



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

Consolidated Report



Ordered by the Pacific Power Ass ociation (PPA)

Prepared by: KEMA Inc. December 20, 2010 – Final Report



Presented by - KEMA Project Team:

Roel Verlaan Hari Cheema Eileen Zhang Kevin Chen

Advisors: Ronald Willoughby Richard Wakefield

Copyright © 2010, Pacific Power Association.

The information contained in this document is the exclusive, confidential and proprietary property of the Pacific Power Association and is protected under the trade secret and copyright laws of Fiji and other international laws, treaties and conventions. No part of this work may be disclosed to any third party or used, reproduced or transmitted in any form or by any means, electronic or mech anical, including photocopying and recording, or by any information storage or retrieval system, without first receiving t he express written permission of Pacific Power Association. Except as otherwise noted, all trademarks appearing herein are proprietary to the Pacific Power Association.





Table of Contents

1.	Introduction	2
2.	Executive Summary	3
3.	Chuuk Public Utility Corporation (CPUC)	8
4.	Pohnpei Utility Corporation (PUC)	11
5.	Kosrae Utility Authority	. 15
6.	Marshalls Energy Company (MEC)	18
7.	Kwajalein Atoll Joint Utility Resources (KAJUR)	21
8.	Guam Power Authority (GPA)	25
9.	Commonwealth Utilities Corporation (CUC)	. 27
10.	Yap State Public Service Corporation (YSPSC)	30
11.	Palau Public Utilities Corporation (PPUC)	. 34

Graph 1: Overview of total losses	4
Graph 2: Overview of Station Losses	5
Graph 3: Overview of power deliveries unaccounted for	5
Graph 4: overview of System Losses	6
Table 1: Overview of quantified losses (in %)	4
Table 2: CPUC Savings and Costs	
Table 3: PUC Savings and Cost	
Table 4: PUC Generation Efficiency	
Table 5: KUA Savings and Cost	
Table 6: KAJUR Savings and Cost Summary	
Table 7: CUC Savings and Cost	30
Table 8: YSPSC Savings and Cost	
Table 9: PPUC Savings and Cost	

ҝемаҶ



1. Introduction

In the year 2010, KEMA Inc conducted a study for the Pacific Power Association (PPA) called "Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States (excluding US Virgin Islands)" for 9 Northern Pacific Island Utilities. This Consolidated Report gives an overview of the major findings and results of the study. KEMA's assignment included 10 Northern Pacific Island Utilities, but during the course of the project, it became necessary to postpone the study for one of the islands, American Samoa, to 2011. The reason was ASPA was re-building its power system, including constructing a new power plant, after damage in 2009 from natural disasters that severely hit the island. Once the rebuilt and recovered system is up and running and operational data becomes available, the study will be performed.

Project objectives for each island utility studied:

- 1. Quantify energy losses in the power system.
- 2. Prepare an Electrical Data Handbook with electrical characteristics for all high voltage equipment.
- 3. Prepare a digital circuit model of the power system using EASY POWER, an established commercial engineering analysis 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 both technical and non-technical losses.

The nine (9) utilities studied were the following:

- 1. Chuuk Public Utility Corporation (CPUC)
- 2. Pohnpei Utility Corporation (PUC)
- 3. Kosrae Utility Authority (KUA)
- 4. Marshalls Energy Company (MEC)
- 5. Kwajalein Atoll Joint Utility Resources (KAJUR)
- 6. Guam Power Authority (GPA)
- 7. Commonwealth Utilities Corporation (CUC)
- 8. Yap State Public Service Corporation (YSPSC)
- 9. Palau Public Utilities Corporation (PPUC)





2. Executive Summary

KEMA prepared a report for each of the nine utilities with findings and results of the study, including recommendations. Supporting documentation was included in appendices containing calculations of losses and cost/benefit analyses of remedial actions to reduce losses and enhance efficiency. In addition, KEMA prepared Data Handbooks for each utility and power system grid models using Easy Power software. Exceptions were YSPSC who already had their grid modeled in Easy Power, and GPA who had successfully modeled their system using PSLF (for Transmission) and SynerGee (for Distribution). GPA was satisfied with PSLF and SynerGee capabilities, making a move to Easy Power unnecessary.

KEMA classified the following types of losses:

- Losses caused by power delivery which are (mostly) not metered and not accounted for, and which are considered by many to be power system losses, such as:
 - Energy usage for water and sewerage activities by the utility, which should be allocated to the cost of service and not classified as a power system loss. If costs are not allocated to the costs of service for water and sewerage, they will remain a *financial loss* for the utility and not a power system loss.
 - Power delivery for street lights, but street lighting should be accounted for and billed. If these revenues cannot be collected, street lighting should be considered a *financial loss* and not a power system loss
 - Energy usage in utility offices and buildings. The cost of these should be allocated to utility expenses and not a power system loss.
- Power plant own usage (so-called Station Losses)
- System losses which consist of
 - Technical losses
 - Non-technical losses

Finally, levels of generation efficiency were investigated by quantifying fuel usage in kWh/gallon.





The table below gives an overview of quantified losses (in %).

Utility	Power delivery unaccounted for (streetlights, water & sewerage facilities, offices, etc)	Power Station Auxiliaries (station losses)	Technical Losses	Non- technical Losses	System Losses: Technical + Non-Technical	Total Losses
CPUC	5.72	3.84	7.71	16.06	23.77	33.33
PUC	1.94	5.12	5.94	5.66	11.60	18.66
KUA	2.58	4.98	5.91	3.27	9.18	16.74
MEC	0.67	8.45	6.41	11.35	17.76	26.88
KAJUR	3.00	4.16	2.77	12.58	15.35	22.51
GPA	0.17	5.36	6.36	0.50	6.86	12.39
CUC	8.91	4.73	4.36	10.75	15 <mark>.11</mark>	28.75
YSPSC	7.59	7.43	6.38	4.05	10.43	25.45
PPUC	0.76	6.51	7.57	4.27	11.84	19.11

Table 1: Overview of quantified losses (in %)

Total losses by loss category are given in the graphs below.





The two utilities with the lowest total losses (and also lowest system losses) are the largest utility and one of the smallest utilities, which means small utilities can also achieve low system losses. Economy of scale becomes a factor when considering generation efficiency and overall company costs.







Graph 2: Overview of Station Losses

Station Losses should be lower than 5%. Best practices show percentages between 2.5 and 3.5%.



Graph 3: Overview of power deliveries unaccounted for

Unaccounted for power delivery losses should not be characterized system losses but financial losses for the utility.







Graph 4: overview of System Losses

Technical losses were calculated using grid data provided by the utilities. In some cases, assumptions were required. Non-technical losses were calculated by subtracting the calculated technical losses and estimated unaccounted for usages from the kWh's entering into the grid. Technical loss percentages between 5% and 8% are considered reasonable, but actual values may be higher since some of the data was missing and assumptions had to be made based on previous similar studies. Recommendations to reduce technical losses were included in individual utility company reports.

If non-technical losses are higher than 2 or 3%, Revenue Protection should be implemented with increased priority, meaning a loss reduction strategy should be developed. For mitigating non-technical losses, recommendations were included in the individual utility company reports.





In the area of **Generation** and **Generation Efficiency**, the following observations are important:

 For several utilities, generators were de-rated because of severe deterioration of the unit, its coolers, and auxiliaries. This was due to a lack of funding to purchase replacement parts and maintain the units properly. Some generating units were found to be inoperable. These units were used for spare parts to keep the remaining units in operation.

Revenues of these utilities are not sufficient to keep them technically and financially healthy. In some cases, the utility cannot supply full load and have to employ load shedding schemes. There is a dependency on grants and loans to survive. Once generating units have been overhauled and replaced from a grant or loan, the utility may return to a crisis situation after some years. Governments generally do not allow rate increases, and even charging fluctuating fuel costs through a fuel surcharge is often not allowed.

Although reduction of losses and enhancing generation efficiency will have a positive impact on utility revenues, allowing them to spend more on maintenance and repairs, the major day-to-day concern is keeping the engines and power grid on line.

2. Generation efficiency is often not optimal due to the above conditions. In the individual utility reports, economic payback periods are calculated for replacing old generators or purchasing a new one.

During the period of the study, KEMA identified utilities where programs were in place (or just started) to improve reliability and efficiency; e.g., Saipan where CUC achieved improvements by executing an overall turnaround program in generation. In Palau, two refurbished engines were installed which will improve reliability and efficiency. Recently, Chuuk started the CRISP program, and the procurement of a new power plant is ongoing.

Individual Reports

Individual reports were prepared for each of the nine utilities. Executive Summaries from the individual reports, which include a summary of investments for implementing loss reduction measures, are presented in Chapters 3 through 9 of this consolidated report.





3. Chuuk Public Utility Corporation (CPUC)

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

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

Technical and non-technical losses total 23.77%.

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

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

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

Recommendations

(The individual report for CPUC and its appendices contain detailed cost and benefit information.)

It is estimated that by taking the following process improvements and making some specified investments, CPUC can start saving \$400,000 to 450,000 per year:

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





- 2. Generation efficiency is currently low at an average of 13.4 (13.2 to 13.5 kWh/gallon). Every 1% increase saves \$30,000. If the efficiency is improved to 15 kWh/gallon savings could reach \$360,000 per year with the installation of new generators, which is expected in 2013. Current generators should be maintained and operated at an efficiency level of 13.5 kWh/gallon, which saves \$66,000 per year compared with an efficiency level of 13.2 kWh/gallon.
- Develop a dispatching routine to provide highest efficiency operation. During our visit, only one generation set was running while others were waiting for repairs and spare parts. Once all generators are running again, efficiency can be gained by dispatching the engines in anticipation of expected load patterns.
- 4. Change and add meters to provide accurate real-time revenue-class and generator and auxiliary plant efficiency data to plant operators. Train operators and develop processes to achieve the best efficiencies from generation resources.
- 5. Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime cost (costs of capital, losses, and maintenance). If most of the islands combine their effort and develop one standard specification to procure large cost items like transformers and engines, the cost of these assets may be lower.
- 6. Add revenue-class meters to the feeders and distribution transformers to measure losses. Use these meters to check customer meters, especially if there is tampering or stealing. Optimize distribution transformers to reduce no-load losses.
- 7. Use an infrared camera at least annually to identify hot spots.
- 8. Start a revenue assurance program for auditing, metering, and billing procedures and for executing a non-technical loss reduction strategy. Assign a staff member to be the Revenue Assurance Officer, responsible for the execution of the loss reduction strategy.

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





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

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

Table 2: CPUC Savings and Costs





4. Pohnpei Utility Corporation (PUC)

KEMA's analysis of Pohnpei Utility Corporation (PUC) power system determined total losses of 18.66 % consisting of the following:

- 5.12% in power station auxiliaries (station losses), which is a relatively high amount of losses. Typically, station losses ar e lower than 5%.
- 1.94% in street lighting and usage for water and sewerage facilities. If these revenues cannot be collected, street lighting should be considered a financial loss for PUC and not a system loss.
- Energy usage for water and sewerage facilities should be accounted for and allocated to the cost of service and lumped with power system loss. However, if the costs are <u>not</u> allocated to service costs, they will remain a financial loss for PUC's power services and should not be considered a power system loss.
- 5.94% in technical losses
- 5.66% in non-technical losses

Technical and non-technical losses total 11.6%.

Overall losses, including power plant usage total 16.72%.

Recommendations

(The individual report for PUC and its appendices contain detailed cost and benefit information.)

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

	6 Yrs NPV of Savings and Cost Summary			
NPV @ Cost of Capital	Savings Cost (NPV) (NPV) Net (NPV			
Auxiliary loss	\$254,373	\$175,000	\$79,373	
Technical Losses	\$410,534	\$344,332	\$66,202	
Non Technical Loss	\$783,367	\$433,717	\$349,649	
Total =	\$1,448,273	\$953,049	\$495,224	

Table 3: PUC Savings and Cost





1% efficiency improvement in generation saves \$81,000 per year. This based on the price of crude oil being \$75 per barrel. At a price of \$100 per barrel the saving s of 1% efficiency improvement increase to \$108,000 per year. This assumption can be influenced by fuel pricing effects related to creditworthiness of customers and transportation costs.

A. Generation

- 1. Operate generating units at high efficiency. The engines should be properly maintained and operated near 80% of full rated output. Funding of on-going maintenance requirements is not included.
- 2. For every generating unit, add instrumentation to show efficiencies to operators (cost \$175,000). Develop a process that p rovides regular management reporting.
- 3. Train power plant operators on load foreca sting and economic dispatch practices.
- 4. Include an economic dispatch module in future SCADA system plans.
- 5. Change and/or add meters to provide accurate real -time revenue-class generator outputs and auxiliary plant consumption statistics.

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

- Automate manual processes using PLC controls t o motor starters (cost not included

 this is considered a next step after process improvements and real time analysis as
 well as focus on energy consumption reduction is in place).
- 8. Apply Frequency Drives (cost not included)

Benefits from these actions are expected to be \$350,000 over 6 years. Savings are produced by reducing auxiliary losses from 1,875 MWh to 1,500 MWh per year. Total cost of these initiatives (recommendations 5 through 7) is \$175,000 over 6 years .





On **Generation Efficiency**, the following has been identified:

(Individual generation unit data was not provided , but overall PUC data was given as shown.)

Generation Efficiency						
	2007	2008	2009	6 mos. 2010	18 Mos. 2009 - 10	
kWh	38,333,400	36,106,000	36,003,600	20,012,500	56,016,100	
Fuel Gals	2,683,412	2,512,777	2,625,760	1,483,785	4,109,545	
kWh / gals	14.29	14.37	13.71	13.49	13.63	

 Table 4: PUC Generation Efficiency

Due to lack of maintenance, which led to a de-rating of the engines, generation efficiency lowered each year, costing PUC \$81,000 per year of fuel cost for each 1% drop in overall efficiency. From 2008 to 2009, the fuel cost increase was \$369,000 due to an efficiency drop of 4.5%. Regular maintenance and optimizing the fuel injection system should bring the e fficiency back to 14.3 to 14.5, which is close to the fuel efficiency of new engines of this size.

Increasing the efficiency from 13.49% (2010) to 14.5% will save \$ 560,000 per year. With these savings, maintenance costs can be covered, as well as replacement of deteriorated radiators.

Nanpil Hydro Plant

It is recommended to pursue funding of the Nanpil Hydro Plant's repair, making use of a business case showing the benefits of operating the hydro plant while saving on fue I costs to justify the initial costs for repair.

B. Distribution

- Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime costs (costs of capital, losses, and maintenance). For example, the cost of 1 kW of core losses for 20 years at 22 cents per kWh of fuel cost (based on \$ 3 per gallon of fuel) is \$23,619 (NPV). For copper losses the NPV is estimated to be \$12,920. These figures should be taken into account when evaluating bids for new transform ers. (An example of transformer evaluation is provided in the individual report's Appendix C).
- 2. Optimize distribution transformer ratings over a 4 -to-6 year period by replacing them with transformers more closely matched to the load (lower losses).





- 3. Add revenue-class meters on feeders and distribution transformers to measure losses. Use these meters to check total loading on individual transformers. These meters can be avoided if customers are tied to distribution transformers in the Customer Information System. To reduce costs, meter only distribution transformers where there is an obvious occurrence of non -technical losses due to tampering, by passing, or where total transformer load measurements are necessary. For transformer load profiling 20 to 40 recording meters could be temporarily installed and rotated. Transformer meter costs are included in Section C of this chapter.
- 4. Use an infrared camera to scan the power system equipment at least annually to find hot spots. These usually occur at connector point s. Repair as necessary.
- 5. Require large customers to maintain the power factor above at least 0.85, preferably at 0.9. Install capacitors in the distribution system to maintain the system power factor above 0.95.

(Total cost of these initiatives is estimated to be \$400,000 over 6 years.)

C. Metering, Billing, and Collection

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 cust omers, functioning of red flags in the case of irregularities and utilizing transformer meters in suspected areas as well as initiating testing of meters and connections) and non -technical loss causes found by meter readers (meter tampering , by-passing, hook ups, etc).

(Total cost of estimated to be \$490,000 over 6 years.)

Assign a senior staff member to be PUC's Revenue Assurance Officer, responsible for PUC's Loss Reduction Strategy, who will plan and initiate loss reduction programs and activities, keep s records of progress and successes, and report s to the General Manager. In PUC's individual report, ways of mitigating non-technical losses, under the leadership of the Revenue Assurance Officer, are described in detail.





5. Kosrae Utility Authority

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

- 4.98% in power station auxiliaries (station losses), which is a reasonable percentage, however there is potential for reducing of these lo sses.
- 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

(The individual report for KUA and its appendices contain detailed cost and benefit information.)

A. Generation

- 1. Operate generating units at high efficiency. The engines should be p roperly 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 fo recasting and economic dispatch of generating units. Include an economic dispatch module in fu ture 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





- Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime cost (costs of capital, losses and maintenance). For example, the cost of 1 kW 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.
- 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 d istribution transformers to measure the losses. Use these meters to check total consumption connected to the individual transformers. If the met ers are tied to transformers in CIS, th ese 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 the following:

- 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 b ased 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.			

Table 5: KUA Savings and Cost





6. Marshalls Energy Company (MEC)

KEMA's analysis of the Marshall Energy Company, Inc. (MEC) power system determined total losses of 26.88% consisting of the following:

- 8.45% in power station auxiliaries (station losses), which is a relatively high amount of losses. Typically, station losses are lower than 5%.
- 0.67% in street lighting (which should be accounted for and billed. If these revenues cannot be collected, street lighting should be considered a financial loss for MEC and not a system loss).
- 6.41% in technical losses.
- 11.35% in non-technical losses.

Technical and non-technical losses total 17.76%.

Recommendations

(The individual report for MEC and its 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. Change and/or add meters to provide accurate real -time revenue-class generator outputs and auxiliary plant consumption statistics.
- **4.** Train power plant operators on load forecasting and economic dispatch practices. Include an economic dispatch module in future SCADA system plans.

(Total cost of these initiatives is estimated to be \$1.3 million over 6 years.)

B. Distribution





- 5. Develop standard specifications for distribution and power transformer purchases, which are based on reducing lifetime costs (the costs of c apital, losses and maintenance). For example, the cost of 1 kW of core losses for 10 years at 20 cents per kWh of fuel cost (based on \$3 per gallon of fuel) is \$13,270 (NPV). For copper losses the NPV is dependent on the transformer loading but is estimated to be \$8,000. These figures should be taken into account when evaluating bids for new transformers. (A transformer evaluation e xample is provided in "Technical Loss Calculation and Financial Model" tab spreadsheet in Appendix C of the individual report for MEC).
- 6. Add revenue-class meters on feeders and distribution transformers to measure losses. Use these meters to check total loa ding 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 excessi ve tampering, by-passing or where total transformer loads are necessary. For transformer load profiling 50 to 100 recording meters could be temporarily installed and rotated. Tr ansformer meter costs are included in Section C of this chapter.
- 7. Optimize distribution transformer ratings over a 4 -to-6 year period by replacing them with transformers more closely matched to the load (lower losses).
- 8. 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 estimated to be \$1.4 million 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. Replace customer meters with digital smart meters (pre -paid).

(Total cost of these initiatives is estimated to be \$ 3.7 million over 6 years.)





Recommended measures and actions will cost \$6.4 million over a 4-to-6 year period, resulting in an estimated savings of \$9.2 million (NPV of \$1.3 million) and reduction of the following:

- 2% for station losses (auxiliaries).
- 2% for technical losses.
- 5% to 6% for non-technical losses. Continuous attention in this effort can further lead to even additional improvements of 4% to 5% of energy savings.
- Savings of \$150,000 per year can be achieved for every 1% improvement in generation efficiency.

Note: MEC is already in the process of replacing all street lights with LED lights , which will save them an additional \$514,000 over 6 years. 20% of the remaining consumption in LED lights should be allocated and billed to proper users and not considered an ene rgy loss. Furthermore, attention must be paid to faulty photocells which keep the lights on during daytime.





7. Kwajalein Atoll Joint Utility Resources (KAJUR)

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

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

Technical and non-technical losses total 15.35%.

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

Recommendations

(The individual report for KAJUR and its appendices contain detailed cost and benefit information.)

A. Generation

- 1. Operate generating units at high efficiency. The engines should be properly maintained and operated near 80% of full rated output. Funding of on-going maintenance requirements is not included.
- 2. Change and/or add meters to provide accurate real-time revenue-class generator outputs and auxiliary plant consumption statistics.

(Total cost of these initiatives is estimated to be \$60,000 over 6 years.)

B. Distribution





- 1. Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime costs (costs of capital, losses, and maintenance). For example, the cost of 1 kW of core losses for 20 years at 20 cents per kWh of fuel cost (based on \$3 per gallon of fuel) is \$21,476 (net present value). For copper losses (loading dependent) the net present value is estimated to be \$11,747. These figures should be taken into account when evaluating bids for new transformers. (A transformer evaluation example is provided in Appendix C of the individual report for KAJUR).
- Add revenue-class meters to the feeders and distribution transformers to measure the losses. Use these meters to check total consumption of customers connected to the individual transformer. These meters can be avoided if customers are tied to transformers in CIS. Cost of the transformer meters is included in item C below with other meter cost.
- 3. Optimize distribution transformers ratings a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses). Not all transformers need to have these meters, only where the need for determining the transformer load is identified due to tampering or other irregularities. KAJUR may also buy 10 to 20 temporary recording meters and install them on the transformers for a time period and subsequently rotate them around to measure transformer load patterns.
- 4. Optimize distribution transformers ratings a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses).
- 5. Work together with Marshall Energy Company (MEC) to use an infrared camera to scan power system equipment at least annually to find hot spots. These usually occur at connector points. Repair as necessary.

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

C. Metering, Billing and Collection

- 1. Develop a Revenue Protection initiative to reduce the non-technical losses. Use revenue protection techniques, technology of digital meters for customers, feeders and distribution transformers along with software, and focus to reduce the non-technical losses.
- 2. Most of the customer meters are of the pre-paid meter type but the accuracy of these meters cannot be assured. Develop a testing program and maintain these meters to revenue-class accuracy.

22





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

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

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

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

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

Table 6: KAJUR Savings and Cost Summary

The cost of reducing technical losses cannot be justified by savings. KAJUR's technical losses are already very low, namely 2.88%. With this low figure, KAJUR belongs to the world's "best in class". Non-technical losses, however, are much too high, and mitigating these losses would be worthwhile. Measures for reducing auxiliary losses cannot be justified at the current fuel price level, but will be worthwhile if crude oil prices reach higher values of US\$ 100 per barrel.

Regarding generation efficiency, only two engines were operable during KEMA's visit. Not the generation efficiency but reliability and availability (and maintenance of the engines) are the key priorities for KAJUR. If overhaul and refurbishment of generators cannot be performed due to a lack of funding, optimization of generation efficiency is currently hardly





possible, only by dispatching the engines as efficient as possible for which the operators need to be trained.





8. Guam Power Authority (GPA)

KEMA's analysis of GPA's power system shows total losses of 12.39% consisting of the following:

- 5.36% in power station auxiliaries (station losses). Generally station losses are lower than 5%.
- 0.17% used by GPA in its own buildings. This unbilled usage cannot be considered to be a system loss. The power usage for own buildings should be accounted for and considered as part of GPA's operational costs.
- 6.36% in technical losses
- 0.50% in non-technical loss.

Technical and non-technical losses total 6.86%.

With non-technical losses being only 0.50%, GPA is "best in class". With a number this low, opportunities for improvement are limited. Also, the figure for technical losses does not leave much room for further reduction in such a way that benefits exceed costs. Station losses in the power plants are somewhat higher than 5% which is considered as a not-to-exceed value at many electric utilities.

Each percentage of loss costs the utility about \$ 2,800,000 at \$2.19 per gallon of fuel. It is estimated when taking the following steps of process improvements, together with recommended investments of \$8.9 million over 6 years, GPA can achieve savings of \$ 3.5 million per year:

- 1. Keep generating units running at highest operating efficiency.
- 2. Maintain optimized dispatching routine to provide highest production efficiencies.
- 3. Update specifications for distribution and power transformers to account for the cost of losses over the total lifetime (capital, losses and maintenance).
- 4. Add revenue-class meters to feeders and distribution transformers. This will also allow timely and accurate identification of non-technical losses from meter tampering, by-passing, or other theft.
- 5. Develop a methodology to optimize distribution transformer sizes to reduce no-load losses.





With these recommendations, it is estimated a net present value savings of \$2.4 million over a period of 6 years is possible. Loss reductions would be as follows:

- Station losses (power plant auxiliaries): from 5.36% to 4.93%
- Technical losses: from 6.36% to 6.26%
- Non-technical losses: from 0.5% to 0.37%





9. Commonwealth Utilities Corporation (CUC)

KEMA's analysis of the Commonwealth Utilities Corporation of Saipan (CUC) power system determined total losses of 28.75% consisting of the following:

- 4.73% in power station auxiliaries (station losses). Typically station losses in power stations of similar sizes are 5%.
- Street lighting 0.98%: Should be accounted for and billed if these revenues cannot be collected, street lighting should be considered a financial loss for CUC and not a power system loss.
- Energy usage for water and sewerage activities 7.93%: Should be allocated to the cost of service and not power system losses. However, if the costs are not allocated to service costs, they will remain a financial loss for CUC's power services and cannot be considered a power system loss.
- 4.36% in technical losses.
- 10.75% in non-technical losses.

Technical and non-technical losses total 15.11%.

Overall losses, including power plant usage total 19.84%.

Recommendations:

(The individual report for CUC and its 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. Change and/or add meters to provide accurate real-time revenue-class generator outputs and auxiliary plant consumption statistics.
- **4.** Train power plant operators on load forecasting and economic dispatch practices. Include an economic dispatch module in future SCADA system plans.

27





(Total cost of these initiatives is estimated to be \$1 million over 6 years.)

B. Distribution

- 1. Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime costs (costs of capital, losses, and maintenance). For example, the cost of 1 kW of core losses for 20 years at 22 cents per kWh of fuel cost (based on \$3 per gallon of fuel) is \$23,161 (net present value). For copper losses (loading dependent) the net present value is estimated to be \$12,609. These figures should be taken into account when evaluating bids for new transformers. (A transformer evaluation example is provided in Appendix C of the individual report for CUC).
- 2. Add revenue-class meters on outgoing transmission lines, distribution feeders, and distribution transformers to measure losses. Use these meters to check total loading on individual transformers. These meters can be avoided if customers are tied to distribution transformers in the Customer Information System. To reduce costs, meter only distribution transformers where there is an obvious need due to tampering, by-passing, or 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.
- 3. Consider the impact of system losses when planning and designing the T&D system. Regularly evaluate the impact of losses due to low power factors and unused transformer capacities (minimizes excessive no-load losses).
- 4. Optimize distribution transformers ratings a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses).
- 5. Require large customers to maintain power factors above a minimum threshold of 0.85. Install capacitors on feeders and in substations to maintain system power factors above 0.95.
- 6. 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.

28

(Total cost of these initiatives is estimated to be \$1.3 million over 6 years.)





C. Metering, Billing and Collection

- 1. Staff a Revenue Protection Department or empower a Revenue Assurance Officer responsible for reducing non-technical losses, who will execute a revenue assurance program that includes regular and un-announced program audits.
- 2. Replace customer meters with digital smart meters (or prepaid meters) for residential customers.

(Total cost of these initiatives is estimated to be \$11.5 million over 6 years.)

Recommended measures and actions under A, B, and C will cost \$13.8 million over a period of 4-to-6 years, resulting in an estimated savings of \$21 million (NPV of \$14.8 million) with a reduction of:

- 0.4% for power plant losses (auxiliaries).
- 1% for technical losses.
- 8% to 9% for non-technical losses.
- Savings of \$600,000 per year can be achieved for every 1% improvement in generation efficiency.

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

Table 7: CUC Savings and Cost

	6 Yrs NPV of Savings and Cost Summary			
NPV @ Cost of Capital	Savings (NPV) Cost (NPV) Net (NP			
Auxiliary loss	\$1,232,616	\$1,000,000	\$232,616	
Non Technical Loss	\$11,906,360	\$9,412,326	\$2,494,034	
Technical Losses	\$1,682,820	\$1,254,994	\$427,827	
Total =	\$14,821,796	\$11,667,320	\$3,154,476	

1% efficiency improvement in generation saves \$ 600,000 per year based on the price of crude oil being \$75 per barrel. At a price of \$100 per barrel the savings of 1% efficiency improvement \$800,000 per year. This assumption can be influenced by fuel pricing effects related to credit worthiness of customers and transportation costs. In this report, economic dispatch of generators has been given highest priority.





10. Yap State Public Service Corporation (YSPSC)

Analysis of the Yap State Public Service Corporation (YSPSC) power system determined total losses of 25.45 % consisting of the following:

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

Technical and non-technical losses total 10.43%.

Overall losses, including power plant usage total 17.86%.

Recommendations

(The individual report for YSPSC and its appendices contain detailed cost and benefit information.)

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

30





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

Table 8: YSPSC Savings and Cost

Generation Park and its efficiency

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

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

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

31





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.
- For every generating unit, add instrumentation to show efficiencies to operators (cost \$125,000). Develop a process that provides regular reporting to management.
- 3. Train power plant operators on load forecasting and economic dispatch practices.
- 4. Include an economic dispatch module in future SCADA system plans.
- 5. Change and/or add meters to provide accurate real-time revenue-class generator outputs and auxiliary plant consumption statistics.
- 6. Develop manual processes to control the operation of fans (cooling fans, exhaust fans and pumps) to run based upon the temperature sensing or other parameters which will optimize the operation and reduce energy consumption.
- Automate manual processes using PLC controls to motor starters (cost not included – this is considered a next step after process improvements and real time analysis as well as focus on energy consumption reduction is in place).
- 8. Apply Frequency Drives (cost not included).
- Benefits from these actions are expected to be \$300,000 over 6 years. Savings are produced by reducing auxiliary losses from 1,033 MWh to 671 MWh per year. Total cost of these initiatives (recommendations 5 through 7) is \$125,000 over 6 years.

B. Distribution

 Develop standard specifications for distribution and power transformers so purchases are based on reducing lifetime costs (costs of capital, losses, and maintenance). For example, the cost of 1 kW of core losses for 20 years at 20 cents per kWh of fuel cost (based on \$3 per gallon of fuel) is \$21,476 (NPV). For copper losses the NPV is estimated to be \$0,519. These figures should be taken into account when evaluating bids for new transformers. (An example of transformer evaluation is provided in Appendix C in the individual report for YSPSC).





- 2. Optimize distribution transformers ratings over a 4-to-6 year period by replacing them with transformers more closely matched to the load (lower losses).
- 3. Add revenue-class meters on feeders and distribution transformers to measure losses. Use these meters to check total loading on individual transformers. These meters can be avoided if customers are tied to distribution transformers in the Customer Information System. To reduce costs, meter only distribution transformers where there is an obvious energy loss due to tampering, by-passing, or where total transformer loads need to be measured. For transformer load profiling 20 to 40 recording meters could be temporarily installed and rotated. Transformer meter costs are included in Section C of this chapter.
- 4. Use an infrared camera to scan the power system equipment at least annually to find hot spots. These usually occur at connector points. Repair as necessary.
- 5. Require large customers to maintain the power factors above 85%. Install capacitors in the distribution system to maintain system powers above 95%.

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

C. Metering, Billing and Collection

- Train a customer service staff member to audit metering and billing processes (including quality checks of billing system data such as multiplier factors, tariff categories applied to customers, functioning of red flags in the case of irregularities and utilizing transformer meters in suspected area or initiating testing of meters and connections) and non-technical loss causes found by meter readers (meter tampering or by-passing, hook ups, etc).
- 2. Assign a senior staff member to be YSPSC's Revenue Assurance Officer, responsible for YSPSC's Loss Reduction Strategy, who will plan and initiate loss reduction programs and activities, keep records of progress and successes, and report to the General Manager. In sections 8.2.3 and 9.1.3 the ways of combating non-technical losses, under the leadership of the Revenue Assurance Officer, are worked out further.

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





11. Palau Public Utilities Corporation (PPUC)

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

- 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

(The individual report for PPUC and its appendices contain detailed cost and benefit information.)

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

	6 Yrs NPV of Savings and Costs					
NPV @ Cost of Canital	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.					

Table 9: PPUC Savings and Cost

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 in the individual report for PPUC) is estimated to be \$350,000.

35

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 in the individual report for PPUC).

- 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.
- 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

 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.