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

Kwajalein Atoll Joint Utility Resources, Inc. (KAJUR)

Ordered by the Pacific Power Association

Prepared by KEMA Inc

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1. Executive Summary

KEMA's analysis of Kwajalein Atoll Joint Utility Resources, Inc (KAJUR) power system shows total losses of 22.51%, which are made up of:

- 4.16% in power station auxiliaries (station losses), which is a relatively reasonable amount of losses. Generally the station losses are between 3% and 5%.
- 3.00% in street lighting, water and sewage pumps (usage for street lights should be accounted for and billed). If these revenues cannot be collected they should be considered a financial loss and not a system loss.
- Power usage for water and sewage facilities should be allocated to the cost of service for water and sewerage activities and should not be considered as a system loss of the power system.
- 2.77% in technical losses.
- 12.58% in non-technical loss.

Technical and non-technical losses total 15.35%.

Overall losses, including power plant own usage, are 19.51%.

Recommendations:

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

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

(Total cost of these initiatives is estimated to be $60,000 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 (net present value). For copper losses (loading dependent) the net present value is estimated to be $11,747. These figures should be taken into account when evaluating bids for new transformers. (A transformer evaluation example is provided in Appendix C).

2. Add revenue-class meters to the feeders and distribution transformers to measure the losses. Use these meters to check total consumption of customers connected to the individual transformer. These meters can be avoided if customers are tied to transformers in CIS. Cost of the transformer meters is included in item C below with other meter cost.

3. Optimize distribution transformers ratings a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses). Not all transformers need to have these meters, only where the need for determining the transformer load is identified due to tampering or other irregularities. KAJUR may also buy 10 to 20 temporary recording meters and install them on the transformers for a time period and subsequently rotate them around to measure transformer load patterns.

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

5. Work together with Marshall Energy Company (MEC) to use an infrared camera to scan power system equipment at least annually to find hot spots. These usually occur at connector points. Repair as necessary.

(Total cost of these initiatives estimated to be $320,000 over 6 years.)

C. Metering, Billing and Collection:

1. Develop a Revenue Protection initiative to reduce the non-technical losses. Use revenue protection techniques, technology of digital meters for customers, feeders and distribution transformers along with software, and focus to reduce the non-technical losses.

2. Most of the customer meters are of the pre-paid meter type but the accuracy of these meters cannot be assured. Develop a testing program and maintain these meters to revenue-class accuracy.

(Total cost of these initiatives estimated to be $ 323,243 over 6 years.)

It is estimated that these recommended measures and actions will cost about $ 703,000 over a period of 4 to 6 years (NPV of $ 0.563 million), resulting in an estimated savings of $ 1 million (NPV of $ 0.759 million) and reduction of:

- 11% in overall losses.
- Savings of about $ 18,000 per year can be obtained for every 1% of impr ovement in generation efficiency.

When cumulating costs and savings the Net Present Values of net savings are given in the table below:

Exhibit 1 – Savings and Cost Summary

	6 Yrs NPV of Savings and Cost Summary		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Auxiliary loss	$41,893	$60,000	-$18,107
Non Technical Loss	$678,678	$291,406	$387,272
Technical Losses	$39,428	$264,970	-$225,542
Total =	$759,998	$616,376	$143,623
1% efficiency improvement in generation saves $17,810 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 $ 190,000 per years. This assumption can be influenced however by fuel pricing effects related to creditworthiness of customers and transportation costs.			

Cost of reducing technical losses cannot be justified by savings. KAJUR's technical losses are already very low, namely 2.88%, and with this low figure of technical losses KAJ UR in fact belongs to the world's "best in class". Non-technical losses however are much too high and combating those losses shows to be worthwhile. Measures for reducing auxiliary losses cannot be justified at the current fuel price level, but will be wor thwhile if crude oil prices reach higher values of US$ 100 per barrel.

Regarding generation efficiency, only two engines were operable during KEMA's visit. Not the generation efficiency but reliability and availability of engines (and maintenance of the en gines) are the key priorities for KAJUR. If overhaul and refurbishment of generators cannot be performed due to a lack of fund ing, optimization of the generation efficiency is currently hardly possible, only by dispatching the engines as efficient as possi ble for which operators should be trained.

2. Introduction

2.1 Project Objectives

KEMA Inc. has been awarded by the Pacific Power Association (PPA) in Fiji to carry out a project called "Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (Excluding US Virgin Islands)". The project has been performed for 10 Northern Pacific Island Utilities and this report covers the study results for Kwajalein Atoll Joint Utility Resources, Inc. (KAJUR) in Ebeye, Marshall Islands.

Objectives of the project:

1. Quantify energy losses in the power system.
2. Prepare an Electrical Data Handbook, containing all electrical characteristics of the power system 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 energy losses. Attention will also be paid to non-technical losses and recommendations made to reduce these losses.

2.2 Quantification of Losses

Losses through the KAJUR system consist of:

1. Power station losses
2. Distribution system losses.

Both categories of losses are quantified.

The following loss categories have been identified.

- Station Losses: Power Plant Auxiliary Loads.
- Distribution System Losses: These losses consist of:
  - Technical losses, which are quantified as a summation of transformer core losses, transformer copper losses, transmission line losses, primary distribution feeder losses, and secondary wire losses. The technical losses will become higher if the power factor in the system or in system parts is lower than the company's targeted power factor.

- Non-technical losses, which can have different causes: inaccurate meters, meter tampering or by-passing, theft, meter reading errors, irregularities with pre-paid meters, administrative failures, wrong multiplying factors, and others

- Unaccounted Usages: These are the energy usages in the KAJUR system that are not metered, or not billed. The unbilled usages should be accounted for and billed, or should otherwise be considered a financial loss rather than as a part of the non-technical losses. Power for water production, distribution, and sewerage should be accounted for and allocated to the cost of service for Water and Sewerage.

3. Data Gathering and Assessment of Current Situation

The data gathering process is to collect existing information and understand the current situation of the power generation and distribution system in Ebeye. KEMA visited Ebeye and conducted meetings with management and staff. Physical inspection was done of one power plant and the electrical distribution facilities including: transformer stations, distribution transformers, and overhead feeder from Ebeye to Gugeegue.

3.1 The KAJUR Power System

KAJUR is managed by its local management team, but the CEO of the utility reports to MEC in Majuro. KAJUR owns and operates one power plant containing diesel engines and 480V generators paralleled to provide residential, commercial and government customers through two 13.8 kV underground feeders. Customers are provided power at 240/120V, 208/120V or 480/277V levels through distribution transformers ranging from 15 kVA to 750 kVA capacity. The system's peak load is 2.0 MW with an average load factor below 0.78.

3.2 KEMA Data Request

A data request was sent to KAJUR prior to on-site meetings. See Appendix A.

3.3 Data Received

No data was received before KEMA's visit.

3.4 Site Visit

The following data was gathered during the site visit of February 2010:

(Please see date in the Electrical Data Handbook in Appendix B.)

Further data collected:

1. Financial reports.
2. Generator energy and fuel used for ten months.
3. Cash Power meters (pre-paid) sold in $ converted to kWh for 12 months.
4. Energy used for meters which are directly read – mostly commercial and some residential.

5. Transformer data.

6. Distribution Feeder sizes and lengths.

Load: The peak load is 2.0 MW with an average load of 1.554 MW. Power factor is 0.96.

Generators: There are three 1.2 MW Cummins Generators but effectively there are only two generators operating at this time. These generator sets are high speed 1.2 MW and can supply the load. Records of fuel usage and energy supplied are kept on a sheet of paper without any daily performance calculations. The generators supply at 480V and then the voltage is stepped up by a step-up transformer 3000 kVA, 480V / 13.8kV (Z=5.8%). The maximum load of 2 MW can be supplied with two Cummins generator sets.

Transformers: KAJUR has both pad-mounted and pole-top transformers. KAJUR's specification is to buy stainless steel tank transformers. The condition of these transformers looked good. There are 59 three-phase (13.8 kV to 208Y/120V) and single-phase (13.8 kV to 240/120V) transformers located around the island. Their sizes vary from 15 kVA to 750 kVA.

Aerial and Underground Feeders: Ebeye upgraded its system with underground 13.8 kV cables while the wires from the distribution transformers (secondary side) to the meters are overhead. One of the feeders to the outer Island (Gugeegue) is served with Aerial line 2/O bare copper. The aerial line is supported with non-steel hardware which is failing due to rusting, structurally in bad shape and requires replacement.

Cables: Two underground feeders (4/O Cu) from power stations go around the island feeding pad-mounted distribution transformers.

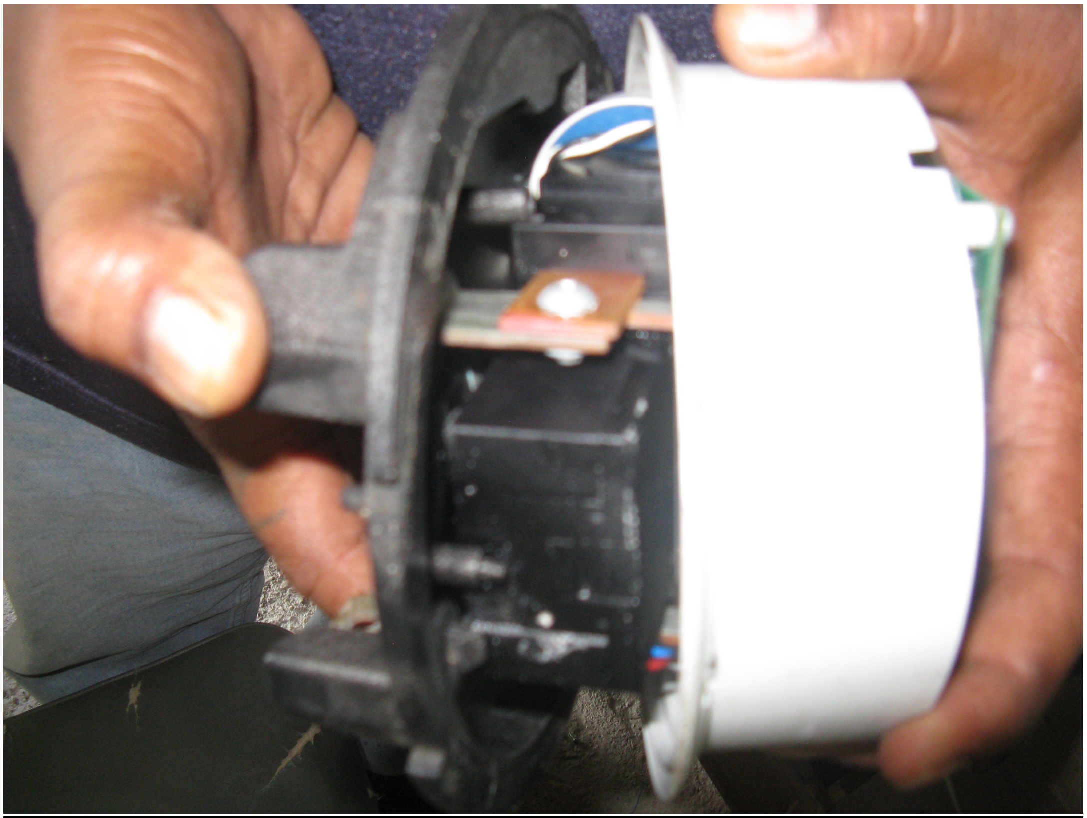
Meters: There are two types of metering systems in Ebeye. One system includes pre-paid meters and is called "Cash Power" (installed in 2001) and the other system includes meters which are physically read every month and is called "Fox Pro" (installed in December 2009). For Cash Power, customers pay in the KAJUR office and get a slip with a code which needs to be entered in a display mounted in the customer's house. Older meters were made by Siemens while the new ones are manufactured by Landis & Gyr.

Meters are not calibrated. Generator and feeder meters are not revenue-class meters.

Exhibit 2: Pre-Paid Meter Key Pad

Above picture shows a home mounted display and key pad to enter the code obtained from KAJUR after pre-paying for energy to be used.

Exhibit 3: Meter with Disconnect



Above picture is showing the internal breaker for load disconnection.

The other system (Fox Pro) is not pre-paid and requires meter reading every month. These customers (about 80) are the largest customers (commercial and government) with some residential customers. There are three meter readers and installers in the distribution department. There are also three linemen who generally work on the medium voltage distribution system.

Billing and Collection Processes: Most of the processes are manual and not documented. Most meters (1,200) are pre-paid meters and about 100 meters are read manually with bills issued monthly. Customers come to the office to pick up their bills and pay. Many customers do not pay the full amount as there is no penalty to carry large debts on their account.

Reliability: No records of any outages. Most of the outages are due to the generation issues.

Maintenance: Planned maintenance is performed but on a limited, affordable schedule and scale.

4. Grid Model and Calculation of Technical Losses

4.1 Estimates and Assumptions for Missing Data

In order to quantify losses, the following assumptions were made:

1. The average power output for the period of January 1 to October 31, 2009 was used to represent annual energy generated. Corresponding energy sold was used from the same period due to lack of energy sold to energy generated in other periods.

2. The typical value of no load and full load losses for transformers from literature[1] are used for the transformer loss estimation.

3. Data on the secondary service wire types and sizes were provided. However, assumptions were made for average wire lengths and general structures to estimate secondary losses after discussions with KAJUR personnel.

4. Loads are distributed along the feeders based on feeder sections and assumed meter locations along feeders from meter reader books.

5. Allocation of distribution transformers and their loads were according to the sections of the feeder shown on the one line diagram.

6. Load is allocated proportionally to the kVA capacity of distribution transformers.

7. The effect of voltage drop through feeders is not considered in the loss estimation except in the power flow study through Easy Power.

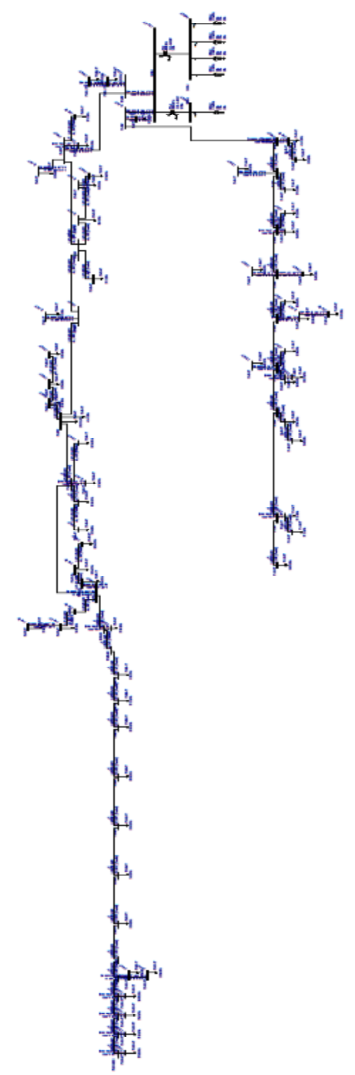
4.2 Easy Power Model

The power plant and primary feeders of the distribution system in Ebeye Island are modeled in Easy Power. Losses through primary feeders and power transformers are calculated in a power flow study. The power flow case is solved for the peak load estimated from the 10 month customer meter data and output data collected at power plants. Since distribution transformers are not associated with the customer meters, load allocation is based on the distribution transformer ratings for each of the three feeders.

The one line diagram of the KAJUR system model is shown in following exhibit.

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

Exhibit 4: KAJUR One Line Diagram



4.3 System Loss Estimation

System losses include technical losses and non-technical losses.

Technical losses: Sum of losses in primary feeders, power transformers, distribution transformers, and secondary wires. Except for transmission lines, primary feeders and power transformer copper losses, all other losses have been calculated in Excel sheets. Where information was not sufficient, assumptions (such as exact location of customers relative to their distribution transformer, load for each of the transformers, load on feeders, load per phase of feeder sections, power factor of the loads) were made to facilitate the estimation, and could result in a margin of difference from the actual loss value.

Non-technical losses: The difference between total system losses and technical losses. The total system losses are total energy entering the system out of power plants minus total energy sold and energy unaccounted for.

The unbilled energy usage identified was for street lights, and for water and sewerage system usage.

A summary of the loss estimation is provided in Exhibit 5.

Exhibit 5: Loss Estimation

KAJUR			
	MWh	**% based on Energy Generated**	**% based on Energy delivered to Distribution System**
Generator Output	14210	100.00%	
Generated Output – Auxiliaries	13619	95.84%	100.00%
Energy sold to customers	11010	77.48%	80.84%
Technical Loss (including feeders, transformers and service wires)	394	2.77%	2.89%
Secondary Service Losses	42	0.30%	0.31%
Distribution Wire and Power Transformer Losses	56	0.39%	0.41%
Distribution Transformer Copper Losses	44	0.31%	0.32%
Transformer Core Losses	252	1.77%	1.85%
Street Lights, sewage and salt water pumps not billed	427	3.00%	3.14%
Non-technical Loss	1788	12.58%	13.13%
Station Auxiliaries	591	4.16%	4.34%

5. Data Handbook

KEMA prepared an Electrical Data Handbook, containing the electrical characteristics of the KAJUR power system high voltage equipment.

The Electrical Data Handbook is provided separately as noted in Appendix B.

6. Analysis of Technical and Non-technical Losses

6.1 Generation Efficiency

Exhibit 6: Cummins Engine

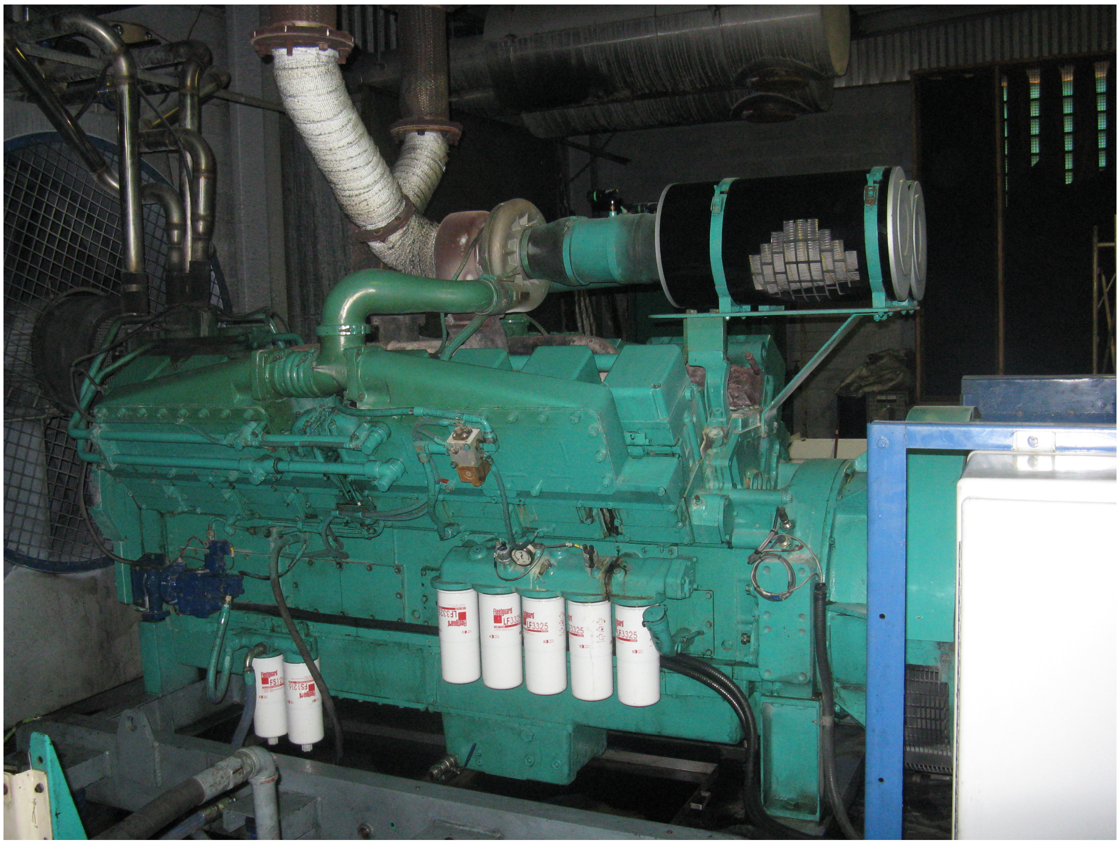


Exhibit 7: Tanks

Exhibit 8: Engine Data

UTILITY ENGINE NO.	ENGINE MAKE	ENGINE MODEL	ENGINE SERIAL NUMBER	NAMEPLATE RATING (kW)	ENG. SPEED (RPM)	ENGINE FUEL TYPE	YEAR INST.
1	Cummins	KTA 50 TQ1286E	LS220649/1	1,200	1,800	Diesel	1984
2	Cummins	KTA 50 TQ1286E		1,200	1,800	Diesel	1984
3	Cummins	KTA 50 TQ1286E		1,200	1,800	Diesel	1984
4	Cummins	KTA 50 TQ1286E		1,200	1,800	Diesel	1984
5	Caterpillar						
6	Caterpillar	D5R-46	84004	1,500	450	Diesel	1984

During our visit the only generators operating were engines 3 and 4. The Caterpillar engines were, for all practical purposes, being used for parts. Reliability and availability of engines and maintenance are key priorities for KAJUR. Since operating hours between maintenance intervals have exceeded the recommended intervals, the generating units are being de-rated.

Exhibit 9: Engine and System Performance Statistics

Engine Performance Jan 1 to Oct 31, 2009						
	Engine 2	Engine 3	Engine 4	F1 Feeder	F2 Feeder	Station
Date	6/6/2007	1-Jan-09	1-Jan-09	1-Jan-09	1-Jan-09	1-Jan-09
Fuel Reading	3,726,012	5,211,824	8,590,747			
kWh reading	43	2,544	1,393	252,490	255,649	53,985
Date	31-Oct-09	31-Oct-09	31-Oct-09	31-Oct-09	31-Oct-09	31-Oct-09
Fuel Reading	4,256,288	6,362,463	9,901,119			
kWh Reading	2,350	6,887	6,585	6,047,526	6,316,077	60,144
Fuel in liters	530,276	1,150,639	1,310,372			
kWh	2,307	4,343	5,192	5,795,036	6,060,428	6,159
Gal / Liter	0.26412687	0.26412687	0.26412687			
Multiplier	1000	1000	1000	1	1	80
Fuel in Gal	140,060	303,915	346,104			
kWh	2,307,000	4,343,000	5,192,000	5,795,036	6,060,428	492,720
kWh/ Gal	**16.47**	**14.29**	**15.00**			
Total Energy Produced			11,842,000			
Energy sold to Commercial			4,589,581			
Energy sold to residential			4,586,260			
Total Energy Sold			9,175,841			
Energy sold / Energy produced (%)			77.49%			
Losses			22.51%			
When adding all energy entering into the feeders and the energy used in the power plant, the total is more than generated, namely 11,861,623 kWh versus 11,842,000 kWh (total energy produced)						
Meter recordings in the Power Plant may possibly be incorrect. This needs to be investigated in order to take corrective measures. It is advised to install new revenue class meters.						

KEMA could only use data available from January 1 to October 31, 2009, but when looking at the generator efficiency measured by kWh / Gal of fuel, there was a wide difference in the engine's performance. Engine 2 has a relatively high efficiency but is least used. Dispatchning of engine 2 should have preference.

The average efficiency of 14.99 kWh / gallon for 10 months seems to be relatively good but first KAJUR needs to verify the accuracy of the metering for fuel and energy to verify performance of the power plant. Once a good set of data is available, the cost of newly installed units needs to be compared with savings obtained from efficiency improvement. Every 1% efficiency improvement can bring around $18,000 savings per year.

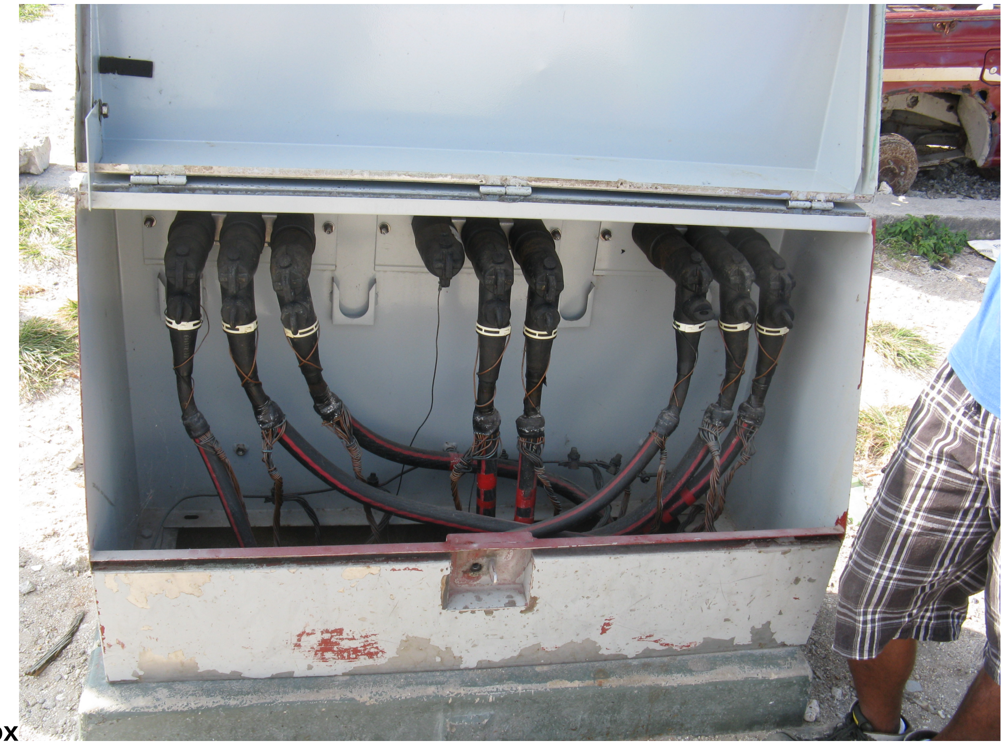
The power plant is consuming 4.16% of the generated energy. However, the auxiliary consumption measurement is not performed with revenue-class meters. Cooling fans with built-in exhaust fans are not optimally controlled to reduce losses. Radiator efficiency should be investigated relative to their design specifications.

6.2 Technical Losses

6.2.1 Distribution Line Losses

Calculated line losses show that these are about 0.41% (as part of 2.77% technical losses) in 13.8 kV overhead and underground wires. Only about 0.3% is in low voltage service wires. Some reasons are short length of feeders, a relatively high power factor due to utilization of underground cables, and a low load relative to size of the cables.

Exhibit 10: Underground Cables Connection



Box

Exhibit 11: Overhead 13.8 kV Feeder from Ebeye to Gugeegue

During KEMA's visit it was noted that the power factor at the generating station was 0.96 without application of capacitors.

Another issue is unbalance (ignored in calculations) in the three phases, which could not be quantified and has therefore been ignored in our calculations.

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 on unloaded but energized transformers there will be 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 KAJUR total losses from distribution and power transformers are estimated to be 296 MWh per year. 252 MWh are core losses and, 44 MWh are copper losses. Transformer losses (2.08%) are the biggest part of the technical losses (2.77%).

The ratings of these transformers (average load is 33% of installed distribution transformer capacity) may be too large for the load and, resulting in higher no-load losses (core losses). The system database did not contain information that matched loads to transformers, so this was done by physical inspection.

Since core losses depend on transformer ratings, and since KAJUR is using only 33% of the total installed capacity in a year, there is room to decrease these losses. Lowering distribution transformer ratings by one size will reduce losses by 20% (60MWh); two lower sizes will reduce losses by 30% (90MWh). The second option (two sizes lower) will load transformers 50% to 60% of the maximum system load of 2,000 kW.

6.3 Non-Technical Losses

12.58% of losses are classified as non-technical losses. There is potential for reduction of these losses. For example, the following issues came forward during conversations KEMA had during the visit.

- Some accounts are not accounted for through metering and billing.
- Energy used by KAJUR offices, stores or workshops and by some of the personnel, is not measured and accounted for.
- Government officials are not being charged for some of the energy.

- Enforcement of disconnection for non-payment is not consistent.
- Identifying energy theft or irregularities is left to meter readers who are part of the community and may not be open to bringing situations to management's attention.
- Meters are never tested.
- Meters are old.
- No regular procedure to check the meter multipliers is in place.
- Organizationally, no person is responsible for loss reduction.
- The billing system does not raise red flags when irregular consumption is detected.

Energy supplied to street lights, sewage and water pumps cannot be classified as a system loss when it is given for the social welfare of the people. This is a policy issue. While KEMA was visiting KAJUR, there was a project to replace the street lights with LED lights, which consume less energy. It is a good solution but, energy consumed by the LED lights will be about 20% of the existing lights and that energy needs to be accounted for.

6.3.1 Metering Losses

Customer meters installed at KAJUR are electronic meters but have never been calibrated or tested. Meters used for measuring generator outputs, main feeders, and auxiliaries are not revenue-class but they should be to better quantify the overall system efficiency. Pre-paid meters are used for most of the residential customers. These meters do not record the maximum demand.

Processes: Most of the meters (1200) are pre-paid while large customers (commercial and industrial) and some residential electronic meters are read monthly. Meter reading, billing, and collection processes are mostly manual processes. Collection of the bills is lax which results in large amounts of receivables.

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 identify which transformers can be replaced loss reduction or because of overloading. It would be beneficial to add meters to the LV side to capture transformer loadings and identify theft or tampering issues. Current transformers (CT's) can be installed with the meters on the poles.

7. Other Issues

Power Generation: Most of the engines were running beyond the allowable maintenance intervals (major and minor overhaul). Not enough funds are available to buy parts or fuel to keep engines in running condition. Continuously buying new generating units without funds for maintenance is not a good alternative and will lead to the same situation.

Feeders, Transformers and Loads: As KAJUR has the majority of load supplied by two underground feeders (recently installed), one of the two feeders is extended through a long overhead feeder to a distant island and is in bad condition. There is no maintenance plan at KAJUR. 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 transformer conditions) is recommended.

Exhibit 12 shows the condition of a few tanks in Ebeye. They appear to be degrading so much that this site could become an environmental problem.

Exhibit 12: Condition of Tanks

8. Options for Improvements

8.1 Power System Improvements/Modifications

Technical losses are unavoidable. However, reducing them should continue to be an integral part of KAJUR's overall loss reduction strategy for the following reasons:

- Electricity rates will continue to increase with increasing fuel prices, which will change the cost-basis for evaluating many technical loss reduction related measures/programs.
- Electrical equipment connections that are corroded or loose can cause heating, which results in higher losses, leading to reliability concerns and safety issues.
- Reducing technical losses is controllable per the results of this study.
- Priority should be given to equipment purchases that lead to lower losses.

The cost of many of the projects/programs that reduce technical losses cannot be justified because of the large capital investment required. See calculations of costs and savings in appendix C. For these projects/programs, giving loss reduction benefits a proper weight when considering total life costs is a key to selecting those that will be most beneficial.

In addition to the above, loss reduction measures could be considered for implementation in the following two areas:

Secondary Circuits and Service Wires

KAJUR should consider using the GPS data collected for 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 in 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 a significant impact on overall loss reduction; e.g., using smaller sizes.

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

- Un-metered loads such as streetlights, illegal connections, etc.

- Unknown exact lengths of circuits/wires.
- Load patterns are difficult to obtain for each customer unless AMI (Advanced Metering Infrastructure) is deployed.

Nevertheless, creating such a GIS map will help KAJUR better estimate losses.

Regularly update loss-cost basis

The loss cost-basis used to estimate lifetime cost of losses should take electricity rate 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 projects. When rates are fast increasing, using current rates will greatly under estimate the life-time savings of reduced losses over a 15-20 year period.

As new equipment is installed and old equipment replaced, the loss-cost basis should be re-evaluated. Results can also be used to re-evaluate other large projects priorities.

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.

Optimize Distribution Transformers

The size of distribution transformers should be optimized. When the transformer sizes are reduced two levels from the existing level, over $30,000 per year can be saved on losses. As optimized sizes cannot be realized in a single year, a multi-year replacement program should be set up:

- Develop the load profile for each transformer and keep it updated once a year (a load profile for each distribution transformer implies a meter per distribution transformer will be needed, unless all customer loads connected to this transformer can be computed).
- Develop proper transformer sizes for each location.
- Optimize transformers that can be optimized without capital cost investment (i.e., by moving them to appropriate locations).
- Develop a new transformer purchase plan based upon the standard sizing, while looking at least lifetime costs which includes capital investment and losses. (See example of transformer evaluation example in Appendix C).

- Replace transformers during emergency (during emergency the utility workers are already occupied with the emergency itself) or during normal time based upon the replacement program.

Optimize Feeder Power Factor

The power factor of various sections of the feeders should be checked regularly (at least once a year) and actions should be taken to always keep it above 0.9, preferably 0.95. The best location to correct the power factor is at the loads, especially at induction motor terminals. 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 a power factor of at least 0.9. If they are found to be less and the customer does not improve it to the required level, KAJUR should charge a penalty and/or advise the customer to install capacitors to bring their power factor to that level. Metering and billing needs need to be coordinated with the tariff and/or low power factor penalty.

Optimize Feeder Reactive Power Compensation

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. Given the currently occurring high power factor level at the generation site feeder reactive power compensation is currently not needed.

In case the situation changes in the future and reactive power compensation measures need to be taken there are two areas that need to be considered:

1. Fixed and manually switched capacitors

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

The size of <u>fixed</u> 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.

The size of <u>switched</u> capacitors can 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 changes between two constant levels, then one large switched capacitor may be sufficient. This should be evaluated on a feeder-by-feeder basis. Determining sizes of switched capacitors requires further study, and more detailed information.

Capacitors also affect the voltage profile along a feeder. When determining capacitor sizes, in particular for switched capacitor banks, voltages should be verified to ensure voltage limits are not violated.

2. 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 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 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 operational procedures and plans for economic dispatch and monitoring of the performance of the plants and of individual generation units.

Reviewing the engine performance table in Section 6.1, the current metering in the power plant does not provide good coordinated readings. KEMA recommends that a first step should be to install revenue-class meters (energy, fuel and other supplies) to accurately measure the efficiency of each generator and to dispatch them based on efficiency considering other operating constraints. Focus on efficiency improvement (which requires training and implementation of processes for the operators) and real time display of engine efficiency helps the operators 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 available. The objective is to improve generator efficiency and reduce consumption in plant auxiliaries.

8.2.2 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 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 transformer, or through physically measuring the load by installing demand type meters on the secondary side of each transformer.

These meters can be installed while using current transformers (CT's) mounted on the pole or on the pad-mounted transformers. It is not necessary to install these meters on all distribution transformers. Areas which are experiencing more tampering, or where transformers seem to be overloaded or under loaded, may benefit from these installations. If customers are equipped with new digital meters and can be linked in a database or in the CIS to the distribution transformers, it may not be necessary to install these meters at the distribution transformers.

8.2.3 Strategy for Reduction of Non-Technical Losses

Considering there are 12.58% non-technical losses, there is potential of savings in this category.

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 operations, 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 like KAJUR implementation of a Revenue Assurance Department and implementation of Revenue Intelligence Software will require a large investment and may have a large organizational impact.

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

KAJUR 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: KAJUR's own experience may possibly 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 inspections, computer generated random daily target lists, and so on. This will help to identify these fraudsters and increase the deterrent effect.

- Prevent repeated 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 KAJUR'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 loss reduction programs, keeps records of progress, and reports to the General Manager.

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

Exhibit 13 is a summary for savings and potential cost over a 6 year implementation

Exhibit 13: Savings and Costs

	6 Yrs NPV of Savings and Cost		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Auxiliary loss	$41,893	$60,000	-$18,107
Non Technical Loss	$678,678	$291,406	$387,272
Technical Losses	$39,428	$264,970	-$225,542
Total =	$759,998	$616,376	$143,623
1% efficiency improvement in generation saves $17,810 per year based on the price of crude oil of $75 per barrel. At a price of $100 per barrel 1% efficiency improvement will amount to around $190,000 per year. This assumption can be influenced by fuel pricing effects related to creditworthiness of customers and transportation costs.			

A summary of assumptions and recommendations are below:

1. Costs (including fuel costs) will increase based on annual 3% inflation.
2. Cost of Capital is assumed to be 8%.
3. Emphasis should be placed on process improvements for economic dispatch of generators, design, purchasing, metering, billing, collection, and operations.
4. Technical and non-technical loss improvements will require investments totaling $643,000 over 6 years. Losses will be reduced from 15.36% to less than 6% (calculated value 5.71%).
5. With proper process improvements and investments of $60,000, it will be possible to provide real time data to operators for the power plant so that efficiency of generator auxiliaries will be improved to reduce usage to less than 4% (calculated value 3.97%).
6. Overall loss reduction objective is to reduce from 19.51% to below 12% 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 Non-Technical Losses

Account for monthly financial losses (i.e., street lights and unaccounted energy by water and sewerage facilities and KAJUR offices).

Develop a regular meter testing program. Add new meters (120) to the secondary sides of transformers and feeders at key locations for measuring transformer loads and auditing customers.

Procure meter testing equipment and training to perform sample testing of meters as required. Replace meters found to be out of specification with new ones (pre-paid type). Make sure each customer is linked to the transformer and its meter (cost $82,000) in a software tool so that tampering and transformer loading can be easily monitored.

It is not necessary to install these meters on every distribution transformer. . It is not necessary to install meters on every distribution transformer. Areas experiencing excessive tampering and where loading profiles are known will be best locations. This can also be accomplished by CIS applications linking transformers to customer meters. For transformer load profiling, 10 to 20 temporary recording meters could be installed on the transformers and relocated as needed.

Installation on pole-mounted transformers can be accomplished by using current transformers.

Add Revenue Protection measures with high visibility reporting to the General Manager through the Revenue Assurance Officer, with a focus on metering and billing policies and goals, audits of meter reading practices, of meter reading data processing and billing processes, of irregularities detected by revenue intelligence software and/or in the field, metering installations, meter accuracy, meter constants, multiplier factors, and tampering.

After year 1, 5% of non-technical losses will be saved; after year 6, 75%. Non-technical losses will reduce to 4.88% (i.e., achieving 893MWh from 2,610MWh in 6 years). Savings in 6 years is expected to be $930,000 resulting in an NPV of $678.678.

9.1.2 Reduction of Generation Auxiliary Losses

When generating units are operating, they need fans, radiators, pumps and other equipment for auxiliary services. Manual processes to operate these equipments depend on having good procedures, but these procedures need to be designed to place focus on saving energy.

- Add instrumentation and displays to show efficiency to operators for every generating unit (Cost $60,000). Develop a process to measure the efficiency of each generator and develop management reporting on generation efficiency.

- 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.

- Automate manual processes through application of PLC control to the motor starters (cost not included).

- Apply Frequency Drives where ever needed (cost not included).

Benefits from these actions are expected to be $57,000 over 6 years. Savings are produced by reducing auxiliary losses from 5,10MWh to 503MWh per year in 6 years. (See spreadsheet Savings Model tab in Appendix C).

9.1.3 Reduction of Technical Losses

In KAJUR's case, as far as losses are concerned there is not too much savings to be gained from modifying the system. As distribution transformers seem to be loaded around 35% of their full capacity, there could be some savings from loss reduction by optimizing them with proper sizes. This could be done over a number of years as new transformers are purchased.

1. Power Factor Improvement

The power factor of KAJUR is reasonable but it needs to be watched and a process should be developed to evaluate it annually.

- Determine power factors at 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 if improvements are not realized (working with MEC staff if assistance is required).

- Use distribution planning (may require training in software use) and add capacitors to improve power factor if required

- Determine optimum locations in feeders where capacitors can be placed to improve overall power factor above 95% and reduce losses. Make sure that a monitoring plan is part of this program.

Cost of adding capacitors and training in planning of distribution is estimated to be $80,000.

2. Transformer Sizing

- Determine proper sizes and specifications of the distribution transformers needed for the loads to be served.

- After determining correct sizes of the distribution transformers determine the standard sizes and relocate to rationalize and optimize sizes such that they are at least 80% loaded at maximum demand.

- Exchange or replace with right size transformers over a 6-year period. Transformers purchases should consider total life time cost. For example, cost of 1kW of core losses for 20 years of transformer life at 20 cents per kWh of fuel cost (based on $ 3 per gallon of fuel) is $21,476 (NPV). Copper losses would be $ 11,747. These figures must be taken into account when evaluating bids for new transformers. (See example of transformer evaluation in Appendix 3).

Cost of right sizing of transformers is estimated to be $200,000.

3. Reduce Line Losses

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 for energy savings by regularly identifying these maintenance issues and taking proactive corrective measures.

9.1.4 Net Present Value Calculations

Exhibit 14: Present Value Calculations

Assumptions:				
Inflation	3%			
Cost of Capital	8.00%			
Cost/KWh	$0.27			
Cost and Savings list	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**	**Cash over 6 years**
Non-Technical Savings:				
Metering updates		$134,141		-$148,243
Revenue Protection Department Software & Training		$157,265		-$175,000
75% loss reduction over 6 years	$678,678		$387,272	
Technical Loss Savings:				
Infrascan camera and training	Use MEC	$0		$0
Right sizing the transformers		$198,728		-$240,000
Capacitors & Training for planning		$66,243		-$80,000
Analysis Software (EZ Power)	Use MEC			
30% loss reduction over 6 years	$39,428		-$225,542	
Auxiliary Losses				
Data Acquisition for Generators and Auxiliaries	$41,893	$60,000	-$18,107	-$60,000
Total =	$759,998	$616,376	$143,623	-$703,243

Note 1 – Detailed calculation of these numbers is provided in the Appendix C file called Technical Loss Calculations and Financial Model for Options to Decrease Losses

Note 2 – Reviewing the figures in the table above it shows that costs of reducing technical losses cannot be justified by savings. KAJUR's technical losses are already very low, 2.88%, resulting in KAJUR belonging to world's "best in class". Non-technical losses are much higher and combating those losses will be worthwhile. Measures for reducing auxiliary losses cannot be justified at the current fuel price level but, will be worthwhile if crude oil prices reach higher values of US$100 per barrel.

For these reasons focus should be on reducing non-technical losses and taking low cost measures in reducing technical losses, such as looking for hot spots with an infrared camera, looking for lower sized distribution transformers in cases of replacement or if possibilities occur to move transformers to other locations. For the auxiliary losses, an energy efficiency program needs to be setup for the power plant, for example by using pumps and fans as optimal as possible.

Regarding generation efficiency: only two engines were operable during our visit. Not the generation efficiency but reliability and availability of engines (and maintenance of the engines) are the key priorities for KAJUR. If overhaul and refurbishment of generators cannot be performed due to a lack of funding, optimization of the generation efficiency is not possible except by dispatching the engines as efficient as possible.

Other Recommendations:

- Develop a maintenance management program and written operational processes to repair and maintain the transmission and distribution systems and provide related linemen training.
- Maintenance funding needs to be provided for power plants as well as distribution operations in order to keep up the efficiency and reliability.
- The feeder from Ebeye to Gugeegue serves little load and needs to be analyzed for providing reliable service. Changing it for loss improvement cannot be justified.

Appendix A: Appendix Data Request

Appendix B: Data Book and One Line Model

DATA BOOK

ONE LINE DIAGRAM

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

TECHNICAL LOSS CALCULATIONS

FINANCIAL MODEL

TRANSFORMER EVALUATION EXAMPLE