PUBLIC UTILITIES COMMISSION OF SRI LANKA

Electricity Supply 2020 and Beyond

Challenges and Recommendations

8/31/2017

Contents

List of Figures

List of Tables

EXECUTIVE SUMMARY

Comparison of past Least Cost Long Term Generation Expansion Plans (LCLTGEP) with actuals suggests that there are significant shortcomings in the implementation of LCLTGEPs. This has resulted cost overruns, load shedding, and unplanned power procurement in past few years and these consequences are expected to be continued in next few years.

The following Short Term and Medium Term Actions are recommended to ensure the continuity of electricity supply until 2020 and the Long Term Actions are recommended as permanent solutions to ensure long term energy security in a sustainable manner.

Short Term (Next 6 Months)

The energy supply is expected to be sufficient in short term (next 6months) under most probable hydro condition and no additional measures will be required. However in an event of an extraordinary low rainfall scenario, (If the hydro reservoir levels fall below the dash line in Figure 9 of Annexure I) the following actions are recommended.

a. For September- October period:-

Electricity demand can be fully catered if 60MW of additional generation capacity is available from September onwards and 110 MW of additional generation capacity is available from October onwards. The following options are available for the required capacity additions.

i. Procurement of electricity from 60MW emergency power plants (PPA expired in mid-August).
ii. Operating the Sojitz Kalanithissa power plant (which is unavailable due to Steam Turbine failure), on open cycle mode (110 MW).
iii. Acquiring more capacities under Self-Generation scheme.
iv. Disconnection of bulk customers who own on-site generators from the system to minimize inconvenience to consumers, in case of sudden load shedding requirement.

b. For November- February period:-

i. Immediately starting the tendering process for procurement of 150 MW thermal generation capacity for 10 months period from November 2017. However, the decision of entering in to a Power Purchase Agreement (PPA) should be subject to the hydro reservoir level as at the end of October. Committing to a PPA can be recommended if the reservoir levels are below 630 GWh and are at a decreasing trend. (Low hydro scenario Figure 9 of Annexure I).

ii. It is recommended to call tenders to obtain the 150 MW capacity as several generation plants (eg. 3×50 MW generation plants), keeping the flexibility to procure lower generation capacity depending on the hydro condition. The size and location of the plants shall be decided by the Transmission Licensee subject to transmission constraints in the national grid.

iii. Options such as open-cycle operation of Sojitz Kalanaithissa Power Plants or extension of expired PPA for 60MW emergency power plants (expired in August 2017) should be given due consideration by transmission licensee in making a decision on power procurement, to ensure the least cost criteria.

iv. However, if the Transmission Licensee decides to procure capacity lower than 150 MW in November 2017, it is recommended to take initiatives to procure said total 150 MW thermal generation capacity from February 2018 to August 2018. The actual capacity addition should be done considering the actual hydro condition at the time of entering in to the PPA (if reservoir level is below 615 GWh and not showing an increasing trend by February 2018, it is considered a low reservoir level - Figure 9).

c. Special attention should be given to ensure continuous fuel supply to all thermal power plants under both hydro scenarios.

d. In addition to what had been discussed above, both rooftop and scattered solar plant additions should be expedited.

<u>Medium Term (2018-2020)</u>

a. The proposed plant additions (both thermal and renewables) in Least Cost Long Term Generation Expansion Plan (LCLTGEP) 2018-37 should be conducted according to the CEB implementation plans presented at the Sub-Committee on Power and Renewable Energy meeting held on August 10, 2017 *(Annexure II)*.

b. Transmission system should be timely expanded according to the new plant additions expected.

c. Groundwork on development of Natural Gas Infrastructure should be started immediately to ensure fuel availability for all existing and future Gas Turbines and Combined Cycle Plants.

d. Continuous fuel supply to all thermal plants should be ensured throughout the period.

e. Even with recommended capacity additions, timely measures should be taken to avoid energy deficits that are likely to occur in the first half of 2018 and also in March and August in 2019 and March 2020, under dry conditions (Eg. Recommendations for January and February 2018 given in the above section on recommendations for Short Term).

f. Demand Side Management measures (energy efficiency, conservation, peak demand shifting, etc.) should be expedited.

g. Immediate technical/ managerial solutions should be taken to increase the reliability of the Norachcholai Lakvijaya coal power plant.

Long Term (Permanent Solutions)

a. Liberalize the generation sector to espouse investments by amending section 8 and 9 of Sri Lanka Electricity Act, while creating a robust power procurement programme that can introduce price competition to electricity sector.

b. India interconnection project should be expedited.

c. Sri Lanka Electricity Act should be amended to allow wheeling.

d. Streamline the generation planning process and revise the format of LCLTGEP in line with exact provisions of the "Grid Planning Code".

e. Fully ring-fencing Transmission Licensee should be followed by administrative separation to ensure that Transmission Licensee operates independently from CEB in broad national interest, to realise the objective of having a reliable, secure and cost competitive electricity industry.

f. The share of NCRE is forecasted to be increased with government policy targets. The planning process needs to take into account this and make amendments to the planning process to cater for new challenges posed by increased NCRE plant additions.

SECTION 1 - GENESIS OF THE PROBLEM

This section attempts to identify the making of the present power situation based on the information presented in past 'Least Cost Long term Generation Expansion Plans (LCLTGEP)' prepared by the transmission licensees since 2006, and also discusses the consequences of events that has led the power sector to this juncture. All comparisons are done with respect to 2016.

Forecast Demand and Generation mix for 2016 and actuals

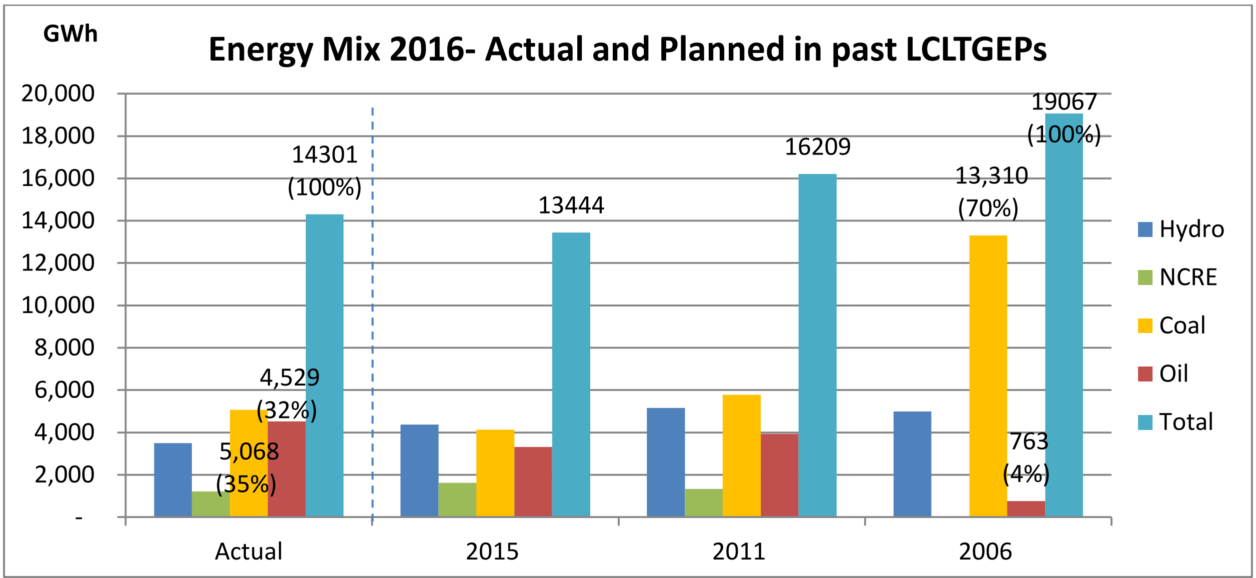

Figure 1 - Forecast Demand and Generation Mix for 2016, and actual

Figure 1 shows the forecast electricity demand and energy mix envisaged for 2016 in each of the previous LCLTGEPs since 2006, against the actual demand and energy mix recorded in 2016.

Observations

- The base demand forecast for 2016 has steadily decreased since 2006. The actual demand of 2016 had been 14,301 GWh, while the forecast demand for 2016 in 2006 is 19,067 GWh.
- Percentage wise the figure indicates a 33% of over-forecast in 2006, 13% over-forecast in 2011, and 6% under-forecast in 2015, for the actual demand of 2016.
- Actual contribution from oil based generation in 2016 is 4,529 GWh, which is 6 times the contribution from oil based generation for 2016 envisaged in 2006.
- The forecast share of energy from hydro plants for 2016 remains approximately the same level despite minor fluctuations. However the actual share has been slightly less than forecasts.

- The 2006 forecast envisages the share of energy from coal to be 70% in 2016. However, the actual share has been 35%.
- The actual share of energy from Non-Conventional Renewable Energy (NCRE) in 2016 is 9% which remains in line with 2011 forecast. The NCRE share does not appear in 2006 forecast because the generation planning exercise back then did not consider NCRE generation.

As a whole there is a marked difference between the actual and forecasted energy figures for 2016.

Forecast generation capacities for 2016 and actuals

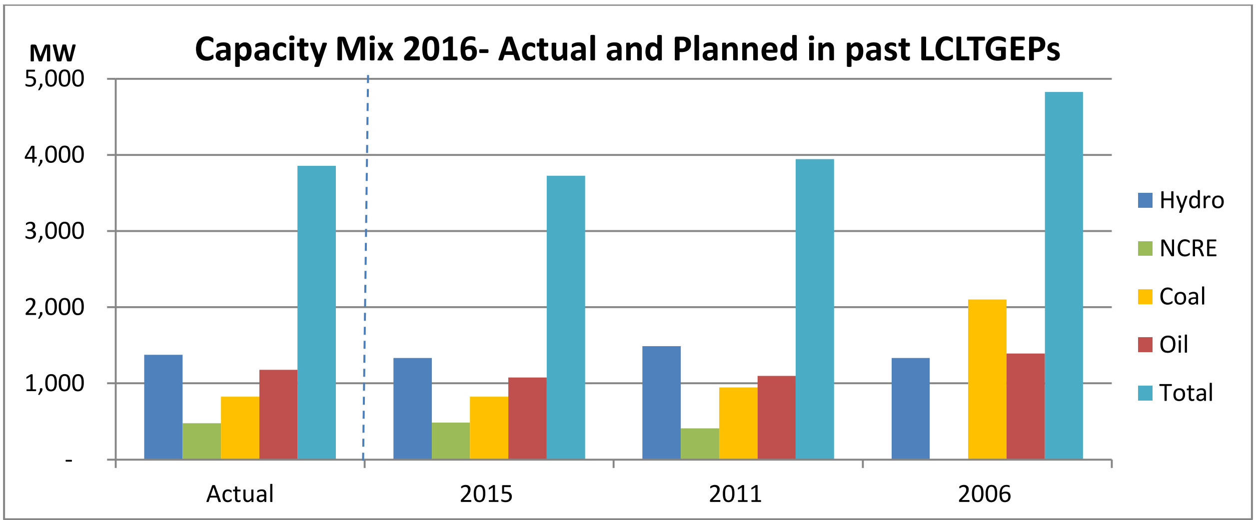

Figure 2 - Forecast Capacity Mix for 2016 and the actual

Figure 2 depicts the forecast generation capacity mix for 2016 expected in previous LCLTGEPs against the actual.

Observations

- The actual available capacity for 2016 has been 3,856MW whereas the forecasted capacity for 2016 had been 4,828MW, 3,946MW& 3,725MW in 2006, 2011 and 2015 respectively. Percentagewise this amounts to 25%, 2% and 3% of difference with the actual value.
- Actual NCRE capacity by 2016 is 477MW which is more than the 411MW forecasted in 2011. This 477MW is mainly comprised of wind and small hydro plants. The 2006 plan does not include NCRE capacity forecast as it was not a part of planning exercise back then.
- Generation plan 2006 has envisaged 2,100 MW of installed coal power plants to be available by 2016. However the actual installed coal plant capacity is only 900MW. About 1200MW of coal power plants that were expected to be operational by 2016, have not been materialized

- The actual capacity contribution from oil plants in 2016 remains approximately the same level as 2006 forecast with respect to overall figures. However the actual combination of oil fired plants as at 2016 is significantly different from what was expected in 2006. The Gas Turbine additions of 520 MW proposed in 2006 plan has not been implemented, while the Kalanithissa Small Gas turbines (68 MW) and Sapugaskanda Diesel plants (72 MW) have not been retired as envisaged in 2006 plan. This has led to unplanned generation procurement which is discussed the next section.

All in all it can be noted that the actual capacity additions has been less than what is expected in previous generation plans. However this has not grown into a full blown crisis because the actual demand has also been consistently less than what was forecasted. These two effects together have cancelled out the negative impact of each other. However neither of these can be endorsed as it causes the sector to operate at economically sub optimal state, and undermines the planning process as a whole.

Consequences - Impact of Non- Implementation of Long Term Plan

The comparison of forecast energy and capacity for 2016 done in previous plans with actuals in 2016 suggests that there are significant shortcomings in the implementation of CEB's Long Term Generation Expansion Plan. Unintended consequences of can be identified as a) Cost overruns, b) Load shedding, and c) unplanned power procurement.

Cost implications

Table 1 shows the forecasted energy mix for 2016 based on LCLTGEP 2006 and the actuals, along with actual generation cost in 2016.

Table 1: - Forecast energy mix vs actual

	Energy Mix-2016 Actual	Forecast Energy Mix for 2016 - LCLTGEP 2006	Generation cost actual in 2016	
			(LKR/kWh)	(USCts/kWh)*
Hydro	24%	26%	5.03	3.45
NCRE	8%	0%	16.71	11.48
Coal	35%	70%	9.90	6.80
Oil	32%	4%	27.28	18.74

*Average Exchange Rate for 2016 published by Central Bank of Sri Lanka:145.60 LKR/USD

Figures presented in Table 1 shows that if the LCLTGEP 2006 were to be implemented as planned, the actual unit generation cost in 2016 would have been LKR 9.32/kWh (USCts 6.40/kWh) approximately. (This is an approximate value because the unit cost includes capacity charge which can change with capacity mix) However the actual unit generation cost has become LKR 14.79/kWh (USCts 10.16/kWh), which is LKR 5.47/KWh (USCts 3.76/kWh) higher than what was originally planned. The resulting cost overrun can be approximated to about LKR 78,210 million for 2016 alone.

Load Shedding

The shortcomings in implementation of the plan had also resulted in short term energy shortages in number of instances during last 24months, which led to planned and unplanned load shedding in following instances.

- February 26-27, 2016
- March 14-17, 2016
- October 17- 19, 2016
- July 24-28, 2017

Power Procurement

The situation also compelled the power plants shown in Table 2 to be procured to overcome energy shortages. None these plants were anticipated in previous Generation Plans.

Table 2: - Unforeseen Power Procurement

Procurement month	Capacity
November 2015	60 MW Barge Power Plant
April 2016	100 MW Ace Power Embilipitiya Plant (1 year)
December 2016	Self- Generation scheme
February 2017	60 MW Emergency Power PPA (6 months)
April 2017	20 MW ACE Power Matara (1 year)
April 2017	100 MW Ace Power Embilipitiya Plant PPA extension for another year
2018	320 MW furnace oil plant additions are planned in LCLTGEP 2018-37

Though unexpected in the circumstances, the consequences discussed herein can be considered typical and standard for any vertically integrated electrical industry that has failed to implement its 'Integrated Resource Plan'. (The LCLTGEP in the case of Sri Lanka).

SECTION 2 - SHORT TERM AND MEDIUM TERM ENERGY OUTLOOK

A. SHORT TERM (next 6months)

a) Capacity Balance

Table 3: - Capacity Balance- Short term

	Available Capacity(MW)*	Peak demand 2017 (MW)
Aug-17	2756.9	2441.3
Sep-17	2756.9	2441.3
Oct-17	2756.9	2441.3
Nov-17	2756.9	2441.3
Dec-17	2756.9	2441.3
Jan-18	2734.1	2441.3
Feb-18	2734.1	2441.3

*Without one unit of Lakvijaya Coal Plant (LVPS), Sojitz Kalanithissa Plant & NCRE

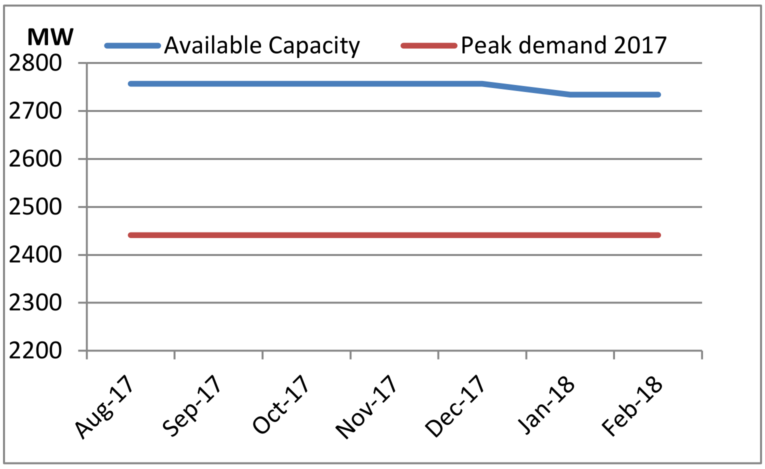

Figure 3 – Capacity Balance - Short Term

b) Energy Balance

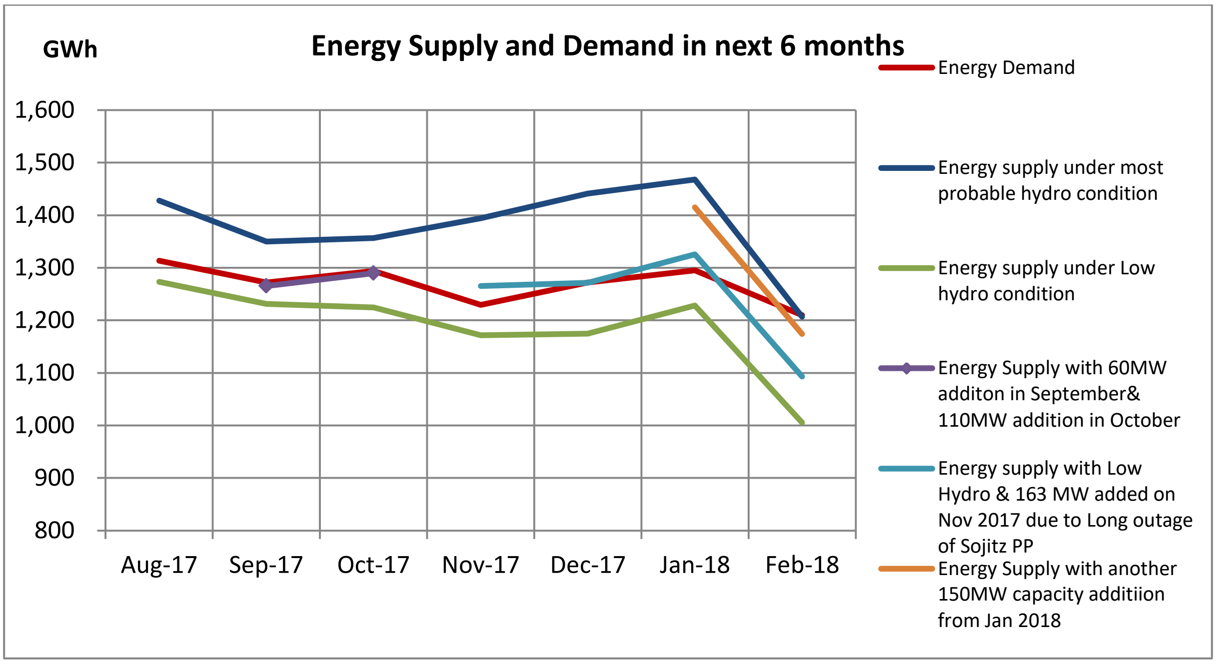

Figure 4: Energy Balance-Short Term

Table 4: Energy Balance- Short Term

				Proposed solutions in case of Low Hydro condition		
	Energy Demand (GWh)	Energy under most probable hydro condition(GWh)*	Energy under Low hydro condition(GWh)*	Energy Supply with 60MW addition in September& 110MW addition in October (GWh)	Energy with Low Hydro ,163 MW added on Nov 2017 due to Long outage of Sojitz PP (GWh)	Energy with another 150MW capacity additiion from Jan 2018 (GWh)
Aug 17	1,313	1,428	1,273			
Sep 17	1,272	1,350	1,231	1,266		
Oct 17	1,294	1,356	1,224	1,290		
Nov 17	1,229	1,394	1,172		1,265	
Dec 17	1,272	1,441	1,174		1,271	
Jan 18	1,295	1,468	1,228		1,325	1,415
Feb 18	1,210	1,207	1,006		1,093	1,174

*Basis of estimation of energy supply is given in ***Annexure I***

c) Observations

a. As per the capacity balance shown in Figure 3, there will be sufficient capacity to meet the system peak demand in next 6 months.

b. Short term energy balance is shown in Figure 4. Energy adequacy in next six month is highly dependent on the rainfall expected during the next few months. If sufficient rainfall is not received, continuous energy inadequacies can be observed.

c. As shown in figure 4, under most probable hydro condition energy supply is sufficient to cater the demand. However, under low hydro condition, there will be energy inadequacies throughout the period.

d. In addition, a significant increase in daytime demand is observed in 2017. Until mid-August, in 65 days the daytime demand had exceeded 2,000MW and among these in 5 days day peak had exceeded the night peak.

d) Recommendations

Under most probable hydro condition, there will be sufficient energy supply during the next 6 months period. Hence, no additional measures will be required in short run.

However, there is a possibility of continuation of the dry condition prevailed throughout 2017 in the next few months (If the hydro reservoir level is below the dash line in Figure 9 of Annexure I, the hydro condition is considered a low hydro scenario for this analysis). Hence, in a low hydro scenario, in order to ensure continuity of supply the following actions are recommended.

a. For September- October period:-

As shown in Figure 4, if 60MW additional thermal generation capacity is available in September and 110 MW additional thermal generation capacity (without considering 60MW addition in September) is available in October, the energy demand can be fully met. The following options are available for the required capacity additions.

i. Procurement of electricity from 60MW emergency power plants (PPA expired in mid-August).

ii. Operating the Sojitz Kalanithissa power plant (which is unavailable due to Steam Turbine failure), on open cycle mode (110 MW).

iii. Acquiring more capacities under Self-Generation scheme.

iv. In order to minimize inconvenience to consumers, in case of sudden load shedding requirement, disconnecting bulk customers who own on-site generators from the system.

b. For November- February period:-

As per Figure 4, if 163 MW Sojitz Kalanithissa plant is available, the energy demand from November 2017- January 2018 can be met. However in February 2018 another 150 MW thermal generation capacity addition is required.

However, Sojitz Kalanithissa power plant is not available for combined cycle operation until January 2018 and there is a risk that the unavailability continuing until April-June 2018. Hence, it is recommended for the Transmission Licensee to acquire 163 MW thermal generation capacity starting from November 2017, to replace the Sojitz Power plant during the long outage.

In addition to the said 163 MW plant, 150 MW thermal generation capacity is required in February. But this capacity addition is not required in March and April as all 3 units of LVPS are scheduled to be available from 1st March to mid-May. Hence, procuring another 150 MW capacity is not recommended. Instead, it is recommended to procure the said 163 MW generation capacity for 10 months period- until August 2018 (it is to be noted that addition of 100MW Barge power plant is expected in August 2018). With this, if Sojitz power plant resumes combined cycle operation in January, demand in February can be fully met. Further, this capacity addition will be required in May - June 2018, where maintenance of LVPS III is scheduled. However, if Sojitz Power plant does not resume combined cycle operation, temporary energy shortfall is possible in February 2018, and hence, temporary measures such as above (a) (iii), (iv) are recommended.

However, according to LCLTGEP 2018-37, thermal generation capacity addition required from January 2018 is 320 MW. Since, 100MW ACE Embilipitiya, 20 MW ACE Matara and 48 MW Asia Power plants will already be available at January 2018, only additional 150 MW thermal generation capacity can be added in 2018. Hence it is recommended to procure generation capacity of 150 MW instead of the said 163 MW from November 2017 onwards.

v. Considering the above, it is recommended for Transmission Licensee to immediately start the tendering process for procurement of 150 MW thermal generation capacity for 10 months period from November 2017.

vi. However, the decision to enter in to the Power Purchase Agreement (PPA) for procurement of electricity from these plants should be taken by the Transmission Licensee if the hydro reservoir level at the end of October is at a low level. If the reservoir level at the end of October is below 630 GWh and is not showing an increasing trend, it is considered a low reservoir level (Figure 9 of Annexure I).

vii. It is to be noted that this analysis has considered only average and lowest hydro scenarios, where, the 150 MW capacity is required in the lowest possible hydro scenario and in average hydro scenario, no capacity additions are required. Hence, if the hydro condition is in between the two scenarios considered, the continuity of electricity supply can be ensured with lower generation capacity addition. Hence, it is recommended to call tenders to obtain the 150 MW capacity as several generation plants rather than a single generation plant (eg. 3×50 MW generation plants), keeping the flexibility to procure lower generation capacity depending on the hydro condition. It is further recommend that the individual plant capacity to be decided by the Transmission Licensee based on a more sensitive analysis, considering the limitations on transmission system.

viii. Subject to the flexibility of the hydro condition, and depending on the price competitiveness compared to the plant selected from the tendering, the Transmission Licensee should consider other options such as open-cycle operation of Sojitz Kalanaithissa Power Plants or extension of expired PPA for 60MW emergency power plants (expired in August 2017).

ix. However, if the Transmission Licensee decides to procure generation capacity lower than 150 MW in November 2017, due to the risk of hydro reservoirs decreasing to a low level in February 2018, it is recommended to take initiatives to procure said total 150 MW thermal generation capacity from February 2018, until August 2018. However, actual capacity addition should be done considering the actual hydro condition at the time of entering in to the PPA (if reservoir level is below 615 GWh and not showing an increasing trend by February 2018, it is considered a low reservoir level - Figure 9).

c. As a solution to the increase in daytime energy demand, solar generation additions (both rooftop and scattered solar plants) should be expedited.
d. It is essential to ensure continuous fuel supply to all thermal power plants under both hydro scenarios.

B. MEDIUM TERM (three years 2018-20)

Power plant additions in 2018-2020 period, required as per the Least Cost Long Term Generation Expansion Plan (LCLTGEP) 2018-37 and the plant additions according the Implementation Plans presented by Ceylon Electricity Board at the Sub-Committee on Power and Renewable Energy meeting held on August 10, 2017, is given in ***Annexure II***.

a) Capacity Balance

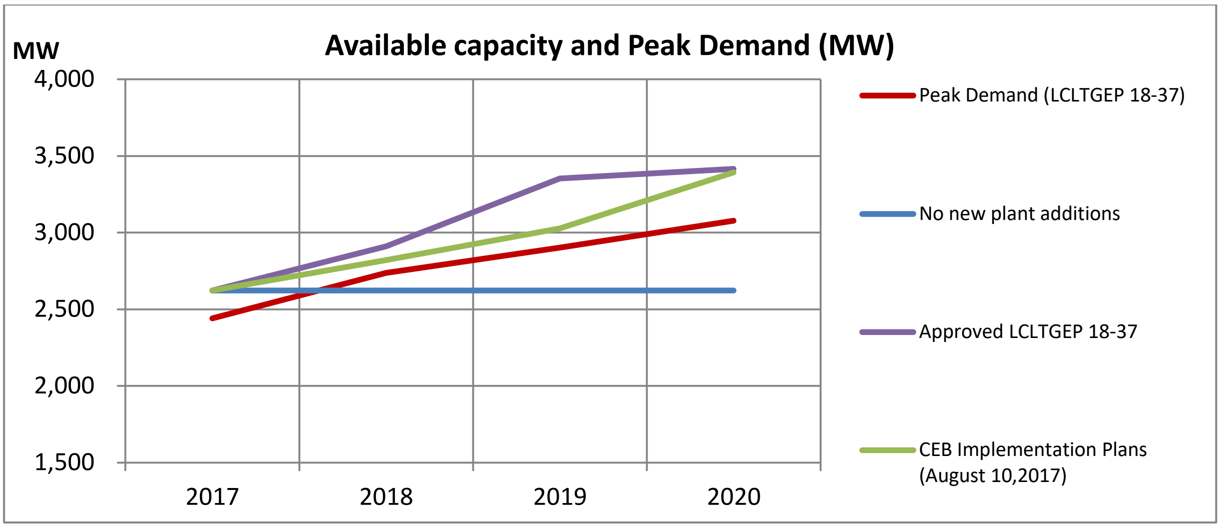

Figure 5: Capacity Balance- Medium Term

Table 5: Capacity Balance- Medium Term

	No new plant additions (MW)*	Approved LCLTGEP 18-37(MW)*	CEB Implementation Plans, August 10,2017 (MW)*	Peak Demand- LCLTGEP 18-37 (MW)
2017	2,622	2,622	2,622	2,441
2018	2,622	2,910	2,820	2,738
2019	2,622	3,353	3,028	2,903
2020	2,622	3,416	3,392	3,077

*Available Capacity: 90% of the Plant capacity, without one unit of LVPS and excluding NCRE

b) Energy Balance

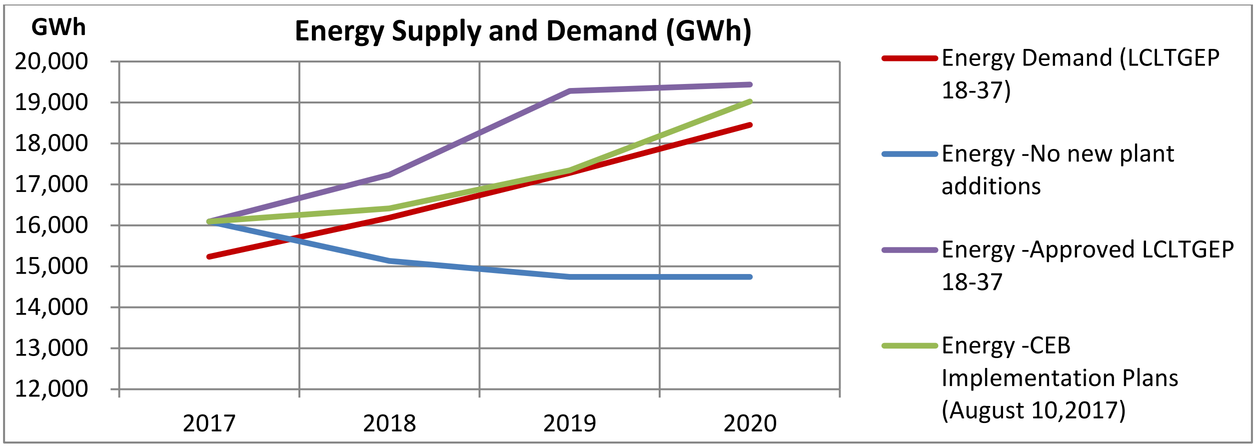

Figure 6: Energy Balance- Medium Term

Table 6: Energy Balance- Medium Term

	No new plant additions (GWh)*	Approved LCLTGEP 18-37 (GWh)*	CEB Implementation Plans -August 10,2017 (GWh)*	Energy Demand-LCLTGEP 18-37 (GWh)
2017	16,093	16,093	16,093	15,233
2018	15,136	17,236	16,410	16,188
2019	14,738	19,279	17,343	17,285
2020	14,738	19,442	19,028	18,456

* Considering 67% plant factor for LVPS and 2012 hydro dispatch (2726 GWh- lowest annual hydro dispatch 2011-16)

c) Observations

a. As shown in Figure 5, if CEB proposed plants are implemented according to CEB implementation plans- August 10, 2017, there will be sufficient capacity to supply system peak demand until 2020. If no new plants are added there will be capacity deficits from 2019 onwards.

b. As shown in the Energy Balance in Figure 6, according to 2012 hydro condition, which is the lowest annual hydro level recorded during 2011-2016, annual energy supply is sufficient to meet demand, if plant implementation is done according to the CEB implementation plans. If no new plants are added, there will be energy inadequacies in each year considered.

c. However, it is to be noted that due to the monthly variations in availability of hydro based energy (due to variations in rainfall and other seasonal limitations such as irrigation water requirement), in a dry year, in certain months energy surpluses and in other months energy deficits are expected. In order to capture this, the monthly energy supply during 2018-2020 with very low hydro availability, shown in Figure 7 (based on lowest hydro dispatch recorded in a particular month from 2011-2017), was conducted.

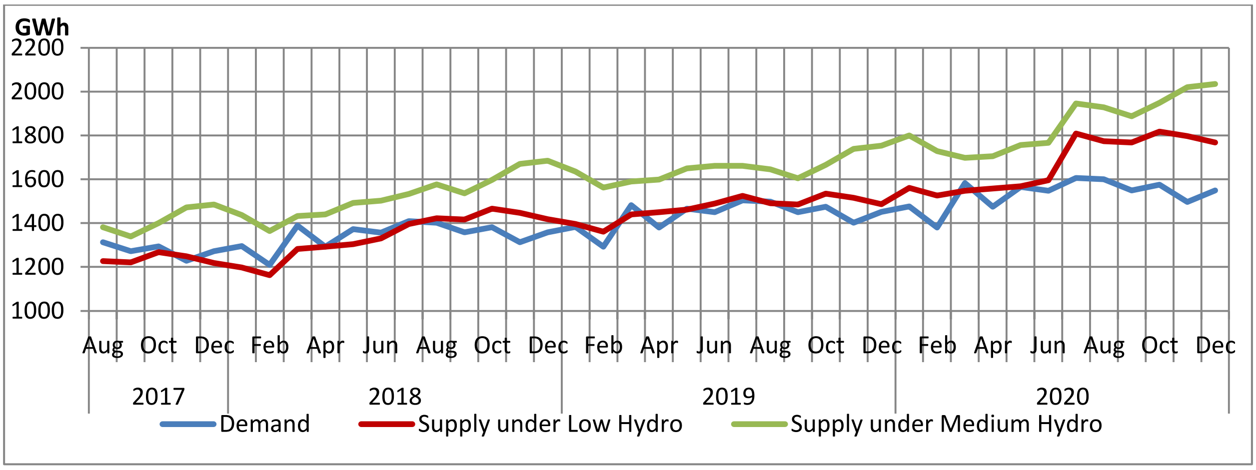

Figure 7: Monthly Energy Supply under low and medium Hydro scenarios

d. As shown in figure 7, if the hydro condition is very low, even if the plant implementation is done according to CEB implementation plans, August 10, 2017, energy deficits are expected in first half of 2018 and also in March and August in 2019 and March 2020.

d) Recommendations

a. The proposed plant additions (both thermal and renewables) in LCLTGEP should be conducted according to the CEB implementation plans presented on August 10, 2017.

b. Transmission system should be timely expanded according to the new plant additions.

c. Continuous fuel supply to all thermal plants should be ensured throughout the period.

d. However, due to the monthly variations in availability of hydro based energy, under low annual hydro condition, short-term energy deficits are expected in first half of 2018 and also in March and August in 2019 and March 2020. Hence, timely measures should be taken to avoid such energy deficits.

   Eg. If 2018 starts with very low hydro reservoir levels, the recommendations for January and February 2018 given under Sub-section A above will be required to ensure continuity of electricity supply.

e. Demand Side Management measures like, energy efficiency, conservation, peak demand shifting, etc. should be expedited to manage/ reduce the increasing electricity demand.

f. Immediate decisions should be taken on Natural Gas supply infrastructure to bring in Natural Gas for all Gas Turbines and Combined Cycle Plants

g. Immediate technical/ managerial solutions should be taken to increase the reliability of the Norachcholai Lakvijaya coal power plant.

SECTION 3 - LONG TERM RECOMMENDATIONS

What had been discussed in section 1 makes it evident that failure to implement previous Long term generation expansion plans is the main reason behind the energy predicament we are in at present.

A comparison of plant schedules in past generation plans shows that over the years there had been a number of ad-hoc changes to the plant schedule.

Uncertainly associated with base demand forecast is another noticeable feature particularly since 2011 plan. However CEB has identified this as a problem and is trying to improve the accuracy of base demand forecast by adopting new forecasting tools. Despite, the electricity demand is expected to be more stochastic in nature all over the world in long run.

No generation plan that had been considered in this analysis has foreseen the present situation. However the actual outcome has been far from what is conceived in any of those plans. Therefore, along with implementation of the recommendations discussed in previous section, the following can be recommended as permanent solutions that can ensure long term energy security in a sustainable manner.

a) Liberalize the generation sector to espouse investments by amending section 8 and 9 of Sri Lanka Electricity Act, while creating a robust power procurement programme that can introduce price competition to electricity sector. (IPPPP unit in South Africa is a good model to study in this regard) Such an act would also be beneficial for the financial sector of the country by mitigating the risk of and crowd out effect in the economy caused by large generation projects, and also avail development finance facilities for transmission projects, that are less attractive financially but more critical for grid security in long term.

b) India interconnection project should be expedited. The feasibility studies on the project are currently in the final stages as reported by the CEB. This will provide Sri Lanka access to energy exchanges in India, and will significantly reduce the risk of needing emergency power. The converter stations of the interconnection should be equipped with emergency reactive power compensation so that the project will also strengthen the transmission network (enhance the grid stability and resilience in transient states) and will make use of planned 'Veyangoda Sampur Line' that would otherwise become a stranded cost. Proper implementation of the project also has the potential to eliminate any future need of small generators for voltage support.

c) Sri Lanka Electricity Act should be amended to allow wheeling. This would significantly increase self-generation as even at present there are number of industrial consumers who are willing to invest in renewable generation if wheeling is allowed, simply for the purpose of using green energy in their production process.

d) Streamline the generation planning process and revise the format of LCLTGEP in line with exact provisions of the “Grid Planning Code”. Such an act would highlight the key assumptions that goes into the planning process and will provide all stakeholders a clear insight into the process and can make a positive contribution to the discourse. This should be done together with Long Term Transmission Expansion Plan (LTTEP) and Distribution development plans such that the connection between the plans will become clear. Such an exercise would also ease and streamline the review process and will serve as a check to ensure proper implementation of the LCLTGEP.

e) Fully ring-fencing Transmission Licensee should be followed by administrative separation to ensure that Transmission Licensee operates independently from CEB in broad national interest, to realise the objective of having a reliable, secure and cost competitive electricity industry.

f) The share of NCRE is forecasted to be increased with government policy targets. The planning process needs to take into account this and make amendments to the planning process to cater for new challenges posed by increased NCRE plant additions. In addition to conventional parameters like LOLP and reserve margin, etc. the study parameters must be developed to reflect the stability issues that is to be prompted by RE integration to our power system. The generation flexibility of conventional (grid friendly) power plants and that of the system as a whole needs to be considered for this purpose. Therefore it is high time for the utility to develop relevant matrices that look into the aspect of “planning for the adequate flexibility”. At present the focus is on some capacity related criteria such as LOLP and ENS. The system flexibility assessment is possible only if there are criteria that consider flexibility in the planning context. One example which might be implemented during system planning activities is Insufficient Ramping Resource Expectation (IRRE). This complements generation adequacy studies to assess whether planned capacity allows the system to respond to short-term changes in net load. Using robust, engineering-based measures for assessing flexibility as a component of a grid integration study can help planners to get informed judgments about the economically optimal amount and mix to procure.

Annexure I: Basis of estimation of Section 2 .A (b): Short Term Energy Balance

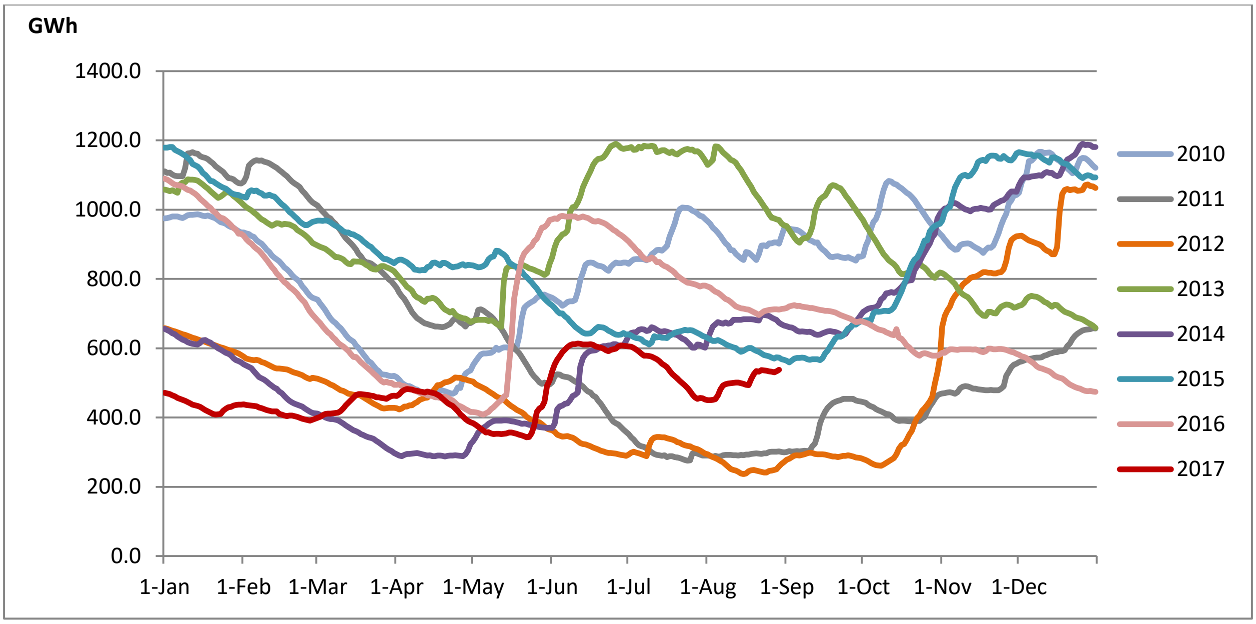

Figure 8: Variation of Major Hydro Reservoirs from 2012

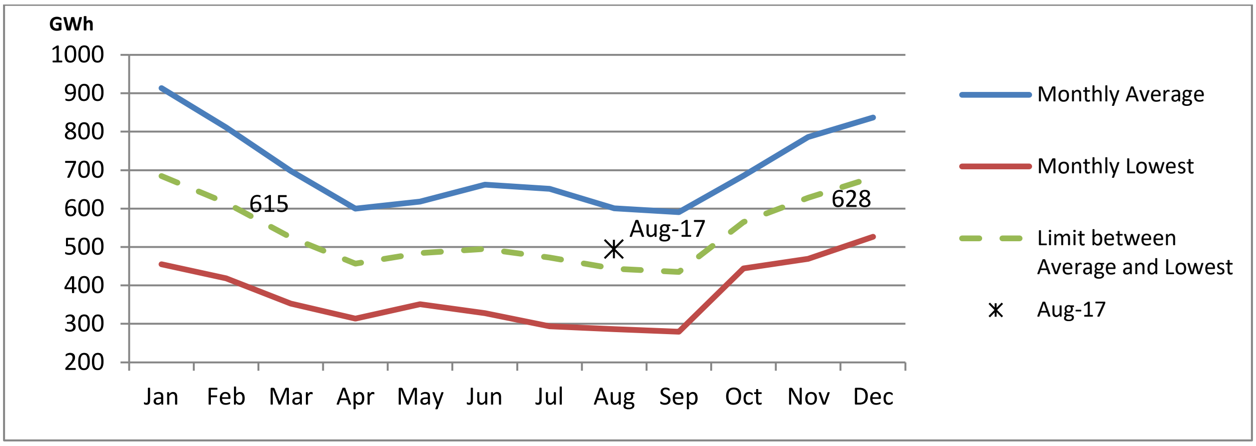

Figure 9: Monthly Reservoir Levels 2011-2017

Figure 8 shows the variation of major hydro reservoirs from 2011. It is observed that the reservoir curve shows an increasing trend in August 2017. Figure 9 shows the average and lowest monthly reservoir levels from 2011- 2017. It can be observed that the reservoir level in August 2017 is closer to the monthly average reservoir levels.

Since, reservoir level in August 2017 is closer to the monthly average reservoir levels and the reservoir curve in August 2017 shows an increasing trend, for this analysis, the average hydro dispatch level of respective month from August –February in each year from 2011-2016 is considered as the most probable hydro scenario. However, considering the possibility of low rainfall in next few months, the lowest hydro dispatch levels of respective month from August –February in each year from 2011-2016 is also considered as a probable scenario. Table 4 gives the monthly hydro dispatch level under each scenario.

Table 7: Hydro dispatch under average and low scenarios

	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Most probable hydro in GWh (monthly average 2011-17)	318	276	337	408	422	373	299
Low hydro (monthly lowest 2011-17) in GWh	164	157	205	185	155	133	98

Major Thermal plant availability for next six months is shown in table 8 below.

Table 8: Major Thermal plant availability for next six months (Source :CEB)

	Capacity (MW)	Aug	Sep	Oct	Nov	Dec	Jan	Feb
LVPS Coal I	270						week 3-4	week 1-4
LVPS Coal II	270	week 4	week 1, 4	week 1-4	week1			
LVPS Coal III	270				week 2-4	week 1-3		
Westcoast	270							
KCCP	164							
Sojitz	163	Forced outage due to Fault in steam turbine						
ACE Emb	100							
KPS GT 7	115							

Unavailable Plants	Unavailable weeks

Other factors considered in calculation of Energy Availability

- For Coal plants and Oil plants 09 and 0.8 load factors were assumed
- Plant factors for NCRE plants: Minihydro: 35%, Solar 15%, Wind 35%, Biomass: 70%
- Demand Forecast: CEB 12 month rolling plan submitted in August 2017.

Annexure II: Plant Additions According to LCLTGEP 2018-37 and CEB Implementation Plans August 10, 2017

Year	Plant Additions as per LCLTGEP 18-37		Plant Additions as per CEB Implementation Plans August 10, 2017	
	Power Plant	Commissioning Month	Power Plant	Commissioning Month
2018	100 MW Furnace Oil (FO)	January 2018	170 MW FO	January 2018 (Already available)
	70 MW FO	January 2018	100 MW FO	August 2018
	150 MW FO	January 2018	50 MW (1×50 plants)	2018
	160 MW Solar	January 2018	60 MW (rooftop)	2018
	15 MW Mini Hydro	January 2018	15 MW	2018
	5 MW Bio Mass	January 2018	5 MW	2018
2019	2× 35 MW Gas Turbines (GT)	January 2019	96 MW GT	March 2019
	300 MW LNG	January 2019		
	122 MW Uma Oya	January 2019		
	95 MW Solar	January 2019	50 MW (rooftop)	2019
	50 MW Wind	January 2019		
	15 MW Mini Hydro	January 2019	15 MW	2019
	5 MW Bio Mass	January 2019	5 MW	2019
2020			300 MW LNG	June 2020
	1× 35 MW Gas Turbines	January 2020	3× 35 MW GT	January 2020
	35 MW Broadlands Hydro	January 2020	35 MW Broadlands	January 2020
	15 MW Thalpitigala Hydro	January 2020		
	100 MW Mannar Wind (CEB)	January 2020	100 MW	January 2020
	120 MW Wind	January 2020	170 MW (Pooneryn)	January 2020
	105 MW Solar	January 2020	100 MW (Siyamabalanduwa)	January 2020
	15 MW Mini Hydro	January 2020	15 MW	2020
	5 MW Bio Mass	January 2020	5 MW	2020