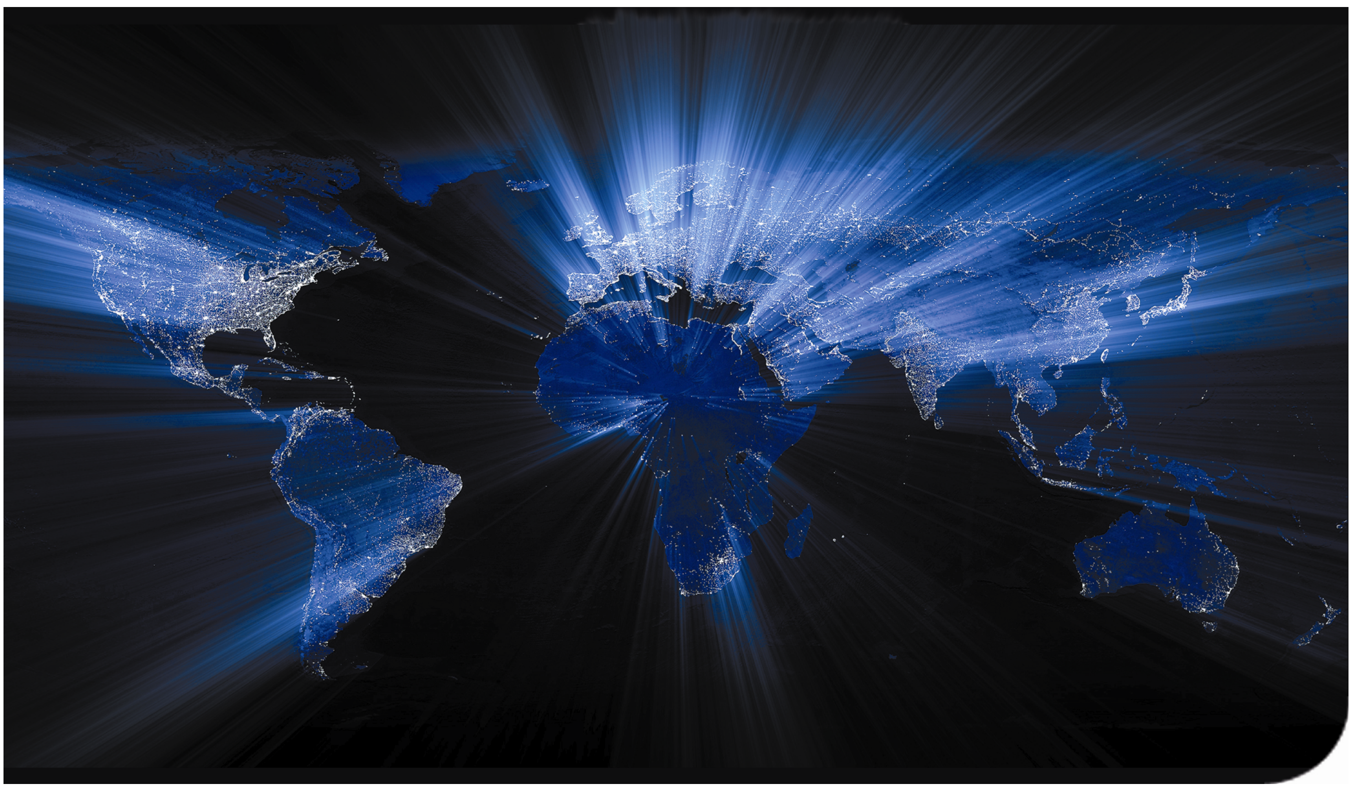
Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)

Yap State Public Service Corporation (YSPSC)



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

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1. Executive Summary

KEMA's analysis of Yap State Public Service Corporation (YSPSC) power system determined total losses of 25.45 % consisting of:

- 7.43% in power station auxiliaries (so-called station losses), which is a relatively high amount of losses. Generally the station losses are lower than 5%.
- 7.59% in street lighting and usage for water and sewerage facilities. (If these revenues cannot be collected, street lighting should be considered a financial loss for YSPSC and not a system loss).
- Energy usage for water and sewerage facilities should be accounted for and allocated to the cost of water and sewerage services and not to power system losses. However, if the costs are not allocated to water and sewerage service costs, they will remain a financial loss for YSPSC's power services and cannot be considered a power system loss.
- 6.38% in technical losses
- 4.05% in non technical losses.

Technical and non-technical losses total 10.43%.

Overall losses, including power plant usage total 17.86%.

Recommendations:

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

Total savings and costs for all loss reduction measures are summarized in the table in Exhibit 1-1:

Exhibit 1-1: Savings and Cost

NPV @ Cost of Capital	Savings (NPV)	Cost (NPV)	Net (NPV)
	6 Yrs NPV of Savings and Cost Summary		
Auxiliary loss	$219,343	$125,000	$94,343
Technical Losses	$255,673	$174,018	$81,656
Non Technical Loss	$238,687	$231,383	$7,304
Total =	$713,703	$530,402	$183,302
1% efficiency improvement in generation saves $28,000 per year based on the price of crude oil of $75 per barrel. At $100 per barrel the saving of 1% improvement will be $37,000 per year. This assumption can be influenced by fuel pricing effects related to creditworthiness of customers and transportation costs			

Generation Park and its efficiency

It can be observed that the generation efficiency has improved through the years from 2004 to 2008. The efficiency of 13.93 kWh/gallon could be improved further. Currently a 3.2 MW generator is providing the load which has a peak of 2.2 MW and an average of 1.5 MW. Installing a new efficient 1.5 MW generator can be justified by having a 6-year payback time of the investment. If the average load is served with a generator with an output rating of 1.5 MW the efficiency will improve up to 15.6 kWh/gallon. Savings will be $ 336,000 per year, while a new 1.5 MW genset will cost $2 million (including installation). Depending on the interest rate, the payback time will be around 6 years (at an interest rate of 8%). The high efficiency may not be reached in periods when the load varies between 1.5 MW and 2.2 MW. This will reduce the savings per year to $260,000, resulting in a payback time of 10 years.

Investing $2 million in a new 1.5 MW generator has a payback time of 6 to 10 years.

Funds for regular maintenance must be available in order to keep the new and the Deutz engines in good condition. In fact, a Cost of Service Study should be done to determine the level of tariffs, or a combination of a certain tariff level with yearly grants, which will allow YSPSC to be self-sustainable.

A. Generation

1. Operate generating units at high efficiency. The engines should be properly maintained and operated near 80% of full rated output. Funding of on-going maintenance requirements is not included.

2. For every generating unit, add instrumentation to show efficiencies to operators (cost $125,000). Develop a process that provides regular reporting to management.

3. Train power plant operators on load forecasting and economic dispatch practices.

4. Include an economic dispatch module in future SCADA system plans.

5. Change and/or add meters to provide accurate real-time revenue-class generator outputs and auxiliary plant consumption statistics.

6. Develop manual processes to control the operation of fans (cooling fans, exhaust fans and pumps) to run based upon the temperature sensing or other parameters which will optimize the operation and reduce energy consumption.

7. Automate manual processes using PLC controls to motor starters (cost not included – this is considered a next step after process improvements and real time analysis as well as focus on energy consumption reduction is in place).

8. Apply Frequency Drives (cost not included).

    a) Benefits from these actions are expected to be $300,000 over 6 years. Savings are produced by reducing auxiliary losses from 1,033 MWh to 671 MWh per year. Total cost of these initiatives (recommendations 5 through 7) is $125,000 over 6 years.

B. Distribution:

1. Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime costs (costs of capital, losses, and maintenance). For example, the cost of 1 kW of core losses for 20 years at 20 cents per kWh of fuel cost (based on $3 per gallon of fuel) is $21,476 (NPV). For copper losses the NPV is estimated to be $10,519. These figures should be taken into account when evaluating bids for new transformers. (An example of transformer evaluation is provided in Appendix C).

2. Optimize distribution transformers ratings over a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses).

3. Add revenue-class meters on feeders and distribution transformers to measure losses. Use these meters to check total loading on individual transformers. These meters can be avoided if customers are tied to distribution transformers in the Customer Information System. To reduce costs, meter only distribution transformers where there is an obvious energy loss due to tampering, by-passing, or where total transformer loads need to be measured. For transformer load profiling 20 to 40 recording meters could be temporarily installed and rotated. Transformer meter costs are included in Section C of this chapter.

4. Use an infrared camera to scan the power system equipment at least annually to find hot spots. These usually occur at connector points. Repair as necessary.

5. Require large customers to maintain the power factors above 85%. Install capacitors in the distribution system to maintain system powers above 95%.

(Total costs of these initiatives are estimated to be $200,000 over 6 years)

C. Metering, Billing and Collection:

1. Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplier factors, tariff categories applied to customers, functioning of red flags in the case of irregularities and utilizing transformer meters in suspected area or initiating testing of meters and connections) and non-technical loss causes found by meter readers (meter tampering or by-passing, hook ups, etc).

2. Assign a senior staff member to be YSPSC's Revenue Assurance Officer, responsible for YSPSC's Loss Reduction Strategy, who will plan and initiate loss reduction programs and activities, keep records of progress and successes, and report to the General Manager. In sections 8.2.3 and 9.1.3 the ways of combating non-technical losses, under the leadership of the Revenue Assurance Officer, are worked out further.

(Total cost is estimated to be $240,000 over 6 years.)

2. Introduction

2.1 Project Objectives

KEMA Inc has been asked by the Pacific Power Association (PPA) to conduct a study called "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 covers the study results for YSPSC, Yap State.

Objectives of the project:

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 of a prioritized replacement list of power system equipment to reduce technical losses.
5. Identify sources of non-technical losses.
6. Recommend strategies for reducing technical and non-technical losses.

2.2 Quantification of Losses

Losses are due to:

1. power station losses
2. Losses in the distribution system.

Both categories are quantified below.

Furthermore financial losses may be present due to a non-optimized efficiency of the generation system and individual generating units. Improvement of the generation efficiency will lead to fuel savings.

- Station Losses: Power Plant Auxiliary Loads
- Transmission & Distribution System Losses:

- Technical losses: Summation of transformer core losses, transformer copper losses, transmission line losses, primary distribution feeder losses, and secondary wire losses. Technical losses will become higher as power factors drop below unity.
- 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 consumptions not billed. Unbilled usage should be considered a financial loss rather than a non-technical loss. Unbilled usage is mostly for street lighting.

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 in Yap State. KEMA visited Yap State and conducted meetings with management and staff. Visits were made to the power plant and distribution facilities, including overhead feeders.

3.1 The YSPSC Power System

YSPSC's main island system is served by one power plant owned and operated by YSPSC with diesel engines. This study is focusing on the main island.

The power station has 5 generating units ranging from 750 kW to 3,200 kW. Two Deutz gensets (each 3,200 kW) and one White Superior genset (750kW) are currently operating. Customers are provided power at 240/120V, 208/120V or 480/277V levels through 400 distribution transformers. The system peak load is 2.2 MW with an average load factor below 0.67.

3.2 KEMA Data Request

Before we visited YSPSC in Yap, a data request was sent to YSPSC. See Appendix A.

3.3 Data Received

Before our visit YSPSC provided part of the data as requested in KEMA's Excel File: Data Request, power consumption data and the one line diagram. YSPSC has been very helpful in providing the Easy Power model, GIS database and other detailed data.

3.4 Site Visit

Further data was gathered during the site visit of February 2010. All data received is included in the Electrical Data Handbook. (Appendix B)

Data collected included:

1. One line diagram

2. Grid model in easy Power

3. GIS grid information

4. Generator energy production logs including fuel and lube-oil used.

5. Load patterns per feeder

6. Substation and Transformer data

7. Distribution Feeder sizes and lengths

8. Metering Information

Load: The peak load is currently 2.2 MW with the average load of 1.5 MW. The overall power factor is around 0.9. The load may increase by 1 MW if a Chinese fish industry starts some operations in Yap.

Generators: There is one power plant and two smaller ones at remote islands. Specific data is listed in the Data Handbook of Appendix B. All generating units use diesel fuel.

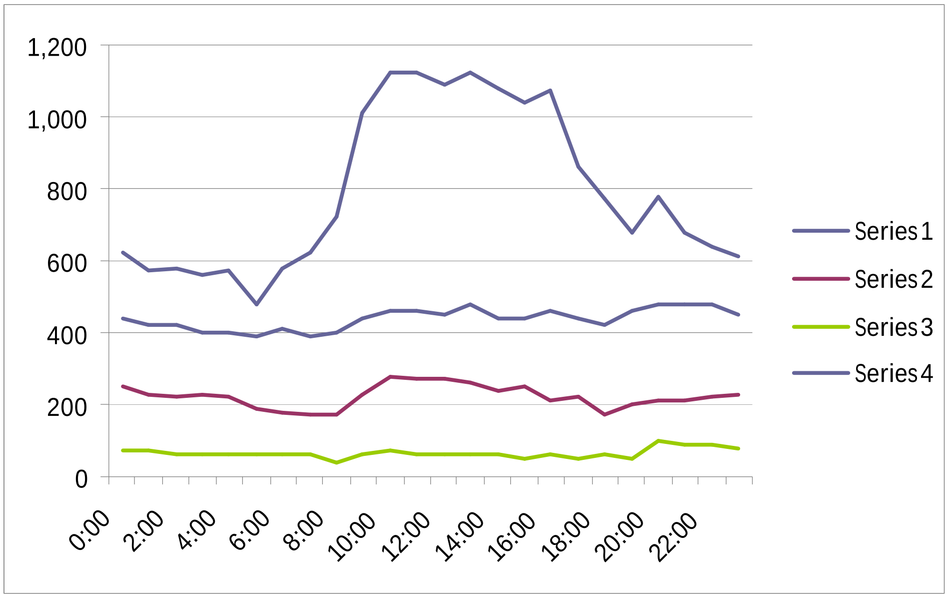
The two Deutz (3,200kW) gensets have 60,000 running hours. The White Superior genset has 130,000 running hours and a similar White Superior genset is currently not operational. In practice one of the Deutz engines is running and providing the load while the other is kept in pre-heated stage which will allow it to be on line in 30 minutes.

Transformers: YSPSC has single-phase and three-phase pole top transformers, connected to 13.8kV feeders in good condition. The power plant substation has two step-up transformers (each 5.6 MVA – 4.16kV to 13.8kV). For condition assessments no oil samples of these transformers are taken. The on-load tap changers for two step-up power transformers were not functioning in automatic mode, which resulted in manual operation being required. Only one transformer is 20% loaded, while the other transformer is kept energized for reliability reasons, at cost of transformer core losses.

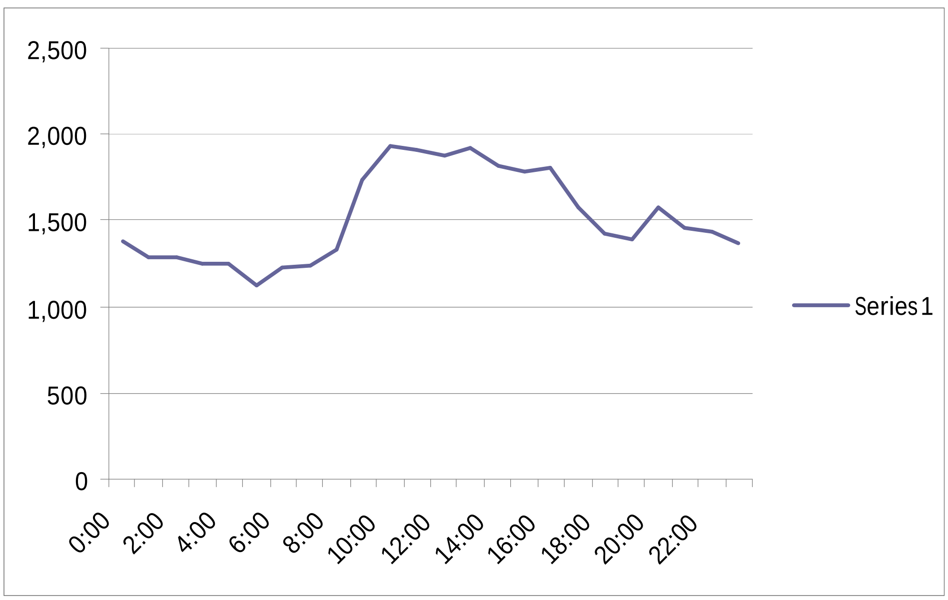
Aerial Feeders: The distribution system voltage was 13.8 kV. The lines and feeders were in good condition. In some feeders, it was recommended to check connectors and clamps with infrared detection equipment for hot spots, and to assess the condition of conductors that have signs of corrosion.

Exhibit 3-1: Typical Feeder Load

Wednesday								
	A (HOSP. Fdr.)		B (AIRPORT Fdr.)		C (D.B. Fdr.)		D (COLONIA Fdr.)	
Hour	kW	kWh	kW	kWh	kW	kWh	kW	kWh
0:00	440	11,199,300	250	11,931,200	70	5,797,800	620	18,326,800
1:00	420	11,199,700	230	11,931,400	70	5,797,800	570	18,327,300
2:00	420	11,200,200	220	11,931,700	60	5,797,900	580	18,328,000
3:00	400	11,200,600	230	11,931,900	60	5,798,000	560	18,328,600
4:00	400	11,200,900	220	11,932,100	60	5,798,000	570	18,329,000
5:00	390	11,201,300	190	11,932,300	60	5,798,100	480	18,329,600
6:00	410	11,201,800	180	11,932,500	60	5,798,100	580	18,330,200
7:00	390	11,202,100	170	11,932,700	60	8,798,200	620	18,330,700
8:00	400	11,202,400	170	11,932,800	40	5,798,200	720	18,331,300
9:00	440	11,203,000	230	11,933,100	60	5,790,300	1,010	18,332,600
10:00	460	11,203,400	280	11,933,300	70	5,798,400	1,120	18,333,600
11:00	460	11,203,800	270	11,933,600	60	5,798,400	1,120	18,334,500
12:00	450	11,204,200	270	11,933,800	60	5,798,500	1,090	18,335,600
13:00	480	11,204,900	260	11,934,200	60	5,798,600	1,120	18,337,000
14:00	440	11,205,200	240	11,934,500	60	5,798,600	1,080	18,338,300
15:00	440	11,205,700	250	11,934,600	50	5,798,700	1,040	18,339,100
16:00	460	11,206,100	210	11,934,800	60	5,798,700	1,070	18,340,000
17:00	440	11,206,500	220	11,935,100	50	5,798,800	860	18,340,900
18:00	420	11,206,900	170	11,935,200	60	5,798,800	770	18,341,700
19:00	460	11,207,400	200	11,935,400	50	5,798,900	680	18,342,400
20:00	480	11,207,900	210	11,935,600	100	5,799,000	780	18,343,100
21:00	480	11,208,500	210	11,935,900	90	5,799,100	680	18,344,100
22:00	480	11,208,900	220	11,936,100	90	5,799,200	640	18,344,600
23:00	450	11,209,300	230	11,936,300	80	5,799,200	610	18,345,100



Series 1: A (Hosp. Feeder.) kW
Series 2: B (Airport Feeder.) kW
Series 3: C (D.B. Feeder.) kW
Series 4: D (Colonia Feeder.) kW



Series 1: Total kW for all feeders

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

Cables: YSPSC has a small number of cables located close to the substation.

Meters: There is a population of aging electromechanical meters with replacements occurring at a slow pace. At customer's response, meters can be tested. During the site visit broken seals were not identified and YSPSC is in process of finding tampering and by-passing of meters, but irregularities are seldom found. Generator and feeder meters are not revenue-class meters.

Billing and collection processes: Meter reading and billing is done monthly (dates vary). YSPSC uses an older version of the Utility Star Billing System for monthly billing. The CIS raises red flags in case of irregularities (e.g., usage lower than usual).

Payment must be received within 90 days. After expiry of this period electricity will be disconnected. The reconnection fee is $ 50 but very few disconnections ever take place.

Rates are subsidized by the government with residential at $0.318/kWh, commercial $0.388/kWh, and Government at $0.737/kWh.

Reliability: The reliability of the YSPSC Power System has a reasonable level with few blackouts. Most of the feeder outages are due to vegetation problems.
T&D Maintenance – Time based maintenance is performed in the substation. For lines, there is a tree trimming schedule. An overall maintenance management program covering all maintenance activities, like for example power transformer oil sampling, is not in place yet.

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 year (2009) was used for the annual energy consumption.

2. A typical value for power transformer no-load losses from literature[1] was used for the Vantran power transformers core losses.

3. Secondary service wire types and sizes were assumed, based on observations and common practices. Assumptions were made for average wire lengths and general structures based on assumed average customer consumption rates.

4. Loads were distributed based on the distribution transformer locations.

5. Loads were proportionally allocated to the kVA capacity for each feeder.

6. Estimated voltage drops through feeders were not considered in loss estimations. Actual voltage drops were calculated in the Easy Power system model.

4.2 Easy Power Model

YSPSC provided the grid model of its power system in Yap. In the distribution system model, the substation and the primary feeders are modeled in Easy Power. The length of primary feeders and the connected load capacities are identified. This model was used and updated to conduct the power flow study. Losses through the primary feeders and step-up power transformers are calculated in a power flow study. Peak demand is identified from technical statistics and per feeder utilization factors are calculated per feeder. Load allocation was based on distribution transformer sizes connected to each feeder.

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

Power Flow Study

System peak load of 2.2 MW at a power factor of 0.9 is represented by applying 0.22 to all loads with a total of 11,094 kVA. This is similar to how loads have been considered in the Easy Power model provided by YSPSC. KEMA put in efforts to improve the accuracy of loss estimation for primary feeders. Particularly, two areas as described below have been examined:

Feeder Utilization Factor

The power flow study was performed for two cases, both representing the peak demand in the YSPSC system.

Case 1: using a system wise utilization factor peak load condition of 22% as calculated for the 2009 peak load. The calculated utilization factor was applied to all loads as the load scaling factor. The power flow report can be found in the Power Flow Summary Report 05-26, which was included in the loss worksheet.xls of Appendix C.

Case 2: using a per-feeder utilization factor peak load condition for each feeder based on metered load statistics and connected kVA's per feeder. The power flow report was attached in Power Flow Summary Report 06-22, which is included in the loss worksheet.xls of Appendix C.

Case 2 reflects the load condition in the YSPSC system more closely to what is observed in reality. The accuracy of the calculated per-feeder utilization factor is affected by:

a. Accuracy of meters. Metered annual kWh statistics were used

b. Accuracy of load modeled in the Easy Power model. The connected kVA's of distribution transformers that were modeled in GIS database were compared with load modeled in the Easy Power system. The table below shows inconsistencies between the two systems observed.

Feeder	Easy Power (kVA)	GIS (kVA)	%
Airport	2087.5	2520	82.84%
Hospital	2575.8	2590	99.45%
Colonia	5767.1	6130	94.08%
DB	665	630	105.56%
System	11095.4	11870	93.47%

The differences of connected kVA's were adjusted when calculating the per feeder utilization factor.

Losses in kW through each feeder as calculated for case 1 and case 2 are compared in the table below:

Feeder Losses (kW)	Case 1	Case 2
Airport	0.8	0.3
Hospital	8.6	13.4
Colonia	8.8	10
DB	0.1	0.1
TOTAL	18.3	23.8

The difference of calculated losses reflects the error introduced by applying a system-wise utilization factor on all feeders compared to using per-feeder utilization.

Unbalanced Feeder Sections

In the GIS database, 1-phase or 2-phase feeder sections are identified. Those feeder sections are also identified in the Easy Power model.

Since Easy Power does not support an unbalanced feeder, additional adjustments need to be made to reflect the real losses through the unbalanced feeder sections. The unbalanced feeder sections are identified in Power Flow Summary Report 05-26, which is included in loss worksheet.xls (Appendix C).

Feeder losses are small due to low amounts of load connected, and the short length of conductors, such that conversion does not have a noticeable effect on the total feeder losses. The Power Flow Output Report produced by Easy Power does not provide accuracy for the values of losses close to zero.

Recommendations

A few recommendations are provided below.

1. Meter Upgrade. Improving the accuracy of meters in both the power plant and feeders will have direct impact on the system losses and help identifying possibilities for improvements.

2. Regularly update the Easy Power model to keep synchronism with the GIS model

3. Monitor and update the utilization factor on per-feeder and system-wise basis.

4. Record peak demand and update load and loss factors for each feeder.

Recommendations listed above are for improving the accuracy of the Easy Power model and will cause the loss estimation to be more accurate within a few years.

YSPSC personnel supported our work. Discussions on the power flow model and the loss study generated the data and information we received from YSPSC. Without the valuable input, we could not have successfully completed this study.

4.3 System Loss Estimation

System losses consist of technical and non-technical losses.

Technical losses: Sum of primary feeders and power transformers, distribution transformers and secondary wires. Except for primary feeders and power transformer copper losses, all other losses were calculated in Excel sheets. Where information was not sufficient, assumptions were made to facilitate the estimation.

Non-technical losses: The difference between total system losses and technical losses; total energy entering the system from the power plants minus total energy sold.

For YSPSC, the unbilled energy usage came from the YSPSC buildings, water and sewage usage, and part of street lights. A summary of losses is provided in Exhibit 4-1.

The total system losses are the total energy entering into the system out of power plants subtracted by total energy sold and the energy unaccounted for. In YSPSC's case, the unbilled energy usage identified is a large amount (7.59%).

Exhibit 4-1: Loss Estimation

Based on 2009 Data	kWh	% of generation	% of system consumption
Annual generation	13,894,832		
Annual station auxiliary	1,033,066	7.43%	
Annual system consumption	12,861,766	92.57%	100.00%
Annual energy sold w/ unbilled usage	11,413,019	82.14%	88.74%
Annual unbilled usage	1,054,556	7.59%	8.20%
Annual energy sold w/o unbilled usage	10,358,463	74.55%	80.54%
System loss	1,448,747	10.43%	11.26%
Technical loss	886,661	6.38%	6.89%
Non technical loss	562,086	4.05%	4.37%

5. Data Handbook

As part of the project's scope of work, KEMA prepared an Electrical Data Handbook, containing electrical characteristics of YSPSC's high voltage power system equipment.

The Handbook can be found in Appendix B.

6. Analysis of Losses

6.1 Generation Efficiency

Exhibit 6-1: YSPSC Generating Units Efficiency 2004 to 2008

Table 10.3 Electricity Production Statistics: FY2004 to FY2008					
Electrical Production Statistics	2004	2005	2006	2007	2008
Total					
Electricity Produced (000 kWh)	16,416	15,140	13,457	13,315	13,126
Energy Production Cost (Cents/kWh)	0.28	0.29	0.35	0.34	0.56
Diesel Fuel Required (000 Gals)	1,367	1,207	1,069	1,040	942
Peak Demand for Electricity (kW)	2,950	2,720	2,390	2,400	2,300
Generating Capacity (kWh)	8,450	8,200	8,300	8,300	8,300
KWh / Gal Yap Proper	12.01	12.54	12.59	12.80	13.93
Electricity Produced (000 kWh)	16,416	15,140	13,457	13,315	13,126
Energy Production Cost (Cents/kWh)	0.28	0.29	0.35	0.34	0.56
Diesel Fuel Required (000 Gals)	1,367	1,207	1,069	1,040	942
Peak Demand for Electricity (kW)	2,950	2,720	2,390	2,400	2,300
Generating Capacity (kWh)	8,450	8,200	8,300	8,300	8,300
kWh / Gal	12.01	12.54	12.59	12.80	13.93

Individual generation unit data was not provided. Overall data was given as shown above.

During our visit, a 3.2 MW generator was providing the load, with a peak of 2.2 MW, and an average of 1.5 MW. During our visit it was discussed that YSPSC could install an efficient 1.5 MW generator with a payback time of 6 years. Generation efficiency improvements are discussed further in Section 8.2.1.

6.1.1 Power Plant Usage, Station Losses

The power plant own usage is 7.43% of the generated energy. This is about 2.5% higher than what is a generally expected value. However, auxiliary consumption measurement is not performed with revenue class meters which implies that maybe the real own usage value is somewhat lower or higher than 7.43%.

Losses in plant auxiliaries can be controlled by paying attention to the operation of fans, radiators, lights, etc. Proper accounting or measurement of the energy being used, and optimization of fans and pumps, can reduce energy consumption.

6.2 Technical Losses

Exhibit 6-2: Technical Losses

Technical Losses			
Type of Losses	Sub Total MWh	MWh	
Dist Transf Core	416		
Dist Transformer Copper	29	444	50.11%
Secondary Wires	186		
Wires	111	296	33.41%
Power Transformer Copper	22	146	16.48%
Power Transformer Core	124		
Total =	887	887	
Core Losses Alone	539		60.83%

Above table illustrates that out of the total calculated technical losses, transformer losses are the majority of them (67%) and wire losses only come up to 33%. Among the transformer total losses, core losses are the majority of the losses.

6.2.1 Distribution Line losses

Calculated line losses show that distribution line losses are 33% of the 6.38% technical losses, including 13.8kV feeder losses, power transformer losses, distribution transformer losses, and secondary service wires losses.

Losses in low voltage service wires were estimated at 186 MWh, or 21% of the technical losses. Assumptions were made of typical sizes and lengths of secondary wires to quantify the losses.

6.2.2 Transformer losses

Transformer losses are separated in two parts – no-load losses and copper losses. No-load losses are magnetizing losses which are present whenever the transformer is energized, independent of the load. Even an unloaded but energized transformer will have no-load losses. Copper losses are only present when load is present and are proportional to the square of loading relative to full load. For YSPSC, the total losses from distribution and power transformers are estimated to be 590 MWh per year. 539 MWh are core losses, and 51 MWh are copper losses.

Sizes of the distribution transformers (the average load is calculated to be around 22% 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. For this, physical inspection should be performed.

As core losses depend upon the size of the transformers and in general YSPSC is using only 22% of the total installed capacity (estimated at equivalent to connected load) in a year, there is 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 40% to 50% of the maximum system load of 2,200 kW.

6.3 Non-Technical Losses

Of the total system losses, 4.05% are non-technical losses.

Possible non-technical loss sources include:

- Not accounting for all energy used by YSPSC offices, stores, or workshops
- Identifying energy theft is left to meter readers or line men, which are part of the community and may not be open to bringing situations to management's attention
- Meters are not tested and not working properly
- Meters are old and not working properly
- No regular procedure to check meter multipliers
- Organizationally, no one person who is responsible for loss reduction

YSPSC has focused its attention to the reduction of the losses. Auditing and assignment of a Revenue Assurance Officer can contribute to reducing non-technical losses.

Unbilled Energy

7.59% of the total energy is not billed. It is mostly used for street lights, YSPSC buildings, water and waste water facilities. The energy usage of each of these usage categories should be accounted for and billed, and if these energy costs cannot be collected the unbilled energy should be considered as a Financial Loss for YSPSC and not a system loss or non-technical loss.

6.3.1 Metering Losses

Meters installed by YSPSC are electromechanical meters but they 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 class meters. These meters should have a revenue class accuracy to contribute to better understanding of the overall system efficiency. These meters also do not record the maximum demand.

Processes: 1,873 meters are read manually once a month. Meter reading, billing, and collection processes are manual.

Customer meters should be tied to transformers, preferably through a Geographical Information System (GIS) in the CIS (Customer Information System). Every year analyses should be performed to see which transformers can be replaced for loss reduction, overloading issues, and general maintenance. It would be beneficial to add meters to the LV side of to capture transformer loadings and identify theft or tampering issues.

7. Other issues

Power Generation: Most of the engines were beyond the allowable maintenance intervals (major and minor overhaul). In the near future, funds for on-going maintenance and aged generator replacement sets will be needed to not fall back in a Power Crisis. In fact the technical health of the utility will only be possible if enough revenues are collected to cover the utility's cost, including maintenance. 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 become clear and initiatives can be taken towards measures to fill the gap (tariff increase, subsidies, securing some amount of grants per year, etc).

Feeders, Transformers and Loads: Developing a regular maintenance program for transformers, transmission lines, feeders, and cables is needed. Performing regular infrared scans (to identify hot spots and unnecessary technical losses) and oil testing (for monitoring power transformers' condition for reliability reasons) is recommended.

8. Options for Improvements

8.1 Power System Improvements/Modifications

Technical losses are unavoidable. KEMA does not expect technical loss reduction efforts to result in substantial amounts of loss reductions based on the assessment. Reducing them should continue to be an integral part of YSPSC's overall loss reduction strategy for the following reasons:

- Electricity rates will continue to increase, particularly because of increasing fuel costs, which will change the cost-basis for evaluating many technical loss reduction related measures/programs.
- Electrical equipment connections that are loose can cause heating, which results in higher losses, loading to reliability concerns, and safety issues.
- Priority should be given to equipment purchases that lead to lower losses.

Many of the projects/programs that reduce technical losses cannot be cost-justified because of the large capital investment required. For these projects/programs, giving loss reduction benefits a proper weight when considering total life costs is key to selecting those that will be most beneficial.

Distribution and power transformers make up 67% of the technical losses. Core losses are the majority of the losses. Over the life time (even over a 10 year life span) the cost of losses represents a major cost relative to overall capital costs. The Distribution Department needs to better match transformer size to supplied load. If implemented, savings are considered when based on the load.

Loss calculation is not a one-time event but needs to be considered when developing all utility processes (e.g., operational procedure, planning and engineering system expansions, purchasing materials, and defining revenue assurance measures). Loss estimation can be improved in the following two areas:

Secondary circuits and service wires

YSPSC should consider using a targeted feeder program to create an initial GIS map for secondary circuits (including customers and service wires). The map could be refined gradually to reflect the actual secondary circuit and service wires in the field. This would provide a solid basis for future technical loss evaluation

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

Customer meters need to be associated with the respective transformers servicing the load. This can be done in a CIS system or using spreadsheet software to take load from metering data and calculate transformer loading. Properly sizing the transformers will have an impact on overall loss reduction (e.g., using smaller sizes).

Loss estimation in this part of the system is more complicated and is affected by:

- Un-metered load such as streetlights, illegal connections, etc.
- Unknown exact lengths of circuits/wires
- The load patterns are difficult to obtain for each customer unless AMI (Advanced Metering Infrastructure) is deployed

Nevertheless, creating such a GIS map would help YSPSC better estimate losses.

Update loss cost-basis on a regular basis

The loss cost-basis used to estimate lifetime cost of losses should take electricity rate increases into full account. When rates are increasing at a slow pace, it may be acceptable to use current rates to calculate projected savings over life spans of equipment (e.g., transformers) and other parts. When rates are fast increasing, using current rates will greatly under estimate the lifetime savings of reduced losses over a long term period.

As new equipment is installed and old equipment replaced, the loss cost-basis should be evaluated. Once a 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. The new cost-basis should also be used to re-evaluate projects/programs that can provide technical loss reductions to select the most beneficial programs.

The new cost-basis should also be used to re-evaluate projects/programs, resulting in Technical Loss reduction to select the most beneficial.

Optimize step up transformers

One substation transformer (5.6 MVA) is generally used while the other is kept energized. Each transformer is double the size of the maximum load, but capital cost investment may not justify replacing them with the smaller sizes. Every kW of loss is $1,700 a year. Full load loss of a 5.6 MVA transformer is over 34kW and at 50% load is 14kW. If one transformer is kept off completely, it can save 7kW of core losses and $12,000 in a year. If both transformers are kept in parallel and each carry half the load, a similar amount will be saved. These savings result out of a lower total of copper losses, compared with copper losses when the full load is going through one transformer.

Optimize distribution transformers

Distribution transformers should be optimized to reduce losses. When the transformer sizes are appropriate for the load and purchased based on total lifetime cost, overall losses will be optimized. As optimized sizes cannot be realized in a single year, a multi-year replacement program should be set up:

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, unless all customer loads connected to this transformer can be computed).

b. Develop proper transformer sizes for each location.

c. Optimize transformers which can be optimized without capital cost investments (e.g., by moving them to appropriate location). Remember transformers can be overloaded for short durations.

d. Develop a new transformer purchase plan based on standard sizing while looking at least lifetime costs, which will include capital investment and losses. (An example transformer evaluation is included in Appendix C.).

Optimize feeder power factor

Overall system power factor (PF) is 0.89. The power factor of feeder sections should be checked regularly (at least once a year) and actions should be taken to keep it above 0.9, preferably 0.95. The best location for corrective measures is at the loads, especially at inductor motor terminals. Develop a plan and tariff (or introduce a low power factor penalty) to make sure each larger commercial and government loads are at a minimum power factor of 0.9. If a customer does not improve its power factor to the required level, YSPSC should charge a penalty. Metering and billing should be coordinated with tariff and/or low power factor penalties.

Optimize feeder reactive power compensation

Shunt capacitor banks on 13.8 kV lines can be used to minimize reactive power flows in the network to help reduce the losses. When operated for this purpose, there are two areas that should be considered:

Fixed and manually switched capacitors

Compensation can use a mix of fixed and switched capacitors to achieve desired reactive power compensation levels.

The size of fixed capacitors can be determined by minimum reactive power compensation requirements of a feeder. It is not necessary to compensate to 1.0 power factor, but should be as close as possible. From a loss reduction point of view, results will be the same regardless if the power factor is leading or lagging. The actual size selection should also take standard capacitor sizes into account that can be procured.

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.

When determining capacitor sizes, in particular for switched capacitor banks, voltages should be verified to ensure voltage limits are not violated.

Automatically switched using capacitor controls

Automatic switching of capacitor banks can be controlled by a variety of system variables or derivatives of system variables. Common controls are described below.

- Voltage Control: 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 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 pre-determined 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 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 when daily load patterns are predictable. Capacitors are switched in and out based on the time of day. This control is the least expensive; however, a disadvantage 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 control type should be based on the load profile of a feeder.

8.2 Operational Recommendations

8.2.1 Generation

Develop written economic dispatch operating procedures and monitor the performance of the plant and individual generation units.

For reviewing the performance of generating units, the current metering in the power plant does not provide good coordinated readings. A first step should be to install revenue-class metering (energy, fuel and other supplies) to accurately measure the efficiency of each generator and to dispatch them based upon efficiency. Focus on efficiency improvement (which requires training and implementation of processes for operators) and real-time display of engine efficiency helps the operators to run the engines in the most optimal way. Minimum display of real-time information providing fuel use, lube oil usage, generator kWh production, and auxiliary kWh usage should be made available. The objective is to improve generator efficiency and reduce consumption in plant auxiliaries. Introduce automated economic dispatch as a module to be added to the SCADA system, which could be an option after a cost/benefit analysis of system automation needs has been performed.

Generation efficiency shown in section 6.1 varies from 12.01 to 13.92 kWh/gal, which is relatively low. The situation should be corrected by eradicating the arrears in maintenance and optimizing fuel injection, cooling, etc. Every 1% increase in efficiency saves $28,000.

Installing a new efficient 1.5 MW generator can be justified by having a payback time of 6 years. Running the average load with a generator with an output rating of 1.5 MW would improve the efficiency up to 15.6 kWh/gallon. Savings will be $336,000 per year, while a new 1.5 MW genset will cost around $ 2 million (all inclusive). Depending on the interest rate, the payback time will be around 6 years (at an interest rate of 8%). The high efficiency may not be reached in periods when the load varies between 1.5 MW and 2.2 MW, which may reduce the annual savings to $260,000, which brings the payback time to a 10-year period.

Funds for regular maintenance must be available in order to keep the new and Deutz engines in good condition. A service study cost should be done to determine the corresponding tariffs or a combination of a certain tariff level with yearly grants, which allow YSPSC to be self-sustainable.

8.2.2 Metering

A procedure should be developed to test and calibrate meters before installation. This should include methodologies to test sample meters to assure accuracies.

Methodologies should be developed to measure distribution transformer load profiles either through

1. software, which takes into account the customer meters on each of the transformers or

2. Physically measuring the load by installing demand-type meters on the secondary of each transformer.

Revenue-class meters can be used to measure the output of the generators, 13.8 kV feeders and auxiliaries for generating plants.

8.2.3 Strategy for Reduction of Non-Technical Losses

One of the main areas in aligning a utilities' operation to Revenue Assurance is to implement a Revenue Assurance Process making use of an advanced Revenue Intelligence System. For conducting most efficient fraud prevention/detection and revenue operation audits with limited resources, an advanced Revenue Intelligence system is very helpful. Such a system can detect 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, implementation of a Revenue Assurance Department and implementation of Revenue Intelligence Software requires a large investment and may have a large organizational impact.

A more pragmatic approach can be developed to locate non-technical losses and increase the effectiveness of revenue-protection operations.

YSPSC could consider the following:

- Develop a program for checking old meters.
- Train meter readers to identify tampering, by-passing, broken seals, hook ups.
- 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.
- 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 revenue recovery potential and hit rates will be the most efficient use of limited resources.
- Make operations less predictable. YSPSC's own experience may possibly show that there are sophisticated fraud activities that take advantage of known patterns of

Revenue Assurance operations. This should be countered with less predictable operations (e.g., occasional night inspections, computer-generated random daily target lists, and so on). This will help to identify these fraudsters and increase the deterrent effect.

- Prevent repeat fraud activities. Once a fraud is found, measures should be implemented to ensure it will not occur again.
- Prevent and curb internal collusion activities. One important aspect of effective revenue protection operation is to prevent and curb potential internal collusion. Internal collusion seriously undermines the effectiveness of any revenue assurance process. One possible solution is to bring in non-local inspection teams to conduct critical revenue-protection operations, such as large account audits under the direct control of YSPSC's top management.
- Employ rights tactics for each group of customers. It is a fact that different types of 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 patterns and payment capabilities. Establishing typical usage patterns and payment capabilities for each group is a very important task of Revenue Assurance. Results should then be used as the basis for employing right tactics for each group of customers.
- Assign a senior staff member to be Revenue Assurance Officer, responsible for Loss Reduction Strategies, and who plans and initiates low reduction programs, keeps records of progress, and reports to the General Manager.

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

Exhibit 9-1 provides a summary of savings and associated costs over a 6-year implementation period:

Exhibit 9-1: Savings and Cost

	6 Yrs NPV of Savings and Cost Summary		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Auxiliary loss	$219,343	$125,000	$94,343
Technical Losses	$255,673	$174,018	$81,656
Non Technical Loss	$238,687	$231,383	$7,304
Total =	$713,703	$530,402	$183,302
1% efficiency improvement in generation saves $28,000 per year. This amount is based on the price of crude oil of $ 75 per barrel. At a price of $ 100 per barrel the saving of 1% efficiency improvement will amount to around $ 37,000 per years. This assumption can be influenced however by fuel pricing effects related to creditworthiness of customers and transportation costs			

Detailed calculation of these numbers is provided in Appendix C called "Technical Loss Calculations and Financial Model for Options to Decrease Losses".

The summary of our recommendations is as follows:

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

2. Cost of Capital at 8% per year was assumed.

3. Emphasis should be placed on process improvements for purchasing, metering, billing, collection, and operations

4. In case the street lighting usage cannot be billed it should be considered a financial loss for YSPSC rather than a system loss. The usage for water and sewerage facilities should be accounted for and allocated to the cost of service for Water and Sewerage. As long as this usage has not been allocated to Water and Sewerage activities, it has to be considered a financial loss for YSPSC and not a system loss. The Financial loss of 7.59% for water, sewerage, and street lights need to be brought in control for financial viability of the enterprise.

5. Technical and non-technical loss improvements will require investments totaling $1 million over 6 years. The goal of loss reduction will be to reduce them from 10.43% to less than 4.32%.

6. Generation auxiliary losses are a rather large portion (7.43%) of overall losses. With process improvements and a $125,000 investment, it will be possible to provide real-time data and efficiency calculations to operators who can then operate the power plants, at maximum efficiencies (4.93%).

7. Overall loss reduction objective around 9.8% in 6 years.

9.1 Recommendations

Recommendations below are prioritized according to costs and benefits. (See spreadsheet Savings Model tab in Appendix C.)

9.1.1 Reduction of Technical Losses

Distribution transformers appear to be loaded at 70% full capacity. Loss reductions are possible if transformer sizing more closely matches connected load. This could be done as part of an on-going transformer replacement program.

1. Power Factor Improvement:

    a) Power factor of YSPSC is very good but it needs to be watched and a process should be developed to evaluate it at least once a year.

        i) Acquire software for power factor analysis.

        ii) Determine power factor of largest customers and require them to improve it over 85%. This may require penalties or tariff changes. Add capacitors to improve the power factor (estimated Cost of $129,000 over 6 years)

iii) Determine what capacitor locations can be placed to improve overall power factor to 95%. Check to make sure maintenance and monitoring are part of the plan.

2. Transformer Right Sizing

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

b) Distribution transformers should be sized to achieve 80% loading at maximum demand.

c) Transformers should be purchased based on lifetime costs (including NPV calculation for losses). For example, the cost of 1 kW of core losses for 20 years of a transformer's life at 20 cents per kWh of fuel cost (based on $3 per gallon of fuel) will be $21,476 (NPV). For copper losses NPV is dependent on transformer loading but is estimated to be $10,519. (See an example transformer evaluation in Appendix C).

Acquire an infrared scan camera and train to use. (Cost of equipment and training $100,000).

Using an infrared camera is a necessary tool for identifying distribution loss issues. An infrared camera will identify hot spots from bad connections and overloading, and as a result, helps in detecting weak spots, prioritizing maintenance work and upgrading feeders. There is a potential energy savings by regularly identifying these maintenance issues and taking proactive correction measures.

Technical losses can be reduced to 2.5% in 6 years through process improvements for an estimated savings of $355,000. Cost of these initiatives is $204,000 over a 6 year period.

9.1.2 Reduction of Generation Auxiliary Losses

1. For every generating unit, add instrumentation to show efficiencies to operators (cost $175,000). Develop a process that provides regular reporting to management.

2. Develop manual processes to control fan operation (cooling fans, exhaust fans and pumps) to run based on temperature sensing or other parameters to reduce energy consumption.

3. Automate manual processes using PLC controls to motor starters and frequency drives (cost not included).

4. Apply Frequency Drives where needed (cost not included).

The benefit of these steps is estimated to be $328,000 over 6 years. Savings are produced by reducing auxiliary losses from 1,875 MWh to 1,500 MWh in 6 years. (See spreadsheet Savings Model tab in Appendix C).

9.1.3 Reduction of Non-Technical Losses

Account for and highlight monthly financial losses associated with street lights and unaccounted energy use. Add new meters to transformer secondary's and feeders at key locations for monitoring loads and auditing customers. Procure meter testing equipment and train users to perform sample meter testing. Replace meters found to be out of specification. Make sure each customer is associated with transformer and its meter (cost $490,000). Software can then be used to identify tampering and transformer issues loading.

It is not necessary to install meters on every transformer. Areas prone to excessive tampering or other theft issues or where loading profiles are unknown would be best locations. Temporary recording meters could be installed for a time period and be rotated to other locations. With this option, manpower costs associated with relocation need to be considered.

Add Revenue Protection measures as described in Section 8.2.4. Include a senior staff member accountable to the Revenue Assurance Officer.

In the first year, it should is reasonable to expect a 10% savings in non-technical losses. Non-technical losses will drop to 1.75% (e.g., achieving 563MWh from 225MWh in 6 years). Savings will be $328,000, resulting in an NPV of $238,000.

9.1.4 Improving Generator Efficiencies

Investing $ 2 million in a new 1.5 MW generator will bring at least $260,000 savings on fuel costs and has a payback time of 6 to 10 years, but an important pre-condition will be that funds for regular maintenance must be available in order to keep the new and Deutz engines in good condition. In fact, a Cost of Service Study should be done to determine the level of tariffs or a combination of a certain tariff level with yearly grants, which allows YSPSC to be self-sustainable.

9.1.5 Net Present Value Calculations

Exhibit 9-2: Net Present Value calculations

Assumptions:				
Inflation	3%			
Cost of Capital	8.00%			
Cost of generation /kWh	$0.32			
Cost and Savings list	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**	**Cash over 6 years**
Auxiliary Losses				
SCADA for generators and process improvement		$125,000		-$125,000
300% loss reduction over 6 years	$219,343		$94,343	
Technical Loss Savings:				
Infrared camera and training		$75,000		-$75,000
Power factor improvement hardware installation and control.		$99,018		-$129,368
45% loss reduction over 6 years	$255,673		$81,656	
Non Technical Savings:				
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.		$231,383		-$242,728
60% Non Technical Loss reduction over 6 years	$238,687		$7,304	
Total =	$713,703	$530,401	$183,302	-$572,097

Detailed calculation of these numbers is provided in the Appendix C file called "Technical Loss Calculations and Financial Model for Options to Decrease Losses".

Other Recommendations:

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

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

3. Develop a testing program for revenue meters. The estimated costs are included in the non-technical savings plan.

A. Data Request

All documents were provided separately per request.

B. Data Book

YAP Engine and Power Transformer Data

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

Technical Loss Calculations and Financial Model

TRANSFORMER EVALUATION EXAMPLE