Karnataka’s Power Sector Roadmap for 2021-22

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Design and Editing by: CSTEP

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July 2013

CSTEP/E/2, 2013

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Contents

Acknowledgements

The authors would like to express their gratitude to several persons who provided inputs at various stages of this report. Several current and retired officers from the State's power sector – Mr. P.R. Mallikarjuna, Mr. Murlidhar Rao, Mr. B.G Rudrappa, Mr. Kapil Mohan, Mr. Selvakumar and Mr. Manivannan – all participated through one-on-one expert sessions to provide invaluable inputs to this report. Thanks are also due to Mr. Ravishankar from SunPV energy and Mr. Hari Hegde from Wipro for sharing their experiences on solar PV installations in the State. Participants of the workshop who discussed preliminary findings of this study and the session Chairs are duly acknowledged for their valuable feedback.

The study benefited immensely through ample support from several officers of KERC – Mr. Srinivas Rao, Mr. V. Hiremath, Mr. Manjunath, Mr. Sheshadri, Mr. Y.K Nagaraj, Mr. V.G Pandit , and Mr. B.R Nagaraju. Their efforts are gratefully acknowledged. Lastly, we thank Chairman, KERC, Mr. M.R. Sreenivasamurthy for providing an overall direction to the report. We hope that the findings of this study will lead to more informed discussions and decisions in the State's power sector.

1. Introduction

1.1 Objective

The objective of this report is to evaluate Karnataka's current and future power position till the year 2021-22. This report will provide a diagnostic analysis of the issues in State's power sector and discuss options to address them. Specifically, the study seeks to estimate the likely electricity demand for the State, appraise existing capacity addition plans, estimate potential shortfalls and recommend several options available to decision makers in the power sector to address the current power shortage scenario. The intended audience for this report are government agencies, policy makers, and power sector experts.

1.2 Structure

This report is divided into four main sections. Section 2 provides a summary of the current power sector position in Karnataka. Section 3 estimates the annual energy and peak demand requirement for the State till FY22. Both unrestricted and restricted demand is projected for the State based on consumer category-wise growth trends observed in the past. The demand is calculated at utility bus-bars and indicates what the State has to plan for. Section 4 provides a discussion of the supply available to meet the estimated future demand. Expected delays in project execution are incorporated after evaluating current project status on the basis of discussions with experts in the sector. This section provides an assessment of the ability of the currently-planned projects to meet the estimated demand in each year. The reference supply scenario considers the State's plan to add generation capacity and also its allocation from central generating stations. This is evaluated against projected demand in each year to evaluate if there is a residual demand that current plans cannot meet adequately. Section 5 examines options to address residual demand. Potential impact of efforts like improving plant load factors (PLF) of State-owned thermal plants, reducing T&D losses, expediting addition of low-cost renewable sources is evaluated. Finally, Section 6 provides a diagnostic discussion of the key challenges - current and foreseeable - in generation, transmission and distribution sectors, and suggests solutions. This is based on stakeholder consultations through one-on-one and roundtable discussions conducted with power sector stakeholders in the State. Demand projections are limited to a time-series based analysis, to serve as a preface for the discussion. The report presents a compounded-annual-growth-rate (CAGR) based demand growth scenario within which the relative impacts of alternative supply-side options and anticipated residual demand can be reasonably evaluated.

2. Karnataka: Current Power Position

2.1 Institutional Structure

Electricity Generation and distribution in Karnataka has a history of over 100 years. The first generating station started operation in Shivanasamudram as early as 1902 (in the then State of Mysore) and was Asia's first hydroelectric generating station. Generation in the State was entirely from hydroelectric power until Raichur thermal power station (RTPS) started operations in 1985. Even before power sector reforms were adopted in the rest of the country, the State had separate entities for generation and distribution. Karnataka Power Corporation Ltd. (KPCL), started in 1970 owned generation while the transmission and distribution networks were owned by Karnataka Electricity Board (KEB). In 1999, Karnataka Electricity Reforms Act was passed by the State legislature and led to major reforms in the power sector. Along with the corporatisation of KEB into Karnataka Power Transmission Corporation Ltd. (KPTCL), Karnataka Electricity Regulatory Commission (KERC) was also constituted in the year as an autonomous body to regulate all aspects of the power sector in the State. In 2002, KPTCL was further unbundled to form a transmission company as well as distribution companies with mandate for distribution and retail supply of electricity to consumers in the State.

Currently, the main entities in Karnataka's power sector are the State-owned Karnataka Power Corporation Ltd. (KPCL) in generation, the State-owned Karnataka Power Transmission Corporation Ltd. (KPTCL) in transmission and five electricity supply companies (ESCOMs) - the Bangalore Electricity Supply Company (BESCOM), the Mangalore Electricity Supply Company (MESCOM), the Hubli Electricity Supply Company (HESCOM), the Gulbarga Electricity Supply Company (GESCOM) and the Chamundeshwari Electricity Supply Corporation Limited (CESC). Additionally, Hukkeri Rural Electric Cooperative Society (HRECS), the only cooperative society in the State with a distribution license, distributes power to consumers in Hukkeri Taluk and a few other villages in the area. The State Load Despatch Centre (SLDC), under KPTCL, performs the role of system operator with duties of real-time load despatch in the State's power system.

In 2007, Government of Karnataka also set up a Special Purpose Vehicle (SPV) viz. Power Company of Karnataka Limited (PCKL). PCKL is responsible for procurement of power on behalf of all the ESCOMs in the State – both through long-term options like power purchase agreements (PPA), and short-term options like exchanges, banks and bilateral transactions.

2.2 Current status of supply, demand and shortages

Karnataka's total installed generation capacity is 18,201 MW as on March 2013 (Table 1). This includes captive generation capacity of 3591[1] MW and renewable-based generation capacity of 4089 MW. Out of this, 12,605 MW has long term power purchase agreements (PPA) with the utilities (Table 2). A detailed list of thermal and hydro generating facilities supplying to the ESCOMs is available in Appendix 1.

[1] CEIG Report , March 2012

Table 1: Installed capacity (as of Mar 2013) (MW)

KPCL Thermal	2848
KPCL Hydel	3671
State share of CGS	1836
IPP Thermal	2166[2]
Renewable Sources	4089
Captive capacity	3591
Total	**18,201**

Table 2: Installed capacity under long-term PPA with utilities (MW)

KPCL Thermal	2848
KPCL Hydel	3671
State share of CGS	1836
IPP Thermal	1080
Renewable Sources	2820
Captive	350
Total	**12,605**

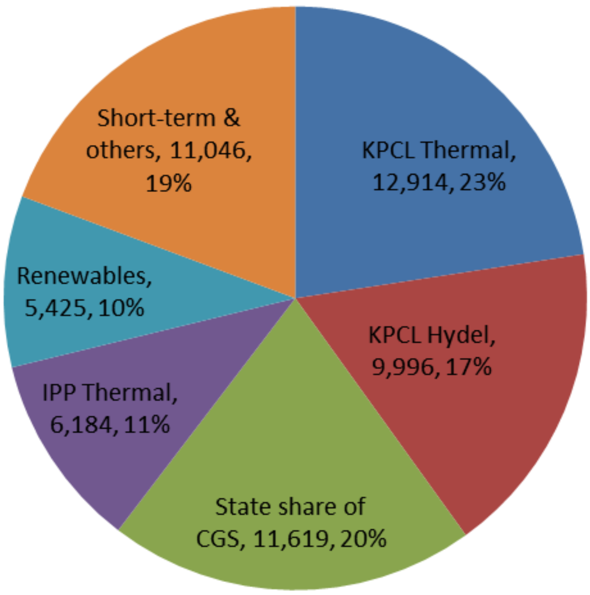

Figure 1:Source-wise purchase by utilities in FY13 (in Million units)

The source-wise contribution of power purchased by all utilities in the State is shown in Figure 1. The State-owned thermal and hydro plants contributed close to 40% of the supply in FY13. About 20% came from the State's share in Central Generating Stations (CGS) and 10% from renewable sources. It is important to note that short-term power purchases account for a significant share of the supply at 19%. As will be explained in a subsequent section, the State is increasingly relying on short-term purchases, often at expensive rates, to meet the growing energy demand.

[2] CEA, IPP-owned thermal capacity in FY12 according to CDM baseline database

During FY13, the State saw an unrestricted demand of 66,274 Million kWh at utility bus bars and a peak of 10,124 MW. As against this, it was able to supply only 57,184 Million kWh and meet a peak of 8,761 MW. It is to be noted that the State regulator approved the purchase of 60,638 Million kWh for FY13 based on tariff applications of the ESCOMs. The demand calculated at utility bus bars after applying the below restrictions is defined as restricted demand:

a) 6 hours of 3-phase supply to agricultural pump sets

b) 24 hours of supply in Bangalore and 22 hours of supply in other urban areas

c) Single phase supply to rural consumers for at least 11 hours at night

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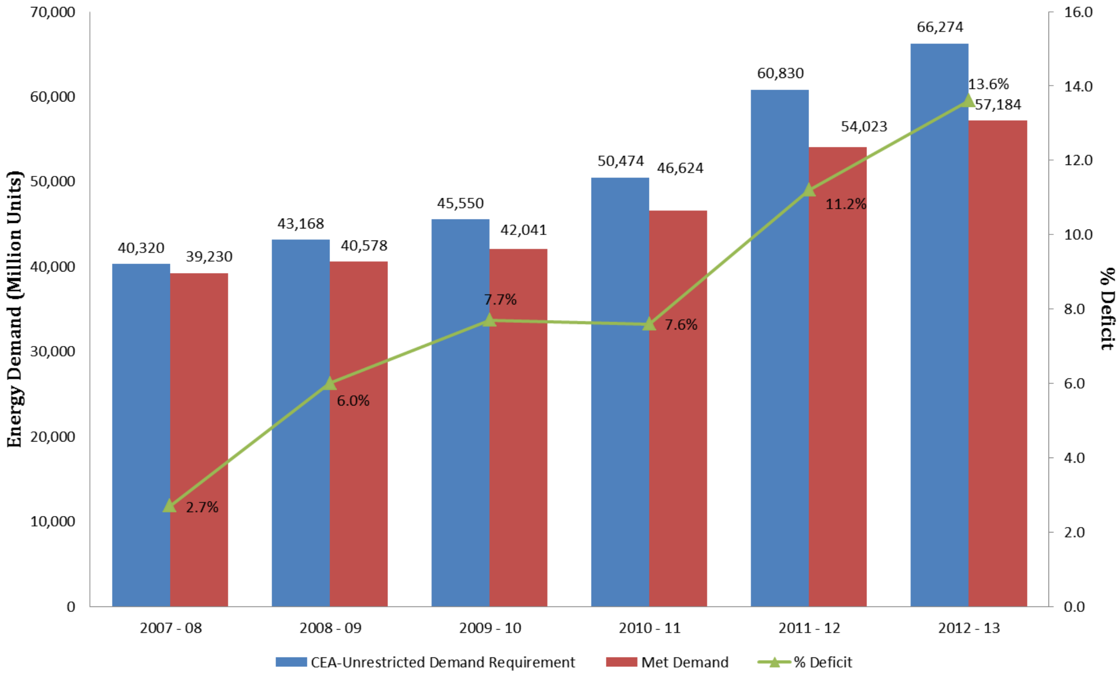

Figure 2: Unrestricted Energy Demand vs. Energy Supplied from FY08 to FY13[3]

The peak demand in the State has grown from 6,583 MW in FY 08 to 10,124 MW in FY 13 with a CAGR growth rate of 9% during the period (Figure 3). The State's peak deficit has varied over the years and was 13.5% in FY13.

[3] CEA LGBR Report 2012-13 ; Demand met at bus-bar in FY13 from KERC

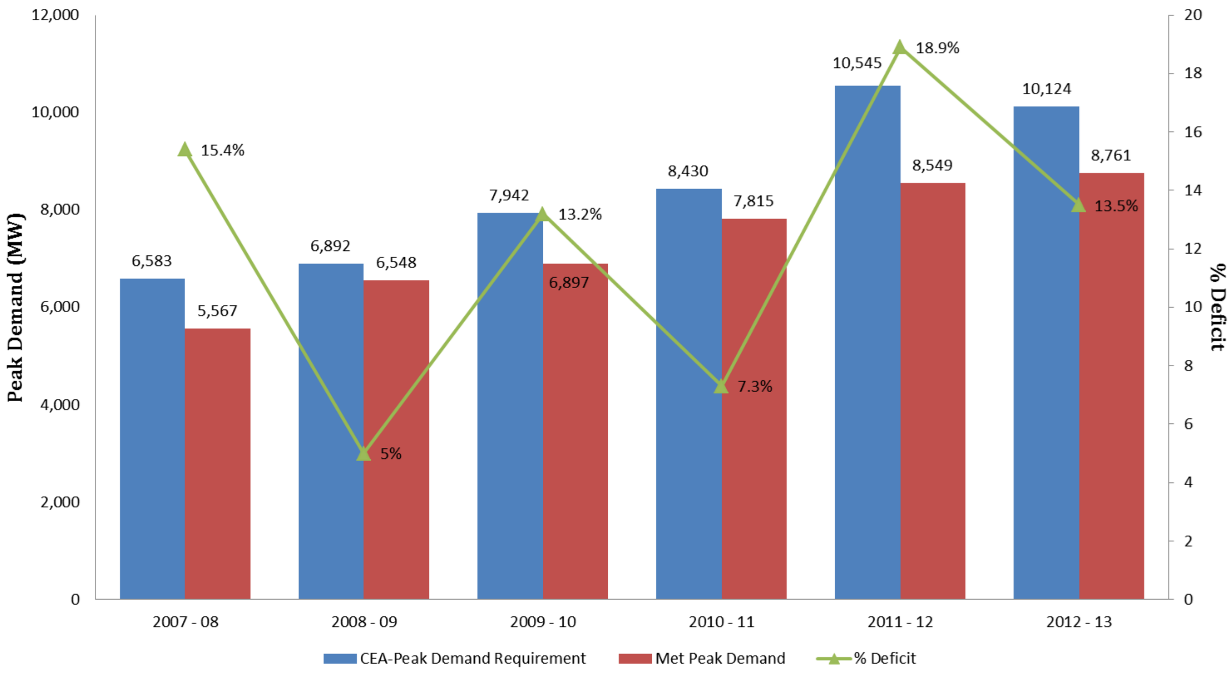

Figure 3: Unrestricted Peak Demand vs. Peak Supply from FY08 to FY13[4]

The month-wise energy and peak demand, supply, and shortfalls for the year FY13 are summarized in Tables 3 and 4.

Table 3: Month-wise energy demand and energy supply (FY13)

Month	Energy Demand (MU)	Energy Met (MU)	Short-term power purchased (MU)	Energy Shortage excluding short-term purchase(MU)	Energy Shortage including short-term purchases (%)	Energy Shortage excluding short-term purchases (%)
April'12	5,453	4,804	973	1622	11.90%	29.75%
May'12	5,506	4,940	1026	1592	10.28%	28.91%
June'12	5,440	4,742	933	1631	12.83%	29.98%
July'12	5,474	4,622	940	1792	15.56%	32.74%
August'12	5,380	4,509	913	1784	16.19%	33.16%
Sept'12	5,153	4,355	873	1671	15.49%	32.43%
Oct'12	5,287	4,620	922	1589	12.62%	30.05%
Nov'12	4,981	4,418	858	1421	11.30%	28.53%
Dec'12	5,656	4,964	893	1585	12.23%	28.02%
Jan'13	6,008	5,177	928	1759	13.83%	29.28%
Feb'13	5,570	4,785	843	1628	14.09%	29.23%
March'13	6,366	5,246	940	2060	17.59%	32.36%
TOTAL	**66,274**	**57,184**	**11,042**	**20,134**	**13.72%**	**30.38%**
Annual Energy Shortage (including short-term purchases):				13.72%		
Annual Energy Shortage (excluding short-term purchases):				30.38%		

The highest peak demand occurred in the month of April'12, while maximum shortfall was observed in March '13 at 19%. The overall peak shortfall in the year, estimated as a difference between the maximum peak demand observed and the maximum peak supplied, was 13.5%.

[4] CEA LGBR report 2012-13

Table 4: Month-wise peak demand and peak supply (FY13)

Month	Peak Demand (MW)	Peak Supply (MW)	Peak Shortage (MW)	Peak Shortage (%)
April'12	10,124	8,264	1,860	18.40%
May'12	9,424	8,148	1,276	13.50%
June'12	9,108	8,066	1,042	11.40%
July'12	9,103	7,831	1,272	14.00%
August'12	8,950	7,689	1,261	14.10%
Sept'12	9,404	7,863	1,541	16.40%
Oct'12	8,978	7,601	1,377	15.30%
Nov'12	9,123	7,852	1,271	13.90%
Dec'12	9,267	7,959	1,308	14.10%
Jan'13	9,801	8,458	1,343	13.70%
Feb'13	9,976	8,761	1,215	12.20%
March'13	9,995	8,096	1,899	19.00%
Annual Peak Shortage:		**13.50%**		

Table 5 below, summarizes the status of power sector in FY13. The State faced an energy shortfall of 5.7% on restricted demand and 13.7% on unrestricted demand. The deficit against unrestricted demand has steadily grown from 2.7% in FY08 to 13.7% in FY13 (Figure 2). This highlights Karnataka's energy challenge - The CAGR growth in unrestricted demand from FY08 to FY13 has been 10.4% while the supply-side availability has grown at a CAGR of 7.9% during the same period. Capacity addition has failed to keep pace with the growing demand.

Table 5: Current features of Karnataka's Power Sector (FY13)

Installed capacity (under long term PPA with utilities)	12, 605 MW
Unrestricted demand	66, 274 Million kWh
Restricted demand (approved by the Commission)	60, 638 Million kWh
Annual energy demand met (FY13)	57, 184 Million kWh
Deficit on approved demand	5.7%
Deficit on unrestricted demand	13.7%
Peak requirement (FY13)	10, 124 MW
Peak met (FY13)	8, 761 MW
Peak deficit	13.5%

As indicated in Table 6, Karnataka's per capita electricity consumption is still low in comparison to other high-growth States in the country. Electricity is an important enabler of economic growth and a continued shortage situation is likely to seriously hamper the State's growth prospects.

Table 6: Comparison of per capita electricity consumption (kWh)

State	Per Capita Electricity Consumption
Karnataka	925
Tamilnadu	1232
Andhra Pradesh	1065
Gujarat	1508
Maharashtra	1095

2.3 Consumer-category-wise consumption

Consumers of electricity in the State include low-tension (LT) consumers – domestic, commercial, agriculture, industries and miscellaneous categories and high tension (HT) consumers – residential apartments, industries, commercial, irrigation, water supply. The demand from agricultural pumpsets and Bhagya Jyothi/Kutir Jyothi (BJ/KJ)[5] consumers is fully subsidized by the State government as part of its policy. While agriculture consumers are mostly unmetered, complete metering is not yet achieved for BJ/KJ consumer households. Table 7 provides a comparison of Karnataka with other States in consumer category-wise consumption. Notably, agriculture sector is the biggest consumer of power in the State, unlike any other State. The share of industrial consumption in the State is low in comparison.

Table 7: Consumer category-wise consumption in various States in FY11[6]

State	Domestic	Commercial	Industrial(LT)	Industrial (HT)	Agriculture	Others
Karnataka	19%	11%	4%	29%	31%	6%
Gujarat	13%	6%	12%	47%	19%	3%
Maharashtra	21%	13%	8%	35%	18%	6%
Andhra Pradesh	20%	7%	4%	36%	26%	7%
Tamilnadu	24%	9%	9%	34%	18%	6%

The consumer category-wise sales in Karnataka for FY12 are shown in Figure 4 below. Since energy sales are reported at the closure of the financial year, the future years considered for projecting the demand are henceforth denoted in terms of the financial year (e.g. FY08).

[5] BJ/KJ connections are for the below poverty line (BPL) consumers for a single-point light connection. The connection is moved to domestic category if the usage is > 18 units/month

[6] CEA General review 2012

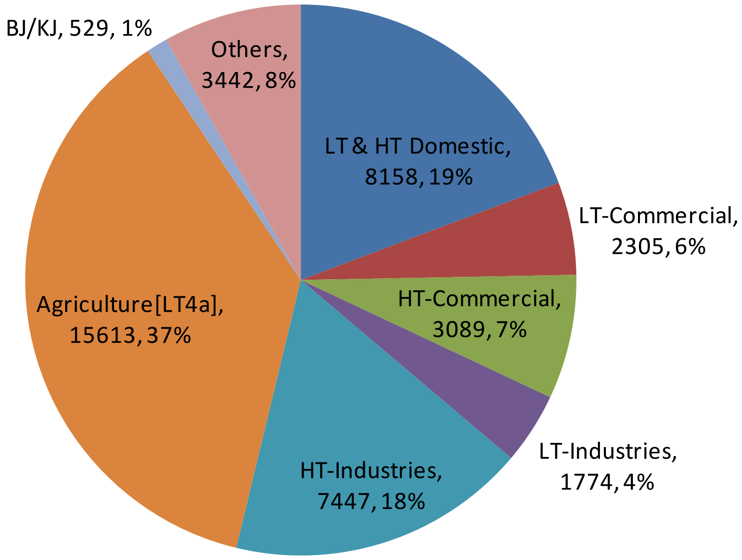

Figure 4: Consumer category-wise energy sales (FY12) (Million Units)

Similar disaggregated sales data are available from FY 08 to FY12 and the year-wise growth rate for the various categories of consumers is summarized in Table 8 below:

Table 8: Year-on-year growth rate of consumption in main consumer categories

Consumer Category	Period			
	FY09	FY10	FY11	FY12
LT & HT-Domestic	8.3%	7.3%	9.8%	8.3%
LT & HT-Industries	5.3%	3.4%	12.4%	9.1%
LT & HT-Commercial	13%	8.4%	11.5%	11.2%
Agriculture [LT4a]	5.3%	4.2%	9.0%	22.5%

Industries, Domestic, and Agriculture categories account for more than three-fourths of the total consumption. The trends for these categories over the past five years are presented below (Figures 5 – 7). It is important to note that the growth trends are an indicator of demand met rather than true demand growth from these consumers. Utilities in the State follow several restrictions (as detailed in Section 2.2) to various consumer categories due to the prevailing shortage situation.

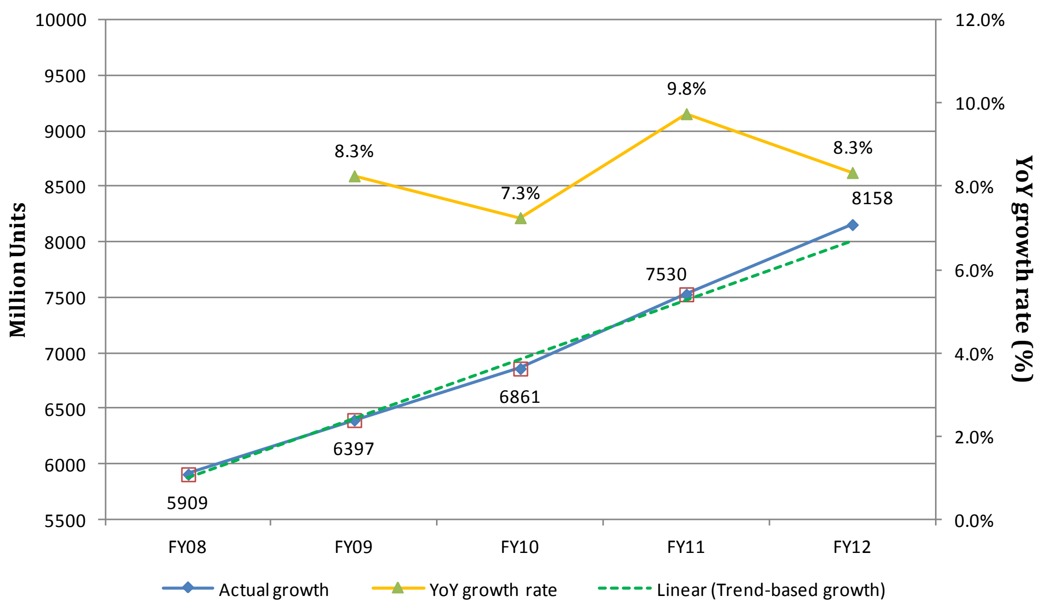

Figure 5: HT&LT-Domestic demand growth (FY08 – FY12)

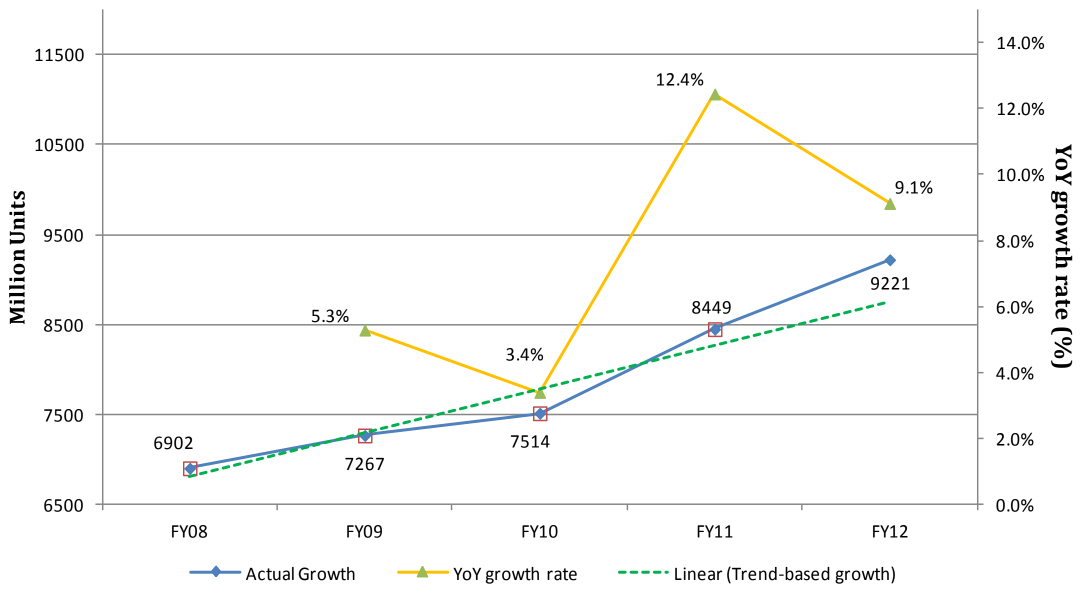

Figure 6: HT& LT Industry energy sales (FY08 – FY12)

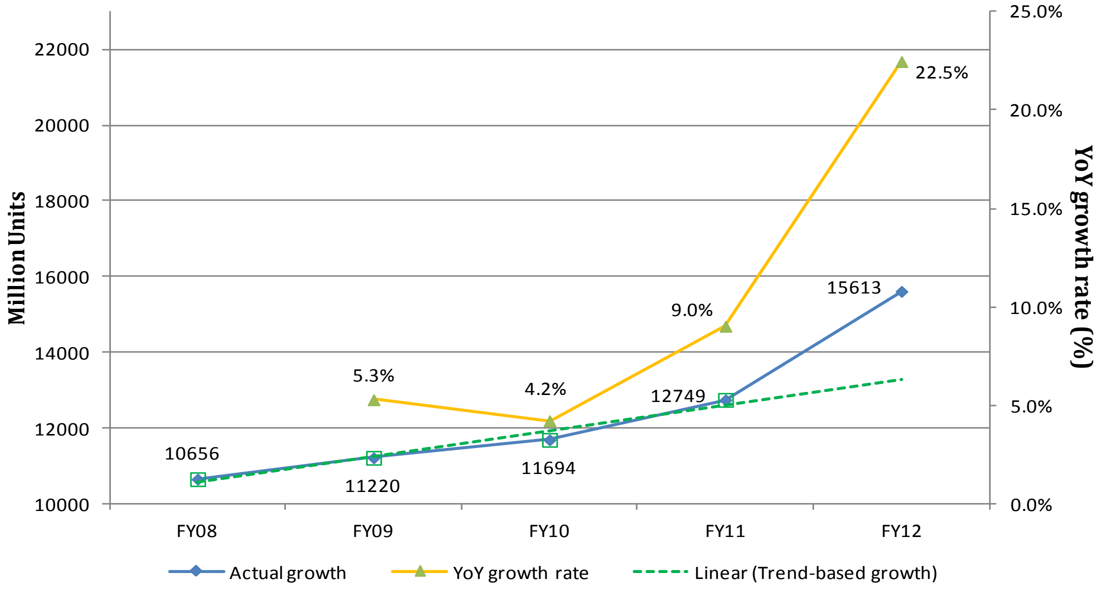

Figure 7: Agriculture LT4a energy sales (FY08 – FY12)

The energy consumption of Domestic and Industry categories grew close to the linear trend. However the energy consumption by the agricultural sector in FY12 increased by 22.5%. In the same period, the real GSDP of agriculture sector declined by 3% as shown in Figure 8. There is therefore, a need to verify the actual consumption in agriculture sector by either metering of all IP sets or through exclusive agricultural feeders.

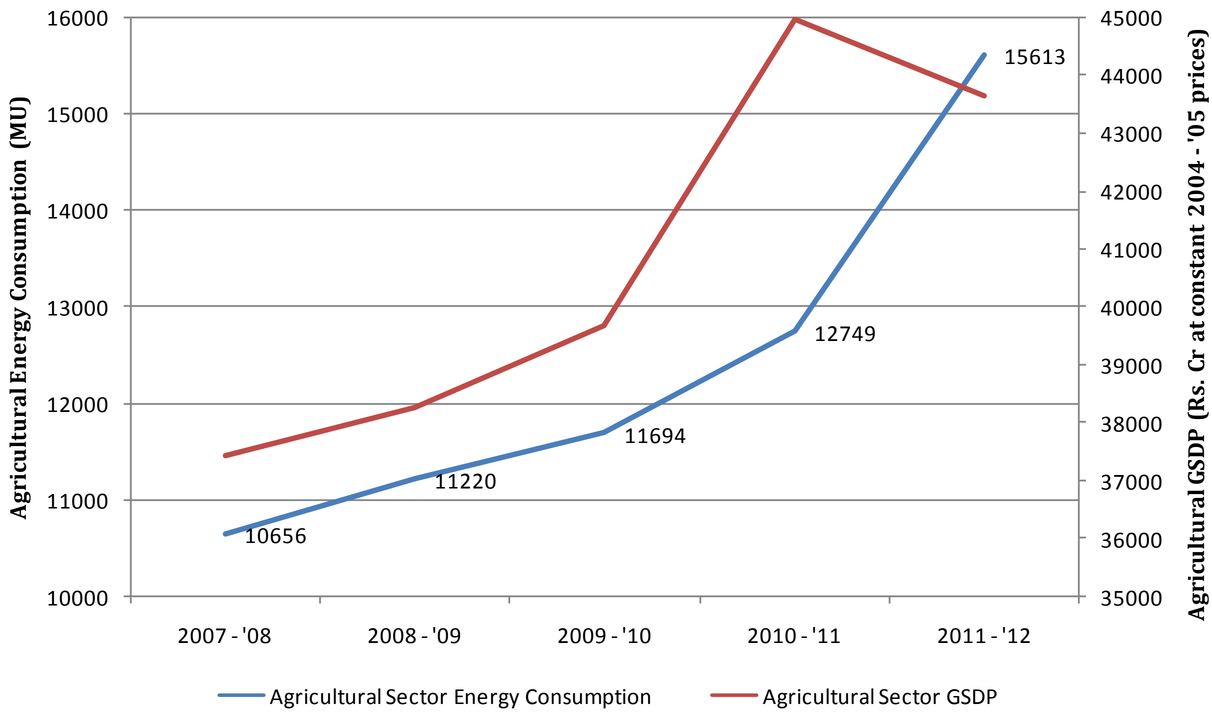

Figure 8: Agriculture Sector: Energy Consumption vs. GSDP (FY08 – FY12)

Source: KERC; Planning, Programme Monitoring & Statistics Dept.

The current features of supply to agriculture consumers are outlined below

a) Unmetered in most cases
b) Fully subsidized by Government of Karnataka since July 2008
c) Policy of the government is to supply 6 hours of 3 phase supply

However, in reality, the 6 hours of supply is not provided at specified hours. Also, agricultural consumption happens across both 3-phase and single-phase supply. There is a need to ensure that it is provided at specified time periods so that it can be used efficiently. The State's subsidy cost towards agriculture consumption showed an increasing trend at 4160 Cr in FY12 and 4722 Cr in FY13. There is an immediate need to plan for and implement a more sustainable policy for supplying power to agriculture sector.

3. Demand Estimation: 2013 - 2022

3.1 Data and Methodology

This analysis uses a CAGR-based methodology for projecting future energy demand. There are multiple methodologies for projecting electricity demand e.g. partial end-use, econometric, etc., some of which may have higher accuracy as they are based on primary data on end-use. However, the primary aim of this analysis is to summarize the challenges faced by the power sector, and enable a discussion for the same. Hence, a single methodology is chosen, in order to provide a basis for such discussion. A comparison is made with other projections (CEA's 18th EPS, and Perspective Planning Study commissioned by KPTCL and carried out by Power Research Development Corporation Ltd. (PRDCL)), in order to see if the projections fall within a reasonable range of expected outcomes.

The data for projecting future growth in demand is drawn from the energy sales data filed by the State ESCOMs with KERC for each year from FY08 and FY12. This is used to determine the 4-year Compounded Annual Growth Rate (CAGR) for each consumer category (Table 9). With FY12 data as the base year, this was used to project the category-wise demand on a yearly basis till FY22. The CAGR growth rates between FY08 and FY12 are used for all consumer categories except agriculture. As mentioned in the previous section, agriculture consumption for FY12 showed a sudden and steep increase, in spite of the decline in State's agricultural productivity in the year. Since the cause for the sudden increase cannot be reasonably ascertained, we have considered FY12 as an outlier for agricultural consumption and excluded it from calculation of CAGR. The 4-yr CAGRs for the consumer categories hence arrived at are listed below:

Table 9: Consumer category-wise CAGRs

Consumer Category	4-yr CAGR
LT-Domestic	8.5%
HT-Domestic	5.2%
LT-Commercial	12.1%
HT-Commercial	10.2%
LT-Industries	2.4%
HT-Industries	8.9%
Agriculture[LT4a]	4.6%
BJ/KJ	9.3%
Others	7.5%

For the sake of comparison, the consumer category-wise CAGRs recently estimated by PRDC for KPTCL[7], are listed below (Table 10):

[7] Perspective Planning study for KPTCL, Power Research Development Consultants (PRDC)

Table 10: Consumer category-wise CAGRs

Consumer Category	4-yr CAGR
BJ/KJ	12.74%
Domestic Lighting	7.51%
LT-Commercial	11.07%
LT-Power	4.37%
Water works	11.18%
IP sets	5.49%
HT Power	9.76%
Street Lighting	8.46%

A point to be noted here is that, the concept of 0.2% Loss Of Load Probability (LOLP) as a reliability criterion has been recommended in the report of the working group on power sector for the 12th and 13th plans. LOLP is the probability that a system will fail to meet the load demand under the specified operating conditions. It is the proportion of days per year, or hours per year, when the available generating capacity is insufficient to serve the load demand. In this analysis, the hourly load projection for all the 8760 Hours in a year is not attempted due to lack of data. Instead, aggregate total energy demand and peak load demand of the year are considered for future projections. Hence, the concept of LOLP is not applied in the report.

The projected category-wise demand using the above CAGRs is summarized for FY13 and for the end of five-year plans in Table 11 below.

Table 11: Projected consumer category-wise energy consumption (Million Units)

Year	LT Domestic	HT-Domestic	LT-Comm.	HT-Comm.	LT-Industry	HT-Industry	Agriculture [LT4a]	BJ/KJ	Others	Total
FY13	8657	186	2584	3406	1817	8112	16328	578	3699	46, 182
FY17	11986	228	4082	5029	1998	11421	19536	824	4934	60, 038
FY22	18002	293	7230	8188	2251	17517	24444	1283	7073	86, 281

To the total projected consumption in each year, shortage in base year (FY12) between restricted energy demand and actual supply is added to arrive at the true energy demand for each year. Further, transmission and distribution (T&D) losses in the State are added to estimate the bus bar restricted demand that the utilities must plan to procure in that year. For the reference scenario, a 0.5 percentage point annual reduction in T&D losses are assumed based on expected improvements in transmission and distribution efficiency. End-use energy efficiency improvements are not accounted for as it requires a detailed assessment of the existing stock of appliances in the State, rate of diffusion of efficient appliances and processes and rebound effects. Assessing this is outside the scope of this work and therefore not considered while estimating demand.

3.2 Demand Projections

Aggregate demand

The year-wise projected restricted and unrestricted demand at utility bus bars, till FY22 is summarized in Table 12 below. It also shows the annual year-on-year (YoY) growth rate in both demand scenarios. For comparison, 18th electric power survey (EPS) projections by CEA are also presented.

Table 12: Projected unrestricted and restricted energy requirement at bus bar (Million Units)

Year	Projected bus-bar requirement (restricted demand)	YoY growth rate	Projected bus-bar requirement (unrestricted demand)	YoY growth rate	18th EPS Projections
FY-14	63,412	4.6%	66,835	4.1%	62980
FY-15	67,355	6.6%	70,778	5.9%	68208
FY-16	71,597	6.6%	75,020	6.0%	73278
FY-17	76,164	6.7%	79,587	6.1%	78637
FY-18	81,081	6.8%	84,504	6.2%	83917
FY-19	86,880	7.5%	90,303	6.9%	89285
FY-20	93,160	7.5%	96,583	7.0%	95059
FY-21	99,965	7.6%	1,03,388	7.0%	101309
FY-22	1,07,342	7.6%	1,10,765	7.1%	108012

Peak Demand Projections

Annual CAGR growth of 9% in unrestricted peak demand is calculated from FY08 to FY12. Peak demand is expected to grow at a faster rate than energy demand due to increased affordability and usage of appliances such as Air-Conditioners, refrigerators, ovens, etc. Peak demand projections under different scenarios are derived (Table 13 & Figure 9). Two sets of peak demand projections are made - Scenario 1 is based on the historical peak growth at 9% and in scenario 2, a load factor[8] of 70% is assumed on the unrestricted demand projected in Table 12. The 18th EPS has considered a load factor of 70.5% in FY14, further reduced by 0.5% every year to reach 69% in FY17. Considering the range of projected load factors under 18th EPS, the 70% load factor has been assumed as reasonable for the purpose of demand projections up to FY22. The results are compared with the 18th EPS projections and PRDC projections.

[8] Load factor is defined as average load divided by peak load in a year, calculated for unrestricted load

Table 13: Peak Demand Projections in different scenarios till FY22

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022
With 9% CAGR	11035	12028	13111	14291	15577	16979	18507	20173	21988
With 70% Load Factor	10899	11542	12234	12979	13781	14727	15751	16860	18063
PRDC Projections	11317	12776	14107	15539	16956	18235	19501	20831	22209
18th EPS Projections	10198	11123	12036	13010	13964	14945	16005	17159	18403

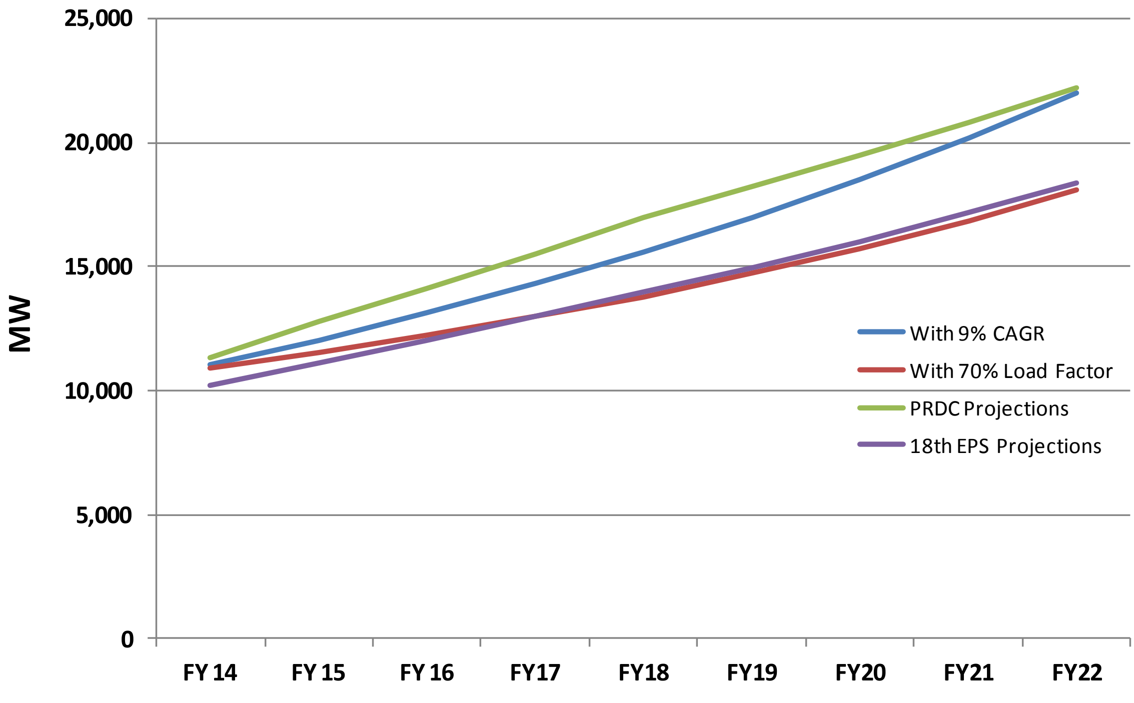

Figure 9: Peak demand projection for various scenarios

KERC regulations mention that EPS projections by CEA will be applicable for the State of Karnataka for planning purposes. This analysis provides a projection for energy demand in 2022, which lie within an overall expected range of outcomes in comparison with other studies. It is recommended that the State take into consideration the range of projections available from the various studies for planning purposes, in addition to those by CEA.

4. Available Supply: 2014 - 2022

In this section, we evaluate the ability of the State's current and planned supply options to meet the demand projected in the previous section. We consider all capacity that has power purchase agreements (PPA) signed with the State's ESCOMs.

4.1 Data sources

The data regarding existing and planned capacity addition and their ownership is obtained from publicly available data for the State. Expected date of commissioning of each project has been arrived at after discussion with PCKL to account for known delays. The delay is attributed to several factors such as environmental clearances and legal issues with tenders and contracting. Therefore, in some cases, the expected date of commissioning differs from scheduled dates. For renewable energy sources (wind, solar, and biomass-based cogeneration), future capacity addition is as per plans of the State Renewable Agency, Karnataka Renewable Energy Development Limited (KREDL) over the next two five-year plan periods. The list of projects, with their expected commissioning dates assumed for our analysis, is presented in Table 15 and Figure 10 provides a corresponding graphical view of the total capacity expected in each year from FY14 to FY22.

4.2 Reference Demand-Supply Scenario

The State's plan to add conventional and renewable–based capacity and also its expected share in CGS are used to construct the reference demand-supply scenario. As per PCKL's estimates for the State Energy Department's Annual Report for FY13[9], a capacity of about 19, 100 MW is expected to be installed from 2013 – '14 to 2021 – '22. The status of the list of projects, under various stages of execution, was further assessed in consultation with PCKL and KERC as mentioned in Section 4.1, in order to incorporate foreseeable delays till 2016 – '17. A more realistic estimate of planned installed capacity, amounting to an addition of 14, 265 MW by 2021 – '22 is considered as a reference scenario. Plant load factors (PLF) of different supply options are based on current PLFs. For e.g., PLF of State coal plants are assumed to be 64% in reference scenario based on current PLF of KPCL thermal plants. Improvements on these PLFs are possible, but require effort from State-owned institutions. Hence, reference scenario is constructed to analyse a situation where PLFs continue in business as usual mode (Table 14)

[9] Annual Report for 2012 – '13, Energy Department, Govt. of Karnataka

Table 14: PLFs/CUFs for reference supply scenario

Category	Annual average PLFs/ CUFs (%)
State Coal	64%
IPP Thermal	70%
Hydro	40%
Gas	40%[10]
Diesel/Oil	30%
Wind	26.5%
Small hydro	30%
Solar	19%
Cogeneration[11]	60%
Biomass	75%
CGS	80%

Further, supply-side estimations for reference scenario are based on the below assumptions:

1. Only capacities contracted by ESCOMs under long-term PPAs are considered
2. PLF for operations are as indicated in Table 14
3. All thermal plants are assumed to provide annual PLFs as indicated in Table 14 in the year after the expected date of commissioning

Table 15 below provides a list of all the planned supply options for the State until FY22.

[10] Since there are no gas-based plants operational in the State, average PLF of gas-based capacity in the State-sector in the country is assumed to apply

[11] About 50% of cogeneration is assumed to be supplied to the grid

Table 15: Expected Year of commissioning of new projects

Expected Year of Commissioning	Project Name	Utility	State Share (MW)	Sector
2013-14	Vallur (Unit - 2&3)(1x500)(JV with TNEB)	NTPC	74	CGS
	NLC Expansion Stage II (Unit - 1&2)(2x250)	NLC	110	CGS
	Tuticorin (Unit - 1&2)(2x500)(JV with TNEB)	NLC	158	CGS
	Jurala (Unit - 1 to 6(6x39)	JV	117	IPP
	NCE	KREDL	413	State
	Sub-Total		**872**	
2014-15	Kudankulam Unit - 1&2 (2x1000 MW)	NTPC	442	CGS
	Guledagudda in Bagalakote district - 100 MW	NTPC	100	State
	NCE	KREDL	350	State
	Sub-Total		**892**	
2015-16	Yermarus (1x800MW) Unit-1	KPCL	640	State
	NCE	KREDL	350	State
	Sub-Total		**990**	
2016-17	Bidadi Gas PP (700 MW)	KPCL	700	State
	Yermarus (1x800 MW) Unit -2	KPCL	640	State
	BTPS Unit - 3 (700 MW)	KPCL	350	State
	GHEP Additional Unit (1x20 MW)	KPCL	20	State
	NCE	KREDL	350	State
	Sub-Total		**2060**	
2017-18	Krishnapatnam UMPP Unit - 1, 2 & 3 (3x660)	UMPP	396	CGS
	Kudgi Unit 1&2 (2x800)	NTPC	800	CGS
	Pudimadaka Unit -1 & Unit -2 (2x800)	NTPC	240	CGS
	Sirkali New TPP (2X500)	NLC	132	CGS
	NLC New TPP (2X500)	NLC	71	CGS
	Orissa UMPP, Unit -1	UMPP	58	CGS
	Edlapur - 800MW	KPCL	640	State
	Munirabad (1x10 MW) - Hydro	KPCL	10	State
	Chattisgarh (Godhana(Unit-1 (1x800 MW)	KPCL	480	State
	Maduragudda in Hassan District -36 MW	NTPC	36	State
	NCE	KREDL	350	State
	Sub-Total		**3213**	
2018-19	Krishnapatnam UMPP Unit - 4, 5 & 6 (3x660)	UMPP	396	CGS
	Pudimadaka Unit -3&4 (2x800)	NTPC	240	CGS
	Sirkali Power Project Unit -2&3 (2x660MW)	NLC	264	CGS
	Kudgi Unit- 3&4 (2x800 MW)	NTPC	800	CGS
	Orissa UMPP, Unit - 2&3	UMPP	116	CGS
	Chattisgarh (Godhana) Unit-2 (1x800MW)	KPCL	480	State
	Case- 2 Gulbarga Unit -1 (660 MW)	PCKL	660	State
	NCE	KREDL	350	State
	Sub-Total		**3306**	
2019-20	Pudimadaka - Unit-5 (1x800 MW)	NTPC	120	CGS
	Kudgi Unit - 5 (1x800 MW)	NTPC	400	CGS
	Orissa UMPP, Unit- 4&5	UMPP	116	CGS
	Case-2 Gulbarga Unit-2 (660 MW)	PCKL	660	State
	NCE	KREDL	350	State
	Sub-Total		**1646**	
2020-21	Orissa UMPP, Unit -6	UMPP	58	CGS
	Cheyyur - TN Unit 1 & 2 (2x660 MW)	UMPP	264	UMPP
	NCE	KREDL	350	State
	Sub-Total		**672**	
2021-22	Cheyyur - TN Unit 3&4 (2x660 MW)	UMPP	264	UMPP
	NCE	KREDL	350	State
	Sub-Total		**614**	
Grand Total			**14265**	

Figure 10 provides a graphical representation of the same.

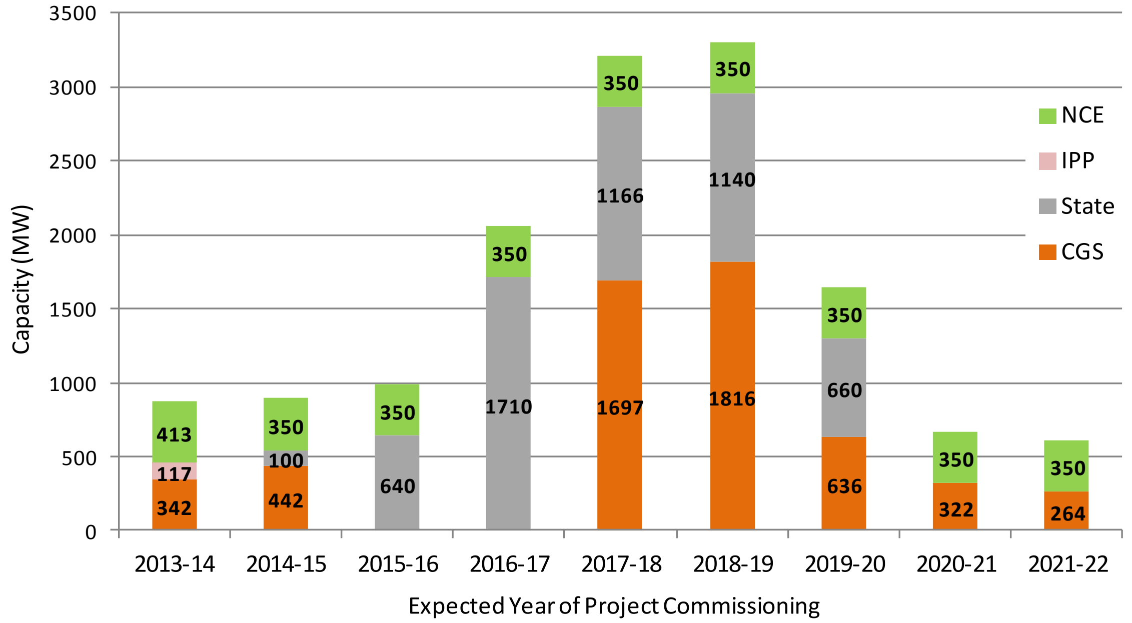

Figure 10: Expected capacity addition from long-term PPAs till FY22

Until FY-16, the State has to rely completely on successful commissioning of central sector projects for major thermal capacity addition. In the renewables sector, KREDL plans to contract 350 MW to renewables from IPPS each year until FY22. Year-wise supply expected until 2017 are listed below:

FY-14: Expected thermal capacity addition is from Vallur unit of NTPC (74 MW), NLC expansion (110 MW) and Tuticorin (158 MW), all central-sector projects.

FY15: Capacity addition is expected from Kudankulam nuclear plant (442 MW). Additionally, NTPC is expected to commission a 100 MW wind farm in Guledagudda (100MW).

FY16: Yermarus Unit 1 (640 MW) is expected only in FY-16 as opposed to the original scheduled date of 2014 because of ongoing delay in getting coal linkages.

FY17: Yermarus Unit 2 (640 MW), BTPS Unit3 (350 MW) and Bidadi gas-based plant, all State-owned projects, are expected only in 2017 provided the current fuel linkage issues and litigation challenges in Bidadi are overcome.

There is little information about status of plans scheduled for beyond 2017. All expected projects are listed in Table 15. Following are the major State-owned projects expected in the next 5 years for which the State must monitor progress periodically and ensure commissioning on schedule to secure its energy supply:

a) Yermarus (2×800 MW) is expected to generate 11,900 Million units (MU) of energy annually. Financial closure was achieved in November 2011 and it is scheduled for commissioning in 2014. However, coal and ash handling systems are incomplete and the unit is unlikely to be commissioned by 2014 as per the original schedule.

b) Bellary Unit 3 (700 MW) is scheduled for 2014 and is expected to generate 5200 MU of energy annually. However, construction work is still in progress. It is important to ensure availability of coal to unit 3 so that delays similar to unit 2 are not experienced. It is unlikely to be on schedule based on current status

c) Edlapur (800 MW) plant is expected to generate 5950 MU of energy annually. Although LoI is issued to BHEL, work will be commenced only after MoEF clearance which is delayed as coal allocation is pending.

d) Godhana (2×800 MW) thermal plant in Chhatisgarh is to be executed as a joint venture with L&T and is expected to generate 11,900 MU of energy annually. Land acquisition and water allocation have been completed by the Government of Chhatisgarh. However, it is still awaiting environmental clearance due to non-allocation of coal linkages.

e) Gulbarga (2×660MW) supercritical units was planned to be established through a Case 2 bidding route. Although 16 bidders have been shortlisted based on expressions of interest, coal linkages and water allocation are pending.

f) Bidadi combined cycle power plant (700 MW) is scheduled for FY16 and is expected to generate 5200 MU of energy annually. Although preliminary work, land acquisition and gas transmission agreement with GAIL have been completed, the tendering process for EPC work is incomplete. With the availability of a gas pipeline, the State can plan for more open-cycle gas-based units. This will contribute toward flexibility of the grid to manage intermittency from renewable sources

4.3 Estimation of Residual Demand

The question to examine is to what extent the State's current and planned capacity is adequate to meet the State's electricity requirements as projected in the previous section (Table 11). We define *residual demand* as the difference between projected energy demand for a year and the expected energy available in that year from current and planned capacity – i.e. residual demand is that portion of the projected demand in a year that will be unmet even after supply options available in that year from long-term PPAs are accounted for. Estimated residual demand is presented in Table 16 below. In this section, we calculate residual demand for each year and discuss several options that the State can explore to meet this.

Table 16: Meeting restricted and unrestricted demand for reference scenario (Million Units)

Year	Available supply at utility bus bar	Restricted demand at utility bus bar	Residual restricted demand	%	Unrestricted demand at utility bus bar	Residual unrestricted demand	%
FY-14	51,635	63,412	11,777	20%	66,835	15,200	23%
FY-15	55,043	67,355	12,312	19%	70,778	15,735	22%
FY-16	58,920	71,597	12,677	19%	75,020	16,100	21%
FY-17	63,358	76,164	12,805	18%	79,587	16,228	20%
FY-18	72,260	81,081	8,822	11%	84,504	12,245	14%
FY-19	91,211	86,880	-4,331	-5%	90,303	-908	-1%
FY-20	1,11,108	93,160	-17,949	-20%	96,583	-14,526	-15%
FY-21	1,20,045	99,965	-20,080	-21%	1,03,388	-16,657	-16%
FY-22	1,23,082	1,07,342	-15,739	-15%	1,10,765	-12,316	-11%

In the reference scenario, the State will continue to have a residual demand until FY18 that cannot be met through current plans for capacity addition alone. State-owned thermal plants are not expected to be commissioned until FY16 and the State will need to rely on capacity share from CGS until then. Until FY16, ~20% of the demand will be residual. This means that State has to plan for about 12,000 Million units of power through capacity beyond its current PPA contracts.

One way to serve this residual demand is through short-term power purchases. In recent times, the State has resorted to considerable short-term power purchase, often at higher rates compared to average cost of purchase from long-term PPAs. This will have an impact on average revenue requirement of ESCOMs and consequently on tariffs. Better planning and determined efforts to improve from the reference scenario (detailed in Section 5) can reduce the quantum of short-term power purchases by ESCOMs in the State.

Based on expected capacities coming up every year, Peak supply availability is estimated with the assumption that availability of each type of source during peak period will remain same as average availability during peak periods in the months of Jan'13, Feb'13 and March'13. Solar capacity is not expected to contribute to peak while 10% of wind capacity is assumed to contribute to peak. Peak availability assumptions are listed in Table 17 and the residual peak demand is estimated for each year till FY22 [Table 18].

Table 17: Availability of each type of source during peak supply

KPCL Thermal	72%
IPP Thermal (coal + diesel)	71%
KPC Hydel	62%
Gas	84%
Diesel/Oil	19%
Wind	10%
Mini hydel	59%
Solar	0%
Biomass + Cogeneration	73%
CGS	68%

Table 18: Peak Supply and Peak shortage estimation till FY22 (with 70% load factor scenario)

	FY-14	FY-15	FY-16	FY-17	FY-18	FY-19	FY-20	FY-21	FY-22
Projected Peak demand	10899	11542	12234	12979	13781	14727	15751	16860	18063
Estimated Peak Supply	9355	10203	10936	12459	13032	15556	17856	19180	19569
Residual Peak demand (%)	14%	12%	11%	4%	5%	-6%	-13%	-14%	-8%

The analysis reveals that the State is staring at a serious power deficit situation till FY18, both in terms of aggregate energy demand and ability to meet peak loads. Due to transmission corridor constraints, importing power from other States is an uncertain option. Electricity being an important enabler of growth, such a continued shortage situation can result in widespread load shedding and can have serious consequence on the State's economy if no proactive steps are taken to improve the power sector situation. In the next section, we discuss options that the State can target to meet the residual demand and improve power sector deficits in the next 5 years.

5. Options to improve power scenario

We consider several options that are determined efforts that the power sector stakeholders in the State can pursue in the next 5 years to address the impending power shortage situation.

Option 1: Improvement in PLF of State thermal plants

Improvement of PLFs of State-owned coal plants to 80%

A major contributing factor for the energy deficit is that the Plant Load Factors (PLFs) of State owned thermal-generating stations have declined. Historically, State plants have operated at high PLFs (close to 90% in FY08), as shown in Table 19. This has declined to about 63% by RTPS and 66% by BTPS in FY12.

Table 19: Historic PLFs of State-owned Coal Plants

Year	RTPS	BTPS
2006-07	71.2%	-
2007-08	89.2%	-
2008-09	84.5%	-
2009-10	67.9%	61.7%
2010-11	78.6%	57%
2011-12	63 %	66%

Source: KPCL

In spite of the addition of 750 MW of thermal capacity since 2010 through RTPS Unit-8 (250 MW) and BTPS Unit 2 (500 MW), the generation from State-owned thermal capacity has stagnated during the last three years. Experts cite a combination of factors contributing to operational challenges faced by the plant:

•Poor coal quality due to the switch from washed to raw coal - Washed coal contract in RTPS was discontinued in 2008 –09 stating cost concerns. Although it cannot be concluded that lower PLFs are a direct result of the switch to raw coal, lower calorific value of raw coal may be a significant contributor to operational problems. Additionally, this switch is also likely to have a degrading effect on boilers and steam pipes and can cause further technical problems

•High frequency of forced outages due to failure of boiler tubes, coal handling, and ash handling systems

•Lack of spares for old equipment, especially Units 1 and 2 which are more than 25 years old

If immediate steps are taken to improve the PLFs of State coal plants to at least 80%, residual restricted demand reduces to about 5,000 MU by FY16. Improved PLFs have a high impact on the State's power situation as shown in Table 20 below.

Table 20: Impact of Option 1 (Million Units)

Year	Incremental energy through Option 1	New residual restricted demand	New residual unrestricted demand
FY-14	7625	4153	7576
FY-15	7625	4687	8110
FY-16	7625	5052	8475
FY-17	8522	4284	7707
FY-18	9909	-1088	2335

In order to maintain a high PLF in State-run plants, it is necessary to have an objective appraisal of costs and benefits of continuing with raw coal. Washed coal has lower ash content, is easier to handle because of uniformity in the size of raw material and causes lower degradation to plant parts. A unit-wise outage analysis can provide better understanding of causes of frequent and recurring forced outages. Additionally, benchmarking plant performance with other units in the country of similar age can be a basis for engineering solutions through refurbishment and modernization (R&M). R&M of old units have the potential to boost operational performance significantly as evidenced by improved performances of central power plants like Badarpur. Table 21 provides the PLF of a few coal plants that have several units commissioned more than 25 years ago.[12]

Table 21: PLF of coal plants with units older than 25 years (during FY11)

Plant	PLF %
Badarpur TPS	74%
Singrauli STPS	97%
Rihand STPS	93%
Unchahar TPS	93%
Dadri(NCTPP)	83%

In addition to the above measures, the State may consider restructuring the management within KPCL to provide greater autonomy to major generating stations for improving operational practices.

[12] Review of performance of thermal power stations 2010-11

Option 2: Reduction in T&D losses

Progressive reduction in T&D losses to 15% by FY17

Karnataka compares favourably with other States in the country in terms of average losses in the distribution sector as indicated in Table 22[13] . Two other Southern States, A.P and Tamilnadu have achieved lower system losses. Further, the global standard for T&D losses for a utility is below 10%. Table 23 details the T&D losses for individual ESCOMs and the overall losses in the State. At current loss levels in the State (19.6%) and current power purchase costs[14], losses equivalent of Rs. 3400 Cr are incurred by all State utilities together. ESCOMs can achieve considerable savings in power purchase costs through potential reduction of T&D losses in their system

Table 22: Comparison of T&D losses across States (FY-11)

States	% Loss (2010-11)
Karnataka	17.34
Andhra Pradesh	16.59
Tamil Nadu	13.47
Gujarat	19.24
Maharashtra	20.68

Table 23: Losses in distribution network for each ESCOM in FY-12

ESCOM	Losses in Distribution network For FY-12	Losses in T&D borne by ESCOMs for FY12 (%)
BESCOM	14.50	17.75
MESCOM	12.09	15.43
CESC	16.20	19.38
HESCOM	19.99	23.03
GESCOM	21.71	24.69
STATE	**15.77**	**19.57**

MESCOM has the lowest losses estimated at 12.09%, while GESCOM is the highest at 21.7%. However, it is to be noted that these numbers are only for the distribution network. Transmission losses (3.8%) are added to these in order to estimate losses for the complete T&D network in the State. The weighted average power loss in Karnataka's network comes to 19.57%.

ESCOMs in the State may undertake proactive steps (detailed 6.3) to reduce T&D losses. Even if a conservative target to improve loss-levels by 1 percentage point each year is achieved about 2,000 MU of energy can be by FY17 (Table 24).

[13] CEA General Review 2012 – State-wise system losses in 2010-11
[14] Average pooled power purchase cost (APPC) = 3.07 Rs/unit

Table 24: Impact of Option 2 (Million Units)

Year	Incremental energy through Option 2	New Residual restricted demand	New residual unrestricted demand
FY-14	425	11381	14775
FY-15	889	11480	14846
FY-16	1396	11366	14704
FY-17	1951	10969	14278
FY-18	2085	6866	10160

<u>Option 3: Rapid Renewable Energy Capacity addition</u>

Rapid addition of wind, solar, and biomass based capacity in the next few years

Karnataka already has a large share of renewable-based capacity. Further, the State has a good wind, biomass and solar-based generation potential. Wind and biomass cogeneration are low cost options among renewables for electricity generation. The State renewable agency (KREDL) has already allocated 9000 MW of wind capacity. There is a need to closely monitor the commissioning schedules and ensure that the capacity allocated is made use of quickly. The State can target additional renewable capacity, in addition to current plans, as shown in Table 25 by utilizing already identified renewable potential.

Table 25: Renewable capacity addition for High RE option

Year	Solar capacity addition in year (MW)	Wind capacity addition in year (MW)	Small Hydro and biomass Capacity addition (MW)	Total Renewable Capacity under PPA-Including existing capacity (MW)
FY-14	50	500	50	3,420
FY-15	100	1,500	100	5,120
FY-16	100	1,500	100	6,820
FY-17	200	1,500	100	8,620
FY-18	250	1,500	100	10,470

The impact of a rapid renewable addition plan on the residual restricted demand, along with the incremental energy generated from exercising this option, is presented in Table 26 below. About 13,000 MU is possible to be tapped from renewable sources by FY17 if this option is exercised.

Table 26: Impact of Option 3 (Million Units)

Year	Incremental energy through Option 3	New Residual restricted demand	New Residual unrestricted demand
FY-14	1367	10411	13834
FY-15	5260	7052	10475
FY-16	9154	3523	6946
FY-17	13214	-409	3014
FY-18	17358	-8536	-5113

It is to be noted here that the ability of the High RE addition option to meet unmet demand is analysed only in terms of aggregate energy. High RE addition option, in general, requires a more flexible grid with several quick ramping sources. It is outside the scope of this work to assess the exact amount of flexible resources like hydro or gas required for managing intermittency from these resources. Therefore, along with plans for augmenting renewable capacity, it is important to also plan for flexible resources like hydro, gas-based units and storage options like pumped hydro.

In the next 5 years, the residual demand may be met by one of the three different options, or a combination of these improvements. For instance, in the year FY14, a combined effort of PLF improvement of State coal plants, T&D loss reduction, and High RE addition will together provide approx. 9400 MU. This means that only about 2400 MU needs to be purchased through contracting more capacity than currently planned for.

Table 27: Total Impact of all options 1+2+3 (Million Units)

Year	*Option 1:* Impact of Improving PLF of Coal Power Plants (1)	*Option 2:* Impact of reduction in T&D losses (2)	*Option 3:* Impact of accelerated renewable generation (3)	Total (1) + (2) +(3)	New Residual restricted demand after combined effort of (1), (2), (3)	New Residual unrestricted demand after combined effort of (1), (2), (3)
FY-14	7625	425	1367	9417	2361	5784
FY-15	7625	889	5260	13774	-1462	1960
FY-16	7625	1396	9154	18175	-5498	-2075
FY-17	8522	1951	13214	23687	-10881	-7458
FY-18	9909	2085	17358	29352	-20530	-17107

Option 4: Long-term power purchase from IPP and captive plants

Utilization of unused capacity in the State

In 2009, the State had called for tenders for long-term power procurement of 2000 MW from IPPs. In spite of a good response from IPPs, these tenders were aborted in 2011. This route of long-term power procurement must be re-initiated to bridge anticipated shortfalls over the next 5 years.

As of March 2013, Karnataka is among the top 3 States[15] that export power to entities outside the State through short term transactions. During FY13, the State exported a total of 5,872 MU to other States through exchanges and bilateral transactions. Since the State is likely to face a residual demand beyond what can be met from existing long-term PPAs, it can explore options to utilize energy from merchant plants within the State by offering reasonable tariffs. Similarly, many captive generators are kept idle during peak periods. Offering reasonable tariffs for such generators to supply to ESCOMs can enable utilizing this idle capacity available in the State.

Option 5: Short term power purchases

Recently, Karnataka has relied heavily on short term power purchases to manage the energy and peak deficit. The State's short term power purchases have grown rapidly in the last few years as shown in Table 28 and Figure 11. Further, the average cost of power for these purchases has come down from about Rs 7 per kWh in FY 08 to Rs 4.3 per kWh in FY13. However, this is still 46% higher than the average power purchase cost of the State utilities. Also, transmission corridor constraints also affect availability of short-term purchases. Hence, short-term purchases must be resorted to only as a means to bridge the short-term demand–supply gap after proactive efforts to implement Options 1-4.

Table 28: Trend in short-term power purchase by State utilities

Year	**Short-term energy purchased (MU)**	**Average rate of (Rs/kwh)**
FY-08	41	7.0
FY-09	1964	6.8
FY-10	1799	6.4
FY-11	7815	5.0
FY-12	6320	4.8
FY-13	11047	4.3

[15] Monthly report on short-term transactions of Electricity in India, Accessed at : http://www.cercind.gov.in/2013/MMC/MMC_March13.pdf

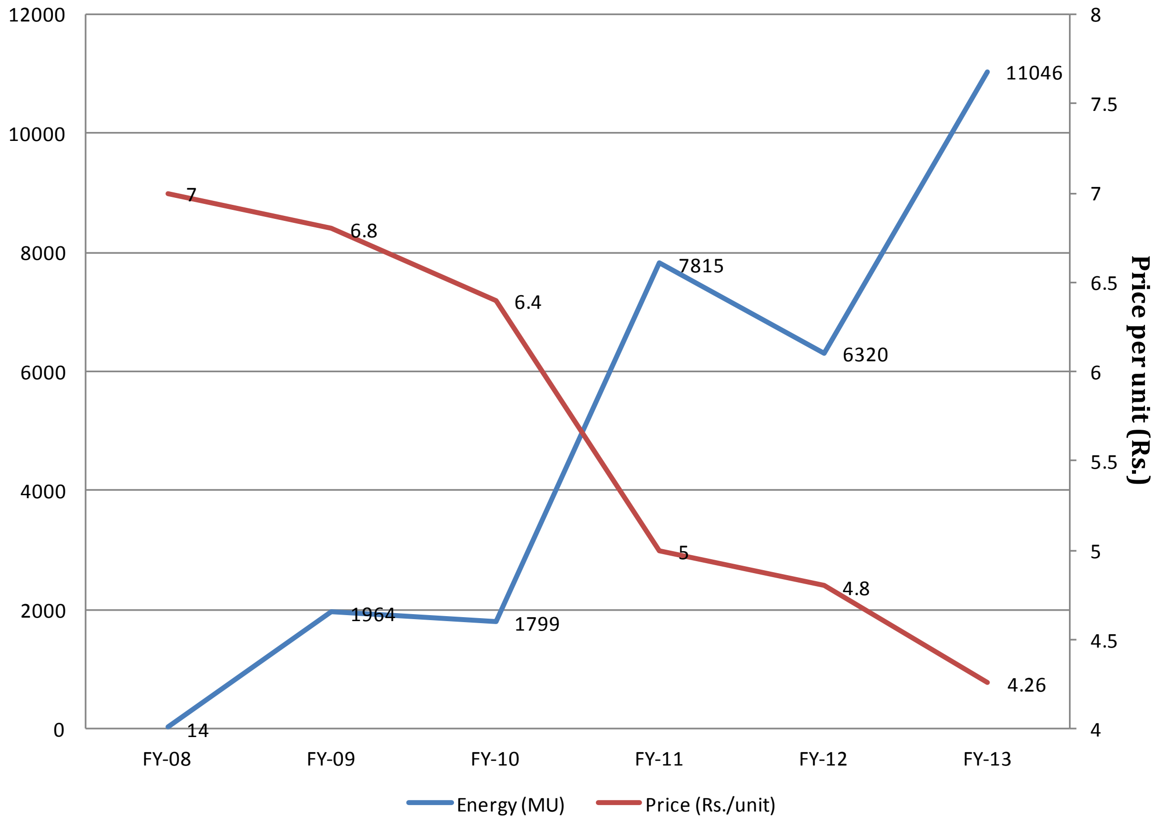

Figure 11: Trend in short-term power purchases by State utilities. Source: KERC

The State is presently contracting about 1500 MW of short and medium term capacity. If this capacity can be contracted under long-term PPAs by offering reasonable rates, short term power purchases can be reduced considerably. This can also reduce the procurement cost as prices may be lower for long-term contracts.

Peak Management

Based on existing capacity addition plans, the State will continue to face peak power shortages in the range of 1000 – 1500 MW in the next five years. This will lead to load shedding, which has social and economic implications or short term power purchases (bilateral, Power Exchange or UI), which have high cost implications to the utility. Therefore, urgent measures must be taken to bridge the peak demand-supply gap. Demand-side measures like implementing differential tariffs for more consumer segments should be explored. Further, there is a need to plan for peaking capacity since more than 90% of the future firm capacity addition plans seem to be from coal. Gas based generation to make use of availability of gas pipelines in the State must be considered along with increasing the peak-rating of existing hydro units through design changes. Pumped storage projects may also be planned for peaking requirement in future.

6. Discussion of challenges in power sector and recommendations

This section presents a diagnostic analysis of main challenges currently faced by the generation, transmission, and distribution sectors of the State. Foreseeable problems in execution of future plans of the power sector are also discussed. The analysis synthesises inputs and opinions from experts in the respective sectors, proposes solutions, and highlights areas for focused intervention.

6.1 Generation

Thermal

KPCL, the State-owned generating utility in Karnataka has about 2,848 MW thermal power capacity installed. In addition, the State has 1,836 MW of share from central generating stations (CGS) and have 2,166 MW owned by independent power producers (IPP). Of the IPP-owned capacity, only 1,080 MW (UPCL) has long-term PPAs with utilities in the State. Following are some of the major challenges in the generation sector:

- **Poor operational performance:** Raichur Thermal Power Station (RTPS) has suffered low operational performance due to a combination of factors discussed in Section 5. Poor performance of State-owned thermal capacity has resulted in major shortages from their annual planned generation. The State-owned plants, like those in the rest of the country, face coal availability issues. Bellary Thermal Power Station(BTPS) units have operated at low plant load factor in the last 2 years due to inadequate coal supply even though the plant has captive mine blocks allocated to it as part of a JV between KPCL and M/s EMTA.
- **Expected delays in planned projects**: By 2017, the State has plans to commission an additional 3100 MW of coal-based capacity and a 700 MW gas-based plant at Bidadi. The State should monitor progress and target commissioning of these plants with some urgency to secure its future supply. Major State-owned plants and their current status are reported in Section 4.2.
- **Weak financial status of KPCL**: The pending dues to KPCL as of FY13 were Rs. 8700 Cr. The financial situation of KPCL is a major concern and can weaken its ability for further investments in the sector.

Hydro

The State has 3,671 MW of State-owned hydro and about 700 MW of mini hydro capacity owned by Independent Power Producers (IPPs). Hydro power plays a significant role if the State has to add capacity in intermittent sources of renewable power like wind and solar. Currently, a major part of the hydro power is being used to meet base load demand due to shortages in the State. Augmenting thermal base load capacity through expediting planned thermal projects can lead to hydro being used as an efficient source for meeting peak load - this would require design changes to increase the peak rating of existing storage-based hydro units. Pumped-hydro projects need to be planned for and tariff determination proposal for this can be submitted to the regulator. This will enhance the State's capacity to meet peak load and also provide flexibility to the grid in its plan for higher renewable capacity addition.

Greenfield projects in large hydro, especially untapped potential in Western Ghats continue to face stringent environment clearance norms and as such, its potential for contributing capacity in future is limited. However, the State can undertake the following hydro schemes on priority and resume discussions with Government of Tamilnadu and Goa to make progress with some of these projects:

1) Power projects in Cauvery basin: The Shivasamudram seasonal power house (345MW), Mekedatu (360 MW) storage-based project, Hognekal (200MW) and Rasimanal (200 MW) may be pursued further. Joint venture route with Government of Tamilandu can be explored for Hognekal and Rasimanal.
2) Mahadayi hydroelectric Project: The DPR was prepared and sent to Government of India. Discussions may be pursued with State of Goa to make progress with this to implement a 345 MW potential project
3) Gundia hydel project: This project has been awaiting environmental clearance. This State government may pursue this further and scope of the project be examined afresh based on recent government proposal to divert water from Nethravati to Bangalore City.

Utility-scale Solar PV

KPCL currently has four solar PV power plants operational in Karnataka under the Arunodaya program, amounting to a total of 14 MW installed capacity. The National Solar Mission policy mandates solar RPOs for all ESCOMs with a current target of 0.25%, to be increased to 3% by 2022. Additionally, the Ministry of Communications & IT has approved a special incentive package to promote large-scale manufacturing in the electronic system design and manufacturing sector, to encourage indigenous manufacturing of Solar PV module components.

At the State level, KREDL, the implementing agency for the Karnataka Solar Policy (2011 – 16), has set a target of commissioning 200 MW solar-based projects by FY16 for procurement by ESCOMs. An annual target of 40 MW has been set for capacity addition in solar. KREDL has recently completed the bid process for allotment of 80 MW (60 MW: Solar PV, and 20 MW: Solar-thermal) at tariffs ranging from Rs. 7.94 – 8.5 (solar PV) and 10.94 – 11.32 (solar thermal). Some of the current issues in the operation of utility-scale solar PV plants in the State are identified below:

- ***Loss of generation at low voltage:*** If evacuation happens at low voltage levels of 11 kV, frequent outages results in loss of generation. Evacuation through HT lines (> 33 or 66 kV) instead of 11 kV lines can prevent loss of generation. Clear mandate for ESCOMs to adhere to minimum levels of commitment for evacuation through better maintenance of substations and protection equipment is necessary for successful evacuation
- ***Equipment performance and maintenance:*** While the modular structure of the solar PV arrays provides for more robustness at the DC side, inverters at the AC conversion side are typically of larger rating (nearly 1 MW) which results in higher impact from conversion equipment failures. Modular choice for AC conversion equipment, e.g. inverters with smaller ratings, can increase system resilience to failure
- ***Clarity on incentives for developers***: Stricter enforcement of RPO mandates with medium-to long-term clarity on policy is necessary for assured functioning of the REC market.
- ***Trained manpower*** : Frequent knowledge sharing workshops to foster communication between concerned departments; nomination of engineers/technical staff for training sessions can help increase experience for KPCL-owned solar plants

Small scale solar PV

The total installed capacity of rooftop PV feasible in Bangalore is estimated to be the order of 36 MWp, based on commercial space assessments in urban Bangalore.[16] Small scale PV-based generation from rooftop systems play a potential role in Demand Side Management (DSM) and peak load reduction for urban areas. Similarly, decentralized PV-grids may provide an opportunity for providing energy supply at desired levels of service in areas with willingness to pay. Some of the key initiatives to incentivize investment in small scale PV generation are identified below:

- Initiate pilots to evaluate success of rooftop PV generation
- Provide incentives similar to green certificates based on consumption of green energy. i.e. incentivize generation from rooftop systems in addition to installation
- Revise current Feed-In-Tariff (FIT) for rooftop solar in line with current costs
- Enable participation of group owners of rooftop PV systems in REC mechanism
- Define and implement connectivity guidelines/standards for interconnection through a technical committee consisting of ESCOMs and solar system installers.

Utility-scale On-shore wind

Until recently, the wind power potential of India was officially estimated to be 102 GW, with Karnataka's estimates at 13.6 GW at 80m turbine hub height. Taking into account land type information, other studies have re-estimated the potential on Karnataka's wasteland alone to be 30.4 GW[17] at the same height.

The current installed capacity in the State is 2, 023 MW, generating about 3, 544 Million units per annum. The current tariff for wind power is Rs. 3.7/ kWh. In order to achieve large-scale capacity addition, the following have been identified as key focus areas:

- *Policy for repowering on existing wind sites to extract more power:* Some of the high potential sites in the State are currently under-utilized due to installation of low-capacity turbines at lower hub heights. Newer machines are more efficient and can also be installed at higher hub heights with a potential to increase generation from these sites. State can evaluate additional generation potential at these sites to determine incentives required for repowering these sites so that investor payback time can be reduced
- *Investment-grade zoning for wastelands:* Wind potential from wastelands in Karnataka is estimated to be about 30 GW at 80 m hub height, based on satellite models of wind resource. To realize this potential, further analysis is required to identify suitable sites based on wind speed quality, land ownership, land terrain suitability, proximity to existing substations and transport infrastructure.
- *Rationalize tariffs according to wind zones*: Depending on the quality of the wind resource, the CUFs of wind turbines may vary from 20% to 30% at 80 m height across the State. This has implications on the cost of generating electricity at various sites.
- *Project and land allocation*: Several wind projects in the State face a land squatting problem Steps to generate government-owned resource data can enable bidding-based competitive tariffs. This would enable the State to move away from the current allocations on an ad-hoc basis, towards fairer methods of project allocation and systematic development of the sector.

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[16] Harnessing Solar Energy: Options for India, CSTEP

[17] Wind Power in Karnataka and Andhra Pradesh, CSTEP

- *Mixed use of agricultural land:* Recent studies have indicated that the footprint of a wind turbine is less than 10% of the total land, after completion of the initial construction period. In case of privately owned land, the State can develop guidelines for determination of lease norms for mixed usage, after mandated environmental and social impact assessments

Key Recommendations: Generation Sector

Thermal

- Analyse cost-benefits of washed vs. raw coal and re-negotiate supply contracts ,if necessary
- Conduct benchmarking study on RTPS units with plants of similar vintage in the country to assess need for refurbishment and modernization
- Restructuring of management within KPCL to provide greater autonomy to major generating stations
- Monitor production from captive mines supplying coal to State-owned plants and enforce penalties for non-performance
- Closely monitor progress in construction and ensure coal supply linkages to Yermarus, Edlapur , BTPS unit 3, Gulbarga and Godhana units
- Plan for more gas-based power stations to make use of the gas pipeline availability
- Address the weak financial situation of KPCL by settling unpaid arrears
- Utilize captive and IPP capacity in the State by offering reasonable tariffs

Hydro

- Expedite decision on Thattihalla diversion scheme proposal
- Pursue power projects in Cauvery basin in discussion with Government of Tamilnadu
- Pursue discussions with State of Goa to make progress with Mahadayi hydro project
- Reassess scope of Gundia hydroelectric project afresh
- Plan for pumped hydro projects in the State

Utility-scale Solar PV

- Mandate ESCOMs to adhere to minimum levels of evacuation
- Stricter enforcement of solar RPO
- Site future PV plants in areas with alternate water supply
- Conduct regular knowledge sharing and technical training sessions for engineers/technical staff in State

Utility-scale On-shore Wind

- Policy to incentivize re-powering of existing wind sites
- Investment-grade zoning of wastelands to enable higher wind capacity addition
- Rationalize tariffs according to wind zones

6.2 Transmission

Karnataka Power Transmission Corporation Ltd. (KPTCL) enables transmission of power from generating stations to the ESCOMs and to the open access consumers within the State. According to KPTCL, the utility is well equipped to handle present levels of generation and have plans in the pipeline to handle future additions of planned conventional and non-conventional generation in the State. Table 49 shows the particulars of transmissions capacity:

Table 49: KPTCL substations and transmission lines

Particulars (As on 31-03-2012)		
No. of Receiving Sub-Stations /Length of Tr. Lines	**Nos./Ckms.**	**966/3,053**
a) 400 kV	Nos./Ckms.	4/1,978
b) 220 kV	Nos./Ckms.	89/9,760
c) 110 kV	Nos./Ckms.	331/9,063
d) 66 kV	Nos./Ckms.	542/9,738

KPTCL has adopted CEA norms for capital investment for allocation between generation, transmission and distribution in the ratio of 2:1:1. Accordingly, considering the cost of thermal generation as Rs. 5 crores/MW, an investment of Rs. 2.5 crores/MW is required in transmission. KPTCL has proposed to add 32,089, 32,689 and 33,889 Ckms of transmission lines at various voltage classes in FY14, FY15 and FY16. The transmission loss in the KPTCL network for FY12 is 3.97%. Losses in KPTCL network in FY12 are summarized in Table 30 below:

Table 50: KPTCL network losses

VOLTAGE CLASS	% LOSS
400	0.334
220	2.144
110	0.425
66	1.004
TOTAL	**3.97**

KPTCL faces challenges while executing transmission projects particularly with regard to usage of land for the establishment of sub-stations and procuring right of way (RoW) for drawing transmission lines. The government should give priority to address the above issues in a time bound manner in order to enable expansion of the transmission network.

State Load Dispatch Centre (SLDC)

Real-time management of demand and supply rests with the SLDC. Currently, the SLDC faces challenges due to shortage of generation capacity, particularly during the summer season when the load demand is high and hydro availability is low. There appears to be a need for closer co-operation between the SLDC and ESCOMs in the State for better operation of the system and to ensure better service to consumers. The State Government must also take steps to ring-fence SLDC so that it can operate as a neutral and independent grid operator.

Further, non-conventional energy sources, being intermittent and seasonal in nature create challenges for the grid operator. The State has a relatively high installed capacity in wind and initial studies indicate very high wind potential. Since high wind generation coincides with monsoon, it results in certain advantages as well as disadvantages in grid operations. While it is possible to conserve water in storage-based hydro projects by utilizing wind generation during monsoon, not all hydro stations in the State are dedicated for power generation. If higher wind capacity is connected to the State-grid in future, wind generation may have to be curtailed to avoid spill over of existing reservoirs if transmission corridor constraints do not enable export of excess power. In summer months, without adequate quick-ramping sources to manage intermittency from these sources, sudden loss of generation can occur. The State must therefore, prioritize planning for intermittency that is typical of renewable generation. It is to be noted that the gas-based generation planned at Bidadi is a combined cycle plant, designed for base load operation. In order to manage intermittency from renewable sources, the State needs to plan for a few open cycle gas plants that can be used as quick ramp-up sources of power. These open cycle plants can also serve as peaking stations in future. Further, proposals pending with the Government to harness current hydro stations to be developed into pumped storage projects should be taken up on priority.

6.3 Distribution

Following are some of the major problems in distribution sector:

- *Weak financial status:* Unrecovered dues from Government and local bodies cause significant financial burden to ESCOMs. The dues as of FY13 were reported at 9,000 Cr. This continued burden significantly limits the ability of ESCOMs to make further investments in the distribution network
- *Incorrect estimates of demand and losses: A*gricultural consumption being unmetered, the demand from these consumers is not exactly known. Demand reported for these consumers is often based on theoretical estimates. The regulator must mandate measurement of all consumption. This measure is crucial to have accurate data of demand and also for correct estimate of losses.
- *Lack of clear long-term policy on supply to subsidized categories*: As detailed in Section 2.3, the cost borne by the State for subsidised power is increasing. As a first step, the State must meter all consumption and frame a long-term and sustainable policy for supply to subsidized categories
- *High distribution losses:* Several ESCOMs in the State have potential to reduce losses in the distribution network. This can provide significant savings in the power purchase costs as detailed in Section 2.3. High Voltage Distribution System (HVDS) implementation can be pursued wherever economically feasible to reduce the distribution losses and to bring down LT/HT line ratio. Additionally, Distribution Transformer Center (DTC)-wise energy audit should

be mandated in all ESCOMs to identify weaker segments of the distribution network. Innovative business models like franchisee arrangements must be explored in order to ensure a more efficient service delivery to electrified rural areas

- *Continued Shortage Situation:* The prolonged supply side shortages can be mitigated to some extent by implementation of below measures by ESCOMs
  - Encourage roof-top solar PV: This will help in technical loss reduction in the grid as the power will be consumed at the point where it is generated. Proper incentives for the consumers and detailing interconnection standards are key requirements
  - Implementation of the Time of day (ToD) tariff for all the HT consumers in a time bound manner. This can later be extended to other consumer categories. However, exact results and outcomes in terms of peak reduction and ESCOM revenues require a detailed study
  - Installation of electronic switching systems for street light controls for switching on and switching off the street lights at fixed timings
  - Bifurcation of 11kV rural feeders under to ensure 6 hours of supply to agricultural purpose and 24 hours supply to villages
  - Proactive implementation of Bachat Lamp Yojana to achieve set targets
  - Replaced inefficient IP sets with BEE-labelled efficient pump sets using appropriate incentives and subsidies from government
- *Institutional Structure*: The current organizational structure of ESCOMs does not encourage profitability due to continued and serious mismatch between expenditure and revenue realization. A few sub-divisions under each ESCOM's jurisdiction should experiment the concept of *strategic business unit* (SBU) with its own cost and revenue centre. This will ensure that field-level operations are made more accountable. This will increase accountability as well as enable loss-reduction in each sub-division in a time-bound manner
- *Shortage of skilled manpower and HR policies:* All the ESCOMs reported a shortage of skilled manpower, mainly among field staff. ESCOMs must invest in training of staff. Alternatively, ESCOMs can also consider outsourcing of regular maintenance work.
- *Reliability of distribution system*: Consumers often experience periodic and prolonged loss of power. Number of interruptions duration of interruptions can be reduced through periodic inspection of lines, preventive maintenance and pre-monsoon works. Periodic calculation of reliability indices should be undertaken to monitor the performance at different sub-divisions
- *Quality of supply*: Even in a shortage situation, ESCOMs can ensure better service delivery to consumers through implementation of following best-practice measures:
  - Staggered load shedding and advanced publication of supply schedules so that consumers can plan activities around it
  - Call centres for recording and responding to complaints in a time-bound manner
  - District-wise grievance redressal forum
  - Mobile service units for quicker resolution of faults
  - Consumer education campaigns in local media for preventive accident control

Key Recommendations: Transmission and Distribution

State Transmission Company

- Solve RoW and land usage issues on priority
- Introduce mandatory and periodic assessment of losses at all levels of the system

State Load Dispatch Centre

- Prioritize planning for intermittency associated with renewable-based generation
- Ring-fence SLDC in a time-bound manner to ensure independent grid operations

Distribution Companies

- Introduce long-term incentives for rooftop-PV systems
- Implement Time of Day (ToD) tariff for all HT consumers
- Install electronic switching systems for street lights
- Replace inefficient IP sets
- Implement HVDS where possible after cost-benefit analysis
- Bifurcate 11 kV rural feeders
- Regulator-mandated 100% metering of all consumers (including IP sets)
- Address HR issues related to recruitment and training
- Pilot implementation of a few sub-divisions under each ESCOM as strategic business units(SBU)
- Implement smart grid projects on pilot basis
- Constitute a technical committee who will approve investments based on results from pilot projects
- Development of reliability indices for grid supply
- Undertake measures to ensure quality of service
    - Programmed staggering of load shedding
    - Advanced publication of supply schedules
    - Call centres for complaints for each ESCOM
    - District-wise grievance redressal forums
    - Mobile service units to attend to faults
    - Consumer education campaigns in local media
    - Explore franchisee models for rural distribution

7. Conclusion

The State's capacity addition plans seem inadequate to meet projected demand in the next 5 years. If the current situation continues, the State is likely to face about 21-26% annual energy shortfall (12,000 – 18,000 Million units) and 15-17% peak shortfall (~ 2000 MW) in the short-term (2 years) and 13-8% (~10,000 Million Units) and 16% (~2500 MW) in the medium term (5 years) . This is after accounting for all likely capacity addition. This implies that the State will have to rely on widespread load shedding or rely on short-term power purchases. The latter is an expensive option for the ESCOMs and likely to have an adverse impact on the electricity tariffs in the State. It is also uncertain because of transmission corridor capacity constraints. The following key action items are identified to improve the power sector situation in the State:

- *Contract long-term capacity from IPP and captive plants*: As a short-term option, the State can contract capacity through the Case-1 bidding route to utilize the underutilized capacity already installed within the State. This can provide secure power at competitive rates with a view to reduce reliance on short-term purchases
- *Improve operational performance of State-owned thermal plants*: The thermal plants in the State have exhibited poor operational performance at 60-64% plant load factors. Several factors like coal quality and frequent forced outages have been identified as possible causes. KPCL needs to explore remedial measures like assessment of coal-supply contracts, improvement of production from captive coal blocks of BTPS and also assess need for refurbishment and modernization in RTPS. Even a reasonable improvement of operational PLFs in State-owed coal plants to 80% can generate an additional 7,600 MU from existing capacity
- *Set progressive targets for reduction in T&D losses in the State*: Currently, about one-fifth of the power purchased is lost as losses. Better and complete energy auditing practices to identify the weaker areas of the network along with institutional reforms in ESCOMs (detailed in Section 6.3) offer significant potential to reduce losses
- *Expedite renewable capacity addition*: This involves both expediting commissioning of projects that are already allocated and also planning for new capacity to utilize the high wind, biomass and cogeneration and small hydro potential in the State
- *Monitor and ensure progress of plants under construction:* Thermal capacity addition plans in the State sector have historically witnessed severe delays due to issues with provision of fuel supply linkages and construction delays. It is crucial that there is strict monitoring of progress in major plants in the pipeline: viz. Yermarus, Edlapur, Godhana, Gulbarga and Bidadi
- *Plan for peaking capacity:* More than 90% of the future firm capacity addition plans are coal-based. The State may leverage the already available gas-pipeline to plan for more gas-based peaking capacity. Plans for pumped hydro as well increasing the peak-rating of existing hydro projects need to be explored to serve peak power requirements

Appendix 1: Generation Facilities supplying to ESCOMs

Thermal Power Plants (KPCL & CGS)

Sl No.	Name of Generating Station	Capacity (MW)	Allotted Share (%)	Allotted (MW)
1	KPCL – RTPS: 1 to 7 (7x210 MW)	1470.00	100.00	1470.00
2	KPCL – RTPS: 8 (1x250 MW)	250.00	100.00	250.00
3	KPCL – BTPS: 1 (1x500 MW)	500.00	100.00	500.00
4	KPCL – BTPS: 2 (1x500 MW)	500.00	100.00	500.00
5	KPCL – DG Plant (10x10.8)	108.00	100.00	108.00
6	CGS – NTPC – Ramagundam: Stage –I&II (3x200 and 3x500MW)	2100.00	19.32	405.65
7	CGS – NTPC – Ramagundam: Stage – III (1x500 MW)	500.00	20.36	101.80
8	CGS – NTPC Talcher: Stage – II (4x500 MW)	2000.00	18.58	371.60
9	CGS – NTPC – Simhadri: Stage – II (2x500MW)	1000.00	20.39	203.90
10	CGS – NLC; TPS-II: Stage-I (3x210 MW)	630.00	22.43	141.33
11	CGS – NLC; TPS-II: Stage-II (4x210 MW)	840.00	22.24	186.79
12	CGS – NLC; TPS-I: Exp (2x210MW)	420.00	25.75	108.14
13	CGS – NPCIL; MAPS (2x220 MW)	440.00	7.39	32.52
14	CGS – NPCIL; KAIGA – 1&2 (2x220 MW)	440.00	27.49	120.96
15	CGS-NPCIL; KAIGA – 3&4 (2x220 MW)	440.00	29.99	131.96
18	CGS- NTECL; STPS- Vallur -1 (1x500 MW)	500.00	8.04	40.20
19	CGS – NTECL; STPS – Vallur -2 (1x500 MW)	500.00	8.04	40.20
20	CGS – NTECL; STPS – Vallur -3 (1x500 MW)	500.00	8.04	40.20
21	Tuticorin (TNEB) (2x500 MW)	1000.00	6.00	60.00
22	Kudankulam (2x1000 MW)	2000.00	6.00	120.00
	Total of Thermal	**16138.00**	**17.12**	**4933.23**

Hydroelectric Power Plants

Sl. No	Name of Generating Station	Capacity (MW)	Allotted Share (%)	Allotted (MW)
1	SVP – Sharavathy Valley Project (10x103.5 MW)	1035.00	100.00	1035.00
2	LDPH – Linganamakki Dam Power House (2x27.5 MW)	55.00	100.00	55.00
3	KVP- Kali Valley Project, Nagjhari (NPH) (5x150MW & 1x135 MW)	885.00	100.00	885.00
4	Supa (2x50 MW)	100.00	100.00	100.00
5	VVP-Varahi Valley Project, Varahi 1&2 (2x115 MW)	230.00	100.00	230.00
6	Mani Dam Power House (2x4.5 MW)	9.00	100.00	9.00
7	Varahi 3&4 (2x115 MW)	230.00	100.00	230.00
8	KPH – Kadra (3x50 MW)	150.00	100.00	150.00
9	KDPH – Kodasalli Dam Power House (3x40 MW)	120.00	100.00	120.00
10	GPH – Gerusoppa Power House (4x60 MW)	240.00	100.00	240.00
11	GHEP – Ghataprabha Hydro Electric Plant (2x16 MW)	32.00	100.00	32.00
12	BEH – Bhadra Electric Power House (2x12 MW, 6 MW, 7.2MW, 2 MW)	39.20	100.00	39.20
13	ADPH – Almatti Dam Power House (5x55 MW, 1x15 MW)	290.00	100.00	290.00
14	MGHE – Mahatma Gandhi Hydro Electric Power Station (4x13.2 MW, 4x21.6 MW)	139.20	100.00	139.20

Sl. No	Name of Generating Station	Capacity (MW)	Allotted Share (%)	Allotted (MW)
15	Shivasamudra Power Station (6x3 MW & 4x6 MW)	42.00	100.00	42.00
16	Shimsha (2x8.6 MW)	17.20	100.00	17.20
17	MPH – Munirabad Power House (2x9 MW, 1x10 MW)		100.00	28.00
18	T B Dam (8x9 MW)	72.00	20.00	14.40
19	Kalmala (1x0.4 MW)	0.40	100.00	0.40
20	Sirawara (1x1 MW)	1.00	100.00	1.00
21	Mallpura (2x4.5 MW)	9.00	100.00	9.00
22	Ganekal (1x0.35 MW)	0.35	100.00	0.35
23	Jurala (6x39.1 MW) (APGENCO)	234.60	28.00	65.69
	Hydro Total	**3886.95**	**2228.00**	**3652.35**