Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)

Chuuk Public Utility Corporation (CPUC)

Ordered by the Pacific Power Association (PPA)
Prepared by: KEMA Inc.

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1. Executive Summary

KEMA's analysis of Chuuk Public Utility Corporation power system determined total losses of 33.33 % consisting of:

- 3.84% in generator auxiliaries
- 5.72% in street lighting, water and sewage.
- Street lighting should be accounted for and billed. If these revenues cannot be collected, street lighting should be considered a financial loss for CPUC and not a power system loss.
- Energy usage for water and sewerage activities of CPUC should be allocated to the costs of service of CPUC's water and sewerage services and not power system losses. However, if the costs are not allocated to service costs, they will remain a financial loss for CPUC's power services and cannot be considered as a power system loss.
- 7.71% in technical losses
- 16.06% in non-technical losses

Technical and non-technical losses total 23.77%.

Overall losses, including power plant usage, total 27.61%.

Losses because of street lights, water and sewerage activities, should be booked as financial losses, as long as these losses have not been accounted for and/or billed and/or allocated to costs of service of CPUC's water and sewerage activities.

Each percentage of loss costs the utility $30,000 at $3.50 per gallon of fuel cost.

Recommendations

(Section 9 and the appendices contain detailed cost and benefit information.)

It is estimated that by taking the following steps of process improvements and by making some investments as specified in this report, CPUC can start saving $400,000 to $450,000 per year.

1. Operate generating units at high efficiency. Funding of on-going maintenance requirements is not included.

2. Generation efficiency is currently low at an average of 13.4 (13.2 to 13.5 kWh/gallon). Every 1% increase saves $30,000. If the efficiency is improved to 15 kWh/gallon savings could reach $360,000 per year with the installation of new generators, which is expected in 2013. Current generators should be maintained and operated at an efficiency level of 13.5 kWh/gallon, which saves $66,000 per year compared with an efficiency level of 13.2 kWh/gallon.

3. Develop dispatching routine to provide highest efficiency operation. During our visit only one generation set was running while others were waiting for repairs and spare parts. Once all generators are running again, efficiency can be gained by dispatching the engines in anticipation of the expected load patterns.

4. Change and add meters to provide accurate real-time revenue-class and efficiency data of generators and auxiliary plants to the plant operators. Train operators and develop processes to achieve the best efficiency from the generation resources.

5. Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime cost (costs of capital, losses, and maintenance). If most of the islands combine their effort and develop one standard specification to procure large cost items like transformers and engines, cost of these assets may be lower.

6. Add revenue-class meters to the feeders and distribution transformers to measure losses. Use these meters to check the customer's meters, especially if there is any tampering or stealing. Optimize distribution transformers so that no load losses are reduced.

7. Use an infrared camera at least annually to find hot spots.

8. Start a revenue assurance program for auditing, metering, and billing procedures and for executing a non-technical loss reduction strategy.

Recommended actions will cost $1.05 M over a 4-to-6 year period, while overall losses will be reduced from 27.61% to 17%.

The savings and potential cost over 6 years of implementation are summarized in the table below:

Exhibit 1-1: - Savings and Costs

	6 Yrs NPV of Savings and Cost Summary		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Non Technical Loss	$822,176	$767,529	$54,647
Technical Losses	$197,309	$195,805	$1,504
Auxiliary loss	$33,517	$25,000	$8,517
Total =	$1,053,002	$988,334	$64,668
Generator Efficiency improvement	1% improvement saves $30,000		

2. Introduction

2.1 Project Objectives

KEMA was asked by the Pacific Power Association (PPA) to conduct an energy efficiency study titled: "Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)" for 10 Northern Pacific Island Utilities. This report summarizes the study results for CPUC, Chuuk.

Project objectives and deliverables:

1. Quantify energy losses in the power system.
2. Prepare an Electrical Data Handbook containing electrical characteristics for all high voltage equipment.
3. Prepare digital circuit model of the power system using EASY POWER, an established commercial package.
4. Prepare a prioritized replacement list of power system equipment to reduce technical losses.
5. Identify sources of non-technical losses.
6. Recommendation strategies for reducing technical and non-technical losses.

2.2 Quantification of Losses

Losses are due to:

1. Power station losses
2. Distribution system losses.

Both losses are quantified.

- Station Losses: Engine / Generator Efficiency and Power Plant Auxiliary Loads
- Distribution System Loss: This can be divided into technical and non-technical parts.

- Technical losses: Summation of transformer core loss, transformer copper loss, feeder loss and secondary wire loss.
- Non-technical losses: Inaccurate meters, meter tampering or by-passing, theft, meter reading errors, irregularities with prepaid meters, administrative failures, and wrong multiplying factors.

- Unbilled Usages: Energy consumption that is not billed should be considered a financial loss rather than a non-technical loss. Examples include the following:
  - Street Lights. Street lights need to be invoiced or be considered a financial loss.
  - Power for water production, distribution and sewerage: Needs to be allocated to the costs of service for Water and Sewerage, or considered a financial loss.
  - Power usage by customers who get power for free. The cost of the freely delivered power should not be considered as system losses, but should be considered a financial loss.

3. Data Gathering and Assessment of Current Situation

Data gathering process is to collect existing information and understand the current situation of the generation and distribution system. KEMA visited Chuuk in March 2010 and conducted meetings with management and staff. Physical inspection was selectively done of power plants and some electrical distribution facilities including the power plant substation, distribution transformers, and overhead feeders. Given that little information was provided, Mr. Andrew Daka of the PPA provided more data following a visit to Chuuk in May 2010, to follow-up on the data request. Below is a Fact Sheet received during KEMA's visit.

GENERAL FACT SHEET	
POPULATION	
TOTAL	54,000
WENO (Capital)	15,000
39 OTHER ISLANDS	39,000
ISLANDS WITH POWER, WATER SEWER INFRASTRUCTURE	1 (WENO ONLY)
COVERAGE	
POWER	25%
WATER	19%
SEWER	14%
ORGANIZATION & FINANCE	
# OF EMPLOYEES	60

POWER INFRASTRUCTURE	
GENERATION CAPACITY	4.5 MW
FIRM CAPACITY	3.1 MW
MAKE	CATERPILLAR
TYPE	3516 (3) and D399 (1)
DEMAND	2.6 MW
	Because of unreliable power most business are self generating
DISTRIBUTION	20 MILES
DISTRIBUTION VOLTAGE	13.8 kV
# OF METERS (CUSTOMERS)	1,880
PREPAID (CASHPOWER)	1,732
CONVENTIONAL METERS	148
THREE-PHASE	89
SINGLE PHASE	1949
RESIDENTIAL TARIFF	$ 0.51 / kWh
COMMERCIAL TARIFF	$ 0.53 / kWh
GOVERNMENT TARIFF	$ 0.55 / kWh

3.1 KEMA Data Request

A data request was sent to CPUC prior to on-site meetings. (See Appendix A.)

3.2 Data Received

No data was received before the site visits by KEMA and PPA.

3.3 Site Visits

Additional data was gathered during KEMA's site visit of March 2010 and PPA's visit of May 2010. (All data collected is in the Electrical Data Handbook of Appendix B.)

Data Collected:

1. CPUC Fact Sheet
2. Generator energy production logs
3. Generator data

May 2010 Mr. Andrew Daka from PPA visited Chuuk and sent more data:

1. Map with feeder indicated
2. Substation and Transformer data
3. Distribution Feeders' sizes and lengths
4. Billing Cycle and Procedures
5. Generation Statistics
6. Customer energy usage statistics
7. CPUC distribution asset Annexure 2.11

Still, many details were lacking and assumptions were made to arrive at the quantification of losses.

3.4 The CPUC Power System

The main system is served by one power plant. In 2007 three 1.45 MW containerized CATERPILLAR 3516 engines with 480V each, were installed.

The generation units in the old power plant are in-operable. In 2009 and the first half of 2010 only one small engine (D399) delivered power to a maximum of 1.2 MW. Even though the three containerized CATERPILLARS were bought with 5,000 running hours, only one operates three years later at a de-rated capacity of 1.2 MW.

Generators in CPUC's plant are in deteriorated condition, as reflected by the data listed in Exhibit 3-1, for an 11-month period from June 2009 to April 2010. In the last 4 months half the energy was generated compared to the same months of the previous year.

The Distribution System has four 13.8kV feeders. Each generator has one step up transformer (3 with a rated power of 2,500 kVA, 480 V to 13.8 kV, and 1 with a rated power of 3,000 kVA, 4,160 V to 13.8 kV). Customers are provided power at 240/120V, 208/120V or 480/277V levels through 157 distribution transformers. The utilization level of the installed capacity is 36% at the system's peak load of 2.6 MW.

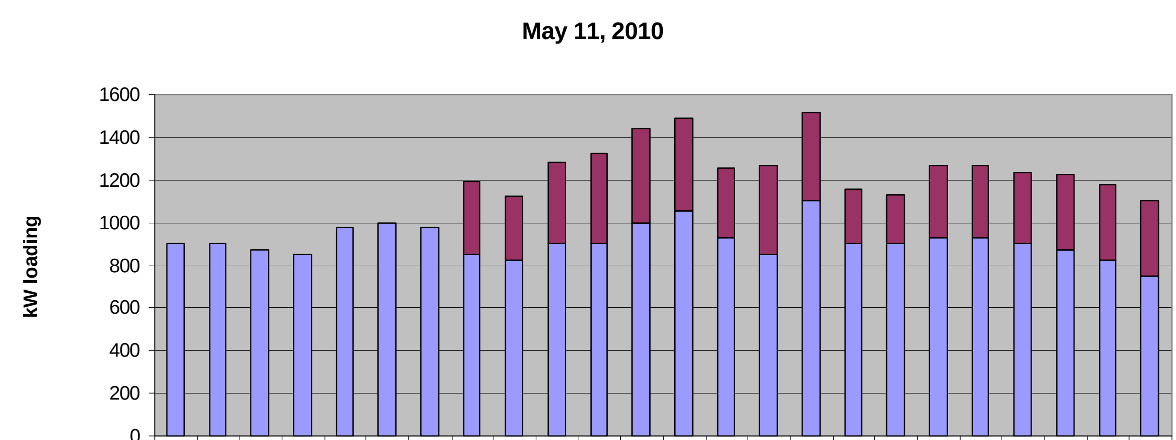
Load: Peak load from July 2009 to January 2010 was 2.6 MW with an average load of 1.251 MW. System load factor is 0.48 reflecting a relatively low base load level. Maximum load was 4.5 MW in previous years and decreased since. One reason is insufficient supply to support the load. Information regarding connected load was not provided. The overall power factor is around 0.89.

The table below lists the amount of energy used by customers. CashPower (prepaid) metered clients are majority of residential customers; while only 1.45% remaining residential usage is still metered and billed (post paid metering).

Commercial	41.58%
Government	4.12%
Residential	1.45%
Cashpower	52.85%

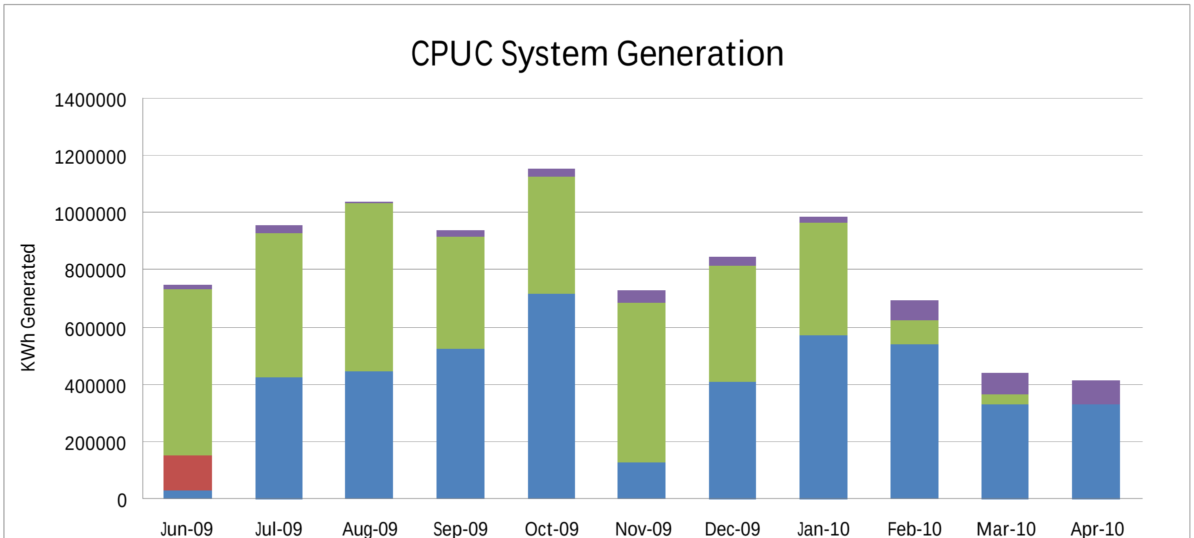
The exhibits on the next page show how much energy is being generated by each of the engines.

Exhibit 3-1: One Day Load as measured at the Generation Plant



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
D399								340	300	380	420	440	440	330	420	420	260	230	340	340	330	350	350	350
Engine 1	900	900	875	850	975	1000	975	850	825	900	900	1000	1050	925	850	1100	900	900	925	925	900	875	825	750

Exhibit 3-2: Energy generated per month



	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10
D399	17221	28625	3260	18713	25045	46715	31270	21455	68340	73970	81190
Unit 3	584217	502340	587618	394074	411507	556815	402875	395825	80500	34465	0
Unit 2	116400	0	0	0	0	0	0	0	0	0	0
Unit 1	33550	423950	445185	523174	718040	127745	410710	570735	542055	331845	331845

Generators: Generating units were in poor condition and could not provide the required load due to maintenance and repair issues. CPUC is looking to develop a new power plant (2x 2.5MW and 2x1MW) funded by ADB. This will take a minimum of 3 years. In the meantime, a solution must be found to keep engines operable. Due to lack of funds, fuel is bought daily with revenues received.

Exhibit 3-3: Engine Data

CPUC	Substation	WENO			
	Engine #	1	2	3	4
GENERATOR DETAILS	ENGINE MAKE	Caterpillar	Caterpillar	Caterpillar	Caterpillar
	ENGINE MODEL	3516	3516	3516	D399 PC
	ENGINE SERIAL NUMBER	25Z06707	25Z06667	25Z06438	36Z01855
	NAME PLATE RATING (KW)	1,600	1,600	1,600	1,600
	DE-RATED (KW)	1,200	1,200	1,200	1,200
	SPEED (RPM)	1800	1800	1800	
	FUEL TYPE	Diesel	Diesel	Diesel	Diesel
	YEAR INSTALLED	2007	2007	2007	1985
ALTERNATOR DETAILS	MAKE	Caterpillar	Caterpillar	Caterpillar	Caterpillar
	TYPE				
	MODEL NO.	SR4B	SR4B	SR4B	800-687361111
	SERIAL NO.	5WN01508	5WN03166	5WN01257	80484-2
	VOLTAGE (V)	480	480	480	4,160
REMARKS			Out of service		Out of service

There are 3 fuel tanks with two (4,000 and 6,000 gallons) not in use. One was removed from the tank stand. The one in use has a storage capacity of 14,000 gallons.

CPUC has initiated discussions with FSM Petroleum Corporation to replace existing fuel tanks with bigger tanks as part of the new power plant project.

Transformers: CPUC has single phase transformers. In some cases their condition is poor.

Exhibit 3-4: Distribution Transformers

Feeder No.	Distr. Transformer Number	Dist. Transformer KVA
F1	38	1621.5
F2	16	372.5
F3	98	4127.5
F4	76	1895
Total	**228**	**8016.5**

Four station transformers had no overload rating but were 50% loaded when generators were running.

Exhibit 3-5: Station Transformers

CPUC	**Substation Name**		**Weno**			
	Transformer Make		WEG #1	WEG #2	WEG #3	KULMAN
	Serial NO.		189098	184814	188408	A67931
	Year of Manufacture		2002	2002	2002	
ELECTRICAL CHARACTERISTICS	**Rating (MVA)**		2.5	2.5	2.5	3
	NO. of Phases		3	3	3	3
	Vector Group		YNd1	YNd1	YNd1	YNd1
	Voltage (V)	**High**	13800	13800	13800	13200/7620
		Low	480	480	480	4160
	Impedance (%)	**Z1**	6.49	6.07	6.18	4.9
		Z0	5.516	5.16	5.253	4.165
		X/R	7.128	7.128	7.128	10.799
	Losses (Watts)	**No Load**				
		Full Load				
	Max. Current (A)	**HV**	110.1	110.1	110.1	138
		LV	3007	3007	3007	418
TANK, CORE & OIL DETAILS	**Oil**	**Vol (Gals)**	269	269	269	1105
		Weight (Lbs)	2006	2006	2006	8940
	WEIGHT (LBS)	**Net**	10913	11045	11045	28560
		Core, Coil & TC	8907	9039	9039	11540
TAPS & TC DETAILS	**NO. of Taps**		5	5	5	5
	Tapchanger Type		NLTC	NLTC	NLTC	NLTC
COOLING METHOD			ONAN	ONAN	ONAN	ONAN
REMARKS						

Feeders: Distribution feeders are at 13.8 kV level and in good condition. All feeders are 3 phase 4 wire. Conductor size is 1/0 or 2/0 Aluminum. In some feeders it is recommended to check connectors and clamps with infrared detection equipment for hot spots and to assess the condition of conductors that have signs of corrosion.

Eventhough 5 feeders are indicated on the Chuuk Map with Feeders as shown in Exhibit 3-7, Feeder 1 and Feeder 5 are connected and provided as single feeder F1 in *CPUC Data Outstanding.docx* which is received in June 2010, see Exhibit 3-6 below.

Exhibit 3-6: Area supplied by each feeder

Feeder No.	Important Area Supplied	Length of Line in Mile	Approximate Load in KW
F1	Hospital, Water Supply Installation, Deep wells, Government Offices, New legislature building and Central part of the island.	2.5	500
F2	Northeast part of the island, Xavier high school and Hans Micronesia Hotel.	3.5	50
F3	Main Down Town, Port, shipping area, Hotels, Blue Lagoon hotel, Southwest and Southeast part of town.	8.0	1200
F 4	Airport, Sewage Plant, High Tide & RS Plaza hotel and North part of town.	6.0	700
TOTAL		20.0	2450

Exhibit 3-7: Chuuk Map with Feeders Indicated

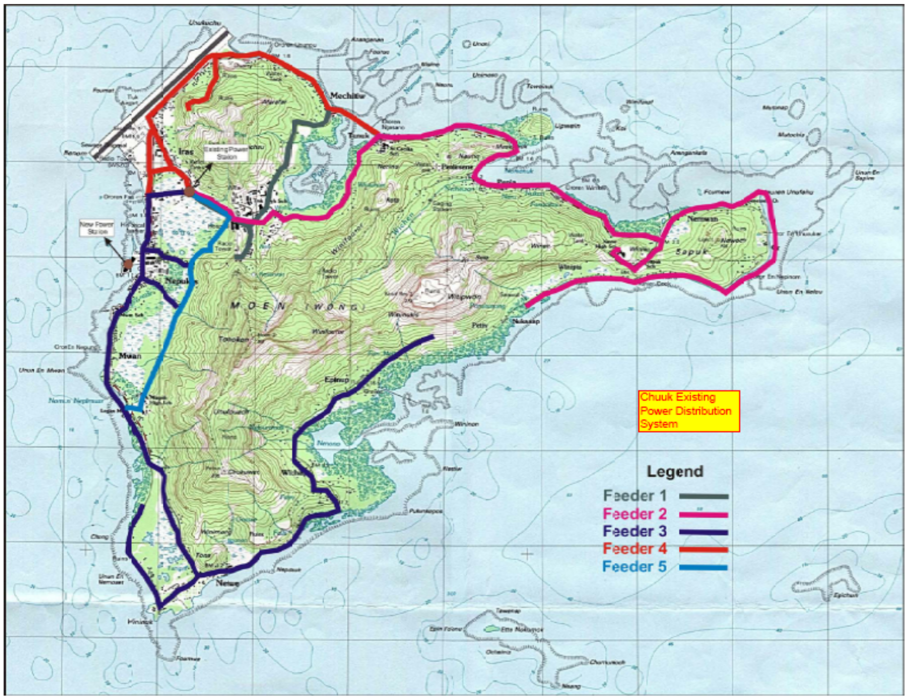


Exhibit 3-8: Distribution Pictures

Capacitors: CPUC does not have any capacitors at this point.

Meters – CPUC has aging electromechanical meters which are being replaced at a very slow pace. CashPower prepaid meters were introduced.

Exhibit 3-9: Meter Installations

There is a limited meter test facility. Meters are tested by customer request. Out of 1850 meters, 1650 are prepaid Landys & Gyr meters, which are having problems with re-use of tokens and operational pads. CPUC has not had vendor support for the prepayment meters because of non-payment of accounts.

Billing and Collection Processes: Meter reading and billing is performed monthly, making use of a CIS (Customer Information System).

The Billing cycle for CPUC is biweekly. The meters are read on the 1st and 15th of the month. The meter readings and distribution of the bills are processed immediately. The due date is 15 days from the reading.

CPUC uses the oldest version of the Dynasty Util Star billing system, which needs to be upgraded. The company that sold the billing system no longer supports this system.

Reliability: Reliability of power delivery depends upon the ability to generate enough power to meet the demand. Feeders are switched off when the available generation is not enough.
T&D Maintenance: No maintenance is performed in the substation. For lines, there is a tree trimming schedule. An overall maintenance management program covering all maintenance activities (e.g., power transformer oil sampling) is not in place.

4. Grid Model and Calculation of Technical Losses

4.1 Estimates and Assumptions for Missing Data

To quantify losses, the following assumptions were made:

1. The average power output over the past 7 months from July 2009 to January 2010 was extrapolated to 12 months and used to represent annual energy consumption.

2. A typical value for power transformer no-load losses literature1 was used for core losses, distribution transformer core losses, and copper loss estimation.

3. The distribution transformer load loss was estimated based on the system load being allocated to distribution transformers proportional to the transformer capacity.

4. Secondary loss consumption was estimated based on average customer consumption. Typical secondary service wire type and size were used based on data provided2. Assumptions are made for average wire lengths and general configuration of the secondary wires to estimate the secondary losses.

5. The effect of voltage drops through feeders was not considered in loss estimations except in the power flow study in Easy Power.

6.

4.2 Easy Power Model

The distribution system model is developed in Easy Power for the CPUC system. The interconnection of the power plant, power transformers, and primary feeders were modeled based on the map of Chuuk Island with feeders indicated. Number of feeders, feeder lengths and connected load capacities, equipment parameters such as generators, power transformers

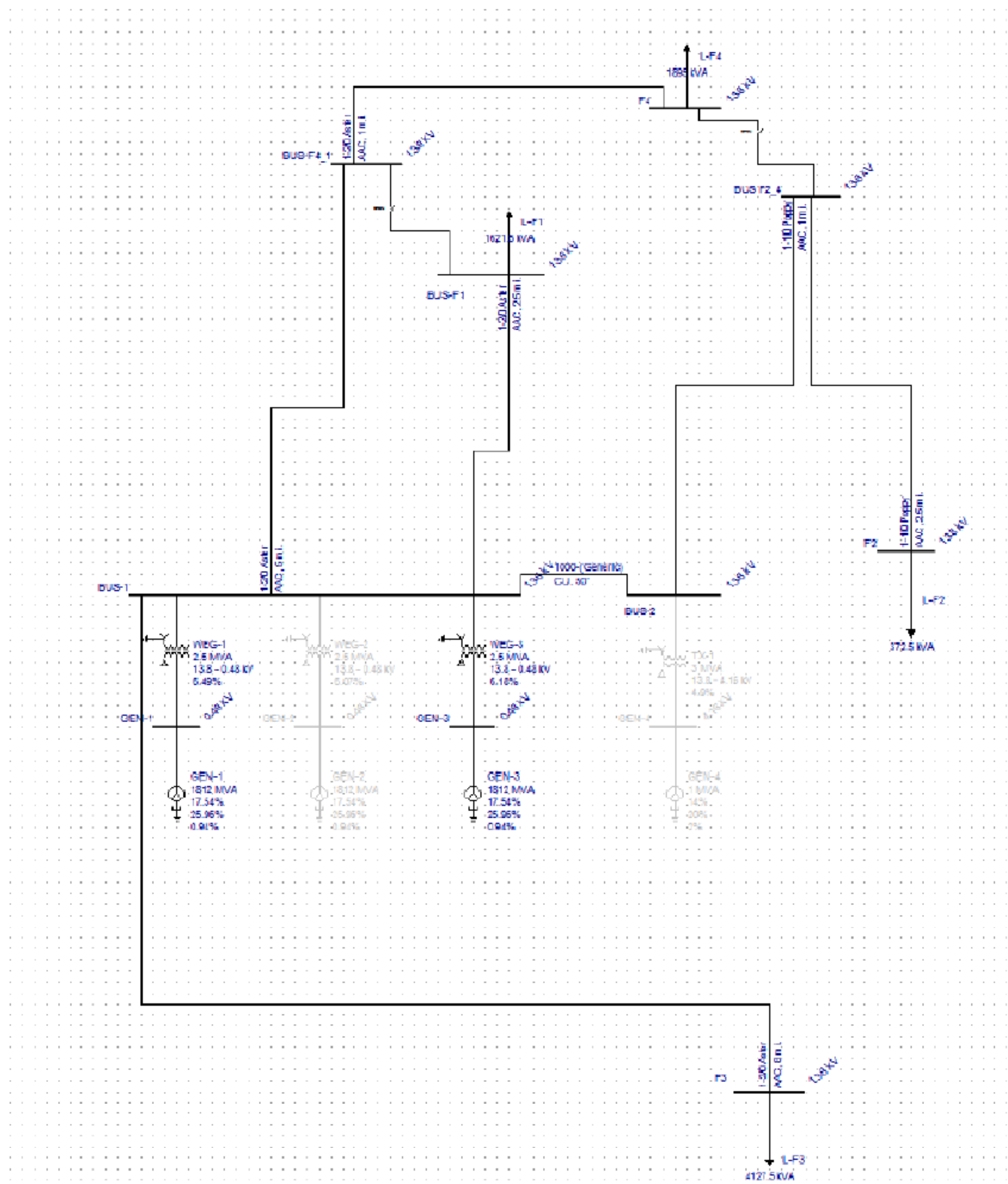
[1] Electric Power Distribution System Engineering, by Turan Gonen

[2] Data provided in CPUC Data Outstanding.docx and annexure 2.11.pdf, both files can be found in Appendix D.

are modeled based on the data provided in *CPUC Data Outstanding.docx* which is received in June 2010. Any future changes of the power system, such as the new power plant and connections of the new plant to the feeders, can be implemented in the Easy Power Model for calculating the impact of these new elements on the grid.

Loads are modeled as lump-sum load connected at the end of each feeder representing feeder loads. Due to lack of information on the exact locations of distribution transformers or loads, no detail load allocation was provided in the model. It was recommended that CPUC should collect details of distribution transformer locations in terms of distances across each feeder and their associated loads to expand the model in the future. The system one-line diagram is shown in Exhibit 4-1. The power system model is in Appendix C.

Exhibit 4-1 – One Line Diagram



Losses through the primary feeders and power transformers are calculated in a power flow study. The power flow is solved for a peak load of 2.6 MW representing the maximum system demand in the time period between July 2008 and January 2009. The system peak load of 2.6 MW at a power factor of 0.9 is represented in the model by applying a scaling factor of 0.36 to all loads with a total connected distribution transformer capacity of 8,016.5 kVA.

4.3 System Loss Estimation

System losses consist of technical and non-technical losses.

Technical losses The sum of: primary feeder and power transformer copper losses, power transformer and distribution transformer core losses, distribution transformer copper losses, and secondary losses. Except primary feeder and power transformer copper losses, all other losses were calculated in an Excel sheet. Where information was not sufficient, assumptions were made to facilitate the estimation.

Non-technical losses The difference between total system losses and technical losses; e.g., the total system loss is the total generation minus the power plants. Usage, the total energy sold and energy unaccounted for. For CPUC, the unbilled energy usage came from street lights and energy used in water production and waste water management.

In the Fact Sheet it is indicated that the peak demand is 2.6 MW, however the peak demand was 1.4 MW at the time of our visit. Generation statistics have been studied and the following trend has been observed:

- June-09: 4 units online
- July-09 to Jan-10: 3 units online generating relatively steady amounts of energy
- February and March 2010: still 3 units online, however the output of unit 3 is significantly reduced, and with some periods with only one unit online
- Apr-10: 2 units online

As observed, during the period of 7 months from July 2009 to January 2010, generators had kept consistent output to support the system demand with a maximum of 2.6 MW. In order to get a reliable estimation, generation output data accumulated for a period of 7 months (from July 2009 to January 2010) has been extrapolated to 12 months and has been used as annual generation output. Based on that, technical losses and non-technical losses have been estimated for that time period.

CPUC has single phase distribution transformers of the sizes 15, 25, 37.5, 50, 75 and 100 kVA. The connected kVA's of distribution transformers for each feeder is identified in "CPUC Data Outstanding.docx" without indicating numbers of distribution transformers of a single kVA rating. Later on, the attached document "Annexure 2.11.pdf" has been received and in this document numbers of distribution transformers for some kVA ratings are indicated. However, the calculated total connected kVA's based on data from "annexure 2.11.pdf" is much smaller compared to the data provided separately in “CPUC Data Outstanding.docx”. With careful consideration, the approach of loss estimation for distribution transformers is to calculate the average percentage of no-load losses and load losses at peak load level based on the actual number of distribution transformers indicated in “annexure 2.11.pdf” by applying typical loss data for each kVA rating, and by then applying the average loss percentage to the total connected kVA’s as identified in “CPUC Data Outstanding.docx”. By doing this, it was assumed that the whole distribution transformer population is distributed across the level of kVA capacity in the same way as indicated in “annexure 2.11.pdf”. Both “CPUC Data Outstanding.docx” and “annexure 2.11.pdf” are in the Appendix D.

A summary of the loss estimation is provided in Exhibit 4-2 below.

Exhibit 4-2: Loss Estimation

Based on 2009 Data	**kWh**	**% of generation**	**% of system consumption**	**Comments**
Annual generation	11,392,587			
Annual station auxiliary	438,000	3.84%		Station Auxiliary might be higher than estimated.
Annual system consumption	10,954,587	96.16%		
Annual energy sold (without unbilled usage)	7,595,515	66.67%	69.34%	
Unbilled usage - CPUC, Offices, Water, Sewage and Street Lights	651,872	5.72%	5.95%	Too much financial loss
System losses	2,707,200	23.76%	24.71%	
Technical losses	877,971	7.71%	8.01%	Can be improved
Non technical losses	1,829,229	16.06%	16.70%	Too much

5. Electrical Data Handbook

As part of the project's scope of work KEMA has prepared an Electrical Data Handbook which contains the electrical characteristics of the CPUC power system high voltage equipment.

The Data Handbook is in Appendix B.

6. Analysis of Technical and Non-Technical Losses

6.1 Generation Efficiency

Efficiency data of the overall power plant and/or of individual generation units has not been provided but a range of efficiency was given between 13.2 and 13.5 kWh/Gal. Diesel fuel is also used for company vehicles and some fuel also may be stolen.

6.1.1 Power Plant Usage, Station Losses

The Power Plant own usage from the measured values amounts to 3.84%. This is a relatively low number for power generation. However, auxiliary consumption measurement is not performed with revenue class meters which implies that maybe the real own usage value is somewhat different. Furthermore the own usage in a setting of containerized units tends to be lower than in a power plant.

Losses in the power plant auxiliaries can be controlled by paying attention to the operation and the condition of fans, radiators, lights, etc. For this Power Plant Energy Efficiency procedures could be worked out and implemented in order to try and reach an even lower loss figure for the Power Plant's own usage.

6.2 Technical Losses

Exhibit 6-1: Technical Losses

Technical Losses			
Type of Losses	**Sub Total MWh**	**MWh**	
Distribution Transformer Core losses	343		
Distribution Transformer Cu losses	31	374	43%
Secondary wires	141		
Feeder Wires	223	364	42%
Power Transformer Cu losses	13	139	16%
Power Transf core	126		
Total =	878	878	
Core Losses Alone	469		53%

Above table illustrates that out of the calculated total losses, transformer losses are the majority of them (59%) and wire losses only come up to 41%. Out of the transformer total losses, core losses are the majority of the losses (91% of the total transformer losses). This means that it is important that transformer specifications should focus on keeping core losses low in order to reduce the technical losses.

6.2.1 Distribution Line Losses

Calculated line losses show that these are about 42% of the 7.8% (878 MWh) total technical losses which include 13.8kV feeder losses, power transformer losses, distribution transformer losses and secondary service wires losses.

Line losses are caused by the wire resistance which is inversely proportional to the size and type of conductor. With a larger size (diameter), the resistance is lower. A same size wire made of copper will have lesser resistance compared to aluminum.

The power factor is at 89% and could be improved to lower some of the losses.

Losses in low voltage service wires are estimated at about 4141 MWh or 16% of the total technical losses. However, because of lack of information on the configuration of the service wires, assumption of the typical size, lengths and connections of secondary wires have been made to quantify the losses. A margin of error could be introduced by the assumption.

6.2.2 Transformer Losses

Transformer losses are separated in two parts – No load losses and Copper losses. No load losses are magnetizing losses and they are always present when the transformer is energized, whether there is no or any load on the transformers, while copper losses are only present when the load is present and these losses are also proportional to the square of the loading, relative to the full load. For CPUC it is estimated that total losses from distribution and power transformers are around 514 MWh per year. 469 MWh are core losses and 44 MWh are copper losses.

The sizes of these transformers (the average load is calculated to be around 36% of the installed distribution transformer capacity may be too big for the load and hence no-load losses (core losses) are relatively high. The system database does not contain information for identifying which load is tied to which transformer, unless physical inspection is performed.

As core losses depend upon the size of the transformers and in general CPUC is using only 36% of the total installed capacity as estimated in a year, there is quite a bit of room to decrease these losses. One lower size for a distribution transformer will save 20% of losses and two lower sizes will save about 30% of losses. The second option (two sizes lower) will load transformers to about 50 to 60% of the maximum system load of 2,600 kW.

6.3 Non-Technical Losses

16.06% of the system losses (calculated from the energy delivered to the distribution system from generating plants) are classified as non technical losses. It is extremely high for the size of the utility. Some of the reasons may be:

- Not all energy used by CPUC offices, stores or workshops is accounted for
- Discovering stealing of energy is left to the individuals (meter readers) which are very much part of the community and may not be as open to bringing those situations to the management's attention
- Meters are not tested
- Meters are old

- There is no regular procedure to check the meter multipliers
- Organizationally there is no one person who is responsible for loss reduction
- The Billing System does not raise red flags for customers that show irregular consumption patterns

CPUC should focus its attention to the reduction of the non-technical losses. The program to install prepaid meters will help the situation, once the problems with re-usage of tokens have been solved. This requires upgrading of the vending software but CPUC will need to settle its outstanding account with the supplier first or should purchase a new vending system altogether.

Focused auditing and assignment of a revenue protection officer with proper responsibilities and authority can contribute to further reduction of non-technical losses by preparing and subsequently executing a non-technical loss reduction strategy.

6.3.1 Metering Losses

Most customer meters installed by CPUC are pre-paid electronic type meters and few remaining electromechanical meters for commercial and governmental organizations. These meters are not calibrated or tested as long as they have been in service. Meters used for measuring generator outputs, main feeders and auxiliaries are not revenue type. These meters should be revenue class to better understand overall system efficiency. These meters also do not record the maximum demand.

Processes: Most of the non prepaid meters are read once a month. The rest of the other meters being prepaid metes are paid in advance and do not require meter reading. There appears to be many issues with the prepaid meters and CPUC is trying to resolve them. There is quite a bit of tampering and theft of energy. Two major hotels have their own generation and do not pay bills when they use the CPUC provided power. Collection of the bills is not optimal which results in excessive amounts of receivables. Key to solving these issues is strong management and implementation/enforcement of written policies.

Customer meters must be tied to transformers, preferably in a Geographical Information System or otherwise in spreadsheets, maybe in the CIS system (Customer Information System) and every year analyses should then be performed to see which transformers can be exchanged for proper utilization (loss reduction), overloading issues and general maintenance. It will be even beneficial to add meters to the LV side of each of the distribution transformers for developing insight into the transformer loading and any theft or tampering issues.

7. Other Issues

Power Generation: Most of the engines were running beyond the allowable time among maintenance intervals (major and minor overhaul). Parts have been cannibalized from some to keep others running. In the near future funds for maintenance on continuous bases and for replacement of aged generator sets are needed. In fact the technical health of the utility will only be possible if enough revenues are collected to cover all the utility's cost, including maintenance costs. A cost of service and tariff study would indicate what tariffs would be necessary for the utility to be self-sustainable. The gap between the existing and the desired situation would then become clear and initiatives could then be taken towards measures to fill up the gap (tariff increase, subsidies, securing some amount of grants per year, etc).

Feeders, Transformers and Loads: Developing a more strictly and regular maintenance program for transformers, transmission lines, feeders and cables is necessary to keep the system reliable. Performing infrared scans (for identifying hot spots and as such unnecessary technical losses) and oil testing (for monitoring transformer conditions for reliability reasons) on a regular basis is advised to be part of maintenance practices.

Furthermore meters must be tested regularly to make sure that they are providing revenue class results. Processes for collection, checking billing constants, auditing meter installations, application of penalties for late payment, including changing tariff, are many of the improvements that need to be implemented for improving the performance and reducing non-technical losses.

8. Options for Improvements

8.1 Power System Improvements/Modifications

Technical losses are unavoidable but should be reduced to what could be considered as a minimum. Since CPUC's technical losses are 7.71% possibilities for technical loss reduction should be identified and subsequently pursued, on a continuous basis. For example:

- Electricity rates will continue to increase, which has changed and will constantly change the cost-basis for evaluating many Technical Loss reduction measures/programs
- Electrical equipment connections start becoming loose and can cause heat, which can result in major problems for higher losses, reliability and safety issues.
- New equipment purchase is an ongoing activity of CPUC and priority should be given to equipment purchases that will lead to lower losses.

However, for different projects/programs that help to reduce technical losses, reducing technical losses alone generally does not justify the large capital investment required. For these projects/programs, giving loss reduction benefits a proper weight over the life span is the key to select those measures that will bring in beneficial results.

Loss calculation is not a onetime event but needs to be kept in mind in all the utility processes, such as planning, design, engineering, maintenance, operations, dispatching optimization, etc. Continuing to determine the accurate amount of technical losses after recommendations are implemented is critical for reducing these losses, for gauging the progress of the technical loss reduction and for determining the exact situation of non-technical losses. Meter installations on distribution transformers and keeping the model of the system updated will be one of the keys to continuously reducing technical losses.

In addition to current efforts, CPUC could improve loss reduction efforts in the following two areas:

Secondary circuits and service wires

CPUC should look into the possibility of using a targeted feeder program to create an initial GIS map for secondary circuits (including customers and service wires). The map should be refined gradually to reflect the actual secondary circuit and service wires layout in the field. This would provide a solid basis for future technical loss estimation in this part of the CPUC system.

Such a GIS map has an advantage that it could use the customer consumption data in the future to more accurately estimate the losses in secondary circuits and service wires.

Customer meters need to be associated with the transformer providing that load. This can be done in a CIS system or in homemade spreadsheet software which can take load from metering data and calculate transformer loadings. Using proper sizing of the (reduced) transformers will have a significant impact on overall loss reduction.

CPUC is to be cautioned that estimation of losses in this part of the system is much more complicated. It is affected by:

- Un-metered load such as streetlights, illegal connections, etc.
- Exact lengths of the circuit/wire may not be available
- The load pattern is difficult to obtain for each customer unless AMI (Advanced Metering Infrastructure) is deployed

Nevertheless, creating such a GIS map would help CPUC in better estimating the losses.

Update the loss cost-basis on a regular basis

The loss cost-basis used to estimate the lifetime costs of losses should take the fast increase of electricity rates into account. When the rate is increasing at a slow pace, it may be acceptable to use the current rate as a basis to calculate the projected saving of any technical losses over the life span of an equipment (e.g., transformers) and other system parts. When the electricity rate is fast increasing, using the current rate could greatly under-estimate the lifetime savings of the reduced losses for equipment or a project over a 15-20 year life span.

In general, as new equipment installation and old equipment replacement is an ongoing process, the task of updating the loss-cost basis should be accomplished as soon as possible to evaluate the impact of various alternatives, especially to understand the cost of life time ownership. The results should also help CPUC to re-evaluate other large projects for determining the priority of these projects.

Once the new cost-basis is established, it should be applied to the cost/benefit analysis of new equipment purchases immediately, such as pad-mounted and pole-mounted transformers. For example, if all the equipment specifications are revised to take into account the life time ownership costs, any equipment which is purchased from now on will bring in immediate results without any additional cost.

The new loss-cost basis should also be used to re-evaluate projects/programs that could result in technical loss reduction to determine/select the most beneficial ones to be carried out first.

Optimize distribution transformers

The sizes of distribution transformers are to be optimized. When the transformer sizes are reduced two levels down (40 to 60% of the sum of kVA's of the distribution transformers) from the existing level, core losses can be saved closed to $30,000 per year. A process could be set up for replacement of the distribution transformers:

a. Develop the load profile for each transformer and keep it updated once a year (a load profile for each distribution transformer implies that a meter per distribution transformer will be needed).

b. Develop proper transformer sizes for each location.

c. Optimize transformers which can be optimized without any capital cost investment i.e. by moving them to appropriate locations. Remember transformers can be overloaded for short durations.

d. Develop a new transformer purchase plan based upon the standard sizing and least cost for lifetime cost which includes capital investments, maintenance costs and costs of losses.

e. Replace transformers during emergency (during emergency the utility workers are already occupied with the emergency itself, in many cases) or during normal time based upon the plan.

Optimize feeder power factors

Overall the Power Factor (PF) of the system is 0.89. The PF of various sections of the feeders should be checked regularly (at least once a year) and actions should be taken to always keep the PF above 0.9, preferably 0.95. In general the best location to correct the power factor is at the loads, especially at the terminals of induction motors. Develop a plan and tariff (or introduce a low power factor penalty) to make sure that each of the larger commercial and governmental customers loads are at minimum 90% of the power factor. If they are found to be less than that and the customer does not improve it to the required level, the utility should be able to charge a penalty and/or advise the customer to install capacitors required to bring their power factor to that level. Metering and billing needs to be coordinated with the tariff and/or low power factor penalty. Overall 600 to 1,000 kVAr capacitors can be added to CPUC's distribution system if the load is 2.6 MW.

Optimize feeder reactive power compensation

The shunt capacitor banks at the 13.8 kV lines could be used to minimize the reactive load flow in the network to help reduce the losses. When operated for this purpose, there are two areas that need to be considered.

Determine the size of fixed and switched capacitors

The compensation could use a mix of fixed and switched capacitors to achieve desired reactive power compensation.

The size of fixed capacitors should be determined by the minimum reactive power compensation requirement of a feeder. It is, however, not necessary to compensate the feeder at the minimum inductive reactive power level to 1.0 power factor, but should be as close as possible. From loss reduction point of view, the result will be the same if the compensated power factor has the same value regardless if it is leading or lagging. The actual size selection should also take the standard capacitor size that can be procured, and whether there are other feeder capacitors that are already installed, etc. into account.

The size of switched capacitors should be determined based on the load pattern of a particular feeder and the granularity of the power factor control. If the reactive power load of a feeder change between two constant levels, then one large switched capacitor may be sufficient. These should be evaluated on a feeder-by-feeder basis.

In addition to power factor compensation, capacitors also affect the voltage profile along a feeder. When determining the capacitor sizes, in particular the switched capacitor bank sizes, this should also be verified to ensure voltage limits are not violated.

Switched capacitor control

Switching of capacitor banks can be controlled by any of the system variables or any derivatives of system variables. The common controls used are described below:

- <u>Voltage Control</u>: This is the most common type of control used to switch capacitors in or out of the circuit. They are switched in during low voltage conditions and switched off when the system voltage is high. This type of control is normally used where a drop of

3% or more of voltage occurs during full load. This type of control is not suitable in a tightly voltage regulated system where the voltage is held at constant values.

- Current Control: This control is used where the voltage control cannot be exercised. The capacitor current is excluded from the monitored current and this ensures that the capacitor will be brought on line during heavy load conditions.

- Current Compensated Voltage Control: This type of control is sensitive to voltage but is current compensated. The control acts as simple voltage control so long as the current is below a predetermined level. If current goes above the pre-determined level, the capacitors are brought on line by changing the calibration of the voltage elements. Hence, the capacitors remain in circuit so long as the current is above the pre-determined level. If the voltage starts to rise and becomes high enough to offset the calibration, the capacitor will be switched off. This is a sophisticated control and ensures that the capacitors are on line when they are most needed.

- Kilo VAr Control: This control operates in response to changes in the clover flow. It has no significant advantage over current compensated control and is usually more expensive.

- Time Control: This type of control is used where the daily load patterns are predictable. The capacitors are switched in and out based on the time of the day. This control is the least expensive; however, the disadvantage of this control is that it cannot accommodate unusual system conditions such as a sudden loss of lines, etc. and will require manual intervention to switch the bank.

Selection of one particular type of the control should be based on the load profile of a feeder.

8.2 Operational Recommendations

Generation

Develop written operating processes and develop plans to monitor the performance of operators and the plant based upon those processes.

Reviewing the Engine Performance, metering in the power plant does not provide good coordinated readings. We recommend that the first step should be to install revenue class metering (energy, fuel and other supplies) to accurately measure the efficiency of each generator and dispatch them based upon efficiency considering other operating constraints. Focusing on efficiency improvement (developed processes for the operators); real time display of engine efficiency helps the operators to run the engines in the most optimum way. Minimum display of real time information providing fuel use, lube oil usage, engine kWh production, auxiliary kWh usage should be made available. Objective of all this is to improve the generation efficiency and reduce consumption in plant auxiliaries.

Generation efficiency is currently low and at an average of 13.4 (13.2 to 13.5 kWh/ Gal). Every 1% increase of the efficiency saves about $30,000. If the efficiency is improved to 15kWh/Gal with new engines this saving could reach $360,000 per year.

Metering

A procedure should be developed to test and calibrate meters before they are installed. Methodologies must be established to test sample meters (based upon statistical sampling) such that their accuracy can be assured during the lifetime of the meters.

Meters to measure the generator output, auxiliary services and feeder output must be of revenue class accuracy.

Methodologies must be developed to measure distribution transformer load profiles either through software which takes into account the customer meters on each of the transformers or physically measuring the load by installing demand type meters on the secondary of each of the transformers.

8.3 Strategy for Reduction of Non-Technical Losses

Considering 16.06% of non-technical losses there must be potential of savings in this category.

One of the main areas in aligning a utilities' operation to Revenue Assurance oriented operations is to implement a Revenue Assurance Process making use of an advanced Revenue Intelligence system. For conducting most efficient fraud prevention/detection and audit operations for revenue protection purpose with limited resources, an advanced Revenue Intelligence system is very helpful. Such a system is able to detect any potential fraud based on information from multiple sources using advanced detection rules. It will vastly increase the hit rate and support a range of revenue assurance activities. These changes/processes should include:

- Implementation of a formal Revenue Assurance Process including an overall Audit Process.
- Implementation of Revenue Intelligence software to support Revenue Assurance oriented operations.

However, for a small utility like CPUC implementation of a Revenue Assurance Department and implementation of Revenue Intelligence Software will require a large investment in costs and may have a large organizational impact.

A more pragmatic approach should be developed in order to fight non-technical losses and to increase the effectiveness of revenue protection operations.

CPUC could consider the following:

- Develop a program for checking old meters.
- Train meter readers on identification of tampering, by-passing, broken seals, hookups.
- Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplying factors, tariff categories applied to customers, functioning of red flags in the case of irregularities) and non-technical loss causes found by meter readers such as meter tampering or by-passing, hook ups, etc.
- Select targets for inspection, also focusing on commercial customers. When selecting targets for inspection, the potential of the estimated amount of revenue recovery should be a major selection factor. With limited resources, selecting accounts with highest potential of revenue recovery and hit rate will be the most efficient use of the limited resources.
- Make operations less predictable: CPUC's own experience may show that there are some sophisticated fraud activities that take advantage of the known pattern of Revenue Assurance operations. This should be countered with less predictable operations; e.g., occasional night inspection, computer generated random daily target list, and so on. This will help to increase the hit rate for these sophisticated fraudsters and increase the deterrent effect of these operations.
- Prevent repeated fraud activities: Once a fraud is found, proper measures should be taken, dependent on the type of fraud, to ensure that it will not occur again.
- Prevent and curb internal collusion activities: One important aspect of effective revenue protection operation is to prevent and curb any potential internal collusion. Internal collusion seriously undermines the effectiveness of any revenue assurance process and efforts. One possible solution could be to bring in NON-LOCAL inspection teams to

conduct the critical revenue protection operations, such as large account audit for largest accounts, under the direct control of CPUC's top management.

- Customers have different needs for electricity, different usage patterns and different payment capabilities. A successful revenue assurance strategy should take this into account to develop corresponding tactics for each group of customers. In general, customers should be grouped based on their usage pattern and payment capability. Establishing typical usage pattern and payment capability for each group of customers will be one very important task of the Revenue Assurance and the results should then be used as the basis for employing the right tactics for each group of customers.
- Last but not least: assign a senior staff member to be CPUC's Revenue Assurance Officer, responsible for CPUC's Loss Reduction Strategy, and who will plan and initiate the loss reduction programs and activities, keeps records of progress and successes and reports to the General Manager.

9. Per Item: Investments Needed, Expected Reduction of Losses, Payback Time

The following is our summary for savings and potential cost over the 6 years of implementation of various recommendations:

Exhibit 9-1: Savings and Cost

	6 Yrs NPV of Savings and Cost		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Non Technical Loss	$822,176	$767,529	$54,647
Technical Losses	$197,309	$195,805	$1,504
Auxiliary loss	$33,517	$25,000	$8,517
Total =	$1,053,002	$988,334	$64,668
Generator Efficiency improvement	1% improvement saves $30,000		

The summary of our recommendations is as follows. Details are provided in Section 8.1.

1. Cost will increase based upon inflation – 3% every year.

2. Cost of Capital is assumed to be 8%.

3. Our major emphasis is on process improvements for design, purchasing, metering, billing, collection and operation.

4. Technical and Non-Technical Loss improvements also require investments in addition to process improvements. Cost of these investments will be around $1.3 million over 6 years. (See description of cost and benefits in section 8.1). Goal of loss reduction will be to reduce them from 27.61% (as calculated, including power plant own usage) to 17%.

5. Generation auxiliary losses are a small portion (3.84% - which show up low with current metering but may be higher if proper revenue class data collection is installed) of the overall losses. With investigating energy efficiency opportunities and implementing energy saving measures the cost can be kept low, because it is expected that a new power plant will be operational in 3 years from now. For

this reason large investments in the current power plant cannot be justified, but still some reduction of power plant usage can be reached for the coming 3 years.

6. The overall loss objective is to drop from the range of 27.61% to 17% in 6 years. This excludes financial losses of providing free power for street lights, water and waste water (5.72%).

9.1 Recommendations

The following recommendations are prioritized based upon the cost and benefits. See attached spreadsheet tab Savings Model in Appendix C.

9.1.1 Reduction of Technical Losses

In CPUC's case, as far as technical losses are concerned there is not too much savings to be gained from modifying the system. As distribution transformers seem to be loaded around 36% of their full capacity, there could be savings from loss reduction by optimizing them with proper sizes. This could be done over a number of years as new transformers are purchased.

Power Factor Improvement:

1. The power factor of CPUC is reasonably well but it needs to be watched and a process should be developed to evaluate it at least once a year.

    a. Acquire software for power factor analysis. (Cost of software and training $50,000)

    b. Determine the power factor of largest customers and require them to improve it over 85% or improve it for them and charge it to customers. This may require penalties or tariff changes. Add capacitors to improve the power factor (estimated cost of $65,000 over 6 years)

    c. Determine where on feeders or transformers capacitors can be placed to improve the overall power factor closest to 95%. Make sure that maintenance and a monitoring plan is part of this plan.

2. Transformer Right Sizing

    a. Determine proper sizes and specifications of the distribution transformers needed for the loads being served.

b. After determining correct sizes of the distribution transformers, determine the standard sizes and move them around to rationalize and optimize sizes such that they are at least 80% loaded to the maximum demand to transformer capacity.

c. As the transformers are reaching the end of life, replace them with right size transformers for the applications. All transformers should be bought considering their life time cost. (including consideration of costs of losses)

The costs of right sizing the transformers are not included in the costs.

3. Reduce Line Losses:

   a. Acquire an infrared scan camera and training to operate it. (Cost of equipment and training $100,000).

Using an infrared scan camera is one of the necessary tools for any distribution utility. The infrared camera on its own will not save any losses; it has to be used to prioritize the work of maintenance and upgrading of feeders. There is a potential savings of approximately 0.5 to 1% of energy losses by repairing hot spots.

From the calculations of a technical loss reduction from 7.71% down to 6% in 6 years through improvements as mentioned savings are estimated to be close to $ 275,000 over the 6 years. Cost of these initiatives is estimated to be $ 215,000 over 6 years. Net present values are given in Exhibit 9-2.

9.1.2 Reduction of Generation Auxiliary Losses

When generating units are operating, they need auxiliary equipment like fans, pumps, etc. In the case of CPUC where currently containerized Caterpillar units are used, while construction of a new power plant is expected to start shortly, it would hardly bring benefits to reduce the auxiliary losses by introducing sophisticated instrumentation, monitoring and control displays, etc, when these containerized units will already be decommissioned in maybe some 3 years from now. For now we would therefore recommend to make an assessment of the current plants' own power usage and identify possibilities for energy efficiency, particularly for fans and pumps operations. This means that some savings could be reached at low costs. A target to be set could be a reduction from 3.84% to 3.34% which would anyway save $ 15,000 per year. As mentioned one should replace the meters in the power plant by revenue class meters, but if construction of the new power plant will start shortly, one could also save the investment and still realize a 0.5% improvement, while the difference by improvement is read with the same, current inaccurate meters.

9.1.3 Reduction of Non-Technical Losses

Account and highlight monthly any of the financial losses (i.e. street lights and unaccounted energy usage by CPUC offices, water and sewerage activities). Develop a regular meter testing program. Add new meters (170) to the secondary sides of transformers and feeders at key locations for measuring transformer loads as well as auditing customers fed from each transformer. Along with adding these new meters, procure meter testing equipment and training to perform sample testing of meters as required. Replace meters which are found to be out of specification with the new ones (prepaid type). Make sure each customer is linked to the transformer and its meter (cost $390,000) in a software tool so that issues with tampering and transformer loading can be easily monitored.

It is not necessary to install these meters on every distribution transformer. This could be restricted to areas with excessive tampering or other theft issues, where it would be appropriate to know the loading profile of the transformers. This can also be accomplished by CIS applications which link the transformers to the customer meters. For transformer load profiling use, a number of temporary recording meters could be installed on the transformers to be studied for a time period, after which they can be rotated to other locations.

Installation of the meters on pole mounted transformers can be accomplished by using current transformers.

Add Revenue Protection measures as already given in chapter 8.2.4, including assignment of a senior staff member to be the Revenue Assurance Officer.

These recommendations go hand in hand as savings will come from the focus attention of the company (i.e. developing and implementing processes), people and tools like modern meters and systems. (Benefit over 6 years is $1,150,000 – savings of 10% non technical losses first year and ending up savings of 50% in 6th years). Non-technical losses reduce to 8.03% (i.e. getting to 1,352 MWh of non-technical losses from 2,707 MWh in 6 years) from 16.06%.

9.1.4 Improving Generator Efficiencies

Every 1% of efficiency increase of generating units at current fuel prices results in savings of $30,000. Increasing the average efficiency of generation from 13.35 to 15 kWh per gallon (12%

improvement) will save $360,000. If new generators are purchased, there must be funds available to make sure they keep running at high efficiency.

Exhibit 9-2 – Net Present Value

Assumptions:				
Inflation	3%			
Cost of Capital	8.00%			
Cost of generation /kWh	$0.29			
Cost and Savings list	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**	**Cash over 6 years**
Non Technical Savings:				
Revenue Assurance		$411,234		-$527,789
Revenue Protection Department - Focus to analyze, audit and pursue issues with metering, billing and tampering. Developing processes, using check meters at distribution transformers and software to pin point losses in the system.		$356,294		-$388,728
50% Non Technical Loss reduction over 6 years	$822,176		$54,647	
Technical Loss Savings:				
Infrascan camera and training		$100,000		-$100,000
Power factor improvement hardware installation and control.		$95,805		-$114,684
30% loss reduction over 6 years	$197,309		$1,504	
Auxiliary Losses				
Audit of auxiliary efficiency and developing energy conservation measures		$25,000		-$25,000
20% loss reduction over 6 years	$33,517		$8,517	
Total =	$1,053,002	$988,334	$64,668	- $1,156,201

Other Recommendations:

1. Develop a maintenance management program and written operational processes to repair and maintain the distribution system and provide training of linemen.

2. Maintenance funding needs to be provided for the power plant as well as for distribution operations in order to keep up the efficiency as well as the reliability.

3. Develop a testing program for revenue meters. Estimated cost of $200,000 included in the non-technical savings plan.

A. Data Request

Data Request.doc
Inception Report.doc

B. Data Book

CUC Data Handbook.xls

C. Technical Loss Calculations and Financial Model for Options to Decrease Losses

Technical Loss Calculations and Financial Model.xls

Transformer Evaluation Example.xls

D. Other Data

CUC One Line Diagram.pdf