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

Palau Public Utilities Corporation (PPUC)

Ordered by the Pacific Power Association (PPA)

Prepared by KEMA Inc.

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1. Executive Summary

KEMA's analysis of Palau Public Utilities Corporation (PPUC) power system determined total losses of 19.11% consisting of:

- 6.51% in power station auxiliaries (station losses), which is a relatively high amount of losses. Typically, station losses are lower than 5%.
- 0.76% in street lighting, which should be accounted for and billed. If these revenues cannot be collected, street lighting should be considered a financial loss and not a system loss.
- 7.57% in technical losses.
- 4.27% in non-technical loss.

Technical and non-technical losses total 11.84%.

Recommendations:

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

The following is a summary of savings and potential costs over a 6 year implementation period:

Exhibit 1-1: Savings and Cost

	6 Yrs NPV of Savings and Costs		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Technical Losses	$1,195,098	$592,568	$602,530
Auxiliary loss	$890,835	$350,000	$540,835
Non Technical Loss	$1,004,585	$920,467	$84,118
Total =	$3,090,518	$1,863,035	$1,227,483
Generator Efficiency improvement	1% improvement saves $186,000. Savings up to $2M per year may be reached after deployment of two new 5 MW generators and implementation of economic dispatch.		

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. Add instrumentation and displays to show generation efficiencies to operators (cost $350,000). Develop a process to measure the efficiency of each generator and develop management reporting process.

3. Train power plant operators on load forecasting and economic dispatch practices. Include an economic dispatch module in the SCADA system.

4. Develop a process to dispatch the Aimeliik and Malakal generators such that the least amount of energy flow across the tie line between Koror and Babeldaob islands.

5. Management of Aimeliik and Malakal generation can reduce technical losses and save $200,000 per year. One way is to use more efficient engines, and then dispatch them to minimize power flows through the 34.5 kV transmission line between Koror and Babeldaob islands.

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

7. 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.

8. Automate manual processes using PLC controls to monitor starters (cost not included – next step after process improvements, real time analysis and focus on energy consumption reduction is in place).

9. Apply Frequency Drives (cost not included)

Savings of $1.3 million per year can be realized by improving generation efficiency to 2008 levels from 13.22 to 14.14 kWh/gallon. Additional efficiency improvements will be possible after new 5 MW generators are put into service. Improvements could increase to 14.9 kWh/gallon bringing the savings to $ 2 M per year

Overall cost savings are expected to be $ 1.2 M over 6 years by reducing auxiliary losses from 5,286 MWh (6.51%) to 4,229 MWh (5.52%) – 1% reduction in 6 years. Total cost (recommendations 5, 6, and 7) is estimated to be $350,000.

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 10 years at 23 cents per kWh of fuel cost (based on $3 per gallon of fuel) is $15,012 (net present value). For copper losses the net present value is estimated to be $6,300. These figures should be taken into account when evaluating bids for new transformers. (A transformer evaluation example is provided in "Technical Loss Calculation and Financial Model" spreadsheet tab in Appendix C).

2. Use the appropriate size of the distribution transformers and optimize the sizes so that no-load losses are reduced.

3. Add revenue-class meters on feeders and distribution transformers to measure losses. Use these meters to check total loading on individual transformers. These meters can be avoided if customers are tied to specific distribution transformers in the Customer Information System. To reduce costs, meter only distribution transformers where there is an obvious need due to excessive tampering, by-passing, where total transformer loads are necessary. For transformer load profiling 50 to 100 recording meters could be temporarily installed and rotated. Transformer meter costs are included in Section C of this chapter.

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

5. Require large industrial and commercial customers to maintain power factor requirements above 85%. Install capacitors to other parts of the distribution system to maintain an overall power factor of the feeders and overall distribution system of above 95%

(Total cost of these initiatives is $700,000 over 6 years.)

C. Metering, Billing, and Collection

1. Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplier factors, tariff categories applied to customers, functioning of red flags in the case of irregularities and utilizing transformer meters in suspected area or initiating testing of meters and

connections) and non-technical loss causes found by meter readers, such as meter tampering or by-passing.

(Total cost of these initiatives is $1 million over 6 years.)

2. 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.

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 covers the study results for PPUC, Palau.

Project objectives and deliverables:

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

2.2 Quantification of Losses

Losses are due to:

1. Power station losses
2. Losses in the transmission system
3. Losses in the distribution system

All three categories are quantified below.

The following loss categories were identified.

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

- Technical losses: Summation of transformer core losses, transformer copper losses, transmission line losses, primary distribution feeder losses, and secondary wire losses. Technical losses will become higher as power factors drop below unity.

- Non-technical losses: Inaccurate meters, meter tampering or by-passing, theft, meter reading errors, irregularities with prepaid meters, administrative failures, and wrong multiplying factors.

- Unbilled Usages: Energy consumptions that is not billed should be accounted for and billed, or a financial loss rather than a non-technical loss. The unbilled usage is for street lighting.

3. Data Gathering and Assessment of Current Situation

Data gathering process is to collect existing information and understand the current situation of the generation, transmission, and distribution systems in Palau. KEMA visited Palau in February and March 2010 and conducted various meetings with management and staff. Physical inspection was selectively done of power plants and electrical distribution facilities, including transformer stations, mid-line breakers, distribution transformers, and overhead feeders.

3.1 The PPUC Power System

The main system is served by two diesel-fired power plants owned and operated by PPUC: the Malakal power station and the Aimeliik power station. There are also three relatively large grid connected solar systems (100 to 150 kW range).

In Appendix B as part of the Electric Data Handbook, generator and alternator data are provided.

PPUC has 5 locations where diesel engines are installed. Aimeliik and Malakal have the 12 largest engines ranging from 1,250 kW to 3,400 kW. Other power plant locations have 8 smaller generators ranging from 100 kW to 750 kW, serving isolated systems on remote islands. In the Malakal power plant two refurbished engines with a production capacity of 5 MW each are to be installed in 2010.

The power grid consists of a 34.5 kV transmission system. The power plant connection between Malakal and Aimeliik is an important backbone. The distribution system is operated at a 13.8 kV. In the Malakal area the system has facilities for creating feeder loops.

Customers are served at 240/120V, 208/120V or 480/277V through approximately 1000 distribution transformers. The system peak load is 14.9 MW with an average load factor below approximately 0.62. The maximum load dropped in 2009, resulting in a decrease of the average load factor from about 0.73 to 0.62.

3.2 KEMA Data Request

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

3.3 Data Received

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

3.4 Site Visits

Additional data was gathered during the site visits of February and March 2010. Remaining data was forwarded after the meetings. (All data collected is in Data Handbook of Appendix B.)

Data collected included:

1. One Line Diagram
2. Generator energy production logs including fuel and lube-oil used
3. Substation and Transformer data
4. Transmission Lines' and Distribution Feeders' sizes and lengths
5. Metering Information

Load: Peak load is 14.9 MW with an average load of 9.3 MW. Maximum load has been dropping over the years due to decreased industrial activities. Overall power factor is 0.89.

Generators: Data for the two major power plants at Malakal and Aimeliik, along with three smaller units at remote islands, are listed in the Electrical Data Handbook (Appendix B). Two refurbished generating units (5 MW each) from Japan, manufactured by Niigata, are to be installed at Malakal in 2010.

Transformers: There are single-phase and three-phase pole-top transformers commercial customers have their own pad-mounted transformers.

There are 28 power plant and substation transformers varying in size (maximum size is 10 MVA). Load tap changers for two substation transformers were not functioning automatically; manual operation was required. Oil samples of older power transformers have not been taken for condition assessments.

Distribution transformers are connected to 13.8 kV feeders and are generally 50% loaded.

Aerial and Underground Transmission Lines and Feeders: The transmission system is at a voltage level of 34.5 kV and the distribution system voltage is 13.8 kV. Most lines and feeders look to be in good condition. A 34.5 kV submarine cable has been installed between the islands of Koror and Babeldaob.

Pictures of typical lines and substations are included in Appendix D.

Capacitors: There are no installable capacitors but a number has been ordered for 34.5 kV and 13.8 kV application. (See Section 4.4 for additional details).

Meters: – There is a population of aging electromechanical meters, which are being replaced at a slow pace. There is a limited meter test facility. Meters are tested by customer request. During site visits broken seals were identified. PPUC is quick to find meter tampering and by-passing. Monthly, irregularities are found. The re-connection fee is $75.

Most self generators (like hotels) get standby power, but no standby fee is charged. This can be considered a loss of return on investment.

Prepaid meters were recently introduced. It is PPUC's intent to increase the number of prepaid meters.

Generator and feeder meters are <u>not</u> revenue-class.

Billing and Collection Processes: Meter reading and billing is done monthly, making use of a CIS (Customer Information System). The CIS system does not automatically initiate red flags to identify irregularities, such as much lower than usual usage.

Reliability: The 34.5 kV transmission line between Malakal and Aimeliik (about 12 miles long) trips off-line due to vegetation issues at least once every two months.

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., power transformer oil sampling) is not in place.

4. Grid Model and Calculation of Technical Losses

4.1 Estimates and Assumptions for Missing Data

To quantify losses, the following assumptions were made:

1. The average power output over the past one year period (2009) was used for annual energy consumption. (This consumption has been dropping over the years.)

2. The typical value for power transformer no-load loss literature1 was used for core losses.

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

4. Loads were distributed based on distribution transformer location (assumed from the distribution transformer lists given for each state). The exact location of loads was not known.

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

6. Loads were 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.

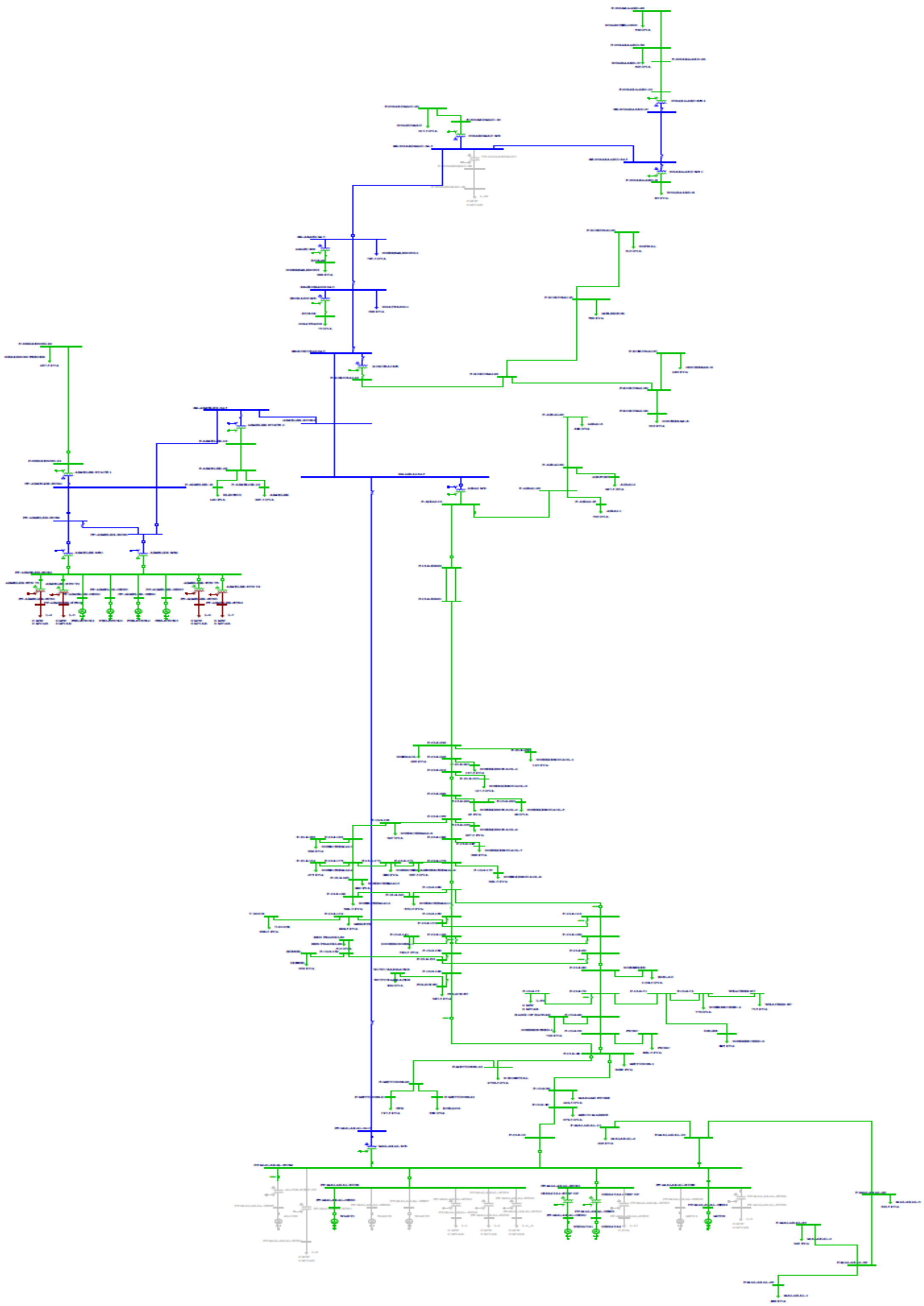
4.2 Easy Power Model

Power plants, the transmission system, and primary distribution feeders were modeled in Easy Power. Feeder lengths and the connected loads were identified based on the one line diagram, the GIS map, and data provided by PPUC. Generators, power transformers, and feeders were

[1] Electric Power Distribution System Engineering by Turan Gonen

modeled based on data provided in response to the data request. Losses through the transmission system, primary feeders, and power transformers were calculated in a power flow study. Peak load of 2009 is provided in “STATISTICAL DATA OF PPUC - UPDATED.xls”. Since distribution transformers are not associated with customer meters, load allocation was based on transformer sizes connected to the feeders. The system one line diagram in Easy Power is shown in the following Exhibit 4-1:

Exhibit 4-1 – PPUC One-Line Diagram (also in Appendix B)



Load Allocation

A power system model was created in Easy Power according to the one line diagram ONE LINE DIAGRAM PPUC PALAU.pdf, AIMELIIK POWER PLANT SINGLE LINE DIAGRAM.xls, and MALAKAL POWER PLANT SINGLE DIAGRAM.xls. (Appendix B) Loads are modeled as lump sum for each feeder section.

Lists of distribution transformers were provided by state. States are identified by names on the geographic map. Some of the states have multiple feeders going through them. The list of distribution transformers per state does not match transformers to specific feeder sections. Allocation of distribution transformers to a feeder section was based on transformer names identifiable on the map. A cross reference of distribution transformers to lump-sum loads modeled in the Easy Power is provided in Load Distribution.xls in Appendix B. These load allocations should be reviewed by to verify actual connected kVA's.

Power Flow Study

A power flow study was conducted for a system peak load of 14.9 MW and a power factor of 0.9. A scaling factor of 0.458 was applied to all loads, based on a total connected capacity of 35,077 kVA. The output of the Aimeliik power plant is 11 MW and of the Malakal power plant is 4.1 MW. A significant amount of reactive power (6.9 MVAr) is provided by Malakal to support the load center Koror.

Major findings from the power flow study:

1. There is significant power transfer from Aimeliik to the load center in Koror through the 34.5 kV lines, resulting in losses through these lines.

2. In Koror, there is great need for reactive power for voltage support.

To address "1", more generator capacity is recommended close to the load center to reduce the amount of power transferred through long lines connected to Aimeliik. Feeder losses can then be reduced.

To address "2", it is recommended for PPUC to install capacitor banks at the load centers in order to serve reactive power directly to the load bus and reduce reactive power flow through the feeders serving loads. (See Section 4.4).

4.3 System Loss Estimation

System losses consist of technical and non-technical losses.

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

Non-technical losses: The difference between total system losses and technical losses. (e.g., the total energy entering into the system from power plants minus total energy sold. A summary of the loss estimation is provided in the exhibit below.

Exhibit 4-2 – Loss Estimation

Based on 2009 figures	MWh	% of generation	% of system consumption
Annual generation	81,154.51		
Annual station auxiliary	5,285.66	6.51%	
Annual system consumption	75,868.85	93.49%	100.00%
Annual energy sold	65,645.09	80.89%	86.52%
System loss	10,223.76	12.60%	13.48%
Unbilled usage (street light)	614.06	0.76%	0.81%
Technical loss	6,142.17	7.57%	8.10%
Non technical loss	3,467.52	4.27%	4.57%

4.4 Capacitor Placement Scenarios

Since capacitor data was not received, a study on the effects of installing capacitors was not performed. However, for the purpose of loss minimization, several scenarios were investigated in Easy Power. Capacitors were placed in 34.5 kV substations and 13.8 kV load centers. System losses were reduced. Installing capacitor banks at load centers in Koror is most effective for loss reduction. Study results show a 10% loss reduction, or 189 MWh. The power factor improved from 0.88 to 0.984. Capacitor banks of 3x1 MVAr and 1x2 MVAr, (total 5 MVAr) were placed in 4 locations on Koror as follows:

1. 1000 kVAr on Meyungs
2. 1000 kVAr on Malakal
3. 1000 kVAr on Koror close to the causeway from Malakal
4. 2000 kVAr on Koror close to the causeway to Babeldaob

All large customers should correct their power factor above 0.85. Actual measurements should be performed at major load centers. With capacitor sizes applied, consider the impact of fixed capacitors on voltage during light load conditions. Having a mix of switched capacitors and fixed capacitors would be ideal. Application should be as close to loads as possible maximizing loss reduction.

The model in Easy Power was developed for loss estimation purposes. All distribution transformer loads were modeled as lump-sum constant power loads. Allocation of loads connected to each feeder section was done based on the locations of the State and identifiable location of distribution feeders within the State. That is because distribution transformers were provided on a per-State basis, rather than per feeder. The model represents total net load connected load to a feeder section.

The power flow was done for peak load conditions, which was represented by applying a utilization factor to all connected loads. The utilization factor was calculated as the maximum system demand kVA over total connected kVA, assuming total system load was allocated to each transformer proportionally. For the purpose of loss estimation, this is a good approach. However, it is not accurate enough to support a thorough study of optimal capacitor placement. Specific meter readings of targeted locations are necessary. Both the allocation and characteristics of loads are important considerations when placing capacitors. Specific load power factors and loads at any specific locations were not provided.

5. Electrical Data Handbook

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

The Handbook can be found in Appendix B.

6. Analysis of Technical and Non-Technical Losses

6.1 Generation Efficiency

Exhibit 6-1 – PPUC Generation Efficiency 2004-2009

UTILITY: PPUC	2004	2005	2006	2007	2008	2009
Generation						
Units Generated, kWh	107,896,928	112,006,579	101,227,939	103,093,863	97,501,600	81,154,509
Overall Fuel Efficiency kWh/gal	**14.362**	**14.185**	**14.131**	**14.185**	**14.143**	**13.217**
kWh/gal of lube oil	263.22	210.54	2,791.98	2,399.31	1,824.94	2,275.15

Individual generation unit data was not provided. Overall data was given as shown in Exhibit 6-1. Energy produced has dropped with energy efficiency experiencing a big drop in 2009. Figures for lube oil in 2004 and 2005 seem to be inaccurate.

With the addition of two newly furbished generator sets at Malakal, base load capacity and reserves margin will increase significantly. This will permit scheduling major overhauls on other generators.

The power plant at Aimeliik is remotely located in Babeldaob with relatively low load levels - one airport, a resort, and domestic and small commercial users. The tie to the main island is 11.6 miles long. The four units at Aimeliik produce 11 MW (de-rated value) with a fuel efficiency of 12.85 to 13.27 kWh/ gallon, which is relatively low. The engines are from 1985. Decommissioning and adding new ones at Malakal has been studied to improve efficiency and reduce transmission losses. During the site visit, the tie line was carrying 7 MW.

Considering the decommissioned engines in Malakal and the two Caterpillar engines to be removed, the capacity in Malakal will be 18.8 MW (5.6 MW (two Mitsubishi's) + 3.2 MW (two Wartsila's) + 10 MW (two new engines), not counting the 500 kW black start unit. To satisfy the n-2 criterion, one more unit with a capacity of 7 MW should be added to Malakal to become less dependent of power production in Aimeliik. Aimeliik could then be used to provide local load only.

6.1.1 Power Plant Usage; Station Losses

The power plant usage from the measured values is 6.51% of the generated energy. This is a relatively high percentage compared with commonly occurring percentages of 5% or lower. However, auxiliary consumption measurement is not performed with revenue-class meters, which implies that real usage value may be somewhat lower or higher than 6.51%.

Losses in the auxiliaries can be controlled by paying attention to the operation of fans, radiators, lights, etc. Operators should be trained on power plant energy efficiency measures.

6.2 Technical Losses

Exhibit 6-2 – Technical Losses

Technical Losses			
Type of Losses	Sub Total MWh	MWh	
Dist Transformer Core	1408.92		
Dist Transformer Cu	330.07	1738.99	28.31%
Secondary wires	442.98		
Feeder Wires	1743.58	2186.56	35.60%
Power Transformer Cu	177.56	2216.56	36.09%
Power Transformer core	2039.00		
Total =	**6142.11**	**6142.11**	
Core Losses Alone	3447.92		56.14%

Exhibit 6-2 illustrates that transformer losses are the majority of total losses (64.4%) and wire losses come up to 35.6%. Among the transformer total losses, core losses are the majority of the losses.

6.2.1 Transmission and Distribution Lines

Calculated line losses are 36% of the 7.57% (6,142 MWh) of total technical losses including 13.8 kV and 34.5 kV overhead lines and feeder losses, power transformer losses, distribution transformer losses and secondary service wires losses.

Low line losses occur because of the presence of 34.5 kV transmission line and low load compared to the size of the wires.

Losses in low voltage service wires are estimated at 443 MWh or 7.21% of the total technical losses. Assumptions were made of typical sizes and lengths of secondary wires to quantify losses. A margin of error could be possible because the assumptions made.

6.2.2 Transformer Losses

Transformer losses are separated in two parts – no load losses and copper losses. No-load losses (core losses) are magnetizing losses which are present whenever the transformer is energized, independent of the load. Even an unloaded but energized transformer will have no-load losses. Copper losses are only present when load is present, and are proportional to the square of loading relative to full load. For PPUC, total losses from distribution and power transformers are 4,746 MWh per year. 3,448 MWh are core losses, and 1,298 MWh are copper losses.

Ratings of these transformers (the average load is calculated to be around 46% of the installed distribution transformer nameplate rating – assuming the transformer ratings are equivalent to the connected loads) may be too large for the loads resulting in higher no-load losses. The system database does not contain information for identifying which loads are tied to which transformers. For this, physical inspection should be performed.

Since core losses depend on transformer ratings, and since PPUC is using only 46% of the total installed capacity (estimated at equivalent to connected load), there is room to decrease these losses. Lowering distribution transformer ratings by one size will reduce losses 20%.; two sizes will reduce losses by 30%. The second option (two sizes lower) will load transformers to 50% to 60% of the maximum system load of 14,900 kW.

6.3 Non-Technical Losses

Of the total system losses, 4.97 % is non-technical. Possible sources include:

- Not accounting for all energy used by PPUC offices, stores, or workshops
- 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 not tested and not working properly
- Meters are old and not working properly
- No regular procedure to check meter multipliers
- Organizationally, no person who is responsible for loss reduction
- The billing system does not raise red flags for customers who show irregular consumption patterns

PPUC has focused its attention to the reduction of the non-technical losses. A program to install prepaid meters will help the situation. Focused auditing and assignment of a revenue protection officer can contribute to further reduction of non-technical losses by executing a non-technical loss reduction strategy.

6.3.1 Metering Losses

Customer meters are electromechanical. They have not been calibrated or tested during their lifetime. Meters used for generator outputs, main feeders, and auxiliaries are not revenue-class meters. Meters do not record maximum demand.

Processes: Most of the meters (5,800) are read manually once a month. Meter reading, billing, and collection processes are manual. Bill collection is not optimal, resulting in excessive amounts of receivables. Key to re-solving these issues is a stringent revenue assurance policy, which is strongly managed.

Location of the customer meters should be tied to transformers which are connected, 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 proper loss reduction or because of overloading and general maintenance.

7. Other Issues

Power Generation: Most of the engines were beyond the allowable maintenance intervals (major and minor overhaul). In the future, funds for on-going maintenance and replacement of aged generator sets will be needed to avoid a power crisis. The technical health of the utility will depend on enough revenues being collected to cover its costs. A cost of service study would quantify what tariffs would be necessary 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).

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

Meters need to be regularly tested to ensure revenue-class results. Processes for meter reading, checking billing constants, collecting, auditing meter installations, and applying penalties for late payment will contribute to improvement of performance and reduction of non-technical losses.

8. Options for Improvement

8.1 Power System Improvements/Modifications

Technical losses are unavoidable. However, reducing them can be achieved in the PPUC system based on the assessment. Reducing them should continue to be an integral part of PPUC's overall loss reduction strategy for the following reasons:

- Electricity rates will continue to increase, particularly because of increasing fuel costs, which will change the cost-basis for evaluating many technical loss-reduction-related measures/programs
- Electrical equipment connections that are corroded or loose can cause heating, which results in higher losses, reliability 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 projects and programs that are giving loss reduction benefits when considering total life costs is key to selecting those that will be most beneficial.

Distribution and power transformers make up 64% of the technical losses. Core losses are the majority (87%) of the losses. Over the life time (even over 10-years life span) the cost of losses represents a major cost relative to overall capital costs. The T&D department needs to better match transformer sizes with actual loads. If implemented, substantial savings are possible.

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

Secondary circuits and service wires

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

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

Customer meters need to be associated with the respective transformer servicing the load. This can be done in a CIS system or using spreadsheet software to take loads from metering data and calculate transformer loadings. 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 are circuits/wires
- A load patterns are difficult to obtain for each customer unless AMI (Advanced Metering Infrastructure) is deployed

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

Update loss cost-basis on a regular basis

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

As new equipment is installed and replaced the loss cost-basis should be accomplished to evaluate the impact of various alternatives, especially to understand the cost of lifetime equipment deployment. Once a new cost basis is established, it should be applied to the cost/benefit analysis of new equipment purchases immediately, such as pad-mounted and pole-mounted transformers. A 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 (60 to 70% of the sum of kVA's of distribution transformers) from the existing level, close to $ 210,000 per year in core losses savings can be realized. As optimized sizes cannot be realized in a single year, a multi-year replacement program should be set up:

1. 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).

2. Develop proper transformer sizes for each location.

3. Optimize transformers which can be optimized without capital cost investments (e.g., by moving them to appropriate locations.)

4. 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 of “Technical Loss Calculation and Financial Model” spreadsheet tab in Appendix C).

Optimize customer power factors

An overall system power factor is 0.89. The power factor of feeder sections 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 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 nevertheless the customer does not improve to the required level, PPUC 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 or 34.5 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 to be considered:

Fixed and manually switched capacitors

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

The size of fixed capacitors can be determined by minimum reactive power compensation requirement 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 size into account.

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 changes between two constant levels, then one large switched capacitor may be sufficient. This should be evaluated on a feeder-by-feeder basis.

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.

Automatically switched using capacitor control

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 capacitors are on line when they are most needed.

kVAr 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.

(Appendix E includes cases run on Easy Power using fixed capacitor installations).

8.2 Operational Recommendations

8.2.1 Generation

Develop written operating procedures and plans for economic dispatch and monitoring of the performance of the plants and individual generation units.

For reviewing the performance of generating units, the current metering in the power plant do not provide good coordinated readings. We recommend a first step should be installing revenue-class metering (energy, fuel and other supplies) to accurately measure efficiency of each generator and dispatching the generators based on efficiency considering other operating constraints. Efficiency improvement (which requires training and implementation of processes for the operators) and real-time display of engine efficiency helps 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 made available. The objective is to improve generator efficiency and reduce consumption in plant auxiliaries. A next step would be introducing an economic dispatch module in the SCADA system.

Generation efficiency has dropped 8% in 2009 versus the previous years (13.22 from 14.14 kWh/ Gal). The cause of this drop should be investigated in order to correct the situation. Every 1% increase in this efficiency saves about $186,000. Based on the specification of the two new, refurbished 5 MW engines their efficiency should be 15.6 kWh/gallon (in the range of 75 to 100% load) which means that if efficiency oriented generation dispatch is applied, the total efficiency will increase 13.22 to 14.9 (12.7% improvement), and even higher at lower loads. This will bring a fuel cost savings of $2,000,000 per year.

8.2.2 Generation Dispatching Among Aimeliik and Malakal

If generation dispatch is managed between Aimeliik and Malakal, a way that there is very little flow over, there is a potential loss savings of $200,000 per year. The four cases studied are calculations in Appendix E. Generator selection should be such that the most efficient are used first.

Exhibit 8-1 – Dispatching Impact on Losses

Scenario	Description	Total Losses (KW)	Savings from Base (kW)	Savings in MWh	Fuel Gals saved	Savings at $3 per gal	Aimeliik Pgen (kW)	Aimeliik Qgen (kVAR)	Malakal Pgen (kW)	Malakal Qgen (kVAR)
BASE	Base case -- This is current model. Aimeliik is providing 11MW supplying northern island (Babeldaob) and about 1/2 of southern island (Koror). Malakal is supplying 1/2 of Koror. Huge power transfer from north to south.	528.2					11000	1091	4101	7076
SC_1	Scenario 1 -- Decrease output of Aimeliik and increase output of Malakal, until minimum power flow on 34.5kV tie. Aimeliik is supplying Babeldaob and small portion of Koror (through 13.8kV tie).	354.2	174	632.86	47872	$143,615	7100	1926	7827	5722
SC_2	Scenario 2 -- Further decrease output of Aimeliik and increase output of Malakal, until minimum power flow on both 34.5kV and 13.8kV tie lines. Aimeliik is supplying Babeldaob alone. And Malakal is supplying Koror alone.	285.3	242.9	883.46	66828	$200,484	3360	1903	11498	5564
SC_3	Scenario 3 -- Close plant Aimeliik, Malakal is supplying the whole system. Power flows from south to north.	336.3	191.9	697.97	52796	$158,389	0	0	14909	7656
For diagrams are illustrations in spreadsheet tabs.										

8.2.3 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 should be of revenue-class.

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

1. software, which takes into account the customer meters on each of the transformers or
2. Physically measuring the load by installing demand type meters on the secondary side of each of the transformers.

8.2.4 Strategy for Reduction of Non-Technical Losses

One of the main areas in aligning a utilities' operation to Revenue Assurance is to implement a Revenue Assurance Process making use of an advanced Revenue Intelligence system. For conducting most efficient fraud prevention/detection and revenue operations audits with limited resources, an advanced Revenue Intelligence system is a must. 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.

PPUC should consider the following:

- Develop a program for checking old meters.
- Train meter readers to identify tampering, by-passing, broken seals, and 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 of and hit rates will be the most efficient use of the limited resources.
- Make operations less predictable. PPUC's own experience may show that there are sophisticated fraud activities that take advantage of known patterns of Revenue Assurance operations. This should be countered with less predictable operations (e.g. occasional night inspections, computer-generated random daily target lists, and so on). This will help to identify these fraudsters and increase the deterrent effect.
- Prevent repeat fraud activities. Proper measures should be taken to ensure that it will not occur again.
- Prevent and curb internal collusion activities. One important aspect of effective revenue protection operation is to prevent and curb 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 PPUC'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 of 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 9-1 provides a summary of savings and associated costs over a 6-year implementation period:

Exhibit 9-1 – Savings and Costs

	6 Yrs NPV of Savings and Cost Summary		
NPV @ Cost of Capital	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**
Technical Losses	$1,195,098	$592,568	$602,530
Auxiliary loss	$890,835	$350,000	$540,835
Non Technical Loss	$1,004,585	$920,467	$84,118
Total =	$3,090,518	$1,863,035	$1,227,483
Generator Efficiency improvement	1% improvement saves $186,000. Savings up to $2M per year may be reached after deployment of two new 5 MW generators and implementation of economic dispatch.		

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

A summary of assumptions and recommendations follows:

1. Cost will increase based on inflation of 3% every year.
2. Cost of Capital was assumed to be 8%.
3. Emphasis should be placed on process improvements for purchasing, metering, billing, collection, and operations, including dispatching of generators.
4. Technical and non-technical loss improvements will require investments totaling $1.8 million over 6 years. Losses will be reduced from 12.54% a calculated value of 8.77%.
5. Generation auxiliary losses are a small portion (6.51%) of overall losses. With process improvements and an investment of $350,000, it will be possible to provide real-time data and efficiency calculations to operators who can then operate the power plants at maximum efficiencies.

6. Overall losses can be reduced from 19.11% to below 15% (calculated value 14.36%) in 6 years.

7. Proper dispatching of generation between Aimeliik and Malakal can reduce technical losses and save $200,000 per year.

9.1 Recommendations

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

9.1.1 Reduction of Technical Losses

1. Power Factor Improvement

The power factor of PPUC is reasonable but it needs to be watched and a process should be developed to evaluate it at least once a year.

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

b. Determine 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.

c. Add capacitors to improve the power factor (estimated cost of $323,000 over 6 years). See also our note in the Appendices section under Appendix F.

d. Determine where in feeders capacitors can be placed to improve the overall power factor close to 95%. Make sure that a monitoring plan is part of this. In Appendix F a further elaboration is given on this topic

2. Transformer Sizing

Distribution transformers appear to be loaded at 45% of full capacity. Loss reductions can be achieved if transformer sizing more closely matches connected load. This could be done as part of an on-going transformer replacement program.

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

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

c. Transformer purchases should consider total lifetime cost (including NPV calculation of losses). For example, the cost of 1 kW of core losses for 10 years of a transformer's life at 23 cents per kWh of fuel cost (based on $3 per gallon of fuel) is $15,012 (NPV). Copper losses would be $6,300. (A transformer evaluation example is in "Technical Loss Calculation and Financial Model" spreadsheet tab in Appendix C).

Cost of right sizing transformers is $240,000.

3. Reduce Line Losses

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

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

Reducing technical losses from a slightly high level of 7.57% by 1.96% in 6 years through above mentioned actions and process improvements, savings are close to $1,655,000. Cost of these initiatives is $713,000 over 6 years.

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 with a focus on saving energy. Improvement measures could include:

1. Adding instrumentation and displays to show efficiencies for every generating unit to operators (Cost $350,000). Develop a process to measure the efficiency of each generator and develop management reporting on generation efficiency.

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 – next step after process improvements and real time analysis and focus of energy consumption reduction is in place.).

4. Apply Frequency Drives (cost not included).

Benefits from these actions are expected to be $1,200,000 over 6 years. Savings are produced by reducing auxiliary losses from 5,286 MWh (6.51%) to 4,229 MWh (5.52%) in 6 years. (See spreadsheet Savings Model tab in Appendix C.

9.1.3 Reduction of Non-Technical Losses

Account and highlight monthly financial losses (e.g., street lights and unaccounted energy usage).

Develop a regular meter testing program. Add new meters (1,000) to the secondary sides of transformers and feeders at key locations for measuring transformer loads as well as auditing customers fed from each transformer.

Procure meter testing equipment. Replace meters by new ones (prepaid type). Make sure each customer is linked to the transformer and its meter (cost $866,000) in a software tool that issues tampering and transformer loading can be easily monitored.

It is not necessary to install meters on every distribution transformer. Areas experiencing excessive tampering would be the best locations. This can also be accomplished by CIS applications which link the transformers to the customer meters. For transformer load profiling, a number of temporary recording meters could be installed on the transformers and relocated as needed.

Install meters on pole-mounted transformers by using current transformers.

Add Revenue Protection measures including assignment of a senior staff member as Revenue Assurance Officer.

These recommendations go hand in hand as savings will come from the focus attention of the company (i.e. developing and implementing processes), people and tools like modern meters and systems. In the first year it is expected to save 5% of non technical losses and end up after 6 years at 40% reduction. Non-technical losses will reduce to 3.16% (i.e. achieving 2,418MWh from 4,030MWh in 6 years). Savings in 6 years is expected to be $1.4 million resulting in an NPV of $84,118.

9.1.4 Improving Generator Efficiencies

A 1% improvement in engine efficiency will result in savings of $188,000 per year, resulting in NPV of $1.36 million over 10 years. Increasing average efficiencies from 13.22 to 14.143 kWh per gallon (7% improvement 2008 levels) will save $1,316,000 in a year, at a NPV of 9 million over 10 years.   If new generators are purchased, there must be funds available to make sure they keep running at high efficiency.

9.1.5 Net Present Value Calculations

Exhibit 9-2 –Net Present Value Calculations

Assumptions:				
Inflation	3%			
Cost of Capital	8.00%			
Cost/KWh	$0.30			
Cost and Savings list	**Savings (NPV)**	**Cost (NPV)**	**Net (NPV)**	**Cash over 6 years**
Technical Loss Savings:				
Infrascan camera and training		$100,000		-$100,000
Right Sizing distribution transformers		$198,728		-$240,000
EZ Power software, power factor improvement hardware installation and control.		$293,841		-$373,420
30% loss reduction over 6 years	$1,195,098		$602,529	
Auxiliary Losses				
SCADA for generators and process improvement		$350,000		-$350,000
20% loss reduction over 6 years	$890,835		$540,835	
Non Technical Savings:				
Training of employees, some additional software and using distribution transformers		$920,467		- $1,041,157
40% Non Technical Loss reduction over 6 years	$1,004,585		$84,118	
Total =	$3,090,518	$1,863,035	$1,227,483	- $2,104,577

(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 transmission and distribution systems and provide related linemen training.

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

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

A. Data Request

(All are attached as separate documents)

Data Request

B. Data Received

Data Handbook

One-Line Diagram

Load Distribution Data

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

D. Pictures

E. Dispatching Options Analysis Details

F. Power Factor Correction Scenarios