APPENDICES

A1: DEMAND FORECAST METHODOLOGY

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DEMAND FORECAST METHODOLOGY

Appendix A1

In an electric utility, the load forecast constitutes the starting point for much of the planning activity. Its accuracy and reliability are intrinsically dependent on the methodology adopted. The demand forecast methodology, elaborated in this appendix, has been used to estimate the 2013-2022 electricity demand for the Island of Mauritius. Features, model and peak estimation method of the forecast methodology are described hereunder.

Key Features of the Forecast Methodology

Having the privilege to hold primary data and information on the electricity consumption of different segments of electricity consumers, CEB has built on its knowledge of the performances of the different economic sub-sectors and its customers' segmentation strategy to develop the forecast methodology for the IEP 2013-2022.

The methodology includes application of statistical and econometric tools and techniques, combined with facts and information collected from end-users through surveys and meetings.

The previous forecast approach, which addressed the electricity demand projections from a macro-level, has been enhanced so as to improve the forecast accuracy. The enhanced-model is now built around sub-categories of customers; hence, it adopts a micro-level approach.

Although aggregated GDP growth rates have not been used as the direct central predictor, for obvious reasons, CEB has focused on the prevailing, and expected future, social and economic conditions of the country in order to work out the demand forecast.

Using these elements, which underlie the adopted forecast methodology, estimates of the electricity requirements of the different electricity customer segments/groups were thus more objectively arrived at.

Enhanced Demand Forecast Model

The enhanced-model first takes on board the key economic players which operate in different sectors of the economy and which largely influence our country's economic activities; that is, those whose transactional behaviours directly influence economic growth. As for other CEB's customer categories, the major customers have been clustered into distinct groups.

At a second stage, the electricity requirements of the other sub-categories of customers, which rely closely on the performances of the major economic players, were then estimated in order to predict the total system electricity requirements for the planning period.

For the next 10-years, demographic or/and economic indicators, as independent factors, were used to estimate the electricity demand for each sector/sub-sector, using regression techniques. However, given that the demand forecast depends intrinsically on the performances of different economic sectors/sub-sectors, an assessment of the performances of different economic sectors/sub-sectors has been made upstream. For this, a simple trending method was used in the absence of long-term economic forecast.

At the outset, it is believed that the inherent momentum of the economy, driven by both government expenditures and the Private Sectors' investments, will create the necessary impetus which will sustain economic development, under the following three possible scenarios:

(1) **Low Scenario:** The economy will be sluggish and may stagnate until the end of the medium-term.
(2) **Base Scenario:** The growth rate in the economic sectors/sub-sectors will reflect the trend of the last decade.
(3) **High Scenario:** A rapid economic recovery in the short term will accelerate the economic growth in the medium to long term.

In general, taking into account the overall resources' (capacities') constraints of Mauritius and to avoid the risk of over-estimation, a **conservative approach** has been adopted, whereby results obtained from applying econometric/statistical techniques are within the range of past values.

Peak Demand Forecast

For this IEP, a new method of estimating the peak electricity demand has been used and is briefly described in sub-section 4.2.5. To confirm the results, the general empirical formula below was used to validate the results.

$$P = \alpha E + \beta\sqrt{E}$$

Where,
P *is Peak Power,* **E** *is Energy Sent-out and*
α *and* β *are coefficients.*

The yearly peak demand forecast has thus been confirmed by using estimated energy sent-out, while assuming a percentage network losses for the ten-year planning horizon. Until a more robust model is developed to estimate the network losses, the simple trending method has been applied in order to estimate the percentage network losses for the period 2013-2022.

DEMAND FORECAST METHODOLOGY OF EACH CUSTOMER GROUP

The electricity sales forecast for each customer category has been worked out as follows:

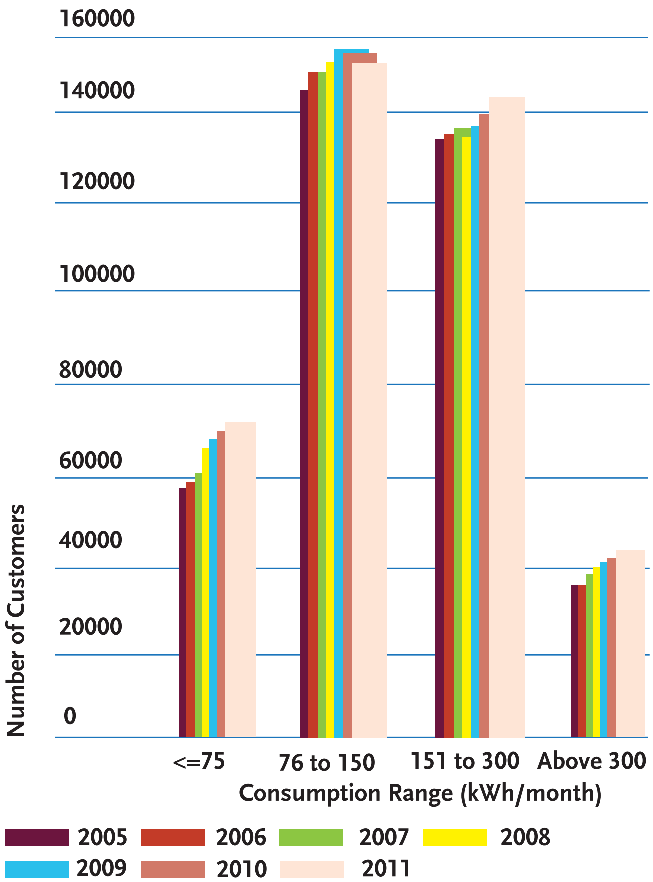
Residential Sector Electricity Sales Forecast

The residential sector, also referred to as the domestic consumers in the CEB's database, has been historically categorized into three electricity tariff categories (tariffs 110, 120 and 140), based on their declared load.

For the purpose of a more accurate forecast, the residential customer group has been segmented according to consumption ranges. Essentially, this segmentation approach provides the possibility of analysing demand-triggering factors relative to each segment/sub-segments. Figure A1.1 below shows the evolution of the size of the sub-segments, in terms of number of accounts, over the period 2005-2011.

The division enables an analysis of electricity consumption with demand-driving factors such as level of income, household size, penetration of home appliances and other relevant qualitative social causes.

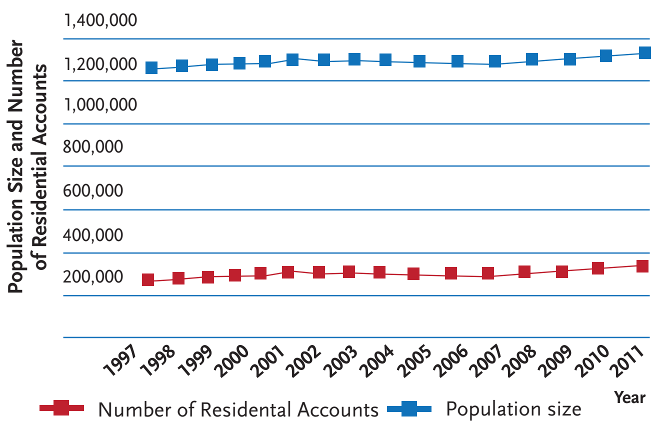
FIGURE A1.1: Number of Accounts by Consumption Range 2005-2011



Forecasting Number of Customers

As revealed in Figure A1.2 below, the growth in the number of residential electricity accounts in Mauritius, for the period 1997-2011, follows closely the growth in the population size.

FIGURE A1.2: Population and Residential Accounts Growth 1997–2011



Using population size as the independent factor, linear estimation, as reproduced in Table A1.1 which follows, confirms that there is a strong correlation between population size and the number of residential electricity accounts.

TABLE A1.1: Result of Regression of Number of Accounts on Population Size

Estimated Y = a + bx	Regression Res & Pop		
Estimated Coefficient ‘b’	2.82	Estimated Coefficient *“a”*	-26.80
Standard Deviation ‘b’	0.06	Standard Deviation *“a”*	0.83
R^2 of Regression	0.996	Standard Error of Y	0.01

Considering the high R^2 of 0.996, the number of residential accounts for the forecast period has been estimated, using the ‘Population Forecast’ prepared by the Statistics Office of Mauritius.

Assumptions

For the different scenarios, it is assumed that the number of customers in each consumption segment will evolve as depicted in Figure A1.3 below. The change in the height of the bars represents the growth rates. Customers from the lowest consumption block (specifically those in the block 76 to 150 kWh) are expected to move progressively to higher consumption bracket. This assumption is dependent on a favourable sustained economic growth, whereby GDP *per capita* will increase satisfactorily and there will be an improvement in the distribution of national income.

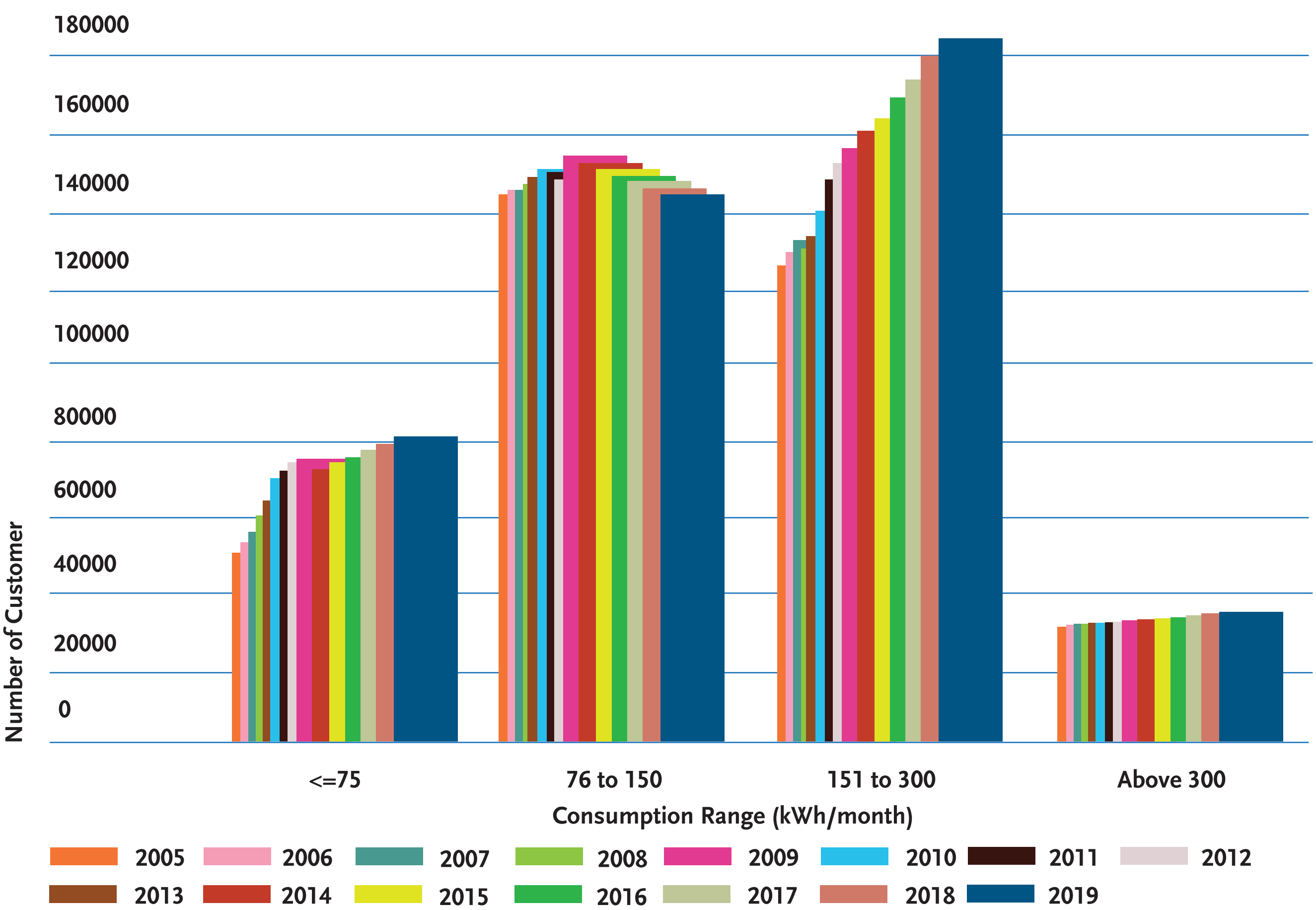
Estimating Energy Intensity (Specific Consumption)

With regard to the energy intensity of a typical Mauritian household, a regression analysis was run, using household size and an estimation of household income as independent factors, based on the following assumptions:

a) The Low Scenario assumed that the residential customers’ specific consumption will tend to decrease in the short to medium term and will eventually stabilize. Reasons behind this assumption are:

(i) For the large majority of households the *real disposable income** will not grow, which is most likely to reflect a fall in purchasing power;

FIGURE A1.3: Number of Accounts by Consumption Segments 2005-2019



* *See glossary*

(ii) Consumers will further embrace energy-saving practice as a result of sustained DSM campaign; and

(iii) Price of electricity will impact negatively on consumption as costs of services increase.

b) In the Base Scenario, CEB presumed that the residential customers' specific consumption will grow at a decreasing rate, as residential consumers will further embrace energy conservation and energy efficiency practices. In addition, more efficient appliances will enter the local market, and, to some extent, electricity prices may hinder the consumption level.

c) In the High Scenario, CEB assumed that the growth rate will be around 3.6% compared to 0.5% and 1.5% for the Low and Base Scenarios, respectively.

At 95% confidence interval, unlike household size, *real disposable income**, as evidenced by the t-ratio 4.93 shown in Table A1.2 is the most influential factor affecting household electricity consumption.

TABLE A1.2: Result of Regression of Residential Demand on Household Size and Real Income

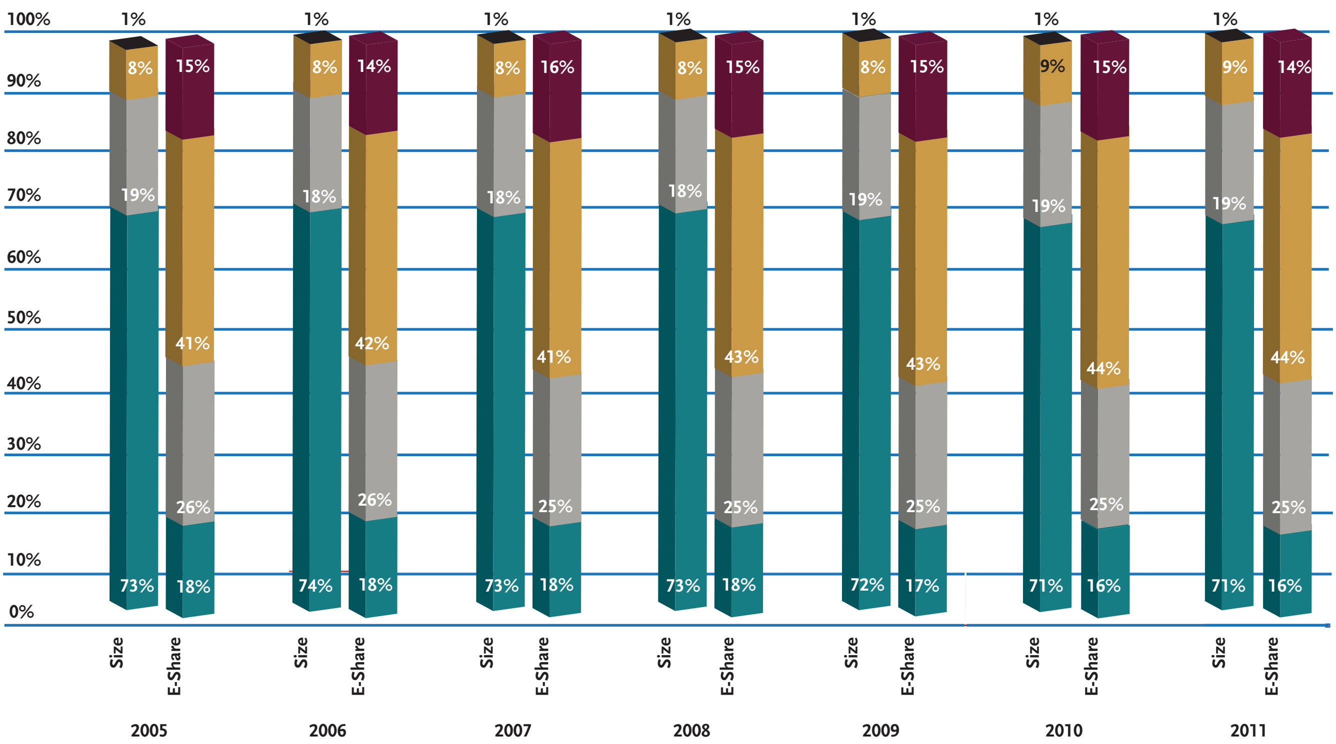
Regressands	Coefficient	Standard Error	T-Ratio	P-Value
Constant	1392.20	534.37	2.61	0.03
Household Size	48.97	127.67	0.38	0.71
Real Income	0.001834	0.000372	4.93	0.00

Commercial Sector Electricity Sales Forecast

The CEB commercial customer category accounts for the highest income-generating sector (approximately 46%). Five types of tariffs are currently available and are applicable to Commercial Customers, namely Tariffs 215, 217, 225, 245 and 250.

The largest number of Commercial Customers is registered under Tariff 215. In 2011, it represented 96% of the CEB's commercial customer base but accounted for only 22% of the energy consumed by the commercial category and 14% of the overall CEB's electricity sales. Figure A1.4 below shows the segments within

FIGURE A1.4: Segments (Size and Energy Share) in Tariff 215 Category



0 to 300 kWh/Month · 301 to 1000 kWh/Month · 1001 to 5000 kWh/Month · Above 5000 kWh/Month

Size: Number of Accounts in Category, E-Share: Energy Share in Category

** See glossary*

Table A1.3 and Figure A1.5, which follow, show the number of accounts (size of the customer-base) and the shares of electricity consumption of commercial sub-categories operating in different economic sub-sectors, such as finance, tourism, utilities, transportation, wholesale and retail trade, recreation, food and beverage supply, health care, education and public administration, hotels, and other non-manufacturing activities. The shares of categories T245 and T250 are not shown because of their small figures.

The key point to note from the above is that a small number of customers accounts for the large portion of electricity sales in the commercial category. This vital information in fact assists in defining the CEB's market monitoring strategy.

Using the above insight, the commercial sales forecast has been developed in two steps. First, the demand of the medium and large commercial categories, which are considered as key economic players, has been examined and projection has been made accordingly. The formulae below underlie the forecast model used to estimate the future demand of the medium and large commercial customer categories classified under Tariffs 217, 225, 245 and 250.

$$\text{Ln CINTER}_t = \alpha + \beta_1 \text{Ln (HO)}_t + \beta_2 \text{Ln (ICT)}_t + \beta_3 \text{Ln (FI)}_t + \xi_t$$

Where,

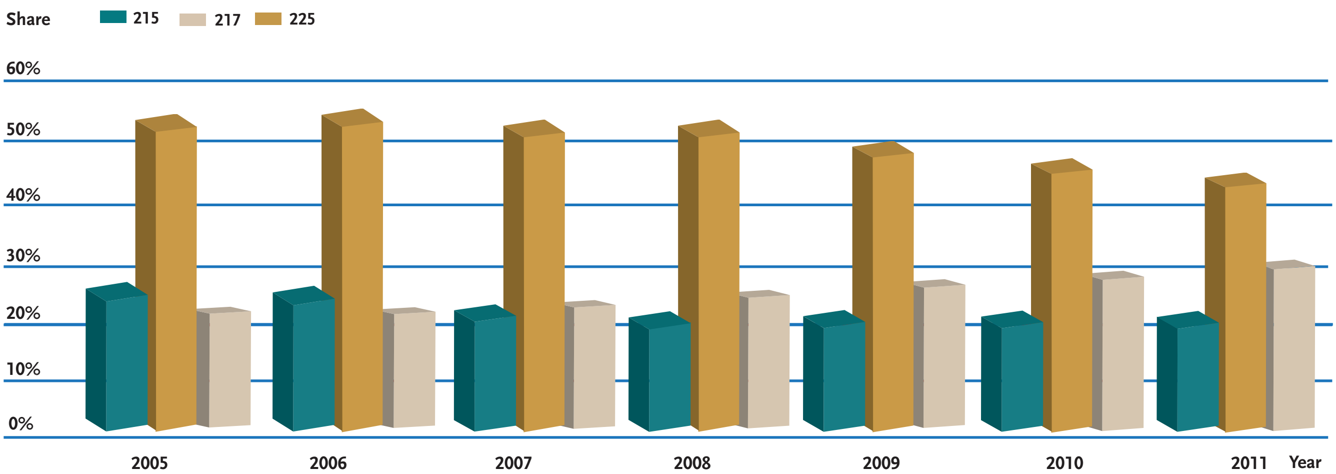
CINTER$_t$	*Value of Outputs of Commercial Sectors whose performance is mostly driven by international factors and which have a spillover effect on the local economy by generating income and wealth*
α	*Constant*
β_i	*Coefficients*
HO$_t$	*Hotels and Restaurants Annual Output Value in year 't'*
ICT$_t$	*Communications Annual Output Value*
FI$_t$	*Financial Intermediation Annual Output Value*
ξ_t	*Error term*

Using the above relationship, the electricity demand of the medium and large commercial customer categories ($COMDDL_t$), whose performances depend on international conditions, was thus determined, using the equation over leaf.

TABLE A1.3: Number of Registered Accounts

Tariff category	2005	2006	2007	2008	2009	2010	2011
215	29,803	30,913	32,109	33,327	33,674	34,332	34,888
217	1,004	1,077	1,138	1,229	1,295	1,373	1,472
225	26	29	31	42	54	69	75
245	28	33	21	19	16	19	18
250	5	8	10	13	12	20	23
Total	30,866	32,060	33,309	34,630	35,051	35,813	36,476

FIGURE A1.5: % Share of Electricity Sales of Commercial Categories



$$\text{Ln COMDDL}_t = \alpha + \beta \,\text{Ln CINTER}_t + \xi_t$$

Where,

COMDDL$_t$ *Annual Demand of medium and large commercial customer categories*

α *Constant*

β *Coefficient*

CINTER$_t$ *The annual Value of Outputs of Commercial Sectors whose performance is mostly driven by international factors and which have a spill-over effect on the local economy by generating income and wealth*

ξ_t *Error term*

The test statistics, shown in Table A1.4, for the above expression revealed that there is a strong relationship between the electricity demand of the targeted commercial customer groups and the selected economic sub-sectors' value of outputs.

TABLE A1.4: Test Statistics

t-ratio	(-6.01)	(30.80)
p-value	[0.000]	[0.000]
R-Squared	0.989	

It has been observed that the increase in the number of new accounts in these customer categories is relatively small and their demand for electricity is known 2 to 3 years in advance, as requests for electricity supply are made prior to construction period and/or the setting up of the business.

As Government enhances business facilitation policies, investment in these non-manufacturing economic sectors is assumed to grow and new entrants are expected to enter into the market during the planning period.

The second step in the demand forecast of the commercial category is about estimating the demand of those commercial customers whose business performances depend on the domestic social and economic conditions, for example small Commercial Customers registered under electricity Tariff 215. They constitute the vast majority of CEB's commercial accounts. Their share of the total electricity sales in 2011 stood at 7.77%.

Based on the test statistics at 5% significance level, as shown in Table A1.5, it is obvious that there exists a strong correlation between the performances of both Small Local-Market Focused and Medium & Large Domestic-Market Focused Commercial Customers and the commercial sectors' growth rate, which is driven by the key above-mentioned players (Medium and Large Commercial Accounts).

TABLE A1.5: Test Statistics

t-ratio	(-3.26)	(27.80)
p-value	[0.000]	[0.000]
R-Squared	0.986	

Given this close relationship, the future electricity demand of the both Small Local-Market Focused and Medium & Large Domestic-Market Focused Commercial Customers (COMDDD$_t$) has been estimated, using the model below.

$$\text{Ln COMDDD}_t = \alpha + \beta \,\text{Ln COLO}_t + \xi_t$$

Where,

COMDDD$_t$ *The electricity demand of Small Local-Market Focused and Medium & Large Domestic-Market Focused Commercial Customers*

α *Constant*

β *Coefficient*

COLO$_t$ *The annual performance of Small Local-Market Focused and Medium & Large Domestic-Market Focused Commercial Customers, which are dependent on the local economic performance, has been regressed on the total value of outputs of the country*

ξ_t *Error term*

Industrial Sector Electricity Sales Forecast

The CEB's Industrial Customers are specifically involved in manufacturing activities. By definition, the purpose of using electricity in the Industrial Sector is when there is necessarily a transformation process taking place. Industrial Customers are classified under one of the nine available tariffs (excluding the tariff for sugar factories).

In 2011, the larger share of electricity consumption in the Industrial Sector was mostly accounted for by a handful of key export-oriented economic players. This trend has prevailed historically.

TABLE A1.6: Shares in Electricity Sales and Number of Accounts in the Industrial Subcategories in 2011

Tariff Category	Characteristics	Share in Sales of Electricity	Share in Number of Account
315	Declared load usually less than 20 kVA	4.45%	85.51%
313	Low Voltage connection with *MDI*[1]	37.91%	11.53%
317	Same as 313, but formerly registered in EPZ sector	12.62%	2.29%
320	Time-Of-Use with MDI on Low Voltage connection	0.22%	0.03%
323	*High Voltage*[2] connection with MDI	14.18%	0.31%
325	Same as 323, but formerly registered in EPZ sector	22.52%	0.12%
330	Same as 325 but with Time-Of-Use	2.09%	0.03%
340	*Low Voltage* connection with MDI in Freeport	1.20%	0.10%
350	High Voltage connection with MDI in Freeport	4.82%	0.08%

Additional information on the tariffs is available in CEB's electricity tariff schedule.

Table A1.6 above provides a workable segmentation of electricity end-users in the industrial category.

As in the case of the commercial category, the linear regression technique, in two steps, has been applied to estimate the demand of the major and small manufacturing firms. In working out the short- medium- and long-term forecast of each industrial subcategory, under the three scenarios, the following assumptions were made:

Small Industrial Customers (T315)

Although the pool of small Industrial Customers represents around 86% of the total industrial customer base, their share of the total electricity sales of 2204 GWh in 2011 stood merely at 1.31%. For this reason, they are considered as secondary economic players. Like the Commercial Customers under Tariff 215, the small Industrial Customers are highly dependent on the prevailing economic conditions, which are strongly influenced by major income-generating key economic players.

Given the close links between them and the other economic players, the number of accounts in the T315 category is expected to evolve in step with the other industrial customer categories. The assumption under each scenario is explained in the Table A1.7.

TABLE A1.7: Forecast Assumptions Under Different Scenarios

Scenario	Assumption
Low	The energy intensity will follow a logarithmic trend, as observed in historical trend.
Base	Given that this category is highly vulnerable to changing economic conditions, it is assumed that the specific consumption will evolve randomly.
High	It is observed that the specific consumption is falling (overall demand of the category is growing at a decreasing rate). It is assumed that this trend will continue as consumers further embrace energy efficiency practices.

Medium Industrial Customers (T313, T317 & T320)

The present forecast for the medium-size industrial customer categories is made on the assumptions elaborated in Table A1.8 which is shown on the next page.

Large Industrial Customers (T323, T325 & T330)

Large Industrial Customers are strong enterprises which had/have made heavy investments to start their business operations. Analysis of their consumption trends, declared loads and demand profiles indicates that most of these existing companies are operating at almost full-load capacity. CEB has estimated that growth, if sufficiently significant, in the large industrial customer category will be caused mostly by new entrants.

[1] *MDI* stands for Maximum Demand Indicator in technical term, which is used to measure maximum demand.
[2] The term *'high voltage'* here refers to the 22 kV distribution voltage level. In general, the 22 kV voltage level is classified as medium voltage.

Short- to medium-term demand estimates of new entrants are based on official requests received from potential customers. Industrial projects are usually known 2 to 3 years in advance, before the commissioning of supply. Such information enables the CEB to arrive at accurate and reliable estimates.

As no major industrial projects have been identified for the long term, the current demand projection has assumed that electricity demand of the large Industrial Customers will grow at a decreasing rate. A decreasing trend has also been assumed so as to reflect a possible shift to other energy sources. In fact, there is already a tendency for large enterprises to invest in renewable energy sources so as to partly meet their power demand.

Industrial Customers Operating in Freeport

In the CEB's customer database, companies involved in Freeport Operations are classified under Tariffs 340 and 350. They are considered as key economic players which generate substantial amount of revenues for the country.

The Freeport Sector has maintained a positive growth in its operations during the recent years. As Mauritius is viewed as a strategic bridge between new emerging industrialized countries (India & China) and the South African Development Communities (SADC) Countries important developments are expected in this sector in the long term.

Table A1.8: Forecast Assumptions For Medium Industrial Customer Categories

	Scenario		
Category	**Low**	**Base**	**High**
T313	This customer category does not benefit from the preferential EPZ electricity tariff. Most of the firms manufacture for the local market. In the Low Scenario, it is assumed that firms in this category will continue to face tougher competition from imported products. Their market shares will remain more or less stable. New entrants will have smaller production capacity.	Specific consumption for both existing and new customers will grow, but at a lower rate. The reasons are: Existing firms will expand production to cater for demand in regional markets but, at the same time, they will gradually improve their processes to adopt more energy efficient technologies. New entrants will opt for more energy efficient processes.	Existing enterprises will explore new business opportunities to take advantage of Multilateral Trade Agreements and Regional Trade Agreements. Firms will increase production capacities through replacement of labour by more automation. Similar expectations are assumed for new entrants.
T317 & T320	Most of the customers in these categories operate in the Textile Sector and benefit from the preferential EPZ tariff. No new entrant is possible in these categories. **T317:** It is expected that the number of customers will decrease gradually for two reasons: (1) When an existing customer increases its load beyond a declared threshold (breach of contract), it will be automatically moved to T313 (Non EPZ tariff); (2) Firms in this category face cut-throat competition from Asian countries, and some of them may close down. **T320:** In this category, there are only two customers which are sufficiently strong and can build-up resistance against international threats. Their specific consumption will increase, but to an extent only, as these firms will increase level of automation to improve competitiveness, subject to a threshold.	For both groups, those with strong credentials, and which are flexible enough to restructure, will consolidate their positions and will grow and expand through niche markets. It is assumed that there will be no further closure, while specific consumption will increase but to a certain extent only, due to increased penetration of automation in the processes.	**T317:** Same as Base Scenario for reasons stated. No new entrant is possible. Increase in load above the declared threshold will result into auto-movement to T313 (Non EPZ tariff). **T320:** CEB foresees that these customers will expand capacity through market diversification and will lobby in order to benefit from preferential rates.

In the short and medium terms, based on recent consumption trends and given the present limited transactional capacity, including the geographical location of the Mauritian port, CEB has projected that the electricity demand in the Freeport Operations will grow at a decreasing rate in the Base Case Scenario. This assumption will be revised in the light of upcoming events.

Industrial Demand Modelling

The business performances of major income-generating key players (medium and large Industrial Customers) have serious implications for the local economy. Evolutions in their operations impact on the electricity requirements of other categories/sub-categories, given the linkages they have built with them.

For the major Industrial Customers, the combined value of outputs, produced by export-oriented firms in the Agricultural and Manufacturing Sectors, was used as the predictive element. Accordingly, as shown in the general equation below, a relationship was modelled. A time factor *'TIME'* was also included in the model to cater for technological progress (advancements & efficiencies).

$$\text{Ln IND}_t = \alpha + \beta_1 \text{Ln (AHF)}_t + \beta_2 \text{Ln (MA)}_t - \beta_3(\text{TIME})_t + \xi_t$$

Where,

IND_t *Industrial Demand for Electricity in GWh*
α *Constant*
β_i *Coefficient*
AHF_t *Annual Output Value of Agriculture, hunting, forestry and fishing*
MA_t *Annual Output Value of Manufacturing in year 't'*
$TIME_t$ *Time trend, a proxy for technical progress and technical efficiency*
ξ_t *Error term*

The test statistics in Table A1.9 below fully support the above modelling, whereby a high R^2 was obtained.

TABLE A1.9: Test Statistics

t-ratio	(-0.88)	(3.09)	(2.96)	(-0.79)
p-value	[0.401]	[0.013]	[0.016]	[0.450]
R-Squared	0.977			

TABLE A1.10: Result of Correlation Test

Estimated Y = a + bx		Regression T315 & All-Led	
Estimated Coefficient "b"	0.22	Estimated Coefficient "a"	5360
Standard Deviation "b"	0.03	Standard Deviation "a"	56
R^2 of Regression	0.817	Standard rror of Y	56

The R^2 of 0.817 suggests that there exists a good relationship between the two groups. Hence, using the above, the number of customers in the T315 category was estimated. To ensure consistency with past values, statistical methods were used to determine the energy intensity per unit of stock for this customer group under the different scenarios. The total electricity demand forecast for the small industrial category has been calculated by finding the product of the number of customers and the energy intensity.

Sales Forecast of Minor Customer Categories

CEB's minor customer category includes sugar factories, street-lighting accounts, irrigation accounts and its own consumption.

These electricity end-users consume approximately 3% of the total national electricity production.

Public Lighting and Traffic Lights

Public infrastructural development is an indicator of real economic progress of a country. Alongside wealth creation by private owners and enterprises, Government has the critical responsibility of ensuring that the national wealth created is effectively distributed. In response to this obligation, Government, among other things, invests so as to widen the availability of electricity-usage public goods, for example, street and traffic lightings.

CEB has noted that demand for public lighting over the years has gradually increased. The following have been identified as the triggering factors:

- Kilometres of lighted highway;
- Lighting along existing roads which were not lit before;
- Increase in number of traffic lights;

FIGURE A1.6: Number of Accounts & Declared Load

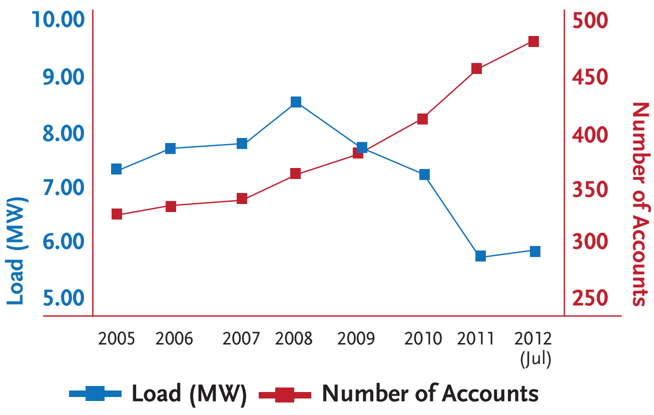


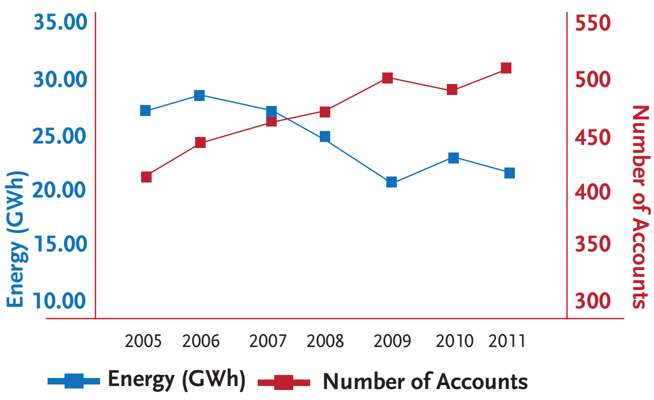
Figure A1.6 above, depicts the increasing trend in the number of accounts of public lighting. Although the number of accounts is increasing, the installed load, however, has fallen substantially over the last four years.

This has been mainly due to the wide replacement of non-efficient bulbs with energy-saving lamps by local authorities.

Electricity for Irrigation Purpose

CEB has been actively supporting the Agricultural Sector by providing a subsidized tariff for water pumping for irrigation purposes. A 2-Tier time-of-use tariff is presently allocated to accounts which use electricity specifically for this purpose. The number of customers in this category has also shown an upward trend. However, recently, electricity sales to this category were on a decreasing trend. This can be explained by the fact that large portions of land, previously under agriculture, have been freed for infrastructural developments. Figure A1.7 below illustrates the observation.

FIGURE A1.7: Number of Accounts & Energy Sales



Based on the above and on knowledge of upcoming developments, it is expected that the share of 3% of minor customers will be maintained in the future. The demand forecast for these minor electricity end-users was based on the following assumptions:

- Sugar factories, which include mostly IPPs, will rely as usual on CEB mainly for *start-up* operations and in cases of breakdowns. No major increase in sales to sugar factories is expected in the future at this stage.
- Although it was forecasted that the number of street-lighting accounts would increase as a result of the construction of new roadways (Ring Road, Dream Bridge, and Terre Rouge-Verdun Road) and improvement of existing ones, demand for electricity for public lighting will, most likely, follow a logarithmic trend. The electric load will grow at a much lower rate than in the recent past, given that more efficient lighting and renewable technologies may be used.
- Demand for electricity for irrigation purposes is expected to grow slightly in response to the Food Security Development Project initiated by the Ministry of Agriculture (MoA). However, the increase may be partly off-set as more lands under agriculture will be released for infrastructural (real estate) developments.

Overall, electricity demand of the minor customer categories is projected to grow negligibly over the planning period. Since the share of the minor categories is relatively small, simple statistical techniques were applied to forecast the future demand.

SYSTEMATIC CONTINUOUS DATA COLLECTION

A proper demand forecast requires that data be systematically gathered and evaluated. In performing these tasks for the preparation of the IEP 2013-2022, CEB has carried out the following exercises:

Consultation with Promoters of Major Projects

To enhance the accuracy of the 10-year electricity demand forecast, in addition to historical data and information, CEB has, on an on-going basis, held consultation meetings with promoters of major projects. By holding such technical meetings, the level of subjectivity implied in forecast exercises is thus minimised.

Mapping of Customers on Substations

For the purpose of studying monthly demand evolution on each CEB's substation and preparing, for the first time, a spatial load forecast, data was extracted from the SAP system, grouped by Meter Reading Units (MRUs) and then mapped out on the electric network appropriately.

In fact, each and every account was mapped out on the respective feeder, and then the monthly aggregate demand for each substation was estimated. Accordingly, a database of monthly energy delivered by each substation, for the period January 2005 to July 2012, was constructed.

In addition to the above, for each major substation, the total power supplied to the loads was computed, using the input power to the station. This has enabled validating the data collected.

Using the above-mentioned database with other relevant information from the SCADA System and data collected through feeder-loading measurements, typical load profiles of CEB's substations were simulated. The annual peak loads, hauled by each existing substation for hot summer periods (January, February and March), were then calculated. Figure A1.8 below summarises the process.

Feeder Loading Measurement Campaign

One of the primary objectives of feeder loading measurement is to determine the load profiles of electric feeders, which can be used as an input for preparing the spatial load forecast.

CEB conducted a feeder loading measurement campaign, involving a sample of feeders, for two consecutive years. The measurements have enabled estimating the typical profile of each major customer group in the system load profile. The information thus obtained has enhanced our understanding of the demand patterns of the different customer groups. Evolution in the demand patterns usually dictates the kind of investment (base, semi-base or peak load) in power generation expansion and, by extension, in network expansion.

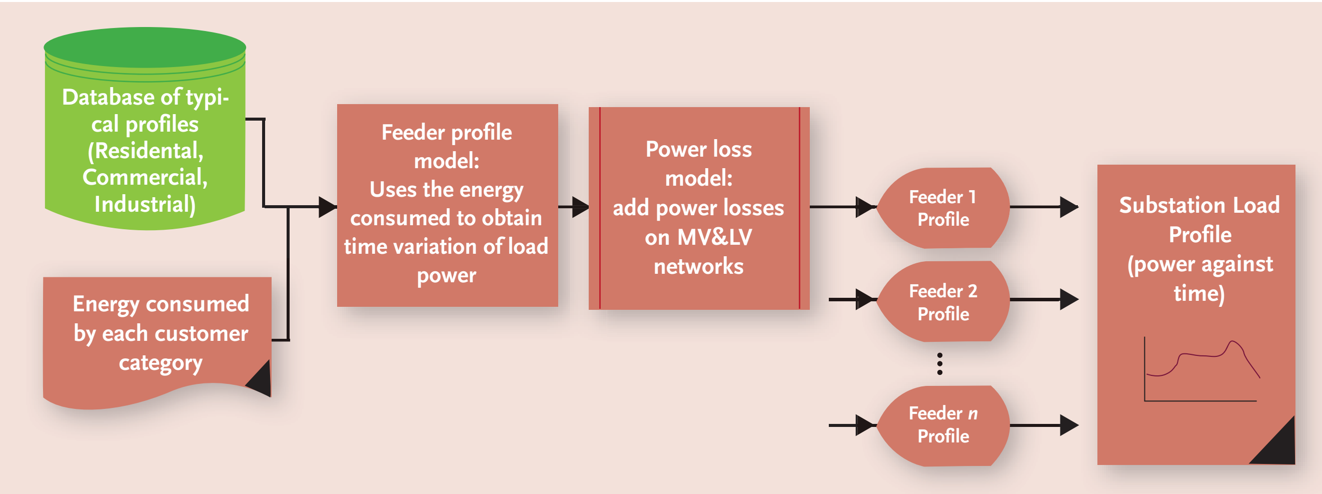
A Power Analyser was used for the feeder loading measurement exercise. Active, reactive and apparent powers, as well as, the power factors, were recorded.

Household Electricity Utilization Survey

Reliable and updated information is a key ingredient in effective decision-making. Holding the right information provides a cutting edge and improves corporate values. Recognizing the intrinsic value of information creates the need for an entity, such as the CEB, to conduct primary data collection, as part of its research work. CEB conducts, on a periodic basis, a national household electricity utilization survey. The survey assists in strengthening our understanding of electricity usage in households and in acquiring pertinent information to formulate Demand-Side Management (DSM) strategy.

The last survey was conducted in May-June 2012. The findings of the survey had helped to validate the residential sector demand forecast and, accordingly, to plan forthcoming DSM initiatives.

FIGURE A1.8: Load Profiles Determination Process



USEFUL INFORMATION ON POWER PLANTS

Appendix B1

The following tables give useful information on the capacity of power generation facilities in Mauritius.

TABLE B1.1: Information on CEB's Power Plants

Engine	Make	Year Commissioned	Effective Capacity (MW)
Fort George Power Station			
G1	Sulzer	1992	22
G2	Sulzer	1993	22
G3	Mitsui & Hyundai	1997	30
G4	Mitsui & Hyundai	1999	30
G5	Mitsui & Hyundai	2000	30
Saint-Louis Power Station			
G1	Pielstick	1978	5
G2	Pielstick	1978	5
G3	Pielstick	1979	5
G4	Pielstick	1979	5
G5	Pielstick	1981	5
G6	Pielstick	1981	5
G7	Wartsila	2006	13.8
G8	Wartsila	2006	13.8
G9	Wartsila	2006	13.8
Fort Victoria Power Station			
G1	Wartsila	2010	15
G2	Wartsila	2010	15
G3	Wartsila	2012	15
G4	Wartsila	2012	15
G5	Wartsila	2012	15
G6	Wartsila	2012	15
G11	MAN	1989	8.5
G12	MAN	1989	8.5
Nicolay Power Station			
G1	GE	1988	21
G2	GE	1991	21
G3	GE	1995	33

TABLE B1.2: Information on CEB's Hydro Power Plants

Hydro Plants	Turbine Type	Year Commissioned	Effective Capacity (MW)
Champagne	Francis	1984	30.0
Ferney	Francis	1971	10.0
Tamarin	Turgo and Pelton	1945-1987	9.30
Le Val	Francis	1961	4.00
Réduit	Francis	1984	1.00
La Ferme	Francis	1959	1.20
Cécile	Francis	1963	1.00
Magenta	Francis	1960	0.90
La Nicolière	Francis	2010	0.35
Midlands Dam	Francis	2013 (expected)	0.35

TABLE B1.3: Information on IPPs Power Plants

Power Plant	Commissioned in	Effective Capacity Coal Mode (MW)	Effective Capacity Bagasse Mode (MW)
CTSav	August 2007	74	65.5
CTBV	June 2000	62	46
CTDS	September 2005	30	N/A*
FSPG	August 1997	27	20
CEL	April 1998	22	11

*Not Applicable.

GENERATION PLANNING METHODOLOGY

Appendix B2

Capacity Planning Methodology

With the increasing load demand and multiple large projects in the pipeline, the CEB has an obligation to supply power to its growing customer database. Addition of new power plants requires proper planning so as to ensure the availability of enough generation capacity at the required time. Different applications are used to perform a least-cost generation expansion plan.

The current generation planning method uses a deterministic approach to predict the addition of future power plants. The Load Forecast section provides two parameters as inputs, namely Peak Power Demand and Energy Sales, which are used to perform the Demand-Supply Balance. This exercise is aimed at determining the need to add more generation capacity to the existing system. In the following sections below the generation planning methodology is explained in detail.

Effective Capacities

The most critical input, in carrying out the Demand-Supply Balance, is information on the latest Effective Capacity of each generator connected to the grid. The effective capacity of each power plant is updated on an annual basis. This exercise is very important as power plants name-plate ratings may be de-rated for the following reasons:

- **Ageing:** Fatigue of certain components in an engine which may lead to failure. So, it is necessary to lower the power output of the engine in order to maximize availability of the generator.
- **Mechanical constraints limiting power output:** Examples include the surging of turbo chargers or excessive vibrations of engines' components if operated at name-plate ratings.
- **Electrical Constraints:** These may occur when the power transmission lines are already overloaded and cannot take all the power from a power plant.

Out of a total effective capacity of 56 MW in hydro power generation in Mauritius, only 25 MW is assumed as *firm* power and is used in the demand-supply matrix. Power outputs from hydro plants are dependent on rainfall and dam levels. Hence, it is not appropriate to assume full hydro capacity for planning purposes.

The Effective Capacities of IPPs are generally assumed, as mentioned in the respective PPAs. For the purpose of the Demand-Supply Balance exercise, a prudent approach has been adopted, whereby effective capacities in 'bagasse'-mode are used rather than that in coal-mode operation. The main reason for adopting this approach is based on the fact that the system peak demand of the country usually occurs in summer, and during these periods, IPPs are using 'bagasse' to generate electricity.

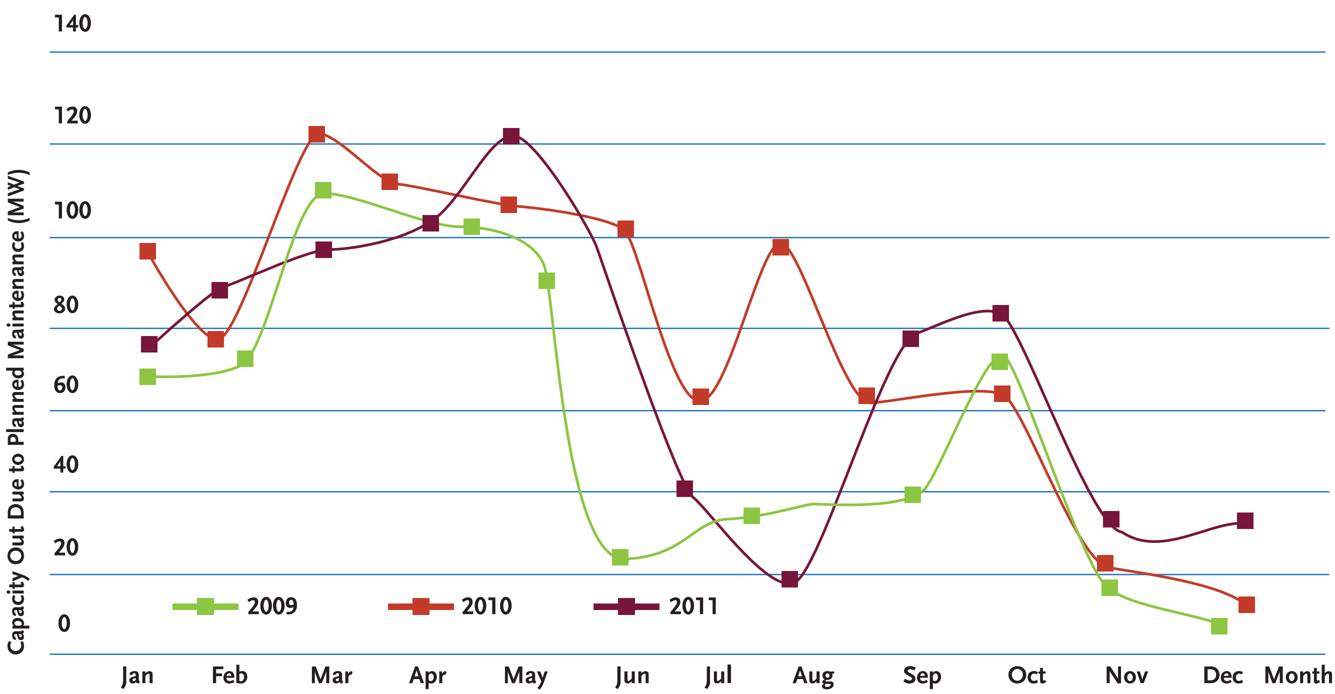
Planned Maintenance

The second important parameter used in the demand-supply balance matrix is the planned maintenance outage, which caters for the downtime of major components, such as engines, boilers and turbines. CEB's records show that the maximum combined capacity which can be out of service, due to planned maintenance, can be as high as 120 MW in a year. Figure B2.1 on the next page illustrates the capacity not available, due to planned maintenance, on a monthly basis for the last 3 years.

It can be noted that during the first five months in each year, there had been a reduction in the availability of generation capacities. This is due to existing IPPs' plants being planned for maintenance in the first half of each year after continuous operation during the sugar-cane crop season. To avoid a further fall in availability of capacity, maintenance of the CEB's generators is carried out during the second half of the year.

For the purpose of capacity planning, an average value of 60 MW is assumed for planned maintenance

FIGURE B2.1: Capacity Out Due to Planned Maintenance (MW)



outage and is used in the analysis for the generation capacity requirements.

Unplanned Outages (Breakdowns)

Despite having scheduled maintenance, some engines or boiler turbine system may encounter unexpected fault which force the ceasing of their operations. Breakdowns are inherent in power plants. As good planning practice, unplanned outage should also be catered for when planning the need for additional generation capacity. It is therefore very critical to factor it into the demand-supply matrix. Generally, in the worst case scenario, the largest generator connected to the grid is assumed to be on forced outage.

In the Mauritius power system, the largest unit connected to the grid is a 37 MW boiler turbine system located at the CTSav power plant. Thus, in the demand-supply matrix, this figure is assumed as forced outage.

Spinning Reserve

Spinning reserve refers to generating capacity that can be called on in a few seconds to supply power in the event of sudden load increases or unit failures. The generator(s) for such reserve should already be in operation on spinning mode. This is essential so as to avoid the time delay required to bring up an engine to full power from a cold-start condition and synchronizing it with the system grid.

There are actually two practices adopted to cater for spinning reserve in planning. First, a spinning reserve capacity equivalent to the largest unit connected to the grid may be opted. Alternatively, a factor equal to ten percent (10%) of the prevailing load on the system can be used. In the CEB's case, the second option is chosen as it is more in line with normal utility practice for small island systems.

Reserve Capacity Margin

The reserve capacity margin (RCM) is expressed as a percentage and is determined as follows:

$$\frac{\left(\Sigma_{i=1}^{n}\ \text{Effective Capacity}_i\right) - (\text{Capacity Out})_{Mtce} - (\text{Capacity Out})_{Bdown}}{(\text{Forecasted Peak Power} + 10\%\ \text{Spinning Reserve})} - 1$$

where,

n — *total number of generating units connected to the grid;*

(Capacity Out) $_{\text{Mtce}}$ — *maximum capacity that is assumed to be unavailable due to maintenance;*

(Capacity Out) $_{\text{Bdown}}$ — *largest generating unit assumed to be unavailable due to breakdown.*

Usually, the RCM is kept at a threshold of minus 5%, which gives the appropriate level of confidence to meet demand. Where the RCM value falls below this threshold, the need for additional capacity to restore supply confidence is triggered.

Firm Capacity versus *Non-Firm* Capacity

As discussed earlier, CEB is already contemplating the addition of a few power projects for the short term. However, only *firm* power generations are considered in the demand-supply balance matrix. By definition, a *firm* power plant is one whose power is available at scheduled times and at controllable levels. For instance, only one of the power projects, listed in Section 5.2.4, is classified as firm power plant. It is the CT Power Coal Plant.

A *non-firm* (also called variable) power plant is defined as a power plant whose capacity availability cannot be scheduled with certainty. The power supplied is typically based upon availability of renewable energy sources.

Therefore, renewable energy projects are considered as *non-firm* power and are not included in the demand-supply balance matrix. Figures B2.2(a) and B2.2(b) below illustrate the power output profile of a typical *firm* power plant and a *non-firm* power plant.

FIGURE B2.2(a): Typical Firm Generation (Coal Plant) Power Output Profile

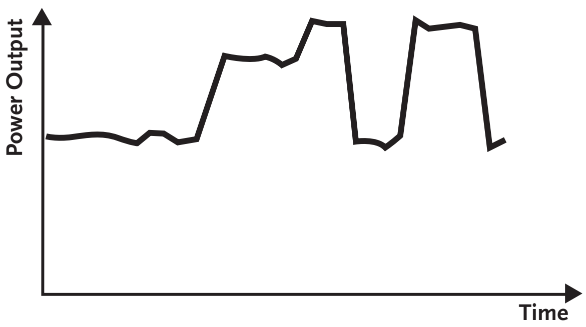
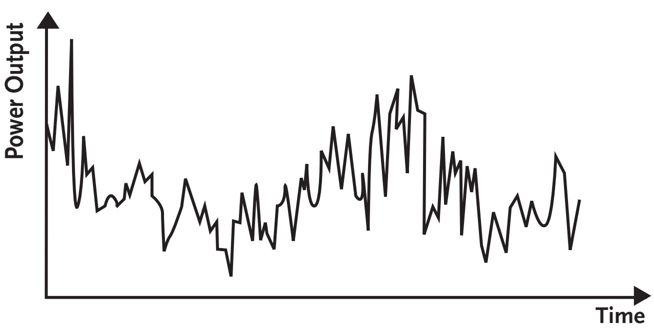


FIGURE B2.2(b): Typical Wind Farm Power Output Profile



Selection of Least-Cost Generation Addition

While formulating a new generation plan, a number of technical, economic and new generation plant assumptions are made. First, one should know what type of technology to adopt and what capacity to install. To sort out these issues, a thorough analysis of the evolution of Load Duration Curves (LDCs) is required.

A LDC is similar to a load curve, but the demand data is arranged in descending order of magnitude. The area under the LDC gives the total energy generated for the period under study. The maximum value on the y-axis is the peak power demand. The first 1000 hours represent the peak loads registered in a given year. Figure B2.3 on the next page shows the evolution of CEB's LDCs from 2002 to 2011.

Generally, the LDC can be subdivided into three areas, namely: base load, semi-base load and peak load. The first 1000 hours is normally assumed to be the peak load, while the position where the LDC starts to kink vertically shows the base load. The region between the peak and the base load areas is referred to as the semi-base load. These three areas are shown in the LDC (Figure B2.3 on the next page) of the year 2002.

Sustained growth in any of the three areas dictates the type of plant technology to be installed. Using historical trends and demand profiles of future load additions, the LDCs of future years can be forecasted. These LDCs show the growth in either base, semi-base or peak regions. Generally, the following rules, as described in Table B2.1, are adopted to select the best generation technology.

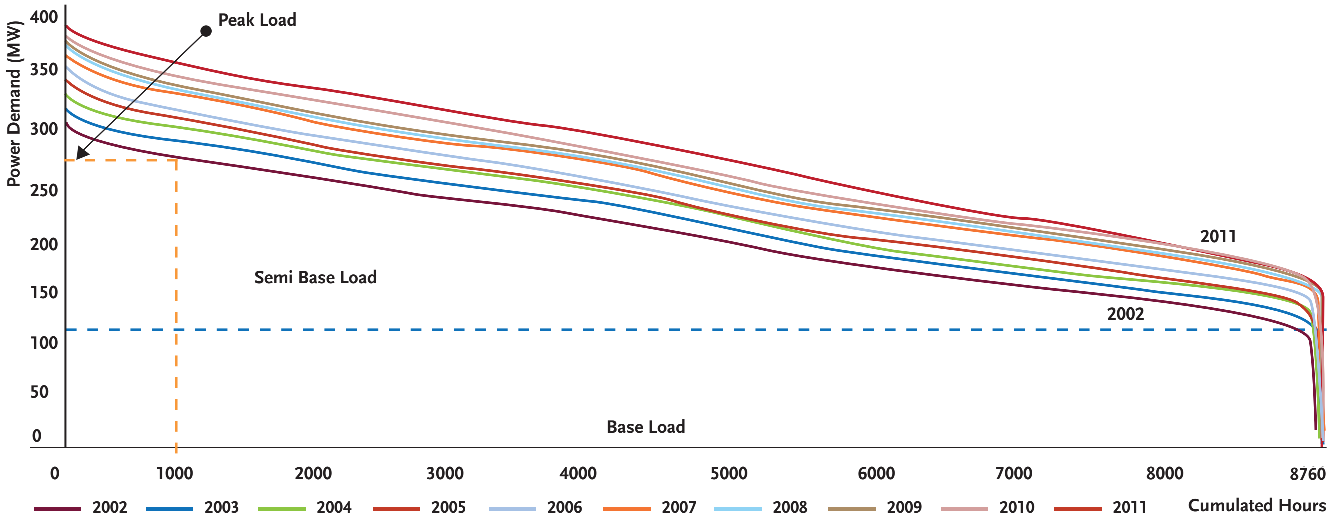
TABLE B2.1: Preferred Generation Technology for each Type of Load

Anticipated Load Growth in Load Duration Curve	Preferred Generation Technology
Base	Coal, Slow Speed Diesel, Combine Cycle, Co-generation plants (coal & bagasse)
Semi-Base	Medium Speed Diesel
Peak	Gas Turbine, Hydro (if water available)

Screening Curves

After the appropriate technology has been chosen, the economic aspects of the candidate plants are analysed. The screening curve approach provides a way to view the trade-offs of the different available power

FIGURE B2.3: Evolution of Load Duration Curves

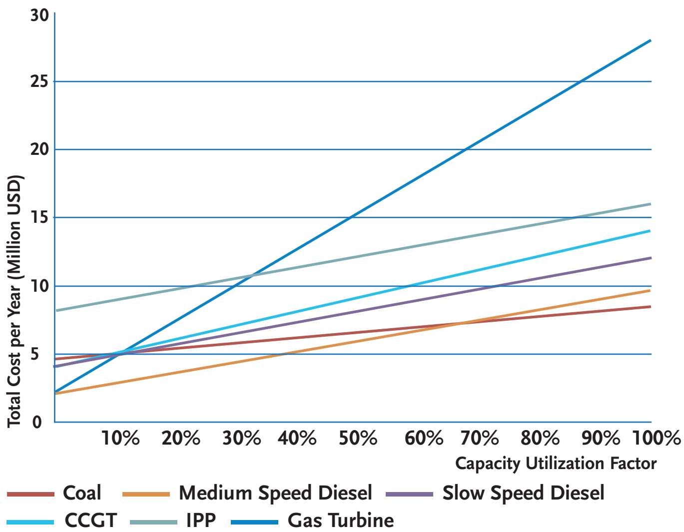


generation technologies, in terms of investment and operating costs.

Basically, the screening curve provides a preliminary understanding of the competitiveness of the different plants (options) at varying capacity factors. From an economic point of view, if the expected load factors of candidate plants are known, the screening curve will illustrate which options are most cost-effective to operate.

From Figure B2.4 below, it can be observed that the gas turbines have the lowest investment costs but the highest operating costs. As such, it is not financially sound to run gas turbines permanently. However, if it is operated below 10% utilization factor - that is, for peaking periods only in a year - it becomes an interesting option. Other technologies, for example coal, have higher initial investment costs but lower operating costs. Therefore, they are best suited for base load (continuous) operations.

FIGURE B2.4: Screening Curves - Power Plant Technologies



Capacity Sizing

The sizing of generating units is very important in capacity expansion planning. Normally, if base plants are to be installed, they are sized according to the peak demand. A factor of 10% of the predicted system peak is used as an estimate for the unit size of a base plant.

In case a semi-base plant (medium-speed diesel) is required, generating units of 12 to 18 MW are most commonly used, as they are readily available worldwide. Moreover, these modular-sized generating units offer the advantage of dispatching the units, as and when required. It is more flexible to connect smaller-sized units for semi-base loads than adding a big generator and operating it at poor efficiency.

As far as sizing of peaking unit is concerned, it depends on how the peak load will evolve in the future. Nevertheless, units, which will be installed for this purpose, will remain available at all times for peak shaving and be synchronized to the grid in minimum time. If well-maintained, a peaking unit can offer a long operating life.

Timing

Another essential factor to consider, while carrying out a capacity expansion planning, is timing. Timing ensures that new generators will be available on time to meet the forecasted peak demand. Therefore, planning to construct a power plant should be done well in advance so that demand can be met in the future. Table B2.2 below gives an idea of the construction period for each type of power plant.

TABLE B2.2: Construction Time by Types of Power Plants

Types of Plant	Construction Time (Months)
Gas Turbine	12 to 15
Medium/ Slow Speed Diesel	18 to 24
Pulverized Coal	30 to 36
Dual-Fired Coal/Bagasse	24 to 30
Combine Cycle	30 to 36
Hydro	9 to 12

ENERGY GENERATION ESTIMATION METHODOLOGY

Appendix B3

Energy generation estimates are essential for budgetary purposes. The methodology adopted to work out the energy generation estimation is detailed hereunder.

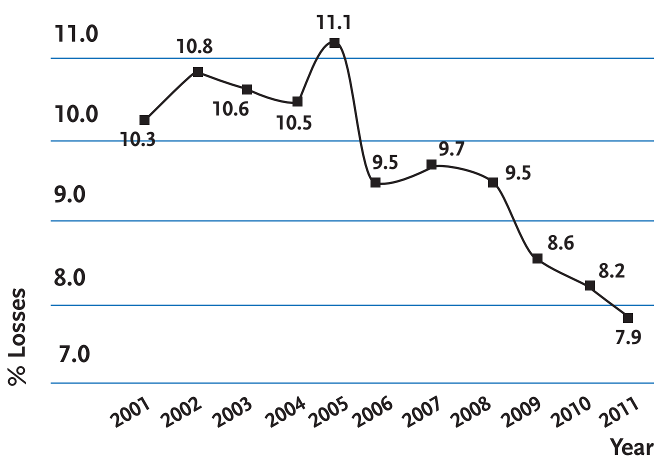
Assumption on Network Losses

Network loss is an essential input in gross generation estimation. It is generally expressed, as shown in the formula below, as a percentage difference between total energy sent-out from power plants and total energy sales.

$$\frac{\text{Total Energy Sent Out} - \text{Total Energy Sales}}{\text{Total Energy Sent Out}} \times 100$$

Network losses can be divided into technical and non-technical losses. Technical losses take into account both transmission and distribution losses, while non-technical losses include energy loss due to fraudulent actions. The line graph in Figure B3.1 below shows the evolution of network losses over the last decade in Mauritius.

FIGURE B3.1: Percentage Network Losses for the Period 2001–2011



It can be observed that the network losses of the country are continuously improving. However, there is a limit to which the system losses can be reduced. For the planning period, CEB has assumed a network loss of around 8%.

Assumptions regarding Used-on-Works

Power plants' auxiliaries consume electricity, and this value is quite significant. The auxiliary consumptions of IPPs are excluded in the estimation, as CEB is concerned with their sent-out energy only. As regards to CEB's power stations, the amount of energy used on works is generally estimated to be in the range of 3.5% to 4% of the total energy generated. CEB has assumed that the units used on works will be around 4%.

'Take-or-Pay' Contracts

CEB has Power Purchase Agreements with IPPs. In these agreements, CEB has guaranteed purchase of a minimum amount of energy. Therefore, when electricity production plan is being prepared the contractual obligations with the IPPs have to be respected. Table B3.1 below shows the IPPs with which the CEB had signed *'take-or-pay'* contract and the corresponding minimum annual quantity of energy agreed.

TABLE B3.1: Minimum Energy Purchased from IPPs

IPPs	(GWh)
CTBV	325
FSPG	160
CEL	110

Energy Generated by Renewable Sources

Unlike capacity planning, renewable energy is taken on board in energy planning exercises. Since CEB has hydro power plants, the energy generation estimates from these power plants are based on historical data. Generally, there are dry and rainy years, but an average of 90 GWh is assumed for hydro power generation.

Given that wind and solar photovoltaic farms will be introduced soon, the forecasted annual energy generation from these sources is estimated using the capacity utilization factor (CUF). The annual energy generation can then be estimated as follows:

Annual Energy Generation = Installed Capacity x CUF x 8760

For upcoming wind farms in Mauritius, the typical CUF may range from 20% to 35%, depending on wind availability on the site. On the other hand, the CUF for solar PV farms may vary from 12% to 20%, depending on the insolation level at the particular site.

Energy Allocation Methodology

The area under the load duration curve (LDC) gives the total energy generated. As discussed above, there are three distinct regions under the LDC, namely, the base, semi-base and peak energy areas.

Based on an analysis of historical behaviour of LDCs, the base energy represents about 60% of the total energy generated. Likewise, the semi-base and peak energy represent about 39% and 1%, respectively. Figure B3.2 below shows the energy allocation in the 3 regions of a typical LDC.

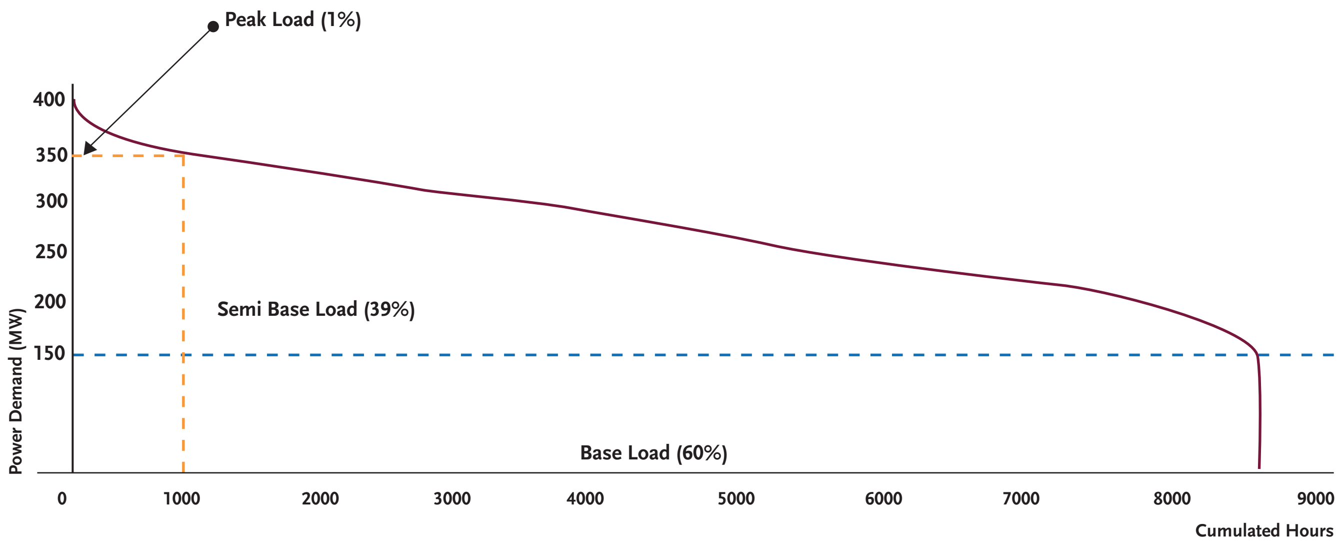
From the energy sales, the Gross Energy Generation is calculated as follows:

Gross Energy Generation = Energy Sales + Used-on-Works + Network losses

Once the gross energy generation is calculated, it is then broken down in the base, semi-base and peak energy proportionately, as mentioned above.

The base energy is supplied mainly by all existing IPPs and the Fort George Power Station. The semi-base energy is generally provided by the medium-speed diesel engines located at the Saint-Louis Power Station and Fort Victoria Power Station. The demand for peak energy is usually met by the Nicolay Power Station and the Champagne Hydro Power Station.

FIGURE B3.2: Energy Allocation Using Load Duration Curve



NETWORK PLANNING METHODOLOGY

Appendix C1

Transmission and Distribution planning is the process of ensuring safe flow of electricity from generation sources to various substations at high voltage, and ultimately to end-users after stepping down to low-voltage level. The process of network planning is mainly dependent on inputs from load forecast and generation planning. The methodology adopted for transmission and distribution network planning over the planning period 2013-2022 is presented in the following sections.

Transmission Network Planning

For the transmission network planning, the following are considered:

'N minus 1' Security Criterion

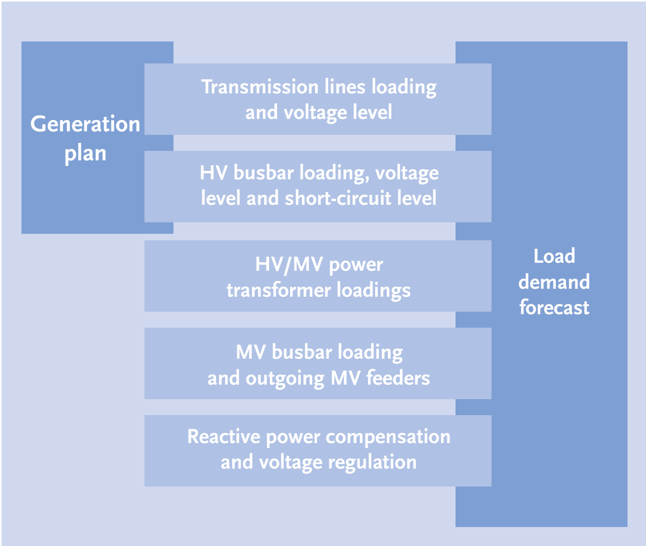
The transmission network consists of high-voltage transmission lines and 66 kV-to-22 kV substations. The transmission plan is mainly based on the *'N minus 1'* security criterion, which requires the transmission system to be in a position to supply the total connected load under both normal and abnormal conditions. The abnormal condition refers to the isolation during fault condition or out of service, due to maintenance of either one transmission line or one power transformer. Under the *'N minus 1'* security criterion, the maximum loading of equipment in the transmission network is limited to 50%.

Input to the Transmission Planning Process

The transmission network plan is largely driven by the loading of the substations and the location of new generation facilities. Inputs to the planning process are thus the spatial load forecasting and generation forecast as shown in the Figure C1.1.

The generation expansion plan mainly impacts on the transmission lines and the 66 kV busbar system requirements, while load demand impacts on the 66 kV-to-22 kV power transformers, 22 kV busbar loadings, reactive power compensation requirements and the 66 kV network.

FIGURE C1.1: Energy allocation using load duration curve



Integrating the Load Forecast

The demand forecast is usually prepared for three scenarios; namely low-case, base-case and high-case. In order to reduce the risk of over-investment in transmission facilities, the 10-year transmission network plan considers the base-case load forecast.

The daily load demand profile of the CEB's system has three peaks referred to as: the morning peak, day peak and evening peak. The time at which a substation experiences its maximum demand depends on the predominant customer category (whether residential, commercial or industrial) connected to the substation. The forecasted system peak and substation demand correspond to the day-peak. Consequently, the loading of the substations during evening peak and morning peak over the planning period have to be estimated by scaling the substation forecast appropriately.

Integration of the New Generation Facilities

The locations of new generation facilities are provided by the generation forecast. However, if the locations are unknown, a number of scenarios are evaluated a geographical basis and the most favourable injection points are ranked, in terms of the least-cost investment transmission facilities.

System Initialization and Study Cases Development

In order to perform power system studies and ultimately formulate a transmission expansion plan, a calibrated transmission model that reflects actual loading condition is required. The CEB's transmission model was developed using the DIgSILENT Powerfactory Software. The current base-case model developed reflects the load flow condition during the system peak demand of 430 MW recorded on Wednesday 22nd February 2012 at 14:00 hours.

Determining the Requirements for Transmission Lines and Power Transformers

For each year of the planning period, the power system is simulated under different network set-ups and conditions to identify the least-cost network expansion solution. In this exercise, the following studies are performed:

- Load flow study to determine transmission line loadings and voltage profile. The resulted loadings guide the upgrade and/or adding of new transmission lines and power transformers so as to meet the increase in the load demand and satisfy the '*N minus 1*' security criterion.
- Transient stability study to identify the interconnection facility requirements for both conventional and renewable generation power plants.
- Reactive power study identifies the need for reactive power compensation to maintain the voltage profile within the regulatory requirements and reduces power loss.
- Fault level study to determine the fault level at the 66 kV busbars, following the addition of generating units and transmission lines, and assess the need for busbar system upgrade.

Reactive Power Compensation

Reactive power compensation is required at the 22 kV busbar of the 66 kV-to-22 kV substation in order to supply the reactive power demand at the substation. Generally, the adopted approach is to provide for reactive power compensation at substations located far from power plants. Having reactive power compensation at substation helps in minimizing the reactive power flow along the transmission network and, thereby, reducing the power loss and voltage drop.

In order to determine the need for reactive power compensation, the following power factors are assumed:

- a power factor of 0.92 lagging for generating units; and
- a power factor of 0.98 lagging for medium-voltage side power transformer.

Fault Levels

Fault levels are largely affected by the addition of generating units and new transmission lines to the system. In this respect, fault level studies are carried out on the DIgSILENT Powerfactory Software. The standard used by the software to perform these calculations is IEC 60909.

For the purpose of this IEP, fault level studies have been performed for the year 2014, 2016 (associated with the commissioning of two new 50 MW generation units) and 2022 (end of the study period and associated with the commissioning of two additional 50 MW generating units) to identify the need for upgrading of the 66 kV busbar system at the older 66 kV-to-22 kV substations.

Distribution Network Planning

In preparing the distribution network plan, the following are considered:

Planning Criterion

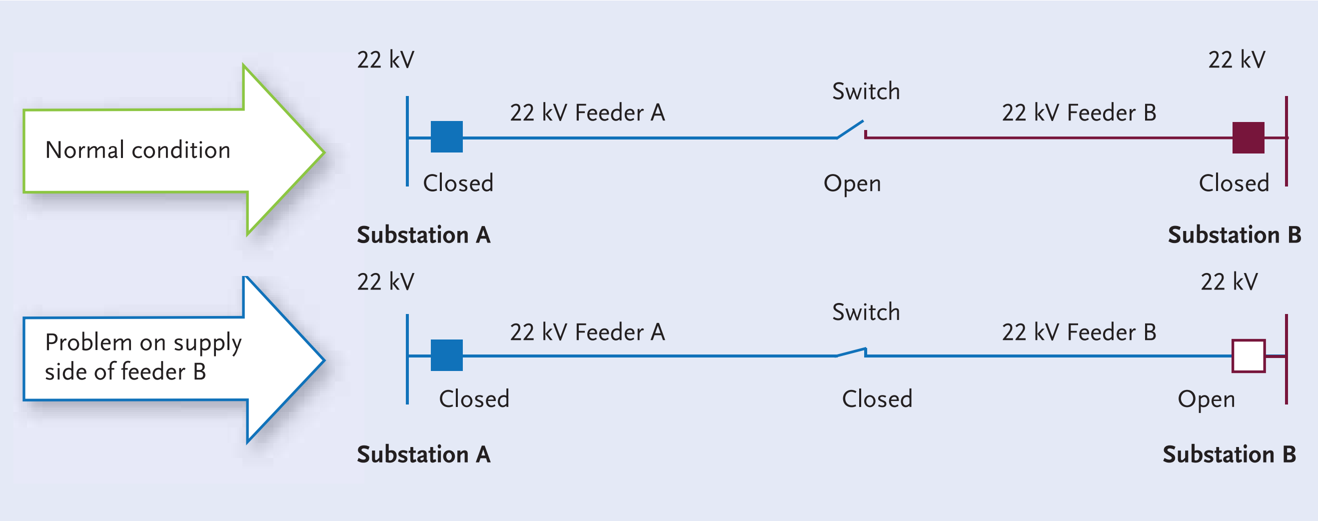
The planning criterion for the medium-voltage distribution network is to have the distribution feeders loaded at 50% of their rated capacity at the instant of the peak system demand so that the distribution feeder can take up the whole load on an adjacent distribution feeder during a contingency on the supply side of that feeder. Figure C1.2 on the next page illustrates this condition.

Adherence to this planning criterion would require limiting the load on a distribution feeder, having conductors size 150 mm^2, to some 6 MVA under normal network conditions while ensuring compliance with the regulatory requirement of maintaining supply voltage within ±6% about the nominal value of 230 Volts at customers' terminals.

Distribution System Expansion

As the loading of the medium-voltage distribution feeder approaches 50% of the rated capacity, distribu

FIGURE C1.2: Single Line Diagram of Feeder Setup Under Normal & Abnormal Conditions



tion network reconfiguration or initiation of a new distribution feeder is proposed to share the load growth. Given the cost implications associated with a new feeder, the load growth of the region supplied by the existing feeder is determined to ascertain the requirement for the new feeder.

Methodology to Study the Impact of Renewable Energy (RE) Integration

The integration of variable renewable energy in a power system has negative impact on the system frequency and voltage profile.

The maximum capacity of renewable energy that can be safely integrated in the system is the maximum capacity that will maintain the system frequency and voltage level within the regulated operating limits.

Limit on RE Integration due to Regulatory Requirement on Frequency

In order to assess the stability of a network, dynamic models of the frequency and voltage control systems of generation units are required. CEB's models have been developed in the DIgSILENT Powerfactory Software, using the IEEE standard models and have been validated through field tests and measurements.

It is required to determine the maximum level of renewable energy integration sustainable for the CEB's system, while adhering to the operational frequency limits within ±1% of the nominal value of 50 Hz and the voltage within ±6% of the nominal value.

The block diagram of the power system model, with the associated variables, in the frequency-domain is shown in Figure C1.3 on page 143.

The frequency response of the power system is different for the low-demand conditions and high-demand conditions, due to different amount of spinning reserve and system inertia. Higher load demand is associated with higher level of spinning reserve and higher system inertia, therefore, the impact of variable renewable energy on the system frequency is less.

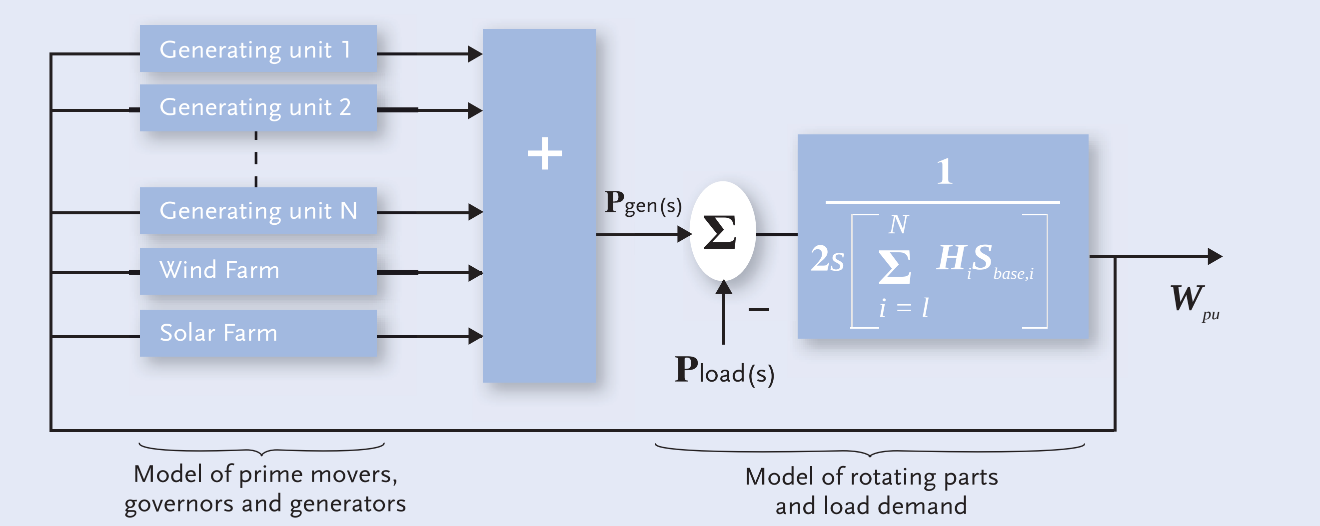
For each of the low-demand and the high-demand conditions, the maximum level of variable renewable energy that can be integrated has been determined by increasing the level in step and determining the corresponding maximum system frequency deviation, which is caused by the variable power output from the renewable energy farms.

The maximum renewable energy integration is taken as that value which brings a maximum operational system frequency deviation of ±0.5 Hz.

Limit on RE Integration due to Regulatory Requirement on Voltage

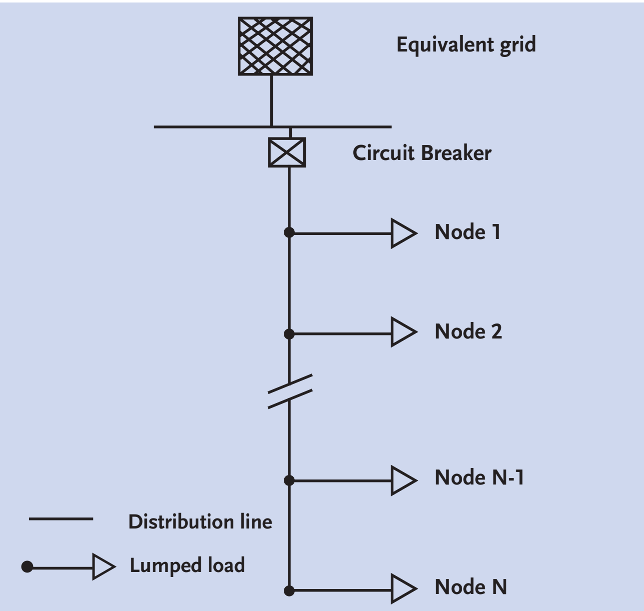
In addition to the above, steady-state models of typical medium-voltage distribution feeders and low-voltage distributed feeders have been developed; where the electrical lines, transformers, loads and equivalent grid system have been accurately modelled. Figure C1.4 on the next page illustrates the model of distribution feeder using a lumped load approach. The

FIGURE C1.3: Block Diagram in the s-domain for the Active Power-Frequency System



i	*Index identifying a generating unit*
N	*Number of generating units in the power system*
$S_{base,i}$	*Apparent power rating of the ith generator in MVA*
P_{load}	*Total active power demand of the system in MW*
P_{gen}	*Total active power generated in MW*
W_{pu}	*Electrical angular frequency in per-unit*
H_i	*Inertia constant of the prime-mover and alternator combined for the ith unit in MJ/MVA*
s	*Laplacian operator*

FIGURE C1.4: Model of Distribution Feeder using a Lumped Load Approach



maximum level of renewable energy that can be integrated on a low-voltage feeder and a medium-voltage feeder has been determined by increasing the level of renewable energy in step until the voltage reaches the upper limit of ±6% of the nominal value.