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

Kosrae Utility Authority (KUA)
Ordered by the Pacific Power Association (PPA)

Prepared by KEMA Inc.
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Experience you can trust.

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1. Executive Summary

KEMA's analysis of Kosrae Utility Authority (KUA) power system determined total losses of 16.74% consisting of:

- 4.98% in power station auxiliaries (station losses), which is a reasonable percentage, however there is potential for reducing of these losses
- 2.58% in street lighting. Street lighting should be accounted for and billed. If revenues cannot be collected the street lighting should be considered a financial loss and not a power system loss).
- 5.91% in technical losses.
- 3.27% in non-technical loss.

Technical and non-technical losses total 9.18%.

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. Develop a generator dispatching routine to provide highest efficiency operation.
3. Provide power plant operators with training on load forecasting and economic dispatch of generating units. Include an economic dispatch module in future SCADA system plans.
4. 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 $50,000 over 6 years)

B. Distribution

1. Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime cost (costs of capital, losses and maintenance). For example, cost of 1kW of core losses for 20 years at 24 cents per kWh of fuel cost (based on $3.50 per gallon of fuel) is $26,210 (NPV), and copper losses can be $14,337 dependent on the load patterns. These figures should be taken into account when evaluating bids for new transformers.

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

3. Add capacitors near the load centers so that overall power factor is above 0.95. They should be in addition to asking large load customers to improve their power factor above 0.85.

4. 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 is $75,000 over 6 years)

C. Metering, Billing and Collection:

1. Staff a Revenue Protection Department or empower a Revenue Assurance Officer to form a group responsible for reducing non-technical losses, who will execute a revenue assurance program that includes regular and un-announced program audits.

2. Add revenue-class meters to the feeders and distribution transformers to measure the losses. Use these meters to check total consumption connected to the individual transformers. If the meters are tied to transformers in CIS, these meters may not be needed. Transformers do not need these meters, only where the need for determining the transformer load is identified due to excessive suspected tampering or other irregularities. To measure transformer load patterns, 10 to 20 temporary recording meters could be temporarily installed and rotated.

3. Most meters are prepaid but the accuracy cannot be assured and problems with tokens have been identified. Develop a testing program and maintain these meters to the revenue-class accuracy (cost not included).

(Total cost of these initiatives is $84,000 over 6 years)

Recommended measures and actions will cost $200,000 over a 4-to-6 year period, resulting in an estimated savings of $270,000 (NPV of $200,000) and reduction of:

- 4% in overall losses
- Savings of $15,000 per year can be obtained for every 1% improvement in generation efficiency.

Total savings and costs for all loss reduction measures are summarized in the table below.

	6 Yrs NPV of Savings and Costs		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Technical Losses	$86,606	$75,000	$11,606
Auxiliary loss	$54,046	$50,000	$4,046
Non Technical Loss	$53,590	$44,500	$9,091
Total =	$194,243	$169,500	$24,743
1% efficiency improvement in generation saves around $15,000 per year based on the price of crude oil being $75 per barrel. At a price of $100 per barrel the saving of 1% efficiency improvement increases to $20,000 per year. This assumption can be influenced by fuel pricing effects related to credit worthiness of customers and transportation costs.			

2. Introduction

2.1 Project Objectives

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

Project objectives and deliverables:

1. Quantify energy losses in the power system.
2. Prepare an Electrical Data Handbook containing 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 losses.
5. Identify sources of non-technical losses.
6. Recommend strategies for reducing technical and non-technical losses.

Attention will also be paid to non-technical losses and recommendations made to reduce these losses. This report is covering the results of this study at KUA, Kosrae.

2.2 Quantification of Losses

Losses through the KUA system consist of power station losses and distribution system losses. Both loss categories are quantified.

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

- Technical losses: Summation of transformer core losses, transformer copper losses, 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 consumption that is not billed should be considered a financial loss rather than a non-technical loss.

3. Data Gathering and Assessment of Current Situation

Data gathering process is to collect existing information and understand the current situation of the generation, transmission, and distribution systems. KEMA visited the power plant and electrical distribution facilities, including the power plant substation, mid-line breakers, distribution transformers, and overhead feeders.

3.1 The KUA Power System

KUA operates one power plant containing 6 diesel engines. Engines 2 and 7 are out of service. Engine 7 is waiting for a new stator winding while engine 2 needs a new cooling system and top-end overhaul. Although the system can still satisfy n-1 reliability conditions, the chance of losing another engine grows if no funding can be made available for maintenance. The system peak load of 1.1 MW can be supplied most efficiently through a proposed new engine 9 with a capacity of 1.2 MW. This would require an all inclusive funding of $1.7 M.

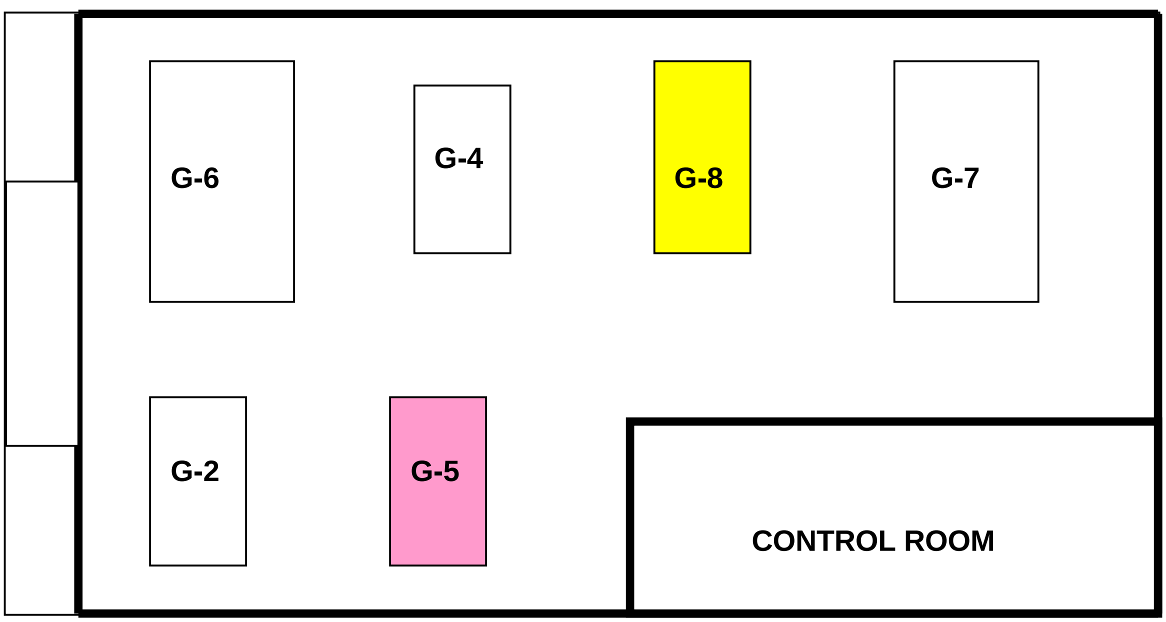
Due to a funding shortage, the last major overhaul was performed for Unit 6 in 2006. KUA's system also has 50 kW of solar power connected to the grid.

Kosrae Data on Generating Units

Legend: (see the layout drawing at the next page)

G-2 CATERPILLAR DIESEL GENERATOR, 750 kW, 4160 V, 3 PHASE, CAT 3508 IC
G-5 CATERPILLAR DIESEL GENERATOR, 750 kW, 4160 V, 3 PHASE, CAT 398 IC
G-4 CATERPILLAR DIESEL GENARATOR, 750 kW, 4160 V, 3 PHASE, CAT 398 IC
G-6 CATERPILLAR DIESEL GENARATOR, 1500 kW, 4160 V, 3 PHASE, CAT 3606 IC
G-7 CATERPILLAR DIESEL GENERATOR, 1650 kW, 4160 V, 3 PHASE, CAT 3606 IC
G-8 CATERPILLAR DIESEL GENERATOR, 1050 kW, 4160 V, 3 PHASE, CAT 3512 IC

Units 2 and 7 are not operational.



SCHEMATIC LAYOUT OF KOSRAE UTILITY AUTHORITY POWER PLANT

From the power station, three 13.8 kV feeders supply power to villages and clients.

Customers are served at 240/120V and 208/120V with 232 distribution transformers. If requested, and transformers are available, 480/277V can be provided.

The system peak load is 1.1 MW and average load factor is below 0.59.

3.2 KEMA Data Request

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

3.3 Data Received

KUA provided a portion of the data prior to on-site meetings, which helped to facilitate the meetings.

3.4 Site visit

Additional data was gathered during the site visit of April 2010. Remaining data was forwarded after the meetings. All data collected is the Electrical Data Handbook of Appendix B.

Data collected:

1. One line diagram
2. Generator energy production logs including fuel used
3. Substation and Transformer data
4. Distribution Feeders' sizes and lengths
5. Metering Information

Customers: 1842.

LOAD: Peak load is 1.1 MW with an average load of 650 kW. power factor is 0.93.

Generators: There is one power plant. Specific data is listed in the Data Handbook (Appendix B). All engines use diesel fuel.

Transformers: There are 232 single-phase pole and three-phase pad transformers.

There are 2 step-up substation transformers, each 2.5 MVA, 4.16 kV to 13.8 kV, used to connect generation units to the 13.8 kV distribution system.

Aerial Feeders: Distribution feeders at 13.8 kV look to be in good condition. For some feeders, it is recommended connectors and clamps be checked with infrared cameras to identify hot spots and identify conductors with corrosion problems.

Capacitors: No capacitors are currently installed.

Meters –80% of meters are prepaid and managed through a system called Cash Power. There is no test facility for meters. By a customer request, meters can be individually tested. KUA is aggressive at trying to find meter tampering and by-passing, but very few irregularities are found. KUA plans to standardize on prepaid meters. Generator and feeder meters are not revenue class-meters.

Billing and Collection Processes: Meter reading and billing is done monthly, making use of a CIS (Customer Information System). The CIS raises red flags in case of irregularities, such as much lower than usual usage.

Reliability: T&D Maintenance: Time-based maintenance is performed in the substations. For lines, there is a tree trimming schedule. An overall maintenance management program covering all maintenance activities (e.g., regular power transformer oil sampling) is not in place.

4. Grid Model and Calculation of Technical Losses

4.1 Estimates and Assumptions for Missing Data

To quantify losses, the following assumptions were made:

1. The averaged power output over the past year (2009) was used for annual energy consumption.

2. A typical value for power transformer no-load and full load losses literature[1] was used for the transformer loss estimation.

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 average customer consumption rates.

4. Loads were distributed based on distribution transformer location. Exact location of load was not known.

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

6. Load was allocated proportionally to the kVA capacities of the distribution transformers.

7. 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

Power plant and primary feeders of the distribution system in Kosrae were modeled in Easy Power. Feeder lengths and connected loads were identified based on the one line diagram and data provided by KUA. Generators and power transformers were modeled based on data provided response to the data request. Losses through the primary feeders and power transformers were calculated in a power flow study. Peak loads were estimated from the sold

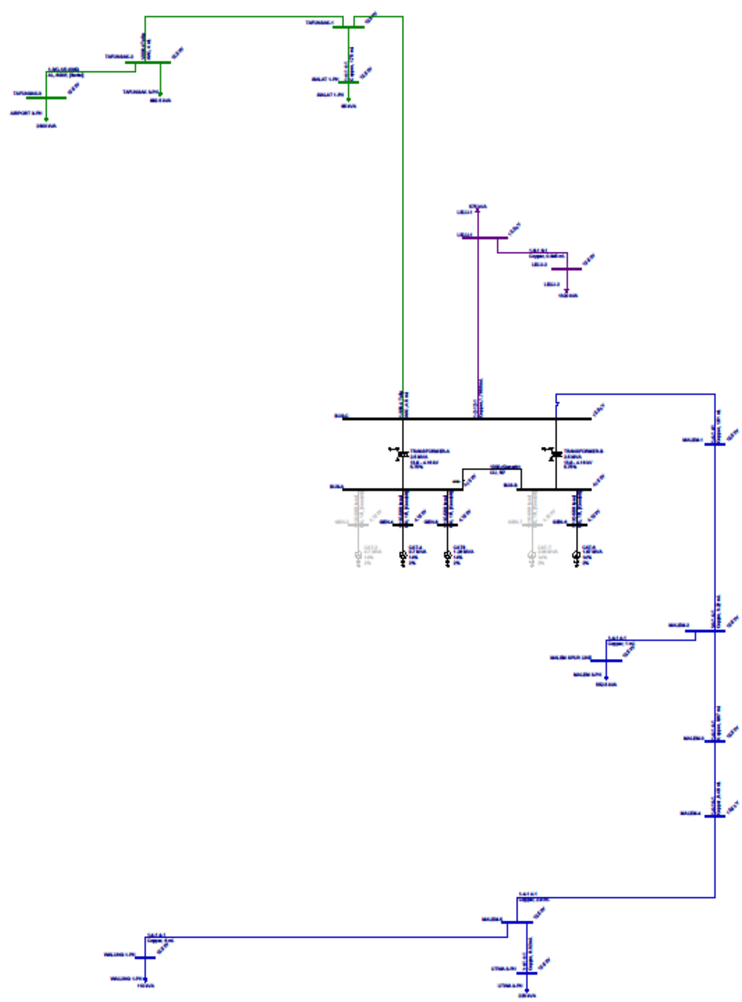
[1] [1] Electric Power Distribution System Engineering, by Turan Gonen

kWh to customers and generation data collected from the power plant. Since distribution transformers are not associated with customer meters, load allocation was based on transformer sizes for each of the feeders.

The system one-line diagram is shown in Exhibit 4-1.

Exhibit 4-1: Kosrae One Line Model

(For large copy see Appendix B)



4.3 System Loss Estimation

System losses consist of technical and non-technical losses.

Technical losses: The sum of losses in several grid parts: primary feeders, 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 (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.

Non-technical losses: The difference between total grid losses and technical losses (e.g., the total energy entering the system from the power plants minus total energy sold.

For KUA, the unbilled energy usage came from for street lights.

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

Exhibit 4-2: Loss Estimation

	MWh	% of generation	% of system consumption
Annual generation	6,022		
Annual station auxiliary usage	300	4.98%	
annual system consumption	5,722	95.02%	100.00%
Annual energy sold w/o street lights	5,014	83.26%	87.62%
Unbilled usage / street lights	156	2.58%	2.72%
System loss	553	9.18%	9.66%
Technical loss	356	5.91%	6.22%
Non technical loss	197	3.27%	3.44%

5. Electrical Data Handbook

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

The Handbook can be found in Appendix B.

6. Analysis of Efficiencies and Losses

6.1 Generation Efficiency

Generator data are listed in Exhibit 6-1.

Exhibit 6-1: KUA Generation

NAME	TO BUS	kV	TYPE	MVA	POWER FACTOR	kWh / Gal	RPM	MODEL	MW	MVAr	FUEL	GOVERNER TYPE
CAT 2	A	4.16	IND	0.7	0.9	12	1200	D 398	0.56	0.26	D	2301 A Elect. Gov
CAT 4	A	4.16	IND	0.7	0.9	12	1200	D 398	0.56	0.26	D	Woodward U-8
CAT 6	B	4.16	IND	1.87	0.93	13	900	CAT 3600	1.5	0.21	D	2301 A Elect. Gov
CAT 7	B	4.16	IND	2.06	0.92	13	900	CAT 3600	1.65	0.59	D	2301 A Elect. Gov
CAT 8	A	4.16	IND	1.26	0.92	15	1200	CAT 3512B	1.01	0.36	D	Electronic

Operational status of KUA generators are listed in Exhibit 6-2.

Exhibit 6-2: KUA Generation Operation Status

UNIT NO.	NAMEPLATE	FIRM CAP.	YEAR INSTALLED	STATUS	REMARKS
G-2	750 kW	580 kW	1980	INOPERATIONAL	FOR REPAIR
G-5	750 kW	580 kW	1984	INOPERATIONAL	FOR REPLACEMENT
G-4	750 kW	580 kW	1984	OPERATIONAL	STAND BY / BACK UP SERVICE
G-6	1500 kW	1500 kW	1990	OPERATIONAL	ON STAND BY
G-7	1650 kW	1650 kW	1996	INOPERATIONAL	FOR REPAIR OF GENERATOR & OVERHAUL
G-8	1050 kW	1050 kW	2007	OPERATIONAL	IN SERVICE

KUA generation production kWh data for calendar year 2009 are listed in Exhibit 6-3.

Exhibit 6-3: KUA Generation kWh Production for Calendar Year 2009

MONTH	GEN 6	GEN 7	GEN 2	GEN 8	GEN 4	TOTAL
JANUARY	277,326			222,682	870	500,878
FEBRUARY				465,912	3,725	469,637
MARCH	1,174			507,876	920	509,970
APRIL	10,904			488,069	1,050	500,023
MAY	315,774	UNITS FOR REPAIR		198,365	1,203	515,342
JUNE	492,138			7,676	1,929	501,743
JULY	499,710			0	19,967	519,677
AUGUST	520,670			550	20,955	542,175
SEPTEMBER	390,930			115,882	21,508	528,320
OCTOBER	0			528,239	21,404	549,643
NOVEMBER	429,680			86,017	9,251	524,948
DECEMBER	534,586				10,168	544,754
Annual Total	3,472,892			2,621,268	112,948	6,207,108
Total						6,207,108

Individual generator efficiencies vary from 12 to 15 kWh / Gal. When the kWh supplied by each generator in calendar year of 2009 was checked, an overall efficiency of 13.75 kWh/ Gal resulted, as shown in Exhibit 6-4.

Exhibit 6-4: KUA Generation Efficiency for Calendar Year 2009

GEN #	kWh	kWh / gal	Gals
4	112,948	12	9,412
6	3,472,892	13	267,146
8	2,621,268	15	174,751
Combined	6,207,108	13.75	451,309

KUA has requested DOI funding to replace generator no. 5 with a 1.2 MW unit that can supply total island load at a better efficiency. If the efficiency increases by 10%, this will save KUA $ 150,000 on fuel costs per year. Payback time will however be longer than 15 years. KUA is also waiting for DOI funding to conduct needed generation maintenance actions.

6.1.1 Power Plant Usage, Station Losses

Station losses are reported to be 4.98%. While typical, this can be improved. Revenue-class meters are not used which implies real usage value might be different than reported.

Losses in plant auxiliaries can be minimized by paying close attention to the operation of fans, radiators, lights, etc.

6.2 Technical Losses

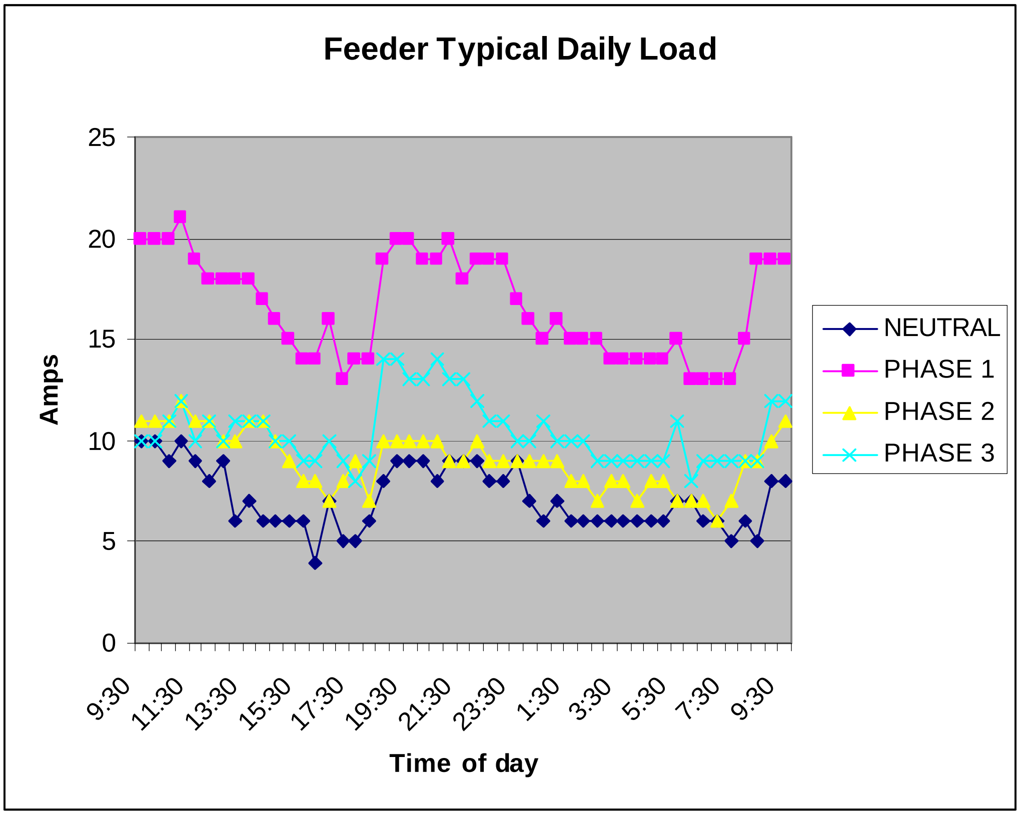
Technical Losses			
Type of Losses	Sub Total MWh	MWh	
Dist Transformer Core	235		
Dist Transformer Cu	10	245	70%
Secondary wires	26		
Wires	39	65	18%
Power Transf Cu	5	45	13%
Power Transf core	40		
Total =	355	355	
Core Losses Alone	275		78%

The above table illustrates demonstrates out of the total calculated technical losses, transformer losses account for the majority of them (83%). Wire losses are 18%. Of the transformer losses of 294MWh, core losses are the major component (95%).

6.2.1 Distribution Line Losses

Line losses in secondary service wires (13.8 kV overhead lines and feeder wires) are about 62 MWh and represent 18% of the total technical losses. It is estimated 7.1% (25 MWh) of the total technical losses are from low voltage service wires. These losses are relatively low when compared to other utilities.

Reasons for the low losses are high power factors (0.93) and relatively low loads compared to the wire sizes.



Line losses are due to wire resistance, which is inversely proportional to the size and type of conductor.

Even though the power factor is 93%, it can still be improved to lower the losses.

Another issue is unbalance in the three phases of the feeders (ignored in calculations), resulting in a current flow on the neutral wire, causing higher copper 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 if 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 KUA, total losses from distribution and power transformers are estimated to be 294 MWh per year. 275 MWh are core losses, and 18 MWh are copper losses.

The ratings of these transformers (the average load is calculated to be around 35% of the installed distribution transformer nameplate rating – assuming the transformer ratings are at least equivalent to connected loads) may be too large for the load, 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 KUA is using only 19% of the total installed capacity in a year (estimated at equivalent to the connected load) there is room to decrease these losses. Lowering distribution transformer ratings by one size will reduce losses by 20%; two lower sizes will reduce losses by 30%. The second option (two sizes lower) will load transformers to 40% to 50% of the maximum system load of 1,100 kW.

6.3 Non-Technical Losses

3.27% of the energy delivered to the distribution system from generating units is classified as non-technical losses

- Not accounting for all energy used by KUA offices, stores, or workshops.
- Identifying energy theft 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 not tested and not working properly
- The non prepaid meters are old and not working properly
- No regular procedure to check the meter multipliers and other data in the billing system
- Organizationally, no person assigned to develop and execute a loss reduction strategy and who is responsible for loss reduction

KUA has focused its attention to the reduction of the losses. The program to install prepaid meters will help the situation.

6.3.1 Metering Losses

Most customer meters are electronic meters (prepaid). They have not been calibrated or tested for as long as they are in service. Meters used for generator outputs, main feeders, and auxiliaries are not revenue-class. Meters do not record maximum demand.

Processes: Most of the meters (1,842) are not read monthly as they are prepaid meters. Meter reading, billing, and collection processes are manual processes. Bill collection is not optimal, resulting in excessive amounts of receivables.

Losses caused by metering and billing are part of the overall non-technical losses and should be identified and quantified further.

Customer meters should be tied to transformers, preferably through a Geographical Information System (GIS) in CIS (Customer Information System). Every year analyses should be performed to see which transformers can be replaced for loss reduction or overloading issues. It would be beneficial to add meters to the LV side to capture the 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). Funding to buy parts and fuel was not available.

The technical health of the utility will depend on enough revenues being collected to cover maintenance costs. A cost of service study would quantify what tariffs would be necessary for to be self sustainable. The gap between existing and desired conditions will become clear and measures can be taken to fill the gap (tariff increase, subsidies, securing some amount of grants per year, etc).

Feeders, Transformers and Loads: Developing a regular maintenance programs for transformers, feeders, and cables is needed. Performing regular infrared scans (to identify hot spots and unnecessary technical losses) and oil testing (for monitoring transformer conditions for reliability reasons) is recommended.

Meters need to be regularly tested to ensure revenue-class results. Develop processes for managing collection, checking billing constants, checking meter installations, and other measures for reducing non-technical losses.

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 KUA's overall loss reduction for the following reasons:

- Electricity rates will continue to increase, which has changed and will constantly change the cost-basis for evaluating technical loss reduction related measures/programs
- Electrical equipment connections that are 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.

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.

Determining the accurate amount of technical losses is important to a loss-reduction program, for determining best investments and progress. Installing meters on distribution transformers and keeping the digital system model up to date are important measures.

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

Secondary circuits and service wires

KUA should consider using a targeted feeder 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
- The load patterns are difficult to obtain for each customer unless AMI (Advanced Metering Infrastructure) is deployed

Creating such a GIS map will help KUA better estimate losses.

Regularly Update Loss Cost-Basis

The loss cost-basis used to estimate lifetime cost of losses should take electricity rates into account. When rates are increasing at a slow pace, it may be acceptable to use current rates to calculate projected savings of any technical losses over life spans of equipment (e.g. transformers) and other system parts. When rates are fast increasing, using current rates will greatly under estimate the lifetime 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 evaluated. Results can also be used to re-evaluate other large projects priorities.

Once a new loss-cost basis is established, it should be applied to new equipment purchases immediately, such as pad-mounted and pole-mounted transformers. This will help to bring in immediate results without additional costs.

The new loss-cost basis should also be used to re-evaluate projects/programs that can provide technical loss reductions in order to select the most beneficial programs.

Optimize Distribution Transformers

Sizes of distribution transformers should be optimized. When the transformer sizes are reduced two levels (40% to 50% of the sum of kVA's of distribution transformers) from the existing level, close to $20,000 per year in core loss savings can be realized. As optimized sizes cannot be realized in a single year, a multi-year 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 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 locations).

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

Optimize Feeder Power Factors

The power factor of feeders should be checked regularly (at least once a year) and actions 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 power factor of at least 0.9. If less the customer does not improve to the required level, KUA 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:

1. **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 <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.

The size of switched 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 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.

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 used 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 capacitors are on line when they are most needed.

- Kilo VAr Control: This control operates in response to changes in the power 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 plant and of individual generation units.

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

Individual generator efficiency varies from 12 to 15 kWh/Gal and the overall efficiency of the generating plant was 13.75 kWh/Gal. Every 1% increase of efficiency saves $15,000 a year. As mentioned before KUA has requested DOI funding to replace generator no. 5 with a 1.2 MW unit that can supply the total island load at a better efficiency. If the efficiency increases this way with 10% this will save KUA $ 150,000 on fuel costs per year. Payback time will however be longer than 15 years.

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.

Meters to measure generator output, auxiliary services, and feeder output need to be revenue-class.

Methodologies should be developed to measure distribution transformer load profile 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.

These meters can be installed 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 experiencing more tampering, or where transformers seem to be overloaded or under-loaded will benefit most. If customers are equipped with new digital meters, and can be linked in a database or in the CIS to the distribution transformers, it is not necessary to install meters at the distribution transformers.

8.2.3 Strategy for reduction of non-technical losses

Considering there are 3.27% of non-technical losses there are 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 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.

KUA should consider the following:

- Develop a program for checking old meters.
- Train meter readers to identify tampering, by-passing, broken seals, hookups.
- Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplying factors, tariff categories applied to customers, functioning of red flags in the case of irregularities) and non-technical loss causes found by meter readers such as meter tampering or by-passing.
- 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 of and hit rates will be the most efficient use of limited resources.
- Make operations less predictable. KUA'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 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 KUA'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

A summary of savings and potential costs a 6-year implementation is below.

	6 Yrs NPV of Savings and Cost Summary		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Technical Losses	$86,606	$75,000	$11,606
Auxiliary loss	$54,046	$50,000	$4,046
Non Technical Loss	$53,590	$44,500	$9,091
Total =	$194,243	$169,500	$24,743
1% efficiency improvement in generation saves $15,000 per year based on the price of crude oil being $75 per barrel. At a price of $ 100 per barrel 1% efficiency improvement translates to $20,000 per year in savings. This assumption can be influenced by fuel pricing, creditworthiness of customers, and transportation costs.			

A summary of assumptions and recommendations follows: (Details are provided in Section 8.1)

1. An inflation of 3% every year was assumed.

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. Technical and non-technical loss improvements will require investments totaling $159,000 over 6 years. Losses will be reduced from 9.18% to less than 6%.

5. With process improvements and a $50,000 investment, it is possible to obtain real-time generator efficiency data for operator use. It is expected generator auxiliaries losses can be reduced to almost 4% (calculated value 4.18%).

6. Unaccounted and unbilled lighting loss (2.58%) should be classified a financial loss. The policy should be changed to recover the cost of supplying this service. Other island utilities are changing to LED lights to reduce losses with funding coming from

international grants. This unaccounted portion for energy loss can be reduced to less than 1%.

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 are loaded to 19% of full capacity. Loss reduction savings can be achieved by optimizing the ratings over a number of years as new transformers are purchased.

1) Transformer Sizing

    a. Determine proper sizes and specifications of distribution transformers to better match served loads.

    b. Determine standard sizes and relocate such that each transformer is 80% loaded at maximum demand.

    c. Replace with right size transformers for the specific application. Transformers purchases should consider total cost (including NPV calculation of losses). For example, the cost of 1 kW of core losses for 20 years of a transformer's life at 24 cents per kWh of fuel cost (based on $ 3.50 per gallon of fuel) is $26,210 (NPV). For copper losses, the NPV is dependent on the transformer loading and is estimated to be $ 14,337. These figures must be taken into account when evaluating bids for new transformers. (An example of transformer evaluation is provided in Appendix C).

2) Reduce Line Losses

    a. Acquire an infrared scan camera and train to use. (Cost of equipment and training is $75,000).

Using an infrared scan camera is a necessary tool for identifying distribution loss issues. An infrared camera will not save any losses; it has to be used to prioritize the work of maintenance and upgrading of feeders. There is a potential energy savings of approximately 0.5% to 1% by improving the system.

Technical losses can be reduced from 5.91% to 3.68% in 6 years through process improvements for an estimated savings of $122,000. If transformer meters are installed, KUA can better determine which transformers need to be replaced to reduce core losses. New purchases should consider lifetime costs to help reduce losses over time.

3) Power Factor Improvement

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

a. Determine power factors of largest customers and require them to improve it over 85% or improve it for them and charge it to customers. This may require penalties or tariff changes. Add capacitors to improve the power factor. (Funding will be available from customers whose power factors are low)

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

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

Reduce the unbalance in the three feeder phases. Phase connections of single-phase transformers should be investigated to reach a better balance.

9.1.2 Reduction of Generation Auxiliary Losses

When generating units are operating, they need fans, pumps and other auxiliary equipment. Manual processes to operate these fans depend upon having good procedures, but these procedures need to be designed with a focus on saving energy.

Improvement measures could include:

1. For every generating unit, add instrumentation to show efficiencies to operators (cost $50,000). 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 (cost not included as cannot be justified from savings of losses).

4. Apply Frequency Drives (cost cannot be justified from savings).

Benefits from these actions are expected to be $74,000 over 6 years. Savings are produced by reducing auxiliary losses from 300 MWh to 240 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 a transformer and its meter (cost $84,000). Software can be used to identify tampering and transformer loading issues.

It is not necessary to install meters on every distribution transformer. Target locations should include suspected tampering and sites where operations need to know transformer loading profiles. For transformer load profiling use, 20 meters could be temporarily installed on transformers and relocated as needed.

Add Revenue Protection measures as decided in Chapter 8.2.4.

These measures are expected to save 5% of non-technical losses in the first year and 40% after 6 years. Non-technical losses will be reduced by 90 MWh per year, with a savings of $75,000 in 6 years, resulting in a NPV of $53,590.

9.1.4 Improving generator efficiencies

Each 1% efficiency increase will result annual fuel savings of $15,000. The current performance of 13.75 kWh/gal as calculated for the year 2009 presents an opportunity to improve by 5% by optimizing generation dispatching and will save $75,000 (fuel efficiency increase from 13.75 kWh/gal to an average of 14.33 kWh/gal). If new generators are purchased, funds must be available to keep running at high efficiency. Purchasing a new 1.2 MW generator ($1.7 million) cannot be justified from savings alone as the payback will be more than 15 years, assuming an efficiency of 15 kWh / gal.

9.1.5 Net Present Value Calculations

Exhibit 9-1: 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**
Technical Loss Savings:				
Infra red camera and training		$75,000		-$75,000
30% loss reduction over 6 years	$86,606		$11,606	
Auxiliary Losses				
SCADA for generators and process improvement		$50,000		-$50,000
20% loss reduction over 6 years	$54,046		$4,046	
Non Technical Savings:				
Distribution Transformer Metering - 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.		$44,500		-$52,500
40% Non Technical Loss reduction over 6 years	$53,590		$9,091	
Total =	$194,243	$169,500	$24,743	-$177,500

(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 systems and provide related linemen training.

2. Maintenance funding should be provided for power plants as well as T&D operations in order to keep up the efficiency and reliability.

Appendix A – Data Request

See separate document KUA Appendices.zip

Appendix B – Data Book

See separate document KUA Appendices.zip

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

See separate document KUA Appendices.zip