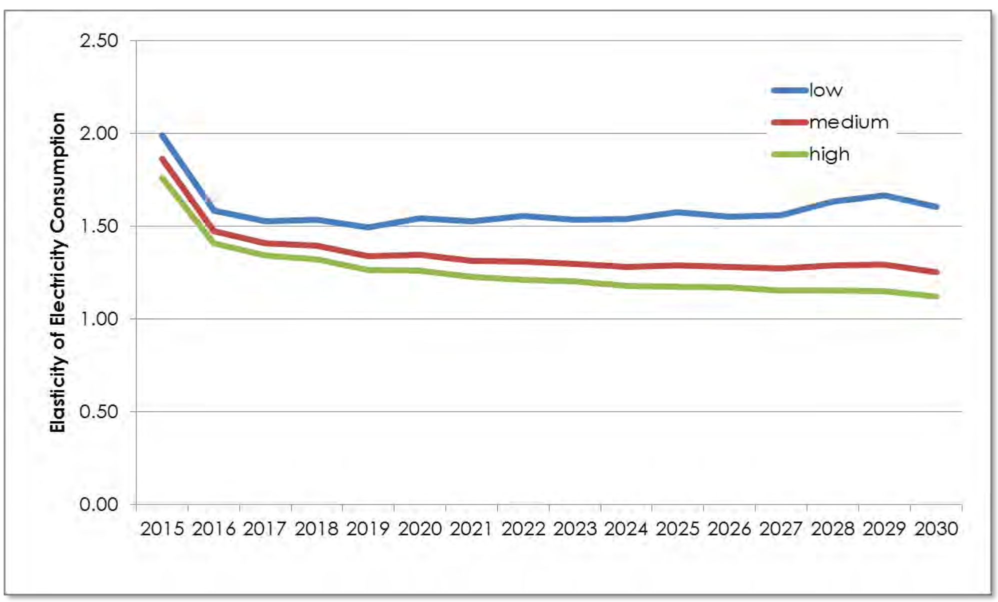


Figure I-7: Myanmar: Elasticity Electricity Consumption



Source: Consultants' analysis

II. FEC FORECASTS BY SECTOR

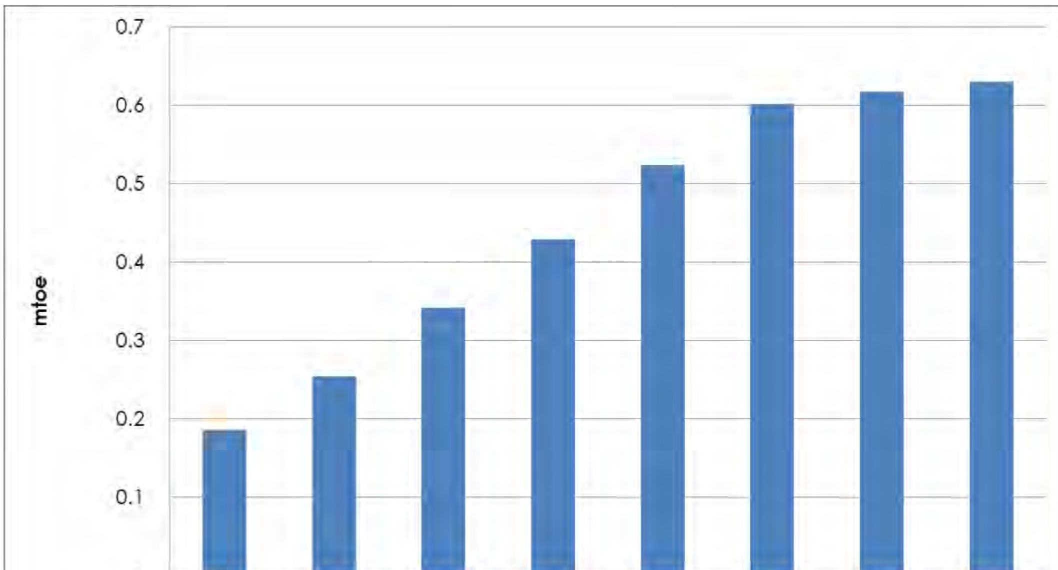
D. Introduction

8. Sector FEC forecasts follow for the medium demand growth case. Forecasts are given for the Agriculture, Industry, Commercial & Public Services, Transport and Household sectors.

E. Agriculture

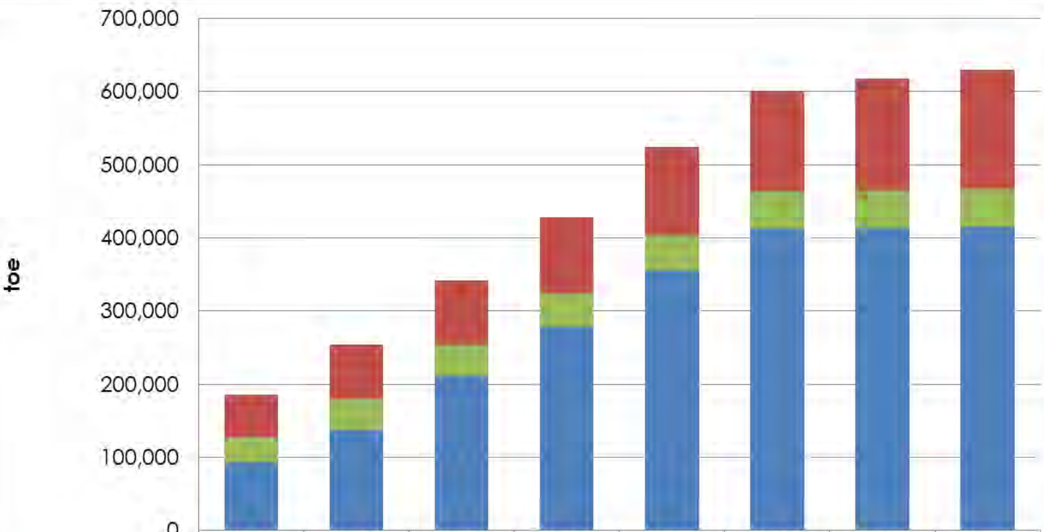
9. The FEC forecast for Myanmar's Agriculture sector are given as a set of charts. Figure II-1 shows that the FEC of Agriculture is forecast to grow at a compound annual rate of 5.0%.

Figure II-1: FEC Projection: Agriculture



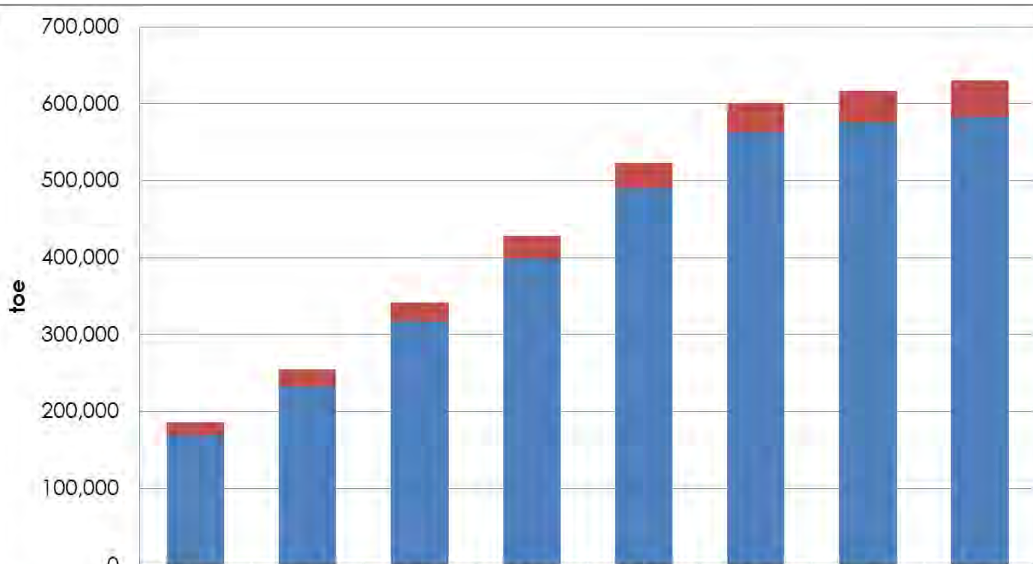
	2009	2012	2015	2018	2021	2024	2027	2030
Agriculture	0.19	0.25	0.34	0.43	0.52	0.60	0.62	0.63

Figure II-2: FEC by Modality: Agriculture



	2009	2012	2015	2018	2021	2024	2027	2030
Water Pumping	57,505	75,000	87,937	104,331	119,609	137,216	152,341	163,181
Tractors	34,896	41,240	42,872	45,899	49,140	51,426	51,426	51,426
Power Tillers	93,901	138,314	210,764	278,268	354,763	412,346	413,616	415,402

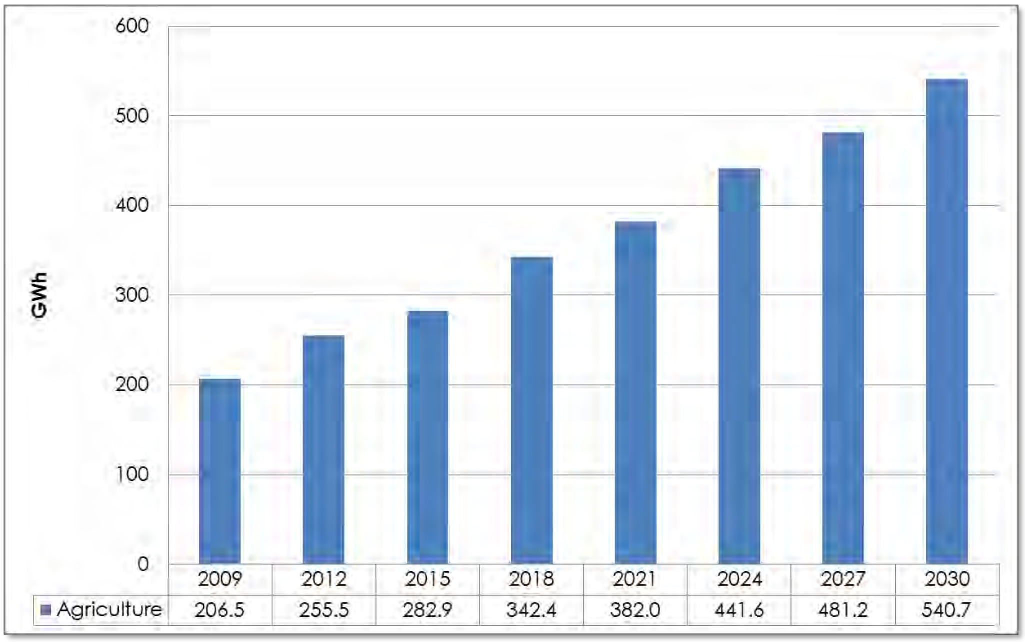
Figure II-3: FEC by Energy Carrier: Agriculture



	2009	2012	2015	2018	2021	2024	2027	2030
Electricity	17,757	21,967	24,323	29,443	32,849	37,968	41,375	46,492
Diesel	168,544	232,587	317,250	399,055	490,662	563,019	576,008	583,518

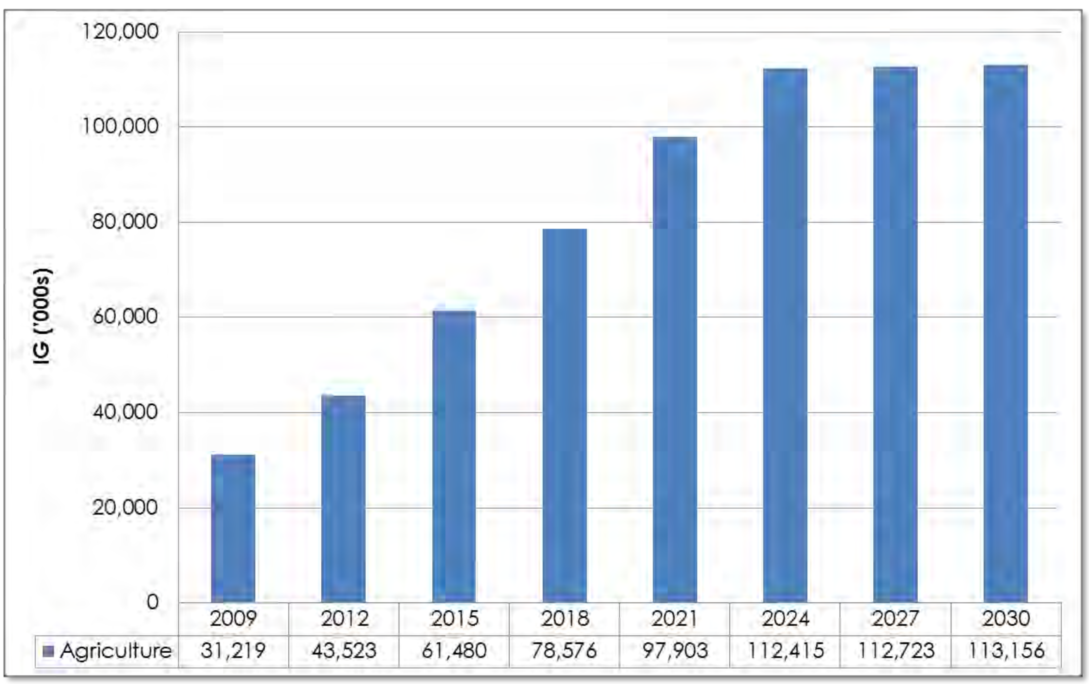
Source: Consultants' analysis

Figure II-4: FEC by Energy Carrier: Electricity, Agriculture



Source: Consultants' analysis

Figure II-5: FEC by Energy Carrier: Diesel, Agriculture

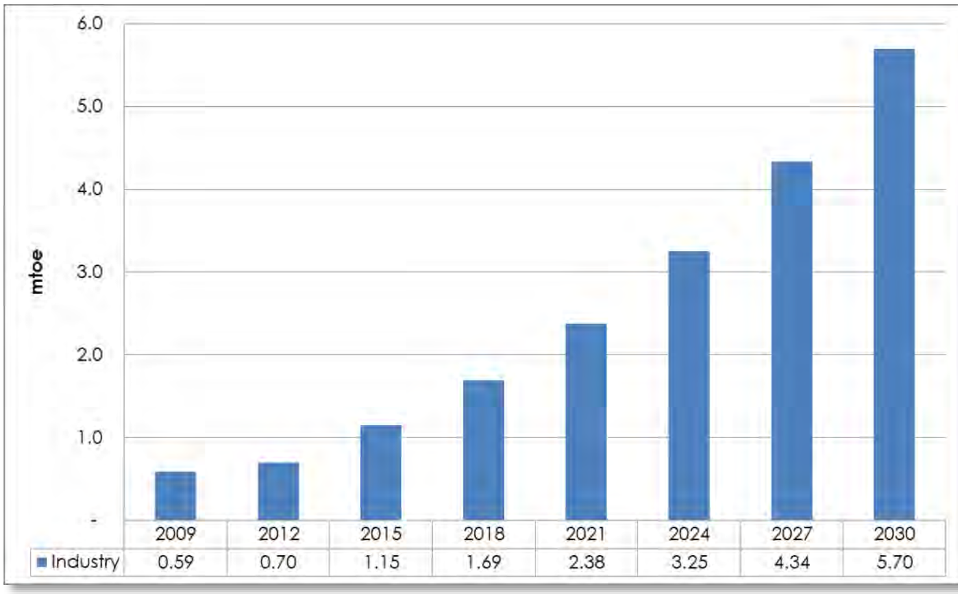


Source: Consultants' analysis

F. Industry

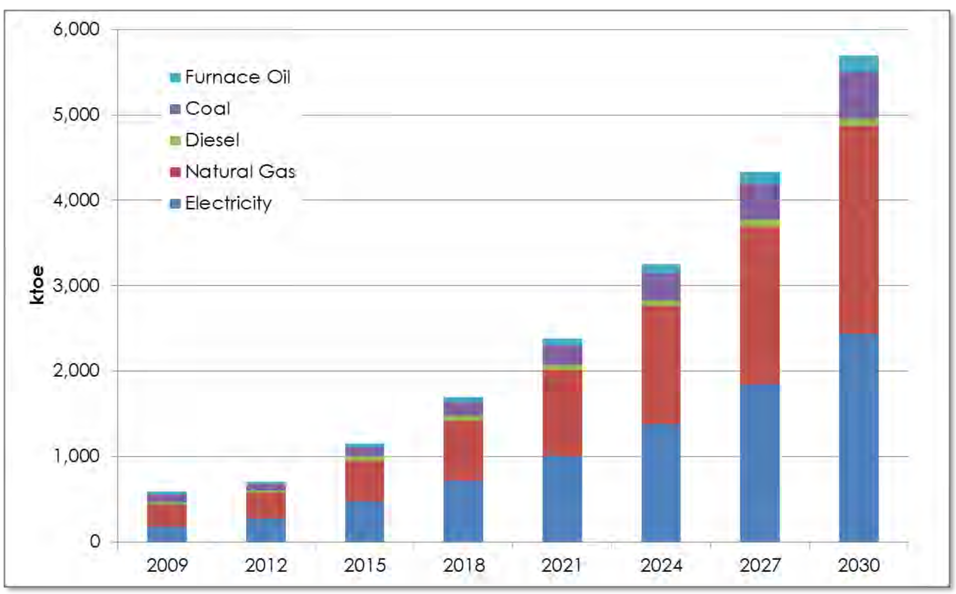
10. The FEC forecast for Myanmar's Industry sector is given by the charts and tables that follow. Figure II-6 shows that the Industry FEC is forecast to rise at a compound annual growth rate of 11.6% from 2012 to 2030.

Figure II-6: FEC Projection: Industry (excluding fertilizer)



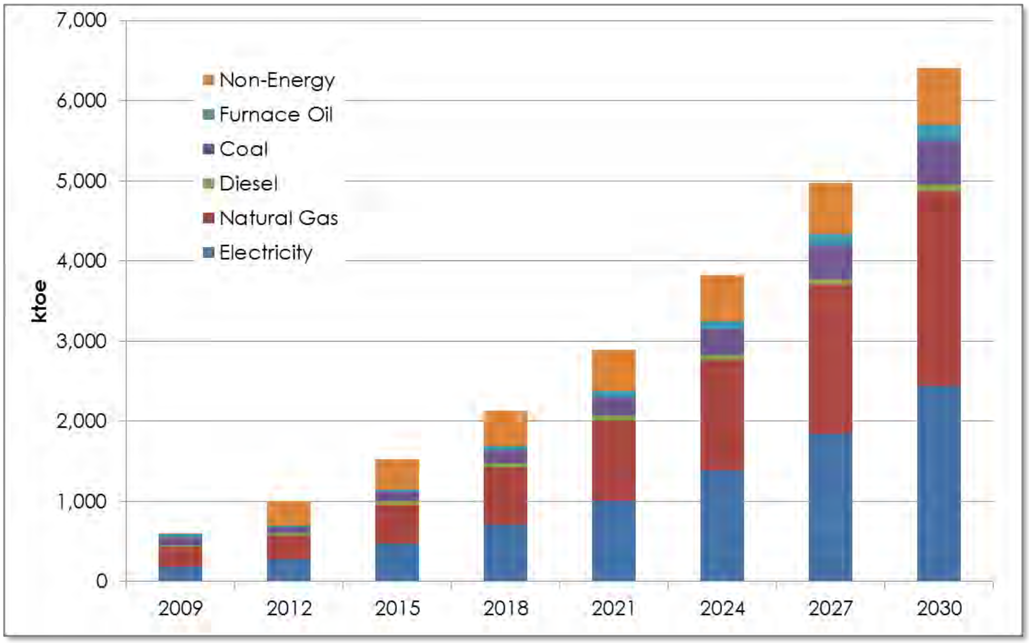
Source: Consultants' analysis

Figure II-7: FEC by Energy Carrier: Industry (excluding fertilizer)



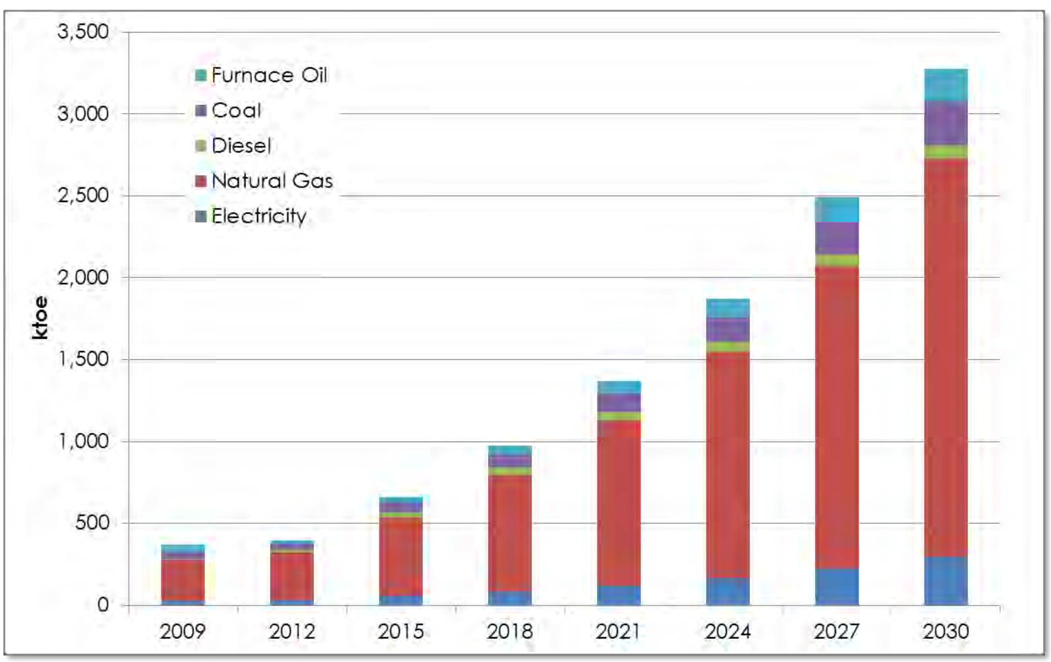
Source: Consultants' analysis

Figure II-8: FEC by Energy Carrier: Industry (including fertilizer)



Source: Consultants' analysis

Figure II-9: FEC Projection: Energy-Intensive Industry



Source: Consultants' analysis

Table II-10: FEC by Energy Carrier: Energy-Intensive Industry

		2009	2012	2015	2018	2021	2024	2027	2030
Electricity	GWh	318	379	663	990	1,403	1,927	2,578	3,397
Natural Gas	tons	212,681	247,546	403,668	602,926	854,279	1,173,641	1,569,684	2,068,738
Diesel[1]	IG '000s	1	3	9	10	12	13	15	18
Coal	tons	64,469	49,929	78,456	117,183	166,035	228,105	305,079	402,073
Furnace Oil	IG	9,116	5,385	8,210	12,263	17,375	23,870	31,925	42,075

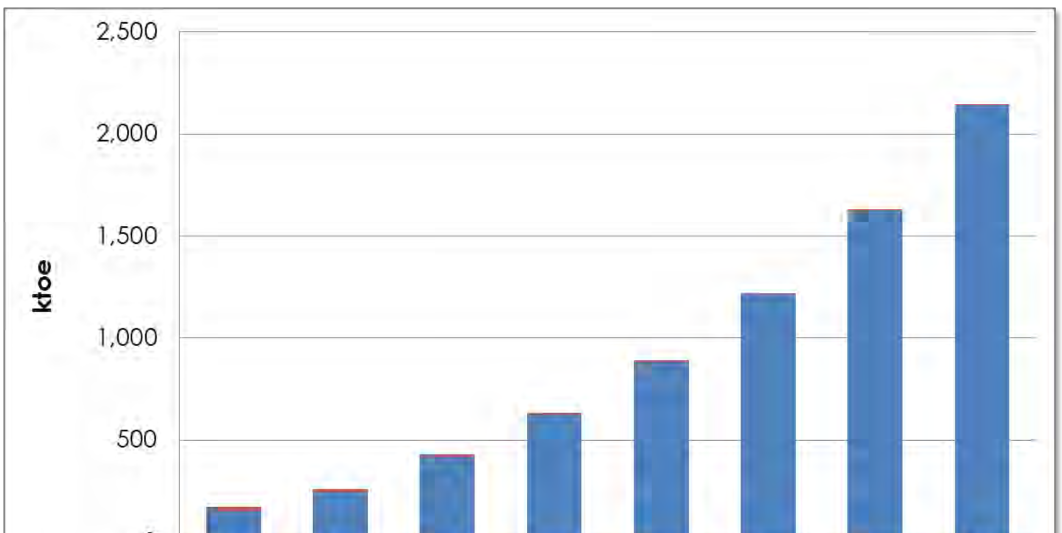
Source: Consultants' analysis

Table II-11: FEC by Energy Carrier: SME

		2009	2012	2015	2018	2021	2024	2027	2030
Electricity	GWh	1,778	2,852	4,861	7,261	10,288	14,133	18,903	24,913
Diesel	IG '000s	3,786	3,276	2,767	2,258	1,748	1,239	729	220

Source: Consultants' analysis

Figure II-12: FEC Projection: Small to Medium Enterprise



	2009	2012	2015	2018	2021	2024	2027	2030
Diesel	19	16	14	11	9	6	4	1
Electricity	153	245	418	624	885	1,215	1,625	2,142

Source: Consultants' analysis

[1] Diesel consumption for transport use associated with industry activity is included in the Transport sector forecasts

G. Commercial & Public Services

11. The FEC forecasts for Myanmar's Commercial & Public Services sector are given as a set of charts. Figure II-13 shows that the FEC of Commercial & Public Services is forecast to grow at a compound annual rate of 2.1%.

Figure II-13: FEC Projection: Commercial & Public Services

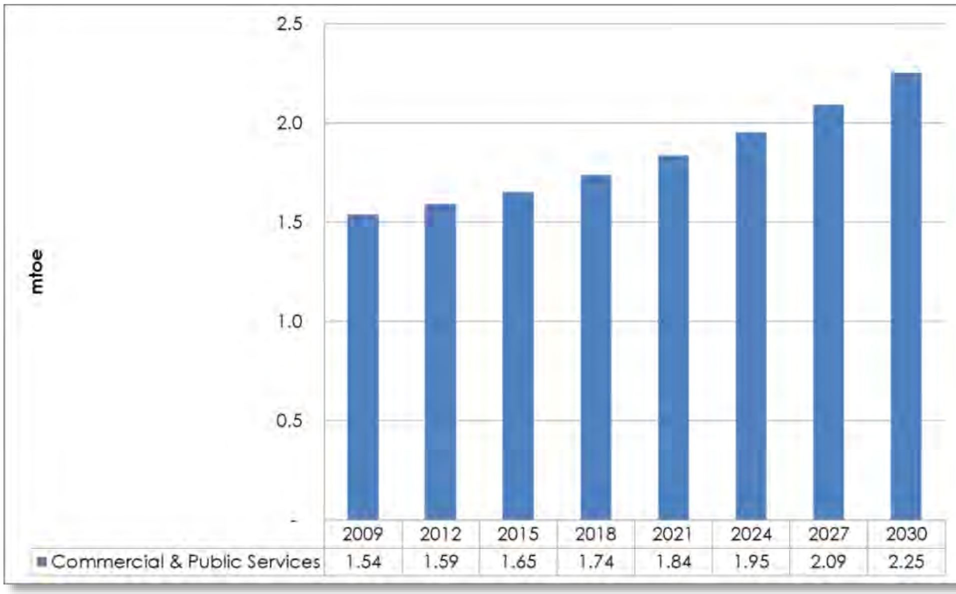
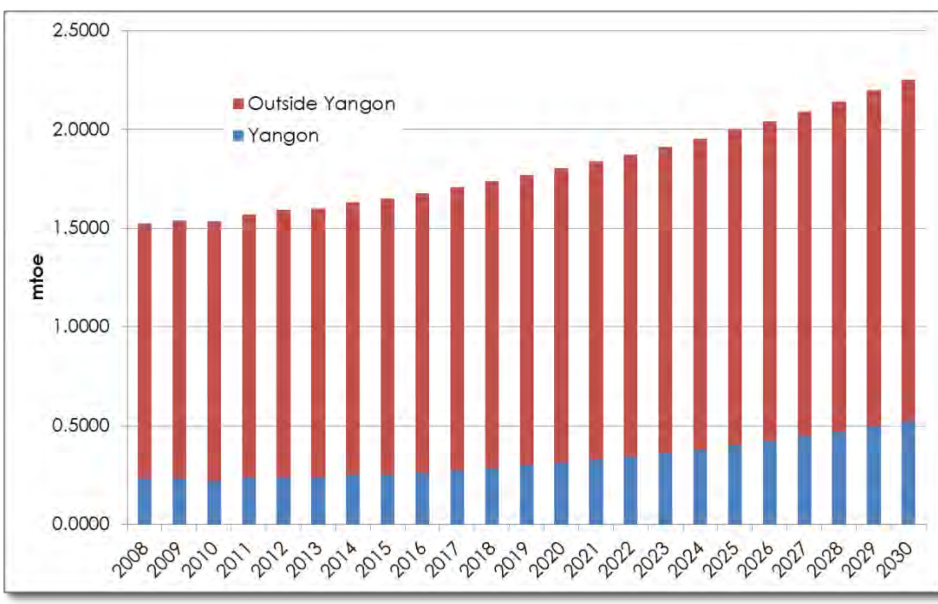
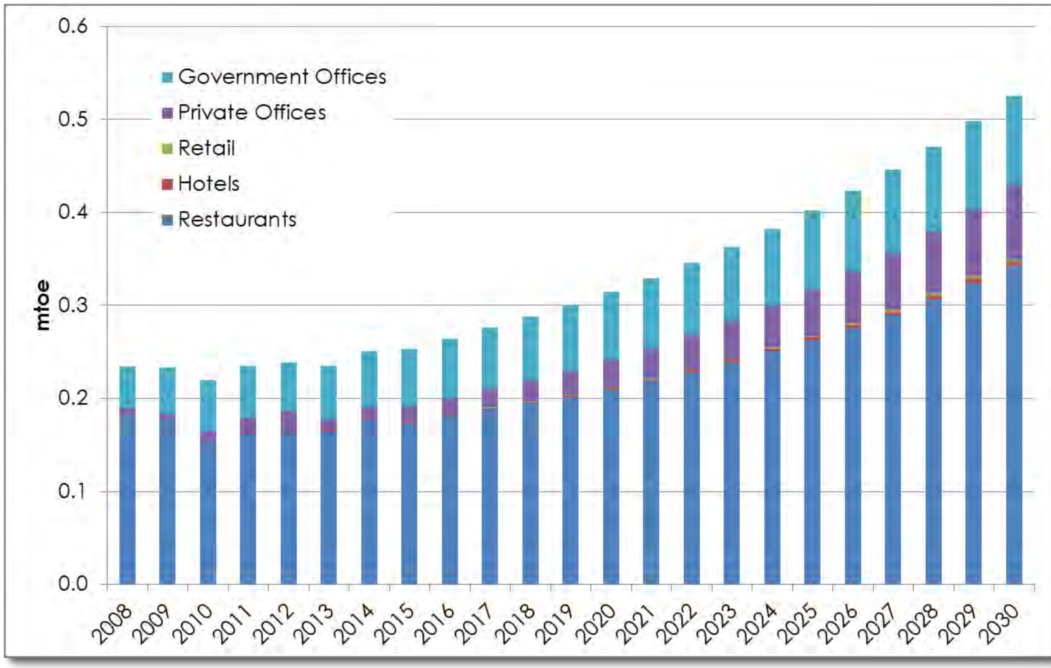


Figure II-14: FEC Projection: Commercial & Public Services



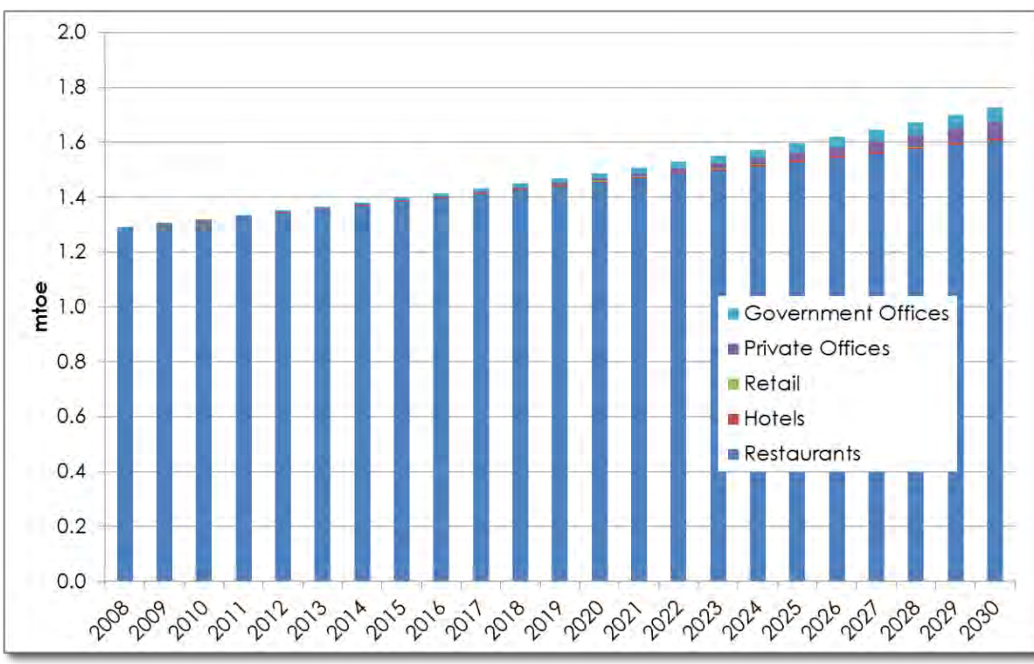
Source: Consultants' analysis

Figure II-15: FEC: Commercial & Public Services by Sub-Sector: Yangon



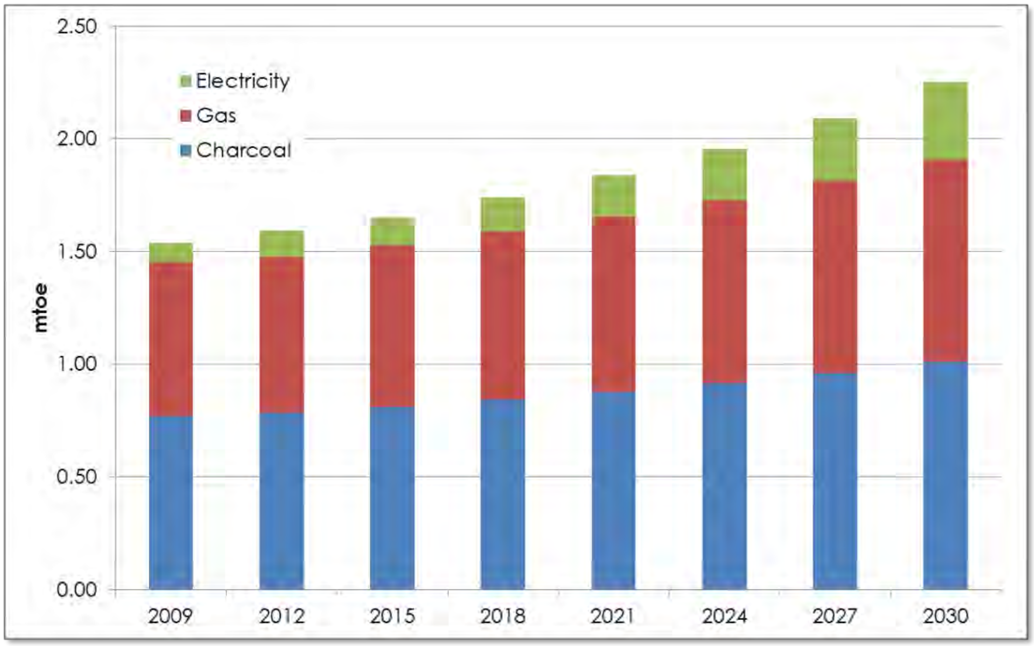
Source: Consultants' analysis

Figure II-16: FEC: Commercial & Public Services by Sub-Sector: Outside Yangon



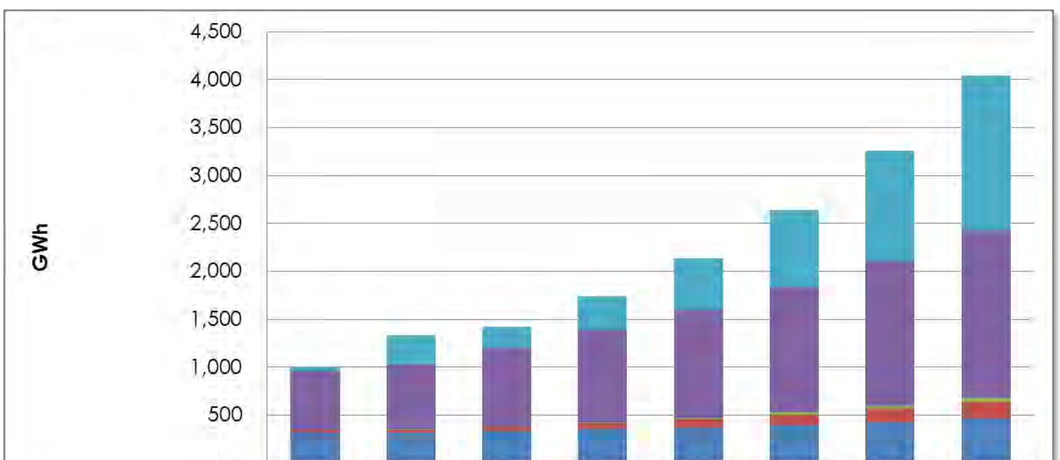
Source: Consultants' analysis

Figure II-17: FEC by Energy Carrier: Public & Commercial Services



Source: Consultants' analysis

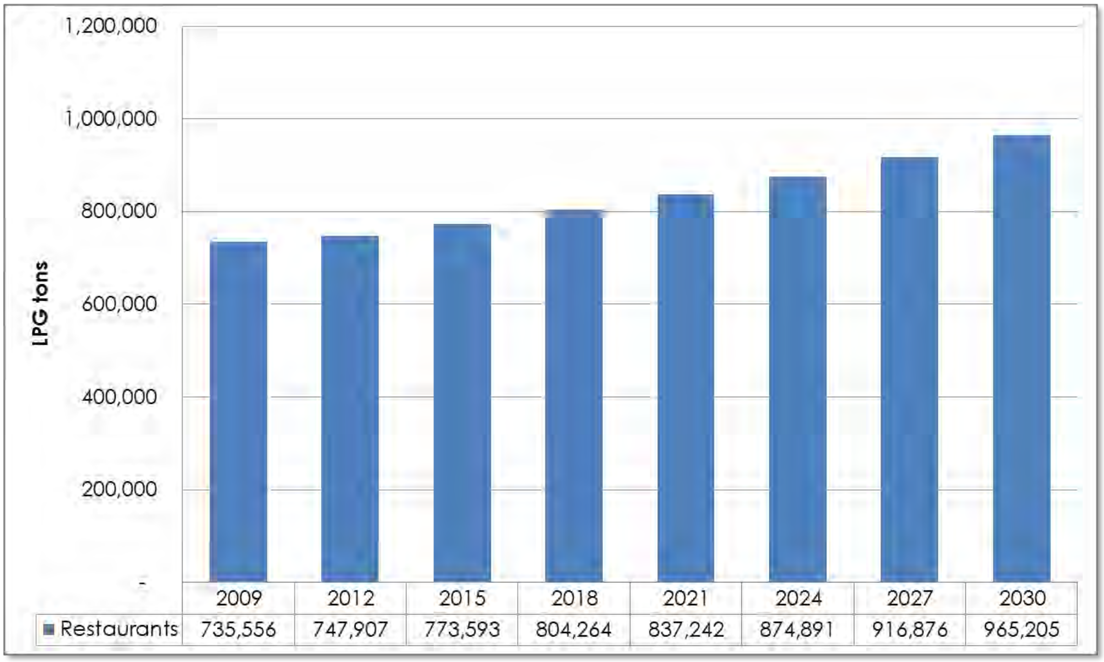
Figure II-18: FEC by Energy Carrier: Public & Commercial Services, Electricity



	2009	2012	2015	2018	2021	2024	2027	2030
Private Offices GWh	44	302	217	351	539	796	1,144	1,610
Gov't Offices GWh	618	676	820	965	1,128	1,311	1,518	1,751
Retail GWh	2	3	5	9	13	20	31	47
Hotels GWh	22	28	45	65	86	110	137	169
Restuarants GWh	324	322	335	353	374	400	430	466

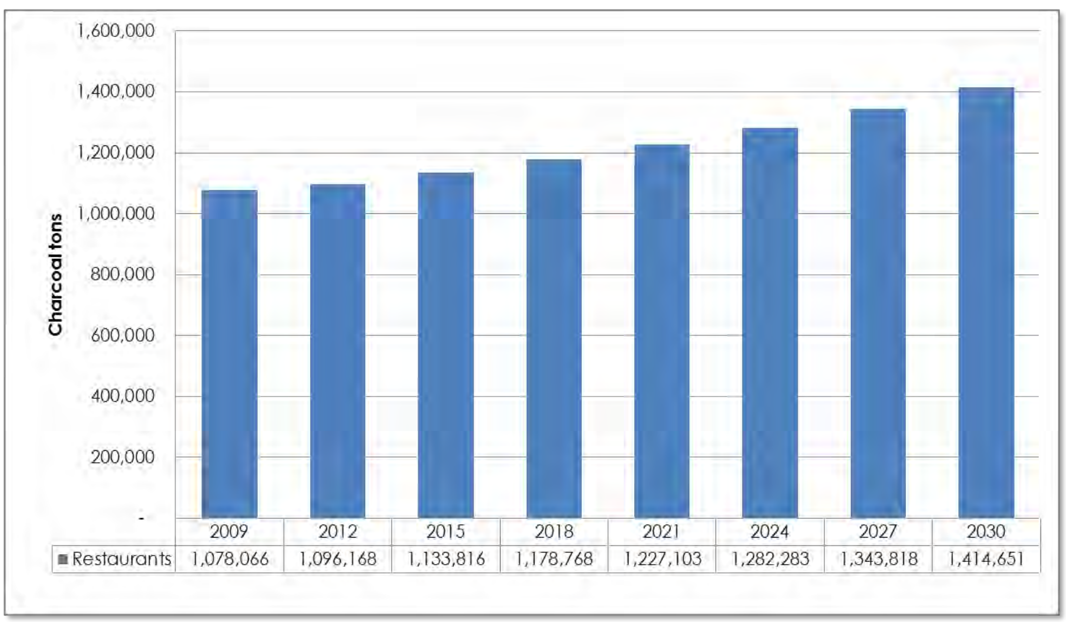
Source: Consultants' analysis

Figure II-19: FEC by Energy Carrier: Public & Commercial Services, LPGas



Source: Consultants' analysis

Figure II-20: FEC by Energy Carrier: Public & Commercial Services, Charcoal

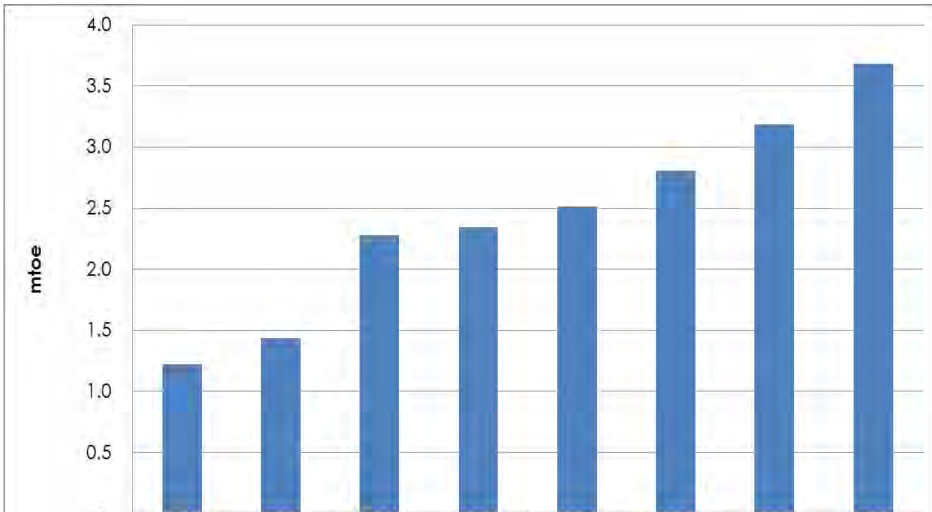


Source: Consultants' analysis

H. Transport

12. The FEC forecasts for Myanmar's Transport Services sector are given as a set of charts. Figure II-13 shows that the FEC of Transport is forecast to grow at a compound annual rate of 15%.

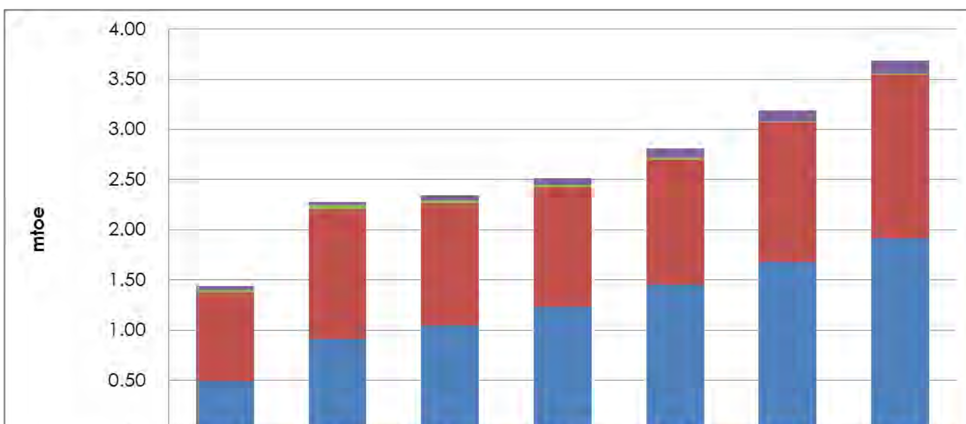
Figure II-21: FEC Projection: Transport



	2009	2012	2015	2018	2021	2024	2027	2030
Transport	1.22	1.44	2.28	2.34	2.52	2.81	3.19	3.68

Source: Consultants' analysis

Figure II-22: FEC Projection by Energy Carrier: Transport



	2012-13	2015-16	2018-19	2021-22	2024-25	2027-28	2030-31
Jet Fuel	0.03	0.03	0.05	0.07	0.09	0.11	0.13
Natural Gas	0.03	0.04	0.03	0.02	0.02	0.01	0.01
Diesel	0.88	1.29	1.21	1.19	1.25	1.39	1.63
Gasoline	0.49	0.91	1.05	1.23	1.46	1.68	1.91

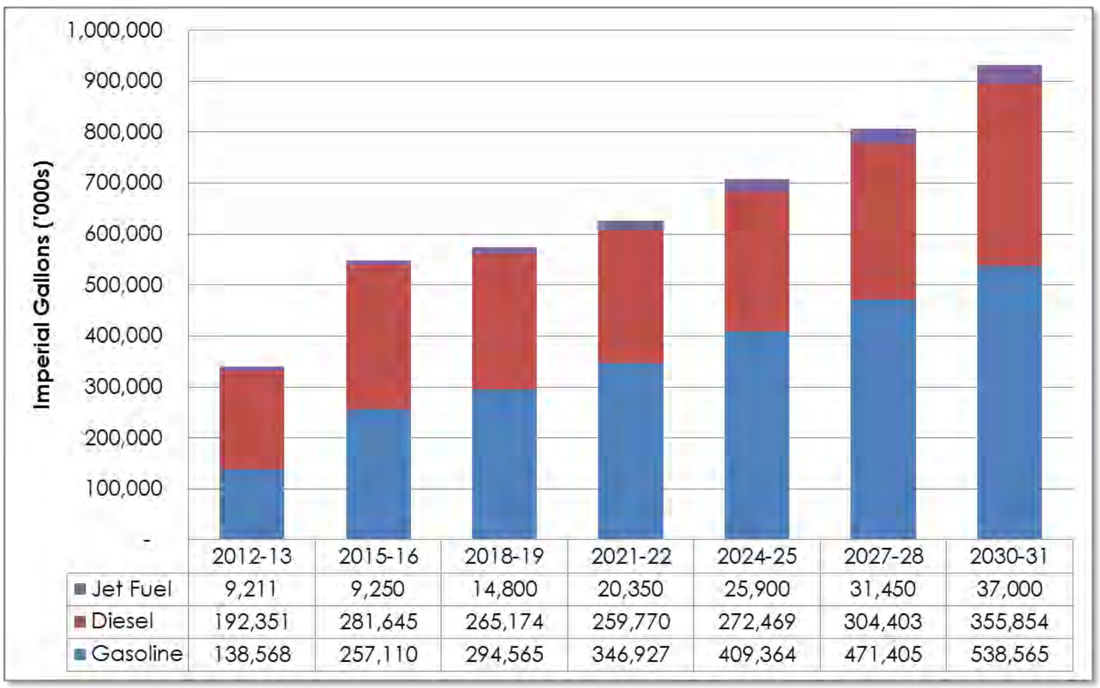
Source: Consultants' analysis

Table II-23: FEC by Energy Carrier Physicals: Transport

	Reference						
	2012	2015	2018	2021	2024	2027	2030
Gasoline (IG - 000's)	138,568	257,110	294,565	346,927	409,364	471,405	538,565
Bioethanol (IG - 000's)	-	-	-	-	-	-	-
Diesel (IG - 000's)	192,351	281,645	265,174	259,770	272,469	304,403	355,854
Natural Gas (cub m - 000's)	37,326	51,621	38,749	29,061	20,825	13,694	14,591
Jet Fuel (IG '000s)	9,211	9,250	14,800	20,350	25,900	31,450	37,000

Source: Consultants' analysis

Figure II-24: FEC by Energy Carrier Physicals: Transport

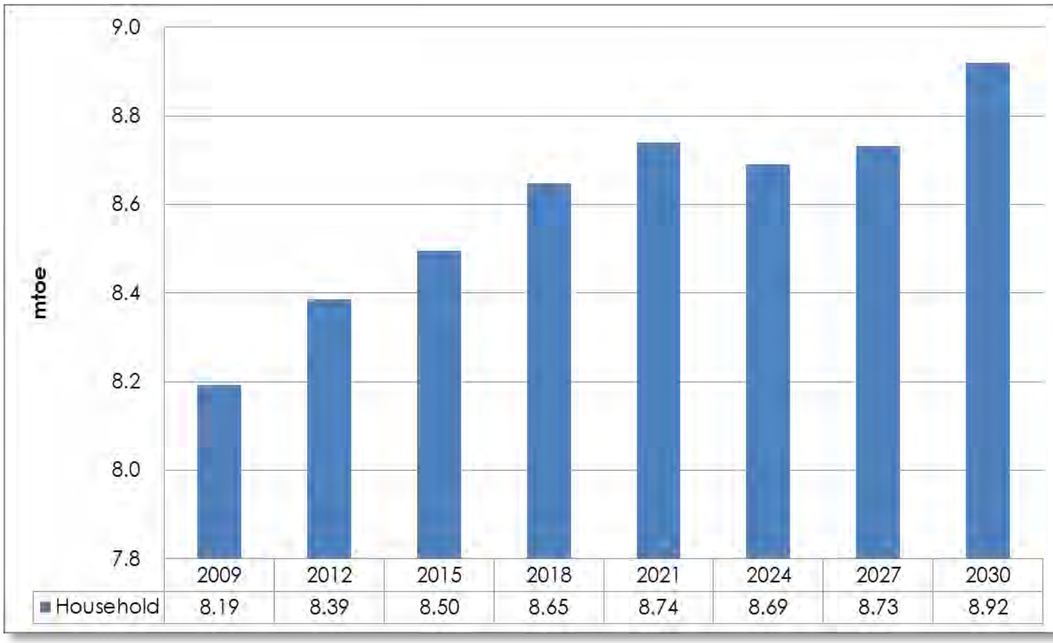


Source: Consultants' analysis

I. Households

13. The FEC forecasts for Myanmar's Household sector are given as a set of charts. Figure II-25 shows that the FEC of Households is forecast to grow at a compound annual rate of 0.4%.

Figure II-25: FEC Projection: Households



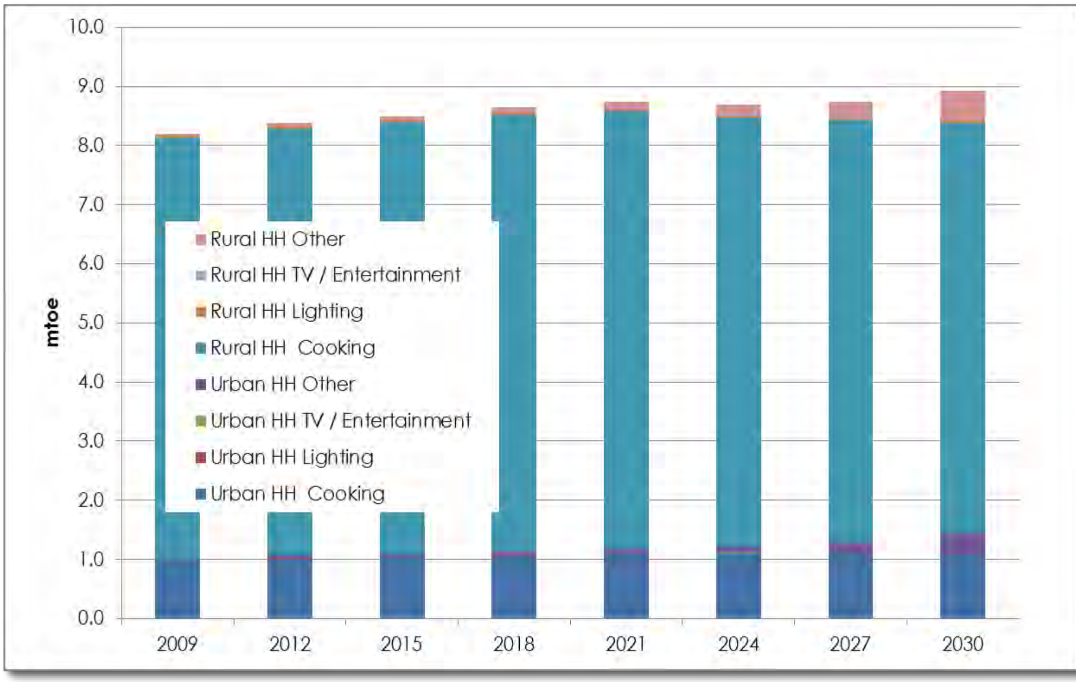
Source: Consultants' analysis

Table II-26: Household FEC by Sub-Sector

	2009	2012	2015	2018	2021	2024	2027	2030	CAGR
Urban HH Cooking	0.9885	1.0121	1.0358	1.0594	1.0819	1.1019	1.1220	1.0651	0.2%
Urban HH Lighting	0.0040	0.0043	0.0046	0.0049	0.0052	0.0059	0.0065	0.0070	2.8%
Urban HH TV / Entertainment	0.0002	0.0003	0.0005	0.0008	0.0010	0.0013	0.0017	0.0021	9.4%
Urban HH Other	0.0163	0.0585	0.0519	0.0674	0.0877	0.1050	0.1632	0.3699	13.1%
Urban HH Total	*1.0090*	*1.0752*	*1.0928*	*1.1325*	*1.1757*	*1.2141*	*1.2934*	*1.4441*	*1.9%*
Rural HH Cooking	7.1287	7.2167	7.3046	7.3925	7.4056	7.2689	7.1323	6.9382	-0.3%
Rural HH Lighting	0.0239	0.0246	0.0253	0.0260	0.0267	0.0267	0.0266	0.0255	0.1%
Rural HH TV / Entertainment	0.0009	0.0010	0.0020	0.0030	0.0040	0.0050	0.0060	0.0076	8.8%
Rural HH Other	0.0297	0.0682	0.0705	0.0941	0.1281	0.1762	0.2735	0.5037	13.1%
Rural HH Total	*7.1832*	*7.3105*	*7.4024*	*7.5156*	*7.5644*	*7.4767*	*7.4384*	*7.4751*	*0.1%*
Total Urban & Rural	*8.1923*	*8.3857*	*8.4952*	*8.6481*	*8.7401*	*8.6909*	*8.7318*	*8.9192*	*0.3%*
% Electricity	1.8%	3.4%	4.0%	5.1%	6.6%	8.8%	12.0%	16.4%	

Source: Consultants' analysis

Figure II-27: FEC Projection by End-Use: All Households

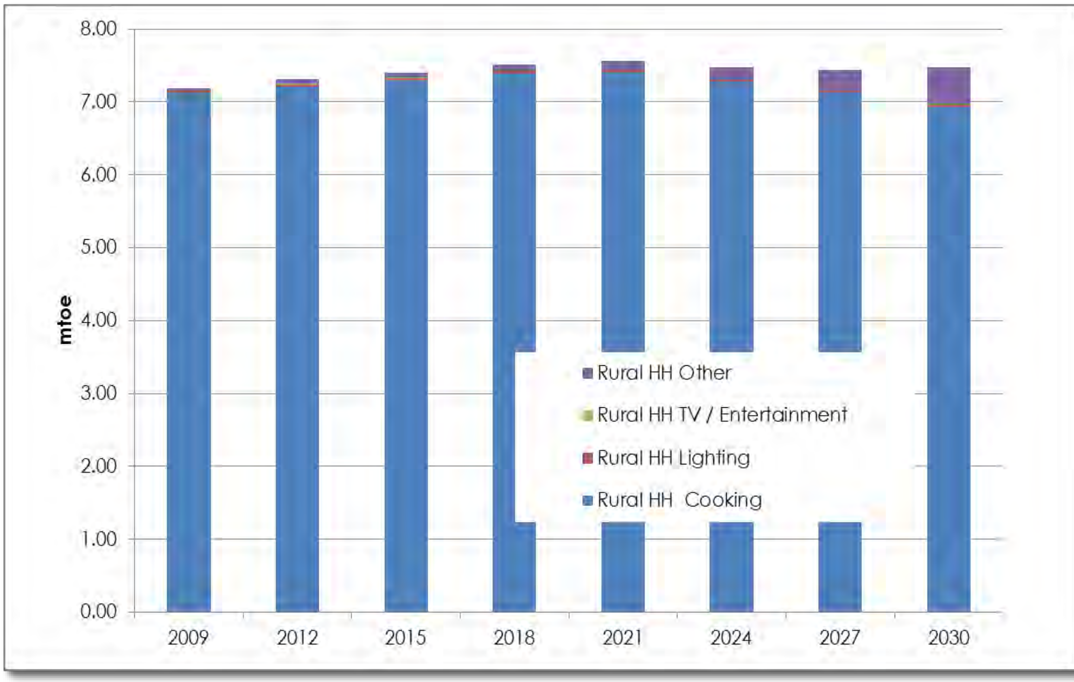


Source: Consultants' analysis

Figure II-28: FEC Projection by End-Use: Urban Households

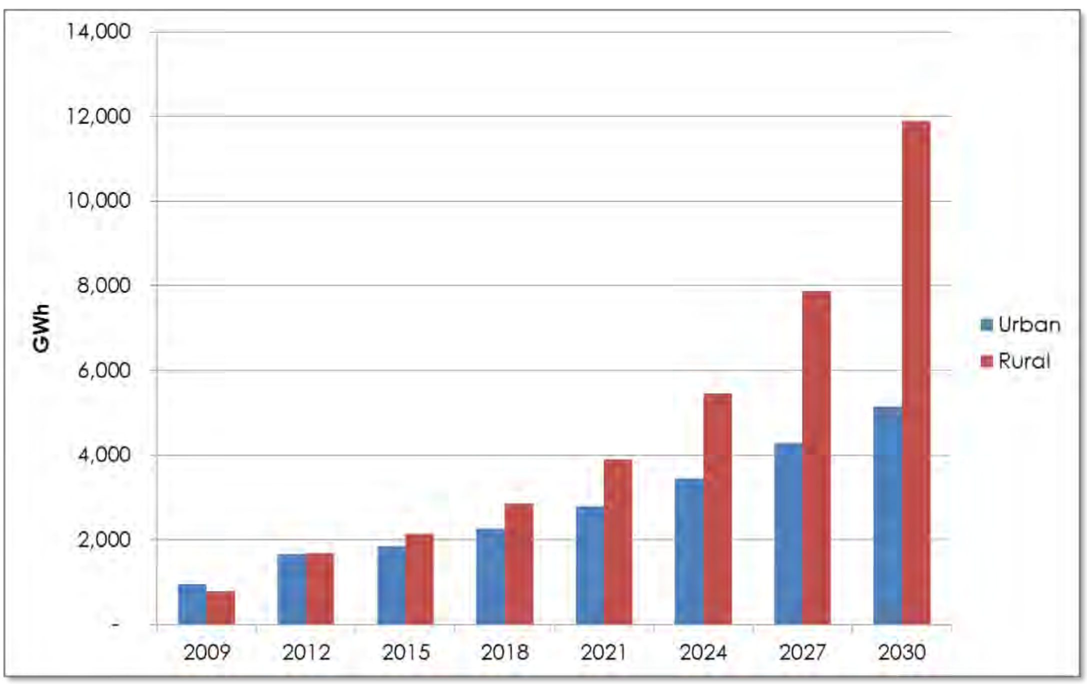
Source: Consultants' analysis

Figure II-29: FEC Projection by End-Use: Rural Households



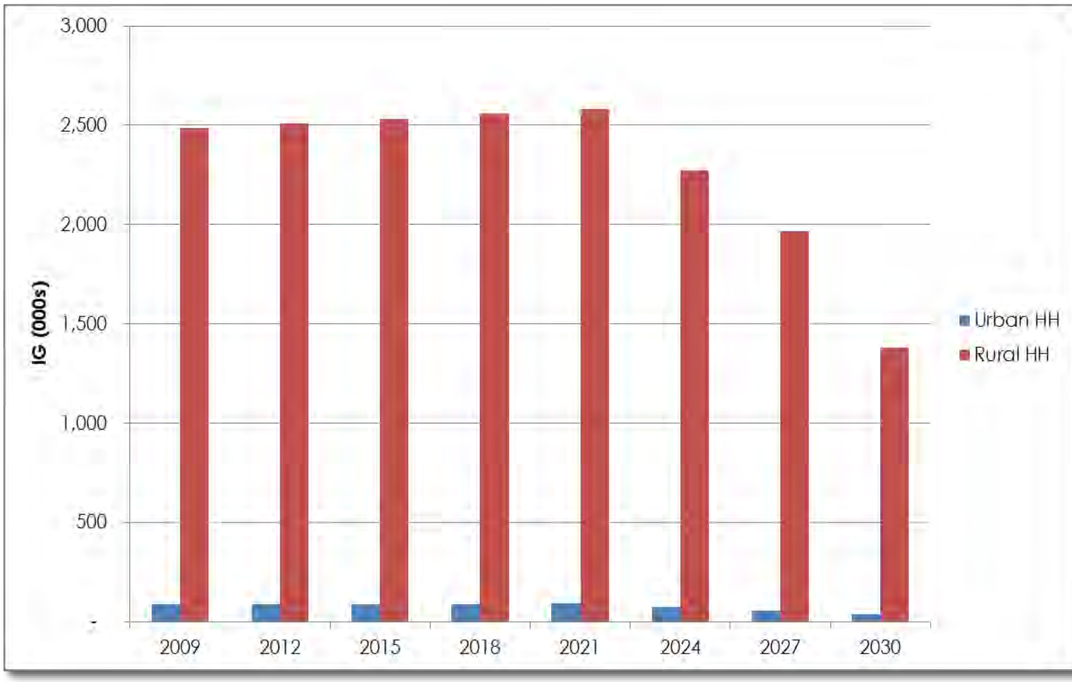
Source: Consultants' analysis

Figure II-30: FEC Projection by Energy Carrier: Households, Electricity



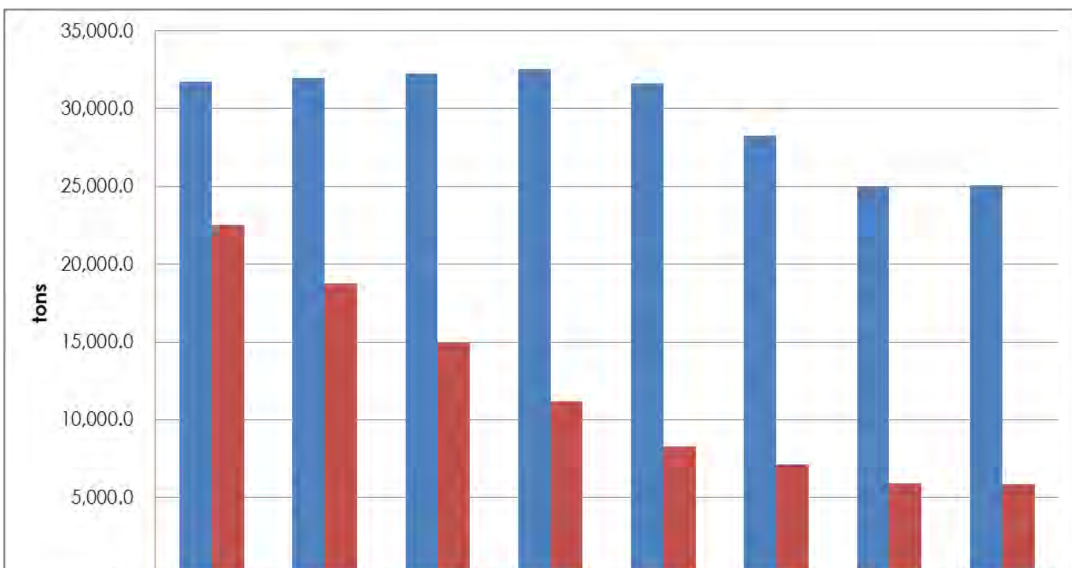
Source: Consultants' analysis

Figure II-31: FEC Projection by Energy Carrier: Households, Diesel



Source: Consultants' analysis

Figure II-32: FEC Projection by Energy Carrier: Households, LP Gas



	2009	2012	2015	2018	2021	2024	2027	2030
Urban HH	31,714.9	31,983.9	32,252.8	32,521.7	31,595.7	28,279.6	24,963.6	25,049.3
Rural HH	22,506.8	18,736.0	14,965.2	11,194.3	8,288.1	7,111.1	5,934.1	5,840.6

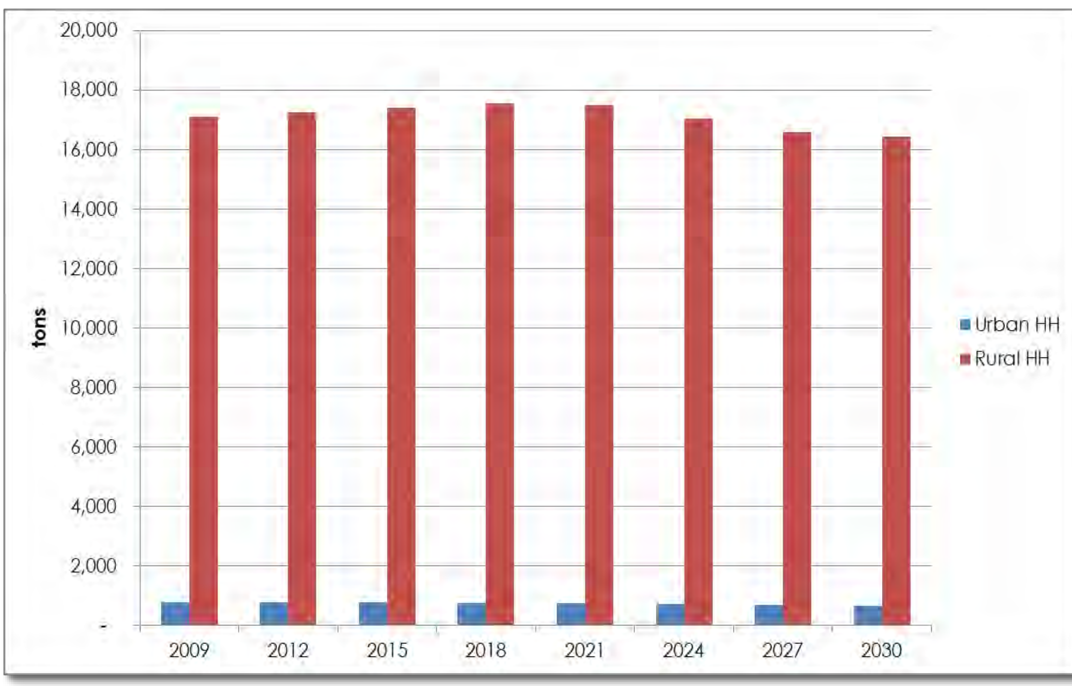
Source: Consultants' analysis

Figure II-33: FEC Projection by Energy Carrier: All Households, Biomass

	2009	2012	2015	2018	2021	2024	2027	2030
Charcoal	373	349	325	301	281	266	251	250
Agricultural Waste	1,161	1,135	1,109	1,083	1,049	999	949	935
Firewood	17,875	18,027	18,178	18,330	18,266	17,770	17,274	17,111

Source: Consultants' analysis

Figure II-34: FEC Projection by Energy Carrier: All Households, Firewood

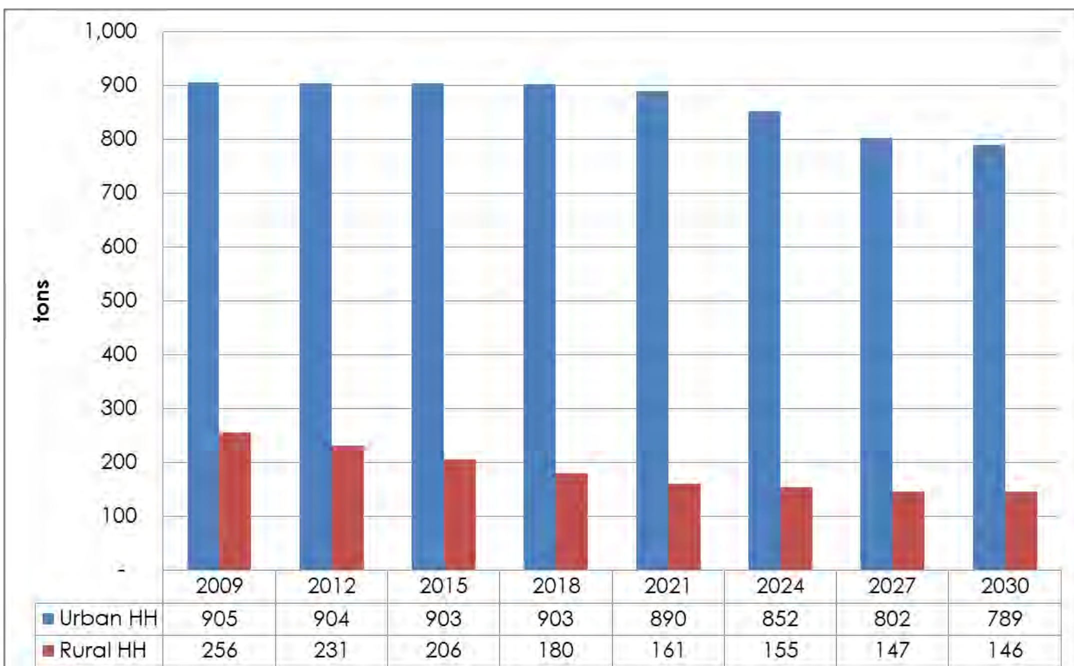


Source: Consultants' analysis

Figure II-35: FEC Projection by Energy Carrier: All Households, Charcoal

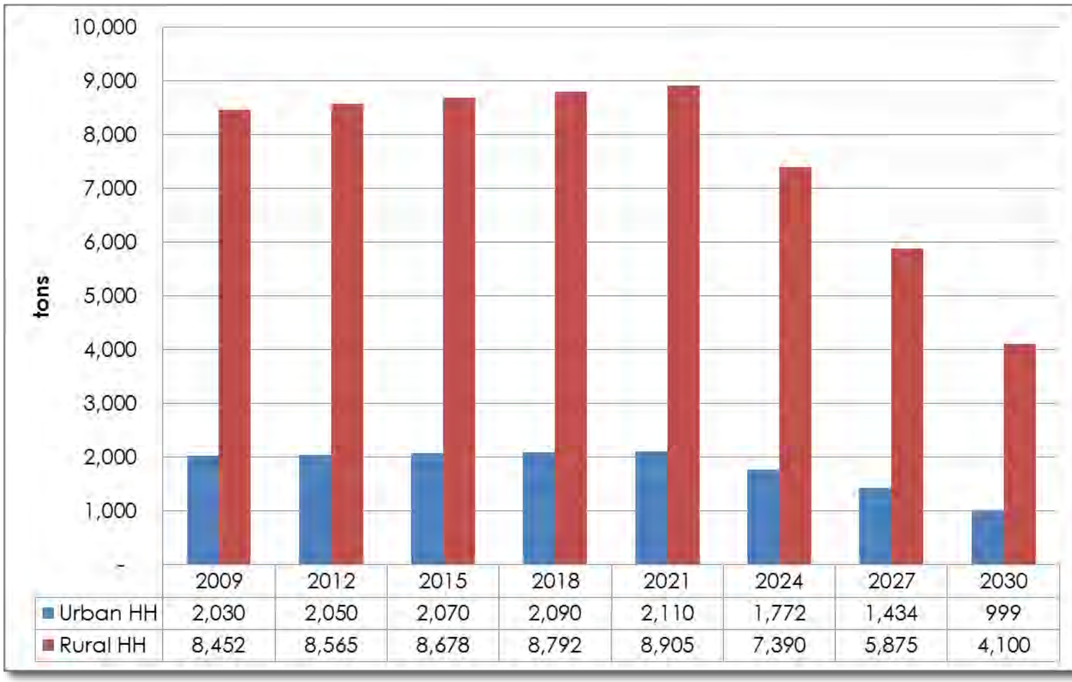
Source: Consultants' analysis

Figure II-36: FEC Projection by Energy Carrier: All Households, Agricultural Waste



Source: Consultants' analysis

Figure II-37: FEC Projection by Energy Carrier: All Households, Paraffin Wax



Source: Consultants' analysis

III. CONSOLIDATED FORECASTS BY ENERGY CARRIER

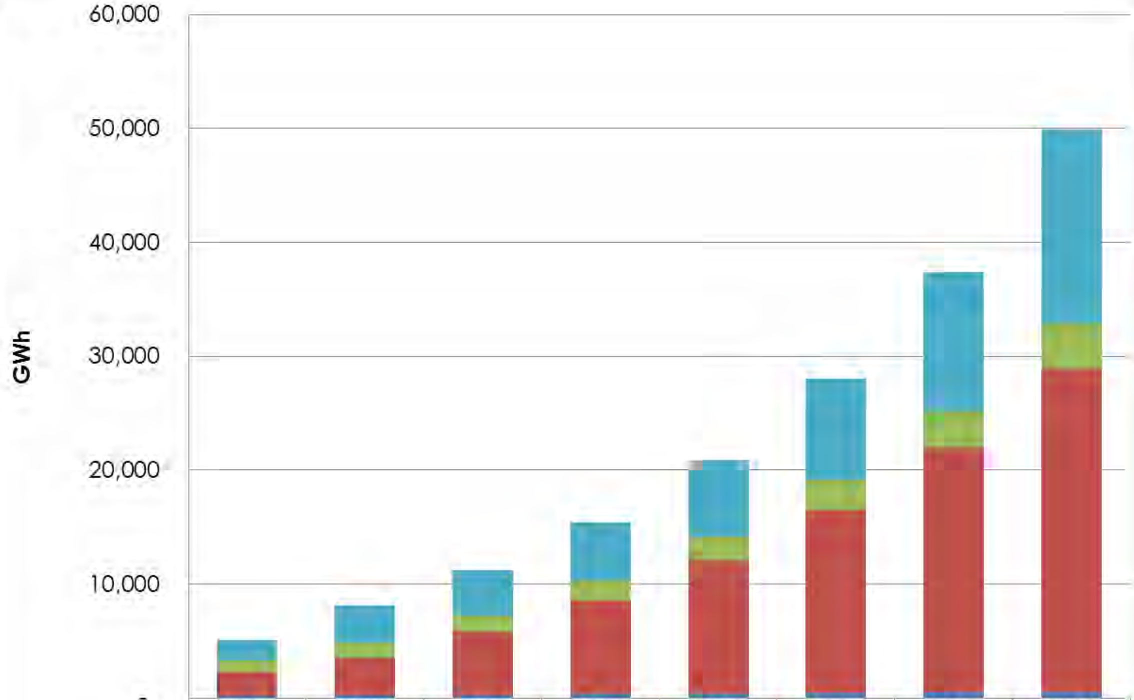
J. Introduction

14. A consolidation of the fuel forecasts, given in the previous section by sector, is given by chart in each of the following sub-sections. These consolidated forecasts represent the total energy carrier demand forecasts for the energy sector of Myanmar to 2030, according to the medium demand growth case.

K. Electricity

15. A consolidation of the electricity forecasts given in the previous section are given as Figure III-1. Historical electricity sales data was gathered from YESC and ESE and used to forecast electricity consumption using a top-down' forecasting method, taking into account the national electrification program. The 'top-down' forecasts and the 'bottom-up' forecasts given in Section II were reconciled. The details of the 'top-down' forecasts are given in Section IV.

Figure III-1: Electricity Forecast (GWh): Total

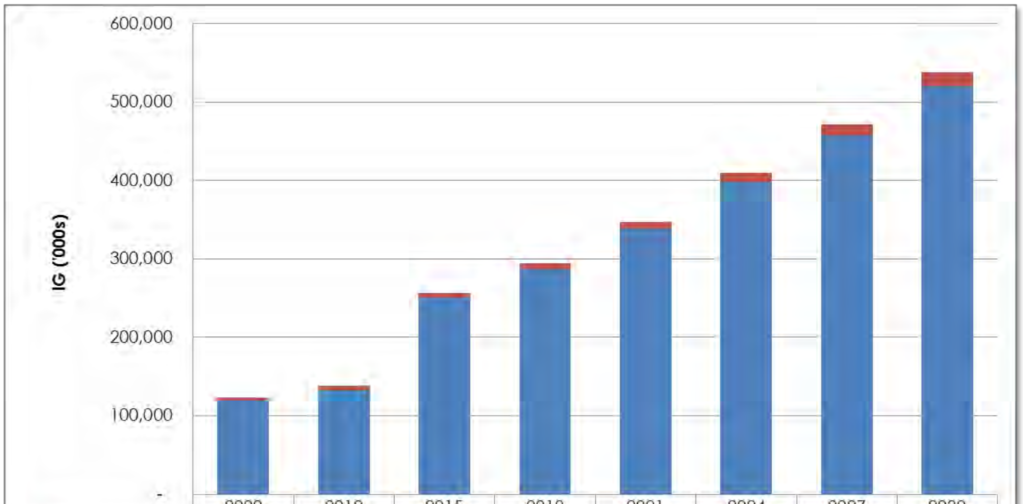


	2009	2012	2015	2018	2021	2024	2027	2030
Household	1,730	3,342	3,979	5,119	6,684	8,900	12,163	17,030
Commercial	1,009	1,332	1,423	1,742	2,140	2,637	3,259	4,043
Industry	2,095	3,231	5,524	8,251	11,690	16,061	21,480	28,310
Agriculture	207	255	283	342	382	442	481	541

Source: Consultants' analysis

L. Motor Spirit

Figure III-2: Motor Spirit Forecast (IG '000s)

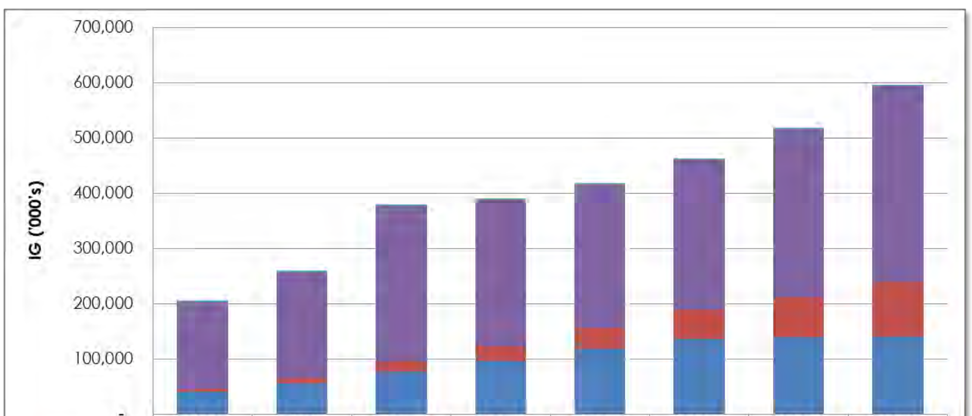


	2009	2012	2015	2018	2021	2024	2027	2030
Road Freight	3,390	5,908	6,818	7,618	9,145	11,356	14,216	18,275
Road Passenger	119,778	132,660	250,291	286,947	337,782	398,009	457,189	520,290

Source: Consultants' analysis

M. Diesel

Figure III-3: Diesel (HSD) Forecast (IG '000s)

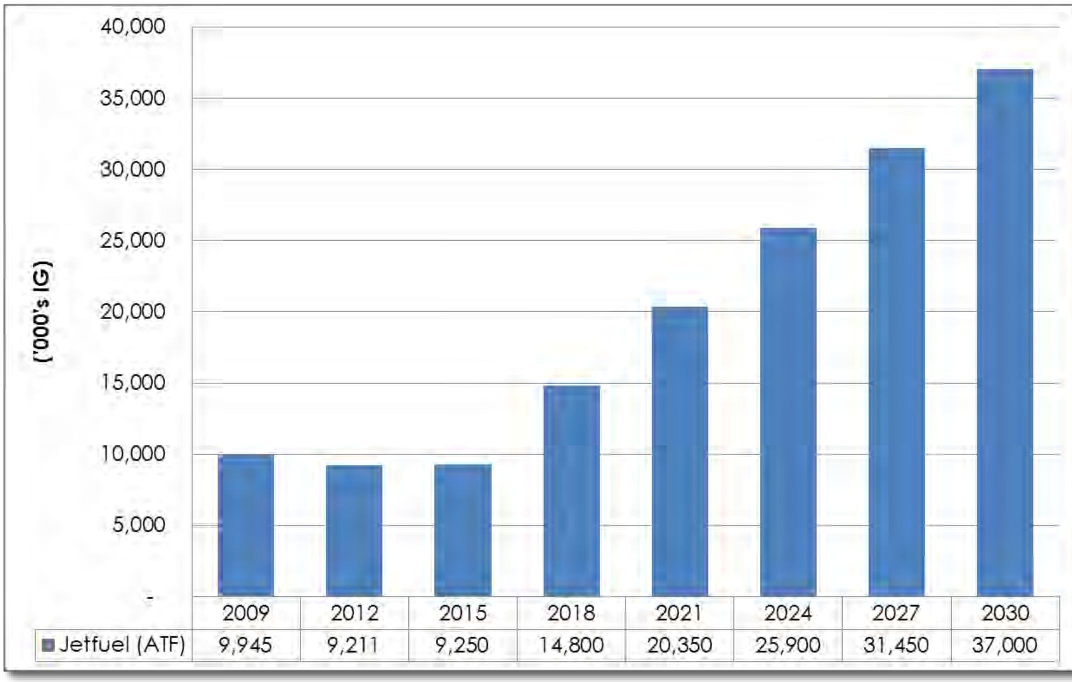


	2009	2012	2015	2018	2021	2024	2027	2030
Household	2,577	2,597	2,622	2,648	2,673	2,349	2,024	1,418
Transport	157,897	192,351	281,645	265,174	259,770	272,469	304,403	355,854
Commercial	-	-	-	-	-	-	-	-
Industry	5,014	9,323	18,913	26,575	37,442	52,275	71,844	98,059
Agriculture	40,854	56,378	76,900	96,728	118,933	136,472	139,621	141,441

Source: Consultants' analysis

N. Jet Fuel

Figure III-4: Jet Fuel (ATF) Forecast (IG '000s)



Source: Consultants' analysis

O. Liquid Gas

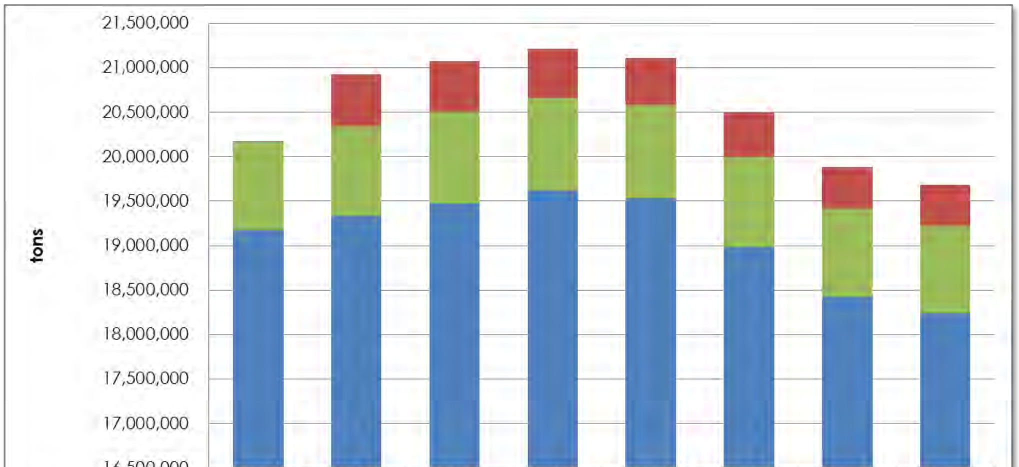
Table III-5: Gas Forecast (tons)

	Heavy Industry	Restaurants	Road Passenger	Urban HH	Rural HH	Fertilizer	Total
2009	212,681	324	16,908	31,715	22,507	12,486	296,620
2012	247,546	322	18,947	31,984	18,736	382,667	700,201
2015	403,668	335	26,889	32,253	14,965	465,555	943,666
2018	602,926	353	21,911	32,522	11,194	548,444	1,217,351
2021	854,279	374	17,866	31,596	8,288	631,333	1,543,737
2024	1,173,641	400	13,964	28,280	7,111	714,222	1,937,617
2027	1,569,684	430	10,026	24,964	5,934	797,111	2,408,148
2030	2,068,738	466	10,578	25,049	5,841	880,000	2,990,673

Source: Consultants' analysis

P. Woody Biomass

Figure III-6: Woody Biomass Forecast (tons)

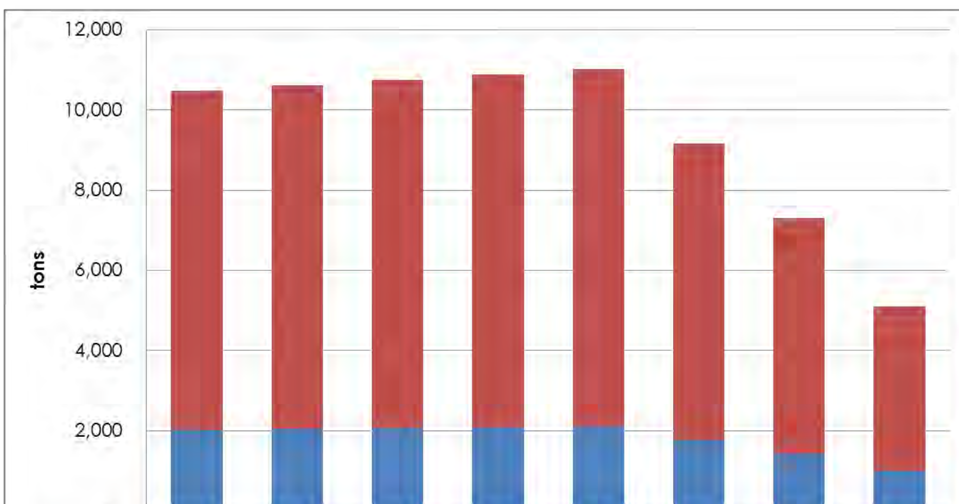


	2009	2012	2015	2018	2021	2024	2027	2030
Charcoal	373	589,428	569,145	548,862	525,302	495,188	465,074	461,488
Agricultural Waste	993,087	1,010,004	1,026,952	1,043,900	1,046,301	1,019,607	992,912	981,033
Firewood	19,174,97	19,329,12	19,476,17	19,623,22	19,535,96	18,980,07	18,424,18	18,238,73

Source: Consultants' analysis

Q. Paraffin Wax (Candles)

Figure III-7: Paraffin Wax Forecast (tons)

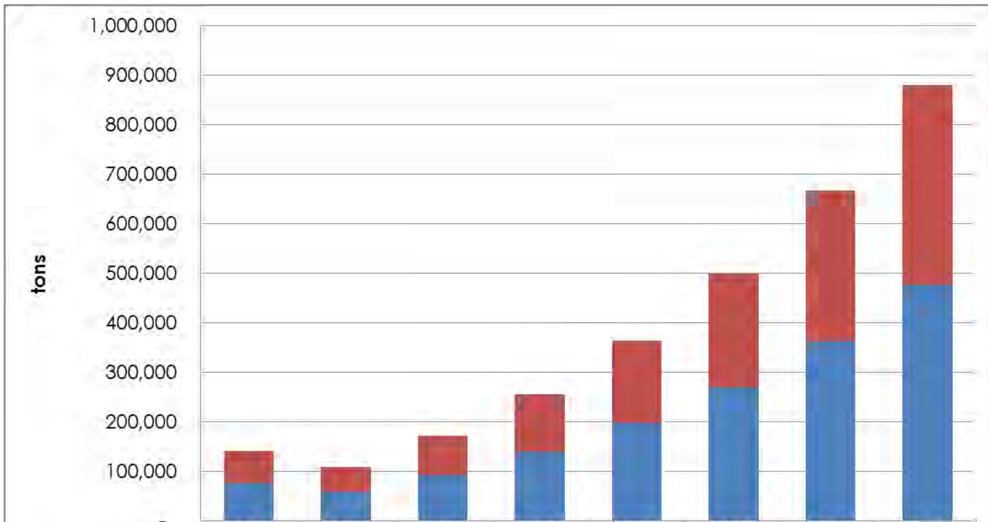


	2009	2012	2015	2018	2021	2024	2027	2030
Rural HH	8,452	8,565	8,678	8,792	8,905	7,390	5,875	4,100
Urban HH	2,030	2,050	2,070	2,090	2,110	1,772	1,434	999

Source: Consultants' analysis

R. Coal

Figure III-8: Coal Forecast (tons)



	2009	2012	2015	2018	2021	2024	2027	2030
Heavy Industry	64,469	49,929	78,456	117,183	166,035	228,105	305,079	402,073
SME	76,540	59,278	93,145	139,123	197,122	270,814	362,200	477,355

Source: Consultants' analysis

IV. ELECTRICITY FORECAST (TOP – DOWN RECONCILIATION)

T. Introduction

16. Electricity consumption forecasts were presented in the previous section as a summary of 'bottom-up' forecasts for each economic sector. These 'bottom-up' forecasts have been reconciled to 'top-down' load forecasts developed by forecasting electricity sales from historical statistics gathered from MoEP and shaped by GDP sector growth. The reconciled 'top-down' forecasts are presented in this section of the report.

17. In the case of the household sector the plan for national electrification was taken into account. National electrification targets were targeted as low case – 80%, medium case – 87% and high case – 96%; to be achieved by 2030. Top-down electricity forecasts were then prepared as follows:

1. Historical consumption and demand trends were examined and modelled by State and Region; the model was calibrated so that estimated demand (including losses) matched with demand reported by MoEP for each State and Region;
2. Electricity consumption was forecast for each State and Region according to national electrification targets, per consumer energy consumption (kWh per customer) and GDP growth across residential, commercial and industrial consumer categories; and
3. The individual sector estimates were aggregated on State and Region basis and for Myanmar as a whole.

18. No allowance has been made for large developments such as the Dawei industrial zone / port development, or for large mines. In these cases it is usual for a developer or a mine owner to construct a captive power plant.

U. Planning Assumptions

19. Planning assumptions extend to electricity losses, energy consumption trends and economic

Table IV-1: Distribution Losses - Yangon (2013)

		2009	2010	2011	2012	2013
Eastern District						
Technical loss	%	23.0	20.67	19.56	17.99	20.46
Non-technical loss	%					
Western District						
Technical loss	%	20.7	19.98	19.16	17.72	18.97
Non-technical loss	%					
Southern District						
Technical loss	%	20.65	20.23	19.65	17.26	19.01
Non-technical loss	%					

		2009	2010	2011	2012	2013
Northern District						
Technical loss	%	29.41	25.28	23.95	25.98	26.63
Non-technical loss	%					

Table IV-2: Distribution Losses – States & Regions

		2006	2007	2008	2009	2010	2011	2012	2013
Technical Loss									
Kachin State	%		10	10	10	11	11	12	12
Kayar State	%		23	23	10	10	22	12	16
Kayin State	%		9	9	9.5	9.5	10	11.5	11
Chin State	%		3	3	3	3	3	3	3
Mon State	%		22.12	16.24	15.39	14.35	20.65	23.24	22.21
Rakhine State	%		0.9	0.5	0.45	0.45	0.45	0.4	0.3
Shan State	%		11.09	25.73	25.85	34.03	33.09	34.78	34.11
Sagaing Region	%		20.19	21.45	20.15	23.45	22	18.35	15.14
Magway Region	%		1.8	2.8	1.8	3.1	4.3	8.7	8.9
Mandalay Region	%		17.13	17.78	18.61	23.5	28.8	32.18	32.24
Bago Region	%		27.7	28.5	31.58	27.33	27.84	26.47	24.32
Tanintharyi Region	%								
Ayeyarwaddy Region	%		21	20	19	19	18	18	18
Naypyitaw	%		6.9	6.6	6	5.4	3.732	3.03	2
Non-Technical Loss									
Kachin State	%			10.53	8.93	8.59	9.71	9.14	6.2
Kayar State	%		12	10	4	5	9	7	5
Kayin State	%		4	4.5	4.5	4.5	4.5	4.12	5
Chin State	%		2	2	2	2	2	2	2
Mon State	%		9.48	6.96	6.59	6.15	8.84	9.96	9.48
Rakhine State	%								
Shan State	%		7.01	6.9	7.23	10.67	8.64	9.22	9.46
Sagaing Region	%		12.51	12.51	7	7.5	6.12	6	5.5
Magway Region	%		7.07	8.26	5.6	7.61	7.55	5.59	7.46
Mandalay Region	%		12.51	12.63	12.68	13.12	12.11	10.57	10.31
Bago Region	%		20.04	20.48	19.89	19.01	18.98	21.96	20.02
Tanintharyi Region	%								

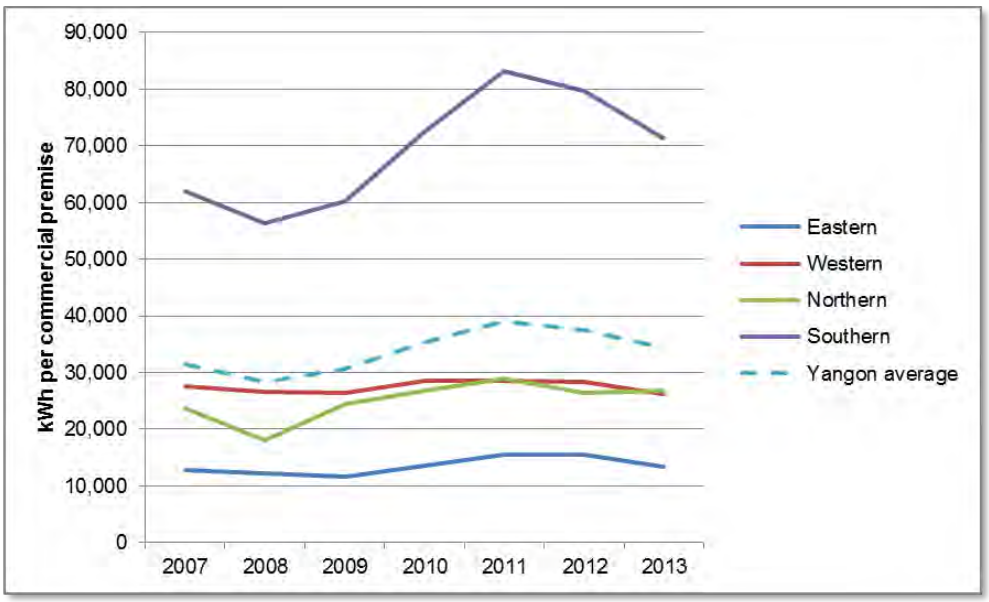
		2006	2007	2008	2009	2010	2011	2012	2013
Ayeyarwaddy Region	%		13	12	11	10	9	9	9
Naypyitaw	%		6.9	6.9	6.8	6.01	4	4.2	2.55

Sources: MoEP

V. Energy Consumption Trends

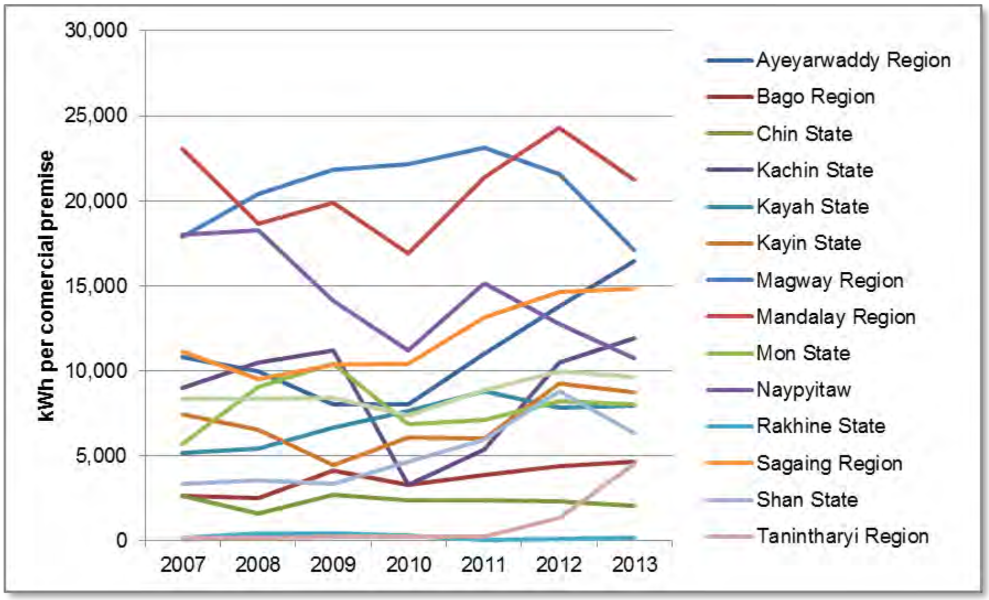
20. Energy consumption trends are observed as a change to the customer's annual consumption of power. In the case of electricity, kWh per consumer is the measure of electricity consumption. Figure IV-3 and Figure IV present the electricity consumption per consumer for the Commercial & Light Industrial segment in Yangon Division and by State / Regions. The kWh per consumer growth trend for the Yangon commercial and light industrial segment shows an average growth of 2%. The kWh per consumer growth trend for the States / Regions in aggregate has averaged 3%.

Figure IV-3: Yangon C&I kWh per Customer



Sources: Consultants' estimate

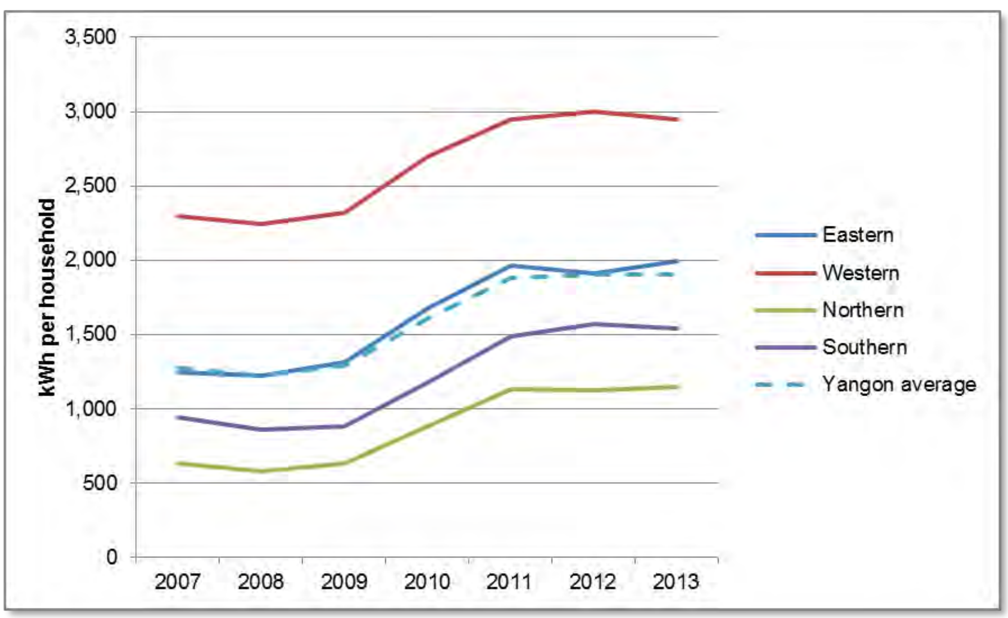
Figure IV-4: State / Region C & I kWh per Customer



Sources: Consultants' estimate

21. Figure IV-5 and Figure IV-6 present the electricity consumption per consumer for the residential segment in Yangon Division and by State / Regions.

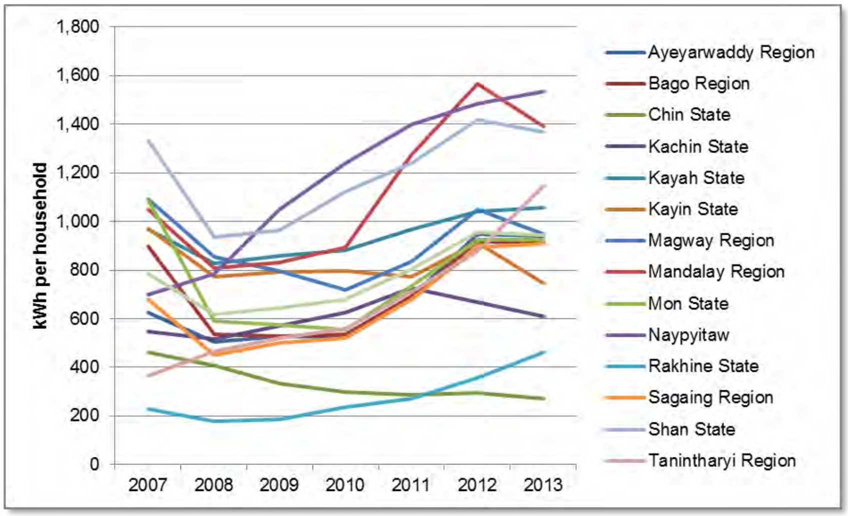
Figure IV-5: Yangon Residential kWh per Customer



Sources: Consultants' estimate

22. The kWh per consumer growth trend for the Yangon residential segment shows an average growth of 7.4%. The kWh per consumer growth trend for the States / Regions in aggregate has averaged 4%.

Figure IV-6: State / Region Residential kWh per Customer

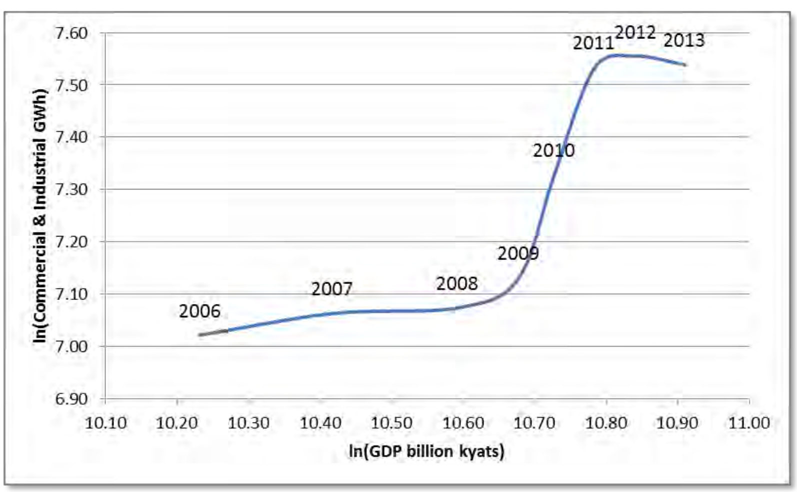


Sources: Consultants' estimate

W. Economic Trends

23. It is observed that in the non-oil producing countries, GDP and the growth in non-residential electricity consumption are strongly correlated. The relationship between the natural logarithm of GDP and the natural logarithm of GWh consumption is typically linear. Figure IV-7 shows that the relationship of non-residential electricity consumption and GDP in Myanmar has not been linear and is therefore unsuitable as an input to forecasting.

Figure IV-7: Myanmar – log (GWh Consumption) vs. log (GDP)



Sources: Consultants' estimate

X. Baseline Energy Consumption

24. Baseline energy data for each State / Region was collected from YESC and ESE. The data was analyzed and a summary is presented in Table IV-8 for FY2013.

Table IV-8: Baseline Energy Sales by State / Region: 2013

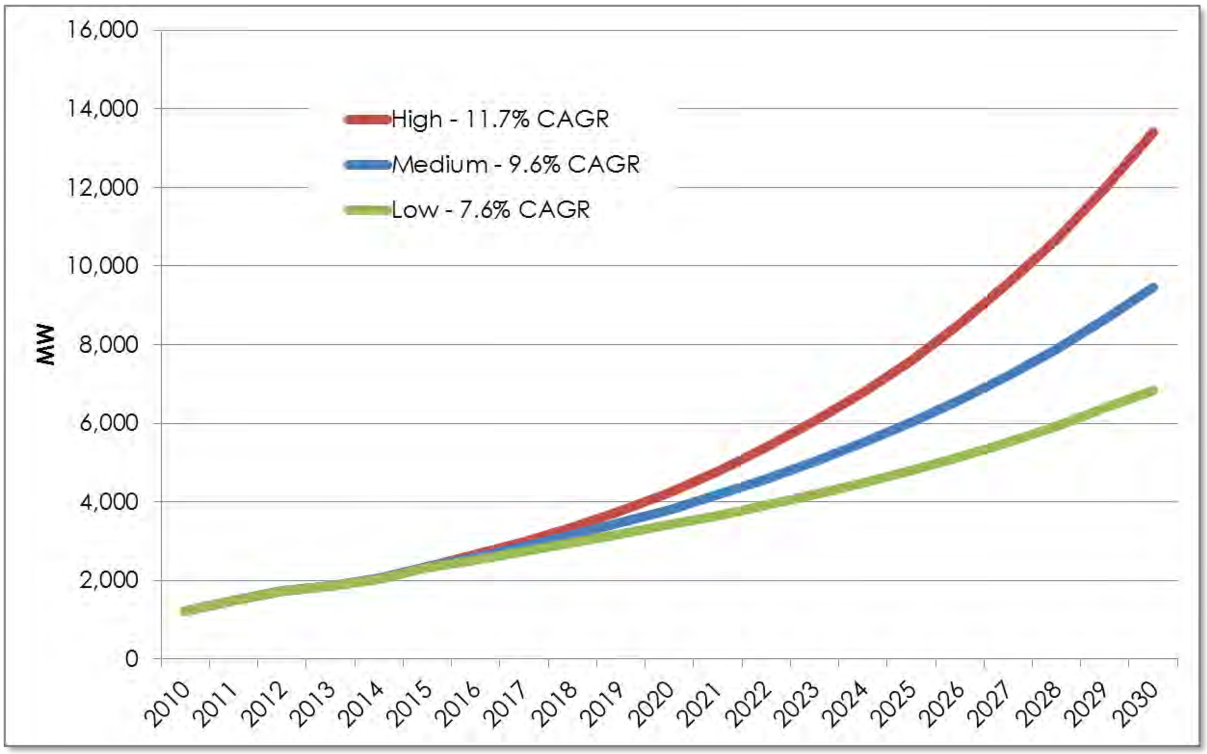
State / Region	Grid-Electrified Residential Customers	Peak Demand MW	Average kWh per HH	Average kWpeak per HH	Note
Ayerwaddy Region	136,021	92	941	0.24	
Bago Region	236,773	140	913	0.20	
Chin State	12,963	4	271	0.34	No supply by ESE
Kachin State	57,555	24	609	0.30	
Kayar State	20,081	10	1,058	0.27	
Kayin State	30,774	15	748	0.19	
Magway Region	126,931	112	948	0.27	
Mandalay Region	372,812	462	1,393	0.48	
Mon State	107,718	49	925	0.20	
Nay Pi Taw	77,425	106	1,534	0.30	
Rakhine State	32,347	13	461	0.31	No supply by ESE
Sagaing Region	191,984	101	908	0.21	
Shan State	207,933	110	1,369	0.35	
Tanintharyi Region	18,610	67	1,148	1.00	
Yangon	921,462	1,096	1,907	0.55	
Total	2,551,389	2,401			
Average Yangon, Mandalay & NPT			1,611	0.45	
Average Other			858	0.33	

Sources: Consultants' estimate

Y. Myanmar Consolidated Electricity Forecasts

25. The medium growth case forecast for Myanmar shows an expected growth of peak demand MW from the current level of 2 100 MW to around 9 500 MW by 2030. This case calls for an average annual addition of generation capacity of around 440 MW from now to year 2030. The growth projections can also be understood in terms of the average kWh / capita growth; from 200 to 800 kWh per capita by 2030.

Figure IV-9: Myanmar Grid Electricity Growth Forecast



Source: Consultants' analysis; includes T&D losses

Table IV-10: Average kWh / Capita Growth

	kWh per Capita		
	Low	Medium	High
2010	125	125	125
2015	225	227	230
2020	316	352	393
2025	423	530	670
2030	573	793	1,124

Source: Consultants' analysis; includes T&D losses

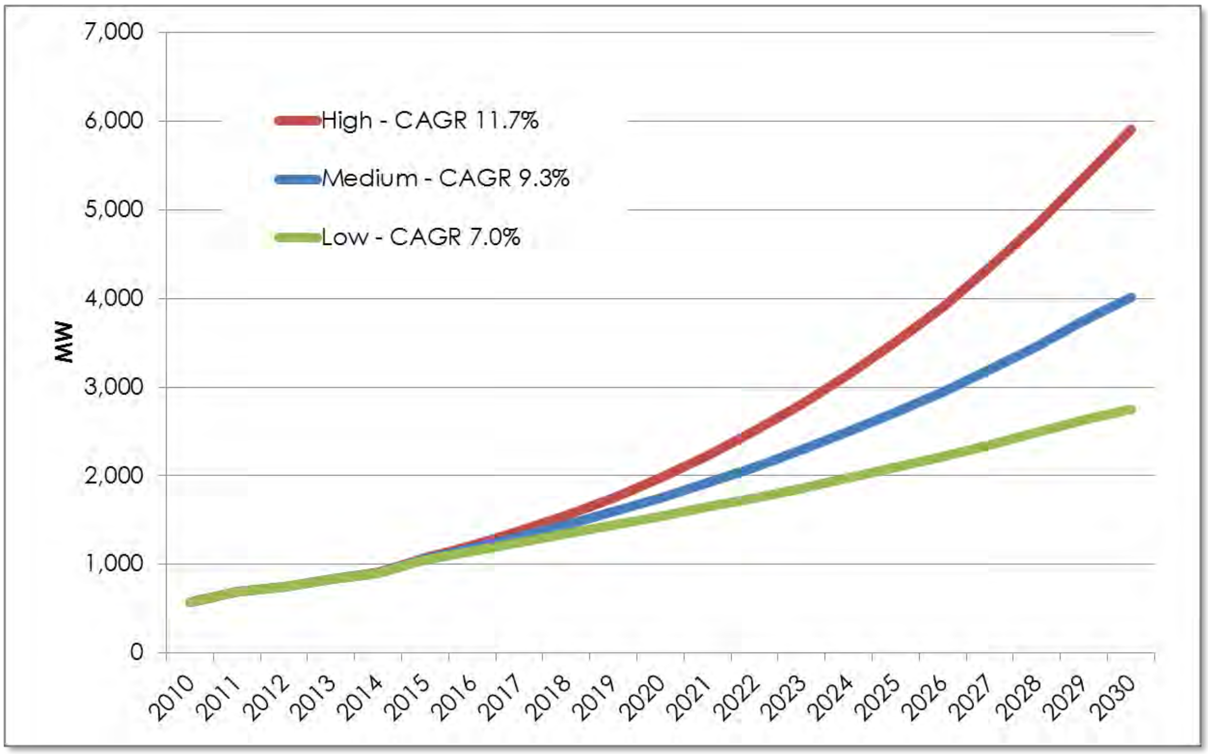
Table IV-11: Myanmar Grid Electricity Growth Forecast

	Low			Medium			High		
	MW	GWh	AGR MW	MW	GWh	AGR MW	MW	GWh	AGR MW
2010	1,221	7,318		1,221	7,318		1,221	7,318	
2011	1,490	8,927	22.0%	1,490	8,927	21.98%	1,490	8,927	22.0%
2012	1,730	10,364	16.1%	1,730	10,364	16.09%	1,730	10,364	16.1%
2013	1,853	10,388	7.1%	1,853	10,388	7.13%	1,853	10,388	7.1%
2014	2,036	12,200	9.9%	2,045	12,255	10.39%	2,055	12,311	10.9%
2015	2,314	13,866	13.7%	2,336	14,000	14.24%	2,359	14,136	14.8%
2016	2,526	15,137	9.2%	2,592	15,531	10.94%	2,660	15,937	12.7%
2017	2,741	16,425	8.5%	2,861	17,143	10.38%	2,986	17,894	12.3%
2018	2,967	17,775	8.2%	3,155	18,906	10.28%	3,356	20,111	12.4%
2019	3,186	19,092	7.4%	3,465	20,762	9.82%	3,769	22,585	12.3%
2020	3,415	20,463	7.2%	3,806	22,805	9.84%	4,244	25,431	12.6%
2021	3,658	21,917	7.1%	4,180	25,047	9.83%	4,784	28,662	12.7%
2022	3,917	23,468	7.1%	4,588	27,491	9.76%	5,387	32,280	12.6%
2023	4,190	25,108	7.0%	5,026	30,112	9.54%	6,050	36,250	12.3%
2024	4,485	26,872	7.0%	5,501	32,962	9.46%	6,786	40,660	12.2%
2025	4,800	28,762	7.0%	6,019	36,064	9.41%	7,606	45,574	12.1%
2026	5,146	30,835	7.2%	6,589	39,481	9.47%	8,525	51,078	12.1%
2027	5,519	33,070	7.2%	7,211	43,205	9.43%	9,547	57,203	12.0%
2028	5,932	35,541	7.5%	7,900	47,334	9.56%	10,698	64,099	12.1%
2029	6,384	38,252	7.6%	8,661	51,892	9.63%	11,990	71,843	12.1%
2030	6,843	41,002	7.2%	9,465	56,715	9.29%	13,410	80,353	11.8%
CAGR 2014-2030	7.6%	7.6%		9.6%	9.6%		11.7%	11.7%	
Average MW added p.a.	255			439			738		

Source: Consultants' analysis; includes T&D losses

26. The medium growth case forecast for Yangon shows an expected growth of peak demand MW from the current level of 950 MW to around 4 000 MW in 2030. This case calls for an average annual addition of generation capacity of around 200 MW from now to year 2030. The growth projections can also be understood in terms of the average kWh / capita growth; from 900 to 3000 kWh per capita by 2030.

Figure IV-12: Yangon Grid Electricity Growth Forecast



Source: Consultants' analysis; includes T&D losses

Table IV-13: Average kWh / Capita Growth

	kWh per Capita		
	Low	Medium	High
2010	526	526	526
2015	916	927	937
2020	1,280	1,450	1,637
2025	1,653	2,141	2,766
2030	2,061	3,013	4,434

Source: Consultants' analysis; includes T&D losses

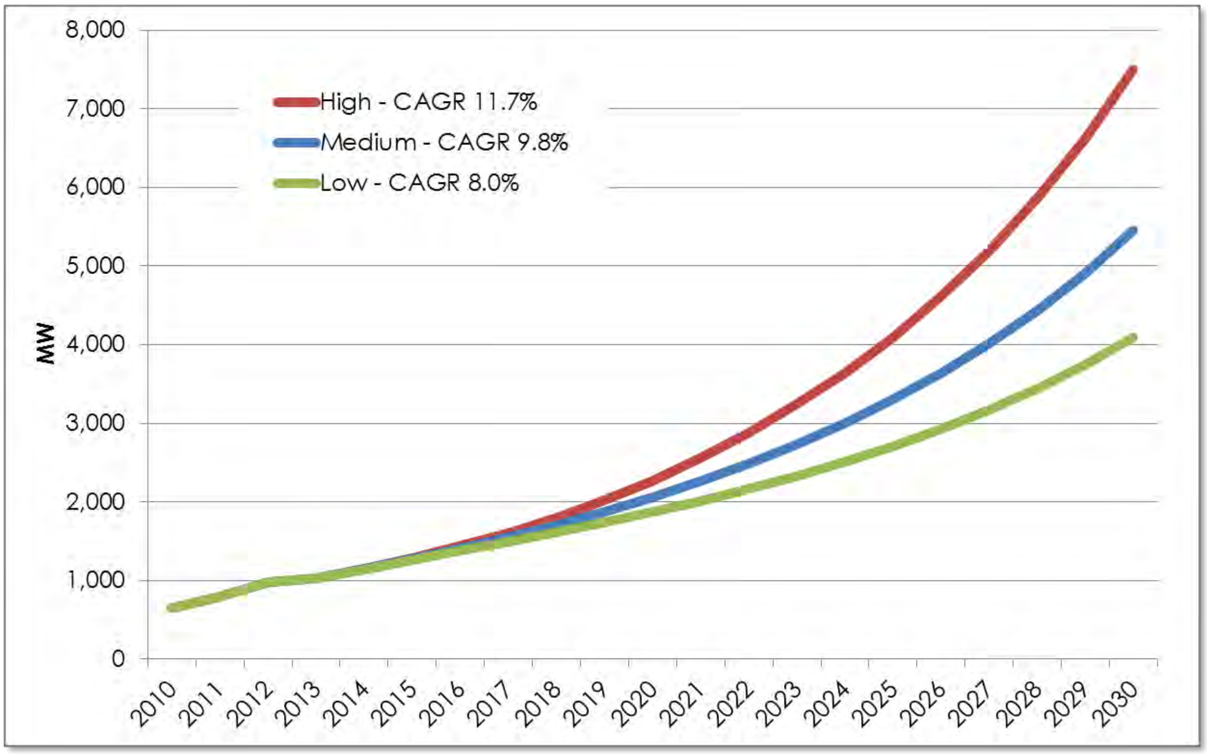
Table IV-14: Yangon Electricity Growth Forecast

	Low			Medium			High		
	MW	GWh	AGR MW	MW	GWh	AGR MW	MW	GWh	AGR MW
2010	573	3,624		573	3,624		573	3,624	
2011	691	4,368	20.53%	691	4,368	20.53%	691	4,368	20.53%
2012	746	4,727	7.96%	746	4,727	7.96%	746	4,727	7.96%
2013	831	4,660	11.43%	831	4,660	11.43%	831	4,660	11.43%
2014	895	5,642	7.62%	901	5,680	8.34%	907	5,719	9.08%
2015	1,052	6,637	17.62%	1,064	6,712	18.17%	1,076	6,789	18.71%
2016	1,149	7,249	9.22%	1,184	7,471	11.30%	1,220	7,696	13.36%
2017	1,248	7,872	8.60%	1,312	8,276	10.78%	1,378	8,691	12.94%
2018	1,349	8,506	8.05%	1,449	9,137	10.41%	1,554	9,800	12.76%
2019	1,447	9,126	7.29%	1,594	10,053	10.02%	1,752	11,049	12.74%
2020	1,544	9,741	6.74%	1,749	11,034	9.75%	1,975	12,459	12.76%
2021	1,647	10,386	6.62%	1,919	12,103	9.69%	2,228	14,052	12.79%
2022	1,752	11,049	6.38%	2,100	13,242	9.41%	2,506	15,807	12.49%
2023	1,862	11,744	6.29%	2,292	14,454	9.16%	2,810	17,721	12.11%
2024	1,978	12,473	6.21%	2,498	15,754	8.99%	3,144	19,829	11.89%
2025	2,097	13,223	6.01%	2,715	17,127	8.72%	3,508	22,125	11.58%
2026	2,221	14,010	5.95%	2,948	18,595	8.57%	3,908	24,645	11.39%
2027	2,352	14,837	5.90%	3,197	20,164	8.44%	4,346	27,413	11.23%
2028	2,490	15,705	5.85%	3,464	21,846	8.34%	4,829	30,459	11.11%
2029	2,635	16,617	5.81%	3,749	23,647	8.24%	5,361	33,813	11.01%
2030	2,748	17,329	4.29%	4,017	25,335	7.14%	5,910	37,278	10.25%
CAGR 2014-2030	7.0%	7.0%		9.3%	9.3%		11.7%	11.7%	
Average MW added p.a.	103			198			343		

Source: Consultants' analysis; includes T&D losses

27. The medium growth case forecast for the States and Regions, excluding Yangon, shows an expected growth of peak demand MW from the current level of 1 150 MW to around 5 450 MW in 2030. This case calls for an average annual addition of generation capacity of around 240 MW from now to year 2030. The growth projections can also be understood in terms of the average kWh / capita growth; from 130 to 500 kWh per capita by 2030.

Figure IV-15: ESE Grid Electricity Growth Forecast



Source: Consultants' analysis; includes T&D losses

Table IV-16: Average kWh / Capita Growth

	kWh per Capita		
	Low	Medium	High
2010	71	71	71
2015	133	134	135
2020	188	206	227
2025	259	315	391
2030	375	497	683

Source: Consultants' analysis; includes T&D losses

Table IV-17: ESE Electricity Growth Forecast

	Low			Medium			High		
	MW	GWh	AGR MW	MW	GWh	AGR MW	MW	GWh	AGR MW
2010	648	3,694		648	3,694		648	3,694	
2011	799	4,559	23.27%	799	4,559	23.27%	799	4,559	23.27%
2012	984	5,636	23.12%	984	5,636	23.12%	984	5,636	23.12%
2013	1,022	5,728	3.86%	1,022	5,728	3.86%	1,022	5,728	3.86%
2014	1,141	6,557	11.73%	1,145	6,575	12.05%	1,148	6,592	12.36%
2015	1,262	7,229	10.55%	1,272	7,287	11.14%	1,283	7,347	11.76%
2016	1,377	7,888	9.11%	1,408	8,060	10.64%	1,440	8,241	12.21%
2017	1,493	8,552	8.43%	1,549	8,868	10.05%	1,608	9,202	11.72%
2018	1,618	9,269	8.37%	1,707	9,769	10.17%	1,803	10,311	12.08%
2019	1,739	9,966	7.51%	1,871	10,709	9.65%	2,018	11,537	11.93%
2020	1,871	10,721	7.54%	2,057	11,771	9.91%	2,269	12,972	12.46%
2021	2,011	11,530	7.51%	2,261	12,944	9.95%	2,556	14,610	12.63%
2022	2,165	12,419	7.65%	2,489	14,249	10.05%	2,881	16,473	12.73%
2023	2,328	13,365	7.56%	2,734	15,658	9.86%	3,240	18,529	12.47%
2024	2,507	14,399	7.68%	3,003	17,209	9.86%	3,642	20,832	12.40%
2025	2,704	15,539	7.84%	3,304	18,938	9.99%	4,098	23,449	12.52%
2026	2,925	16,825	8.18%	3,641	20,886	10.21%	4,617	26,432	12.66%
2027	3,167	18,233	8.27%	4,014	23,040	10.23%	5,200	29,790	12.64%
2028	3,441	19,836	8.68%	4,436	25,488	10.53%	5,868	33,639	12.84%
2029	3,749	21,635	8.95%	4,911	28,246	10.71%	6,629	38,030	12.96%
2030	4,095	23,673	9.23%	5,448	31,380	10.94%	7,500	43,075	13.14%
CAGR 2014-2030	8.0%	8.0%		9.8%	9.8%		11.7%	11.7%	
Average MW added p.a.	152			241			395		

Source: Consultants' analysis

Z. National Electrification

28. The current status of electrification and connection rates in 2014 was reported by MoEP. The national electrification goals were used to project the status of electrification by State and Region in 2030. New connection rates were estimated for the period from 2014 to 2030, taking into account household growth. The status of electrification is estimated for 2030.

Table IV-18: Status of Electrification - 2014

	HH 2014	% Grid Electrified	HH Grid Electrified	New Connection Rates p.a. 2014
Ayeyarwaddy	2,025,306	7%	149,949	13,928
Bago Region	1,511,883	17%	256,870	20,097
Chin State	113,308	12%	13,710	747
Kachin State	320,677	19%	62,342	4,787
Kayah State	76,957	28%	21,896	1,815
Kayin State	399,431	8%	33,010	2,236
Magway Region	1,414,382	10%	136,881	9,950
Mandalay Region	1,738,036	24%	410,605	37,793
Mon State	702,485	17%	116,329	8,611
Naypyitaw	287,319	30%	86,288	8,863
Rakhine State	775,128	4%	33,227	880
Sagaing Region	1,463,932	15%	219,151	27,167
Shan State	1,244,589	19%	233,056	25,123
Tanintharyi Region	370,026	5%	18,930	320
Yangon Division	1,789,736	53%	949,925	60,000
Total	14,233,196		2,742,169	222,317
			19%	

Sources: MoEP, Consultant

Table IV-19: New Connection Rates – (Medium Electrification – 87%)

	2014	2015	2018	2021	2024	2027	2030
Ayeyarwaddy Region	13,928	16,714	29,251	52,513	94,273	169,243	303,831
Bago Region	20,097	22,107	33,667	51,706	79,408	121,954	187,294
Chin State	747	896	1,510	2,418	3,872	6,200	9,927
Kachin State	4,787	5,266	7,155	10,133	14,349	20,320	28,775
Kayah State	1,815	1,906	2,190	2,477	2,803	3,171	3,587
Kayin State	2,236	2,684	4,911	10,077	20,680	42,438	87,088
Magway Region	9,950	11,939	20,801	36,835	65,231	115,515	204,563

	2014	2015	2018	2021	2024	2027	2030
Mandalay Region	37,793	39,682	49,619	72,386	105,601	154,056	224,745
Mon State	8,611	9,042	12,018	21,061	36,909	64,680	113,348
Naypyitaw	8,863	9,306	11,743	13,316	15,100	17,124	19,418
Rakhine State	880	1,056	2,217	6,868	21,279	65,925	204,249
Sagaing Region	27,167	29,883	39,865	53,424	71,595	95,946	128,579
Shan State	25,123	27,635	34,235	36,740	39,428	42,313	45,409
Tanintharyi Region	320	384	835	2,872	9,878	33,982	116,902
Yangon Division	60,000	64,897	82,119	103,911	131,487	166,380	97,324
Total	224,331	245,413	334,153	478,759	713,917	1,121,274	1,777,070
Yr on Yr Rate of Increase	-	9.4%	11.9%	13.2%	14.8%	17.0%	12.9%

Sources: Consultant

Table IV-20: Status of Electrification in 2030 (Medium Electrification – 87%)

	HH 2030	% Grid Electrified 2030 at 2014 connection rates	HH Grid Electrified with current connection rates	HH not grid electrified
Ayeyarwaddy	2,228,735	80%	1,789,563	439,172
Bago Region	1,663,742	91%	1,519,004	144,738
Chin State	124,689	61%	76,437	48,252
Kachin State	352,886	81%	284,371	68,515
Kayah State	84,687	76%	64,774	19,913
Kayin State	439,551	99%	433,357	6,194
Magway Region	1,556,447	81%	1,260,613	295,834
Mandalay Region	2,205,543	94%	2,065,902	139,641
Mon State	773,045	97%	750,955	22,090
Naypyitaw	316,179	100%	315,819	360
Rakhine State	852,984	80%	682,615	170,369
Sagaing Region	1,610,974	81%	1,312,087	298,887
Shan State	1,369,600	61%	839,086	530,514
Tanintharyi Region	407,192	90%	365,000	42,192
Yangon Division	2,867,737	99%	2,831,660	36,077
Total	16,853,991		14,591,243	2,262,748
			87%	13%

Sources: Consultant

APPENDIX: Myanmar State and Region Electricity Demand Growth

AYERWADDY REGION

1. Ayerwaddy occupies the delta region of the Ayerwaddy River (Irrawaddy River). It is bordered by Bago Region to the north, Bago Region and Yangon Region to the east, and the Bay of Bengal to the south and west. It is contiguous with the Rakhine State in the northwest. The Region is heavily forested and wood products are an important component of the economy. The principal crop of Ayerwaddy is rice, and the region is called the "granary of Burma." In addition to rice, other crops include maize, sesame, groundnut, sunflower, beans, pulses and jute. Fisheries are also important; the Region produces fish, prawn, fish-paste, dry fish, dry prawn and fish sauce.

2. Ayerwaddy Region also has considerable tourist potential. The city of Pathein has numerous historic sights and temples. Outside Pathein are the beach resorts of Chaungtha Beach and the lake resort of Inye Lake. Inye Lake is well known for fishery as the major supplier of fresh water fish. However, hotel and transportation infrastructure is still very poorly developed.

Residential Connections Forecast

3. In the last six years the reported new connection rate has been high at an average of 9%; the rate appears to reflect the low electrification rate.

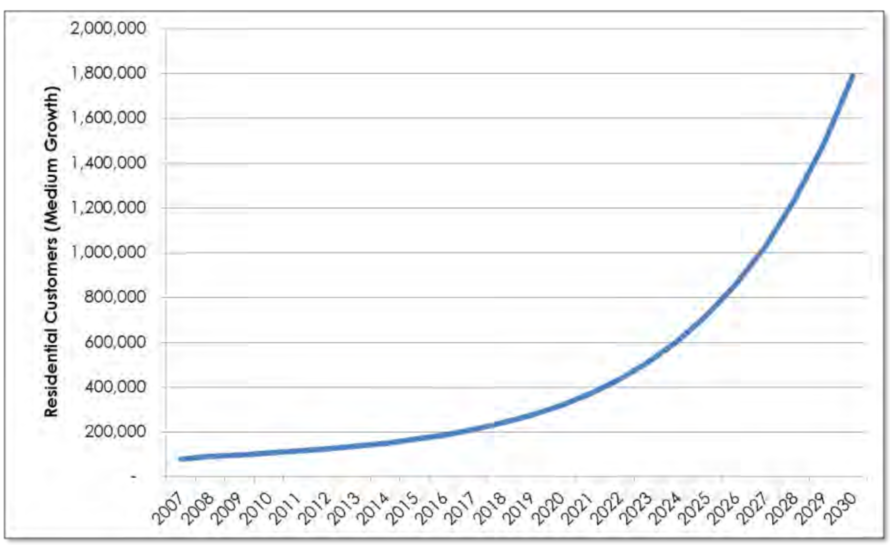
Table IV-21: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	91 029	97 867	106 617	114 219	123 359	136 021
Growth (new connections p.a.)	10,993	6,838	8,750	7,602	9,140	12,662
Growth %	14%	8%	9%	7%	8%	10%

Sources: MoEP

4. The forecast growth of residential grid supply connections is shown in Figure IV-22 for the 87% national electrification goal.

Figure IV-22: Growth of Residential Connections

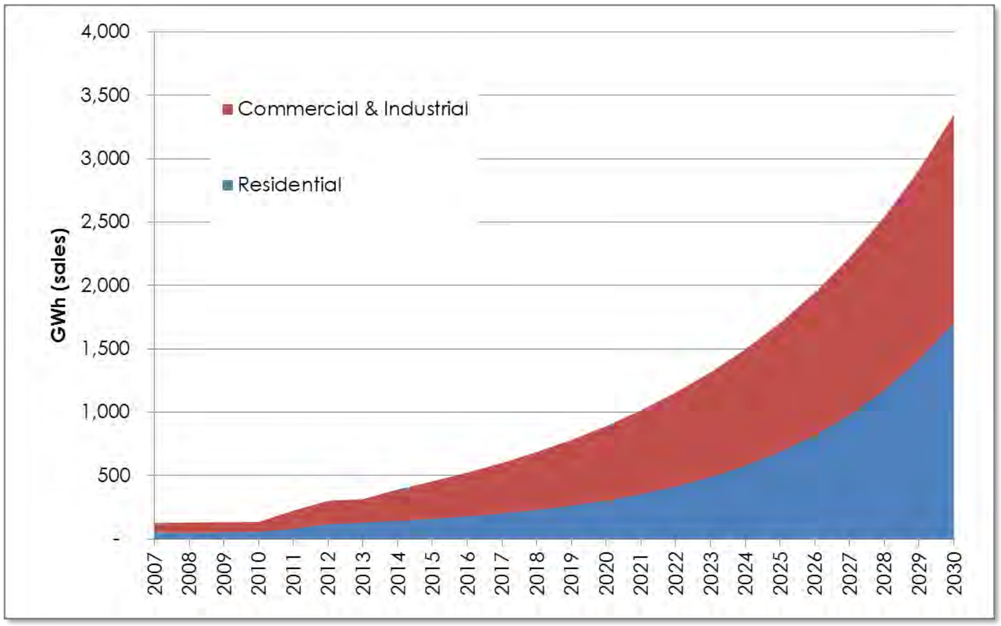


Sources: Consultant

Electricity Forecasts

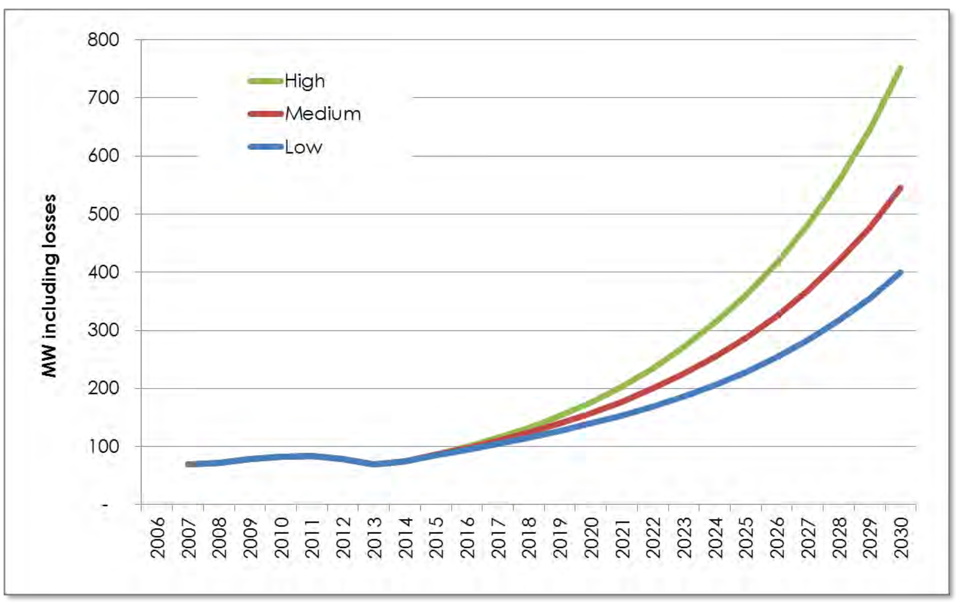
5. The average kWh per residential customer increased from 506 in 2008 to 940 in 2013. Commercial and light industrial consumption is reported by MoEP at average16 500 kWh per customer. There were no industrial customers of 2 MVA or above reported.

Figure IV-23: Forecast Electricity Consumption Growth



Sources: Including losses; Consultant

Figure IV-24: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

BAGO REGION

6. Bago Region is located in the southern central part of the country. It is bordered by Magway Region and Mandalay Region to the north; Kayin State, Mon State and the Gulf of Martaban to the east; Yangon Region to the south and Ayerwaddy Region and Rakhine State to the west.

7. The regional economy is strongly dependent on the timber trade. Taungoo, in the northern end of the Bago Region, is bordered by mountain ranges, home to teak and other hardwoods. Another natural resource is petroleum. The major crop is rice which occupies over two-thirds of the available agricultural land. Other major crops include betel nut, sugarcane, maize, groundnut, sesamum, sunflower, beans and pulses, cotton, jute, rubber, tobacco, tapioca, banana, Nipa palm and toddy. Industry includes fisheries, salt, ceramics, sugar, paper, plywood, distilleries and monosodium glutamate.

8. Bago has a small livestock breeding and fisheries sector, and a small industrial sector. In 2005 it had over 4 million farm animals; nearly 3 000 acres (12 km^2) of fish and prawn farms; and about 3 000 private factories and about 100 state owned factories.

Residential Connections Forecast

9. In the last six years, the reported new connection rate has been high at an average of 16%. This rate appears to have resulted in the relatively high electrification rate of 54%. This rate suggests that Bago Region citizens are relatively wealthy due to the diverse nature of economic activity including a degree of industrialization.

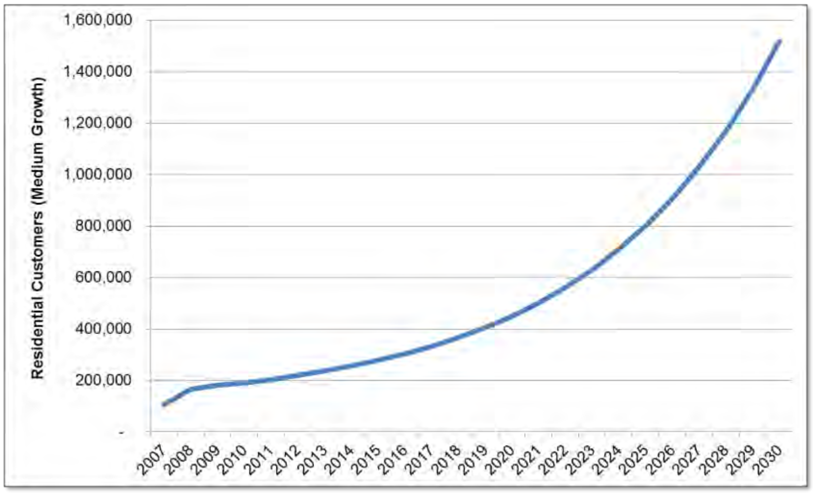
Table IV-25: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	164 879	181 680	189 582	201 519	218 503	236 773
Growth (new connections p.a.)	16 801	7 902	11 937	16 984	18 270	20 000
Growth %	58%	10%	4%	6%	8%	8%

Sources: MoEP

10. The forecast growth of residential grid supply connections is shown in Figure IV-26 for the 87% national electrification goal.

Figure IV-26: Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

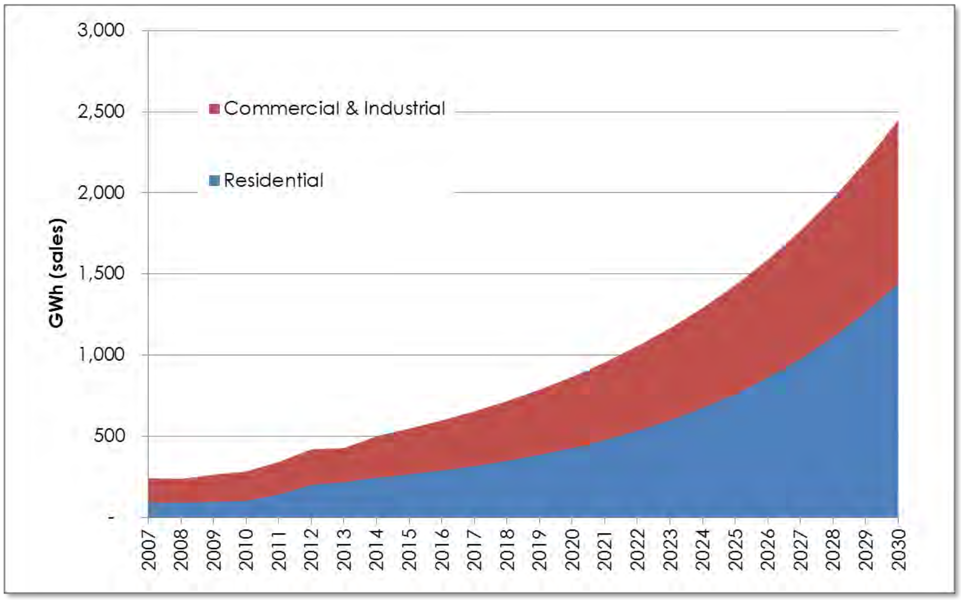
11. The average kWh per residential customer has increased from 540 in 2008 to 910 in 2013. Commercial and light industrial consumption is reported by MoEP at 4 700 kWh per customer. The following industrial customers of 2 MVA or above were reported to be active in 2013.

Table IV-27: Bago Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
Chin Su	3	33/11	Plywood
Inn lay	3	33/11	Shoes
Myan Star	3	33/11	Ready-Made Garments(RMG)
Daw Yone Shwin	3	33/11	Ready Made Garments(RMG)
Dawoo	2.5	33/11	Plywood
Pyay Industrial Zone	5	66/11	Machinery Food processing Rice/Oil Ice mill
Shwedaing Textiles Machinery	10	66/11	Textiles
Nawaday Sugar Mill	2	33/11	Food processing
Nyaung Cha Tauk Steel Mill	20	66/6.6	Iron and steel
Procelan	5	33/11	Porcelain

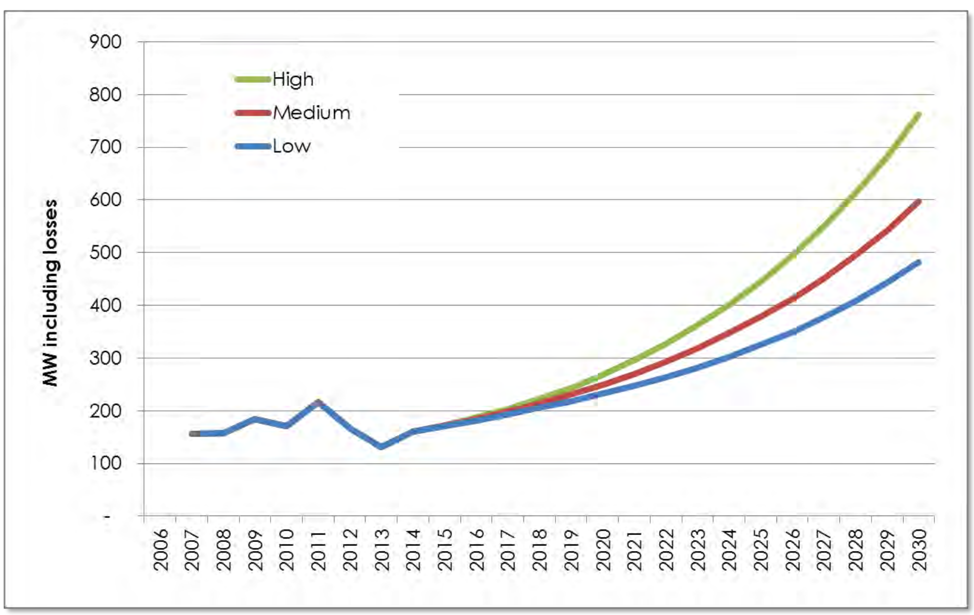
Sources: MoEP

Figure IV-28: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-29: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

CHIN STATE

12. Chin State is located in the western part of the country. The State is bordered by Rakhine State in the south, Bangladesh in the south-west, Sagaing Division and Magwe Division in the east, the Indian state of Manipur in the north and the Indian state of Mizoram in the west. Chin has been restricted to visitors but it is reported that tourism may provide an opportunity in future.

Residential Connections Forecast

13. In the last six years the reported new connection rate has been high at an average of 7% although the rate has declined in recent years. The residential electrification rate of 10% appears to have been mainly achieved in recent years.

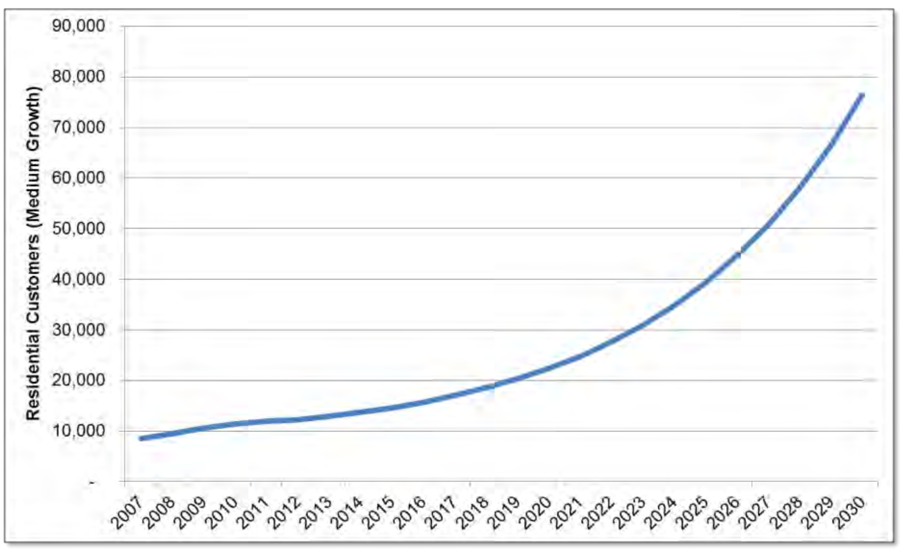
Table IV-30: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	9 445	10 587	11 395	11 937	12 284	12 963
Growth (new connections p.a.)	1 142	808	542	347	679	600
Growth %	12%	12%	8%	5%	3%	6%

Sources: MoEP

14. The forecast growth of residential grid supply connections is shown as Figure IV-31 for the 87% national electrification goal.

Figure IV-31: Growth of Residential Connections

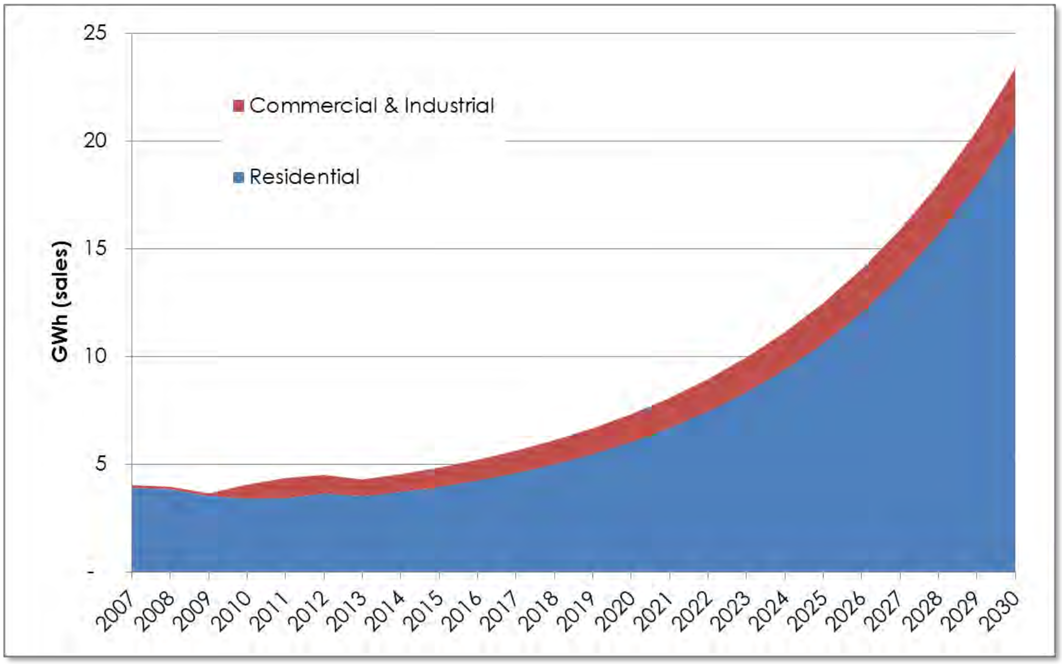


Sources: Consultant

Electricity Forecasts

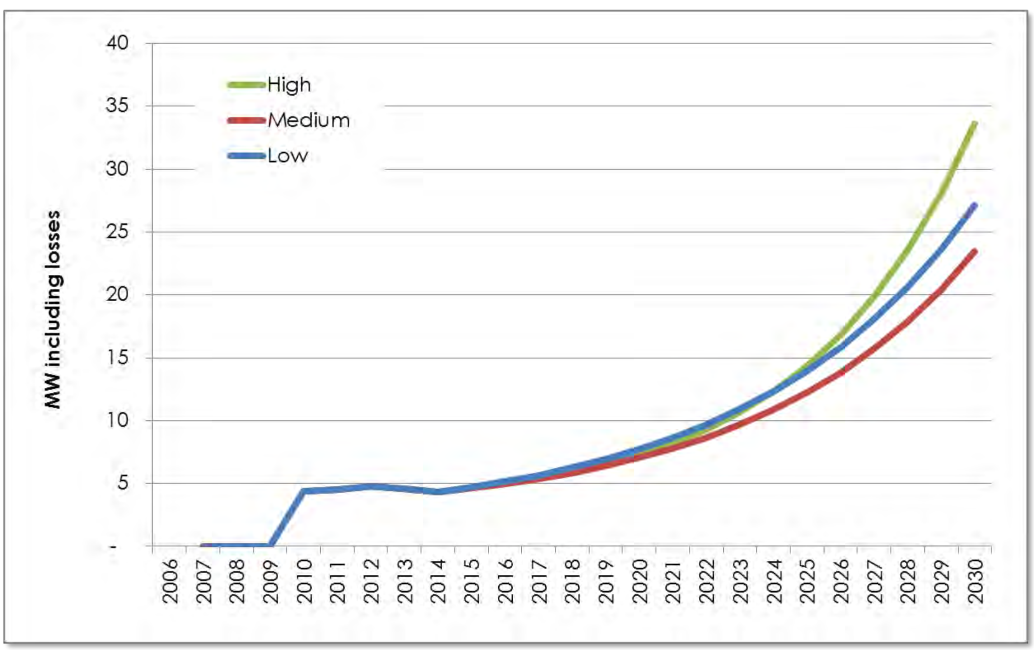
15. The average kWh per residential customer has fallen from 400 in 2008 to 270 in 2013 suggesting a declining population or hardship. Commercial and light industrial consumption is reported by MoEP at 2 000 kWh per customer. There were no industrial customers of 2 MVA or above reported.

Figure IV-32: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-33: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

KACHIN STATE

16. Kachin State is the northernmost state of Myanmar. It is bordered by China to the north and east; Shan State to the south; and Sagaing Region and India to the west. The economy of Kachin State is predominantly agricultural. The main products include rice, teak and sugar cane. Mineral products include gold and jade. Kachin has deep economic ties with China which is the largest trading partner and chief investor in development projects in the region. However, recently the Myitsone hydro-electric power plant was cancelled amid protests over relocation of around 15 000 local residents.

Residential Connections Forecast

17. In the last six years, the reported new connection rate has been high at an average of 18%. The residential electrification rate of 15% appears to have been mainly achieved in recent years.

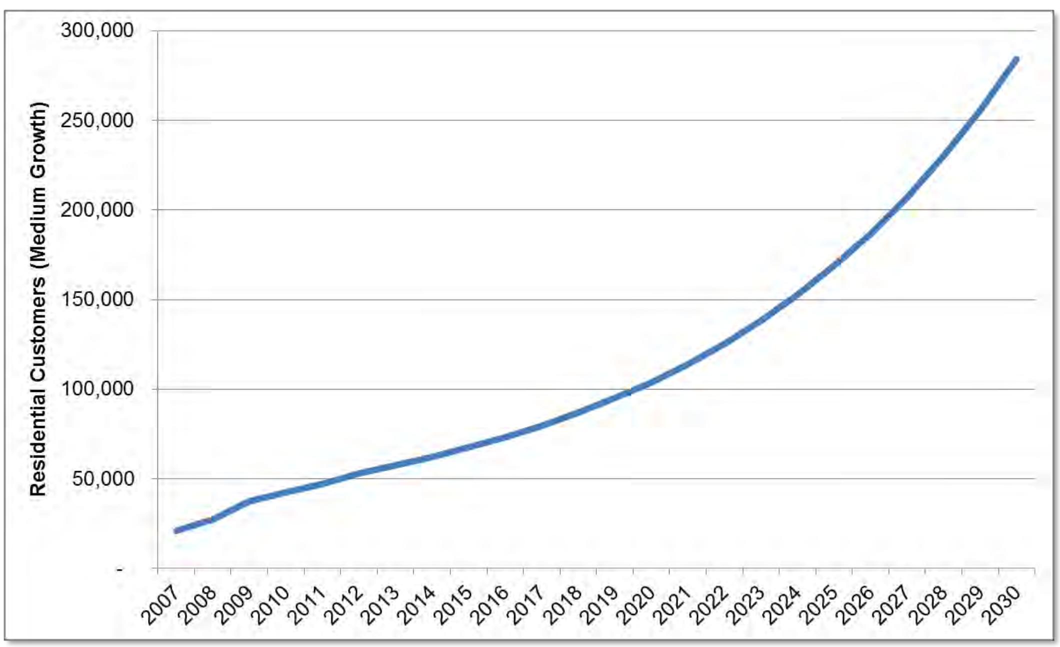
Table IV-34: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	27 582	37 339	42 439	47 346	53 203	57 555
Growth (new connections p.a.)	9 757	5 100	4 907	5 857	4 352	4 400
Growth %	30%	35%	14%	12%	12%	8%

Sources: MoEP

18. The forecast growth of residential grid supply connections is shown in Figure IV-35 for the 87% national electrification goal.

Figure IV-35: Growth of Residential Connections

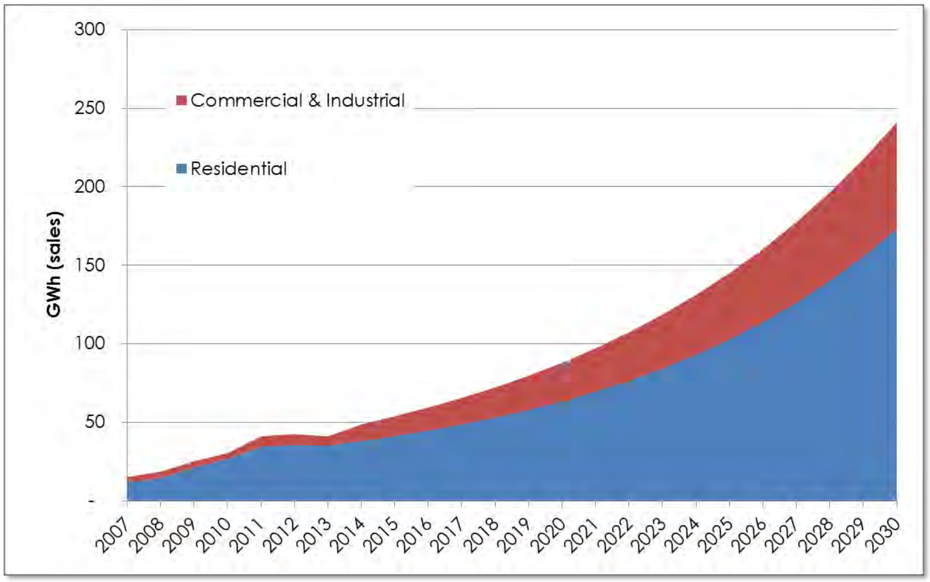


Sources: Consultant

Electricity Forecasts

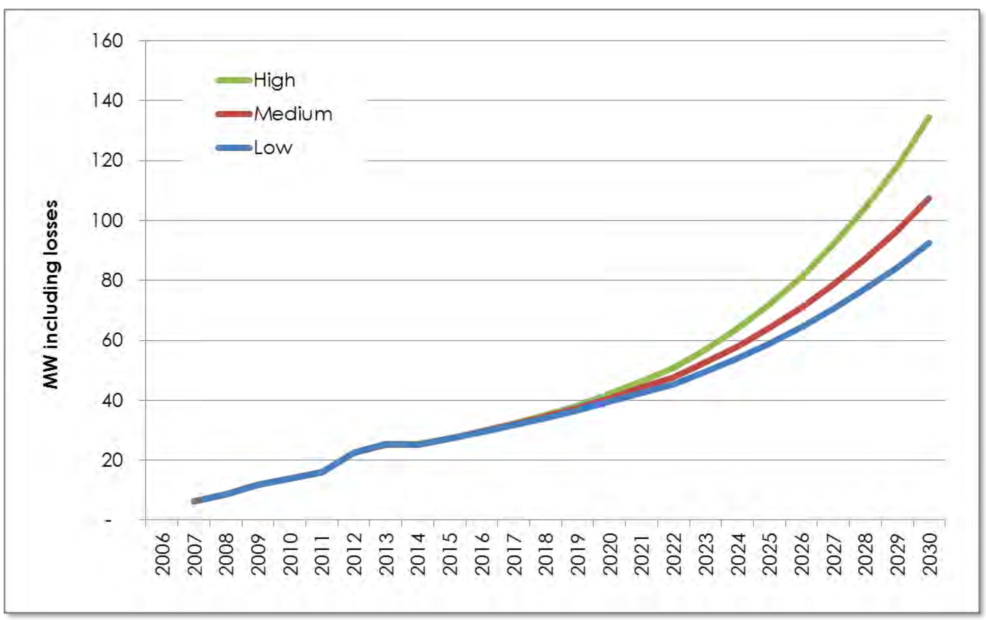
19. The average kWh per residential customer has increased from 500 in 2008 to 600 in 2013. Commercial and light industrial consumption is reported by MoEP at an average 12 000 kWh per customer. There were no industrial customers of 2 MVA or above reported.

Figure IV-36: Forecast Electricity Consumption Growth to 2035



Sources: Excluding losses; Consultant

Figure IV-37: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

KAYAR STATE

20. Kayar State is situated in eastern Myanmar; it is bounded on the north by Shan State, on the east by Thailand's Mae Hong Son Province, and on the south and west by Kayin State.

21. Kayah State has a primarily extraction-based economy. The main crop is rice, mostly irrigated, with other important crops including millet, maize, sesame, groundnut, garlic and vegetables. Mineral products include alabaster, tin and tungsten. Valuable woods such as teak and pine were once produced, but the forests have largely been stripped bare by illegal logging. The hydroelectric power plant at Lawpita Falls outside of Loikaw is of strategic importance, as it supplies over 20% of Myanmar's total electrical power. Kayah State has theoretical tourist potential, if the political situation is resolved. The state has rugged mountains, river streams, lakes and waterfalls; however, transport and communication are difficult.

Residential Connections Forecast

22. In the last six years the reported new connection rate has been high at an average of 9%. This rate appears to have supported the achievement of a moderately high residential electrification rate of 40%.

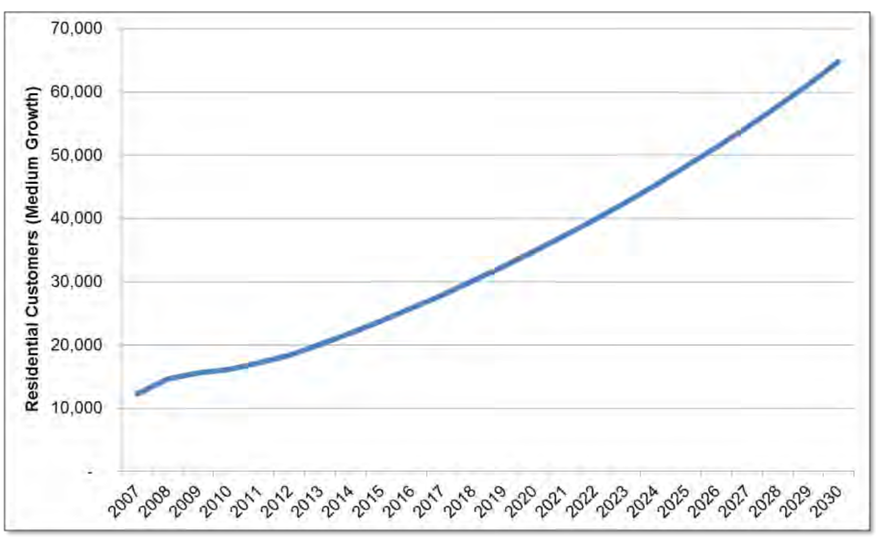
Table IV-38: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	14 664	15 559	16 083	17 143	18 352	20 081
Growth (new connections p.a.)	895	524	1 060	1 209	1 729	1 500
Growth %	19%	6%	3%	7%	7%	9%

Sources: MoEP

23. The forecast growth of residential grid supply connections is shown in Figure IV-39 for the 87% national electrification goal.

Figure IV-39: Growth of Residential Connections

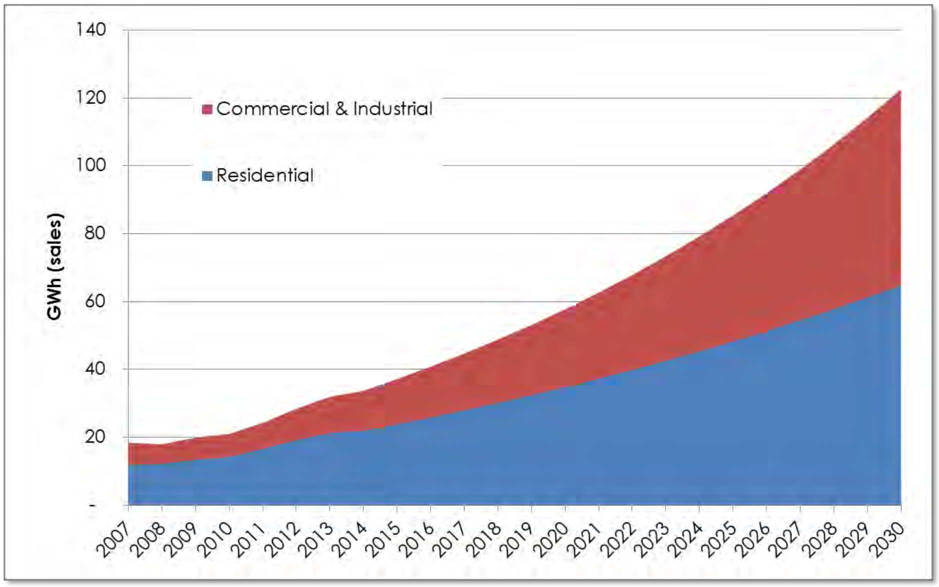


Sources: Consultant

Electricity Forecasts

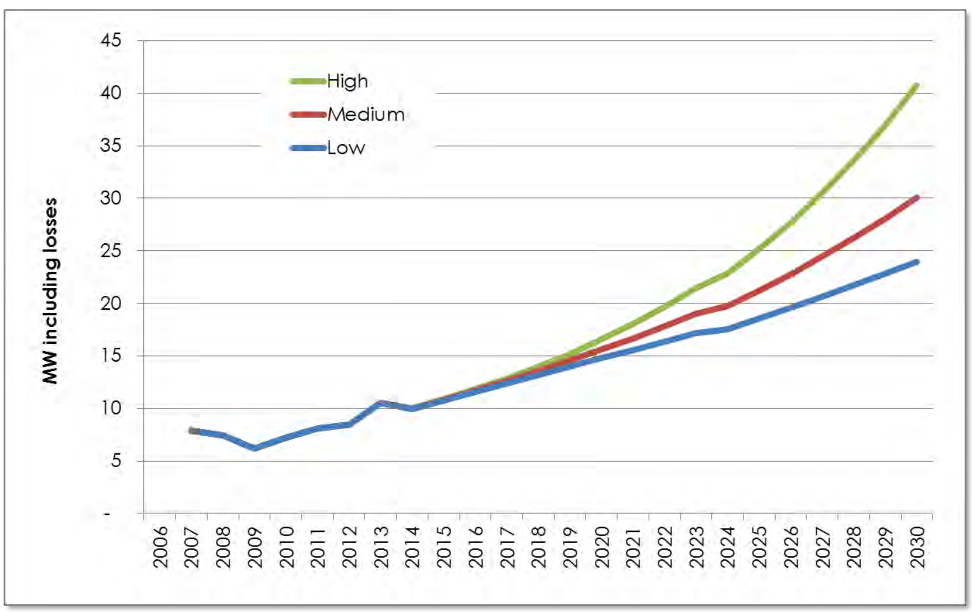
24. The average kWh per residential customer has increased from 830 in 2008 to 1 030 in 2013. Commercial and light industrial consumption is reported by MoEP at 8 000 kWh per customer. There were no industrial customers of 2 MVA or above reported.

Figure IV-40: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-41: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

KAYIN STATE

25. Kayin State is mountainous with the Dawna Range running along the state in a NNW - SSE direction. The southern end of the Karen Hills is to the northwest. The State is bordered by Mae Hong Son Tak and Kanchanaburi provinces of Thailand to the east; Mon State and Bago Region to the west and south; and Mandalay Region Shan State and Kayah State to the north.

Residential Connections Forecast

26. In the last six years the reported new connection rate has been high at an average of 10%. This rate appears to reflect the low residential electrification rate of 8%.

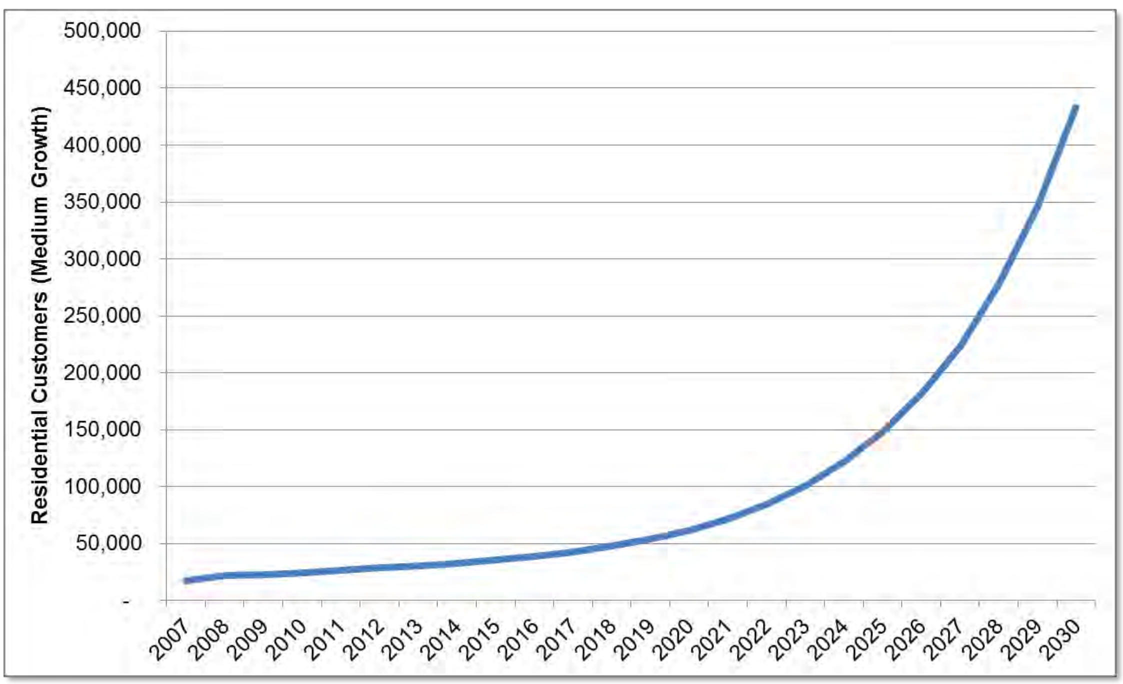
Table IV-42: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	22 185	22 931	24 355	26 580	28 741	30 774
Growth (new connections p.a.)	746	1 424	2 225	2 161	2 033	2 000
Growth %	26%	3%	6%	9%	8%	7%

Sources: MoEP

27. The forecast growth of residential grid supply connections is shown as Figure IV-43 for the 87% national electrification goal.

Figure IV-43: Forecast Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

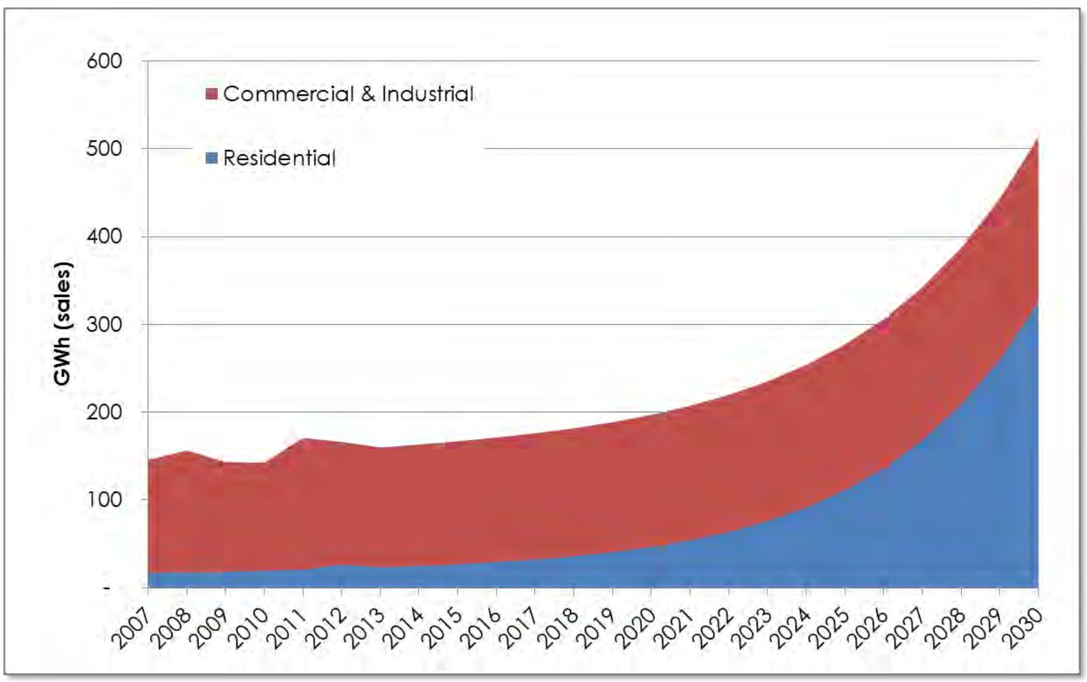
28. The average kWh per residential customer has remained steady from 2008 to 2013 at around 750. Commercial and light industrial consumption is reported by MoEP at 8 700 kWh per customer. There following industrial customers of 2 MVA or above were reported to be active in 2013.

Table IV-44: Kayin Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
Tan 4000 Industrial(Myaing Kalay)	35	66	Cement
Tan 900 Industrial(Myaing Kalay)	15	66	Cement
Tan 900 Industrial(Myaing Kalay)	10.5	33	Cement

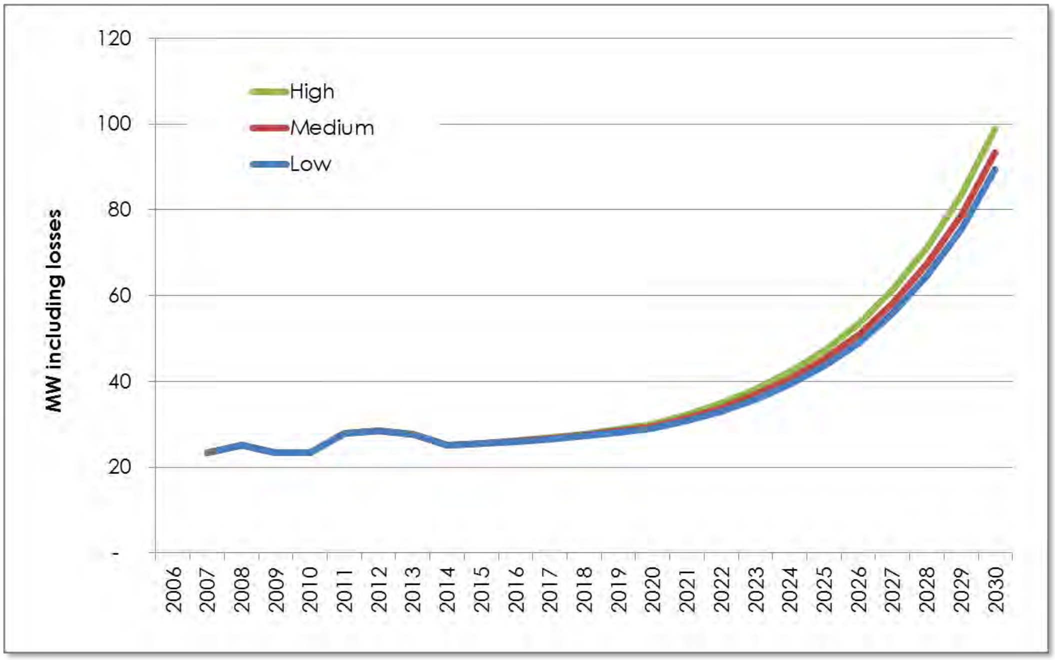
Sources: MoEP

Figure IV-45: Forecast Electricity Consumption Growth to 2035



Source: Excluding losses; Consultant

Figure IV-46: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

MAGWE REGION

29. Magwe is located in the central part of Myanmar. The principal product of Magwe Region is petroleum; the region produces most of Myanmar's oil and natural gas. The oil fields located in the Magwe Region are the Mann, Yenangyaung, Chauk, Kyauk-khwet, Letpando and Ayadaw oil fields. Petroleum is produced and Magwe is referred to as the 'oil pot of Myanmar'.

30. Other industries include cement, cotton weaving, tobacco, iron and bronze. The major agricultural crops are sesamum and groundnut. Other crops grown are rice, millet, maize, sunflower, beans and pulses, tobacco, toddy, chili, onions and potatoes. Famous products of Magwe Region include: Thanaka (Limonia acidissima) and Phangar (Chebulic myorobalan) fruit. Magwe Region also produces a large quantity of edible oil. Magwe has almost no tourist industry.

Residential Connections Forecast

31. In the last six years the reported new connection rate has been high at an average of 12%. This rate appears to reflect the achievement of the residential electrification rate of 10%.

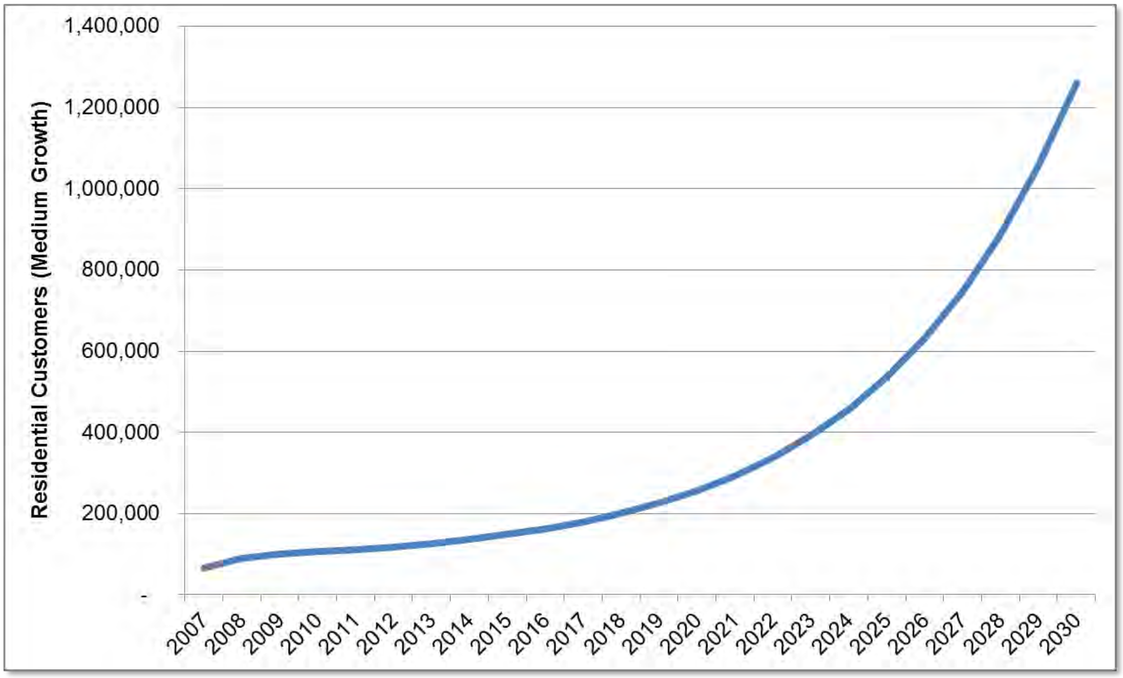
Table IV-47: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	88 898	101 381	106 618	111 359	117 886	126 931
Growth (new connections p.a.)	12 483	5 237	4 741	6 527	9 045	10 000
Growth %	34%	14%	5%	4%	6%	8%

Sources: MoEP

32. The forecast growth of residential grid supply connections is shown as Figure IV-48 for the 87% national electrification goal.

Figure IV-48: Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

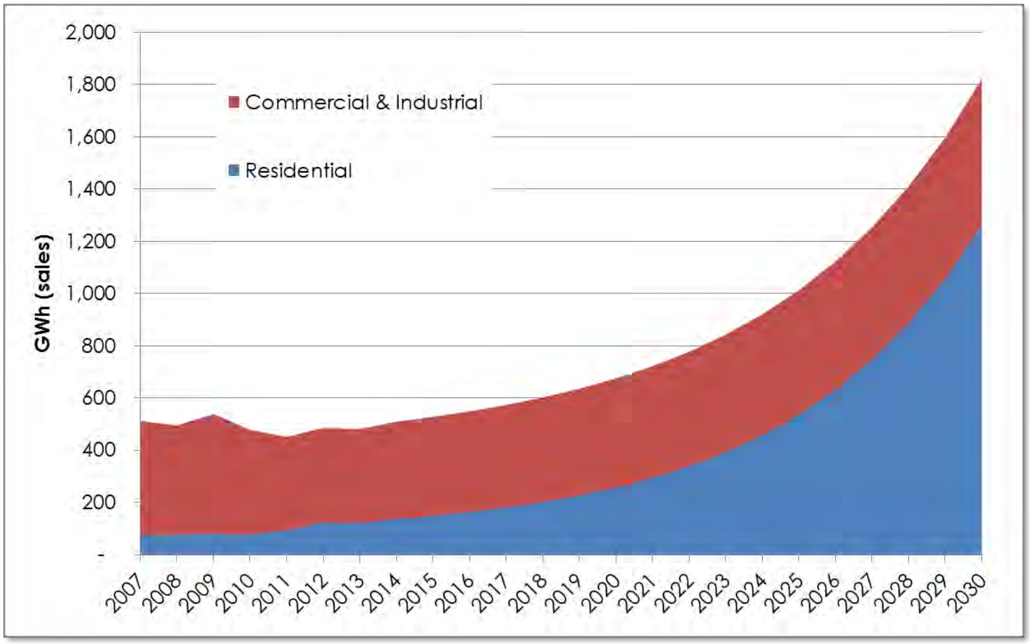
33. The average kWh per residential customer has increased from 850 in 2008 to 950 in 2013. Commercial and light industrial consumption is reported by MoEP at 17 000 kWh per customer. The following industrial customers of 2 MVA or above were reported to be active in 2013.

Table IV-49: Magwe Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
Tan 4000 Industrial(Myaing Kalay)	35	66	Cement
Tan 900 Industrial(Myaing Kalay)	15	66	Cement
Tan 900 Industrial(Myaing Kalay)	10.5	33	Cement

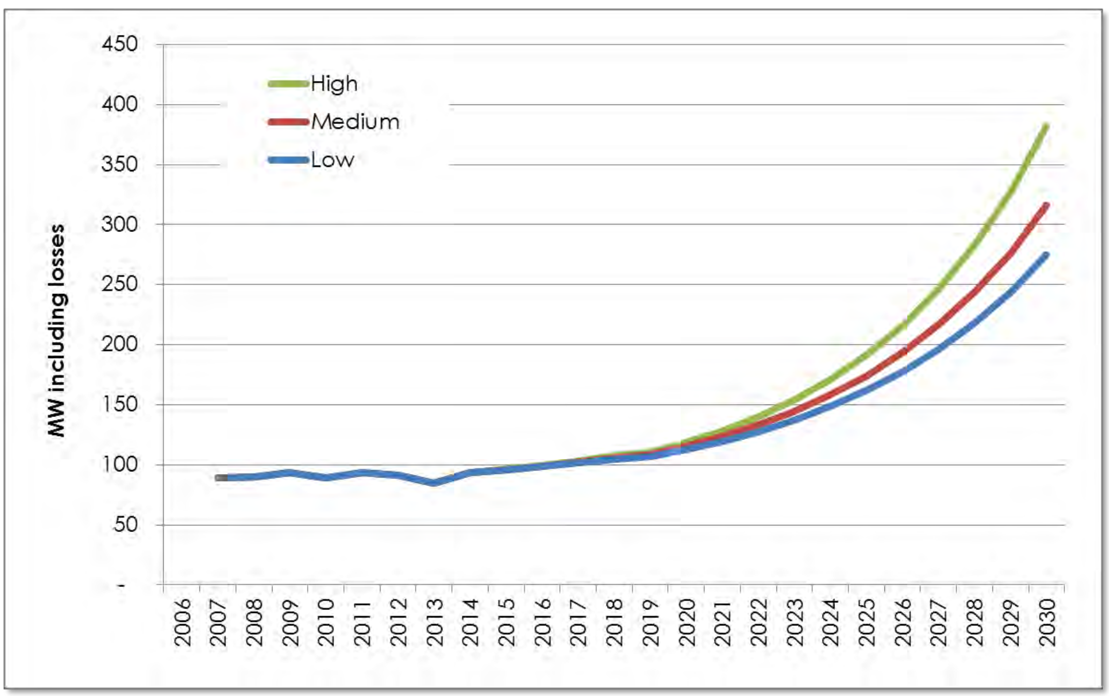
Sources: MoEP

Figure IV-50: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-51: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

MANDALAY REGION

34. Mandalay is located in the center of the country, bordering Sagaing Region and Magway Region to the west, Shan State to the east, and Bago Region and Kayin State to the south. The regional capital is Mandalay. The national capital of Naypyidaw is found in the south of the region.

35. Agriculture is the primary economic activity. The primary crops grown within Mandalay Region are rice, wheat, maize, peanut, sesame, cotton, legumes, tobacco, chilli and vegetables. Industry, including alcohol breweries, textile factories, sugar mills and gem mines also exist. Tourism forms a substantial part of Mandalay Region's economy, as the region contains many historical sites including Mandalay, Amarapura, Bagan, Pyin U Lwin, Mount Popa and Ava. Hardwoods such as teak and thanaka are also harvested.

Residential Connections Forecast

36. In the last six years the reported new connection rate has been high at an average of 11%. This rate appears to have supported the achievement of the residential electrification rate of 11%.

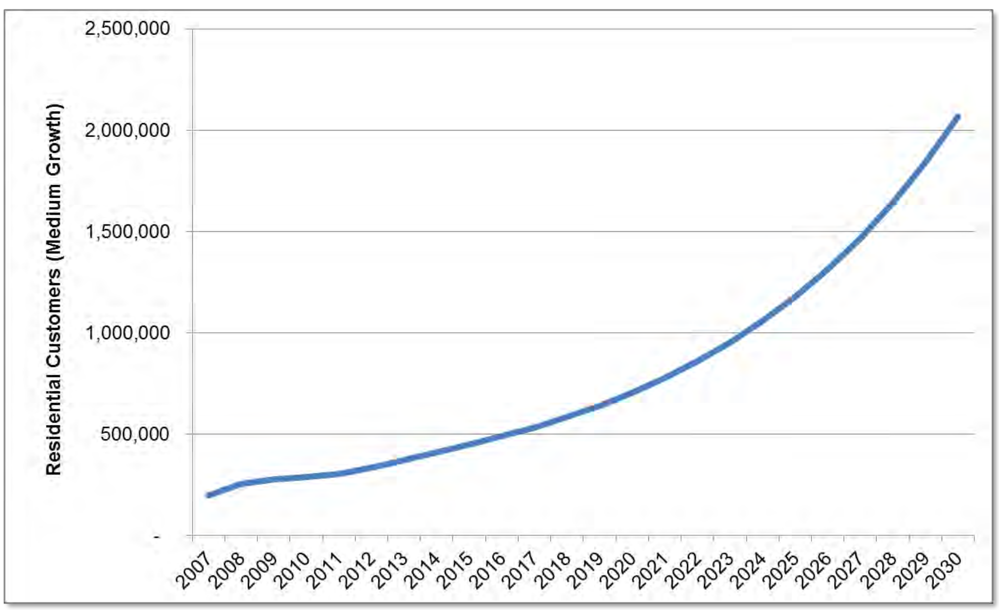
Table IV-52: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	254 438	276 769	290 692	305 586	336 819	372 812
Growth (new connections p.a.)	22 331	13 923	14 894	31 233	35 993	36 000
Growth %	28%	9%	5%	5%	10%	11%

Sources: MoEP

37. The forecast growth of residential grid supply connections is shown as Figure IV-53 for the 87% national electrification goal.

Figure IV-53: Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

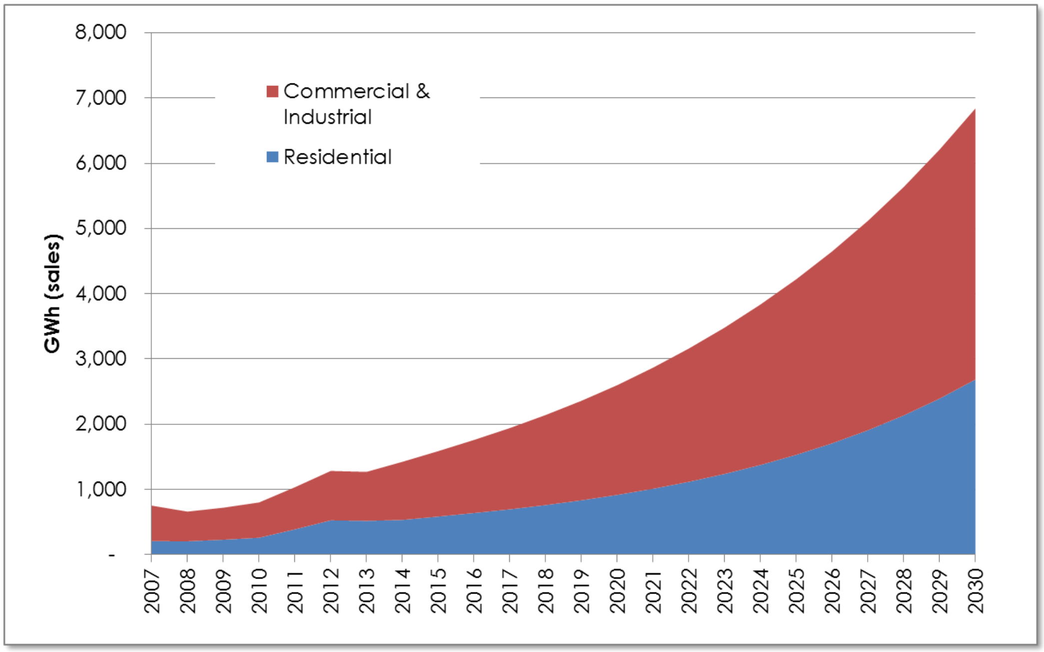
38. The average kWh per residential customer has increased from 800 in 2008 to 1 400 in 2013. Commercial and light industrial consumption is reported by MoEP at 21 200 kWh per customer. The following industrial customers of 2 MVA or above were reported to be active in 2013.

Table IV-54: Mandalay Large Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
Daw San Kyu	2.5	33/0.4	Food processing
U Htun Naing	3	33/0.4	Textiles
U Maung Soe	3	33/0.4	Iron and steel
U Myint Aung	3	33/0.4	Iron and steel
Daw Khin Tidar Win	2	11/0.75	Iron and steel
U Sein Win	3	33/0.4	Other
Aung Myint Shaing Co. Ltd	5	33/11	Iron and steel
103 Wood Factory	5	33/11	Other
AAA Cement Factory	10	33/6.3	Cement
Myanmar Elephant Cement Factory	3.15	33/10	Cement
Steel Mill	85	33/10	Iron and steel
Steel Mill	4	33/10	Iron and steel
Vest Mill	2	33/10	Textiles
Petrol	0.16	33/10	Petrol
Pozolan	10	33/10	Pozolan
Shwe Taung	16	33/10	Textiles
Max Myanmar	6.3	33/10	Cement
Iron and Steel Factory	35.9	33/10	Iron and steel
Pharmaceutical Factory	5	33/10	Phamacutical

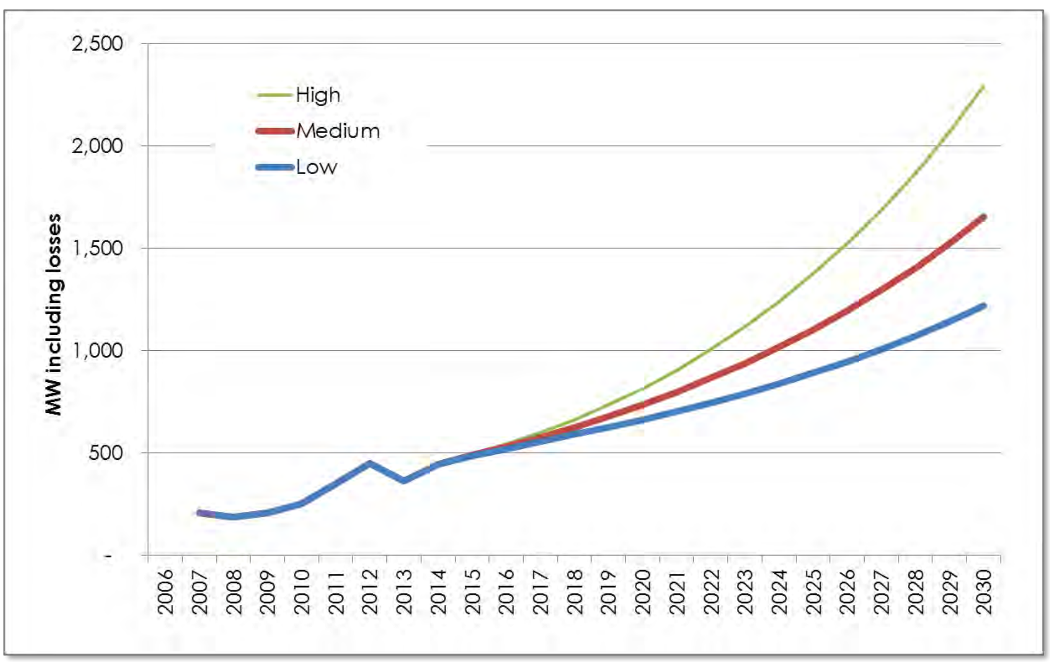
Sources: MoEP

Figure IV-55: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-56: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

MON STATE

39. Mon State is located between Kayin State on the east, the Andaman Sea on the west, Bago Region on the north and Tanintharyi Region on the south, and has a short border with Thailand's Kanchanaburi Province at its south-eastern tip.

40. Mon State has a cultivated area of nearly 4.5 million acres, mostly under rice. The major secondary crop is rubber. Orchards and rubber plantations are found in the mountainous areas while coastal fishing and related industries such as production of dried fish, fish sauce and agar-agar are in southern part. Other industries include betel nut production, paper, sugar and rubber tires. Thaton has a major factory (Burmese Ka-Sa-La) of rubber products run by the Ministry of Industry. Forests cover approximately half of the area and timber production is one of the major contributors to the economy. Minerals extracted from the area include salt, antimony and granite. Natural resources such as forest products, and onshore and offshore mineral resources, are exploited only by top Myanmar military leaders and foreign companies. The Yadana Gas project pipelines pass through Mon State.

Residential Connections Forecast

41. In the last six years the reported new connection rate has been high at an average of 18% and does not appear to reflect the low residential electrification rate of 8%.

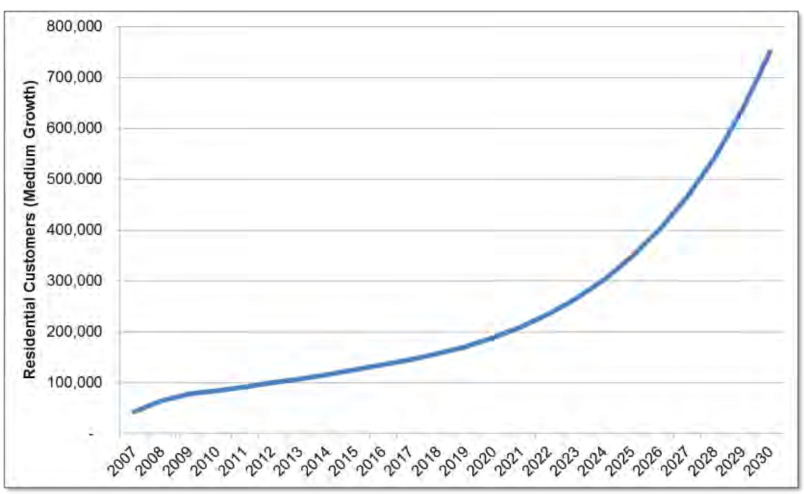
Table IV-57: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	64 826	77 733	84 442	91 134	99 517	107 718
Growth (new connections p.a.)	12 907	6 709	6 692	8 383	8 201	8 000
Growth %	53%	20%	9%	8%	9%	8%

Sources: MoEP

42. The forecast growth of residential grid supply connections is shown as Figure IV-58 for the 87% national electrification goal.

Figure IV-58: Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

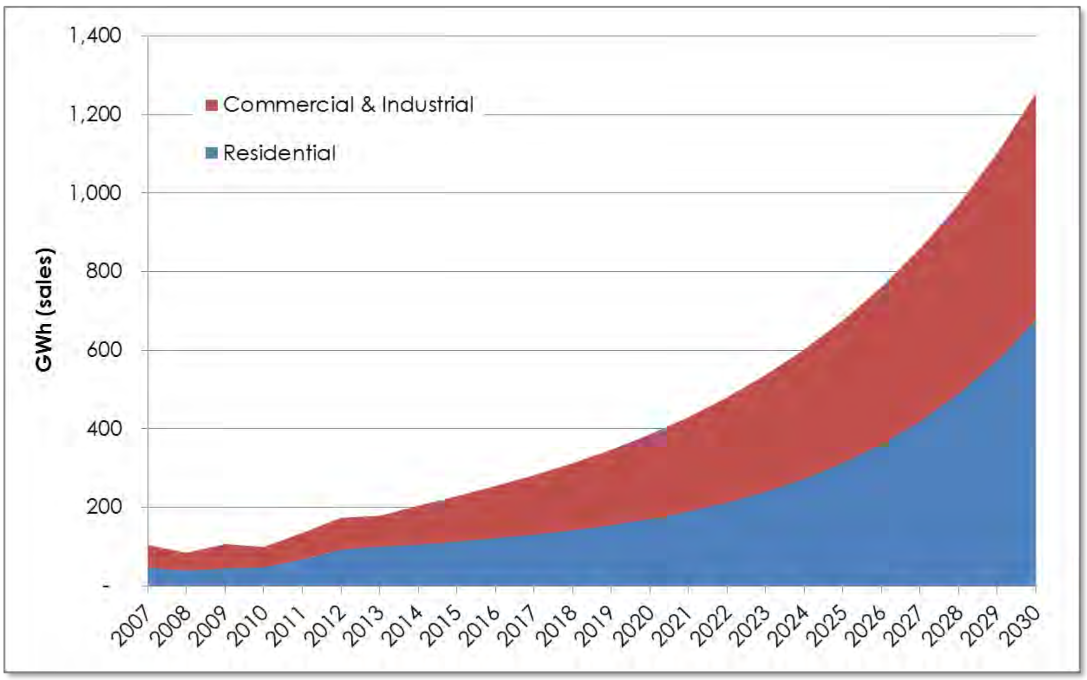
43. The average kWh per residential customer has increased from 590 in 2008 to 920 in 2013. Commercial and light industrial consumption is reported by MoEP at 8 000 kWh per customer. The following industrial customers of 2 MVA or above were reported to be active in 2013.

Table IV-59: Mon Large Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
U Nyi Nyi Htwe	2	11	Iron and steel

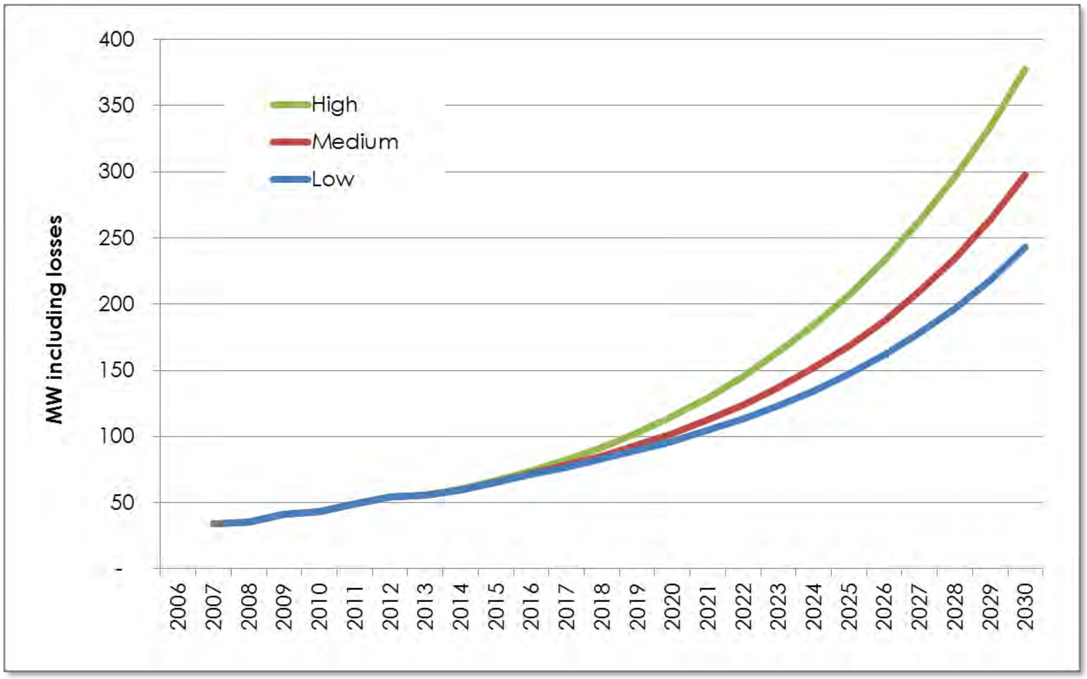
Sources: MoEP

Figure IV-60: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-61: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

NAY PYI TAW

44. Nay Pyi Taw is the capital city of Myanmar. It is located in the southern part of the Mandalay region.

Residential Connections Forecast

45. In the last six years the reported new connection rate has been high at an average of 28%. This rate appears to have supported the achievement of a high electrification rate of 37%.

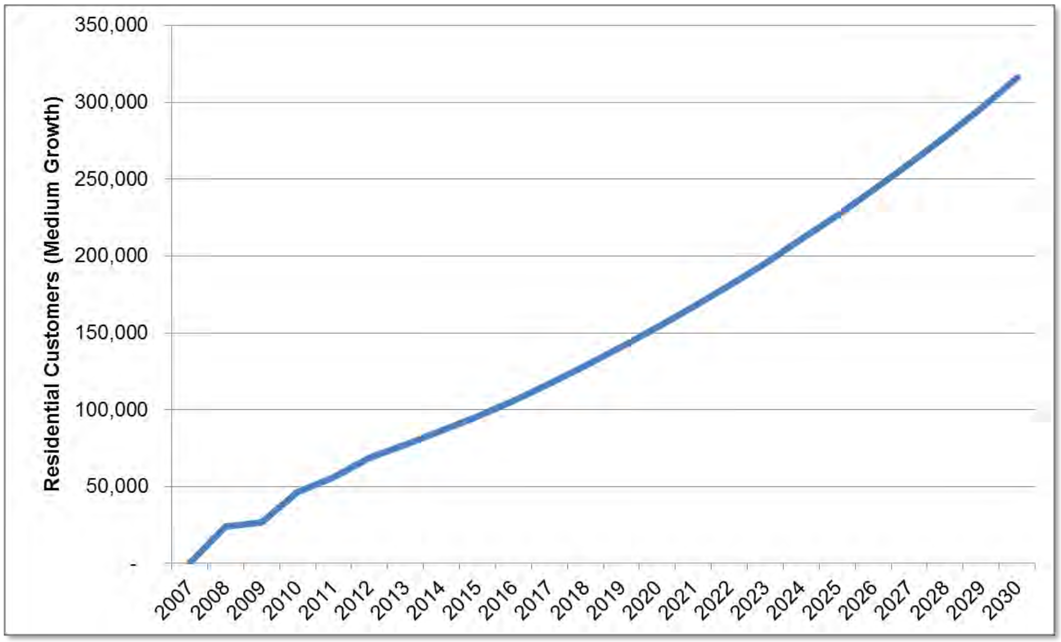
Table IV-62: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	24 018	26 763	46 358	56 195	68 984	77 425
Growth (new connections p.a.)	2 745	19 595	9 837	12 789	8 441	8 500
Growth %	11%	73%	21%	23%	12%	11%

Sources: MoEP

46. The forecast growth of residential grid supply connections is shown as Figure IV-63 for the 87% national electrification goal.

Figure IV-63: Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

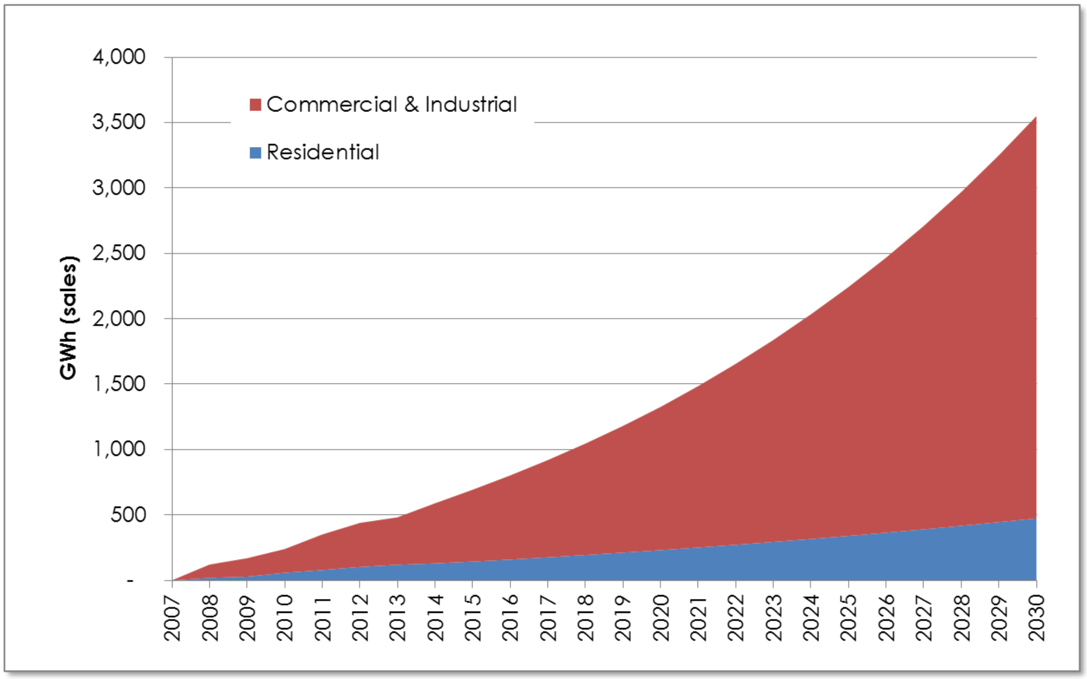
47. The average kWh per residential customer has increased from 780 in 2008 to 1 530 in 2013. Commercial and light industrial consumption is reported by MoEP at 10 800 kWh per customer. The following industrial customers of 2 MVA or above were reported to be active in 2013.

Table IV-64: Nay Pyi Taw Large Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
Max Myanmar Cement	6.3	33	Cement
Naypyitaw Sipin Cement	6.3	33	Cement
Naypyitaw (Brick)	5	33	Other

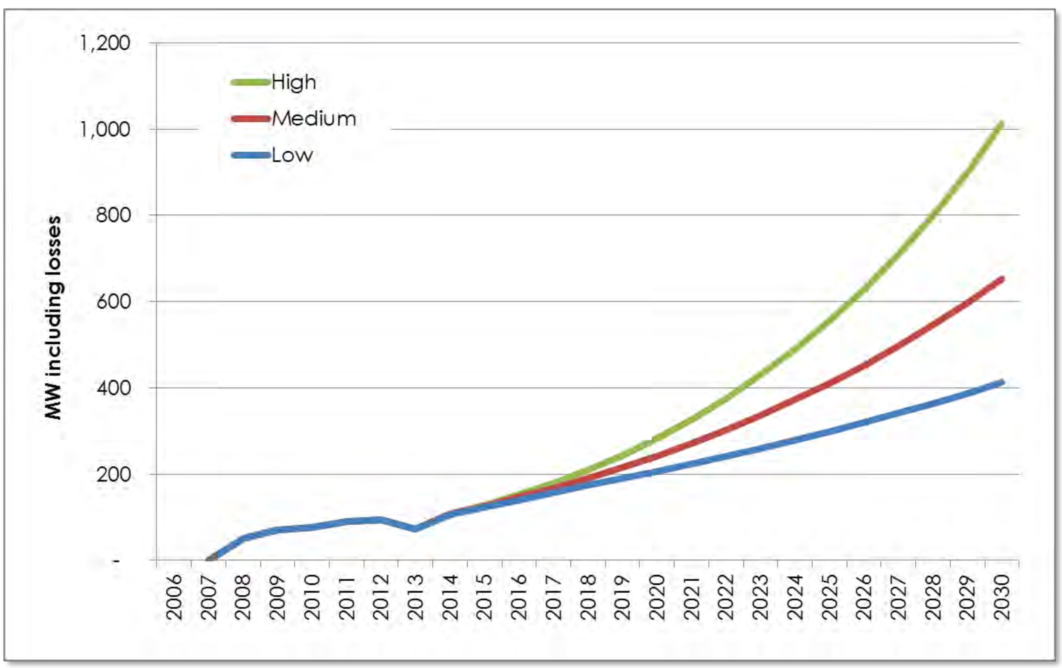
Sources: MoEP

Figure IV-65: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-66: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

RAKHINE STATE

48. Rakhine State is situated on the western coast; it is bordered by Chin State in the north, Magway Region, Bago Region and Ayeyarwady Region in the east, the Bay of Bengal to the west, and the Chittagong Division of Bangladesh to the north.

49. Rice is the main crop in the region, occupying around 85% of the total agricultural land. Coconut and nipa palm plantations are also important. Fishing is a major industry, with most of the catch transported to Yangon, but some is also exported. Wood products such as timber, bamboo and fuel wood are extracted from the mountains. Small amounts of inferior-grade crude oil are produced from primitive, shallow, hand-dug wells, but there is yet unexplored potential for petroleum and natural gas production.

50. Tourism is slowly being developed. The ruins of the ancient royal town Mrauk U and the beach resorts of Ngapali are the major attractions for foreign visitors.

Residential Connections Forecast

51. In the last six years new connection rate has been high at an average of 8%. This relatively low rate, with decline in recent years, appears to reflect the residential electrification rate of 3%.

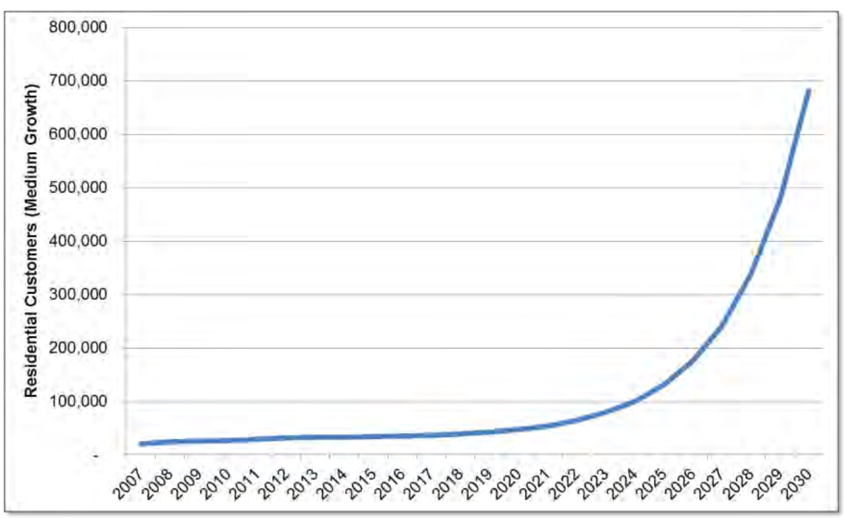
Table IV-67: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	23 968	25 673	27 382	29 104	31 547	32 347
Growth (new connections p.a.)	1 705	1 709	1 722	2 443	800	2 000
Growth %	15%	7%	7%	6%	8%	3%

Sources: MoEP

52. The forecast growth of residential grid supply connections is shown in Figure IV-68 for the 87% national electrification goal.

Figure IV-68: Growth of Residential Connections

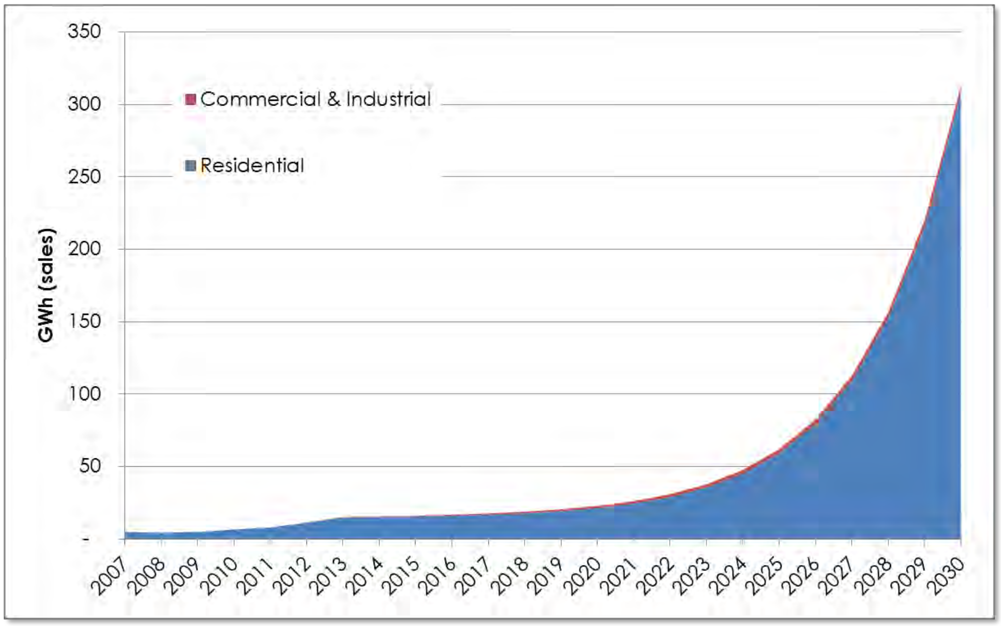


Sources: Consultant

Electricity Forecasts

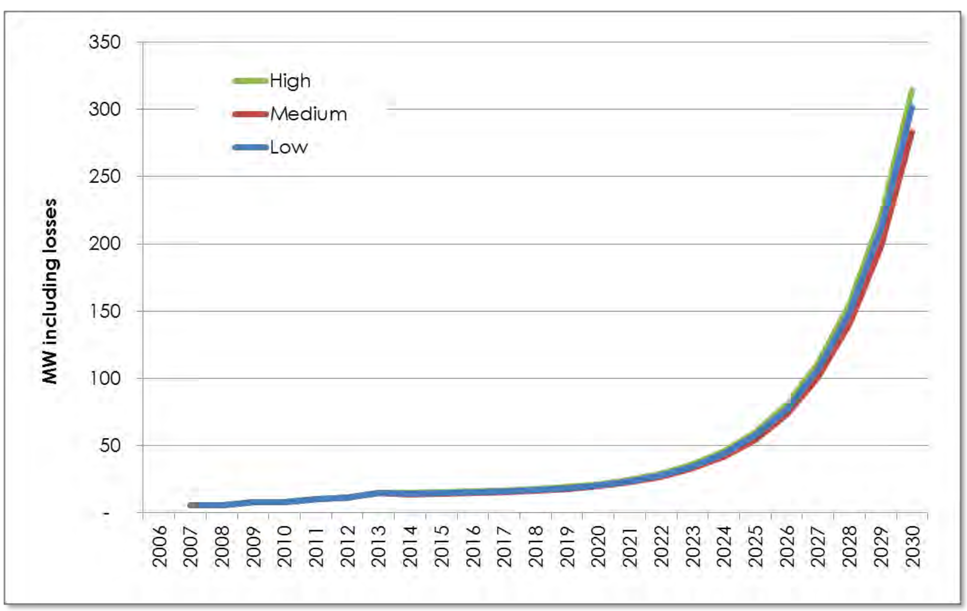
53. The average kWh per residential customer has increased from 180 in 2008 to 460 in 2013. Commercial and light industrial consumption is reported by MoEP at a very low 190 kWh per customer. There were no industrial customers of 2 MVA or above reported.

Figure IV-69: Forecast Electricity Consumption Growth



Sources Excluding losses; Consultant

Figure IV-70: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

SAGAING REGION

54. Sagaing Region is located in the north-western part of Myanmar. It is bordered by India's Nagaland and Manipur States to the north, Kachin State, Shan State and Mandalay Region to the east, Mandalay Region and Magwe Region to the south, with the Ayerwaddy River forming a greater part of its eastern and also southern boundary, and Chin State and India to the west.

55. Agriculture is the main economic activity with rice occupying most of the arable ground. Other crops include wheat, sesame, peanut, pulses, cotton and tobacco. Sagaing is Myanmar's leading producer of wheat, contributing more than 80% of the country's total production. Forestry is important in the wetter upper regions along the Chindwin River, with teak and other hardwoods extracted. Important minerals include gold, coal, salt and small amounts of petroleum. Industry includes textiles, copper refining, gold smelting and a diesel engine plant. The Region has many rice mills, edible oil mills, saw mills, cotton mills and mechanized weaving factories. Local industry includes earthen pots, silverware, bronze-wares, iron-wares and lacquerware.

Residential Connections Forecast

56. In the last six years the reported new connection rate has been high at an average of 14%. This rate appears to reflect the residential electrification rate of 15%.

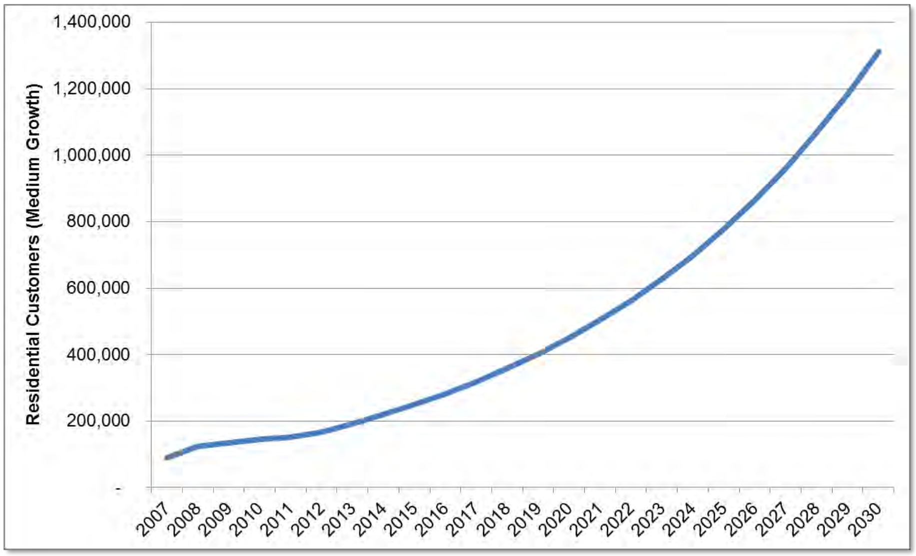
Table IV-71: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	124 074	135 240	145 568	152 556	167 287	191 984
Growth (new connections p.a.)	11 166	10 328	6 988	14 731	24 697	20 000
Growth %	37%	9%	8%	5%	10%	15%

Sources: MoEP

57. The forecast growth of residential grid supply connections is shown in Figure IV-72.

Figure IV-72: Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

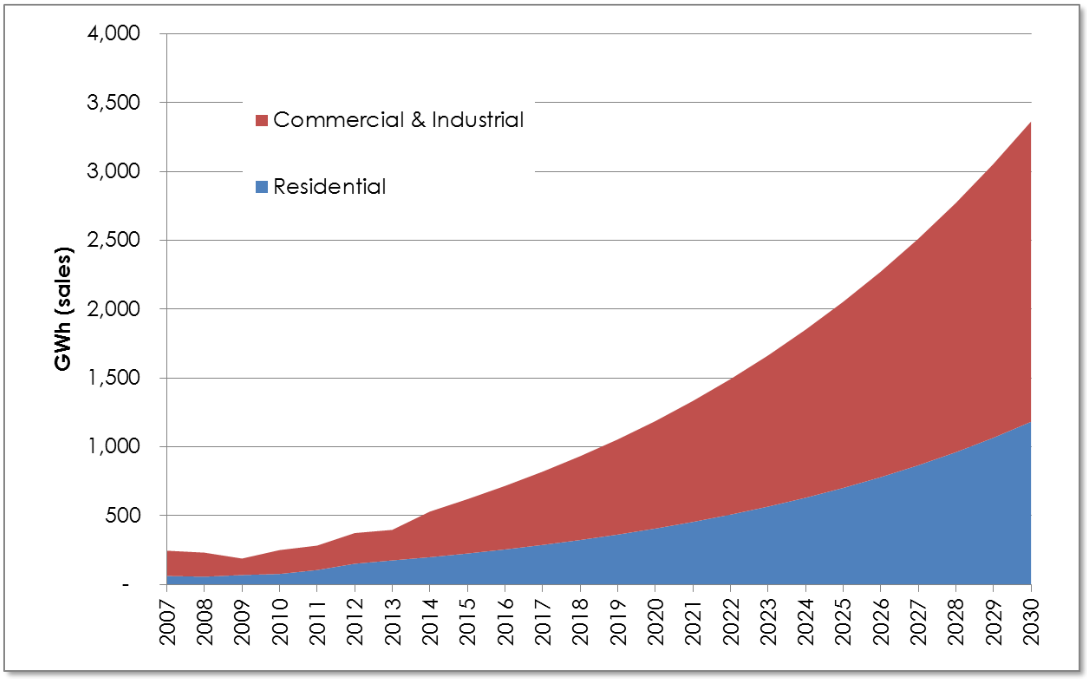
58. The average kWh per residential customer has increased from 450 in 2008 to 910 in 2013. Commercial and light industrial consumption is reported by MoEP at 14 800 kWh per customer. The following industrial customers of 2 MVA or above were reported to be active in 2013.

Table IV-73: Sagaing Large Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
Iron and steel	5	33/11	Iron and steel
Other	2	33/11	Other
Chemicals	2x10	33/11	Chemicals
Chemicals	3.15	33/10	Chemicals
Iron and steel	2	33/11	Iron and steel

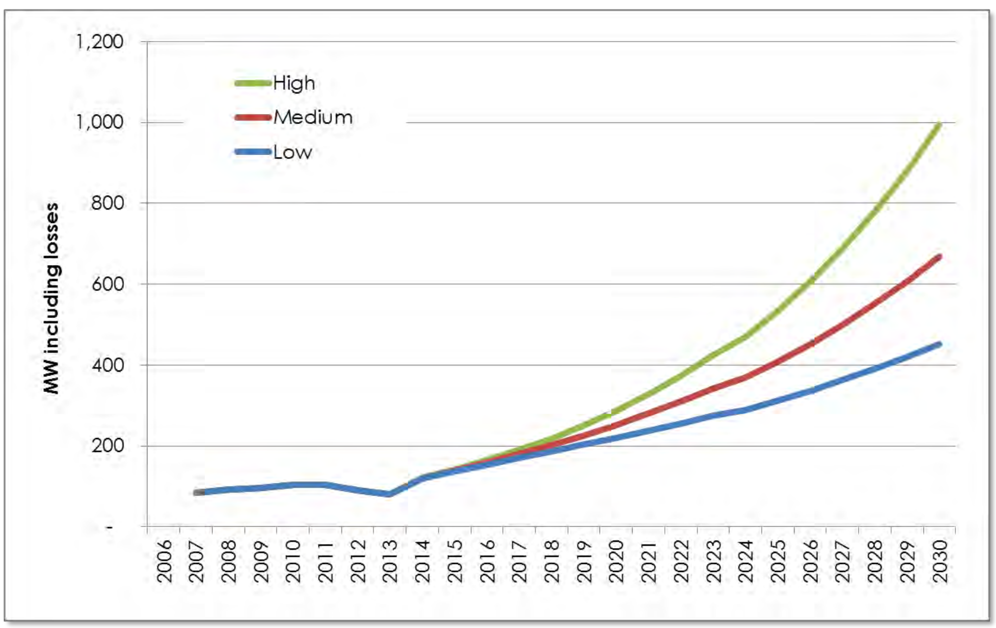
Sources: MoEP

Figure IV-74: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-75: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

SHAN STATE

59. Shan State borders China to the north, Laos to the east, Thailand to the south, and five

administrative divisions of Myanmar to the west.

60. Silver, lead and zinc are mined, notably at the Bawdwin mine, and there are smelters at Namtu. Teak is extracted from the local forests. Rice and all sorts of fresh fruit and vegetables are grown due to the temperate but sunny climate. Shan State is part of the Golden Triangle, an area in which much of the world's opium and heroin are illegally produced.

61. There are border trading centres along the Shan State border and neighbour countries. Muse, the largest border trading centre along the Myanmar China border and Tachileik and another important trading centre between Myanmar and Thailand. The China-Myanmar oil and gas pipelines pass through the northern part of Shan State.

Residential Connections Forecast

62. In the last six years the reported new connection rate has been high at an average of 16%. This rate appears to have supported the achievement of a residential electrification rate at 23%.

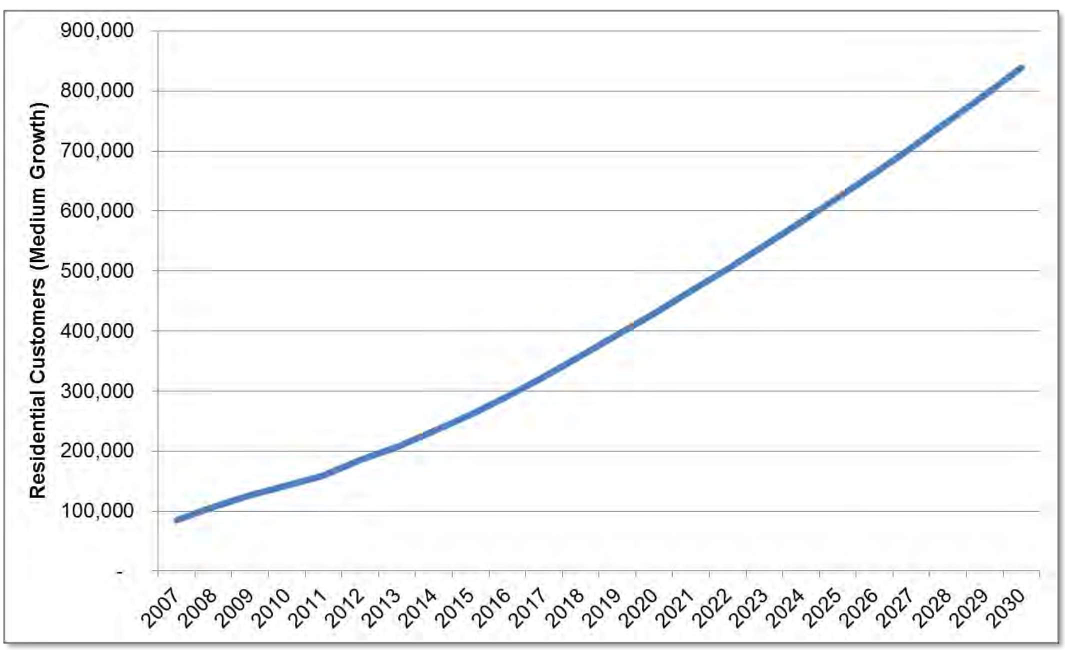
Table IV-76: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	107 724	126 761	142 972	159 739	185 094	207 933
Growth (new connections p.a.)	19 037	16 211	16 767	25 355	22 839	23 000
Growth %	27%	18%	13%	12%	16%	12%

Sources: MoEP

63. The forecast growth of residential grid supply connections is shown as Figure IV-77 for the 87% national electrification goal:

Figure IV-77: Growth of Residential Connections



Sources: Consultant

Electricity Forecasts

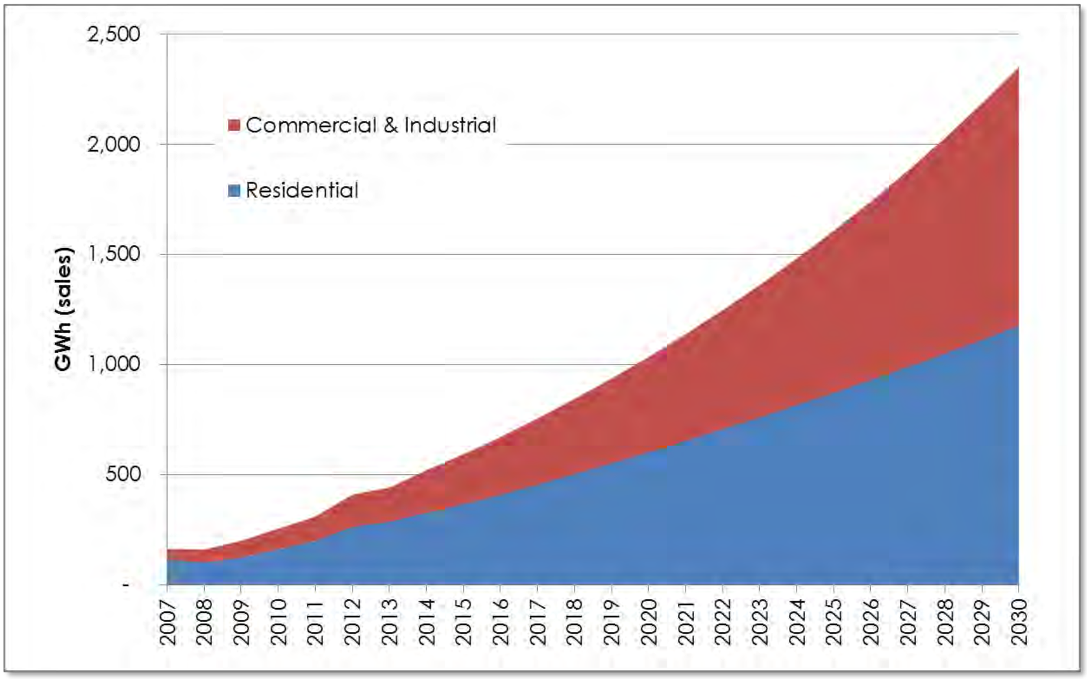
64. The average kWh per residential customer has increased from 940 in 2008 to 1 370 in 2013. Commercial and light industrial consumption is reported by MoEP at 6 360 kWh per customer. The following industrial customers of 2 MVA or above were reported to be active in 2013:

Table IV-78: Shan Large Industrial Customers (2013)

Customer	Load	Supply Voltage	Type of Business
	MVA	kV	
Ayetharyar(Iron Company)	5	66	Iron and steel
Tigyit(charcoal)	5	33	Charcoal
Dragon Cement	6.3	66	Cement
Pinprick Steel	2	33	Steel
Pinprick Steel	4	33	Steel
Khaungtawe Innarriye	5	33	Recycle Project

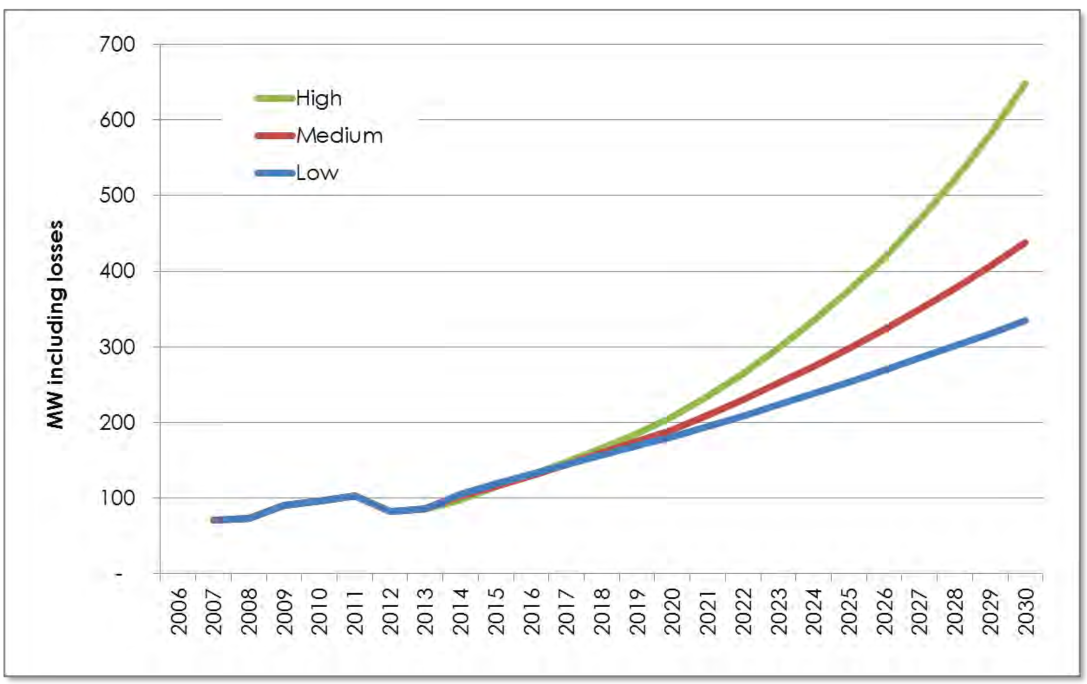
Sources: MoEP

Figure IV-79: Forecast Electricity Consumption Growth



Sources: Excluding losses; Consultant

Figure IV-80: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

TANINTHARYI REGION

65. Tanintharyi Region covers a long narrow southern part of the country on the Kra Isthmus. It borders the Andaman Sea to the west and the Tenasserim Hills beyond which lies Thailand to the east. To the north is the Mon State. There are many islands off the coast the large Mergui Archipelago in the southern and central coastal areas and the smaller Moscos Islands off the northern shores. The capital of the division is Dawei (Tavoy).

Residential Connections Forecast

66. In the last six years the reported new connection rate has been low at an average of 1%. This rate appears to reflect the low population.

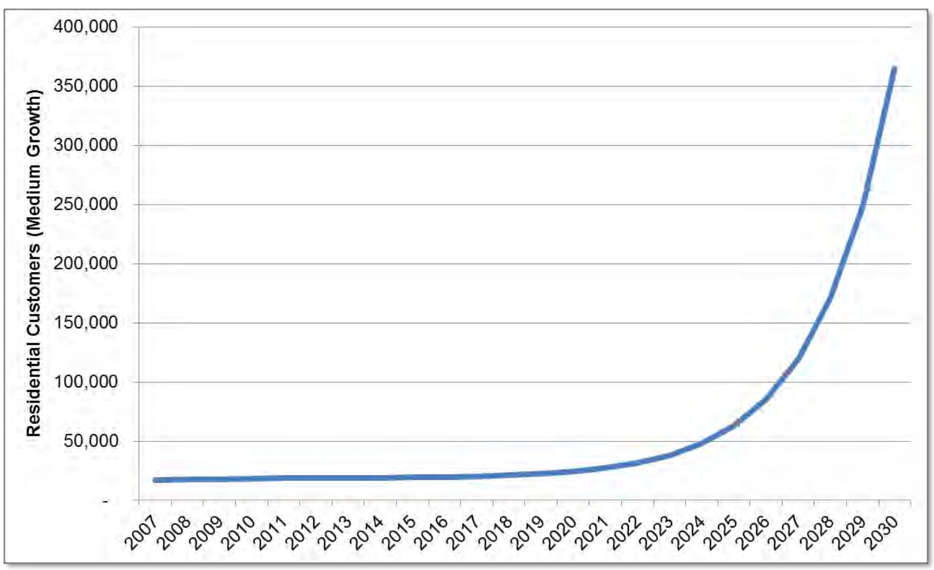
Table IV-81: National Grid Supply Connections to 2013

	2008	2009	2010	2011	2012	2013
Total	17 609	17 747	18 251	18 646	18 908	18 610
Growth (new connections p.a.)	138	504	395	262	(298)	300
Growth %	2%	1%	3%	2%	1%	-2%

Sources: MoEP

67. The forecast growth of residential grid supply connections is shown as Figure IV-82 for the 87% national electrification goal.

Figure IV-82: Growth of Residential Connections

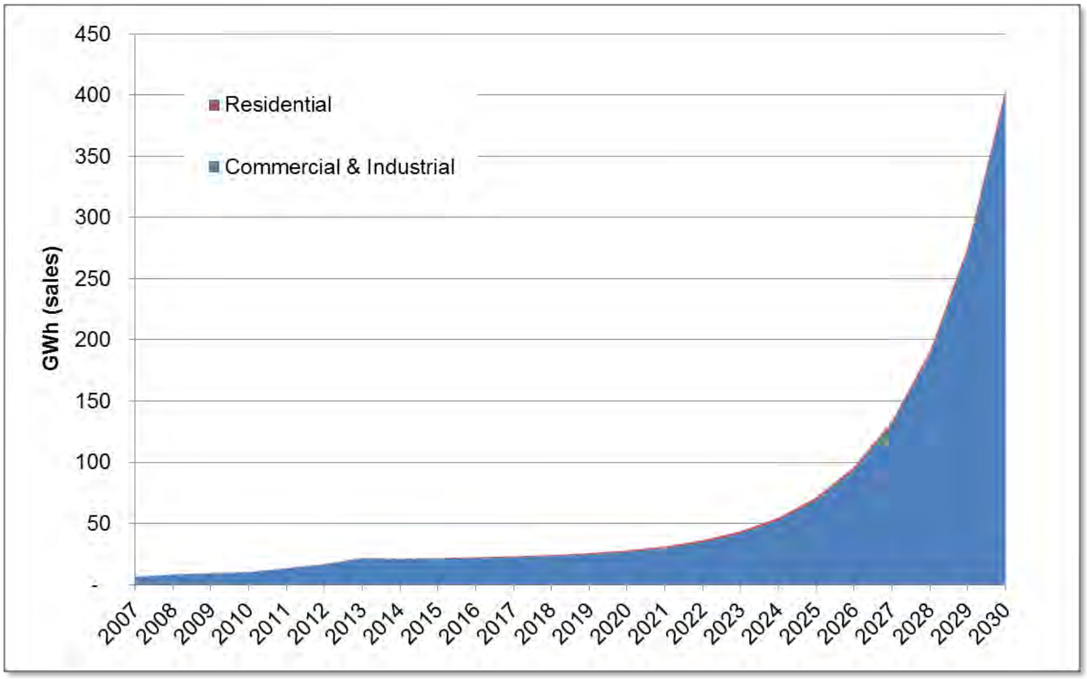


Sources: Consultant

Electricity Forecasts

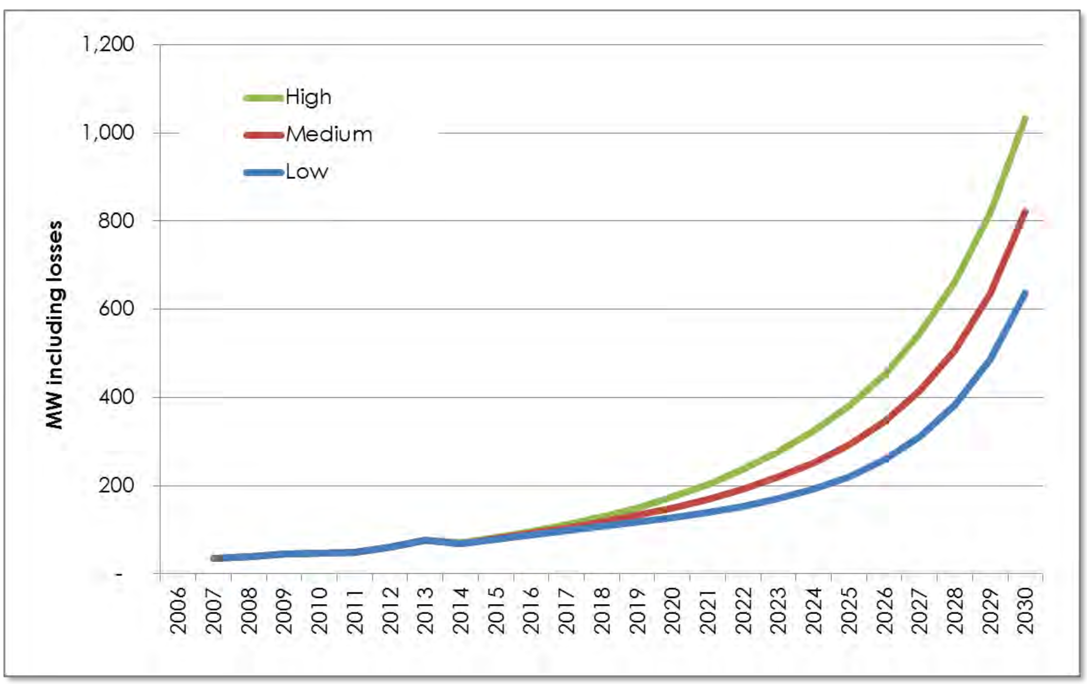
68. The average kWh per residential customer has increased from 460 in 2008 to 1 150 in 2013. Commercial and light industrial consumption is reported by MoEP at an average 4 530 kWh per customer. There were no industrial customers of 2 MVA or above reported.

Figure IV-83: Forecast Electricity Consumption Growth



Sources Excluding losses; Consultant

Figure IV-84: Forecast Electricity Demand Growth



Sources: Consultant; includes losses

YANGON

69. Yangon is the country's main centre for trade, industry, real estate, media, entertainment and tourism. The city of Yangon alone represents about one fifth of the national economy. According to official statistics for FY 2010–2011, the size of the economy of Yangon Region was 8.93 trillion kyats, or 23% of the national GDP.

70. The city is Lower Burma's main trading hub for all kinds of merchandise – from basic food stuffs to used cars although commerce continues to be hampered by the city's severely underdeveloped banking industry and communications infrastructure. Bayinnaung Market is the largest wholesale centre in the country for rice, beans and pulses, and other agricultural commodities. Much of the country's legal imports and exports go through Thilawa Port, the largest and busiest port in Burma. There is also a great deal of informal trade, especially in street markets that exist alongside street platforms of Downtown Yangon's townships.

71. Manufacturing accounts for a sizable share of employment. At least 14 light industrial zones ring Yangon, directly employing over 150,000 workers in 4,300 factories in early 2010. The city is the centre of country's garment industry which exported US$292 million in 2008/9 fiscal year. More than 80 % of factory workers in Yangon work on a day-to-day basis. Most are young women between 15 and 27 years of age who come from the countryside in search of a better life. The manufacturing sector suffers from both structural problems (e.g. chronic power shortages) and political problems (e.g. economic sanctions). In 2008, Yangon's 2500 factories alone needed about 120 MW of power; yet, the entire city received only about 250 MW of the 530 MW needed. Chronic power shortages limit the factories' operating hours between 8 am and 6 pm.

72. Tourism represents a major source of foreign currency for the city although by Southeast Asian standards the actual number of foreign visitors to Yangon has always been quite low. The number of visitors dipped even further following the Saffron Revolution and Cyclone Nargis. The recent improvement in the country's political climate has attracted an increasing number of businessmen and tourists. It is estimated that between 300 000 to 400 000 visitors went through Yangon International in 2011. However, after years of underinvestment, Yangon's modest hotel infrastructure—only 3 000 of the total 8 000 hotel rooms in Yangon are "suitable for tourists"—is already bursting at seams, and will need to be expanded to handle additional visitors. As part of an urban development strategy, a hotel zone has been planned in Yangon's outskirts, encompassing government- and military-owned land in Mingaladon, Hlegu and Htaukkyant Townships.

Residential Connections Forecast

73. In the last six years the residential new connection rate is reported to have averaged 8%.

Table IV-85: National Grid Supply Connections to 2013

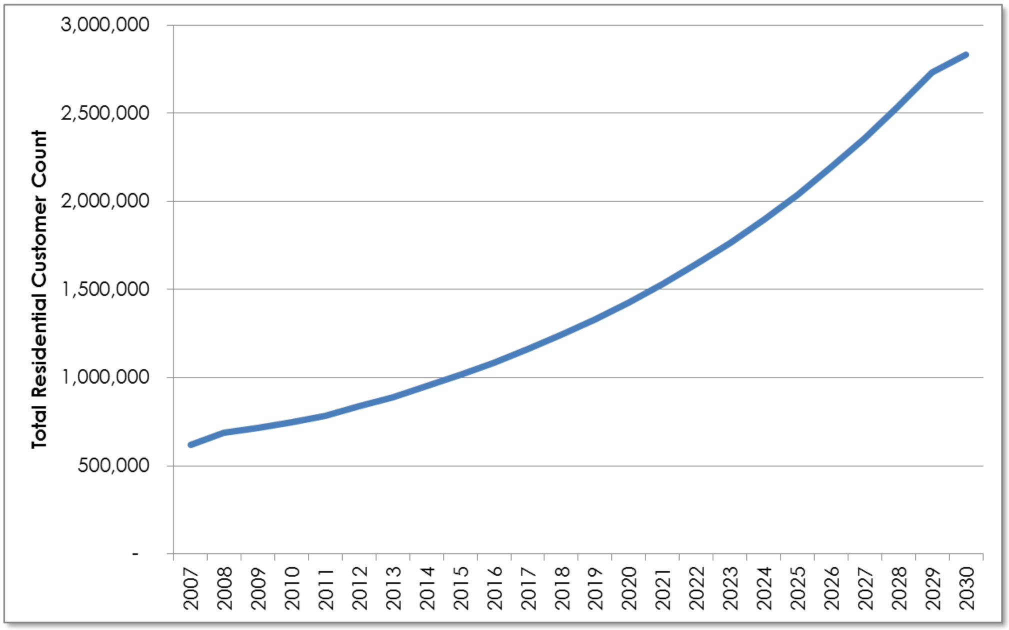
	2006	2007	2008	2009	2010	2011	2012	2013
Eastern	274 298	313 761	330 641	339 184	349 894	361 610	378 876	393 235
Western	159 723	171 009	182 911	190 852	198 532	204 699	213 508	222 626
Northern	26 335	38 823	51 342	54 597	59 331	64 714	73 941	81 917
Southern	77 065	119 555	149 795	159 301	167 747	180 085	202 390	223 684
Total	537 421	643 148	714 689	743 934	775 504	811 108	868 715	921 462
Growth (new connections p.a.)		105 727	71 541	29 245	31 570	35 604	57 607	52 747

Growth %		20%	11%	4%	4%	5%	7%	6%

Sources: MoEP

74. The forecast growth of residential grid supply connections is shown in Figure IV-86.

Figure IV-86: Forecast Growth of Residential Connections



Sources: Consultant

75. The average kWh per residential customer has increased from 800 in 2008 to 1 900 in 2013. For the purpose of forecasting residential consumption it has been assumed that this average consumption will be maintained for the period of the planning horizon.

Commercial Sector Consumption Forecast

76. In the last six years the commercial consumer new connection rate has been reported at an average of 8%. Average commercial consumer consumption was reported by MoEP at 33 340 kWh per customer.

Table IV-87: Commercial Consumers to 2013

	2006	2007	2008	2009	2010	2011	2012	2013
Eastern	8 812	8 866	9 049	9 206	9 248	9 548	9 852	10 003
Western	8 293	8 407	8 498	8 568	8 538	8 557	8 643	8 659
Northern	1 382	1 149	1 199	1 161	1 168	1 200	1 230	1 247
Southern	3 902	3 872	4 068	4 137	4 153	4 195	4 417	4 631
Total	22 389	22 294	22 814	23 072	23 107	23 500	24 142	24 540
Growth %		-0.4%	2.3%	1.1%	0.2%	1.7%	2.7%	1.6%

Sources: MoEP

Table IV-88: kWh per Commercial Consumers to 2013

	2006	2007	2008	2009	2010	2011	2012	2013	Average
Eastern	14 093	12 802	12 136	11 686	13 611	15 446	15 498	13 331	13 575
Western	29 708	27 478	26 674	26 405	28 561	28 508	28 363	26 136	27 729
Northern	18 261	23 708	18 065	24 526	26 707	28 910	26 355	26 856	24 174
Southern	57 737	62 070	56 420	60 255	72 430	83 245	79 689	71 246	67 886

Sources: MoEP

Light Industry Sector Consumption Forecast

77. In the last six years the light industry consumer new connection rate has been reported at an average of 11%. Average light industry consumer consumption was reported by MoEP at 33 340 kWh per customer.

Table IV-89: Light Industry Consumers to 2013

	2006	2007	2008	2009	2010	2011	2012	2013
Eastern	529	603	660	707	772	831	924	1 049
Western	97	108	115	134	145	202	243	266
Northern	1 011	1 151	1 297	1 388	1 533	1 651	1 884	2 069
Southern	27	35	41	55	60	68	75	88
Total	1 664	1 897	2 113	2 284	2 510	2 752	3 126	3 472
Growth %		14%	11%	8%	10%	10%	14%	11%

Sources: MoEP

Table IV-90: kWh per Light Industry Consumers to 2013

	2006	2007	2008	2009	2010	2011	2012	2013	Average
Eastern	187 812	193 791	178 772	140 352	176 461	221 321	194 286	146 568	179 920
Western	176 911	144 731	134 696	133 668	197 436	220 693	280 617	283 806	196 570
Northern	195 691	204 250	206 639	225 442	260 799	334 975	277 267	282 442	248 438
Southern	173 018	153 064	165 285	167 436	184 547	226 244	274 398	243 544	198 442

Sources: MoEP

Bulk Power (Heavy Industry) Sector Consumption Forecast

78. In the last six years the bulk power consumer new connection rate has been reported at an average of 11%. Average bulk power consumer consumption was reported by MoEP at 200 000 kWh per customer.

Table IV-91: Bulk Power Consumers to 2013

	2006	2007	2008	2009	2010	2011	2012	2013
Eastern	129	138	157	164	187	206	228	254
Western	333	377	411	438	485	541	585	662
Northern	194	192	198	204	223	245	272	314
Southern	21	31	29	36	48	68	111	151
Total	677	738	795	842	943	1 060	1 196	1 381
Growth %		9%	8%	6%	12%	12%	13%	15%

Sources: MoEP

Table IV-92: kWh per Bulk Power Consumers to 2013

	2006	2007	2008	2009	2010	2011	2012	2013	Average
Eastern	350 644	320 278	278 843	276 272	295 739	321 849	322 757	264 295	303 835
Western	362 664	330 974	306 009	313 585	337 979	341 183	368 353	311 341	334 011
Northern	66 699	64 256	65 599	69 092	102 109	164 156	154 755	124 966	101 454
Southern	66 108	45 109	67 896	51 898	62 804	79 488	55 644	53 512	60 307

Sources: MoEP

Yangon Industrial Zones

79. Yangon has 18 established industrial zones (IZ's) with another 3 under consideration. These zones represent a significant part of the daily Yangon load. The rate of electricity demand growth has been analysed and Gompertz saturation curves developed to describe the anticipated growth of the IZ's until 2035 (both existing and planned).

Table IV-93: Yangon Industrial Zones (status end 2012)

	District	IZ Name	Start Year	Total Acre	Industrial Acres	Operating	Not Operating	Under Construction
1	East	Dagon Seikkan	1997	1 209	440	102	14	7
2	East	East Dagon	2000	784	146	45	49	98
3	East	North Okkalapa	1998	110	110	94	23	13
4	East	Shwelinban	2002	1 100	209	85		
5	East	South Dagon (1)	1992	475	475	136	35	

6	East	South Dagon (2)	1996	215		773	330	170
7	East	South Dagon (3)	2000	53		1 509		
8	East	South Okkalapa	2000	35	35	70	6	
9	East	Thaketa	1999	200	73	90		
10	West	No industrial zones	1996			659		
11	North	Hlaing Thar Yar (1 2 3 4 6 7)	1995	1 401	1 088	518	43	32
12	North	Hlaing Thar Yar - 5	1996	223		170		65
13	North	Shwe Pyi Thar (1)	1990	336	310	132		
14	North	Shwe Pyi Thar (2 3 4)	1998	987	764	108	65	42
15	North	Shwepaykkan	1998	95	95	244		3
16	North	Yangon Industrial Zone	2000	903	903	31	23	34
17	South	Thilawar	2000	433		3	6	2
18	South	Than Lyan/Kyauk Tan	1996			76		

Sources: MoI

Figure IV-94: Yangon Industrial Zones Saturation Load Curve

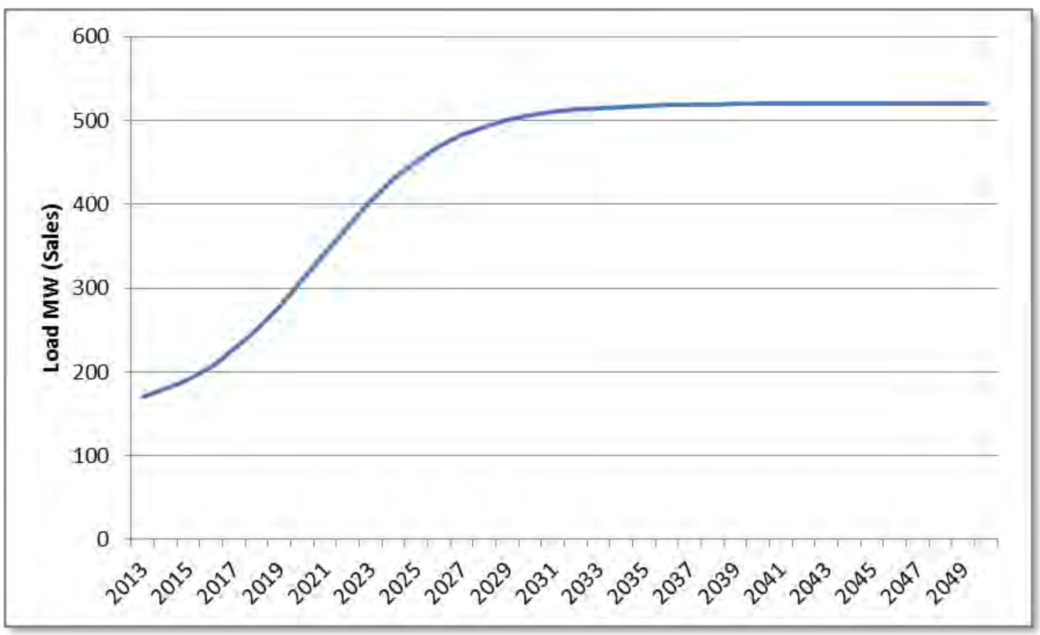


Table IV-95: Yangon Industrial Zones (status end 2012)

	MVA Substation	MW	Sq. km	Year	Yrs operation	Avge MW growth per year	Average kW per factory	Years of growth remaining	kVA per ind acre
Dagon Port	30	8.99	4.89	1997	16	0.56	88	37	68
East Dagon	25	7.08	2.7	2000	13	0.54	157	33	171
North Okkalarpa	10	4.8		1998	15	0.32	51	16	91
Shwe Lin Pan	35	12.9	8.03	2002	11	1.17	152	19	167
South Dagon	100	18.1	1.39	1994	19	0.95	7	86	211
South Okkalarpa	10	2.3	0.14	2000	13	0.18	33	44	286
Thaketa	10	2.25	0.51	1999	14	0.16	25	48	137
Hlaing Thar Yar	75	42.1	30.04	1995	18	2.34	61	14	69
Shwe Pyi Thar	55	21.2	7.35	1996	17	1.25	88	27	177
Shwe Pauk Kan	25	5.21	0.39	1998	15	0.35	21	57	263
Yangon Industrial	20	4.5	3.65	2000	13	0.35	145	45	22
Min Ga Lar Don	5	2.75	0.9	1996	17	0.16	36	14	
Pyin Ma Pin	10	2.5	2.25						
War Ta Yar	10	1.8	4.56						
Myaung Ta Gar	100	32.3	3.85						

Sources: Consultant

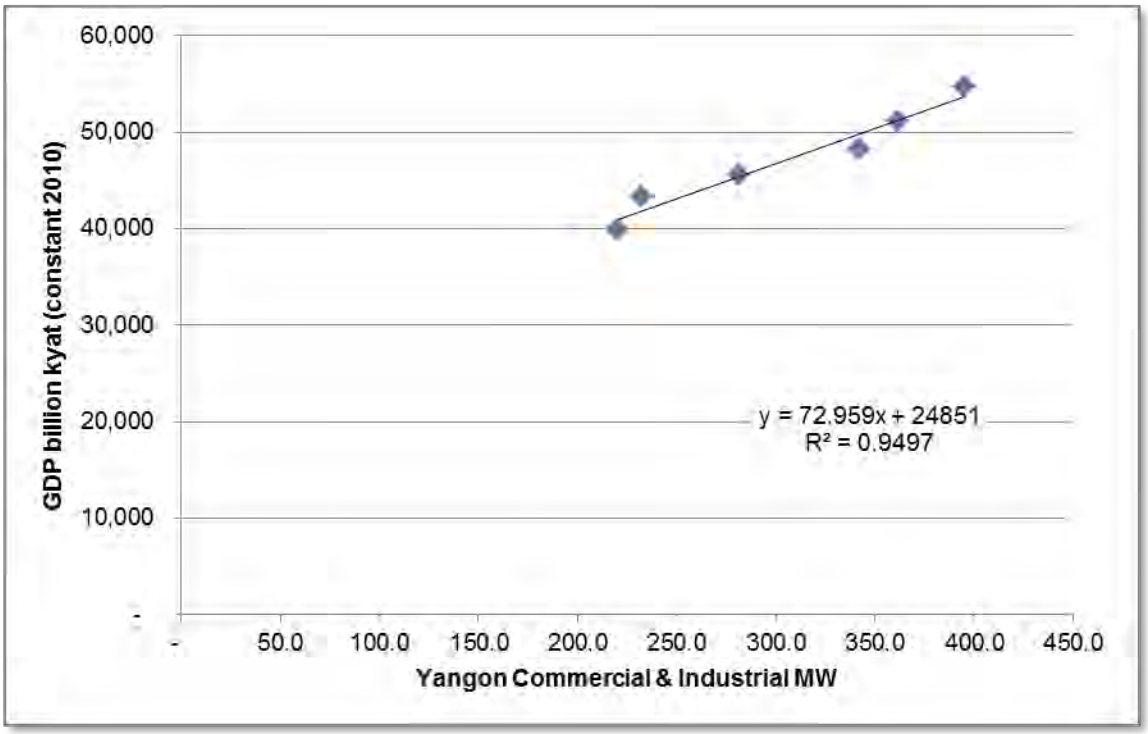
80. The saturation curve shown in Figure IV-94 represents an aggregated load demand curve. Saturation growth curves were developed for each IZ according to the load in 2013 and the substation capacity supplying the IZ. The individual saturation curves were summated to determine the total IZ load forecast. However this load does not represent the total heavy industrial load as industry also operates outside the IZ's.

Total Demand Projection for Yangon

81. The approach used to project total demand was as follows.

1. The residential load was forecast based on customer growth and a constant kWh per customer assumption of 1 900kWh per consumer;
2. Total commercial and industrial load GWh was projected by the use of linear regression on Myanmar GDP. The load included in the regression included light and heavy industry including the load of the IZ's;

Figure IV-96: Regression – GDP versus C&I MW



82. These two energy forecasts were summed and the IZ load determined by the saturation curve method was then subtracted to determine a 'public load' forecast (in the manner that YESC reports load). Using this approach all end-use sector energy was forecasted and finally aggregated.

Project Number: TA No. 8356-MYA

FINAL REPORT
LIQUID & GASEOUS FUEL STRATEGY

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

in association with

ABBREVIATIONS

ADB	–	Asian Development Bank
ASEAN	–	Association of Southeast Asian Nations
CSO	–	Central Statistics Organisation
EIA	–	U.S. Energy Information Administration
FAO	–	Food and Agriculture Organization
FAME	–	Fatty Acid Methyl Ester
GDP	–	Gross Domestic Product
GoM	–	Government of the Republic of the Union of Myanmar
LNG	–	Liquefied Natural Gas
MOE	–	Ministry of Energy
MPE	–	Myanmar Petroleum Enterprise
PRC	–	People's Republic of China
USD	–	United States Dollar

UNITS OF MEASURE

IG	–	Imperial Gallon
km	–	Kilometre
l	–	Litre
mcm	–	Million Cubic Meters
bbl	–	Barrels
bcm	–	Billion Cubic Meters
boe	–	Barrels of Oil Equivalent
bopd	–	Barrels of Oil Per Day
mmbbl	–	Million Barrels
mtoe	–	Million tons of Oil Equivalent

CONVERSION FACTORS

1 litre	=	0.22 Imperial Gallon
1 km	=	0.62137 mile
1 barrel	=	159 litres or 35 imperial gallons
1 ha	=	2.47105 acre
1 km^2	=	100 ha

CONTENTS

I. LIQUID & GASEOUS FUEL STRATEGY

A. Introduction

1. Myanmar's economy is expected to grow at a rate of 7.1%, which will result in an increase in the demand for liquid fuels – a demand which is currently covered mainly with imported hydrocarbons. Covering the liquid fuel needs of a growing economy with imports would negatively affect Myanmar's trade balance in the future – identification of local alternatives is therefore wise. Some possibilities for initiating local production of liquid and gaseous fuels are presented in this report.

2. The Republic of the Union of Myanmar possesses large resources of natural gas. It plays a significant role in the country's energy mix: in recent years natural gas accounted for 45% of the total primary energy production. At home the natural gas was mainly used for electricity production and industrial purposes, whereas the largest part of the gas produced in Myanmar was given for export. Myanmar's proven petroleum gas reserve lies between 6 and 32 times the energy value of proven oil reserves, according to whether the Ministry of Energy or US Energy assessments are correct. Pending further discoveries of oil, it is only Myanmar's petroleum gas that can be considered to be a strategic resource – it is in demand internationally, whereas locally gas could potentially be allocated to pharmaceutical and chemical industry processes, to fertilizer production, to the production of refined petroleum products, to power production, for passenger vehicles, and as a cooking fuel as economic development takes place. In recent years the Government has considered the possibility to establish an LNG terminal to supplement indigenous natural gas supplies.

3. Biodiesel / bioethanol production in Myanmar is currently limited to only a few production facilities. Existing bioethanol facilities have more or less stopped production due to lack of subsidies and no information indicating new facilities being under construction was found. Only pilot scale biodiesel facilities have been built in Myanmar, which are producing small amounts of biodiesel for use by agricultural machinery. Approximately ten years ago Myanmar began an ambitious biofuel implementation program with a plan to plant a total of 3.5 million hectares of jatropha curcas trees. The program was unsuccessful failing to live up to the expectations of making Myanmar self-sufficient as far as the demand for diesel goes. The estimated yield of the jatropha trees planted as part of the program is not available, but considering that several reports have claimed that jatropha plantations covered an area of approximately 2 million hectares, the trees seem to have offered a significant source of non-edible oil that could be used for the production of biodiesel

B. Liquid & Gaseous Fuel Strategy

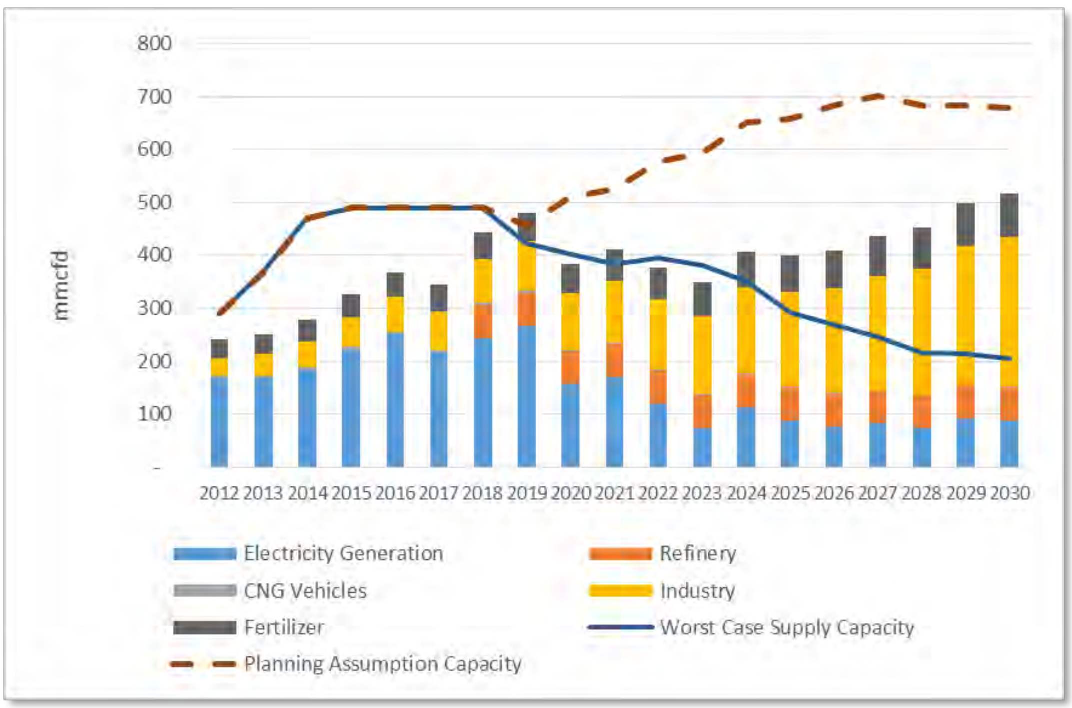
4. **Refined Oil Products.** The first step in defining the strategy for liquid fuels is to identify what should be done with the country's existing refinery capacity. Three small refineries are currently in operation in Myanmar, but all three are old and their operating efficiency is low. Even if The Myanmar Petroleum Enterprise decides to upgrade at least one of the existing refineries, the throughput will not be sufficient to cover the increasing demand; hence the strategy for liquid fuels must be based on construction of new capacity and / or by importing. For the imports there are initial plans for a new import terminal, which could at a later stage support a new local refinery. However, it is believed that a small scale coastal refinery may not be economically feasible under the competitive pressure from large, world class refineries in the Middle East, India and Southeast Asia.

5. Myanmar has the right to use 50 000 bbl/day of the transfer capacity of the Sino-Burma pipeline, which could be used as a feedstock for a potential new refinery. Locating a refinery inland, adjacent to the pipeline, could result in a competitive advantage as production would be close to consumption which would in turn reduce transportation costs.

6. Accordingly it is recommended to undertake a detailed feasibility study for a new inland oil refinery. The concept is based on the development of a small, low complexity inland oil refinery that is powered by residual heavy distillates (supplemented by a small coal-fired power plant using Myanmar coal). The strategic advantage of this approach is that a low complexity refinery does not require a supply of natural gas. The sizing of the refinery at 50,000 bpd is consistent with Myanmar's quota of Arab heavy sour oil, furthermore, the liquid fuel demand of the transport sector requires a balanced production of gasoline and diesel fuel which leads to efficient refinery operation. The economic feasibility of this proposal is largely based on the inland location of the refinery (at the pipeline) with associated low cost to transport fuel to consumers. Intangible benefits relate to the tradition of refining in Myanmar through the three existing refineries; refining provides the domestic industry sector with added depth, supporting the existence of a downstream industry. On the other hand a small refinery will no supply all of Myanmar's highly refined petroleum product needs – while the transport and industry sector needs can be satisfied, imports of diesel fuel will be required to meet the demands of agriculture up to 25% of total by 2030.

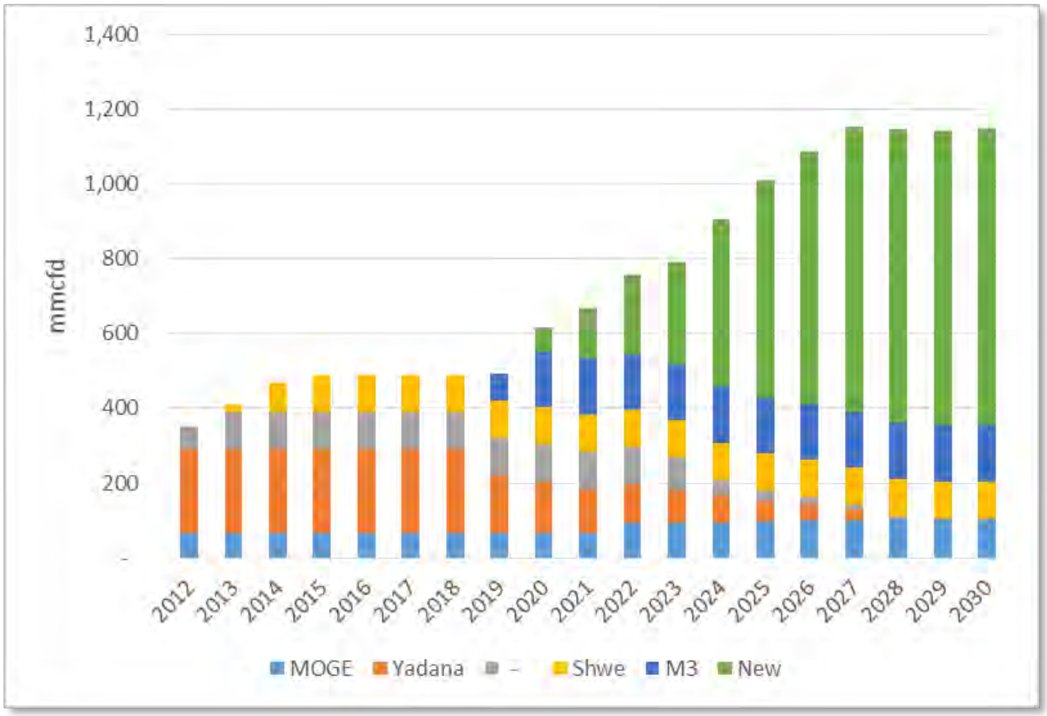
7. **Natural Gas.** The projection for gas supply – demand shows that the outlook is tight. The following supply – demand projection shows that the M3 gas field will be needed to meet demand. If there is any delay to the development of the field would result in a sustained supply shortfall from 2018.

Figure I-1: Projections for Natural Gas Supply & Demand by Sector



Source: Consultant's analysis

Figure I-2: Projection for Gas Supply (JICA 2014)



Source: JICA (2014)

8. There is an opportunity to manage the risks that natural gas supplies do not develop as anticipated. If required, fuel imports can be used to supplement the supply to the transportation and agriculture sectors to release the capacity required to serve the industry and power sectors. Nevertheless, ahead of the development of firm supplies of natural gas, it is considered as a prudent practice to minimize the use of natural gas in the power sector in favor of allocation to industry.

9. Moreover a local refinery can be designed to minimize gas consumption. Power at peak times could be provided by additional storage hydropower or gas / oil plants mainly powered by oil to conserve gas. A fertilizer plant appears to be uneconomic and gas will be saved by importing urea. An LNG terminal would deliver gas at international prices but would be expensive for Myanmar, particularly for the power sector. Moreover the development of an LNG terminal would take at least 5 years. In the recent past it was considered that the M3 field would commence operation in 2019 but recent developments in Thailand and the depressed international prices for oil and gas is expected to result in an indefinite delay. It is recommended that the development of an LNG terminal is considered in conjunction with the timing of the M3 field, and in the meantime a detailed study of industry need for gas is undertaken complete with a Willingness-to-Pay assessment to establish the viability of high-price LNG imports (and therefore the viability of an LNG terminal).

10. In summary, gas could be reserved for industry and the power sector. Other demands could be met by alternative means. The decision to pursue alternatives, such as an LNG terminal, can be decided as a matter of government policy as the natural gas supply – demand balance unfolds in the coming years.

11. **Biofuels.** In future diesel and gasoline production could be supplemented by production of biodiesel from oily plants and of bioethanol from starchy crops. Considering the large surface area

and good growing conditions in Myanmar, liquid fuels produced from renewable feedstock could play a significant role in the supply of transportation fuels.

12. Other crops could also be utilized for the production of biodiesel, but the first step recommended to be taken is to identify the current state of the planted jatropha trees and the means that are available for improving the yield from these trees. Afterwards the focus should be shifted on harvesting methods and defining how the seeds are best processed into biodiesel and whether this should be conducted in large facilities or on a community level.

13. Use of bioethanol should also be considered. Sugarcane, whether used as whole or only in the form of molasses seems to present the most cost-effective way of producing bioethanol utilizing first generation production technology. The concept of blend wall, meaning in essence that approximately 10 % bioethanol can be blended with gasoline without the need for updating the vehicle fleet is coming less important as flex-fuel vehicles, either new one or retrofits, have proved a low-cost solution to pursue consumer side interest in bioethanol fuel.

14. Both biodiesel and bioethanol seem economically feasible for Myanmar. A biofuel policy with set mixing targets for 2020 and 2030 is recommended. Assuming a 10 % target for both diesel and gasoline by 2020, and 20 % target by 2030, transport de-carbonisation case can be developed. Alternative scenarios are discussed in this report, namely a base case, a small inland refinery case, and domestic biofuel case, and their impacts to the supply side of liquid fuels until 2030 in Myanmar.

II. PETROLEUM FUELS

C. Introduction

15. Myanmar's liquid fuel production capacity is insufficient for satisfying the growing demand for liquid fuels in the transportation sector. However, increased dependence on imported petroleum products poses a risk to national fuel security and is a burden on the nation's trade balance.

16. The expansion of a local refinery has been under consideration of the government. The cost and benefits of such an expansion are discussed in detail. The possibility to supplement the current oil based liquid fuel system with biodiesel and bioethanol to satisfy transport demands is also discussed. However, the demand for liquid fuels outside of the transport and industry sectors is not considered. The agriculture sector demand for diesel is expected to grow, to support farm mechanization, but this demand is relatively uncertain compared to that of the transport and industry sectors. Again, biodiesel and bioethanol could be attractive alternatives to petroleum products for agriculture, due to the close proximity of the feedstock, otherwise the agriculture sector could be supplied by imported fuels until the trend towards agricultural mechanization is better established.

17. A concept for increasing Myanmar's oil refining capacity is introduced. The concept is based on a relatively small inland refinery with feedstock sourced from the Sino-Burma pipeline. The expected competitive advantage of the refinery against some of the large scale refineries located at Southeast Asia lies in its inland location, which minimizes the costs related to transportation of the refined products to the local inland market. The size of the refinery is dictated by the quota of 50 000 barrels per day (bbl/day) Myanmar has for the Sino-Burma pipeline. The concept of an inland refinery based on crude in the Sino-Burma pipeline has been criticized for its choice of crude, which is ultimately determined by the Chinese off-taker. Local crude is of different quality, and can be

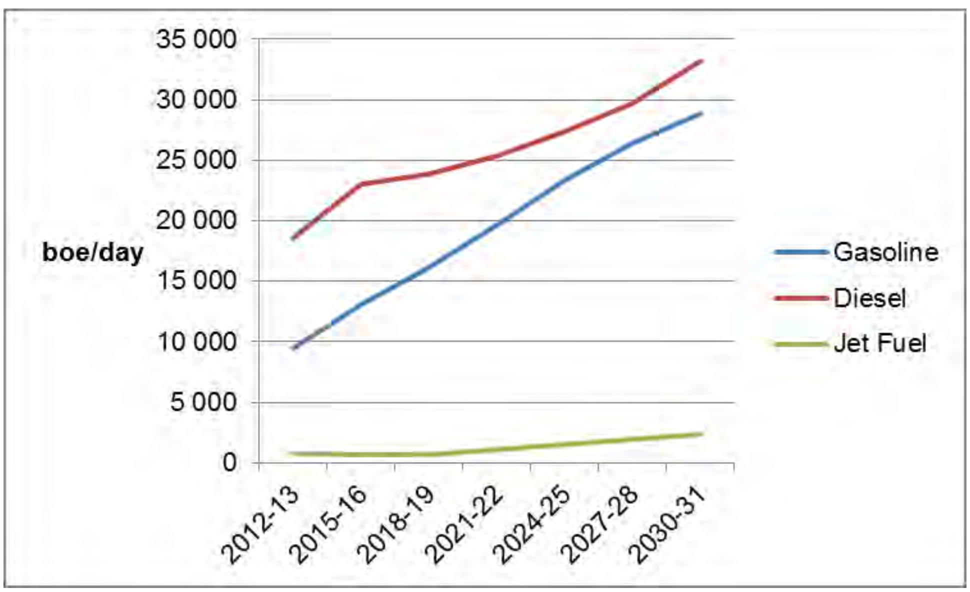
utilized only partly in the contemplated concept. Therefore, an alternative idea of having crude receiving terminal at the coastal area of Myanmar, and a possible local refinery at a later stage attached to it, which would be able to process a mixture of imported and domestically sourced crude oil. Whilst an import terminal may be needed for Myanmar's continuing need to import petroleum products, it is believed that it would be difficult for a finery of relatively modest capacity in international standards to find competitive advantage against new Middle Eastern, Indian and Southeast Asian refineries, many of which represent large scale, cost competitive refinery concepts and latest technology, but there could be a clear location based advantage for an inland refinery, which, however, needs to be proven by thorough feasibility analysis.

Table II-1: Myanmar Petroleum Fuel Sales Projection (in boe/day)

Fuel	2012-13	2015-16	2018-19	2021-22	2024-25	2027-28	2030-31
Gasoline	9 424	13 042	16 129	19 648	23 298	26 394	28 877
Diesel	18 580	22 980	23 900	25 379	27 406	29 684	33 148
Jet Fuel	744	689	692	1 108	1 523	1 938	2 353
Total	28 748	36 711	40 721	46 135	52 227	58 016	64 378

18. Information presented in Table II-1 is also presented in Figure II-2 to highlight the expected increase in demand for liquid fuels in Myanmar.

Figure II-2: Demand of Petroleum Fuels in Myanmar



19. Considering that the combined demand for diesel and gasoline in Myanmar is currently about 30 000 bbl/day (not including illegal imports), and that only the Thanbyakan refinery is capable of producing diesel and gasoline at 10 000 bbl combined per day, without a significant increase in

local refining capacity Myanmar will become increasingly dependent on imported petroleum products with attendant fuel security concerns.

20. So as to further elaborate the issues surrounding fuel security, the Consultant has developed a new oil refinery concept for Myanmar, the merits of which concept, however, need to be analysed by a more comprehensive feasibility analysis. The concept is discussed in the following sections.

21. **Options for Oil Refinery Investment.** Three options have been identified for development of the oil refinery sector in Myanmar. The identified options are:-

1. To invest in a small inland refinery by the Sino-Burma pipeline to cover the growing need for transportation fuels at the inland market;
2. To invest in a medium sized refinery to cover the need for transportation fuels in the whole country;
3. To invest in oil refining sector and build a globally competitive oil refinery producing high quality liquid transportation fuels to cover the domestic demand and to be exported to the Asia Pacific petroleum product markets.

22. **Small Size Refinery.** Out of the three identified alternatives, the first one seems most attractive. It could be realized by lowest capital investment and its inland location would offer competitive advantage as both the feedstock from the Sino-Burma pipeline as well as the target market would be in the close proximity of the refinery. A small refinery size would also fit well with Myanmar's quota of 50 000 bbl/day from the Sino-Burma pipeline.

23. **Middle and Large Size Refinery.** Due to Myanmar's limited oil quota (50 000 bbl/day) to the Sino-Burma oil pipeline, middle or large size refinery cannot be considered to be built inland. A coastal refinery would not have the advantage of being in the middle of the country where there is direct access to the transportation fuel market of Myanmar's second largest city Mandalay. Middle and large size refineries would need significant quantities of natural gas for cracking of heavy distillates as the demands for refinery residues and heavy products are not expected to experience large scale growth. As the availability of natural gas is unclear, building a middle or large sized refinery might require constructing an unloading terminal for liquefied natural gas (LNG). An LNG terminal would not only significantly increase the investment cost but due to the high LNG price at the Asia Pacific market, it would also increase the refinery's operating costs remarkably. A middle size refinery could be an attractive proposition in the event that domestic natural gas production was to grow, or other sources of natural gas could be secured below the market price for LNG. However, according to what is known at the present time, both middle and large size refineries appear to be unattractive under the current circumstances; therefore this report only develops the option of investing in a small scale refinery.

D. Investment in a Small Size Refinery

24. A small size refinery would enjoy a competitive advantage against refineries located in neighbouring countries, such as the new Paradip Refinery in India. The advantage would be gained in the lower transportation cost of both the feedstock and of the refined products to consumers More than half of Myanmar's population lives in landlocked states and regions and of the 12 major cities only four – Sittwe, Yangon, Pathein and Mawlamyaing – have direct access to or are located very close to the sea (see Table II-3 and Figure II-4). If transportation fuels were also in future mostly imported e.g. from the Paradip Refinery, it would be necessary to unload fuel at the major port cities, then to transport by road, river barge or by rail to the landlocked regions and cities.

25. The refinery would mostly use the Arab Heavy Blend (Heavy, Sour) available from the Sino-Burma pipeline as a feedstock, supplemented by small quantities of the local heavy sweet crude sourced from local onshore oil fields. Freight costs and quality differences between the condensate produced at the offshore oil and gas fields and the Arab Heavy Blend suggest that it could be more cost-effective to export the condensate to neighbouring coastal refineries than transporting it to a domestic inland refinery.

26. The sea freight cost for supplying the fuel from Paradip Refinery to coastal cities like Sittwe and Yangon would be approximately 1.5 – 2.5 $ per barrel. Furthermore, the freight cost for transporting the fuel from Sittwe e.g. to Mandalay Region would add another 2.5 – 3.5 $ per barrel. If production is located in close proximity to consumption, a significant competitive advantage would be gained according to reduced freight costs. Another item that must be considered is the economy of scale. A large refinery such as Paradip (300 000 bbl/day) benefits from reduced operating costs. The difference in operating costs between a large scale and a small scale refinery is around 1 – 2 $ per barrel depending on the complexity of the smaller refinery.

Table II-3: Population Spread in Myanmar

Name	Location	Landlocked	Population
Ayerwaddy Region	Lower	No	6,663,000
Bago Region	Lower	No	5,099,000
Chin State	West	Yes	480,000
Kachin State	North	Yes	1,270,000
Kayah State	East	Yes	259,000
Kayin State	South	Yes	1,431,377
Magway Region	Central	Yes	4,464,000
Mandalay Region	Central	Yes	7,627,000
Mon State	South	No	2,466,000
Rakhine State	West	No	2,744,000
Shan State	East	Yes	4,851,000
Sagaing Region	North	Yes	5,300,000
Tanintharyi Region	South	No	1,356,000
Yangon Region	Lower	No	5,560,000
Naypyidaw Union Territory	Central	Yes	925,000
		Total	**50,495,377**
		Landlocked Regions	**26,607,377**

Figure II-4: The Sino-Burma Pipeline[1]

27. Three different scenarios for the estimated freight costs are shown in Table II-5. The scenarios are chosen based on the distance of the demand from the inland refinery (short, medium and long distance). As can be seen from Table II-5, a small inland refinery would face serious competition when it comes to the transportation fuel market of Myanmar's coastal cities. Yangon International Airport would for example most likely continue to import jet fuel even in the case a small domestic refinery was built.

28. Note that the freight cost of crude oil from the Middle East to the deep water port at Kyaukpyu

[1] Landlocked and coastal regions are indicated with a purple colour, the approximate location of the Sino-Burma pipeline with red.

were not taken into account in calculations presented in Table II-5; it was assumed that the freight cost of crude oil would be approximately the same to all refineries in neighbour countries.

Table II-5: Freight Cost Comparison[2]

All figures in $ per boe	Average Distribution Cost of Transportation Fuels to Inland Consumers			Average Distribution Cost of Transportation Fuels to Consumers at Coastal Regions			Pipeline Transportation Cost of Crude Oil in Myanmar
	Truck & Rail	Sea	Total	Truck & Rail	Sea	Total	Total
Large Neighboring Coastal Refinery	$2.50	$1.50	$4.00	$1.00	$1.50	$2.50	$0.00
	$3.25	$2.00	$5.25	$1.75	$2.00	$3.75	$0.00
	$4.00	$2.50	$6.50	$2.50	$2.50	$5.00	$0.00
Small Domestic Refinery in Mandalay	$1.00	$0.00	$1.00	$2.50	$0.00	$2.50	$0.30
	$1.75	$0.00	$1.75	$3.25	$0.00	$3.25	$0.60
	$2.50	$0.00	$2.50	$4.00	$0.00	$4.00	$0.90
Distribution Cost Difference	To Inland Consumers			To Consumers at Coastal Cities			
	$2.70			-$0.30			
	$2.90			-$0.10			
	$3.10			$0.10			

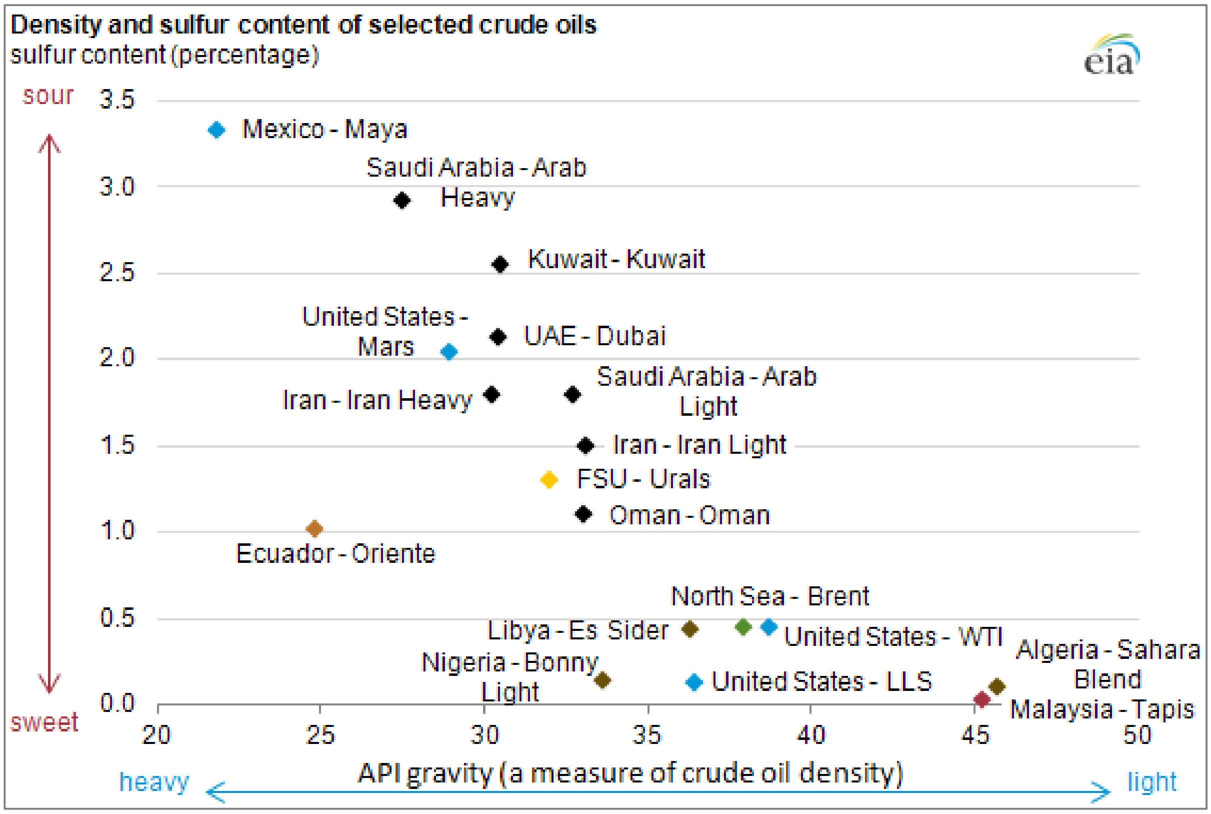
29. According to Table II-5, a small domestic inland refinery would have a clear freight cost advantage against its competitors in Myanmar's inland transportation fuel markets. Based on the population spread presented in Table II-3, inland transport fuel sales can be assumed to account for approximately 60 % of the total sales. According to the demand prognosis (Table II-1) Myanmar's total gasoline, diesel and jet fuel consumption in 2030 would be around 81 000 boe/day and assuming that consumption would increase evenly in inland and coastal regions, the total inland consumption in 2030 would be 48 500 boe/day.

[2] The table presents three cases: best, average and worse depending on the distance between the inland refinery and the point of demand – the reduction in revenue in pipeline tariff is assumed to be $0.3 for the best case and $0.9 for the worst case.

30. One of the main uncertainties of the presented small inland refinery business case is the tariff revenue that Myanmar gets for transporting oil to the People's Republic of China (PRC) along the Sino-Burma pipeline. In the calculation presented in Table II-5 it was presumed that PRC pays Myanmar a transportation fee for each barrel they receive and that the operating margin Myanmar receives for oil transportation would be 0.3 $, 0.6 $ or 0.9 $ per barrel. The pipeline transportation tariff rate could have a major impact on the profitability of the refinery since oil used at the refinery would reduce the income from oil transport to PRC.

31. In addition to the competitive advantage that an inland refinery could have against other refineries it is important to understand the total refinery margin. Refine margin is the difference in total price of the products that a refinery sells minus the price of the feedstock. The total operating margin per barrel is calculated by deducting the operational costs from the refining margin. In general a more complex refinery has a higher refining margin and a higher investment cost. More complex refineries are capable of using cheaper heavier oil blends with higher sulphur content whereas simpler refineries have to buy lighter oil blends with lower sulphur content. The most common crude oil blends and their characteristics are shown in the Figure II-6.

Figure II-6: Characteristics of Crude Oil Blend



Source: EIA (2014)

32. There are numerous variations for how the oil refining process could be designed. Each oil refining process has different functions and yield profiles which directly affect the refining and operating margins. One way of simplifying numerous different oil refinery processes is to sort them into four generalized categories according to their process complexity as presented in Table II-7.

Table II-7: Generalized Process Complexity Categories

Process Complexity	Category	Feedstock
High	Deep Conversion	Heavy Sour
Intermediate	Hydrocracking	Heavy Sour
Elementary	Catalytic Cracking	70 % Light, Sweet & 30 % Heavy, Sweet
Low	Hydro-skimming, Topping	Light, Sweet

33. Since the goal is to achieve maximum production of high quality transportation fuels, and the main feedstock is assumed to be heavy and sour (Arab Heavy) from the Sino-Burma pipeline, for a satisfactory refining margin to be achieved a small inland refinery must have intermediate or high process complexity. A hydrocracking refinery using heavy and sour feedstock produces significantly more middle distillates (diesel and jet fuel) than a catalytic cracking refinery.

34. An example of the product slate received from different refinery configurations is shown in Table II-8. It should be emphasized that today's modern hydrocracking and deep conversion refineries are relatively flexible giving the refiners control over the proportion of middle and light distillates that are produced. In Table II-9, the differences in the product slate are converted into sales according to the average market prices at New York and Rotterdam between October 1, 2013 and September 30, 2014. It can be seen that with crude prices of the same period exceeding 100 $/bbl hydro-skimming and catalytic cracking type of refineries are not feasible, and many of such types have not been developed anymore except under special circumstances.

35. It has to be noted that the prices of the residue and heavy products have significant differences depending on their location. Furthermore, the refinery configurations given in Table II-8 and Table II-9 have been generalized and the exact product slate in the residue and heavy products category is also depended on the exact production line configuration of the refinery within the given generalized refinery configurations. For example a deep conversion refinery can have a fluid coking unit that, as a residue, produces low energy content gas that cannot be sold outside the refinery but can easily be burned in process furnaces. Alternatively a refinery can have a delayed coking unit that produces coal-like petroleum coke as a residue that can either be sold or used in a circulated fluidized bed boiler for refinery's steam and electricity production.

Table II-8: Examples of the Product Slates by Refinery Configuration

Product	Hydro skimming	Catalytic Cracking	Hydrocracking	Deep Conversion
Gases (Propane, Butane etc.)	3 %	2 %	2 %	2 %
Light Distillates	14 %	32 %	18 %	18 %
Middle Distillates	29 %	27 %	58 %	65 %
Heavy Products	27 %	19 %	14 %	11 %
Residue	27 %	18 %	8 %	4 %

Table II-9: Example of Oil Product Sales by Refinery Configuration

(USD per refiner barrel)

Product	Hydro skimming	Catalytic Cracking	Hydrocracking	Deep Conversion
Gases (Propane, Butane etc.)	$1.39	$0.92	$0.92	$0.92
Light Distillates	$16.35	$37.37	$21.02	$21.02
Middle Distillates	$35.57	$33.12	$71.14	$79.72
Heavy Products	$19.74	$13.89	$10.23	$8.04
Residue	$12.29	$8.19	$3.64	$1.82
Total Price per Barrel of Oil	**$85.33**	**$93.49**	**$106.96**	**$111.53**

36. An oil refinery consumes a significant amount of energy in process furnaces and in form of steam and electricity. In addition to energy consumption, a hydrocracking process requires also significant quantities of hydrogen. The lack of natural gas for domestic consumption in Myanmar means that the refinery's energy supply and production configuration cannot be standard, as natural gas is often the main source for steam and electricity generation and in most cases it is also the most important source of the hydrogen used by the hydrocracking unit. For the small inland refinery, the energy supply could be based on a combination of coal, refinery residue and petroleum coke from the delayed coking unit. The investment cost of a combined heat and power plant burning solid fuel with a high sulphur content, would be significantly higher than the cost to build an ordinary combined cycle gas turbine power plant, but the power plant investment could be made in co-operation with a local power generation company and the power plant could in addition to the refinery's energy needs also generate electricity to the national power grid.

37. For a hydrocracking unit with capacity between 15,000 and 20,000 barrels per day about 45,000 – 60,000 cubic meters of natural gas per day would be needed for hydrogen production. The exact amount of natural gas consumption depends on the feedstock and the desired product slate.

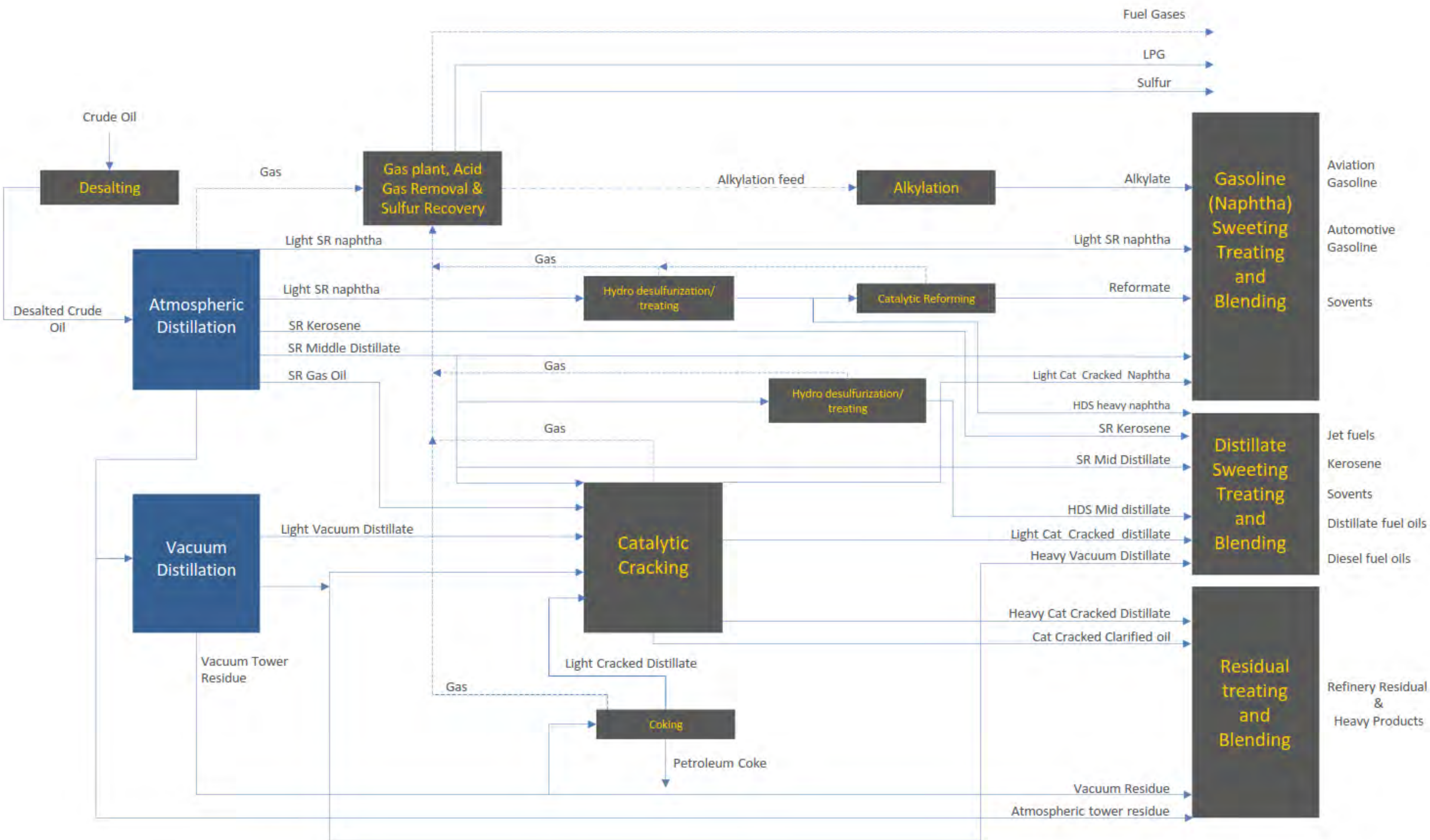
Production of light distillates such as gasoline requires more hydrogen than the production of middle distillates such as jet fuel, diesel and heating oil. Since it is unlikely that there is enough natural gas for a hydrocracking unit, the ideal configuration of a small inland refinery could be based on a catalytic cracking design with a delayed coking or vis-breaking unit. In principle this configuration could operate without any natural gas, instead steam and electricity could be produced by using the refinery residues, coal and petroleum coke. A refinery with catalytic cracking and delayed coking configuration (no hydrocracking) would produce more low value refinery residue and heavy products but the deficit in natural gas supply means that the demand for the refinery residue and heavy products would be stable.

38. An example of the potential production capacity of a refinery designed to use Arab heavy sour oil, is presented in Table II-10. A process schematic of the envisaged refinery is given as Figure II-11.

Table II-10: Refinery Process Capacity

Production Unit	Capacity (bbl/day)
Atmospheric Distillation	50 000 – 60 000
Vacuum Distillation	20 000 – 25 000
Delayed Coker or Visbreaker	8 000 – 9 000
Fluid Catalytic Cracker	20 000 – 25 000
Naphtha Hydrotreater	10 000 – 14 000
Catalytic Reformer	10 000 – 14 000
Kero/Jet Reformer	4 000 – 5 000
Diesel Hydrotreater	10 000 – 12 000
Alkylation Unit	5 500 – 7 000
Isomerizer	8 000 – 10 000

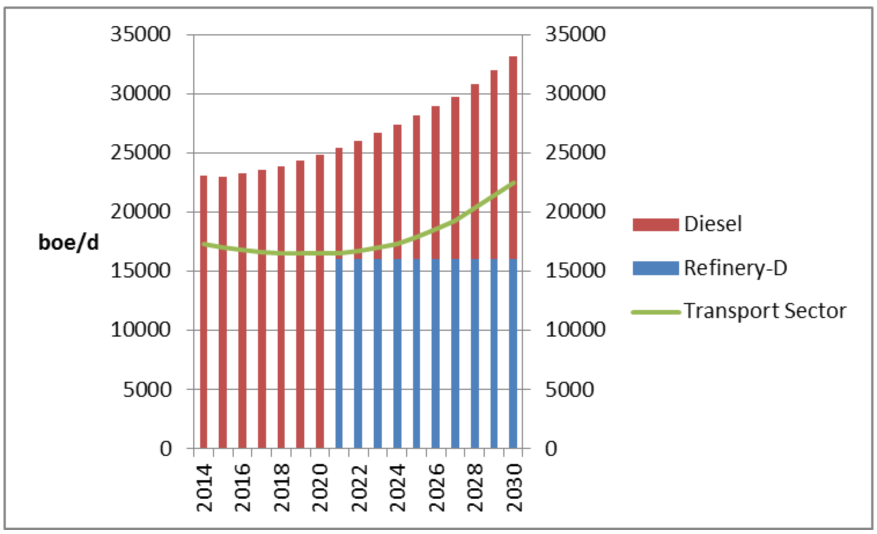
Figure II-11: Schematic of Concept Refinery Process



39. Due to the high share of residue and heavy products produced by a catalytic cracking refinery, the optimal throughput capacity could be more than 50 000 barrels per day. A feedstock capacity of 50 000 barrels per day would yield approximately 35 000 boe per day in transportation fuels even if in addition to the catalytic cracking unit a delayed coking or vis-breaking unit were to be added. Additionally, refinery downtime would reduce the total yield by 8 – 10 % which means that the total transportation fuel output would be about 20 % lower than the predicted inland consumption in 2030 (40 500 boe per day). However, due to the relatively low refinery complexity and the possibility for outsourcing the steam and electricity production, the total investment cost of the small inland refinery with catalytic cracking and delayed coking or vis-breaking could be under 1 200 million US dollars even if the feedstock capacity were to be slightly increased.

40. Figure II-12 and Figure II-13 present the total production of diesel and gasoline compared to the estimated demand (as presented in Table II-3). The demand presented is the estimated total demand, so it can be assumed that part of the local production deficit will be balanced by imports especially to the coastal regions. Figure II-12 shows the diesel demand of the transport sector by a green line. As all of the gasoline demand is for transport sector, one can observe from the graphs that the conceptual 50 000 bbl/d refinery would cover most of domestic transport sector fuel demand. If liquid biofuels were to be introduced to the supply portfolio, Myanmar could achieve almost full fuel independence for at least the first years of refinery operation.

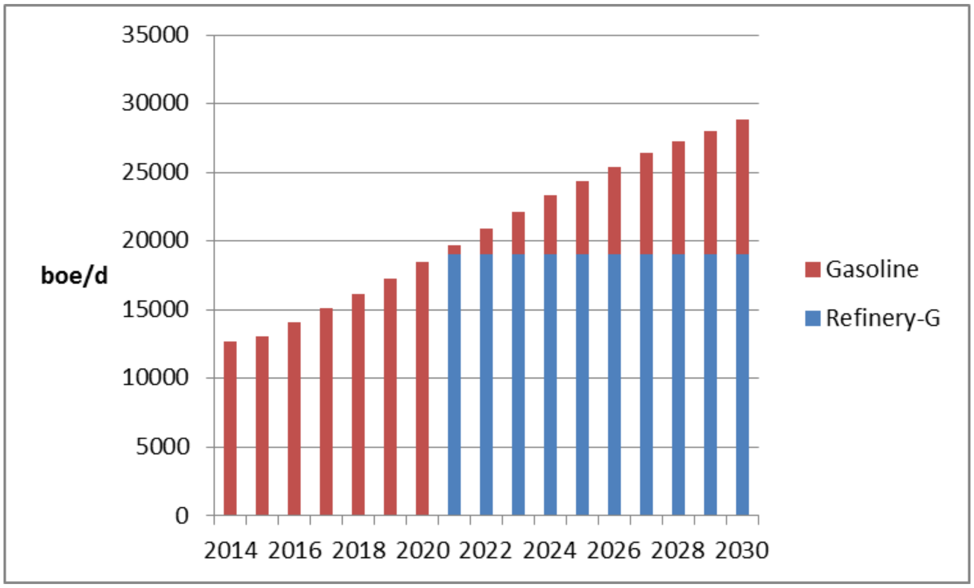
Figure II-12: Estimated Diesel Demand & Production



Source: Consultant's analysis

41. In the future, once the technologies for producing renewable transportation fuels in the form of biodiesel and bioethanol become more advanced and therefore more cost competitive, the production of the new refinery can be supplemented with a construction of both biodiesel as well as bioethanol production facilities to further improve Myanmar's supply security. The size of the facilities producing renewable transportation fuels should be determined, once the final configuration of the small refinery is known. Considering the current demand forecasts, there seems to be a larger need for a facility producing bioethanol that could be blended with gasoline to reduce the supply deficit. It would be wise to locate the possible biodiesel and bioethanol production facilities closer to coastal regions to achieve a good nationwide balance between supply and demand. Biodiesel and bioethanol are discussed in more detail in Section VII.

Figure II-13: Estimated Gasoline Demand & Production



Source: Consultant's analysis

42. **Feasibility of the Small Inland Refinery.** The feasibility of an investment in a small inland refinery is mainly dependent on the heavy product consumption and energy supply of the envisaged inland refinery, as well as future investments in oil refineries in neighboring countries. Even though the small inland refinery will benefit from lower freight costs and from the relatively low price of the Arab Heavy Blend oil, the refinery complexity will remain moderate until a cost effective natural gas supply can be made available. Energy supply (steam and electricity) often accounts up to 40 % of the refinery's operating expenses and so the cost of the energy supply largely determines the net benefits case.

43. The most effective way to organize the energy supply of the refinery would be a large scale power plant based on circulated fluidized bed boiler that would be able to utilize refinery residues and coal and, in addition to supplying energy to the refinery, could sell electricity to the grid.

44. Feasibility is also affected by the development of competition from the refineries producing in neighbouring countries and willing to sell to Myanmar. This risk appears to be small. Apart from the Paradip Refinery in India, which is expected to start operation in 2015, there are no new large scale refineries under construction. It is anticipated that the Paradip Refinery's production will be mostly sold at the Indian domestic transportation fuel market.

E. Conclusion

45. Myanmar's economy is expected to grow at a rate of 7.1%, which will result in an increase in the demand for liquid fuels – a demand which is currently covered mainly with imported hydrocarbons. Covering the liquid fuel needs of the growing economy with imports would negatively affect Myanmar's trade balance in the future – identification of local alternatives is therefore wise. Some possibilities for initiating local production of both fossil and renewable based liquid fuels were presented in this report.

46. The first step in defining the strategy for liquid fuels is to identify what should be done with the

country's existing refinery capacity. Three small refineries are currently in operation in Myanmar, but all three are old and their operating efficiency is low. Even if The Myanmar Petroleum Enterprise decides to upgrade at least one of the existing refineries, the throughput will not be sufficient to cover the increasing demand; hence the strategy for liquid fuels must be based on construction of new capacity and / or by importing. For the imports there are initial plans for a new import terminal, which could at a later stage support a new local refinery. However, it is believed that a small scale coastal refinery may not be economically feasible under the competitive pressure from large, world class refineries in the Middle East, India and Southeast Asia.

47. Myanmar has the right to use 50 000 bbl/day of the transfer capacity of the Sino-Burma pipeline, which could be used as a feedstock for a potential new refinery. Locating the refinery inland, adjacent to the pipeline, could result in a competitive advantage as production would be close to consumption which would in turn reduce transportation costs. According it is recommended to undertake a detailed feasibility study for a new refinery.

III. NATURAL GAS

F. Introduction

48. Myanmar's natural gas is in demand internationally whereas locally, Myanmar's natural gas could potentially be allocated to fertilizer production, as a fuel for the production of refined petroleum products, to industry, to the power sector. LPG could also be produced and used as a cooking fuel.

49. At the present time Myanmar's proven reserves of gas are insufficient to meet the projected demands of all sectors of the economy. Given the relationship between GDP growth and natural gas supply, it is considered that Myanmar's natural gas should be allocated to export, to fertilizer production and to industry.

G. Power Sector Consumption

50. There is a role for gas in power generation, potentially supplemented by liquid fuels. The existing (and under construction/development) capacity for gas based power will be about 1 700 MW within a few years, which would consume over 200 MMCFD when simultaneously in operation. Given the relative uncertainty surrounding hydropower development with storage capacity, as reserve capacity needs increase to 2030, and if gas would be used to meet this capacity need, then total gas consumption could reach as high as 1 000 MMCFD. This requirement for gas may not be able to be met through a future domestic gas quota but could instead be met by imported LNG or by light fuel oils. However, the cost of LNG exceeds 18 $/MMBtu and this means that LNG would be a very expensive solution for power generation. In principle however, power generation could comprise a gas plant capacity of less than 10% in 2030 if light fuel oil was used to fuel fast-acting reserve capacity plant. In this case, the total annual gas consumption by the power sector would be very modest; in 2020 only 18 BCF and in 2030 only 31 BCF. When the existing gas contracts governing domestic quotas expire it may be feasible to negotiate for a higher quota, or new gas fields may be discovered, but in the meantime, it is considered prudent to plan the expansion of the power sector to minimize the consumption of gas to ensure that industry needs are met.

H. Refinery

51. A 50 000 bblpd hydro-cracking refinery would require around 10 000 MMCF of natural gas to produce hydrogen and to power the refinery. This gas requirement can be much reduced by using an alternative refinery design that does not require hydrogen, and one that is powered using heavy distillates.

52. The oil supplied to the refinery will have fractions that are gaseous (condensates) and gas will be produced, some of which can be used for power production and some which can be sold to consumers for profit. Table III-1 provides an estimate of the quantities of refined oil products that would be produced by a vis-breaking 50 000 bblpd refinery, expressed in energy terms. Table III-2 provides an estimate of the gas and residue fuels that could be used to power a vis-breaking refinery, along with the residual quantities that could be sold to consumers. The residues are of sufficient quantity to power a 100 MW power plant; the residues could be stored and called upon to power reserve gas / oil plant, or the refinery power plant could be over-sized and the additional 100 MW capacity could be used to supply consumers living in the vicinity of the refinery.

Table III-1: Energy Content of Refined Oil Products (50 000 bbld)

Product	Share	Thermal Value	Total Energy Content (MJ/Day)
Gases	2%	50	6,439,500
Light Distillates	37%	46	110,308,635
Middle Distillates	29%	42	79,180,092
Heavy Products	17%	37	40,723,398
Residue	15%	35	33,807,375
		Total	270,459,000

Table III-2: Vis-breaking Refinery Power Production

Fuel	Used for Energy Production (MJ/Day)	Sold to Consumers (MJ/Day)	Used for Energy Production (barrels per day)	Sold to Consumers (barrels per day)
Gas	3,219,750	3,219,750	450	450
Residue	7,511,130	26,296,245	1,250	4,375

I. Fertilizer

53. As discussed in the Agriculture Sector demand report, the use of fertilizer in Myanmar has fallen to around 10 kg per hectare. Agricultural experts Naing and Kingsbury found that a fertilizer load of 80 kg per hectare produced significantly increased yields of all major crops including rice.

54. A standard production run for a modern fertilizer plant is 1 725 metric tons per day. This equates to around 600 000 tons of fertilizer per annum. Myanmar has around 17 million hectares which means that the standard production run output would provide for around 35 kg per hectare. For the purpose of evaluation of the economics of a standard fertilizer plant, a urea production equivalent to 35 kg per hectare has been assumed. A 70 – 80 kg per hectare production could be achieved with two standard run fertilizer plants, each located in the north and south of the country.

55. Table III-3 presents an outline calculation for a standard run fertilizer plant. The plant would produce 1 000 mt of ammonia per day before adding water for conversion to 1 725 mt of urea. The natural gas requirement would be 31 mmcfd or 10 200 mmcf per annum. The investment cost would be $ 1.2 billion.

Table III-3: Conceptual Fertilizer Plant (Ammonia / Urea)

	Plant Capacity
	1 725 mtpd
Urea	595 000 t/a
Gas	10 200 mmcf/a
Investment Cost	1 200 MUSD
O&M	2.5% of capital cost

56. An economic evaluation has been conducted with the objective of determining the price of natural gas that would result in a competitive cost for locally-produced urea. The economic discounting rate (real) has been assumed as 6 % and the life of the fertilizer plant as 20 years.

57. The economic evaluation shows that the price of natural gas would need to be set at no more than $ 6 per MMBtu if a local fertilizer plant was to be cost competitive against an international price for urea of around $ 350 per mt. The gas price appears to be too low if an economic value of $ 18 per MMBtu is considered as an opportunity cost, or if the government's current subsidized price of $ 11.2 per MMBtu is considered. Therefore it is assumed that fertilizer would be imported rather than manufactured locally.

J. Industry, Commercial, Household Sector

58. Industry uses natural gas for processes that require fine control of heat, e.g. petrochemical production. The commercial sector uses LPG for cooking, primarily in restaurants. There is also production required for household use for cooking. LPG is being imported and could continue to be imported while natural gas is in short supply and demanded by industry.

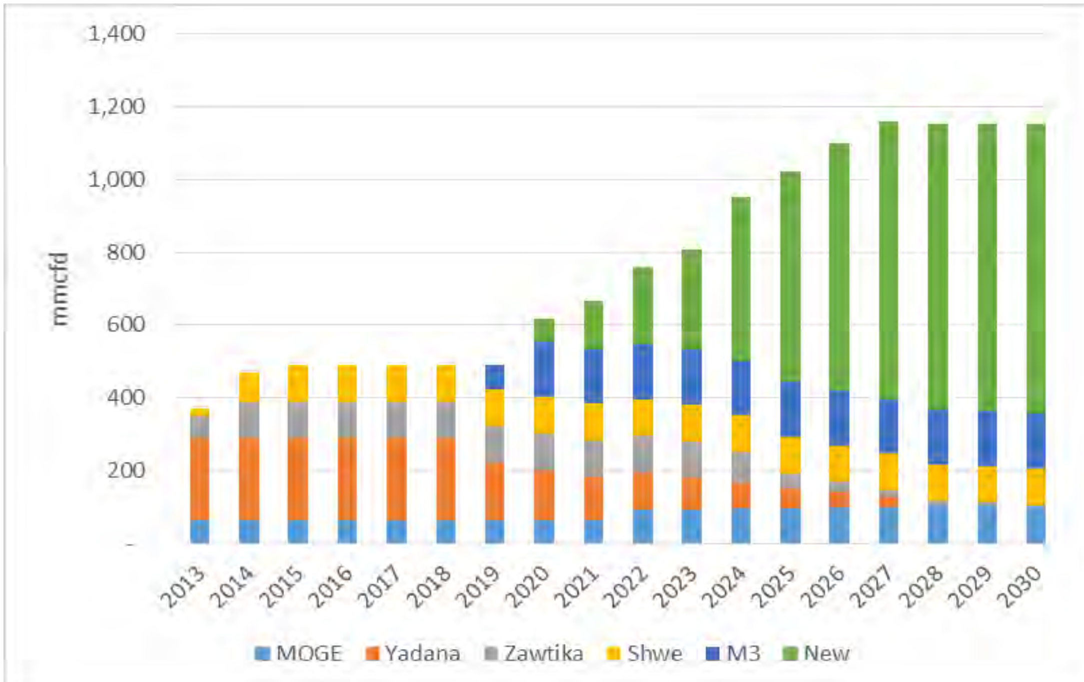
K. Natural Gas Supply – Demand Balance

59. The natural gas supply-demand balance takes into account the estimated production of the operation gas fields, based on domestic needs, and known and likely development of new gas fields.

60. The Aung Thein Kha (M3) field has been planned to start production in 2019. However, in early 2015, the new Thai government indicated that Thailand's dependence on Myanmar for natural gas has reached a comfortable limit and further purchases may not be in Thailand's strategic interest. This announcement, coupled with depressed international prices for oil and gas, has led to public announcements by PTT Thailand that the development of the M3 field may be indefinitely delayed. The production of other new fields are speculative, e.g. the announced find of an Indian company in Block A6 (Phyithar discovery) was not accompanied by an estimate for the commencement operation date.

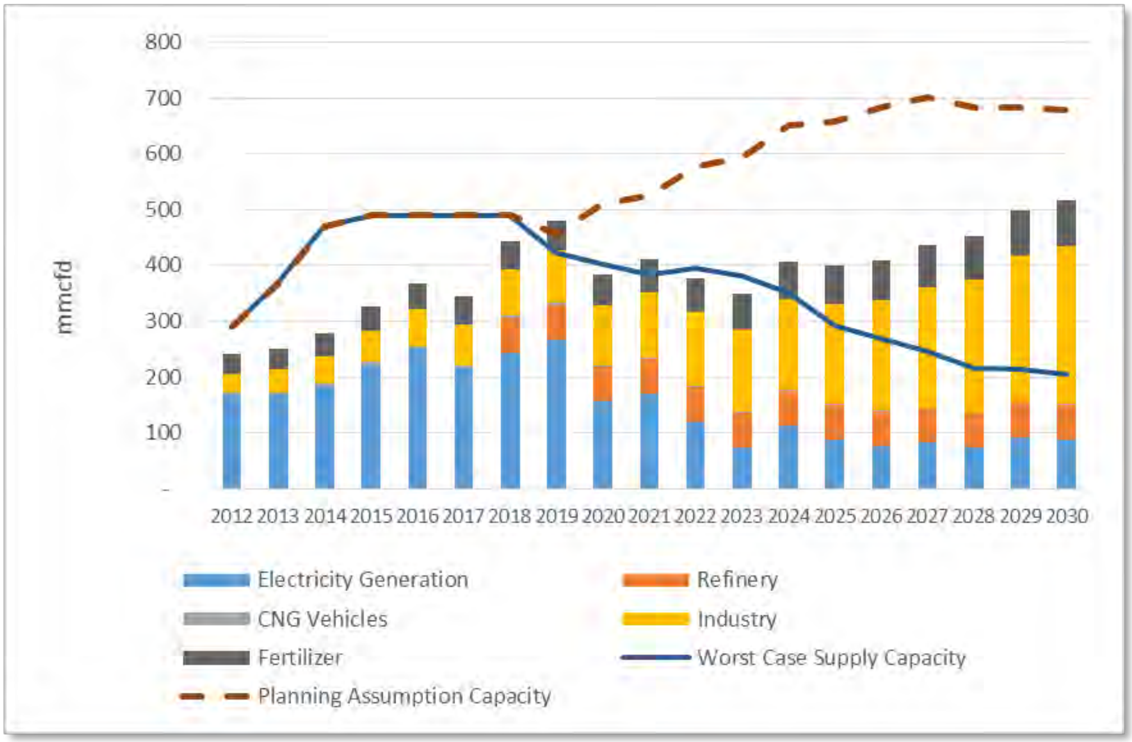
61. Figure III-1 presents a gas supply – demand balance projection developed by JICA under their Electricity Masterplan. The projection includes the M3 field and other fields identified by JICA in the course of their study in 2014.

Figure III-1: Projection for Gas Supply (JICA 2014)



Source: JICA 2014

Figure III-2: Projections for Natural Gas Supply & Allocation



Source: JICA 2014, Consultant's analysis

62. Figure III-2 provides a projection according to the worst case where the M3 and other fields are indefinitely delayed. The planning assumption capacity trajectory represents a capacity half way between JICA's projection in Figure III-1 and the worst case trajectory. The sector demands are based on the electricity growth scenario developed in ADICAs Electricity Expansion plan and the refinery development of Section II above. Fertilizer production need for gas is included to understand the relationship between demand and available capacity. Whilst the planning assumption capacity trajectory could be considered as likely, in practice it is considered prudent to minimize gas consumption. This issue is further discussed below in terms of risk mitigation.

63. Unless natural gas development and consumption is managed through policy means, there is a real potential for significant shortages of gas within 10 years. In the past MOE has negotiated with gas suppliers from Thailand for additional gas supply to Myanmar. Also, as a separate development, MOEP has explored the possibility to purchase LNG. The principal options available therefore include demand-side measures, such as limiting gas supply to sectors outside power generation sector, or giving the industry sector high priority and the power sector priority for peaking generation needs. Policy measures could be used to shift from gas to liquid fuels in these sectors.

64. On the supply side, there is a relatively high certainty of new, feasible gas finds, although their timing is uncertain, as well as the possibility to import gas as LNG. It has been reported that Yadana gas field operator has claimed ability to sell additional gas, but the offer is of course subject to commercial negotiation. Careful assessment of the issue and evaluation of various measures is needed in order to find an optimal way forward. However, planners for electricity system expansion cannot consider any new gas-based power plants to be built prior to 2020 – and even thereafter; inclusion of any substantial amount of gas-based power capacity should be subject to identifying

new sources of gas, either from physical gas fields or through re-negotiating some of the gas export deals currently in force with the neighbouring countries.

Table III-4: Natural Gas – Supply & Demand Balance (MMCFD)

65.	2013	2014	2015	2016	2017	2018	2019	2020	2021
Supply									
MOGE	65	65	65	65	65	65	65	65	65
Yadana	225	225	225	225	225	225	225	157	137
Zawtika	-	60	100	100	100	100	100	100	100
Shwe	-	20	80	100	100	100	100	100	100
M3	-	-	-	-	-	-	-	70	150
New	-	-	-	-	-	-	-	-	66
Total	290	370	470	490	490	490	490	492	618
Demand									
Electricity Generation	168	184	214	241	200	221	222	96	112
Refinery	-	-	-	-	-	62	62	62	62
CNG Vehicles	4	5	5	5	4	4	4	3	3
Industry	41	48	55	65	74	83	94	106	117
Fertilizer	38	41	43	46	49	51	54	56	59
Total	252	278	318	356	327	421	436	324	353

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Supply									
MOGE	92	94	95	97	99	101	102	104	105
Yadana	104	87	70	54	43	26	-	-	-
Zawtika	100	100	87	42	28	19	14	9	-
Shwe	100	100	100	100	100	100	100	100	100
M3	150	150	150	150	150	150	150	150	150
New	211	275	448	580	678	763	786	790	797
Total	757	806	950	1,023	1,098	1,159	1,152	1,153	1,152
Demand									
Electricity Generation	149	105	83	83	66	71	58	99	96
Refinery	62	62	62	62	62	62	62	62	62
CNG Vehicles	3	2	2	2	2	1	1	1	1
Industry	132	147	161	179	197	216	238	261	284
Fertilizer	61	64	67	69	72	74	77	79	82
Total	407	380	375	395	399	424	437	503	526

66. **LNG.** With regard to the identified shortage of natural gas in the short run, MOEP has deliberated a Feasibility Study on the LNG receiving facilities in Myanmar, which was completed in March 2014. The study suggested location of the Floating Storage Regasification Units (FSRU) 80 km to south from the Yangon estuary where the sea depth is around 15m (satisfactory for the LNG carrier). There are three alternatives of gas pipeline landfall location; all consider gas as receiving terminal the South Dagon Junction. MOGE plans to extend the gas pipeline from South Dagon Junction to Thilawa SEZ. The purchase of the LNG was considered from LNG portfolio suppliers.

67. Specifications of the considered facilities were as follows:

- FSRU storage capacity: 173,000 m^3
- Regasification capacity: 120 mmscfd x 4 units (1 unit is spare)
- Gas pipeline length: 80 km (offshore), 50 km (onshore)
- Size of gas pipeline: 24 inch
- Design of jetty: Cross jetty
- Expected timing: 53 months from the design to LNG supply, including EPC 33 months

68. The feasibility study estimated the required capital costs of the facility as follows:

- FSRU: 278 MUSD
- Jetty: 82 MUSD
- Offshore gas pipelines: 154 MUSD
- Consulting fee: 15 MUSD
- Interest during construction, etc.: 69 MUSD
- Tax: 25.2 MUSD
- Total: 624 MUSD

69. Financial analysis of the project showed good results with expected LNG price of 14 USD/MMbtu. The expected electricity tariff with LNG fuel were set at 11.3 c/kWh, which together with LNG facility cost of 0.8 c/kWh, would have resulted in electricity generation cost of 12.1 c/kWh.

70. Before the feasibility study, the MOEP had already started activities on the LNG development and related infrastructure. A tender invitation was announced in 2013 with a specification of 150 to 200 mmscfd of LNG supplied before March 2014, and 500-600 mmcfd after 2014 for the next 5 to 10 years period. In August 2013 MOEP selected 14 bidders qualified for the LNG purchase. YESB (Yangon Electricity Supply Board) has evaluated them and submitted the report to MOEP, which was further submitted to NEMC (National Energy Management Committee). NEMC has since then suspended the evaluation reports. The main challenge with the LNG project was considered the selection of the location of the FSRU. A commercial offer has also been submitted thereafter to the government, which indicated a price of approximately 18 $/mmbtu for the gas supplied from the LNG facility.

71. Realization of the LNG project is not clear at the moment. If there is a decision to realize this project, it will take a few years until its commissioned and the LNG supply begun. Also upgrade and rehabilitation of GT to GTCC requires some years for implementation. Therefore the use of liquid fuel such as light oil, crude oil and heavy fuel oil, rather than natural gas, will be needed by any thermal capacity that is developed in Myanmar to meet the short term power demand. The LNG options would be an expensive one for the electricity generation sector, and it would require

approximately five years to develop to production, and therefore other solutions should be identified and firmed up if gas based power generation is proposed.

L. Natural Gas Supply Risk Mitigation Strategy

72. There is an opportunity to manage the risks that natural gas supplies does not develop as anticipated. If required, fuel substitution can first be made in the transportation and agriculture sectors to release the capacity required to serve the industry and power sectors. However, the decision to develop these sectors may come ahead of the development of firm supplies of natural gas, in which case it can be considered as a prudent practice to minimize the use of natural gas in the power sector and for fertilizer production in favor of allocation to industry.

Table III-5: Gas Supply Risk Mitigation circa 2019

	MMCF	MMCFD	Comment
Refinery	22,630	62	Hydro-cracking refinery needs hydrogen and usually powered with natural gas power plant
Power	81,030	222	EMP estimate
Fertilizer	20,552	56	Standard-run production plant 1 725 mtpd
Industry	38,623	106	EMP estimate
Total	~165,000	~548	
Available gas	~150,000	~411	Yadana, Yetagun, Shwe, Zawtika
	Potential to Reduce Gas Consumption		
Refinery	(7,500)	(21)	Power the refinery using liquid fuels (30 – 40 MW)
Power sector	(30,250)	(83)	Increase hydropower, gas / oil plant
Fertilizer	(10,000)	(27)	Import fertilizer
Total	(50,000)	(137)	

Source: Consultant's analysis

73. Clearly the gas supply – demand outlook is tight. However, the refinery design can be modified to minimize gas consumption. In principle the use of gas for power generation could be replaced by oil or storage hydropower capacity for deployment at times of peak demand. A fertilizer plant appears to be uneconomic and gas could be saved by importing urea. The M3 gas field will ease the situation considerably, through an increase in capacity, however the delay in the development of the field means that a prudent approach is indicated.

74. In summary, gas could be reserved for industry and the power sector. Other demands could be met by alternative means. The decision to pursue alternatives can be decided as a matter of government policy as the natural gas supply – demand balance unfolds in the coming years.

IV. Biofuels

M. Introduction

75. Increasing use of biofuel in diesel engines is tried and tested in many markets including in Myanmar. Most current passenger cars and truck diesel vehicles are today B7 capable. The compatibility of large engines and heavy-duty vehicles with higher blends is better than for light duty vehicles. It has been estimated that about 80 % of the trucks can run safely on B30. Therefore the introduction of 5 to 10 % of biodiesel does not require specific actions or issues to be resolved but fuel suppliers can increase the level of biodiesel (Fatty Acid Methyl Ester – FAME in accordance with international EN 14214 standard, or so called advanced biodiesels with properties almost

76. Biofuel consumption is a key indicator in many countries of the deployment of renewable energy in the transport sector. Fuel ethanol already accounts for nearly 10 % of the gasoline market in the USA and a major share in Brazil. Current European fuel standards allow up to 7 volume% in diesel fuel (the most common type of biodiesel, B7) and 10 volume% of ethanol (E10).

77. Biofuel consumption is a key indicator in many countries of the deployment of renewable energy in the transport sector. Fuel ethanol already accounts for nearly 10 % of the gasoline market in the USA and a major share in Brazil. Current European fuel standards allow up to 7 volume% in diesel fuel (the most common type of biodiesel, B7) and 10 volume% of ethanol (E10).

78. Myanmar is well positioned to adopt progressive policies towards renewable fuels. The country is endowed by suitable natural resources and has already entered into several experiments for domestic biofuels production. At the same time new technologies have been developed allowing the country to step in to applying the second generation refining technologies, which allow a wider range of feedstock especially for ethanol production. At the same time car manufacturers around the world are increasingly adapting their products to allow use of higher mixing ratios of biofuels.

79. Biofuels considered for potential production in Myanmar include the following:-

a) Biodiesel – a diesel fuel obtained from non-edible oil plants (e.g. jatropha, rubber seeds and edible oilseed crops (palm oil, coconut, rapeseed and soybean), through a chemical reaction process. Like bioethanol, also biodiesel can be used as a fuel either alone or blended with petroleum diesel (e.g. B20 consists of 20 % biodiesel and 80 % petroleum diesel);
b) Bioethanol – a substitute for gasoline produced from sugar- and starch-based crops such as sugarcane, cassava, paddy rice, or maize. Bioethanol could be used as a fuel either alone or blended with gasoline (e.g. E10 consists of 10 % ethanol and 90 % gasoline).

80. About ten years ago the Government of Myanmar introduced a biofuel implementation program with an aim to minimize the country's dependence on imported liquid fuels. The program was based on an ambitious plan of mass cultivating approximately 200 000 ha of jatropha curcas in each state and division. The program included plans for blending bioethanol with conventional gasoline, for establishing small scale processing plants in rural areas, and for implementing projects on biofuel production with the assistance of the FAO and ASEAN countries.

81. However, as there are currently no facilities capable of producing biodiesel or bioethanol in large scale and to the extent outlined by the Government of Myanmar at the time the biofuel implementation program was initiated, then it seems fair to conclude that the biofuel implementation

program has thus far been unsuccessful.

82. It is understood that the cornerstone of the biofuel implementation plan – cultivation of jatropha – failed due to poor planning and execution, and as the planted jatropha plants did not deliver the yields expected, the ambitious biodiesel program was eventually discarded by the Myanmar Government. Today the production of biodiesel is limited to local level facilities producing biodiesel mainly to be used by agricultural machinery.

83. For the time being, no support scheme has been identified for the production of biodiesel or bioethanol, which seemingly directly reflects the lack of new initiatives by the private sector.

84. Despite the unsuccessful implementation of the biofuel program, which is not rare because the global experience of domestic biofuel schemes is rather mixed, it should be kept in mind that Myanmar holds significant potential for liquid biofuels and they should therefore not be excluded from country's energy mix. It is recommended that the lessons learned from the biofuel program and from the cultivation of jatropha trees are thoroughly reviewed and taken into consideration in any possible future project.

85. The following two sections, present more information regarding biodiesel and bioethanol, including some indicative calculations related to the investment cost for selected production facility configurations and consequent pre-feasibilities of domestic biofuel production.

N. Biodiesel

86. Increasing use of biofuel in diesel engines is tried and tested in many markets including in Myanmar. Most current passenger cars and truck diesel vehicles are today B7 capable. The compatibility of large engines and heavy-duty vehicles with higher blends is better than for light duty vehicles. It has been estimated that about 80 % of the trucks can run safely on B30. Therefore the introduction of 5 to 10 % of biodiesel does not require specific actions or issues to be resolved but fuel suppliers can increase the level of biodiesel (Fatty Acid Methyl Ester – FAME in accordance with international EN 14214 standard, or so called advanced biodiesels with properties almost equal to petroleum diesel) without causing vehicle compatibility problems or requiring modifications to fuel distribution, and without significant consumer involvement.

87. Biodiesel can be produced from a myriad of different plants that can be roughly divided into edible and non-edible crops. The use of edible crops for biodiesel production is controversial, as this could impact food prices and in some cases also worsen mal-nutrition in developing countries. Edible crops that could be considered for biodiesel production include oil palm, coconut, groundnut, soybean, sesame etc. Some non-edible crops that could be considered for biodiesel production include jatropha curcas, castor oil plant and rubber trees. So called third generation sources of biodiesel such as algae are currently under development. This paper focuses mainly on the use of jatropha seeds for production of biodiesel due to the fact that the number of jatropha trees in Myanmar is assumed to be significant as a result of the national effort to plant jatropha trees between 2006 and 2008.

88. Jatropha growing has potentially many benefits. It can be intercropped with many other cash crops such as coffee, sugarcane and vegetables with the Jatropha offering both fertilizer and protection against livestock. Jatropha needs at least 600 mm of rain annually to thrive but it can survive three years of drought by dropping its leaves. Jatropha is excellent at preventing soil erosion, and the leaves it drops act as a soil enriching mulch.

89. The oil content of jatropha seeds is between 36 and 38 %. The plant starts to bear fruit in 4 – 5 years after planting and economic yields start from the fifth year. The seeds of jatropha are

non-edible and therefore production of biodiesel from jatropha seeds does not limit country's food production capacity assuming jatropha is farmed on a land unsuited for farming of edible crops. It should however be emphasized that, as with every plant crop, the quality of the farmland, the amount of sunshine hours and irrigation define the annual yield. If grown on non-arable land, the annual yield from jatropha trees can be assumed to be between 0 and 2.2 t/ha[3] (0 – 800 kg/acre). Table II-9 presents an estimation of yields for jatropha trees of different age.

Table IV-1: Yield Estimation for Jatropha Trees of Different Age

Plant Age (years)	Seed Yield (kg/acre)	Oil Yield (gallons/acre)
1 – 2	32	1.6
2 – 3	280	14
3 – 4	600	29
4 – 5	800	40
5 – onward	1 000 – 1 200	50 – 60

Source: Myanmar Industrial Crops Development Enterprise, Ministry of Agriculture and Irrigation. The source indicates that seed yield for plats aged 4 – 5 years would be 4 800 kg/acre, which is assumed to be a mistake.

90. As at October 2012, Myanmar had reportedly cultivated around 2 million ha of jatropha4. These numbers should however be interpreted with a level of caution as several reports have highlighted that a significant portion of the jatropha seedlings planted under the biofuel program between 2006 and 2008 have failed to grow into seed-bearing trees. Assuming that the total cultivation area of two million hectares mentioned in several reports is correct, the biodiesel production potential from jatropha trees alone assuming a conservative biodiesel yield of 20 gallons per acre can be calculated to be:

a. 2 000 000 ha = 4 941 932 acres
b. 20 gallons/acre x 4 941 932 acres = 98 838 640 gallons

91. The estimated biodiesel production capacity potential of 100 million gallons could, if utilized, cover a significant portion of Myanmar's diesel demand. However, as mentioned above, it is unclear if the conservative yield estimation of 20 gallons per acre reflects the actual yield from the jatropha trees planted under the biofuel implementation program. Whatever the current yield, 2 million hectares represents a significant cultivation area and if the jatropha trees planted were well tended in the future the annual harvest could become large enough to cover a relatively large part of the diesel demand especially at a rural community level.

92. It is understood that there are no large scale production facilities currently in operation or under construction, in Myanmar. The following jatropha processing pilot facilities were at one time in operation but it is unclear whether or not these plants are still in operation:-

a. Pilot production in Yangon (Myanmar Industrial Crops Development Enterprise, Ministry of Agriculture), output 100 gls/day;
b. Pilot jatropha crude oil expeller and processing plant, Hline Tet Farm, Myanmar Agricultural Service, Mandalay Division. The small demonstration plant needs six

[3] Ouwens et al. Position paper on Jatropha curcas State of the Art, small and large scale project development
[4] Source: Myanmar Energy Sector Initial Assessment. ADB, October 2012

hours to refine 100 liters of jatropha crude oil to 97 liters of refined biodiesel and cost ca. 50,000 USD;

c. North-eastern Military Command, Lashio, Shan State; refines 240 gals of jatropha crude oil per day. Estimated cost was 10 million kyats (circa 2008); and

d. Jatropha and Rubber Plantation in Man Pan Project (Hill 5), Lashio, Shan State.

93. Table IV-2 presents an outline calculation for two different sized jatropha based biodiesel production facilities assuming oil content of 37 % in the jatropha seeds, a yield extraction efficiency of 92 % and a loss of 2 % in the trans-esterification process. The press cake that is a by-product of the oil extraction process could be used for the production of the process steam needed for the process.

Table IV-2: Conceptual Jatropha Based Biodiesel Refinery

	Plant Capacity	
	10 000 t/a	100 000 t/a
Biodiesel	3 336 t/a	33 359 t/a
Steam	5 000 MWh/a	50 000 MWh/a
Electricity	1 000 MWh/a	10 000 MWh/a
Investment Cost	1.5 MUSD	8.0 MUSD

94. Assuming Myanmar adopted an objective of increasing use of biofuels so that diesel fuel sold in the country consisted on average of 20 % biodiesel and 80 % petroleum diesel, the impacts of such policy can be estimated as follows:-

- The cost of jatropha seeds is the single most important cost factor in jatropha based biodiesel production representing 75 to 90 % of the production cost. There is no direct cost reference from Myanmar available to the Consultant, but international references from Africa, India and South-East Asia indicate that the price paid to the farmers have ranged between 120 to 170 $/ton whilst the price of the output oil ranges from 400 to 700 $/ton (September 2014). Feedstock cost of 170 $/ton (146,000 Kyat/ton) is therefore assumed.
- The cost of steam generation is estimated only based on the capital cost of a solid-fuel boiler plant at 12 $/MWh(th) (11,700 Kyat/MWh(th)) and electricity purchase price at 95 $/MWh (93 Kyat/kWh, representing economic long run marginal cost including generation and T&D). The operating costs are estimated at 3 % and 2.5 % of CAPEX for the smaller and larger facility, respectively.
- The economic cost of petroleum diesel is assumed on basis on international fuel prices. For estimation purposes the diesel cost is set at 0.73 $/liter corresponding approximately to crude price of 100 $/bbl. The current pump price of diesel in Myanmar including transport and distributions cost is about 0.91 $/liter (890 Kyat/liter, 4,154/Kyat/gallon).
- Petroleum diesel has net heat value of 42 MJ/kg, density of 0.8 kg/liter, and CO_2 emission factor of 73.6 g/MJ, i.e. 2.51 kg/liter.
- Economic discounting rate (real) is assumed at 6 % and life of the refinery at 20 years.

95. With these assumptions for the two above plant capacities the cost of domestic biodiesel is in the range of 0.47 and 0.5 $/liter (584 to 628 $/ton), on average 0.48 $/liter. Therefore blending ratio of 20 % would results in net savings of 0.25 $ per liter of diesel. Having B20 policy would

subsequently result in savings of $713 million calculated as a present value of the annual costs for 15 years until 2030. For the most part this saving would also contribute to the national trade balance as much of the transport fuels are is currently imported. Totally 11.9 million tons of CO2 emissions would be reduced. If valued at 30 $/ton of CO2 further economic savings of $ 357 million can be achieved.

96. B20 policy would result in the increase of biodiesel demand from 290 to 413 million litres, ie. 64 to 91 million gallons from year 2016 to 2030. This would require correspondingly that the about 2 million hectares (4.9 million acres), which was targeted in the mid-2000's, would need to be brought again under active jatropha cultivation by 2030.

97. The above calculation is only for demonstrating that policy encouraging production and use of biodiesel remains desirable and seems economically and technically feasible for Myanmar. The calculation itself is highly sensitive to (i) feedstock price and (ii) reference price of petroleum diesel. Furthermore, the mixing policy would cause some economic cost on the consumer side, which is difficult to quantify, such as slightly increased operation and maintenance cost of the vehicle fleet in the event shift to B20 level be rapid and based on existing engines and fuel qualities. However, technological development work of car manufacturers is addressing these maintenance issues and selecting new materials more suited to biodiesel use than the current ones. Fast development is happening also on the production side, where different second and third generation biodiesel production methods are already entering the business.

98. The referenced diesel price corresponds roughly to crude price of 100 $ per barrel. With prices of 70 $ and 130 $ per barrel, the referenced international diesel price could be estimated at 0.51 and 0.95 $/liter respectively. With the lower level, the refinery price of biodiesel would roughly match the international diesel cost, whereas with the higher level, the present value of savings in the country's fuel bill until 2030 would increase to $1.3 billion.

99. As mentioned earlier, international experience on developing jatropha based biofuel businesses is mixed, and many pilot schemes have failed. Assuming seed yield of 1 to 1.2 tons per acre, one acre generates 150 to 180 dollars annual income to the farmer per acre. As the sown land of most Myanmar farmers is 5 acres and less, introducing a less-income generating crops, such as jatropha, among the traditional cash crops, which provide substantially higher income, would be difficult. For jatropha cultivation, large scale specialized private agricultural companies, who also have an interest in the upstream side of the business, in production and selling biodiesel, would probably provide a more suited business model than small farmer or community based cultivation. Large private corporations should, however, address the problems encountered in the past with land allocation practices. Biofuels are still contested in many countries due to uncertainties surrounding positive environmental and social benefits, concerns about potentially negative impacts, and the manner with which land is acquired for these projects.

100. As significant amounts of jatropha trees have already been planted around Myanmar, it is recommended that it is considered, how the seeds of the jatropha trees could best be used for biodiesel production. If nothing is done, it seems possible that the significant national push for promoting the jatropha has been in vain and the planted trees might wither away. A recommended first step would be to identify the current state of the planted jatropha trees, the most suitable regions for cultivating jatropha, and the means that are available for improving the yield from the planted trees. Afterwards the focus should be shifted to harvesting methods and defining how the seeds are best processed into biodiesel and whether this should be conducted in large facilities or on a community level. Private sector driven and environmentally and socially sustainable business model for jatropha cultivation and processing should be developed.

O. Bioethanol

101. The drive towards sustainable economy has caused the governments around the world introduce ambitious policies and mandatory targets for renewable fuels. This has brought ethanol to the fuel markets. The US and Brazil together represent around 90 % of the ethanol produced and consumed in the world. In Brazil, ethanol can be used as a standalone biofuel in over half of the country's light vehicle fleet. This is because of the widespread introduction of flex-fuel cars, which can run on either gasoline or ethanol or any mixture of the both. The additional price of a flex-fuel-vehicle currently ranges from zero to about $ 2,000 per vehicle depending on the manufacturer and model. This would allow the consumer side also in Myanmar follow the extending provision of ethanol.

102. Currently, commercial bioethanol is produced by first generation (1G) technology from sugars found in arable crops, which can easily be extracted using conventional technology. The second generation (2G) technologies use non-food ligno-cellulosic biomasses such as bamboo and are on the threshold of commercialization. First generation sources of bioethanol in Myanmar include crops such as sugarcane, cassava, maize, sweet potato, yam, sorghum and rice. Second generation bioethanol could be produced from non-food parts of crops already under cultivation such as stems, leaves and husks of maize and sugarcane as well as stems, leaves and husks of non-food crops such as jatropha.

103. First generation bioethanol is produced by fermenting plant-derived sugars to ethanol in processes similar to those used for making alcoholic beverages such as wine. Second generation bioethanol production is more complicated; as an example the sugars in ligno-cellulosic biomasses are locked within a fibrous matrix and are therefore not readily available for extraction. An important consideration related to the use of bioethanol blended with gasoline is the so-called “blend wall” i.e. blending more that 10 % of ethanol with gasoline requires the use of flex-fuel vehicles as car manufacturers are claiming that blends higher than 10 % have the potential to damage conventional vehicle engines. However, as mentioned earlier and by referencing Brazil experience, the flex-fuel vehicle is already today in the market allowing up to 85 % ethanol content. Modifications to fuel distribution infrastructure could also be needed if more than 10 % of bioethanol is blended into gasoline as RE85 or similar ethanol products would need to be provided dedicated pumps.

104. The current production capacity of bioethanol in Myanmar is based on first generation biomass, especially sugarcane and maize. In the future, production of bioethanol utilizing the second generation technology for extraction of bioethanol e.g. from the non-oily parts of the jatropha tree could be considered assuming the technology becomes more accessible.

105. Since 2002, the Myanmar Chemical Engineers Group (MCE) has constructed four plants for 99.5 % ethanol production in Mandalay, Sagaing and Bago; their total capacity is 1.95 million gallons/year5. The Myanmar Economic Cooperation has furthermore built two large bioethanol plants with combined capacity of 1.8 million gallons/year[6]. Commercial production started at these plants in 2008. A private company Great Wall Food Stuff Industry has also built an ethanol plant (3 700 gals/day) based on sugarcane.

106. The Consultant has not come across any information indicating that any bioethanol production facilities have been established since 2008. Furthermore, the Consultant has discovered that the existing facilities are no longer producing bioethanol due to lack of legal support and subsidies.

[5] Source: Myanmar Energy Sector Initial Assessment. ADB, October 2012
[6] Source: Myanmar Energy Sector Initial Assessment. ADB, October 2012

107. As to maize based ethanol production, in Table IV-3 below, an outline calculation is presented for two different size bioethanol production facilities with an assumed moisture content of 13.5 %, starch content of 70 % of dry matter and ethanol yield of 50 % of the inherent starch. Similar or slightly higher yields could be expected if polished rice was used instead of maize.

Table IV-3: Conceptual Maize Based Ethanol Refinery

	Plant Capacity	
	100 000 t/a	200 000 t/a
Ethanol production	30 275 t/a	60 550 t/a
	8.4 Million gallons/a	16.9 Million gallons/a
Fodder production (10 % moisture)	34 000 t/a	68 000 t/a
Steam	55 000 MWh/a	110 000 MWh/a
Drying, steam/gas	45 000 MWh/a	90 000 MWh/a
Electricity	15 000 MWh/a	30 000 MWh/a
Investment costs	40 MUSD	60 MUSD

108. Cassava could also be considered as a suitable feedstock for bioethanol production due to its high starch content. The following Table IV-4 presents an outline calculation for two different size production facilities based on cassava assuming a dry matter content of 25 %, starch content of 80 % of the dry matter and finally ethanol yield of 50 % of the inherent starch in cassava.

Table IV-4: Conceptual Cassava Based Ethanol Refinery

	Plant Capacity	
	200 000 t/a	400 000 t/a
Ethanol production	20 000 t/a	40 000 t/a
	5.6 Million gallons/a	11.1 Million gallons/a
Steam	25 000 MWh/a	50 000 MWh/a
Electricity	8 000 MWh/a	15 000 MWh/a
Investment costs	20 MUSD	35 MUSD

109. A similar outline calculation as presented for maize and for cassava is presented for two facility sizes for both molasses as well as for sugarcane (sugarcane juice + molasses) in in Table IV-5 and Table IV-6 below. For calculation on molasses a sucrose content of 50 % and ethanol from sucrose efficiency of 50 % are assumed.

Table IV-5: Conceptual Molasses Based Ethanol Refinery

	Plant Capacity	
	50 000 t/a	100 000 t/a
Ethanol production	12 500 t/a	25 000 t/a
	3.5 Million gallons/a	7.0 Million gallons/a
Steam	15 000 MWh/a	30 000 MWh/a
Electricity	3 000 MWh/a	6 000 MWh/a

Investment costs	8 MUSD	12 MUSD

Table IV-6: Conceptual Sugarcane Based Ethanol Refinery

	Plant Capacity	
	300 000 t/a	1 000 000 t/a
Ethanol production	15 500 t/a	51 000 t/a
	4.3 Million gallons/a	14.3 Million gallons/a
Steam	15 000 MWh/a	50 000 MWh/a
Electricity	4 000 MWh/a	12 000 MWh/a
Investment costs	12 MUSD	25 MUSD

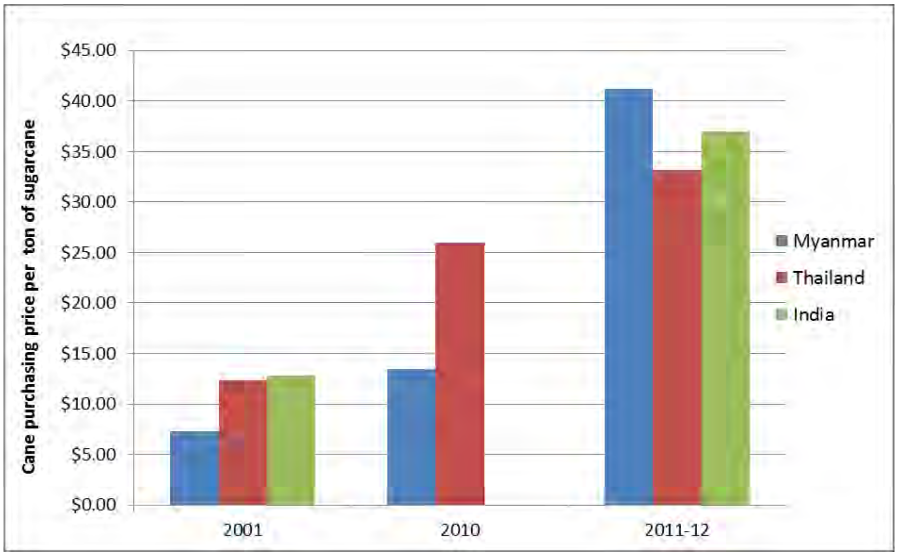
110. If sugarcane was to be used, process steam and electricity could be generated by combustion bagasse, which is a byproduct of the sugarcane production. In the future, bagasse could also be used as a feedstock for bioethanol production in a second generation bioethanol plant. As can be seen from the tables above, sugarcane can be considered as the most advantageous feedstock for the production of first generation bioethanol in Myanmar, especially on a larger scale. As with all first generation biofuels, if the production capacity of sugarcane based bioethanol is increased, it must be ensured that this does not result in shortages in food supply.

111. It is also recommended to study the ongoing second generation bioethanol projects (1 in Brazil, 1 in Italy, 3 in the USA). If a cost-competitive way for producing bioethanol from ligno-cellulosic materials becomes available, Myanmar could base its bioethanol production on more sustainable feedstocks such as maize and jatropha stover.

112. Assuming Myanmar adopted objective of shifting to a mixing standard so that all gasoline sold in the country would be replaced totally by gasohol consisting of 10 % ethanol and 90 % regular gasoline, the impacts of such policy are estimated in the following by reviewing two feedstock as an example, (i) sugarcane and (ii) maize.

113. The cost of feedstock is again the most important cost factor. At the moment, the sugar industry in Myanmar has experienced rapidly rising feedstock cost. Whilst sugarcane ton was sold at 13,500 kyat in 2007-2008, it was sold at 30,000 kyat in 2012-2013 (31 $/ton). The current level may not sustain as the sugar mills compete against globally competitive prices. There are 18 sugar mills in the country and all of them have a capacity at or below 2,000 tons of cane per day (TCD) whereas a competitive facility size can be estimated at around 10,000 TCD. The two fuel refineries of Table IV-6 represent approximately 1000 and 3000 TCD capacities.

Figure IV-1: Cane Intake Prices as Compared to Thailand and India



Source: Sun Thein, Myanmar Agriculture Sector at a Glance and its Evolution: Opportunities and Challenges, paper presented to "Investing in Sustainable Agriculture in Myanmar" Yangon, July 2014

114. Maize is an internationally traded commodity. International maize price averaged about 194 $/ton (IMF Commodity Prices) during the second and third quarters of 2014. Farmers in India sell maize at around 134 $/ton (800-840 rupees per 100 kg). Therefore, the reference price is set for the calculation at 150 $/ton (146,000 Kyat/ton).

115. The reference price for gasoline corresponding to about 100 $/bbl of crude oil price, is 0.68 $/liter. The current pump price of gasoline in Myanmar is about 1.08 $/liter (1,050 Kyat/liter, 4,770 Kyat/gallon). International ethanol prices, e.g. as quoted in Chicago or Rotterdam, vary more regionally than prices of petroleum products. The international reference price for ethanol is assumed at 0.71 $/liter, which roughly represents an average of Chicago and Rotterdam price levels.

116. Gasoline and ethanol have different fuel properties and therefore a 10 % renewable target would correspond to a volume consumption, which is not divided 90/10 in liters as in E10. Gasoline has net heating value of 42.4 MJ/kg and density of 0.75 kg/liter. Its CO_2 emission factor is 73.6 g/MJ equal to 2.33 kg/liter. Ethanol has net heating value of 27.0 MJ/kg, density of 0.79 kg/liter, and no CO_2 emissions if feedstock is cultivated sustainably and/or provided from excess production.

117. The 10 % mixing ratio here is assumed in terms of fuel heating value. Because ethanol has lower heating value, mixing results in higher volume of fuel consumed than without mixing. However, several studies have shown that due to higher octane value of ethanol, this relationship is not directly proportional to heating values only, but some fuel volume is saved because of efficiency gains in vehicle engine combustion due to ethanol's octane value. When these relationships are summed up, a 10 % mixing ratio is estimated to result to a liter of regular gasoline to be replaced by 4.1 % higher volume of gasohol. With 10 % renewable energy target, the mix therefore has 85.8 % gasoline and 14.2 % ethanol when expressed in liters.

118. The maize based plant concepts provide ethanol costs of 0.53 $/liter whereas sugarcane based refining produces ethanol at 0.55 to 0.58 $/liter, both below the international reference prices

for gasoline and ethanol.[7] Because resulting ethanol prices are near to each other, 0.56 \$/liter is assumed as the common price for locally produced ethanol. The contemplated biofuel policy would therefore result in a small net cost of \$123 million to the economy calculated as a present value of the annual costs for 15 years until 2030. Totally 5.9 million tons of CO_2 emissions would be reduced. The implicit cost of CO_2 reduction would be 38 \$/ton. Changes to the net impact to the economy remain small even if the crude price assumptions are let to change ± 30 \$/bbl.

119. The results of bioethanol policy would be more modest than those of biodiesel policy. Production of domestic biodiesel seems already now more economical that diesel imports, whereas local ethanol is of slightly higher cost than gasoline. It should also be noted that the underlying demand forecast for gasoline is less than that for diesel and the assumed blending ratio is smaller.

120. The 10 % renewable energy in gasoline policy would result to some 286 million liters (63 million gallons) of ethanol consumed in 2030, which, if all would be produced from sugarcane, would require 4.4 million tons of sugarcane to be delivered for biofuel production. Today the total sown acres for sugarcane are 180,000 hectares with an average yield of 6.58 tons per hectare.[8] Therefore 670,000 hectares would be needed for biofuels if fuel ethanol production depended solely on sugarcane. This calls for having a wider feedstock base and introduction of second generation ethanol production technologies, which can utilize agricultural waste such as leaves and stalks of maize, excess bagasse and ordinary straw from rice and wheat farming.

P. Conclusion

121. In future diesel and gasoline production could be supplemented by production of biodiesel from oily plants and of bioethanol from starchy crops. Considering the large surface area and good growing conditions in Myanmar, liquid fuels produced from renewable feedstock could play a significant role in the supply of transportation fuels.

122. Biodiesel / bioethanol production in Myanmar is currently limited to only a few production facilities. Existing bioethanol facilities have more or less stopped production due to lack of subsidies and no information indicating new facilities being under construction was found. Only pilot scale biodiesel facilities have been built in Myanmar, which are producing small amounts of biodiesel for use by agricultural machinery.

123. Approximately ten years ago Myanmar began an ambitious biofuel implementation program with a plan to plant a total of 3.5 million hectares of jatropha curcas trees. The program was unsuccessful failing to live up to the expectations of making Myanmar self-sufficient as far as the demand for diesel goes. It is unclear, what is the estimated yield of the jatropha trees planted as part of the program, but considering that several reports have claimed that jatropha plantations cover an area of approximately 2 million hectares, the trees seem to offer a significant source of non-edible oil that could be used for the production of biodiesel. Other crops could also be utilized for the production of biodiesel, but the first step recommended to be taken is to identify the current state of the planted jatropha trees and the means that are available for improving the yield from these trees. Afterwards the focus should be shifted on harvesting methods and defining how the seeds are best processed into biodiesel and whether this should be conducted in large facilities or on a community level.

[7] It is understood that there exists business cases where an ethanol refinery would have revenues from side products such as fodder for animal feed. It is further realized that with second generation technologies ethanol can be produced from side products and agriwaste at very low feedstock price. These aspects were ignored for the simplicity of calculating the example.

8 Crop Summary in Myanmar, by Issares Thumrongthunyawong, www.bangkokbank.com.

124. Use of bioethanol should also be considered. Sugarcane, whether used as whole or only in the form of molasses seems to present the most cost-effective way of producing bioethanol utilizing first generation production technology. The concept of blend wall, meaning in essence that approximately 10 % bioethanol can be blended with gasoline without the need for updating the vehicle fleet is coming less important as flex-fuel vehicles, either new one or retrofits, have proved a low-cost solution to pursue consumer side interest in bioethanol fuel.

125. Both biodiesel and bioethanol seem economically feasible for Myanmar. A biofuel policy with set mixing targets for 2020 and 2030 is recommended. Assuming a 10 % target for both diesel and gasoline by 2020, and 20 % target by 2030, transport de-carbonisation case can be developed. Table IV-7 below summarizes cases discussed in this report, namely base case, a small inland refinery case, and domestic biofuel case, and their impacts to the supply side of liquid fuels until 2030 in Myanmar.

Table IV-7: Liquid Fuels under Different De-Carbonization Regimes

ktoe	Gasoline					Diesel					Renewables
Year	Demand	Refinery	Decarbonization Case			Demand	Refinery	Decarbonization Case			Share
			Gasoline	Ethanol	Total			Diesel	Biodiesel	Total	%
2014	644	0	644	0	644	1169	0	1169	0	1169	0 %
2015	661	0	661	0	661	1165	0	1165	0	1165	0 %
2016	714	0	698	14	712	1181	0	1157	24	1181	2 %
2017	766	0	733	30	763	1196	0	1149	48	1196	4 %
2018	818	0	774	41	815	1212	0	1139	73	1212	6 %
2019	877	0	802	70	872	1237	0	1138	99	1237	8 %
2020	937	0	837	93	930	1262	0	1136	126	1262	10 %
2021	996	964	879	109	988	1287	871	1145	142	1287	11 %
2022	1058	964	923	126	1049	1321	871	1163	159	1321	12 %
2023	1120	964	965	144	1109	1356	871	1179	176	1356	13 %
2024	1181	964	1006	164	1169	1390	871	1195	195	1390	14 %
2025	1234	964	1037	183	1220	1428	871	1214	214	1428	15 %
2026	1286	964	1068	203	1271	1467	871	1232	235	1467	16 %
2027	1338	964	1097	225	1322	1505	871	1249	256	1505	17 %
2028	1380	964	1132	232	1363	1564	871	1282	281	1564	18 %
2029	1422	964	1151	253	1404	1622	871	1314	308	1622	19 %
2030	1464	964	1170	274	1444	1681	871	1345	336	1681	20 %

Source: Consultant

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FINAL REPORT
ELECTRICITY STRATEGY

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and

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IES
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MYANMAR
INTERNATIONAL
CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
BBL	–	Barrel
BOPD	–	Barrels of Oil per Day
CFB	–	Circulating Fluidized Bed
CHP	–	Combined Heat Power
CO_2	–	Carbon Dioxide
CPI	–	Consumer Price Index
CSO	–	Central Statistics Organisation
EHV	–	Extra High Voltage
EIA	–	U.S. Energy Information Administration
EUR	–	European currency unit EURO
FAO	–	Food and Agriculture Organization
GDP	–	Gross Domestic Product
GHG	–	Greenhouse Gases
GoM	–	Government of the Republic of the Union of Myanmar
IDC	–	Interest during construction
LCOE	–	Levelized Cost of Energy
LNG	–	Liquefied Natural Gas
MOE	–	Ministry of Energy
MOEP	–	Ministry of Electric Power
MPE	–	Myanmar Petroleum Enterprise
NOx	–	Nitrogen Oxides
O&M	–	Operation and Maintenance
PPA	–	Power Purchase Agreement
PV	–	Photovoltaic
SOx	–	Sulfur Oxides
USD	–	United States Dollar
VAT	–	Value Added Tax

UNITS OF MEASURE

kWh	-	Kilowatt-hour
MWh	-	Megawatt-hour
MWel	-	Megawatt electric
MWth	-	Megawatt thermal
kJ	-	Kilojoule

GJ	-	Gigajoule (one thousand megajoules)
PJ	-	Petajoule (1000 GJ)
TJ	-	Terajoule (1000 PJ)

CONVERSION FACTORS

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

CONTENTS

I. SUMMARY

A. Electricity Development Strategy

1. The optimal long-term fuel mix of Myanmar is determined to a significant extent by the fuel mix of the electricity generation sector. The selection of a fuel mix that is most suitable for electricity generation in Myanmar is shaped by the economic value of fuels available to Myanmar, the competition for fuels outside of the electricity sector, and the cost to convert fuels to electricity.

2. These factors are particularly relevant to the consideration of Myanmar's proven natural gas resource. The gas is in demand internationally whereas locally, Myanmar's gas could potentially be allocated to fertilizer production, to the production of refined petroleum products, to industry, to fuel passenger vehicles (CNG), to the power sector, or as a cooking fuel. At the present time Myanmar's proven reserves of gas are insufficient to meet the projected demands of all sectors of the economy. Given a basic analysis of the relationship between GDP growth and natural gas supply, it is considered that Myanmar's natural gas should be allocated to export and to industry. Economic analysis suggests that it would be economical to import fertilizer rather than to produce fertilizer locally. Other needs, including power sector needs, can instead be met by liquid fuels.

3. In principle, power generation could comprise a gas plant capacity of less than 10% in 2030. In this case, the total annual gas consumption by the power sector would be very modest; in 2020 only 18 BCF and in 2030 only 31 BCF. The existing (and under construction/development) capacity for gas based power will be about 1 700 MW within a few years, which will consume over 300 MMCFD when simultaneously in operation. As reserve capacity needs increase to 2030, and if gas would be used to meet this capacity need, then total gas consumption could reach to around 1 000 MMCFD. This requirement for gas may not be able to be met through a future domestic gas quota but could instead be met by imported LNG or by light fuel oils. On the other hand the cost of LNG exceeds 18 $/MMBtu whereas the subsidized price to the current gas fired plants in Myanmar is around 5 $/MMBtu for domestic consumers and 11-12 $/MMBtu for industries. This cost difference means that LNG would be a very expensive solution for the country (whether LNG is used by the power sector or by industry). Therefore it is clear that it is preferable to use light fuel oil to fuel fast-acting reserve capacity plant. LNG imports can be considered again nearer to the time when the current gas supply contracts expire, if it is feasible to negotiate for a higher quota for domestic consumption. In the meantime new gas fields may be discovered.

4. A set of alternative long-term fuel mixes have been examined in detail, each with a low dependence on natural gas. Concerns regarding seasonal variation in hydropower output have been addressed by analysing in detail and by modelling hydropower generation profiles on a conservative basis, on hourly and monthly basis. The cost of each fuel mix has been estimated, according to the optimal use of power generation technologies as they apply in Myanmar. These technologies extend from hydropower, to thermal and renewable energy forms of power generation. Whilst the focus of the EMP is on the optimal long-term fuel mix, it has been necessary to undertake generation sector expansion planning to quantify the cost of the fuel mix and also to take into account the practicability of implementing the optimal fuel mix strategy.

II. INTRODUCTION

B. Optimal Fuel Mix Selection

5. The selection of a fuel mix that is most suitable for electricity generation in Myanmar is shaped by the economic value of fuels available to Myanmar, the competition for fuels outside of the electricity sector, and the cost to convert fuels to electricity.

6. The fuels considered for electricity generation are hydropower, gas, coal, wind, solar PV and fuel oil.

a) **Gas.** Myanmar's future gas reserves are uncertain and care must be taken to make the most efficient use of gas for the purpose of power generation.

b) **Coal.** Myanmar's coal reserves are small in quantity and of poor calorific value. Therefore it is assumed that, for efficiency of conversion of coal to electricity, sub-bituminous coal would need to be imported.

c) **Oil.** It is not a preferred practice to use oil for power production. However, the use of heavy and light fuel oil can be economic when used to fuel reserve power plant. Such oil is stored adjacent to gas / oil engines that are used under emergency conditions. If a local refinery is established the heavy distillates that have no other use could be used for this purpose.

d) **Type I Renewables.** Myanmar has abundant hydropower resources. Myanmar's solar energy and wind resources are suitable for grid-connected large-scale electricity generation.

7. Electricity technology costs and efficiency of fuel conversion is considered in detail in this report. Cost and performance assumptions are based on the Consultants' extensive experience of Asian power plant costs and performance[1].

8. Optimization of a generation portfolio is a modern practice that relies on economic dispatching principles. The EMP is based on hourly economic dispatch, allowing for detailed modelling to 288 time periods. This level of granularity is important to capture the variable characteristics of the generation profiles of seasonal hydropower and intermittent renewable energy. A key planning criterion for electricity expansion planning is related to the security of the electricity system. Security is determined by the reserve capacity (spinning reserve or standby). Up until the 1990's reserve capacity was mostly set on a deterministic basis as a % of installed capacity. Economists were dissatisfied with this approach as the spare capacity could not be valued economic terms. With the advent of advanced computer tools, it became feasible to compute the Loss of Load Probability (LOLP). The associated Expected Unserved Energy could then be valued in strict economic terms and compared to the cost to find the trade-off point between security and cost. However, the LOLP approach is problematic in a hydro-dominated system where the impact of water limitations can far outweigh power plant unit failures. Accordingly for the EMP the reserve margin was set on a deterministic basis, allowing for the seasonal variations in hydropower output based on best available hydrological data and climate change projections.

[1] The Consultants' have previously worked with Poyry (China, Singapore, Thailand) and Parsons Brinckerhoff Asia (PB Power HK and PB Power Singapore) and have extensive experience in costing power plant developments in Asia and internationally.

III. Supply Side Options

9. The following section considers power plant development by fuel type. Fuel price projections are developed and presented. Finally, classical screening curves are developed for all technology options deemed suitable for Myanmar over the period of the planning horizon. Screening curves provide a hi-level appreciation of the relationship between costs and capacity factors of different technologies. Such appreciation supports the development of a range of potential planting schedules based on policy considerations.

C. Gas.

10. There are plans for construction of new gas power plants at various stages of development. If all planned projects are completed, the installed capacity of gas PPs will increase to 4,148 MW. If rehabilitation plans are successfully implemented, the available capacity of gas fired PPs would be 4,514MW.

Table III-1: Proposed Gas Fired Power Plants in Myanmar and Their Development Status

Station	Capacity (MW)	Type	Contraction		
Hlawga	541	GE	Local/ IPP	Phase 1	MOA/PPA
				Phase 2	MOA
			JV/IPP	Phase 1	MOU
				Phase 2	MOU
Ywama	292	52 GE + 240 GT	Local/IPP		MOA/PPA
Ahlone	121	82 GT + 39 ST	Local/IPP	Phase 1	MOA/PPA
				Phase 2	MOA/PPA
Thaketa	1,070	GE	Local/IPP		MOA/PPA
			JV/IPP	Phase 1	MOA
				Phase 2	MOA
			JV/IPP	Phase 1	MOU
				Phase 2	MOU
Mawlamyaing	200	GTCC	Local/ IPP	Phase 1	MOA/PPA
				Phase 2	MOA/PPA
Kanpouk (New)	525		Local/IPP	Phase 1	MOU
			or JV/IPP	Phase 2	MOU
Ayeyarwaddy/ Yangon	500	GT	JV/IPP		MOU
Additional information:					
Kyaukphyu (new)	50	GT	**JICA assumption*		

Station	Capacity (MW)	Type	Contraction
Myin Guam	250	GTCC	*JICA assumption*
Kyause	100	GE, rental	*JICA assumption*
Hlaingtharyar	500		
TOTAL	**4,148**	**MW**	

Source: JICA report (2014)

11. The capital cost of a turnkey (EPC) delivery for a gas combustion plant significantly depends on the power plant capacity, its location, and delivery terms. Thus, a recent (2014) feasibility study carried out by the consultant for a location in Kazakhstan provided with CAPEX level of about 1,500 USD/kW for a 210 MW CCGT plant. On the other hand, a study carried out by PA Consulting Group for Singapore in 2010 defined CAPEX for a 423 MW CCGT plant to be only 850 USD/kW (890 USD/kW if adjusted by inflation to 2014). This notable difference is mainly explained by the equipment manufacture location (delivery to Kazakhstan would have been done from Europe), long transportation distances, transportation means involved (both by sea and then on-land in case of Kazakhstan), as well as by associated technical and country risks.

12. The CAPEX assumptions used for the current analysis for Myanmar take into consideration higher capacity of the considered CCGT units (650 MW) but also include project contingency which altogether leads to an estimated cost of 918 USD/kW for a power plant operating with 80 % capacity factor. The fixed operating cost is assumed at 1.8 % of CAPEX, and variable operating costs (other than fuel costs) being 0.59 USc/kWh. Lead time for a CCGT plant is assumed to be 2.5 years.

13. Costs for an open cycle gas combustion turbine are assumed to be 486 USD/kW (CAPEX including contingency), 1.2 % of total CAPEX for fixed operating costs, and 0.99 USc/kWh for variable operating costs (other than fuel costs). Open cycle gas power plant capacity factor in this study is 10 % (assuming that this power plant provides with capacity to cover peak loads). Lead time is assumed to be 1.5 years.

14. For both CCGT and open cycle power plants, low OPEX reflects low labour costs in Myanmar. Life time for the both types of gas power plants is set at 25 years.

D. Coal.

15. Myanmar possesses large coal reserves (230 million ton probable and 120 million ton possible). The largest reserves are in Kalewa region and central east of Myanmar (Maingsat). Coals are accessible for extraction but due to road conditions could be difficulties for their further transportation. Projects for infrastructure improvement are ongoing thus this factor may be mitigated in the future. However, the currently identified domestic coal resources are not sufficient for developing coal-based electricity generation capacities in thousands of megawatts as a 1000 MW coal fired base load plant would consume over its life around 90 to 100 million tons.

16. Myanmar coals are not of high quality and possess low calorific values (3 200 to 6 700 kcal/kg); however their low sulphur contaminant allows using them for power production. Modern technologies allow more efficient utilization of low-quality coals' potential.

17. A 300 MW coal-fired power unit would consume around 1 to 1.3 million tons of coal annually (depending on type of plant and calorific value of coal). Therefore, over the life of 30 years the coal supply amounts to 30 to 39 million tons. The largest coal reserve currently listed is Maingsat in Shan

State with a capacity of 118 Mtons of probable lignite to sub-bituminous and 4 Mtons of possible sub-bituminous coals. The largest deposit of sub-bituminous coals is at Kalewa in Southern Sagaing Division with total capacity of 87 Mtons, 5 Mtons of which are positive, 18 Mtons are probable and 65 Mtons are possible. These reserves do not suffice for large scale power development, for example in the range of 1,000 MW supercritical power units, currently typical in the People's Republic of China (the PRC). Therefore the development of coal based power should be carried out in synchrony with the mining development so that capacities of mine mouth plants are properly dimensioned to match the proven and probable resources.

18. There are indicators that environmental and social approaches in developing new coal-fired power plants projects are not completely adequate. More attention shall be paid to these issues while developing future power plants. Three types of coal-fired power units have been selected as representative for Myanmar's future coal capacity, namely 600 MW supercritical, 150 MW circulating fluidized bed, and 50 MW pulverized coal fired unit. Cost and operational parameters have been defined for these three representative units for further analysis and expansion planning.

19. At the present time Myanmar operates only one coal-fired power plant at Tigyit. The plant is of 120 MW installed capacity but operates at only 27 MW due to inadequate maintenance. The plans for its rehabilitation have not yet been approved. Data on plans for new coal-fired PPs is somewhat undefined. MOM and MEP have announced three projects with total installed capacity 876 MW (Kalewa, Yangon and Tanintharyi).

20. MoM and MoEP have announced three projects with total installed capacity 876 MW (Kalewa, Yangon and Tanintharyi). The JICA 2014 study, referring to Hydropower Generation Enterprise, provides information for 11 projects with a total capacity of 15 GW. All projects were expected to be developed by the private sector by both domestic and foreign investors. Some projects included a provision that 50 % of the generated electricity would be exported to neighbouring countries.

- Yangon PP (270 MW) in 2013;
- Kalewa PP (600 MW) in 2014;
- Tanintharyi (6MW) in 2015.

21. In 2014 JICA, referring to an interview with the Hydropower Generation Enterprise2 (HPGE), concluded that plans for expansion of the coal sector were wider – see Table III-2 for details and Figure III-1 for schematic representation of locations of the planned generation projects.

Table III-2: Candidate Projects of Coal-Fired PPs

NN	Location	Planned capacity	MOU signed
Yangon Region			
1	Htan Ta Bin Township, Near Kukowa River	2 x 135 MW (1st Phase) 2 x 135 MW (or) 1 x 300 MW (2nd Phase)	11.2.2010
2	Kyun Gyan Gon Township, Thoung Khon Village	2 x 150 MW (1st Phase) 2 x 300 MW (2nd Phase)	24.8.2012

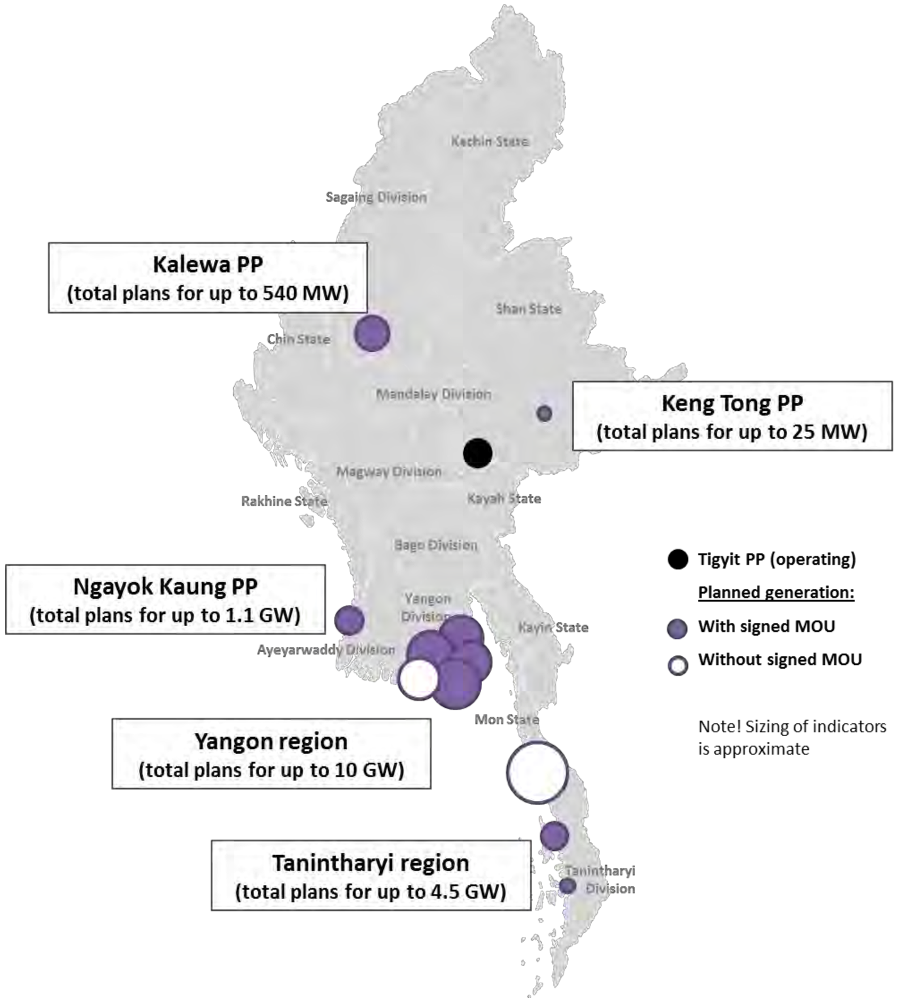
[2] Scope of work of the Hydropower Generation Enterprise also includes coal-fired thermal generation

NN	Location	Planned capacity	MOU signed
		2 x 600 MW (3rd Phase)	
3	Thilawa Industrial Zone	650~1200 MW (1st Phase) 1200~2000 MW (2nd Phase) 3000 MW (3rd Phase)	21.3.2013
4	Kyauk Tan Township, Chaungwa Village	2 x 250 MW	8.10.2013
5	Htan Ta Bin Township, Shwe Lin Ban Industrial Zone	1 x 350 MW (1st Phase) Total 1,050 MW	no - at the MOU proposal stage
Sagaing Region			
6	Kale District, Kalewa Township	2 x 135 MW (1st Phase) 2 x 135 MW (2nd Phase)	27.5.2010
Tanintharyi Region			
7	Myeik Township, Lotlot Village	1 x 50 MW	27.7.2012
8	Kawthaung District, Bokpyin Township, Manawlone	1 x 250 MW (1st Phase) 1 x 250 MW (2nd Phase)	21.9.2012
9	Dawei Special Economic Zone	1 x 400 MW (1st Phase) 2 x 1800 MW(2nd Phase)	no - at the MOU proposal stage
Ayeyarwady Region			
10	Ngayok Kaung	2 x 270 MW (or) 2 x 300 MW	11.4.2013
Shan State			
11	Keng Tong	25 MW	1.10.2013

Source: JICA report, 2013

22. Whilst many proposed projects in have large units at a later stage, the first phases of proposed plants call for 25 MW, 50 MW, 135 MW, 250 MW, 300 MW and 400 MW units to be built.

Figure III-1: Locations of New Coal-Fired Generation



Source: JICA report, 2013

23. The major coal based technologies that are available today globally at various stages of development include (i) conventional pulverized coal combustion (PC), (ii) circulating fluidized bed combustion (CFB), (iii) supercritical (SC) and ultra-supercritical (USC) PC combustion, and (iv) integrated gasification combined cycle (IGCC). There are also add-on technologies that can be combined with some or all of the mentioned technologies to improve environmental performance of coal combustion. Among them are carbon capture and storage (CCS) technologies either as a retrofit to running power plants or as part of the new ones. CSS technologies have not yet been commercialized.

24. There is limited experience of coal fired units in Myanmar's power industry, and there is not a large scale for coal-based power foreseen in Myanmar, it is believed the choice of technologies can be limited to PC, SC, USC and CFB technologies. IGCC technology, whilst already demonstrated in several plants, is not yet fully commercial and competitive in comparison to PC technology. Not only that the capital cost of IGCC technology is high, the technology is perceived to involve unquantifiable operating risks. Furthermore, the advances in PC combustion through substantial efficiency gains achieved with SC and USC technologies have overall reduced interest in IGCC technology.

25. USC and SC plants are already commercially available, cost effective, and there is rapidly accumulating worldwide operational experience of them. Steam parameters of typical sub-critical power plants are 150 to 180 bar pressure and 540 to 565 ºC temperature; SC plants operate at around 245 bar pressure and 540 to 570 ºC temperatures, and USC plants have temperatures of around 600 ºC or higher. Supercritical pressure is reached at 221 bar, above which level water/steam reaches a state where there is no distinction between liquid and gaseous state. Consequently the boiler does not need to separate steam from water and the substance is heated in a once-through process.

26. The design efficiencies of USC plants are between 39% and 46%. This stands in an apparent contrast with the typical efficiencies of 30% to 37% of the conventional PC and CFBC technologies. However, it should be noted that the SC and USC technologies have not yet been designed for high ash and low grade coal. Therefore, large SC and USC plants can be an option primarily for large IPPs on the coast depending on imported bituminous or higher NCV sub-bituminous coal.

27. CFBC technology is mature and offers many benefits in Myanmar conditions. Compared to traditional PC technology, CFBC is less sensitive to coal quality variation, allows mixing various kinds of coals, and provides opportunity to low-cost solution for the reduction of SO2 and NOx emissions. It is believed that for Myanmar, CFBC technology is commendable in the unit capacity range below 300 MW.

28. These considerations lead to the emergence of three types of coal-fired power units as more fitting with Myanmar’s future coal capacity, namely 600 MW supercritical, 150 MW circulating fluidized bed, and 50 MW pulverized coal fired unit. Cost and operational parameters are defined in this report for these three representative units for further analysis and expansion planning.

29. The 600 MW SC unit represents future IPPs which are planned on the coast to serve both exports and domestic demand and rely on imported coal. The 150 MW CFBC unit represents a typical coal fired unit whether mine-mouth combusting low-quality lignite or IPP on the coast which is built in multitude of stages of 150 MW and uses either imported or locally produced coal. The 50 MW PC represents a typical mine-mouth unit designed for a designated coal.

30. The capital costs assumed here range from 1300 $/kW to 2300 $/kW from the largest 600 MW SC plant to the smallest PC unit of 50 MW. The plant own use of electricity has been estimated to range from 7 % and 8 % to 10%, and plant efficiencies from 41 %, 35 % and 33 %, respectively from largest unit to the smallest.

31. It should be noted that the plant capital costs vary significantly country-by-country. The cost levels are considerably lower in the PRC than those in OECD countries including Japan and Korea. IEA data from 2010 collected for SC and USC plants, so called overnight costs, which exclude construction time interest, and were expressed in 2008 US dollars calculated on the net capacities, ranged from 800 $/kW to 3,500 $/kW whilst the median cost was at around 2,100 $/kW. The costs in the Chinese domestic market were between 600 $/kW and 700 $/kW.

32. The cost estimates chosen here are clearly higher than the costs in China but lower than the median costs reported by IEA in 2010. The cost levels provided by mainly Chinese EPC contractors in South-East Asia have been used as a reference. There is no economy of scale in the domestic market of Myanmar and each project should be considered a stand-alone site. Even though some plants would be of standard design, Myanmar will face a local first-of-kind phenomenon, whereby project faces risks as to experience of local contractors and labour. With not many large projects to construct annually in Myanmar, there are no major domestic contractors experienced in implementing large subcontracts for power projects.

33. With the above issues in mind, this study assumes gradually increasing unit costs over the planning period. The first power plants in the expansion plan are assumed to have lower specific costs than the later units of the same kind due to real-term increase of relevant raw material prices and labour costs.

34. Key assumptions pertaining to the power plant costs are summarized as follows:

Table III-3: Power Plant Cost Assumptions for Expansion Planning

Plant Type Example	Efficiency	CAPEX US$/kW	Fixed O&M % of CAPEX	Variable O&M USc/kWh	Typical Fuel
Supercritical 600 MW	41 %	1,300	2.0 %	0.31	Bituminous
Fluidized-Bed 150 MW	35 %	1,800	2.5 %	0.33	Sub-bituminous
Pulverized Coal 50 MW	33 %	2,300	3.0 %	0.35	Lignite

E. Oil.

35. The reserve plant could be fuelled by fuel oil. The engines would be capable of accepting gas or oil fuel. The cost of the engines would be the same as for gas engines and were discussed above under the Gas section.

F. Type 1 Renewables - Hydropower.

36. The hydropower plants, which are currently under construction, are listed in Table III-4. All plants in the list are planned to be commissioned by end of financial year 2020/21. Out of the total capacity of 2,143 MW, 1,994 MW (93 %) are developed by MOEP or MOAI.

37. Overall, there is a major uncertainty with respect to project development and the timing of the plant commissioning. During recent years, several projects, which have started construction, have progressed slowly because of either financial or technical difficulties encountered during the project. Construction times have extended from the typical 4 to 8 years so that many projects, now under construction, have anticipated construction periods up to 13 years.

38. As of July 2014, among the listed projects, the largest one, Shweli 3 of 1,050 MW, has not yet secured full financing although work on site has commenced with infrastructure and civil works. Debt financing from overseas remains open. Progress of civil works on Upper Kengtawng project has been impacted by fiscal limitations. Financing for Middle Paunglaung 100 MW project has not yet been closed. Technical concepts for the Tha Htay 111 MW project in Western Myanmar were changed during construction, which caused delay in the project schedule.

Table III-4: Hydropower Project by Investment Category 2014-2020

Station Name	Location	Capacity	Energy	Construction Period (Year)	
		MW	MWh	Start	On-line
		Investments by MOEP			
Phyu	Bago	40	120,000	2001	2015
Upper Paunglaung	Mandalay	140	454,000	2004	2015

Station Name	Location	Capacity	Energy	Construction Period (Year)	
		MW	MWh	Start	On-line
Upper Kengtawng	Shan	51	267,000	2008	2018
Upper Yeywa	Shan	280	1,409,000	2010	2019
Thahtay	Rakhine	111	386,000	2005	2019
Middle Paunglaung	Mandalay	100	500,000	2014	2019
Shweli 3	Mandalay	1,050	3,400,000	2010	2020
Dee Doke	Mandalay	66	297,600		2020*)
Sub-total		***1,838***	***6,833,600***		
		Investments by MOAI			
Upper Bu	Magway	150	334,000	2006	2016 *)
Kaingkan	Shan	6	22,000*)		2016 *)
Sub-total		***156***	***354,000***		
		Domestic entrepreneurs on BOT basis			
Baluchaung 3	Kayah	52	334,000	2008	2015
Upper Baluchaung	Shan	30	135,000	2010	2017
Ngot Chaung	Shan	17	63,000*)		2020*)
Mong Wa	Shan	50	184,000*)		2020*)
Sub-total		***149***	***716,000***		
TOTAL		**2,143**	***7,903,600***		

**) Data not available. Consultant's estimates for planning purposes. Energy by uniform capacity factor of 42%*

39. In 2012, MOEP completed an assessment of hydropower opportunities which indicated that there are as many as 92 potential sites for hydropower development, each having capacity greater than 10 MW. The MOE Energy Statistics Review of 2013 indicated that these hydro sites have been grouped into 60 potential hydro projects including 10 projects that are in various stages of development. Similarly as many as 210 sites for small and medium size plants each with capacity of less than 10 MW with a total potential installed capacity of 231 MW have been identified.

40. About 46 GW of new hydro capacities were planned until 2030 and beyond. Unlike earlier, when most of the existing plants as well of those currently under construction, belonged to MOEP or MOAI, major part of plants in the list for long-term development are planned to be built under a JV/BOT arrangement by foreign investors and domestic private entrepreneurs.

41. During recent years private and foreign project developments in Myanmar have become subject to higher level of scrutiny by the public and media, and even direct opposition by various interest groups and stake holders. A large Myitsone dam project in Kachin state was suspended in 2011 and is today considered as cancelled. It was part of agreements signed in 2007 with Chinese companies about their participation in the development of seven major hydropower projects on the confluence of the Ayeyarwaddy River and the Mali and the Mai Rivers in Kachin State. The total capacity of these developments is 13,360 MW. Two other projects from the 2012 list of MOEP (Mawlaik, 520 MW and Belin 280 MW) have also been cancelled.

42. The draft National Electricity System Masterplan issued in 2014 by JICA includes a thorough review of the hydropower prospects and their status as of June 2013. The JICA study highlighted some potential concerns over the environmental and social impacts related to large dams. The study therefore outlined two scenarios, in which large hydropower developments were minimized and replaced by coal and gas fired power station respectively, and in both scenarios by increasing amount of small and medium size hydropower.

43. EMP Consultant requested MOEP to list prospective projects for future expansion. MOEP's list of preferred hydropower opportunities are shown in Table III-5. This list of projects is used in the continuation as the base hydropower option for expansion planning.

Table III-5: Hydropower Prospects in 2021-2025 and 2026-2030

Station Name	Location	Installed Capacity	Myanmar Capacity	Estimated Annual Energy	Developer's Status
	State/Region	MW	MW	MWh	
		Years 2021-2025			
Middle Yeywa	Shan	320	320	1,438,080*)	MOEP
Bawgata	Bago	160	160	500 000	MOEP
Upper Thanlwin (Kunlong)	Shan	1400	700	7,142,000	JV
Naopha	Shan	1200	600	6,182,000	JV
Mantong	Shan	225	225	992,000	JV
Dapein (2)	Kachin	140	84	641,700	JV
Shweli (2)	Shan	520	260	2,814,000	JV
Sub-total		**3,965**	***2,349***	***19,709,780***	
		Years 2026-2030			
Nam Tamhpak	Kachin	200	100		JV
Gaw Lan	Kachin	100	50		JV
Hkan Kawn	Kachin	160	80		JV
Lawngdin	Kachin	600	300		JV
Tongxingqiao	Kachin	340	170		JV
Keng Tong	Shan	128	64		JV
Wan Tan Pin	Shan	33	17		JV
So Lue	Shan	160	80		JV
Keng Yang	Shan	40	20		JV
He Kou	Shan	100	50		JV
Nan Kha	Shan	200	100		JV
Namtu (Hsipaw)	Shan	100	50		BOT
Mong Young	Shan	45	22		not specified

Station Name	Location	Installed Capacity	Myanmar Capacity	Estimated Annual Energy	Developer's Status
	State/Region	MW	MW	MWh	
Dun Ban	Shan	130	65		not specified
Nam Li	Shan	165	82		not specified
Nam Khot	Shan	50	25		not specified
Taninthayi	Taninthayi	600	600		not specified
Upper Sedawgyi	Mandalay	64	64		MOAI
Sub-total		***3,215***	***1,939***		***716,000***
TOTAL (2021-2030)		***7,180***	***4,288***		***7,903,600***

**) Estimated CF 51% **) Estimated CF 42%*

44. The hydropower expansion plan excludes a number of projects included in the previous plans. The excluded projects are listed below. Many of those are large projects, which would involve mainstream dams in Myanmar's major rives and are therefore more environmentally and socially sensitive than those listed above. No projects in the Chindwin river system are included. The exclusion of some projects, however, is not an indication that this study would have regarded them not-feasible or environmentally or socially controversial. The prospects should be considered to remain in the pipeline for the case the demand growth necessitates and government strategy calls for more hydropower to be developed. Should there be need to re-prioritize projects, their economic and social merits should be independently weighed against their possibly negative social and environmental impacts.

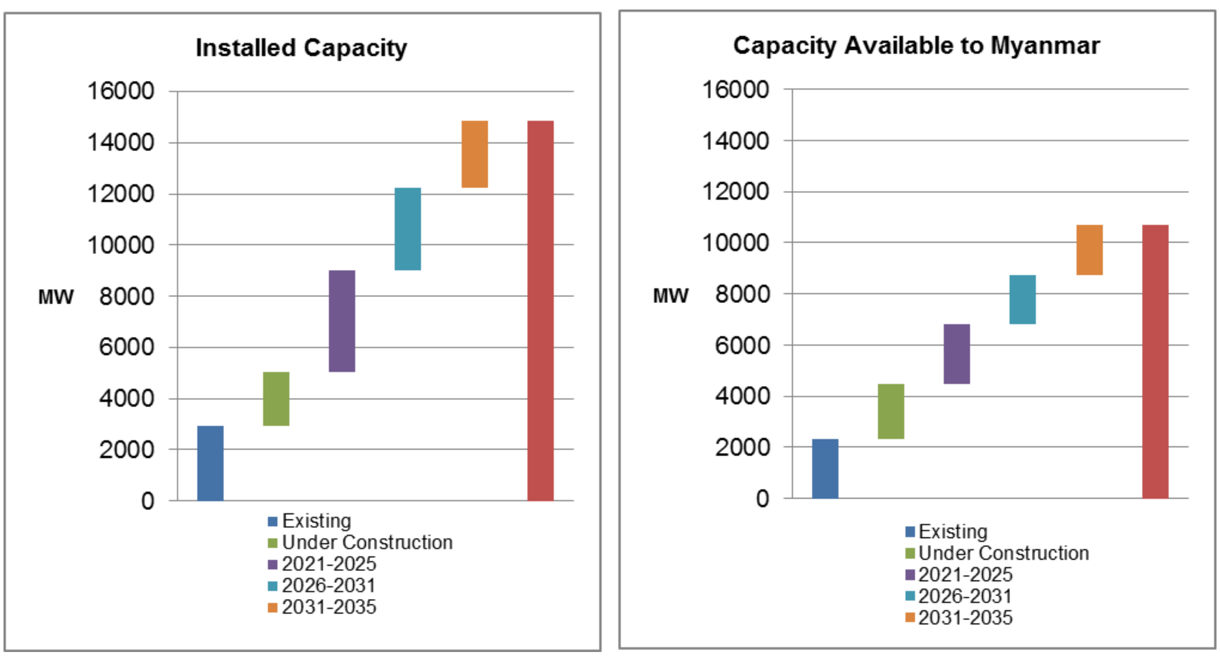
Table III-6: Large Hydropower Prospects

	No	Name of the plant	Owner	Installed Total	Installed Myanmar
				MW	MW
Very Large Projects	1	Chipwi	JV, JVA	6000	1700
	2	Wutsok	JV, JVA	1800	900
	3	Kaunglangphu	JV, MOA	2700	1350
	4	Renam (Yenam)	JV, MOA	1200	600
	5	Hpizaw (Pisa)	JV, MOA	2000	1000
	6	Laza	JV, JVA	1900	950
	7	Upper Thanlwin (Mongton)	JV, MOA	7110	3555
	8	Hutgyi	JV, MOA	1360	680
	9	Yawathit (Thanlwin)	JV, MOA	4000	2000
		Sub-Total Large		**28070**	**12735**
Small and Mediu	1	Wu Zhongzhe	JV, MOA	60	30
	2	Sinedin	JV, MOA	76.5	38.25

No	Name of the plant	Owner	Installed	
			Total	Myanmar
			MW	MW
3	Lemro (Laymyo)	JV, MOA	600	300
4	Lemro 2	JV, MOA	90	45
5	Htu Kyan (Tuzhing)	JV, MOA	105	52.5
6	Hseng Ne	JV, MOA	45	22.5
7	The Hkwa	JV, MOA	150	75
8	Palaung	JV, MOA	105	52.5
9	Bewlake	JV, MOA	180	90
10	Manipur	JV, MOA	380	190
	Sub-Total Others		**1791.5**	**895.75**

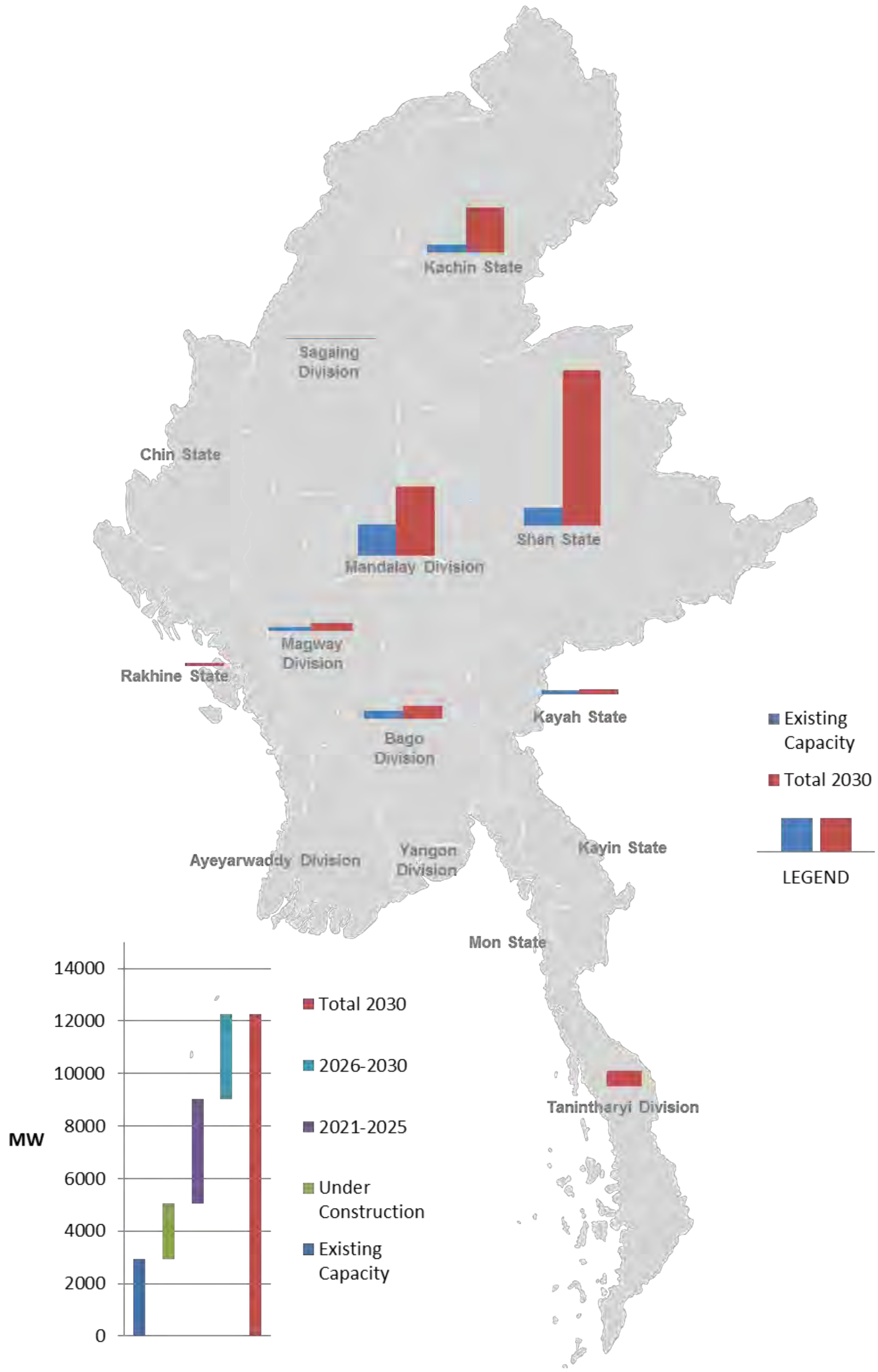
45. The base case for expansion plan has total installed capacity of 14,842 MW in 2035. The installed capacity to Myanmar, after the assumed 50 % export share of IPPs with foreign investments has been extracted, is 10,690 MW. Major part of the new hydropower schemes are located in the Shan State and include that electricity is exported to Thailand or China. Most new schemes in the Kachin State are developed in partnerships with Chinese companies. Major hydropower schemes not having an assumed export obligation include Shweli 3 (1,050 MW), which is under construction, Middle Yeywa (320 MW) and Mangton (225 MW) in the Shan State, Bawgata (160 MW) in the Bago Division, and Taninthayi (600 MW) in the South of Myanmar.

Figure III-2: Base Case Hydropower Expansion (Installed Capacity) until 2035



Source: Consultant's Analysis

Figure III-3: Base Case Hydropower Expansion (Installed Capacity) until 2030



Source: Consultant's Analysis

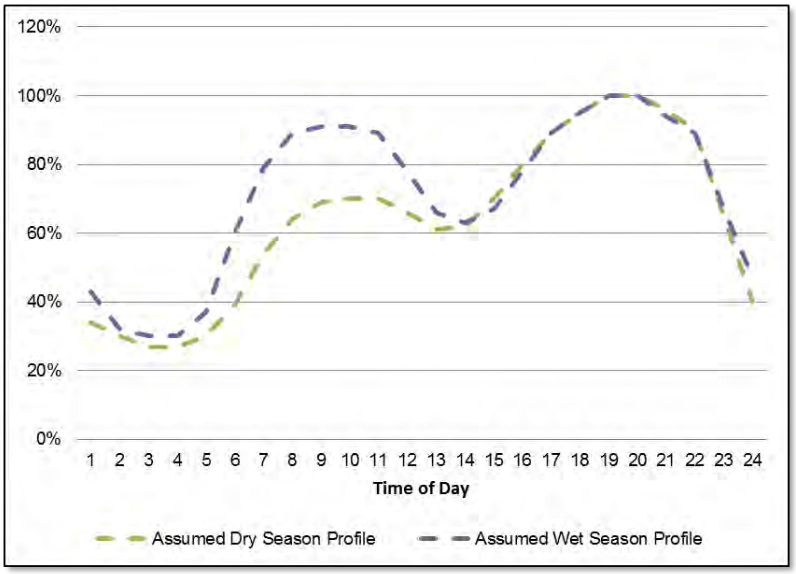
46. The availability of hydropower capacity was considered carefully in light of MoEP concerns regarding the constraints on hydropower in the dry season. Seasonal production of each plant, capacity factors and available hydrological data were considered in establishing hourly, daily and monthly production profiles. Moreover the impact of solar PV resources in supporting storage of water during the day time in reservoir schemes, particularly in the dry season, was considered. The hydropower profiles developed for the purpose of expansion planning are shown for the wet and dry seasons in the following table and figures:

Table III-7: Daily Production Profiles by Season

	DRY	% of max		WET	% of max		May/Dec
	DAILY	Adjusted	Share %	DAILY	Adjusted	Share %	average
1	42%	34%	2.2 %	61%	43%	2.5 %	2.4 %
2	41%	30%	2.0 %	57%	32%	1.9 %	1.9 %
3	39%	27%	1.8 %	54%	30%	1.8 %	1.8 %
4	39%	27%	1.8 %	56%	30%	1.8 %	1.8 %
5	47%	30%	2.0 %	63%	37%	2.2 %	2.1 %
6	60%	39%	2.6 %	78%	60%	3.5 %	3.0 %
7	71%	54%	3.5 %	95%	79%	4.6 %	4.1 %
8	81%	64%	4.2 %	97%	89%	5.2 %	4.7 %
9	81%	69%	4.5 %	99%	91%	5.3 %	4.9 %
10	88%	70%	4.6 %	100%	91%	5.3 %	5.0 %
11	89%	70%	4.6 %	98%	89%	5.2 %	4.9 %
12	84%	66%	4.3 %	88%	78%	4.6 %	4.4 %
13	78%	61%	4.0 %	77%	66%	3.9 %	3.9 %
14	75%	62%	4.1 %	79%	63%	3.7 %	3.9 %
15	80%	70%	4.6 %	79%	67%	3.9 %	4.3 %
16	76%	80%	5.2 %	88%	78%	4.6 %	4.9 %
17	80%	89%	5.8 %	92%	89%	5.2 %	5.5 %
18	93%	95%	6.2 %	94%	95%	5.6 %	5.9 %
19	98%	100%	6.5 %	95%	100%	5.9 %	6.2 %
20	100%	100%	6.5 %	94%	100%	5.9 %	6.2 %
21	100%	96%	6.3 %	89%	94%	5.5 %	5.9 %
22	93%	90%	5.9 %	80%	89%	5.2 %	5.6 %
23	72%	65%	4.3 %	69%	67%	3.9 %	4.1 %
24	59%	40%	2.6 %	61%	47%	2.8 %	2.7 %

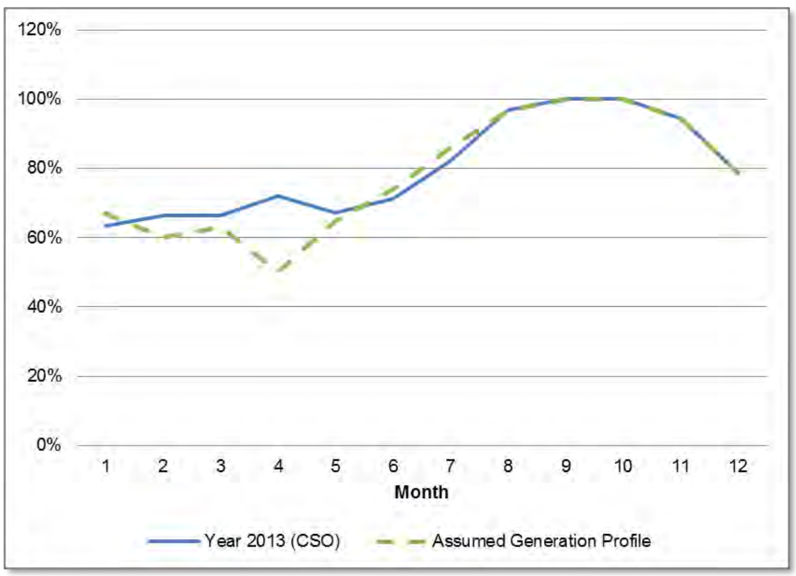
Source: MoEP (per datapack issued by the Consultant)

Figure III-4: Daily Hydropower Generation Profiles (% of the Daily Peak Demand MW)



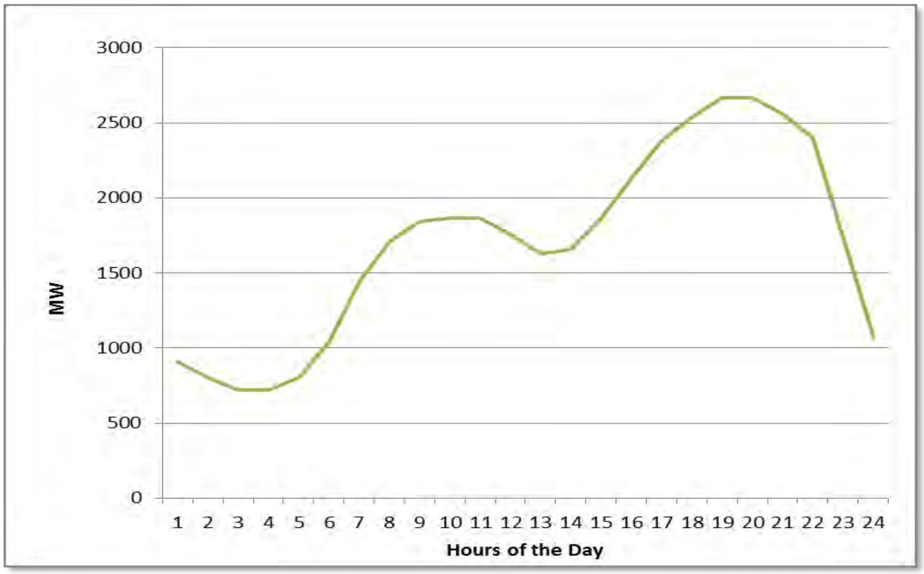
Source: Consultant's analyses of existing HPPs and hydrological data

Figure III-5: Monthly Hydropower Generation Profiles (% of the Season Peak Demand MW)



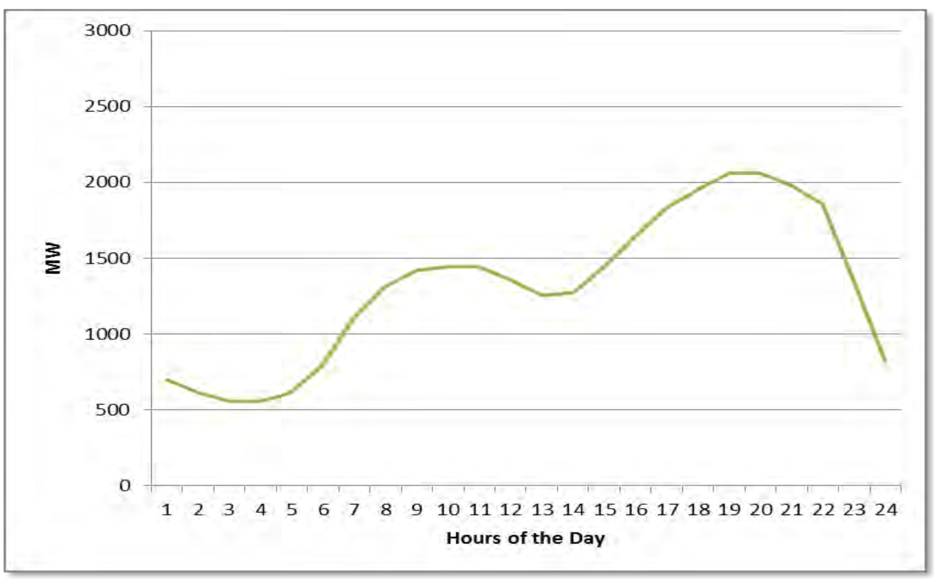
Source: Consultant's calibration against reported HPP production (CSO 2013)

Figure III-6: Monthly Hydropower Generation Profile – January (Wet Season)



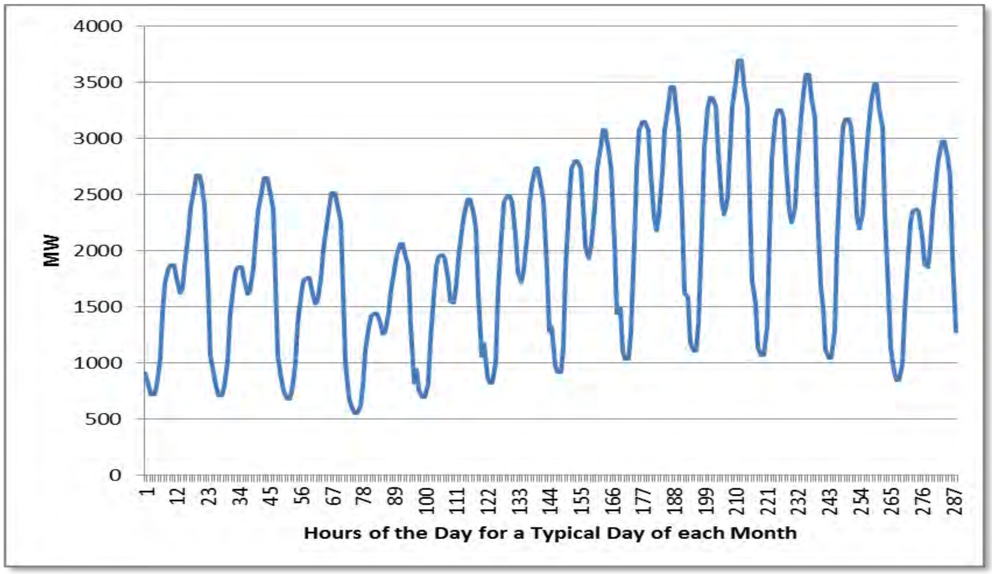
Source: Consultant's model

Figure III-7: Monthly Hydropower Generation Profile – April (Dry Season)



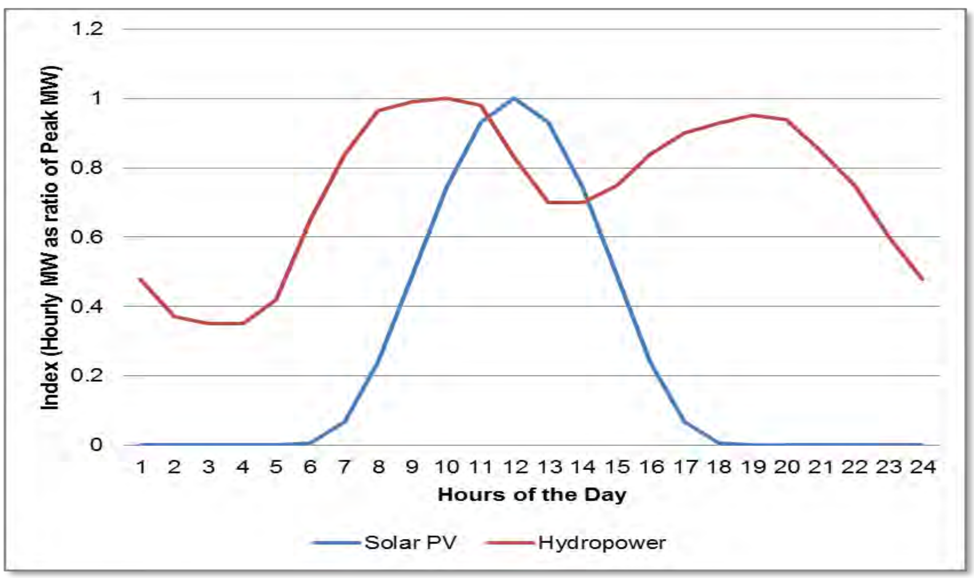
Source: Consultant's model

Figure III-8: Annual Hydropower Generation Profile (Typical Day for each Month)



Source: Consultant's model

Figure III-9: Solar Power & Hydropower Balancing Potential



Source: Consultant's model

G. Type 1 Renewables - Solar PV

47. The PV technology in utility-level applications can be divided to classes roughly by two important technical parameters. One is whether the project uses crystalline-silicon (c-SI) modules or amorphous Si thin film modules. The second dimension is whether or not the modules are mounted at a fixed-tilt or on a tracking system. Due to mass production and fierce competition typical residential

PV systems based on crystalline-silicon (c-SI) modules challenge well the amorphous Si thin film modules, which used to be more common and economical in earlier utility scale applications from 2005 to 2010. The system costs have since then converged.

48. As to the tracking system, it represents an additional cost but provides a higher energy yield. One-axis tracking, although it increases capital costs by 10 % to 20 %, can be economically attractive because of the increase in energy-production (20 % to 30 % more kWh/kW/year in areas with a good solar resource).3

49. A recent study by Lawrence Berkeley National Laboratory in the USA gathered cost and price data for 202 utility-scale (i.e. ground-mounted and larger than 2 MW) solar projects in the USA totalling more than 1,735 MWAC, of which 194 representing 1,544 MWAC consisted of PV projects.[4] Important observations were made on recent cost trends. The clear convergence in the average price of c-Si and thin-film projects was observed. The development is due to declined price of silicon combined with global excess of c-Si module manufacturing capacity. The economies of scale appear to diminish considerably when the system capacity goes beyond 5-10 MW. Overall, the system prices had fallen from around 5,600 $/kW of the period of 2007-2009 to 3,900 $/kWh on average for projects completed in 2012. Anecdotal evidence was given about cost reductions continuing to 2013-2014 to the extent that a large US project had reported an installed price of 2,030 $/kW to the regulator.

50. The operation and maintenance (O&M) costs reported in the USA appear to be in the range of 20 to 40 $/kW, or 10-20 $/MWh. These represent approximately 0.5 % to 1 % of the installed capital cost annually. The O&M costs are related to module cleaning, panel repairs and replacements, vegetation control, maintenance of mounting structures, and maintenance of the power system covering inverters, transformers, switchgear, internal wiring and grid connection. Part of the maintenance is labour intensive and therefore lower costs can be assumed in Myanmar than the US reference.

51. A Memorandum of Understanding was recently signed between MOEP and US investors of a solar PV project to Myanmar. The project consists of two 150 MW facilities, one in Nabuai and the other in Wundwin, both locations in Mandalay Region. The published project cost is 480 m$, equal to 1,600 $/kW. The targeted commissioning of the project is in 2016. Also a Thai company has been pursuing a 50 MW solar power plant in Minbu in Magway Region.

52. The cost assumptions made here are 2,100 $/kW for a solar PV plant operating on average at 20 % capacity factor. The capacity factor is highly site and project technology specific, including whether or not the project uses tracking devices. The operation cost is assumed at 0.4 % of CAPEX reflecting low labour cost of Myanmar.

53. Another solar power technology is Concentrated Solar Power (CSP) that uses mirrors to focus sunlight to either vertical pipes (parabolic troughs) or to a single point tank (solar tower), in which heat transfer fluid, typically water or oil, is heated and led further to evaporate steam for an ordinary thermal power process. This technology allows heat storage and scale, which is suitable for utility operations, typically from 50 to 100 MW. There are competing technological development lines for CSP including parabolic trough, tower systems, linear Fresnel and dish Stirling.

54. A CSP plant with the heat storage provides the benefit of higher dispatchability than a PV plant,

[3] IRENA Cost Analysis Series 4/5, Solar Photovoltaics, International Renewable Energy Agency, 2012

[4] Utility-Scale Solar 2012, An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States, Authors: Mark Bolinger and Samantha Weaver, Lawrence Berkeley National Laboratory, the USA, September 2013

albeit at higher capital costs typically over 5,000 $/kW. With thermal storages CSP plants can extend power supply to the evening hours, which are often also peak hours of the system. However, as Myanmar's power system is dominated by hydropower, this feature is of lesser importance. As mentioned earlier, hydropower can be used for hourly-level regulation so that the energy supplied by solar systems during day-time can be effectively stored by the hydropower system and utilized in the evening. Therefore, CSP technology is not considered prospective in Myanmar over the planning period of this study.

H. Type 1 Renewables - Wind

55. Global wind power has also seen a substantial reduction in initial capital costs of wind farms. There has been continuous up scaling in the unit sizes of wind turbines so that the current standard in many European markets seems to be around 3 MW. Another major factor in cost reductions has been that Chinese and Indian turbine manufacturers have consolidated their place in the international market place. Around half of the wind turbine cost is in the installation and farm infrastructure. They include grid connection costs, farm internal power network, track and crane pad, foundation survey, design and ground works. In these areas, the low cost of labour has some significance to the costs. In this study, grid-connected wind onshore in about 100 MW class will be assumed to operate at a capacity factor of 30 %, and the CAPEX is assumed at 1,360 $/kW, OPEX at 0.8 % of CAPEX annually and the project lead time in two years.

I. Fuel Price Projections

Table III-8: Base Fuel Costs and Prices Used for Expansion Planning

Fuel type	Unit	Value	Date & Source
Crude oil	US$/bbl Kyat/bbl	108.01 105,202	June 2014, Crude oil, Dubai (WB Commodities Price Data (the Pink Sheet))
Diesel	US$/l Kyat/gal	0.82 3,631	META method: crude oil price x 120%
Fuel oil	US$/kl Kyat/gal	441.59 1,955	META method: crude oil price x 65%
Gasoline	US$/l Kyat/gal	1.30 5,756	India, 14.7.2014 http://www.globalpetrolprices.com/India/gasoline_prices/
Natural Gas	US$/mmbtu Kyat/mmbtu	10.62 10,344	Consultant conversion from June 2014, Natural Gas, LNG Japan (WB Commodities Price Data (the Pink Sheet)) considering LNG gasification, regasification and transport.
Coal - lignite	US$/ton Kyat/ton	45 43,830	Consultant
Coal - Sub-bituminous	US$/ton Kyat/ton	75 73,050	Platts, Coal Trader International Consultant
Coal - Bituminous	US$/ton	93	Consultant

Fuel type	Unit	Value	Date & Source
	Kyat/ton	90,582	
Biomass	US$/ton Kyat/ton	82.88 80,725	India, Biomass Briquettes Fuel (Sawdust, Cane Waste) as per 18.7.2014, http://www.biomassbriquettesystems.com/listings Reference firewood 250 Kyat per viss i.e. 1.63293 kg, equivalent of 157 US$/ton,
Average electricity price	US$/kWh Kyat/kWh	0.09 88	Myanmar: average over the range of 0.08 - 0.10 $/kWh "The Rise of Distributed Power" by Brandon Owens, 2014, GE Company

56. Assumed heating values for fuels are typical for the region where Myanmar is located and are presented in the table below.

Table III-9: Heating Value of Fuels, kJ per unit

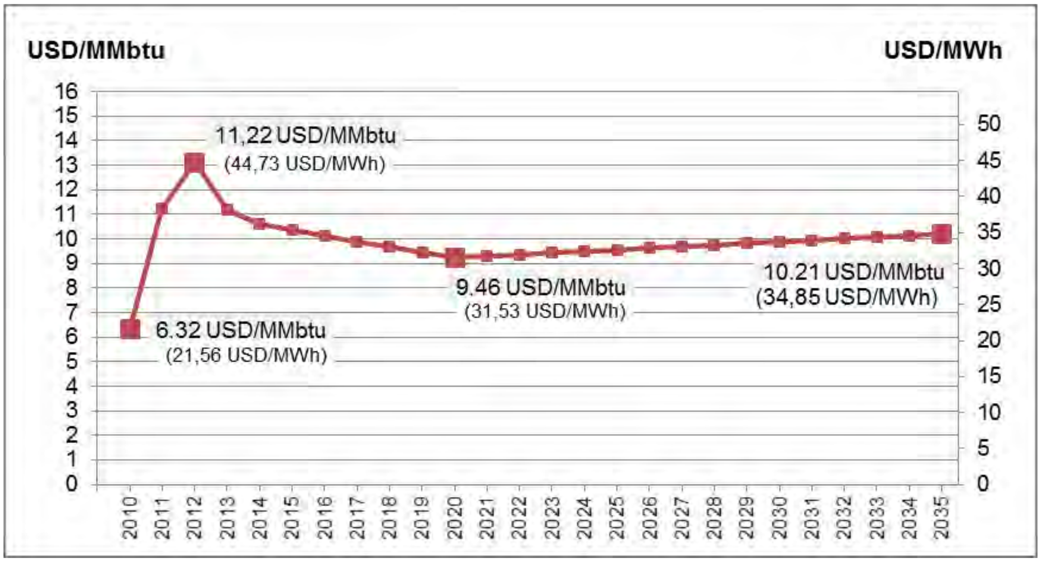
	Unit	Heating value
Crude oil	MJ/l	38.50
Diesel	MJ/l	35.80
Fuel oil	MJ/l	38.90
Gasoline	MJ/l	32.10
Natural Gas	MJ/m^3	37.26
Coal – lignite	MJ/ton	14,655
Coal - Sub-bituminous	MJ/ton	23,029
Coal – Bituminous	MJ/ton	25,122
Biomass	MJ/ton	13,500

Source: Consultant's assumption based on various sources

57. Growth rates for fuel prices are based on Current Policies Scenario forecast in World Energy Outlook 2013 prepared by the International Energy Agency (IEA). It is assumed that crude oil and coal prices will continue to grow over the following 11 years, while natural gas price will decline during the next 6 years but thereafter the prices would start to moderately recover (see the table below). Electricity price is expected to grow over the whole forecast horizon.

58. The assumed gas price has been based on the Japan Liquefied Natural Gas Import Price (Ycharts 2010 to 2013), with subtraction of 5 USD/MMbtu for LNG gasification, regasification and transport costs that are not relevant for Myanmar's domestic gas consumers. This reference price is used as a proxy of the economic value of domestic gas and it reflects well the realized export prices of the same periods. The gas price forecast from 2014 to 2030 has been based on the IEA forecasts (on reduction of the gas price by 13 % till 2020, and its further recovery at 3.4 % during every five years). The base gas price and results of the forecasts are presented in the Figure III-10 below in two units for reader's convenience.

Figure III-10: Natural Gas Price Forecast for Myanmar



Source: Japan Liquefied Natural Gas Import Price (Ycharts 2010-2013), IEA, consultant's calculations

59. IEA sees that coal demand trends diverge across regions. Growth in coal production over 2011-2035 comes mainly from non-OECD countries, with India, Indonesia and China accounting for 90 % of incremental coal output. Whilst the three countries are all major producers, they are also the large consumers with India and China using vast majority of own coal domestically. Australia is the principal OECD country with higher production, and therefore price references have been sought from Australian coal which is traded throughout South-East Asian region. Coal resources will not be a constraint for many decades, yet the cost of supply is likely to increase moderately in real terms as a result of rising mining and transportation costs as well as forecast tightening supply/demand balance. The Current Policies Scenario of IEA does not reflect any measures which would limit the use of coal, other than those measures and policy trends that are already visible.

60. Whilst the New Policies Scenario has coal prices to grow in real terms approximately 10 % from the current levels to 2035, the so called 450 Scenario, which is most determined with respect of climate change mitigation efforts, sees 25 % reduction in coal prices under the pressure of declining demand. It is considered here, however, that the Current Policies Scenario, which extends the currently prevailing global trends, and has an in-built assumption of increased coal consumption which causes increasing prices, is a conservative assumption for a country that would depend on coal imports, if it were to decide to enter the path of building substantial amounts of coal based electricity generation capacity. The reference is made to this scenario only as a matter of prudency, and the choice does not in any way reflect the Consultant's views on desired future development.

Table III-10: Forecast Fuel and Electricity Real Price (2014) Changes (Over the Previous 5 Years)

Fuel/Electricity	2020	2025
Crude oil	10.10 %	5.80 %
Natural Gas	-13.00 %	3.40 %
Coal (Australian)	6.90 %	3.90 %
Off-peak electricity from the grid	10.00 %	10.00 %

Source: Consultant's analysis

J. Technology Screening

61. For the purpose of technology screening curve analysis, selected generation assets were divided into two groups, so-called large and small power plants. This division is somewhat relative and is not always based on installed capacities scale but rather on what can be considered "large" or "small" for a particular generation technology.

62. The screening curves presented in the following figures reflect range of capacity factors assumed to be realistic for the selected power generation technologies. Solid part of each screening curve represents a highly probable ("guaranteed") capacity factor range, while dashed part of the curve represents less probable capacity factor still achievable under given technologic and economic conditions.

63. Large scale power plants cover large oil/gas and coal combustion plants, as well as large hydro and on-shore wind. All selected large-scale power plants except the solar PV can assume construction of both transmission and distribution facilities, including 220 kV overhead double circuit lines and 220/132kV substations. The table below contains main features of the considered large power plants.

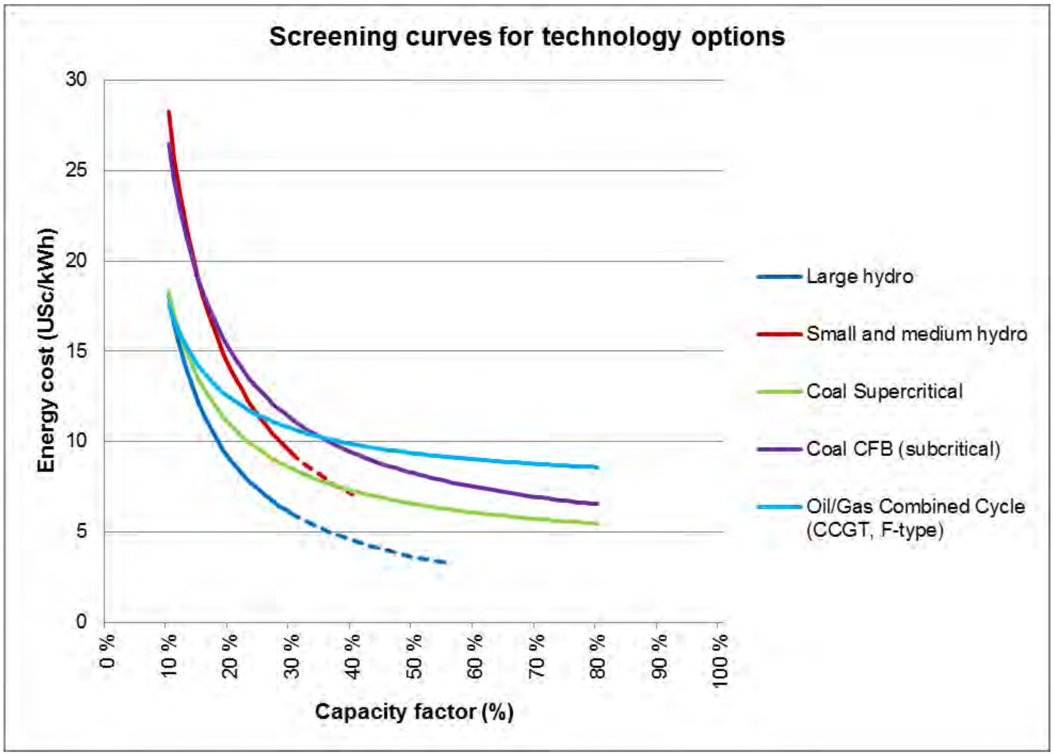
64. The following graphs show the estimated levelised costs of main large scale power generation options as a function of capacity factor. The large scale hydro, on the lower level, and the small & medium size hydro on the higher level, can be considered to represent a range for hydropower costs as there is a major uncertainty, and case by case dependence on site specific conditions, of hydro project capital costs. Whilst large scale hydropower delivers the lowest LCOE, supercritical coal based power reaches the same level if it is run as base load plant with annual capacity factor exceeding 80 %.

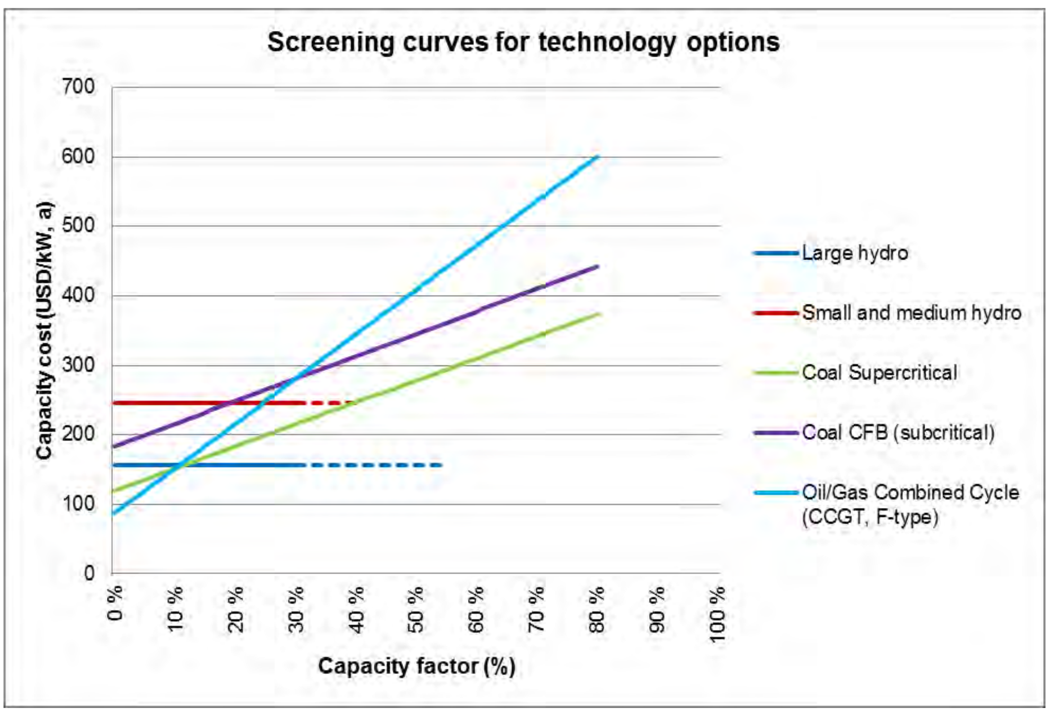
Table III-11: Main Features of Selected Large-Scale Power Plants

	Installed capacity	Capacity factor	Life time	CAPEX overnight cost	Fixed O&M cost	Variable O&M cost	Lead time
	MW	%	a	US$/kW	% of CAPEX	USc/kWh	A
Oil/Gas Combustion Turbine (F-type)	250	10 %	25	486	1.2 %	0.99	1.5
Oil/Gas Combined Cycle (CCGT, F-type	650	80 %	25	918 (*)	1.8 %	0.59	2.5
Coal Supercritical	600	80 %	30	1,300	2.0 %	0.31	3
Coal CFB (subcritical)	150	80 %	30	1,800	2.5 %	0.33	2
Coal PC (subcritical)	50	80 %	30	2,300	3.0 %	0.35	2
Solar PV (large)	50	20 %	25	2,100	0.4 %		1
Wind onshore (large)	100	30 %	20	1,360	0.8%		2
Small and medium hydro	100	50 %	70	2,800	1.2 %		7
Large hydro	600	50 %	70	1,700	1.2 %		9

(*) PA Consulting Group, September 2010 (Singapore costs adjusted to the price level of 2014); estimate for a 423 MW CCGT F-type power unit

Figure III-11: Screening Large Scale Conventional Power Plants

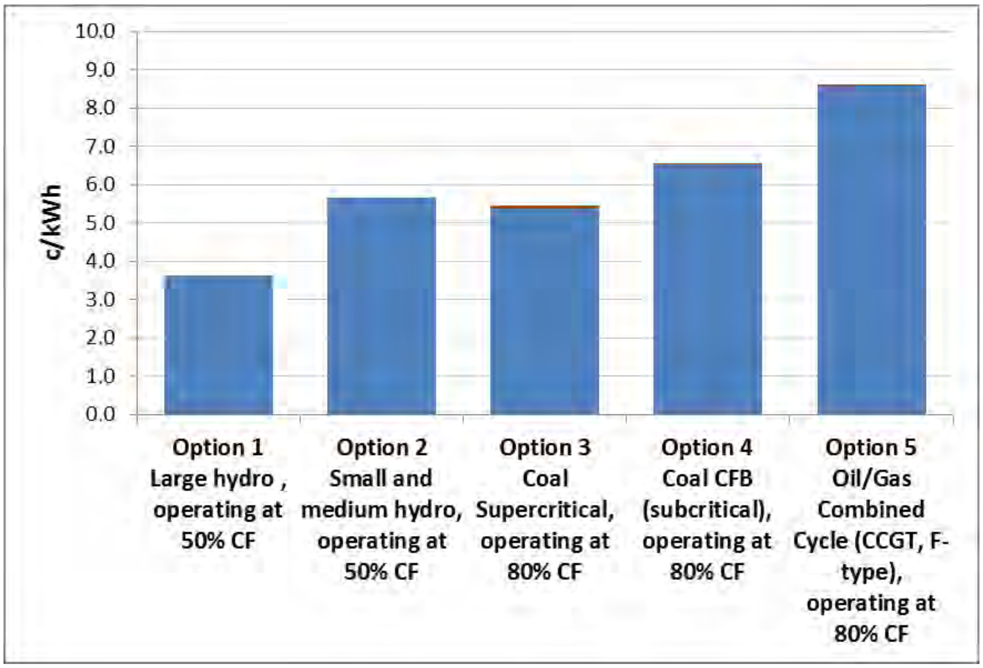




Source: Consultant's analysis

65. The LCOE of generation is the lowest with large scale hydro (3.62 c/kWh), but the cost is also dependent on capacity factor (assumed here at 50 %) and capital cost (1,700 $/kW). The costs of coal based power vary rather little as the higher CAPEX and OPEX of smaller CFB and PC plants is offset by correspondingly lower cost of lignite and sub-bituminous coal versus bituminous coal of supercritical large coal plant. With the current value of natural gas, assumed here to the level of gas exported to Thailand, gas-firing base load is not feasible compared to hydro and coal. The F-class GTCC plant selected as representative of gas combined cycle technology delivers LCOE of 8.58 c/kWh.

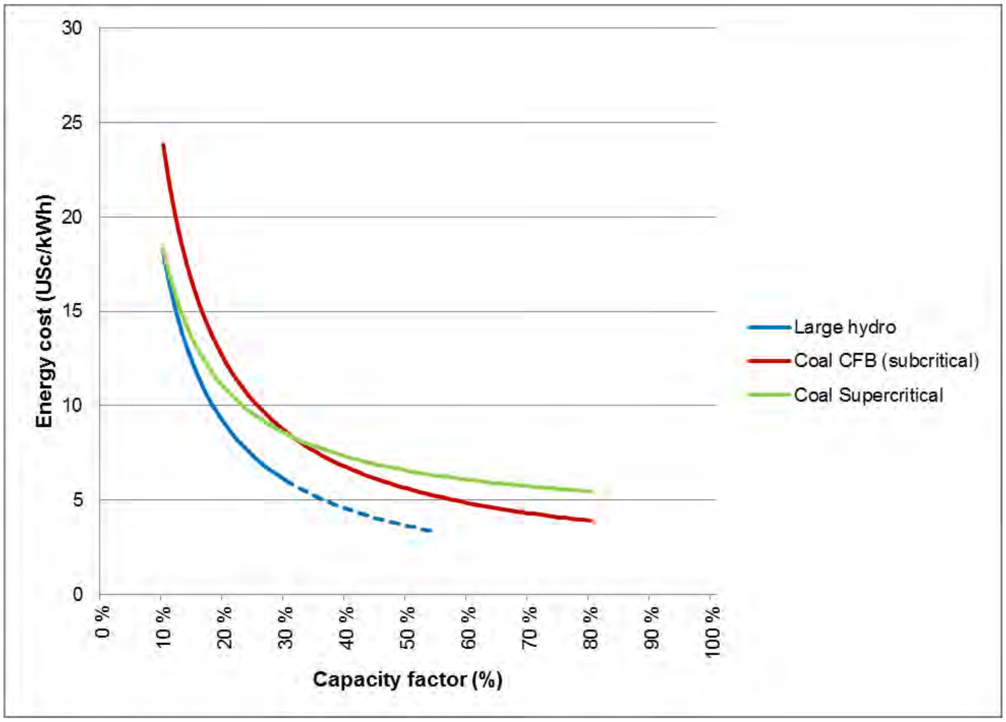
Figure III-12: Generation LCOE of Large Scale Conventional Power Plants



Source: Consultant's analysis

66. The underlying assumptions for all coal fired technologies above was use of imported coal, which is largely justified. However, there is domestic coal available albeit not in very large amounts supporting large scale mine-mouth power plants. Whilst the cost of imported coal is set here to vary between 40 $ and 90 $/ton, is can be assumed that cost of mine-mouth generation could be based on coal prices varying between 10 and 20 $/ton, depending on coal quality. With such low level of coal cost, mine-mouth power generation seems feasible, especially, if the mine and its associated facilities would consume major part of generated power whereby there would be less marginal need to strengthen electricity transmission and substation systems. The following graph compares the costs of large scale hydro and bituminous coal power plant to small-medium scale lignite fired power plants.

Figure III-13: Lignite-Fired Mine Mouth Power Station, Large Scale Hydro & Coal-fired Power Plant (Imported Coal)



Source: Consultant's analysis

67. Transmission and distribution makes up an important part of the total cost of the power supply system, but the cost impact can be only roughly estimated in a screening analysis, and such is inevitably based on averages for illustration only rather than actual costs, which are highly site specific. A logical location for a gas turbine peaking plant is close to the load centre and in the vicinity of major transmission lines, and therefore this production type is estimated to have the smallest requirement for transmission development. These power plants are used only periodically, short periods at a time and their site areas are limited so that suitable sites are usually not difficult to identify insofar as noise abatement issues are adequately considered. Large thermal plants (coal and CCGT) are assumed to be located in coastal locations in Myanmar, not in immediate vicinity of major population centres, but optimized to be not too far from the transmission system and source of fuel (coal by sea and gas pipeline). Location of a large coal fired plant has specific requirements related to access to seaborne transportation of coal and the construction of jetty.

68. Longest transmission distances can be expected for wind and hydropower. Likely locations for wind are in the South of Myanmar and not very near to the major transmission lines. Hydropower sites in the Shan State and the Kachin State, may be remote from the perspective of current national load centre, but once hydropower construction in these region starts, several plants are planned to the same area and to the same river system, sometimes in cascades, so that the share attributable to one single plant of the transmission system development remains limited. The modelled capacity for photovoltaic power is 5 MW, which is already a large plant of that type, but in reality it is possible that PV will be developed in even larger units if sparsely inhabited land is available and taken into use, and panels are clustered to form a large single entity up to tens of megawatts requiring HV transmission. Therefore 30 km of 132 kV line has also been assumed for PV of 100 MW capacity.

69. Assumptions for the transmission system of the various types of large scale power plants in the META model are as presented in the following table.

Table III-12: Assumptions for T&D Facilities Associated with Power Plants

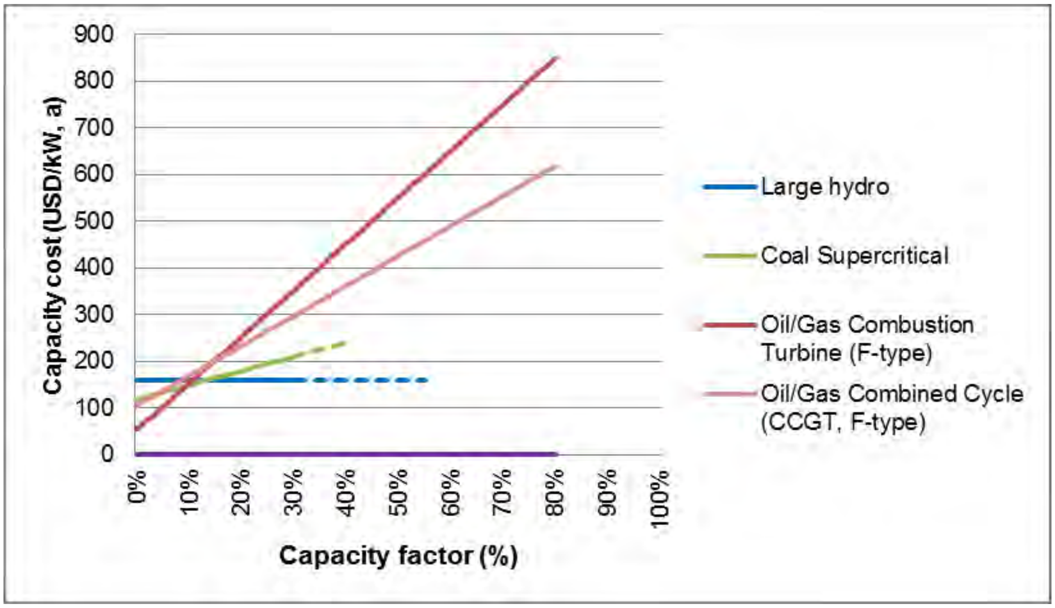
	Installed capacity	Capacity factor	400 kV	220 kV	132 kV	440/220 kV substation	220/132 kV substation
	MW	%	km	km	km	no	No
Oil/Gas Combustion Turbine (F-type)	250	10 %		10			1
Oil/Gas Combined Cycle (CCGT, F-type	650	80 %	30			1	
Coal Supercritical	600	80 %	30			1	
Coal CFB (subcritical)	150	80 %		50			
Coal PC (subcritical)	50	80 %			50		1
Solar PV (large)	50	20 %			50		1
Wind onshore (large)	100	30 %			50		1
Small and medium hydro	100	50 %		50		1	
Large hydro	600	50 %	50			1	

Source: META model

70. The inclusion of the transmission and distribution cost does not have an impact on the ranking order of generation technologies. The distribution cost of the delivered energy is the same for all options, and it also has the highest share within all T&D costs. The distribution cost is 3.18 c/kWh. High voltage (HV) transmission and substation costs are minor, only 0.07c/kWh and 0.07 c/kWh, respectively, for large hydro. The share of HV transmission and substation is so small, about 4 % of the LCOE that despite minor differences in those between different plant options, they will not differentiate various generation types.

71. One possible policy option for Myanmar is to develop strongly a hydropower based power supply system. However, with hydropower, large 'extra' capacity is needed for peaking purposes. Hydropower is highly capital intensive and it would not be rational to build hydro capacity to such level that every peak could be covered considering rare adverse hydrological events and droughts. The following screening curve shows that gas turbine peaking power is the least cost option up to the capacity factor of around 10 % representing about 900 operational hours a year in average. Open cycle gas turbine is of low CAPEX – high OPEX type. It seems reasonable to include this technology option in system expansion planning when hydropower provides the base and medium load.

Figure III-14: Open Cycle Gas Turbine as Part of the System

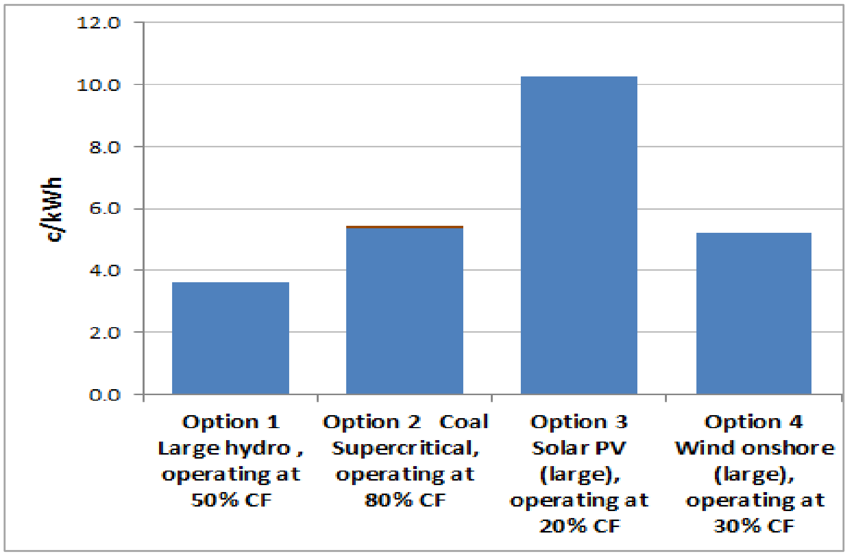


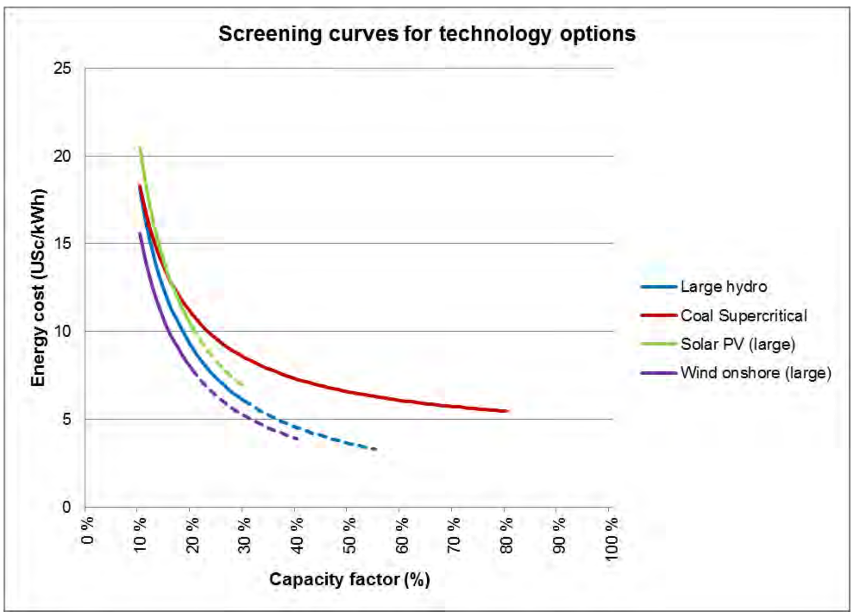
Source: Consultant's analysis

72. Since 2010, the costs of both solar PV and wind technologies have declined significantly with increasing numbers of installations globally. One of the main contributing factors to PV power generation growth has been the sharp reduction in the cost of crystalline silicon PV modules. Their prices have fallen by more than 65 % in the past three years to less than 1,000 $/kW. Whilst the worldwide cumulative installed capacity of wind still exceed that of solar PV, in 2013, for the first time, solar installations exceeded wind albeit by a narrow margin. The massive investments in wind energy installations in China and India have caused these countries to develop own design capability and manufacturing base for wind turbines bringing competition in technology to a new level.

73. With the given assumptions the LCOE of PV technology is 10.24 c/kWh. LCOE of wind energy is 5.2 c/kWh, almost equal to that of coal fired power. For the solar PV, technology improvement over years (annual 2% decrease of CAPEX) has been taken into consideration in META.

Figure III-15: Large Scale Conventional Power Plants vs Wind and Solar PV





Source: Consultant's analysis

74. Small-scale island power plants do not assume construction of any transmission infrastructure but their downside is poorer service quality, which means that some technologies can provide electricity to consumers only part time of the day, and that electricity supply is dependent on natural forces (river discharge, wind, solar). With the exception of a small diesel generator, all selected small-scale technologies below are based on renewable energy. The main features of the considered small power plants are presented in the following table.

Table III-13: Main Features of Selected Small-Scale Power Plants

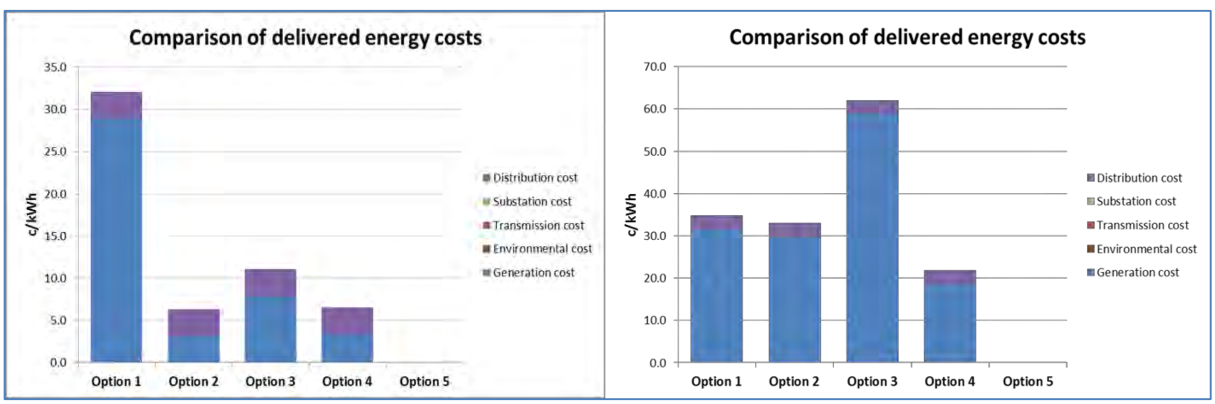
	Installed capacity	Capacity factor	Life time	CAPEX	Fixed O&M cost	Variable O&M cost	Lead time
	MW	%	a	US$/kW	% of CAPEX	USc/kWh	A
Diesel generator (small) (option 1, graph 1)	5	10 %	20	391	6.5%	2.7	0.5
Biogas, Landfill gas (option 2, graph 1)	5	80 %	20	1,088	8.1%		0.5
Micro hydro (option 3, graph 1)	0.1	30 %	30	2,108	0.8%		0.5
Mini hydro (option 4, graph 1)	5	45 %	30	1,316	0.8%		1
Solar PV (mini) (option 1, graph 2)	0.0003	20 %	25	5,681	0.2%		0.5
Wind onshore (micro) (option 2, graph 2)	0.0003	30 %	20	7,162	0.3%		0.5
PV-wind hybrid (micro) (option 3, graph 2)	0.0003	25 %	20	11,804	0.1%		1
Pico hydro (mini) (option 4, graph 2)	0.001	30 %	15	3,564	0.8%		1

Source: Consultant's analysis

75. As can be seen from the figures below, major share of delivered energy costs for small power plants consists of generation costs. Solar PV, and especially PV-wind hybrid plants have significantly higher unit delivered energy costs when compared to other selected options. Diesel and onshore wind unit costs are almost equal. Biogas and mini hydro are the most attractive. It is worth noticing that these power plants also have significantly higher installed capacity when compared to the most expensive options (respectively 5 MW vs. not more than 0.1 MW).

Figure III-16: Delivered Energy Costs, Small Power Plants

Graph 1 **Graph 2**

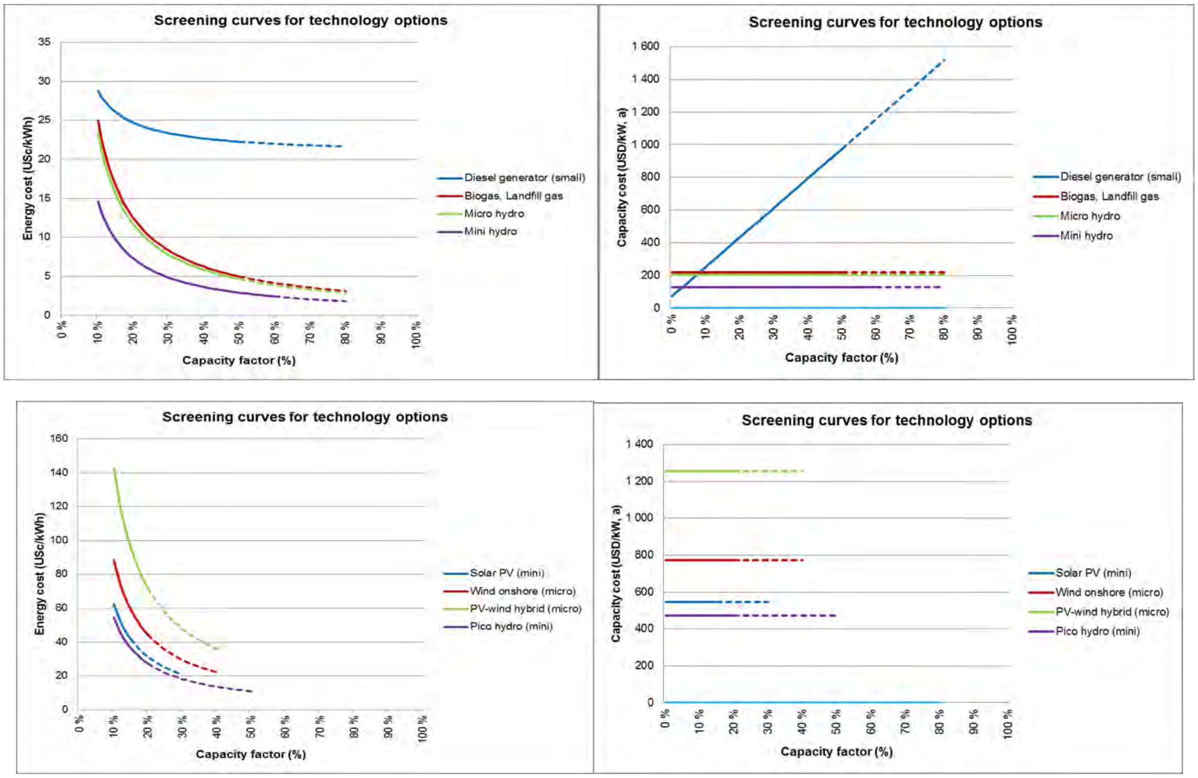


Source: Consultant's analysis

76. Graph 1 above represents the costs of small-scale units suitable for a village level system; whereas Graph 2 shows costs of systems designed more for individual households. The screening curve analysis for small-scale power plants indicates that under given conditions, a micro PV-wind hybrid plant is the most expensive generation option. Even a small diesel plant is less expensive until its capacity factor starts to exceed 70%. The least expensive generation options in this group are mini hydro, micro hydro and landfill biogas (the last two having practically similar unit costs). Pico hydro

mini and mini solar PV have mid-level unit costs. Onshore micro wind starts to be more attractive than e.g. diesel power only if its capacity factor exceeds 40%.

Figure III-17: Screening Curves, Small Power Plants



Source: Consultant's analysis

77. A screening curve method based on the Model for Electricity Technology Assessment (META) was applied for generic analysis and illustration of the costs of various electricity generation technologies in Myanmar. The analysis gave the following guidance:

- Myanmar's power sector today relies heavily on hydropower. Hydropower is likely to provide the least-cost option for further system expansion.
- Next in cost-based ranking order come large scale coal-fired power and wind energy. The underlying assumption for coal power plants was that they are built on the coast and depend on imported coal sourced from Australia or Indonesia.
- The LCoE of small scale mine-mouth coal fired power is 1.5 - 2.5 c/kWh higher than that of large scale coal when lignite is valued at word market prices whereas if lignite is valued at domestic cost at mines, it would be 1.0 - 1.5 c/kWh cheaper, but still higher than the LCoE of large hydropower.
- Of the new forms of renewable energy, wind energy is currently most cost-competitive and feasible for utility-scale application.
- Because Myanmar has the opportunity to sell natural gas to her neighbouring countries, natural gas was valued at market prices valid in South-East Asia. At such fuel cost, power generation of in CCGT plants is relatively costly and not feasible on economic grounds for Myanmar.

- Open-cycle gas turbines provide a low capital cost alternative to build fast-reacting capacity for serving the peak loads. Such plants are feasible and should be dimensioned so that their annual capacity factor is approximately 10 %.

IV. POWER SUBSECTOR EXPANSION

K. Introduction

78. Commercial energy planning software such as MARKAL / TIMES and MESSAGE has the functionality to produce a power section expansion with acceptable accuracy for long-term planning purpose. However, due to the concerns on historical data, bespoke planning models emulating MARKAL / TIMES methodology were used to model the economic and household sectors. In the case of power sector expansion, ADICA used software WASP (in Appendix 4) and the Consultant used an optimization model.[5] The Consultant's optimization model used a deterministic approach, a pseudo-reserve margin was set at 15% of demand, and alternative long-term fuel mixes were examined using a least-cost hourly dispatch optimization technique. The methodology and approach is explained in more detail in Appendix A.

79. Five expansion cases were defined based on a practical consideration of available resources, recent policy direction and the advice of the Ministry of Electric Power. The five cases were chosen to represent the widest possible spread of fuel mixes. The definitions of the five cases are given in Table IV-1. Capacity planting schedules were developed for each case and the portfolios were dispatched according to marginal cost considerations with a variable operating cost merit order as follows – solar PV, wind, large hydropower, small hydropower small, gas and coal.

Table IV-1: Fuel Mix Cases

Case	Name	Description
Case 1	Planned Hydro / Coal	Includes all committed and planned hydro, existing coal and gas fired generation, committed 300 MW solar PV starting from 2016, and moderate large coal expansion starting from 2026
Case 2	Balanced (Hydro / Coal / Solar PV)	Same as the Base Case but with less planned hydro displaced by a balance of large thermal resources and solar PV resource (the solar PV balances the hydropower)
Case 3	Maximum Hydro	Same as the Base Case but with maximum dependence on hydropower (including existing, committed and planned resources – the latter to the maximum technically-feasible) and no new thermal capacity
Case 4	Maximum Coal	Same as the Base Case but without planned hydro (only existing and committed) and with large scale coal-fired power development
Case 5	Maximum Solar PV / Wind	Same as the Base Case but with large scale solar PV and wind development

[5] The model was based on a public domain OpenSolver using the Open Source, COIN-OR CBC optimization engine, designed to rapidly solve large Linear and Integer problems

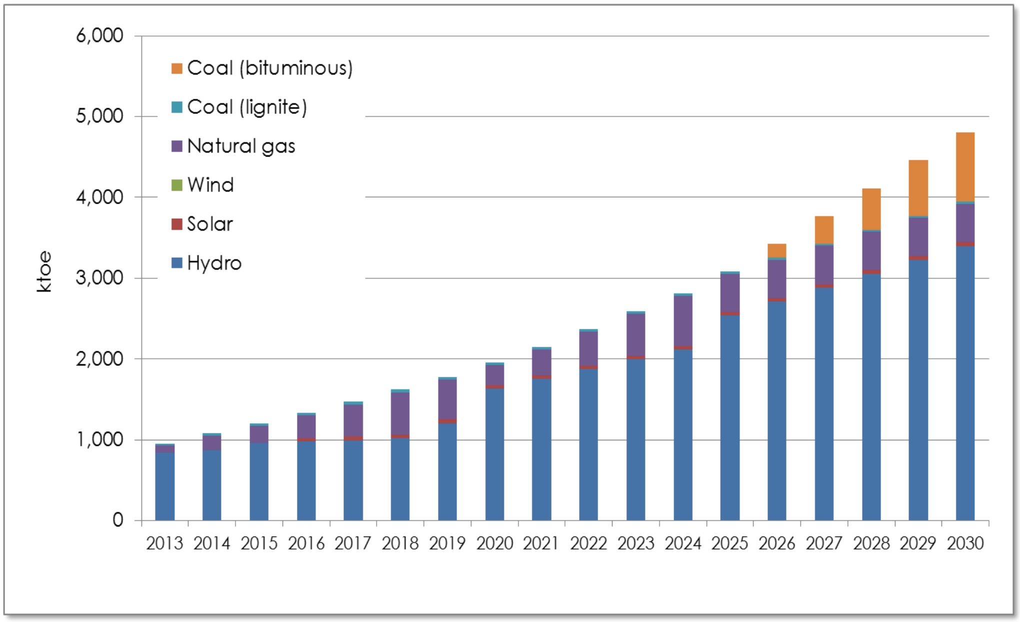
80. In mid-2015, the ADB commissioned ADICA[6] to develop a least-cost power subsector expansion using probabilistic expansion planning techniques (WASP software). ADICA set a minimum reserve margin of 20% and settled on different planning assumptions. As the ADICA report did not quantify energy conversion losses, the least-cost capacity expansion plan produced by WASP was modelled by the EMP team to determine the energy content of the fuel and the energy conversion losses based on EMP fuel calorific values and conversion efficiency factors.

L. Electricity Fuel Mix & Conversion Efficiency (TPES)

81. The following charts provide the outputs for the five fuel mix cases. In each case, a pair of charts represents the primary energy fuel use and the useful energy and energy conversion losses respectively. In all cases the projections are for the medium electricity growth case defined in the Consolidated Demand Forecasts report of this EMP.

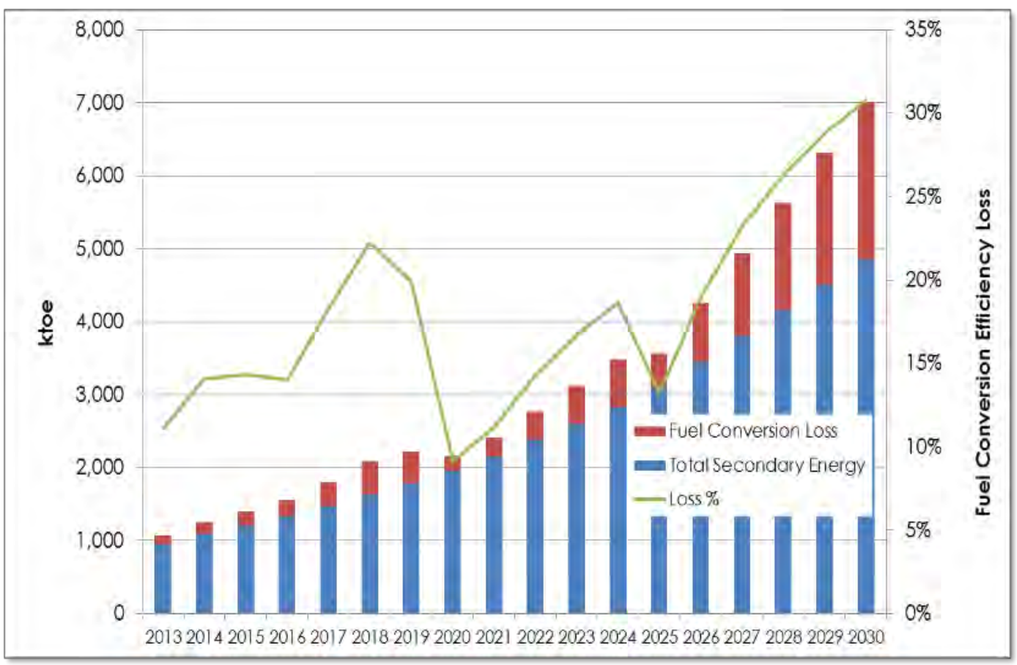
[6] NATIONAL POWER EXPANSION PLAN; prepared by ADICA using the Wien Automatic System Planning software (WASP-IV). The expansion plan is based on the EMP 'medium' electricity demand forecast

Figure IV-1: Case 1 – Planned Hydropower / Coal



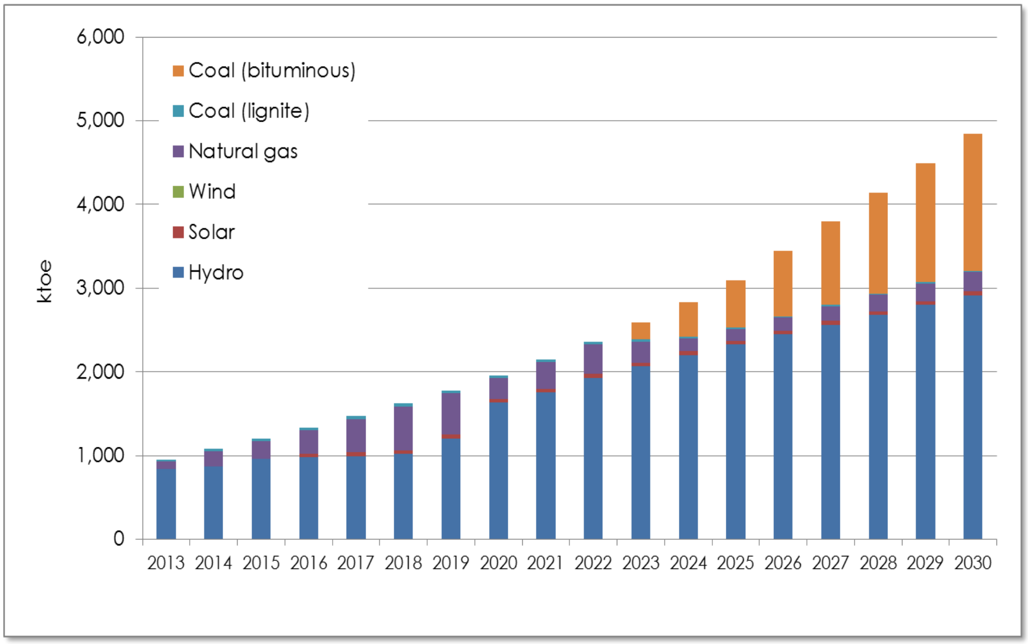
Source: Consultant's analysis

Figure IV-2: Case 1 – Energy Conversion Loss



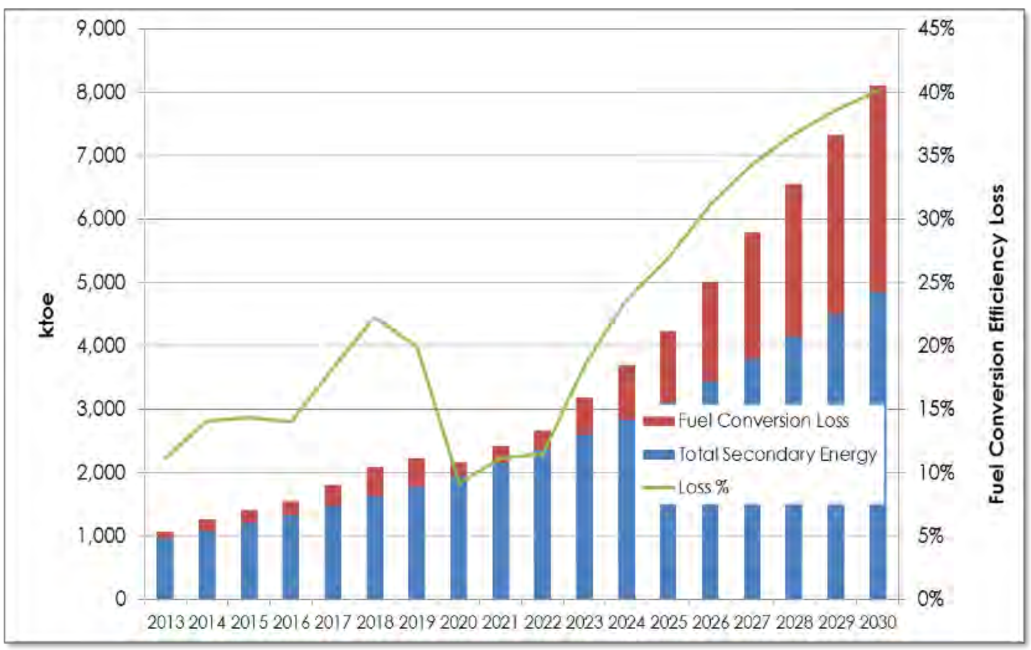
Source: Consultant's analysis

Figure IV-3: Case 2 – Balanced (Hydro / Coal / Solar PV)



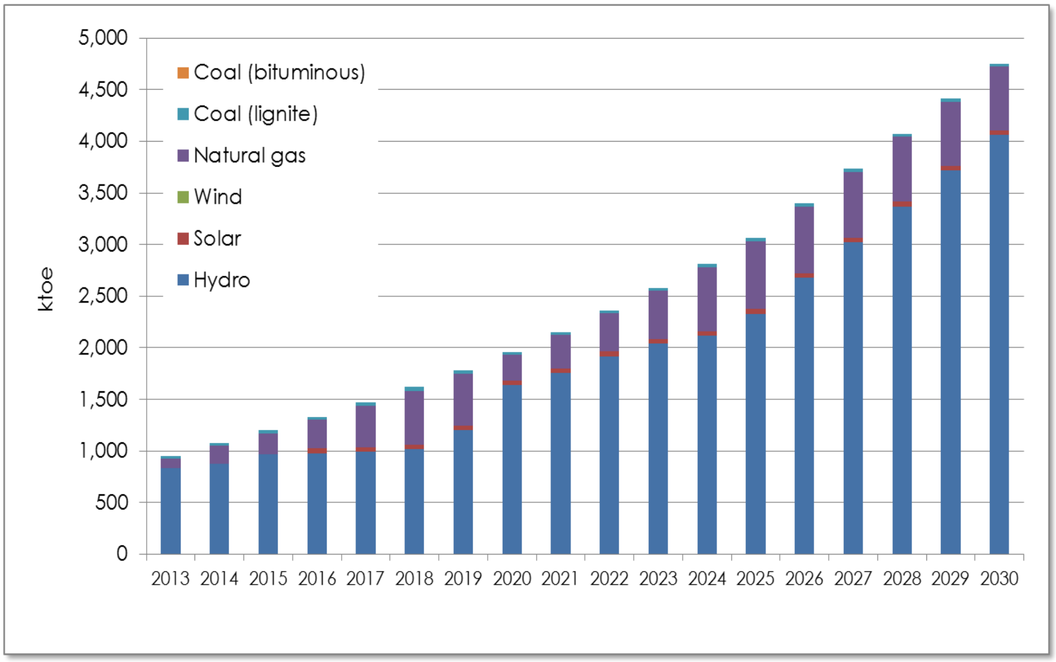
Source: Consultant's analysis

Figure IV-4: Case 2 – Energy Conversion Loss



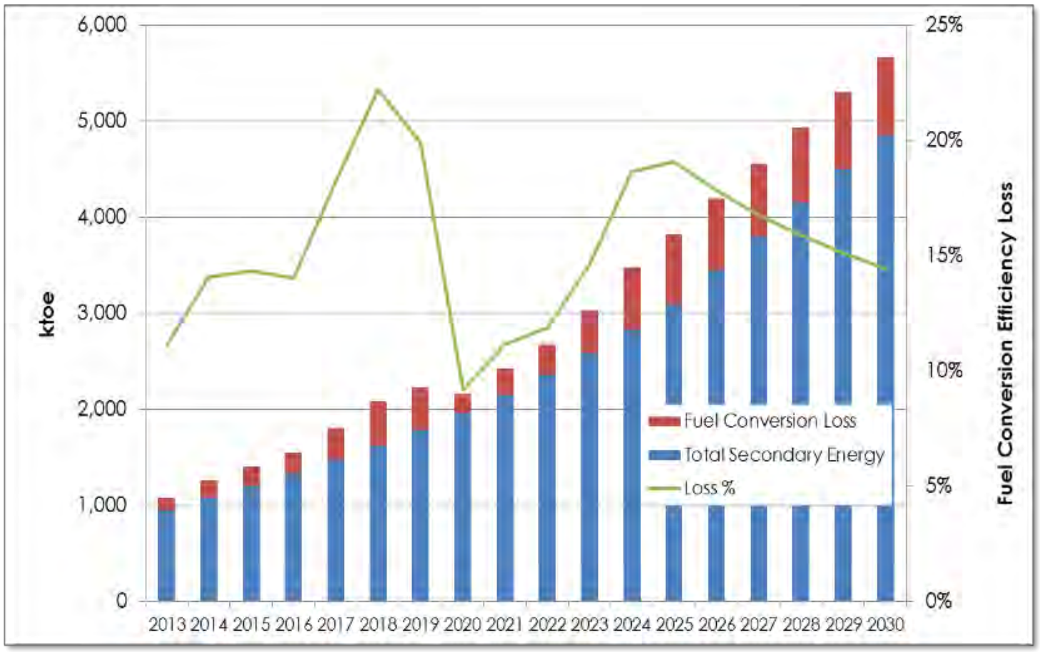
Source: Consultant's analysis

Figure IV-5: Case 3 – Large Hydropower



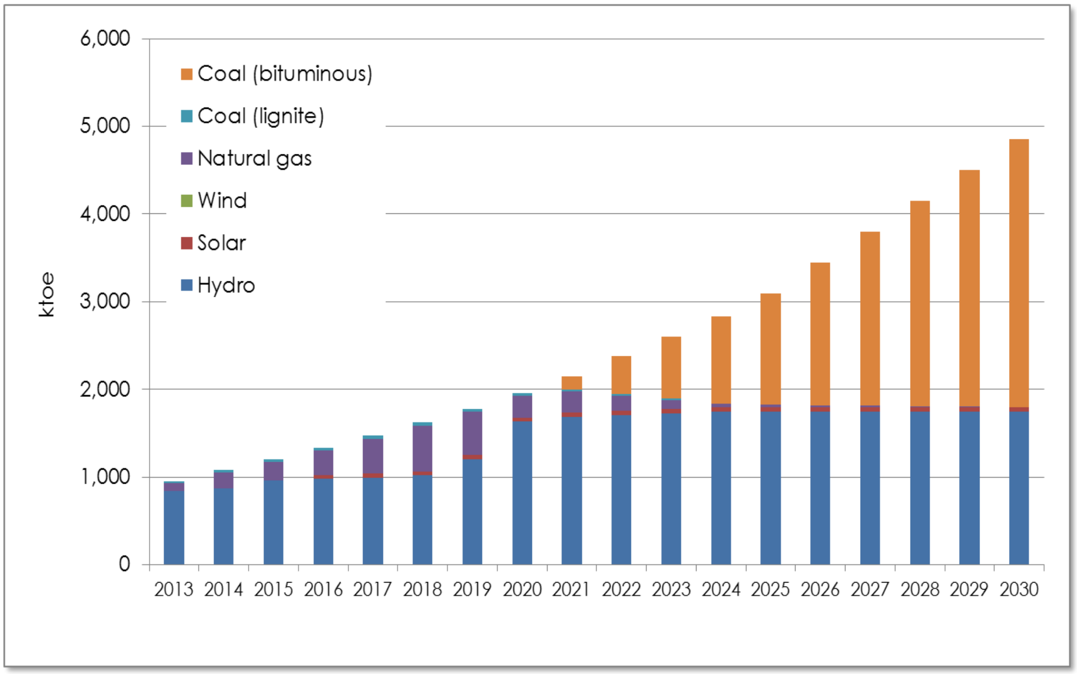
Source: Consultant's analysis

Figure IV-6: Case 3 – Energy Conversion Loss



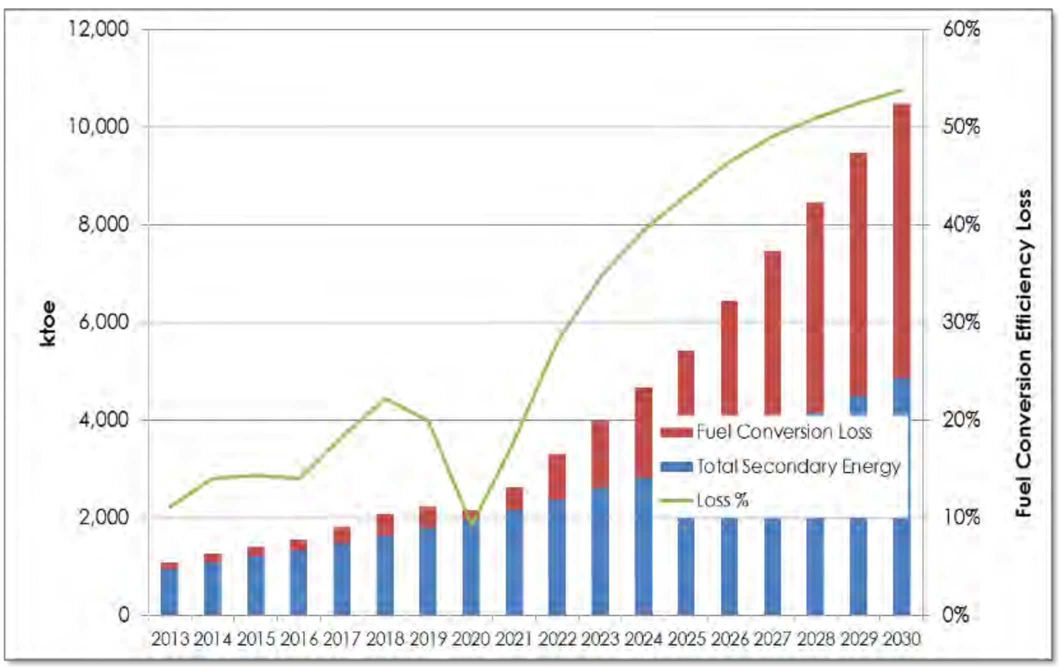
Source: Consultant's analysis

Figure IV-7: Case 4 – Large Coal



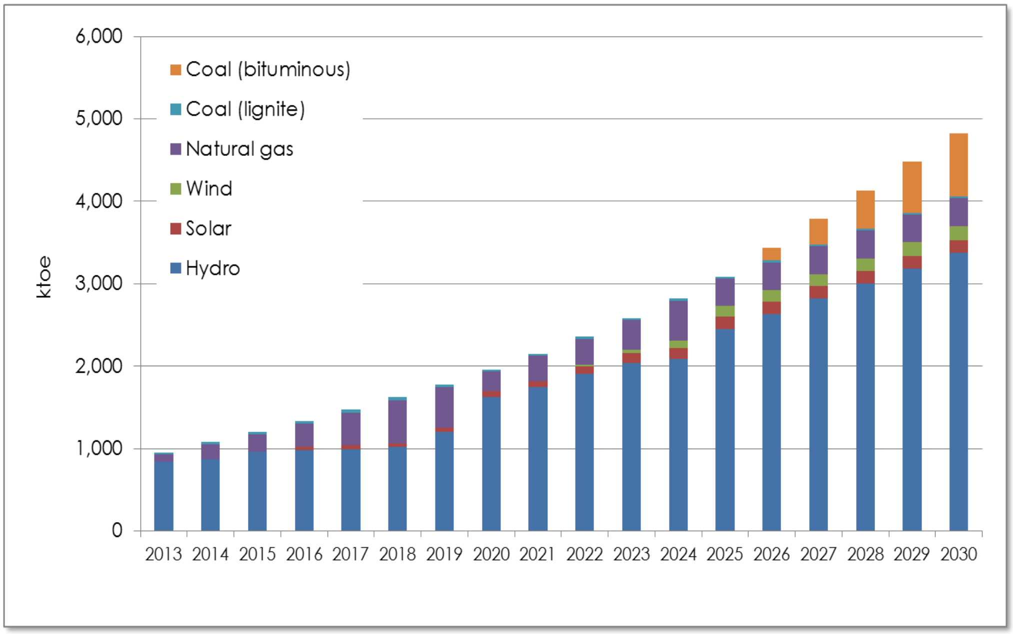
Source: Consultant's analysis

Figure IV-8: Case 4 – Energy Conversion Loss



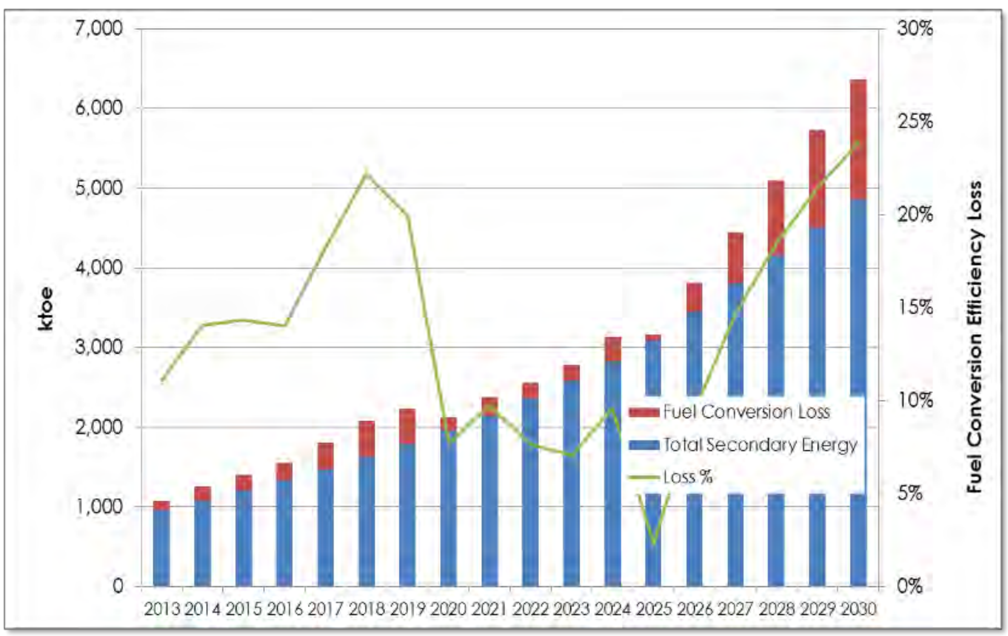
Source: Consultant's analysis

Figure IV-9: Case 5 – Large Solar PV / Wind



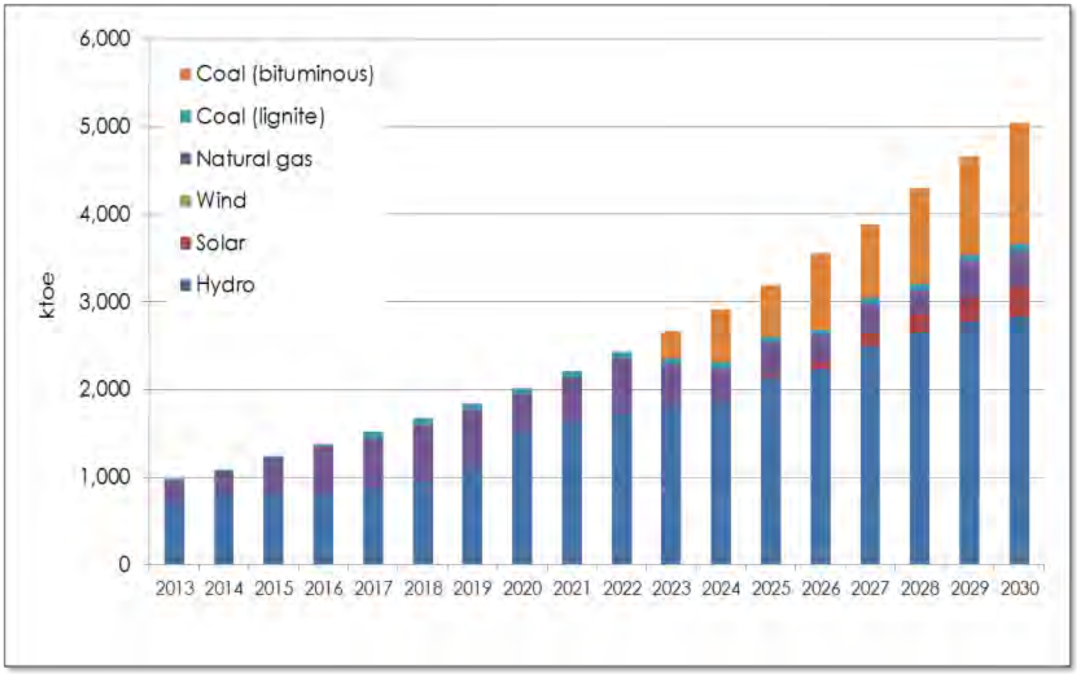
Source: Consultant's analysis

Figure IV-10: Case 5 – Energy Conversion Loss



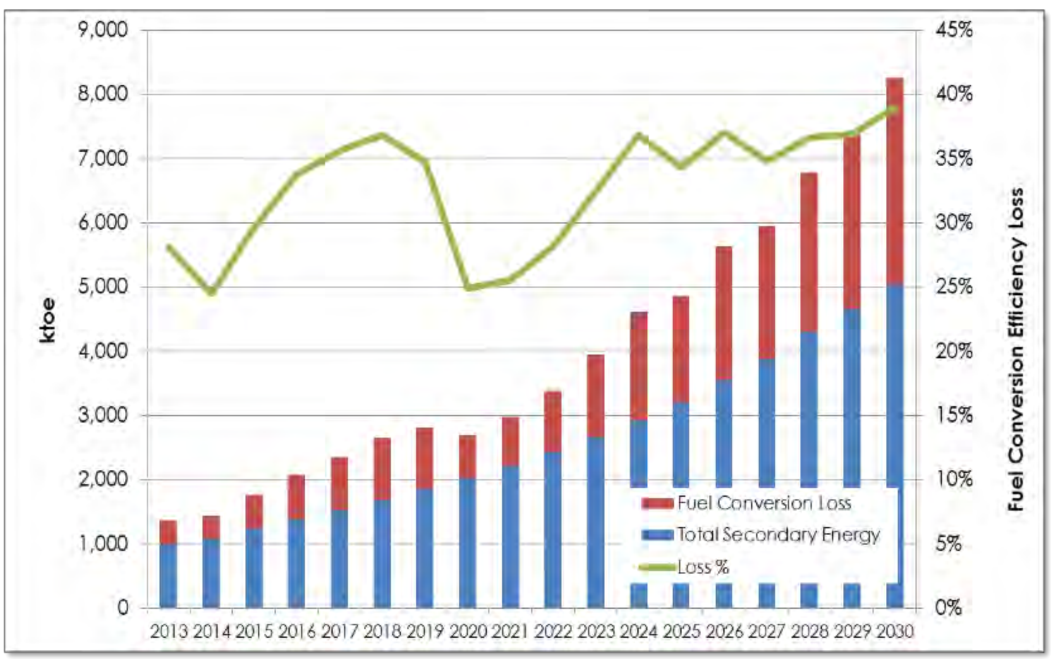
Source: Consultant's analysis

Figure IV-11: ADICA Least-Cost



Source: ADICA 2015

Figure IV-12: ADICA – Energy Conversion Loss



Source: ADICA 2015

82. The preceding charts show that if fossil fuel use and energy efficiency (thermal losses) were considered as the key determinants of an optimal expansion plan then Case 3 would be the optimal expansion due to the large amount of hydropower capacity. The lowest efficiency expansion is Case 4 due to a high dependence on coal. The expansion plan defined by ADICA shows a fuel consumption and energy conversion efficiency falling between Case 3 and Case 4. The ADICA case is stated by ADICA as the least-cost expansion; given current technology costs, there is an evident trade-off between cost and thermal efficiency.

M. Portfolio Analyses (5 Cases)

83. Table IV-2 provides a summary of key performance indicators, for the 5 cases examined by the EMP team. The planning horizon spans from 2015 to 2035; 20 years is the minimum planning horizon considered acceptable for a Present Value comparison given that power plants are long-lived assets. ADICA did not provide an expansion plan to 2035 and cost assumptions differed, and so the ADICA expansion plan was not included in the portfolio analyses.

Table IV-2: Summary of Portfolio Analyses (2015-2035)

	CASE 1 Base	CASE 2 Balanced	CASE 3 Max Hydro	CASE 4 Max Coal	CASE 5 Max Solar PV / Wind
PV ($ billion) - no CO2 costs	19.2	18.5	20.4	19.9	17.8
LCoE (USc/kWh) - no CO2 costs	4.87	4.69	5.17	5.05	4.51
Annual CAPEX ($ million) (*)	1 563	1 394	1 980	1 165	1 569
CO2 (million tons)	167	240	74	444	134
CO2 cost ($ million)	1 440	2 073	632	3 835	1 159
Other pollution ($ million)	136	236	35	476	119
LCoE (USc/kWh) incl. CO2 costs	5.23	5.22	5.33	6.02	5.75

(*) Annual average for 2015-2030

N. Policy-Adjusted Expansion Plan

84. Raw performance scores were determined by a Portfolio Analysis Model (refer Appendix A) for the Financial, Environmental, Diversity and Project Development Risk policy factors. The following table provides a summary of the raw scores:-

Table IV-3: Raw Performance Scores for each Case

Case	Name	CO2, Sox and Nox Emissions Cost (in 2030)	Normalised PV cost of plan	Dependence (% Gas-fired Generation Sent Out on Total in 2030)	Risk factor Associated with Projects
1	Planned Hydro / Coal	680.8	1.149	10.8%	4.43
2	Balanced Hydro / Coal / Solar PV	1089.8	1.051	4.9%	4.61
3	Maximum Hydro	**435.3**	1.329	14.8%	4.33
4	Maximum Coal	1958.3	**1.000**	**0.1%**	**5.14**
5	Maximum Solar PV / Wind	469.5	1.100	7.5%	4.07

Source: Consultant's analysis

85. Partial value functions were used to normalize the raw scores (refer Appendix A for the functions). This step was carried out by normalizing the raw performance scores above across the partial value function range. Table IV-4 provides the normalized scores (with 100 being the best score, and 0 being the worst).

Table IV-4: Partial Value Function Normalized Scores

Case	Name	CO2 Emissions	Cost of Plan	Diversity	Risk Factor
1	Planned Hydro / Coal	94	66	46	96
2	Balanced Hydro / Coal / Solar PV	76	90	90	94
3	Maximum Hydro	100	3	0	97
4	Maximum Coal	0	100	100	82
5	Maximum Solar PV / Wind	98	79	74	100

Source: Consultant's analysis

86. The normalized scores shown in Table IV-4 were weighted by policy weights to produce the final 'policy-weighted value' scores for each case.

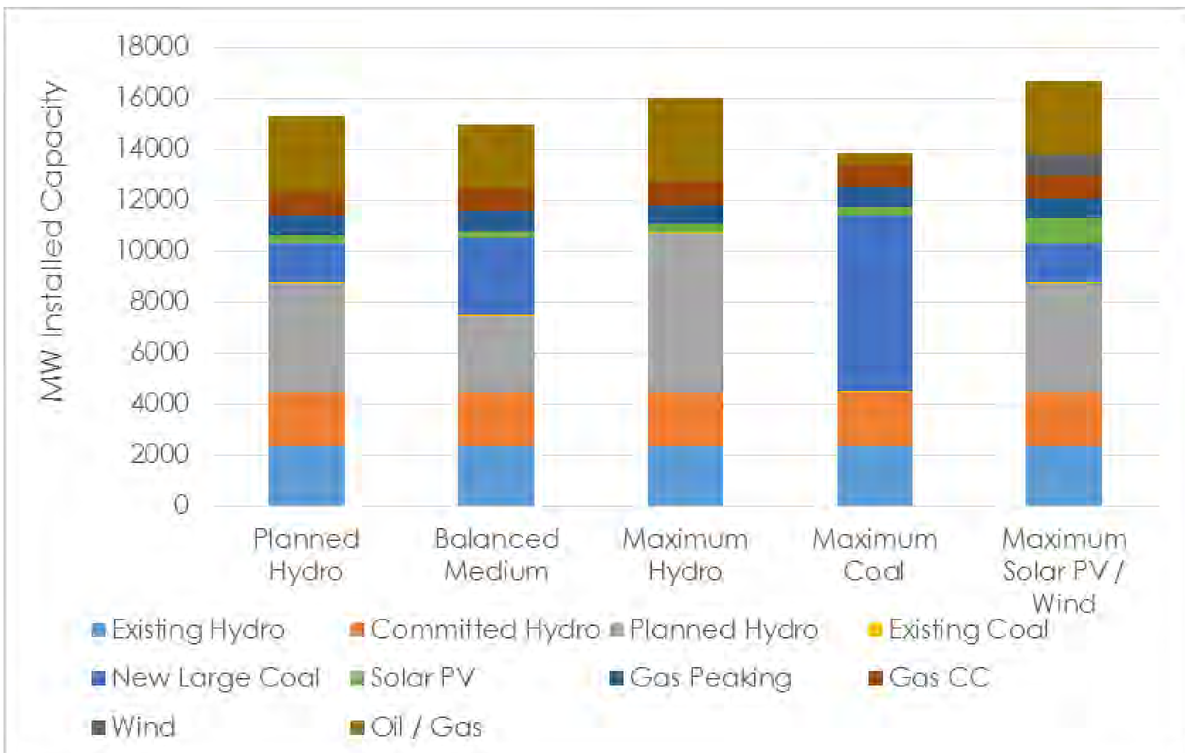
Table IV-5: Final Policy-Weighted Value Scores

Case	Name	CO2	Cost of	Diversity	Risk	Total
1	Planned Hydro / Coal	18.8	33.0	11.4	4.8	68.1
2	Balanced Hydro / Coal /	15.3	45.1	22.4	4.7	**87.5**
3	Maximum Hydro	20.0	2	-	4.9	26.4
4	Maximum Coal	-	50.0	25.0	4.1	79.1
5	Maximum Solar PV /	19.7	39.4	18.5	5.0	82.6
	Policy Weights	20%	50%	25%	5%	

Source: Consultant's analysis

87. Thus, from a multi-criteria decision analysis, when policy considerations are taken into account, it is found that Case 2 – the balanced portfolio is the most attractive option. The capacity mix for each case is shown for year 2030 by Figure IV-13.

Figure IV-13: Installed Capacity by Plan (MW) in 2030



Source: Consultant's analysis

88. Figure IV-15 to Figure IV-34 provide for all Cases, including a high electricity demand Case 2, the optimal fuel mix for the resources deployed, the planting schedule by annual MW, and the cumulative and annual investment requirements. In addition the composition of installed capacity is

given for Case 2 (medium growth) for years 2015, 2020 and 2030. A summary of the planting schedules are given here to 2030 for the medium electricity growth case:-

Table IV-6: Planting Schedule Summary – Case 1

	2020		2025		2030	
	MW	%	MW	%	MW	%
Hydro	4,462	61%	6,811	65%	8,751	57%
Coal	60	1%	60	1%	1,560	10%
Gas	1,670	23%	1,670	16%	1,670	11%
Solar PV / Wind	300	4%	300	3%	300	2%
Oil / Gas	850	12%	1,700	16%	3,000	20%
Total	7,342		10,541		15,281	

Source: Consultant's analysis

Table IV-7: Planting Schedule Summary – Case 2

	2020		2025		2030	
	MW	%	MW	%	MW	%
Hydro	4,462	61%	6,065	60%	7,450	50%
Coal	60	1%	1,260	12%	3,060	20%
Gas	1,670	23%	1,670	16%	1,670	11%
Solar PV / Wind	300	4%	300	3%	300	2%
Oil / Gas	850	12%	850	8%	2,500	17%
Total	7,342		10,145		14,980	

Source: Consultant's analysis

Table IV-8: Planting Schedule Summary – Case 3

	2020		2025		2030	
	MW	%	MW	%	MW	%
Hydro	4,462	61%	5,990	60%	10,691	67%
Coal	60	1%	60	1%	60	0%
Gas	1,670	23%	1,670	17%	1,670	10%
Solar PV / Wind	300	4%	300	3%	300	2%
Oil / Gas	850	12%	2,000	20%	3,300	21%
Total	7,342		10,020		16,021	

Source: Consultant's analysis

Table IV-9: Planting Schedule Summary – Case 4

	2020		2025		2030	
	MW	%	MW	%	MW	%
Hydro	4,462	66%	4,462	47%	4,462	32%
Coal	60	1%	2,760	29%	6,960	50%
Gas	1,670	25%	1,670	18%	1,670	12%
Solar PV / Wind	300	4%	300	3%	300	2%
Oil / Gas	300	4%	350	4%	450	3%
Total	6,792		9,542		13,842	

Source: Consultant's analysis

Table IV-10: Planting Schedule Summary – Case 5

	2020		2025		2030	
	MW	%	MW	%	MW	%
Hydro	4,462	64%	6,811	59%	8,751	52%
Coal	60	1%	60	1%	1,560	9%
Gas	1,670	24%	1,670	14%	1,670	10%
Solar PV / Wind	450	6%	1,600	14%	1,800	11%
Oil / Gas	300	4%	1,400	12%	2,900	17%
Total	6,942		11,541		16,681	

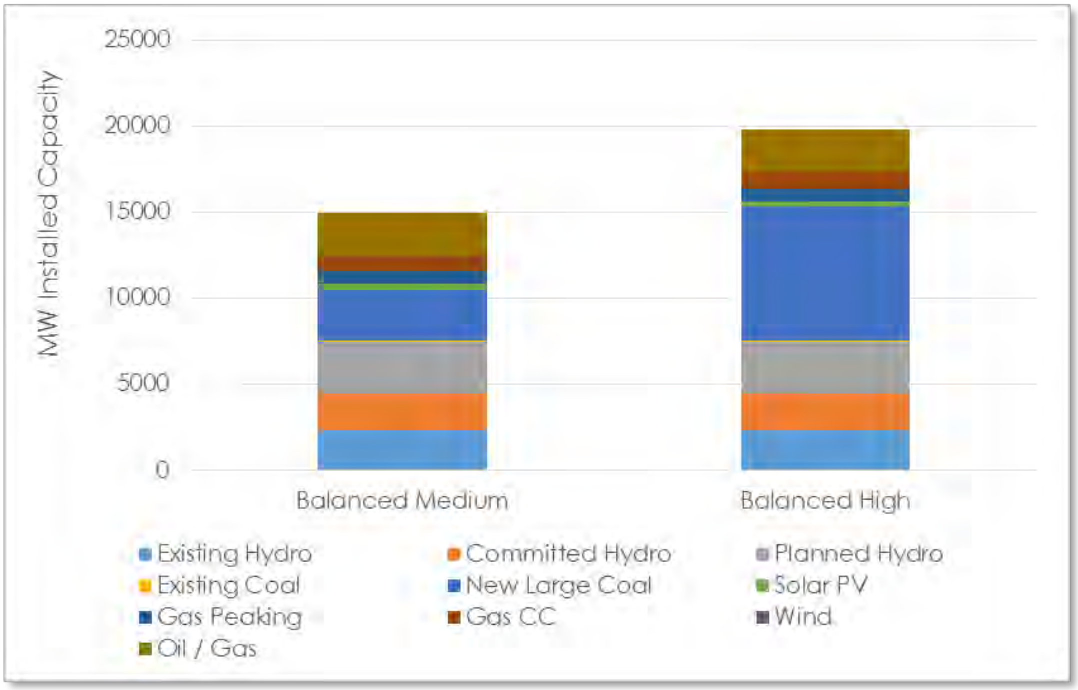
Source: Consultant's analysis

O. Long-Run Marginal Cost

89. Case 2 was run against a high electricity growth scenario wherein the electricity growth was that provided in the Consolidated Demand Forecasts report of this EMP. Figure IV-14 shows a comparison between the installed capacity in 2030 for the medium growth and high growth cases.

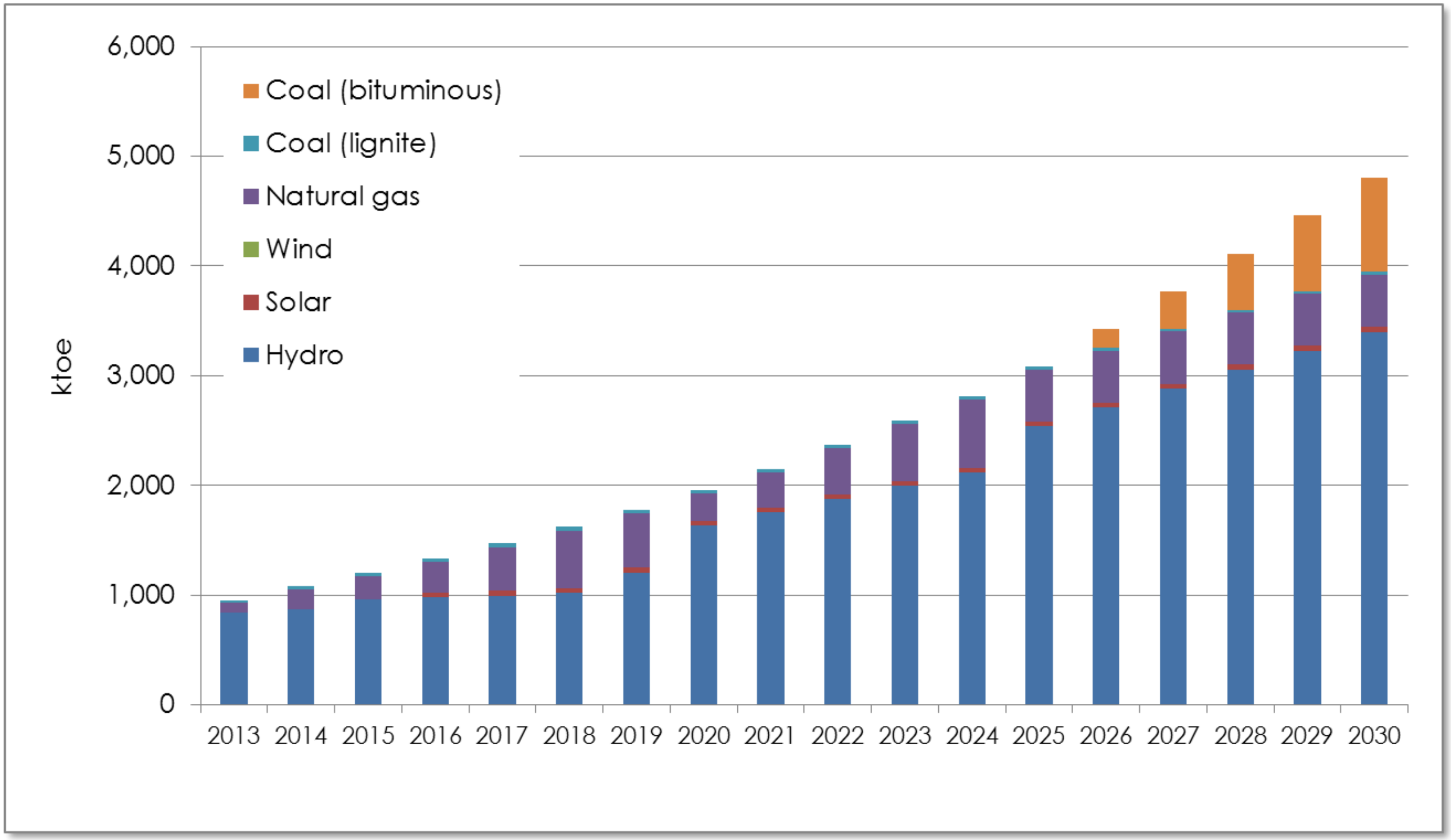
90. Using Case 2 as the basis for computation, comparing the incremental investment and capacity needs for the medium- and high-growth Case 2, the long-run marginal cost (2015 to 2030) is computed to be $ 1 200 per kW. If the out-turn growth was in line with the high growth case, the total additional Capex from 2015 to 2030 would be $ 6 B (real terms) or $ 400 M per annum.

Figure IV-14: Installed Capacity for Case 2 Medium & High Growth (MW) in 2030



Source: Consultant's analysis

Figure IV-15: Long-Term Fuel Mix – Case 1 (Planned Hydro / Coal)[7]



[7] Source of Figures IV-15 to IV-34, and Tables IV-11 to IV-16 is: Consultant's Analysis.

Table IV-11: Long-Term Expansion – Case 1 (Planned Hydro / Coal)

		Group 1	Group 2	Group 3	Group 4	Group 7	Group 8	Group 9	Group 10	Group 11	Group 12
	Installed Capacity	Existing Hydro	Committed Hydro	Planned Hydro	Existing Coal	New Large Thermal	Solar PV	Existing Gas Peaking	Existing Gas CC	Wind	Reserve & Peaking
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2013	3083	2144			60			229	300		350
2014	3499	2319			60			303	767		50
2015	3881	2319	232		60			303	767		200
2016	4481	2319	232		60		300	503	767		300
2017	4781	2319	232		60		300	503	767		600
2018	5182	2319	283		60		300	703	767		750
2019	5773	2319	774		60		300	703	767		850
2020	6942	2319	2143		60		300	903	767		850
2021	7486	2319	2143	244	60		300	903	767		600
2022	8371	2319	2143	729	60		300	903	767		967
2023	9291	2319	2143	1049	60		300	903	767		1333
2024	10091	2319	2143	1049	60		300	903	767		1700
2025	11541	2319	2143	2349	60		300	903	767		1700
2026	12449	2319	2143	2737	60	180	300	903	767		1960
2027	13357	2319	2143	3125	60	360	300	903	767		2220
2028	14265	2319	2143	3513	60	540	300	903	767		2480
2029	15173	2319	2143	3901	60	720	300	903	767		2740
2030	16681	2319	2143	4289	60	1500	300	903	767		3000

Figure IV-16: Cumulative Investment Profile – Case 1 (Planned Hydro / Coal)

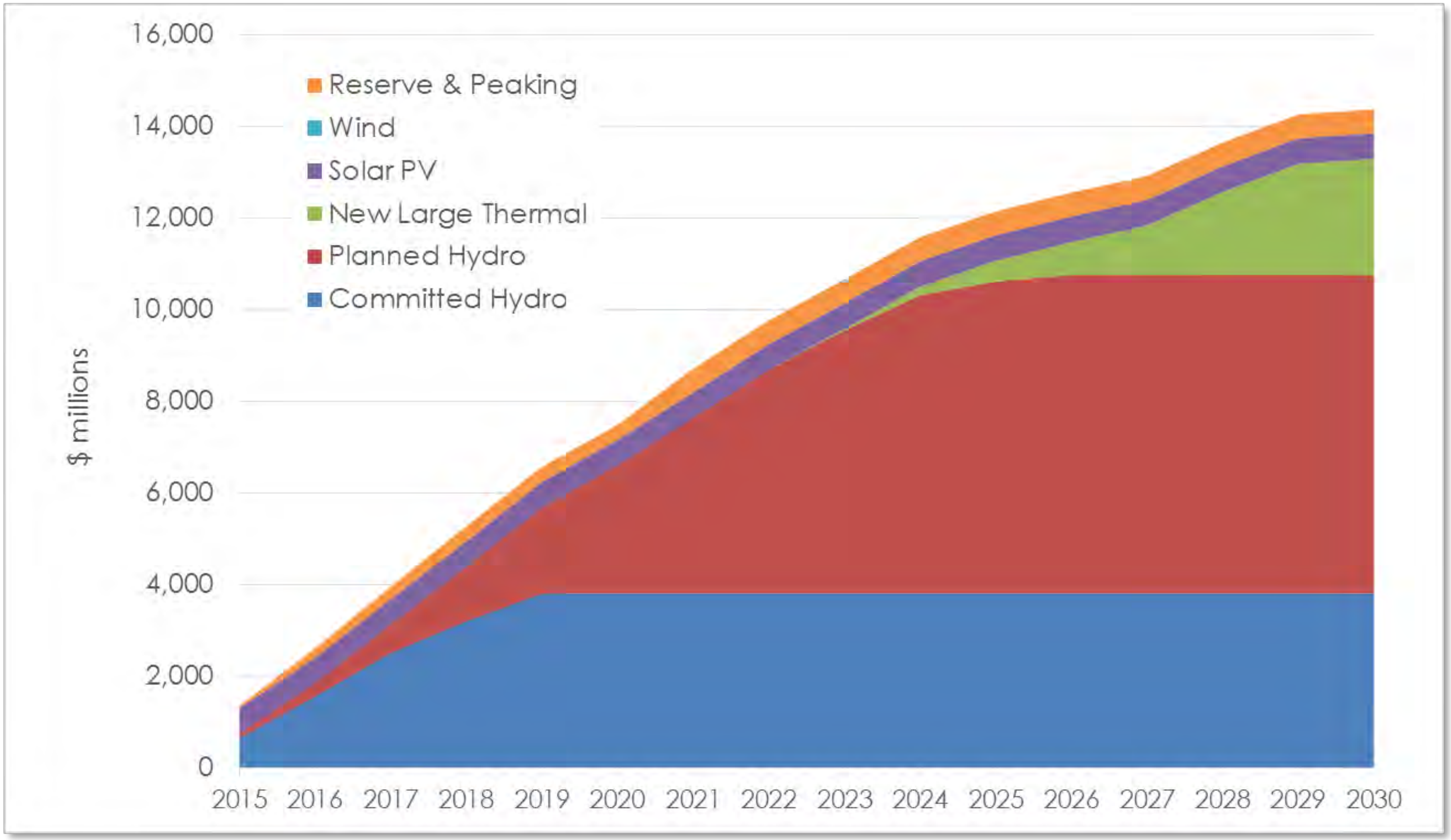


Figure IV-17: Annual Investment Profile – Case 1 (Planned Hydro / Coal)

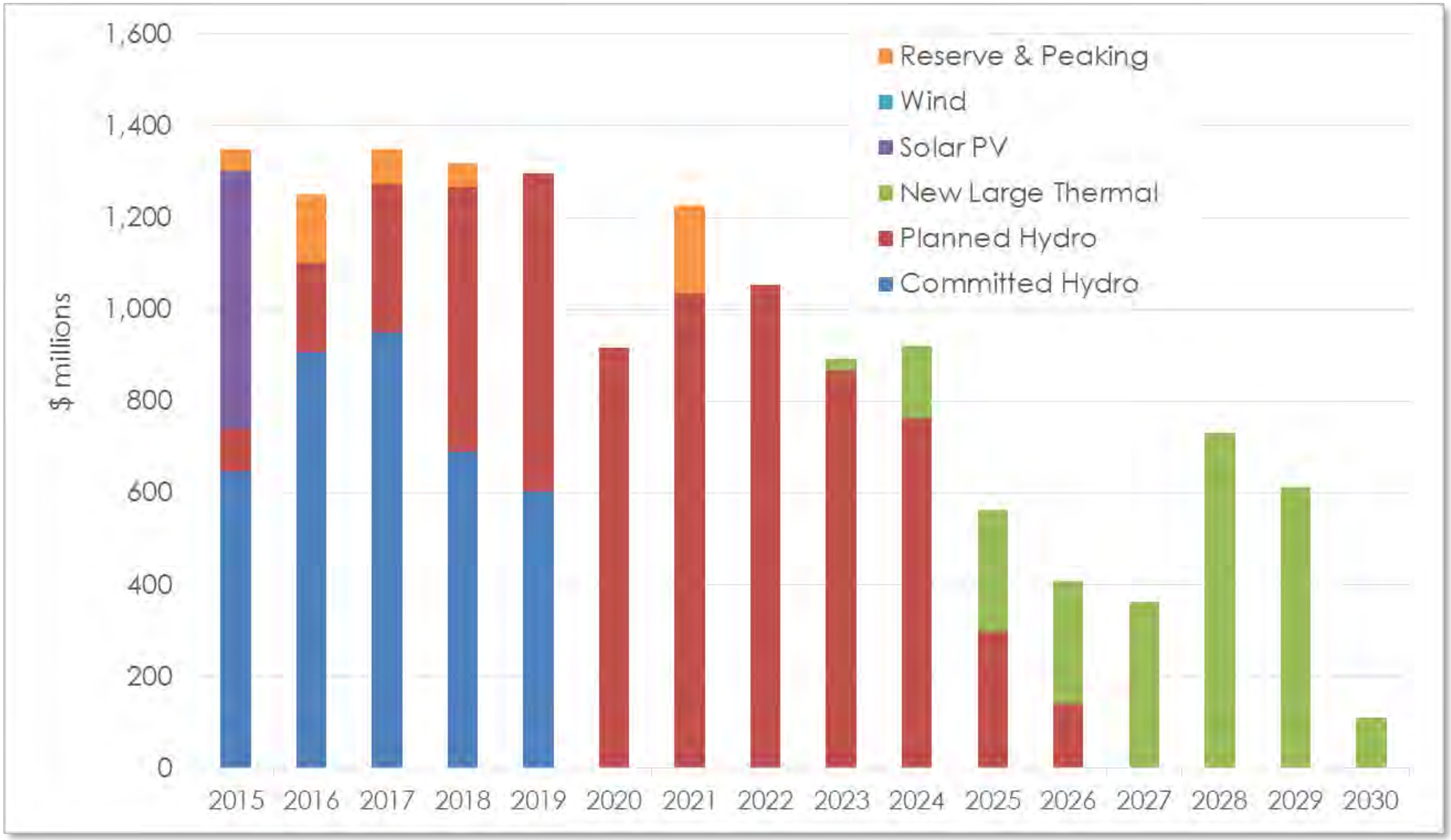


Figure IV-18: OPTIMAL Long-Term Fuel Mix – Case 2 (Balanced Hydro / Coal / Solar PV)

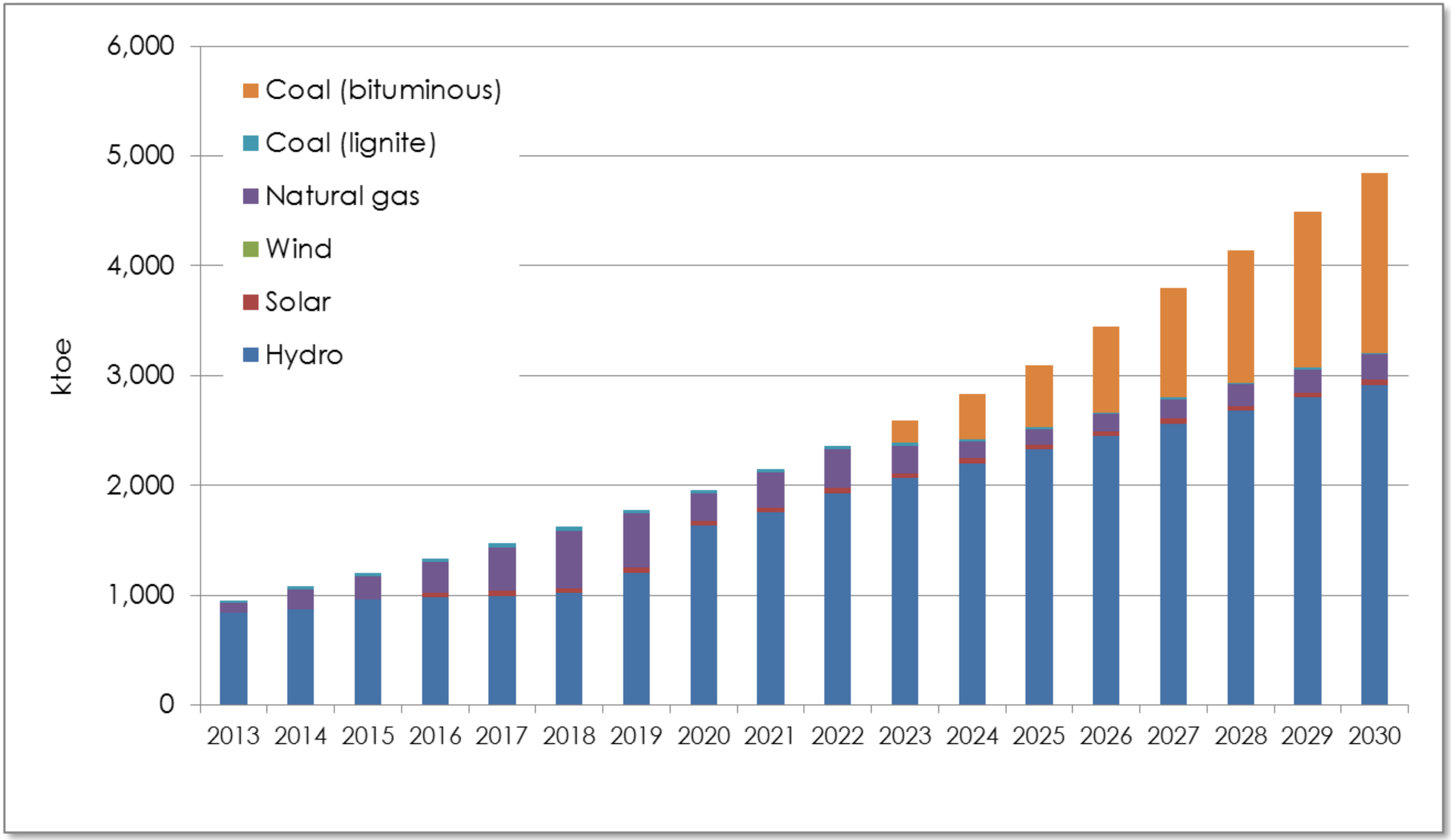


Table IV-12: OPTIMAL Long-Term Expansion – Case 2 (Balanced Hydro / Coal / Solar PV)

		Group 1	Group 2	Group 3	Group 4	Group 7	Group 8	Group 9	Group 10	Group 11	Group 12
	Installed Capacity	Existing Hydro	Committed Hydro	Planned Hydro	Existing Coal	New Large Thermal	Solar PV	Existing Gas Peaking	Existing Gas CC	Wind	Reserve & Peaking
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2013	3083	2144			60			229	300		*350*
2014	3499	2319			60			303	767		50
2015	3881	2319	232		60			303	767		200
2016	4481	2319	232		60		300	503	767		300
2017	4781	2319	232		60		300	503	767		600
2018	5182	2319	283		60		300	703	767		750
2019	5773	2319	774		60		300	703	767		850
2020	7342	2319	2143		60		300	903	767		850
2021	7586	2319	2143	244	60		300	903	767		850
2022	8071	2319	2143	729	60		300	903	767		850
2023	8631	2319	2143	1049	60	240	300	903	767		850
2024	9568	2319	2143	1326	60	900	300	903	767		850
2025	10145	2319	2143	1603	60	1200	300	903	767		850
2026	10752	2319	2143	1880	60	1200	300	903	767		1180
2027	11359	2319	2143	2157	60	1200	300	903	767		1510
2028	11966	2319	2143	2434	60	1200	300	903	767		1840
2029	12573	2319	2143	2711	60	1200	300	903	767		2170
2030	14980	2319	2143	2988	60	3000	300	903	767		2500

Figure IV-19: Installed Capacity 2015 – Case 2

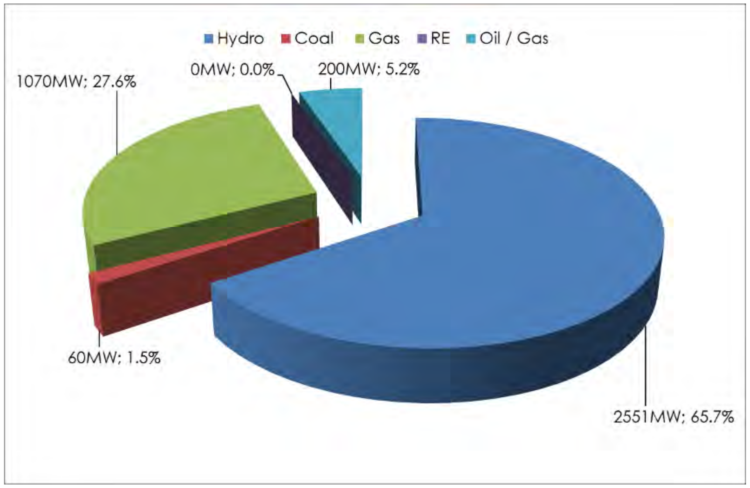


Figure IV-20: Installed Capacity 2020 – Case 2

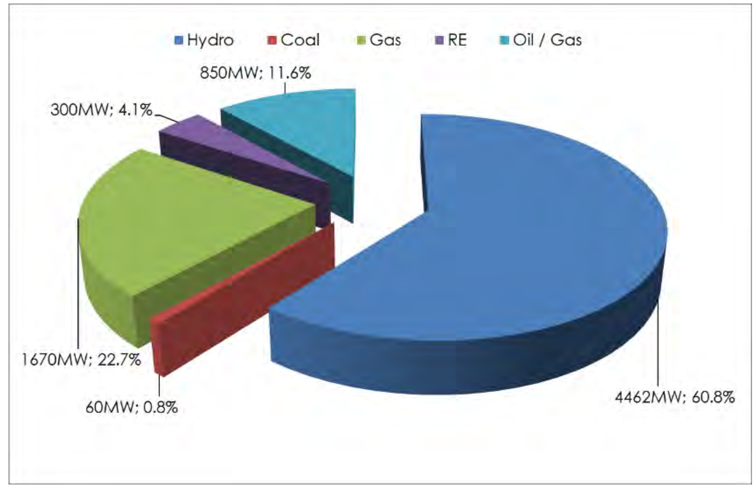


Figure IV-21: Installed Capacity 2030 – Case 2

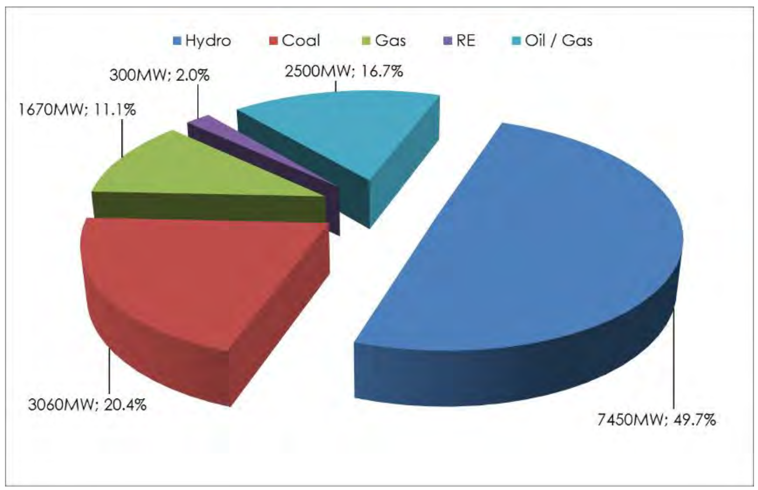


Figure IV-22: Cumulative Investment Profile – Case 2 (Balanced Hydro / Coal / Solar PV)

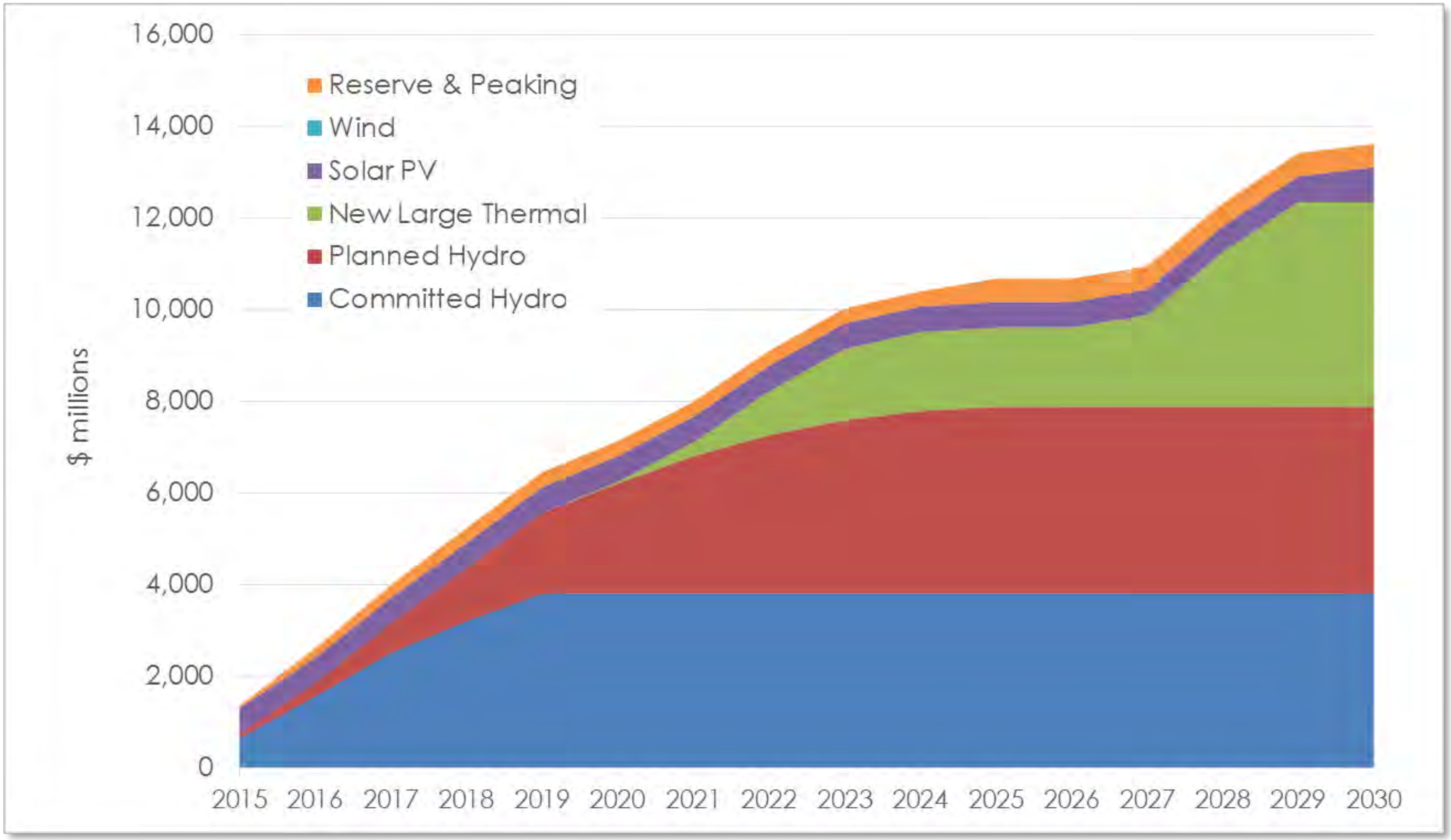


Figure IV-23: Annual Investment Profile – Case 2 (Balanced Hydro / Coal / Solar PV)

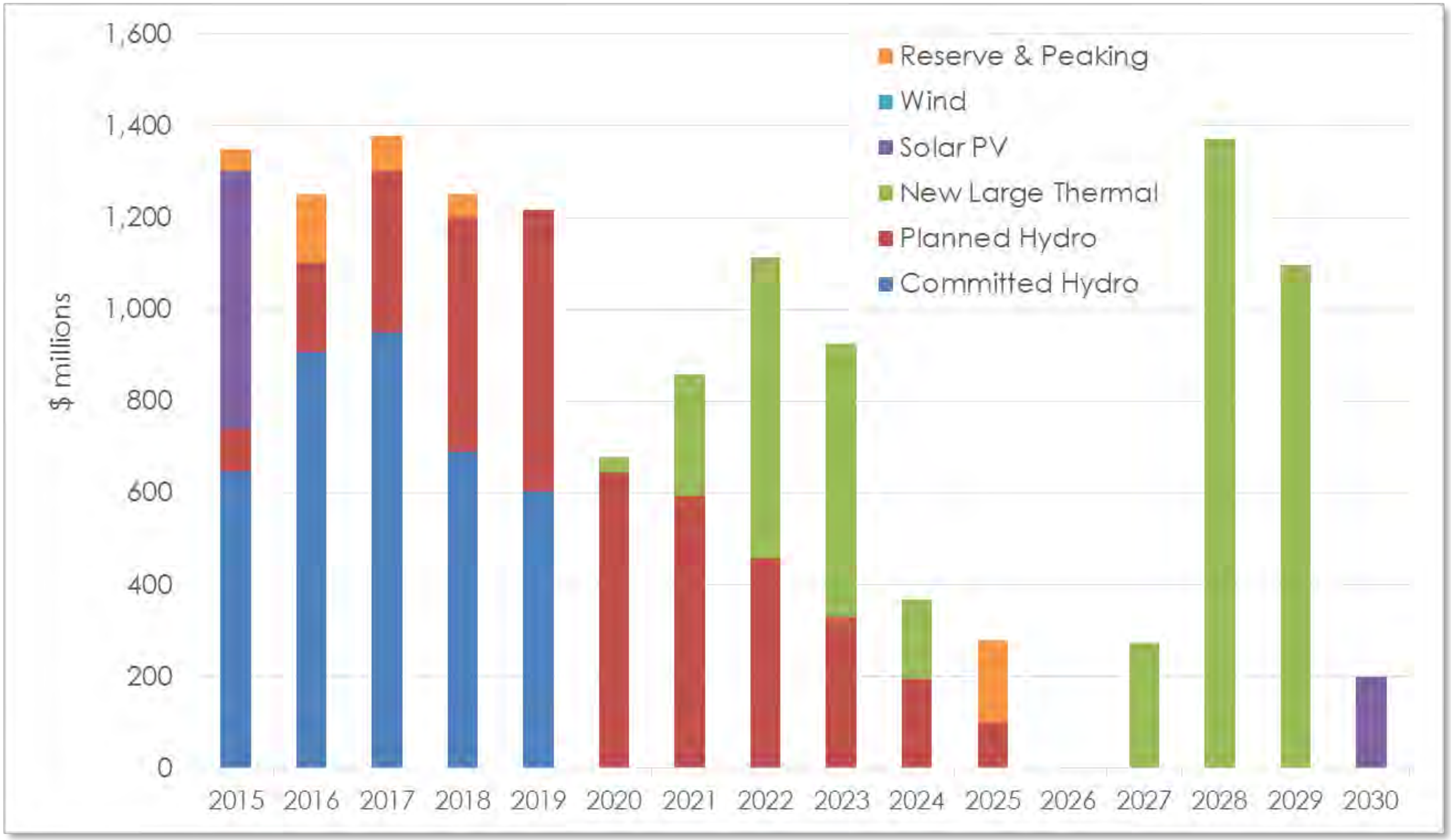


Figure IV-24: Long-Term Fuel Mix – Case 3 (Max Hydro)

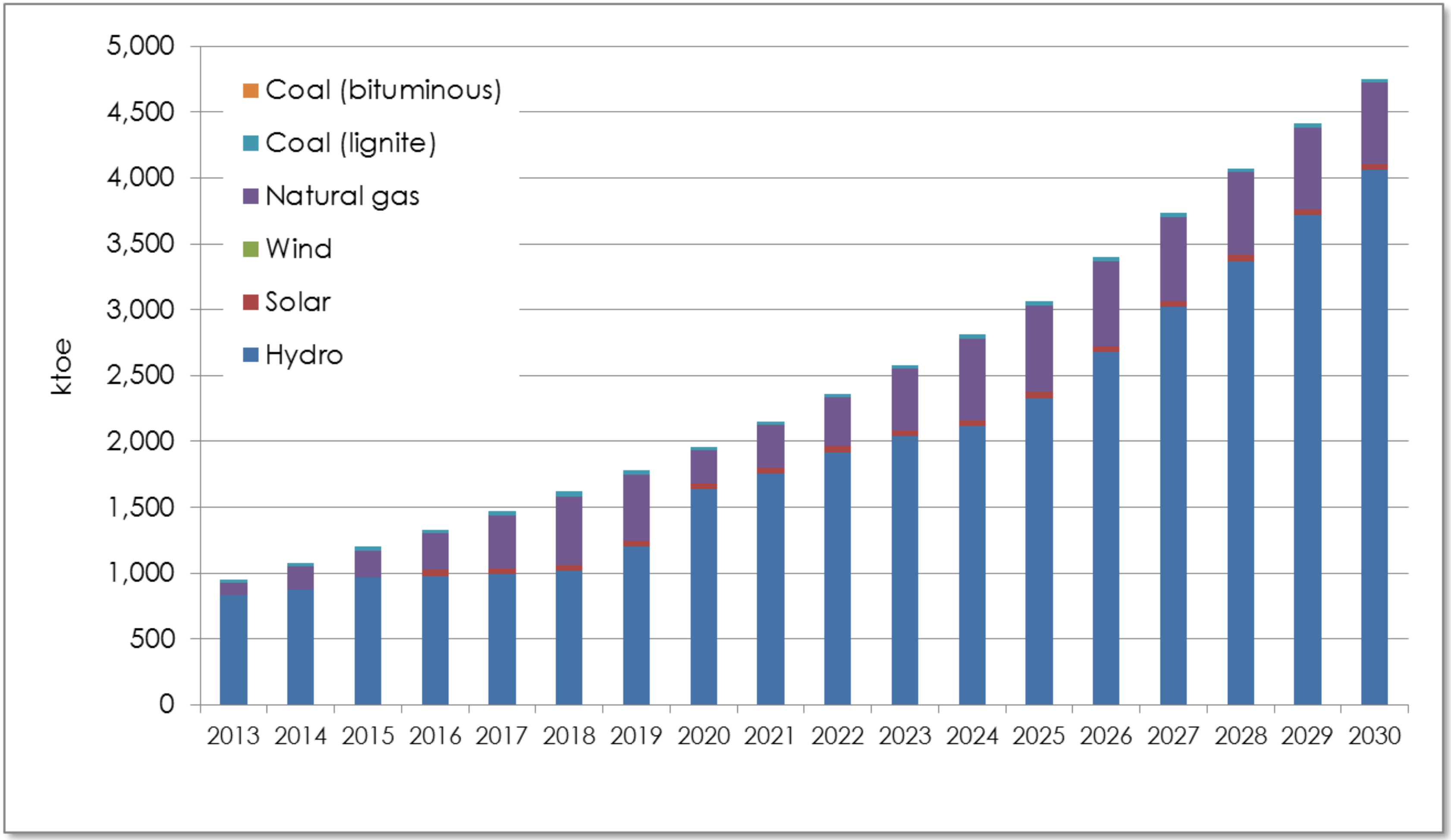


Table IV-13: Long-Term Expansion – Case 3 (Max Hydro)

		Group 1	Group 2	Group 3	Group 4	Group 7	Group 8	Group 9	Group 10	Group 11	Group 12
	Installed Capacity	Existing Hydro	Committed Hydro	Planned Hydro	Existing Coal	New Large Thermal	Solar PV	Existing Gas Peaking	Existing Gas CC	Wind	Reserve & Peaking
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2013	3083	2144			60			229	300		*350*
2014	3499	2319			60			303	767		50
2015	3881	2319	232		60			303	767		200
2016	4481	2319	232		60		300	503	767		300
2017	4781	2319	232		60		300	503	767		600
2018	5182	2319	283		60		300	703	767		750
2019	5773	2319	774		60		300	703	767		850
2020	7342	2319	2143		60		300	903	767		850
2021	7325	2319	2143	233	60		300	903	767		600
2022	7943	2319	2143	651	60		300	903	767		800
2023	8568	2319	2143	826	60		300	903	767		1250
2024	9192	2319	2143	1000	60		300	903	767		1700
2025	10020	2319	2143	1528	60		300	903	767		2000
2026	11220	2319	2143	2468	60		300	903	767		2260
2027	12420	2319	2143	3408	60		300	903	767		2520
2028	13621	2319	2143	4349	60		300	903	767		2780
2029	14821	2319	2143	5289	60		300	903	767		3040
2030	16021	2319	2143	6229	60		300	903	767		3300

Figure IV-25: Cumulative Investment Profile – Case 3 (Max Hydro)

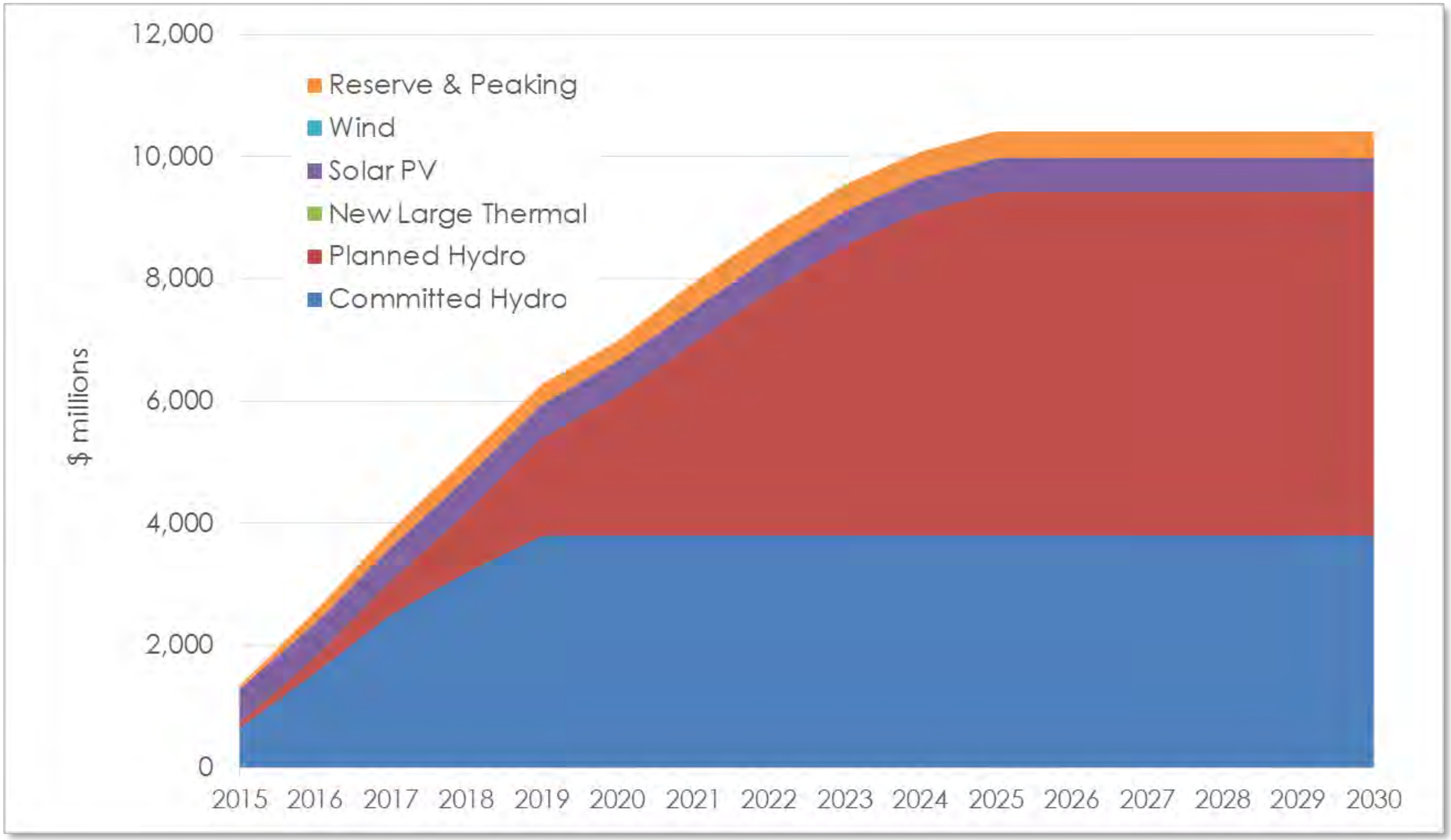


Figure IV-26: Annual Investment Profile – Case 3 (Max Hydro)

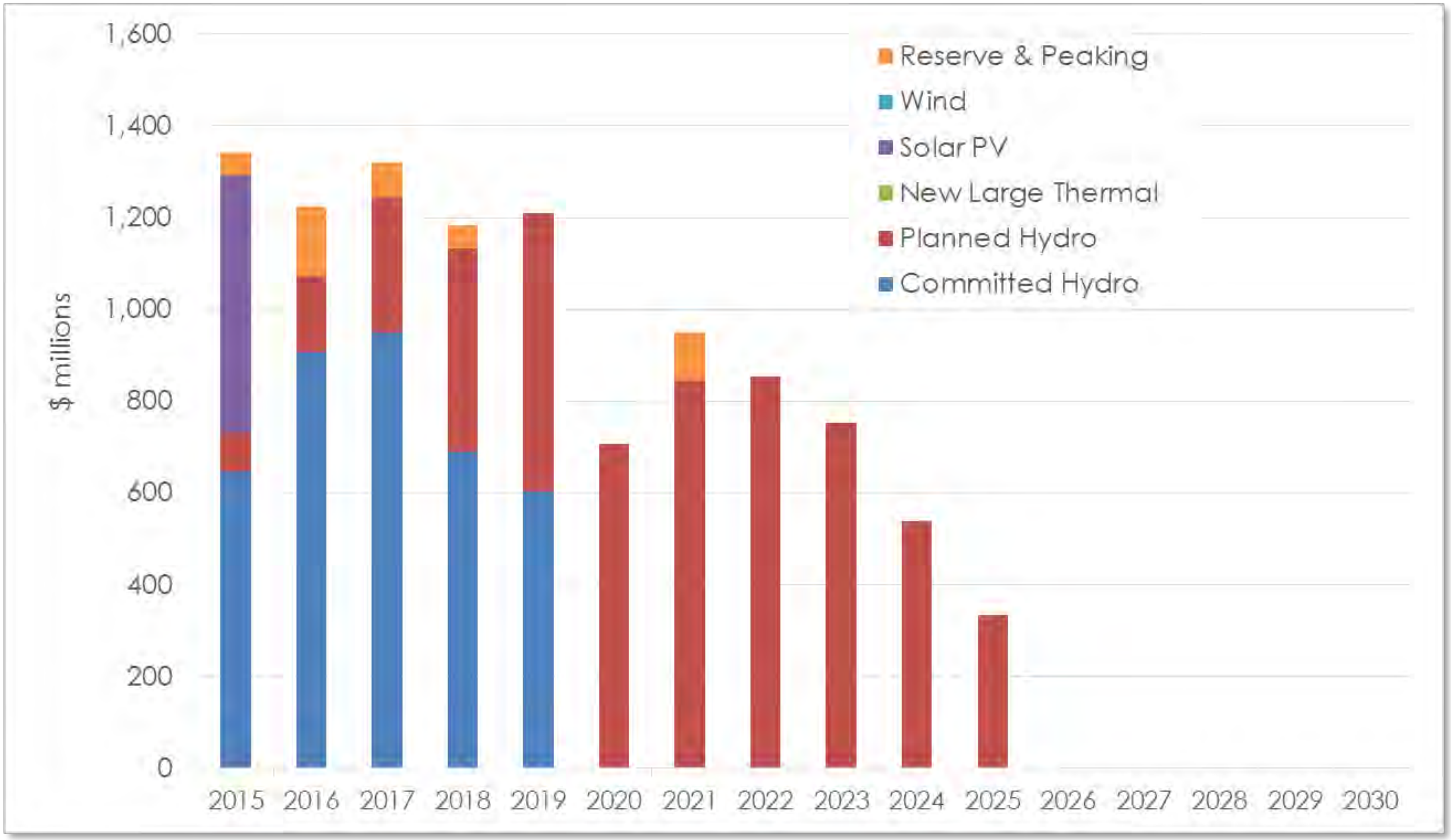


Figure IV-27: Long-Term Fuel Mix – Case 4 (Max Coal)

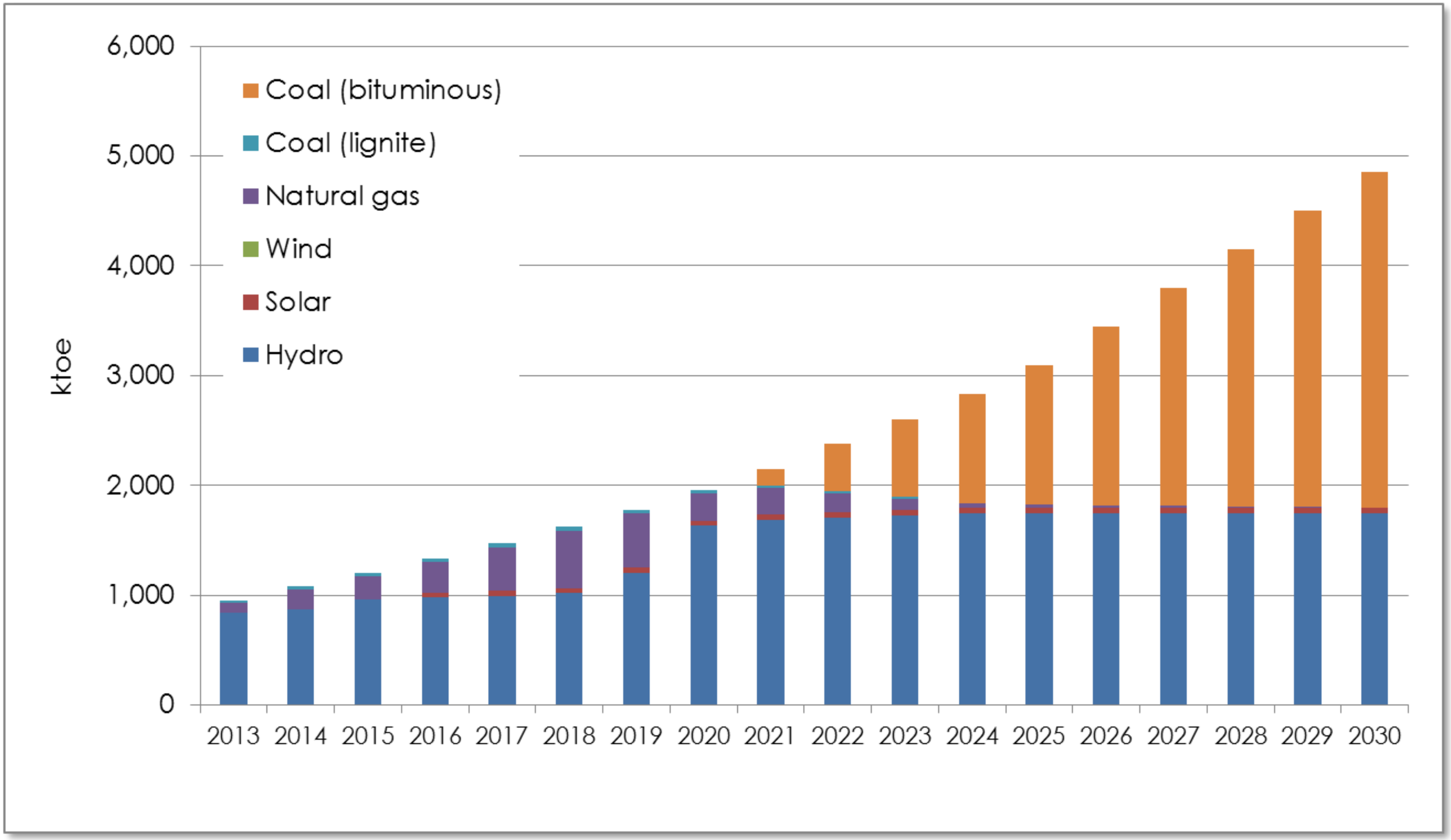


Table IV-14: Long-Term Expansion – Case 4 (Max Coal)

		Group 1	Group 2	Group 3	Group 4	Group 7	Group 8	Group 9	Group 10	Group 11	Group 12
	Installed Capacity	Existing Hydro	Committed Hydro	Planned Hydro	Existing Coal	New Large Thermal	Solar PV	Existing Gas Peaking	Existing Gas CC	Wind	Reserve & Peaking
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2013	3083	2144			60			229	300		*350*
2014	3499	2319			60			303	767		50
2015	3881	2319	232		60			303	767		200
2016	4481	2319	232		60		300	503	767		300
2017	4781	2319	232		60		300	503	767		600
2018	5182	2319	283		60		300	703	767		750
2019	5773	2319	774		60		300	703	767		850
2020	6792	2319	2143		60		300	903	767		300
2021	7242	2319	2143		60	300	300	903	767		450
2022	7732	2319	2143		60	840	300	903	767		400
2023	8222	2319	2143		60	1380	300	903	767		350
2024	8892	2319	2143		60	2100	300	903	767		300
2025	9542	2319	2143		60	2700	300	903	767		350
2026	10342	2319	2143		60	3480	300	903	767		370
2027	11142	2319	2143		60	4260	300	903	767		390
2028	11942	2319	2143		60	5040	300	903	767		410
2029	12742	2319	2143		60	5820	300	903	767		430
2030	13842	2319	2143		60	6900	300	903	767		450

Figure IV-28: Cumulative Investment Profile – Case 4 (Max Coal)

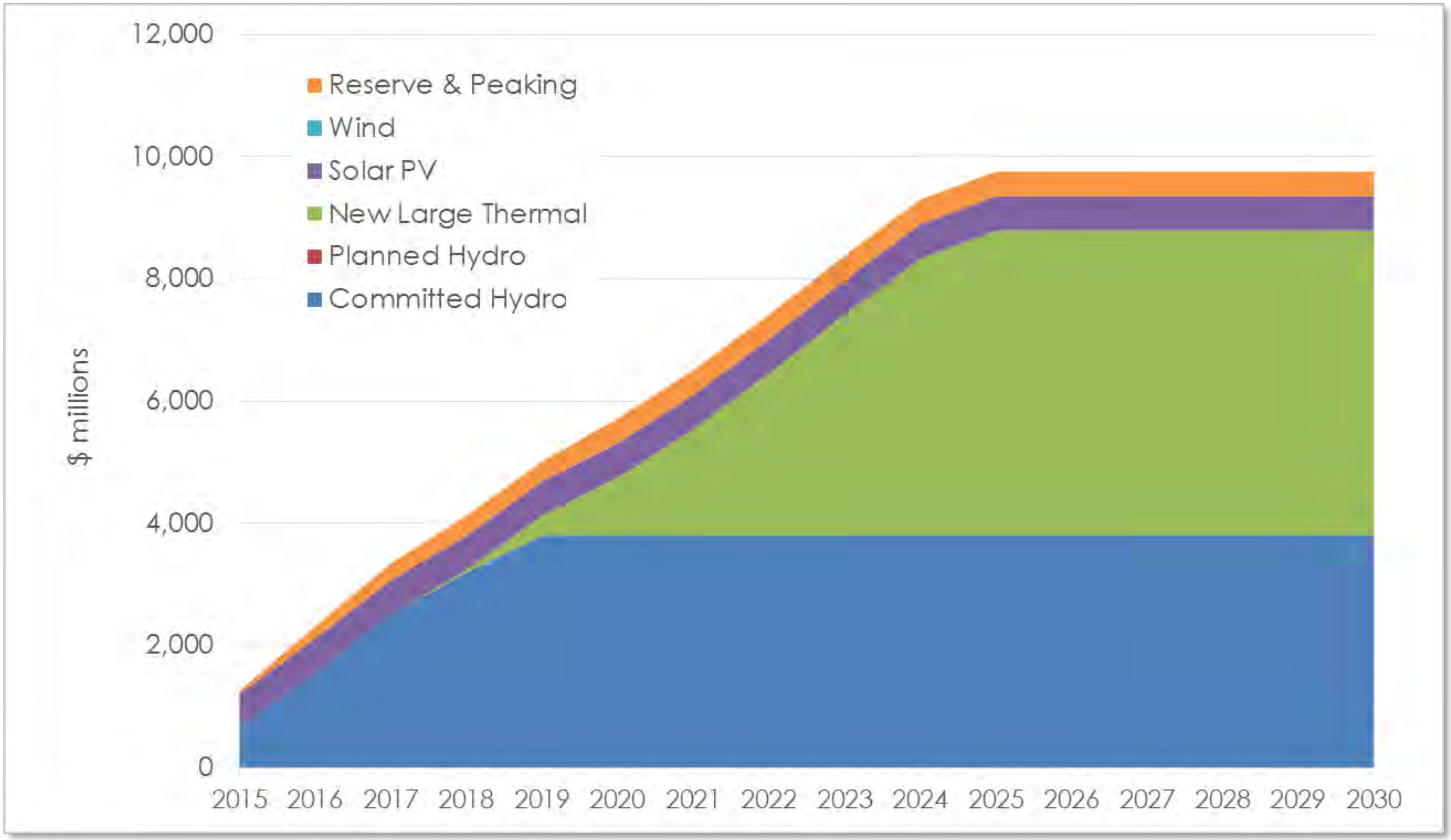


Figure IV-29: Annual Investment Profile – Case 4 (Max Coal)

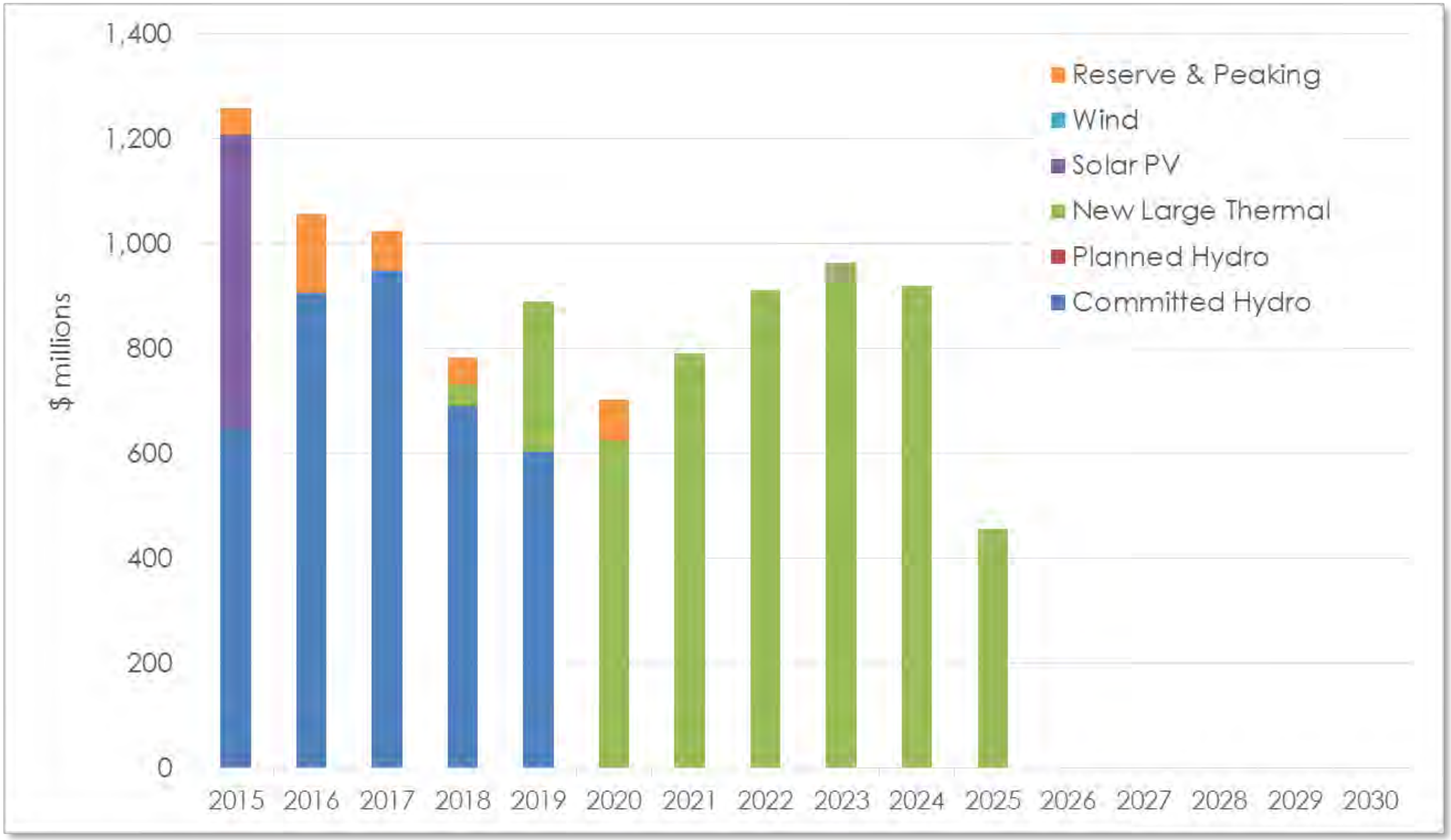


Figure IV-30: Long-Term Fuel Mix – Case 5 (Max Solar PV / Wind)

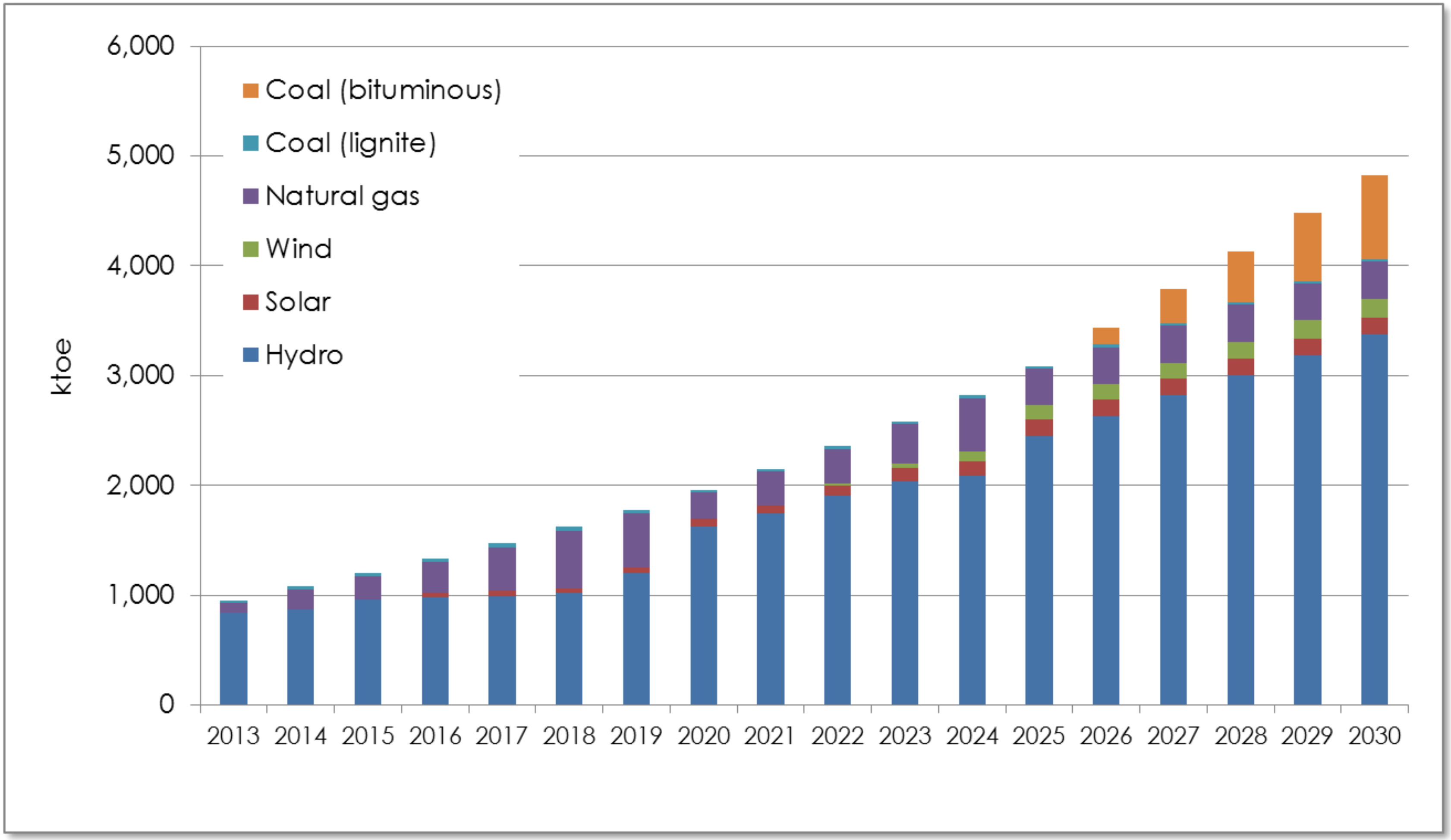


Table IV-15: Long-Term Expansion – Case 5 (Max Solar PV / Wind)

		Group 1	Group 2	Group 3	Group 4	Group 7	Group 8	Group 9	Group 10	Group 11	Group 12
	Installed Capacity	Existing Hydro	Committed Hydro	Planned Hydro	Existing Coal	New Large Thermal	Solar PV	Existing Gas Peaking	Existing Gas CC	Wind	Reserve & Peaking
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2013	3083	2144			60			229	300		*350*
2014	3499	2319			60			303	767		50
2015	3881	2319	232		60			303	767		200
2016	4481	2319	232		60		300	503	767		300
2017	4781	2319	232		60		300	503	767		600
2018	5182	2319	283		60		300	703	767		750
2019	5773	2319	774		60		300	703	767		850
2020	6942	2319	2143		60		450	903	767		300
2021	7486	2319	2143	244	60		450	903	767		600
2022	8371	2319	2143	729	60		600	903	767	100	750
2023	9291	2319	2143	1049	60		800	903	767	200	1050
2024	10091	2319	2143	1049	60		900	903	767	400	1550
2025	11541	2319	2143	2349	60		1000	903	767	600	1400
2026	12449	2319	2143	2737	60	180	1000	903	767	640	1700
2027	13357	2319	2143	3125	60	360	1000	903	767	680	2000
2028	14265	2319	2143	3513	60	540	1000	903	767	720	2300
2029	15173	2319	2143	3901	60	720	1000	903	767	760	2600
2030	16681	2319	2143	4289	60	1500	1000	903	767	800	2900

Figure IV-31: Cumulative Investment Profile – Case 5 (Max Solar PV / Wind)

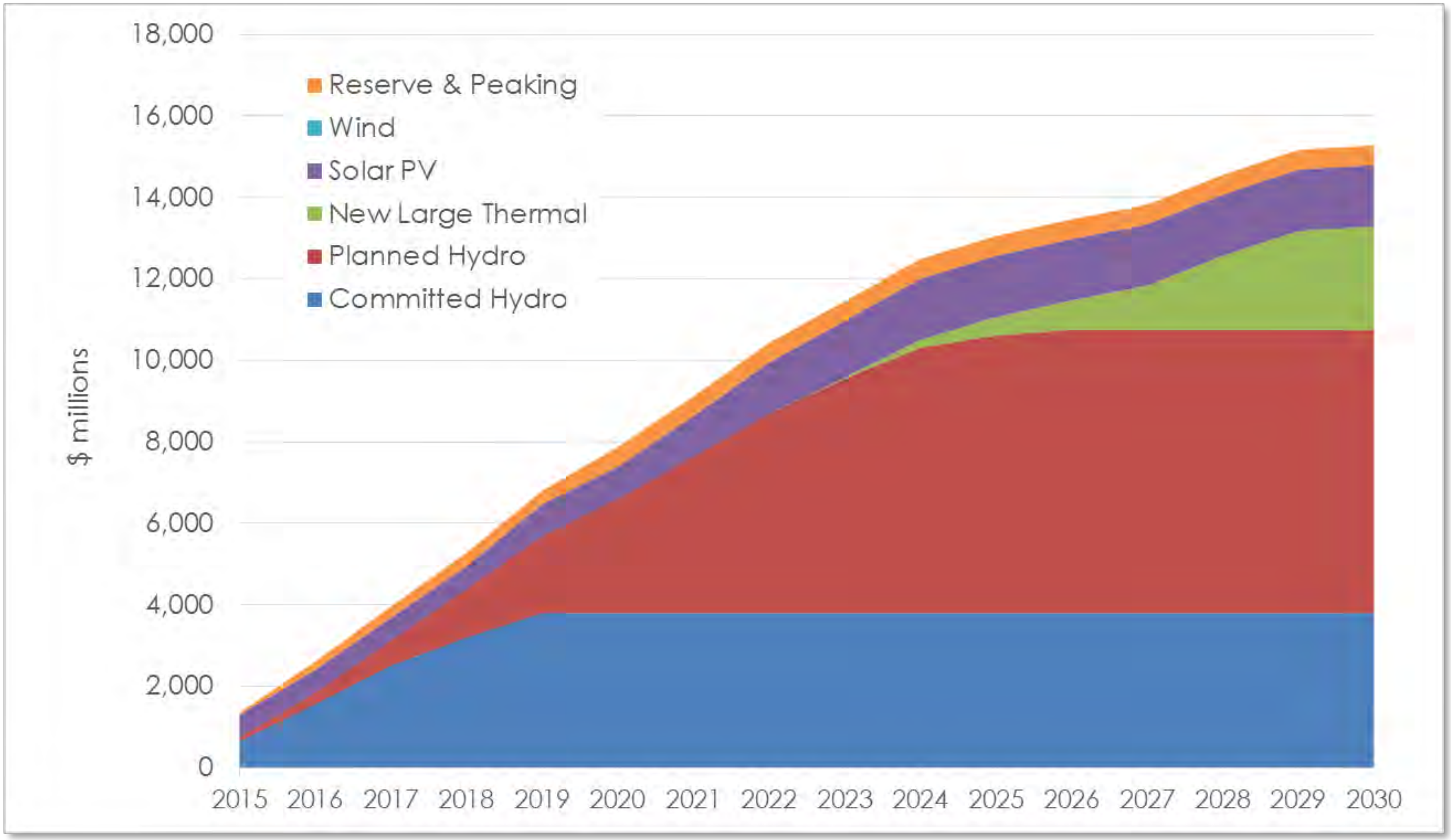


Figure IV-32: Annual Investment Profile – Case 5 (Max Solar PV / Wind)

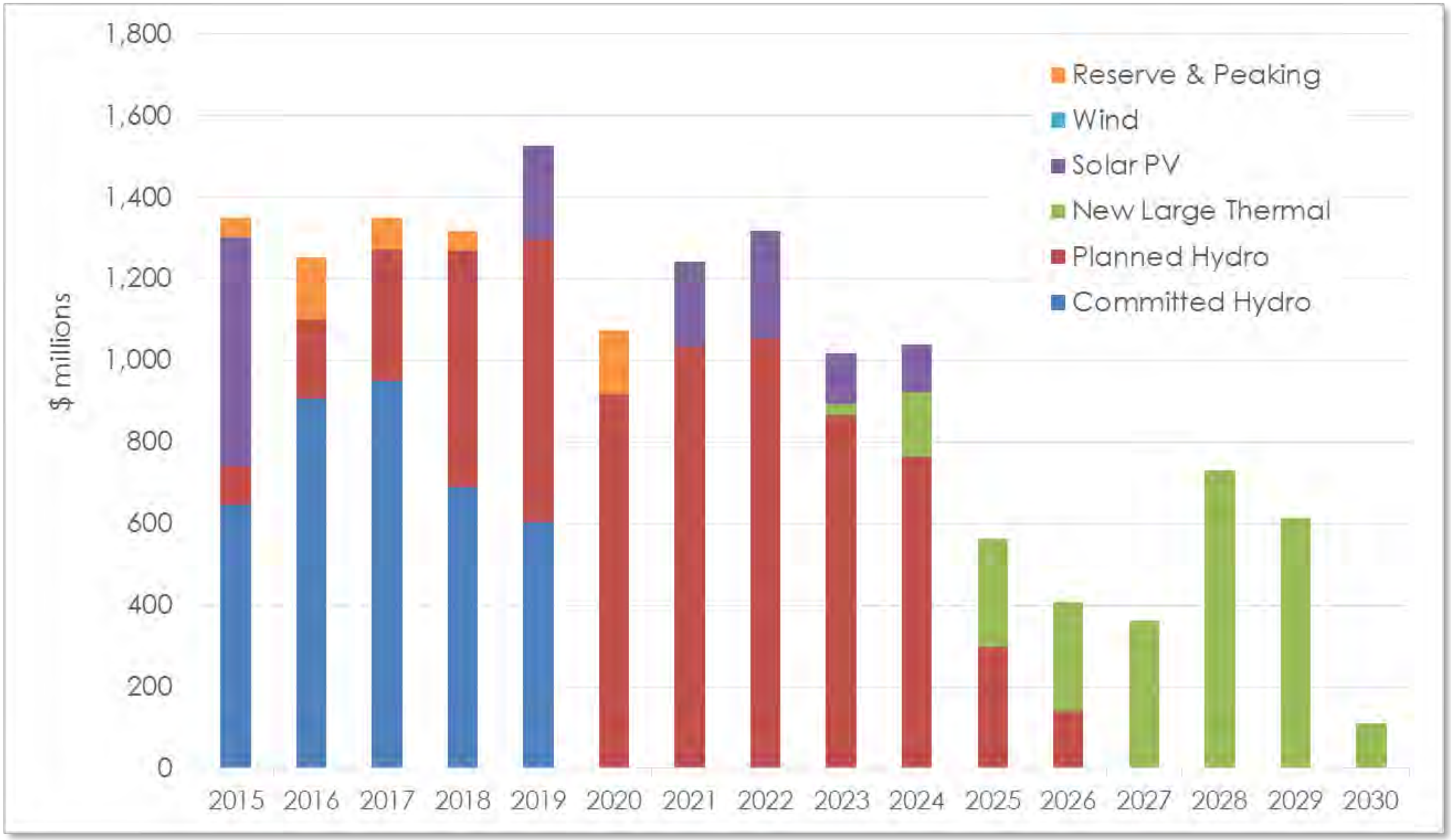


Table IV-16: Long-Term Expansion – Case 2 HIGH GROWTH

		Group 1	Group 2	Group 3	Group 4	Group 7	Group 8	Group 9	Group 10	Group 11	Group 12
	Installed Capacity	Existing Hydro	Committed Hydro	Planned Hydro	Existing Coal	New Large Thermal	Solar PV	Existing Gas Peaking	Existing Gas CC	Wind	Reserve & Peaking
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2013	3083	2144			60	0	0	229	300		*350*
2014	3499	2319			60	0	0	303	767		50
2015	3931	2319	232		60	0	0	303	767		250
2016	4581	2319	232		60	0	300	503	767		400
2017	4931	2319	232		60	0	300	503	767		750
2018	5382	2319	283		60	0	300	703	767		950
2019	6123	2319	774		60	0	300	703	767		1200
2020	7342	2319	2143		60	0	300	903	767		850
2021	8036	2319	2143	244	60	450	300	903	767		850
2022	8971	2319	2143	729	60	900	300	903	767		850
2023	9951	2319	2143	1049	60	1560	300	903	767		850
2024	11068	2319	2143	1326	60	2400	300	903	767		850
2025	12245	2319	2143	1603	60	3300	300	903	767		850
2026	13812	2319	2143	1880	60	4260	300	903	767		1180
2027	15379	2319	2143	2157	60	5220	300	903	767		1510
2028	16946	2319	2143	2434	60	6180	300	903	767		1840
2029	18513	2319	2143	2711	60	7140	300	903	767		2170
2030	19780	2319	2143	2988	60	7800	300	903	767		2500

Figure IV-33: Cumulative Investment Profile – Case 2 HIGH GROWTH

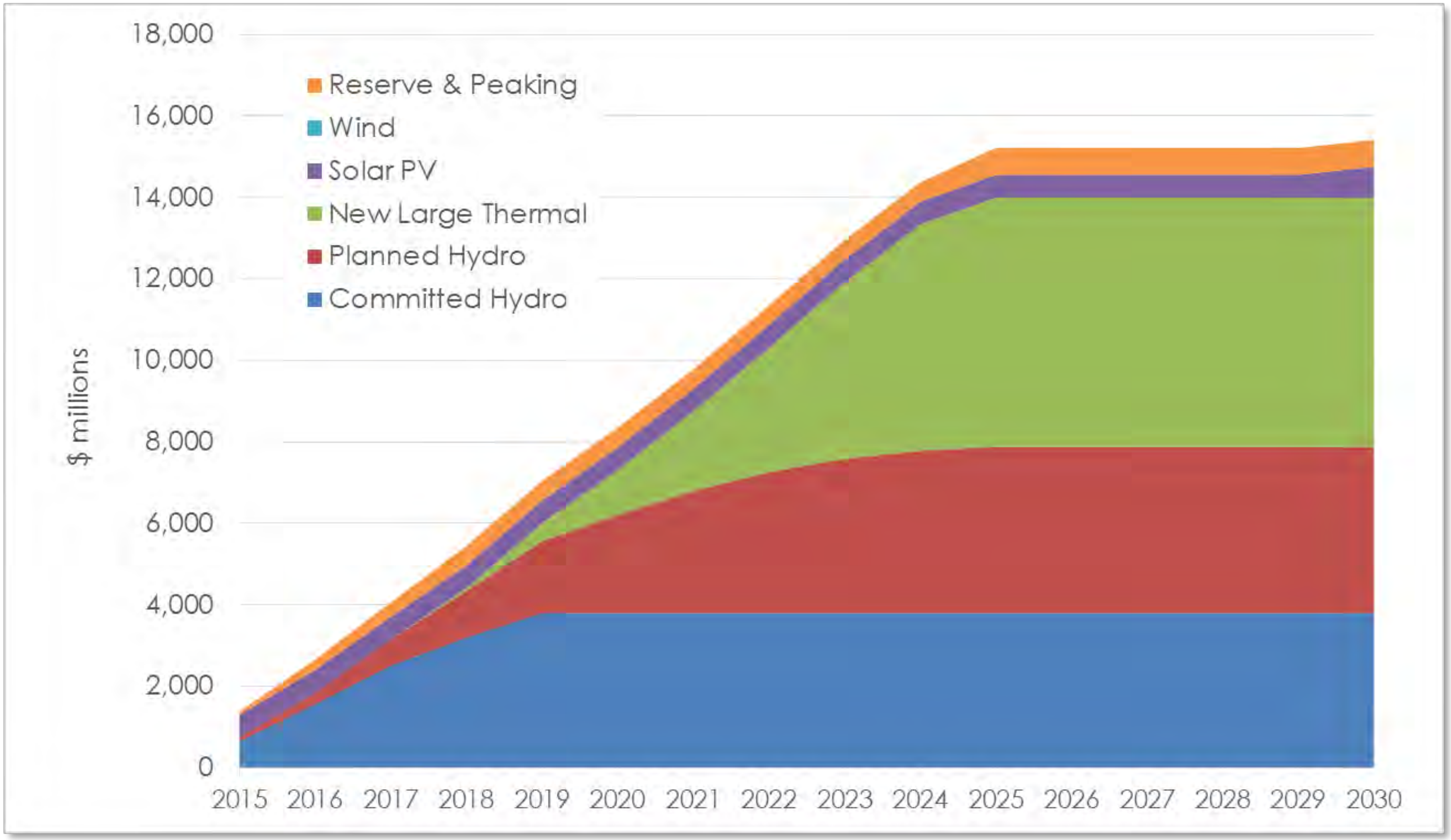
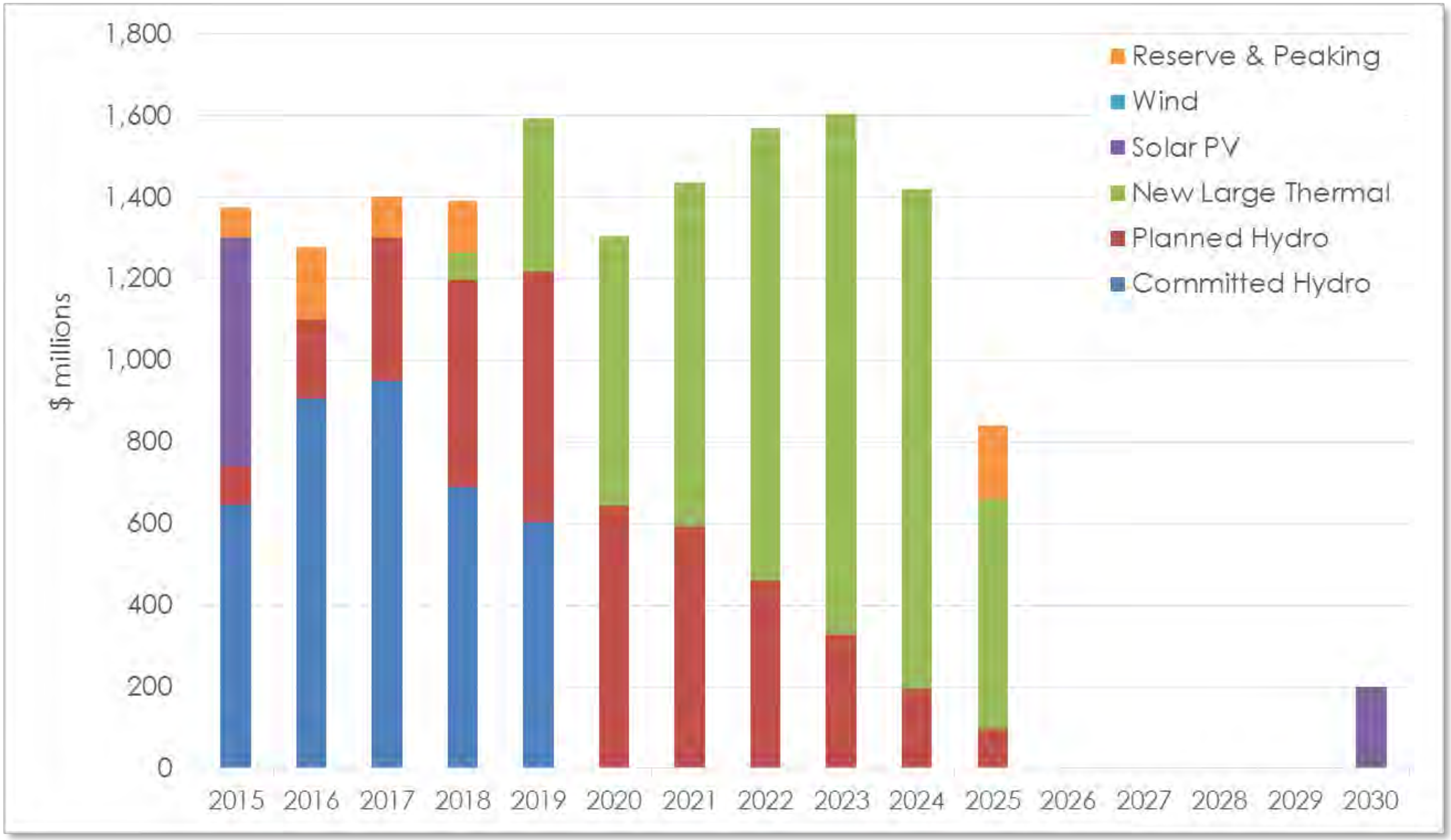


Figure IV-34: Annual Investment Profile – Case 2 HIGH GROWTH



APPENDIX A: Methodology & Approach for EMP Expansion Planning

Long-Term Fuel Mix Optimization Model

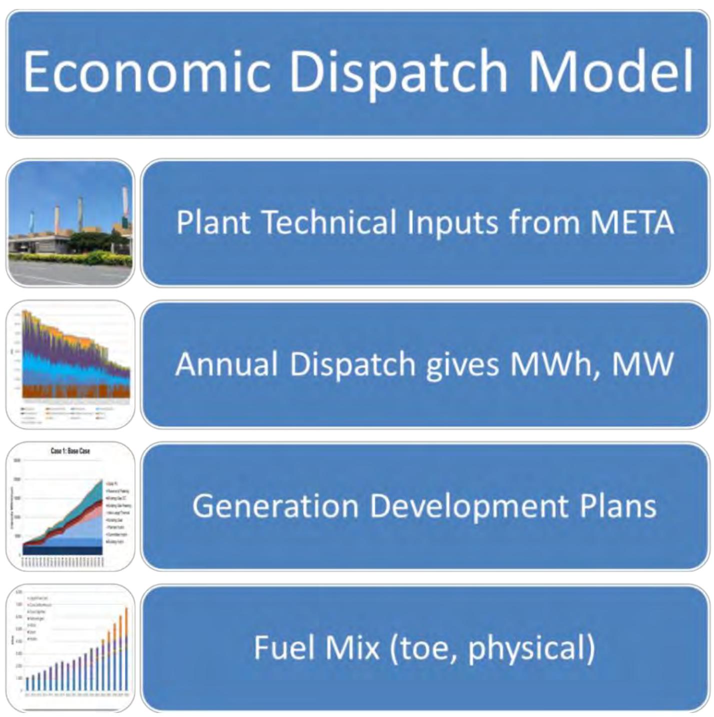
An optimization model was used to identify the optimal long-term fuel mix. The model comprises three modules: 1) An Economic Dispatch Model; 2) A Portfolio Analysis Model; and 3) a Portfolio Prioritization & Ranking Model (a Multi-Criteria Decision Model).

Economic Dispatch Model

The Economic Dispatch Model takes technical inputs for power plants (as energy pools) and computes the optimal plant dispatch that minimizes fuel costs. Fuel cost optimization is determined primarily by heat rate considerations. However, the maximum capacity available from each pool acts as a constraint. The model produces the generated MWh and reports the peak MW produced by each energy type.

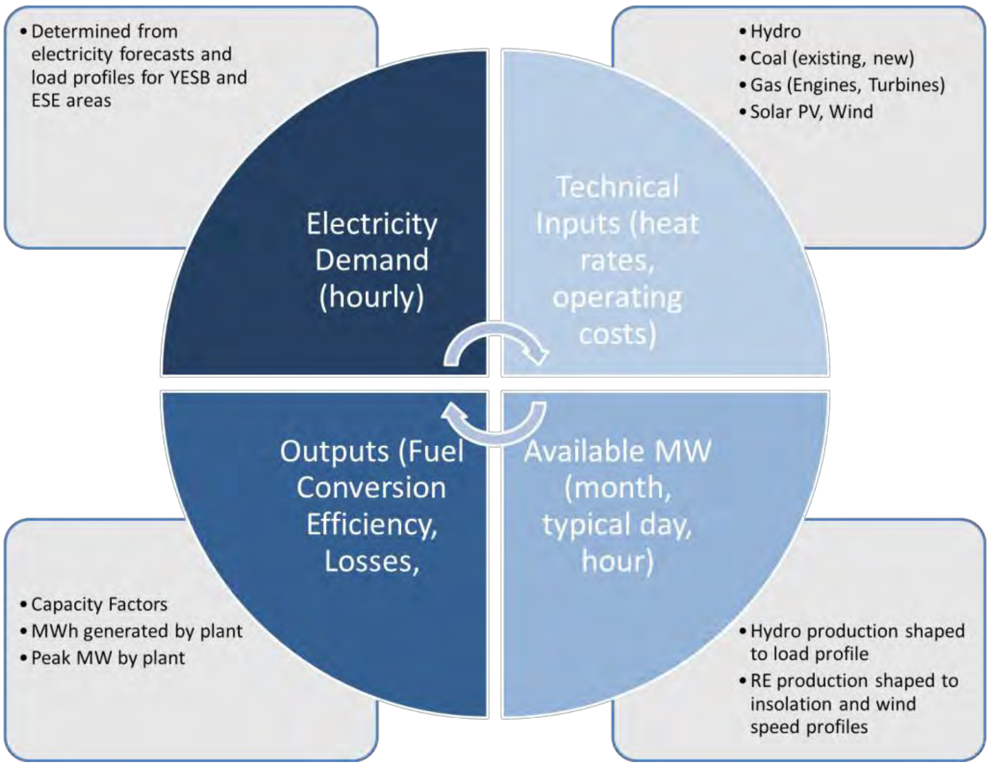
The schema of the Economic Dispatch model is shown by Figure A1 and A2:

Figure A1: Economic Dispatch Model



Source: Consultant

Figure A2: Economic Dispatch Modeling Process



Source: Consultant's analysis

Portfolio Analysis Model

The Portfolio Analysis Model computes the Levelized Cost of Energy (LCoE) for a portfolio of generation assets. The levelised cost of energy (LCoE) is the total discounted unit cost of power generation over the asset lifetime, and includes CAPEX, fixed and variable O&M costs, fuel costs, and the option to include environmental costs.

The capital investment (CAPEX) for each generation asset type has been determined as the 'overnight' capital costs which include costs of equipment, construction, installation and engineering, but excludes interest during construction (IDC). IDC is calculated as a separate cost item and is based on a predetermined cost of debt.

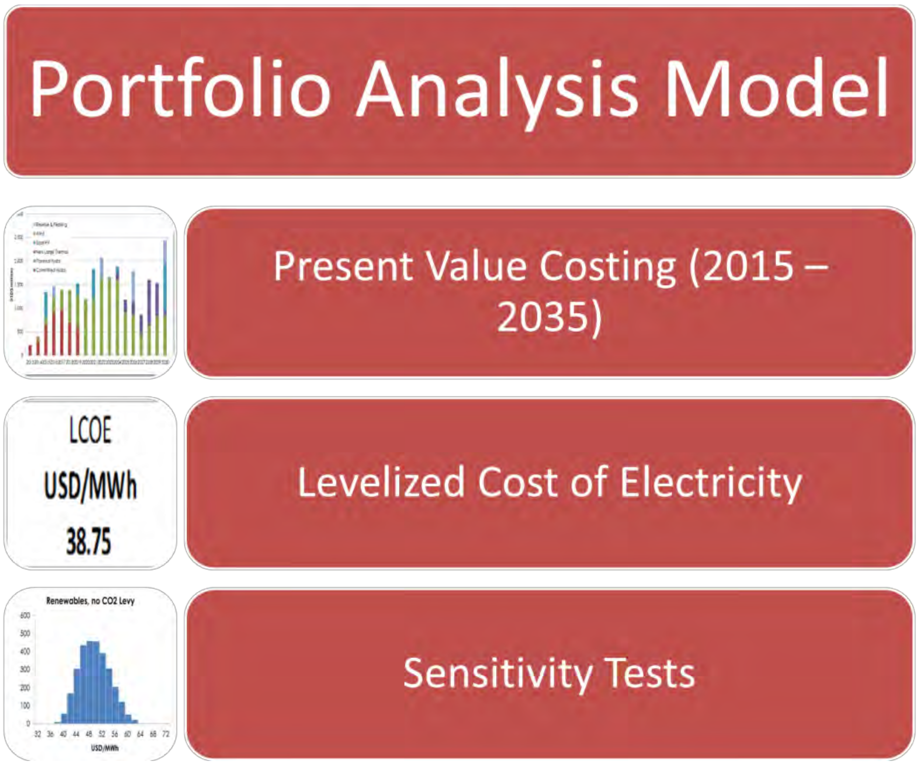
The Model calculates CAPEX, fixed and variable O&M costs as well as decommissioning costs based on initial values for the base year (2014) and respective profiles over the calculation horizon. The CAPEX profile takes into consideration both price escalation reflecting changes in raw material and labour costs over the period, as well as change of unit CAPEX costs related to generation unit size. Fixed O&M and decommissioning costs are defined as shares of the CAPEX.

The Model supports evaluation of three CO_2 price scenarios: zero levy, flat price of 30 USD/ton, and price increase over the calculation time horizon (from 8.07 USD/ton in 2014 to 30 USD/ton in 2035). The price increase scenario is used for final ranking of the portfolios according to their LCoE levels.

The Model supports the evaluation of asset portfolio investment using a deterministic approach based on the most likely expenditure and price values, or by including uncertainties related to price and cost levels and their future developments. This is achieved by introducing additional expert-based estimates of possible minimum and maximum boundaries for unit CAPEX and fuel growth rates. The expected CAPEX and price values are estimated using Monte Carlo simulation for beta-binomial (PERT) distribution.

The Model calculates the present value of total portfolio costs at 4%, 6% and 8% real discount rates. Real prices of 2014 are used throughout the whole calculation chain (both for the input and output data).

Figure A3: Portfolio Analysis Model



Source: Consultant's analysis

It has been assumed that 40% of the total investment program expenditures will be financed with equity, the cost of equity being equal to 10%. The remainder is assumed to be financed with long-term loans, the cost of debt being 3.3%. This rate is also used for calculating IDC.

Base year values for CAPEX, OPEX, fuel prices and discrete fuel price change rates for each 5-year period over the calculation horizon are based on the Model for Electricity Technology Assessments (META)[8]. Using the META data, the portfolio evaluation model calculates smoothed price curves for crude oil, natural gas, bituminous and sub-bituminous coal, and lignite fuels.

Assumptions for unit CAPEX and fuel price change rates used for deterministic and probabilistic

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[8] For description of META and of CAPEX, OPEX and price assumptions used, see the Primary Energy & Technology Options Report

evaluation are presented in the tables below. The US dollar is the base currency of the portfolio evaluation model. All input and output costs and prices are expressed in real US dollar terms for 2014.

Table A1: Unit CAPEX (USD/kWh)

Plant Type	Most Likely		
	Min	META	Max
Existing Hydro		2 000	
Committed Hydro	1 500	2 800	4 000
Planned Hydro	1 000	2 000	4 000
Existing Coal		2 300	
New Large Thermal	1 000	1 300	2 200
Solar PV	1 700	2 100	2 500
Existing Gas Peaking		486	
Existing Gas CC	600	918	1 300
Wind	1 000	1 360	2 000
Reserve & Peaking		486	

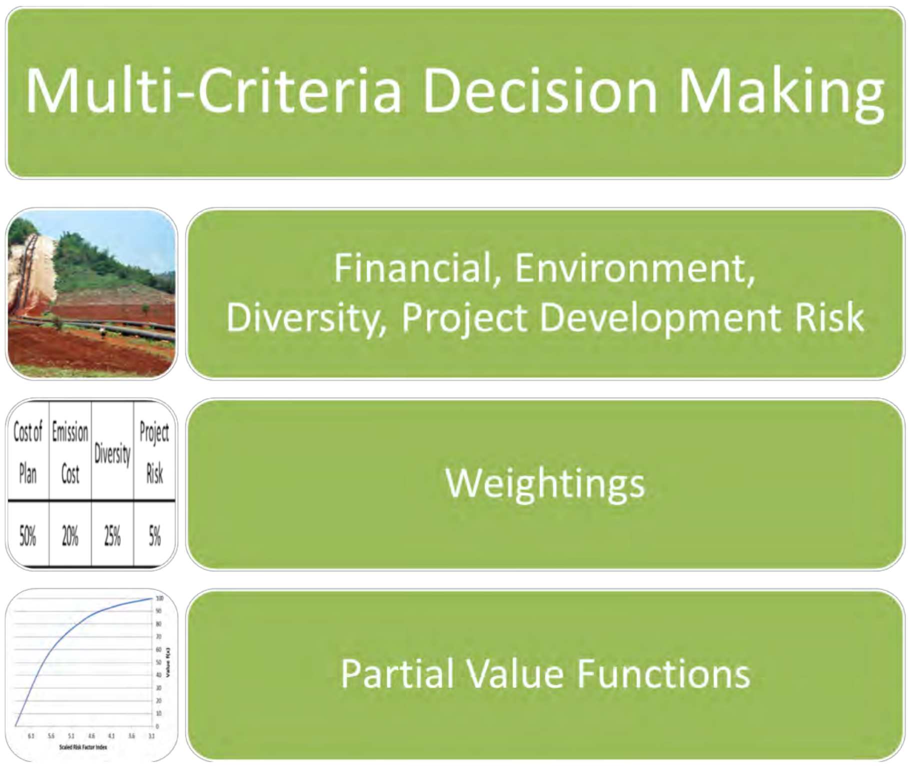
Table A2: Fuel Price Change Assumptions

Fuel prices	Most Likely		
	Min	META	Max
Coal price growth			
2014-2020	5.9 %	6.9 %	7.9 %
2020-2025	2.9 %	3.9 %	4.9 %
2025-2030	2.9 %	3.9 %	4.9 %
2030-2035	2.9 %	3.9 %	4.9 %
Gas price growth			
2014-2020	-14.0 %	-13.0 %	-12.0 %
2020-2025	2.4 %	3.4 %	4.4 %
2025-2030	2.4 %	3.4 %	4.4 %
2030-2035	2.4 %	3.4 %	4.4 %
Oil price growth			
2014-2020	9.1 %	10.1 %	11.1 %
2020-2025	4.8 %	5.8 %	6.8 %
2025-2030	4.8 %	5.8 %	6.8 %
2030-2035	4.8 %	5.8 %	6.8 %

Portfolio Prioritization & Ranking Model

A Multi-criteria Decision Making process has been used to prioritize and rank the alternative cases. Prioritization is applied according to weighted policy objectives. The policy performance is scored and partial value functions applied to normalize the scores.

Figure A4: Portfolio Prioritization & Ranking Model



Source: Consultant's analysis

For the purpose of scoring the cases, the performance measures are as follows:-

- The cost of the plan is determined as the present value total operating cost. This cost is normalised by indexing against the cost of the lowest cost plan.
- The emissions factor is determined as the total cost of CO2, Nox, Sox and particulates.
- Dependence on gas is determined as the installed capacity of gas-fuelled plant as a percentage of the total installed capacity.
- Project development risk is scored for each case, weighted by the MW of installed capacity for the generation technologies employed.

Some further elaboration of project development risks is necessary. One of the key risks relates to the learning curve associated with the use of a new technology in a new environment. An obvious example is the introduction of large solar PV farms in Myanmar. Such risks would be further elevated if two technologies were to be introduced at the same time, e.g. solar PV farms and large wind farms.

The following table provides a risk assessment of project risk factors including the scores associated with various technology choices, where the scoring is related to the use of the technology in Myanmar.

Table A3: Project Development Risk Factors

	CFB Coal 300MW	Wind Farm	Small Hydro	Large Hydro	Solar PV Farm	Gas CCGT	Gas Engine	Coal Supercritical
Confidence in Cost Assumptions	0	0	1	2	0	0	0	1
Confidence in Technology	0	0	0	0	0	0	0	0
Confidence in Timing	2	0	2	3	0	1	1	3
Confidence in Reliability	0	0	0	0	0	0	0	0
Safety Concerns	0	0	0	0	0	0	0	0
Resource Concerns	0	2	0	0	0	3	3	2
TOTAL	2	2	3	5	0	4	4	6

Sources: Consultants' analysis

The raw scores determined as the abovementioned performance measures, cannot be added directly as the policy factors are of different nature. The raw scores are weighted by policy weighting factors as follows:-

- Cost of plan – Weighting 50%;
- Emissions – Weighting 20%;
- Diversification (dependence on gas) – Weighting 25%; and
- Project Development Risk – Weighting 5%.

Again the weighted scores cannot be added directly. It is first required to normalize the weighted scores using a 'value preference' approach. The values are determined separately for each policy factor and normalized using partial value functions.

The weighting of the project development risk factors by MW of installed capacity is given for each case as follows:

Table A4: Risk Factor Scores

Risk rating			
Projects	**R**	**Rationale**	**Scoring**
No risk project	0	High confidence in cost assumptions	
		High confidence in technology	
		High confidence in timing	
		High confidence in reliability	
		Minimal safety concerns	
		No resource concerns	
CFB Coal 300MW	2	Moderate confidence in cost assumptions	0
		Moderate confidence in technology	0
		Moderate confidence in timing	2
		High confidence in reliability	0

Risk rating			
Projects	**R**	**Rationale**	**Scoring**
		Minimal safety concerns	0
		Moderate resource concerns: water	0
Wind Farm	2	Confidence in cost assumptions	0
		Low confidence in technology	0
		Fair confidence in timing	0
		Low confidence in reliability: typhoons in Myanmar	0
		Minimal safety concerns	0
		Low resource concerns: wind speed	2
Small Hydro	3	Confidence in cost assumptions	1
		High confidence in technology	0
		Confidence in timing	2
		Poor confidence in reliability: history in Myanmar	0
		Minimal safety concerns	0
		Moderate resource concerns: water	0
Large Hydro	5	Low confidence in cost assumptions	2
		High confidence in technology	0
		Moderate confidence in timing	3
		Moderate confidence in reliability	0
		Minimal safety concerns	0
		Moderate resource concerns: water	0
Solar PV Farm	0	Moderate confidence in cost assumptions	0
		High confidence in technology	0
		Moderate confidence in timing	0
		High confidence in reliability	0
		Minimal safety concerns	0
		No resource concerns	0
Gas CCGT	4	Low confidence in cost assumptions	0
		High confidence in technology	0
		Moderate confidence in timing	1
		High confidence in reliability	0
		Minimal safety concerns	0
		Moderate resource concerns: water	3
Gas Engine	4	High confidence in cost assumptions	0
		High confidence in technology	0

Risk rating			
Projects	**R**	**Rationale**	**Scoring**
		Moderate confidence in timing	1
		High confidence in reliability	0
		Minimal safety concerns	0
		Moderate resource concerns: water	3
Coal Supercritical	6	High confidence in cost assumptions	1
		High confidence in technology	0
		Moderate confidence in timing	3
		High confidence in reliability	0
		Moderate safety concerns: Ash, Dust	0
		Moderate resource concerns: water	2

Source: Consultant's analysis

Table A5: Weighted Risk Factors for Each Case

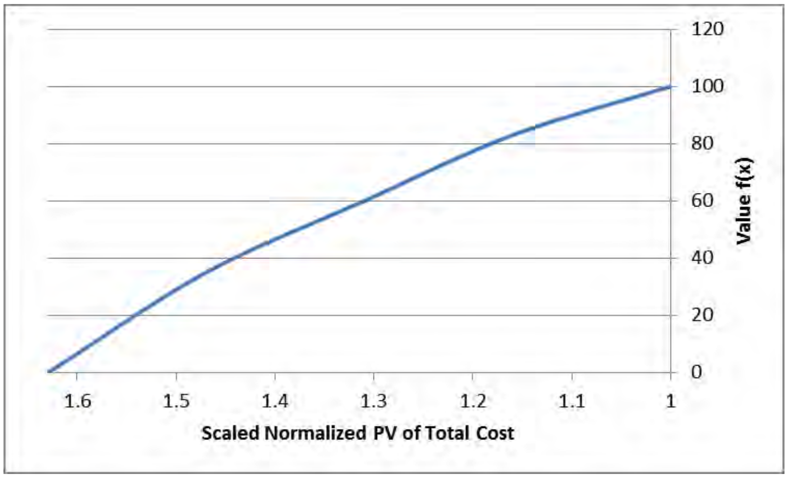
	Risk rating				
Case	**Plan**	**R**	**Projects**	**New Capacity by 2030**	**Scoring**
1	Planned Hydropower	4.4	CFB Coal 300MW	300	2.0
			Wind Farm		2.0
			Small Hydro	1,442	3.0
			Large Hydro	5,766	5.0
			Solar PV Farm	300	0.0
			Gas CCGT	3,800	4.0
			Gas Engine		4.0
			Coal Supercritical	1,560	6.0
2	Balanced	4.6	CFB Coal 300MW	300	2.0
			Wind Farm		2.0
			Small Hydro	1,026	3.0
			Large Hydro	4,105	5.0
			Solar PV Farm	300	0.0
			Gas CCGT	2,500	4.0
			Gas Engine		4.0
			Coal Supercritical	2,700	6.0
3	Maximum Hydro	4.3	CFB Coal 300MW		2.0
			Wind Farm		2.0
			Small Hydro	1,975	3.0
			Large Hydro	7,899	5.0
			Solar PV Farm	300	0.0
			Gas CCGT	3,940	4.0

	Risk rating				
Case	**Plan**	**R**	**Projects**	**New Capacity by 2030**	**Scoring**
			Gas Engine		4.0
			Coal Supercritical		6.0
4	Maximum Coal	5.1	CFB Coal 300MW	900	2.0
			Wind Farm		2.0
			Small Hydro	429	3.0
			Large Hydro	1,714	5.0
			Solar PV Farm	300	0.0
			Gas CCGT	850	4.0
			Gas Engine		4.0
			Coal Supercritical	7,560	6.0
5	Maximum Solar PV / Wind	4.1	CFB Coal 300MW	300	2.0
			Wind Farm	750	2.0
			Small Hydro	1,209	3.0
			Large Hydro	4,835	5.0
			Solar PV Farm	1,000	0.0
			Gas CCGT	3,050	4.0
			Gas Engine		4.0
			Coal Supercritical	1,680	6.0

Source: Consultant's analysis

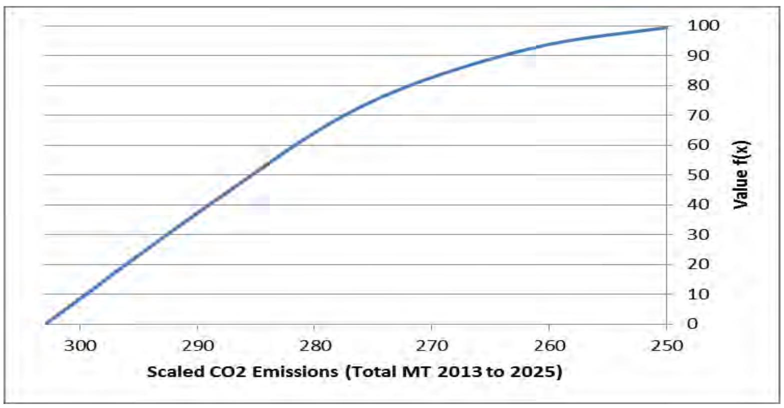
Partial value functions are based on prior experience of the Consultant; they were developed using preference testing techniques with an audience of energy professionals. The partial value functions are given by the following curves:

Figure A5: Cost Value Curve



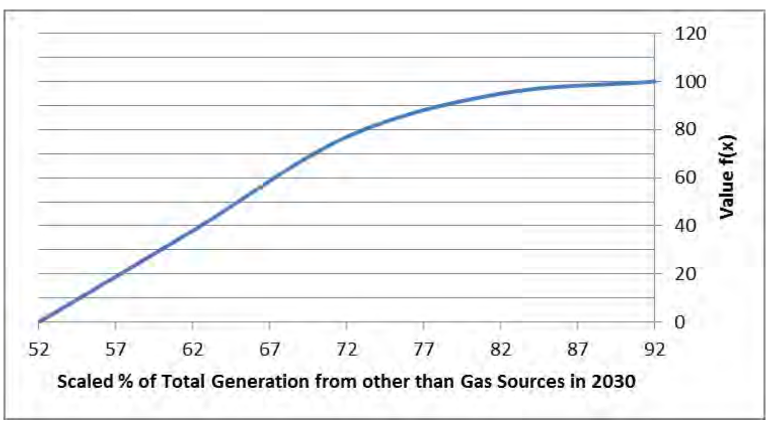
Source: Consultant

Figure A6: Emissions Value Curve



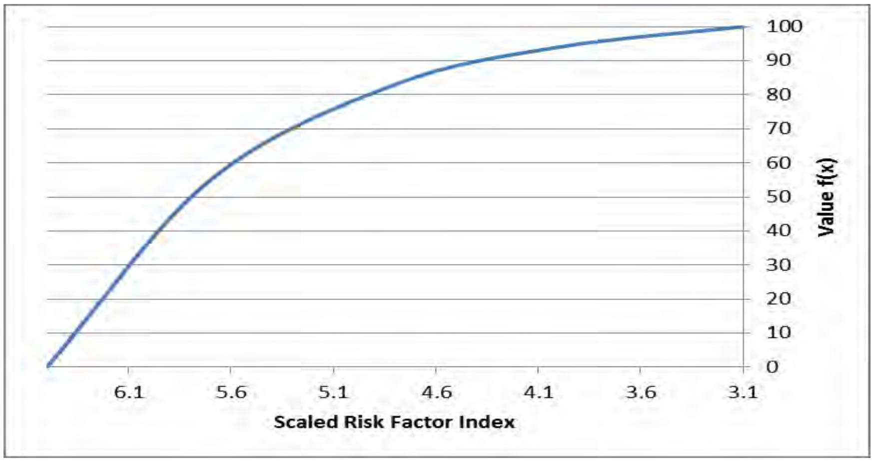
Source: Consultant

Figure A7: Diversity Value Curve



Source: Consultant

Figure A8: Risk Value Curve



Source: Consultant

Project Number: TA No. 8356-MYA

FINAL REPORT
ENERGY SUPPLY OUTLOOK

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

Intelligent Energy Systems

in association with

MYANMAR INTERNATIONAL CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
ASEAN	–	Association of Southeast Asian Nations
CSO	–	Central Statistics Organisation
EIA	–	U.S. Energy Information Administration
FAO	–	Food and Agriculture Organization
FAME	–	Fatty Acid Methyl Ester
GDP	–	Gross Domestic Product
GoM	–	Government of the Republic of the Union of Myanmar
LNG	–	Liquefied Natural Gas
MOE	–	Ministry of Energy
MPE	–	Myanmar Petroleum Enterprise
TFEC	–	Total Final Energy Consumption
TPEP	–	Total Primary Energy Production
TPES	–	Total Primary Energy Supply
USD	–	United States Dollar

UNITS OF MEASURE

IG	–	Imperial Gallon
km	–	Kilometre
l	–	Litre
mcm	–	Million Cubic Meters
bbl	–	Barrels
bcm	–	Billion Cubic Meters
boe	–	Barrels of Oil Equivalent
bopd	–	Barrels of Oil Per Day
mmbbl	–	Million Barrels
mtoe	–	Million tons of Oil Equivalent

CONVERSION FACTORS

1 litre	=	0.22 Imperial Gallon
1 km	=	0.62137 mile
1 barrel	=	159 litres or 35 imperial gallons
1 ha	=	2.47105 acre
1 km^2	=	100 ha

CONTENTS

I. SUMMARY

A. Introduction

1. The EMP includes projections for Total Primary Energy Production (TPEP), Total Primary Energy Supply (TPES) and for Total Final Energy Consumption (TFEC)[1].

- The TFEC is the Total Final Energy Consumption. This represents the consumption by end-use sectors, agriculture, transport, industry, commerce / government and residential.
- The TPES is the Total Primary Energy Supply. This represents the TFEC plus the addition of locally supplied energy.
- The TPEP is the Total Primary Energy Production. This represents the TPES plus the addition of energy exports less energy imports.

2. Whilst care has been taken to develop an historical energy balance and to make projections using the 2012 balance as a baseline, it must be noted that projections are by their nature speculative. They represent one possible future amongst many. Therefore it is most important to define assumptions regarding sources of energy in the future since any deficit in the local energy supply capacity would made up by import. In this regard the key assumptions to note are:

- All electricity needs can be met by local power plants, however bituminous coals would be imported for all new power plants[2]
- A local oil refinery of 50 000 bopd will commence operation in 2019
- The M3 field will be delayed indefinitely, with no new fields commencing operation during the planning horizon
- Fertilizer will be imported from 2018 (consistent with the Liquid & Gaseous Fuel Strategy report); and
- LPG will be fully imported from 2018 (consistent with the Liquid & Gaseous Fuel Strategy report)
- Biofuels are potentially viable but not considered for substitution during the energy outlook period

B. Energy Balance Projection to 2030

3. Table I-1 to Table I-2 is given as an Energy Balance projection for Myanmar to 2030. This Energy Balance projection is based on the abovementioned assumptions. Moreover, because Saudi Arabian crude oil is transported across the country, with an allowance of 50 000 bopd provided to Myanmar, it is only the allowance that appears in the Energy Balance. Unlike oil exports, gas exports to Thailand and China appear in the energy balance because the gas is produced in Myanmar. Finally hydropower electricity produced by Chinese merchant hydropower plants, and exported directly to China, is not included in the Energy Balance.

4. The Energy Balance predicts that Myanmar will become a net importer of energy (slightly) by 2030 if no new gas fields export gas abroad. As mentioned the projection assumes that the M3 field will be indefinitely delayed; this is due to the recent change in government policy in Thailand and the weak international market for oil and gas.

[1] 3. The formulation used for the development of energy projections and Energy Balance is that of the IEA. The rules regarding the classification of forms of energy is given by the IEA's Energy Statistics Manual (2005).
[2] By instruction of ADB

Table I-1: Supply Projection to 2030 (mtoe)

	2012	2015	2018	2021	2024	2027	2030
TOTAL PRODUCTION	23.7	27.5	27.7	26.3	26.4	24.9	25.1
Hydro	0.7	0.8	0.9	1.6	1.9	2.5	2.8
Solar PV & Wind	0.0	0.0	0.0	0.0	0.0	0.1	0.3
Gas	13.0	16.6	15.7	12.8	11.3	9.1	8.5
Oil	1.0	1.0	1.5	2.2	3.5	3.6	3.6
Coal[1]	0.2	0.3	0.5	0.7	0.8	1.1	1.3
Biomass Type II[2]	8.8	8.9	9.0	9.0	8.8	8.6	8.4
TOTAL NET IMPORTS	-10.2	-11.3	-11.2	-8.7	-6.2	-2.5	0.8
Hydro Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas Exports	11.9	13.9	13.9	11.1	9.5	7.0	5.9
Imports[4]	0.0	0.0	0.4	0.5	0.6	0.6	0.7
Net Imports	-11.9	-13.9	-13.5	-10.6	-9.0	-6.3	-5.2
Oil Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imports	1.7	2.6	2.3	1.9	1.0	1.4	2.0
Net Imports	1.7	2.6	2.3	1.9	1.0	1.4	2.0
Coal Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imports	0.0	0.0	0.0	0.0	1.7	2.4	4.0
Net Imports	0.0	0.0	0.0	0.0	1.7	2.4	4.0
TOTAL STOCK CHANGES	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL SUPPLY (TPES)	13.5	16.2	16.5	17.6	20.2	22.4	25.8
Hydro	0.7	0.8	0.9	1.6	1.9	2.5	2.8
Solar PV & Wind	0.0	0.0	0.0	0.0	0.0	0.1	0.3
Gas	1.1	2.6	2.2	2.2	2.4	2.7	3.4
Oil	2.6	3.6	3.8	4.0	4.5	5.0	5.6
Coal	0.2	0.3	0.5	0.7	2.6	3.5	5.3
Biomass Type II	8.8	8.9	9.0	9.0	8.8	8.6	8.4
Electricity trade[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shares (%)							

	2012	2015	2018	2021	2024	2027	2030
Hydro	4.9	5.0	5.7	9.4	9.3	11.1	11.0
Solar PV & Wind	0.0	0.0	0.0	0.0	0.0	0.4	1.2
Gas	8.4	16.2	13.5	12.5	11.8	12.3	13.0
Oil	19.5	22.2	22.9	23.1	22.5	22.4	21.7
Coal	1.6	1.7	3.3	3.8	12.8	15.4	20.4
Biomass Type II	65.5	54.9	54.6	51.2	43.7	38.4	32.6
Electricity trade	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Consultant's analysis

Table I-2: Electricity Demand & Transformation Losses

	2012	2015	2018	2021	2024	2027	2030
INPUT (mtoe)	1.97	2.22	2.21	2.52	4.22	5.45	7.54
OUTPUT Electricity (GWh)	10,364	14,398	19,446	25,763	33,904	44,238	57,654
Electricity output shares (%)							
Hydro	69.7%	65.0%	56.5%	74.1%	64.0%	65.7%	57.1%
Solar PV	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	5.2%
Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural gas	28.1%	33.4%	38.9%	22.4%	12.7%	8.3%	8.2%
Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coal	2.2%	1.6%	4.6%	3.4%	23.3%	24.0%	29.5%
TOTAL LOSSES (mtoe) of which:							
Electricity generation	0.37	0.52	0.98	0.76	1.70	2.07	3.21
T&D losses	0.19	0.24	0.30	0.36	0.42	0.50	0.58
Total	0.56	0.76	1.27	1.12	2.12	2.57	3.79
Electricity generation[8]	18.6%	23.5%	44.1%	30.1%	40.3%	38.0%	42.6%
T&D losses	9.6%	10.8%	13.4%	14.1%	10.0%	9.2%	7.7%
Total	28.2%	34.3%	57.6%	44.2%	50.4%	47.2%	50.3%

Source: Consultant's analysis

Table I-3: Total Final Energy Consumption (TFEC, mtoe)

	2012	2015	2018	2021	2024	2027	2030
TFC	12.6	14.2	15.3	16.5	17.9	19.6	21.9
Coal[1]	0.1	0.1	0.2	0.2	0.3	0.4	0.6
Oil	2.5	3.4	3.6	4.0	4.4	4.9	5.5
Gas	0.6	0.9	1.2	1.5	2.0	2.5	3.2
Electricity	0.7	1.0	1.3	1.8	2.4	3.2	4.3

	2012	2015	2018	2021	2024	2027	2030
Biomass Type II[2]	8.8	8.9	9.0	9.0	8.8	8.6	8.4
Shares (%)							
Coal	0.6	0.8	1.1	1.4	1.7	2.1	2.5
Oil	19.3	23.9	23.7	23.9	24.5	24.8	25.0
Gas	5.0	6.2	7.7	9.3	11.0	12.7	14.4
Electricity	5.5	6.7	8.7	10.9	13.5	16.4	19.6
Biomass Type II	69.6	62.3	58.8	54.5	49.2	43.9	38.5
TOTAL INDUSTRY	0.7	1.2	1.7	2.4	3.3	4.3	5.7
Coal[1]	0.07	0.11	0.16	0.23	0.31	0.42	0.55
Oil	0.06	0.09	0.11	0.14	0.18	0.22	0.28
Gas	0.29	0.48	0.71	1.01	1.38	1.85	2.44
Electricity	0.28	0.47	0.71	1.01	1.38	1.85	2.43
Biomass Type II[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Shares (%)							
Coal	10.7	9.5	9.5	9.5	9.6	9.7	9.7
Oil	8.1	7.9	6.7	6.0	5.5	5.1	4.9
Gas	41.6	41.3	41.9	42.3	42.5	42.6	42.8
Electricity	39.6	41.3	41.9	42.2	42.4	42.6	42.7
Biomass Type II	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRANSPORT[5]	1.4	2.3	2.3	2.5	2.8	3.2	3.7
TOTAL OTHER SECTOR[6]	10.54	10.86	11.25	11.61	11.82	12.08	12.51
Coal[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil	0.99	1.09	1.20	1.32	1.42	1.47	1.51
Gas	0.31	0.37	0.44	0.51	0.57	0.64	0.70
Electricity	0.42	0.49	0.62	0.79	1.03	1.37	1.86
Biomass Type II[2]	8.82	8.90	9.00	8.99	8.80	8.61	8.43
Shares (%)							
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	9.4	10.1	10.7	11.4	12.0	12.1	12.1
Gas	2.9	3.4	3.9	4.4	4.8	5.3	5.6
Electricity	4.0	4.5	5.5	6.8	8.7	11.3	14.9
Biomass Type II	83.7	82.0	79.9	77.5	74.4	71.3	67.4

Source: Consultant's analysis

Table I-4: Key Performance Indicators

	2012	2015	2018	2021	2024	2027	2030
GDP (billion 2010 US$)	52.2	64.5	79.8	98.8	122.4	151.6	187.9
Population (millions)	61.0	63.5	65.4	67.4	69.4	71.5	73.7
TPES/GDP[9]	0.26	0.24	0.21	0.18	0.17	0.15	0.14
Energy production/TPES	1.76	1.72	1.66	1.49	1.29	1.10	0.97
Per capita TPES[10]	0.22	0.25	0.26	0.27	0.29	0.32	0.36
Oil supply/GDP[9]	0.05	0.06	0.05	0.04	0.04	0.03	0.03
TFEC/GDP[9]	0.24	0.22	0.19	0.17	0.15	0.13	0.12
Per capita TFEC[10]	0.21	0.22	0.23	0.24	0.26	0.27	0.30
Energy–related CO2 emissions[11]	5.8	8.7	11.5	12.5	16.4	19.5	24.9
CO2 Emissions (Million tons)							
Electricity	0.66	1.05	1.83	1.47	3.56	4.36	6.74
Gas (excludes electricity production)	1.45	2.08	3.92	4.78	5.85	7.14	8.75
Transport	3.65	5.54	5.77	6.26	7.01	8.05	9.43

Source: Consultant's analysis

Footnotes to all EB tables above

1 Includes lignite and bituminous coal

2 Comprises solid biomass.

3 Total supply of electricity represents net trade. A negative number indicates that exports are greater than imports.

4 Includes non-energy use. (Note: Assumed that fertilizer will be imported after 2018).

5 Includes no non-oil fuels.

6 Includes residential, commercial & government and agricultural sectors.

7 Inputs to electricity generation refers to gross energy inputs to electricity plants. Output refers only to net electricity generation.

8 Losses arising in the production of electricity at public utilities. For non-fossil-fuel electricity generation, losses are zero.

9 Toe per thousand US dollars at 2010 prices and exchange rates.

10 Toe per person.

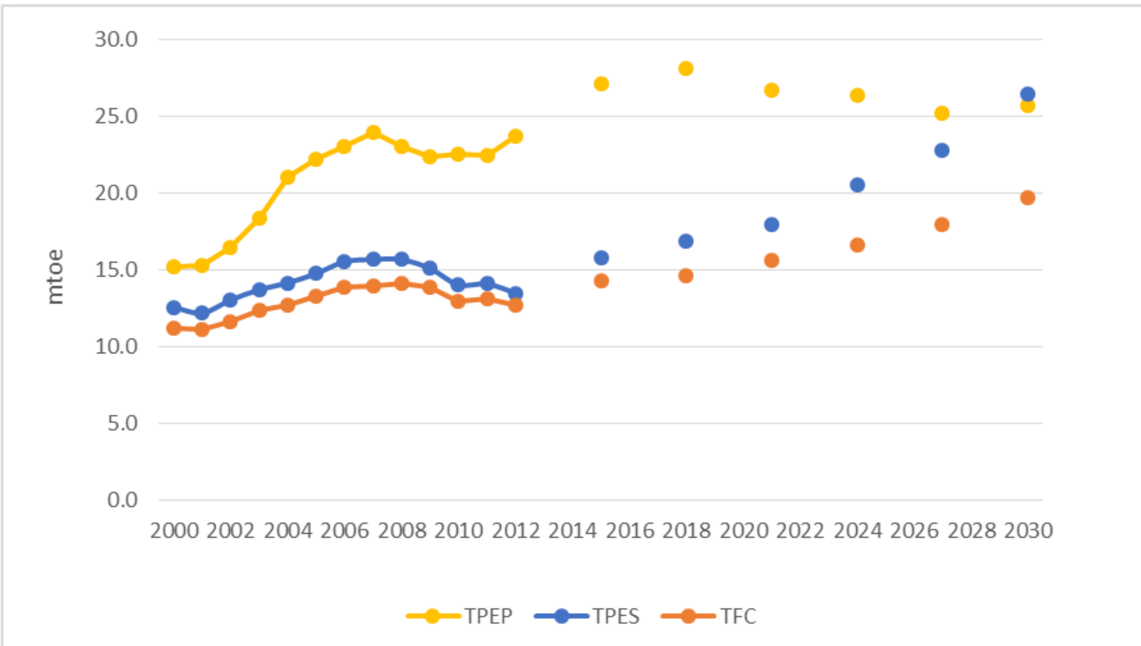
11 "Energy related CO2 emissions" specifically means CO2 from the combustion of the fossil fuel components of TPES (i.e. coal and coal products, crude oil and derived products and natural gas), while CO2 emissions from the remaining components of TPES (i.e. electricity from hydro, other renewables and nuclear) are zero. Emissions from the combustion of biomass-derived fuels are not included, in accordance with the IPCC greenhouse gas inventory methodology. TPES, by definition, excludes international marine bunkers. Units in million tons (Mtons).

C. Total Supply & Demand Outlook

5. An Energy Balance was constructed from the EMP using a bottom up method. Surveys were used to capture energy consumption and production data in as rigorous a manner as possible. The Energy Balance was projected on a three-year basis from 2012 to 2030.

6. The forecast is shown by Figure I-1. The forecast matches with the energy projections presented as Table I-1 to Table I-4. It can be observed that local production capacity (TPES) rises to create a healthy margin over TFEC. TPEP falls as gas production and export reduces to the point where Myanmar becomes a net importer of energy (slightly).

Figure I-1: Total Supply & Demand Outlook



Source: Consultant's analysis

7. Figure I-2 and Figure I-3 show the fuel mix composition for the TPES in 2015 and 2030. It can be seen clearly that the composition of the fuel mix could change dramatically over a 15 year period, due in particular to the growth in electricity displacing the use of fuelwood for household cooking in rural areas. Other changes are related to the growth in demand for passenger and freight services. Also the increased use of coal for power production after 2020.

Figure I-2: TPES – Energy Mix 2014

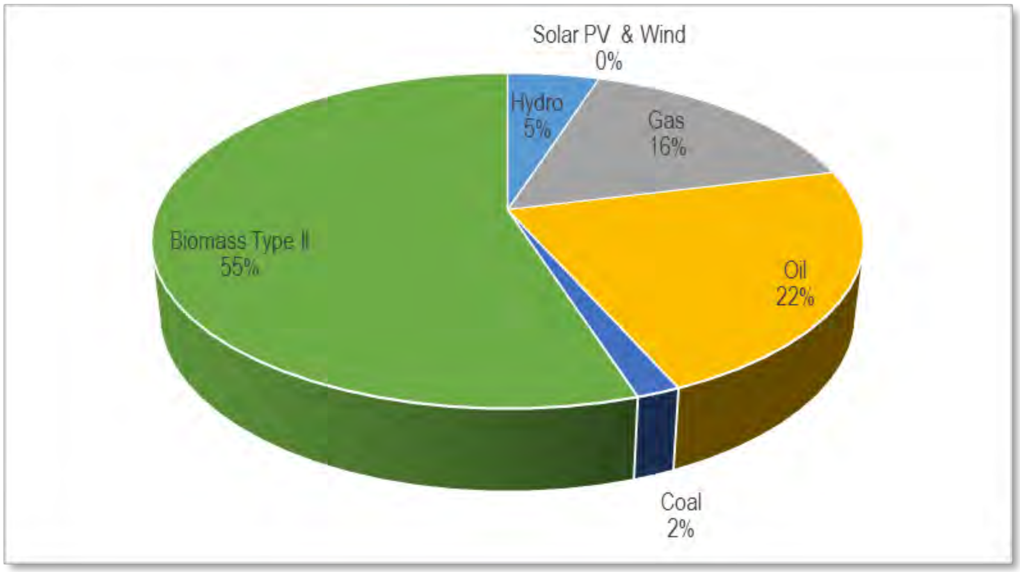
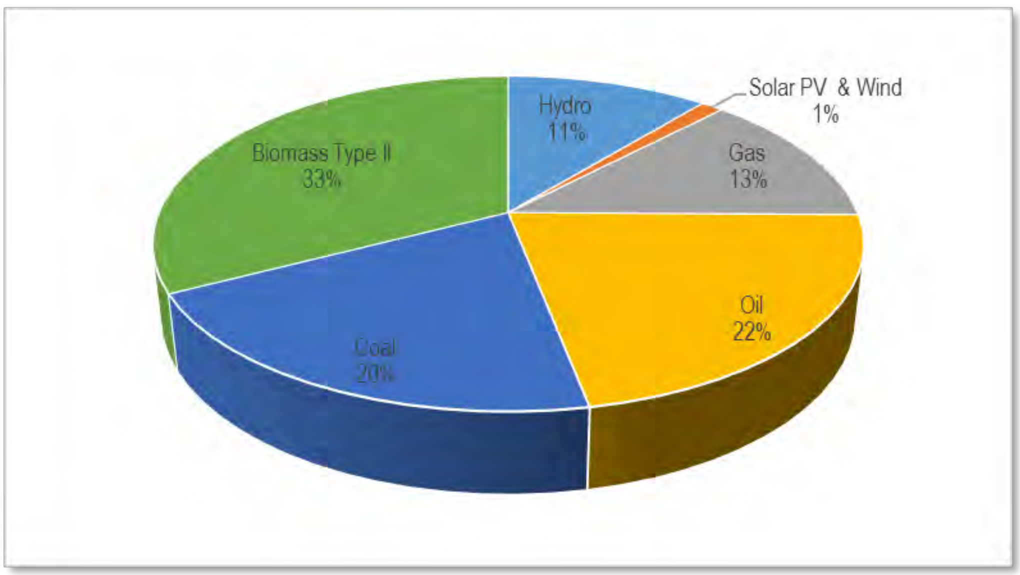


Figure I-3: TPES – Energy Mix 2030



Source: Consultant's analysis

8. The sections that follow describe first the Total Primary Energy Production outlook before proceeding to the Primary Energy Supply outlook. The fundamental driver of the production and supply outlook is Total Final Energy Consumption. The forecasts for Total Final Energy Consumption were developed in detail in the EMP Consolidated Demand forecasts report.

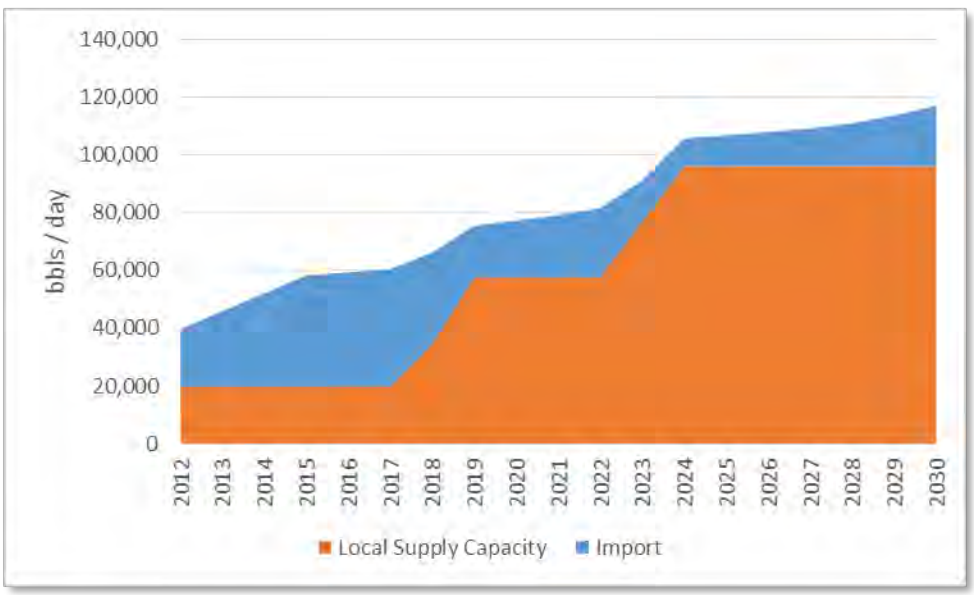
D. Total Primary Energy Production (TPEP)

9. In the case of electricity, the Consultant has assumed that all local electricity needs will be met by local power plants. Electricity that is currently produced by hydropower schemes dedicated for export to China is not considered as part of an IEA energy balance since Myanmar neither produces nor consumes any part of the plant output. It has been assumed that no further electricity export will take place during the planning period to 2030, in other words it has been assumed that Myanmar will not build large hydropower schemes or any other power plants specifically for electricity trade.

10. Under the optimal expansion, defined by the ADB as the ADICA electricity expansion in the Electricity Strategy report, electricity output shares would change in favour of coal, i.e. the electricity asset portfolio would become more balanced in terms of the fuel mix. The dominance of hydropower would reduce to around 57% from its current level of 65%. The dependence on natural gas will also reduce as expected when gas is used to meet peak demand. Electricity losses will increase as load increases and as coal-fired power plants are introduced. The conversion efficiency of large coal plants is of the order of 43% and so conversion losses increase in proportion to the amount of coal used for electricity generation. The increase can be mitigated to some extent if T&D losses can be reduced.

11. In the case of oil, the Consultant has assumed that a local refinery will be constructed by 2019. The capacity will initially be 50 000 bpd. The projection for refined oil products suggests that additional capacity of 50 000 bpd will be required by 2024. Nevertheless in most years it will be necessary to import oil. It has been assumed that LPG will be totally imported from 2020.

Figure I-4: Oil Production Local vs. Import (physical)



Source: Consultant's analysis

12. In the case of natural gas the Consultant has assumed that the M3 field will be indefinitely delayed and no new gas fields will commence operation during the period of the planning horizon. This represents a worst case scenario with a tight gas supply – demand outlook. However, as was discussed in the Liquid & Gaseous Fuel Strategy report there is an opportunity to manage the risks that natural gas supplies does not develop as anticipated.

Table I-5: Gas Supply Risk Mitigation circa 2019

	MMCF	MMCFD	Comment
Refinery	22,630	62	Hydro-cracking refinery needs hydrogen and usually powered with natural gas power plant
Power	81,030	222	EMP estimate
Fertilizer	20,552	56	Standard-run production plant 1 725 mtpd
Industry	38,623	106	EMP estimate
Total	~165,000	~548	
Available gas	~150,000	~411	Yadana, Yetagun, Shwe, Zawtika
		Potential to Reduce Gas Consumption	
Refinery	(7,500)	(21)	Power the refinery using liquid fuels (30 – 40 MW)
Power sector	(30,250)	(83)	Increase hydropower, gas / oil plant
Fertilizer	(10,000)	(27)	Import fertilizer
Total	(50,000)	(137)	

Source: Consultant's analysis

13. The refinery design can be modified to minimize gas consumption. In principle the use of gas for power generation could be replaced by oil or storage hydropower capacity for deployment at times of peak demand. A fertilizer plant appears to be uneconomic and gas could be saved by importing urea. These measures have been assumed ahead of the development of an LNG terminal because the cost of LNG will be high and market acceptance may therefore be low.

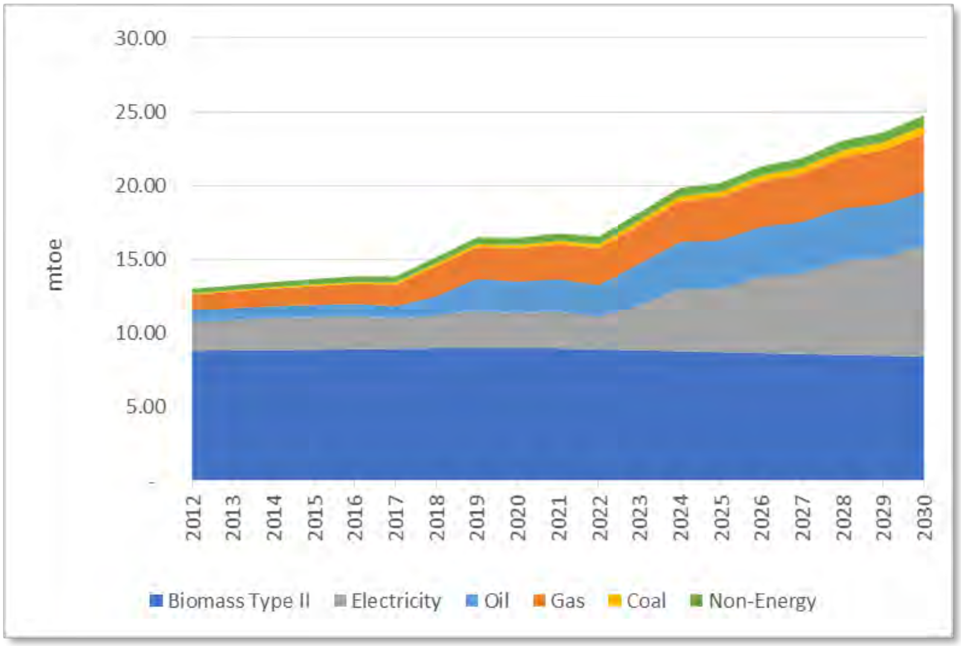
14. In the case of coal, the Consultant has assumed that all coal used to power large coal-fired plants (in coastal locations) will be imported bituminous coal of high calorific value. Industrial need for coal will be met mainly with indigenous coal.

15. In the case of fuelwood, the Consultant has assumed that primary energy production is equivalent to primary secondary energy production. There was insufficient data available to quantify fuelwood losses arising between forests and distribution centres. Furthermore the conversion losses associated with the burning of fuelwood has not been accounted for in the energy balance – such losses are important from an energy efficiency standpoint, but from an energy balance perspective they occur within consumer premises and are therefore ignored.

E. Total Primary Energy Supply (TPES)

16. The primary energy forecast for Myanmar is given by Figure I-5. It can be seen that as a result of rural electrification, the use of biomass type II falls with time. The growth in electricity in particular replaces the need to produce and consume fuelwood thereby easing pressure on Myanmar's forests. Oil, gas and coal production requirements increase with economic development.

Figure I-5: TPES – Total Primary Energy Supply Forecast (mtoe)



Source: Consultant's analysis

17. The production of all other fuels gradually increases over time as the population grows and the economy further develops. The corresponding compound annual growth rates are given in Table I-6.

Table I-6: Compound Annual Growth Rate Projections – TPES

Fuel	CAGR	Comment
Total Energy	3.4%	
Secondary Conversion Efficiency	4.2%	Average fuel conversion loss not including losses in consumer's premises
Import	-1.3%	
TFEC	3.0%	
Total Primary Energy Supply		
Electricity	7.6%	Rural electrification
Oil	8.9%	Vehicle ownership and freight
Gas	7.3%	Power production
Coal	10.9%	Power production
Biomass Type II	-0.3%	Rural electrification replaces fuelwood

Source: Consultant's analysis

18. The primary energy forecast for Myanmar's oil is given by Figure I-6. It can be seen that over time, oil production must increase to supply the transport and industry sectors. The corresponding compound annual growth rates are given in Table I-7.

Figure I-6: Oil TPES Forecast (toe)

Figure I-7: Oil TPES Forecast (physical)

Source: Consultant's analysis

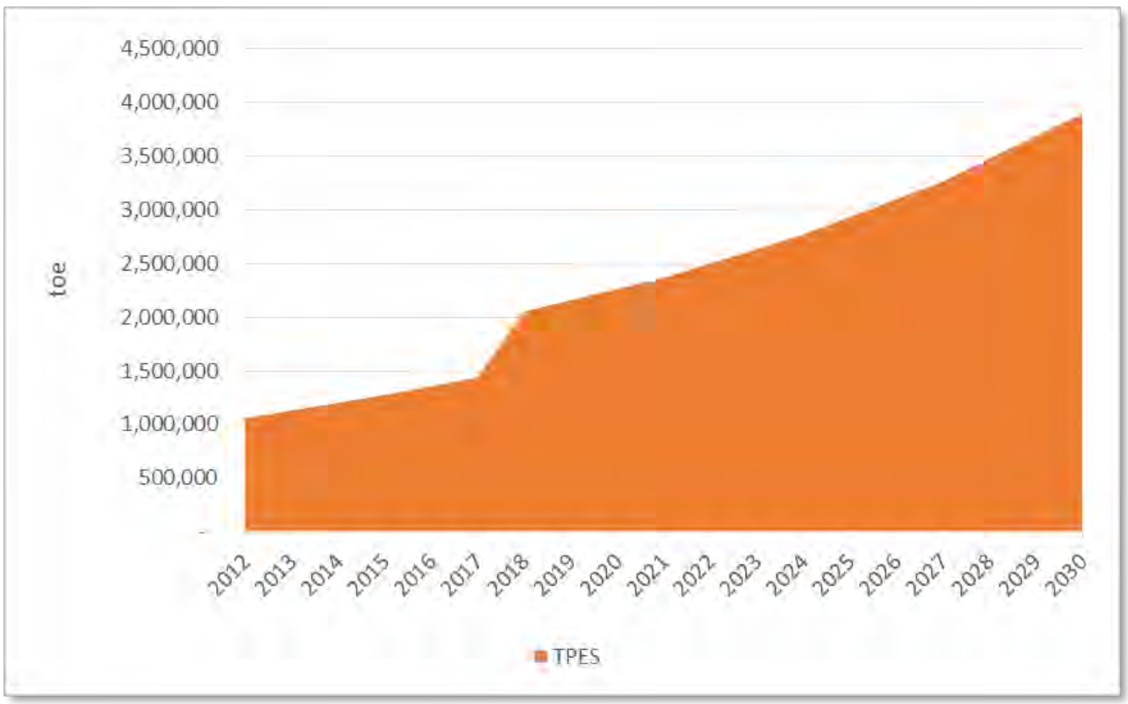
Table I-7: Compound Annual Growth Rate Projections – Oil

Fuel	CAGR	Comment
Total Oil Production	8.9%	Increasing due to economic growth
Fuel Conversion Loss	3.5%	Reducing with new refinery
Oil Product Demand	4.7%	TFEC

Source: Consultant's analysis

19. The primary energy forecast for Myanmar's natural gas is given by Figure I-8. It can be seen that total gas production is required to increase over time, mainly due to industrial demand. The production allocation by sector is given as Figure I-9. The corresponding compound annual growth rates are given in Table I-8.

Figure I-8: Natural Gas TPES Forecast (toe)



Source: Consultant's analysis

Figure I-9: Natural Gas - Primary Energy Demand by Sector (MMCFD)

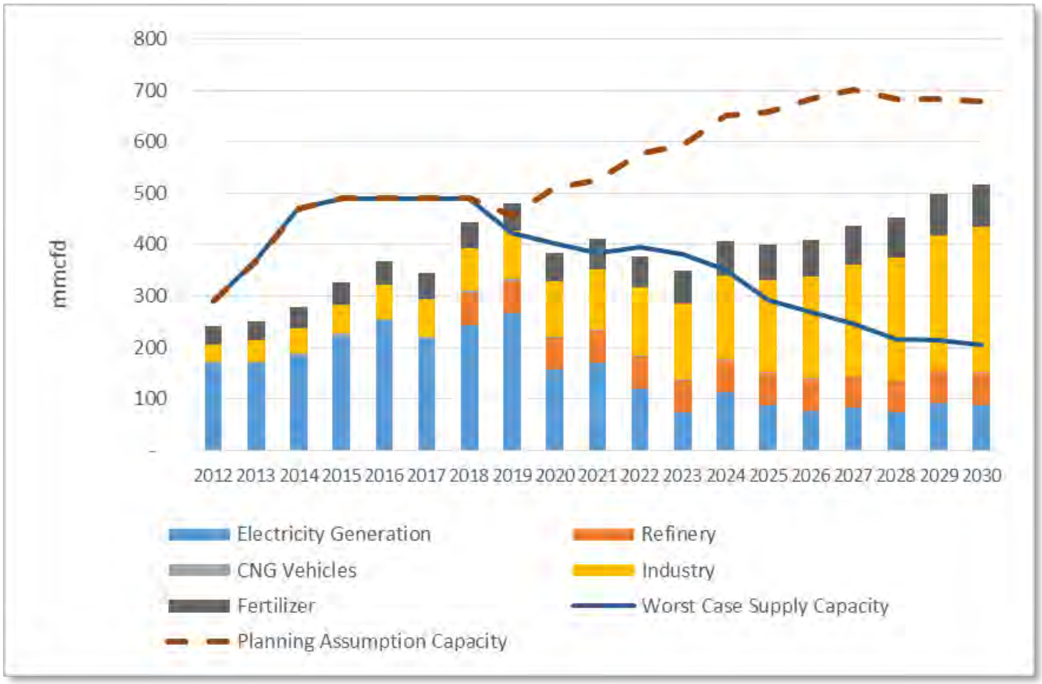
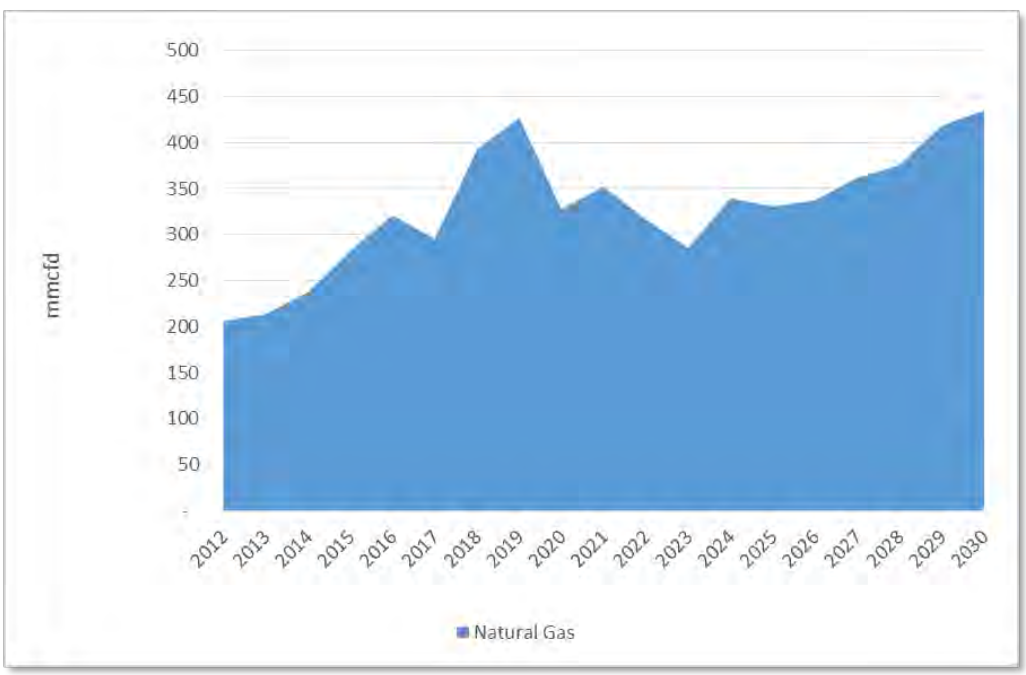


Figure I-10: Natural Gas TPES Forecast (physical)



Source: Consultant's analysis

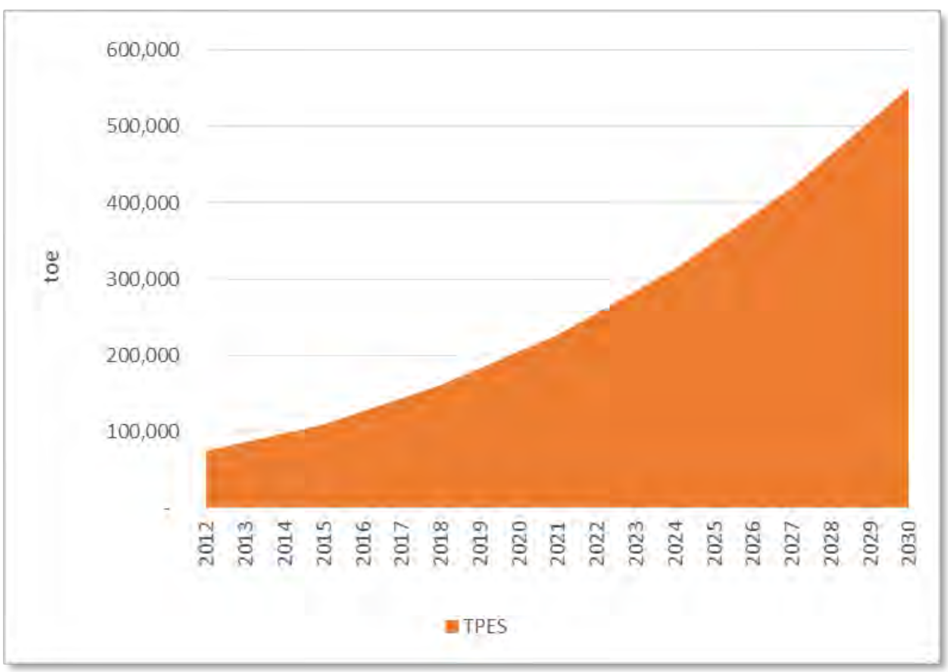
Table I-8: Compound Annual Growth Rate Projections – Gas

Fuel	CAGR	Comment
Total Gas Production	7.3%	Increasing mainly due to industry consumption
Fuel Conversion Loss	7.3%	Increasing as gas increases in supply mix
Net Production	7.3%	TFEC
Electricity Generation	-10.5%	Decreasing as gas decreases in supply mix
Refinery	0.0%	Excluded due to recommendation to power the refinery with distillate
Fertilizer	4.5%	Included but noting that economics of fertilizer production does not appear to be positive for Myanmar
Transport	-6.2%	Reducing as CNG is reduced
Industrial	11.4%	Strongly increasing due to economic growth

Source: Consultant's analysis

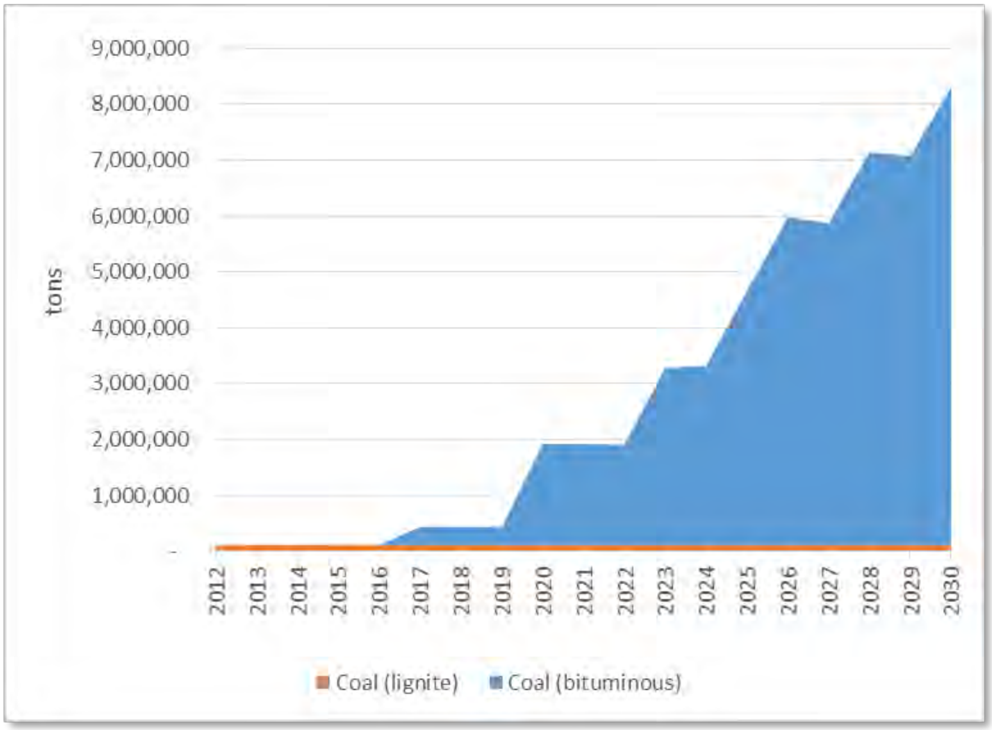
20. The primary energy forecast for Myanmar's industrial coal use is given by Figure I-11. It can be seen that the coal requirement increases strongly with time. The corresponding compound annual growth rates are given in Table I-9. Figure I-12 shows the coal consumption projection to meet the industrial and power generation sector needs.

Figure I-11: Coal TPES Forecast (toe)



Source: Consultant's analysis

Figure I-12: Coal TPES Forecast (physical)



Source: Consultant's analysis

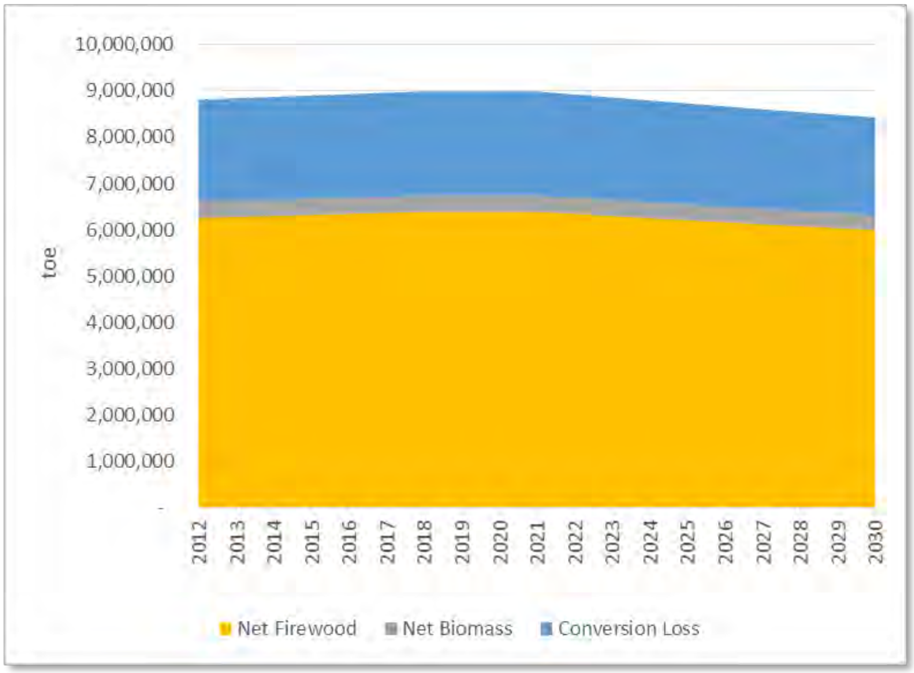
Table I-9: Compound Annual Growth Rate Projections – Coal

Fuel	CAGR	Comment
Total Coal Production	10.9%	Increasing due to power production
Fuel Conversion Loss	0.0%	No losses accounted for in coal winning and transport
Net Production	10.9%	TFEC
Electricity Generation	25.5%	Increasing due to increasing coal in supply mix
Industry	10.9%	Increasing with economic growth

Source: Consultant's analysis

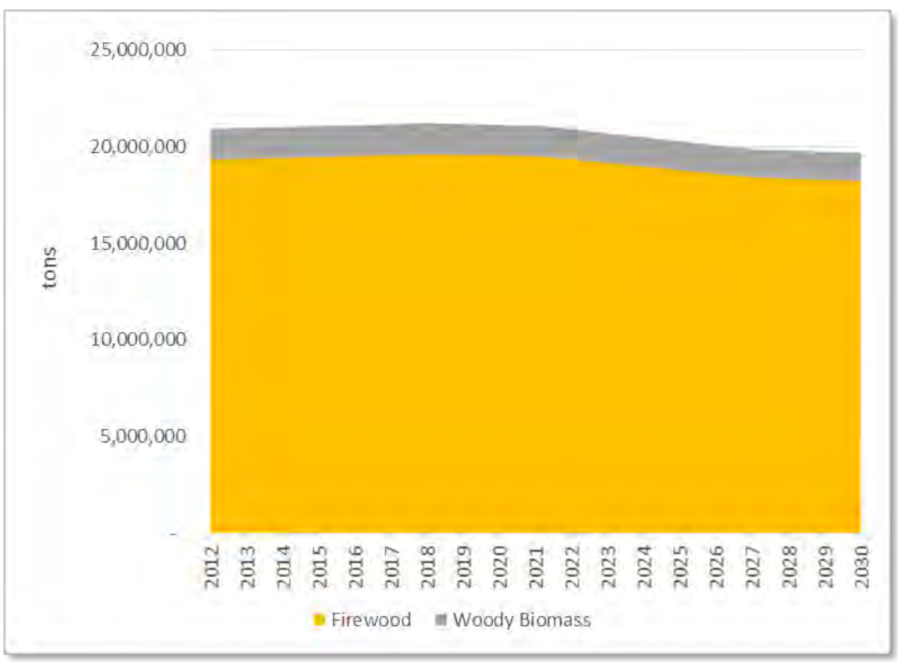
21. The primary energy forecast for Myanmar's Type II biofuel (fuel woods including firewood, charcoal and woody biomass) is given by Figure I-13. It can be seen that as a result of rural electrification, the use of fuelwood falls with time. This growth pattern is based on an assumption that the delivered price of electricity in rural areas will be sufficiently low that electricity substitutes widely for the use of fuelwood for cooking. The corresponding compound annual growth rates are given in Table I-10.

Figure I-13: Fuelwood TPES Forecast (toe)



Source: Consultant's analysis

Figure I-14: Fuelwood TPES Forecast (physical)



Source: Consultant's analysis

Table I-10: Compound Annual Growth Rate Projections - Fuelwood

Fuel	CAGR	Comment
Total Fuelwood Production	-0.3%	Reducing due to substitution with electric cooking
Fuel Conversion Loss	-0.3%	Reducing due to substitution with electric cooking
Net Production	-0.3%	TFEC
Firewood (Cooking)	-0.3%	Reducing due to substitution with electric cooking
Woody biomass (Cooking)	-0.3%	Reducing due to substitution with electric cooking

Source: Consultant's analysis

F. Secondary Energy

22. The secondary energy forms considered are electricity and refined oil products. The secondary energy is equivalent to primary energy net of conversion losses. However, conversion losses in consumer's premises are not included in the projections.

23. The energy forecast for electricity for Myanmar is given by Figure I-15. It can be seen that as a result of rural electrification, electricity use increases substantially. The growth in electricity replaces the need to produce and consume fuelwood thereby easing pressure on Myanmar's forests. The production of by all forms of generation gradually increases over time as the population grows and the economy further develops. The corresponding compound annual growth rates are given in Table I-11.

Figure I-15: Electricity TPES Forecast (toe)

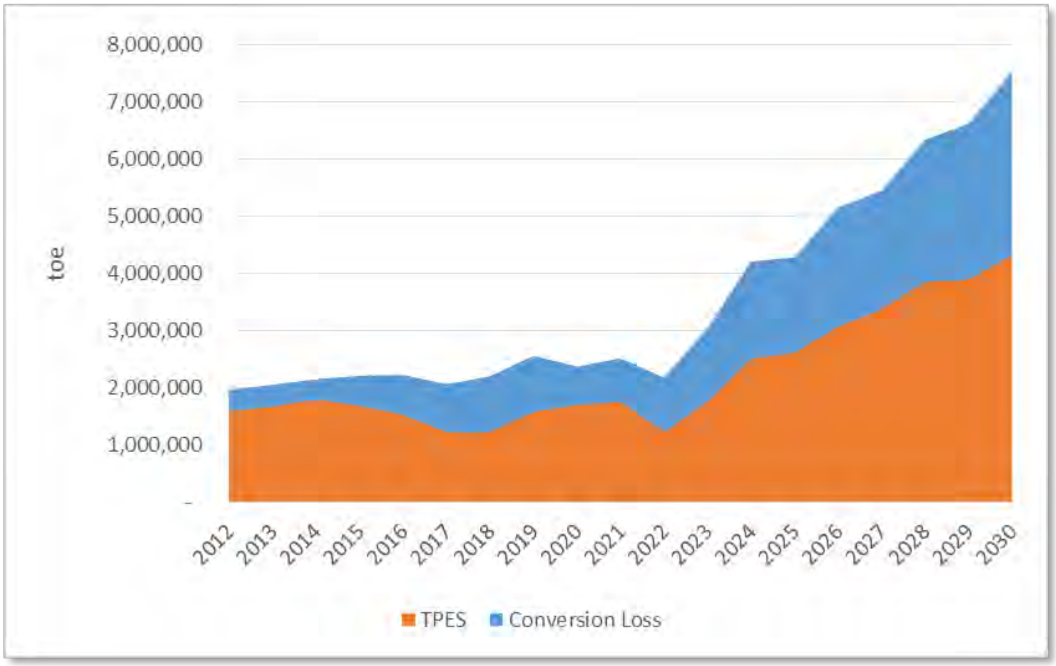
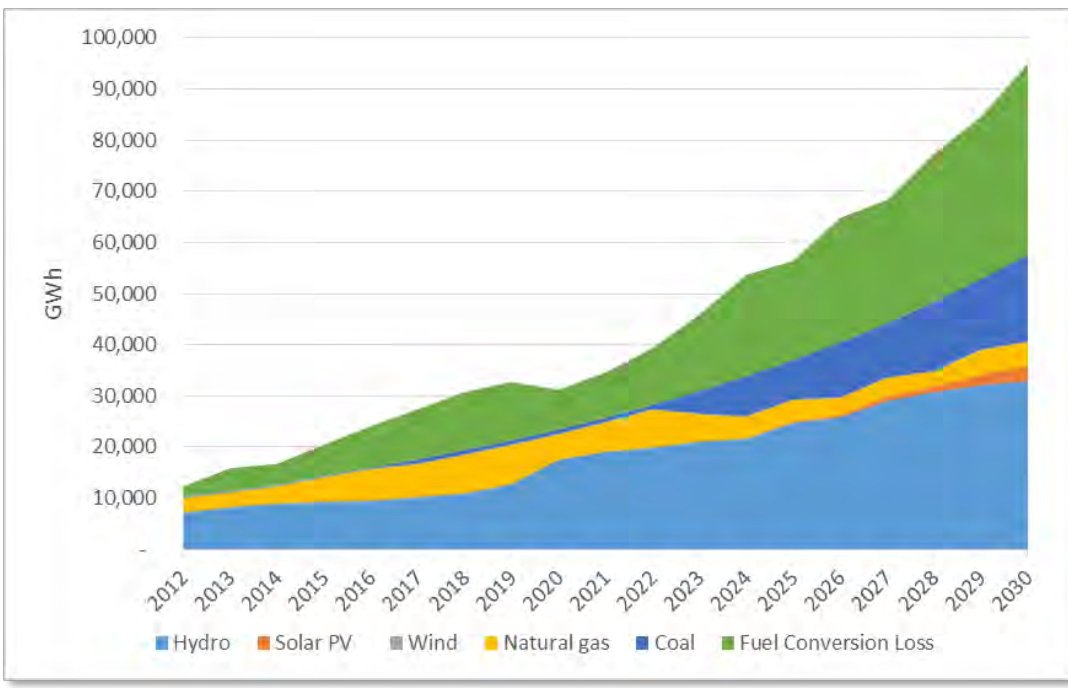


Figure I-16: Electricity TPES Forecast (physical)



Source: Consultant's analysis

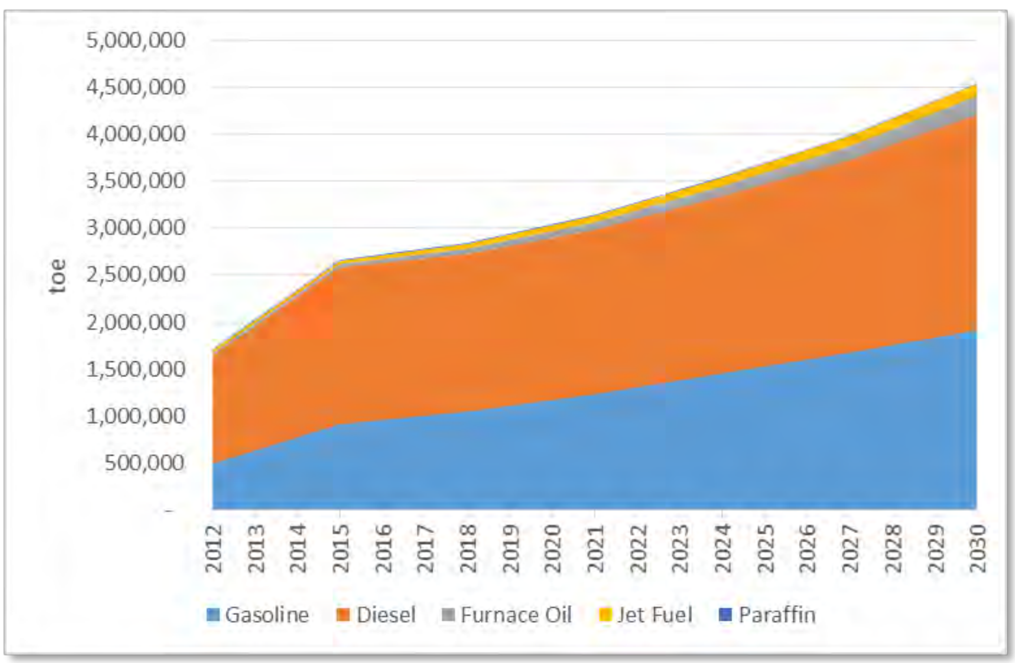
Table I-11: Compound Annual Growth Rate Projections – Electricity

Fuel	CAGR	Comment
Total Electricity Production	7.6%	Strong growth due to rural electrification
Fuel Conversion Loss	12.5%	Increasing due to thermal power
Net Total Energy	5.6%	TFEC rate
Hydropower	8.1%	Increasing due to MoEP programme
Solar PV	n.a.	Enters in 2015
Wind	0.0%	Not included
Gas	-10.5%	Increase to 2022, then declines as coal-fired power and hydropower increases
Coal	25%	Increasing strongly due to thermal power

Source: Growth rates projections based on ADICA – see EMP Electricity Strategy report

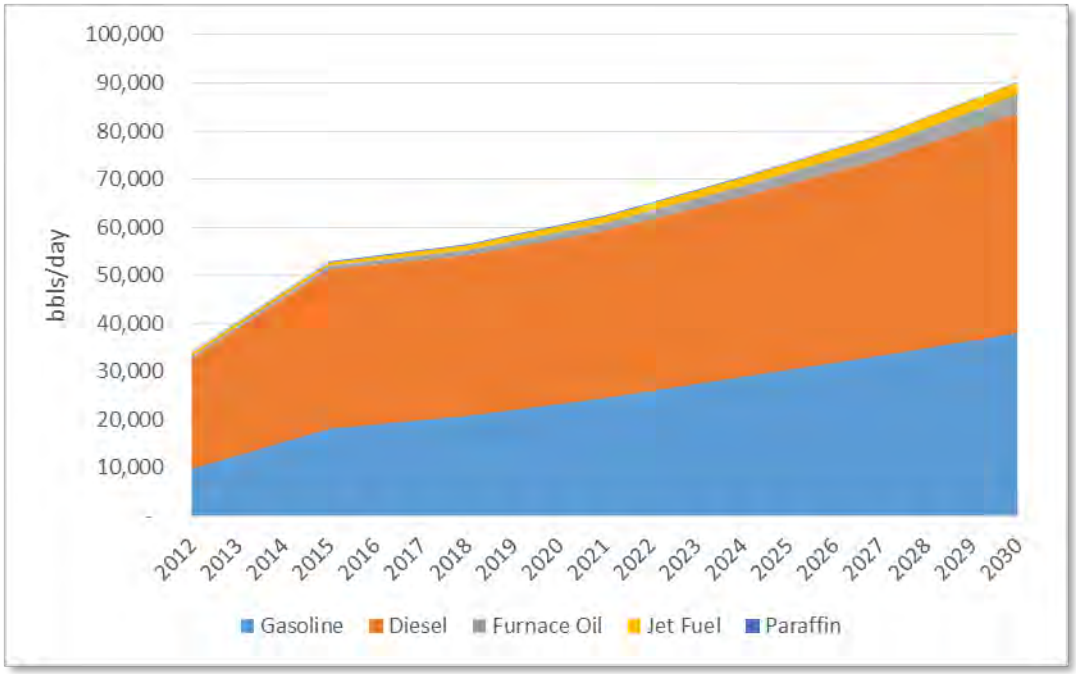
24. The secondary energy forecast for refined oil products is given by Figure I-17. It can be seen that the production of refined oil products increases strongly as demand grows due to economic development. The efficiency of the oil refining sector will increase with a new refinery. If one refinery of 50 000 bopd is built, then imports will be required above this limit. The corresponding compound annual growth rates are given in Table I-12.

Figure I-17: Refined Oil Products TPES Forecast (toe)



Source: Consultant's analysis

Figure I-18: Refined Oil Products TPES Forecast (physicals)



Source: Consultant's analysis

Table I-12: Compound Annual Growth Rate Projections – Refinery

Fuel	CAGR	Comment
Total Oil Production	8.9%	Increasing due to economic growth
Fuel Conversion Loss	3.5%	Reducing with new refinery
Oil Product Demand	4.7%	TFEC
Gasoline	6.5%	Increasing due to economic growth
Diesel	3.2%	ditto
Furnace Oil	11.1%	ditto
Jet Fuel	8.2%	ditto
Paraffin	-2.8%	Reducing due to substitution of paraffin with electricity for lighting
LPG	1.2%	Increasing slowly mainly due to restaurant use; assumed that LPG will not penetrate households due to electrification programme

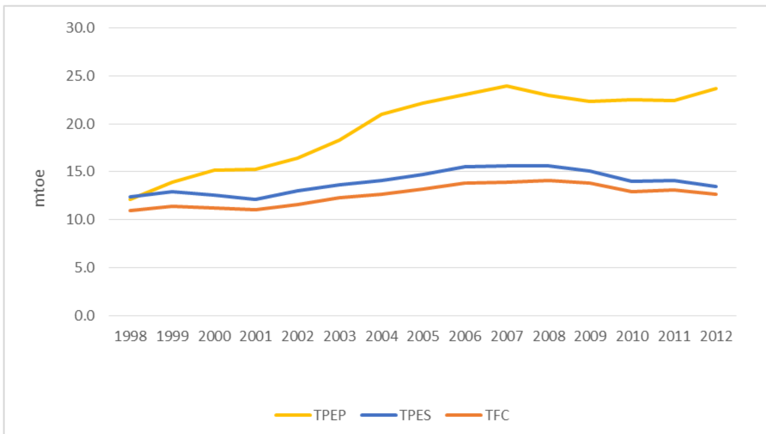
Source: Consultant's analysis

II. IEA ENERGY BALANCE RECONCILIATION

G. Historical Trend

26. The IEA has tracked Myanmar's Energy Balance since at least 1998. The Consultant understands that the Energy Balance has been formulated each year based on reports provided by the Ministry of Energy. Figure II-1 shows the reported trend in TPEP, TPES and TFEC for the years 2000 to 2011.

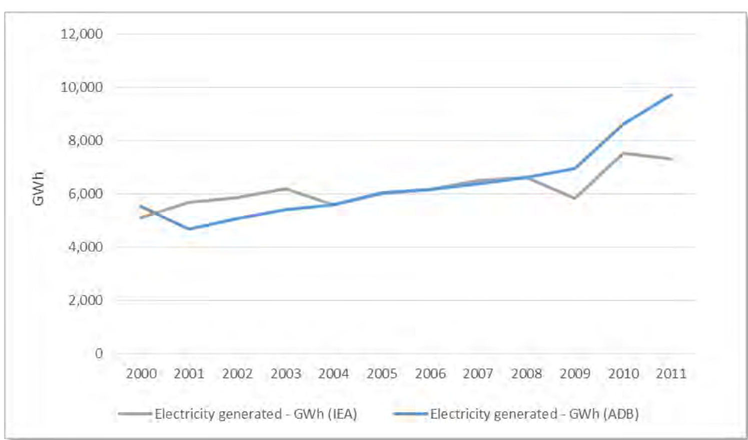
Figure II-1: Historical IEA Energy Balance



Source: Consultant's analysis

27. In addition a comparison has been prepared showing the sent-out electricity generation reported by the IEA and by the ADB. There are clearly some discrepancies, most notably in the last few years.

Figure II-2: Historical Electricity Generation (IEA, ADB)

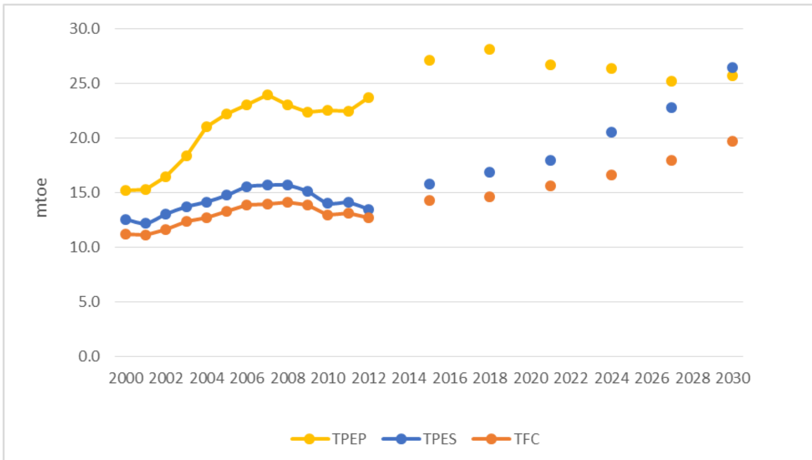


Source: Consultant's analysis

28. An Energy Balance was constructed from the EMP using a bottom up method. Surveys were used to capture energy consumption and production data in as rigorous a manner as possible. The Energy Balance was projected on a three-year basis from 2012 to 2030.

29. The forecast is shown by Figure II-3. The forecast matches with the energy projections presented as Table I-1 to Table I-4. It can be observed that local production capacity (TPES) rises to create a healthy margin over TFEC. TPEP falls as gas production and export reduces.

Figure II-3: Energy Balance Projection to 2030

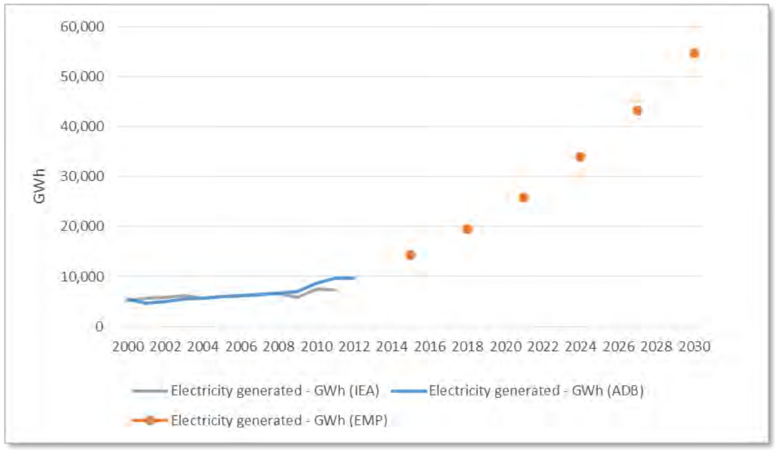


Source: Consultant's analysis

30. It can be seen from Figure II-3 that the IEA Energy Balance and EMP Energy Balance show a smooth extrapolation across the 2012 boundary point. The full set of Energy Balance tables for years 2012, then 2015, 2018, 2021, 2024, 2027 and 2030 is provided as Appendix A to this report. The Energy Balance tables are provided in IEA format.

31. Sent-out electricity generation has also been forecast and is shown here against the historical figures. It can be seen that electricity generation rises at a substantial rate due to anticipated rural electrification. It can also be seen that the projection is smoothly in line with the historical figures reported by the IEA and the ADB. The noticeable fall in the growth rate of electricity in 2021 is due to the introduction of a large hydropower plant with associated reduction in conversion losses.

Figure II-4: Energy Balance Projection to 2030



Source: Consultant's analysis

III. ELECTRICITY

H. Electricity – Total Primary Energy Production

32. The Consultant has assumed that all local electricity needs will be met by local power plants. Electricity that is currently produced by hydropower schemes dedicated for export to China is not considered as part of an IEA energy balance since Myanmar neither produces nor consumes any part of the plant output. It has been assumed that no further electricity export will take place during the planning period to 2030, in other words it has been assumed that Myanmar will not build large hydropower schemes or any other power plants specifically for electricity trade.

Table III-1: Electricity Demand & Transformation Losses

	2012	2015	2018	2021	2024	2027	2030
INPUT (mtoe)	1.97	2.22	2.21	2.52	4.22	5.45	7.54
OUTPUT Electricity (GWh)	10,364	14,398	19,446	25,763	33,904	44,238	57,654
Electricity output shares (%)							
Hydro	69.7%	65.0%	56.5%	74.1%	64.0%	65.7%	57.1%
Solar PV	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	5.2%
Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural gas	28.1%	33.4%	38.9%	22.4%	12.7%	8.3%	8.2%
Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coal	2.2%	1.6%	4.6%	3.4%	23.3%	24.0%	29.5%

TOTAL LOSSES (mtoe) of which:

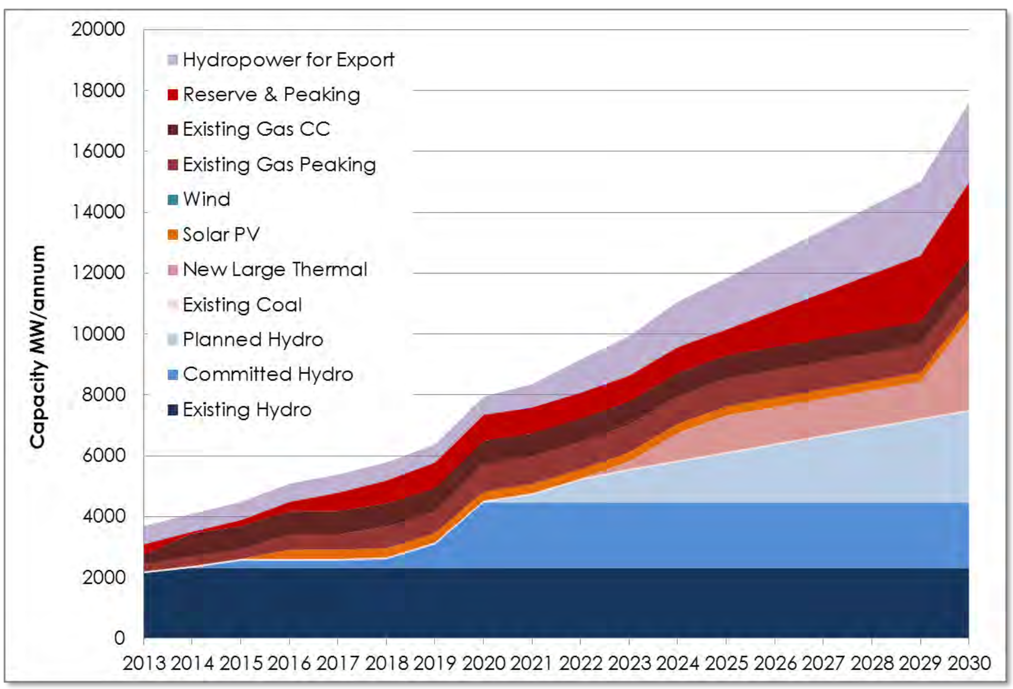
Electricity generation	0.37	0.52	0.98	0.76	1.70	2.07	3.21
T&D losses	0.19	0.24	0.30	0.36	0.42	0.50	0.58
Total	0.56	0.76	1.27	1.12	2.12	2.57	3.79
Electricity generation[8]	18.6%	23.5%	44.1%	30.1%	40.3%	38.0%	42.6%
T&D losses	9.6%	10.8%	13.4%	14.1%	10.0%	9.2%	7.7%
Total	28.2%	34.3%	57.6%	44.2%	50.4%	47.2%	50.3%

Source: Consultant's analysis

33. Under the optimal expansion, defined as the ADICA expansion, electricity output shares would change in favour of coal, i.e. the electricity asset portfolio would become more balanced in terms of the fuel mix. The dominance of hydropower would reduce to around 56% from its current level of 72%. The dependence on natural gas will also reduce as expected when gas is used to meet peak demand. Electricity losses will increase as load increases and as coal-fired power plants are introduced. The conversion efficiency of large coal plants is of the order of 43% and so conversion losses increase in proportion to the amount of coal used for electricity generation. The increase can be mitigated to some extent if T&D losses can be reduced.

34. The export capacity of hydropower was not quantified in ADICA's expansion plan. The capacity is given for Case 2 in Figure III-1. However, the associated energy has not been included in the Energy Balance since the plants are owned by Chinese and supply China.

Figure III-1: EMP Case 2 – Hydropower Export to 2030

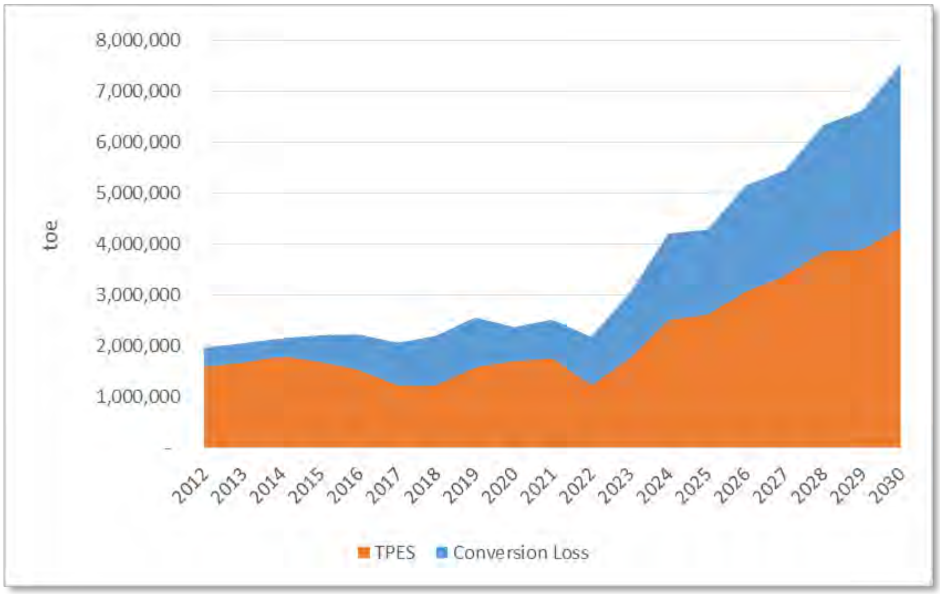


Source: Consultant's analysis

I. Electricity – Total Primary Energy Supply Outlook

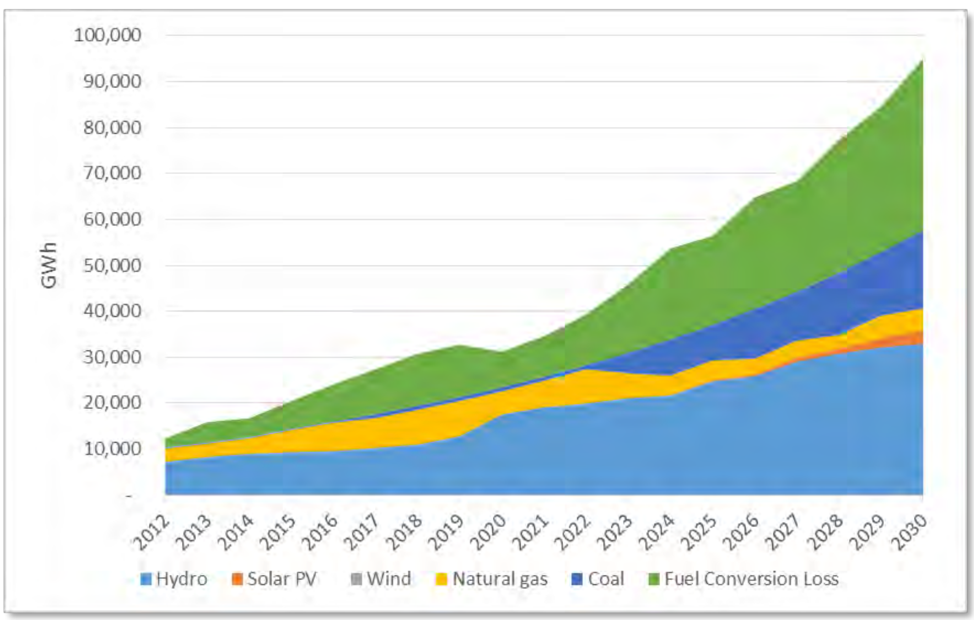
35. The Consultant has determined the TPES for electricity for the ADICA expansion as follows:

Figure III-2: Electricity TPES Forecast (toe)



Source: EMP Consultant forecast

Figure III-3: Electricity TPES Forecast (physical)



Source: Consultant's analysis

36. The compound annual growth rates of electricity production are given between 2013 and 2030 unless otherwise noted.

Table III-2: Compound Annual Growth Rate Projections – Electricity

Fuel	CAGR	Comment
Total Electricity Production	7.6%	Strong growth due to rural electrification
Fuel Conversion Loss	12.5%	Increasing due to thermal power
Net Total Energy	5.6%	TFEC rate
Hydropower	8.1%	Increasing due to MoEP programme
Solar PV	n.a.	Enters in 2015
Wind	0.0%	Not included
Gas	-10.5%	Increase to 2022, then declines as coal-fired power and hydropower increases
Coal	25%	Increasing strongly due to thermal power

Source: Consultant's analysis

37. The energy projection for forecast electricity production, that matches Figure III-3, is given here as Table III-3 for convenience.

Table III-3: Electricity TPES Forecast (ktoe)

	Total	Hydro	Solar PV	Wind	Natural gas	Oil	Coal (lignite)	Coal (bituminous)	Fuel Conversion Loss	Loss	Sent Out Electricity
	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	%	ktoe
2012	1,972	621	0	0	1295	0	55	-	366	19%	1,606
2013	2,063	712	0	0	1295	0	55	-	383	19%	1,680
2014	2,160	772	0	0	1332	0	55	-	352	16%	1,808
2015	2,219	805	0	0	1359	0	55	-	520	23%	1,698
2016	2,237	821	0	0	1361	0	55	-	700	31%	1,537
2017	2,073	882	0	0	971	0	57	162	837	40%	1,235
2018	2,210	945	0	0	1046	0	57	162	975	44%	1,235
2019	2,566	1,103	0	0	1244	0	57	162	977	38%	1,589
2020	2,380	1,511	0	0	653	0	13	204	669	28%	1,711
2021	2,524	1,643	0	0	665	0	13	204	759	30%	1,765
2022	2,190	1,715	0	0	257	0	13	205	953	43%	1,237

	Total	Hydro	Solar PV	Wind	Natural gas	Oil	Coal (lignite)	Coal (bituminous)	Fuel Conversion Loss	Loss	Sent Out Electricity
	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	%	ktoe
2023	3,053	1,815	0	0	138	0	38	1,062	1,280	42%	1,773
2024	4,215	1,866	0	0	405	0	67	1,877	1,699	40%	2,516
2025	4,289	2,130	27	0	237	0	46	1,849	1,667	39%	2,623
2026	5,165	2,227	34	0	226	0	51	2,626	2,088	40%	3,077
2027	5,455	2,498	95	0	250	0	51	2,561	2,071	38%	3,383
2028	6,346	2,650	109	0	241	0	53	3,292	2,482	39%	3,863
2029	6,624	2,764	211	0	238	0	55	3,355	2,723	41%	3,900
2030	7,542	2,832	314	0	216	0	57	4,122	3,210	43%	4,332

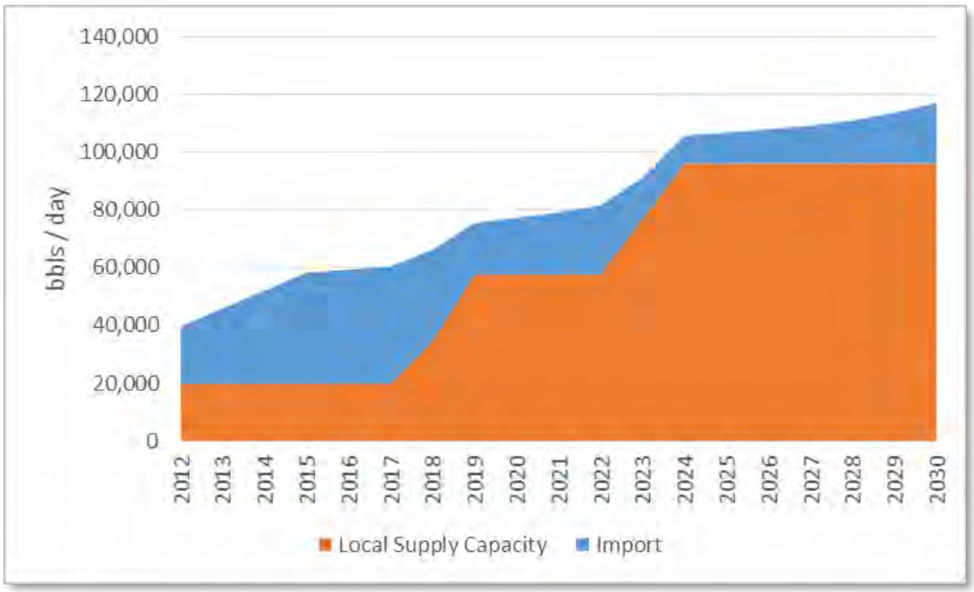
Source: Consultant's analysis

IV. OIL & REFINED OIL PRODUCTS

J. Oil – Total Primary Energy Production

38. The Consultant has assumed that a local refinery will be constructed by 2019. The capacity will initially be 50 000 bpd. The projection for refined oil products suggests that additional capacity of 50 000 bpd will be required by 2024. Nevertheless in most years it will be necessary to import oil.

Figure IV-1: Oil Production Local vs. Import (physical)



Source: Consultant's analysis

K. Oil – Total Primary Energy Supply Outlook

39. The primary energy supply requirements of oil has been forecast in terms of tons of oil, barrels per day and imperial gallons per annum. The results are given in the following charts and table.

Figure IV-2: Oil TPES Forecast (toe)

Figure IV-3: Oil TPES Forecast (physical)

Source: Consultant's analysis

40. The compound annual growth rates for oil production are given between 2013 and 2030 unless otherwise noted.

Table IV-1: Compound Annual Growth Rate Projections (2013 to 2030)

Fuel	CAGR	Comment
Total Oil Production	8.9%	Increasing due to economic growth
Fuel Conversion Loss	3.5%	Reducing with new refinery
Oil Product Demand	4.7%	TFEC
Gasoline	6.5%	Increasing due to economic growth
Diesel	3.2%	ditto
Furnace Oil	11.1%	ditto
Jet Fuel	8.2%	ditto
Paraffin	-2.8%	Reducing due to substitution of paraffin with electricity for lighting
LPG	1.2%	Increasing slowly mainly due to restaurant use; assumed that LPG will not penetrate households due to electrification programme

Source: Consultant's analysis

Table IV-2: Oil & Gas Condensates TPES Forecast (ktoe)

	Total Primary Energy	Conversion Efficiency	Loss	Total	Gasoline	Diesel	Furnace Oil	Jet Fuel	Paraffin	LPG
	ktoe	ktoe	%	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe
2012	583	58	10%	525	302	236	20	16	8	78
2013	587	59	10%	587	302	236	24	16	8	78
2014	590	59	10%	590	302	236	28	16	8	78
2015	594	59	10%	594	302	236	31	16	8	78
2016	599	60	4%	599	302	236	36	16	8	78
2017	604	60	4%	604	302	236	41	16	8	78
2018	1,023	41	4%	1,023	527	413	47	28	9	78
2019	1,674	67	4%	1,674	878	688	53	46	9	78
2020	1,681	67	4%	1,681	878	688	59	47	9	-
2021	1,688	68	4%	1,688	878	688	66	47	9	-
2022	1,696	68	4%	1,696	878	688	74	47	9	-
2023	2,201	88	4%	2,201	1,129	917	82	63	8	-
2024	2,507	100	4%	2,507	1,190	1,146	91	72	8	-
2025	2,582	103	4%	2,582	1,250	1,146	101	77	7	-

	Total Primary Energy	Conversion Efficiency	Loss	Total	Gasoline	Diesel	Furnace Oil	Jet Fuel	Paraffin	LPG
2026	2,654	106	4%	2,654	1,310	1,146	111	79	7	-
2027	2,724	109	4%	2,724	1,370	1,146	121	79	7	-
2028	2,801	112	4%	2,801	1,435	1,146	134	79	6	-
2029	2,841	114	4%	2,841	1,463	1,146	147	79	6	-
2030	2,853	114	4%	2,853	1,463	1,146	160	79	5	-

Source: Consultant's analysis

Table IV-3: Oil TPES Forecast (bbl per day)

	Total Primary Energy	Conversion Efficiency	Loss	Total	Gasoline	Diesel	Furnace Oil	Jet Fuel	Paraffin
	bbl/day	bbl/day	%	bbl/day	bbl/day	bbl/day	bbl/day	bbl/day	bbl/day
2013	14,158	1,416	10%	12,743	7,326	5,742	496	396	198
2014	14,245	1,425	10%	14,245	7,326	5,742	583	396	198
2015	14,332	1,433	10%	14,332	7,326	5,742	670	396	198
2016	14,419	1,442	10%	14,419	7,326	5,742	757	396	198
2017	14,543	1,454	10%	14,543	7,326	5,742	881	396	198
2018	14,668	1,467	10%	14,668	7,326	5,742	1,006	396	198
2019	24,847	994	4%	24,847	12,787	10,022	1,130	691	216
2020	40,646	1,626	4%	40,646	21,312	16,704	1,288	1,125	217
2021	40,830	1,633	4%	40,830	21,312	16,704	1,445	1,152	218
2022	40,988	1,640	4%	40,988	21,312	16,704	1,602	1,152	219
2023	41,178	1,647	4%	41,178	21,312	16,704	1,801	1,152	209
2024	53,437	2,137	4%	53,437	27,428	22,272	2,001	1,536	199
2025	60,878	2,435	4%	60,878	28,897	27,840	2,200	1,750	190
2026	62,701	2,508	4%	62,701	30,357	27,840	2,448	1,875	180
2027	64,443	2,578	4%	64,443	31,817	27,840	2,696	1,920	171
2028	66,141	2,646	4%	66,141	33,277	27,840	2,943	1,920	161
2029	68,023	2,721	4%	68,023	34,857	27,840	3,255	1,920	151
2030	68,988	2,760	4%	68,988	35,520	27,840	3,567	1,920	141

Source: Consultant's analysis

Table IV-4: Oil TPES Forecast (IG '000's)

	Total Primary Energy	Conversion Efficiency	Loss	Total	Gasoline	Diesel	Furnace Oil	Jet Fuel	Paraffin
	IG '000s	IG '000s	%	IG '000s	IG '000s	IG '000s	IG '000s	IG '000s	IG '000s
2012	147,771	14,777	-90%	132,993	76,461	59,929	5,181	4,133	2,067
2013	148,676	14,868	10%	148,676	76,461	59,929	6,087	4,133	2,067
2014	149,582	14,958	10%	149,582	76,461	59,929	6,993	4,133	2,067
2015	150,488	15,049	10%	150,488	76,461	59,929	7,899	4,133	2,067
2016	151,788	15,179	10%	151,788	76,461	59,929	9,199	4,133	2,067
2017	153,088	15,309	10%	153,088	76,461	59,929	10,499	4,133	2,067
2018	259,329	10,373	4%	259,329	133,459	104,603	11,798	7,214	2,255
2019	424,215	16,969	4%	424,215	222,432	174,338	13,438	11,743	2,264
2020	426,144	17,046	4%	426,144	222,432	174,338	15,077	12,023	2,273
2021	427,793	17,112	4%	427,793	222,432	174,338	16,717	12,023	2,283
2022	429,776	17,191	4%	429,776	222,432	174,338	18,800	12,023	2,182
2023	557,714	22,309	4%	557,714	286,267	232,451	20,883	16,031	2,082
2024	635,379	25,415	4%	635,379	301,600	290,564	22,966	18,267	1,982
2025	654,403	26,176	4%	654,403	316,836	290,564	25,549	19,572	1,882
2026	672,589	26,904	4%	672,589	332,073	290,564	28,133	20,039	1,781
2027	690,308	27,612	4%	690,308	347,309	290,564	30,716	20,039	1,681
2028	709,954	28,398	4%	709,954	363,802	290,564	33,971	20,039	1,578
2029	720,024	28,801	4%	720,024	370,719	290,564	37,226	20,039	1,475
2030	723,176	28,927	4%	723,176	370,719	290,564	40,482	20,039	1,372

Source: Consultant's analysis

V. NATURAL GAS

L. Natural Gas – Total Primary Energy Production

41. The Consultant has assumed that the M3 field will be indefinitely delayed and no new gas fields will commence operation during the period of the planning horizon. This represents a worst case scenario with a tight gas supply – demand outlook. However, as was discussed in the Liquid & Gaseous Fuel Strategy report there is an opportunity to manage the risks that natural gas supplies does not develop as anticipated.

Table V-1: Gas Supply Risk Mitigation circa 2019

	MMCF	MMCFD	Comment
Refinery	22,630	62	Hydro-cracking refinery needs hydrogen and usually powered with natural gas power plant
Power	81,030	222	EMP estimate
Fertilizer	20,552	56	Standard-run production plant 1 725 mtpd
Industry	38,623	106	EMP estimate
Total	~165,000	~548	
Available gas	~150,000	~411	Yadana, Yetagun, Shwe, Zawtika
	Potential to Reduce Gas Consumption		
Refinery	(7,500)	(21)	Power the refinery using liquid fuels (30 – 40 MW)
Power sector	(30,250)	(83)	Increase hydropower, gas / oil plant
Fertilizer	(10,000)	(27)	Import fertilizer
Total	(50,000)	(137)	

Source: Consultant's analysis

42. The refinery design can be modified to minimize gas consumption. In principle the use of gas for power generation could be replaced by oil or storage hydropower capacity for deployment at times of peak demand. A fertilizer plant appears to be uneconomic and gas could be saved by importing urea. These measures have been assumed ahead of the development of an LNG terminal because the cost of LNG will be high and market acceptance may therefore be low.

M. Natural Gas – Primary Energy Supply Outlook

43. Natural gas production requirements are expected to rise significantly mainly due to industrial sector demand. The compound annual growth rates of Table V-2 show this clearly.

Figure V-1: Natural Gas TPES Forecast (toe) (excl. electricity)

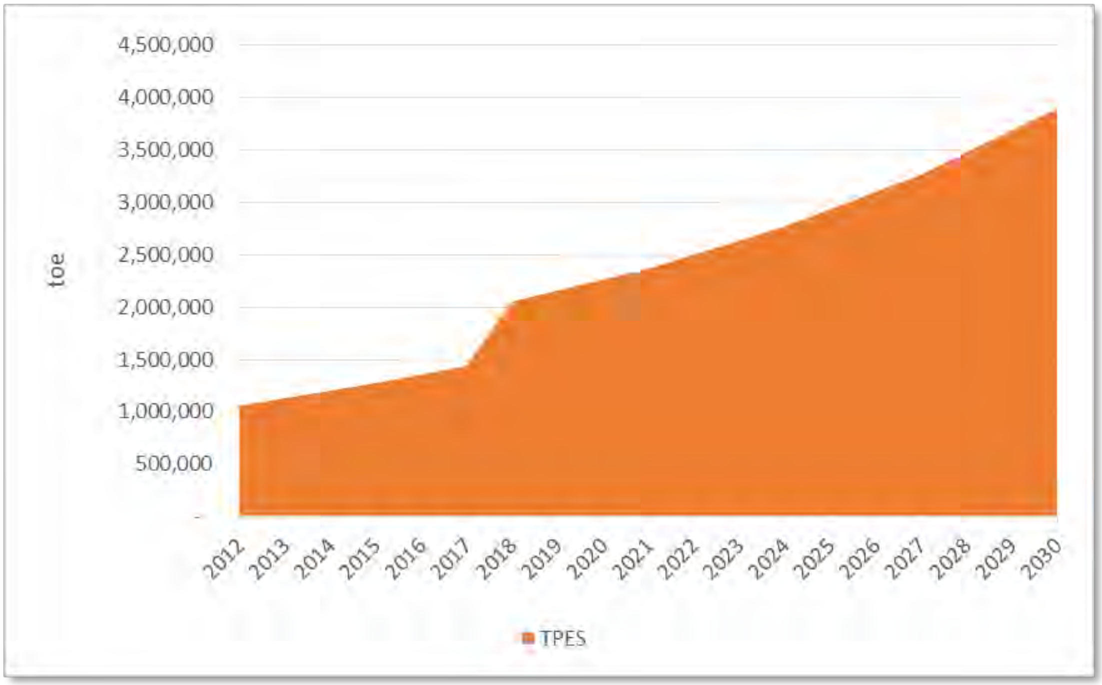
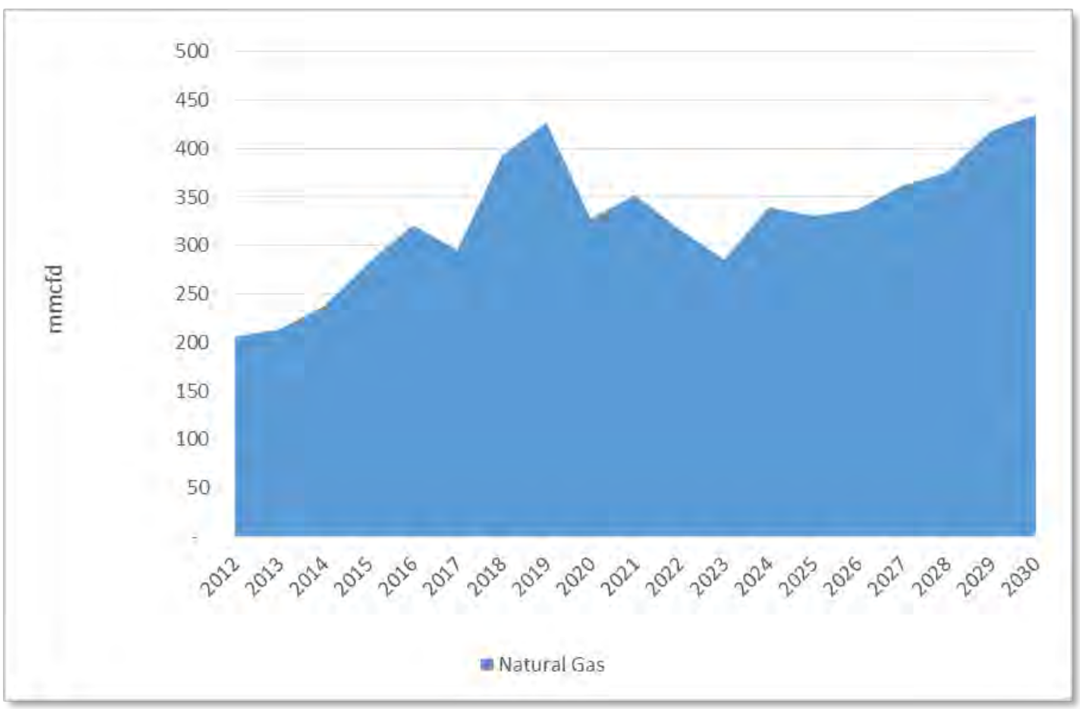


Figure V-2: Natural Gas TPES Forecast (physical) (incl. electricity)



Source: Consultant's analysis

44. The compound annual growth rates for gas production are given between 2013 and 2030 unless otherwise noted.

Table V-2: Compound Annual Growth Rate Projections (2013 to 2030)

Fuel	CAGR	Comment
Total Gas Production	7.3%	Increasing mainly due to industry consumption
Fuel Conversion Loss	7.3%	Increasing as gas increases in supply mix
Net Production	7.3%	TFEC
Electricity Generation	-10.5%	Decreasing as gas decreases in supply mix
Refinery	0.0%	Excluded due to recommendation to power the refinery with distillate
Fertilizer	4.5%	Included but noting that economics of fertilizer production does not appear to be positive for Myanmar
Transport	-6.2%	Reducing as CNG is reduced
Industrial	11.4%	Strongly increasing due to economic growth

Source: Consultant's analysis

45. The energy projection for forecast natural gas production, that matches Figure V-2, is given here as a table for convenience:

Table V-3: Natural Gas TPES Forecast (toe)

	Total Primary Energy	Conversion Efficiency	Loss	Total with Electricity	Electricity Generation	Refinery	Transport	Industrial
	toe	toe	%	toe	toe	toe	toe	toe
2012	324,642		0%	324,642	1,295,429	-	31,738	291,609
2013	389,998	-	0%	389,998	1,295,429	-	35,789	352,913
2014	455,391	-	0%	455,391	1,332,382	-	39,841	414,217
2015	520,773	-	0%	520,773	1,358,717	-	43,893	475,521
2016	595,369	-	0%	595,369	1,360,866	-	40,244	553,763
2017	669,573	-	0%	669,573	971,245	-	36,596	632,005
2018	1,276,046	-	0%	1,276,046	1,046,338	531,805	32,948	710,247
2019	1,372,196	-	0%	1,372,196	1,243,894	531,805	30,202	808,945
2020	1,467,557	-	0%	1,467,557	652,517	531,805	27,456	907,643
2021	1,563,521	-	0%	1,563,521	664,559	531,805	24,710	1,006,341
2022	1,686,182	-	0%	1,686,182	257,080	531,805	22,376	1,131,744
2023	1,809,131	-	0%	1,809,131	137,745	531,805	20,042	1,257,146
2024	1,932,466	-	0%	1,932,466	405,005	531,805	17,707	1,382,549

	Total Primary Energy	Conversion Efficiency	Loss	Total with Electricity	Electricity Generation	Refinery	Transport	Industrial
2025	2,085,790	-	0%	2,085,790	236,889	531,805	15,686	1,538,062
2026	2,239,271	-	0%	2,239,271	226,188	531,805	13,665	1,693,575
2027	2,392,787	-	0%	2,392,787	250,089	531,805	11,644	1,849,088
2028	2,588,994	-	0%	2,588,994	241,454	531,805	11,898	2,045,050
2029	2,785,207	-	0%	2,785,207	238,151	531,805	12,152	2,241,012
2030	2,981,401	-	0%	2,981,401	215,911	531,805	12,407	2,436,974

Source: Consultant's analysis

Table V-4: Natural Gas TPES Forecast (MMCF)

	Total Primary Energy	Conversion Efficiency	Loss	Total with Electricity	Electricity Generation	Refinery	Transport	Industrial
	mmcf	mmcf	%	mmcf	mmcf	mmcf	mmcf	mmcf
2012	75,189	-	0%	75,189	61,432	-	1,351	12,409
2013	77,970	-	0%	77,970	61,432	-	1,523	15,018
2014	86,628	-	0%	86,628	67,307	-	1,695	17,626
2015	102,987	-	0%	102,987	78,221	-	1,868	20,235
2016	117,184	-	0%	117,184	87,962	-	1,713	23,564
2017	107,802	-	0%	107,802	73,022	-	1,557	26,894
2018	143,242	-	0%	143,242	80,633	22,630	1,402	30,223
2019	155,830	-	0%	155,830	81,079	22,630	1,285	34,423
2020	119,580	-	0%	119,580	35,114	22,630	1,168	38,623
2021	128,482	-	0%	128,482	40,892	22,630	1,052	42,823
2022	115,505	-	0%	115,505	54,384	22,630	952	48,159
2023	104,244	-	0%	104,244	38,284	22,630	853	53,496
2024	123,898	-	0%	123,898	30,168	22,630	754	58,832
2025	120,648	-	0%	120,648	30,254	22,630	668	65,449
2026	123,092	-	0%	123,092	24,059	22,630	581	72,067
2027	132,069	-	0%	132,069	25,880	22,630	495	78,685
2028	137,060	-	0%	137,060	21,221	22,630	506	87,023
2029	152,673	-	0%	152,673	36,204	22,630	517	95,362
2030	158,833	-	0%	158,833	35,101	22,630	528	103,701

Table V-5: Natural Gas TPES Forecast (MMCFD)

	Total Primary Energy	Conversion Efficiency	Loss	Total with Electricity	Electricity Generation	Refinery	Transport	Industrial
	mmcfd	mmcfd	%	mmcfd	mmcfd	mmcfd	mmcfd	mmcfd
2012	206	-	0%	206	168	-	4	34
2013	214	-	0%	214	168	-	4	41
2014	237	-	0%	237	184	-	5	48
2015	282	-	0%	282	214	-	5	55
2016	321	-	0%	321	241	-	5	65
2017	295	-	0%	295	200	-	4	74
2018	392	-	0%	392	221	62	4	83
2019	427	-	0%	427	222	62	4	94
2020	328	-	0%	328	96	62	3	106
2021	352	-	0%	352	112	62	3	117
2022	316	-	0%	316	149	62	3	132
2023	286	-	0%	286	105	62	2	147
2024	339	-	0%	339	83	62	2	161
2025	331	-	0%	331	83	62	2	179
2026	337	-	0%	337	66	62	2	197
2027	362	-	0%	362	71	62	1	216
2028	376	-	0%	376	58	62	1	238
2029	418	-	0%	418	99	62	1	261
2030	435	-	0%	435	96	62	1	284

Source: Consultant's analysis

VI. COAL

N. Introduction

46. Myanmar possesses large coal reserves (230 million ton probable and 120 million ton possible). The largest reserves are in Kalewa region and central east of Myanmar (Maingsat). Coals are accessible for extraction but due to road conditions could be difficulties for their further transportation. Projects for infrastructure improvement are ongoing thus this factor may be mitigated in the future. However, the currently identified domestic coal resources are not sufficient for developing coal-based electricity generation capacities in thousands of megawatts as a 1000 MW coal fired base load plant would consume over its life around 90 to 100 million tons.

47. In 2013 Myanmar produced 790 thousand tons of coal and the production is likely to grow in the future. The government estimates production growth at 40% annually till 2030 in order to meet the growing demand. The growth of demand for coal in Myanmar can be linked to: (i) growing demand in pyro-metallurgical industry; (ii) plans to construct new coal-fired power plants; (iii) replacement of firewood with coal in order to prevent deforestation.

48. Myanmar coals are not of high quality and possess low calorific values (3200 to 6700 kcal/kg); however their low sulphur contaminant allows using them for power production. Modern technologies allow more efficient utilization of low-quality coals' potential.

O. Power

49. At present Myanmar operates only one coal-fired power plant at Tigyit. The plant is of 120 MW installed capacity but operates only 27 MW due to inadequate maintenance. The plans for its rehabilitation have not yet been approved.

50. Data on plans for new coal-fired PPs is somewhat undefined. MOM and MEP have announced three projects with total installed capacity 876 MW (Kalewa, Yangon and Tanintharyi). JICA study referring to Hydropower Generation Enterprise provide information of about 11 projects with a total capacity of 15 GW. All projects are developed by the private sector by both domestic and foreign investors. Some projects include that 50 % of the generated electricity will be exported to neighbouring countries.

51. There are indicators that environmental and social approaches in developing new coal-fired power plants projects are not completely adequate. More attention shall be paid to these issues while developing future power plants. Three types of coal-fired power units have been selected as representative for Myanmar's future coal capacity, namely 600 MW supercritical, 150 MW circulating fluidized bed, and 50 MW pulverized coal fired unit. Cost and operational parameters have been defined for these three representative units for further analysis and expansion planning.

52. Apart from limitations due to available infrastructure, another issue to be considered is the rather limited capacity of the mines. A 300 MW coal-fired power unit would consume around 1 to 1.3 million tons of coal annually (depending on type of plant and calorific value of coal). Therefore, over the life of 30 years the coal supply amounts to 30 to 39 million tons. The largest coal reserve currently listed is Maingsat in Shan State with a capacity of 118 Mtons of probable lignite to sub-bituminous and 4 Mtons of possible sub-bituminous coals. The largest deposit of sub-bituminous coals is at Kalewa in

Southern Sagaing Division with total capacity of 87 Mtons, 5 Mtons of which are positive, 18 Mtons are probable and 65 Mtons are possible. These reserves do not suffice for large scale power development, for example in the range of 1,000 MW supercritical power units, currently typical in the People's Republic of China (the PRC). Therefore the development of coal based power should be carried out in synchrony with the mining development so that capacities of mine mouth plants are properly dimensioned to match the proven and probable resources.

53. The power generation sector supply requirement for coal was defined by the ADICA power sector expansion as follows:-

P. Industry Sector

54. The industry sector demands raw coal for industrial furnace applications. This may be phased out in time if more gas is available to industry.

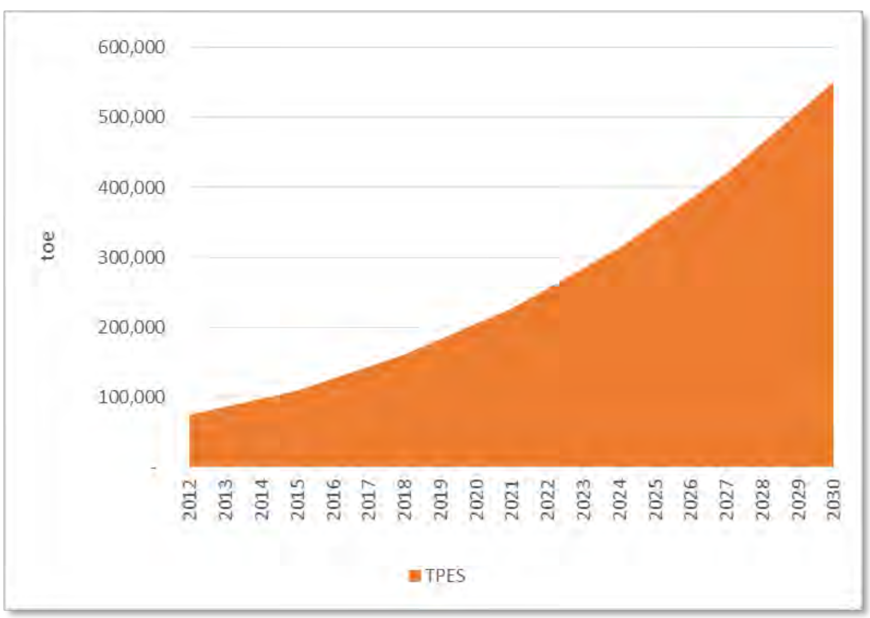
Q. Coal – Total Primary Energy Production

55. The Consultant has assumed that all coal used to power large coal-fired plants (in coastal locations) will be imported bituminous coal of high calorific value. Industrial need for coal will be met mainly with indigenous coal.

R. Coal – Primary Energy Supply Outlook

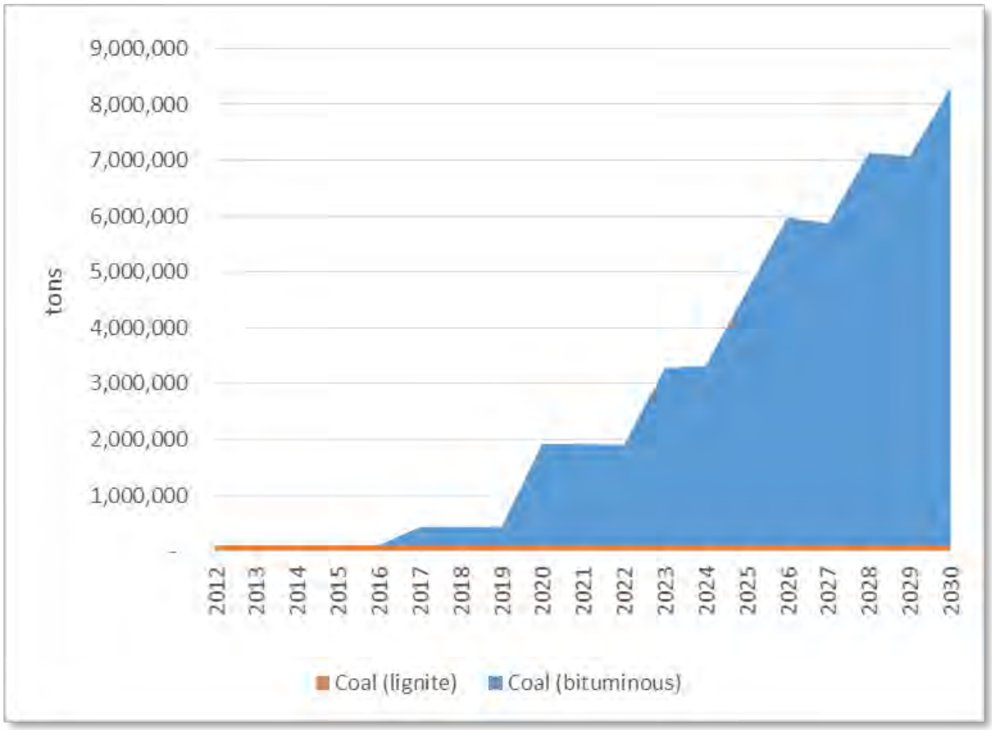
56. Coal production requirements are expected to rise significantly mainly due to power generation demand. However, it is anticipated the sub-bituminous coal will be imported. The compound annual growth rates of Table VI-1 show this clearly.

Figure VI-1: Coal TPES Forecast (toe) (excl. electricity)



Source: Consultant's analysis

Figure VI-2: Coal TPES Forecast (physical) (incl. electricity)



Source: Consultant's analysis

57. The compound annual growth rates for coal production are given between 2013 and 2030 unless otherwise noted.

Table VI-1: Compound Annual Growth Rate Projections (2013 to 2030)

Fuel	CAGR	Comment
Total Coal Production	10.9%	Increasing due to power production
Fuel Conversion Loss	0.0%	No losses accounted for in coal winning and transport
Net Production	10.9%	TFEC
Electricity Generation	25.5%	Increasing due to increasing coal in supply mix
Industry	10.9%	Increasing with economic growth

Source: Consultant's analysis

Table VI-2: Coal TPES Forecast (toe)

	Total Primary Energy	Fuel Conversion Loss	Loss	Total	Industrial
	toe	toe	%	toe	toe
2012	74,770		0%	74,770	74,770
2013	86,237		0%	86,237	86,237
2014	97,703	-	0%	97,703	97,703
2015	109,169	-	0%	109,169	109,169
2016	126,362	-	0%	126,362	126,362
2017	143,554	-	0%	143,554	143,554
2018	160,746	-	0%	160,746	160,746
2019	182,748	-	0%	182,748	182,748
2020	204,750	-	0%	204,750	204,750
2021	226,751	-	0%	226,751	226,751
2022	255,413	-	0%	255,413	255,413
2023	284,074	-	0%	284,074	284,074
2024	312,736	-	0%	312,736	312,736
2025	348,333	-	0%	348,333	348,333
2026	383,931	-	0%	383,931	383,931
2027	419,528	-	0%	419,528	419,528
2028	463,134	-	0%	463,134	463,134
2029	506,740	-	0%	506,740	506,740
2030	550,346	-	0%	550,346	550,346

Source: Consultant's analysis

Table VI-3: Coal TPES Forecast (tons)

	Total Primary Energy	Fuel Conversion Loss	Loss	Total	Industrial
	tons	tons	%	tons	tons
2012	49,929	-	0%	49,929	49,929
2013	45,849	-	0%	45,849	45,849
2014	66,951	-	0%	66,951	66,951
2015	78,456	-	0%	78,456	78,456
2016	90,451	-	0%	90,451	90,451
2017	103,294	-	0%	103,294	103,294

	Total Primary Energy	Fuel Conversion Loss	Loss	Total	Industrial
	tons	tons	%	tons	tons
2018	117,183	-	0%	117,183	117,183
2019	132,073	-	0%	132,073	132,073
2020	148,182	-	0%	148,182	148,182
2021	166,035	-	0%	166,035	166,035
2022	185,213	-	0%	185,213	185,213
2023	205,806	-	0%	205,806	205,806
2024	228,105	-	0%	228,105	228,105
2025	251,827	-	0%	251,827	251,827
2026	277,434	-	0%	277,434	277,434
2027	305,079	-	0%	305,079	305,079
2028	334,986	-	0%	334,986	334,986
2029	367,342	-	0%	367,342	367,342
2030	402,073	-	0%	402,073	402,073

Source: Consultant's analysis

VII. RENEWABLES (TYPE II)

S. Introduction

58. Type I renewables include hydropower, solar power and wind power. These renewables were discussed in the electricity production section above. Type II renewables include biomass and biofuels. Solid biomass in the form of fuelwood and woody agricultural residues is the most used fuel in Myanmar by far, due to the dominance of the fuel in household cooking in rural areas.

59. Biofuels have been trialed in Myanmar with poor results. The production of bioethanol and biodiesel is discussed further, albeit there is sufficient uncertainty that these fuels have not been included in the energy projections.

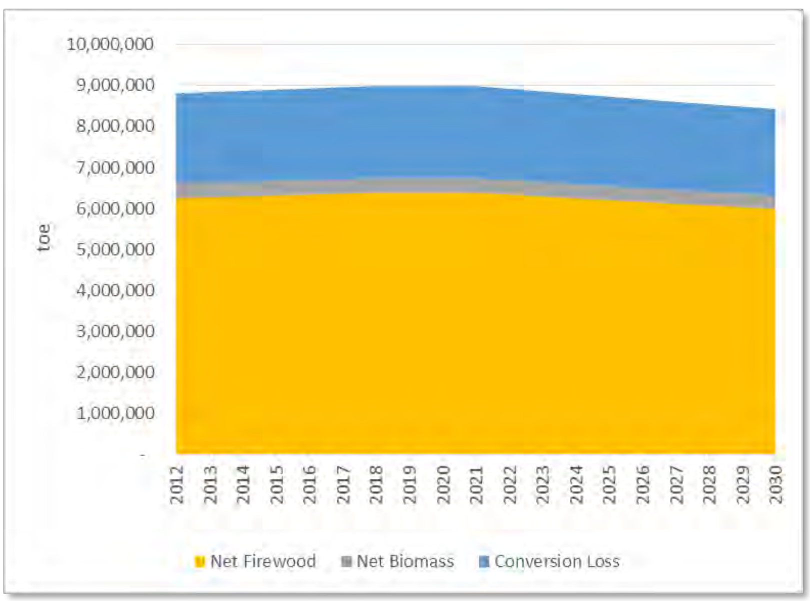
T. Fuelwood – Total Primary Energy Production

60. The Consultant has assumed that primary energy production is equivalent to primary secondary energy production. There was insufficient data available to quantify fuelwood losses arising between forests and distribution centres. Furthermore the conversion losses associated with the burning of fuelwood has not been accounted for in the energy balance – such losses are important from an energy efficiency standpoint, but from an energy balance perspective they occur within consumer premises and are therefore ignored.

U. Fuelwood – Primary Energy Supply Outlook

61. The projection for fuelwood is shown in Figure VII-1. The chart shows a significant decline in fuelwood production needs, easing pressure on Myanmar's forests. The reduction is due to the substitution of fuelwood by electricity for the purpose of household cooking.

Figure VII-1: Fuelwood TPES Forecast (toe)



Source: Consultant's analysis

Figure VII-2: Fuelwood TPES Forecast (toe)

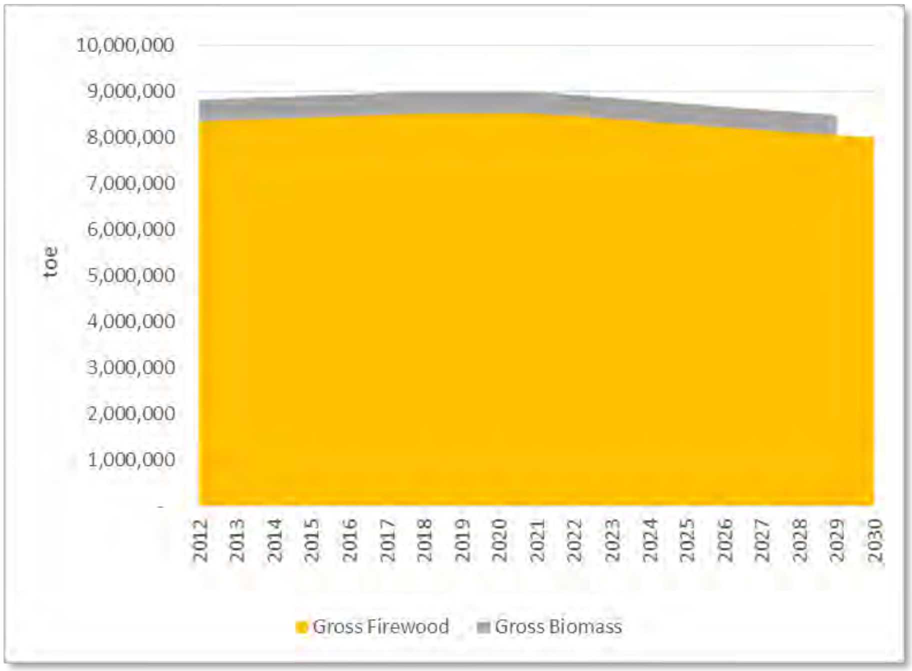
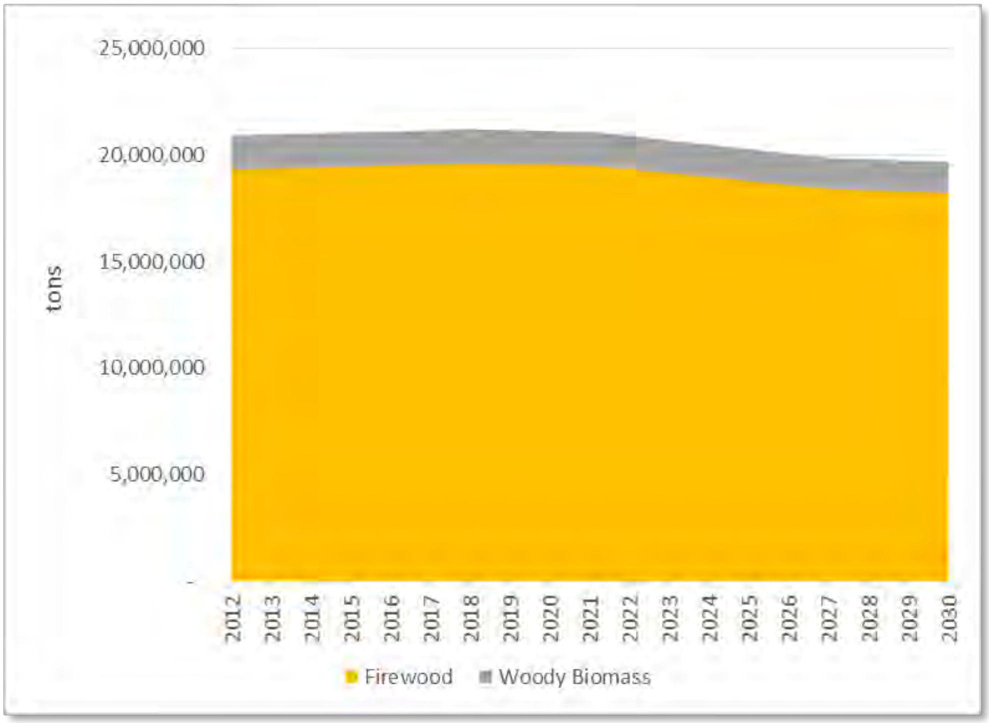


Figure VII-3: Fuelwood TPES Forecast (physical)



Source: Consultant's analysis

62. The compound annual growth rates for fuelwood production are given between 2013 and 2030 unless otherwise noted.

Table VII-1: Compound Annual Growth Rate Projections (2013 to 2030)

Fuel	CAGR	Comment
Total Fuelwood Energy Supply	-0.3%	Reducing due to substitution with electric cooking
Net Production	-0.3%	TFEC considered as TPES
Firewood (Cooking)	-0.3%	
Woody biomass (Cooking)	-0.3%	

Source: Consultant's analysis

63. The total energy supply projection for fuelwood, that matches Figure VII-2, is given here as a table for convenience:

Table VII-2: Fuelwood TPES Forecast (toe)

	Total Primary Energy Supply	Conversion Efficiency	Loss	Gross Firewood	Net Firewood	Gross Biomass	Net Biomass
	toe	toe	%	toe	toe	toe	toe
2013	8,847,089	-	0%	8,373,737	6,280,303	473,352	118,338
2014	8,875,819	-	0%	8,402,298	6,301,723	473,521	118,380
2015	8,904,548	-	0%	8,430,858	6,323,144	473,689	118,422
2016	8,935,016	-	0%	8,461,158	6,345,869	473,858	118,465
2017	8,965,485	-	0%	8,491,458	6,368,593	474,027	118,507
2018	8,995,953	-	0%	8,521,757	6,391,318	474,196	118,549
2019	8,994,627	-	0%	8,521,654	6,391,241	472,973	118,243
2020	8,993,301	-	0%	8,521,551	6,391,163	471,750	117,938
2021	8,991,975	-	0%	8,521,448	6,391,086	470,527	117,632
2022	8,927,078	-	0%	8,460,557	6,345,418	466,522	116,630
2023	8,862,182	-	0%	8,399,666	6,299,750	462,516	115,629
2024	8,797,286	-	0%	8,338,776	6,254,082	458,510	114,628
2025	8,733,902	-	0%	8,279,398	6,209,548	454,504	113,626
2026	8,670,519	-	0%	8,220,020	6,165,015	450,499	112,625
2027	8,607,136	-	0%	8,160,643	6,120,482	446,493	111,623
2028	8,548,363	-	0%	8,106,010	6,079,507	442,353	110,588
2029	8,489,589	-	0%	8,051,377	6,038,533	438,212	109,553
2030	8,430,816	-	0%	7,996,744	5,997,558	434,072	108,518

Source: Consultant's analysis

Table VII-3: Fuelwood TPES Forecast (tons)

	Total Primary Energy Supply	Conversion Efficiency	Loss	Gross Firewood	Gross Biomass
	tons	tons	%	tons	tons
2013	20,983,536	-	0%	19,378,139	1,605,397
2014	21,027,903	-	0%	19,427,157	1,600,747
2015	21,072,271	-	0%	19,476,175	1,596,097
2016	21,120,178	-	0%	19,525,193	1,594,985
2017	21,168,084	-	0%	19,574,211	1,593,873
2018	21,215,991	-	0%	19,623,229	1,592,762
2019	21,179,850	-	0%	19,594,141	1,585,709
2020	21,143,710	-	0%	19,565,054	1,578,656
2021	21,107,570	-	0%	19,535,967	1,571,603
2022	20,903,336	-	0%	19,350,669	1,552,667
2023	20,699,102	-	0%	19,165,372	1,533,730
2024	20,494,868	-	0%	18,980,074	1,514,794
2025	20,290,635	-	0%	18,794,776	1,495,858
2026	20,086,401	-	0%	18,609,479	1,476,922
2027	19,882,167	-	0%	18,424,181	1,457,986
2028	19,815,196	-	0%	18,362,365	1,452,831
2029	19,748,226	-	0%	18,300,549	1,447,676
2030	19,681,255	-	0%	18,238,734	1,442,521

Source: Consultant's analysis

Appendix A – IEA Energy Balance Tables (2012 to 2030)

2012

	Thousand tonnes of oil equivalent										
SUPPLY AND CONSUMPTION	**Coal & peat**	**Crude oil**	**Oil products**	**Natural Gas**	**Nuclear**	**Hydro**	**Geotherm. solar etc.**	**Biofuels & waste**	**Electricity**	**Heat**	**Total**
Production	219	879	82	13005		664	0	8818			23668
Imports			1669								1669
Exports				-11880							-11880
Intl. marine bunkers											
Intl. aviation bunkers											
Stock changes											
TPES	**219**	**879**	**1751**	**1125**		**664**		**8818**			**13458**
Electricity and CHP plants	-144		-2	-190		-664			804		-196
Oil refineries		-792	713								-79
Other transformation		-87	-12	-306							-405
TFC	**75**		**2451**	**629**				**8818**	**701**		**12675**
INDUSTRY	**75**		**57**	**292**					**278**		**701**
Iron and steel				8					5		
Chemical and petrochemical									0.3		
Non-metallic minerals	13			272					15		301
Other/non-specified	61		57	11					257		386
TRANSPORT			**1404**	**32**							**1436**
Domestic aviation			31								31
Road			1368	32							1400
Other/non-specified			5								5
OTHER			**990**					**8818**	**423**		**10232**
Residential			63					8035	287		8386
Comm. and public services			694					783	114		1592
Agriculture/forestry			233						22		255
Other/non-specified											
NON-ENERGY USE				**306**							**306**
					Electricity and Heat Output						
Electricity generated - GWh	703		16	1917		7728					10364

2015

		Thousand tonnes of oil equivalent									
SUPPLY AND CONSUMPTION	**Coal & peat**	**Crude oil**	**Oil products**	**Natural Gas**	**Nuclear**	**Hydro**	**Geotherm. solar etc.**	**Biofuels & waste**	**Electricity**	**Heat**	**Total**
Production	273	894	80	16561		805		8905			27518
Imports			2625								2625
Exports				-13938							-13938
Intl. marine bunkers											
Intl. aviation bunkers											
Stock changes											
TPES	**273**	**894**	**2705**	**2623**		**805**		**8905**			**16205**
Electricity and CHP plants	-164		0	-1359		-805			1698		-629
Oil refineries		-807	726								-81
Other transformation		-87	-12	-372							-471
TFC	**109**		**3420**	**892**				**8905**	**963**		**14289**
INDUSTRY	**109**		**91**	**476**					**475**		**1151**
Iron and steel				11					8		
Chemical and petrochemical									1		
Non-metallic minerals				438					27		465
Other/non-specified	109		91	26					440		666
TRANSPORT			**2235**	**44**							**2278**
Domestic aviation			31								31
Road			2199	44							2243
Other/non-specified			4								4
OTHER			**1094**					**8905**	**488**		**10487**
Residential			58					8,095	342		8495
Comm. and public services			718					810	122		1650
Agriculture/forestry			317						24		342
Other/non-specified											
NON-ENERGY USE				**372**							**372**
					Electricity and Heat Output						
Electricity generated - GWh	224		0	4815		9359					14398

2018

	Thousand tonnes of oil equivalent										
SUPPLY AND CONSUMPTION	**Coal & peat**	**Crude oil**	**Oil products**	**Natural Gas**	**Nuclear**	**Hydro**	**Geotherm. solar etc.**	**Biofuels & waste**	**Electricity**	**Heat**	**Total**
Production	540	1391	79	15728		945	0	8996			27679
Imports			2306	439							2744
Exports				-13938							-13938
Intl. marine bunkers											
Intl. aviation bunkers											
Stock changes											
TPES	**540**	**1391**	**2385**	**2228**		**945**	**0**	**8996**			**16485**
Electricity and CHP plants	-380		0	-1046		-945	0		1235		-1136
Oil refineries		-1304	1251								-52
Other transformation		-87	-12								-99
TFC	**161**		**3624**	**1182**				**8996**	**1328**		**15292**
INDUSTRY	**161**		**113**	**710**					**709**		**1694**
Iron and steel				17					12		
Chemical and petrochemical									1		
Non-metallic minerals				655					40		695
Other/non-specified	161		113	39					657		970
TRANSPORT			**2311**	**33**							**2344**
Domestic aviation			50								50
Road			2256	33							2289
Other/non-specified			5								5
OTHER			**1200**	**0**				**8996**	**619**		**10815**
Residential			54					8,154	440		8648
Comm. and public services			747					842	149		1738
Agriculture/forestry			399						29		428
Other/non-specified											
NON-ENERGY USE				439							**439**
				Electricity and Heat Output							
Electricity generated - GWh	891		0	7568		10987					19446

2021

		Thousand tonnes of oil equivalent									
SUPPLY AND CONSUMPTION	**Coal & peat**	**Crude oil**	**Oil products**	**Natural Gas**	**Nuclear**	**Hydro**	**Geotherm. solar etc.**	**Biofuels & waste**	**Electricity**	**Heat**	**Total**
Production	670	2150	1	12805		1643	0	8992			26262
Imports			1898	505							2403
Exports				-11110							-11110
Intl. marine bunkers											
Intl. aviation bunkers											
Stock changes											
TPES	**670**	**2150**	**1899**	**2201**		**1643**	**0**	**8992**			**17555**
Electricity and CHP plants	-443			-665		-1643	0		1765		-985
Oil refineries		-2150	2064								-86
Other transformation			-12								-12
TFC	**227**		**3951**	**1536**				**8992**	**1796**		**16502**
INDUSTRY	**227**		**142**	**1006**					**1005**		**2380**
Iron and steel				24					16		
Chemical and petrochemical									1		
Non-metallic minerals				928					57		984
Other/non-specified	227		142	55					931		1354
TRANSPORT			**2492**	**25**							**2516**
Domestic aviation			69								69
Road			2417	25							2442
Other/non-specified			5								5
OTHER			**1318**	**0**				**8992**	**791**		**11101**
Residential			50					8,115	575		8740
Comm. and public services			777					877	184		1837
Agriculture/forestry			491						33		524
Other/non-specified											
NON-ENERGY USE				505							**505**
					Electricity and Heat Output						
Electricity generated - GWh	882		0	5780		19101					25763

2024

			Thousand tonnes of oil equivalent								
SUPPLY AND CONSUMPTION	**Coal & peat**	**Crude oil**	**Oil products**	**Natural Gas**	**Nuclear**	**Hydro**	**Geotherm. solar etc.**	**Biofuels & waste**	**Electricity**	**Heat**	**Total**
Production	843	3541	2	11340		1866	0	8797			26390
Imports	1726		998	571							3296
Exports				-9535							-9535
Intl. marine bunkers											
Intl. aviation bunkers											
Stock changes											
TPES	**2570**	**3541**	**1000**	**2377**		**1866**	**0**	**8797**			**20151**
Electricity and CHP plants	-2257		0	-405		-1866	0		2516		-2012
Oil refineries		-3541	3400								-142
Other transformation		0	-12								-12
TFC	**313**		**4388**	**1972**				**8797**	**2410**		**17880**
INDUSTRY	**313**		**178**	**1383**					**1381**		**3254**
Iron and steel				33					22		
Chemical and petrochemical									2		
Non-metallic minerals				1274					78		1352
Other/non-specified	313		178	75					1279		1844
TRANSPORT			**2791**	**18**							**2808**
Domestic aviation			88								88
Road			2697	18							2714
Other/non-specified			6								6
OTHER			**1420**	**0**				**8797**	**1029**		**11246**
Residential			44					7,881	765		8691
Comm. and public services			812					916	226		1954
Agriculture/forestry			563						38		601
Other/non-specified											
NON-ENERGY USE				571							**571**
					Electricity and Heat Output						
Electricity generated - GWh	7912		0	4290		21702					33904

2027

	Thousand tonnes of oil equivalent										
SUPPLY AND CONSUMPTION	**Coal & peat**	**Crude oil**	**Oil products**	**Natural Gas**	**Nuclear**	**Hydro**	**Geotherm. solar etc.**	**Biofuels & waste**	**Electricity**	**Heat**	**Total**
Production	1057	3588	4	9071		2498	95	8607			24920
Imports	2394		1428	638							4459
Exports				-6961							-6961
Intl. marine bunkers											
Intl. aviation bunkers											
Stock changes											
TPES	**3450**	**3588**	**1432**	**2749**		**2498**	**95**	**8607**			**22419**
Electricity and CHP plants	-3031		0	-250		-2498	-95		3383		-2491
Oil refineries		-3588	3444								-144
Other transformation		0	-12								-12
TFC	**420**		**4864**	**2498**				**8607**	**3214**		**19603**
INDUSTRY	**420**		**222**	**1849**					**1847**		**4338**
Iron and steel				44					30		
Chemical and petrochemical									2		
Non-metallic minerals				1704					104		1809
Other/non-specified	420		222	101					1710		2453
TRANSPORT			**3176**	**12**							**3188**
Domestic aviation			107								107
Road			3063	12							3075
Other/non-specified			6								6
OTHER			**1466**	**0**				**8607**	**1367**		**11440**
Residential			39					7,647	1,046		8732
Comm. and public services			851					960	280		2091
Agriculture/forestry			576						41		617
Other/non-specified											
NON-ENERGY USE				638							**638**
					Electricity and Heat Output						
Electricity generated - GWh	10627		0	3661		29049					43337

2030

	Thousand tonnes of oil equivalent										
SUPPLY AND CONSUMPTION	**Coal & peat**	**Crude oil**	**Oil products**	**Natural Gas**	**Nuclear**	**Hydro**	**Geotherm. solar etc.**	**Biofuels & waste**	**Electricity**	**Heat**	**Total**
Production	1318	3635	5	8541		2832	314	8431			25077
Imports	3962		1978	704							6644
Exports				-5876							-5876
Intl. marine bunkers											
Intl. aviation bunkers											
Stock changes											
TPES	**5280**	**3635**	**1984**	**3369**		**2832**	**314**	**8431**			**25846**
Electricity and CHP plants	-4730		0	-216		-2832	-314		4332		-3760
Oil refineries		-3635	3490								-145
Other transformation			-12								-12
TFC	**550**		**5461**	**3153**				**8431**	**4292**		**21888**
INDUSTRY	**550**		**278**	**2437**					**2434**		**5699**
Iron and steel				58					40		97
Chemical and petrochemical									3		3
Non-metallic minerals				2246					138		2384
Other/non-specified	550		278	133					2254		3215
TRANSPORT			**3669**	**12**							**3682**
Domestic aviation			126								126
Road			3537	12							3549
Other/non-specified			7								7
OTHER			**1514**	**0**				**8431**	**1858**		**11803**
Residential			34					7,420	1,464		8919
Comm. and public services			896					1,010	347		2254
Agriculture/forestry			584						46		630
Other/non-specified											
NON-ENERGY USE				704							**704**
Electricity and Heat Output											
Electricity generated - GWh	17010		0	4735		32932					54677

Project Number: TA No. 8356-MYA

FINAL REPORT

INSTITUTIONAL ARRANGEMENTS TO SUPPORT ENERGY MASTER PLANNING

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

IES Intelligent Energy Systems

in association with

MMIC MYANMAR INTERNATIONAL CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
BOT	–	Build Operate Transfer
DSM	–	Demand Side Management
EEG	–	Energy Expert Group
EGAT	–	Electricity Generating Authority of Thailand
EMP	–	Energy Master Plan
EPD	–	Energy Planning Department
EPPO	–	Energy Policy and Planning Office (Thailand)
ESI	–	Energy Saving Initiative (Australia)
GDE	–	General Directorate on Energy (Vietnam)
IEP	–	Integrated Energy Planning
IPP	–	Independent Power Producer
LNG	–	Liquefied Natural Gas
LPG	–	Liquefied Petroleum Gas
LRES	–	Large-scale Renewable Energy Scheme (Australia)
MES	–	Myanmar Engineering Society
MOA	–	Ministry of Agriculture
MGS	–	Myanmar Geoscience Society
MOECAF	–	Ministry of Environment, Conservation and Forestry
MOE	–	Ministry of Energy
MOEP	–	Ministry of Electric Power
MOGE	–	Myanmar Oil and Gas Enterprise
MOI	–	Ministry of Industry
MOIT	–	Ministry of Industry and Trade (Vietnam)
MOLFRD	–	Ministry of Livestock, Fisheries and Rural Development
MOM	–	Ministry of Mines
MOST	–	Ministry of Science and Technology
MPE	–	Myanmar Petrochemical Enterprise
MPPE	–	Myanmar Petroleum Products Enterprise
NEC	–	National Energy Policy Council (Thailand)
NEMC	–	National Energy Management Committee
NESA	–	National Energy Security Assessment (Australia)
NTNDP	–	National Transmission Development Plan (Australia)
PPC	–	Pakistan Planning Commission
PMO	–	Prime Minister's Office (Vietnam)
RET	–	Renewable Energy Target (Australia)
REAM	–	Renewable Energy Association Myanmar
SPP	–	Small Power Producer
SRES	–	Small-scale Renewable Energy Scheme (Australia)

CONTENTS

I. SUMMARY

1. An important aspect of any Energy Master Plan (EMP) is to ensure that the process is supported by an appropriate institutional framework. Establishing such a framework is key to the long-term viability of the EMP as it is necessary to monitor, update and refine the EMP over time.

2. The formation of the National Energy Committee (NEMC) represents a commitment to the concept of integrated energy planning. Integrated Energy Planning (IEP) takes into account plans relating to transport, agriculture, electricity, industry, petroleum, water supply, trade, macroeconomic infrastructure development, housing, air quality management, greenhouse gas mitigation within the energy sector and integrated development plans of local and provincial authorities. The IEP needs to inform and be informed by plans across all sectors (primary, secondary and tertiary) whose plans impact on or are impacted by the EMP.

3. This report discusses the key concepts of IEP including benefits and barriers for establishing a set of institutional arrangements that can support it on an ongoing basis. The report identifies a number of critical factors in the implementation of an EMP process.

4. We review the present governance structure in place for Myanmar's energy sector and draw upon international experience before commenting on:

- Institutional and regulatory impediments to collecting energy information and preparing the long-term outlook, and
- Improvements necessary in the institutional and regulatory framework to support the function of integrated energy planning in the Ministry of Energy (MOE).

5. For completeness, we also present the outcomes of a review of the approaches taken for the implementation of IEP in a number of selected countries with a view to identifying and benefiting from the experience gained and lessons learned.

6. Our recommendations are made for the three facets of the IEP process:

- Organisational structure and allocation of responsibilities.
- Defining of the IEP / EMP process within the recommended organisational structure.
- Human capacity requirements.

7. We discuss the key recommendations of each in turn.

IEP organisational structure and allocation of responsibilities

8. We recommend establishing of a permanent and specialist IEP team within the existing governance structure at NEMC, and allocating the roles and duties of the concerned IEP team, the ministries and NEMC in a way that can support the IEP process.

9. The ministries will be represented by ministry specialist advisors who will feed into the IEP team critical information relevant to the ministries that each present. The ministerial provisions of information could include macroeconomic policy options, sectoral strategic development plans and primary resource assessments.

10. The IEP team would be responsible for the key activities within the IEP process such as compilation of energy statistics, definition of planning criteria and targets, and performance of Integrated Energy Modelling.

11. The IEP team can be structured as a specialised energy planning entity with a director of energy planning, an energy planning division, an energy statistics division, and a ministry advisory team (ministry specialists).

12. NEMC, as a Planning Commission, would be responsible for ratification of projections of estimated future energy needs in support of macroeconomic and socio-economic requirements, and recommend energy policy to support the preferred path.

IEP / EMP process

13. The IEP / EMP is recommended to be carried out on a 5 year cycle. Typical components of any IEP implementation should include data collection; data compilation, analysis and statistical reporting; energy demand forecasting; energy supply forecasting; developing an overall strategy; and monitoring and evaluation.

Human capacity requirements

14. The IEP team are required to have a set of specific skills to undertake the different components in the energy planning task. The team members should have knowledge and practical expertise to autonomously complete undertakings in energy statistics, energy demand forecasting, and energy supply modelling. The energy modellers perform a crucial part of the task and are expected to possess multidiscipline expertise covering engineering, economics and finance.

II. INTEGRATED ENERGY PLANNING

A. Integrated Energy Planning Process

1. An EMP must be based on sound research on the national energy consumption trends, existing and potential energy supplies, energy prices, supply and demand-side technologies, population growth, environmental and social impacts, and political situation of a country. It is critical to understand the importance that IEP enables informed decisions to be made in terms of energy policy; robust research into the present context and assessing numerous scenarios allows for more informed and robust decision-making.

2. The basic features of integrated energy planning are similar to those of the current energy planning and environmental planning practices, including integrated assessment, life-cycle assessment and integrated resource planning. However, IEP is unique because it mainly focuses on issues relating to energy extraction, transportation, transmission, distribution and use. The planning can be multifaceted, including economic, environmental, social or institutional aspects.

3. IEP is the methodology for developing a roadmap to both satisfy the energy needs of a nation as well as to stimulate the development of economic activity. These are defined and outlined by the EMP. IEP must deal with issues relating to the supply, transformation, transport, storage of and demand for energy in a way that accounts for:-

- Security of supply;
- Economically available energy resources;
- Affordability;
- Universal access to energy;
- Social equity;
- Employment;
- Environment;
- International commitments;
- Consumer protection; and
- Contribution of energy supply to socioeconomic development.

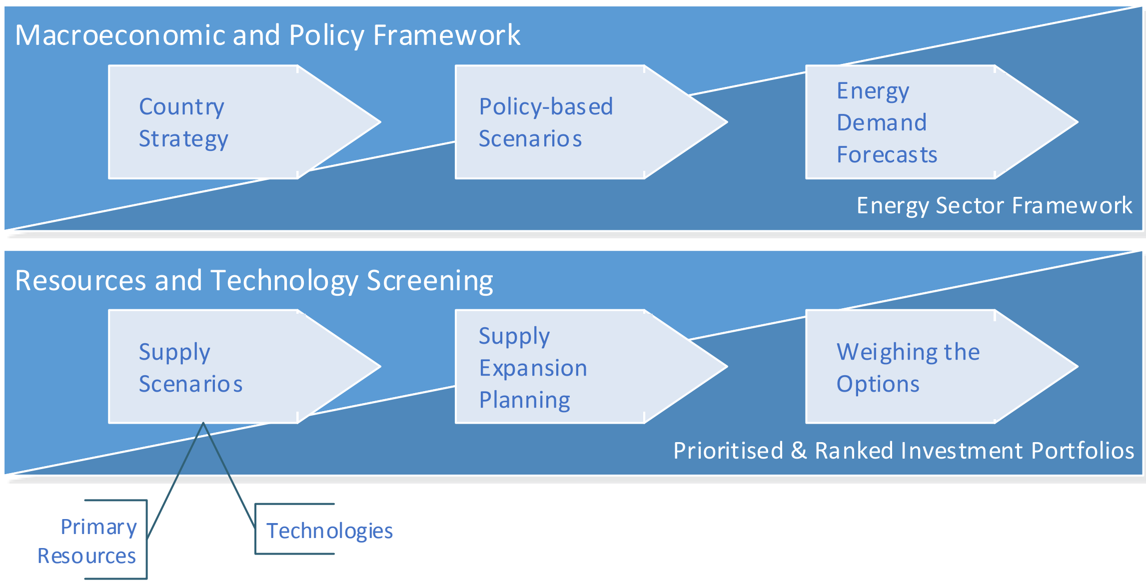
4. The IEP approach differs from strategic supply planning because it includes not only the costs incurred by the individual/organisation, but also societal costs and other externalities, such as environmental impact mitigation necessitated by some resource choices.

5. It involves making an integrated assessment of supply and demand-side options of increasing energy services, whilst attempting to minimise all costs subject to a set of assumptions made over the planning horizon. The end result – the EMP, is a flexible plan that allows for uncertainty and adjustment in response to changing circumstances.

B. Stages and Implementation of IEP

6. An approach to IEP is illustrated in Figure II-1.

Figure II-1: Integrated Energy Planning Process



Source: Consultant

7. The following are the main stages of the IEP process:-

A. Macroeconomic and policy framework – a clear specification of the country's objectives and economic policies;

B. Energy forecasts – developing energy forecasts into the future based on assessments of the energy requirements attributable to different end-users – industrial, commercial, residential sector, agriculture sector and transport sector.

C. Supply side technologies and resources – developing estimates of primary energy resource potentials, and feasible energy supply-side technology options;

D. Supply-side expansion planning and costing – determine the costing of the supply side expansion options and develop a sequence of investments that can best satisfy projected energy requirements, usually a least-cost approach is preferred (subject to various constraints that reflect the physical limits of the energy conversion chain and policy objectives); and

E. Multi-criteria scenario assessment – which involves ranking a set of EMP scenarios based on a set of criteria that are reflective of priorities suitable for the country. This type of approach is appropriate when one attempts to satisfy multiple objectives, as is the case in the EMP.

C. Critical Issues for an IEP Framework to Address

8. The IEP process needs to inform and be informed by plans for specific subsectors. It also

needs to be aligned with the broader strategic and economic direction of the country. With this, comes the potential for there to be some overlaps and/or inconsistencies between an EMP and the plans developed by other government agencies. For example, "master plans" and/or "roadmaps" for the economy, industry, power, gas and oil, electrification, transport, forestry and agriculture, renewable energy, energy efficiency, coal, greenhouse gas mitigation and others, are often developed in isolation.

9. An IEP also needs to be designed as a process that can support continuous refinement and adaption. While EMP scenarios can be devised to span a range of scenarios to overcome uncertainty, invariably, new issues emerge, unforeseen events evolve and lessons are learned. The IEP must therefore be institutionalised and implemented in such a way that it can be updated and evolve over time.

10. Importantly in the fast-changing landscape of energy technology, IEP needs to be technologically neutral, provide equal treatment of demand-side options including end-use efficiency improvements and demand-side management (DSM) and supply side options. This means that deferred or avoided end-use energy consumption needs to be recognised.

11. The IEP must be supported by an organisational structure that is able to accommodate diverse, yet specialised capability that can collectively undertake.

12. Issues that need to be addressed as part of IEP implementation and development of the associated institutional arrangements needs to address:-

A. Defining objectives and scopes for each of formal planning study that avoid overlap.

B. Defining interfaces or formal processes of data exchange between planning studies. For example, submission of data or key policy parameters by one entity for use in the IEP process and/or the use of IEP outputs as an input into other planning processes.

C. Setting in place an appropriate organisational structure that enables the IEP to be informed by the specialist knowledge across all subsectors it seeks to coordinate.

D. Introduce processes to identify and rectify inconsistencies between and/or to seek consistency between certain assumptions.

E. Process that enables some level of refinement.

F. Setting some level of precedence and/or ordering between plans.

G. Incorporating a process to support change and also updating.

H. Staffing the agency responsible for IEP with people who have the capacity and knowledge to undertake the different components of the IEP.

III. REVIEW OF INTERNATIONAL EXPERIENCE IN IEP

13. This section provides a review of the energy planning frameworks implemented in a number of selected countries. We have reviewed these frameworks in order to identify the aspects that have work well and identify any useful organisational structures that could be applied to the Myanmar context.

D. Thailand

Institutional arrangements for energy policy and planning

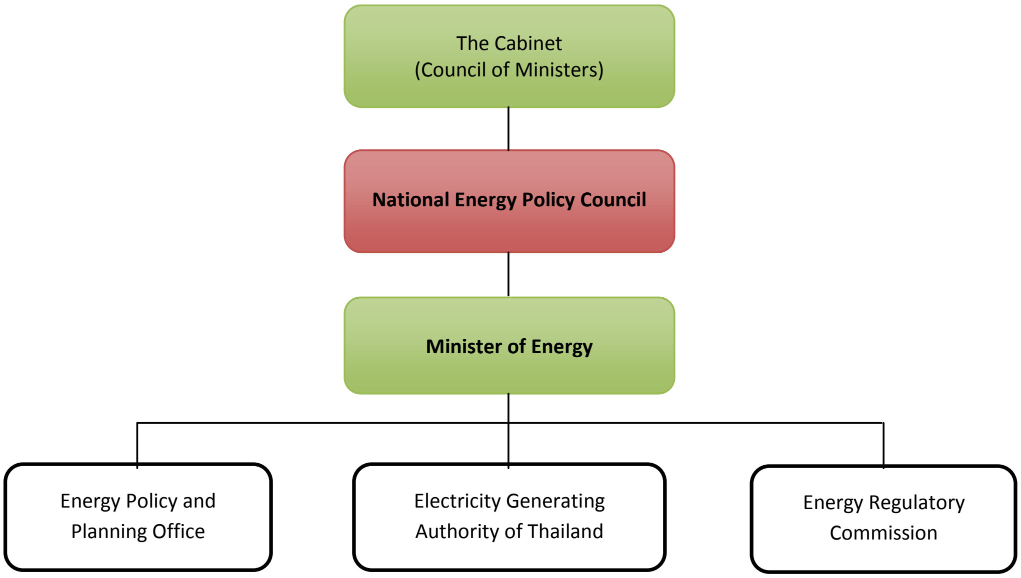
14. The highest authority in terms of energy policy in Thailand is the National Energy Policy Council (NEPC) which sits directly under the Cabinet and the Prime Minister.

15. NEPC has the following powers and duties:

- To submit the National Energy Policy and the National Management and Development Plan to the Council of Ministers Development Plan to the Council of Ministers;
- To lay down rules and conditions for prescribing the price of energy in accordance with the National Energy Policy and the National Energy Management and Development Plan;
- To monitor, supervise, coordinate, support and expedite the operations of all committees with the powers and duties related to energy, government agencies, state enterprises and the private sector related to energy, ensuring their operations are in accordance with the National Energy Policy and the National Management and Development Plan;
- To evaluate the results of the implementation of the National Energy Policy and the National Management and Development Plan; and
- To perform other functions as entrusted by the Prime Minister or the Council of Ministers.

16. Administratively placed under the NEPC, the Ministry of Energy Ministry of energy is responsible for implementing the mission in providing, developing, and managing energy suitably and effectively for sustainable economic and social development. The MOE entrusts the planning and regulating functions to subordinate agencies including the Energy Policy and Planning Office (EPPO), the Electricity Generating Authority of Thailand (EGAT) and the Energy Regulatory Commission. Figure III-1 below depicts an institutional hierarchy in relation to policy and planning decision making in Thailand's energy sector.

Figure III-1: Thailand Energy Policy and Planning Institutional Hierarchy



Source: Consultant

Energy Policy and Planning Office (EPPO)

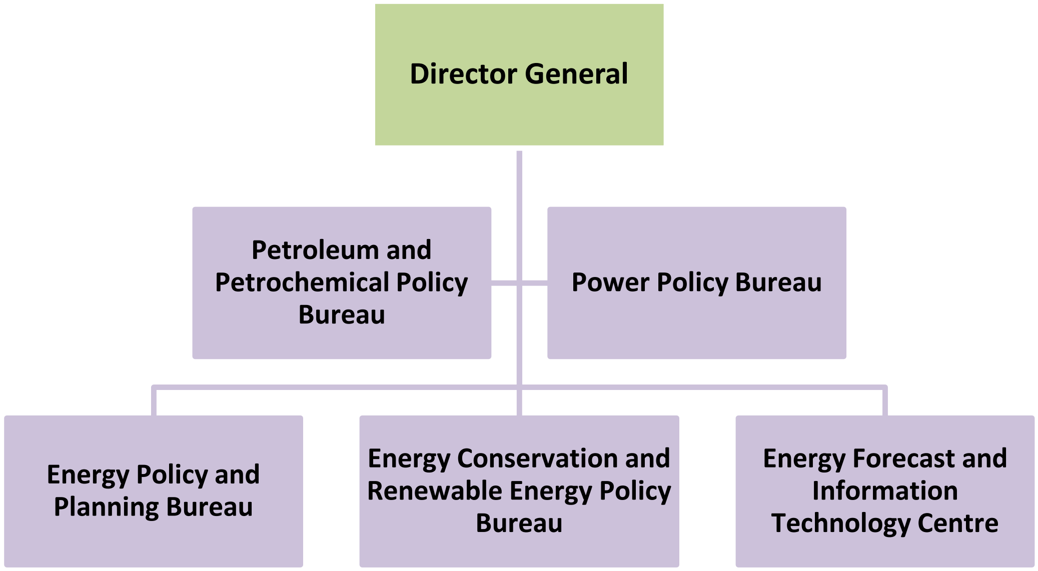
17. EPPO is a pivotal agency in the formulation and administration of energy policies and planning for the national sustainability. This agency has a mission to study, to analyse the policies and energy management and development plans of the country, to coordinate, monitor and evaluate the implementation and outcomes pursuant to energy policies and energy plans. EPPO has the following responsibilities:

- Recommend energy policies and integrate/review energy management plans of the country;
- Recommend national strategies for energy conservation and alternative energy promotion;
- Recommend measures to solve and prevent oil shortage in both short and long terms;
- Supervise, monitor and evaluate the effectiveness of national energy policy and energy management plans;
- Administer the information and communication technology with regard to energy issues of the country; and
- Enhance EPPO to become a strategic organisation.

18. One of EPPO key functions is to formulate energy policies and administer energy planning of the country.

19. EPPO has five key divisions: (1) Petroleum and Petrochemical Policy Bureau, (2) Power Policy Bureau, (3) Energy Policy and Planning Bureau, (4) Energy Conservation and (5) Renewable Energy Policy Bureau and Energy Forecast and Information Technology Centre (Figure III-2).

Figure III-2: EPPO Organisational Structure



Source: Consultant

EGAT

20. EGAT's main responsibilities are:-

- Power production. EGAT is a government-owned power producer owning and operating power plants with a total installed capacity over 15,000 MW, or about 46% of the entire generation system;
- Owner and operator of Thailand's high voltage transmission network.
- Undertake the role of single buyer in Thailand's "Single Buyer" electricity supply model. Specific responsibilities are: (1) purchasing bulk electricity from private power producers and neighbouring countries, and (2) selling wholesale electric energy to two distributing authorities and a small number of direct industrial customers as well as neighbouring utilities.

Energy Regulatory Commission

21. The responsibilities of the Energy Regulatory Commission are:

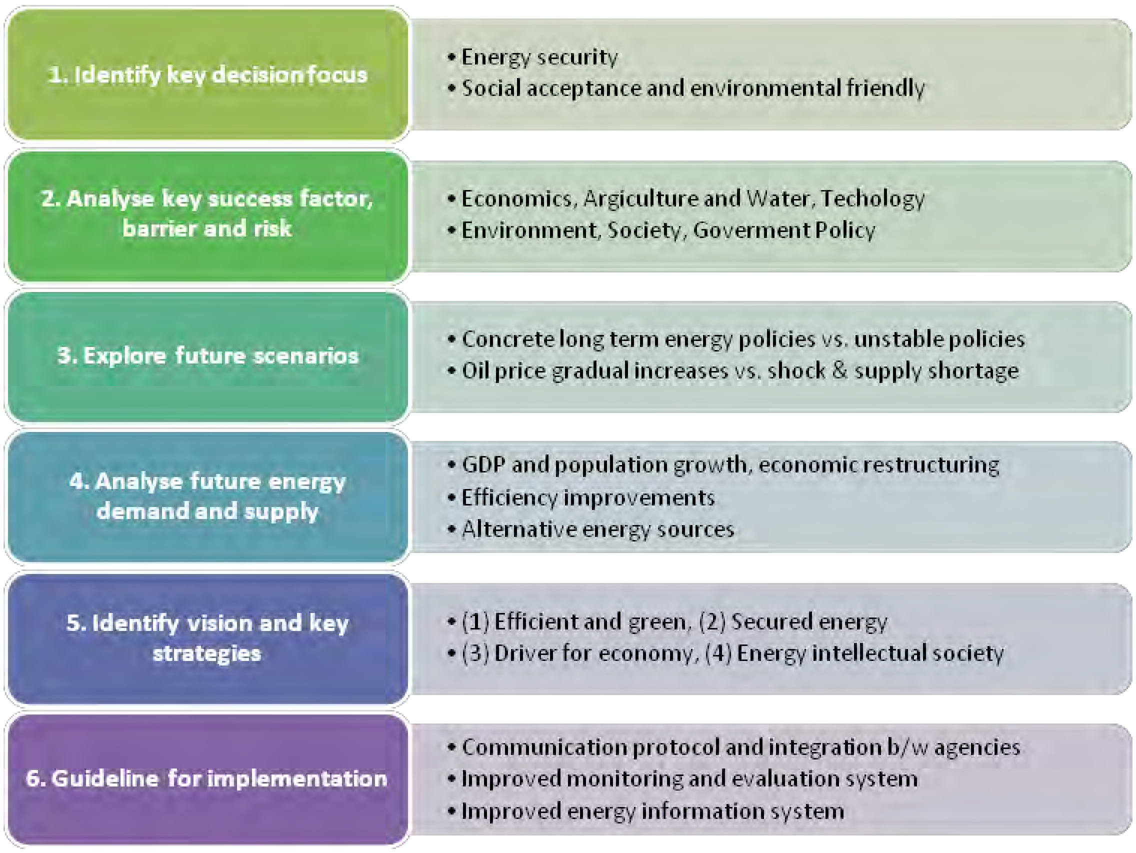
- Regulate electricity tariffs;
- Administer licencing schemes for energy activities (electricity and gas licences);
- Approval of power purchase agreements; and
- Providing a platform to management disputes.

The Energy Master Planning Process

22. EPPO has been administering the development of the first national energy master plan for the

period 2015-2035. The energy master plan is intended to integrate a number of other plans, including: Power Development Plan, the forecasts of the country's oil and gas consumption, the Energy Efficiency Development Plan and the Alternative (Renewable) Energy Development Plan. The energy master planning process in Thailand involves the six steps that are shown in Figure III-3.

Figure III-3: Thailand Energy Master Planning Process



Source: EPPO

Thailand Power Development Plan

23. The national Power Development Plan is developed by EGAT within the framework of the Ministry of Energy's policies. EGAT, which also manages and operates the state-owned generation and transmission assets, formulated the last such plan for the period of 2010-2030, known as PDP 2010. Compared to the previous PDP 2007, PDP 2010 had a greater focus on renewable energy integration.

24. The plan was first approved by the NEPC and the Cabinet in November, 2010. Following the Fukushima incident in Japan, the plan has been twice revised, as Thailand's approach to harnessing nuclear energy had to be revisited. The third and current (as of March 2013) revision was approved by the Cabinet in June, 2012. The plans have been used to guide planning and construction of EGAT's new power plants, power purchases from independent power producers (IPPs), small power

producers (SPPs) and neighbouring countries, as well as transmission system development to accommodate these new power capacities.

25. The main strategies that the PDP 2010 focused on were:-

- Security and adequacy of the power system, following the policies of the Ministry of Energy on environmental concerns;
- Promotion of energy efficiency and renewable energy to be in line with the Energy Efficiency Development Plan ("EEDP 2011-2030") and the Alternative Energy Development Plan ("AEDP 2012-2021"); and
- Promotion of cogeneration systems for efficient electricity generation.

E. Pakistan

Ministries Governing the Energy Sector

26. In Pakistan, two ministries oversee different parts of the country's energy industry. The Ministry of Water and Power is responsible for policies in electricity sector including alternative and renewable energy. The Ministry of Petroleum and Natural Resources is in charge of the oil, gas and coal sectors.

Planning Commission

27. The Pakistan Planning Commission (PPC) is a government agency attached to the Ministry of Planning, Development and Reform. The Prime Minister is the Chairman of Planning Commission which apart from the minister as Deputy Chairman, comprises of nine Members including Secretary, Planning & Development Division / Member Coordination, Chief Economist, Director, Pakistan Institute of Development Economics, Executive Director, Implementation and Monitoring, and Members for Social Sectors, Science and Technology, Energy, Infrastructure, and Food and Agriculture.

28. The strategies of PPC are:-

- Preparing the National Plan and review and evaluating its implementation;
- Formulating annual development plans;
- Monitoring and evaluating implementation of major development projects and programs;
- Stimulating preparation of sound projects in regions and sectors lacking adequate portfolio;
- Continuously evaluating the economic situation and coordinate economic policies; and
- Organising research and analytical studies for economic decision making.

Energy Expert Groups for Integrated Energy Plan

29. The Economic Advisory Council was set up by the Government of Pakistan under the umbrella of the Ministry for Finance, and mandated an Energy Expert Group (EEG) to prepare an Integrated Energy Plan which would provide a short, medium and long term strategy. The EEG is chaired by a member of the Economic Advisory Council and has representatives who hold senior management positions at energy companies.

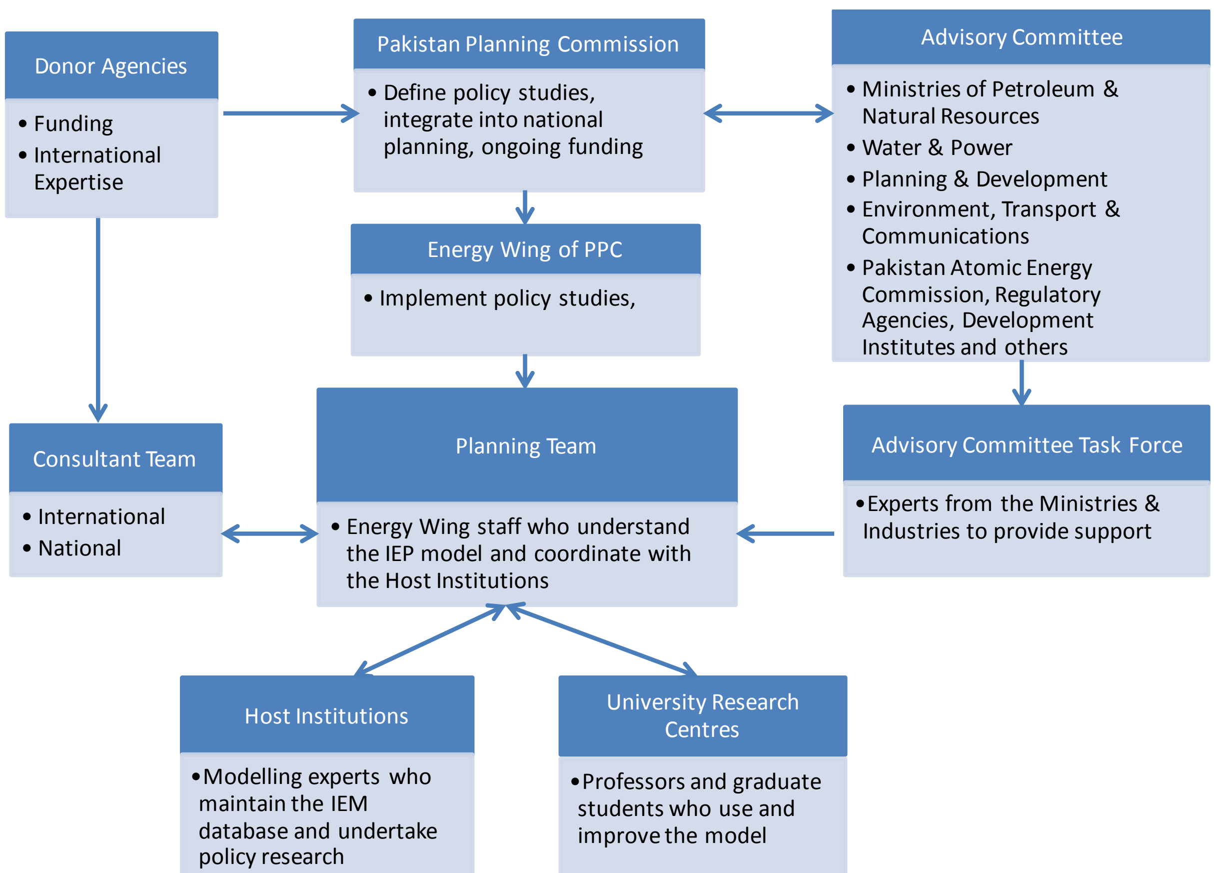
30. In March 2009 the EEG developed the first integrated energy plan for the period 2009-2022.

The purpose of the integrated energy plan is to provide a roadmap for Pakistan to achieve greater energy self-sufficiency by pursuing policies that are sustainable, provide for energy security and conservation, and are environmentally friendly. The practical goal is to meet the demand for energy needs of all sectors in a sustainable manner at competitive prices with a greater reliance on indigenous resources. A focus group was set up under the EEG to undertake the task of collating, digesting, integrating and articulating the work of the various sectoral study groups which included:-

- Exploration and production;
- Natural gas and LNG;
- Oil (including refining, OMC, liquefied petroleum gas, and ethanol);
- Power (hydro, thermal, transmission and distribution);
- Coal;
- Alternative and renewable (wind, solar, mini-hydro, biomass, biodiesel); and
- Nuclear.

31. The energy planning structure in Pakistan is illustrated in Figure III-4

Figure III-4: Energy Planning Functions in Pakistan



Source: Consultant

Recommendation on the Creation of National Energy Authority

32. As part of the integrated energy plan, the EEG recommended the creation of a National Energy Authority for streamlining decision making and planning processes in Pakistan's Energy sector. This recommendation was primarily based on the view of the Asian Development Bank (ADB) that there appeared to be confusion about the proper decision making authorities in terms of additional generation capacity (one example). The two main ministries related to energy, Water and Power, and Petroleum and Natural Resources do not necessarily have a collective and integrated country, regional or world view. For an integrated approach on energy, a single Ministry/Authority would be needed to address this issue.

33. To date, the recommendation to create a National Energy Authority has not been implemented.

The Integrated Energy Model

34. In 2011, the Asian Development Bank (ADB) provided a technical assistance (TA) to Pakistan's Planning Commission to assist the Government of Pakistan in developing an integrated energy system planning model for the entire sector. This so called Integrated Energy Model (IEM) would encompass resource supplies, refineries and power plants, transmission and distributions systems for fuels and electricity and the end-use devices. The IEM objective is to assess the impacts of various options and strategies for meeting the country's future energy needs in an optimal manner.

35. The IEM followed the same planning structure as depicted in Figure III-4. The international consultant selected for this TA was International Resources Group. Domestic agencies who took part in the planning team for the IEM development included:

- The Planning Commission;
- Global Change Impact Studies Centre;
- Hydrocarbon Development Institute of Pakistan;
- National Transport Research Centre;
- Pakistan Atomic Energy Commission;
- Pakistan Electric and Power Company;
- Pakistan Institute of Engineering and Applied Sciences;
- Pakistan Institute of Development Economics;
- University of Engineering and Technology, Lahore; and
- University of Engineering and Technology, Taxila.

36. The IEM employed the MARKAL/TIMES modelling framework. In particular, it utilised the TIME model generator, which is the successor to the MARKAL framework, and the VErsatile Data Analyst (VEDA).

37. The Pakistan IEM reference Scenario produced the following results for the year 2030:

- 82,000 MW of new power generation capacity to be added;
- Four-times increase in electricity generation from 94,000 GWh to 410,000 GWh; and
- Three-times increase in consumption of high value petroleum products from 6.2 Mtoe to 18 Mtoe.

38. As part in the IEM, recommendations were made for establishing an institutional structure for a sustainable implementation of IEM MARKAL/TIMES modelling capacity in future. The

recommendations included:

- Create of a dedicated Planning Unit overseen by the Planning Commission to manage and coordinate modelling activities in Pakistan;
- Recruit highly capable individuals to the Planning Unit who have an engineering or economics background;
- Set up the model at several different institutions where it is likely to be used (e.g. agencies participating in the IEM planning team);
- Produce annual or biannual energy outlook report;
- Establish at network of data providers from different sectors that can provide information for model updates; and
- Maintain the Advisory Committee Task Force.

F. Vietnam

Sector Policy and Planning Process

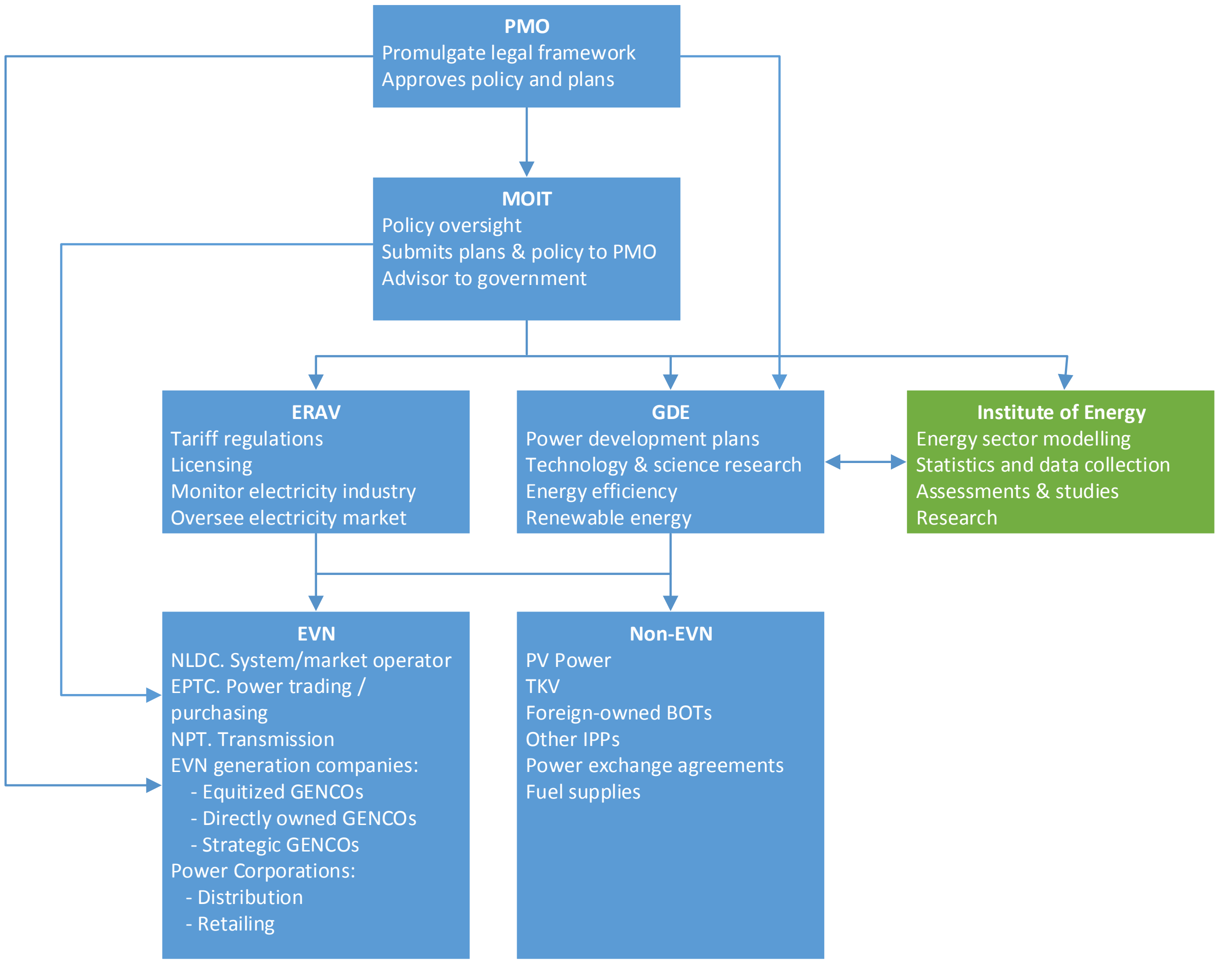
39. The Ministry of Industry and Trade (MOIT) is the government body for energy policy and planning. MOIT is responsible for overseeing all aspects of Vietnam's energy sector including electricity, new and renewable energy, coal, and the oil and gas industry. Specifically, MOIT is responsible for formulating and submitting to the Government draft laws, decrees and policies; preparing and submitting to the Government, or the Prime Minister for approval, overall development strategies and master plans; promulgating circulars, decisions, directives and other documents on state management and regulation for the listed sectors and fields. Under the current organisational structure, the MOIT's functions of energy policy making and planning are effectively carried out by the General Directorate of Energy (GDE).

40. GDE was established in September 2011 to carry out the function of advising and assisting the MOIT to execute the tasks of state management over the energy sector. GDE is responsible for drafting laws and degrees, preparing and evaluating development strategies and national master plans. In particular, GDE oversees the execution of approved electricity development master plans, and is heavily involved in negotiations with Build Operate Transfer (BOT), and IPP investors for approval of new power generation projects. GDE is responsible for national energy planning and energy policy, but they are not involved in the day-to-day management of Vietnam's energy industry. There have been discussions that a separate ministry for energy could be created from GDE in the coming years.

41. In relation to energy planning, GDE/MOIT prepares separate national development plans (also called master plans) for the power, coal and petroleum sectors. The current power master plan (number 7) was developed in 2011 for the period 2011–2020. The coal master plan was developed in early 2012 for same period, and the petroleum plan was approved in 2011 for a period until 2015. The plans are updated as required, for example, power master plan 7 was updated in 2013.

42. Figure III-5 illustrates the governance structure of Vietnam's electricity industry showing in particular the responsibilities between GDE, MOIT and the Prime Minister Office (PMO) in the planning process. The planning for coal and petroleum industries shall follow the same procedure, i.e. the plan being prepared by GDE and proposed by MOIT to PMO for approval. The Institute of Energy is a specialist group that supports the GDE, and in particular provides statistical and modelling services in support of developing Vietnam's Power Master Plan (PMP).

Figure III-5: Governance Structure of Vietnam's Energy Industry



Source: Consultant based on ERAV and EVN

Vietnam Power Master Plan (PMP)

43. The PMP is developed every 10 years for the following 10 year period with outlook to further 10 subsequent years. The PMP is also subject to a midterm revision which occurs 5 years after the start of each PMP.

44. The PMP shall include the following main contents:

- Current status of the power sector and the implementation of the previous PMP;
- National socio-economic background;
- Electricity demand forecast;
- Primary energy availability for power generation;
- Renewable energy generation;
- Planned generation projects;

- Planned transmission projects;
- Regional interconnections;
- Rural electrification;
- Financing options for the planned power projects;
- Environmental impact;
- Land use impact;
- Economic assessment of the PMP (including the evaluation LRMC and electricity tariffs);
- Implementation plan.

45. GDE shall prepare the general proposal, select and engage a capable consultant to prepare the PMP, and carry out the appraisal of the plan prepared by the consultant.

46. The Vietnam Institute of Energy is a dedicated entity (under MOIT) that has continually been involved in the preparation of Vietnam's PMPs. They have established energy planning expertise, adequate planning tools and a network of updated industry data and information required for the PMP modelling.

47. The current PMP (number 7) for the 2011-2020 period with the vision to 2030, which was approved on 21 July 2011, has strong emphasis on energy security, energy efficiency, renewable energy and power market development. It sets out six key directions and four specific targets for the Vietnam's power sector.

48. The six directions of the current PMP:-

A. Integrate the development of the power sector into socio-economic development and ensure sufficient supply of electricity for the national economic and social activities.

B. Supplement the efficient use of domestic energy resources with reasonable levels of imported electricity and fuels, diversify the primary energy resources for power generation and promote fuel conservation to ensure energy security in the future.

C. Gradually improve the quality of electricity supply and electricity services, adjust the electricity tariffs in accordance with market-based mechanisms to encourage investment and the efficient use of electricity.

D. Develop the power sector in parallel with safeguards of natural resources, ecosystems and the environment.

E. Create a competitive power market by diversifying forms of electricity investment and trading. The State shall maintain monopoly only over the power transmission network for the security of the national energy system.

F. Develop the power sector based on reasonable and efficient use of primary energy resources in each region and continue rural electrification to ensure sufficient supply of electricity to the entire country.

49. Specific targets of the current PMP:

A. Increase the aggregate electricity production (including import) from 200 billion kWh by 2015 to 350 billion kWh by 2020 and 700 billion kWh by 2030.

B. Increase the proportion of renewable energy in the total electricity production from the present 3.5% to 4.5% in 2020 and 6% in 2030.

C. Reduce the average energy intensity elasticity (the ratio between the growth rate of energy consumption and the growth rate of GDP in the same period) from the current 2.0 to 1.5 in 2015 and 1.0 in 2020.

D. Promote rural electrification programs in remote areas and islands so that most of the rural households will have access to electricity by 2020.

Coal Sector Development Plan

50. The current Vietnam Coal Sector Development Plan was approved in January 2012 and is the first of its kind in the country. It contains development visions and objectives, and specific plans for the coal sector for a period until 2010 with outlook to 2030.

51. The main content of the current coal development plan is:-

- Development visions for the sector;
- Development objectives for exploration and production;
- Coal demand forecast;
- Total coal reserves and prioritising;
- Exploration plan;
- Production and processing plan;
- Coal transportation plan;
- Coal export and import plan;
- Facility planning for coal export and import;
- Financial requirements;
- Policy recommendations; and
- Implementation plan.

52. The Coal Sector Development Plan provides a development vision as follows:-

A. Develop the sector with rational production and use of coal, and with the priority to meet the domestic demand and contribute to supporting national energy security. Gradually reduce coal export and limit it only to the types of coal that are not used by local consumers.

B. Promote exploration and assessing activities to ensure there are reliable and adequate coal resources for the sector sustainable, long-term growth and for meeting the future demands.

C. Diversify the financing sources with the state-owned enterprises retaining dominating roles, and implement market-based mechanisms for coal trading.

D. Develop the coal sector in parallel with safeguards of natural resources, ecosystems and the environment.

53. It also sets out the following targets for the sector:-

A. Specific exploration timelines for each coal basin; and

B. Production targets set at 58 million tons by 2015, 65 million tons by 2020, 70 million tons by 2025 and 75 million tons by 2030.

Petroleum Sector Development Plan

54. The current Vietnam Petroleum Sector Development Plan was approved in March 2011 and is the first of its kind in the country. It contains development visions, objectives and directions for the petroleum sector for a period until 2015 with outlook to 2025.

55. The main contents of the current petroleum development plan include:-

- Development visions for the sector;
- Development objectives for exploration and production;
- Development directions for exploration and production;
- Development directions for the gas pipe network;
- Development directions for LPG terminals;
- Trading and pricing mechanisms;
- Financial requirements;
- Policy recommendations; and
- Implementation plan.

56. The development vision arising from the Petroleum Sector Development Plan is:-

A. The state maintains the leading role in investing into the petroleum sector infrastructure;

B. Develop the sector with rational exploitation and use of natural resources, increasing import to ensure sustainable energy supply in future;

C. Promote investments into natural gas processing and refining activities, reduce LPG share in the total petroleum import;

D. Effectively utilise the existing infrastructure such as pipelines, terminals and processing facilities;

E. Develop the gas consumption market with state regulation; gradually integrate into regional and international markets.

57. Development objectives:

A. Natural gas production to achieve 14 billion cubic meters in 2015 and 19 billion cubic meters in 2015; and

B. LPG production to achieve 2 million tons in 2015 and 4 million tons in 2015.

Integrated Energy Planning

58. The development strategy for the energy sector to the year 2020 with a vision to 2050 was approved by the Prime Minister in 2007. The strategy outlined broad development objectives of the energy subsectors including electricity, coal and petroleum. It also set out the MOIT responsibility for preparing the energy sector development plan and development plans for the individual subsectors.

59. Nevertheless, in Vietnam, developing a single IEP process has not been done. Coordination between plans is largely achieved by simply setting a broad set of development objectives for each subsector. For the electricity, coal and petroleum sectors, these objectives largely shape the formal planning that is carried out.

G. Australia

Energy Sector Management

60. The energy sector in Australia is under the management of the Australian Federal Government and the state governments. The federal government is responsible for making national policies and regulations while the jurisdictions manage their state-bound energy resources and infrastructure.

61. The federal overseeing body for energy is the Department of Industry (formerly, the Department of Resources, Energy and Tourism). Another essential agency is the Standing Council on Energy and Resources (SCER) which is attached to the Council of Australian Governments (COAG). SCER coordinates the national energy policy among the states and is responsible for pursuing priority issues of national significance in the energy and resources sectors and progressing the key reform elements. SCER specific duties include:

- Progress consistent upstream petroleum administration and regulation standards;
- Address issues affecting investment in resources exploration and development;
- Develop a nationally consistent approach to clean energy technology;
- Promote efficiency and investment in generation and networks;
- Build on Australia's resilience to energy supply shocks.

Energy Sector Planning Overview

62. Since Australia has liberalised its energy markets, the planning practice was made to a minimum. There is no such a centralised planning process for development of energy industries as could have been witnessed in other developing countries. Instead, most investment decisions have been taken by businesses purely based on market circumstances. Nevertheless, the government does carry out the overall Australia's Energy Resource Assessment and National Energy Security Assessment, as well as different initiatives and plans for targeted areas such as National Strategy on Energy Efficiency, Energy Savings Initiative (ESI) and Renewable Energy Target (RET).

63. Recent developments may suggest there is a trend back to a more consolidated and centralised approach of managing the energy policy and planning issues. In particular, since 2013 the National Transmission Network Development Plan has been commenced for the electricity market. A mandatory petroleum data reporting regime is now being drafted for the petroleum sector, and the government is also in the process of preparing the first Energy White Paper dubbed as an integrated approach to Australia's energy policy.

Australia's Energy Resource Assessment

64. On 1 March 2010, the former Minister for Resources and Energy released the first edition of the Australian Energy Resource Assessment. The assessment, undertaken by Geoscience Australia (GA) and the Australian Bureau for Agriculture and Resource Economics (ABARE) provides a national prospectus of Australia's energy resources. For the first time it brings together a comprehensive understanding of the country rich energy resource endowment, integrating geoscience and long term economic energy outlooks with common terms and definitions.

65. The assessment examines identified and potential capacities from both non-renewable (coal, uranium and increasingly gas) and renewable energy resources (wind, geothermal, solar and

bioenergy). It also considers the factors likely to influence Australia's energy future in a low-carbon economy to 2030. The next edition of the assessment is expected to be released soon.

National Energy Security Assessment

66. In 2011 the former department of Resources, Energy and Tourism released the National Energy Security Assessment (NESA) which considers the key influences on the supply of energy in Australia in the short, medium and long terms covering the period 2011–2035. The NESA identifies key strategic energy security issues in the liquid fuels, natural gas and electricity sectors currently, and those likely to impact the level of energy security. The assessment collates and analyses available information and provides an assessment of energy security. The assessment considers how the identified strategic issues could affect adequacy, reliability and affordability in each of the energy sectors.

67. In 2012, the department commissioned two additional reports to further examine issues identified in the 2011 NESA.

National Strategy on Energy Efficiency

68. In July 2009, the COAG approved the comprehensive, 10-year National Strategy on Energy Efficiency (NSEE), to accelerate energy efficiency improvements and deliver cost-effective energy efficiency gains across all sectors of the Australian economy. The NSEE aims to streamline roles and responsibilities across government by providing a nationally consistent and coordinated approach to energy efficiency.

69. The NSEE was updated in July 2010.

Energy Savings Initiative

70. The Energy Savings Initiative Working Group released their information paper in July 2013. The Australian Government committed to do further work to investigate the merits of a national ESI. ESI is a market-based approach for driving economy-wide improvements in energy efficiency. It would place a requirement on obligated parties (typically energy retailers) to find and implement energy savings in households and businesses. An ESI would help energy consumers to save money by encouraging the identification and take-up of energy efficient technologies.

Renewable Energy Target

71. The Renewable Energy Target (RET) scheme is designed to ensure that 20 per cent of Australia's electricity comes from renewable sources by 2020. The RET scheme is helping to transform our electricity generation mix to cleaner and more diverse sources and supporting growth and employment in the renewable energy sector.

72. Since January 2011 the RET scheme has operated in two parts: the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET).

73. Large-scale Renewable Energy Target:

- The LRET creates a financial incentive for the establishment or expansion of renewable energy power stations, such as wind and solar farms or hydro-electric power stations. It does this by legislating demand for Large-scale Generation Certificates (LGCs). One LGC can be created for each megawatt-hour of eligible renewable electricity produced by an accredited renewable power station. LGCs can be sold to entities (mainly electricity retailers) who surrender them annually to the Clean Energy Regulator to demonstrate their compliance with the RET scheme's annual targets. The revenue earned by the power station for the sale of LGCs is additional to that received for the sale of the electricity generated.

- The LRET includes legislated annual targets which will require significant investment in new renewable energy generation capacity in coming years. The large-scale targets ramp up until 2020 when the target will be 41,000 GWh of renewable electricity generation.

74. Small-scale Renewable Energy Scheme:

- The SRES creates a financial incentive for households, small businesses and community groups to install eligible small-scale renewable energy systems such as solar water heaters, heat pumps, solar photovoltaic (PV) systems, small-scale wind systems, or small-scale hydro systems. It does this by legislating demand for Small-scale Technology Certificates (STCs). STCs are created for these systems at the time of installation, according to the amount of electricity they are expected to produce or displace in the future. For example, the SRES allows eligible solar PV systems to create, at the time of installation, STCs equivalent to 15 years of expected system output.
- The RET scheme is currently under the review as to whether the objective to deliver 41,000 GWhand small solar generation by 2020 is still appropriate.

National Transmission Network Development Plan

75. The purpose of the National Transmission Network Development Plan (NTNDP) is to facilitate the development of an efficient national electricity network that considers potential transmission and generation investments. The NTNDP provides an independent, strategic view of the efficient development of the National Electricity Market (NEM) transmission network over a 25-year planning horizon. It is focused on large-scale electricity generation and the main transmission networks that connect this generation to population and industrial centres.

76. The first NTNDP was prepared by the Australian Energy Market Operator (AEMO) using information available at 1 November 2013; however the impact of changes after this date has been assessed where practical. The plan contains a consolidated list of projects for the Transmission Network Service Providers (TNSP) in Australia.

Mandatory petroleum data reporting regime

77. On 25 January 2013, the then Minister for Resources and Energy announced the Australian Government's decision to develop and implement a mandatory petroleum data reporting regime. Mandatory reporting will improve the quality and coverage of data on the production, sale, stock holding and trade of petroleum across the Australian supply chain.

78. On 20 May 2013, a discussion paper was released to facilitate the first stage of consultation with stakeholders on the design and implementation of the regime. The main objectives of the discussion paper are to:

- identify the data and data reporters required to develop a precise and comprehensive petroleum dataset for Australia;

- determine whether existing regulatory activities and/or the business data systems developed for them could separately or collectively be used as part of the mandatory petroleum data reporting regime; and
- facilitate future government data requirements in a manner which minimises the regulatory burden on reporting entities.

79. Further stakeholder consultation is being undertaken to facilitate the development of the mandatory petroleum data reporting regime.

Australia's Energy White Paper

80. Referred to as an integrated approach to energy policy, the Australia's Energy White Paper will set out a coherent and integrated approach to energy policy to reduce cost pressure on households and businesses, improve Australia's international competitiveness and grow the export base and economic prosperity. It will consider Australia's supply and use of energy resources, including how increases in new energy sources can meet demand. The Energy White Paper will also look at regulatory reform to put downward pressure on prices and improve energy efficiency.

81. The Department of Industry is leading the development of the Energy White Paper with advice from an Expert Reference Panel. There are three stages in the development of the White Paper:

- The Issues Paper, which provides an overview of the identified issues of interest to the Government.
- The Green Paper, which will draw on submissions to the Issues Paper and assess the issues and policy approaches.
- The White Paper, which will draw on submissions to the Green Paper and present the Government's strategic direction and policy commitments.

82. The first Australia's Energy White Paper is expected to be released in December 2014.

H. Lessons from Review of International Practices for Myanmar IEP

83. It is important to have a streamlined set-up of the governmental authorities/agencies who are involved in policy making and planning for the energy sector. The planning functions of each authority should be clearly spelt to avoid being overlapped, and it is desirable that there is a single minister with sufficient mandate and resources to oversee the entire planning matter. Such an arrangement is helpful for achieving better coordination of efforts and more efficient management and utilisation of energy data.

84. Key to successful planning is to set out detailed procedure, timing, scope and contents of the planning activities. It will reduce the time spent and help to coherently address the planning objectives. While energy planning horizons are normally medium to long terms, there should be a timeframe for updates and revisions to accommodate changes in the underlining circumstances during the planned term.

85. It is beneficial to have a dedicated institution for energy plan preparation. Energy planning requires specific, multidiscipline expertise and a continuously updated bank of data about the industry and the wider economy. A specialised energy planner would be the best venue to consolidate needed expertise and manage an updated planning database. The examples of dedicated energy planners are the Institute of Energy for preparing PMPs in Vietnam and an recommended Planning Unit for implementing IEM in Pakistan.

86. More integrated approaches have been used, whether this is for planning an individual sector or the entire energy industry. The power sector development plans, for example, have become more comprehensive in countries by incorporating considerations of renewable and alternative energy sources, accounting for primary energy sectors such as oil, gas and coal, and considering linkages with other parts including land use and water supply.

87. Having a holistic development plan for the entire energy industry is on agenda for all countries under the above review. Although there have been different levels of planning details and actual realisation, the countries will likely look at implementing full integrated energy sector planning in future. The advantage of producing one energy plan in a single is to achieve more efficient allocation of natural resources, avoid counterproductive nexus effects and make the industry growth more sustainable and resilient with better environmental considerations.

88. It is noted that in cases with developed energy markets, with Australia being an example, despite many investment decisions in the industry being shifted from a planning-driven process to a market-driven approach, centralised planning processes are still maintained for strategic and/or regulated areas such as the power transmission networks and "backbone" infrastructure. The Government also periodically conducts assessments of national energy resources and the implications for energy security. In addition, the introduction of the Energy White Paper in Australia suggests a recent trend towards having a higher level of consolidation of energy planning activities. Thus, market liberalisation, as has occurred in the energy space does not necessarily mean the role of coordinated energy planning becomes diminished; in fact, this remains a key tool for coordination of planning both regulated or government elements of the energy industry with those areas that are driven more by market-based investment decisions. This is critical for assessing and providing some assurance for national energy security.

IV. CURRENT ENERGY PLANNING ARRANGMENETS IN MYANMAR

I. Energy Sector Governance in Myanmar: Current Situation

89. Regarded as an enabler for economic activity in the country, Myanmar's energy sector has received significant attention in recent years. In January 2013, the government established NEMC with a view of being a multi-ministerial coordinating body to comprehensively address all energy demand and supply related issues.

90. NEMC has its Patron being the Vice President of Myanmar and its Chairman being the Union Minister for Energy. NEMC primary function is to provide administrative functions for all energy policy and planning matters. In addition, the government also constituted Energy Development Committee (EDC) to support the activities of NEMC.

The present governance structure of Myanmar's energy sector is set out in

91. Figure IV-1. This illustrates the relationship between NEMC, EDC and other entities that influence Myanmar's energy industry.

92. The following are the entities referenced in the diagram:

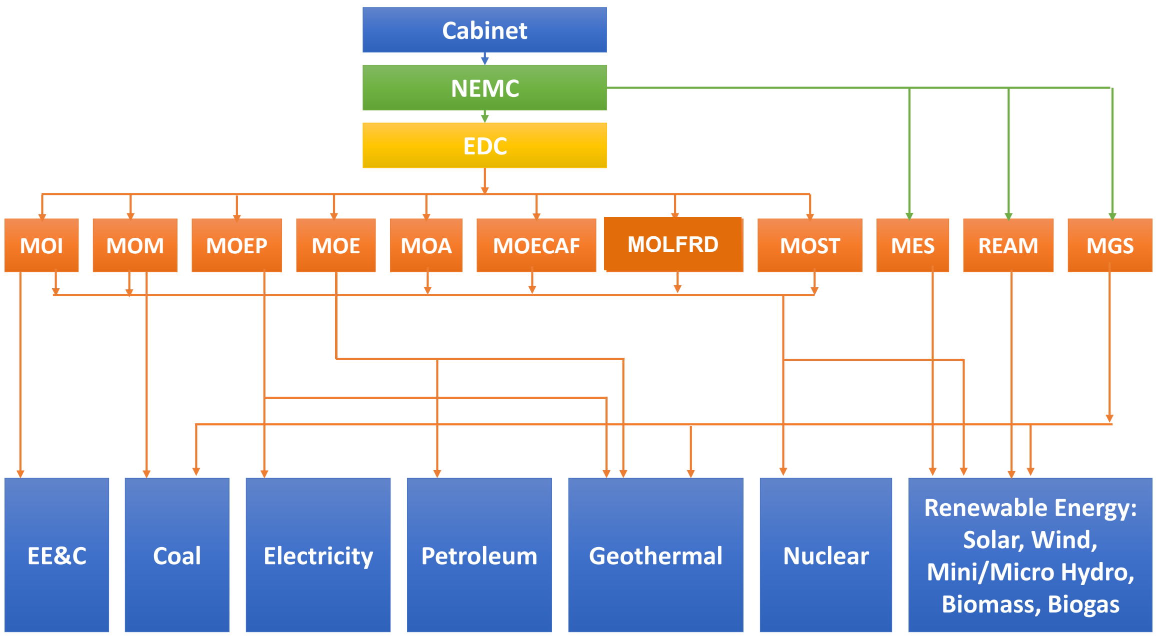
- NEMC National Energy Management Committee;
- EDC Energy Development Committee;
- MOI Ministry of Industry – energy efficiency and conservation (EE&C), nuclear power, renewable energy (RE);
- MOM Ministry of Mines – coal;
- MOEP Ministry of Electric Power – electricity sector and geothermal sector ;
- MOA Ministry of Agriculture – mini-hydro;
- MOE Ministry of Energy – oil and gas, petroleum industry, and geothermal;
- MOECAF Ministry of Environment, Conservation and Forestry – fuel wood and biomass;
- MOLFRD: Ministry of Livestock, Fisheries and Rural Development;
- MOST: Ministry of Science and Technology – nuclear, renewable energy, nuclear power, biomass, wind and solar;
- MES: Myanmar Engineering Society – renewable energy;
- REAM: Renewable Energy Association Myanmar – renewable energy; and
- MGS: Myanmar Geoscience Society – renewable energy, geothermal and coal.

93. Other critical entities in Myanmar's energy sector, not illustrated in the diagram include:

- MOGE: Myanmar Oil and Gas Enterprise, who is concerned with the commercial management of Myanmar's oil and gas resources;

- MPPE: Myanmar Petroleum Products Enterprise, concerned with the commercial management of Myanmar's petroleum sector; and
- MPE: Myanmar Petrochemical Enterprise, who is concerned with the commercial management of Myanmar's petrochemical industry.

Figure IV-1: Governance of Myanmar's Energy Sector[1]



Source: Consultant

J. Duties and Functions of NEMC

94. The duties and functions of NEMC are formally defined in Myanmar's National Energy Policy. In summary the 22 duties and functions fall into the following broad categories[2]:

A. Policy:

i. Formulate National Energy Policy based on energy demand and supply.

ii. Coordinate with the Privatization Commission and Myanmar Investment Commission to adjust the ratio between state-owned and private-owned sectors through privatization.

B. Regulatory:

i. Formulate energy regulations for implementation of energy development of the state.

[1] "The Republic of the Union of Myanmar- National Energy Management Committee: National Energy Policy" (Draft, 2013) ("Draft NEP, 2013")
[2] "The Republic of the Union of Myanmar- National Energy Management Committee: National Energy Policy" (Draft, 2013) ("Draft NEP, 2013")

C. Energy Statistics:

i. Supervise the facts and figures on energy for ensuring qualified and accurate statistics.

D. Energy Planning:

i. For development of electrical sector, to fulfil the current requirements by laying down short-term plans.

ii. Lay down long-term plans based on sustainable development of industrial sector of the State and GDP to be able to meet increased demand for electricity.

iii. To generate electricity with the use of coal as in many other countries as there has been greater demand for electricity and to use Clean Coal Technology (CCT) aimed at placing emphasis on environmental conservation

iv. Strive for generating electricity based on regional and topographical conditions with the use of solar power, hydro power, wind power, geothermal, biomass and bio-fuel to be able to meet the public demand for electricity.

v. Formulate necessary measures for adequate supply of energy for development of industrial sector.

vi. Take systematic measures in laying down development plans to be able to cover three sectors as energy, industrial and electrical sectors are mutually dependent.

vii. Prioritize and supervise oil and gas, and other natural resources to be able to meet domestic demands.

viii. Carry out oil & gas production through local and foreign investments in accordance with international regulations.

ix. Sell out value-added petrochemical products rather than raw materials.

x. Coordinate natural gas and electricity generation in order to meet urea fertilizer demand of the agriculture sector by planning production target.

E. Energy Security:

i. Enforce an energy sufficiency ambition in industry, transport and household sectors and minimise energy wastage.

ii. To adopt a National Energy Security Strategy that envisages the future generations, apart from the current energy issues.

F. Technology Research:

i. Conduct necessary assessment to participate in civil nuclear energy activities in ASEAN.

G. Environment:

i. Conduct environmental impact and social impact assessments of the region ahead of implementation and raise community awareness for the people who live in affected project areas.

H. Finance & Economics:

i. Adopt convenient pricing policy for both consumers and investors depending on international prices.

ii. Invite foreign and local investments for the energy sector development and increase FDI in accordance with international norms.

I. Administration

i. To make arrangement for drafting necessary law, rules and regulations to be able to implement in accordance with the National Energy Policy and National Energy Security Strategy

ii. Engage with members of the President Office, Natural Resources and Environmental Conservation Committee and the Mineral and Natural Resources Affairs Committee.

K. Comments on the present state

95. The duties and functions NEMC as formally defined can be placed within the context of an IEP process. The present governance structure and supporting National Energy Policy provides a foundation for an EMP process, however a number of enhancements are required in order for it to become a well-functioning process.

96. However, the roles and responsibilities at the working level need to be strengthened in order to enable NEMC to achieve its overarching objectives. NEMC could be considered to be analogous to a planning commission, while the NEMC working level staff could be responsible for essentially undertaking energy planning.

97. As illustrated in Figure IV-1 responsibilities are spread over many different ministries for different components of Myanmar's energy sector. This is a considerable impediment to developing a holistic and coherent IEP / EMP process as to information transfers and synchronisation of the inputs/outputs between the EMP and many other ministerial planning works.

98. A number of other planning processes have been established in Myanmar by the different ministries for particular subsectors of the energy industry. Among others, there is a Power Master Plan (PMP), a Forestry Master Plan (FMP), a Transport Plan, and short and long term plans for the oil and gas sector. Thus the relationship between an IEP process and these other plans needs to be carefully developed and considered as part of enhancing Myanmar's institutional arrangements for an IEP process.

V. INSTITUTIONAL ARRANGEMENTS TO SUPPORT IEP IN MYANMAR

99. The previous sections have set out the issues that an IEP process needs to address, reviewed the arrangements in several comparator countries, and reviewed and critiqued the arrangements presently in place in Myanmar. We can leverage these insights to make some recommendations to enhance Myanmar's current arrangements to better support an IEP / EMP process.

100. In particular, we have organised a number of options and recommendations in the following way:

A. Organisational structure and allocation of responsibilities.

B. Definition of IEP / EMP process and how it is managed within the organisational structure that we recommend.

C. Human capacity requirements.

D. Software tools and training considerations.

L. Organisational Structure

101. Figure IV-1 combined with the roles and duties of NEMC defined in the National Energy Policy provide a reasonable foundation for a coordinated approach to energy planning. However, the following are the two key enhancements to the existing structure that we recommended:

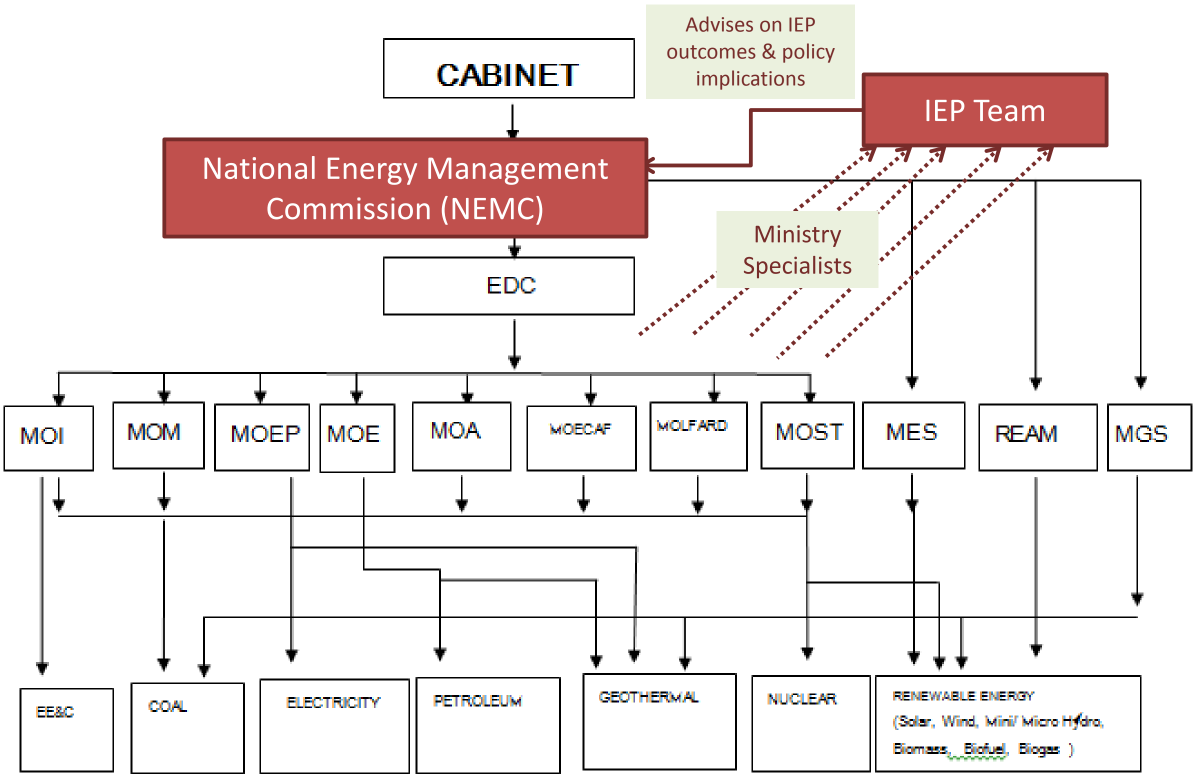
A. Establish a permanent and specialist IEP team within the existing governance structure at NEMC.

B. Allocate the roles and duties of the concerned IEP team, the Ministries and NEMC in a way that can support the IEP process.

Concept of IEP Team and Allocation of Duties for the Purpose of IEP

102. NEMC itself could be thought of as more of a Planning Commission and the NEMC working level staff as an Energy Planning team, for example, an "Energy Wing" of the Planning Commission. This is a common structure implemented in other countries. The concept is illustrated in Figure V-1, where we have introduced the IEP Team to the current structure in Myanmar.

Figure V-1: IEP Team



Source: Consultant

103. Shown in the diagram is the concept of the ministry specialist advisors, who feed into the IEP Team critical information relevant to the ministries that each represents. In essence the Ministry specialists would be responsible for the following duties:

A. Provide macroeconomic policy options;

B. Provide strategic development plans for economic sectors;

C. Provide primary resource assessments;

D. Develop roadmaps (pipelines, storage depots, roads, railway lines, power plant sites);

E. Evaluate energy supply technologies; and

F. Report on energy statistics for consolidation to the IEP Team.

104. The IEP Team would be responsible for the key activities associated with the IEP process:

A. Definition of policy and socio-economic issues;

B. Definition of regulations;

C. Compilation of Energy Statistics;

D. Definition of planning criteria and targets;

E. Selection of Primary Resource & Technology options (screening curves);

F. Performance of Integrated Energy Modelling;

G. Development of financing & tariff strategies; and

H. Industry & Public Consultation.

105. And finally, NEMC taking the form of a Planning Commission, would be responsible for:

A. Ratification of projections of estimated future energy needs in support of macroeconomic and socio-economic requirements;

B. Recommend preferred energy supply options in light of:-

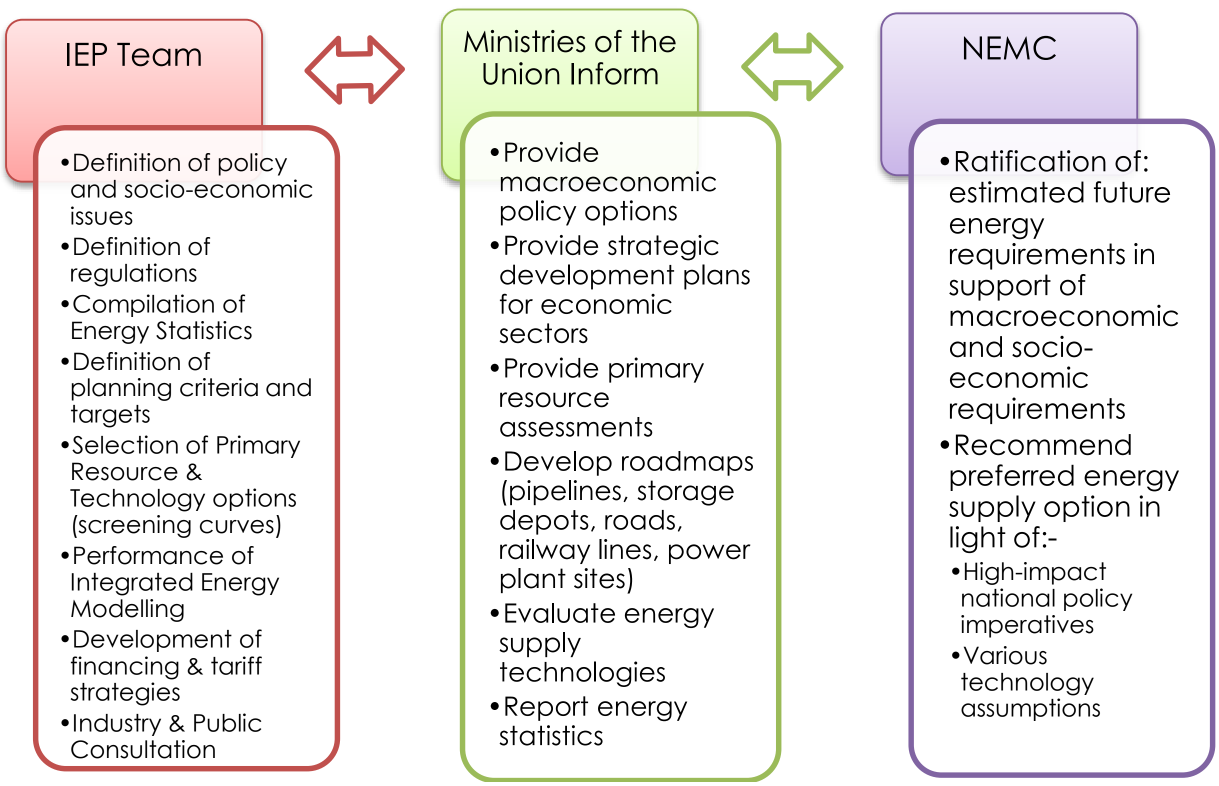
i. High-impact national policy imperatives

ii. Various technology assumptions

C. Recommend energy policy to support the preferred path.

106. The delineation in responsibilities between the IEP Team, Ministry Specialists and NEMC is illustrated in Figure V-2.

Figure V-2: Responsibilities of the IEP Team, Ministries and NEMC



Source: Consultant

IEP Team Structure

107. The IEP Team itself can be structured as a specialised energy planning entity, with a structure such as that illustrated in Figure V-3.

108. The roles within the IEP Team would be:

A. **Director General**. The Director General would be responsible for delivering the Integrated Energy Plan to the NEMC. The Director would identify policy issues and make recommendations on policy options for NEMC's consideration. These could form the basis of policy-based expansion scenarios in accordance with national economic growth aspirations, international obligations and other criteria. The expansion scenarios could be modelled by energy planners and subsequently assessed for its suitability. It would then ultimately lead to a final recommendation to be made to NEMC.

B. **Ministry Specialist Advisors**. The ministry specialist advisors are needed to contribute as advisors to the IEP in respect of (1) primary resource development, specifically to advise the projected economic value of local fuels, (2) consumption patterns, (3) supply technology selection based on field experience and capability, and (4) provision of energy statistics to the energy statistics team. Development partners could play the role of specialist advisors to assist the Director General in relation to energy planning and energy policy.

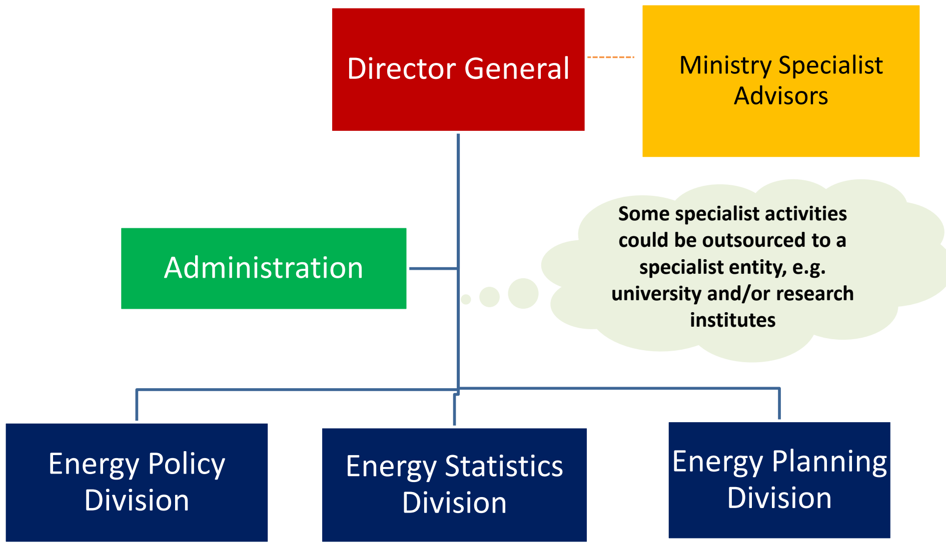
C. **Energy Policy Division**. Develop high-level scenarios in accordance with national development plan and strategic policy etc. Develop policy implications of the IEP. Conduct energy demand forecast through modelling specialists.

D. **Energy Statistics Division**. The energy statistics team is responsible for maintaining an energy statistics digest on an annual basis, by sector (for example, solid fuel, petroleum, gas, renewables, electricity etc.) The team would also be responsible for developing demand and supply statistics to the demand and supply modelling specialists within the energy modelling team.

E. **Energy Planning Division**. The energy planning team could be structured so that it comprises: (1) a demand modelling specialist capability, to consolidate energy demand forecasts by Primary, Secondary and Tertiary sectors, (2) a supply modelling specialist capability to develop policy-based expansion plans, and (3) an economist / financial capability to cost supply expansion plans and to undertake tariff analysis. Another role of the energy planning team would be to monitor the progress of previously developed plans, and identify and improve the IEP process over time, so that over time it can become more aligned with outcomes to date as well as reflective of emerging issues. Note that some functions of the energy planning team described here could be outsourced to specialist institutions.

F. **Outsourcing of specialist activities**. It may make sense for certain functions to be outsourced to specialist entities, such as institutions or universities. For example, other entities could perform energy consumption surveys, they could perform analysis and diagnosis of pilot projects to enhance energy efficiency or renewable energy, or they could take a larger role, such as performing least cost energy planning, which would mean that the energy planning division would take on more of a role of oversighting the modelling and planning rather than being directly responsible for it.

Figure V-3: IEP Team Structure



Source: Consultant

M. IEP Process

109. The EMP is typically repeated on a cycle of 5 years.

110. The main aspects of any IEP implementation includes the following:-

A. Data collection. A strategy needs to be put into place to support the routine collection and reporting of. While data uncertainty can never be completely eliminated, the need for verification and validation is important as it ultimately informs the IEP process of trends in energy supply and energy demand. Furthermore, a process to recognise and set in motion a process for obtaining any missing data is required – for example, designing targeted surveys or legislating mandatory declarations of stocks and inventory for commercial enterprise. Tools such as spreadsheets and databases are required to support this.

B. Compilation, analysis and statistical reporting on data. Data will necessarily be fragmented across different agencies who are concerned with different subsets of the energy conversion chain (gas, oil, electricity, commerce, industry, etc.). The data needs to be transformed to develop a holistic picture of the energy situation. This may require analytics and/or reconciliation processes to eliminate gaps. Analysis of this kind enables one to identify any emerging trends in energy supply and demand, which in turn is necessary for use in the development or calibration of forecasting models.

C. Energy demand forecasting. The IEP requires as a key input projections of energy demand for all key sectors: industry, commerce, residential, agriculture, transport and others. These need to be consistent with an underlying set of economic scenarios. The IEP may involve developing a set of independent forecasts or leveraging externally developed forecasts[3]. Other dimensions to this include the issue of energy efficiency

[3] For example, individual ministries or government agencies may have established processes or models in place, or

and energy access. Models to support the development of energy demand forecasts are essential.

D. Energy supply forecasting. Issues to be addressed include estimates of primary energy resources, existing and planned infrastructure, options for development, cost of developing primary energy resources, fuel costs, operational expenditure, capital costs, assessments of conventional and emerging technologies, and costs of developing them etc. Again, a database and basic supply option cost models support this process.

E. Developing an overall strategy. A process to translate the projections and modelling results into a meaningful set of recommendations. The demand and supply analysis will require consideration of a range of scenarios that need to eventually be used to guide key decisions on policy and a concrete set of implementation plans or roadmaps for each of the main subsectors.

F. Monitoring and evaluation. Finally, the progress, and effectiveness of any IEP needs to be checked. This process is one of comparing actual outcomes to those that had been planned, identifying areas of discrepancy and making refinements to the IEP process to better address these issues on a go-forward basis.

111. It may be possible to streamline some aspects of the preparation of the EMP so that some aspects are updated more frequently than others.

N. Relationship between EMP and Other Planning Processes

112. Figure V-4 conceptually illustrates the linkage between the EMP and other planning or policy processes in Myanmar[4]. This highlights the need for coordination between the different planning processes and also the potential for there to be interface issues; the boundaries between the EMP and other planning processes must be carefully defined and managed.

113. A number of the ministries already have in place their own forward-looking process, in particular:

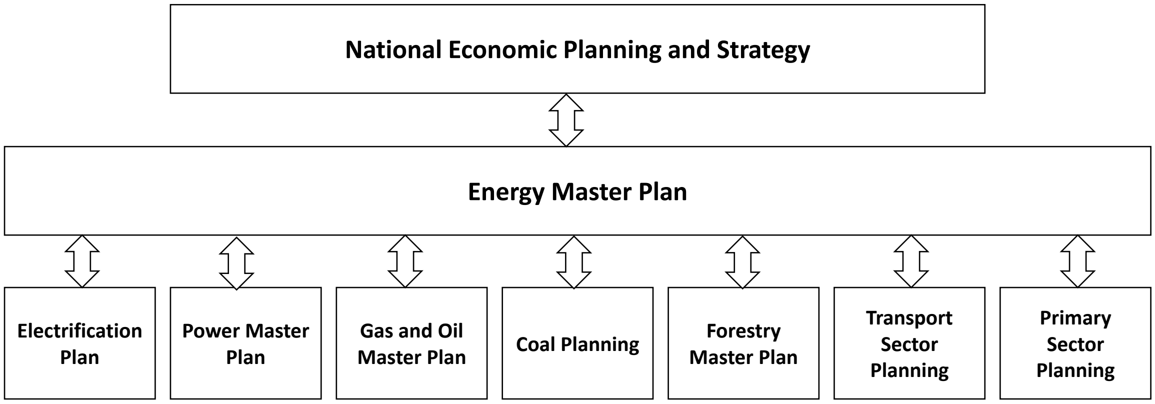
- MOEP – 20-year Power Master Plan;
- MOGE – 30-year plan that is updated as required, and a 20-year oil and gas plan;
- MOECAF – Forestry Master Plan; and
- Most of the other ministries also have in place planning processes.

114. The IEP process is intended to provide an integrated implementation of the individual subsectors. A key issue is the relationship between EMP and other ministry-level plans. Ideally the top-down and bottom-up assessments will be consistent, although this can't always be guaranteed. In this context, the EMP is defining the broad parameters or a broad space that then needs to be filled in with the details by the concerned ministry.

115. For instance, for the power sector, the EMP provides the broad direction, but it does not provide a detailed consideration of transmission and distribution investments, this is an issue for MOEP to address. For other sectors, the situation is similar.

they could be independently developed as part of a centrally coordinated EMP framework.
[4] In fact, it could be any country.

Figure V-4: Energy Master Plan Relationship to other Planning Processes



Source: Consultant

O. Human Capacity

116. The previous sections set out an organisational structure and procedure for successfully implementing the IEP. As discussed, functionality falls into four (4) main categories that can be either common across all the Phases or embedded within one Phase. These categories are:

- Co-ordination & program management;
- Demand side assessment;
- Supply side assessment; and
- Statistics.

117. The skill sets required to undertake these critical functions are discussed in the subsections that follow. We have detailed the total skill sets required to complete the tasks that fall within the categories outlined. It is envisaged that these skill sets would reside within multiple individuals who are in the IEP Team structure that was set out earlier. It is unlikely that one individual could either (a) undertake the work required within the timeframe provided, or (b) have sufficient diversity in expertise across all areas to undertake the work to a sufficiently high standard.

118. All the members of this team must have good communication skills particularly with regards to coordination with ministries, and the production of documents for circulation amongst ministries. The ability to engage and collaborate with stakeholders at all levels of this team is very important.

Energy statistics

119. Energy statistics involves initial data gathering as well as the measurement and monitoring of the success of the prior period EMP. This area requires people qualified in mathematics, statistics and/or econometrics.

120. Energy statisticians specialise in the compilation verification and dissemination of information on all aspects of energy including its production transformation and consumption of all fuels renewables emergency reporting system energy efficiency indicators CO2 emissions and energy prices and taxes done managers are responsible for receiving reviewing and importing data submissions from ministries and other sources into last computerised databases.

121. The statisticians check for completeness correct calculations internal consistence consistency accuracy and consistency with definitions. Often this will entail proactively investigating and helping to resolve anomalies in collaboration with ministries.

122. Data managers and statisticians also play a key role in helping design and implement computer macros used in the preparation of the EMP.

123. These team members should have a university degree in a topic relevant to either energy, computer programming or statistics. They should have experience in the basic use databases and computer software.

124. Members of the statistics team must have the ability to work accurately, to pay attention to detail, and work to deadlines. They also must have the ability to deal simultaneously with a wide variety of tasks and to organise the work efficiently.

125. At least one or two of the members of this team must have good communication skills particularly with regards to coordination with ministries, and the production of documents for circulation amongst ministries.

126. Subsets of the skills required to undertake this function would include data collection and analysis, the ability to perform an energy balance and experience in conducting surveys on energy use and consumption.

Energy demand forecasting

127. Energy demand forecasting is a specialised skill area.

128. The senior in charge of the energy forecasting group should be responsible for the delivery of all energy forecast across various energy sources. These sources include coal, electricity, gas, petroleum and biomass.

129. The senior requires a team that is capable of undertaking statistical and mathematical modelling to develop both short and long-term energy forecasts. The team are also required to develop technical solutions to problems that impact energy demand.

130. Relevant tertiary qualifications in statistics, mathematics, econometrics, science, engineering or economics will be useful in this role. At least one or two members must have an understanding of the workings and impacts (on demand forecasts) of demand management and energy efficiency.

131. In addition, strong programming and data management skills as well as experience in statistical or mathematical modelling and database development are important.

132. Due to the scope and importance of the function of this team, members must have the ability to take ownership of pieces of analytical work.

133. The team members should have an interest in macroeconomic modelling and forecasting and a keen interest in real world economic issues and policy developments.

134. At least one or two of the members of this team must have good communication skills particularly with regards to coordination with ministries, and the production of documents for circulation amongst ministries. The ability to engage and collaborate with stakeholders at all levels of this team is important.

Energy supply modelling

135. A large proportion of the functionality that is required of this team lies in their ability to undertake research. Research into processes and trends that are emerging in the technology or conversion market that is being assessed, as well as the external environment that may affect all the future supply options.

136. The team as a whole must have the capacity to develop solutions and organise a complex workflow.

137. At least one or two of the members of this team must have good communication skills particularly with regards to coordination with ministries, and the production of documents for circulation amongst ministries. The ability to engage and collaborate with stakeholders at all levels of this team are important

138. This team could be divided into two types of groups: (a) engineering group, and (b) financial group.

Energy supply modelling: engineering group

139. The engineering group would be concerned more with technology assessments and supply options for its applicability in energy extraction or conversion within an energy system. Across multiple streams there need to be specialists with backgrounds in engineering for coal, gas, electricity, renewables, petroleum, demand management & energy efficiency. Within these categories an understanding of the following is required:

- Technology assessments;
- Renewable energy / non-conventional technologies; and
- Primary energy resource assessments.

140. The members within the engineering group should have experience in some (or all) of those areas combined with strong communication skills, and the ability to research. As a whole, the team must have the ability to undertake analytical thinking and to take a logical, defensible approach to resolution of problems.

Energy supply modelling: economics and financial group

141. The economics group would need to be responsible for costing models for the supply chain, assessing value of expansion options, fuel sources, capital costs and so on. The team would need to be able to understand and develop:

- costing models;
- expansion models;
- macro-economic outlooks;
- cost-benefit analysis; and
- tariffs / pricing analysis.

142. Therefore there is a requirement for a group within the supply modelling team that understand the costing of different types of technology, and the capacity to forecast changes in technology costs over time (technology curve).

143. Ideally the staff engaged in this area would have some level of exposure to energy specific analysis, costing structures, and event forecasts. Team members should have considerable experience in working with and developing applied macroeconomic models, combined with excellent macro-modelling and macro-econometric skills.

Comments on Training Areas

144. Figure V-5 sets out possible areas of training and capacity building which provides coverage of all key areas and topics that the energy planning team requires.

Figure V-5: Possible Areas of Training and Capacity Building

1a	Energy demand forecasting techniques (theory, electricity with electrification targets)
1b	Energy demand forecasting applied (practice using Excel, demonstration of e-Views, discussion of MAED)
2a	Load / production profile development theory (capacity factors, load factors etc.)
2b	Load / production profile development applied (practice, discussion of MAED)
3a	Screening curve theory (electricity)
3b	Screening curve (practice)
4a	Economic dispatch theory
4b	Economic dispatch applied (practice solving a number of problems of increasing degrees of sophistication, the final one to be electricity expansion)
5a	Portfolio costing theory
5b	Portfolio costing applied (focus on the economic / financial evaluation principles – NPV, IRR, payback etc.)
6a	Energy balance theory
6b	Energy balance practice

Source: Consultant

P. Models and Tools to Support Energy Planning

145. The following are specialist energy planning tools that could be considered:

A. MAED = Model for the Analysis of Energy Demand
B. MESSAGE = Model for Energy Supply System Alternatives and their General Environmental impacts
C. MARKAL/TIMES with ANSWER or VEDA (as user interfaces) = Market Allocation
D. LEAP = Long-range Energy Alternatives Planning system
E. WASP = Wien Automated System Planning
F. EViews = Regression / statistical modelling

G. eSankey = Sankey Diagram Visualisation software suitable for visualisation of energy flows

146. A summary of these tools is provided in Figure V-6.

Figure V-6: Summary of Energy Planning Tools

Tool	**Developer**	**Scope**	**Method**	**Suitable?**
MAED	IAEA	Integrated Energy / Environment Analysis	Physical accounting, simulation	Yes, for demand (need MESSAGE for supply)
MESSAGE	IAEA	Final and useful energy supply	Optimization	Yes, for supply (need MAED for demand)
MARKAL / TIMES	ETSAP	Integrated Energy / Environment Analysis	Optimization	Yes, for demand & supply
LEAP	SEI	Integrated Energy / Environment Analysis	Physical accounting, simulation, optimization	Yes, but not as flexible as others
WASP	IAEA	Electricity sector	Simulation and optimization	No, electricity planning focus
EViews	his	Generic statistical modelling tools	Statistical models	Useful
eSankey!	ifu Hamburg	Generic Sankey diagram generator	Provides tools to make drawing easy	Useful but not essential

Source: Consultant's analysis

Project Number: TA No. 8356-MYA

FINAL REPORT

MYANMAR ENERGY MASTER PLAN

APPENDICES

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

IES
Intelligent Energy Systems

in association with

MMIC
MYANMAR INTERNATIONAL CONSULTANTS

December 2015

Project Number: TA No. 8356-MYA

FINAL REPORT

APPENDIX 1:
TERMS OF REFERENCE

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

IES Intelligent Energy Systems

in association with

MMIC MYANMAR INTERNATIONAL CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
IES	–	Intelligent Energy Systems Pty Ltd
MMIC	–	Myanmar International Consultants
NEMC	–	National Energy Management Committee
TA	–	Technical Assistance
TOR	–	Terms of Reference

CONTENTS

I. INTRODUCTION

1. Intelligent Energy Systems Pty Ltd (IES) in association with Myanmar International Consultants Co. Ltd. (MMIC) were contracted by the Asian Development Bank (ADB) to undertake the following Technical Assistance (TA) project: "TA-8356 MYA: Institutional Strengthening of National Energy Committee in Energy Policy and Planning – 1 Energy Master Plan Consultant (46389-001)". The project objectives are to: (1) provide technical assistance and institutional strengthening to the National Energy Management Committee (NEMC) in Energy Policy and Planning, and (2) to prepare a 20-year Myanmar Long-Term Energy Master Plan for the energy sector of Myanmar.

2. The detailed terms of reference (TOR) for the project as specified by ADB is reproduced in Section II.

II. PROJECT TERMS OF REFERENCE

A. Scope of Work

3. Under the technical assistance for Institutional Strengthening of NEMC in Energy Policy and Planning, a team of consultants will be engaged to prepare a 20-year energy master plan for Myanmar, including an energy demand forecast, supply options, investment requirements, and legal and institutional arrangements. To strengthen the abilities of NEMC and the EDC to prepare an energy policy, a renewable energy development strategy, and an energy efficiency policy in coordination with seven concerned ministries, three (3) international and four (4) national experts were engaged. The project team will be required to prepare several reports, set up systems and procedures, implement a variety of capacity development activities, and monitor project implementation.

B. Long-Term Energy Master Plan

4. A team of international and national consultants from a consulting firm will be engaged to prepare the 20-year energy master plan. This will be done in accordance with the Asian Development Bank (ADB) Guidelines on the Use of Consultants (2010, as amended from time to time). The work will require about 18 person-months of international consulting services and 20 person-months of national consulting services. A team of experts comprising an energy statistician, an energy planner, and an energy economist will be engaged from a consulting firm that has expertise in energy demand and market analysis, demand projections, assessing supply options to meet energy demand, investment requirements, and legal and institutional arrangements.

5. The energy statisticians (international, 6 person-months; national, 12 person months) will undertake the following activities:

(i) Consolidate the existing fragmented energy statistics and planning studies and reports for the energy sector from the seven concerned ministries, including the Ministry of Energy (oil and gas sectors); the Ministry of Electric Power (power sector); the Ministry of Mines (coal development); the Ministry of Agriculture and Irrigation (biofuels, and micro-hydro for irrigation purposes); the Ministry of Science and Technology (renewable energy); the Ministry of Environmental Conservation and Forestry (fuelwood, climate change, and environmental safeguards requirements); and the Ministry of Industry (energy efficiency).

(ii) Collect and compile energy statistics and energy outlooks prepared by the International Energy Agency, ADB, the Association of Southeast Asian Nations, and other development partners.

(iii) Conduct the surveys on the use of energy in various sectors.

(iv) Review existing energy data and develop an energy balance for 2000 – 2012 for Myanmar, adapting the methodology used by the Asia-Pacific Economic Cooperation forum in its Energy Demand and Supply Outlook, including overall energy balances, as an input to energy projection.

(v) Develop the manual or tool kit for preparing a primary energy consumption and energy balance table.

(vi) Train staff from concerned ministries on the developed manual or tool kit and will develop a capacity development plan.

6. The energy planners (international, 5 person-months; national, 4 person-months) will undertake the following activities:

(i) Develop a common methodology for energy demand and supply analysis and make demand projections for each primary energy and each sector based on the developed energy balance for the next 20 years. These projections will take into account projections for gross domestic product, population and other economic indicators in close consultation with the Ministry of National Planning and Economic Development and research institutions.

(ii) Assess the supply potential of primary energy sources in Myanmar such as biomass, coal, oil, gas, hydro, and renewable energy.

(iii) Assess the technical feasibility of primary energy supply options in close consultations with the energy economist.

(iv) Recommend least-cost options for delivering the energy supply required to meet the energy demand, in close consultation with the energy economist.

(v) Train staff from the concerned ministries on the developing common methodology and develop the capacity development plan.

(vi) Design, organize, facilitate, and document public discussions with a range of stakeholders, including civil society, and ensure that these discussions follow ADB models of good practice for consultation.

7. The Energy Economists (international, 7 person-months; national, 4 person-months will undertake the following activities:

(i) Assess the economic feasibility of primary energy supply options in close consultations with the energy planner.

(ii) Recommend least-cost options for delivering the energy supply required to meet energy demand, also in close consultation with the energy planner.

(iii) Assess the availability of financial resources from domestic and international bilateral, multilateral, and private sector sources to meet investment needs, and develop a financing plan to implement the long-term planning.

(iv) Suggest the financing modality, including public – private partnerships.

(v) Identify the institutional and regulatory impediments to collecting energy information and preparing the long-term outlook.

(vi) Determine the improvements necessary in the institutional and regulatory framework to support the function of energy planning in the Ministry of Energy (MOE).

(vii) Supervise and organize the necessary workshops and seminars and conduct the necessary training and capacity building on energy balance and planning, including a capacity development implementation program.

8. The consultants will prepare an inception report within 1 month, an interim report within 6 months, and a draft final report within 11 months from the commencement of consulting services. For each report, the consultants will organize a workshop to enhance staff skills in energy planning from the concerned ministries.

C. Variations to Scope of Work

The following variations to the scope of work were initiated by ADB:

9. ADB separately engaged a Consultant to undertake a power expansion plan. IES was instructed to follow this expansion plan as the electricity sector strategy for Myanmar and to not consider independently developed views or cost estimates for the electricity sector.

10. The ADB expansion plan is to be included as an appendix to the Energy Master Plan (EMP) final report.

11. The long-term energy plan was to be determined to 2030 in order to facilitate comparison to other studies and work. In the report it is only necessary to provide projections on outcomes for a 15-year period from 2015 to 2030.

12. Only a single medium-case energy supply outlook is to be developed.

Project Number: TA No. 8356-MYA

FINAL REPORT

APPENDIX 2:
NOTES ON ENERGY PLANNING

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

IES
Intelligent Energy Systems

in association with

MMIC
MYANMAR
INTERNATIONAL
CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
APERC	–	Asia Pacific Energy Research Centre
ASEAN	–	Association of South East Asian Nations
EMP	–	Energy Master Plan
GDP	–	Gross Domestic Product
MOAI	–	Ministry of Agriculture & Irrigation
MOE	–	Ministry of Energy
MOEP	–	Ministry of Electric Power
RE	–	Renewable Energy

CONTENTS

NOTES ON ENERGY PLANNING

A. Introduction

1. Strategic energy sector planning requires the use of formal methods that ensure transparency, comprehensiveness, consistency between subsectors and reproducibility. As least-cost strategies are to be identified for each scenario considered in this project, the tools used for energy planning must be capable of optimization. Also, the tools must be suited for the size of the energy systems of the country and must lend itself to integration of country results to study all aspects of energy substitution.

2. The key considerations involved in selection of energy planning tools are as follows:-

- The planning horizon;
- The focus on short versus medium and long-term need;
- The confidence in historical data describing the economy and the energy industry;
- The need to take into account regional issues versus national issues; regional issues are usually significant when an energy system is small and there are one or two large load centres and many regional load centres at various stages of development;
- The maturity of the energy sector and the degree to which fuel substitution is evidenced; in particular the role that natural gas plays, within the context of the economy, is a critical issue; and
- The suitability of the planning tools for transfer to energy planning staff in the responsible Ministries.

3. The Consultant has worked to a planning horizon spanning the years 2014 to 2035. This planning horizon of slightly more than 20 years is relatively short. Given the social reforms that are taking place in Myanmar, and the uncertainty surrounding the economic growth outlook, a 20 year planning horizon is considered to be the longest period for a meaningful energy planning study.

4. In regards to the energy needs of Myanmar, it is clear that the focus is on the short to medium-term. The current shortfall in electricity supply and declining on-shore production of liquid fuels point to the need for near-term action.

5. Confidence in historical performance data is somewhat mixed. There is no shortage of literature in the public domain, wherein consultants and analysts have questioned the accuracy of economic and technical data reported by the Government of Myanmar. Whilst the experience of the ADB Consultant has been generally positive with regard to data accuracy, nevertheless the confidence is considerably less than is the case for transition and OECD-economy countries.

6. Myanmar's energy system is small and characterized by the very large load centre of Yangon, a moderate size centre of Mandalay, and a range of State/Region centres at different levels of development. Myanmar is a long country, from south to north, with marked differences in topology and climate. As a result there are three agricultural zones and three fuel zones to consider. Energy planning from a national perspective only will not deal adequately with this mixed presentation;

some level of disaggregation to regional level is needed.

7. Myanmar's energy system is relatively immature when compared to those of developed world countries. This is not a comment on the maturity of the energy technologies in use; rather it highlights the shortage of gas available for domestic use. In the coming years, gas supplies might be expected to increase and so the potential for fuel substitution. This means that energy planning tools must be able to evaluate the optimal use of gas across the economy.

8. Energy planning tools come with various levels of sophistication. It is understood that energy planning staff in the Ministries have had exposure to a moderately sophisticated energy planning package called LEAP. It is understood that the planning staff involved came away with the opinion that it was too soon to apply such a model in Myanmar. The lack of reliable data in particular was a concern, along with general concerns regarding the lack of transparency with such a model.

9. With reference to the key considerations outlined above as bullet points, and the ensuing discussion points, the Consultant considers that the best approach to energy modelling is a bottom-up optimization / accounting approach applied at regional level. Considering the energy planning tools that are applied consistently throughout the world, and their characteristics, this leads to the conclusion that individual economic sector models are most appropriate for Myanmar at the present time. The tools and their characteristics are tabled as follows:-

Table 0-1: Energy Modelling Tools

Approach	Space	Sector	Time	Examples	Suitability for developing countries
Top down simulation	Global, national	Macro-Economy, Energy	Long term (20+ years)	AIM, SGM2, I/O models	4
Bottom up optimization	National	Energy	Long term (20+ years)	MARKAL / TIMES	3
Bottom up accounting	National, regional	Energy	Long term (20+ years)	LEAP	2
Bottom up optimization / accounting	National, regional, local	Energy	Medium term (20 years), short term	Sector models (e.g. agriculture, transport, industry, household, etc)	1

Source: Consultant

10. There are advantages and disadvantages in using sector models for energy planning

- Sector models better facilitate training in the concepts involved in sector planning as the models are transparent;
- Sector models are weak when it comes to modelling fuel substitution effects; however in Myanmar the key issue is the use of gas and the allocation can be readily tested by

sector, notably the diversion of gas for fertilizer and / or CNG-fuelled vehicles, versus the savings that could be gained if the gas is instead used for power generation; and

- The sector model approach supports the use of a long-term planning tool, such as LEAP or MARKAL / TIMES, because the accurate calibration of sector energy consumption against historical fuel production/imports will ultimately provide a high level of confidence in historical data; this confidence is a pre-requisite for setting parameters within the more sophisticated planning packages. In future such multi-criteria optimisation models could be developed for Yangon Division and the rest of the country, or for north and south partitions of the country.

11. A final comment regarding the MARKAL / TIMES planning package is that the power of the software is fully released when consumer price behaviour is included in the model. At the present time there is insufficient knowledge of consumer behaviour to support such an approach, particularly in the rural sector. A possible evolution would be to develop a simple MARKAL / TIMES model for a typical rural village. This model could later be integrated into a national model thereby ensuring that energy consumption of the country is correctly characterized at the consumer end.

B. Myanmar Energy Planning Model

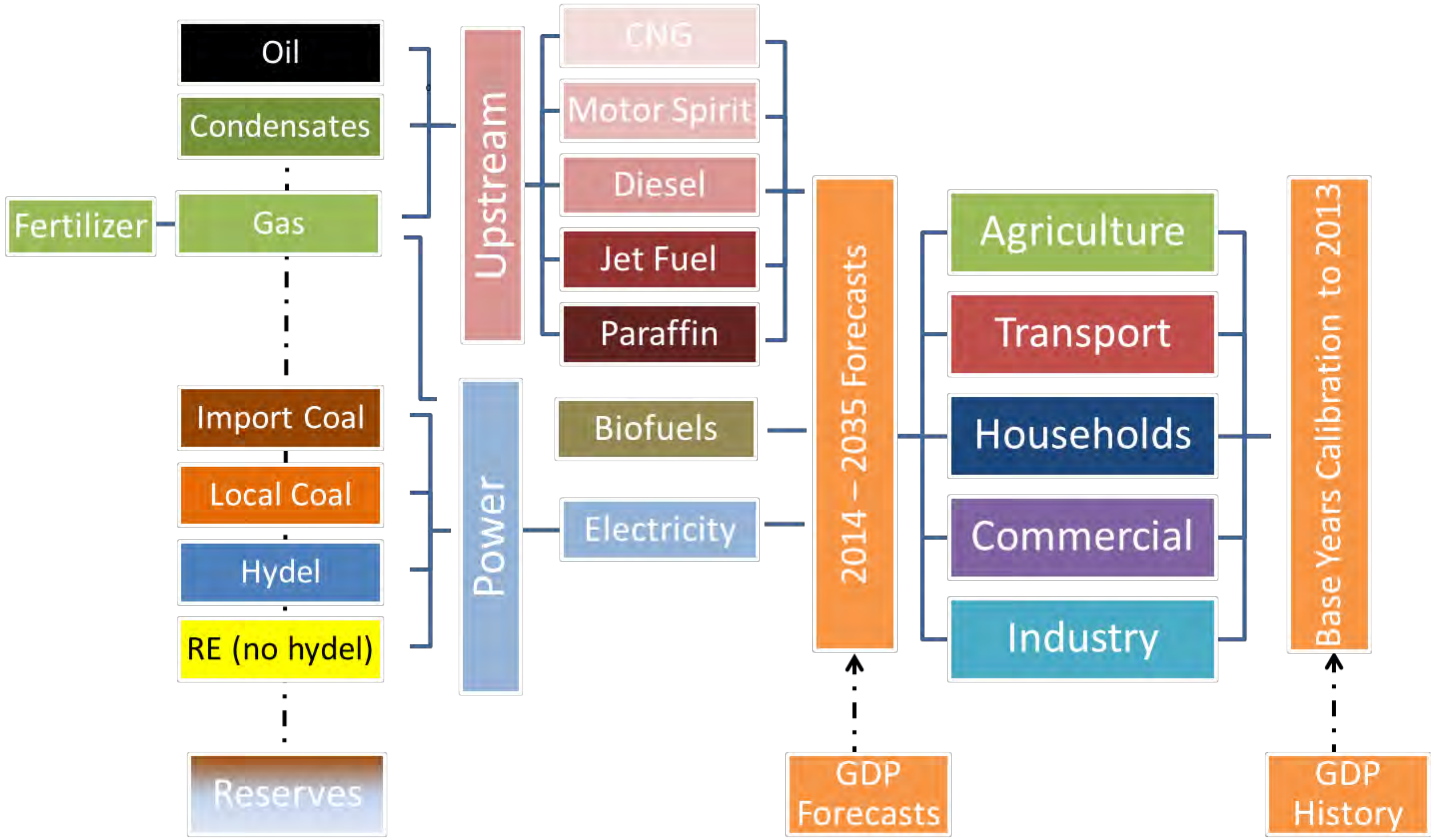
12. The energy planning model developed to support the development of Myanmar's Energy Masterplan is based on a modular approach. The model comprises separate demand side and supply side components as shown in Figure 0-2.

13. On the demand side, the economic and household sectors are modelled as separate modules. Each of these modules contains bottom-up and top-down historical data used for calibration purposes. Forecasts are developed within each module according to the economic or other relevant growth drivers, e.g. GDP per capita.

14. On the supply side, the optimization of electricity supply is performed according to economic despatch principles. This is because electricity cannot be stored and supply and demand must be balanced at all times according to economic least-cost supply principles (for a given supply scenario). In the case of liquid fuels the petroleum product requirement is expressed in the form of a refinery slate. The least cost supply of petroleum products is determined by a conventional economic evaluation of alternatives, including off-shore and on-shore oil purchase, on-shore refining, import of petroleum products. Total upstream energy costs are determined simply according to volumes supplied and price rates for each petroleum product.

15. Gas supply is modelled by constraining the supply of gas to relevant individual sectors.

Figure 0-2: Integrated Energy Planning Model for Myanmar



Source: Consultant

16. Further details of the energy planning modules are discussed in the sections that follow. At the time of preparation of these notes, the GDP growth and demand-side models were fully complete. Not shown in Figure 0-2 is an electricity forecast module. Electricity forecasts are prepared in a single module according to consumer class (residential, commercial, light industrial, industrial, Government and agriculture) then disaggregated by household, commercial and industry sectors where other energy forms are added to account for the total energy consumption of the sector (e.g. diesel, wood fuel, etc).

17. Some further minor development may be required to apply the electricity economic dispatch model to the Myanmar system; at this time it is not decided whether the economic dispatch modelling will be undertaken separately for Yangon Division and the southernmost portion of the country, on a fully integrated national basis, or both if a particular expansion scenario of interest should require it.

C. GDP Growth Module

18. The GDP growth model is based on an overall target growth rate for the economy, and disaggregated targets for individual sectors viz a viz, the primary, secondary and tertiary sectors. The model also forecasts manpower needs by sector as well as specifically for the agriculture sub-sector. These forecasts are used in the consideration of farm mechanization. The details are provided in the Economic Outlook report.

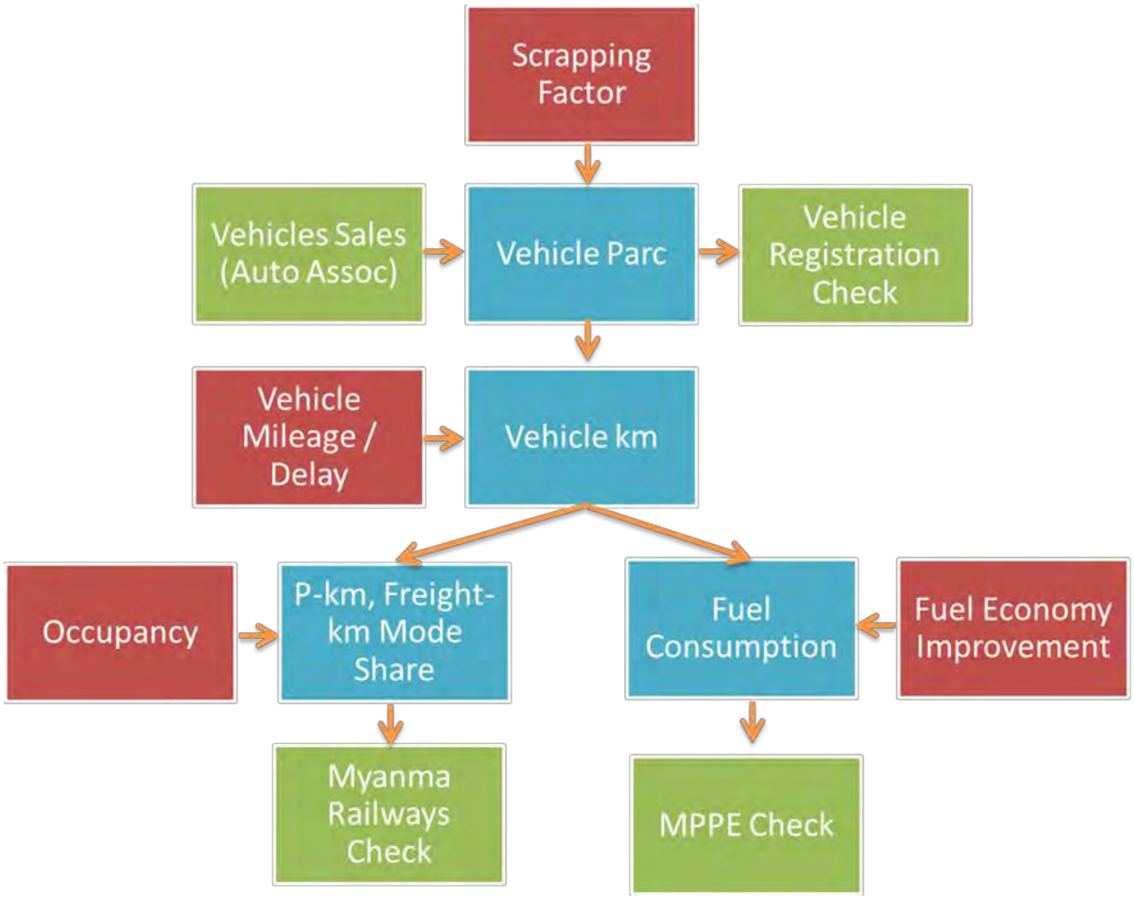
D. Transport Module

19. There are several approaches that could be used to model transport sector demand. International transport research centres tend to favour a bottom-up approach where the objective is fuel consumption and energy analysis. A bottom up approach is a disaggregated analysis of the transportation system as a provider of energy services. The calculation of energy demand in terms of services performed ('useful' energy) as opposed to the amount of energy supplied ('final' energy), offers a better understanding of the substitution between alternative energy forms, as well as an appraisal of the effect that evolution of the technological improvements has on demand. Such insights are essential in developing energy policy.

20. In a bottom-up approach, energy consumption by the transport sector is directly driven by two factors: vehicle-km travelled, and conversion efficiency of the vehicle (whether a road, rail, waterway or air vehicle). Vehicle-kms travelled are in turn driven by the needs of society and the economy to move people and goods from place to place. Conversion efficiency depends mostly on the underlying technology, i.e. the type of vehicle, fuel and vintage that makes up the vehicle 'parc'[1], and to some degree the patterns of utilisation of that technology. It is a best practice to treat passenger transport and freight transport separately, as the need for mobility by people and goods have different drivers and technologies.

[1] The vehicle 'parc' is a term used to describe the total number of active vehicles on the road

Figure 0-3: Transport Planning Module



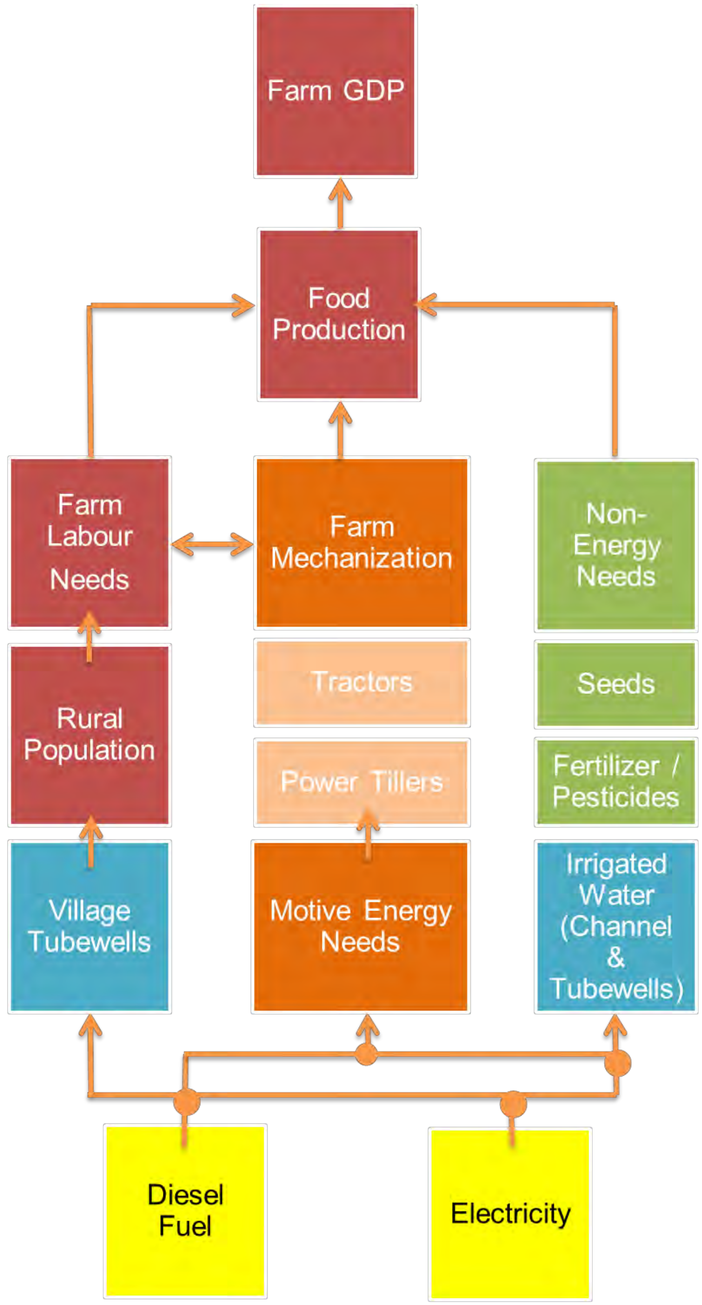
Source: Consultant

E. Agriculture Module

21. The calculation of agriculture sector energy demand is based on the farm energy forecasting model depicted in Figure 0-4 below. The model determines the total commercial energy requirement (for irrigation), and the total mechanization energy requirement (tractors and other machinery). Furthermore the model determines the efficiency of converting solar energy by agriculture as it increases through the additional input of energy from humans, animals, machinery, fertilizer, manure, pesticide, irrigation fuel (petroleum and electricity), as well as from water and seeds. The details are provided in the Primary Sector Demand Forecast report.

22. The agriculture sector requires fertilizer, and the option exists to manufacture on-shore or to import. The production of urea requires gas as a fuel supply and as a feedstock. The agriculture module is designed such that a change in fertilizer load per hectare can be accounted for in the sector energy balance and in terms of GDP impact. This means that as the gas supply allocation to the agriculture sector is varied the net benefit can be assessed in terms of farm sector GDP contribution. The economic benefits can then be understood in relation to the cost saving associated with local fertilizer production (usually fertilizer imports are more costly).

Figure 0-4: Agriculture Sector Energy Planning Module



Source: Consultant

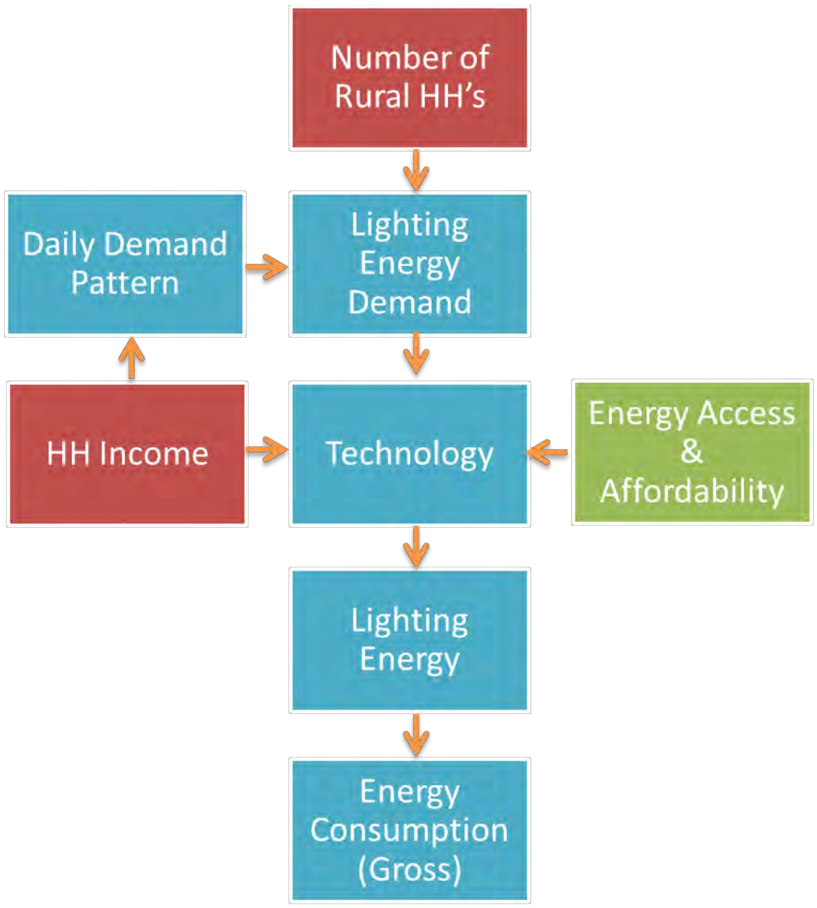
F. Rural HH Lighting Module

23. Rural household lighting energy analysis is concerned with the determination of the existing stock of lighting appliances in use by household income bracket. End-use behaviour is established by survey. When both the stock and usage are known, the household lux (illumination per square

metre) can be estimated. Household lux is a measure of the demand for lighting services.

24. The demand for lighting services can be met in different ways, and a model is required to forecast the optimal supply from standpoint of lux and total cost of ownership. Once the trade-offs are understood an energy policy can be developed. The form of the lighting module is as follows:-

Figure 0-5: Rural HH Lighting Energy Planning Module

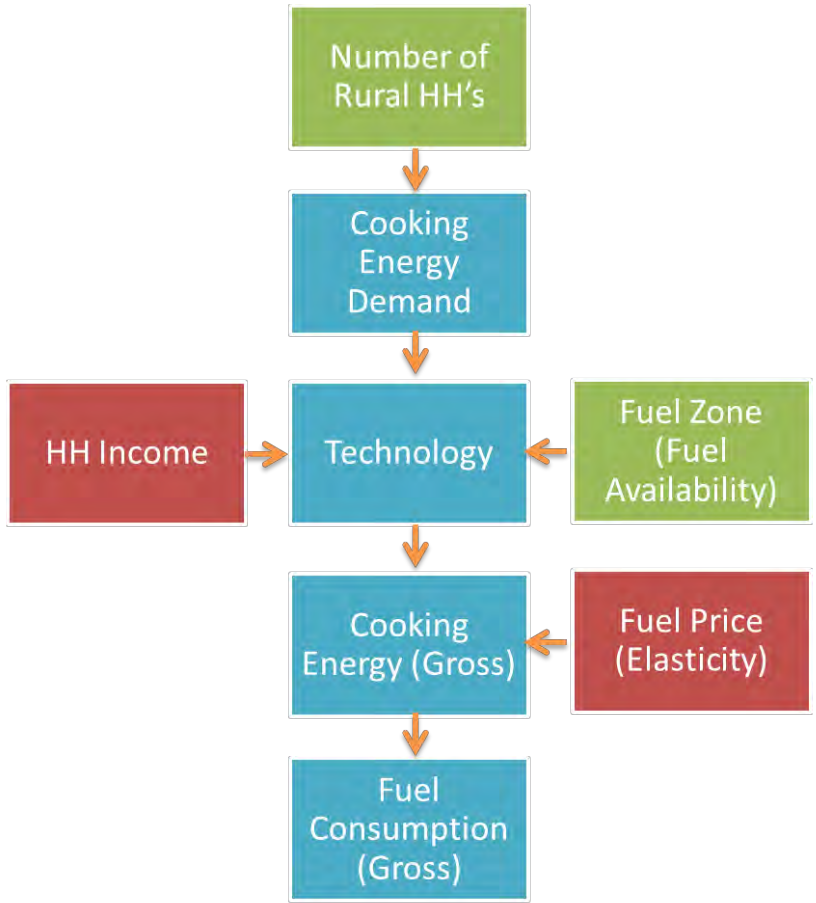


Source: Consultant

G. Rural HH Cooking Module

25. The same principles apply to rural HH cooking energy as described above for lighting, with final cooking energy substituting for lux. The form of the cooking energy module is as follows:-

Figure 0-6: Rural HH Cooking Energy Planning Module



Source: Consultant

H. Electricity Forecasts

26. Electricity forecasts are produced based on bottom-up and top-down forecasting methods.

27. For bottom-up forecasting there are typically five methods that can be applied 1) Land-based, 2) Customer-based, 3) Percentage growth, 4) Trend-method, and 5) Geo-spatial based approach. In practice a combination of these techniques is usually necessary.

28. For top-down forecasting the typical method is econometric regression

29. For the Energy Masterplan, the bottom-up methods used are 2), 3) and 4). The details are described in the Electricity Forecast report. Further details will be provided as part of knowledge

transfer as appropriate to the level of knowledge of Ministry staff participating in training.

30. In summary however, the key features of the forecasting model are as follows:-

- kWh per consumer type is used as a basic indicator;
- Population growth and kWh per household are used for residential forecasts
- Commercial and light industrial forecasts were based on trending + known developments;
- Industrial zone growth was based on Gompertz curves (using Monte Carlo techniques); and
- Regression methods and measured demand data were used for validation.

I. Electricity Supply Optimization

31. For an Energy Masterplan it is important to formulate policy-driven supply portfolio alternatives and to compare them on a net present cost basis. This requires basic economic dispatch modelling to forecast individual plant output, and a financial evaluation model that handles capital investment (including disbursement profiles for new plants), and the forecast production, to determine levelized costs of energy for the portfolio. For a policy-driven expansion planning, a prioritization and ranking criteria model is also required to weight and score each expansion alternative according to a set of agreed criteria, including a net present cost criterion.

32. MoEP is using the software package WASP for electricity supply expansion planning. WASP is a software tool that contains an economic dispatch optimization engine and this tool can be used to test supply expansion alternatives. However, in the interests of time, the Consultant will carry out a basic economic dispatch modelling using a bespoke modelling tool. The bespoke model is not a commercial model and will not be provided. However, the theory of economic dispatch optimization can be given as part of training if required. The financial evaluation model will be provided in the form of an Excel spreadsheet. Unlike WASP, this model is open and transparent and will support training in economic evaluation for a power system if required. The prioritization and ranking model will also be provided with familiarization training as required.

33. It is envisaged that in future the updating of the expansion plan could be carried out using WASP to generate the production outputs of a given portfolio of interest. The production figures could be submitted to the financial evaluation model or the financial calculations of WASP could be used for the purpose of policy-based prioritization and ranking.

J. Petroleum Products Supply Optimization

34. The petroleum products supply optimization is modelled using standard economic evaluation techniques to determine the optimal supply option from amongst on- and off-shore options.

35. The determination of on-shore refinery costs and refinery product prices, for a given demand slate, is a specialized task undertaken by only a handful of international firms. For a simple refinery structure, benchmark costs can be used without loss of accuracy.

Project Number: TA No. 8356-MYA

FINAL REPORT

APPENDIX 3: HOUSEHOLD ENERGY CONSUMPTION SURVEY

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

IES

Intelligent Energy Systems

in association with

MMIC

MYANMAR INTERNATIONAL CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
CSO	–	Central Statistics Organisation
EMP	–	Energy Master Plan
FES	–	Fuel Efficient Stove
HH	–	Household
LIFT	–	The Livelihoods for Food Security Trust
NEMC	–	National Energy Management Committee
TA	–	Technical Assistance

CONTENTS

I. INTRODUCTION

1. As part of TA-8356, the Terms of Reference (TOR) requires the Consultant to "conduct the surveys on the use of energy in various sectors". It is understood from the inception phase that the energy surveys were to focus on end-use energy consumption, which is consistent with the MOE's perspective that end use energy consumption data has the greatest level of uncertainty.

2. The energy consumption surveys have the intent of enhancing our understanding of energy consumption trends in Myanmar, which in turn will enhance the level of confidence in the quality of the data that is used to inform the energy demand forecasts that underpin the Energy Master Plan (EMP). The surveys should also assist in being able to develop more accurate historical energy balances, which become the baseline for the energy sector projections.

3. Following an assessment of data availability with in the ministries, other previous survey work in Myanmar and a general consideration of where the energy survey work could best assist this project, the Consultant recommended in the Inception Report that the main focus areas of the energy consumption surveys be in the following areas:

- Rural and urban household (HH) energy consumption;
- Private industry energy consumption; and
- Commercial sector energy consumption.

4. Of the three areas identified above, the rural and urban HH energy surveys were identified to be the highest priority since they correspond the area for which the least amount of information is available. Furthermore, surveys of this nature take considerable time to plan and execute. Hence the focus of survey work during the initial stages of the project has been to focus on executing a rural and urban HH energy survey. The purpose of this discussion paper is to describe the present state of the urban and rural household survey work that is being undertaken.

5. This paper has been organised as follows:

- Section II provides a preliminary review of other survey work, the intent is to leverage any insights from previous work and understand the nature of any publicly available data sets that offer insights into rural and urban HH energy consumption trends in Myanmar;
- Section III then sets out the methodology that we have adopted for the HH energy consumption survey. Because this is a work in progress, we briefly touch upon the present state of field work execution;
- Appendix A provides a copy of the HH energy survey that was used; and
- Appendix B provides relevant supporting data from a previously conducted study.

6. It should be noted that this paper contains preliminary findings for discussion. At the time of writing the HH energy consumption surveys were ongoing and thus we can only present the data that was provided by the energy survey team as of 1 June 2014. We expect to be able to provide a far more comprehensive presentation of HH energy consumption trends at the draft report stage.

II. REVIEW OF PREVIOUS SURVEYS IN MYANMAR

A. Previous Work

7. A number of surveys have been recently undertaken in Myanmar that provides insight into energy consumption trends. It is important to briefly review the nature and scope of these surveys as the household survey that we have conducted can be thought to essentially complement these surveys and enhance our overall understanding of present energy consumption trends in Myanmar.

8. Two recent and relevant surveys that have been undertaken include: (i) The Livelihoods for Fuel Security Trust (LIFT) baseline survey, a joint funding effort by multiple donors[1] conducted in 2012 to provide a comprehensive assessment of rural households in general[2], and (ii) a MercyCorps Poverty Survey, which focused on the issue of Fuel Efficient Stoves (FES), and was conducted in 2011.

B. LIFT Baseline Survey

9. LIFT baseline survey's objective was to gain a better understanding of trends in the rural households of Myanmar. The Livelihoods for Food Security Trust (LIFT) conducted a survey covering 4,000 rural households to seek information concerning fuel use for cooking and lighting by residence zone and income deciles.

10. Methodology. The surveyed locations included the Hilly, Dry and Delta/Coastal agro-ecological zones of Myanmar. Four thousand households were chosen from 252 villages with probability proportional to their number of households. Specifically, eight-hundred households were randomly selected from each zone (coastal/delta, hilly and dry) 800 from Rakhine (Giri-affected areas), and 800 as a control. By income, the respondents were grouped into deciles (10 categories), ranging from earning less than Ks 25,000 to over Ks 300,000 per household per month.

11. Summary of key findings:

- Overall, only 7% of the sample households were connected to the electricity grid; ranging from maximum of 16% of households in the Hilly Zone to less than 1% of households in the Giri-affected areas. Similarly households from the Hilly Zone were most likely to be connected to a village generator (15.6%) or have their own generator (3.8%). By contrast households in Giri-affected areas were most likely to use candles for lighting (55%) and households in the Delta/Coastal Zone most likely to use a kerosene or oil lamp (60%). Households in the Dry Zone were the second most connected to the grid (11%) but most likely to share a generator with other households (11%).
- Á it can be expected, access to electricity either from the grid or generators (other than village generators) was correlated with level of household average monthly income. In general, the larger the household average monthly income the more likely the household

[1] The donors are Australia, Denmark, the European Union, the Netherlands, New Zealand, Sweden, Switzerland and the United Kingdom.

[2] Livelihoods and Food Security Trust (LIFT), "Baseline Survey Results", July 2012. Accessible at: http://www.lift-fund.net/downloads/LIFT%20Baseline%20Survey%20Report%20-%20July%202012.pdf.

had electricity from the grid, had its own generator or shared a generator with other households. Conversely the poorer the household the more likely it used candles or lamps for lighting.

- Sources of cooking fuel were similar between regions with a very high reliance on fuel wood. The use of fuel wood ranged from a low of 90% of households in the Delta/Coastal Zone to a high of 99% of households in Giri-affected areas.
- Firewood collection and sale was an important source of income for poor households. In some cases especially the Giri-affected villages the community had to travel long distances to collect fuel wood. These results suggest that community forestry, agroforestry and fuel efficient stoves may be important areas for support in some locations.

12. Appendix B has tabulated a number of extracts from the LIFT baseline survey.

C. MercyCorps Energy Poverty Survey (2011)

13. MercyCorps Energy Poverty Survey objective: The Energy Poverty Survey was conducted with a focus to analyse village households' energy consumption and a market for FES's.

14. Methodology: The samples were taken for 396 households from 18 villages (22 HHs each) in 22 village tracts of Laputta Township.

15. Results: The main findings of the survey are summarised for cooking, firewood collection and lighting in the following paragraphs.

16. Cooking:

- The majority of households (88%) use wood, either with open fire or "three-stone" method (69%) or with a fuel efficient stove (19%) for cooking and heating water. 10% use plain rice husk (not compressed into bricks). Other fuel types used by some households are charcoal (1%) and electricity grid (1%).
- The most preferred type of fuel for cooking is wood with FES (42% of total respondent households), followed by wood with open fire (22%), electricity grid (18%), charcoal (11%), and rice husk (5%).
- The reasons, stated by the households, for preferring wood-burning FES are as follows: (i) Convenient and easy to use, (ii) Wood is easier to buy and more affordable than charcoal, (iii) FES are less of a fire hazard and are safer for children, (iv) FES can reduce deforestation

17. Firewood collection:

- Overall, 61% of wood-fuel is purchased and 38% is collected. Significantly, 43% of the respondents buy 100% of firewood because there is no longer any wood collector in the household. An average of 233 hours per year is spent by a household for collecting the firework.

- Households get the firewood mainly from state land resources (reserve areas) (49%) and personal forest resources (29%). Some get it from community forest resources (12%) and privately held forest resources (4%).

18. Household Lighting:

- The majority of households (56%) use diesel lamps, followed by 29% using power from the electricity grid as the main fuel sources for lighting. Other fuel types used by some households are candle (9%), and battery (6%).
- The most preferred type of fuel for lighting is electricity grid (55% of total respondent households), followed by diesel lamps (25%), and battery-powered lamps (18%). The rest prefer solar (1%) and candle (0.3%).
- The common reasons, stated by the households, for preferring the electricity grid, diesel and battery are as follows: (i) Good quality lighting power, (ii) More affordable, (iii) Convenient and easy to use, (iv) Can use anytime, (v) More suitable for business and income generating work, (vi) Reduced fire hazard, (v) Can use for any social activities and (vi) Can use for education (studying at night)
- Households can afford an average of 3.8 hours of light per night although they would like 5 hours on average.

III. URBAN AND RURAL HOUSEHOLD ENERGY CONSUMTPION SURVEY DESIGN

D. Broad Design Parameters

19. A key constraint in undertaking the rural and urban HH energy consumption survey is time and budget. As noted, we have identified, collected and compiled as much of the relevant existing data sets that we have been able to locate, but we observe that they are not necessarily complete from a holistic energy consumption perspective; for example, electricity consumption data will not include other fuel inputs, similarly, the central statistics office data does not necessarily provide the type of coverage that would be ideal.

20. As such we need to complement the collection of existing data exercise with surveys that target the gaps in our knowledge and/or that can in some way confirm or enhance the quality of the data that already exists. For the rural and urban HH energy consumption survey, we have attempted to fill that gap. However, it should be noted that a key practical constraint that had to be satisfied in the design was being limited to 700 HH surveys. Furthermore, the level of detail in the surveys themselves needs to be carefully managed so that they can be quickly completed "on the fly". Another important consideration is to ensure adequate coverage of different income brackets and trends within the different "fuel zones" of Myanmar.

21. In consultation with the national consultants who have a firmer grasp on what can be achieved and what areas can be readily accessed, we have arrived at the survey approach that is documented in Table III-1. Note that some of the regions can be covered with minimal barriers owing to the fact that the local government or community leaders already have experience in having surveys conducted their regions / townships. Other regions are more problematic as the local

government may oppose having the survey issued or may wish to have control over the questions asked. As such Table III-1 is essentially a “compromise” between all of the factors that have had to be taken into account in the design of the HH energy consumption.

Table III-1: Summary of Urban and Rural Household Energy Consumption Survey Approach

Region	No. of HHs	General Purpose Consumption (kWh)	Electrification Rate (%)	kWh / HH	Regional access?	Type and No. of Surveys Planned
Ayeyarwaddy	1,335,968	116,522	9%	267	Yes	Rural / 60
Rakhine	527,654	29,650	6%	285	Yes	Rural / 60
Sagaing	862,616	154,404	18%	640	No	-
Mon	340,971	92,945	27%	672	Yes	Rural / 60
Shan (south)	382,428	94,596	25%	678	Yes	Rural / 60
Bago (east)	556,540	124,615	22%	705	No	-
Tanintharyi	207,153	18,659	9%	709	No	-
Magway	770,123	113,214	15%	716	Yes	Rural / 60
Shan (north)	326,799	53,461	16%	721	Yes	Rural / 60
Kachin	217,309	48,094	22%	757	No	-
Kayar	47,514	17,396	37%	823	Yes	Rural / 60
Bago (west)	448,323	80,662	18%	929	No	-
Kayin	221,825	27,171	12%	954	Yes	Rural / 60
Shan (east)	131,549	19,637	15%	1,219	No	-
Naypyitaw	116,995	60,660	52%	1,247	No	-
Mandalay	1,060,762	311,876	29%	1,294	Yes	Urban & Rural / 80
Yangon	1,270,090	801,949	63%	1,757	Yes	Urban & Rural / 80
Chin	81,055	12,001	15%	2,293	Yes	Rural / 60
Total	**8,905,674**	**2,177,512**	**24%**	**1,219**	**No**	**Total / 700**

Source: Consultant

E. Household Energy Questionnaire Design

22. The questionnaire for the household energy consumption survey was designed with consideration of the results of the previous surveys by LIFT and MercyCorps. The focus was to gather information on fuel end-user patterns, which could supplement the previous findings in establishing an estimate of energy consumption by rural households.

23. The survey questionnaire consists of 14 parts (A to N), in detail as follows:

A. Household information: to gather information about the location and type of household including the size of the house and the number of occupants.

B. Household income and expenses: Covers the monthly income, expenses on different energy needs and the other household expenditure.

C. Household appliances: Information about appliances by purpose and fuel used, and the respondent's preference in terms of appliances' importance.

D. Energy uses – Cooking: Types of coking ovens, daily cooking duration, cooking fuel types, and quantity of fuel used in month.

E. Energy uses – Lighting: Types of lighting appliances, the time and duration of use, and main fuel sources.

F. Energy uses – Water heating: Types of appliances, duration of use and main fuel sources.

G. Total non-electricity fuel consumption: Information about quantities of different non-electricity types of fuel used by the household each month.

H. Electricity supply: Whether the household is connected to the power grid and (if yes) what purposes the electricity is used for.

I. Past energy usage: To compare the consumption between this and the last year.

J. Fuel source and usage: For enquiring whether the household pays for the fuel they need or gets any of it for free, purchases from market or gets the fuel delivered by someone else, what is the form of payment and how often it is made?

K. Generators: Information about whether the household has a generator and the features of the generator if they own one, including the fuel type and quantity consumed.

L. Motor vehicles: Whether the household has a vehicle, vehicle type and fuel type, quantity of fuel consumed, and how it is obtained.

M. Agriculture energy: Types of equipment and fuel used for farming activities.

N. Solar power: Whether the household has a solar panel installed.

24. A complete copy of the HH energy consumption is provided in Appendix A.

F. Approach to Survey Fieldwork

25. Prior to undertaking HH energy consumption survey the following was undertaken:

- The MOE provided an endorsement letter for the survey work and to also explain how the energy consumption results will feed into a process of national energy planning;
- An advocacy process then was required for each local / regional authority to get their buy-in and endorsement; and
- A survey team was formed and the national consultant leading the HH energy survey undertook a series of workshops to explain the survey forms and concepts. This is to

ensure that the energy survey team members fully understand the questions and to explain how to obtain the answers from those that are being surveyed.

26. The survey team has then travelled to the different regions listed in Table III-1 to conduct their fieldwork. For each region the process was as follows:

- The survey team met with the community leader and village volunteers for a consultation workshop, which involved explaining survey content and its objectives, which is extremely important to ensuring buy-in from the community leader – in general, it was explained that the survey is intended for national planning purposes and the community leader supported the initiative. An illustration of this occurring in the Ngaputaw Township, Ayeyarwaddy is illustrated in Figure III-1.
- The community leader then assisted the survey team in terms of the HH selection process in order to maximise the coverage of different income levels. Furthermore, volunteers within the community would be recruited to facilitate the survey team in conducting their field work. An illustration of this is given in Figure III-2.
- A basic strategy was devised to then carry out the HH survey in the village for the sample of HHs.
- The approach to taking the surveys was then generally perform a combination of door-to-door surveys or selected HH occupants were invited to a temporary office to come and fill out the survey. An example is illustrated in Figure III-3.
- Finally those completing the survey were provided with a small gift, as illustrated in Figure III-4.

27. The remaining part in the process is then for the survey team to compile the results of the surveys into spreadsheets to enable data analysis.

G. Actual numbers of surveyed regions and households

28. In total, 967 surveys were conducted in 11 regions across Myanmar. Table III-2 lists the regions and townships where the surveys took place; it also shows the number of surveyed households in each location. Geographical spread of the surveyed areas is showed in Figure III-5.

Table III-2: Summary of Urban and Rural Household Energy Consumption Survey Approach

No	Region	Township	Number of Surveyed HHs
1	Ayeyarwaddy Region	Ngaputaw	85
2	Magway Region	Magway	61
3	Mandalay Region	Kyaukpadaung / Mandalay	184
4	Yangon Region	Kyauktada / Dala	101
5	Shan state (North)	Thein Ni	69
6	Shan State (South)	Pekon	72
7	Kayah State	Demoso	61
8	Rakhine State	Taunggup	75
9	Chin State	Palatwa	95
10	Mon State	Chaung Sone	78
11	Kayin State	Hlaing Bwae	86
Total			**967**

Source: Consultant

Figure III-1: Meeting with community leader in Ngaputaw Township, Ayeyarwaddy

Source: Consultant's Energy Survey Team

Figure III-2: Training and workshop with volunteers in Ngaputaw Township, Ayeyarwaddy

Source: Consultant's Energy Survey Team

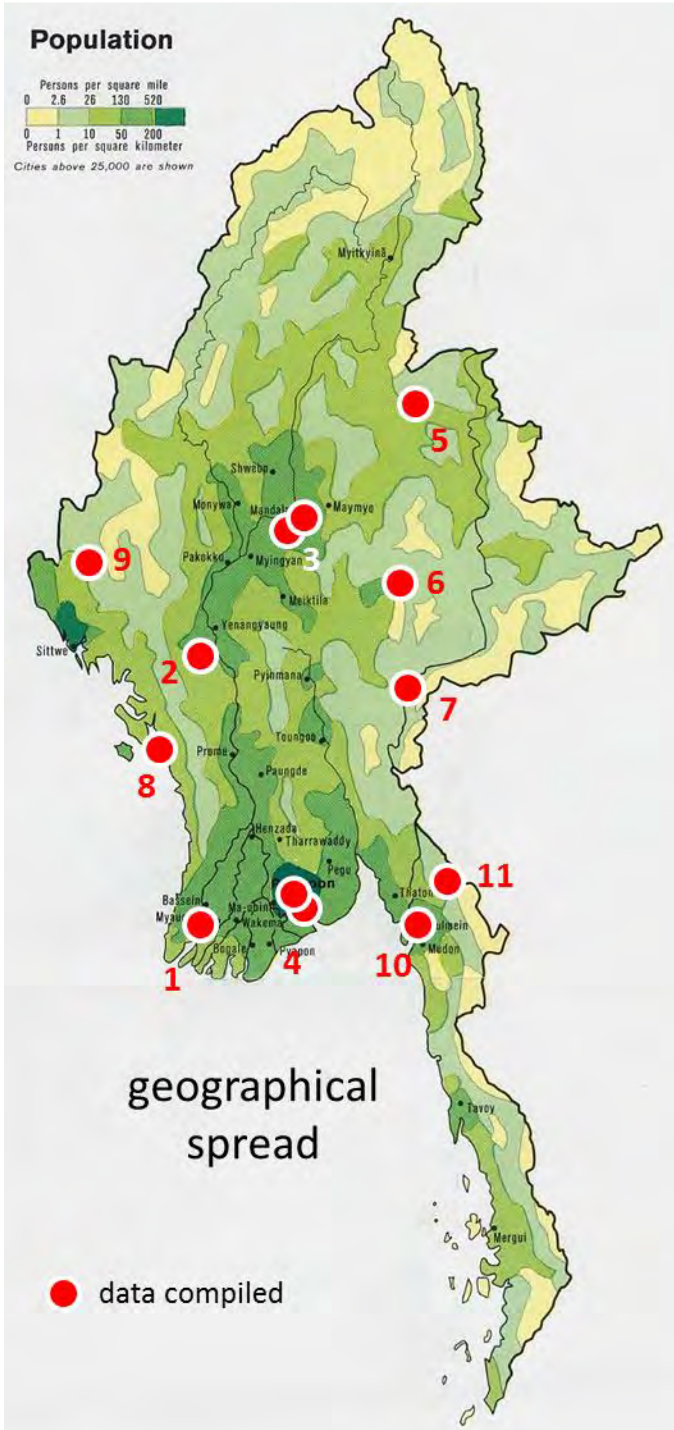
Figure III-3: Conducting the Survey in Ngaputaw Township, Ayeyarwaddy

Source: Consultant's Energy Survey Team

Figure III-4: Conducting the Survey in Ngaputaw Township, Ayeyarwaddy

Source: Consultant's Energy Survey Team

Figure III-5: Geographical Spread of the Surveyed Areas



Source: Consultant analysis

Appendix A:

Household Energy Consumption Survey

ADB – TA-8356 Energy Master Plan

Household Energy Consumption Survey

Purpose of this survey

The Ministry of Energy (MOE) is conducting a household energy survey in order to gain a better understanding of energy consumption patterns in Myanmar households. This survey is intended to collect data on the types and quantities of energy consumed in households in Myanmar. This information will be used by the MOE for the purpose of enhancing energy planning, with the longer-term objective being to enhance energy access in the country.

Your participation is important

This survey is conducted under the authority of the Ministry of Energy. However, completion of the survey is voluntary. The use of this survey will enhance the Ministry of Energy's understanding of household energy consumption and will assist in planning Myanmar's future energy needs, which is in the national interest.

Completion of the survey

Please complete this survey and return it to the person that issued it.

Details of person completing this survey

	Township
	Address / location of household
	Phone no.

Details of person issuing this survey

	Person issuing survey form
	Phone no.

Cover Page

A) Household Information

A1) Location of House: ☐

A2) Type of house location (tick one):

☐ City ☐ Town ☐ Village

☐ Farm ☐ Other, please specify:

☐

A3) Number of occupants: ☐ Number of people

A4) Number of rooms in house: ☐ Number of rooms

A5) Type of home (tick one):

☐ Single family detached house (a free standing house)

☐ Single family attached house (attached to one or more houses)

☐ An apartment building with a total of 2 to 4 units

☐ An apartment building with 5 or more units

☐ Other, please specify:

☐

A6) Area of property (floor space): ☐ ☐ Units of measure (Example: meters squared)

B) Household Income and Expenses

B1) Total Monthly Income: ________ Kyat

B2) Monthly Expenses:

(please tick those that are relevant and give the monthly spend)

Tick	Item	Monthly Spend	
	Electricity		Kyat
	LP gas		Kyat
	Batteries		Kyat
	Fuel Wood		Kyat
	Candles		Kyat
	Coal		Kyat
	Charcoal		Kyat
	Kerosene		Kyat
	Paraffin		Kyat
	Rice Husk		Kyat
	Petrol		Kyat
	Diesel		Kyat
	All other monthly expenditure		Kyat
	Total monthly household expenditure		Kyat

) Household Income and Expenses

C1) What are the main types of household appliances that you have and what are they used for?

	Cooking	Lighting	Space Cooling	Water Heating	Television	Refrigeration	Pumping	Other (please specify)
Electricity								
LP gas								
Paraffin								
Candles								
Torches								
Batteries								
Rice Husk								
Generator								
Other (please specify)								

C) Household Income and Expenses (cont.)

C2) Rank the appliances listed below in order of importance to you.

	Tick if you have the appliance	Rank the appliance in order from 1 (most important) to 9 (least important)
Lighting		
Water Heating (example: kettle)		
Rice Cooker		
Microwave Oven		
Toaster		
Refrigerator		
Freezer		
Radio		
Air Conditioner		
Pump		
Television		

D) Energy Uses: Cooking

D1) What of the type of oven used for cooking?

☐ 3 stone stove ☐ Fuel efficient stove ☐ Wood fire ☐ Coal stove

☐ Electric stove ☐ Rice husk stove ☐ LPG stove ☐ Charcoal stove

☐ Other, specify: ______

D2) How many hours per day do you use your stove/fire? ______ Hours

D3) What fuel do you use for cooking? ______

D4) How much of this fuel is used per month? ______ Quantity of fuel/month

E) Energy Uses: Lighting

E1) List the type of appliances used for lighting and their number

Tick Item:	Approx. Number:	Tick Item:	Approx. Number:
☐ Lantern		☐ Lp Gas Light	
☐ Incandescent light		☐ Candles	
☐ Fluorescent light		☐ Torch	
☐ LED lighting		☐ Other (please explain):	
☐ Compact Fluorescent Lamp (CFL)			

E2) How many hours a day are your lights turned on? ______

E3) What is the main fuel used for lighting?

☐ LP gas	☐ Electricity	☐ Fire Wood	☐ Batteries
☐ Dung	☐ Kerosene	☐ Paraffin	☐ Candles

☐ Other – please explain: ______

E4) Reason for using this fuel? ______

E5) What hours of the day are the lights usually turned on?

______ hours

☐ am to ☐ am

☐ pm to ☐ pm

F) Energy Uses: Water Heating (for washing)

F1) Type of appliance used for water heating?

☐ LP gas cooker ☐ Wick stove ☐ Pressure stove ☐ Electric stove

☐ Coal/wood stove ☐ Other – please specify ______

F2) What is the main fuel used for water heating?

☐ LP gas ☐ Electricity ☐ Fire Wood ☐ Dung ☐ Rice husk

☐ Other – please explain: ______

F3) How many hours a day do you use appliances for water heating? ☐ Hours

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G) Total Fuel (Non-Electricity) Consumption

G1) Provide information on how much fuel is used each month by specifying the type of fuel and what quantities of those fuels you use.

Type of Fuel	Tick if used	Quantity used	Unit	Specify, if other
LP Gas				
Fire wood				
Dung				
Kerosene				
Paraffin				
Candles				
Coal				
Charcoal				
Rise Husk				
Petrol				
Diesel				
Other				

G2) Compare consumption between winter and summer

Energy consumption is ☐ More in winter (or cold days) than in summer (or hot days)

☐ The same in winter (cold days) compared to summer (hot days)

H) Electricity Supply

H1) Is the house electrified? ☐ Yes ☐ No

H2) If yes, for how long? ☐ Years

H3) What is the electricity used for?

☐ Cooking ☐ Water heating for washing ☐ Space cooling ☐ Black & White TV

☐ Ironing ☐ Water heating (kettle) ☐ Colour TV ☐ Incandescent lights

☐ Candescent lights ☐ LED lighting ☐ Compact Fluorescent Lights (CFLs)

☐ Other – specify: ☐

I) Past Energy Usage

I1) This time last year, what was the household income? ☐ Kyat per month

I2) This time last year, what was your monthly fuel bill? ☐ Kyat per month

I3) Did you spend about the same amount on fuel last year as you do now? ☐ Yes ☐ No

I4) Do you use the same fuels now as you did last year? ☐ ☐

I5) If not, which fuels did you use this time last year?

☐ Paraffin ☐ Dung ☐ Fuel wood ☐ LP Gas ☐ Kerosene

☐ Candles ☐ Coal ☐ Rice husk ☐ Charcoal

☐ Other - specify ☐

J) Fuel Source and Usage

J1) I buy all the fuel I use ☐ Yes ☐ No

J2) Where do you buy your fuel?

- [ ] Someone delivers to home
- [ ] Purchase from market
- [ ] Other – please specify: ______

J3) From how many suppliers do you buy your fuel?

- [ ] Always the same supplier
- [ ] I purchase from: ______ Suppliers (enter number)

J4) I get some of the fuel for free

- [ ] Yes
- [ ] No

J5) If you get some fuel for free please specify what and how much:

	Tick	Quantity	Unit	Specify (if other)
LP Gas				
Fire Wood				
Dung				
Kerosene				
Paraffin				
Candles				
Rise Hush				
Other				

J6) How do you pay for the fuel?

- [ ] In cash each time I buy
- [ ] In cash at the end of the week
- [ ] In cash at the end of the month
- [ ] In cash advance at the start of the month
- [ ] By cheque, credit card in advance
- [ ] By cheque, credit card at the end of the month
- [ ] In kind (in exchange for something else)
- [ ] Other, specify: ______

J7) What happens if you can't pay for your fuel?

- [ ] Supplier gives credit
- [ ] Supplier gives loan
- [ ] Obtain fuel from another supplier
- [ ] Borrow money from friends/relatives
- [ ] Borrow fuel from friends/relatives
- [ ] Avoid use of fuel
- [ ] Other, specify: ______

K) Generators

K1) Does the household have one or more generators? ☐ Yes ☐ No

IF "NO" THEN PLEASE SKIP THE REMAINING QUESTIONS ON THIS PAGE

K2) How many hours a day does the generator operate? ☐ pm/am to ☐ pm/am

If operating also in other hours, specify: ☐ pm/am to ☐ pm/am

☐ pm/am to ☐ pm/am

K3) What is the generator capacity? ☐ HP OR ☐ kVA

K4) What fuel does the generator use?

☐ Petrol ☐ Diesel ☐ LPG ☐ Other

K5) How many litres of fuel does the generator use each month?

☐ Petrol ☐ Diesel ☐ LPG ☐ Other

K6) How much does the fuel cost per litre? ☐ Kyat

L) Motor Vehicles

L1) Does the household have a vehicle? ☐ Yes ☐ No

IF "NO" THEN PLEASE SKIP THE REMAINING QUESTIONS ON THIS PAGE

L2) Vehicle type(s)

Tick Items:	Number:
☐ Mini Bus	☐
☐ Car - Sedan	☐
☐ Car - Wagon	☐
☐ 2-wheel	☐
☐ 3-wheel	☐
☐ Other	Details: ☐

L3) What is the main fuel used in your vehicle? ☐ Petrol ☐ Diesel ☐ LPG

Other – please explain: ☐

L4) I buy all the fuel I use ☐ ` Yes ☐ No

L5) Where do you buy your fuel? ☐ Someone delivers to home ☐ Purchase from market

☐ Other – please specify: ☐

L6) From how many suppliers do you buy your fuel? ☐ Always the same supplier

☐ I purchase from: ☐ Suppliers (enter number)

L) Motor Vehicles (cont.)

L7) I get some of the fuel for free ☐ Yes ☐ No

L8) If you get some fuel for free please specify what and how much:

	Tick	Quantity	Unit	Specify (if other)
Petrol				
Diesel				
LPG				
CNG				
Bio-diesel				
Bio-ethanol				
Other				

L9) How do you pay for the fuel?

- ☐ In cash each time I buy
- ☐ In cash at the end of the week
- ☐ In cash at the end of the month
- ☐ In cash advance at the start of the month
- ☐ By cheque, credit card in advance
- ☐ By cheque, credit card at the end of the month
- ☐ In kind (in exchange for something else)
- ☐ Other, specify:

L10) What happens if you can't pay for your fuel?

- ☐ Supplier gives credit
- ☐ Supplier gives loan
- ☐ Obtain fuel from another supplier
- ☐ Borrow money from friends/relatives
- ☐ Borrow fuel from friends/relatives
- ☐ Avoid use of fuel
- ☐ Other, specify:

M) Agricultural Energy

M1) Is the property part of an agricultural area or farm? ☐ Yes ☐ No

IF "NO" THEN PLEASE SKIP THE REMAINING QUESTIONS ON THIS PAGE

M2) Area of farm ☐ ☐ Unit (example: meter squared)

M3) What crops do you grow?

Crop type	Area used

M4) What livestock do you keep?

Livestock Type	Number of Animals

M5) Is there heavy equipment used on the farm? ☐ Yes ☐ No

M6) Specify equipment:

Equipment Type	Powered by? (e.g. petrol, diesel, wind)

M7) Irrigation

a) Do you own a portable diesel or petrol engine for pumping water? ☐ Yes ☐ No

b) What is its horsepower? ☐

c) On average how many hour in the engine used each day? ☐

M) Agricultural Energy (cont.)

M8) Provide information on how much fuel is used on your farm each month by specifying the types of fuels and what quantities of those fuels you use:

Type of Fuel	Tick if used	Enter quantity that is used	Unit (Kg, litre, number, etc.)	Specify, if other
LP Gas				
Petrol				
Diesel				
Other #1				
Other #2				

M9) What was your monthly fuel bill for farm equipment this time last year? Kyat per month

M10) Did you spend about the same amount of fuel last year as you do now? Yes No

M11) If not, what is your fuel bill for farm equipment this year? Kyat per month

M12) If not, which fuel did you use this time last year?

Paraffin
Dung
Fuel wood
LP Gas
Kerosene
Candles
Coal
Rice husk
Charcoal
Petrol
Diesel
Other, specify:

N) Solar Power

N1) Does the household have a solar panel for electricity? ☐ Yes ☐ No

IF "NO" THEN PLEASE SKIP THE REMAINING QUESTIONS ON THIS PAGE

N2) How many solar panels? ☐

N3) If you know the size (in Watts) pf the solar panel please specify: ☐ ☐ ☐

N4) Approximate cost per solar panel ☐ Kyat

Appendix B:

LIFT Baseline Survey Extracts

Table III-3: Frequency of Household Energy Sources for Lighting, by Region[3]

Source	Hilly	Dry	Delta / coastal
Electricity from the grid	16%	11%	4%
Village generator	16%	9%	1%
Own generator	4%	1%	3%
Shared generator*	6%	11%	6%
Lamp (kerosene/oil)	16%	2%	60%
Candle	24%	18%	16%
Other	19%	48%	10%

** Shared generator with other households*

Table III-4: Frequency of Household Sources of Energy for Lighting, by Income Level[4]

Monthly household income range (Ks)	Electricity from grid	Village generator	Own generator	Shared generator	Lamp (kerosene / oil)	Candle	Other
Less than 25,000	4%	7%	0%	2%	31%	33%	23%
25,001-50,000	5%	7%	1%	4%	34%	27%	23%
50,001-75,000	6%	8%	1%	8%	24%	27%	26%
75,001-100,000	10%	8%	3%	13%	18%	26%	22%
100,001-150,000	15%	3%	3%	15%	15%	26%	24%
150,001-200,000	17%	8%	10%	15%	14%	11%	26%
200,001-250,000	24%	20%	5%	12%	17%	10%	12%
250,001-300,000	23%	9%	9%	6%	11%	11%	31%
Over 300,000	29%	7%	19%	16%	9%	10%	10%
Don't know / nil response	10%	0%	0%	5%	14%	43%	29%

3 Extracted from LIFT Baseline Survey 2012 – Table 121, p. 71.
4 Extracted from LIFT Baseline Survey 2012 – Table 122, p. 72.

Figure III-6: Plot of Household Energy Sources for Lighting, by Region

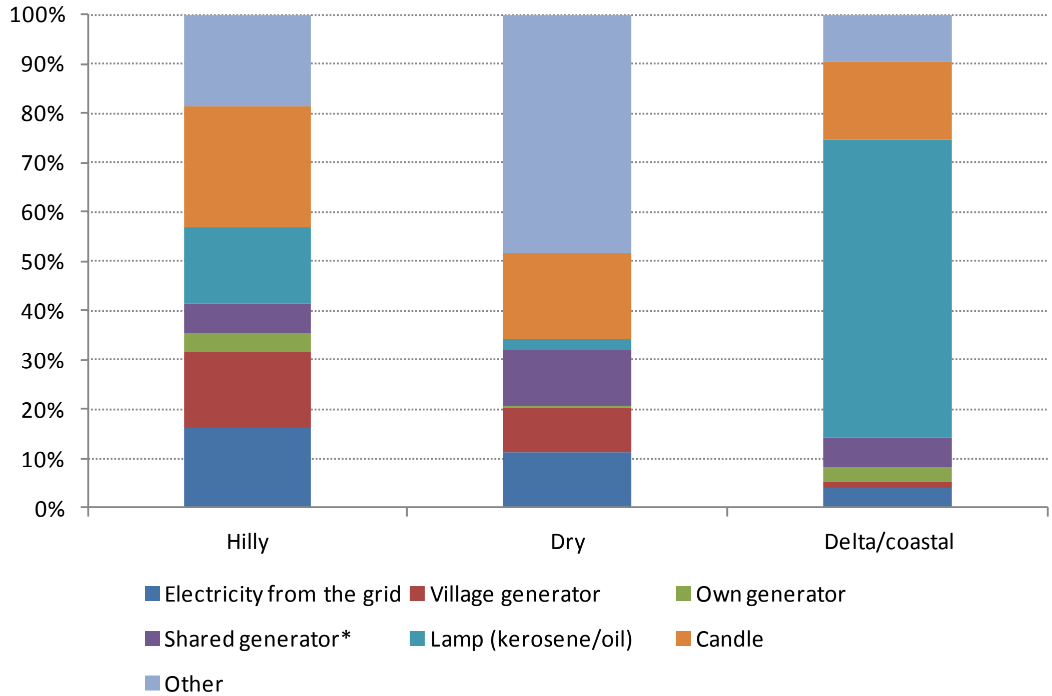


Figure III-7: Plot of Household Sources of Energy for Lighting, by Income Level

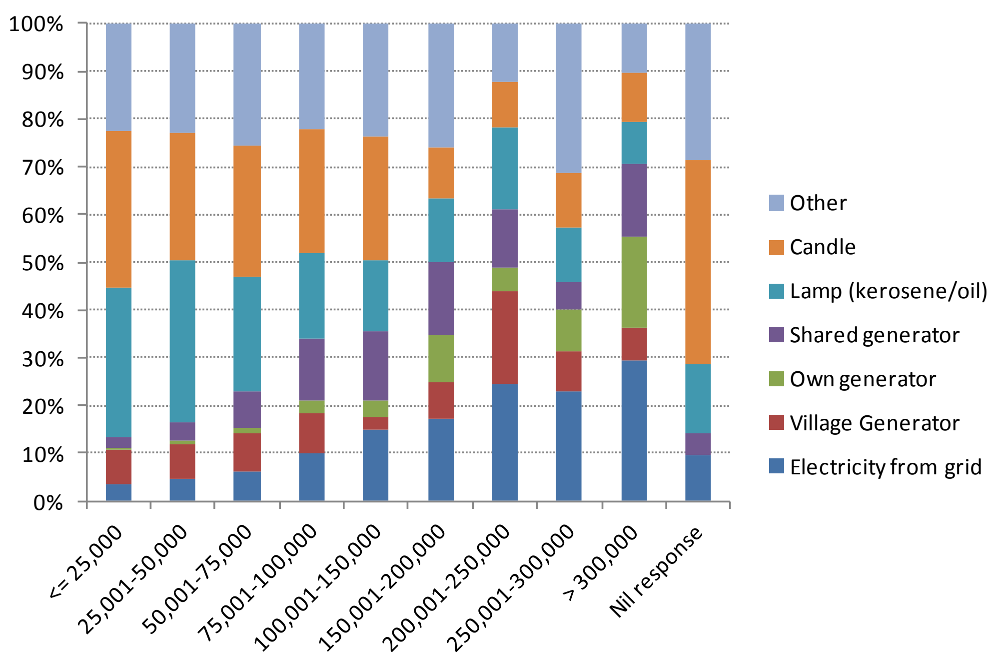
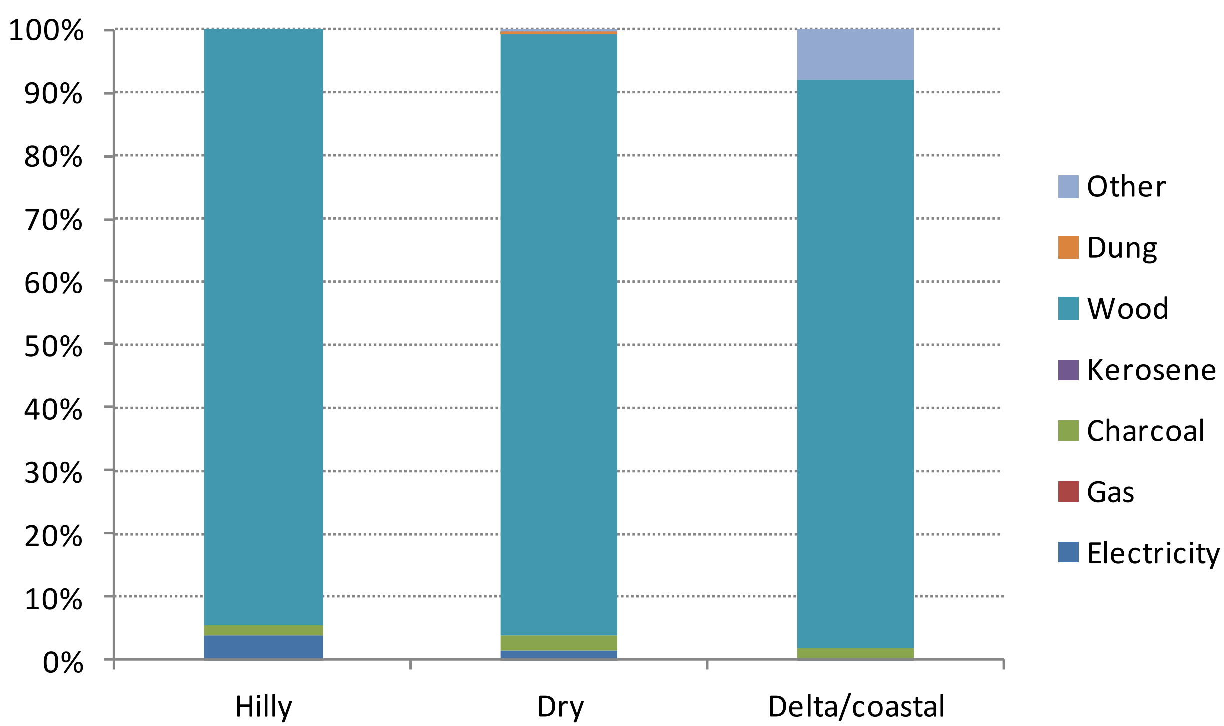


Table III-5: Statistics on Rural Household Cooking, by Region[5]

Frequency of Energy Source for Cooking			
Source	**Hilly**	**Dry**	**Delta / coastal**
Electricity from the grid	4%	1%	0%
Village generator	0%	0%	0%
Own generator	1%	2%	2%
Shared generator*	0%	0%	0%
Lamp (kerosene/oil)	95%	96%	90%
Candle	0%	1%	0%
Other	0%	0%	8%
Frequency of Rural Households using Fuel Efficient Wood Stoves			
Percentage of households using Fuel Efficient Wood Stoves	9%	13%	14%

Figure III-8: Plot of Household Energy Sources for Cooking, by Region



5 Extracted from LIFT Baseline Survey 2012 – Table 123a and Table 123b, p. 72.

Project Number: TA No. 8356-MYA

FINAL REPORT

APPENDIX 4:
NATIONAL POWER EXPANSION PLAN

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

IES
Intelligent Energy Systems

in association with

MMIC
MYANMAR
INTERNATIONAL
CONSULTANTS

I. DISCLAIMER

1. This chapter reproduces the report from a separate study on Myanmar's power sector for which ADB engaged the services of ADICA. IES was not involved in scoping, executing or in any stakeholder consultations in this study. IES takes no responsibility for the accuracy, sources of material used and will not be liable in any way for any of its findings. Where necessary we have drawn on the findings of the power sector study in the body of the energy master plan report with references to this appendix.

Project Number: TA No. 8356-MYA

NATIONAL POWER EXPANSION PLAN

A study conducted for The Asian Development Bank and The Myanmar Ministry of Energy

Prepared by

ADICA®

"The Ultimate in Strategic Analysis"

16 October 2015

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TABLE OF CONTENTS

I. INTRODUCTION

A. BACKGROUND

1. During the **6th Electric Power Sector Working Group Meeting** organized in Nay Pyi Taw, on 23rd February 2015, key government participants and development partners (DPs) discussed recent activities in the energy and power sector. In his opening remarks, Deputy Minister H.E. U Aung Than Oo stressed the need for consistency in concurrent energy and power sector master plans being formulated for relevant Myanmar Government agencies[1] with Asian Development Bank (ADB), Japan International Cooperation Agency (JICA), and World Bank Group (WBG) support, including:

a) Myanmar Energy Master Plan (EMP) – ADB
b) National Electricity Master Plan (NEMP) – JICA
c) Myanmar National Electricity Plan – WBG

2. ADB's EMP study has completed energy surveys and data collection, historical energy balances, primary energy resource assessments, and energy demand forecasts. The remaining chapters of the EMP concern recommendations on supply options and investment requirements in the power sector as well as finalization of total primary energy supply forecasts and the final energy balance reflecting fuel requirements identified from the optimal generation expansion plan.

3. As JICA's NEMP study finalized generation expansion plans using the Wien Automation System Planning model (WASP IV) for a high growth case[2], ADB decided and MOE/NEMC agreed to complete the remaining chapter using WASP IV to analyze a medium growth case[3], to provide robust results and ensure consistency between the EMP and NEMP studies.

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[1] The relevant Myanmar Government agencies include: MOE (Ministry of Energy); MOEP (Ministry of Electric Power); NEMC (National Energy Management Committee)

[2] In the NEMP study, a macro and top-down approach is applied to project electric power demand growth rate by multiplying elasticity and GDP growth rate. The elasticity of 1.4 is used based on its analysis of the average elasticity during 2002-2010 and GDP growth rate for 2013-2030 is assumed as (i) for a high growth case, 8.7% which is the growth rate of 2011-2012, and (ii) for a low growth case, 6.4% based on IMF Economic Outlook. As a result, peak demand in 2030 is projected as 14.5 GW for its high growth case and 9.1 GW for its low growth case. The NEMP study analyzed the high growth case as a base case for preparing power expansion plan.

[3] In the EMP study, a micro and bottom-up approach is applied to project electric power demand by examining historical consumption and demand trends of households, commercial, agriculture, and industrial sectors for each of the 14 states and regions of Myanmar. Electricity consumption drivers are for (i) households: cooking , lighting, water heating, TV / entertainment and cooling services; (ii) commercial: restaurants, hotels, retail space, office space, (iii) agriculture: tractors, power tillers, harvesters, irrigation pumps, and (iv) industry: production of steel, non-metallic minerals (bricks, cement, glass), non-metallic metals (copper, zinc, tin), food (sugar), electronics, plastics, ice storage, food processing, automotive parts, footwear and garments. GDP growth rate for 2013-2030 is assumed as (i) for a high growth case, 9.5% which is the highest growth rate forecasted from ADB's Country Diagnostic Study (CDS, 2014), (ii) for a medium growth scenario, 7.1% which is the government growth forecast, and (iii) for a low growth scenario, 4.8% which is the lowest growth rate forecasted from ADB's CDS. As a result,

B. OBJECTIVES

4. The objective of this study is to apply the WASP IV model in identifying an optimum generation expansion plan for the Myanmar power sector, and determine the associated system costs, fuel requirements, and environmental emissions under the EMP's medium growth case.

5. Study assumptions are to be consistent with the NEMP, while making adjustments based on additional information and insights provided by relevant Myanmar Government agencies, DPs, and project personnel.

6. The ADB consultants for this engagement are tasked with: (i) Assembling all required data for executing WASP IV in consultation with the MOEP and JICA consultants; (ii) Developing plausible generation expansion scenarios in consultation with the MOE, MOEP, NEMC and ADB; (iii) Executing WASP IV to identify the optimum generation expansion plan under the EMP's medium growth case; and (iv) Drafting this chapter on the National Power Expansion Plan as part of the EMP report.

II. MODELING APPROACH

C. DESCRIPTION OF THE WASP MODEL

7. WASP is an optimization model for examining medium- to long-term development options for electrical generating systems. The International Atomic Energy Agency (IAEA) distributes and maintains this model, which is the public domain's most frequently used program for expansion planning of electrical generating systems.

8. The latest version of the model, called WASP IV, is designed to find the economically optimal generation expansion policy for an electric utility system. It utilizes *probabilistic estimation* of system production costs, unserved energy cost, and reliability, a *linear programming technique* for determining optimum dispatch policy satisfying exogenous constraints on environmental emissions, fuel availability and electricity generation by groups of plants, and the *dynamic programming method of optimization* for comparing the costs of alternative system expansion policies.

9. WASP IV permits finding the optimal expansion plan for a power generating system over a period of up to thirty years, within constraints given by the planner. The optimum solution is evaluated in terms of minimum discounted total costs. Each possible sequence of power unit additions that meets the specified constraints is evaluated by means of a cost function (i.e., the "objective function") represented by the following equation:

peak demand in 2030 is projected as 13.4 GW for a high growth case, 9.5 GW for a medium growth case, and 6.8 GW for a low growth case. The EMP study is using the medium growth case as a base case for estimating fuel requirements from all sectors including power sector.

$$B_j = \sum_{t=1}^{T} [\ \overline{I}_{j,t} - \overline{S}_{j,t} + \overline{L}_{j,t} + \overline{F}_{j,t} + \overline{M}_{j,t} + \overline{O}_{j,t}\ ]$$

Where:

I is the depreciable capital investment costs
S is the salvage value of investment costs
L is the non-depreciable capital investment costs
F is the fuel costs
M is the non-fuel operation and maintenance costs
O is the cost of the energy-not-served

10. WASP IV comprises the following eight modules.

11. **LOADSY** (Load System Description): Processes information describing the peak loads and load duration curves for up to 30 years. The objective of LOADSY is to prepare all the demand information needed by subsequent modules.

12. **FIXSYS** (Fixed System Description): Processes information describing the existing generating system. This includes performance and cost characteristics of all generating units in the system at the start of the study period and a list of retirements and "fixed" additions to the system. Fixed additions are power plants already committed and not subject to change.

13. **VARSYS** (Variable System Description): Processes information describing the various generating units to be considered as candidates for expanding the generating system.

14. **CONGEN** (Configuration Generator): Calculates all possible year-to-year combinations of expansion candidate additions that satisfy certain input constraints and that, in combination with the existing system, can adequately meet the electricity demand.

15. **MERSIM** (Merge and Simulate): Considers all configurations put forward by CONGEN and uses probabilistic simulation of system operation to calculate the associated production costs, unserved energy, and system reliability for each configuration. The module also calculates plant loading orders and maintenance schedules.

16. **DYNPRO** (Dynamic Programming Optimization): Determines the optimum expansion plan as based on previously derived operating costs along with input information on capital cost, economic parameters, unserved energy cost, and system reliability constraints.

17. **REMERSIM** (Re-MERSIM): Simulates the configurations contained in the optimized solution. By providing a detailed output of the simulation, REMERSIM allows the user to analyze particular components of the production-cost calculation, such as unit-by-unit capacity factors and fuel requirements for each season and hydroelectric condition.

18. **REPROBAT** (Report Writer of WASP): Writes a report summarizing the results for the optimum power system expansion plan.

III. STUDY PARAMETERS

D. REFERENCE INFORMATION

19. In the process of defining study assumptions, the ADB consultants reviewed technical information available in the documents listed below.

- *Myanmar Energy Sector Assessment, Strategy and Roadmap*, ADB, Mar 2015
- *Institutional Strengthening of National Energy Management Committee in Energy Policy and Planning*, ADB TA-8356 MYA, 2015
- *The Project for Formulation of the National Electricity Master Plan in the Republic of the Union of Myanmar*, Newjec Final Report (for MOEP), JICA, Dec 2014
- WBG Comments on Myanmar National Electricity Master Plan, Oct 2014
- *Myanmar Energy Master Plan*, Intelligent Energy Systems/Myanmar International Consultants (IES/MIC) Draft Report (for NEMC), ADB TA 8316 MYA, Dec 2014
- *Myanmar National Electricity Plan*, Earth Institute, Columbia University & Castalia Strategic Advisors report (for MOEP), World Bank TA, Oct 2014
- *Preparing the Power Transmission and Distribution Improvement*, Project Final Report by Fichtner, ADB - TA 8342 MYA, Oct 2014
- *Capacity Building Support for Project Identification*, Final Report by SMEC, Aug 2014

20. The first five documents include referenced planning reports, along with issues raised by others relating to the overall energy and power planning process. The last three reports provide information more relevant to transmission planning issues. Additional data relevant to the study was provided by MOEP and Newjec.

E. STUDY PERIOD

21. Consistent with the NEMP, the reference case and all sensitivity analyses performed in this study span a period of 18 years from 2013 through 2030.

F. DISCOUNT RATE

22. Consistent with NEMP study assumptions, this study uses a discount rate of 10% in the present worth discounting of costs to the reference year of 2013.

G. RESERVE MARGIN

23. Reserve Margin and Loss of Load Probability (LOLP) are common approaches for introducing reliability into system planning. The Asia Pacific Energy Research Centre (APERC) reports while

Peninsular Malaysia and Singapore require a 30 percent reserve margin, other areas in the region define reliable service as maintaining an LOLP no greater than 1 day per year.[4]

24. System reserve margin is a reliability criteria used in WASP IV. When simulating system operations in each year, WASP IV identifies the "critical period" as the period of the year for which the difference between corresponding available generating capacity and peak demand has the smallest value. For a configuration of unit additions to satisfy the reserve margin constraint, the installed capacity in the critical period must lie between the given minimum and maximum reserve margins above the peak demand in the critical period of the year.

25. A minimum reserve margin of 20% is applied in this study. As countries in the region typically use a value between 15% to 30% for planning purposes, sensitivity analyses should be performed to evaluate the costs and benefits of a more or less stringent reserve margin constraint.

H. COST OF ENERGY NOT SERVED

26. Energy not Served (ENS) is the amount of energy required by the system, which cannot be supplied by the generating equipment existing in the system. WASP IV computes ENS in GWh.

27. The planner can specify a cost of unserved energy (CUE) in US$/kWh representing the average loss to the economy due to unsupplied electrical energy. Approaches for estimating CUE include the *production loss method* – relating the value of lost production to the loss of power supply, the *captive generation method* – estimating the extra cost incurred by consumers that must rely on alternative or back-up power generation, and the *willingness to pay method* – determining a value based on surveys of consumer's willingness to pay for a reliable and uninterrupted electricity supply.

28. In the absence of reference evaluations of estimated outage costs to consumers in Myanmar, the ADB consultant chose to remain consistent with the NEMP and apply a CUE of 1.0 US$/kWh in this study. In comparison, a survey of the production loss for twelve major industries in Bangladesh reports the associated average cost of unplanned outages at 0.83 US$/kWh.[5]

I. LOSS OF LOAD PROBABILITY

29. LOLP is defined as the percentage of time during which the system load exceeds the available generating capacity of the system. For example, a cumulative failure duration of one (1) day per year has a corresponding LOLP of 0.274%.

30. As noted in a recent ADB study report, the security and reliability requirements in Lao PDR specify a maximum cumulative failure duration for the generating system of 5.5 days/year, while

[4] **Electric Power Grid Interconnections in the APEC Region**, APERC, 2004
[5] **Energy Strategy Approach Paper Annexes**, Sustainable Development Network, WBG, Oct 2009

planning criteria in Thailand call for LOLP not more than 24 hours per year.[6] The planning criteria adopted by the Korea Power Exchange (KPX) calls for a maximum LOLP of 12 hours per year.[7]

31. This study specifies a maximum system LOLP of 24 hours per year to be met beginning in 2025.

IV. ELECTRICITY DEMAND

J. DEMAND FORECAST

32. As part of the EMP, IES/MMI prepared an electricity demand forecast using a "bottom-up" approach for agriculture, industry, transport and household power and energy demand. The report examines energy trends by region and by customer class and aggregates the results, including system losses, to provide one consolidated electricity demand forecast for the country. The EMP postulates three demand forecasts: high (11.7% CAGR), medium (9.6% CAGR) and low (7.6%CAGR).

33. The medium demand forecast used in this study is displayed in Table 1. Under this forecast the country's electricity demand is expected to grow from 1,853 MW in 2013 to 9,465 MW in 2030. The annual energy generation requirement grows in line with demand to reach 58,336 GWh in 2030.

Table 1: EMP Medium Demand Forecast [8]

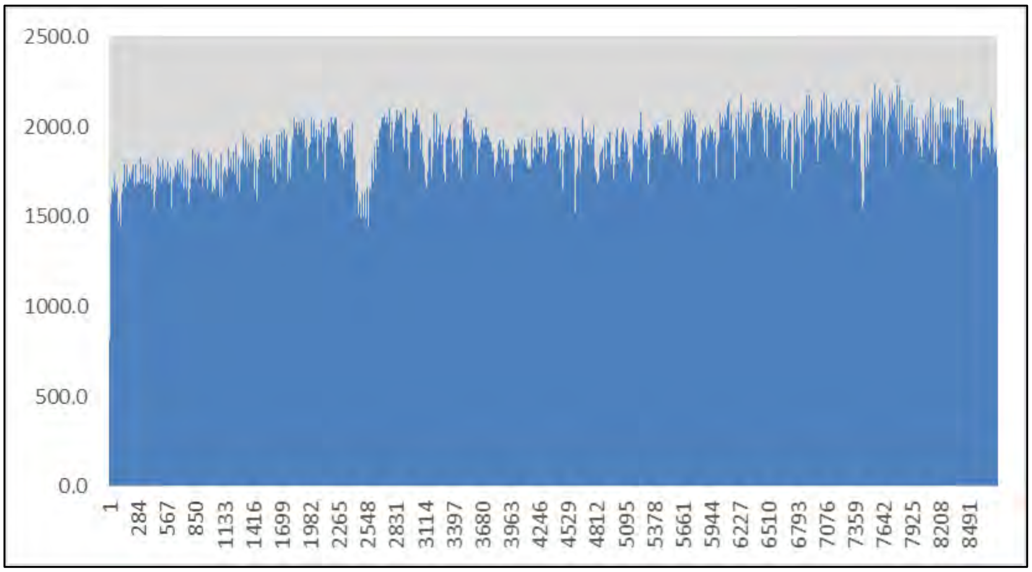
Year	Peak Load		Generation	
	MW	AGR	GWh	AGR
2013	1,853		11,421	
2014	2,045	10.36%	12,604	10.36%
2015	2,336	14.23%	14,398	14.23%
2016	2,592	10.96%	15,975	10.96%
2017	2,861	10.38%	17,633	10.38%
2018	3,155	10.28%	19,445	10.28%
2019	3,465	9.83%	21,356	9.83%
2020	3,806	9.84%	23,458	9.84%
2021	4,180	9.83%	25,763	9.83%
2022	4,588	9.76%	28,278	9.76%
2023	5,026	9.55%	30,977	9.55%
2024	5,501	9.45%	33,905	9.45%
2025	6,019	9.42%	37,097	9.42%
2026	6,589	9.47%	40,610	9.47%
2027	7,211	9.44%	44,444	9.44%
2028	7,900	9.55%	48,691	9.55%
2029	8,661	9.63%	53,381	9.63%
2030	9,465	9.28%	58,336	9.28%

[6] **Final Technical Report on Harmonization Study for ASEAN Power Grid**, ADB TA 7893 REG, Sep 2013
[7] **The 5thBasic Plan for Long-term Electricity Supply and Demand (2010-2024**), KPX, 2010
[8] IES/MIC, **Myanmar Energy Master Plan**, ADB TA 8316 MYA, Dec 2014

K. Seasonal Load Characteristics

34. In order to better capture the variability in system load characteristics and hydro power plant operations, the ADB consultant developed the EMP WASP IV database enable the model to operate with 12 periods per year.

35. At the advice of staff of the MOEP National Control Center, hourly systems loads for 2014, as represented in Figure 1, were used to define seasonal load characteristics as input to the EMP power expansion study.



Source: MOEP

Figure 1: 2014 Hourly System Loads

36. The PRELOAD program was used to read in the 8760 values of hourly system load and create representative period load duration curves and peak load ratios required as input to WASP. The computed period peak load ratios are displayed in Table 2.

Table 2: Period Peak Load Ratios

Period	1	2	3	4	5	6	7	8	9	10	11	12
Peak Load Ratio	0.82	0.87	0.92	0.94	0.94	0.89	0.92	0.94	0.97	0.98	1.00	0.97

Source: Consultant, MOEP Hourly Loads 2014

V. EXISTING GENERATING SYSTEM

37. In 2013, Myanmar produced 11,681 GWh of electricity, the bulk of which was from hydropower (73%), followed by gas-fired (25%) and coal-fired (2%) generation. (source: MOEP)

38. As of March 2013, actual installed capacity for Myanmar is 2,259 MW of hydropower, 363 MW of gas power plants, and one 30 MW coal power plant. (source: JICA Study Team)

39. Though in 2013 the installed capacity provides a %70 reserve margin over annual peak load, system reserve drops significantly in the dry season when hydropower plants receive insufficient water to generate at full capacity.

L. THERMAL POWER PLANTS

40. Existing gas-fired plants depend on domestic supply from the Yadana, Zawtika, and Shwe gas fields. As noted in Table 3, up to 261 bbtud (billion British Thermal Units per day) of gas is currently allocated to the power sector. This maximum volume is not expected to be increased until commissioning of the new gas field of M-3 in 2019. Imported gas and high speed diesel is considered for use in satisfying potential near term supply shortages.

Table 3: Domestic Gas Supply for Electricity through 2018 (bbtud)

Year	2013	2014	2015	2016	2017	2018
Supply for Electricity	201	248	261	261	261	261

Source: Newjec, NEMP 2014

41. The allocation of domestic gas supply to the power sector is expected to increase following commissioning of the new gas field of M-3 in 2019.

Table 4: Domestic Gas Supply for Electricity after Commissioning of M-3 Gas Field (bbtud)

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Supply for Electricity	272	309	302	311	306	291	259	246	235	221	219	215

Source: Newjec, NEMP 2014

42. As the NEMP reports Yadana gas has a substantially lower heating value than gas from the other fields, the EMP power expansion plan includes a separate category of fuel type for Yadana gas.

43. This study uses the fuel characteristics listed in Table 5 and operational characteristics for existing thermal power plants (TPPs) in Table 6, both of which are consistent with assumptions for the NEMP.

Table 5: Thermal Fuel Types

Type	Description	Fuel Cost ($/mmbtu)	Heat Value
1	COAL	domestic 1.93 imported 4.26	5000 (kcal/kg)
2	Yadana NGAS	11.19	6099 (kcal/m^3)
3	NATURAL GAS	11.19	8581 (kcal/m^3)
4	High Speed Diesel	19.40	10146 (kcal/kg)
5	SOLAR		
6	WIND		

Source: Consultant, Newjec NEMP 2014

Table 6: Characteristics of Existing Thermal Power Plants

Thermal Plant Type	Number of Units	Min. Operationg Level	Max Generating Capacity	Heat Rate	Fuel Cost	Fuel Type	Spinning Reserve	Forced Outage	Scheduled Maintenance	Maintenance Class Size	Fixed O&M	Variable O&M
		(MW)	(MW)	(kcal/kWh)	(c/million kcal)		(%)	(%)	(Day)	(MW)	($/kW-month)	($/MWh)
GT	1	48	95	4504	4442	3	0	7	37	95	1.9	2
GTCC	1	136	271	4389	4442	2	0	7	37	275	2.3	1
COAL	1	15	30	2545	765	1	0	7	32	60	2.5	2
GT2	0	29	93	4463	4442	3	0	7	37	394	1.9	2
GTCC	0	216	481	2182	4442	2	0	7	37	449	2.3	1
COAL	0	60	120	2450	765	1	0	7	32	120	2.5	2
GEHD	0	25	50	1886	7696	4	0	7	37	50	1.9	2

Source: Consultant, Newjec NEMP 2014

44. Rehabilitations to enhance the operating efficiency of several existing gas- and coal-fired power plants are scheduled to be completed by 2017.

M. HYDRO POWER PLANTS

45. With support of the MOEP National Control Center and Department of Electric Power (DEP), ADB consultants received detailed data on historical operations of existing hydro power plants in Myanmar, including: hydro power plant (HPP) classification, available installed capacity, energy storage capacity, and monthly generation and average capacity.

46. MOEP classifies HPPs in the following categories:

(i) HPPs not related to reservoir
(ii) HPPs to be operated at accord of the Irrigation Department
(iii) HPPs to be operated by Reservoir water.

47. The EMP WASP IV database is defined with the following two hydro types:

- Type HYD1 includes HPPs of category (i) or (ii) (i.e., run-of-river or irrigation controlled)
- Type HYD2 includes HPPs of category (iii) (i.e., reservoir storage).

48. Characteristics for existing HPPs are displayed in Table 7. Based on these values, HPPs of type HYD1 have an average capacity factor of 58%, while the average for HPPs of type HYD2 is 36%. The average capacity factor for the combined set of existing HPPs is 42%.

49. In addition to the 2,259 MW of installed hydropower capacity in 2013, 165 MW is added with the Phu Chuang, Nancho, Baluhaung-3, and Chipwinge-1 HPPs are commissioned in 2014, and 66 MW with commissioning of Chipwinge-2 in 2015.

Table 7: Characteristics of Existing Hydropower Plants

WASP Hydro Type	Sr.	Hydro Category	Name of Hydroelectric Power Station	Installed Capacity	Start of Operation	Actual available Capacity	Storage Capacity	Montly Generation (GWh) in 2013											
		Storage Irrigation Run-of-River		(MW)	Year	(MW)	(GWh)	1	2	3	4	5	6	7	8	9	10	11	12
HYD2	1	S	Ba Luchang No.1	28	1992	28	28	19.7	17.8	19.4	19.2	19.2	18.7	18.5	11.5	7.7	8.4	9.8	16.3
HYD2	2	S	Ba Luchang No.2	168	1974	168		106.7	96.3	105.3	103.8	103.5	101.1	99.7	61.7	39.9	44.4	50.8	89.8
HYD1	3	I	Kinda	56	1985	56		0.0	4.6	11.1	10.1	0.0	0.0	0.0	0.0	2.4	2.4	11.1	2.2
HYD1	4	I	Sedawgyi	25	1989	25		3.8	3.5	7.8	9.0	7.1	7.7	4.9	8.9	16.2	11.1	13.5	6.3
HYD1	5	R	Zawgyi No1	18	1995	18		4.8	4.0	3.9	3.4	3.8	5.6	5.5	10.0	9.8	10.7	9.0	6.6
HYD1	6	I	Zawgyi No2	12	1998	12		1.3	3.0	6.4	6.2	4.1	4.5	0.2	0.0	1.2	1.8	3.9	2.1
HYD2	7	S	Zaungtu	20	2000	20	20	1.0	0.9	1.5	1.3	0.7	5.7	9.9	12.0	11.5	8.4	5.2	1.1
HYD1	8	I	Thapanseik	30	2002	30		0.2	1.9	5.5	5.1	4.1	4.5	7.5	5.6	7.4	7.8	15.3	0.1
HYD2	9	S	Mone	75	2004	75	75	14.7	15.7	14.7	10.0	4.0	9.9	17.5	37.4	44.1	43.3	25.0	9.0
HYD2	10	S	Paunglaung	280	2005	280	280	41.0	36.6	25.9	39.8	30.4	33.4	35.3	69.3	66.9	72.6	72.8	68.1
HYD2	11	S	Yenwe	25	2007	25	25	6.4	8.2	10.5	11.7	11.9	12.2	10.8	0.6	0.1	0.1	0.0	0.0
HYD2	12	S	Kabaung	30	2008	30	30	6.9	6.6	6.8	8.9	12.5	14.2	8.0	0.3	0.1	0.3	0.2	1.6
HYD1	13	R	Shweli	600	2008	300		170.7	142.3	151.6	166.4	214.0	188.3	212.4	145.3	132.2	143.5	155.6	183.1
HYD1	14	R	Keng Tong	54	2008	54		31.4	26.8	25.6	22.9	24.0	26.8	34.3	27.8	25.9	33.7	36.8	38.2
HYD2	15	S	Yeywa	790	2010	790	790	168.4	154.6	165.9	160.8	103.9	127.7	155.2	326.1	324.5	344.2	316.0	232.4
HYD2	16	S	Shwegyin	75	2011	75	75	17.5	19.7	18.9	22.1	15.6	11.1	18.5	23.6	29.3	31.2	14.1	5.8
HYD1	17	R	Dapein No.1	240	2011	19		0.0	0.0	0.0	0.5	1.8	2.3	2.3	2.3	2.3	2.2	2.1	2.2
HYD2	18	S	Kun	60	2012	60	60	19.2	24.2	32.1	37.8	35.1	24.0	10.6	0.9	0.2	2.3	14.6	8.0
HYD1	19	I	Kyee On Kyee Wa	74	2012	74		16.3	15.5	18.4	13.5	10.2	14.8	16.8	37.4	41.2	45.8	30.3	8.7
HYD2	20	S	Thauk Ye Khat	120	2013	120	120	24.8	13.1	16.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	12.3
2013	HYD1	R & I				588	0	229	202	230	237	269	254	284	237	239	259	278	250
	HYD2	S				1,671	1,503	426	394	418	415	337	358	384	543	524	555	518	444
	TOTAL					2,259	1,503	655	595	648	652	606	612	668	781	763	814	796	694
	A		Phu Chaung	40	2014	40	0												
	B		Nancho	40	2014	40	0												
	C		Baluhaung - 3	52	2014	52	0												
	8		Chipwinge-1	33	2014	33	0												
2014	HYD1	R & I				165	0	74	60	55	81	56	42	76	35	42	64	56	55
	8		Chipwinge-2	66	2018	66	0												
2018	HYD1	R & I				66	0	18	20	27	14	18	19	2	25	37	24	32	19

Source: Consultant, MOEP Operations Statistics 2014

VI. CANDIDATE PLANTS FOR FUTURE SYSTEM EXPANSION

50. Given the abundant energy resources in Myanmar, the EMP power expansion study considered a range of generation options, including: hydro, fossil fuel based thermal, wind and solar power. A large number of factors including cost of development, operation and maintenance costs, technical operational characteristics, impact on system reliability, and environmental effects were evaluated in order to consider the suitability of these candidates for system expansion.

N. THERMAL POWER PLANTS

51. The operational characteristics for candidate thermal power plants in Table 8 are consistent with assumptions in the NEMP. This includes equipping new Gas Engine and Gas Turbine plants to run on either gas or high speed diesel.

Table 8: Candidate Thermal Power Plant – Operational Characteristics

Thermal	Min. Operating Level	Max Generating Capacity	Heat Rate	Fuel Cost	Fuel Type	Spinning Reserve	Forced Outage	Schedule Maintenance	Maintenance Class Size	Fixed O&M	Variable O&M
	(MW)	(MW)	(kcal/kWh)	(c/million kcal)		(%)	(%)	(Day)	(MW)	($/kW-month)	($/MWh)
GT-N	25	50	2765	natural gas 4442 diesel oil 7696	3 or 4	0	7	37	50	1.9	2.0
GTCN	125	250	1700	4442	3	0	7	37	250	2.3	1.0
GE-N	25	50	1886	natural gas 4442 diesel oil 7696	3 or 4	6	7	37	50	1.9	2.0
COAN	250	500	2000	1690	1	0	7	32	250	2.5	2.0

Source: Consultant, Newjec NEMP 2014

52. An effort was made to harmonize capital cost assumptions between the EMP and NEMP with additional advice from the WBG. The capital cost for Gas Engine and Coal-fired plants are from the NEMP, while the value for Gas Turbine Combined Cycle (GTCC) is from IES. In addition, the capital cost for Gas Turbines was reduced from the original NEMP value in response to comment from the WBG. Thermal power plant capital cost assumptions for this study are presented in Table 9.

Table 9: Candidate Thermal Power Plant – Capital Cost

Thermal	Capital Cost	Plant Life	Construction Time
	(2013 US$/kW)	years	years
GT	653	25	2.5
GTCC	918	25	3.5
GE	890	25	2.5
COAL	2,222	25	5

Source: Consultant, Newjec NEMP 2014, IES EMP 2015, and WBG review

53. Air pollutant emission rates in Table 10 were obtained from the referenced generation technology document prepared by Black & Veatch[9] and are used in this study.

Table 10: Thermal Power Plant – Emission Rates

Thermal	Emission Rate (lb/mmbtu)			
	SO_2	NO_x	PM10	CO_2
GT	0.0002	0.033	0.006	117
GTCC	0.0002	0.0073	0.0058	117
COAL	0.055	0.05	0.011	215

Source: Black & Veatch, NREL Technology Review 2012

O. Hydro Power Plants

54. As noted in the NEMP, Myanmar has over 100 GW of hydroelectric reserves.

55. Newjec staff consulted with MOEP to identify a list of thirty-eight (38) candidate HPPs for the NEMP, along with the associated installed capacity, first possible year of operation, and prioritized sequence of hydro developments considering distribution of HPPs with respect to load centers and transmission, economic, social and other factors. This same set of 38 HPPs, with a total available capacity for Myanmar of 6,328 MW, are included as candidates in the EMP power expansion study.

56. With support of the MOEP DEP and Department of Hydroelectric Power Planning (DHPP), ADB consultants developed representative values of monthly generation, average available capacity, and energy storage capacity (where applicable) for candidate HPPs. Operational and cost parameters for these candidates are listed in Table 11.

57. Consistent with NEMP assumptions, due to limited availability of information on the estimated cost of HPP candidates, an average value of $2,000 US$/MW developed by Newjec in consultation with MOEP applies to all HPP candidates in the EMP power expansion study.

[9] Black & Veatch, **Cost and Performance Data for Power Generation Technologies**, National Renewable Energy Laboratory, 2012

Table 11: Candidate HPP – Operational and Cost Parameters

Sr.	Hydro Type	HPP Name in WASP	Name of Hydroelectric Power Station	Location Region/State	Overnight Capital Cost (mUS$/MW)	Available Capacity (MW)	Monthly Generation (GWh)											
							1	2	3	4	5	6	7	8	9	10	11	12
E		UPAU	Upper Paunglaung	Bago	2,000	140	42	40	46	46	43	40	34	45	51	51	49	37
P		DAPO	Dapain (only supply)	Kachin	2,000	101	31	29	33	33	31	29	24	33	37	36	36	27
37		MOWA	Mong Wa	Shan (S)	2,000	50	15	14	16	17	15	14	12	16	18	18	18	13
H		UKEN	Upper Kengtawng	Shan St (S)	2,000	51	15	15	17	17	16	15	12	16	18	18	18	14
O		NGOT	Ngotchaung		2,000	16.6	5	5	5	5	5	5	4	5	6	6	6	4
Q		PROJ	Projects		2,000	79	24	23	26	26	24	23	19	25	29	29	28	21
D		UBAL	Upper Baluchaung	Bago	2,000	30.4	9	9	10	10	9	9	7	10	11	11	11	8
G		THAH	Thahtay	Rakhine St	2,000	111	34	32	36	37	34	32	27	36	40	40	39	29
I		UYEY	Upper Yeywa	Shan St (N)	2,000	280	85	80	92	92	86	81	67	90	101	101	99	74
M		MPAU	Middle Paunglaung	Mandalay	2,000	100	30	29	33	33	31	29	24	32	36	36	35	26
R		DEED	Dee Doke		2,000	66	20	19	22	22	20	19	16	21	24	24	23	17
J	HYD2	SHW3	Shweli - 3	Shan St (N)	2,000	1,050	318	299	345	347	324	303	253	339	379	379	371	278
L		UBU	Upper Bu	Magway	2,000	150	45	43	49	50	46	43	36	48	54	54	53	40
S		KKHA	Keng Kham		2,000	6	2	2	2	2	2	2	1	2	2	2	2	2
9		DAP2	Dapein - 2	Kachin	2,000	84	25	24	28	28	26	24	20	27	30	30	30	22
T		MYEY	Middle Yeywa	Bago	2,000	320	97	91	105	106	99	92	77	103	116	115	113	85
U		USED	Upper Sedawgyi		2,000	64	19	18	21	21	20	18	15	21	23	23	23	17
K		BAWG	Bawgata	Bago	2,000	160	48	46	53	53	49	46	38	52	58	58	57	42
10		GAWL	Gawlan	Kachin	2,000	50	15	14	16	17	15	14	12	16	18	18	18	13
33	HYD2	SHW2	Shweli - 2	Shan (N)	2,000	260	79	74	85	86	80	75	63	84	94	94	92	69
34		KTON	Keng Tong	Shan (S)	2,000	64	19	18	21	21	20	18	15	21	23	23	23	17
35		WATA	Wan Ta Pin	Shan (S)	2,000	17	5	5	5	5	5	5	4	5	6	6	6	4
36		SOLU	So Lue	Shan (S)	2,000	80	24	23	26	26	25	23	19	26	29	29	28	21
15	HYD2	UTHA	Upper Thanliwn (Kunlong)	Shan (N)	2,000	700	212	200	230	231	216	202	168	226	253	253	247	185
40	HYD2	NKHA	Nam Kha	Shan (S)	2,000	100	30	29	33	33	31	29	24	32	36	36	35	26
38		KYAN	Keng Yang	Shan (S)	2,000	20	6	6	7	7	6	6	5	6	7	7	7	5
39		HEKU	He Kou	Shan (S)	2,000	50	15	14	16	17	15	14	12	16	18	18	18	13
20	HYD2	TANI	Taninthayi	Taninthayi	2,000	300	91	86	99	99	93	87	72	97	108	108	106	79
12		HKAN	Hkan Kawn	Kachin	2,000	80	24	23	26	26	25	23	19	26	29	29	28	21
16,17	HYD2	NAMA	Naopha, Mantong	Shan (N)	2,000	713	216	203	234	235	220	206	171	230	257	257	252	189
13		TONG	Tongxinqiao	Kachin	2,000	170	51	48	56	56	52	49	41	55	61	61	60	45
14		LAWN	Lawngdin	Kachin	2,000	300	91	86	99	99	93	87	72	97	108	108	106	79
46	HYD2	DUBA	Dun Ban		2,000	130	39	37	43	43	40	38	31	42	47	47	46	34
48		NKHO	Nam Khot		2,000	25	8	7	8	8	8	7	6	8	9	9	9	7
42		NATA	Nam Tamhpak (Kachin)	Kachin	2,000	100	30	29	33	33	31	29	24	32	36	36	35	26
44		NATU	Namtu		2,000	100	30	29	33	33	31	29	24	32	36	36	35	26
45		MOYO	Mong Young		2,000	45	14	13	15	15	14	13	11	15	16	16	16	12
47	HYD2	NALI	Nam Li		2,000	165	50	47	54	54	51	48	40	53	60	60	58	44

Source: Consultant, MOEP Operations Statistics 2014, and Newjec NEMP 2014

P. RENEWABLE GENERATION OPTIONS

58. With estimated reserves of 365 TWh/year from wind and 52,000 TWh/year from solar[10] and the strong emphasis renewable energy receives in the National Energy Policy Myanmar, this study investigated the viability of large-scale renewable energy projects by evaluating wind and solar energy candidate projects in the context of the least-cost generation expansion plan.

59. IES consultants analyzed wind speed and solar irradiation estimates in order to understand geographical dispersion of RE potential in the country. As illustrated in Figures 2 & 3, the analysis suggests that: (i) solar is better located with respect to the transmission system and distance to major load centres, and (ii) wind potential is generally in less favorable locations further away from existing transmission.

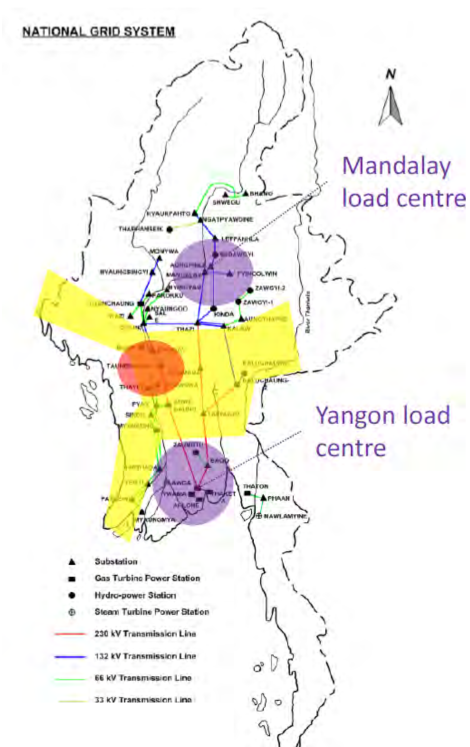


Figure 2: Areas with High Solar Potential

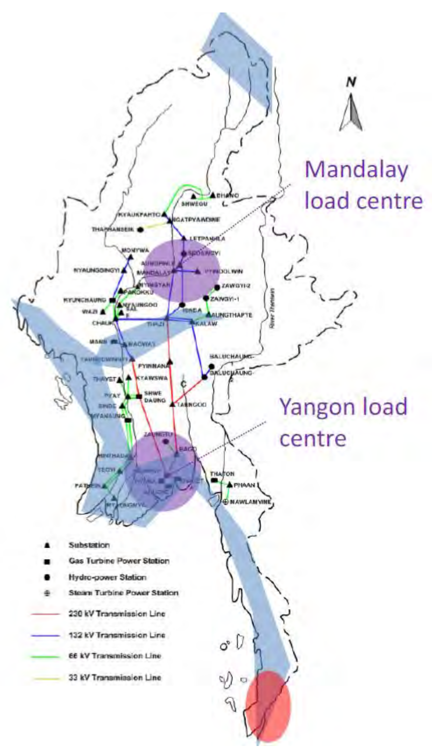


Figure 3: Areas with Significant Wind Potential

Source: IES, EMP 2015

60. ADB undertook a study on renewable energy potential in Myanmar.[11] This assessment, study and roadmap effort developed estimates of full-load hours of generation for solar PV and wind energy converters at different sites throughout the country. Study results were used to estimate annual forced outage rates for renewable candidates in the EMP power expansion plan.

[10] Source: MOE (2013), ADB (2012) and Japan Electric Power Information Center (2012) documents.
[11] H.-W. Boehnke, **ASR Report**, TA-8356 Myanmar 2014

Table 12: Estimated Annual Outage Rate for Solar PV in Myanmar

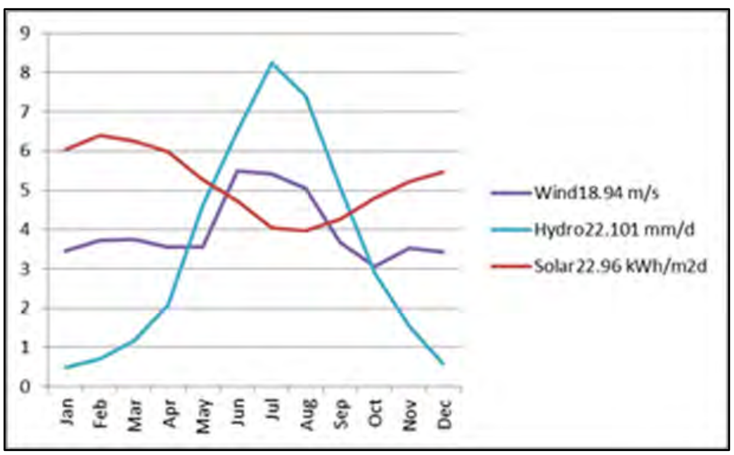
Location	Myitkyina	Mandalay	Magwey	Sittwey	Yangon	Dawei
G kWh/m²d	4.507	5.048	5.138	4.736	4.694	4.844
E kWh/kWp	**1532**	1716	1746	1610	1596	1647
Outage Rate (%)	82.5	80.4	80.1	81.6	81.8	81.2

Source: H.-W. Boehnke, ASR Report, ADB TA-8356 Myanmar 2014

61. Based on the outage rate estimates for a variety of sites listed in Table 12, the EMP power expansion study assumes an average annual forced outage rate of 81.3% for solar PV candidates.

62. According to members of the ADB ASR study team, global wind data suggests Myanmar has a few sites where wind speed reaches 6 m/s. For these sites, an estimate of available power was developed assuming wind energy converter operating at a height of 50m. Based on results of this analysis, the EMP power expansions study assumes an average annual forced outage rate of 71.4% for wind candidates.

63. Another interesting observation from the renewable energy study, as illustrated in Figure 4, is that the strong seasonal variations of solar, wind, and hydro energy potential complement each other over the year.



Source: Consultant, IES EMP 2015

Figure 4: Season Variation of Solar, Wind and Hydro

64. While the WASP IV model was originally designed to analyze conventional thermal and hydroelectric generation options, planners have employed a number of special unit representations to analyze renewables. The most common approach is to represent renewable generation candidates as thermal power plants, which enables the planner to: (i) analyze viability of solar and wind generation in an expansion plan without having to specify a predefined scenario, (ii) produce an accurately accounting of annual renewable generation (through specification of planned maintenance and force outage rate) and cost (through specification of capital cost and fixed O&M), and (iii) evaluate the impact of renewables on system reliability. Others have commented on the merits of this type of approach to

modeling renewable energy resources in long-term planning models, including the following quote from the referenced National Renewable Energy Laboratory (NREL) publication:

> *If time-of-day power delivery information is not available, modeling a time-dependent resource as a generating unit with constant capability and an appropriate forced outage rate may yield a reasonable approximation. The benefit of modeling the resource as a generating unit is that many utility planning models [such as WASP] have probabilistic algorithms for addressing generating unit unavailability attributable to random equipment failures. This feature could be used to reflect the uncertainty associated with renewable power delivery. In some models, [like WASP] unit unavailability is specified by a forced outage rate - the percentage of time that a unit is expected to be unavailable. Other models (notably those of a chronological nature) allow a user to model a unit's availability by specifying probability distributions for the time between outages and the time it may take to restore the unit to service. In renewable resource modeling, any of these availability features could be used to represent the renewable generation that would be curtailed because of equipment failure (usually a minor factor) or lack of wind or sunshine (the major factor that limits wind and solar resource generation).*[12]

65. For the EMP power expansion study, renewable energy options are represented with the operational characteristics listed in Table 13.

Table 13: Candidate Renewables – Operational Characteristics

Renewables	Min. Operationg Level	Max Generating Capacity	Heat Rate	Fuel Cost	Fuel Type	Spinning Reserve	Forced Outage	Scheduled Maintenance	Maintenance Class Size	Fixed O&M	Variable O&M
	(MW)	(MW)	(kcal/kWh)	(c/million kcal)		(%)	(%)	(Day)	(MW)	($/kW-month)	($/MWh)
SOLAR	1	50	0	0	5	0	81.3	10	50	2.0	0.0
WIND	1	100	0	0	6	0	71.4	10	50	3.3	0.0

Source: Consultant, H.-W. Boehnke ASR Report, ADB TA-8356 Myanmar 2014

66. When simulating system operation for a configuration of unit additions that includes a 50 MW solar PV candidate with a forced outage rate of 81.3%, the WASP IV model reflects that the PV candidate operates only 18.7% of the time. For the remainder of time, when the solar PV unit is not generating, the full system load must be satisfied by other units or result in increased cost of unserved energy and a higher loss of load probability.

67. Capital cost assumptions for candidate renewables are listed in Table 14. The estimated cost of 1.8 US$/W for solar PV in Myanmar is on advice of the WBG. As the cost of solar PV continues to decline due to learning curve and mass production effects, with reference to the Black & Veatch generation

[12] RCG/Hagler, Baily, Inc., **Modeling Renewable Energy Resources in Integrated Resource Planning**, NREL, 1994

technology report,[13] this study applied a scaling factor to reduce the cost of PV by 5.5% in 2020, and another 5.4% in 2025.

Table 14: Candidate Renewables – Capital Cost

Renewables	Capital Cost	Plant Life	Construction Time
	(2013 US$/kW)	years	years
SOLAR	1,800	20	2
WIND	1,782	20	2

Source: Consultant, WBG Review Comments and IES EMP 2015

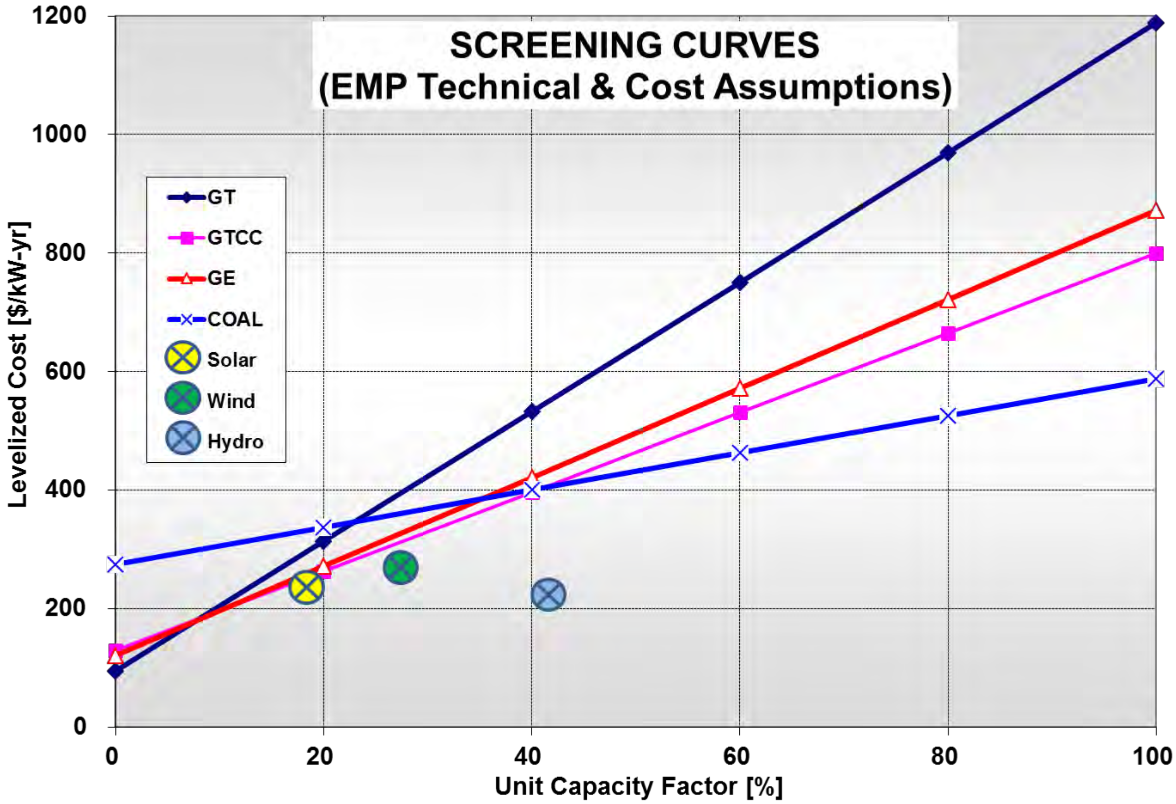
VII. POWER EXPANSION PLANNING PROCESS

Q. PRELIMINARY SCREENING OF GENERATION OPTIONS

68. A preliminary screening exercise was performed to chart the economic competitiveness of expansion candidates as a function of their technology utilization. This approach is used to develop initial insights into the relative competitiveness of generation options over a range of technical and cost assumptions before carrying out the expansion planning study.

69. The Screening Curve diagram in Figure 5 shows the levelized generation cost expressed in US$/kW-yr calculated at different capacity factors for all candidates using a discount rate of 10% and technical and cost parameters for described above. As an initial indication, the diagram points to hydro candidates (with average capacity factor of 42%) being most competitive, while solar appears more economic than wind. In comparing the dispatchable thermal power plants, Gas Turbine has an advantage when dispatched to operate at a low capacity factor, GTCC performs well within the capacity factor range of 10% to 35%, and COAL has an advantage over other thermal candidates for base load generation.

[13] Black & Veatch, **Cost and Performance Data for Power Generation Technologies**, NREL, 2012

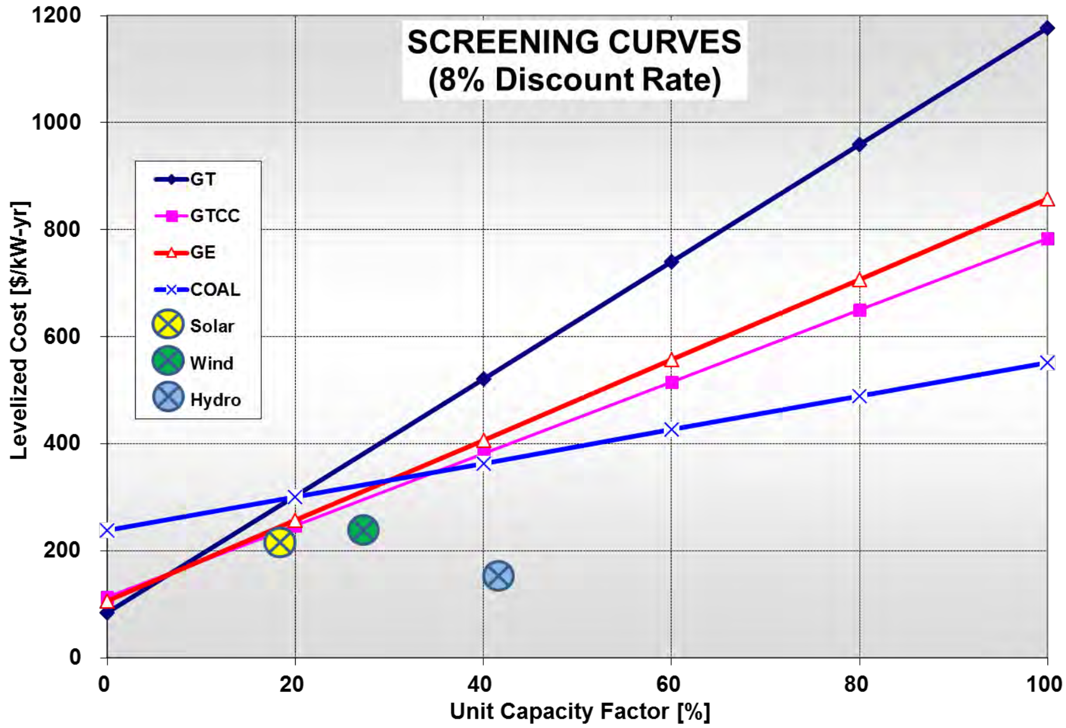


Source: Consultant

Figure 5: Screening Curves for Expansion Candidates - EMP Study Assumptions

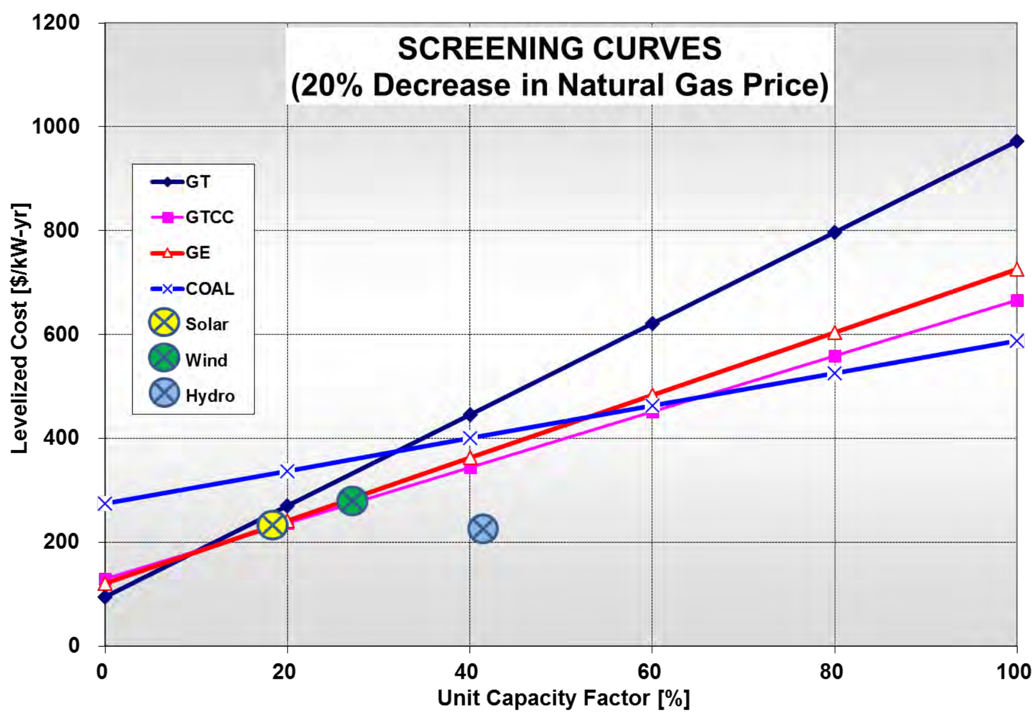
70. Note that screening curves provide a very rough estimate of candidate competitiveness and do not account for many factors, such as existing generation mix, price escalation, environmental constraints, forced outage rates, and system reliability.

71. The following diagrams illustrate the impact of reducing the discount rate to 8% (Figure 6), or decreasing natural gas price by 20% (Figure 7) on plant competitiveness.



Source: Consultant

Figure 6: Screening Curves for Expansion Candidates - Discount Rate of 8%



Source: Consultant

Figure 7: Screening Curves for Expansion Candidates - Natural Gas Price Decrease of 20%

R. BENCHMARKING MODEL SIMULATION VS SYSTEM OPERATIONS

72. After assembling the WASP IV database for the EMP power expansion study and running the model, a validity check was performed to compare the generation mix reported by the WASP simulation against actual system operations in 2013. WASP IV model simulated results are presented in Table 15 and actual system operation statistics received from MOEP are presented in Table 16.

Table 15: WASP IV Simulated Results (MWh)

	NEMC-EMP Myanmar Only		
Period	Hydro	Gas	Coal
1	655,000	148,000	20,400
2	596,000	243,200	20,400
3	648,000	282,500	20,400
4	652,000	292,300	20,400
5	606,000	359,100	20,400
6	612,000	337,400	20,400
7	668,000	286,500	-
8	780,000	169,800	20,400
9	763,000	215,500	20,400
10	814,000	173,200	20,400
11	796,000	163,300	20,400
12	694,000	242,100	20,400
Total	8,284,000	2,912,900	224,400
	11,421,300		

Source: Consultant

Table 16: Actual System Operations (MWh)

	MOEP Actual Including Export		
Month	Hydro	Gas	Coal
Jan	630,040	225,422	24,774
Feb	594,998	210,256	13,114
Mar	659,482	278,571	16,744
Apr	685,622	208,497	16,643
May	629,492	278,542	17,486
Jun	626,444	285,619	16,018
Jul	690,901	294,447	14,254
Aug	812,727	232,556	18,587
Sep	825,385	203,714	11,032
Oct	870,771	211,691	-
Nov	829,618	223,133	-
Dec	734,607	278,125	12,393
Total	8,590,086	2,930,573	161,045
	11,681,704		

Source: MOEP Operations Statistics

73. While recognizing that the actual system operation statistics include an amount of hydro generated electricity for exports and the WASP simulation focuses exclusively on electricity generation for Myanmar, there is a tight correlation between the seasonal generation mix for the simulated results and actual values.

74. In the WASP simulation for 2013, hydropower is dispatched with an average capacity factor of 44%, while coal plants averaged 85%, existing GTCC 81% and Gas Turbines 38%. In 2013, no additional generation was required from new GTCC power plants.

VIII. LEAST COST POWER SYSTEM EXPANSION PLAN

S. OPTIMUM POWER EXPANSION PLAN

75. This section presents model results for the least cost power expansion plan developed under the EMP's medium growth case and assumptions described above.

76. The capacity mix associated with the Myanmar power sector in 2013 is provided in Table 17. In contrast, the resulting capacity mix in 2030 for the least cost expansion plan is provided in Table 18.

Table 17: Actual Capacity Mix for Myanmar Power System in 2013

Plant Type	Installed Capacity in 2013	
	MW	%
Gas	866	27%
Coal	30	1%
Hydro	2259	72%
Renewables	0	0%
Total	3155	

Source: MOEP

Table 18: Least Cost Expansion Plan - Capacity Mix in 2030

Plant Type	Installed Capacity in 2030	
	MW	%
Gas	2374	15%
Coal	2620	16%
Hydro	8818	55%
Renewables	2300	14%
Total	16112	

Source: Consultant Analysis

77. The schedule of capacity additions for the least cost expansion plan is provided in Table 19. The timing of commercial operation for committed power plants through 2016 is according to the implementation schedule reported in the NEMP.

Table 19: Least Cost Strategy - Power Expansion Plan

Existing Plants	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Combined Cycle	271	271	271	271	481	481	481	481	481	481	481	481	481	481	481	481	481	481
Gas Turbine	95	95	95	95	93	93	93	93	93	93	93	93	93	93	93	93	93	93
Coal	30	30	30	30	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Hydropower	2259	2424	2424	2424	2424	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490
Annual Fixed Capacity (MW):	2655	2820	2820	2820	3118	3184	3184	3184	3184	3184	3184	3184	3184	3184	3184	3184	3184	3184
Candidate Plants																		
Gas	500	400	450	350														100
Coal											500	500		500		500		500
Hydro			101	50	191	126	491	1266	410	224	310	161	820	50	1093	470	355	210
Solar													200	50	450	100	750	750
Wind																		
Annual Capacity Additions (MW):	500	400	551	400	191	126	491	1266	410	224	810	661	1020	600	1543	1070	1105	1560
Total Capacity Additions:	500	900	1451	1851	2042	2168	2659	3925	4335	4559	5369	6030	7050	7650	9193	10263	11368	12928
Total Supply Capacity	3155	3720	4271	4671	5160	5352	5843	7109	7519	7743	8553	9214	10234	10834	12377	13447	14552	16112
Renewable Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0	200	250	700	800	1550	2300
Renewable % of Total Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	2.3%	5.7%	5.9%	10.7%	14.3%

Source: Consultant Analysis

78. In the least cost expansion plan, all 6,328 MW of candidate hydropower projects is added over the period of study.

79. 2,500 MW of new coal-fired generation is added beginning with the first 500 MW unit in 2023.

80. In addition to the 1,700 MW of committed additions of new gas-fired generation through 2016, an additional 100 MW of Gas Turbines is brought online in the final year of the study.

81. Concerning renewables, no wind generators were selected in the least cost plan. However, after the second scheduled cost reduction takes effect in 2025, solar power becomes quite competitive and 2,300 MW is added to the system from 2025 to 2030.

82. The cumulative capacity (i.e., existing system plus new additions) by plant type for the least cost expansion strategy is displayed in Figure 8.

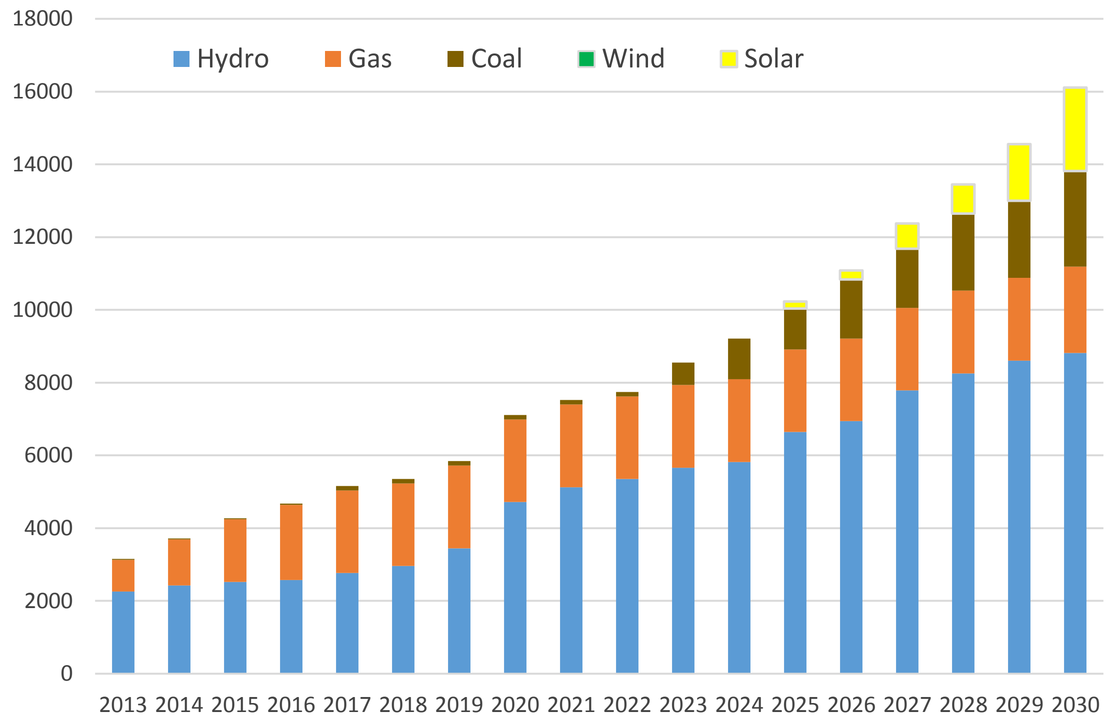


Figure 8: Least Cost Strategy - Cumulative Capacity (MW) by Plant Type

Source: Consultant Analysis

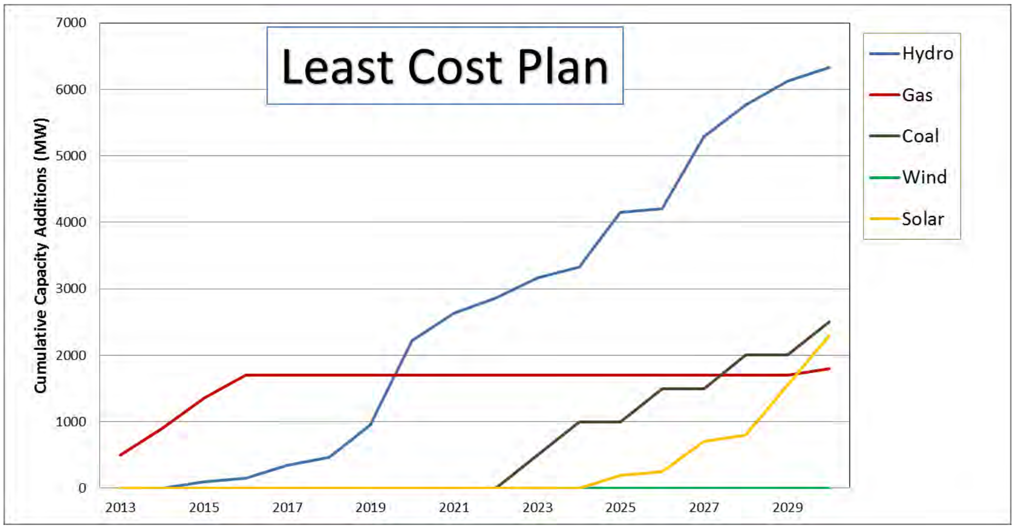
83. The schedule of hydro power plant additions for the least cost expansion plan is listed in Table 20. While all candidate HPPs are selected for construction in the optimum expansion plan, commissioning for 300 MW of potential additions is delayed past the HPP's first year of available operation.

Table 20: Least Cost Strategy – Schedule of Hydro Power Plant Additions

Sr.	HPP Name in WASP	First Year of Operation	Name of Hydroelectric Power Station	Location Region/State	Available Capacity (MW)
P	DAPO	2015	Dapain (only supply)	Kachin	101
37	MOWA	2016	Mong Wa	Shan (S)	50
E	UPAU	2017	Upper Paunglaung	Bago	140
H	UKEN	2017	Upper Kengtawng	Shan St (S)	51
O	NGOT	2018	Ngotchaung		16.6
Q	PROJ	2018	Projects		79
D	UBAL	2018	Upper Baluchaung	Bago	30.4
G	THAH	2019	Thahtay	Rakhine St	111
I	UYEY	2019	Upper Yeywa	Shan St (N)	280
M	MPAU	2019	Middle Paunglaung	Mandalay	100
R	DEED	2020	Dee Doke		66
J	SHW3	2020	Shweli - 3	Shan St (N)	1,050
L	UBU	2020	Upper Bu	Magway	150
S	KKHA	2021	Keng Kham		6
9	DAP2	2021	Dapein - 2	Kachin	84
T	MYEY	2021	Middle Yeywa	Bago	320
U	USED	2022	Upper Sedawgyi		64
K	BAWG	2022	Bawgata	Bago	160
10	GAWL	2023	Gawlan	Kachin	50
33	SHW2	2023	Shweli - 2	Shan (N)	260
34	KTON	2024	Keng Tong	Shan (S)	64
35	WATA	2024	Wan Ta Pin	Shan (S)	17
36	SOLU	2024	So Lue	Shan (S)	80
40	NKHA	2025	Nam Kha	Shan (S)	100
15	UTHA	2025	Upper Thanliwn (Kunlong)	Shan (N)	700
38	KYAN	2025	Keng Yang	Shan (S)	20
39	HEKU	2026	He Kou	Shan (S)	50
20	TANI	2027	Taninthayi	Taninthayi	300
12	HKAN	2027	Hkan Kawn	Kachin	80
16,17	NAMA	2027	Naopha, Mantong	Shan (N)	713
13	TONG	2028	Tongxinqiao	Kachin	170
14	LAWN	2028	Lawngdin	Kachin	300
46	DUBA	2029	Dun Ban		130
48	NKHO	2029	Nam Khot		25
44	NATU	2029	Namtu		100
42	NATA	2029	Nam Tamhpak (Kachin)	Kachin	100
45	MOYO	2030	Mong Young		45
47	NALI	2030	Nam Li		165

Source: Newjec NEMP 2014 and Consultant Analysis

84. In the least cost plan, by the year 2030, hydropower plants comprise approximately 55% of system installed capacity and 56% of annual generation. At the same time, installed capacity for solar nearly matches that of gas- and coal-fired power plants. The progression of capacity additions by plant type for the least cost expansion strategy is presented in Figure 9.



Source: Consultant Analysis

Figure 9: Least Cost Case - Cumulative Capacity Additions by Plant Type

85. Annual generation by plant fuel type is reported in Table 21.

Table 21: Least Cost Strategy – Annual Generation by Plant Type

Year	Hydro		Gas		Coal		Solar		Wind	
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%
2013	8,284	73%	2,913	26%	224	2%	0	0%		0%
2014	8,980	71%	3,400	27%	224	2%	0	0%		0%
2015	9,359	65%	4,815	33%	224	2%	0	0%		0%
2016	9,545	60%	6,207	39%	224	1%	0	0%		0%
2017	10,260	58%	6,483	37%	891	5%	0	0%		0%
2018	10,987	57%	7,568	39%	891	5%	0	0%		0%
2019	12,825	60%	7,641	36%	891	4%	0	0%		0%
2020	17,566	75%	5,007	21%	884	4%	0	0%		0%
2021	19,101	74%	5,780	22%	882	3%	0	0%		0%
2022	19,941	71%	7,450	26%	886	3%	0	0%		0%
2023	21,102	68%	5,397	17%	4,478	14%	0	0%		0%
2024	21,702	64%	4,290	13%	7,912	23%	0	0%		0%
2025	24,772	67%	4,296	12%	7,712	21%	317	1%		0%
2026	25,898	64%	3,420	8%	10,896	27%	397	1%		0%
2027	29,049	65%	3,661	8%	10,627	24%	1,106	2%		0%
2028	30,811	63%	2,997	6%	13,615	28%	1,267	3%		0%
2029	32,142	60%	4,901	9%	13,877	26%	2,458	5%		0%
2030	32,932	56%	4,735	8%	17,010	29%	3,655	6%		0%

Source: Consultant Analysis

86. With the amount of candidate hydro power projects limited to just over 6,300 MW, the share of hydro in the system capacity mix drops from 72% in 2013 to 55% in 2030. In line with the reducing share of hydro capacity, hydro generation is reduced from 73% in 2013 to 56% in 2030.

87. Gas-fired generation rises from 26% of total in 2013 to a high of 39% in 2018, then drops to just 8% of total electricity generation in 2030.

88. Although there is about an equal share of installed capacity for solar (14%), gas- (15%), and coal-fired (16%) power plants in 2030, their respective shares of total generation are far from equal with coal at 29%, gas 8%, and solar 6%.

T. Fuel Requirement and Expenditure

89. To meet increased demand for electricity over the period 2013 – 2030, consumption of coal, and natural gas in the power sector is expected to increase as elaborated in Table 22. Also noted is the associated fuel expenditures in current year (non-discounted) values.

Table 22: Least Cost Strategy – Fuel Consumption and Expenditure

Year	Coal		Gas	
	1000MT	US $ million	million m^3	US $ million
2013	114	4	1,740	509.3
2014	114	4	1,906	569.2
2015	114	4	2,215	686.9
2016	114	4	2,491	792.1
2017	436	17	2,068	649.4
2018	436	17	2,283	731.6
2019	436	17	2,296	736.5
2020	433	17	994	379.0
2021	432	17	1,158	439.7
2022	434	17	1,540	576.3
2023	1,871	138	1,084	411.6
2024	3,245	254	854	325.4
2025	3,164	247	857	326.2
2026	4,438	355	681	259.3
2027	4,330	346	733	278.6
2028	5,525	447	601	228.2
2029	5,630	456	1,025	380.8
2030	6,883	562	994	368.9

Source: Consultant Analysis

90. Table 23 shows the gas supply and demand balance until 2030. Annual gas consumption volumes reported above are converted to a daily gas volume basis in million cubic feet per day (MMcfd) and to a gas calorific value basis (in bbtud). These projections of fuel requirements were developed under the EMP's medium growth case and with the assumptions described in this report. The values listed for annual domestic gas supply for electricity were obtained from the NEMP.

Table 23: Least Cost Strategy – Gas Demand vs Supply for Electricity

Year	Gas Demand for Electricity		Gas Supply for Electricity
	MMcfd	bbtud	bbtud
2013	168.3	**124.7**	**201**
2014	184.4	**139.3**	**248**
2015	214.3	**168.1**	**261**
2016	241.0	**193.9**	**261**
2017	200.1	**159.0**	**261**
2018	220.9	**179.1**	**261**
2019	222.1	**180.3**	**272**
2020	96.2	**92.8**	**309**
2021	112.0	**107.6**	**302**
2022	149.0	**141.0**	**311**
2023	104.9	**100.7**	**306**
2024	82.7	**79.6**	**291**
2025	82.9	**79.8**	**259**
2026	65.9	**63.5**	**246**
2027	70.9	**68.2**	**235**
2028	58.1	**55.9**	**221**
2029	99.2	**93.2**	**219**
2030	96.2	**90.3**	**215**

Source: Consultant Analysis and Newjec NEMP 2014

91. Fuel requirements could increase under a higher forecast of demand. Information on power sector fuel requirements under such conditions, is elaborated in *The Project for Formulation of the National Electricity Master Plan in the Republic of the Union of Myanmar*, JICA, Dec 2014.

U. POWER DEVELOPMENT COST

92. To implement the EMP Reference Case Power Expansion Plan through 2030, the 2013 present worth of capital cost investment is approximately 10.5 billion US$ and O&M cost - including fuel cost – approximately 6.3 billion US$. Annual and cumulative discounted costs for the least cost plan are provided in Table 24.

Table 24: Least Cost Strategy – System Costs

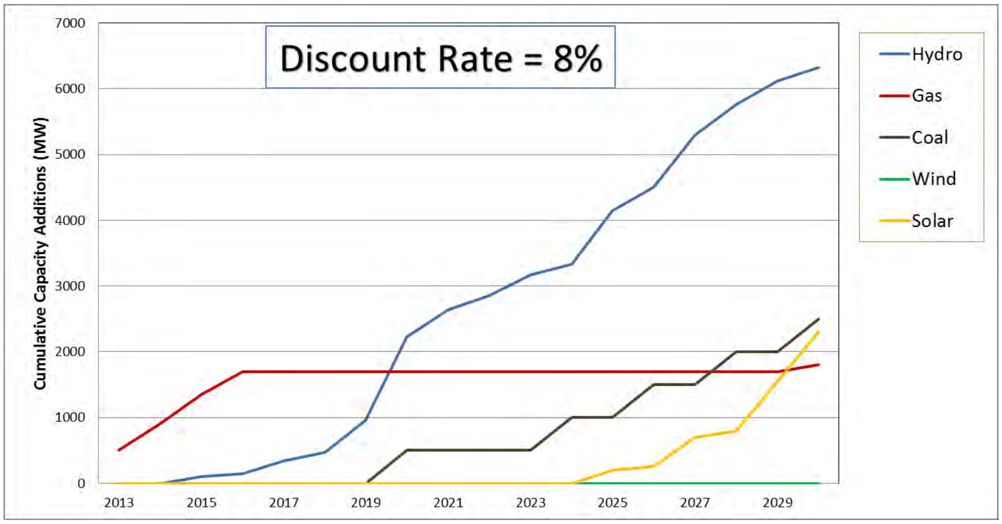
Year	Present Worth Cost of 2013 (K$)						LOLP
	Investment	Salvage	Operating	ENS	Total	Cumulative	
2013	447750	43193	529747	0	934,304	934,304	0
2014	364955	42437	543841	0	866,359	1,800,663	0
2015	577633	95479	597961	0	1,080,115	2,880,778	0
2016	371488	67079	626725	0	931,134	3,811,912	0
2017	337358	86702	492250	0	742,906	4,554,818	0
2018	202319	57370	497518	0	642,467	5,197,285	0
2019	716727	224176	456720	0	949,271	6,146,556	0
2020	1680017	579460	242759	0	1,343,316	7,489,872	0
2021	494619	188086	249267	0	555,800	8,045,672	0
2022	245665	102970	283401	0	426,096	8,471,768	0.001
2023	839197	361318	249663	0	727,542	9,199,310	0.001
2024	627856	297722	244182	2	574,318	9,773,628	0.002
2025	764621	422316	223178	10	565,493	10,339,121	0.005
2026	642136	381366	220639	15	481,424	10,820,545	0.007
2027	722096	483445	207245	51	445,947	11,266,492	0.019
2028	648417	476992	205838	73	377,336	11,643,828	0.026
2029	382266	310096	225382	751	298,303	11,942,131	0.224
2030	550771	495479	230694	877	286,863	12,228,994	0.269

Source: Consultant Analysis

V. EFFECTS OF DISCOUNT RATE ON LEAST COST PLAN

93. Sensitivity analysis was performed to evaluate the robustness of the identified least cost power expansion plan and assess the impact on the plan to changes in a number of key factors, including discount rate, potential schedule delays in commissioning of new hydropower plants, and environmental considerations.

94. To analyze the effects of discount rate on the least cost plan, planning studies were carried for discount rates of 8% and 5%. The sequences of plant additions for these cases are given in Figures 10 and 11.

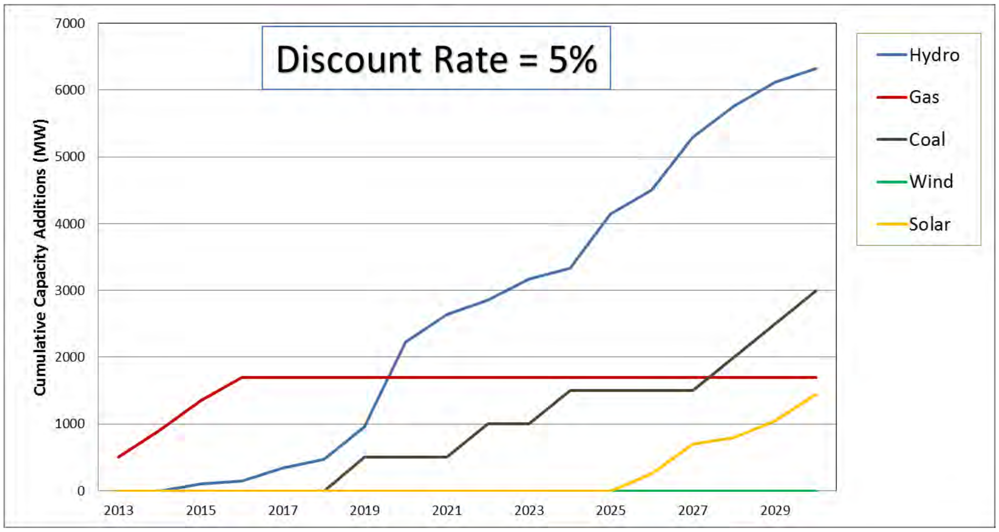


Source: Consultant Analysis

Figure 10: Sensitivity Analysis #1 – Discount Rate of 8%

95. Reducing the discount rate from 10% to 8% produces an expected result of accelerating the commission of capital intensive projects. All candidate hydropower plants are commissioned on their first year of availability and the timing of the first new coal unit moves forward from 2023 to 2020. The number and timing of candidate additions for gas, wind, and solar remains unchanged.

96. With a discount rate of 5%, the least cost plan once again commissions all candidate hydropower plants on their first year of availability. The timing of the first coal unit advances to 2019 and an extra unit is introduced bring the total amount of capacity added for coal to 3,000 MW. For the lower capital intensive candidates (e.g., solar and gas), the timing of new unit additions is delayed and number reduced.

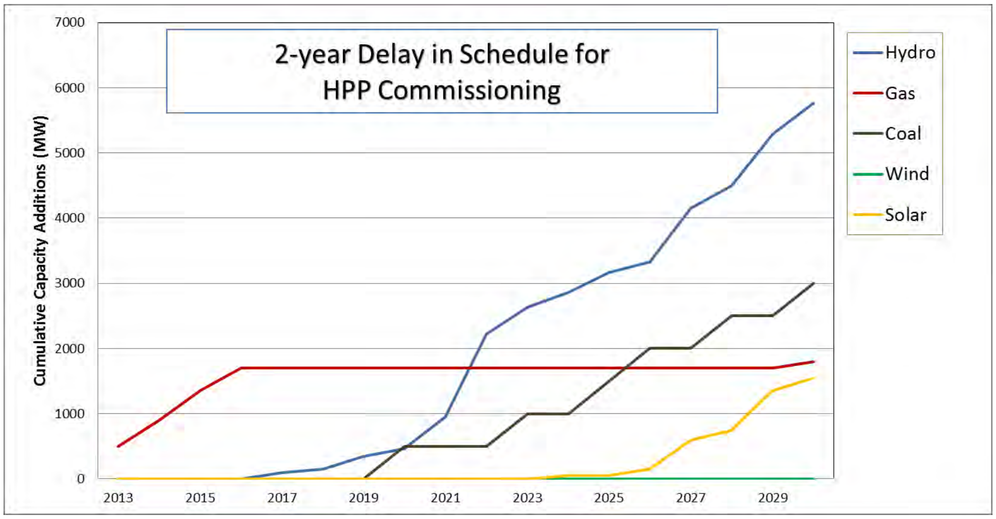


Source: Consultant Analysis

Figure 11: Sensitivity Analysis #2 – Discount Rate of 5%

W. EFFECTS OF HPP SCHEDULE DELAY ON LEAST COST PLAN

97. To analyze the effect of delays in hydropower plant commissioning on the least cost plan and associated fuel requirements, the least cost plan was re-optimized after adjusting the schedule of candidate hydropower project additions to delay the first year of availability for each candidate by two years. This case assumes that no new hydro project can be added before 2017. The resulting sequences of plant additions is displayed in Figure 12 and associated fuel requirements listed in Table 25. HPP schedule delays result in increased levels of gas consumption through 2019 followed by construction of six 500 MW coal power plants with the first commissioned in 2020.



Source: Consultant Analysis

Figure 12: Sensitivity Analysis #3 – Delay in Schedule for Candidate HPPs

Table 25: Sensitivity Analysis #3 – Fuel Requirements with HPP Schedule Delay

Year	Fuel Requirements for Electricity				Gas Supply for Electricity
	Coal	Gas	Gas	Gas	
	ktonne	million m^3	MMcfd	bbtud	bbtud
2013	114.0	1739.6	168.3	124.7	201
2014	114.0	1905.9	184.4	139.3	248
2015	114.0	2290.1	221.6	175.1	261
2016	114.0	2602.7	251.8	204.3	261
2017	436.5	2247.4	217.4	175.7	261
2018	436.5	2519.9	243.8	201.2	261
2019	436.5	2760.7	267.1	223.6	272
2020	1920.9	1618.8	156.6	148.6	309
2021	1920.8	1754.6	169.8	158.9	302
2022	1909.0	1238.9	119.9	114.8	311
2023	3280.1	771.7	74.7	72.0	306
2024	3324.4	1180.6	114.2	108.5	291
2025	4655.1	902.9	87.4	83.6	259
2026	5977.4	787.7	76.2	73.1	246
2027	5876.5	856.4	82.9	79.0	235
2028	7137.5	761.3	73.7	70.4	221
2029	7079.6	967.0	93.6	88.4	219
2030	8300.6	905.0	87.6	82.4	215

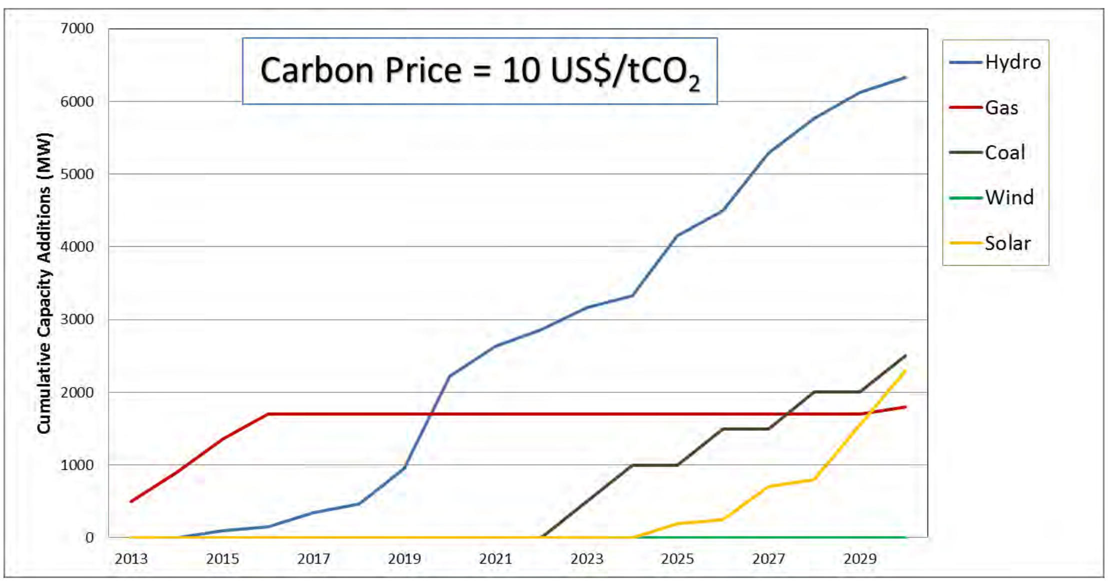
Source: Consultant Analysis and Newjec NEMP 2014

X. EFFECTS OF ENVIRONMENTAL CONSIDERATIONS ON LEAST COST PLAN

98. While this study focused on development of an economically optimal generation expansion strategy that satisfies specified reliability constraints, it is important to value both environmental protection and economic considerations in the development of an optimum solution.

99. One method of assigning a value to environmental protection, is through use of a carbon pricing mechanism. WBG's Carbon Pricing Watch 2015 brief notes the following recent carbon pricing developments: Beijing and Kazakhstan use a fee of 8 US$/t$CO_2$, Korea 9 US$/tCO_2, and France 15 US$/t$CO_2$.

100. To begin analyzing the effect of environmental considerations on the least cost plan, the expansion strategy was re-optimized using carbon pricing rates of 10 US$/t$CO_2$ and 15 US$/ t$CO_2$. The resulting sequences of plant additions are displayed in Figures 13 and 14.

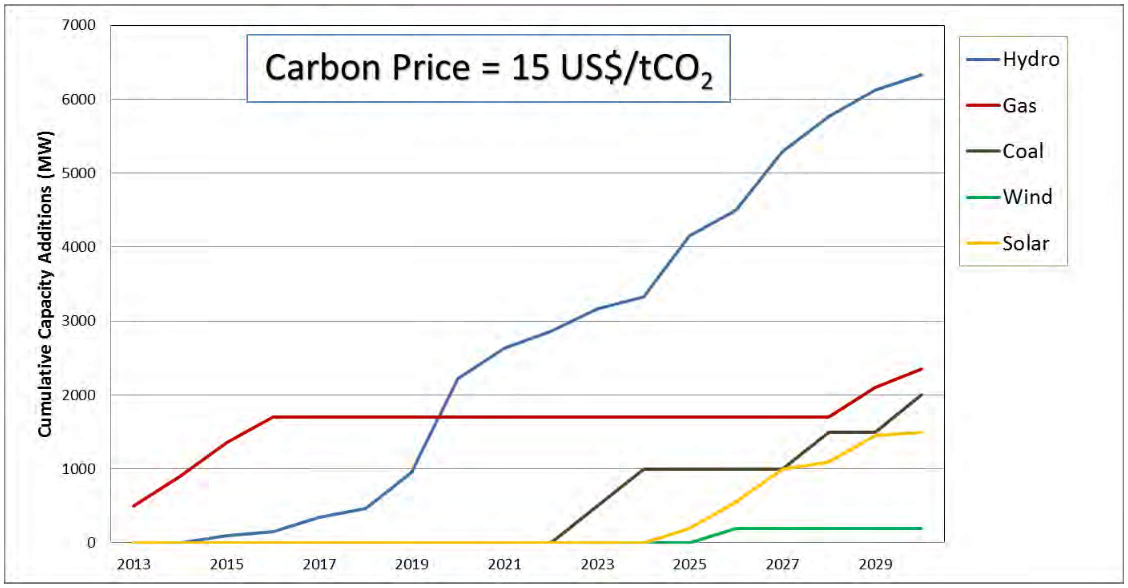


Source: Consultant Analysis

Figure 13: Sensitivity Analysis #4 – Carbon Price of 10 US$ per tonne CO_2

101. As illustrated in Figure 13, a carbon price of 10 US$/t$CO_2$ has little effect on the least cost expansion strategy. The schedule for commissioning of candidate hydropower plants is accelerated so that all HPPs are selected on their first year of availability. However, the number and timing of new unit additions remains unchanged for all other expansion candidates.

102. In contrast, Figure 14 illustrates that a carbon price of 15 US$/t$CO_2$ has a profound effect on the least cost expansion strategy. The schedule of new coal-fired units is delayed and number of units is reduced. As a substitute for coal, an additional 600 MW of gas-fired capacity is brought online, along with a total of 1500 MW of solar and 200 MW of wind.



Source: Consultant Analysis

Figure 14: Sensitivity Analysis #5– Carbon Price of 15 US$ per tonne CO_2

Y. Effects of Government Policy on Least Cost Plan

103. Upon reviewing the draft report of this power expansion study, responsible government agencies commented on the desire for increased diversification of energy sources in the national power expansion plan.

104. MOEP commented "it is necessary to develop diverse generation mix," and NEMC noted "We suggest modification should be made to the proposed expansion plan because the dependency on the hydroelectricity is relatively high during the mid-term."

105. NEMC provided further guidance noting "Although the expansion plan is based on least cost option, it still needs to encourage the renewable power generation. According to the discussion between MOEP and interested parties, it is also needed to consider the possible establishment of solar farms in the near future," and "the timing of introducing coal power plant in the ADICA's power expansion plan should be reconsidered."

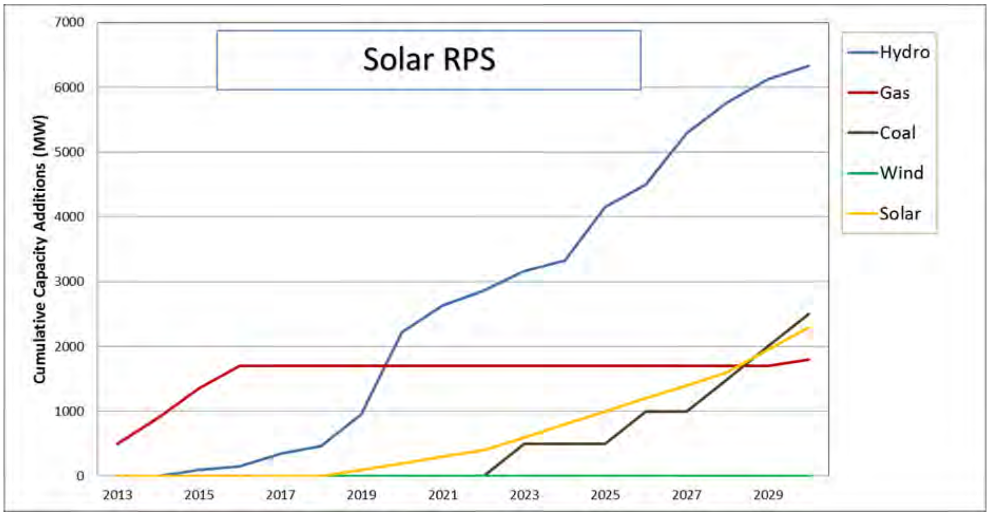
106. In response to the above comments, ADICA conducted additional sensitivity analyses to demonstrate how the WASP model can be used to evaluate the effect of potential government policies related to renewable energy integration and diversification of energy sources on the least cost expansion plan. The following three sensitivity cases were analyzed:

(i) Solar RPS: Establish a Renewable Portfolio Standard (RPS) setting a goal for 100 MW of new solar power integration each year from 2019 to 2022, 200 MW new solar added annually from 2023 to 2028. No RPS is needed in the last two years of the study when comparative economics of generation options results in higher levels of solar adoption.

(ii) Coal 2020: Consider potential government decision to advance timing of introducing new coal plants in the least cost plan by three years with first plant added in 2020.

(iii) Solar RPS + Coal 2020: Implement the Solar RPS and Coal 2020 policies in combination.

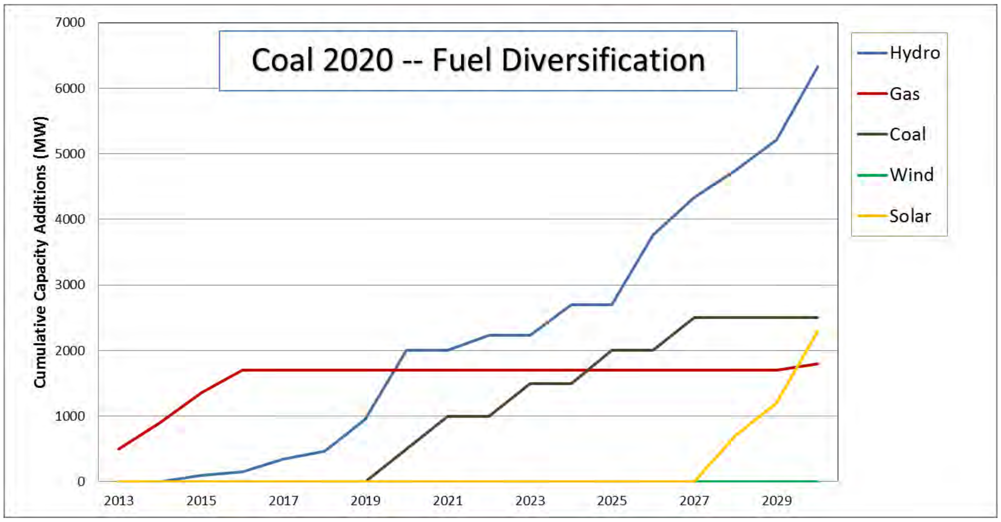
107. As illustrated in Figure 15, the impact of a Solar RPS policy as defined in 106.i is to delay the construction of the new coal-fired plants, and accelerate the construction of one hydro plant.



Source: Consultant Analysis

Figure 15: Sensitivity Analysis #6 – Solar RPS

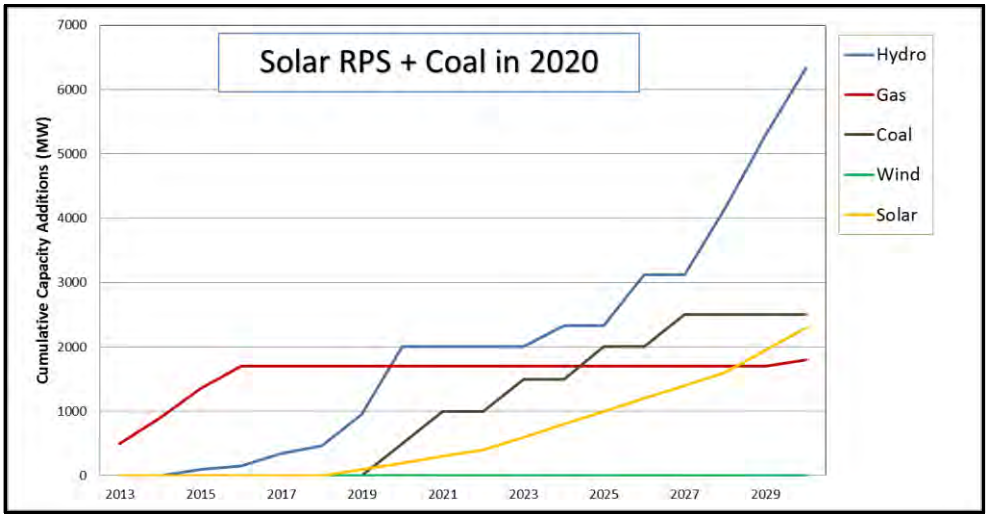
108. In contrast, Figure 16 illustrates the effect of a fuel diversification policy as defined in 106.ii, which delays the timing of new hydro and solar generation.



Source: Consultant Analysis

Figure 16: Sensitivity Analysis #7 – Coal 2020

109. The estimated effect of combining the RPS and fuel diversification policies is displayed in Figure 17, which shows a substantial reduction in the reliance on hydroelectricity in the mid-term.



Source: Consultant Analysis

Figure 17: Sensitivity Analysis #8 – Solar RPS + Coal 2020

110. As noted in Table 26, government policies can have a profound impact on the capacity mix and total cost associated with the national power expansion plan.

Table 26: Impact of RPS and Fuel Diversification Policy on Capacity Mix and Total Cost

Least Cost	2020		2025		2030	
	MW	%	MW	%	MW	%
Hydro	4,715	66	6,640	65	8,818	55
Gas	2,274	32	2,274	22	2,374	15
Coal	120	2	1,120	11	2,620	16
Solar	0	0	200	2	2,300	14
Present Worth of Cummulative Costs (2013$)			$12,228,994,000			
Solar RPS	**2020**		**2025**		**2030**	
	MW	%	MW	%	MW	%
Hydro	4,715	65	6,640	63	8,818	55
Gas	2,274	31	2,274	22	2,374	15
Coal	120	2	620	6	2,620	16
Solar	200	3	1,000	9	2,300	14
Present Worth of Cummulative Costs (2013$)			$12,396,110,000			
Coal 2020	**2020**		**2025**		**2030**	
	MW	%	MW	%	MW	%
Hydro	4,499	61	5,189	54	8,818	55
Gas	2,274	31	2,274	24	2,374	15
Coal	620	8	2,120	22	2,620	16
Solar	0	0	0	0	2,300	14
Present Worth of Cummulative Costs (2013$)			$12,359,010,000			
Solar RPS + Coal 2020	**2020**		**2025**		**2030**	
	MW	%	MW	%	MW	%
Hydro	4,499	59	4,825	47	8,818	55
Gas	2,274	30	2,274	22	2,374	15
Coal	620	8	2,120	21	2,620	16
Solar	200	3	1,000	10	2,300	14
Present Worth of Cummulative Costs (2013$)			$12,603,830,000			

Source: Consultant Analysis

Z. Comparing the Least Cost Strategy with Other Options

111. To identify an expansion strategy that best meets national goals for a sustainable, reliable, and competitive electricity supply, we recommend evaluating alternative expansion strategies with respect to key performance indicators, like the following:

a) *Sustainability* of an expansion strategy assessed in terms of air pollutant emissions over the study period and amount of renewable energy in the national capacity mix in 2030.

b) *Reliability* assessed in terms of system LOLP and security of energy supply in 2030.

c) *Competitiveness* of an expansion strategy assessed in terms of total discounted system cost over the study period, total revenue obtained from the placement of a value on CO_2 emissions, and the associated foreign fuel bill.

112. Summary results for the least cost plan displayed in Table 27 can be used in comparing this plan with alternative expansion strategies developed under a consistent set of assumptions.

Table 27: Summary Results of Least Cost Plan for Key Performance Indicators

GOALS	Key Performance Indicators		Units	Least Cost
Sustainable	Emissions over study period	CO_2	M tonnes	114.8
		SO_2	M tonnes	19.0
		NO_x	M tonnes	21.0
		PM10	M tonnes	5.8
	Renewable energy in system in 2030		%	14.3%
Reliability	Loss of Load Probability in 2030		%	0.269%
	Security of energy supply in terms of total fuel consumed over study period	Coal	k tonnes	38,152
		NGas	M m^3	25,520
Competitive	Total discounted system cost over study		k $	12,228,994
	Total discounted revenue from CO_2 fee		k $	-
	Foreign fuel bill		Qualitative	Lower NGas

Source: Consultant Analysis

113. Linking the comparison of alternative expansion strategies to key performance metrics highlights the costs and benefits of each option and provides useful information for decision making on power system expansion.

114. The following section highlights issues recommended for consideration in future transmission system planning.

IX. TRANSMISSION DEVELOPMENT

115. It is difficult to assess the corresponding transmission development plans to match the generation expansion plans for the medium growth case without estimates of individual substation load growth to perform detailed load flows of the power system. The EMP study provided regional demand estimates that could have been used to estimate substation loads but the study but did not perform the necessary load flows to establish transmission requirements. The EMP regional forecasts however showed that there would significantly higher growth outside Yangon which more closely matched the high load demand case.

116. For the forecast high case study, Newjec provided substation load estimates based on pro-rata growth rates assuming all regions would develop at the same rate. This indicated the total matching transmission investment would be $2.37b to 2020 and an additional $3.38 by 2030 for a total investment of $5.75b. Newjec included provision for a second 500kV line to be built in parallel with the 500kV line that is currently committed for completion by 2020. Newjec also considered other transmission arrangements for the high demand case necessary to evacuate large amounts of hydro power from northern areas of Myanmar to the southern load centres using an HVDC link. However, this would increase the total investment by a further $2.2b. Their analysis indicates that if it was possible to develop hydro resources faster than appears feasible at present, it would be necessary to look at alternative ways of staging the investments of the 500kV and HVDC lines to effect the north south power evacuation requirements to meet the medium growth case.

117. Separately the consultants Fichtner[14] prepared a transmission investment plan using pro-rata load growth estimates corresponding to the medium demand forecast. Their investment requirements to 2025, with provision for the ongoing 500kV line construction included, is summarized below and corresponds closely to the first stage of the Newjec estimates for transmission investments to 2020. Without more detailed analysis this combined investment program should therefore be considered a proxy for the investment needs for the medium forecast.

Table 28: Transmission Projects identified by Fichtner/MOEP [14]

Summary of Transmission Projects Identified By Fichtner/MOEP					
Priority Investments for 2017-2025	IPP	Transmission		S/S	Total
	MW	km	US$	US$	US$
Connection of Power Plants	5064	1022	554	339	893
Connection of new Areas NEM Project		975	365	187	552
500kV Backbone system (MOEP)		1795	1077	149	1226
Strengthening of Network		408	143	78	221
Total Transmission Investments		4200	2140	753	2892

[14] See ADB - TA 8342 MYA Preparing the Power Transmission and Distribution Improvement Project, Fichtner October 2014

118. Notably neither Newjec nor Fichtner considered the issues that can be expected to arise as a result of developing hydro projects on a shared basis with Yunnan and/or Thailand. As noted in Annex A, one solution is to operate a hybrid transmission interconnection arrangement using 500kV and HVDC systems connected in parallel with each other. This mode of operation will provide a continuous interconnection between all three parties that should increase flexibility and security of supplies to both systems. The proposed interconnection arrangement is adapted from one of the scenarios proposed in the 2014 MOEP-NEMP. It indicates that it may be feasible to build the HVDC line, in advance of the second 500kV line, to meet the base load. The proposal should be studied further when the NEMP masterplan is revised.

X. OBSERVATIONS AND RECOMMENDATIONS

119. This power planning study had as objective to apply the WASP IV model in identifying an economically optimum generation expansion plan under the EMP's medium growth case, and was successful in developing the reported least cost power expansion plan.

120. It is important to keep in mind that the role of the energy planner is not do develop “the plan” to be implemented. Rather, energy planning involves analysis of the energy system with the intent of providing decision makers information that will enable them to make informed judgments on strategies needed to meet current and future energy objectives.

121. This study provides useful information for decision making on energy development in Myanmar, including but not limited to the following observations:

a) The national power expansion plan designed to meet the EMP medium growth forecast of 9.6% CAGR on a least-cost basis shows hydroelectric and gas-fired generation playing a dominant role in meeting the countries electrical needs through 2021 – at which time coal, then renewables become viable candidates.

b) Under the least cost expansion plan, natural gas demand for electricity generation is not expected to exceed the NEMP-reported limit of domestic gas supply allocation for the power sector through 2030. Still, sufficient natural gas supply for power production is essential for reliable supply of electricity – particularly in the case of delays in HPP construction.

c) Based on the assumed technical and cost parameters for the EMP national power expansion plan, which are consistent with the NEMP, hydro power generation is the most economic supply option followed by coal. All thirty-eight hydropower candidates (totaling 6,328 MW), and 2,500 MW of coal-fired capacity are selected for construction in the least cost expansion plan. Reducing the discount rate below the value of 10% assumed in this study results in capital intensive coal and hydro candidates becoming even more competitive as compared with gas and solar.

d) In evaluating the potential role of coal-fired power plants in the least cost expansion plan, this study determined that, under the EMP medium growth forecast and assumptions listed in this report, new coal-fired generation is not economically justifiable before 2023. However, sensitivity analyses highlight that new coal could be required earlier in response to delayed commissioning of new hydro power plants or a reduction in the forecasted supply of natural gas available for electricity generation.

e) Sensitivity analysis related to hydro power plant commissioning points to a 2-year delay in the schedule of HPP additions resulting in increased levels of gas consumption through 2019 followed by construction of six 500 MW coal power plants with the first commissioned in 2020.

f) This study investigated the viability of large-scale renewable energy projects by evaluating wind and solar energy candidate projects in the context of the least cost generation expansion plan and identifies substantial potential for solar PV. Contributing factors include: (i) declining price of PV, (ii) renewable potential for solar being high in locations close to the grid and major load centres, (iii) Myanmar's largely hydro based system with significant spinning reserve capability, and (iv) the strong seasonal variations of solar and hydro energy potential in the country complement each other over the year.

g) While this study focuses on development of an economically optimal ("least cost") generation expansion plan that satisfies specified constraints on system reliability, it is important to value both environmental protection and economic considerations in development of an optimum strategy for the country. One method of assigning a value to environmental protection is through use of a carbon pricing mechanism. Results of sensitivity analyses point to a price of 15 US$/t$CO_2$ having a profound effect on the least cost expansion strategy – reducing the number of new coal-fired units, increasing gas-fired capacity by 600 MW over the least cost plan, and adding a total of 1,500 MW of solar and 200 MW of wind energy through 2030.

h) Sensitivity analyses further demonstrate that government policies related to renewable energy integration and diversification of energy sources can have a profound impact on the least cost power expansion plan and substantially reduce the reliance on hydroelectricity.

122. In the conduct of this study, a number of enhancements were made to the national WASP IV database and power system planning process. To maximize the benefits from this effort, we recommend that WASP IV training be provided to MOEP and NEMC staff through ongoing capacity building initiatives organized with the ADB and JICA.

123. As planning is a process, the power system expansion plan should be revised annually by MOEP according to updated information and assumptions related to energy demand, fuel prices and availability, government policies, etc. Suggested priority issues warranting further consideration in the next update of the national power expansion plan, include:

i) *Hydropower Development*: Due to limited availability of information on candidate hydro plants, the EMP expansion planning study used an average cost of new hydro developed by Newjec and applied aggregated characteristics of existing HPPs to develop initial estimates of seasonal operations for new hydro candidates. The ADB consultants agree with earlier comments by the WBG, that "a proper hydropower development study is needed to … optimize hydropower development." We note that a Norwegian effort over the next 18 months intends to upgrade MOEPs hydro data base and recommend that this effort also be deployed to capture information tailored to represent hydro capital cost and operational data for the WASP database. In parallel with the data collection effort, we recommend that MOEP consider complementing the current WASP-based planning with use of additional models that are able to capture the stochastic representation of hydropower that is lacking in WASP. For example, WASP is regularly run together with the VALORAGUA model (and others) for systems with a substantial amount of hydro.

j) *Natural Gas Price for the Power Sector*: The EMP expansion planning study assumed $11.2 per mmBTU as the price of natural gas to the power sector, which is the MOE-proposed gas price to MOEP and is consistent with the value used in the JICA-supported MOEP's NEMP. We note that WBG is carrying out a gas price study and suggest that results of this study will enhance understanding on appropriate economic value of gas in the country and should be reflected in future updates of the national power expansion plan.

k) *Demand Forecast and System Load Characteristics*: The current study defined seasonal load characteristics based on actual hourly loads in 2014 and uses the medium growth forecast of peak load and generation requirements developed in the EMP study. It is advised for MOEP to acquire and apply a tool such as the IAEA's Model for Analysis of Energy Demand (MAED) for forecasting electricity demand. MAED provides a systematic framework for mapping trends and anticipating change in energy needs corresponding to alternative scenarios for socioeconomic development and producing an associated hourly load forecast.

l) *Integrated Generation and Transmission System Planning:* Modeling the generation and transmission system in an integrated manner is more important in hydro-dominated power system because of significant investment cost of transmission connections between load centers and relatively remote hydropower plants. In addition, properly managed, hydro reservoir storage can deliver benefits in moderating seasonal variations in electricity supply due to changing water inflows and balancing hourly variability in generation from future renewable energy sources. It is recommended that MOEP should acquire suitable planning tools and build institutional capacity for developing an integrated generation and transmission plan for the country. Analyses to support the integrated plan should: (i) address short term system operation and stability issues at a higher level of detailed (e.g., hourly simulation) than is computationally possible with current long-term planning models, (ii) evaluate the value of hydro storage capacity in prioritizing the hydro development program, and (iii) identify transmission lines which are highest priority to support generation expansion and regional integration.

Annex A
Transmission Interconnection Strategy for Hydro Exports to GMS Countries

Transmission Interconnection Strategy for Hydro Exports to GMS Countries

Myanmar has considerable hydroelectric resources, some of which the Gov't wishes to develop to export power to its neighbours, notably China and Thailand. Some larger potential hydro sites located close to the borders with both countries have been identified as potential resources that could be developed on a shared basis. In particular, there are a group of hydro stations in northern Kachin state with an aggregate potential of 8835MW near the border with Yunnan, along with the proposed 7000MW Ta Sang[15] scheme in Shan State near the border with Thailand.

For some of the border projects, the Gov't envisages that a joint development agreement could be arranged so that up to 50% of the hydro power output could be evacuated to the major load centres in Yangon and Mandalay with the other 50% exported under a Power Purchase Agreement (PPA). Recently there has also been a suggestion that China may have excess hydro power in the short term and could be interested in exporting surplus power to Myanmar.

Since there are currently no plans to synchronise the three adjacent power systems of Yunnan, Thailand and Myanmar, it has been suggested that the busbars of the border hydro generating units should be separately synchronised the respective power systems in the border countries. This mode of operation will be difficult to operate safely and could cause system operational difficulties. Faults that occur on one or other of the transmission systems and will reduce the security and reliability of service from the hydro stations.

This paper therefore proposes that a feasible solution would be to operate a hybrid transmission interconnection arrangement using 500kV and HVDC systems connected in parallel with each other. This mode of operation will provide a continuous interconnection between all three parties that should increase flexibility and security of supplies to both systems. The proposed interconnection arrangement is adapted from one of the scenarios proposed in the 2014 MOEP-NEMP and will also provide the lowest cost means of supplying bulk power from the northern states to the southern load centres of Myanmar.

Myanmar National Electricity Master Plan MOEP-NEMP (JICA-NewJec)

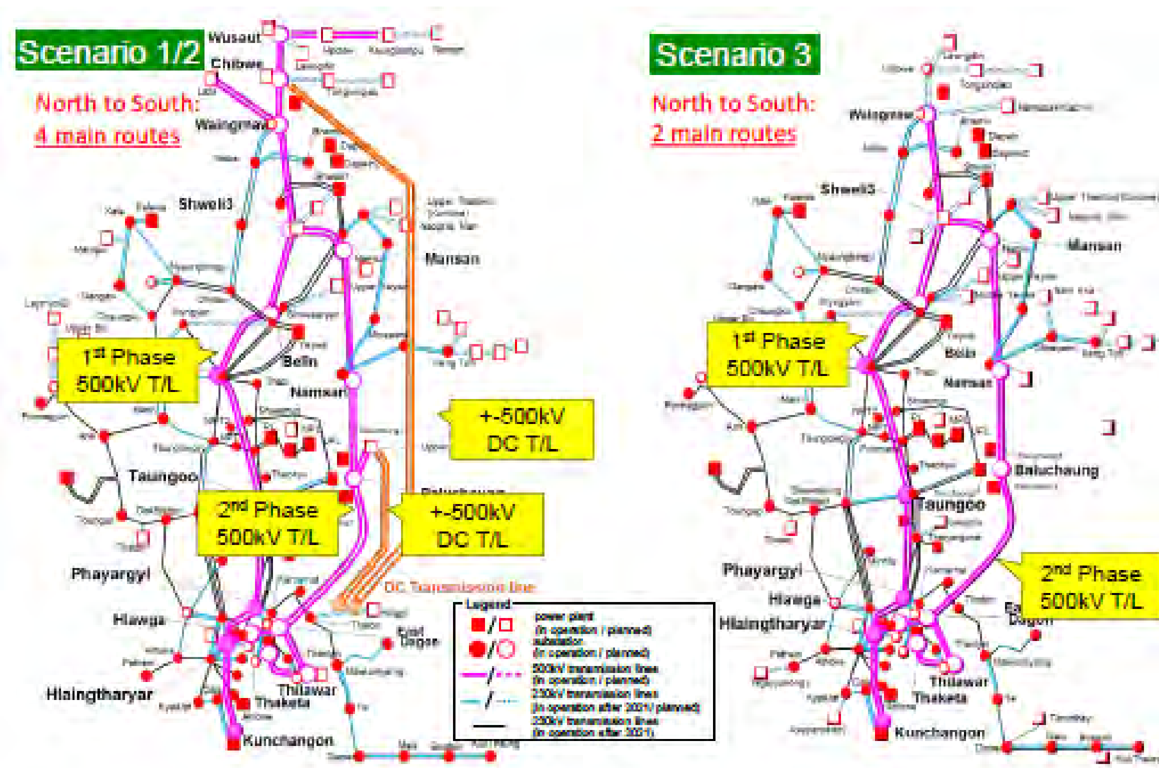
The MOEP-NEMP completed in December 2014 proposes various interconnection arrangements for evacuating hydro power from the north to the south of Myanmar assuming these projects would be developed to meet a high demand growth scenario. Two of the MOEP-NEMP proposed Scenarios (1/2) as shown below suggest the concept of building parallel 500kV and HVDC circuits are best suited to evaluate large amounts of hydro at least cost to Yangon. However, the NEMP does not indicate how the three power systems could be interconnected to maintain security and reliability of the respective networks. Nor does the plan suggest the order in which the transmission projects would be developed if demand grew more slowly – in accordance with a medium demand scenario.

Notably many of the proposed larger hydros in the MOEP-NEMP generation expansion plan (Yenan-1200MW, Kaungglanphu-2700MW, Pisa-2000MW, Wutsok-1880MW, Lawngdin plus three others-1055MW) are grouped together in the border area of the Kachin state. Some of these plants are

[15] https://en.wikipedia.org/wiki/TaSang_Dam

included in the WASP generation expansion scenarios based on the assumption that 50% of hydro output will be exported to China and 50% evacuated to Myanmar.

<u>MOEP-NEMP Transmission proposals for Three Scenarios of Generation Expansion</u>



Notably the transmission arrangements shown above indicate the Myanmar system will be synchronised with China although there are no such plans under consideration. An alternative proposal would be to synchronise all of northern hydro plants with China, and separate the two respective Mynamar and Chinese 500kV systems at the future Myitsone hydro (6000MW) project substation. To enable Myanmar to continuously evacuate its 50% share of hydro power from the future Kachin plants, as well as any surplus power from China, it would therefore be desirable to advance the building of the proposed HVDC line to Yangon (i.e. build it ahead of the proposed second 500kV line programmed in Scenario 1/2and 3). However, to simplify operations the 500kV and HVDC terminal should be at the Myitsone 500kV busbars (instead of Chibwe as shown above). At a future date when/if the huge 6000MW Myitsone hydro station is built it may be appropriate to consider installing an HVDC b/b facility interconnecting the station 500kV busbars.

Since the proposed bipolar HVDC line will be about 1100km[16] long, it would be significantly cheaper to build than an equivalent 500kV d/c line and would offer the advantage of providing increasing stability

[16] When comparing HVAC and HVDC the cost crossover where HVDC is much cheaper is about 400-700km depending on the volume of power transmitted: http://electrical-engineering-portal.com/analysing-the-costs-of-high-voltage-direct-current-hvdc-transmission

and security of supplies at the Yangon and Myitsone 500kV busbars. Moreover, the HVDC line can be designed so its capacity can be upgraded in (say) 1500MW stages (e.g. by changing from a monopolar to bipolar configuration, and/or by incrementally increasing terminal capacity and/or operating voltages from (say)±400kV to ±800kV). Because an HVDC line would operate in parallel to the underlying 500/230kV HVAC systems, it could be developed for private sector financing and/or operation on the basis a long term BOT contract with revenues based on agreed availability charges.

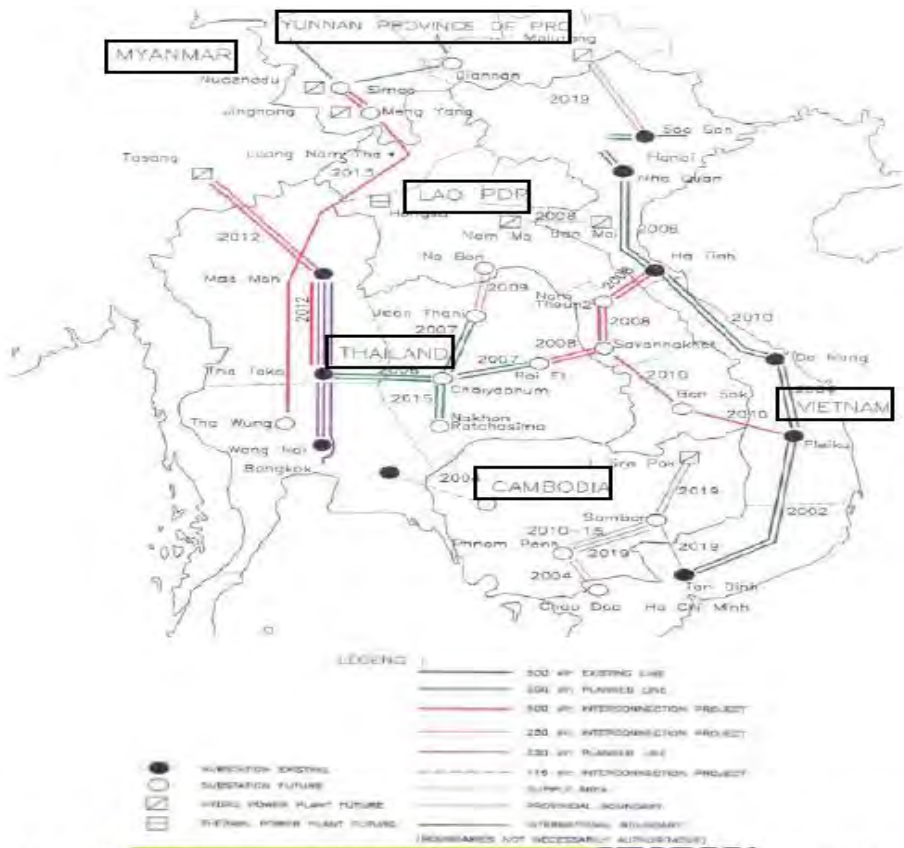
Proposals for Myanmar-GMS Interconnections

As a member of the Greater Mekong Subregion (GMS) Mynamar needs to consider ways in which its transmission export projects are compatible with GMS interconnection planning. As shown below a recent GMS Road Map includes a plan (a) to extend 500kV lines from Tha Wang S/S (substation) in Thailand to Meng Yang S/S and Simao S/S in Yunnan China- the latter will presumably be connected to the large HVDC terminal at the Chuxiong converter station[17]; and (b) to build a new 500KV line from Mae Moh S/S to Ta Sang S/S in Shan State. This arrangement however does not address or explain how the three currently asynchronous power systems will be interconnected – in fact it implies that Thailand, Myanmar and Yunnan will all be synchronised with each other[18]!

[17] The Yunnan-Guangdong project has a rated voltage of an ±800-kV dc, a capacity of 5,000 MW and a transmission distance of 1,418 km (881 miles). The main parts of the system are the Chuxiong converter station, the Suidong converter station, the dc transmission lines and electrodes at both ends

[18] This is probably the most important technical issue that needs resolution in the next five years. It is generally accepted that HVAC power systems must be synchronised to safely and optimally manage generation and power flows under various operational conditions.

Masterplan for GMS EHV Grid Integration (June 2013)



Source: "The GMS Road Map and Work Plan for Expanded Energy cooperation" (from materials presented at the second Subregional Forum).

Potential for HVDC Interconnections within GMS

Within the South East Asian subcontinent, most of the GMS cross border transmission proposals propose the use 500kV interconnections. While HVDC links are also proposed in a few situations this is largely because it is not practical to have long HVAC submarine cables (e.g. as required between Malaysia to Sumatera and Java-Sumatera). However, HVDC is increasingly being recognised as a suitable technology for interconnecting regional grids particularly where these are relatively small with long distances between main generation and load centres.

HDVC is indeed being used in both within China and India to link their various states together and to transfer large amounts of power over long distances. In this respect HVDC is much easier to control than HVAC and can link systems together without having to be concerned about local synchronisation issues. Unlike HVAC, HVDC links can be turned on/off, as power flows transferred up or down in response to system control instruction or as required by commercial load transfer requirements. There is clearly opportunity for ASEAN countries to make the technological leap beyond 500kV HVAC lines and consider the possibility using HVDC links for easily controllable power exchange within the GMS regions[19].

Notably even in the EU, where the UCTE operates a relatively tight 400kV networks, grid integration with the remoter EU systems (e.g. Scandinavian countries, UK, Eastern Europe) is being enhanced by a number of HVDC links. Moreover, there is considerable discussion within the EU about the need for a future HVDC grid overlay to facilitate power exchange between regions[20]: Part of this revived interest in HVDC is because the HVDC technology is increasingly being employed to integrate large intermittent offshore wind farm production into onshore HVAC grids. As a consequence, the limitations the older variety of HVDC (as used in the NZ HVDC link for the last 50 years) are being addressed using the versatility of modern electronic control systems[21].

[19] HVDC can be extended into neighbouring countries in much the same way as proposed for the WB funded CASA 1000 project linking Tajikistan, Afghanistan and Pakistan: http://www.casa-1000.org/

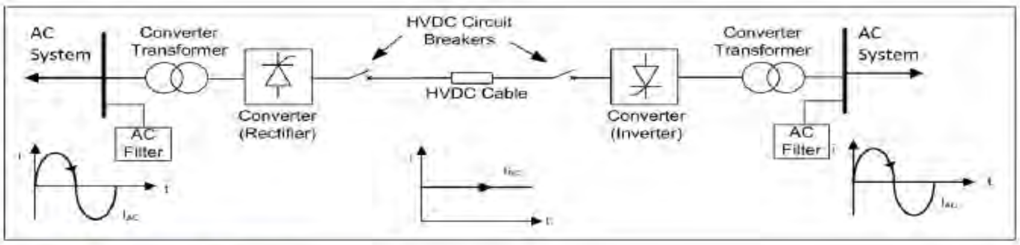
[20] https://en.wikipedia.org/wiki/Super_grid

[21] https://en.wikipedia.org/wiki/Intermittent_energy_source

Characteristics of HVDC Systems

For point-to-point transmission of bulk power over 500 km or more, HVDC transmission links can normally be built at a lower overall cost than conventional HVAC lines. Although HVDC transmission lines can be constructed at about 50% of the cost of an equivalent HVAC line, the cost of the necessary HVDC/HVAC converter stations are about $120/kW, compared with $20/kW for a conventional HVAC/HVAC substation.

Typical HVDC Interconnection Arrangements



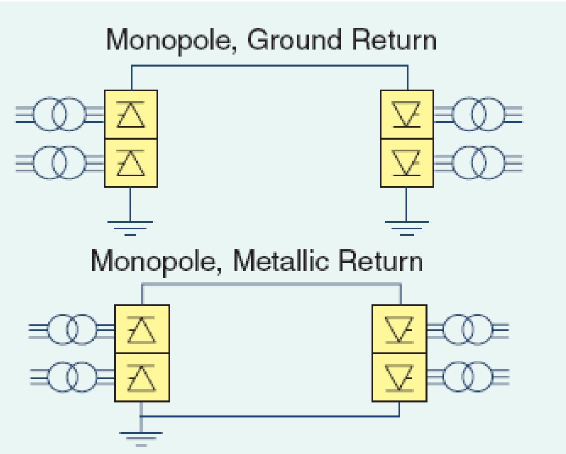
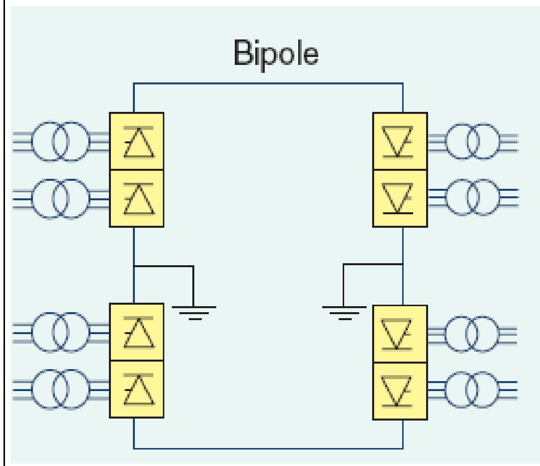
An HVDC interconnection for interconnecting asynchronous systems is sometimes effected with an HVDC back-to-back (b/b) facility, thereby enabling adjacent power systems to maintain their own system frequencies independently of the other. HVDC effectively enables two power systems to be interconnected without having to re-synchronize after every forced or planned disconnection. However, in considering an HVDC b/b facility, it is prudent to also consider building a long HVDC transmission interconnection instead to achieve the same objective at much lower cost. HVDC is also used in many countries, in parallel with HVAC systems, to improve system stability at both ends of the HVDC line as well as moving power more economically over long distances. In effect, HVDC can be designed to act as a very fast FACTS operating device designed to inject power into the HVAC system and counteract inherent instability problems.

Although HVDC technology has many years of operational experience,[22] new control systems have been developed recently which reduce cost and improve flexibility and performance. This is based on modern, newly developed voltage source converters (VSC[23]) with series-connected insulated gate bi-polar transistor (IGBT) valves controlled with pulse width modulation (PWM) that have already reached levels of 1,200 MW and ±500 kV. Notably, HVDC can also be built in stages to increase loading, as required. This can be done by first building the line for monopole operation, then later uprating to bipole operation – and, if necessary, uprating again using a higher operating voltage. Provided that the line is designed for its ultimate operating configuration (at little extra cost), the cost lies primarily in uprating the HVDC/HVAC terminals at each end of the lines.

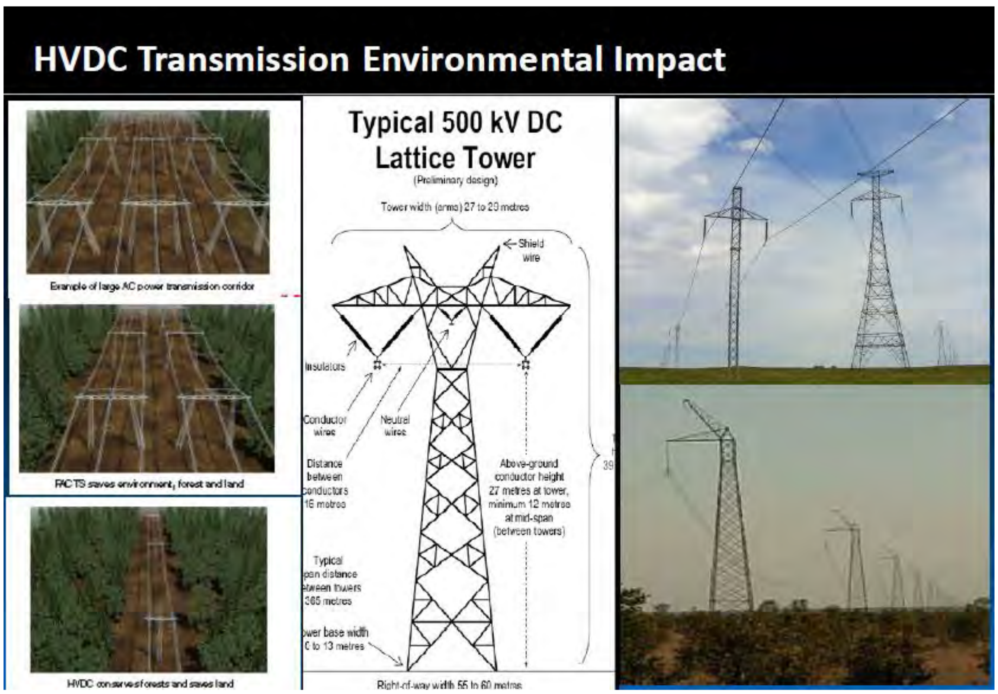
22 HVDC was originally developed to supply large volumes of power over long distances. The first large-scale commercial project was installed in 1965 in New Zealand where a 600 MW HVDC line was built to carry power from the South Island 600 km to the North Island. This has operated very reliably for over 45 years and was recently upgraded to 1,400 MW. Over 200 HVDC systems have been built over the years. The longest HVDC link in the world is currently the 2,071 km ±800 kV, 6,400 MW link connecting Xiangjiaba Dam to Shanghai in the People's Republic of China.

23 e.g., ABB’s HVDC Light, Siemens HVDC Plus, Alstom’s HVDC Maxsine.

Uprating HVDC Interconnection from Monopole to Bipole Configuration

HVDC Monopole Configurations	**Monopole Uprated to Bipole Configuration**
	

It is also important to note that HVDC lines have a much smaller environmental footprint than HVAC which is especially important for crossing mountainous forested areas as typically exist in Myanmar. The picture below (left) compares the ROW requirements for a typical 500kV triple and double circuity 500kV line with the equivalent capacity HVDC line (left-bottom). The pictures below (right) show the equivalent ROW requirements for two bipole lines (right-tope) and a monopole line with earth return (right-bottom).



HVDC versus HVAC Costs

It would be difficult to compare the cost of developing the HVAC and HVDC solutions without taking into account the stages of development of the hydro resources, the strategy for synchronisation between countries and the respective quantities of power planned to be exported over time to Myanmar, China and Thailand. It can be generally stated that for the distance involved (1100km) the unit costs associated with the transfer of about 2400MW of through an HVDC bipole system would be about 0.52 $/MW.km compared with an HVAC solution of about 0.86 $/MW.km[24].

The table below shows a comparison of the total investment cost might be expected to change for the transfer of up to 6000MW over distances of 320, 640and 1290km.

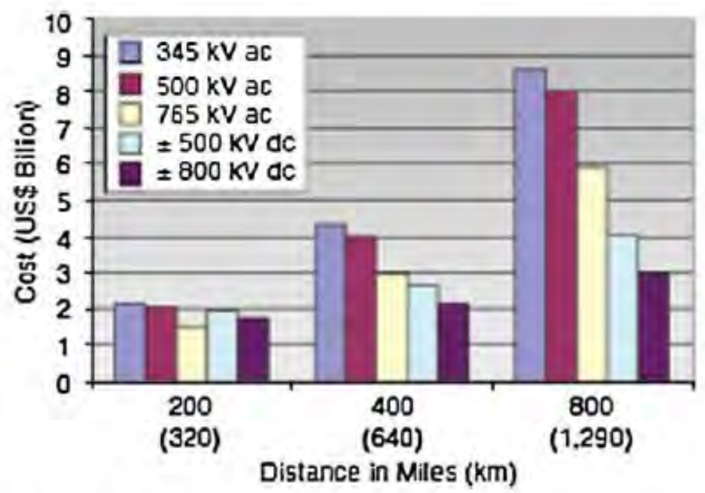


Fig. 9. HVDC and EHVAC investment cost comparisons for 6000 MW capacity.

Proposed Interconnection Arrangement for Myanmar-Yunnan-Thailand

The proposed adaption of the MOEP-NEMP 500kV-HVDC arrangement is shown geographically over page and in the schematic diagram below. 500kV lines are shown in red, HVDC lines in orange. The geographic picture has utilized Google Earth design features to select possible routes along valleys or near existing roads. In the schematic drawing details of the Thailand and Yunnan substations connections, and cross border lines are not shown but could be inserted in the diagram when more information is available. The picture however shows the two areas of Myanmar that could be operated in synchronism with China and Thailand.

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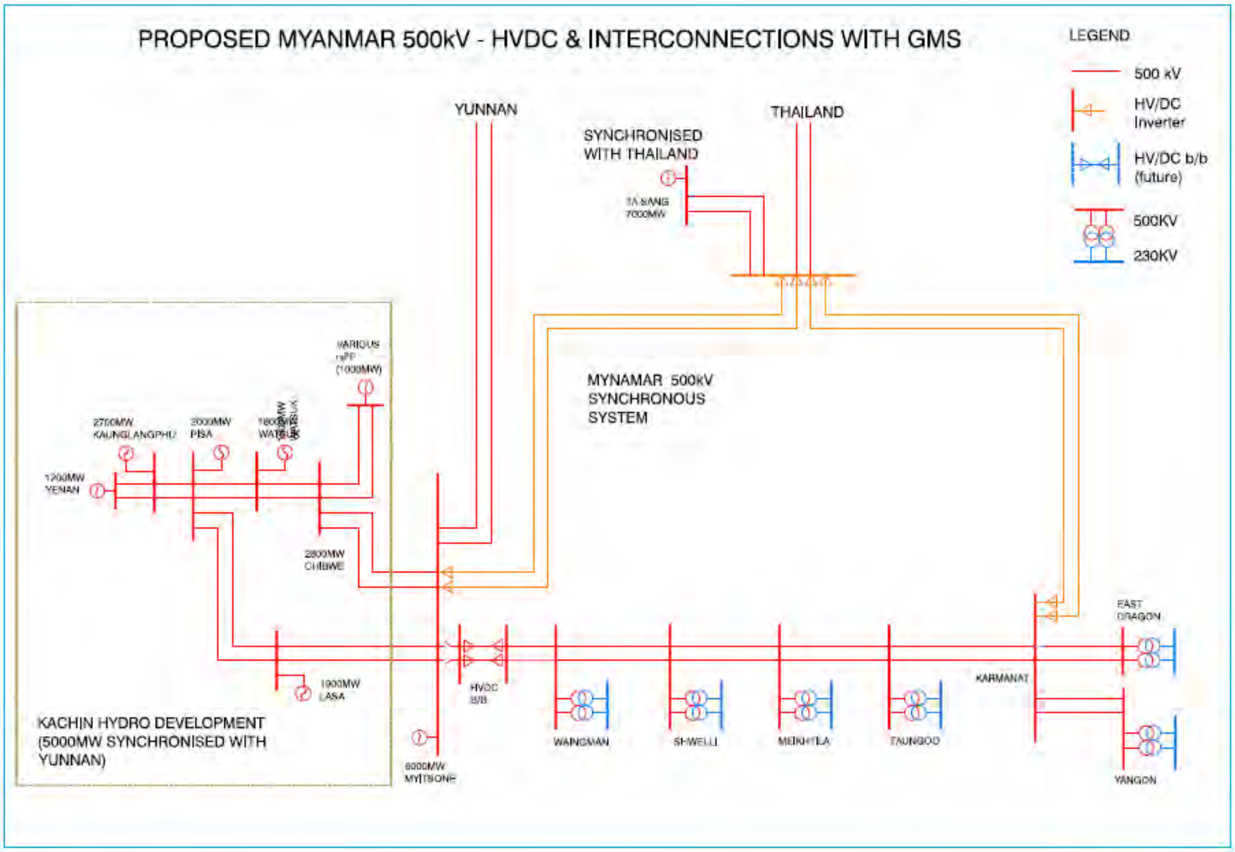
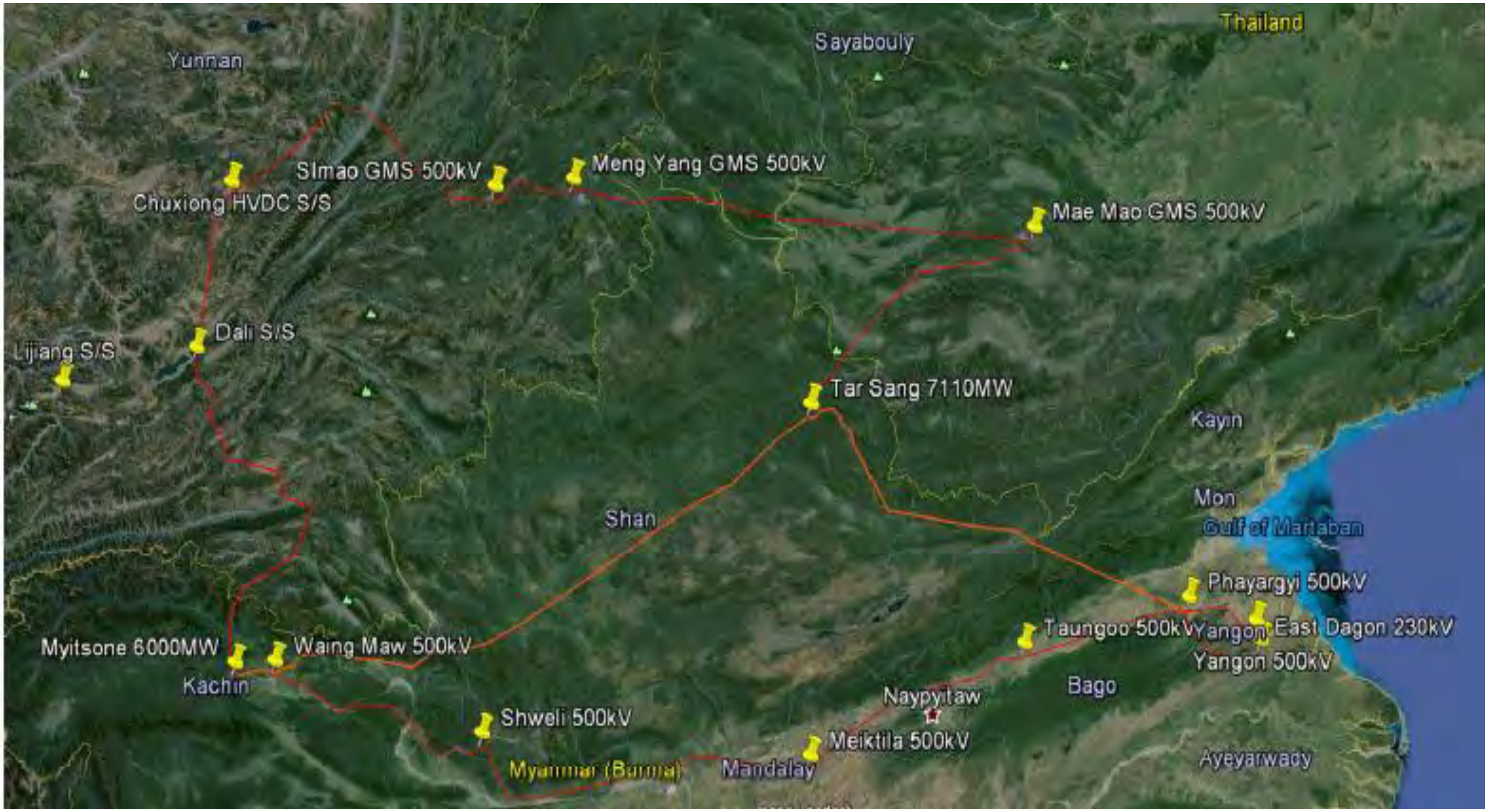
[24] The cost of power transferred under the different technologies is derived from Table xx of the paper: "A survey of transmission technologies for planning long distance bulk transmission overlay in US" James D. McCalley, Venkat Krishnan, 14 August 2013 The paper can be downloaded from ScienceDirect Electrical Power and Energy Systems: www.elsevier.com/locate/ijepes


PROPOSED MYANMAR 500kV - HVDC & INTERCONNECTIONS WITH GMS
LEGEND
500 kV
HV/DC Inverter
HV/DC b/b (future)
500KV
230KV
YUNNAN
THAILAND
SYNCHRONISED WITH THAILAND
TA SANG 7000MW
MYNAMAR 500kV SYNCHRONOUS SYSTEM
VARIOUS HPP (1000MW)
2700MW KAUNGLANGPHU
2000MW PISA
1200MW YENAN
2800MW CHIBWE
1900MW LASA
KACHIN HYDRO DEVELOPMENT (5000MW SYNCHRONISED WITH YUNNAN)
6000MW MYITSONE
HVDC B/B
WAINGMAN
SHWELLI
MEIKHTILA
TAUNGOO
KARMANAT
EAST DRAGON
YANGON

Google Earth Map of Possible Transmission Routes for Interconnecting Myanmar with GMS Countries (Thailand and Yunnan)



(Red line 500kV, Orange line HVDC, Yellow pointers show locations of main substation

Project Number: TA No. 8356-MYA

FINAL REPORT

APPENDIX 5: COMMENTS MATRIX

Prepared for

The Asian Development Bank

and

The Myanmar Ministry of Energy

Prepared by

Intelligent Energy Systems

in association with

MYANMAR INTERNATIONAL CONSULTANTS

ABBREVIATIONS

ADB	–	Asian Development Bank
IES	–	Intelligent Energy Systems Pty Ltd
MMIC	–	Myanmar International Consultants
NEMC	–	National Energy Management Committee
TA	–	Technical Assistance
TOR	–	Terms of Reference

CONTENTS

I. INTRODUCTION

1. The draft version of the Myanmar Energy Master Plan (EMP) report was submitted to ADB on 19 November 2014. It was subsequently issued by ADB to the Ministry of Energy on 19 December 2014.

2. On 26 March 2015, ADB provided the Consultant with comments from the concerned Myanmar ministries on the Draft EMP report.

3. It should be noted that the original concept was for IES to subsequently undertake consultations with each of the concerned ministries on the Draft EMP report findings and their feedback. However, circumstances did not allow this to occur. As such, the Final report has sought to address the comments raised by the concerned ministries as best as possible, but in the absence of any meaningful consultation with the concerned ministries. This means that in some cases we were not able to confirm or clarify the intent of some questions and also confirm / verify our understanding of additional data that was provided to IES by the concerned ministries as part of their feedback.

4. We have therefore taken a “best endeavours” approach to addressing the stakeholder comments but can’t guarantee that we have adequately resolved all issues to the same level as would have occurred had IES been able to engage in consultations following the issuance of the draft report.

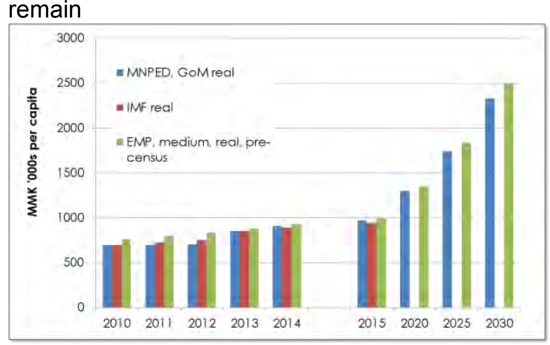
II. RESPONSES TO QUESTIONS FROM CONCERNED MINISTRIES

A. Responses to Comments from Ministry of Industry (MOI)

5. The Consultant’s responses to the feedback and comments from the Ministry of Industry are set out in Table II-1.

Table II-1: Response to Ministry of Industry Comments

Comment	Response
For Chapter (D) Demand Forecast: Industry Sector:	
In paragraph of 6, although it is indicated that the earning form the export of natural gas in year 2012 is about 3.6 billion dollar but the cumulative contribution of Oil & Gas, Electricity and water in the total GDP is only 1.2%. So, it is needed to be consistent.	The 1.2% is based on constant price evaluation according to ADB statistics. ADB statistics give the GDP of Electricity, Gas and Water as 611 billion kyats in 2012 (current value) at an exchange rate of 660 kyats per USD$. This does not equate to $3.6 billion, rather it equates to ~$1 billion. It appears that the ADB include oil in the mining sector GDP (this will be checked with ADB). The figure of $3.6 billion includes a contribution from the mining sector; therefore the reference to oil in clause 6 is misplaced and will be revised.
The basic calculation, concept and methodology used for Industry Sector FEC forecast should be indicated.	The calculations, concept and methodology were planned to be explained as part of consultation or training process (or directly with Ministry of Industry representatives if preferred). The energy demand forecasts for the Industry Sector are amongst the most difficult given the wide range of activities involved.
In figure I.8: although the heading is “Energy-Intensive Industry Sector FEC Forecast” but the figure shows just only actual consumption data for the period of 2005 to 2013.	The heading has been corrected.
How figure I.7, I.9, I.10 and I.13 are related to each other and it should be explained. Additionally, it should also be explained how figure I.13 is created including its details calculation.	The details will be explained during upcoming training / appreciation workshop (or directly with Ministry of Industry representatives if preferred).
In the energy planning, only the manufacturing industry is taken into account under energy intensive industry category while the others, such as mining & quarrying, construction and power & gas sectors are eliminated due to the availability of its information. However, those sectors are	Mining and quarrying activities of significant scale were assumed to use captive power sources; while this is important for the energy balance it does not affect electricity expansion planning. It was mentioned that construction activities in themselves are not energy

Comment	Response
also developing and it is also needed to consider their influence on the energy consumption of industry sector.	intensive but the production of construction materials such as bricks, glass and cement require significant amounts of energy. The power and gas sector either provides its own captive power sources, e.g. supplying platforms/wells, or involves secondary transformation; the former is treated as captive power whereas the latter has been modelled and own-use has been included
Sources of reference are important for Table II-3.	The figures in Table II-3 were computed from the survey data provided by Myanmar industry. The figures are average figures for each of the industries mentioned. These points will be clarified with a note below the table.
It is indicated, energy efficiency of some selected Industries is higher than IEA efficiency benchmark but in the paragraph 10, it is also mentioned that the efficiency of the industry sector has been increasing rapidly in recent years.	Paragraph 10 refers to 'energy intensity', not energy efficiency. An increase in energy intensity, as shown in Figure I-13, is to be expected when an industrial sector grows; from an energy efficiency perspective it is not a positive development.
GDP forecast in the energy master plan should be in line with the forecast made by Ministry of National Planning and Economic Development.	The GDP forecast is in line with the MNPED forecast. Change to the population base to match with Census 2014 will affect the figures equally and the comparison will remain valid. 
For Chapter C: Primary Reserves and Technology Options Environmental conservation law is enacted on 8 August 2014 and the section 52, 53 and 54 of environmental conservation law indicates that it is needed to conduct the pre environmental impact assessment for the proposed projects. Currently, Environmental Conservation Department of Ministry of Environmental Conservation and Forestry is undertaking to review the hydropower projects proposals from the environmental point of view and they are also reviewing the environmental impact assessment reports submitted by contractors. Therefore, the following sentence from the paragraph 231 should be deleted "As mentioned above, the current environmental legislation does not require the commissioning of EIAs and thus the environmental and social standards and practices employed by the investors themselves are extremely relevant in the host country."	Noted and deleted from the report.
For Chapter B: Historical Energy Balance: The same graph is used in Figure VI-2 and Figure VI-3 and it should be corrected. Under those graphs, it should be denoted "MOECAF" as a source of information not "MOF" Abbreviation of MOECAF should be included	Noted and corrections have been made in Chapter B.
For Chapter E: Vol.1: Consolidated Demand Forecast: In figure III-6, the physical unit should be changed to "000' tons".	Agree and adjustments made.

B. Responses to Comments from Ministry of Mining (MOM)

6. The Consultant's responses to the feedback and comments from the Ministry of Mining are set out in Table II-2.

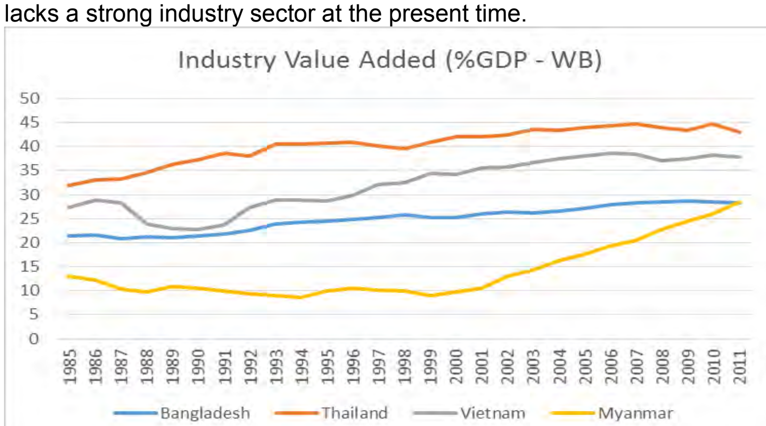
Table II-2: Response to Ministry of Mining Comments

Comment	Response
For Chapter B: Historical Energy Balance: Reserve Potential shown in Table II-4 includes Proven of Positive Ore Reserve (P1), Probable Ore Reserve (P2), Possible Ore Reserve (P3), and Potential Ore Reserve (P4). Among them, P3 and P4 are only potential reserve and the accuracy of coal reserve amount from P3 and P4 class coal mines is low. In the case of proven reserves, all the coal reserve cannot be extracted due to technical and other constraints such as the thickness, dip angle, overburden, groundwater.	This is noted, and some clarifying text added to the Energy Balance chapter.
Coal reserve identified in Table II -4 is not the remaining amount. Some coal mines, such as Maw Taung, San Laung, Namma and Kalaywa Coal mines cannot bear the same amount because those coal mines have been operating since many years ago. And most of the large coal deposits have already been handed over to private sector. Figure II-5 indicates the potential large coal deposits in Myanmar but it will be difficult for coal production due to steep coal bed dripping. Efficiency of conventional coal fired power plant is very low and high technology coal fired power plants have high efficiency but they need exported high class coal. On the other hand, environmental and social acceptance on coal fired power plants is very low in Myanmar. Therefore, high expectation should not be made to establish coal fired power plant.	As above, noted. Figure II-5 has been replaced by a more detailed overview of the locations of Myanmar's coal resources.
For Chapter C: Primary Reserves and Technology Options: In Table III-1, coal production forecast for 2015-2016 is 2316000 ton and it is about 4 times higher than 2013-2014 production. Increasing the coal production to 4 times depends on coal market and coal fired power plants.	This is noted and some text adjusted in the report.
For Chapter C: Primary Reserves and Technology Options: In paragraph 60, it is mentioned that the 80% of the coal production in 2004-2005 is exported to China and Thailand and coal export was significantly reduced after construction of Tigyit thermal power plant. Actually, coal export was reduced due to stop production from Maw Taung coal mines and it is not because of consumption of Tigyit thermal power plant.	This is noted at paragraph 60 revised.
For Chapter C: Primary Reserves and Technology Options: In paragraph 66, the update status of private sector participation in coal sector is that 6 companies are operating coal mines out of 19 companies.	This change has been reflected.

C. Responses to Comments from Ministry of Energy (MOE)

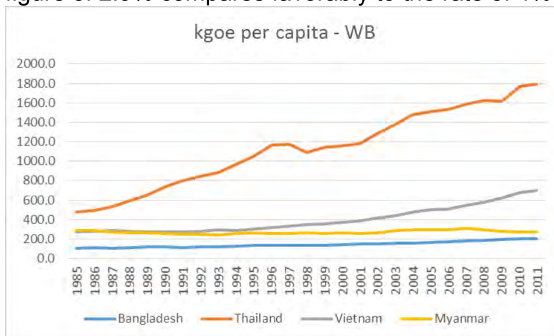
7. The Consultant's responses to the feedback and comments from the Ministry of Energy are set out in Table II-3.

Table II-3: Response to Ministry of Energy Comments

<table>
<tr><th>Comment</th><th>Response</th></tr>
<tr><td>Annual Growth Rate of 2.9% for Final Energy Consumption is too low as compare to the expected GDP growth rate of 7.1%. Its growth rate should be at least 5 or 6%.</td><td>
The following World Bank statistics for Thailand (THA), Vietnam (VNM), Bangladesh (BGD) show that the relationship between GDP growth and energy growth is correlated. The growth rate for energy is higher than the rate for GDP per capita. Myanmar's GDP per capita growth has not been published by the World Bank due to doubts on the statistics from 2000 to 2010 but most likely the growth rate for energy has been lower than for GDP per capita.
<table>
<tr><td colspan="2">CAGR for ktoe - period 1985 to 2011</td></tr>
<tr><td>THA</td><td>5.8%</td></tr>
<tr><td>VNM</td><td>5.0%</td></tr>
<tr><td>BGD</td><td>4.2%</td></tr>
<tr><td>MMR</td><td>0.9%</td></tr>
<tr><td colspan="2">CAGR for GDP per capita - period 1985 to 2011</td></tr>
<tr><td>THA</td><td>4.1%</td></tr>
<tr><td>VNM</td><td>4.7%</td></tr>
<tr><td>BGD</td><td>3.0%</td></tr>
<tr><td colspan="2">CAGR for kgoe per capita - period 1985 to 2011</td></tr>
<tr><td>THA</td><td>4.9%</td></tr>
<tr><td>VNM</td><td>3.5%</td></tr>
<tr><td>BGD</td><td>2.5%</td></tr>
<tr><td>MMR</td><td>-0.2%</td></tr>
</table>
The Consultant considers that the GDP and energy growth statistics of Thailand and Vietnam in particular are influenced heavily by energy-intensive industry growth; the growth in heavy industrial activity has resulted in relatively high energy growth rates.
The following chart for Industry Value Added includes a time series that is a composite of figures agreed by the World Bank (to 2000) and from other sources. Again the World Bank has not published figures post-2000 due to doubts regarding the statistics – it is considered that the rise in the Industry Value Added statistic since 2000 may not be significant – in other words that growth in the energy consumption of the industrial sector has been slow until recent times. The energy consumption and production statistics gathered from the public and private sector energy-intensive industries appears to support the likelihood that the Industry Value Added is low. Another way to consider this issue is to say that Myanmar is an agriculture + oil / gas economy that lacks a strong industry sector at the present time.


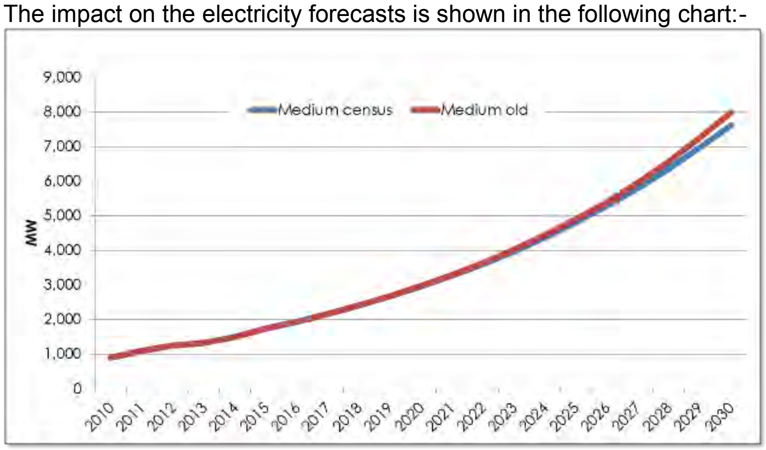
World Bank Indicators; Index Mundi
Myanmar's ktoe and kgoe per capita growth rates are recorded by the World Bank at 0.9% and -0.2% respectively. In this context, with a falling kgoe per capita rate over
</td></tr>
</table>

<table>
<tr><th>Comment</th><th>Response</th></tr>
<tr><td></td><td>
the last decade, an energy growth rate of 2.9% represents a significant turn-around. The figure was derived using bottom-up estimates for each sector but from top-down perspective it is not inconsistent with an historical ktoe growth rate of 0.9%. The figure of 2.9% compares favorably to the rate of 4% experienced by Bangladesh.



World Bank Indicators

In any case the accuracy of the energy growth rate forecast is less important than the assumptions for the drivers of energy growth, e.g. the growth in passenger vehicles. So rather than focussing on the resultant energy growth rate it would be more helpful to understand if the assumptions for the drivers of energy growth are reasonable. In the meantime there does not appear to be a justification to arbitrarily change the 2.9% to a higher rate.
</td></tr>
<tr><td>Expected population growth rate of 0.9% is acceptable. However, the size of country population used in the planning process should be based on the preliminary result of national census.</td><td>At the time of preparation of demand forecasts the results of the national census had not been validated. Since that time it is apparent that there is agreement between national and international experts that the population estimates determined by the census are robust. Therefore it is sensible to use the census results. In fact this approach was taken before the release of the draft EMP, but the ADB gave instructions to revert to the pre-census population for ease of comparison with other studies using the pre-census figures and so the higher population was used for demand forecasts and expansion planning.</td></tr>
<tr><td>Vehicle and income growth rates are also expected to change due to the new base line population.</td><td>
The impact of the change in population is not as significant to energy demand forecasts as might be expected. This is because the historical demand forecasts that are driven by population, were calibrated against reported energy consumption (electricity, transport gasoline and diesel, and firewood). The effect of reducing the historical population statistics means that the historical per capita energy rates increase. When these new energy consumption rates are applied to the (lower) projections for population, using the census 2014 figures as a base, the change to the total energy consumption is not affected significantly.
The impact on the electricity forecasts is shown in the following chart:-



The ‘medium census’ forecast is based on the census population; the ‘medium old’ forecast is based on the ADB time series for the population. The difference in population assumption shows in the forecast after 2025. The Consultant considers that the difference in the forecast is not significant enough to require rework of the electricity expansion modelling.
The impact on transport energy is shown in the 2 charts in APPENDIX A.
</td></tr>
</table>

Comment	Response
	The consumption rises because of the impact of GDP per capita, but again the impact is insignificant. The impact on agriculture has been checked, the difference is also insignificant. The impact on HH energy consumption has not been checked in detail. Here there are two conflicting drivers. If we were to assume fixed kgoe per capita figures for urban and rural HH's then a 15% reduction in population would result in an energy consumption reduction of 15%. Against this is that the census revealed that the urban population is higher than was assumed for the EMP (and the rural population is lower). Since urban energy consumption per HH is higher than for rural HH's, then from overall perspective it is expected that the change to the census population statistics will not result in a significant change to the total HH sector energy projection, however, the split of energy consumption between urban and rural HH will change and the change could be significant. The HH sector estimates will be reworked with the census population to verify these opinions.

D. Responses to Comments from Ministry of Rail Transportation (MORT)

8. The Consultant's responses to the feedback and comments from the Ministry of Rail Transportation are set out in Table II-4.

Table II-4: Response to Ministry of Rail Transportation

Comment	Response
For Chapter D: Demand Forecasts: Transport Sector All the expression of "Myanma Railways" should be replaced with "Road Transport Administration Department"	Noted and replacement made
Data are updated for the Figure I. 1, Table I-2, Table I-3, Table II-1, Table III-9. (See APPENDIX B.)	Noted and updated.

E. Responses to Comments from Ministry of Hotel and Tourism (MOHT)

9. The Consultant's responses to the feedback and comments from the Ministry of Rail Transportation are set out in Table II-5.

Table II-5: Response to Ministry of Hotel and Tourism

Comment	Response
For Chapter (D): ENERGY FORECASTS, COMMERCE & PUBLIC SERVICES SECTOR: Update the tables as discussed in APPENDIX C below.	All tables noted and updated.

F. Responses to Comments from Ministry of Electricity Power (MOEP)

10. The Consultant's responses to the feedback and comments from the Ministry of Electricity Power are set out in Table II-6.

Table II-6: Response to Ministry of Electric Power

Comment	Response
For Chapter (A) Economic Outlook, the caption of "Figure (1-4) should be changed into "Major River & Existing Hydro Power in the Union of Myanmar".	Noted, title has been changed.
For Chapter (B) Historical Energy Balance, In paragraph (74) Electricity Transmission and Distribution System, the voltage of Transmission line is" 230 kV". It is not "220 kV". Figure V-8: Myanmar National Grid map is updated in Annex (1). In paragraph (76), the amount of electricity consumption by industry, resident and commercial/services sectors in total final consumption are "32%, 44 % and 20% respectively."	This is noted and the information in the report updated accordingly.

Comment	Response
Table V-13 is updated in Annex (2).	
For "Chapter (C) Primary Reserve and Technology Option II. NATURAL GAS " Table II-5 is updated in Annex (3). In paragraph (71),the location of coal power plant is Kalaw city in the Shan State. It is not "Kalewa". Paragraph (142) should be replaced with "As for renewable energy development, MOEP is in charge of solar and wind power project with IPP development. Currently (2014) there are two foreign companies with several development in the country. Under their respective memorandums of understanding from 2011 with the ministry, a Thai (Gunkul Engineering Public Co., Ltd) and China Three Gorges Corporation (CTG) company are carrying out feasibility analysis of building wind farms in several locations. The Gunkul Engineering Public Co., Ltd has seven sites in the Mon and Kayin States and in Tahintharyin Region, which would produce 1,000 MW and in Shan and in Kayah States, which would produce 1930 MW. The China Three Gorges Corporation (CTG) company is studying locations in the Chin State, Rakhine State, Ayeyarwaddy Region and Yangon Region to the capacity of 1,102 MW." In paragraph (175) , the first four sentences should be replaced with "As of June 2014, the total installed capacity of hydropower plants in Myanmar was 3005 MW. This includes 23 hydropower plants of installed capacity higher than 10 MW, and some 40 mini and micro hydropower plants of 34 MW in total capacity. Detailed information on the hydropower plants is listed in Annex 15. The planned annual hydropower generation totals 14,956.8 GWh (excluding mini hydro)." In paragraph (182), the actual commissioning year of both Thaukyegat-2 and Chipwenge plants is 2013. It is not 2014. Paragraph (178) should be replaced with "Nearly half of the number of hydropower developments in Myanmar are multipurpose schemes, in which provision of irrigation services plays important role. It permits the dry- season cropping of maize, peanuts, sesame, wheat, cotton, millet, and other dry crops. The installed capacities of the plants associated with irrigation dams are typically not high. Kinda (56 MW), Mone (75MW),Paunglaung (280 MW), Sedawgyi (25 MW), Thapainzeik (30 MW), Yenwe (25 MW), Kyeeon Kyeewa (74 MW), Zaungtu (20 MW) and Zawgyi-2(12 MW) plants are installed to large dams for irrigation. Their total electric capacity is 597 MW." Paragraph (181) should be replaced with" For the Dapein-1 Hydropower plant (240 MW), also being developed by the PRC investors, 100% can be made available to the Myanmar central grid and 10% of the generated electricity will be free power as royalty."	All points noted and agreed, revisions have been made accordingly.
For Chapter (E) Vol-1 Final Energy Consumption Forecast IV.ELECTRICITY FORECAST (TOP - DOWN RECONCILIATION): Table IV-1: Distribution Losses - Yangon (2013) is updated as APPENDIX E.	The figures shown here in Table IV-1 were used for the demand forecasts but the figures in Table IV-1 in the report were not matching; they have now been updated in the report
Table IV-8: Baseline Energy Sales by State / Region: 2013 is updated in Annex (4).	Noted.
For the Analysis Results of Chapter(C) Primary Reserve and Technology Option, it is also suggested that the recommendation	The concept and methodology will be explained during a training session, or if preferred by way of a

Comment	Response
should include "To use different sources for electricity generation in the long term in order to bring the Energy Balance and for the short term, Combined Cycle Power Plant should be implemented only after the Open Cycle Plants are implemented. Concept and methodology used for Electricity Demand Forecast should be explained.	separate meeting with MoEP specialists.

G. Responses to Comments from Ministry of Energy (MOE) on Draft Final

Comment	Response
Supply Gas (3.4) at Table I-1 Supply Projection at Page No. 651, and Consumption Gas (4.1) at Table I-3 Energy Consumption at Page No. 653 are not the same. Supply gas is less than consumption gas.	*Two problems surfaced when looking at this issue. One was that LPG consumption was incorrectly gathered under the Natgas category when the IEA approach is to gather under Oil. It was noticed that light industry consumption was not gathered for some years in the IEA tables (from years 2021 to 2030). Corrections have been made, and the TFEC table and IEA tables revised.*
Table III-3 at Page No. 677: Coal (lignite) column is missing. 7,542 (Total Primary Energy) is not equal to the combination of 2,832 (Hydro), 314 (Solar PV), 216 (Natural Gas) and 57 (Coal bituminous).	*The fuel consumption figures were primary quantities and summed to the primary energy total, this has been clarified by re-arranging the columns in the table.*
LPG Column is missing at Table V-3 Natural Gas at Page No. 685 and Table V-4 Natural Gas at Page No. 686. Different units are used there.	*In first draft of the Energy Outlook report, LPG was accounted for under gas, but it was later remembered that, under IEA approach, LPG must be accounted for under Oil / Refined Petroleum, not under the Natural Gas category. In checking this issue it was noticed that Table V-5 included a column for LPG - this column has been removed.*
Figure I-3 TPES – Fuel Mix 2030 at Page No. 656 needs to be adjusted in percentage.	*This chart and Figure I-2 have been replaced.*
Table V-2: Compound Annual Growth Rate Projections at Page No. 685: "- 6.2 %" is mentioned under Transport. Actually, consumers prefer CNG as it is cheaper.	*A major barrier to widespread deployment of CNG is the availability of onshore gas; as such the assumptions was made that widespread use of CNG was limited and the view adopted was that we do not project increased CNG use. It would be possible to run a sensitivity of CNG consumption to understand the overall natural gas use if needed but best done by way of a demonstration in the development of a transport scenario, perhaps in a workshop setting.*
Table V-3: Natural Gas TPES Forecast (toe) at Page No. 685: Much are reduced under Electricity Consumption (2012-2014 were finished already.) compared to the previous report.	*This was the result of having to change our original gas consumptions figures over to those provided in the ADICA report. Unfortunately not all gas consumption projections in all tables and figures had been completely updated. We have fixed this and updated the figures.*
Fix the consistency between the following figures / tables: Figure I-3: Myanmar: FEC Projection by Energy Carrier (medium) from Consolidated Demand Forecasts Chapter Table I-1: Supply Projection to 2030 (mtoe) from	*This was related to a change in classification of LPG from the gas category to the oil category to be consistent with IEA categorisation – this was a late change that had not been reflected across all parts of the report. This is now fixed.*

Comment	Response
Energy Supply Outlook Chapter TableI-3: Total Final Energy Consumption (TFEC, mtoe) from Energy Supply Outlook Chapter	

Annexes

ANNEX A:

Original forecast using ADB population statistics

	Reference Case						
	2012-13	2015-16	2018-19	2021-22	2024-25	2027-28	2030-31
Gasoline	492.7	681.8	843.2	1,027.1	1,218.0	1,379.81	1,509.6
Bioethanol	-	-	-	-	-	-	-
Diesel	880.3	1,064.5	1,033.7	1,027.0	1,077.7	1,209.91	1,423.9
Natural Gas	31.7	29.9	24.4	20.4	16.3	12.74	8.9
Jet Fuel (ATF)	31.3	31.5	50.4	69.3	88.1	107.04	125.9
Total	1,436.1	1,807.7	1,951.7	2,143.8	2,400.1	2,709.50	3,068.3

Forecast based on census population

	Reference Case						
	2012-13	2015-16	2018-19	2021-22	2024-25	2027-28	2030-31
Gasoline	492.7	700.9	862.5	1,047.1	1,239.3	1,400.33	1,521.2
Bioethanol	-	-	-	-	-	-	-
Diesel	880.3	1,082.2	1,047.5	1,037.6	1,085.6	1,216.94	1,430.5
Natural Gas	31.7	31.1	25.3	21.0	16.7	12.94	15.0
Jet Fuel (ATF)	31.3	31.5	50.4	69.3	88.1	107.04	125.9
Total	1,436.1	1,845.7	1,985.7	2,175.0	2,429.7	2,737.25	3,092.6

ANNEX B:

Figure1-1: Myanmar Registered Vehicle Statistics

	05-06	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14
Two wheeler	641777	646872	658997	1612423	1749083	1883958	1995505	3219213	3595474
Other	11307	11758	13008	13933	14514	15862	15693	18806	25730
Bus	18038	18857	19291	19683	19807	20944	19579	19812	22151
Truck(heavy duty)	31437	31990	33160	33928	35125	36820	38478	43881	52069
Truck(light duty)	23364	23392	24051	24929	26007	28068	29272	30665	72528
Passenger car	193940	202068	217018	233227	245921	265642	249561	292919	382774

Table I-2: Modelled Passenger Transport Use For Myanmar (2012)

		Total Vehicle
Modality	Fuel	No
Passenger Vehicle (Public And Private Passenger cars and diesel buses)	Gasoline	148073
	CNG	19431
	Diesel	221735

Table I-3: Model Freight Transport Use for Myanmar (2012)

		Total Vehicle
Modality	Fuel	No.
Heavy Commercial Vehicle	Diesel	38950
Light Commercial Vehicle	Gasoline	4385

Table II-1: Motorization of Myanmar's Provinces (February 2013)

State/ Region	Private Car	Truck (Light Duty)	Truck (Heavy Duty)	Passenger	Motorcycles
Other	38981	7981	18696	5248	2146877

Table III-9: Vehicle Parc

	2012
Passenger Car	281575
Bus	19522
Light Commercial Vehicle	29478
3 wheel Trawlergi	71082

ANNEX C:

Update data for table II.4 are as follow:

Year	No	Room
2004	591	19540
2005	594	19947
2006	594	20265
2007	599	20346
2008	619	21474
2009	631	21375
2010	677	22373
2011	731	25002
2012	787	28291
2013	923	34834
2014	1106	43243

Update data for table II-5 are as follow:

Sr. No	State / Region	2010 (Dec)		2011 (Dec)		2012 (Dec)		2013 (Dec)		2014 (Dec)	
		No.	Room	No.	Room	No.	Room	No.	Room	No.	Room
1	Yangon	181	7658	187	7934	204	8915	232	10175	287	13146
2	Mandalay	195	6291	219	7861	234	8636	287	11995	337	14475
3	Bago	33	770	33	770	36	879	37	926	43	1099
4	Sagaing	10	223	10	242	12	298	16	462	19	646
5	Tanintharyi	9	484	11	570	11	598	14	695	21	1005
6	Ayeyarwady	39	1456	43	1565	46	1824	53	2081	54	2254
7	Magway	7	101	11	173	13	244	17	347	21	471
8	Kachin	16	423	18	495	18	495	21	607	22	628
9	Kayah	3	44	5	98	6	109	7	135	8	175
10	Kayin	7	172	7	172	7	172	7	180	10	325
11	Chin	-	-	-	-	-	-	-	-	1	27
12	Mon	18	444	19	478	21	652	28	980	37	1300
13	Rekhine	25	735	27	791	30	933	35	1104	40	1250
14	Shan	134	3572	141	3853	149	4536	169	5147	206	6442
	Total	**677**	**22373**	**731**	**25002**	**787**	**28291**	**923**	**34834**	**1106**	**43243**

For Paragraph 73, the number of visitors arrival to Myanmar is provided as follow:

Visitors Arrival to Myanmar

Sr. No	Mean of Travelling	2011	2012	2013	2014
1	By Air	385732	588298	871153	1082140
2	By Water	131273	147139	226559	242217
3	By Land	299364	323558	946595	1757055
	Total	**816369**	**1058995**	**2044307**	**3081412**

Visitors Arrival through Yangon International Airport

Sr. No	Year	Person
1	2011	362810
2	2012	557462
3	2013	809100
4	2014	991208

ANNEX D:

		2009	2010	2011	2012	2013
Eastern District						
Technical loss	%	23.0	20.67	19.56	17.99	20.46
Non-technical loss	%					
Western District						
Technical loss	%	20.7	19.98	19.16	17.72	18.97
Non-technical loss	%					
Southern District						
Technical loss	%	29.41	25.28	23.95	25.98	26.63
Non-technical loss	%					
Northern District						
Technical loss	%	20.65	20.23	19.65	17.26	19.01
Non-technical loss	%					