D GRAHAM BOTHA, ESQ.
Legal Counsel
Guam Power Authority
1911 Route 16, Suite 227
Harmon, Guam 96913
Ph: (671) 648-3203/3002
Fax: (671) 648-3290

BEFORE THE GUAM PUBLIC UTILITIES COMMISSION

IN THE MATTER OF:	**GPA DOCKET NO. 12-13**
GUAM POWER AUTHORITY	
LEVELIZED ENERGY ADJUSTMENT	**LEAC FILING**
CLAUSE (LEAC)	

COMES NOW, the GUAM POWER AUTHORITY (GPA), by and through its counsel of record, D. GRAHAM BOTHA, ESQ., and hereby files GPA's LEAC petition to adjust the LEAC factor effective February 1, 2013. Guam Power Authority is requesting to increase the Fuel Recovery Factor from $.18683/kWh to $.20768/kWh effective for meters read on or after February 1, 2013. The change reflects an increase in the LEAC factor which represents a 7.59% increase in the total bill or a $20.85 increase for a residential customer utilizing an average of 1,000 kilowatt hours per month. In addition, there is a forecast of the Working Capital Fund Requirement for an increase of $.00061/kWh which equates to a change of .22% or $.61 per month for a residential customer using an average of 1,000 kWh per month and will result in a monthly increase of $13,157 to Navy billings for a total monthly charge of $192,309.

The basis for the LEAC filing is that there has been a slight increase in fuel prices from $103.58/bbl to around $104.34/bbl which represents a slight increase in fuel costs from the prior LEAC period; the increased blending costs for the fuel supply contract will lead to an increase in fuel costs of approximately 10%; and GPA is forecasting increased use of diesel fuel because Cabras 3 will be unavailable during the upcoming LEAC period. The billing illustrations in Attachment VII show the effect of the change in the Fuel Recovery Factor on customers.

GPA requests that the PUC review GPA's request to move to a quarterly LEAC. Testimony was submitted in the base rate filing, and GPA has submitted additional testimony attached herein as Exhibit "A", and incorporated by reference. It includes the testimony of Randall Wiegand, Liquidity Study, Standard & Poor's Rating, and Moody's Rating. The LEAC worksheets are attached herein as Exhibit "B", and incorporated by reference. Pursuant to the PUC Order of November 10, 2008, the Line Loss Reports are now filed as part of the LEAC Report. The Line Loss Report for June 2012 to November 2012 consists of a Progress Report, Gross Generation/Sales/Line Losses, Monthly Progress Report on Distribution System Improvements, and Feeder Analysis Summary are attached herein as Exhibit "C", and incorporated by reference herein as if fully set forth.

CONCLUSION

The PUC should approve GPA's request for an adjustment to the Fuel Recovery Factor from $.18683/kWh to $.20768/kWh effective February 1, 2013, and an increase of $.00061/kWh and $13,157 in Navy billings in the Working Capital Fund Surcharge, as it is reasonable, prudent, and necessary.

RESPECTFULLY SUBMITTED this 17th day of December, 2012.

D. GRAHAM BOTHA, ESQ.
GPA Legal Counsel

GUAM POWER AUTHORITY
ATURIDÅT ILEKTRESEDÅT GUAHAN
P.O.BOX 2977 • AGANA, GUAM U.S.A. 96932-2977

December 18, 2012

Mr. Frederick J. Horecky, Esq.
Administrative Law Judge
Public Utilities Commission
643 Chalan San Antonio, Suite 102B
Tamuning, Guam 96913

RE: Levelized Energy Adjustment Clause Petition for the Period February 1, 2013 through July 31, 2013
GPA Docket # 12-13

Dear Judge Horecky:

The Guam Power Authority is submitting its petition to the Public Utilities Commission (PUC) for a change in the Levelized Energy Adjustment Clause (LEAC) for the period from February 1, 2013 through July 31, 2013. The petition requests an increase in the LEAC rate from $0.18683/kWH to $0.20768/kWh.

Although market prices for high sulfur fuel oil have been fairly flat since the last fuel rate was established, GPA's next supply agreement will be impacted by the scarcity in blending component products required to meet GPA's fuel oil specifications. GPA is currently reviewing responses to its recently issued bid for its fuel supply; however, the indications from the bid are that the premium portion of the contract will increase significantly as a result of the higher cost of blending components.

Additionally, GPA is submitting further testimony in support of its desire to move to a quarterly LEAC. GPA included testimony in the recently completed base rate filing and wishes to revisit this matter and bring it before the PUC for resolution at this time. This matter is important to GPA credit rating agencies and bondholders who would like to see more regularity in the setting of GPA's fuel rate.

We have done our best to comply with the last order from the PUC with respect to the transmission level discounts. We have carefully reviewed the order and we believe we have utilized the factors desired by the Commission.

The Authority is also requesting to change the Working Capital Fund Surcharge from $0.00778/kWh to $0.00839/kWh for the civilian customers and from $179,152.00 /month to $192,309.00/month for the Navy. Attachment IX WCF Surcharge Adjustment shows the calculation of the surcharge as a result of the change in FY 13 Fuel Costs budget. We are proposing to amortize the change in twelve (12) months effective February 1, 2013 through January 31, 2014.

Aside from these issues, we believe this filing is fairly standard and does not contain any additional significant matters.

Please let me know if you have any questions or concerns regarding this matter.

Yours truly,

Joaquin C. Flores, P.E.
General Manager

cc: Mr. Randall V. Wiegand, CFO
Mr. Graham Botha, Staff Attorney
GM/CFO 008 13

LEAC – DOCKET 12-13

EXHIBIT A:	**Testimony** - Randall V. Wiegand, Chief Financial Officer Exhibit A, Appendix A: Resume Exhibit A, Appendix B: Proposed Tariff Schedule Z Exhibit A, Appendix C: Liquidity Study Exhibit A, Appendix D: Standard & Poor's Rating Exhibit A, Appendix E: Moody's Rating
EXHIBIT B:	**ATTACHMENT I** Current Period (August 2012 to January 2013) LEAC Reconciliation
	ATTACHMENT II Projected Spreadsheets (February 2013 to July 2013) LEAC Reconciliation
	ATTACHMENT III FY12 Actual LEAC Recovery
	ATTACHMENT IV Support for Dispatch Assumption
	ATTACHMENT V Support for Fuel Price per Barrel
	ATTACHMENT VI Documentation on all Fuel Handling Expenses (Existing contracts submitted in the previous LEAC Filing)
	ATTACHMENT VII Billing Illustrations – Residential, Large Power Service, Large Government Service
	ATTACHMENT VIII Actual vs. Planned Fuel Cost per Barrel
	ATTACHMENT IX Working Capital Fund Surcharge Adjustment
	ATTACHMENT X Excess Bond Fund Transactions
EXHIBIT C:	Line Losses & Quarterly Management Plan (Progress Report)
EXHIBIT D:	LEAC – GPA Resolution No. 2012-77
EXHIBIT E:	Fuel Hedging Recommendations - Ordering Provision #4 Ref: GPA Docket 12-06 LEAC – PUC Order (Stamped July 30, 2012)
EXHIBIT F:	Cabras #2 (Actions taken to reduce forced outages/meeting availability standard) – Ordering Provision #6 Ref: GPA Docket 12-06 LEAC – PUC Order (Stamped July 30, 2012)

EXHIBIT A

GUAM PUBLIC UTILITIES COMMISSION

DOCKET NO. 12-13

DIRECT TESTIMONY OF

Randall V. Wiegand

ON BEHALF OF

GUAM POWER AUTHORITY

Hagåtña, Guam

December 18, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF GUAM

In the Matter of GUAM POWER AUTHORITY LEAC Filing	))))))	**Docket No. 12-13**

AFFIDAVIT OF RANDALL V. WIEGAND

TERRITORY OF GUAM	)))

RANDALL V. WIEGAND, being first duly sworn on his oath, states:

1. My name is **RANDALL V. WIEGAND**. My office is in Harmon, Guam, and I am employed by Guam Power Authority as the Chief Financial Officer.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Guam Power Authority, consisting of One Hundred and twenty Eight (128) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

____
RANDALL V. WIEGAND

Subscribed and sworn before me this 18th day of December 2012.

____
Notary Public

ANTONIO S. GUMATAOTAO
NOTARY PUBLIC
In and for Guam, U.S.A.
My Commission Expires: **Dec. 20, 2014**
P.O. Box 2977 Hagatna, GU 96932-2977

DIRECT TESTIMONY OF

RANDALL V. WIEGAND

Docket No. 12-13

INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH GPA.

A. My name is Randall V. Wiegand. My Business Address is 1911 Army Drive, Harmon, Guam. I am the Chief Financial Officer of the Guam Power Authority (GPA).

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my current position with GPA, my primary responsibilities involve overseeing the Financial Department which strives to provide accurate and timely financial information to internal and external stakeholders; overseeing and helping to shape the capital structure of GPA, including debt, equity, and internal financing decisions; and overseeing economic and financial planning to ensure that GPA improves its financial health so as to better serve its customers and reach its strategic goals.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE, INCLUDING YOUR EMPLOYMENT HISTORY WITH GPA.

A. My resume, which contains a summary of my educational and professional experience, is attached as Exhibit A, Appendix A.

Q. HAVE YOU EVER TESTIFIED IN A PROCEEDING BEFORE THE GUAM PUBLIC UTILITY COMMISSION AND IF SO, IN WHAT CAPACITY?

A. Yes. I have provided testimony before the Guam Public Utilities Commission (Guam PUC) on numerous occasions on behalf of GPA as well as the Guam Waterworks Authority.

Q. HAS THE TESTIMONY YOU ARE PROVIDING BEEN PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. GPA is submitting its bi-annual Levelized Energy Adjustment Clause (LEAC) and is making an additional attempt to modify the LEAC tariff to allow for a quarterly LEAC true up process. This was submitted by GPA in the context of its November 2011 rate petition and is a continuing issue GPA wishes to have addressed by the PUC.

Q. WHAT CHANGE IS GPA REQUESTING TO THE TARIFF?

A. GPA is requesting that the LEAC tariff be modified to allow for the normal filing to be made every June 15 and December 15 with effective dates of August 1 and February 1, respectively, and to allow for a modified LEAC filing to enable a streamlined review to be made every March 15 and September 15 with effective dates of May 1 and November 1, respectively.

Q. PLEASE LIST THE APPENDIXES YOU ARE PRESENTING WITH YOUR SUPPLEMENTAL TESTIMONY.

A. I am presenting the following appendixes:

Exhibit A, Appendix A: Resume

Exhibit A, Appendix B: Proposed Tariff Schedule Z

Exhibit A, Appendix C: Liquidity Study

Exhibit A, Appendix D: Standard & Poor's Credit Report

Exhibit A, Appendix E: Moody's Credit Report

QUARTERLY LEAC

Q. WHAT HAS GIVEN RISE TO THIS PETITION FOR A QUARTERLY LEAC?

A. R.W. Beck, Inc. conducted a Liquidity Study on behalf of GPA with a final report dated December 30, 2009 (See Appendix C attached)[1]. The purpose of the study was to make recommendations to bring the liquidity of the Authority in line with comparable utilities. One of the issues discussed in the report is the impact of the LEAC on cash requirements. The study noted that the liquidity requirement for a utility with a LEAC of one, two or three months is fairly similar. However, beyond (4) four months, the need for liquidity increases. If the utility is in a position where it must wait (6) six months to file for relief from increasing fuel costs, the impact on liquidity requirements increases.

Q. ARE THERE OTHER FACTORS THAT HAVE LED GPA TO MAKE THIS PETITION?

A. Yes. As the Commission is aware, cash on hand is the most important factor rating agencies consider when they review the creditworthiness of GPA. They have expressed their concern on many occasions as to the impact the (6) six month Levelized Energy Adjustment Clause has on GPA's cash requirements. The rating agencies are aware that GPA has the ability to petition for mid-term relief; however, they have noted that there have been many times where GPA has absorbed the cash impact of increasing fuel costs and have not taken advantage of the ability to get mid-term relief. They have expressed their strong desire to GPA to move to a quarterly LEAC tariff in order to minimize the risk that rising fuel costs could have a negative impact on GPA's cash flow. This was included by Moody's in their recent credit review report and noted it would be positive for GPA's credit. (See Appendix D) Standard and Poor's mentioned the move to a quarterly LEAC indicating it is a point of interest for them. (See Appendix E)

Q. IS THIS THE FIRST TIME GPA HAS SUBMITTED A PETITION TO MOVE TO A QUARTERLY LEAC FILING TO THE PUC?

---

[1] See Section 3 of Report.

A. GPA has made similar filings on two previous occasions – most recently in conjunction with its base rate petition filed in November 2011. In response to the first filing, the PUC expressed concern over the administrative burden the petition would require. The concern was that GPA and the PUC would be continually engaged in LEAC filings. In the second petition GPA proposed a streamlined process that would mitigate the administrative burden; however, the PUC response was that the discretion given to the CCU as to whether or not the rate should be changed was not acceptable. This filing addresses both of the concerns raised by the PUC and we believe the PUC will find this proposal to be acceptable. The filings must be made every quarter and every other filing is an abbreviated filing to be fully trued up during a period of a full filing.

Q. PLEASE DESCRIBE THE CHANGES GPA IS REQUESTING.

A. GPA is petitioning for relatively small changes in the LEAC. The six month filings which GPA is calling "Full Filings" would continue to be due each June 15 and December 15 without any change. The petition would create two new "Abbreviated Filings" to be due on March 15 and September 15 of each year. The Abbreviated filings would update the Full Filing with actual results, new forward curve pricing information, and a (6) six month forecast of fuel requirements. Other than these factors, everything else in the filing would need to remain as it was in the previous Full Filing. This should allow for a streamlined review and should not create any significant administrative burden or cost on the PUC. Additionally, it removes any discretion on the part of the Authority or the CCU as a filing will be made each quarter – a full filing every (6) six months and an abbreviated filing in between the full filing periods.

Q. PLEASE DESCRIBE HOW THE FILING PERIODS WOULD WORK?

A. The Full Filings would remain (6) six month filings. The Abbreviated Filings would also be (6) six month filings for the periods ending October 31 and April 30 respectively. For example, at this time GPA is petitioning the PUC with a Full Filing for the period from February 1, 2013 through July 31, 2013. Under the proposed plan, GPA would file an Abbreviated Filing on March 15 for the period from May 1, 2013 through October 31, 2013. The filing would consist of the same assumptions as the prior Full Filing and would only be updated with up to date fuel pricing data and historical cost information. The PUC review would consist of confirming the price data and reviewing the historical data for reasonableness. The filing would then be subject to a full true up during the review of the Full Filing for the period August 1, 2013 through January 31. 2014. This scenario would continue on through subsequent filings.

Q. WHY IS GPA REQUESTING THAT ALL OF THE FORECASTS BE FOR A (6) SIX MONTH PERIOD?

A. Due to the nature of GPA's fuel accounting, at times it can take (3) three months for current fuel inventory to be run through the LEAC. Under GPA's First In First Out accounting method, the fuel in GPA's inventory is recognized through the LEAC before any new purchases can be recognized. GPA has (2) two types of fuel for which it needs to maintain supply reserves. Thus, at any given point, GPA can have between 30 and 90 days of supply in its inventory. If at the beginning of a 90 day LEAC period, there is 90 days of fuel in inventory, only that fuel would be expensed during the LEAC period and any recent change in fuel prices would not be reflected in the LEAC factor. This would create a significant cash problem for GPA in that it would be required to pay fuel costs in one quarter but would not be reimbursed until the following quarter. For this reason, GPA is petitioned for (6) six month LEAC periods petitioned on a quarterly basis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY IN THIS FILING?

A. Yes, it does.

PMB 551
535 Chalan Pale RH Ste 116
Yigo, Guam 96929-2430
Work (671) 648-3066
Home (671) 653-9673
E-mail: rwiegand@gpagwa.com

Randall V. Wiegand

Objective

To obtain a finance/accounting related position that presents new challenges and opportunities for professional growth.

Education

1988 - 1990 University of Washington Seattle, WA

Masters of Business Administration (Finance/Int'l Business)

1980 -1983 Seattle Pacific University Seattle, WA

Bachelor of Arts; Business Finance

1979 - 1980 University of Washington Seattle, WA

General Undergraduate studies

Professional experience

2003 – Present Guam Power Authority
2003 - 2007 Guam Waterworks Authority Harmon, GU

Chief Financial Officer

- Responsible for overseeing the accounting and budget divisions of the Guam Power Authority and the Accounting, Customer Services, Data Processing, and Procurement divisions of the Guam Waterworks Authority. Provide reports and analysis to the Consolidated Commission on Utilities. Helped bring GWA to near investment grade rating and reverse the rating slide at GPA. Worked on rate petitions with the Guam Public Utilities Commission.

2001 – 2003 Office of the Public Auditor Hagåtña, GU

Audit Manager

- Responsible for managing audit staff in the completion of performance audits for agencies and departments within the Government of Guam. Assisted in re-establishing the Office under Guam's first elected public auditor. Developed the staff audit manual and various SOP's. Managed all audits conducted by the Office and all audit personnel. Oversaw the creation of a local area network for the agency, the development of a website, and managed computer/networking purchases.

2000 – 2001 PacifiCare Asia Pacific Tamuning, Guam

Healthcare Economics Manager

- Responsible for managing the pricing of healthcare plans, evaluating risk of potential new business, large contract negotiations, coordinating new plan development, managing benefit database, etc. Played a key role in the implementation of an enterprise-wide healthcare administration software package.

1995 - 2000 Guam Power Authority Harmon, Guam

Comptroller

- Served as the agencies chief financial officer reporting to the Board of Directors. Responsible for accounting systems, transactions, and controls; development of budget; financial planning and forecasting; long and short term financing; cash management; management of bond issuances: risk management; fuel contract management; coordination of rate related activities; project manager for implementation of financial management system.

1990 - 1995 Deloitte & Touche – Guam Hagatna, Guam

Audit Supervisor

- Responsible for audits of small- to medium-sized businesses and various agencies of the Government of Guam. Industries audited include retail, construction, health care, property management, and banking .

Professional memberships

Certified Public Accountant, State of Washington and Territory of Guam,
Certified Government Financial Manager
Certified Fraud Examiner (pending)

Other activities

President; Association of Government Accountants
Treasurer/Elder, Yigo Baptist Church

References Available Upon Request

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GUAM POWER AUTHORITY

SCHEDULE "Z"

Levelized Energy Adjustment Clause
(LEAC)

Purpose

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The purpose of the Levelized Energy Adjustment Clause is to make GPA whole for the funds it spends on fuel and fuel related costs which are less predictable than many of GPA's other recurring costs. The tariff schedule establishes the methodology for calculating the amount of the tariff as well as establishing timelines for the review and adjustment of the rate to recover these costs.

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Definitions

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Abbreviated Filing. An Abbreviated Filing will include LEAC spreadsheets, recent fuel invoices, and GPA's forecast for future fuel costs. The Abbreviated Filing includes limited variable changes in order to enable a streamlined review process.

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Full Filing. A Full Filing will include the list of items indicated in Exhibit A and will be the mechanism for a full review and true up of the fuel rate.

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Filing Deadlines.

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The effective dates for LEAC rates based on Full Filings are February 1 and August 1. The effective dates for LEAC rates based on Abbreviated Filings are May 1 and November 1. Filings for each of these periods shall be due to the Public Utilities Commission 45 days prior to the start of a LEAC period. The LEAC is a revenue neutral rate and will be fully trued up with every Full Filing.

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Computation of LEAC Factor

The calculation of each bill, pursuant to the rates and charges contained in the applicable rate schedule, shall be subject to an adjustment for variations in fuel cost. The adjustment will be made by multiplying a Fuel Recovery Charge times the total kilowatt hours for which the bill is rendered.

The Fuel Recovery Charge will be calculated semi-annually by the following formula:

$$\text{Fuel Recovery Charge} = \frac{A +/- B +/- C}{D}$$

Where:

A - Equals the projected fuel expense for the next LEAC period, including amounts GPA is required to pay under the fuel risk management program and adjustments to the carrying value of GPA's fuel inventory so long as the number of barrels is consistent with parameters adopted by the PUC[1], but excluding net fuel reimbursement from Navy through the Customer Agreement settlements.

B - Equals the difference between the fuel revenue and actual fuel expenses as approved by the Public Utilities Commission, including the true up of the second prior six month period excluding net revenue from Navy through the Customer Agreement settlements.

C - Refunds or credits from supplier, excluding legal settlements.

D - Equals the projected retail KWH sales for the next six months.

The Fuel Recovery Charge will be recalculated quarterly, with a six month forward projection and be subject to the approval of the Guam Public Utilities Commission. In the event that GPA has a cumulative under [or over] recovery balance of more than $2 million or if the under [over] recovery balance is projected to exceed $2 million during the six-month levelized period, excluding net revenues from the Navy under The Customer Agreement, the Fuel Recovery Charge may be adjusted to recover such deficit.

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[1] For the LEAC period ending July 31, 2008 the adjustment to the carrying value has been established to be $5.296 million. For periods beginning after July 31, 2008 the change in carrying value will be based on projected changes for the succeeding six month period and (for periods beginning after January 31, 2009) a true up of projected versus actual costs for the preceding six month period.

Issued March 21, 1994
Revised May 2011
Effective with meters read
on and after February 1, 2013

Rate Schedule "Z"

GUAM POWER AUTHORITY

SCHEDULE "Z"

Levelized Energy Adjustment Clause (LEAC)

Purpose

The purpose of the Levelized Energy Adjustment Clause is to make GPA whole for the funds it spends on fuel and fuel related costs which are less predictable than many of GPA's other recurring costs. The tariff schedule establishes the methodology for calculating the amount of the tariff as well as establishing timelines for the review and adjustment of the rate to recover these costs.

Definitions

Abbreviated Filing. An Abbreviated Filing will include LEAC spreadsheets, recent fuel invoices, and GPA's forecast for future fuel costs. The Abbreviated Filing includes limited variable changes in order to enable a streamlined review process.

Full Filing. A Full Filing will include the list of items indicated in Exhibit A and will be the mechanism for a full review and true up of the fuel rate.

Filing Deadlines.

The effective dates for LEAC rates based on Full Filings are February 1 and August 1. The effective dates for LEAC rates based on Abbreviated Filings are May 1 and November 1. Filings for each of these periods shall be due to the Public Utilities Commission 45 days prior to the start of a LEAC period. The LEAC is a revenue neutral rate and will be fully trued up with every Full Filing.

Computation of LEAC Factor

The calculation of each bill, pursuant to the rates and charges contained in the applicable rate schedule, shall be subject to an adjustment for variations in fuel cost. The adjustment will be made by multiplying a Fuel Recovery Charge times the total kilowatt hours for which the bill is rendered.

The Fuel Recovery Charge will be calculated semi-annually by the following formula:

$$\text{Fuel Recovery Charge} = \frac{A \pm B \pm C}{D}$$

Where:

A - Equals the projected fuel expense for the next LEAC period, including amounts GPA is required to pay under the fuel risk management program and adjustments to the carrying value of GPA's fuel inventory so long as the number of barrels is consistent with parameters adopted by the PUC[1], but excluding net fuel reimbursement from Navy through the Customer Agreement settlements.

B - Equals the difference between the fuel revenue and actual fuel expenses as approved by the Public Utilities Commission, including the true up of the second prior six month period excluding net revenue from Navy through the Customer Agreement settlements.

C - Refunds or credits from supplier, excluding legal settlements.

D - Equals the projected retail KWH sales for the next six months.

The Fuel Recovery Charge will be recalculated quarterly with a six month forward projection and be subject to the approval of the Guam Public Utilities Commission. In the event that GPA has a cumulative under [or over] recovery balance of more than $2 million or if the under [over] recovery balance is projected to exceed $2 million during the six-month levelized period, excluding net revenues from the Navy under The Customer Agreement, the Fuel Recovery Charge may be adjusted to recover such deficit.

[1] For the LEAC period ending July 31, 2008 the adjustment to the carrying value has been established to be $5.296 million. For periods beginning after July 31, 2008 the change in carrying value will be based on projected changes for the succeeding six month period and (for periods beginning after January 31, 2009) a true up of projected versus actual costs for the preceding six month period.

Working Capital and Cash Reserve Financial Analysis

Guam Power Authority

December 2009

R·W·BECK

An SAIC Company

Working Capital and Cash Reserve Financial Analysis

Guam Power Authority

December 2009

R·W·BECK

An SAIC Company

R·W·BECK
An SAIC Company

December 30, 2009

Mr. Randall V. Wiegand
Chief Financial Officer
Guam Power Authority
1911 Route 16
Harmon, Guam 96912

Subject: **2009 Working Capital and Cash Reserve Financial Analysis**

Dear Mr. Wiegand:

R. W. Beck, Inc., is pleased to submit this final report on the Working Capital and Cash Reserve Financial Analysis of Guam Power Authority. The report describes the development of potential improvements that may help GPA meet its financial, operational, and customer service goals. The document sets forth the approach, methodology, and results of our analysis.

This project was a joint effort between GPA and R. W. Beck and we wish to express our appreciation for your assistance along with the assistance of other GPA staff members who provided the timely information and review necessary for the successful completion of this project.

Once again, we appreciate the opportunity to be of service to GPA.

Very truly yours,

R. W. BECK, INC.

Jennifer White

Jennifer A. White
Senior Associate

Angelo Muzzin

Angelo Muzzin
Senior Director

File: 000008 / 11-01323-10102-0101

Working Capital and Cash Reserve Financial Analysis

Guam Power Authority

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Section 1
SUMMARY AND RECOMMENDATIONS

Study Summary

High oil prices and their impact on the cost of power have caused periods of extremely poor liquidity and cash scarcity within Guam Power Authority (GPA). GPA has below-average credit ratings for a public power utility and has had recent difficulty securing bank loans. Volatile and high fuel prices and the inability to access financial markets have highlighted the need to determine appropriate levels of working capital and cash reserves necessary for normal business operations going forward.

In June of 2009, GPA requested R. W. Beck, Inc. (R. W. Beck) assess the following: if normal industry practices related to these issues are being followed within GPA; if the current levels of working capital and cash are appropriate to meet its needs and mitigate risks; if changes to its debt service coverage, equity ratio, and cash positions may improve access to financial markets. Based on these findings, GPA asked R. W. Beck to recommend potential improvements that may help GPA better meet its financial, operational, and customer service goals. R. W. Beck developed an action plan, and with the assistance and support of GPA staff, conducted the requested analyses.

Details of the methodology and findings are provided in the following report sections. As a brief overview, R. W. Beck first compiled financial and operational data for a set of nine "comparable utilities" and measured GPA's performance and practices against those utilities. We examined standard metrics such as levels of working capital, days cash on hand, debt/equity ratios, and debt service coverage (DSC). We also compared GPA's fuel/energy cost adjustment mechanism, regulatory structure, and self-insurance policies and practices with the comparable utilities. We then examined how changes in the Levelized Energy Adjustment Clause (LEAC) would change GPA's cash and working capital levels and determined GPA's current fuel-related working capital and cash needs. We also reviewed GPA's regulatory DSC goal and the bond covenant DSC requirement and examined the impact of raising GPA's DSC to be more in line with investment-grade utilities.

Conclusions and Recommendations

Based on these analyses, our principal findings and recommendations are as follows:

1. GPA's available cash on hand is much lower than the comparable utilities and generally does not follow standard industry practice. From an examination of monthly data from October 2006 to July 2009, GPA's average cash on hand, measured in days of operating expenses covered, or "days cash on hand," was

21 days. The comparable utilities averaged 125 days for years 2006, 2007, and 2008.

R. W. Beck found that comparable utilities following typical industry practice average a minimum of between 45-60 days cash on hand. We recommend GPA set a policy of achieving at least 60 days cash on hand as a minimum cash level, given its above average vulnerability to volatile fuel pricing and extreme weather events. Using Fiscal Year 2008 as an example, GPA actually averaged only $20.1 million of unrestricted cash and cash equivalents (about 24 days). To meet the 60 days cash on hand target, it would require $51.3 million of unrestricted cash and cash equivalents, an increase of $31.2 million.

2. GPA's available working capital is much lower than the comparable utilities. An examination of monthly data from October 2006 to July 2009 indicated GPA's average working capital (measured in months of operating expenses covered, or "operating months of working capital") was 1.03 months. The comparable utilities average 4.5 months for years 2006 through 2008.

   R. W. Beck recommends GPA set a policy of achieving at least 3 months of working capital at a minimum, given its past inability to fund planned and budgeted capital improvement projects, and its vulnerability to volatile fuel pricing and extreme weather events. Using Fiscal Year 2008 as an example, GPA actually averaged only $34.3 million of unrestricted net working capital (about 1.3 months). To meet the 3 operating months of working capital target would require approximately $78.0 million of unrestricted net working capital, an increase of $43.7 million, which is inclusive of the $31.2 million increase of cash and cash equivalents provided in recommendation number one above.

3. GPA's current levels of fuel-related working capital are not sufficient given the current LEAC mechanism. On average, from October 2005 to July 2009, the LEAC has been adjusted every 4.9 months. Using this average and average fuel prices over that period, the current net revenue lag of 44 days (weighted revenue lags minus weighted expense leads) requires $24.9 million of working capital. Higher fuel prices, for example those experienced in October 2008 (the peak month of that period), would require $46.4 million of working capital. Using Fiscal Year 2008 as an example, GPA's total unrestricted net working capital for both fuel and non-fuel items was only $34.3 million on average. This would indicate that if oil prices rise dramatically as they have done in recent years, GPA would likely not have enough fuel-related working capital to cover its net revenue lag. Either a monthly or quarterly LEAC (which between them would require the same working capital levels) would allow GPA to maintain less fuel-related working capital than the amounts indicated above. However, no matter the adjustment mechanism or timing decided on in the future, GPA's fuel-related working capital must be sufficient to cover the net revenue lag resulting from the given expense leads, the customer revenue/billing lag, and the LEAC adjustment lag.

R. W. Beck recommends GPA move to a quarterly LEAC to lesson the fuel-related working capital requirements and to mitigate the negative impacts of extremely volatile fuel prices.

4. GPA sets its rates using a regulatory DSC goal of 1.75 that does not include the IPP (Independent Power Producers) obligations as part of its debt. However, credit rating agencies include these fixed financial obligations as part of their debt and DSC calculations. GPA falls well short of the 1.75 goal when these are included—with the IPP obligations, GPA had a DSC ratio of 1.34 for Fiscal Year 2008. R. W. Beck believes GPA not meeting a higher DSC level is a contributing factor to its lower-than-investment-grade debt ratings by two of the three rating agencies.

   R. W. Beck recommends GPA set a policy to use a DSC goal of 2.00, that includes the IPP obligations as debt for its ratemaking purposes, with a less ambitious but improved target level of 1.75 as an initial ratemaking implementation policy. These levels are more in line with the comparable utilities and with the public power utility industry in general.[1]

5. GPA currently has an equity ratio, based on an equity to total capitalization calculation basis, of approximately 22%. If GPA wishes to obtain consistent long-term investment-grade ratings and reduce its financial risk profile, it is incumbent on the utility to increase its system equity level as part of its capital funding needs. A higher level of system equity will benefit GPA and its customers by reducing debt and associated debt service costs needed to fund capital expansion and system improvements over the long-run.

   R. W. Beck recommends that GPA set a policy of achieving a long-term equity ratio of between 30% and 40% in the future, a level consistent with other well-rated public power utilities.

Rate Setting Recommendations

Based on the above recommended changes in financial and regulatory policies, R. W. Beck recommends GPA undertake a rate filing(s) that would incorporate the following changes:

1. GPA's next rate filing should include a 3% to 5% rate increase above the level necessitated by other revenue requirement needs so as to improve its DSC, days cash on hand, and working capital levels, as discussed above. This increase would need to be in place for approximately 2 to 4 years for GPA to obtain the minimum financial improvements recommended in this report.

2. GPA's revenue requirements in the rate filing should be based on a 2.00 ratemaking DSC level using all debt expenses, including short-term debt and fixed payments associated with IPP obligations.

[1] There were available DSC ratios for eight of the comparable utilities, together they averaged a DSC of 2.08 for 2006-2008. HECO Consolidated DSC ratios were not available.

3. GPA's new rate levels should be maintained until such time as GPA achieves a minimum system equity goal of 30%.

While we have not quantified the total rate impact these recommendations would have on GPA's rates or on individual rate classes, we believe it may be appropriate to "phase in" some of these recommendations over two rate filing periods.

Meeting these recommendations will improve GPA's financial and operational performance in several ways. GPA's improved cash, working capital, and DSC levels will enable it to better handle volatile fuel prices and to address costs resulting from extreme weather events. Instead of having to suspend operation and maintenance and system improvement programs because of cash shortfalls, GPA will be able to implement these programs in a timely and cost-effective manner. This will increase efficiency, improve reliability, and reduce the cost of operations—which result in better service and a lower cost to customers over the long term. Meeting these recommendations will also move GPA towards meeting its strategic goal of obtaining secure investment-grade credit ratings, which will enable GPA both to better access financial markets and to lower its future debt costs.

Section 2
BENCHMARKING OF COMPARABLE UTILITIES

Examining GPA's past financial performance and developing ways to improve its liquidity, DSC, and system equity positions will result in a number of practical implications, including:

- Strengthening GPA's debt ratings by major rating agencies and improving its access to lower-cost capital resources;
- Enabling GPA to deal with unexpected events, such as fuel price spikes and extreme weather events, in a way that limits disruption of normal operations due to lack a cash and working capital; and
- Assuring GPA's operation and maintenance and system improvement programs are implemented in a timely and cost-effective manner and that they are not suspended due to periodic cash short falls. This will increase efficiency, improve reliability, and reduce the cost of operations—which result in better service and a lower cost to customers over the long-term.

To help assess GPA's working capital and cash reserve requirements, R. W. Beck first determined what standard, appropriate levels of working capital and cash reserves are for utilities similar to GPA. As an alternative to a more expensive and time-consuming lead/lag analysis of all GPA costs and revenues, R. W. Beck adopted a benchmarking approach, compiling and analyzing available financial data, such as debt, working capital, cash reserves, self-insurance, operations expenses, etc., for a sample set of utilities. This set of "comparable utilities" included those that are similar in island configuration and oil-dependency to GPA, such as utilities in Hawai`i. It also included other U.S. utilities of a size similar to GPA that also have substantial generation resource responsibilities including fuel procurement. Selected utilities all have investment-grade credit ratings and several are rate-regulated by public utility commissions.

In total, nine utilities were identified and used for the analysis:

1. Anaheim Public Utilities, Electric Utility (Anaheim);
2. Anchorage Municipal Light & Power (Anchorage);
3. Gainesville Regional Utilities (Gainesville);
4. Hawaiian Electric Company, Consolidated (HECO Consolidated);
5. Kaua`i Island Utility Cooperative (Kaua`i);
6. Modesto Irrigation District (Modesto);
7. Riverside Public Utilities (Riverside);

8. The City of Tallahassee Electric Utility (Tallahassee); and
9. Turlock Irrigation District (Turlock)

We gathered publicly available financial and rating agency documents, such as published Annual Reports, FERC Form 1 reports, and detailed rating agency reports. We reviewed these reports and documents, and catalogued the data necessary to complete the analysis in spreadsheet format. This data included general information such as the type of entity (investor-owned, municipal utility, etc.), the regulatory structure (Board, Council, PUC, etc.), and number of customers, as well as more detailed financial data, such as operating revenues, operating expenses and fuel costs, operating margins, assets, depreciation, debt and equity ratios, working capital, cash reserve availability, and other information.

R. W. Beck staff also contacted each of the comparable utilities and asked them to complete a written informational request, in order to confirm the data we had gathered was correct and to provide more detail related to their financial and operating guidelines and practices. Of the nine comparable utilities contacted, Anaheim, Gainesville, Kaua`i, and Riverside returned the requested surveys, and this information was added to the benchmarking spreadsheet analysis. A copy of the benchmarking informational request is provided as Appendix A. An electronic copy of the benchmarking spreadsheet analysis was provided to GPA staff. A summary of the data gathered for each of the comparable utilities is provided in Appendix B.

Table 2-1 presents some basic structural, regulatory, and rating information for the comparable utilities from the benchmarking analysis.

Table 2-1
Basic Information for GPA and Comparable Utilities[2]

Utility	Entity Type	Rate Governing/ Regulatory Bodies	Reporting for Fiscal Year or Calendar Year (Start Month/ Day)	Fuel Adjustment / Power Cost Adjustment Mechanism	Available Bond Ratings (Rating Agency)
Anaheim Public Utilities, Electric Utility	Municipal Utility	Anaheim City Council	Fiscal (Jul 1)	Quarterly Rate Stabilization Adjustment, includes a Power Cost Adjustment and Environmental Mitigation Adjustment	Fitch Ratings: AA- Moodys: Aa3 S&P: AA-
Anchorage Municipal Light & Power	Municipal Utility	Regulatory Commission of Alaska	Fiscal (Jul 1)	Quarterly Fuel and Purchased Power Cost Adjustment (COPA)	Fitch Ratings: A+ Moodys: A1 S&P: A+
Gainesville Regional Utilities	Municipal Utility	Gainesville City Commission	Fiscal (Oct 1)	Monthly Retail Fuel Adjustment Mechanism	Fitch Ratings: AA Moodys: Aa2 S&P: AA
Hawaiian Electric Company, Consolidated	Investor-Owned Utility	Hawaii Public Utilities Commission	Calendar (Jan 1)	Energy Cost Adjustment Clause (ECAC)	Fitch Ratings: n/a Moodys: Baa1 S&P: BBB
Kaua'i Island Utility Cooperative	Cooperative	Hawaii Public Utilites Commission	Calendar (Jan 1)	Energy Rate Adjustment Clause (ERAC)	Fitch Ratings: n/a Moodys: n/a S&P: n/a
Modesto Irrigation District	Public Utility District	Modesto Irrigation District Board of Directors	Calendar (Jan 1)	No information available	Fitch Ratings: A+ Moodys: A1 S&P: A+
Riverside Public Utilities	Municipal Utility	Board of Public Utilities, appointed by Riverside City Council	Fiscal (Jul 1)	Quarterly Power Cost Adjustment Factor (PCAF)	Fitch Ratings: AA- Moodys: Aa3 S&P: AA-
The City of Tallahassee Electric Utility	Municipal Utility	Tallahassee City Commission	Fiscal (Oct 1)	Monthly Energy Cost Recovery Clause (ECRC)	Fitch Ratings: AA- Moodys: Aa3 S&P:AA-
Turlock Irrigation District	Public Utility District	Turlock Irrigation Distric Board of Directors	Calendar (Jan 1)	Bi-Annual Power Supply Adjustment	Fitch Ratings: A+ Moodys: A1 S&P: A+
Guam Power Authority	Governmental Utility	Consolidated Commission on Utilities/ Guam Public Utilities Commission	Fiscal (Oct 1)	Bi-Annual Levelized Energy Adjustment Clause (LEAC)	Fitch Ratings: BB+ Moodys: Ba1 S&P: BBB-

Once information was gathered, we compared the financial parameters of interest for GPA to the nine comparable utilities. The results and findings of this comparison as they relate to working capital requirements and financial debt ratings are described in the following report sections. Information related to automatic energy/fuel cost adjustment mechanisms for GPA and the comparable utilities is provided in Section 2.

2 Kaua`i is a cooperative and as such is not rated by the ratings agencies.

Days Cash on Hand

A useful indicator of a utility's liquidity and ability to fund normal business operations is the number of days of operating expenses it can cover with cash available at a given point in time, or days cash on hand. In comparing GPA to the comparable utilities, R. W. Beck used year-end financial data. We have defined days cash on hand as Moody's Investors Service defines it—equivalent to unrestricted cash and investments times 365 divided by total annual operating expenses (total operating expenses including fuel, less depreciation and amortization). GPA's cash on hand consists of those accounts reported as "Cash and Cash Equivalents: Bond Indenture Funds" in GPA's financial statements. Although GPA may have other cash reserves, only unrestricted funds—those that can be freely used for a wide variety of purposes—should count towards the cash on hand measurement. For example, GPA's self-insurance fund is to be used only for specific restricted purposes, monies from this account must be used to cover transmission/distribution losses and/or damage. Therefore the self-insurance fund does not count towards GPA's days cash on hand. Figure 2-1 compares GPA's days cash on hand with the comparable utilities for the three-year period 2006 to 2008.

Using this metric, GPA is below the 2006 to 2008 average of 125 days for the comparable utilities. Using year-end data, from Fiscal Years 2006 to 2008 GPA averaged 29 days cash on hand. At the end of Fiscal Year 2008, GPA reported only 23 days cash on hand, consisting of $19.8 million in the bond indenture funds held by GPA.

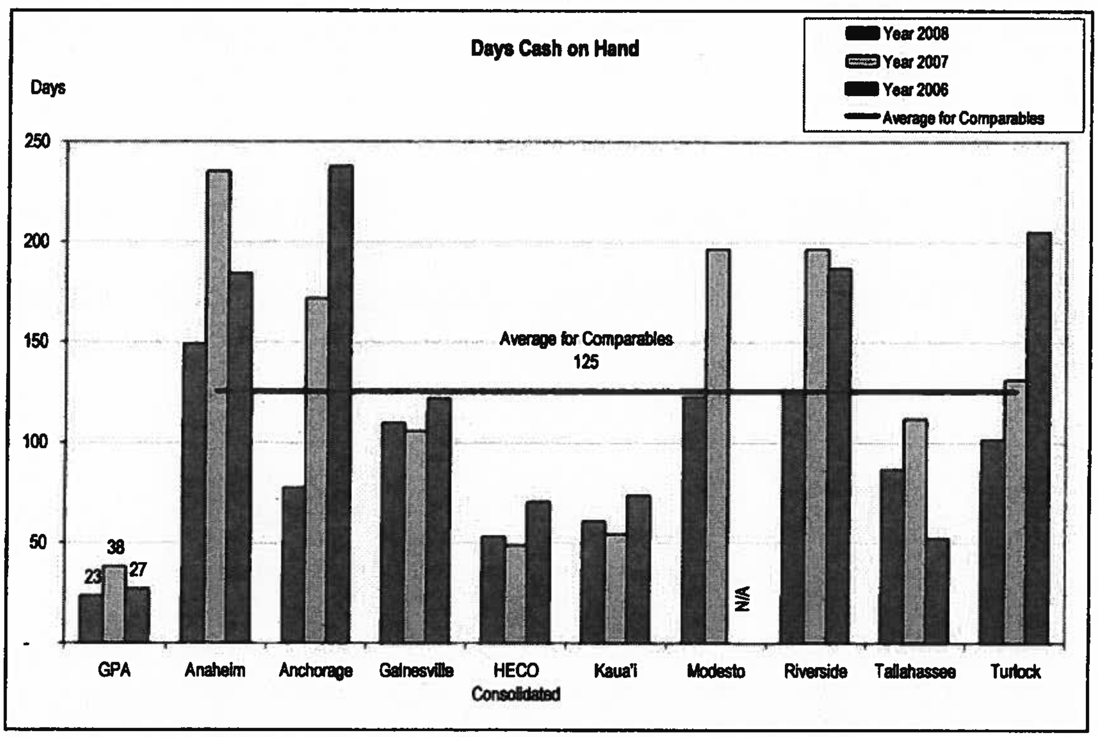

Figure 2-1: Days Cash on Hand, Year-End Financial Data for 2006-2008

However, a more frequent monthly analysis of GPA's financial statements, which also includes Fiscal Year 2009 data, reveals a more constricted cash position than the Fiscal Year-end data for 2006 through 2008. An analysis of monthly data from October 2006 to July 2009 shows an average of 21 days cash on hand.

Based on this analysis and given GPA's above average vulnerability to volatile fuel pricing and extreme weather events, R. W. Beck recommends GPA set a policy to reach a minimum level of 60 days cash on hand. Averaging $16.9 million in cash and cash equivalents over this time period, GPA would have required an additional $31.4 million to reach a 60 days cash on hand level of $48.4 million, approximately a 186% increase.

Looking at monthly data for Fiscal Year 2008 as a test year, GPA averaged 24 days cash on hand or $20.1 million of unrestricted cash and cash equivalents. To meet the 60 days target, GPA would have required $51.3 million in cash and cash equivalents, an increase of $31.2 million.

Working Capital

Another useful indicator of a utility's ability to fund expansion, renewal, and improvement to the enterprise is the amount of working capital available. In order to compare working capital amongst the utilities, which have different levels of assets and liabilities, R. W. Beck used as a more comparable measurement each utility's net unrestricted working capital against its operating expenses, which we call operating months of working capital.

Net unrestricted working capital is defined as Moody's defines it—current unrestricted assets minus current unrestricted liabilities (those liabilities payable from unrestricted assets). Operating months of working capital are equivalent to net unrestricted working capital divided by average monthly total operating expenses (operating expenses not including depreciation and amortization).

Figure 2-2 compares this measure of working capital for GPA and the comparable utilities. Using Fiscal Year-end data from 2006 to 2008, GPA averaged 2.8 operating months of working capital. This is lower than the average of 4.5 months for the comparable utilities.

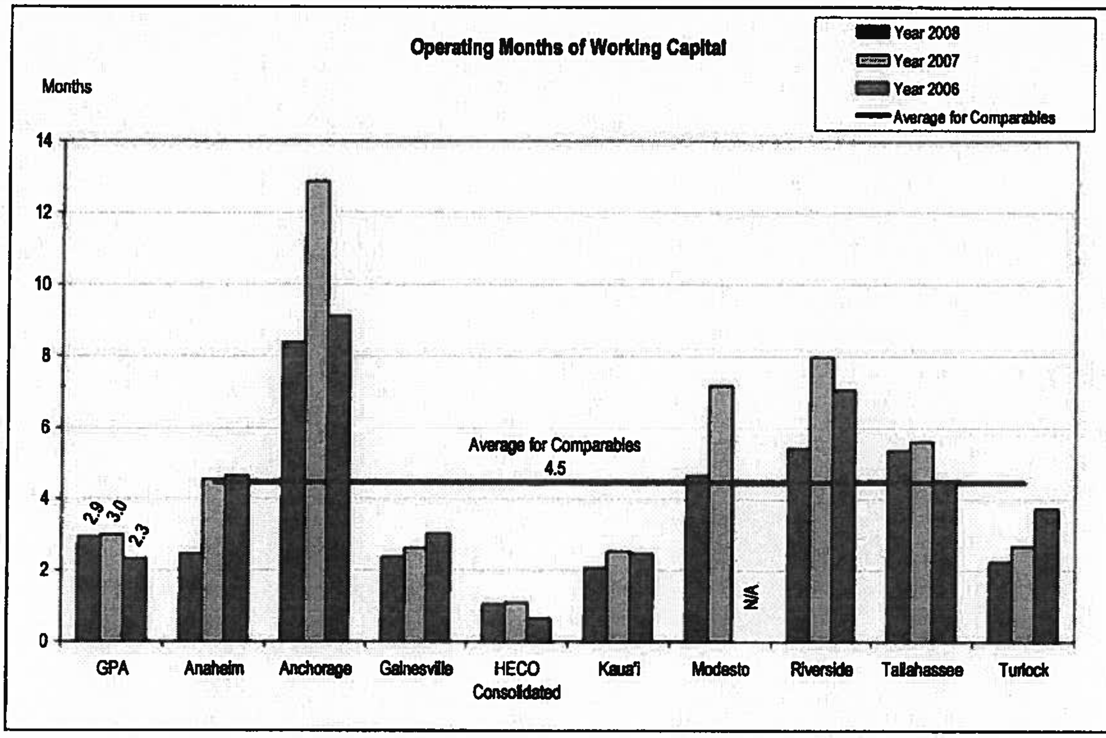

Figure 2-2: Operating Months of Working Capital, Year-End Financial Data for 2006-2008

A more detailed monthly analysis of GPA's financial statements, which also includes Fiscal Year 2009 data, reveals even lower amounts of working capital than is indicated by the annual Fiscal Year-end data for 2006 through 2008. The monthly data from October 2006 to July 2009 show an average of 1.03 operating months of working capital.

R. W. Beck recommends GPA set a policy to achieve 3 operating months of working capital, given its past inability to complete planned for and budgeted capital improvement projects, and its greater than average vulnerability to volatile fuel pricing and extreme weather events. Another factor facing GPA is the regulatory rate adjustment lag provided for in the "Ratepayers Bill of Rights." Generally speaking, it takes at least seven months from the time of the proposed change to the new rate levels' final implementation. Given these factors, it is important that GPA avoid cash and working capital shortfalls that result in inefficient operations and suspension of necessary programs, which over the long-run will lead to higher costs and diminished service to customers.

Averaging $25.4 million of unrestricted net working capital from October 2006 to July 2009, GPA would have required an additional $48.2 million to reach 3 operating months of working capital ($73.6 million)—almost three times the amount that has been available.

Using monthly data for Fiscal Year 2008 as a test year, GPA averaged 1.3 operating months of working capital, or $34.3 million of unrestricted net working capital. To meet the 3 operating months of working capital target would have required $78.0 million in unrestricted net working capital, an increase of $43.7 million.

Debt Ratio

As part of the benchmarking analyses, R. W. Beck investigated average debt ratios for GPA and the comparable utilities. Similar to the rating agency calculation of debt ratios for public power entities, we calculated debt ratio as equivalent to net funded debt divided by the sum of net fixed assets and net working capital.

Net funded debt is all long-term debt plus accrued interest payable less the balance in both the debt service reserve fund and debt service fund. Net fixed assets are fixed assets less accumulated depreciation. Net unrestricted working capital is the same as previously defined: current unrestricted assets minus current unrestricted liabilities.

For GPA, we have included as part of debt the amounts termed in its financial statements as "Obligations Under Capital Leases;" as these are GPA's IPP-related debt equivalent obligations and are considered debt obligations by the rating agencies. For GPA these obligations totaled approximately $132 million at the end of Fiscal Year 2008.

Figure 2-3 shows the comparison of debt ratios for GPA and each of the comparable utilities. GPA's average debt ratio of 81% is significantly above the average of 62% for the comparable utilities for years 2006 to 2008.

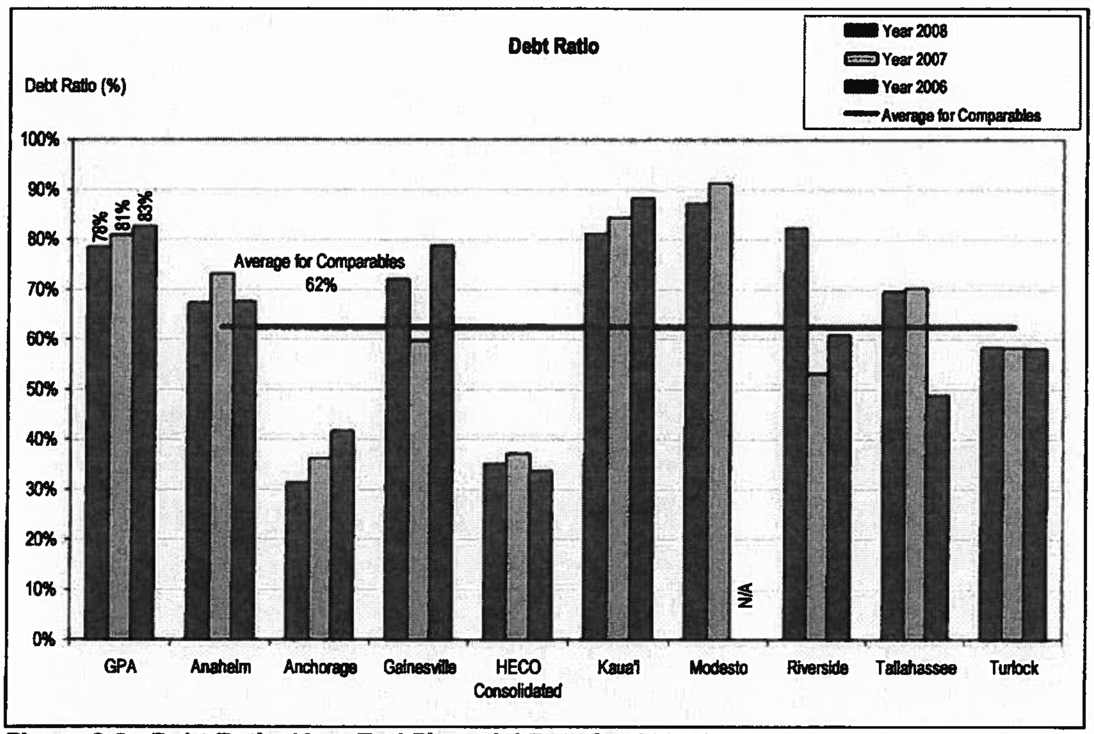

Figure 2-3: Debt Ratio, Year-End Financial Data for 2006-2008

Another indicator of relative debt levels is net debt per utility customer served. GPA's average net debt per customer for Fiscal Years 2006 to 2008 was $10,655. This is significantly above the average of $4,416 for the comparable utilities.

Debt Service Safety Margin

Another useful measurement when comparing the debt levels of these utilities is debt service safety margin. This ratio provides an indicator of the amount of revenue reduction a utility would be able to absorb and still pay its debt service obligations. We used Moody's definition of this measurement, equivalent to net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization).

Figure 2-4 illustrates GPA's margin and the comparable utilities' margins. Although several utilities had years without any debt service safety margin, the average margin for years 2006-2008 was 7.7%, meaning that on average the comparable utilities could withstand a 7.7% drop in revenues and still pay debt service. GPA had no safety margin in Fiscal Year 2007 or Fiscal Year 2006. GPA's Fiscal Year 2008 debt service safety margin of 2.5% is below the comparables' average.

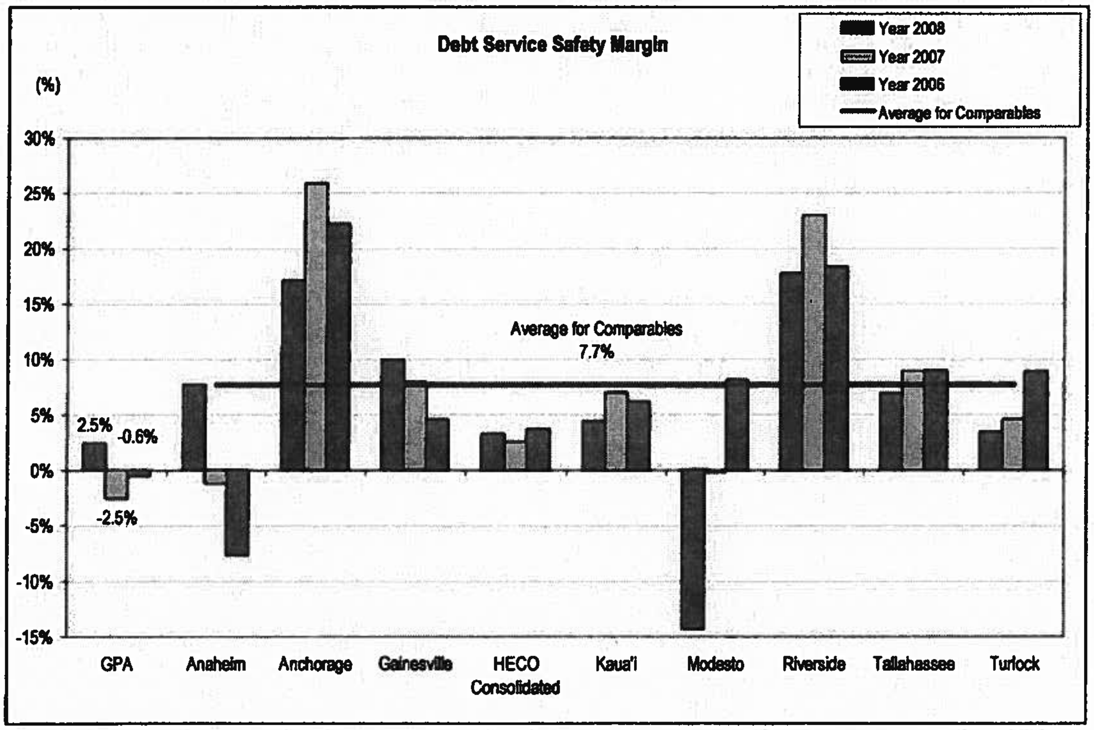

Figure 2-4: Debt Service Safety Margin, Year-End Financial Data for 2006-2008

Debt Service Coverage

GPA sets its rates using a regulatory DSC goal of 1.75 without including the IPP obligations as part of its debt. However, credit rating agencies include these fixed financial obligations as part of their debt and DSC calculations. GPA falls well short of the 1.75 goal when these are included. With the IPP obligations as debt, GPA had a DSC ratio of 1.34 for Fiscal Year 2008. R. W. Beck believes GPA not meeting a higher DSC level is a contributing factor to its lower-than-investment-grade debt ratings by two of the three rating agencies.

R. W. Beck recommends GPA set a policy to use a DSC goal of 2.00, that includes the IPP obligations as debt for its ratemaking purposes, with a less ambitious but improved target level of 1.75 as an initial ratemaking implementation policy. These levels are more in line with the comparable utilities and the public power utility industry in general. Of the nine comparable utilities, there were available DSC ratios for eight of them; together they averaged a DSC of 2.08 for years 2006 to 2008. HECO Consolidated DSC ratios were not available. The following section compares debt ratings for GPA and the comparable utilities and provides more detail of the rating agencies' assessments of GPA.

Rating Agency Perspective

GPA has a strategic goal of achieving an investment-grade bond rating by the three major credit rating agencies—Moody's Investors Service, Standard & Poor's, and Fitch Ratings. As of the date of this report, GPA had a split rating, rated BBB- by Standard & Poor's, the lowest level of investment grade, and Ba1 by Moody's and BB+ by Fitch, both below investment-grade ratings.

Table 2-2 compares the debt ratings for GPA and the comparable utilities. GPA's debt rates are below all of the comparable utilities. Anchorage, Modesto, and Turlock received A ratings and Anaheim, Gainesville, Riverside, and Tallahassee received AA ratings from the three rating agencies. The HECO companies received Baa1 and BBB ratings. There are no debt ratings available for Kaua'i because it is an electric cooperative and does not have publicly traded debt.

Table 2-2
Debt Ratings for GPA and Comparable Utilities

Utility	Fitch Ratings	Moody's	Standard & Poor's
Anaheim Public Utilities, Electric Utility	AA-	Aa3	AA-
Anchorage Municipal Light & Power	A+	A1	A+
Gainesville Regional Utilities	AA	Aa2	AA
Hawaiian Electric Company	n/a	Baa1	BBB
Modesto Irrigation District	A+	A1	A+
Riverside Public Utilities	AA-	Aa3	AA-
City of Tallahassee Electric Utility	AA-	Aa3	AA-
Turlock Irrigation District	A+	A1	A+
8 Utility Average	AA-	A1	A+
Guam Power Authority	BB+	Ba1	BBB-

Based on recent rating agency reports reviewed, it is clear that GPA's credit ratings are below those of other publicly owned utilities and investor-owned utilities. This is due to a number of factors.

In its June 2009 report "U.S. Public Power Peer Study," Fitch Ratings rated GPA and several of the comparable utilities and provided DSC ratios. Fitch shows for 2008 a median DSC of 2.21 for BBB rated Retail public power systems, 2.46 for A rated systems, and 2.33 for AA rated systems. Fitch Ratings shows that GPA had a 2.35 DSC ratio, but only a 1.46 coverage ratio when "Full Obligations" are included.[3]

In this same report, Fitch Ratings shows for 2008 a median of 78 days cash on hand for those utilities classified as "Retail—Self Generating Public Power Systems."[4] As discussed previously, we calculated GPA's days cash on hand for Fiscal Year-end 2008 to be only 23 days. Fitch reported GPA had only 11 days cash on hand.

Fitch also shows that for all "Self-Generation Retail Systems" included in the report, GPA had the highest reported debt amount per customer, at $12,169.

In Standard & Poor's largely positive credit analysis of GPA dated December 2008, they noted GPA's much below average DSC and liquidity levels, and stated GPA had a 1.5 annual DSC and a 1.21 fixed charge coverage, when factoring in the capital lease obligations to the IPPs. They also noted that the on-balance-sheet cash and equivalents of $25 million was equivalent to a "modest 36 days" cash on hand. Standard & Poor's stated that moderating the liquidity position was the history of good support by the PUC and a $10 million line of credit. They cautioned:

> *"A higher rating is still precluded by the lack of certainty regarding the general government's ability to reduce its long-term liability with the authority and how much that may affect the authority's cash flows, ability to fund revenue requirements, and rates...Additional financial challenges will be funding identified T&D system improvements in a prioritized and proactive manner, establishing and maintaining emergency liquidity reserves as a hedge against the next severe weather event, and maintaining the supportive regulatory relationship that have benefitted the authority since the implementation of its new governance structure in 2003."*[5]

For any utility, not having adequate cash, working capital, and DSC levels certainly can result in lowered rating agency evaluations and lead to higher interest rates paid and higher costs for electric customers. However, beyond this impact of its below-average credit ratings, GPA is experiencing another severe consequence of its deteriorating financial performance. Specifically, GPA has recently encountered difficulty negotiating bank loans. This lack of short-term borrowing facilities may cause significant risk to GPA's operations and maintenance and capital improvement programs, especially if GPA must once again endure recent challenges such as sharply rising oil prices and/or extreme weather events.

3 Fitch Ratings, "U.S. Public Power Peer Study," June 2009, page 28.
4 Fitch Ratings, "U.S. Public Power Peer Study," June 2009, pages 15-16.
5 Standard & Poor's Public Finance Ratings Direct Credit Analysis of GPA, December 23, 2008, pages 2-3.

Long-Term System Equity

For a public power utility, system equity is the amount of accumulated ratepayer funding a utility uses to fund its capital investments. System equity is an alternative to debt financing of capital requirements and results from the accumulation of funds resulting from a DSC level that is greater than 1.0. Utilities typically need to balance equity funding of capital requirements with maintaining rate levels at reasonable and acceptable levels as part of their capital improvement funding plans.

As indicated above, GPA has an above-average debt level compared to the comparable utilities. Corresponding to this higher level of debt, GPA has a significantly lower system equity level. In its June 2009 report, Fitch used equity-to-capitalization ratios to compare relative system equity levels. Table 2-3 compares GPA's equity-to-capitalization levels with the average for other retail municipal public power entities and other BBB rated retail municipal public power entities. For comparison purposes, Fitch-reported DSC and days of cash on hand levels for GPA and these two groups are also provided in this table.[6]

Table 2-3
Fitch's 2008 Public Power Financial Metrics

	DSC	Equity-to-Total Capitalization Ratio	Days Cash on Hand
All Retail Systems	2.35	46.0%	78
BBB-Rated Retail Systems	2.21	37.3%	37
GPA	1.46	22.3%	11

As indicated in Table 2-3, GPA's 2008 equity ratio, DSC level, and days of cash on hand level were all significantly below both the average for other retail municipal public power entities and the average for other BBB rated retail municipal public power entities.

If GPA wishes to obtain consistent long-term investment-grade ratings, it is incumbent on the utility to increase its system equity level as part of its capital funding needs. As such, R. W. Beck recommends that GPA target a long-term equity ratio of between 30% and 40% in the future. A higher level of system equity will benefit GPA and its customers by reducing debt and associated debt service costs needed to fund capital expansion and system improvements over the long-run.

Impact of GPA Meeting Higher Financial Targets

R. W. Beck reviewed GPA's DSC ratios for the past five completed Fiscal Years 2004 to 2008. GPA did not meet the ratemaking target of 1.75 DSC with the IPP obligations included as debt in any of the Fiscal Years examined. Taking monthly data for Fiscal Year 2008 as an example, we have estimated the additional revenues needed in order for GPA to meet four financial recommendations: having a 1.75 DSC

6 Fitch Ratings, "U.S. Public Power Peer Study," June 2009

with IPP obligations included as debt, a 2.00 DSC with IPP obligations included, 60 days cash on hand, and 3 operating months of working capital.

Table 2-4 shows Fiscal Year 2008 actual monthly average financial data and the amount of funds required to meet the 60 days cash on hand and 3 operating months of working capital goals. Using Fiscal Year 2008 as a test year, Table 2-5 illustrates that for GPA to meet the most ambitious of these recommendations, the 3 operating months of working capital, it would require an approximately 11.8% rate increase if implemented all at one time. Implemented over a four-year timeframe, meeting this goal would require a 3.0% increase the first year declining slightly each year to a 2.7% increase by the fourth year (over the previous year's rates). Under each of the goal headings, data showing the goal is met is highlighted in yellow.

Table 2-4
Monthly Average Fiscal Year 2008 Data and Goal Requirements

	Actual Fiscal Year 2008:	Recommended Goal:	% Increase
Historical Days Cash on Hand	23.5	60.0	155%
Historical Average Cash Available ($000)	20,080	51,273	155%
Historical Operating Months of Working Capital	1.3	3.0	127%
Historical Average Working Capital Available ($000)	34,299	77,978	127%

Table 2-5: Impact of Meeting 1.75, 2.0, 60 Days Cash on Hand, and 3 Operating Months of Working Capital Goals

Fiscal Year 2008:	Actual Historical	Meeting 1.75 DSC	Meeting 2.0 DSC	Meeting 60 Days Cash on Hand	Meeting 3 Operating Months of Working Capital
Funds Available for Debt Service ($000)					
Earnings from Operations	30,310	30,310	30,310	30,310	30,310
Additional Revenues Required to Meet New Target	-	*11,238*	*18,108*	*31,193*	*43,679*
Interest Income	2,459	2,459	2,459	2,459	2,459
Depreciation Expense	27,170	27,170	27,170	27,170	27,170
Balance Available for Debt Service	59,939	71,177	78,047	91,132	103,618
IPP - Capital Costs ($000)					
Principal	6,305	6,305	6,305	6,305	6,305
Interest	16,780	16,780	16,780	16,780	16,780
Total IPP Payments	23,085	23,085	23,085	23,085	23,085
Bond Debt Service ($000)					
Principal	7,080	7,080	7,080	7,080	7,080
Interest	20,401	20,401	20,401	20,401	20,401
Total	27,481	27,481	27,481	27,481	27,481
Resulting DSC					
DSC including the IPP Costs	1.34	1.75	2.00	2.48	2.93
DSC Using Bond Covenant Methodology	2.18	2.59	2.84	3.32	3.77
DSC Requirements					
Existing Ratemaking DSC Target	1.75				
Minimum Bond Covenant Requirement	1.30				
Resulting Cash and Working Capital Positions					
Projected Days Cash on Hand if New Target is Met		36.65	44.69	60.00	74.61
Projected Operating Months of Working Capital if New Target is Met		1.75	2.02	2.52	3.00
Annual Rate Increases (Average Over All Customer Classes) for One-Year to Four-Year Implementation Timeframes					
One-Year Rate Increase Required to Meet New Target (¢ per kWh)		0.69	1.11	1.91	2.67
Two-Year Rate Increase Required to Meet New Target (¢ per kWh)		0.34	0.55	0.95	1.33
Three-Year Rate Increase Required to Meet New Target (¢ per kWh)		0.23	0.37	0.64	0.89
Four-Year Rate Increase Required to Meet New Target (¢ per kWh)		0.17	0.28	0.48	0.67
Annual Percent per Year Increase (Over Previous Year's Rates) for One-Year to Four-Year Implementation Timeframes					
One-Year Rate Increase Required to Meet New Target		3.0%	4.9%	8.5%	11.8%
Two-Year Rate Increase Required to Meet New Target, First Year		1.5%	2.5%	4.2%	5.9%
Second Year		1.5%	2.4%	4.1%	5.6%
Three-Year Rate Increase Required to Meet New Target, First Year		1.0%	1.6%	2.8%	3.9%
Second Year		1.0%	1.6%	2.7%	3.8%
Third Year		1.0%	1.6%	2.7%	3.7%
Four-Year Rate Increase Required to Meet New Target, First Year		0.8%	1.2%	2.1%	3.0%
Second Year		0.8%	1.2%	2.1%	2.9%
Third Year		0.8%	1.2%	2.0%	2.8%
Fourth Year		0.7%	1.2%	2.0%	2.7%

Based on this analysis, R. W. Beck recommends GPA's next rate filing include a 3% to 5% rate increase so as to improve DSC, days cash on hand, and working capital levels, as discussed above. This increase would likely need to be in place for approximately 2 to 4 years to reach the higher financial targets. We have not quantified the impact these recommendations would have on GPA's rates or rate classes.

Summary of Recommendations

Based on the analyses conducted and our conclusions discussed above, our principal recommendations are as follows:

1. GPA's available cash on hand is much lower than the comparable utilities and generally does not follow standard industry practice. We recommend GPA set a policy of achieving of 60 days minimum, given its above average vulnerability to volatile fuel pricing and extreme weather events. Using Fiscal Year 2008 as an example, GPA actually averaged only $20.1 million of unrestricted cash and cash equivalents (about 24 days). In order to meet the 60 days target, it would require $51.3 million of unrestricted cash and cash equivalents, an increase of $31.2 million.
2. GPA's available working capital is much lower than the comparable utilities. R. W. Beck recommends GPA set a policy of achieving at least 3 months of working capital minimum, given its historic inability to fund planned/budgeted capital improvement projects, and its vulnerability to volatile fuel pricing and extreme weather events. Using Fiscal Year 2008 as an example, GPA actually averaged only $34.3 million of unrestricted net working capital (about 1.3 months). In order to meet the 3-month target, it would require approximately $78.0 million of unrestricted net working capital, an increase of $43.7 million, which would include the $31.2 million increase of cash and cash equivalents given in our recommendation numbered one above.
3. GPA not meeting a higher DSC level is a contributing factor to its lower-than-investment-grade debt ratings by two of the three rating agencies. R. W. Beck recommends GPA set a policy to use a DSC goal of 2.00, that includes the IPP obligations as debt for its ratemaking purposes, with a less ambitious but improved target level of 1.75 as an initial ratemaking implementation policy. These levels are more in line with the comparable utilities and with the public power utility industry in general.
4. If GPA wishes to obtain consistent long-term investment-grade ratings, it is incumbent on the utility to increase its system equity level as part of its capital funding needs. As such, R. W. Beck recommends that GPA set a policy of achieving a long-term equity ratio of between 30% and 40% in the future, a level consistent with other well-rated public power utilities.

Rate Setting Recommendations

Based on the above-recommended changes in financial and regulatory policies, R. W. Beck recommends GPA undertake a rate filing(s) that would incorporate the following:

1. GPA's next rate filing should include a 3% to 5% rate increase above the level necessitated by other revenue requirement needs so as to improve its DSC, days cash on hand, and working capital levels, as discussed above. This increase would need to be in place for approximately 2 to 4 years for GPA to obtain the minimum financial improvements recommended in this report.

2. GPA's revenue requirements in the rate filing should be based on a 2.00 ratemaking DSC level using all debt expenses, including short-term debt and fixed payments associated with IPP obligations.
3. GPA's new rate levels should be maintained until such time as GPA achieves a minimum system equity goal of 30% to 40%.

While we have not quantified the total impact these recommendations would have on GPA's rates or individual rate classes, we believe it may be appropriate to "phase in" some of these recommendations over two rate filing periods.

Meeting these recommendations will improve GPA's financial and operational performance in several ways. GPA's improved cash, working capital, and DSC levels will enable it to better handle volatile fuel prices and to address costs resulting from extreme weather events. Instead of having to suspend operation and maintenance and system improvement programs because of cash shortfalls, GPA will be able to implement these programs in a timely and cost-effective manner. This will increase efficiency, improve reliability, and reduce the cost of operations—which result in better service and a lower cost to customers over the long-term. Meeting these recommendations will also move GPA towards meeting its strategic goal of obtaining secure investment-grade credit ratings, which will enable GPA both to better access financial markets and to lower its future debt costs.

Energy/Fuel Cost Adjustment Mechanisms

Variability in fuel and purchased power expenses is often significant enough to require electric utilities to incorporate a cost of fuel and purchased power adjustment charge that allows the utility to recover these costs within a timely manner. Compared with GPA, many of the comparable utilities have automatic energy/fuel cost adjustment mechanisms that allow for speedier recovery of purchased power and/or fuel-related expenses through customer rates. Of all the comparable utilities with energy cost adjustment mechanisms, two had an adjustment that occurred every 6 months (Tallahassee and Turlock) similar to GPA—the rest were either quarterly or monthly.

The following information summarizes the adjustment factors used by GPA and the other comparable utilities.

GPA and the LEAC

The current GPA Levelized Energy Adjustment Clause (LEAC)[7] allows for recovery of fuel costs over a six-month period (to be adjusted bi-annually in October and April). This adjustment assists in reducing the variability in the fuel costs to the customers. The LEAC calculation consists of the following factors:

LEAC Adjustment = (Projected fuel expense for next six months (includes amounts for fuel risk management program and excludes net fuel reimbursement from the Navy) + Difference between fuel revenue and actual fuel expense for the previous 6 months (excluding net revenue from the Navy) + Refunds or credits from supplier (excluding legal settlements)) / Projected retail kWh sales for the next six months.

GPA is required to file before the Commission any proposed adjustments 45 days before the effective date. A comparison of the actual fuel oil mix, fuel oil cost, transmission and distribution losses, and station use of energy to the projected data used for the previous six-month period are also required to be filed. Also included in the filing is information on the over or under recovery of fuel costs for the previous six-month period. If at any time the over/under recovery amount exceeds $2.0 million, GPA can file for an expedited LEAC adjustment prior to the next scheduled bi-annual adjustment.

[7] Docket 98-001, In the Matter of the Guam Power Authority's Petition to Increase Rates in FY96. Appendix D. Before the Public Utilities Commission, Territory of Guam. 29 Jan. 1996. Print.

Anaheim Public Utilities, Electric Utility's Quarterly Adjustment

Anaheim recovers the cost of power supply and environmental mitigation costs under a Rate Stabilization Adjustment[8] (Schedule RSA) that includes a Power Cost Adjustment (PCA) and an Environmental Mitigation Adjustment (EMA). The Rate Stabilization Adjustment factor is designed to assist the utility in maintaining a DSC ratio of 1.50, a rate stabilization account balance of $50 million, and the recovery of costs not recovered through EMA. The exact equation used for this adjustment is not provided in Schedule RSA. The PCA is calculated each quarter to allow for the recovery of costs related to the procurement and generation of energy based on projected data and actual 12-month rolling costs for power production, purchased power, regulatory compliance, and debt service. This adjustment does not apply to the domestic lifeline rates. Revenues from the sale of excess power from wholesale customers and revenues generated from the use of the utility's transmission lines are used to reduce the costs recovered through this adjustment. EMA recovers costs associated with the purchase of emission credits, taxes on emissions, projected environmental mitigation costs (not limited to the difference in costs between the utility's renewable and carbon based power supply not recovered in the PCA). There is no limit on the level of decrease in the adjustments, but the billing factor is limited to no more than a half cent per kWh increase during any 12-month period. This adjustment does not apply to the commercial, industrial or municipal rates.

These adjustments are revised on a quarterly basis using projected and actual data over the 12-month period, which differs from GPA's bi-annual adjustment based on projected and actual data over a six-month period. Costs for purchased power, regulatory compliance, debt service and environmental mitigation all also included adjustments beyond the fuel expense only component used by GPA. These adjustments do not apply to all customer classes and any increases in the adjustment are limited.

Anchorage Municipal Light & Power's Quarterly Adjustment

Anchorage Municipal Light & Power uses a fuel and purchased power cost adjustment (COPA)[9] which is applicable to all of the filed rate schedules. These adjustments are revised on a quarterly basis and filed before the Commission. The adjustment is based on the following:

1) Base Cost of Power (TY 2001):

   (Natural Gas Purchase + Transportation – Gas used for Sales for Resale + Purchased Power + Fuel Oil + Intertie Expense + Economy Energy Purchases + Cogeneration/Small Power) / Retail Sales (kWh)

[8] Anaheim: Public Utilities Department. *Electric Rates, Rules & Regulations*. 2009. Web. 23 Sept. 2009. <www.anaheim.net>.

[9] Anchorage Municipal Light and Power. *Schedule 01: Fuel and Purchased Power Cost Adjustment*. 2009. Web. 23 Sept. 2009. <www.mlandp.com>.

2) Average Cost of Power (Estimated data for the ensuing quarter):

   (Natural Gas Purchase + Transportation + Purchased Power + Fuel Oil + Intertie Expense + Economy Energy Purchases + Cogeneration/Small Power – Profits from Economy Energy Sales +/– Cost of Power Balance Amount (estimated over or under recovery for the quarter)) / Estimated Retail Sales (kWh)

3) Quarterly Cost of Power Adjustment

   Average Cost of Power ($/kWh) – Base Cost of Power ($/kWh) = Cost of Power Adjustment ($/kWh)

Anchorage is required to file before the Commission a schedule of the projected amount of retail kWh that will be sold in the ensuing quarter, estimated cost of retail energy generated and purchased in the ensuing quarter, documentation on the actual fuel and purchased power costs of the most recent quarter, and actual monthly average heat rate for thermal generation. A Fuel and Purchased Power Cost Balance Account is required to record the actual monthly purchased power and consumed fuel costs for retail customers, monthly kWh of retail energy sold multiplied by the based cost of power factor plus the adjustment factor applied, any costs for interruptions, monthly profits earned from the economy energy sales, and any Alaska Intertie related expenses.

The adjustment factor is calculated based on the change from the projected average cost of power over a base cost of power data from test year 2001. This is done on a quarterly basis using projected and actual data over the six-month period, which differs from GPA's bi-annual adjustment based on projected and actual data over a six-month period. COPA includes other types of expenses beyond the fuel expense that GPA's adjustment factor includes; such as, purchased power, intertie expense, economy energy purchases, costs for cogeneration and small power, which is offset by any profits from the economy energy sales.

Gainesville Regional Utilities, Electric's Monthly Adjustment

The Gainesville Regional Utilities monthly retail fuel adjustment mechanism[10] is designed to recover the costs of fuel consumed for their generation plants and the cost portion of the interchange purchases less the fuel cost portion of interchange sales. This adjustment factor is based on fuel cost and energy sales each month and incorporates a levelization amount and a true-up correction factor (based on the actual system performance in the second month preceding the billing month). The formula used to determine the retail fuel adjustment includes:

[10] Gainesville Regional Utilities. *Article II. Electricity*. Sec. 27-28 & 27-31. 2009.Web. 23 Sept. 2009. <www.municode.com>.

1) Projected System Fuel Cost (for the billing month):

   Projected Billing Month Fuel System Costs + Projected Billing Month MWh of Retail Sales + (Projected Billing Month MWh of Wholesale Sales x 91.2% for Delivery Losses between Retail and Wholesale Customers) + System Fuel Cost Attributed to Retail Sales

2) Plus true-up calculation from second month preceding the billing month (see Article II, Section 27-28)

3) Less 6.5 mills x Projected Billing Month MWh of Retail Sales

4) Plus levelization amount (any fluctuation offset to the fuel adjustment that is in the interest of the public and/or the cost of fuel imbedded within base rates for retail service on October 1, 1973 of $0.0065 per kWh)

5) The total is then divided by Projected Billing Month MWh of Retail Sales

This fuel adjustment charge is also applicable to the public streetlight and rental outdoor light services and is based on the estimated average energy use per fixture according to the schedule provided in Section 27-31.

The adjustment factor is revised on a monthly basis using projected and actual data over a one-month period, which differs from GPA's bi-annual adjustment based on projected and actual data over a six-month period. Rather than using a six-month adjustment period to offset significant variability, as GPA does, Gainesville incorporated a levelizing component in their adjustment factor.

Hawai`i Comparables' Quarterly Adjustment

The Hawai`i Public Utilities Commission (HPUC) provides rate regulatory oversight of the Hawaiian Electric Company (HECO) (island of Oahu), Hawai`i Electric Light Company (HELCO) (island of Hawai`i), Maui Electric Company (MECO) (islands of Maui, Lana`i, and Moloka`i), and Kaua`i Island Utility Cooperative (KIUC). The HPUC has stipulated a uniform methodology for these electric providers to recover the cost of fuel and purchased energy through an Energy Cost Adjustment Clause (ECAC for HECO, MECO and HELCO) and the Energy Rate Adjustment Clause (ERAC for KIUC)[11]. These adjustments are determined as follows:

[11] Hawaiian Electric Company, Inc. *Energy Cost Adjustment Clause – Revised Sheet No. 63, Docket No. 04-0113 (Effective June 20, 2008), 2009 Web. 11 Nov. 2009.* <www.heco.com>.
Maui Electric Company, Inc. *Energy Cost Adjustment Clause – Revised Sheet No. 69, Docket No. 97-0346, Amended D&O No. 16922 (Effective April 15, 1999), 2009 Web. 11 Nov. 2009.* <www.heco.com>.
Hawai`i Electric Light Company, Inc. *Energy Cost Adjustment Clause – Revised Sheet No. 63, Docket No. 99-0207, Amended PUC D&O No. 18365 (Effective February 13, 2001), 2009 Web. 11 Nov. 2009.* <www.heco.com>.
Kaua`i Island Utility Cooperative. *Tariff Applicable to Electric Service of Kaua`i Island Utility Cooperative. 2009. Web. 23 Sept. 2009.* <www.kiuc.coop>.

1) Company Generation + Purchased Energy + DG Generation (company-owned distributed generation, HECO only) = ECAC or ERAC

   a) Company Generation (difference between Current Generation and Base Generation adjusted for additional revenue taxes):

      i) Current Generation = Current fuel cost in ¢/million Btu x the generation conversion factor (HECO: 0.01114, MECO: 0.011032, HELCO: current factor, KIUC: 0.11230) in million Btu/kWh (weighted by the proportion of current company generation (exclusive of company-owned DG for HECO) to the total system net energy in kWh)

      ii) Base Generation = Base fuel cost in ¢/million Btu of (HECO: 869.64, MECO: 369.60, HELCO: 469.72, KIUC: 422.94) x the generation conversion factor (HECO: 0.01114, MECO: 0.011032, HELCO: 0.014629, KIUC: 0.11230) in million Btu/kWh (weighted by the proportion of the test year (HECO: TY 2005, MECO: TY 1999, HELCO: TY 2000, KIUC: TY 1995) company generation to the total system net energy in kWh)

   b) Purchased Energy (difference between Current Purchased Energy and Base Purchased Energy):

      i) Current Purchased Energy = Current purchased energy cost weighted by the proportion of current purchased energy to the total system net energy in kWh

      ii) Base Purchased Energy = Base energy purchased cost in ¢/kWh (HECO: 5.568, MECO: 5.028, HELCO: 6.404, KIUC: 4.9404) weighted by the proportion of the test year (HECO: TY 2005, MECO: TY 1999, HELCO: TY 2000, KIUC: TY 1995) purchased energy to the total system net energy in kWh (adjusted to the sales delivery level and for additional revenue taxes)

   c) DG Generation (difference between Current Cost of DG Energy and Base DG Energy Cost):

      i) Current Cost of DG Energy = Current cost of DG energy in ¢/kWh weighted by the proportion of current company-owned DG energy to the total system net energy

      ii) Base DG Energy = Base DG energy of 14.076 ¢/kWh (HECO only) weighted by the proportion of the test year 2005 (HECO) purchased energy to the total system net energy in kWh (adjusted to the sales delivery level and for additional revenue taxes)

Any adjustment to the ECAC or ERAC is effective on the date of the change in cost, and any changes in the cost that occur during a billing period are prorated to recover the change in cost. If required, a reconciliation adjustment is made on a quarterly basis that compares the actual year-to-date revenue from the ECAC or ERAC with that year-to-date revenue that was projected from the ECAC or ERAC and is applied to the subsequent quarter (lagged by two months).

The adjustment factor is calculated based on the change from the projected current cost of power and fuel over a base cost of power and fuel data from the test year, which is different than the methodology used by GPA. Any adjustments required are filed at the time of the change in cost and any true-up due to over or under recovery is included on a quarterly basis using projected and actual data over that 12-month period, which differs from GPA's bi-annual adjustment based on projected and actual data over a six month period. The ECAC and ERAC also contain purchased energy, which differs from GPA's LEAC.

Riverside Public Utilities' Quarterly Adjustment

The Power Cost Adjustment Factor (PCAF)[12] recovers the cost of generation and purchased power and is used to minimize fluctuations in rates. The exact equation used for this adjustment is not provided in the General Provisions section of the Electric Rules and Rates Schedules. The PCAF is revised quarterly if the actual changes are within 10% of the Basic Power Cost Component of 7.4432 (¢/kWh), which is included in the rates of each rate schedule. Changes in the wholesale fuel cost adjustment billing factor, wholesale rates, ownership costs related to San Onofre Nuclear Generating Station (SONGS) including fuel and energy costs, transmission and wheeling payments, scheduling and dispatching payments, economy energy payments, decommissioning costs and nuclear fuel disposal, take-or-pay obligations, and cogenerated power purchases.

The adjustment factor is revised on a quarterly basis, which differs from GPA's bi-annual adjustment based on projected and actual data over a six-month period. Revisions in the PCAF only occur if the costs are above or below 10% of the Basic Power Cost Component, but it is unclear how Riverside compensates for the over or under recovery of these costs. This adjustment recovers for costs beyond the fuel expense that is recovered in GPA's LEAC adjustment factor.

City of Tallahassee, Electric Utility's Bi-Annual Adjustment

Tallahassee's Energy Cost Recovery Clause (ECRC)[13] is applicable to all retail customers and is included in the monthly charges. The recovery factor is determined on a projected sixth-month basis, which is fixed for the sixth-month period unless significant changes in costs occur that would necessitate a change. The formula for determining the ECRC factor is as follows:

$$\text{ECRC (\$/kWh)} = (\text{Fm}/\text{Sm}) \times 1/1 - \text{L}$$

Fm = Includes the estimated cost of fossil fuel + estimated net cost of purchases (scheduled maintenance and energy purchases) + amount for over or under recovery of total energy costs (difference between actual and estimated energy costs during the

[12] City of Riverside, Public Utilities Department. *Electric: General Provisions*. 2009. Web. 23 Sept. 2009. <www.riversideca.gov/utilities>.

[13] City of Tallahassee, Electric Utility. *Article VII. Electric Service*. Section 21-233. 2009. Web. 23 Sept. 2009. <www.municode.com>.

prior period) – estimated energy costs for intersystem sales (fuel costs related to economy energy sales and other energy sold on an economic dispatch basis)

Sm = Estimated net kWh (net generation, purchases, interchange less intersystem sales for economy energy sales and other energy sold on an economic dispatch basis)

L = System loss factor

There are some similarities between the ECRC and GPA's LEAC adjustment factor. Both are based on the same time period and the adjustment factor methodologies are similar. However, ECRC includes the cost of purchased power and a system loss factor, which differs from the methodology used by GPA.

Turlock Irrigation District Bi-Annual Adjustment

The power supply adjustment (PSA) rate[14] is a mechanism to recover costs associated with the uncertainty of forecasting wholesale revenue and power cost fluctuations. The exact equation used for this adjustment is not provided in the District's *Conditions & Surcharges*, but it covers purchased power, fuel and gas field costs (including related capital costs) and is offset by wholesale gas and energy sales. The PSA is adjusted on a bi-annual basis (June and December), and the Board is limited to resetting amounts from ($0.005) to $0.01 per kWh. Fitch Ratings reports the following in regard to one of the District's recent key rating drivers, "The fuel and purchased power cost component of rates is currently not providing the timely cost recovery that was intended as a result of the $0.01-per-kilowatt-hour (kWh) cap. Fitch will look for near-term reductions to the under-collected amount or relief as to the amount of costs that can be recovered through the mechanism."[15]

Modesto Irrigation District, Electric

For Modesto Irrigation District, no information regarding any cost of power or fuel adjustment was available. Fitch Ratings recently reported that "The District's rate structure does not include a power or fuel cost adjustment mechanism that generally allows utilities to automatically recover variable costs related to fuel or purchased power without seeking rate approval. "The lack of such a mechanism in the rate structure results in a greater importance of reserves that are needed to buffer variable expenses related to fuel and purchased power."[16] However, new rates can be established within 60 days.[17]

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14 Turlock Irrigation District. *Conditions & Surcharges*. 2006. Web. 23 Sept. 2009. <www.tid.org>.

15 Masterson, Kathy and Lina Santoro. *Tuolumne Wind Project Authority, CA, Turlock Irrigation District*. New York: Fitch Ratings, June 18, 2009.

16 Ferrigan, Joanne, and Kathy Masterson. *Modesto Irrigation District, Calif., Electric System*. New York: Fitch Ratings, March 4, 2009.

17 Aschenbach, Dan, and Patrick Ford. *Moody's Upgrades to A1 Modesto Irrigation District's Certificates of Participation; Stable Outlook*. New York: Moody's Investor Services, March 5, 2009.

Fuel-Related Working Capital

Fuel-related working capital can be described briefly as the cash needed to support GPA's outlays due to timing differences between the receipt of fuel-related revenues from customers and the payment of fuel-related expenses to vendors.

No matter a utility's primary fuel source, fuel-related working capital should be sufficient to operate the utility and cover expected deviations in fuel prices. Generating all of its power from oil-fired resources, GPA's financial standing, liquidity, and capital improvement program are vulnerable to large and unexpected increases in oil prices. For Fiscal Years 2006-2008, GPA spent more than 70% of its total operating expenses (without interest or depreciation) on fuel.

In order to estimate the working capital requirements for fuel, R. W. Beck has developed a lead/lag analysis of fuel-related expenses and revenues. We used actual monthly data from for Fiscal Years 2006, 2007, 2008 and Fiscal Year 2009 (through July) for the analysis.

As with other similar lead/lag studies, our fuel-related working capital analysis looks at the "revenue lag time" between when fuel is used to generate power for customers and when customers' payments for that fuel are available for use by GPA. It also considers the offsetting "expense lead time" between GPA receiving the fuel and handling services and paying the fuel and handling costs at a later date.

Fuel-related working capital requirements are determined by calculating the average net lag in days (revenue lags minus expense leads) and multiplying that net lag by the average fuel expense over that period of time. For example, a utility with a daily average fuel expense of $1,000 and a net lag of 10 days (weighted revenue lags minus weighted expense leads) would have a fuel-related working capital requirement of $10,000.

Data related to lead/lag times for the various revenue and expense components came from GPA personnel. Some lead/lag times have been estimated, but generally should be close to actual averages experienced.

Expense Leads

There are two broad categories for expense leads: fuel commodity costs and fuel handling costs. Within these expense categories, we have assigned weights to the lead times for all of the various components of fuel handling, depending on what each component has historically contributed to total cost, to arrive at an overall weighted-average expense lead time.

These various components include commodity expenses for each of the different fuels used (high sulfur, low sulfur, diesel) and the array of various handling costs GPA has paid (almost all historical items have been included, from dock fees, excess laytime/overtime fees, storage tanks, and pipeline fees, to SGS inspection fees and bank fees).

Table 3-1 summarizes the components of the commodity expense lead. Table 3-2 summarizes the components of the fuel handling lead. Table 3-3 shows the division between the commodity and fuel handling portion. The weighted average expense lead amounted to a little over 16 days.

Table 3-1
Fuel Commodity Lead

	Expense Lead Time (Days)	% of Expense	Weighted Expense Lead Time (Days)
Fuel Commodity Costs:			
High Sulfur Fuel Invoice Lead	20.00	-	-
High Sulfur Fuel Payment Lead	2.00	-	-
High Sulfur Lead	22.00	62%	13.65
Low Sulfur Fuel Invoice Lead	20.00	-	-
Low Sulfur Fuel Payment Lead	2.00	-	-
Low Sulfur Lead	22.00	32%	7.11
Diesel Fuel Invoice Lead	15.00	-	-
Diesel Fuel Payment Lead	30.00	-	-
Diesel Lead	45.00	6%	2.54
Total Fuel Commodity Lead	-	-	16.19

Table 3-2
Fuel Handling Lead

	Expense Lead Time (Days)	% of Expense	Weighted Expense Lead Time (Days)
Fuel Handling Costs:			
Total Dock Fee-Shell Invoice Lead	15.21		
Total Dock Fee-Shell Payment Lead	15.21		
Total Dock Fee-Shell Lead	30.42	1.3%	0.38
Excess Laytime/Overtime-Shell Invoice Lead	15.21		
Excess Laytime/Overtime-Shell Payment Lead	15.21		
Excess Laytime/Overtime-Shell Lead	30.42	0.1%	0.02
Storage Tank Rental-Shell Invoice Lead	15.21		
Storage Tank Rental-Shell Payment Lead	15.21		
Storage Tank Rental-Shell Lead	30.42	2.8%	0.86
Pipeline Fee-Shell Invoice Lead	15.21		
Pipeline Fee-Shell Payment Lead	15.21		
Pipeline Fee-Shell Lead	30.42	1.2%	0.36
PEDCO Management Fee Invoice Lead	15.21		
PEDCO Management Fee Payment Lead	15.21		
PEDCO Management Fee Lead	30.42	1.3%	0.41
Ship Demurrage Cost Invoice Lead	15.21		
Ship Demurrage Cost Payment Lead	15.21		
Ship Demurrage Cost Lead	30.42	0.3%	0.08
Fuel Hedging loss/gain Invoice Lead	2.00		
Fuel Hedging loss/gain Payment Lead	11.00		
Fuel Hedging loss/gain Lead	13.00	84.3%	10.96
Lube Oil Invoice Lead	15.21		
Lube Oil Payment Lead	15.21		
Lube Oil Lead	30.42	2.4%	0.72
Subscription Delivery fee, Vacuum Rental, Hauling Invoice Lead	15.21		
Subscription Delivery fee, Vacuum Rental, Hauling Payment Lead	15.21		
Subscription Delivery fee, Vacuum Rental, Hauling Lead	30.42	0.2%	0.05
Sale of fuel to Matson Invoice Lead	15.21		
Sale of fuel to Matson Payment Lead	15.21		
Sale of fuel to Matson Lead	30.42	-1.3%	(0.41)
Inventory growth to be recovered over six month period	91.25	5.4%	4.92
SGS Inspection Invoice Lead	15.21		
SGS Inspection Payment Lead	15.21		
SGS Inspection Lead	30.42	0.4%	0.13
Labor charges Invoice Lead	15.21		
Labor charges Payment Lead	15.21		
Labor charges Lead	30.42	0.3%	0.08
L/C Charges,Bank Charges Invoice Lead	15.21		
L/C Charges,Bank Charges Payment Lead	15.21		
L/C Charges,Bank Charges Lead	30.42	1.5%	0.44
Total Handling Costs Lead			19.01

Table 3-3
Total Fuel Expense Lead

	Expense Lead Time (Days)	% of Expense	Weighted Expense Lead Time (Days)
Total Fuel Commodity Lead	16.19	89.6%	14.51
Total Handling Costs Lead	19.01	10.4%	1.98
Total Fuel Expense Lead	-	-	16.48

Revenue Lags

There are three broad categories for revenue lags: the civilian metering and billing-related lag, the LEAC lag, and the Navy fuel reimbursement lag. They contribute to GPA's overall revenue lag in different ways.

On the civilian side, the metering/billing lag and the LEAC lag start concurrently, meaning they both start at the same time—when fuel is consumed to generate power to serve customers. However, they end at different times. Typically the LEAC lag is longer than the metering/billing lag. The Civilian Metering/Billing lag is a little over 52 days. Between the start of Fiscal Year 2006 and July 2009, the LEAC has been adjusted on average every 4.9 months, creating an average lag of 74 days.

Because GPA must wait to be reimbursed for its fuel-related expenses until the LEAC is adjusted, it is the longer LEAC lag that counts in determining the total civilian revenue lag. If the LEAC lag was shorter than the metering/billing revenue lag, the metering/billing revenue lag would have determined the total civilian revenue lag.

The fuel-related revenues pertaining to Navy customer service have only one lag time, as the Navy pays for its fuel use automatically and on a weekly basis. We have assigned weights to the lag times for the civilian and Navy components, depending on what each customer type has historically contributed to total fuel cost, to arrive at an overall weighted-average revenue lag time.

As is shown in Table 3-4, the total weighted average revenue lag considering the weighted civilian and Navy components amounted to a little over 60 days.

Table 3-4
Revenue Lag

	Revenue Lag Time (Days)	% of Total Revenues	Weighted Revenue Lag Time (Days)
Civilian Revenues:			
Civilian Metering/Billing Lag:			
Civilian Service to Metering Lag	15.21	-	-
Civilian Metering to Billing Lag	5.00	-	-
Civilian Billing to Collections Lag	30.00	-	-
Civilian Payment Processing Lag	2.00	-	-
Total Civilian Metering/Billing Revenue Lag	52.21	79%	41.29
LEAC Lag	74.35	79%	58.80
Total Civilian Lag (Greater of Civilian Metering/Billing or LEAC)	74.35	79%	58.80
Navy Revenues:			
Navy Fuel Reimbursement Lag	7.60	21%	1.59
Total Revenue Lag (Total Civilian Plus Navy Fuel Reimbursement Lags)			60.39

Fuel Price and LEAC Scenarios

There are several fuel cost and LEAC scenarios we examined to determine working capital requirements. The first scenario could be considered a "status quo" case: using average historical fuel costs (which were $17.3 million per month for Fiscal Years 2006 to 2009 (to July)) and the average LEAC lag time experienced of 4.9 months.

Taking the weighted average expense lead of 16.5 days from the weighted average revenue lag of 60.4 days results in a net lag of 43.9 days, or 1.44 months. Multiplying this net lag of 1.44 months by the average monthly fuel-related expense of $17.3 million results in a working capital requirement of $24.9 million.

We also examined the impact of fuel prices at their historical peak over the last 4 years: using the peak monthly fuel cost of $32.1 million (which occurred in October 2008) and the average LEAC lag time experienced of 4.9 months. The lead/lags in this scenario are the same—resulting in a net lag of 43.9 days, or 1.44 months. Multiplying this net lag of 1.44 months by the peak monthly fuel-related expense of $32.1 million results in a working captal requirement of $46.4 million.

We also examined several alternatives to the LEAC adjustment period to illustrate how the LEAC affects working capital requirements. As discussed, historically since the start of Fiscal Year 2006, the LEAC has been adjusted on average every 4.9 months. We looked at what would happen to working capital requirements if the LEAC were adjusted more often—on a monthly or quarterly basis; and as it was intended to be adjusted—less often, on a bi-annual basis.

Both monthly or quarterly LEAC adjustment periods reduce the revenue lag from 60.4 days to 42.9 days. Under these LEAC scenarios, the civilian metering/billing revenue lag is longer than the LEAC lag and as such, the civilian metering/billing lag determines the overall revenue lag time. The expense lead remains the same. This results in a net lag of 27 days and a fuel-related working capital requirement of $15.2 million under either a monthly or a quarterly LEAC—a reduction of 39% compared to the average 4.9-month LEAC adjustment period.

A Bi-Annual LEAC adjustment period increases revenue lag to 73.8 days, resulting in a net lag of 58 days and a fuel-related working capital requirement of $32.7 million. This is a 31% increase in working capital compared to the average 4.9-month LEAC adjustment period.

Figure 3-1 compares the fuel-related working capital required under the various LEAC adjustment periods and fuel prices examined.

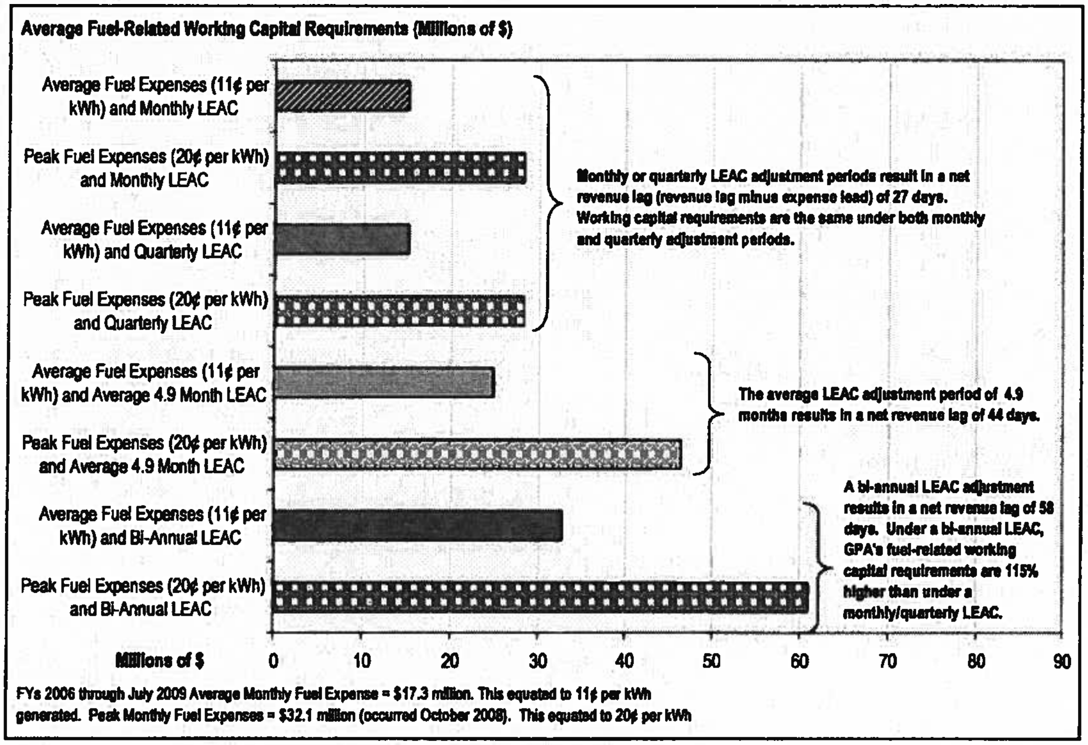

Figure 3-1: Fuel-Related Working Capital Requirements

Findings and Recommendations

The current levels of fuel-related working capital are not sufficient given the current LEAC mechanism. On average, from October 2005 to July 2009, the LEAC has been adjusted every 4.9 months. Using this average and average fuel prices over that period, the current net revenue lag of 44 days (weighted revenue lags minus weighted expense leads) requires $24.9 million of working capital. Higher fuel prices, for example those experienced in October 2008 (the peak month of that period), would require $46.4 million of working capital. Using Fiscal Year 2008 as an example, GPA's total unrestricted net working capital for both fuel and non-fuel items was only $34.3 million on average.

This data indicates that if oil prices rise dramatically as they have done in recent years, GPA would likely not have enough fuel-related working capital to cover its net revenue lag. A monthly or quarterly LEAC would require less fuel-related working capital. However, no matter the adjustment mechanism or timing decided on in the future, GPA's fuel-related working capital must be sufficient to cover the net revenue lag resulting from the given expense leads, the customer revenue/billing lag, and the LEAC adjustment lag.

R. W. Beck recommends GPA move to a quarterly LEAC to lessen the fuel-related working capital requirements and to mitigate the negative impacts of extremely volatile fuel prices.

The following discussion addresses approaches some of the comparable utilities are undertaking regarding insurance programs. This section is provided as background information as it relates to working capital requirements and cash on hand during emergency situations. R. W. Beck does not provide advice on insurance programs.

R. W. Beck has reviewed insurance coverage based on information available for the comparable utilities as well as very limited confidential information available to us from other clients. In general, most utilities reviewed were insured for property for at least $75 million, one as high as $4.16 billion. Coverage for liability generally was at least $35 million, ranging up to $200 million. Directors and Officers (D&O) insurance ranged from $5 million to $100 million. Retentions, or the self-covered portions, varied widely. For property, retentions were as low as $25,000, going up to $1 million. For liability, retentions ranged from $25,000 to $2 million. For D&O, retentions ranged from $100,000 to $2 million.

R. W. Beck attempted to contact personnel at each of the comparable utilities to discuss insurance levels and requirements. We were able to speak with personnel at Anaheim, Anchorage and Modesto directly, and have limited responses from Gainesville, Kaua`i, and Riverside from their completed informational request. Along with this information provided directly by the comparable utilities, we have gathered material from their publicly available annual reports.

Guam Power Authority, 2008 Annual Financial Statement

Self-Insurance [18]

> *GPA self-insures its transmission and distribution (T&D) plant, because no insurance is available at reasonable rates. As the result of a PUC Decision and Order, GPA added an insurance charge of $.00145 per kilowatt hour to customer billings effective January 1, 1993 until a self-insurance fund balance of $2.5 million is established. On February 12, 2008, PUC has approved the amendment of self insurance program to be effective March 1, 2008 to reflect the following: (1) increase in surcharge ceiling from $2.5 million to $10 million; (2) increase in the surcharge from $0.00145 per kWh to $0.00290 per kWh for civilian ratepayers and from $0.00035 per kWh to $0.00070 per kWh for Navy. As required by the Decision and Order, GPA records the insurance charge as sales revenue and records self-insurance expense in the same amount. Insurance charge proceeds are transferred to the restricted self-insurance fund to be used to cover uninsured or self-*

[18] "Guam Power Authority, Financial Statements and Additional Information and Independent Auditors' Report, Years Ended September 30, 2008 and 2007"; page 30.

insured damages to the T&D plant in the event of a natural catastrophe. The self-insurance fund, included in cash and cash equivalents held by GPA, is $2,233,834 and $1,032,628 at September 30, 2008 and 2007, respectively.

City of Anaheim, Electric Utility Fund

Anaheim is by-and-large insured entirely through the City of Anaheim's insurance program. Anaheim's electric utility department does not carry a separate self-insurance fund to cover generation and transmission losses/damages or workers compensation, property, or liability claims, etc. The utility pays annual premiums to the City and the City's insurance covers the utility as it does all other City departments.

Like other utilities in the region, Anaheim potentially faces the major risk event of serious earthquake damage, and to a smaller extent, flooding—although the U.S. Army Corps of Engineers has successfully mitigated most flooding issues in the area in recent years. In the past, Anaheim's electric utility had purchased separate earthquake insurance but stopped several years ago because the costs were extremely high. It would expect that in the event of a major catastrophic earthquake, for example, one that was strong enough to cause significant damage to the utility's generation, transmission, and distribution assets, the region would be declared an official "disaster area." Once declared an official disaster, the Federal Emergency Management Agency (FEMA) would then assist the utility with recuperation efforts and with covering a majority of costs. For lesser events, the City's insurance would be adequate.

Self-Insurance Program[19]

The Electric Utility participates in the City's self-insured workers' compensation and general liability program. The liability for such claims, including claims incurred but not reported, is transferred to the City in consideration of self-insurance premiums paid by the Electric Utility. Premiums for workers' compensation and general liability programs are charged to the Electric Utility by the City based on various allocation methods that includes actual cost, trends in claims experience, exposure base, and number of participants. Premiums charged and paid were $501,000 and $418,000 for the years ended June 30, 2008 and 2007, respectively.

At June 30, 2008, the City was full funded for self-insured workers' compensation and general liability claims (self-insured retention levels of $1,000,000 per occurrence for workers' compensation claims and $1,000,000 per occurrence for general liability claims). Above these self-insured retention levels, the City's potential liability is covered through various commercial insurance and intergovernmental risk pooling programs. Settled claims have not exceeded insurance coverage in any of the past

[19] "City of Anaheim Electric Utility Fund Financial Statements, June 30, 2008 and 2007"; page 40.

three years, nor does management believe that there are any pending claims that will exceed insurance coverage.

Anchorage Municipal Power & Light

Anchorage is self-insured for various retention levels as follows:

- Workers Compensation: $1 million self-insured, statutory coverage in excess.
- Auto & General Liability: $2 million self-insured, $20 million of commercial coverage in excess of retention level.
- Property: This is covered by commercial insurance under Standard Market Insurance. There is a $100,000 deductible in general. The turbine generators have deductibles between $500,000 to $1.5 million. Their Beluga Gas Field is fully covered through commercial insurance under Standard Market Insurance.
- They have only exceeded their commercial coverage levels once.
- The levels are based on actuarial estimates based on prior and current year claims.

Risk Management and Self-Insurance[20]

The Municipality is exposed to various risks of loss related to torts; theft of, damage to and destruction of assets; errors and omissions; illness of and injuries to employees; unemployment; and natural disasters. The Municipality utilizes three risk management funds to account for and finance its uninsured risks of loss. The Municipality provides coverage up to a maximum of $2,000,000 per occurrence for automobile and general liability claims and $1,000,000 for each workers' compensation claim. Coverage in excess of these amounts is insured by private carriers. Settled claims have not exceeded this commercial coverage in any of the past three years. Unemployment compensation expense is based on actual claims paid by the State of Alaska and reimbursed by the Municipality.

All Municipal departments participate in the risk management program and make payments to the risk management funds based on actuarial estimates of the amounts needed to pay prior and current year claims. Claims payable represent estimates of claims to be paid based upon past experience modified for current trends and information. The ultimate amount of losses incurred through December 31, 2008 is dependent upon future developments. At December 31, 2008 claims incurred but not reported included in the liability accounts are $12,327,800 in the General Liability/Workers' Compensation Fund and Medical/Dental Self-Insurance Fund. Changes in the funds' claim liability amounts in 2008 and 2007 are as follows:

[20] "Municipality of Anchorage, Alaska Electric Utility Fund Financial Statements, December 31, 2008 and 2007 (With Independent Auditor's Report Thereon)"; page 32.

In accordance with the Utility's labor agreements, the International

		Liability balance January 1	Current year claims and changes in estimates	Claims payment	Liability balance December 31
2008:					
General Liability/Workers' Compensation	$	14,709,671	6,981,750	(6,495,198)	15,196,223
Medical/Dental		4,123,844	44,020,522	(42,883,966)	5,260,400
Unemployment		61,453	225,235	(234,514)	52,174
	$	18,894,968	51,227,507	(49,613,678)	20,508,797
2007:					
General Liability/Workers' Compensation	$	13,522,232	6,943,260	(5,755,821)	14,709,671
Medical/Dental		4,949,843	39,907,930	(40,733,929)	4,123,844
Unemployment		89,314	236,905	(264,766)	61,453
	$	18,561,389	47,088,095	(46,754,516)	18,894,968

Brotherhood of Electrical Workers (IBEW) employees' medical/dental coverage is provided through the Alaska Electrical Health and Welfare Trust Fund. The Utility's liability for coverage for IBEW employees is limited to its contribution and is not included in the numbers above. The Utility's contributions to this fund were $2,659,954 and $2,526,580 for 2008 and 2007, respectively.

Gainesville Regional Utilities

Risk Management[21]

GRU is exposed to various risks of loss related to theft of, damage to, and destruction of assets, errors and omissions, injuries to employees, and natural disasters and insures against these losses. GRU purchases plant and machinery insurance from a commercial carrier. There have been no significant reductions in insurance coverage from that in the prior year, and settlements have not exceeded insurance coverage for the past three fiscal years. The City is self-insured for workers' compensation, auto liability, and general liability but carries excess workers' compensation coverage. These risks are accounted for under the City of Gainesville's General Insurance Fund. GRU reimburses the City for premiums and claims paid on its behalf, recording the appropriate expense. However, GRU does maintain its own insurance reserve, for the self-insured portion. An actuarial study completed during the fiscal year resulted in an increase to a balance of $3,337,000. The present value calculation assumes a rate of return of 4.5% with a confidence

[21] "Building Living Thinking: Gainesville Regional Utilities, Annual Report 2007-2008"; page 50. This data was confirmed by Gainesville in its written response to the Financial Benchmarking Study Informational Request.

level of 75%. This reserve is recorded as a fully amortized deferred credit. All claims for fiscal 2008 and 2007 were paid from current year's revenues.

Hawaiian Electric Industries, Inc.

Limited Insurance[22]

HECO and its subsidiaries purchase insurance to protect themselves against loss or damage to their properties against claims made by third-parties and employees. However, the protection provided by such insurance is limited in significant respects and, in some instances, there is no coverage. HECO, HELCO and MECO's overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $4 billion and are uninsured. Similarly, HECO, HELCO and MECO have no business interruption insurance. If a hurricane or other uninsured catastrophic natural disaster were to occur, and if the PUC were not to allow the utilities to recover from ratepayers restoration costs and revenues lost from business interruption, their results of operations and financial condition could be materially adversely impacted. Also, certain insurance has substantial "deductibles", limits on the maximum amounts that may be recovered and exclusions or limitations of coverage for claims related to certain perils. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business, each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, HECO, HELCO and MECO could incur losses in amounts that would have a material adverse effect on its results of operations and financial condition.

Kaua`i Island Utility Cooperative

Kaua`i does not have a self-insurance program.[23]

Modesto Irrigation District

Modesto is self-insured for various retention levels as follows:

- Property: Deductibles will vary between $10,000 - $250,000 per item and $1.0 million for the gas turbines.
- General and Auto Liability: $2 million self-insured, and up to $60 million in commercial insurance above the retention level.
- Liability for Directors & Officers: $100,000 self-insured retention.

[22] Hawaiian Electric Company, Inc.'s FERC Financial Report FERC Form No. 1: "Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report," 2008/Q4, 2/27/2009; page 123.37.

[23] From Financial Benchmarking Study Information Request.

- Employment Benefits: $1 million self-insured retention. They have only had one claim that was above the $1 million in the past 20 years.
- If they need to pay for any claims, they would use the cash reserves.
- The self-insurance retention levels are determined by the level of risk that they want to take on and what levels the Board is comfortable with. They have increased these levels over the years.

Note 12 – Risk Management[24]

> *The District is exposed to various risks of loss related to torts; theft of, damage to, or destruction of assets; errors and omissions; workers compensation; and health care of its employees. These risks are covered through the purchase of commercial insurance. The District is self insured for general and liability claims up to $1,000,000. The District also has excess liability insurance for claims over $1,000,000. There was no significant decrease in coverage over the prior year. Settled claims have not exceeded insurance coverage in each of the past three years.*

(Thousands of Dollars)

	2008	2007	2006
Claims liability - beginning of year	$ -	$ -	$ -
Claims accrued	199	556	268
Claims paid/other	(199)	(556)	(268)
Claims Liability - End of Year	$ -	$ -	$ -

City of Riverside – Public Utilities

Insurance Programs[25]

> *The Electric Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administered by the City. The Electric Utility pays an amount to the City based on actuarial estimates of the amounts needed to fund prior and current year claims and incidents that have been incurred but not reported. The City maintains property insurance on most City property holdings, including Utility Plant with a limit of $100 million. City-wide information concerning risks, insurance policy limits and deductibles and designation of general fund balance for risk for the year ended June 30, 2008, may be found in the notes to the City's "Comprehensive Annual Financial Report." Although the ultimate amount of losses incurred through June 30, 2008 is dependent upon future developments, management believes that amounts paid to the City are sufficient to cover such losses. Premiums paid to the City by the Electric Utility were $709,000 and $358,000 for the years ended June 30, 2008 and 2007, respectively. Any losses above the City's reserves would be covered through increased rates charged to the Electric Utility in future years.*

[24] "Annual Report 08 Modesto Irrigation District: The Balance of Power"; page 36.
[25] "Financial Report 2007-2008 City of Riverside Public Utilities"; page 25.

Nuclear Insurance

The Price-Anderson Act ("the Act") requires that all utilities with nuclear generating facilities purchase the maximum private primary nuclear liability insurance available ($300 Million) and participate in the industry's secondary financial protection plan. The secondary financial protection program is the industry's retrospective assessment plan that uses deferred premium charges from every licensed reactor owner if claims and/or costs resulting from a nuclear incident at any licensed reactor in the United States were to exceed the primary nuclear insurance at that plant's site. The Act limits liability from third-party claims to approximately $10.8 billion per incident. Under the industry wide retrospective assessment program provided for under the Act, assessments are limited to $101 million per reactor for each nuclear incident occurring at any nuclear reactor in the United States, with payments under the program limited to $15 million per reactor, per year, per event to be indexed for inflation every five years. The next inflation adjustment will occur no later than August 20, 2008. Based on the Electric Utility's interest in Palo Verde and ownership in SONGS, the Utility would be responsible for a maximum assessment of $4,583,000 limited to payments of $681,000 per incident, per year. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

City of Tallahassee

***Risk Management Program*[26]**

The Risk Management program provides coverage for workers' compensation by self-insuring primary losses up to $1 million. Losses above that amount are insured through an excess policy. General liability, automobile and employment liability are totally self-insured. General and automobile liability losses are statutorily limited by sovereign immunity of $100,000 per person and $200,000 per accident. Settlement amounts in workers' compensation claims have not exceeded the self-insured retention during the past three years. The Risk Management program is also responsible for the purchase of certain other exposures including airport liability coverage in the amount of $100,000,000. The City's buildings and contents are covered by an all-risk, blanket program with varying deductibles. Statutory death benefits for police and firefighters is also purchased and such policy pays pursuant to the benefits specified by state law. The Risk Management Fund, which is classified as an Internal Service Fund, is responsible for collecting premiums from all of the departments for both self-insured and commercial programs, paying claim settlements on self-insured claims and procuring commercial insurance. Claims settlements

[26] "City of Tallahassee, Florida Comprehensive Annual Financial Report for the Fiscal Year Ended September 30, 2008"; page 80.

and loss expenses are reserved for the expected value of the known losses and also for estimated incurred but not reported losses (IBNRs). The Risk Management program also provides for Employment Practice Liability such as allegations of race, gender, and other discrimination or disparate treatment allegations. Annually, as of August 31 and extrapolated to September 30, the program has a third party actuary review the claim history for all claim years for which open self-insurance claims are outstanding. The actuary projects the ultimate claim payment obligation (including the IBNRs) for each year's claim experience and projects the new year's probable loss fund cost and a discounted alternative. The City elected to establish the liability at the discounted value (3.5%). Employee health insurance is provided through two programs. Employees may choose a health maintenance organization, or a traditional insurance program. For both options, the City pays a premium and retains no additional liability. The Human Resources department administers this program.

Changes in the balances of self-insured claims for the years ended September 30, 2008 and 2007 are as follows (in thousands):

	2008	2007
Unpaid Claims – October 1 (including IBNRs)	$ 9,067	$ 11,180
Expenses	4,427	1,933
Claim Payments	(4,040)	(4,046)
Unpaid Claims – September 30 (including IBNRs)	$ 9,454	$ 9,067
Estimated Amount due in one year	$ 2,748	$ 2,575

Turlock Irrigation District

Self-insurance Liability[27]

Substantially all of TID's assets are insured against possible losses from fire and other risks. TID carries insurance coverage to cover general liability claims in excess of $1,000,000 per occurrence up to $35,000,000 worker's compensation claims in excess of $750,000 per occurrence and medical claims in excess of $125,000 per employee and covered retiree. TID records liabilities for unpaid claims when they are probable of occurrence and the amount can be reasonably estimated. TID purchases its excess workers' compensation insurance from the California State Association of Counties (CSAC) Excess Insurance Authority. The risk of loss in excess of $750,000 per occurrence is transferred to the insurance pool. The accompanying financial statements include accrued expenses for general liability, workers' compensation and medical, dental and vision claims based on TID's best estimates of the ultimate cost of settling outstanding claims and claims incurred, but not reported. At December 31, 2008 and 2007, TID's estimated self-insurance liability for its worker's compensation claims totaled $3,450,000 and $3,260,000, respectively, and is reported as a component of accounts payable and accrued expenses in the consolidated balance sheets.

[27] "Turlock Irrigation District Annual Report 2008"; page 25.

At December 31, 2008 and 2007, TID's estimated self-insurance liability for its medical claims totaled $780,000 and is reported as a component of accrued salaries, wages and related benefits in the consolidated balance sheets.

Appendix A
FINANCIAL BENCHMARKING SURVEY: INFORMATION REQUEST

R·W·BECK

An SAIC Company

Appendix A
FINANCIAL BENCHMARKING SURVEY: INFORMATION REQUEST

Overview

On behalf of Guam Power Authority, R. W. Beck, Inc., is conducting a benchmarking study related to electric utilities' financial policies and planning. We appreciate your willingness to answer the following questions, which generally are not confidential or proprietary in nature. The information collected from this effort will be summarized for all of the responding entities and distributed as a brief report. If you would like a copy of the study results, we would be happy to send you a copy once it is completed. There is a place to indicate your request at the end of the document.

Please note the following general directions/information for completing the information request.

- Several types of entities are being asked to participate in this study, e.g., cooperatives, public power utilities owned by communities and irrigation districts, as well as investor-owned utilities. For the sake of consistency, we are referring to these endeavors simply as electric utilities. If your enterprise also includes water, waste, or other services, please provide your answers as they pertain to the electric power portions only, where you are able to do so.
- In an effort to save you time, where appropriate, we have attempted to pre-populate this information request with publicly available information we have gathered. Answers we have filled in are highlighted light blue in dark blue text. Please confirm that our answers to the questions are correct. If they are incorrect, please erase our answers and fill in as appropriate. All pre-populated data was derived from the report entitled:
- This document is coming to you via email. Please save this document to a hard drive or server prior to completion and save the file periodically while filling it out to avoid the loss of information.
- You can use the tab key to navigate through the document.
- For most questions, please mark the appropriate box with a computer mouse click. If you make an error just click on the box again to erase your answer.
- Certain boxes are available for you to provide written responses. You may type as long an answer in these response boxes as you like.
- If you operate on a Fiscal Year basis, please provide data for the listed Fiscal Year. For example, in Question 7, we ask for Gross Revenues for 2008, 2007, and 2006. Please provide Gross Revenues for your Fiscal Years 2008, 2007,

and 2006. If you operate on a Calendar Year basis, please provide Gross Revenues for calendar years 2008, 2007, and 2006.

- If you have any questions, please contact Jennifer White via email at jawhite@rwbeck.com or at (206) 695-4424.
- When the information request is completed, please save the file and send it as an attachment to an e-mail message to jawhite@rwbeck.com or you may mail it to Jennifer White at the address provided at the end of the document.

General Questions

QUESTION 1. Name of Company:

Address:

QUESTION 2. Person(s) completing this form:

Name/Title: _____

Contact Phone: _____

Date/Time: _____

QUESTION 3. How many customers, including all segments (Residential, Commercial, Industrial, and Other), did your electric utility have in years 2006, 2007, and 2008?

2006 Customer count:_____

2007 Customer count:_____

2008 Customer count:_____

QUESTION 4. Do you operate on a Fiscal Year or Calendar Year basis when calculating annual financial statements? If you operate on a Fiscal Year, please provide the starting day of your fiscal year.

- ☐ Fiscal Year—Start Month/Day: _____ (For the remaining questions pertaining to annual data, please provide answers based on your Fiscal Year)
- ☐ Calendar Year (For the remaining questions pertaining to annual data, please provide answers based on the given Calendar Year)

Debt and Equity

QUESTION 5. Is there an established policy goal or objective for Debt Service Coverage to be achieved by your electric utility, such as a Debt Service Coverage Ratio (DSCR), separate from coverage requirements in your mortgage or bond covenants?

- ☐ Yes—If Yes, what is this goal or objective? _____
- ☐ No
- ☐ Don't Know

QUESTION 6. Is there an established goal or objective for an equity ratio to be achieved by your electric utility?

- ☐ Yes—If Yes, what is this goal or objective? _____
- ☐ No
- ☐ Don't Know

QUESTION 7. Have any of these policy goals or objectives changed significantly during the last 10 years?

- ☐ Yes—If Yes, please summarize how they have changed: _____
- ☐ No
- ☐ Don't Know

QUESTION 8. What were your Debt Service Coverage Ratios (DSCRs), as defined in your mortgage and/or bond covenants, for years 2006, 2007, and 2008?

2006 Covenant Required DSCR: _____

2007 Covenant Required DSCR: _____

2008 Covenant Required DSCR: _____

QUESTION 9. What DSCRs were actually achieved in years 2006, 2007, and 2008?

2006 Achieved DSCR: _____

2007 Achieved DSCR: _____

2008 Achieved DSCR: _____

QUESTION 10. The following financial data is usually found on an "Income Statement" or "Statements of Revenues, Expenses, and Changes in Net Assets" and is required to evaluate operating performance and in order for us to calculate what we are calling Debt Service Safety Margin, which helps us evaluate how large a drop in revenues the electric utility can withstand and still pay debt service. We are also requesting data that will help us to understand how large a portion fuel and purchased power are of total operating expenses.

Please provide following data in Thousands of Dollars ($000s)	2006	2007	2008
A) Gross Revenues, including operating revenues and non-operating revenues, such as, interest or investment income, capital credits, and gains on the retirement of plant/debt.	____	____	____
B) Fuel-Related Operating Expenses	____	____	____
C) Purchased Power-Related Operating Expenses	____	____	____
D) Other Operating Expenses, without Interest or Depreciation	____	____	____
E) Total Operating Expenses, without Interest or Depreciation (should be the sum of B+C+D)	____	____	____
F) Depreciation Expense	____	____	____
G) Interest Expense	____	____	____
H) Miscellaneous Transfers Out (In)	____	____	____

QUESTION 11. The following data usually is found on a "Balance Sheet" or "Statement of Net Assets," and is required in order for us to calculate the electric utility's debt ratio and the amount of debt per customer. We are requesting information regarding Net Debt, Net Fixed Assets, and Net Working Capital. We are using the following broad definitions for Net Debt, Net Fixed Assets, and Net Working Capital: 1) Net Debt is long-term debt plus accrued interest payable less the balance in Debt Service Reserve Funds and Debt Service Funds, 2) Net Fixed Assets are fixed assets less accumulated depreciation, and 3) Net Working Capital is equal to current unrestricted assets minus current liabilities (payable from unrestricted assets).

Please provide following data in Thousands of Dollars ($000s)	2006	2007	2008
A) Long-term debt	____	____	____
B) Accrued interest payable	____	____	____
C) Balance in Debt Service Reserve Fund and Debt Service Funds	____	____	____
D) Net Debt (Should be A+B-C)	____	____	____
E) Fixed Assets (including Utility plant, land, and construction in progress, etc.)	____	____	____
F) Accumulated Depreciation	____	____	____
G) Current Unrestricted Assets	____	____	____
H) Current Liabilities (payable from Unrestricted Assets)	____	____	____

Financial Reserves and Hedging

QUESTION 12. We are requesting data regarding Unrestricted Cash, Cash Equivalents, and Investments in order to calculate Days Cash On Hand.

Please provide following data in Thousands of Dollars ($000s)	2006	2007	2008
A) Unrestricted Cash and Cash Equivalents	____	____	____
B) Unrestricted Investments, those easily convertible to cash	____	____	____
C) Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments	____	____	____

QUESTION 13. Is there an established goal, objective, or target for working capital and how are your levels of working capital determined?

- ☐ Yes—If Yes, what is the goal, objective, or target? _____

  If Yes, how do you determine the utility's working capital (what items are included and what is the equation)? _____

  If Yes, did you meet this target the last two years? _____

- ☐ No

- ☐ Don't Know

QUESTION 14. Is there an established goal, objective, or target for cash and cash equivalents and how are your levels of cash determined?

- ☐ Yes—If Yes, what is the goal, objective, or target? _____

  If Yes, how do you determine the utility's cash and cash equivalents (what items are included and what is the equation)? _____

  If Yes, did you meet this target the last two years? _____

- ☐ No

- ☐ Don't Know

QUESTION 15. Has your utility conducted a Lead/Lag Study, or some other type of analysis, to determine what should be the appropriate levels of working capital and/or cash?

- ☐ Yes—If Yes, please describe the type of study conducted _____

  If Yes, were fuel costs and purchased power costs included as part of the analysis? _____

  If Yes, may we have a copy of this study? _____

- ☐ No

- ☐ Don't Know

QUESTION 16. Is there an established goal, objective, or target for fuel-related working capital and how is fuel-related working capital determined?

- ☐ Yes—If Yes, what is the goal, objective, or target? _____

  If Yes, how do you determine the utility's fuel-related working capital (what items are included and what is the equation)? _____

  If Yes, did you meet this target the last two years? _____

- ☐ No

- ☐ Don't Know

QUESTION 17. Is there an established goal or objective for <u>power purchase</u>-related working capital and how is power purchase-related working capital determined?

- ☐ Yes—If Yes, what is the target goal or objective? _____

  If Yes, how do you determine the utility's power purchase-related working capital (what items are included and what is the equation)? _____

  If Yes, did you meet this target the last two years? _____
- ☐ No
- ☐ Don't Know

QUESTION 18. Do you have a fuel and/or purchased power hedging program?

- ☐ Yes—If Yes, please describe how your hedging program works _____
- ☐ No
- ☐ Don't Know

QUESTION 19. What percentage of next year's fuel-related costs is fixed at this time using hedges?

- ☐ 5% or Less (0-5%)
- ☐ Between 6% and 20% (6-20%)
- ☐ Between 21% and 50% (21-50%)
- ☐ Between 51% and 75% (51-75%)
- ☐ More than 75%
- ☐ Don't Know

QUESTION 20. What percentage of next year's purchased power-related costs is fixed at this time using hedges?

- ☐ 5% or Less (0-5%)
- ☐ Between 6% and 20% (6-20%)
- ☐ Between 21% and 50% (21-50%)
- ☐ Between 51% and 75% (51-75%)
- ☐ More than 75%
- ☐ Don't Know

QUESTION 21. Does your utility have a self-insurance program?

- ☐ Yes—If Yes, please describe how your self-insurance program works: ______
- ☐ No
- ☐ Don't Know

Rate Responsiveness and Regulation

QUESTION 22. Do you have an automatic adjustment clause which changes rates to reflect increases or decreases in the cost of fuel and/or the cost of purchased power?

- ☐ Yes, for fuel costs
- ☐ Yes, for purchased power costs
- ☐ No for both *(If No, skip to Question 24)*
- ☐ Don't Know

QUESTION 23. Please briefly describe how your fuel/purchased power automatic rate adjustment mechanism works, including how often it is used to change rates. Please verify the following summary for accuracy and content. (Each utility was provided with our summary of their fuel/purchased power automatic rate adjustment mechanisms.)

QUESTION 24. If you do not have a fuel/purchased power automatic rate adjustment mechanism, or if your mechanism is not adequate to address increases/decreases in these costs, how often do you request fuel- and purchased power-related rate increases/decreases through your governing body (such as a Board or Council) and/or regulating body (such as the State Commission)?

QUESTION 25. Once a rate increase/decrease is requested, how many days are generally required to receive necessary approval and implement the requested change in rates?

- ☐ One month or less (31 days or less)
- ☐ More than one month but less than 3
- ☐ 3 months to 6 months
- ☐ Longer than 6 months
- ☐ Don't Know

QUESTION 26. Is your electric utility rate-regulated by a State or local commission or board?

- ☐ Yes—If Yes, by whom? _____
- ☐ No *(If No, please skip to Question 29)*

QUESTION 27. Is the return or margin level regulated?

☐ Yes—If Yes, by what methodology, e.g., rate of return, Times Interest Earned Ratio)? _____

☐ No

QUESTION 28. Is the TIER, DSC, or MFI/I level set?

☐ Yes—If Yes, which and at what level has it been set?)

______________/______________/____________

☐ No

QUESTION 29. In general, how would you describe the mood or role of this regulation towards your electric utility?

☐ Supportive/Helpful

☐ Neutral/Objective

☐ Unsupportive/Restrictive

☐ Other (please specify) _____

Comments and Requests

QUESTION 30. Do you have any comments or questions concerning this study or any of the questions asked? _____

QUESTION 31. Would you like to receive an electronic copy of the study results when completed?

☐ Yes, send a copy to:

Name: _____

Email address: _____

☐ No

This completes our study questions. We sincerely thank you for your time and help.

R. W. Beck Contact Information:

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1001 Fourth Avenue, Suite 2500
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Appendix B
FINANCIAL DATA

An SAIC Company

Appendix B
FINANCIAL DATA

Following are summaries of the financial data used in the analysis for GPA and the comparable utilities.

GPA

Comparable Utility Letter Designation	n/a	
Utility Name and/or Department:	Guam Power Authority	
Source Document(s):	1)	Guam Power Authority, Financial Statements and Additional Information and Independent Auditors' Report, Years Ended September 30, 2008 and 2007
	2)	Guam Power Authority, Financial Statements and Additional Information and Independent Auditors' Report, Years Ended September 30, 2007 and 2006
	3)	Financial spreadsheets provided by GPA: "Historical No of Customers FY 06 - FY08.xls" and "Financial Operating ratios 2009-07-20.xls" and "FY 2003 - FY 2008 DSC (2).xls"

Utility Staff Contact(s): Name, Title, and Phone:		Name:	Title:	Phone Number:
	1)			
	2)			

Type of Entity: Governmental Utility

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data Item as it appears in document and any clarifying comments, page number*

Regulating Body: Public Utilities Commission

	Year 2008	Year 2007	Year 2006	
Total Number of Customers:	45,664	45,081	44,729	*3)Historical No of Customers FY 06 - FY08.xls*
Residential Customers:	39,097	38,464	37,709	*3)Historical No of Customers FY 06 - FY08.xls*
Total Electricity Sales (MWh)	1,636,791	1,634,622	1,669,001	*3)Financial Operating ratios 2009-07-20.xls*
Residential Sales (MWh)	472,873	485,931	495,229	*3)Financial Operating ratios 2009-07-20.xls*

Fiscal Year or Calendar Year	Fiscal
Start Month/Day	Oct 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage	Year 2008	Year 2007	Year 2006	
Utility Debt Service Coverage Ratio–Target/Requirement	1.75	1.75	1.75	*3) "FY 2003 - FY 2008 DSC (2).xls" Existing Ratemaking DSC Target*
Utility Debt Service Coverage Ratio–Achieved	1.34	1.54	1.40	*3) "FY 2003 - FY 2008 DSC (2).xls" Bond Covenant DSC (3)*
Target/Requirement	1.75	1.75	1.75	*3) "FY 2003 - FY 2008 DSC (2).xls" Existing Ratemaking DSC Target*
Equity Ratio Goal/Objective	None	None	None	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

GPA

Operating Data

	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	393,226	319,539	298,396	2008 (1): includes Total revenues plus Recovery of GovGuam receivable plus Interest revenue plus Allowance for funds used during construction plus Grants from the United States Government, page 8. 2007 (1): includes Total revenues plus Interest revenue plus Establishment of regulatory asset plus Allowance for funds used during construction plus Prior year typhoon loss recoveries plus Grants from the United States Government, page 8. 2006 (2): includes Total revenues plus Interest revenue plus Allowance for funds used during construction plus Grants from the United States Government, page 10
Fuel-Related Operating Expenses ($000s)	237,063	174,748	157,122	2008 and 2007 (1): includes Production Fuel, page 8. 2006 (2): page 10
Purchased Power Operating Expenses ($000s)				
Other Operating Expenses ($000s)	76,082	69,245	73,541	2008 and 2007 (1): includes Other Production plus Administrative and general plus Energy conversion costs plus Transmission and distribution plus Customer accounting, page 8. 2006 (2): page 10
Total Operating Expenses, without Interest or Depreciation ($000s)	313,144	243,993	230,662	2008 and 2007 (1): includes Total operating and maintenance expenses less Depreciation and amortization, page 8. 2006 (2): page 10
Depreciation Expense ($000s)	27,170	27,154	24,268	2008 and 2007 (1): includes Depreciation and amortization, page 8. 2006 (2): page 10
Interest Expense ($000s)	39,471	41,236	41,860	2008 and 2007 (1): includes Interest expense, page 8. 2006 (2): page 10
Other Non-Operating Expenses ($000s)	3,780	15,258	1,351	2008 (1): includes COLA/supplemental annuities plus Other expense, page 8. 2007 (1): includes Provision for GovGuam receivable plus COLA/supplemental annuities plus Interest expense, page 8. 2006 (2): includes COLA/supplemental annuities plus Other expense, page 10.
Total Expenses ($000s)	383,565	327,641	298,141	2008 and 2007 (1): Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses, page 8. 2006 (2): page 10
Transfers Out (Transfers In) ($000s)				
Net Revenues ($000s)	9,660	-8,101	-1,745	Gross Revenues minus Total Expenses minus Transfers Out
Debt Service Safety Margin	2.46%	-2.54%	-0.59%	Net Revenues plus Transfers Out (In) divided by Gross Revenues

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

	Year 2008	Year 2007	Year 2006
Fuel % of Total Operating Expense	76%	72%	68%

GPA

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	Notes
Net Debt ($000s)	469,817	480,803	492,275	2008 and 2007 (1): includes Long-term debt, net of current maturities plus Obligations under capital leases, net of current portion plus Interest payable plus Current maturities of long-term debt plus Current obligations under capital leases less Cash and cash equivalents - held by trustee - interest and principal funds for debt repayment less Bond reserve funds held by trustee less Unamortized debt issuance costs, page 6. 2006 (2) page 8
Net Fixed Assets ($000s)	522,422	534,371	551,628	2008 and 2007 (1): includes Electric plant in service plus Construction work in progress less Accumulated Depreciation, page 6. 2006 (2): page 8.
Unrestricted Net Working Capital ($000s)	76,579	60,821	44,517	2008 and 2007 (1): includes total unrestricted current assets (Total current assets minus interest and principal fund for debt repayment minus bond indenture funds for restricted purposes minus Escrow account and Self-insurance fund minus Short-term investments held by trustee) minus total current unrestricted liabilities (Total current liabilities minus Current maturities of long-term debt minus interest payable). pages 6-7 2006 (2): page 8-9
Debt Ratio (%)	78%	81%	83%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	10.289	10.670	11.006	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service–measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilities would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	Notes
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	19,817	25,351	17,080	2008 and 2007 (1): includes Cash and cash equivalents; Bond Indenture funds page 6. 2006 (2): page 8
Operating Expenses, without Interest or Depreciation ($000s)	313,144	243,993	230,662	2008 and 2007 (1): includes Total operating and maintenance expenses less Depreciation and amortization, page 8. 2006 (2): page 10
Days Cash on Hand	23	38	27	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

	Year 2008	Year 2007	Year 2006
O&M Months of Working Capital	2.93	2.99	2.32

Target levels for fuel-related working capital?	Description from utility staff:	No
Target levels for non-fuel related working capital?	Description from utility staff:	No
Did you meet or exceed these targets in the last two years? (Yes/No)		

GPA

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No
Automatic energy cost/fuel cost adjustment charges? (Y/N)	Yes
Rates are sufficient to meet debt service coverage? (Y/N)	
Regulation of public power utility rates? (Yes/No)	Yes
Mood/Role of regulatory body	
Once requested, how many days required to implement rate increase?	
Days Cash on Hand Minus Days to Implement Rate Increase	
Automatic Fuel/Power Cost Adjustment Mechanism Frequency	Semi-Annually

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)	
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)	

Fuel and/or purchased power hedging program? Description from utility staff: Yes, see GPA-provided spreadsheets. FY10 FUEL HEDGING ACTUALS.xls

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff: Yes, but limited to T&D coverage.

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"A" Anaheim

Comparable Utility Letter Designation: "A"

Utility Name and/or Department: Anaheim Public Utilities, Electric Utility

Source Document(s):

1) "City of Anaheim Electric Utility Fund Financial Statements, June 30, 2008 and 2007 (With Independent Auditor's Report Thereon)"
2) Financial Benchmarking Study: Anaheim Public Utilities--Information Request, returned 10/22/09
3)

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)	Marcie L. Edwards	General Manager	(714)765-4284
2)	Russell E. Dowell	Controller	(714) 765-4628

Type of Entity: Municipal Utility

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data Item as it appears in document and any clarifying comments, page number*

Regulating Body: Anaheim City Council — *2) Question 26, page 14*

	Year 2008	Year 2007	Year 2006	
Total Number of Customers:	111,784	111,319	110,729	*2) Question 3, page 3*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year: Fiscal — *2) Question 4, page 3*

Start Month/Day: Jul 1 — *2) Question 4, page 3*

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006	
Utility Debt Service Coverage Ratio--Target/Requirement	1.60	1.60	1.60	*2) Question 5, page 4*
Utility Debt Service Coverage Ratio--Achieved	1.60	1.60	1.70	*2) Question 9, page 4*
Target/Requirement	1.25	1.25	1.25	*2) Question 8, page 4*
Equity Ratio Goal/Objective	None	None	None	*2) Question 6, page 4*

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"A" Anaheim

Operating Data	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	382,436	333,329	339,384	2008 and 2007 (1): includes total operating revenues plus interest income plus capital contributions plus grants, page 19. Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 6.
Fuel-Related Operating Expenses ($000s)	25,382	35,154	39,696	2008 and 2007 (1): includes fuel and generation, page 19 Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 5.
Purchased Power Operating Expenses ($000s)	235,301	198,957	193,482	2008 and 2007 (1): includes purchased power, page 19 Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 5.
Other Operating Expenses ($000s)	38,851	31,229	35,096	2008 and 2007 (1): includes operations, maintenance, and administration, page 19 Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 5.
Total Operating Expenses, without Interest or Depreciation ($000s)	299,534	265,340	268,274	2008 and 2007 (1): includes total operating expenses less depreciation, (equals sum of Fuel-Related, Purchased Power, and Other line items) page 19 Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 5.
Depreciation Expense ($000s)	28,191	49,927	73,833	2008 and 2007 (1): for years 2007 and 2006, Depreciation (includes Accelerated SONGS Depreciation), page 19 Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 5.
Interest Expense ($000s)	25,091	22,188	23,342	2008 and 2007 (1): includes interest expense, page 19 Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 5.
Other Non-Operating Expenses ($000s)	0	0	0	
Total Expenses ($000s)	352,816	337,455	365,449	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)	21,658	16,315	15,449	2008 and 2007 (1): includes transfers to the General Fund, right-of-way fees, and other funds of the City, page 19 Confirmed with responses provided through 2). 2006 data is from 2), Question 10, page 5.
Net Revenues ($000s)	7,962	-20,441	-41,514	Gross Revenues minus Total Expenses minus Transfers Out. The negative Net Revenues for 2006 and 2007 reflect accelerated SONGS Depreciation of $20,540 in 2007 and $42,002 in 2006.
Debt Service Safety Margin	7.75%	-1.24%	-7.68%	Net Revenues plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City. Without the accelerated SONGS depreciation in 2007 and 2006, Debt Service Safety Margin would have been +4.92% and +4.70%, respectively.

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

	Year 2008	Year 2007	Year 2006
Fuel % of Total Operating Expense	8%	13%	15%

"A" Anaheim

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	Notes
Net Debt ($000s)	549,092	584,661	457,246	2) Question 11, page 6
Net Fixed Assets ($000s)	754,923	672,452	574,821	2008 and 2007 (1): includes total depreciable utility plant less accumulated depreciation plus nondepreciable utility plant (land and construction in progress), page 17 Confirmed with responses provided through 2). 2006 data is from 2), Question 11, page 6.
Unrestricted Net Working Capital ($000s)	61,251	100,284	103,717	2008 and 2007 (1): includes total current assets, page 17, minus total current liabilities (payable from unrestricted current assets), page 18 Confirmed with responses provided through 2). 2006 data is from 2), Question 11, page 6.
Debt Ratio (%)	67%	73%	67%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	4.91	5.07	4.13	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilities would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	Notes
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	121,958	170,898	135,300	2008 and 2007 (1): includes Current Assets: cash and cash equivalents plus investments, page 17. Confirmed with responses provided through 2). 2006 data is from 2), Question 12, page 7.
Operating Expenses, without Interest or Depreciation ($000s)	299,534	265,340	268,274	2008 and 2007 (1): includes total operating expenses less depreciation, (equals sum of Fuel-Related, Purchased Power, and Other line items) page 19. Confirmed with responses provided through 2). 2006 data is from 2), Question 12, page 7.
Days Cash on Hand	149	235	184	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

	Year 2008	Year 2007	Year 2006
O&M Months of Working Capital	2.45	4.54	4.64

Target levels for fuel-related working capital?	Description from utility staff:	No	2) Question 13, page 7
Target levels for non-fuel related working capital?	Description from utility staff:	No	2) Question 16, page 9
Did you meet or exceed these targets in the last two years? (Yes/No)			

"A" Anaheim

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

		Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Y/N)		Yes	2) *Question 22, page 12*
Rates are sufficient to meet debt service coverage? (Y/N)		Yes	2) *Question 24, page 13*
Regulation of public power utility rates? (Yes/No)		No	2) *Question 27, page 14*
Mood/Role of regulatory body		Supportive/Helpful	2) *Question 29, page 15*
Once requested, how many days required to implement rate increase?		More than one month but less than 3	
Days Cash on Hand Minus Days to Implement Rate Increase		59	
Automatic Fuel/Power Cost Adjustment Mechanism Frequency		Quarterly	

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)		75% or More	2) *Question 19, page 10*
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)		75% or More	2) *Question 20, page 11*
Fuel and/or purchased power hedging program?	Description from utility staff:	Anaheim uses several strategies to mitigate our fuel and purchased power risk. For natural gas, we have 1/3 of our long-term gas requirements locked up through prepaid gas financing or natural gas reserves, with the remaining 2/3 being procured through mid and short term hedges. Our purchased power agreements are mostly fixed and offer stable pricing.	2) *Question 18, page 10*
Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):	According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.		
Self-insurance program?	Description from utility staff:	Yes, First $1 million	2) *Question 20, page 11*

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"B" Anchorage

Comparable Utility Letter Designation: "B"

Utility Name and/or Department: Anchorage Municipal Light & Power

Source Document(s):

1) "Municipality of Anchorage, Alaska Electric Utility Fund Financial Statements, December 31, 2008 and 2007 (With Independent Auditor's Report Thereon)"
2) "Municipality of Anchorage, Alaska Electric Utility Fund Financial Statements, December 31, 2007 and 2006 (With Independent Auditor's Report Thereon)"
3)

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)	Richard E. Miller	Chief Financial Officer/Assistant GM	(907)263-5201
2)	James M. Posey	General Manager	(907)263-5201

Type of Entity: Municipal Utility

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data item as it appears in document and any clarifying comments, page number*

Regulating Body: Regulatory Commission of Alaska — *(1): Overview of the Financial Statements, page 4*

	Year 2008	Year 2007	Year 2006	
Total Number of Customers:	30,352	30,244	30,091	*2008, 2007, and 2006 (1): From Miscellaneous Statistical Information, page 75*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year: Fiscal

Start Month/Day: Jul 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006	
Utility Debt Service Coverage Ratio–Target/Requirement	1.35	1.35	1.35	*2008, 2007, and 2006 (1): From Schedule of Reveue Bond Coverage Last Ten Years, page 69*
Utility Debt Service Coverage Ratio–Achieved	1.90	2.14	1.86	*2008, 2007, and 2006 (1): From Schedule of Reveue Bond Coverage Last Ten Years, page 69*
Target/Requirement				

Equity Ratio Goal/Objective

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"B" Anchorage

Operating Data	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	108,968	104,457	123,302	2008 and 2007 (1): includes Total operating revenues plus Total interest plus Other revenues, page 25. For 2008, also includes Special item-NPO/OPEB write-off. 2006 (1): page 12.
Fuel-Related Operating Expenses ($000s)				
Purchased Power Operating Expenses ($000s)				
Other Operating Expenses ($000s)				
Total Operating Expenses, without Interest or Depreciation ($000s)	52,422	39,297	57,582	2008 and 2007 (1): includes total operating expenses less depreciation and amortization (equals sum of Production, Transmission, Distribution, Customer service and sales, Administrative and general, Regulatory Credits, Taxes other than income line items) page 25. 2006 (1): page 12.
Depreciation Expense ($000s)	25,933	25,995	24,386	2008 and 2007 (1): includes Depreciation and amortization, page 25. 2006 (1): pg 12.
Interest Expense ($000s)	11,798	12,744	13,310	2008 and 2007 (1): includes Total interest, page 25. 2006 (2): includes Total interest, page 24.
Other Non-Operating Expenses ($000s)	175	-640	631	2008 and 2007 (1): includes Allowance for funds used during construction, amortization of deferred charges, and other expenses, page 25. 2006 (2): includes Allowance for funds used during construction, amortization of deferred charges, and other expenses, page 24.
Total Expenses ($000s)	90,328	77,395	95,910	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)	9,415	9,640	9,515	2008 and 2007 (1): includes Municipal Utility Service Assessment, Miscellaneous grant fund, Medical/Dental Self-Insurance Fund, and Transfer (dividend), page 25. 2006 (1): pg 12.
Net Revenues ($000s)	9,225	17,422	17,877	Gross Revenues minus Total Expenses minus Transfers Out
Debt Service Safety Margin	17.11%	25.91%	22.22%	Net Revenues Plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City (debt would be paid and transfers would be zero).

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

Fuel % of Total Operating Expense	0%	0%	0%

"B" Anchorage

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	
Net Debt ($000s)	123,902	140,778	156,743	2008 and 2007 (1): includes Total revenue bonds payable plus Accrued interest, page 24, minus Debt service account minus Revenue bond operations and maintenance minus revenue bond reserve investments, page 23 2006 (2): includes Total revenue bonds payable plus Accrued interest, page 23, minus Debt service account minus Revenue bond operations and maintenance minus revenue bond reserve investments, page 22
Net Fixed Assets ($000s)	359,711	347,708	333,323	2008 and 2007 (1): includes Plant in service, at cost less accumulated depreciation and depletion plus Intangible plant plus Construction work in progress, page 23. 2006 (2): includes Plant in service, at cost less accumulated depreciation and depletion plus Intangible plant plus Construction work in progress, page 22
Unrestricted Net Working Capital ($000s)	36,583	42,155	43,691	2008 and 2007 (1): includes Total current assets, page 23, minus Total current liabilities (payable from current assets), page 24. 2006 (2): includes Total current assets, page 22, minus Total current liabilities (payable from current assets), page 23
Debt Ratio (%)	31%	36%	42%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	4.08	4.65	5.18	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilities would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	11,082	18,460	37,484	2008 and 2007 (1): includes Equity in general cash pool, page 23. 2006 (2): includes Equity in general cash pool, page 22
Operating Expenses, without Interest or Depreciation ($000s)	52,422	39,297	57,582	2008 and 2007 (1): includes total operating expenses less depreciation and amortization, (equals sum of Production, Transmission, Distribution, Customer service and sales, Administrative and general, Regulatory Credits, Taxes other than income line items) page 25. 2006 (1): page 12
Days Cash on Hand	77	171	238	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

	Year 2008	Year 2007	Year 2006
O&M Months of Working Capital	8.37	12.87	9.11

Target levels for fuel-related working capital? Description from utility staff:

Target levels for non-fuel related working capital? Description from utility staff:

Did you meet or exceed these targets in the last two years? (Yes/No)

"B" Anchorage

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Yes/No)	Yes	2008 (1): COPA (cost of power adjustment), page 6.
Rates are sufficient to meet debt service coverage? (Yes/No)	Yes	2008 (1): page 42 and 69.
Regulation of public power utility rates? (Yes/No)	Yes	2008 (1): page 28.
Mood/Role of regulatory body		
Once requested, how many days required to implement rate increase?		
Days Cash on Hand Minus Days to Implement Rate Increase		
Automatic Fuel/Power Cost Adjustment Mechanism Frequency	Quarterly	2008 (1): page 6.

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)	
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)	
Fuel and/or purchased power hedging program? Description from utility staff:	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff:

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"C" Gainesville

Comparable Utility Letter Designation: "C"

Utility Name and/or Department: Gainesville Regional Utilities

Source Document(s):

1) Building Living Thinking: Gainesville Regional Utilities, Annual Report 2007-2008
2) People/Ideas: Gainesville Regional Utilities, Annual Report 2006-2007
3) Evolving the Landscape of GRU: Gainesville Regional Utilities, Annual Report 2005-2006
4) Gainesville Regional Utilities-Information Request completed by Jennifer Hunt, CFO

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)	Jennifer L. Hunt	Chief Financial Officer	352-393-1300
2)	David M. Richardson		352-334-3400

Type of Entity: Municipal Utility

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data Item as it appears in document and any clarifying comments, page number*

Regulating Body: Gainesville City Commission (The Florida PSC does not regulate rate levels; however, it has jurisdiction over rate structure for the electric system.) — *1) Rates and Regulation, page 39*

	Year 2008	Year 2007	Year 2006	Source
Total Number of Customers:	92,849	89,912	88,663	*2008 and 2007 (1): includes Total electric only, page 23. 2006 (2): page 25*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year: Fiscal

Start Month/Day: Oct 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006	Source
Utility Debt Service Coverage Ratio--Target/Requirement	No Goal	No Goal	No Goal	*4) Question 5*
Utility Debt Service Coverage Ratio--Achieved	2.12	2.05	1.88	*2008 and 2007 (1): From Fiscal Year 2008 Highlights, Total debt service coverage ratio, page 23. 2006 (2): page 25*
Target/Requirement	1.25	1.25	1.25	*4) Question 8*
Equity Ratio Goal/Objective	No Goal	No Goal	No Goal	*4) Question 6*

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"C" Gainesville

Operating Data	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	251,859	209,656	210,428	4) *Question 10*
Fuel-Related Operating Expenses ($000s)	6,156	3,630	3,317	4) *Question 10*
Purchased Power Operating Expenses ($000s)	121,078	101,310	112,986	4) *Question 10*
Other Operating Expenses ($000s)	57,407	47,990	46,300	4) *Question 10*
Total Operating Expenses, without Interest or Depreciation ($000s)	184,641	152,930	162,603	4) *Question 10*
Depreciation Expense ($000s)	26,577	24,586	22,881	4) *Question 10*
Interest Expense ($000s)	15,269	15,335	15,164	4) *Question 10*
Other Non-Operating Expenses ($000s)	323	171	226	*2008 (1): includes <u>Reduction of plant costs recovered through contributions</u>, page 62. 2007 (2): page 62. 2006 (3): page 60*
Total Expenses ($000s)	226,831	193,022	200,874	*Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses*
Transfers Out (Transfers In) ($000s)	19,500	18,927	18,574	*2008 (1): includes <u>Operating transfer to City of Gainesville General Fund</u>, page 62. 2007 (2): page 62. 2006 (3): page 60*
Net Revenues ($000s)	5,528	-2,293	-9,020	*Gross Revenues minus Total Expenses minus Transfers Out.*
Debt Service Safety Margin	9.94%	7.93%	4.54%	*Net Revenues Plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City (debt would be paid and transfers would be zero).*

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

	Year 2008	Year 2007	Year 2006
Fuel % of Total Operating Expense	3%	2%	2%

"C" Gainesville

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	
Net Debt ($000s)	457,740	316,902	380,673	2008 (1): includes Debt payable--current portion plus Total long-term debt, page 61, minus Restricted assets: Debt service--cash and investments, page 60. 2007 (2): pages 60-61. 2006 (3): pages 58-59
Net Fixed Assets ($000s)	600,116	497,197	443,101	2008 (1): includes Utility plant in service plus Plant unclassified less Accumulated depreciation and amortization plus Plant held for future use plus Construction in progress, page 60. 2007 (2): page 60. 2006 (3): page 58
Unrestricted Net Working Capital ($000s)	36,363	33,370	40,878	2008 (1): includes Total current assets, page 61, minus Total current liabilities, plus Utility plant improvement fund page 62. 2007 (2): pages 61-62. 2006 (3): pages 58-59
Debt Ratio (%)	72%	60%	79%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	4.93	3.52	4.23	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilities would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	55,270	44,197	54,111	2008 (1): includes Cash and cash equivalents plus Rate stabilization-cash and investments plus Utility plant improvement fund, page 60. S&P sites the Rate Stabilization and Utility improvment funds as providing liquidity. 2007 (2): page 60. 2007 (3): page 58
Operating Expenses, without Interest or Depreciation ($000s)	184,641	152,930	162,603	2008 (1): includes Total operating expenses less Depreciation and amortization, (equals sum of Operation and maintenance and Administrative and general line items) page 62. 2007 (2): page 62. 2006 (3): page 60
Days Cash on Hand	109	105	121	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

O&M Months of Working Capital	2.36	2.62	3.02

Target levels for fuel-related working capital? Description from utility staff: Revenue at Risk, Uninsured Exposure, Fixed Non-Fuel O&M, Construction Risk, Swap Termination Payments 4) Question 13

Target levels for non-fuel related working capital? Description from utility staff:

Did you meet or exceed these targets in the last two years? (Yes/No)

"C" Gainesville

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Yes/No)	Yes	*See pages 28 and 38-39 (1)*
Rates are sufficient to meet debt service coverage? (Yes/No)		
Regulation of public power utility rates? (Yes/No)	Yes	*2008 (1): Electric utility: Yes - Regulation of rate structure. Other utilities: No, See page 39 (1)*
Mood/Role of regulatory body		
Once requested, how many days required to implement rate increase?	More than one month but less than 3	*4) Question 25*
Days Cash on Hand Minus Days to Implement Rate Increase		
Automatic Fuel/Power Cost Adjustment Mechanism Frequency	Monthly	*2008 (1): page 39.*

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)	75% or More	*4) Question 19*
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)	75% or More	*4) Question 20*
Fuel and/or purchased power hedging program? Description from utility staff:		

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff:

The City is self insured for worker's compensation, auto liability and general liability. GRU Reimburses the City for premiums and claims paid on it's behalf. However, GRU does maintain it's own insurance reserve, for the self insured portion, in the amount of $2,106,000 based on an actuarially computed liability. The present value calculation assumes a rate of return of 4.5% with a confidence level of 75%. *4) Question 21*

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"D" HECO

Comparable Utility Letter Designation	"D"
Utility Name and/or Department	Hawaiian Electric Company, Consolidated
Source Document(s):	1) Hawaiian Electric Company, Inc's FERC Financial Report FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, 2008/Q4, 2/27/2009
	2) MECO's FERC Financial Report FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, 2008/Q4, 4/17/2009
	3) MECO's FERC Financial Report FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, 2007/Q4, 4/14/2008

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)			
2)			

Type of Entity: Investor-Owned Utility

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data Item as it appears in document and any clarifying comments, page number*

Regulating Body: Hawaii Public Utilities Commission — 2) General, page 123.1

	Year 2008	Year 2007	Year 2006	Source Note
Total Number of Customers:	440,507	437,490	432,386	1) Avg. No. Customers per Month, Total Sales of Electricity, page 301 Plus MECO and HELCO
Residential Customers:	382,821	379,611	375,143	1) Avg. No. Customers per Month, Residential Sales, page 301 plus MECO and HELCO
Total Electricity Sales (MWh)	7,558,342	7,677,798	7,703,020	1) Megawatt Hours Sold, Total Sales of Electricity, page 301 Plus MECO and HELCO
Residential Sales (MWh)	2,049,604	2,135,436	2,135,320	1) Megawatt Hours Sold, Residential Sales, page 301 Plus MECO and HELCO

Fiscal Year or Calendar Year	Calendar
Start Month/Day	Jan 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006
Utility Debt Service Coverage Ratio--Target/Requirement			
Utility Debt Service Coverage Ratio--Achieved			
Target/Requirement			

Equity Ratio Goal/Objective			

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"D" HECO

Operating Data	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	2,868,688	2,101,550	2,059,883	2) 2008: Sum of Operating Revenues and Other Income for HECO Consolidated, page 123.34 2007: page 123.35 3) 2006: page 123.24
Fuel-Related Operating Expenses ($000s)	1,229,193	774,119	781,740	2) 2008: Fuel Oil for HECO Consolidated, page 123.34 2007: page 123.35. 3) 2006, page 123.24
Purchased Power Operating Expenses ($000s)	689,828	536,960	506,893	2) 2008: Purchased Power for HECO Consolidated, page 123.34 2007: page 123.35. 3) 2006, page 123.24
Other Operating Expenses ($000s)	663,003	548,523	514,460	2) 2008: Total Operating Expenses minus Fuel Oil minus Purchased Power minus Depreciation for HECO Consolidated. page 123.34 2007: page 123.35. 3) 2006, page 123.24
Total Operating Expenses, without Interest or Depreciation ($000s)	2,582,024	1,859,602	1,803,093	Sum of Fuel-Related Operating Expenses, Purchased Power, and Other Operating Expenses.
Depreciation Expense ($000s)	141,678	137,081	130,164	2) 2008: Depreciation for HECO Consolidated, page 123.34 2007: page 123.35 3) 2006, page 123.24
Interest Expense ($000s)	51,931	51,631	50,599	2) 2008: Total Interest and other charges for HECO Consolidated, page 123.34 2007: page 123.35 3) 2006: page 123.25
Other Non-Operating Expenses ($000s)				
Total Expenses ($000s)	2,775,633	2,048,314	1,983,856	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)				
Net Revenues ($000s)	93,055	53,236	76,027	Gross Revenues minus Total Expenses minus Transfers Out.
Debt Service Safety Margin	3.24%	2.53%	3.69%	Net Revenues Plus Transfers Out (In) divided by Gross Revenues.

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

	Year 2008	Year 2007	Year 2006
Fuel % of Total Operating Expense	48%	42%	43%

"D" HECO

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	
Net Debt ($000s)	919,898	899,818	776,830	2) 2008: Sum of Long-term debt, net and Interest and preferred dividends payable for HECO Consolidated, page 123.34 2007: page 123.35 3) 2006: page 123.22
Net Fixed Assets ($000s)	2,408,182	2,262,583	2,207,375	2) 2008: Net utility plant for HECO Consolidated minus Investment in wholly owned subsidiaries at equity, page 123.34 2007: page 123.35 3) 2006: page 123.22 (Investments in wholly owned subsidiaries at equity was removed from the fixed assets because this amount was removed from the total capitalization amount.)
Unrestricted Net Working Capital ($000s)	222,800	168,476	94,627	2) 2008: Total current assets minus Total current liabilities less Interest and preferred dividends payable for HECO Consolidated, page 123.34 2007: page 123.35 Also includes Letter of Credit (from which there were no borrowings). "At December 31, 2008 and 2007 the Company maintained syndicated credit facilities of $250 million and $175 million, respectively," page 123.10
Debt Ratio (%)	35%	37%	34%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	2.09	2.06	1.78	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilities would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	372,451	247,069	346,366	2) 2008: Cash and equivalents plus Short-term borrowings-affiliate plus Short-term borrowing-nonaffiliates for HECO Consolidated, page 123.34 2007: page 123.35 3) 2006 page 123.23 Also includes Letter of Credit (from which there were no borrowings). "At December 31, 2008 and 2007 the Company maintained syndicated credit facilities of $250 million and $175 million, respectively," page 123.10
Operating Expenses, without Interest or Depreciation ($000s)	2,582,024	1,859,602	1,803,093	
Days Cash on Hand	53	48	70	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

O&M Months of Working Capital	1.04	1.09	0.63

Target levels for fuel-related working capital? Description from utility staff:

Target levels for non-fuel related working capital? Description from utility staff:

Did you meet or exceed these targets in the last two years? (Yes/No)

"D" HECO

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No
Automatic energy cost/fuel cost adjustment charges? (Yes/No)	
Rates are sufficient to meet debt service coverage? (Yes/No)	
Regulation of public power utility rates? (Yes/No)	
Mood/Role of regulatory body	
Once requested, how many days required to implement rate increase?	
Days Cash on Hand Minus Days to Implement Rate Increase	
Automatic Fuel/Power Cost Adjustment Mechanism Frequency	

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)

Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)

Fuel and/or purchased power hedging program? Description from utility staff:

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff:

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"E" Kauai

Comparable Utility Letter Designation: "E"

Utility Name and/or Department: Kaua'i Island Utility Cooperative

Source Document(s):
1) Independent Auditor's Report and Financial Statements December 31, 2008 and 2007
2) Financial Statements with Accompanying Information for the Years Ended December 31, 2007 and 2006 and Report of Certified Public Accountants
3) Financial And Statistical Report, 2008 Rural Utilities Service (RUS) Form 7 Amended, 03/23/09
4) Kaua'i Island Utility Cooperative-Information Request

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)	Tim Blume (tblume@kiuc.coop)		
2)	David Bissell (dbissell@kiuc.coop)		

Type of Entity: Cooperative

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data Item as it appears in document and any clarifying comments, page number*

Regulating Body: Hawaii Public Utilities Commission — *1) Regulatory Accounting, page 7*

	Year 2008	Year 2007	Year 2006	
Total Number of Customers:	35,713	35,217	34,684	*2008 (3): No. Consumers Served, page 9. 2007 and 2006 (2): Services at End of Year, page 26.*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year: Calendar

Start Month/Day: Jan 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006	
Utility Debt Service Coverage Ratio--Target/Requirement	No Target	No Target	No Target*	*4) Question 5*
Utility Debt Service Coverage Ratio--Achieved	1.97	2.10	1.99	*4) Question 9*
Target/Requirement	1.25	1.25	1.25	*4) Question 8*
Equity Ratio Goal/Objective	30%	30%	30%	*4) Question 6*

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"E" Kauai

Operating Data	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	190,676	164,652	147,632	2008 and 2007 (1): includes Total operating revenues plus interest income, capital credits, other nonoperating income, and unrealized gain on available-for-sale securities, page 4. 2006 (2): page 3
Fuel-Related Operating Expenses ($000s)	98,149	76,294	63,748	4) Question 10
Purchased Power Operating Expenses ($000s)	6,586	4,705	5,526	4) Question 10
Other Operating Expenses ($000s)	49,976	45,348	42,860	4) Question 10
Total Operating Expenses, without Interest or Depreciation ($000s)	154,711	126,347	112,134	2008 and 2007 (1): includes Total operating expenses less Depreciation and amortization, page 4. 2006 (2): page 3
Depreciation Expense ($000s)	16,450	16,208	15,898	2008 and 2007 (1): includes Depreciation and amortization, page 4. 2006 (2): page 3
Interest Expense ($000s)	9,941	10,167	10,466	2008 and 2007 (1): includes Interest on Long-Term Debt, page 4. 2006 (2): page 3
Other Non-Operating Expenses ($000s)	1,218	400	0	2008 and 2007 (1): includes Adjustment for FASB Statement No. 158, page 4. 2006 (2): page 3
Total Expenses ($000s)	182,320	153,122	138,498	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)				
Net Revenues ($000s)	8,357	11,529	9,134	Gross Revenues minus Total Expenses minus Transfers Out.
Debt Service Safety Margin	4.38%	7.00%	6.19%	Net Revenues Plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City (debt would be paid and transfers would be zero).

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

	Year 2008	Year 2007	Year 2006
Fuel % of Total Operating Expense	63%	60%	57%

"E" Kauai

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	
Net Debt ($000s)	215,938	224,573	229,929	2008 and 2007 (1): includes Long-term debt obligation, less current maturities plus Current maturities of long-term debt, page 3. Restricted cash and cash equivalents is cash restricted for rural economic development loans, per Note 2 on page 9. 2006 (2): page 2
Net Fixed Assets ($000s)	240,033	240,051	237,565	2008 and 2007 (1): includes Electric Plant in service plus Electric plan acquisition cost minus Accumulated depreciation and amortization plus construction work in progress, page 2. 2006 (2): page 2
Unrestricted Net Working Capital ($000s)	26,353	26,605	22,990	2008 and 2007 (1): includes Total current assets plus Other Investments less Restricted cash and cash equivalents, page 2, minus Total current liabilities, page 3. 2006 (2): page 2 Laurie Tomczyk included Other Investments in her survey response for Current Assets, 4) Question 5
Debt Ratio (%)	81%	84%	88%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	6.05	6.38	6.63	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilites would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	25,587	18,734	22,531	2008 and 2007 (1): includes Current Assets: Cash and cash equivelents plus Other Investments, page 2. According to Note 2 on page 9, KIUC has classified Other Investments as available-for-sale. These consist of U.S. Governement Agencies, U.S. Treasury Obligations, and Corporate bonds and notes, per Note 3 on page 12. 2006 (2): page 2
Operating Expenses, without Interest or Depreciation ($000s)	154,711	126,347	112,134	2008 and 2007 (1): includes Total operating expenses less Depreciation and amortization, page 4, 2006 (2): page 3
Days Cash on Hand	60	54	73	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

O&M Months of Working Capital	2.04	2.53	2.46

Target levels for fuel-related working capital?	Description from utility staff:	15 days	4) Question 16
Target levels for non-fuel related working capital?	Description from utility staff:	For Working Capital, No. For Cash, Yes. 2 Months O&M excluding F&PP, 15 days F&PP, 30 days interest.	4) Question 14
Did you meet or exceed these targets in the last two years? (Yes/No)			

"E" Kauai

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Y/N)	Yes	*2008 (1): Energy rate adjustment clause (ERAC), page 10*
Rates are sufficient to meet debt service coverage? (Y/N)		*KIUC has not made it's DSC requirements in 2009 or 2008*
Regulation of public power utility rates? (Yes/No)	Yes	*2008 (1): page 7*
Mood/Role of regulatory body	Neutral/Objective	*4) Question 29*
Once requested, how many days required to implement rate increase?	Longer than 6 months	*4) Question 26*
Days Cash on Hand Minus Days to Implement Rate Increase		
Automatic Fuel/Power Cost Adjustment Mechanism Frequency	Quarterly	*See KIUC Residential Tariff.pdf on network, Adobe pages 3-4*

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)			
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)			
Fuel and/or purchased power hedging program?	Description from utility staff:	None	*4) Question 18*

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program?	Description from utility staff:	None	*4) Question 21*

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"F" Modesto

"F"

Utility Name and/or Department: Modesto Irrigation District

Source Document(s):
1) Annual Report 08 Modesto Irrigation District: The Balance of Power
2) Modesto Irrigation District, 2006 Annual Report
3)

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)			(800) 304-5373
2)			

Type of Entity: Public Utility District

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data Item as it appears in document and any clarifying comments, page number*

Regulating Body: Modesto Irrigation District Board of Directors — *1) Note 1: Organization and Description of Business, Page 21*

	Year 2008	Year 2007	Year 2006	Source Note
Total Number of Customers:	110,907	110,524	112,386	*2008, 2007, and 2006 (1): includes <u>Total Retail Customers</u>, page 11*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year: Calendar

Start Month/Day: Jan 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006	Source Note
Utility Debt Service Coverage Ratio--Target/Requirement				
Utility Debt Service Coverage Ratio--Achieved Target/Requirement	1.10	1.49	2.31	*2008, 2007 and 2006 (1): includes <u>Debt Service Coverage-Jr. Lien Debt</u> (MID had no Sr. Lien Debt in years 2007 and 2008), page 11*

	Year 2008	Year 2007	Year 2006
Equity Ratio Goal/Objective			

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"F" Modesto

Operating Data	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	352,706	337,736	324,394	2008 and 2007 (1): includes Total Operating Revenues plus Investment Income plus Capitalized interest plus amortization of premium plus Other non-operating income plus Capital Contributions, net, page 19, from Consolidated Statements of Revenues, Expenses and Changes in Net Assets which includes the Domestic Water and Irrigation Water services. Water services account for approximately 12% of Operating Revenues. 2006 (2): includes Total Operating Revenues plus Net investment income plus Other non-operating income, net, page 21
Fuel-Related Operating Expenses ($000s)				
Purchased Power Operating Expenses ($000s)	195,732	162,403	148,413	2008 and 2007 (1): includes Purchased power, page 19. 2006 (2): page 21
Other Operating Expenses ($000s)				
Total Operating Expenses, without Interest or Depreciation ($000s)	313,703	275,920	244,917	2008 and 2007 (1): includes total operating expenses less depreciation and amortization, page 19. 2006 (2): page 21
Depreciation Expense ($000s)	30,302	28,008	25,787	2008 and 2007 (1): includes Depreciation and amortization, page 19. 2006 (2): page 21
Interest Expense ($000s)	32,388	30,292	27,225	2008 and 2007 (1): includes Interest expense, page 19. 2006 (2): page 21
Other Non-Operating Expenses ($000s)	26,819	4,119		2008 and 2007 (1): includes Amortization of debt discount and issuance costs plus Amortization of loss on refunding plus Mark to market adjustment for derivative contracts, page 19. Year 2008 includes a relatively large expense for Mark to market adjustment for derivative contracts of $24,051. 2006 (2): page 21
Total Expenses ($000s)	403,212	338,339	297,929	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)				2008 and 2007 (1): No transfers occurred in 2008 or 2007, page 24. 2006 (2): page 26
Net Revenues ($000s)	-50,506	-603	26,465	Gross Revenues minus Total Expenses minus Transfers Out.
Debt Service Safety Margin	-14.32%	-0.18%	8.16%	Net Revenues Plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City (debt would be paid and transfers would be zero).

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

Fuel % of Total Operating Expense	0%	0%	0%

"F" Modesto

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	
Net Debt ($000s)	644,529	659,583	588,292	2008 and 2007 (1): includes Long-term debt, net of current portion plus Current portion of long-term debt plus Interest payable, page 18, minus Restricted Asset Accounts: Reserve fund, and Redemption fund, page 26. 2006 (2): includes Long-term debt, net of current portion plus Current portion of long-term debt plus Interest payable, page 20, minus Restricted Asset Accounts: Revenue bond and COP reserve funds, and Debt service fund, page 26
Net Fixed Assets ($000s)	617,874	558,109	527,852	2008 and 2007 (1): includes Plant in service - net plus Construction work in progress, page 18. 2006 (1): includes Total capital assets less Accumulated depreciation plus Construction work in progress, page 26.
Unrestricted Net Working Capital ($000s)	121,486	164,557	Not Available	2008 and 2007 (1): includes (Total Current Assets plus Investments-unrestricted less Cash and cash equivalents - restricted) minus (Total Current Liabilities less Current liabilities payable from restricted assets (current portion of long-term debt and interest payable)), page 18. 2006 (2): Can not calculate because they do not break out restricted vs. unrestricted current assets and liabilities.
Debt Ratio (%)	87%	91%	Not Available	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	5.81	5.97	5.24	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilities would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	105,385	148,244	Not Available	2008 and 2007 (1): includes Cash and cash equivalents - unrestricted plus Investments-unrestricted. 2006 (2): Can not calculate because they do not break out restricted vs. unrestricted cash and cash equivalents.
Operating Expenses, without Interest or Depreciation ($000s)	313,703	275,920	244,917	2008 and 2007 (1): includes total operating expenses less depreciation and amortization, page 19. 2006 (2): page 21
Days Cash on Hand	123	196	Not Available	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

O&M Months of Working Capital	4.65	7.16	

Target levels for fuel-related working capital? **Description from utility staff:**

Target levels for non-fuel related working capital? **Description from utility staff:**

Did you meet or exceed these targets in the last two years? (Yes/No)

"F" Modesto

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Yes/No)		*See Residential Rate Tariff on network.*
Rates are sufficient to meet debt service coverage? (Yes/No)		
Regulation of public power utility rates? (Yes/No)	No	*2008 (1); page 21.*
Mood/Role of regulatory body		
Once requested, how many days required to implement rate increase?		
Days Cash on Hand Minus Days to Implement Rate Increase		
Automatic Fuel/Power Cost Adjustment Mechanism Frequency		

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)	
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)	
Fuel and/or purchased power hedging program? Description from utility staff:	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff:

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"G" Riverside

Comparable Utility Letter Designation	"G"
Utility Name and/or Department:	Riverside Public Utilities
Source Document(s):	1) Financial Report 2007-2008 City of Riverside Public Utilities
	2) Financial Statements 2005-2006 City of Riverside Public Utilities
	3) Riverside Public Utilities-Information Request completed by Brian Seinturier, Finance/Rates Manager

Utility Staff Contact(s): Name, Title, and Phone:	Name:	Title:	Phone Number:
	1) Reiko Kerr (rkerr@riversideca.gov)	Assistant GM Finance & Customer Ser	(951) 826-5914
	2) David H. Wright (dwright@riversideca.gov)	General Manager	(951) 826-5784
	3) Brian Seinturier	Finance/Rates Manager	(951) 826-2215

Type of Entity: Municipal Utility

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data Item as it appears in document and any clarifying comments, page number*

Regulating Body: Board of Public Utilities, appointed by Riverside City Council — *2) page 4 3) Qustion 26*

	Year 2008	Year 2007	Year 2006	Source
Total Number of Customers:	105,015	105,226	104,294	*2008, 2007, and 2006 (1): From* *Number of Meters as of Year End (Electric)*, *page 39. Confirmed by Information Request*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year	Fiscal
Start Month/Day	Jul 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006	Source
Utility Debt Service Coverage Ratio–Target/Requirement	2.00	2.00	2.00	*3) Question 5*
Utility Debt Service Coverage Ratio–Achieved	2.62	3.09	2.67	*2008, 2007, and 2006 (1): From* *Management's Discussion and Analysis: Electric*, *page 15*
Mortgage/Bond Covenant Debt Service Coverage Ratio–Target/Requirement	1.10	1.10	1.10	*2008, 2007, and 2006 (1): From* *Management's Discussion and Analysis: Electric*, *page 15*
Equity Ratio Goal/Objective	None	None	None	*3) Question 6*

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"G" Riverside

Operating Data

	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	327,834	300,939	275,098	2008 and 2007 (1): includes Total operating revenues, net of (reserve)/recovery plus Investment income plus Gain on retirement of utility plant plus Other plus Capital contributions, page 20. 2006 3) Question 4
Fuel-Related Operating Expenses ($000s)	5,283	5,037	1,176	All years are from 3) Question 10
Purchased Power Operating Expenses ($000s)	146,168	124,944	128,122	All years are from 3) Question 10
Other Operating Expenses ($000s)	80,037	66,243	65,246	All years are from 3) Question 10
Total Operating Expenses, without Interest or Depreciation ($000s)	231,488	196,224	194,544	2008 and 2007 (1): includes Total operating expenses minus Depreciation, page 20. 2006 (3) Question 10
Depreciation Expense ($000s)	22,193	20,836	16,501	2008 and 2007 (1): includes Depreciation, page 20. 2006 (2): page 16
Interest Expense ($000s)	15,972	14,602	13,615	2008 and 2007 (1): includes Interset expense and fiscal charges, page 20. 2006 (2): page 16. Confirmed by 3) Question 10
Other Non-Operating Expenses ($000s)				
Total Expenses ($000s)	269,653	231,662	224,660	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)	27,371	27,393	22,037	2008 and 2007 (1): Includes Transfers Outs-Contributions to City's general fund, page 20. 2006 (2): page 16. Confirmed by 3) Question 10
Net Revenues ($000s)	30,810	41,884	28,401	Gross Revenues minus Total Expenses minus Transfers Out.
Debt Service Safety Margin	17.75%	23.02%	18.33%	Net Revenues Plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City (debt would be paid and transfers would be zero).

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

	Year 2008	Year 2007	Year 2006
Fuel % of Total Operating Expense	2%	3%	1%

"G" Riverside

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	
Net Debt ($000s)	500,912	309,232	329,017	3) Question 11
Net Fixed Assets ($000s)	505,444	452,712	426,853	2008 and 2007 (1): includes sum of Production, Transmission, Distribution, and General Utility Plant less Accumulated Depreciation plus Land, Construction in progress, and Nuclear fuel, at amortized cost, page 18. 2006 (2): page 14. Confirmed by 3) Question 11
Unrestricted Net Working Capital ($000s)	104,334	130,236	114,191	2008 and 2007 (1): includes Total unrestricted current assets, page 18, minus Total current liabilities, page 19. 2006 (2): page 15 Confirmed by 3) Question 11
Debt Ratio (%)	82%	53%	61%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	4.72	2.94	3.13	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilites would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	78,667	105,388	99,368	2008 and 2007 (1): includes Unrestricted assets: Cash and cash equivalents (Note 2), page 18. 2006 (2): page 14. Confirmed by 3) Question 12
Operating Expenses, without Interest or Depreciation ($000s)	231,488	196,224	194,544	2008 and 2007 (1): includes Total operating expenses minus Depreciation, page 20. 2006 (2): page 16
Days Cash on Hand	124	196	186	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

O&M Months of Working Capital	5.41	7.98	7.04

Target levels for fuel-related working capital?

Description from utility staff: No — 3) Question 16

Target levels for non-fuel related working capital?

Did you meet or exceed these targets in the last two years? (Yes/No)

Description from utility staff: For Working Capital: Yes, Monitored against industry median and goals are established with financial plan, however there are no requirements. For Cash and Cash Equivalents: Yes, Included in cash and cash equivalents are operating reserves. Minimum operating reserves are to be at least 3 months operating expenses. Reviewed periodically with Financial Plan. — 3) Questions 13 and 14.

"G" Riverside

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Yes/No)	No	3) Question 22
Rates are sufficient to meet debt service coverage? (Yes/No)	Yes	2008 (1): page 15.
Regulation of public power utility rates? (Yes/No)	Yes	2008 (1): page 17. It does not appear that they're regulated by a PUC. 3) Qustion 26 states they are regulated by City Council and Board of Public Utilities
Mood/Role of regulatory body	Other	3) Question 29
Once requested, how many days required to implement rate increase?	3 months to 6 months	3) Question 25
Days Cash on Hand Minus Days to Implement Rate Increase		
Automatic Fuel/Power Cost Adjustment Mechanism Frequency		

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)	75% or More	3) Question 19
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)	75% or More	3) Question 20

Fuel and/or purchased power hedging program? Description from utility staff: Riverside hedges its fixed price fuel and purchase power costs over a two period ensuring that the prompt and nearby year total power cost financial exposure as does not exceed 10% and 25% for each respective year. 3) Question 18

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable): According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff: The Electric Utility participates in a self-insurance program for workers' compensation and general liability coverage that is administed by the City. The Electric Utility pays an amount to the City based on actuarial estimates of the amounts needed to fund prior and current year claims and incidents that have been incurred but not reported. The City maintains property insurance on most City property holdings, including Utility Plant with a limit of $1 billion

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"H" Tallahassee

Comparable Utility Letter Designation: "H"

Utility Name and/or Department: The City of Tallahassee Electric Utility

Source Document(s):

1) City of Tallahassee, Florida Comprehensive Annual Financial Report for the Fiscal Year Ended September 30, 2008
2) City of Tallahassee, Florida Comprehensive Annual Financial Report for the Fiscal Year Ended September 30, 2007
3) City of Tallahassee, Florida Comprehensive Annual Financial Report for the Fiscal Year Ended September 30, 2006

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)			
2)			

Type of Entity: Municipal Utility

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data item as it appears in document and any clarifying comments, page number*

Regulating Body: Tallahassee City Commission (The Florida PSC does not regulate rate levels; however, it has jurisdiction over rate structure for the electric system.) — *TalGov website: http://www.talgov.com/you/about.cfm*

	Year 2008	Year 2007	Year 2006	
Total Number of Customers:	112,152	112,152	110,550	*From Energy Velocity Data for 2006 and 2007*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year: Fiscal

Start Month/Day: Oct 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage

	Year 2008	Year 2007	Year 2006	
Utility Debt Service Coverage Ratio–Target/Requirement				
Utility Debt Service Coverage Ratio–Achieved	2.40	2.43	2.40	*2008, 2007, and 2006 (1): from Revenue Bond Coverage, Energy Revenue Bonds, page 144*
Target/Requirement				

Equity Ratio Goal/Objective			

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"H" Tallahassee

Operating Data

	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	377,155	357,901	345,288	2008 (1): includes Electric (only) Total Operating Revenues, page 40, plus Net Investment Earnings plus Securities Lending: Income plus Other Revenues, page 41. 2007 (2): includes Electric (only) Total Operating Revenues, page 40. plus Net Investment Earnings plus Net Increase in the Fair Value of Investments plus Securities Lending: Income plus Grant revenues plus Other revenues, pages 40-41. 2006 (3): includes Electric (only) Total Operating Revenues, page 40, plus Interest Revenue plus Net increase in the Fair Value of Investments plus Grant revenues plus Other revenues, page 41.
Fuel-Related Operating Expenses ($000s)	197,300	185,069	194,623	2008 (1): includes Electric (only) Operating Expenses: Fossil Fuel, page 40. 2007 (2): page 40. 2006 (3): page 40.
Purchased Power Operating Expenses ($000s)	39,009	34,289	28,801	2008 (1): includes Electric (only) Operating Expenses: Power Purchased, page 40. 2006 (3): page 40.
Other Operating Expenses ($000s)	61,247	62,335	56,733	2008 (1): includes Personnel Services plus Contractual Services plus Materials and Supplies plus Other Expenses, page 40. 2007 (2): page 40. 2006 (3): page 40.
Total Operating Expenses, without Interest or Depreciation ($000s)	297,556	281,693	280,157	2008 (1): includes Electric (only) Total Operating Expenses minus Depreciation and Amortization, page 40. 2007 (2): page 40. 2006 (3): page 40.
Depreciation Expense ($000s)	29,678	25,859	21,687	2008 (1): includes Electric (only) Depreciation and Amortization, page 40. 2007 (2): page 40. 2006 (3): page 40.
Interest Expense ($000s)	14,402	15,960	11,633	2008 (1): includes Electric (only) Interest Expense, page 41. Does not include the Interest Expense item under Securities Lending. 2007 (2): page 40. 2006 (3): page 41.
Other Non-Operating Expenses ($000s)	9,470	2,281	748	2008 (1): includes Electric (only) Net Decrease in the Fair Value of Investments, Securities Lending: Interest Expense and Agent Fees, and Other Expenses, page 41. 2007 (2): includes Other Expenses, page 40. 2006 (3): includes Other Expenses, page 41.
Total Expenses ($000s)	351,106	325,793	314,225	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)	22,950	22,630	19,258	2008 (1): includes Electric (only) Total Capital Contributions and Transfers, page 41. 2007 (2): page 41. 2006 (3): page 41.
Net Revenues ($000s)	3,099	9,478	11,805	Gross Revenues minus Total Expenses minus Transfers Out
Debt Service Safety Margin	6.91%	8.97%	9.00%	Net Revenues Plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City (debt would be paid and transfers would be zero).

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

	Year 2008	Year 2007	Year 2006
Fuel % of Total Operating Expense	66%	66%	69%

"H" Tallahassee

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	Notes
Net Debt ($000s)	523,171	477,134	287,424	2008 (1): Includes Bonds Payable, Unamortized Bond Premium (Discount), Deferement of Gain (Loss) on Early Retirement of Debt plus Loans Payable - Current and Bonds Payable - Current, page 39, minus Unamortized Bond Issue Costs, page 38. Could not locate information on any balances in debt service reserve funds. Very close to the table showing Long term debt on page 74, which shows approx.$526 million, from the summation of Ending Balances for these Business-Type Activities: Energy System - 1998 A, Energy System - 1998 B, energy System Refunding 2001, Energy System 2005, Energy System 2007, and AMI Loan, page 74. 2007 (2): pages 38-39. 2006 (3): pages 38-39.
Net Fixed Assets ($000s)	619,197	548,125	485,847	2008 (1): Includes Capital Assets: Land and Construction in Progress plus Other, Net of Accumulated Depreciation, page 38. 2007 (2): page 38. 2006 (3): page 38.
Unrestricted Net Working Capital ($000s)	132,890	131,704	105,329	2008 (1): Includes (Total Current Assets less Cash and cash Equivalents - Restricted less Investments - Restricted less Securities Lending Collateral - Restricted less Receivables - Restricted), page 38, minus (Total Current Liabilities less Obligation Under Securities Lending - Restricted less Retainage Payable and Accounts Payable - Restricted less Loans Payable - Current less Bonds Payable - Current), page 39. This includes Restricted Assets and Liabilities, asked Comparable to break out what is unrestricted vs. restricted. 2007 (3): page 38-39. 2006 (3): page 38-38.
Debt Ratio (%)	70%	70%	49%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	4.66	4.25	2.60	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilites would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	Notes
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	70,409	85,969	39,998	2008 (1): Includes Cash and Cash Equivalents plus Investments, page 38. 2007 (2): page 38. 2006 (3): page 38.
Operating Expenses, without Interest or Depreciation ($000s)	297,556	281,693	280,157	2008 (1): includes Electric (only) Total Operating Expenses minus Depreciation and Amortization, page 40. 2007 (2): page 40. 2006 (3): page 40
Days Cash on Hand	86	111	52	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

	Year 2008	Year 2007	Year 2006
O&M Months of Working Capital	5.36	5.61	4.51

Target levels for fuel-related working capital? Description from utility staff:

Target levels for non-fuel related working capital? Description from utility staff:

Did you meet or exceed these targets in the last two years? (Yes/No)

"H" Tallahassee

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Yes/No)	Yes	*Fuel and Purchase Power Charge Rate (ECRC). http://www.talgov.com/you/rates.cfm*
Rates are sufficient to meet debt service coverage? (Yes/No)		
Regulation of public power utility rates? (Yes/No)		
Mood/Role of regulatory body		
Once requested, how many days required to implement rate increase?		
Days Cash on Hand Minus Days to Implement Rate Increase		
Automatic Fuel/Power Cost Adjustment Mechanism Frequency	Monthly	*http://www.municode.com/Resources/gateway.asp?pid=19980&sid=9*

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)	
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)	
Fuel and/or purchased power hedging program? Description from utility staff:	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff:

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

"I" Turlock

Comparable Utility Letter Designation: "I"

Utility Name and/or Department: Turlock Irrigation District

Source Document(s):
1) Turlock Irrigation District Annual Report 2008
2) Turlock Irrigation District Annual Report 2007
3)

Utility Staff Contact(s): Name, Title, and Phone:

	Name:	Title:	Phone Number:
1)			
2)			

Type of Entity: Public Utility District

Allowable Entries Include: Cooperative, Investor-Owned Utility, Public Utility District, or Municipal Utility

Source Note Format: *Year(s) (Source Document Number): Data item as it appears in document and any clarifying comments, page number*

Regulating Body: Turlock Irrigation Distric Board of Directors — *(1): Rates and Charges, page 7*

	Year 2008	Year 2007	Year 2006	Source Note
Total Number of Customers:	98,548	98,423	97,443	*2008, 2007, and 2006 (1): Average Customers at End of Period, page 2*
Residential Customers:				
Total Electricity Sales (MWh)				
Residential Sales (MWh)				

Fiscal Year or Calendar Year: Calendar

Start Month/Day: Jan 1

DEBT, DEBT SERVICE COVERAGE AND OPERATING PERFORMANCE

Debt Service Coverage	Year 2008	Year 2007	Year 2006	Source Note
Utility Debt Service Coverage Ratio--Target/Requirement				
Utility Debt Service Coverage Ratio--Achieved	2.13	1.91	2.38	*2008, 2007, and 2006 (1): Debt Service Coverage-Revenue Bonds/COP's, page 4*
Target/Requirement				
Equity Ratio Goal/Objective				

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Coverage=Net revenues divided by principal and interest requirements for the fiscal year. An "A" rating for this parameter for the "Electric Generator" class of Public Power Utilities indicates a sound debt service coverage with stable three-year trend; three year average debt service ratio between 1.75-2.25x (or 1.5x to 2.00x including General Fund transfers as O&M Expense). Higher ratings (Aaa and Aa) would indicate three year average ratios between 2.25-3.00x (or 2.0-2.5x including GF transfers as O&M)

Standard & Poor's Notes for U.S. Public Finance: Electric Utility Ratings

While debt service coverage is a traditional financial metric for municipal utilities, it is more common for municiapl electric systems to structure their operations using off-balance sheet debt for generation projects, and purchased power agreements that have debt-like characteristics. As such, fixed charge coverage, which imputes fixed payments associated with power and transmission purchases, whether through debt service or capacity payments tied to purchase contracts, is the more critical coverage ratio in the financial analysis of public power utilities. Transfers to other governments, while often expressly subordinate, are factored into the anlysis as operating and maintenance expenses that reduce available net revenues...

"I" Turlock

Operating Data	Year 2008	Year 2007	Year 2006	
Gross Revenues ($000s)	356,633	319,446	270,083	2008 and 2007 (1): includes Operating revenues, plus Net investment income, plus Other income, net, page 18. 2006 (2): page 18
Fuel-Related Operating Expenses ($000s)				
Purchased Power Operating Expenses ($000s)	95,460	93,293	65,177	2008 and 2007 (1): includes Purchased power, page 18. 2006 (2): page 18
Other Operating Expenses ($000s)				
Total Operating Expenses, without Interest or Depreciation ($000s)	291,610	253,090	202,033	2008 and 2007 (1): includes Operating expenses minus Depreciation and amortization, page 18. 2006 (2): page 18
Depreciation Expense ($000s)	32,404	27,854	23,126	2008 and 2007 (1): includes Depreciation and amortization, page 18. 2006 (2): page 18
Interest Expense ($000s)	20,388	23,894	20,955	2008 and 2007 (1): includes Interest expense, page 18. 2006 (2): page 18
Other Non-Operating Expenses ($000s)				
Total Expenses ($000s)	344,402	304,838	246,114	Sum of Total Operating Expenses, without Interest or Depreciation, Depreciation, Interest, and Other Non-Operating Expenses
Transfers Out (Transfers In) ($000s)				
Net Revenues ($000s)	12,231	14,608	23,969	Gross Revenues minus Total Expenses minus Transfers Out.
Debt Service Safety Margin	3.43%	4.57%	8.87%	Net Revenues Plus Transfers Out (In) divided by Gross Revenues. We assume debt service obligations would be met before transfers to the City (debt would be paid and transfers would be zero).

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt Service Safety Margin is equivalent to Moody's Margin After Debt Service=Net revenues less debt service costs divided by gross revenues and income (not including depreciation and amortization). Moody's looks at margin after debt service to evaluate how large a drop in revenues the enterprise can withstand and still pay debt service. A Margin After Debt Service greater than 15% would be consistent with Aa credit ratings, while margins below 5% would indicate weaker Baa rated credits.

Fuel % of Total Operating Expense	0%	0%	0%

"I" Turlock

Debt, Assets, and Working Capital Data

	Year 2008	Year 2007	Year 2006	Notes
Net Debt ($000s)	488,299	465,633	444,280	2008 and 2007 (1): includes Long-term debt, net of current portion plus Current portion of long-term debt plus Commercial paper notes, page 17. minus designated funds for Debt service, page 34 minus Reserve Funds, page 34. 2006 (2): page 30
Net Fixed Assets ($000s)	782,936	743,515	701,873	2008 and 2007 (1): Total nondepreciable utility plant plus Total depreciable utility plant minus accumulated depreciation, amortization and depletion, page 29. 2006 (2): page 29
Unrestricted Net Working Capital ($000s)	54,503	56,352	62,773	2008 and 2007 (1): includes Current assets, page 16, minus Current Liabilities less Current portion of long-term debt less Commercial paper notes (commercial paper was included as debt), page 17. 2006 (2): page 23. The restricted portion of these current cash and cash equivalents is generally available for withdrawal on demand. Includes Deposits, Commercial Paper, U.S. Trasury bills, Government sponsored enterprises, Repurchase agreements, and the Local Agency Investment Fund.
Debt Ratio (%)	58%	58%	58%	Net Debt divided by the sum of Net Fixed Assets and Net Working Capital
Net Debt per Customer ($000s)	4.95	4.73	4.51	Net Debt divided by Number of Customers

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Debt ratio=net funded debt divided by the sum of net fixed assets and net working capital. Net fixed assets are fixed assets less accumulated depreciation. Net funded debt is long-term debt plus accrued interest payable less the balance in both the Debt Service Reserve Fund and Debt Service Fund. Net working capital are current assets minus current liabilities plus assets not devoted to debt service--measures the funds available for expansion, renewal and improvement to the enterprise. Net working capital is also a conservative measurement of liquidity since it measures funds available after deducting fixed obligations. Using net fixed assets in the calculation of the debt ratio is a very conservative measure since depreciated asset value may not equal the book or market value of the asset.

An "A" rating for the "Electric Generators" class of utilities would indicate a Debt Ratio would be less than 70% with moderate to significant additional capital needs. Higher ratings would indicate Debt Ratios less than 60% with an easily manageable capital program....The median debt ratio for a municipal elec. distributor has averaged in the 20%-30% range for the past 20 years...Public power utilities than own generation and transmission assets will be more heavily leveraged against their depreciated assets than distribution systems. For example, utilities that own generation have a median debt ratio of about 50%.

FINANCIAL RESERVES

Cash Position

	Year 2008	Year 2007	Year 2006	Notes
Unrestricted Cash and Cash Equivalents Plus Unrestricted Investments ($000s)	64,104	61,196	78,333	2008 and 2007 (1): includes Cash and cash equivalents, including restricted amounts plus Short-term investments, including restricted amounts, page 16. 2006 (2):
Operating Expenses, without Interest or Depreciation ($000s)	291,610	253,090	202,033	2008 and 2007 (1): includes Operating expenses minus Depreciation and amortization, page 18. 2006 (2): page 18
Days Cash on Hand*	101	131	205	Turlock does not break out restricted vs. unrestricted cash and investments. Therefore, for all years, Days Cash on Hand are from Fitch Reported Days Cash on Hand. Source: Masterson, Kathy and Lina Santoro. Tuolumne Wind Project Authority, CA, Turlock Irrigation District. New York: Fitch Ratings, June 18, 2009

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

Days Cash on hand=cash and investments times 365 divided by total operating expenses (not including depreciation and amortization). This measures the number of days an enterprise can cover its operating expenses using current unrestricted cash and investments assuming no additional revenue is collected. An "A" rating means between 125-60 days cash on hand. Higher ratings would indicate greater than 125 days.

O&M Months of Working Capital	2.24	2.67	3.73

Target levels for fuel-related working capital? Description from utility staff:

Target levels for non-fuel related working capital? Description from utility staff:

Did you meet or exceed these targets in the last two years? (Yes/No)

"I" Turlock

COST RECOVERY AND RATE SETTING PROCESS, MOST RECENT YEAR

	Yes/No	
Automatic energy cost/fuel cost adjustment charges? (Yes/No)	Yes	*2008 (1): Power supply adjustment, page 40.*
Rates are sufficient to meet debt service coverage? (Yes/No)		
Regulation of public power utility rates? (Yes/No)	No	*2008 (1): page 7.*
Mood/Role of regulatory body		
Once requested, how many days required to implement rate increase?		
Days Cash on Hand Minus Days to Implement Rate Increase		
Automatic Fuel/Power Cost Adjustment Mechanism Frequency	Semi-Annually	*2008 (1): page 40.*

HEDGING AND INSURANCE

Percentage of Next Year's Fuel Price Fixed through Hedges (%)		
Percentage of Next Year's Purchased Power-Related Costs Fixed through Hedges (%)		
Fuel and/or purchased power hedging program?	Description from utility staff:	

Moody's Notes for U.S. Public Power Electric Utilities (Electric Generator Category, where applicable):

According to Moody's an "A" rating for would indicate that rate setting is unregulated; there is adequate rate policy and increases; there are timely energy or fuel cost adjustments and total days needed to implement a rate increase is between 31-60 days. Higher ratings (Aaa and Aa) would have unregulated rate setting; sound rate policy and rate increases; timely energy or fuel cost adjustments and less than 30 days to implement rate increases.

Self-insurance program? Description from utility staff:

Rating Agency Source Data:

Moody's Rating Methodology for U.S. Public Finance: U.S. Public Power Electric Utilities, April 2008
Moody's Global Credit Research Rating Update, August 27, 2007
Standard & Poor's Public Finance RatingsDirect Credit Analysis of GPA, December 23, 2008
FitchRatings "Public Power 2009 Mid-Year Review"; June 9, 2009
Fitch Ratings, "U.S. Public Power Peer Study," June 2009

STANDARD
& POOR'S
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Guam Power Authority; Retail Electric

Credit Profile		
US$361.205 mil rev bnds (Sr) ser 2012A due 10/01/2034		
Long Term Rating	BBB/Stable	New
US$5.0 mil rev bnds (Subord) ser 2012A due 10/01/2034		
Long Term Rating	BBB-/Stable	New
Guam Pwr Auth rev bnds		
Long Term Rating	BBB/Stable	Affirmed

Rationale

Standard & Poor's Ratings Services has assigned its 'BBB' long-term rating to Guam Power Authority 's (GPA) series 2012A senior-lien revenue bonds and its 'BBB-' long-term rating to GPA's series 2012A subordinate-lien revenue bonds. At the same time, we affirmed our 'BBB' long-term rating on GPA's senior-lien revenue bonds and our 'BBB-' long-term rating and underlying rating (SPUR) on GPA's subordinate-lien series 2010A revenue bonds. The outlook is stable.

In our opinion, factors that continue to support an investment grade rating include GPA's:

- Ongoing strong availability and capacity factors of its key generating units, allowing it to reduce dependence on its less economic units. Where historically these fuel-oil burning base-load units had averaged as low as 83% of all energy production, by 2006, output was in excess of 97% and has consistently remained at about that level ever since. These improvements allowed the authority to shift emphasis on its capital program to continued efforts for placing more of its transmission and distribution (T&D) system underground as well as implementing overall T&D system stability and reliability improvements, which are scheduled to be largely completed by 2015.
- Continued support from the Guam Public Utilities Commission (PUC-Guam) under the Consolidated Commission on Utilities (CCU) governance structure that oversees both GPA and Guam Waterworks Authority. GPA continues to be supported in its twice-a-year levelized energy adjustment clause (LEAC) fuel adjustment portion of its rates, as well as the authority to incorporate virtually all fuel-related costs into the LEAC beyond just direct fuel expenses. The PUC-Guam has also been generally supportive of GPA's base rate cases.
- The continued rebounding of the territory's economy, both in the near-term, with increased tourism to the island and related expansions in that sector, and in the long-term, with prospects associated with the relocation of as many as 4,700 Marines from U.S. Department of Defense (DOD) to Guam, mainly from Okinawa, by the end of the decade. The U.S. and Japanese governments have already made a multibillion dollar commitment to this end. While we expect slippage in the timeline, given the U.S. government's difficult budget situation and the 2011 earthquake and tsunami exacerbating Japan's already sluggish economy, the commitments by both governments to eventually foment the relocation for now seems unchanged. In fiscal 2011 alone, the U.S. Navy accounted for about 18% of GPA revenues. Earlier in 2012, the Navy renewed its commitment to GPA for an additional 10 years, essentially making it a wholesale customer of the authority.

In our opinion, the rating remains constrained by:

- The island electric system, which requires the utility to maintain a capacity margin of at least 50%, requiring even

more emphasis on system reliability and efficiency;
- Ongoing efforts to ensure that military-related growth effects--both direct and indirect--will not affect the existing rate base but still allow GPA to meet all load requirements;
- Interdependence with the general government ("GovGuam", B+/Stable), which is typically about 15% of GPA's operating revenues and has at times historically had delays in meeting its obligations to GPA and often displays very tight cash flows--even though most of the intergovernmental receivables owed to GPA have been greatly paid down, and GovGuam remains current on its monthly bills, the risk remains; and
- A dependence on oil, with fuel diversification, possibly including liquefied natural gas (LNG), as the next operational focus.

GPA will mainly use bond proceeds to restructure existing obligations to provide some cash flow relief from a lease-purchase agreement related to 87 megawatts (MW) of installed capacity at two fuel oil units. Guam entered into a 20-year lease in 2000, after which time ownership of the units and any related improvements reverts to GPA. While the last payment is still scheduled to take place in 2019, GPA management has represented that the useful life of the units will far exceed that. Therefore, the series 2012 bonds will be structured to more closely match the useful life of the units, which in fiscal 2011 provided about 30% of GPA's energy requirements. The benefit to GPA's cash flow is to reduce fixed costs by about $9 million per year through 2018 and create more level overall revenue requirements through 2034.

GPA will also use a portion of bond proceeds to refund its parity senior-lien series 1993 and 1999 revenue bonds for interest rate savings purposes. GPA will use the subordinate-lien bonds to terminate a forward purchase agreement it entered into in fiscal 2000 for the purposes of funding a debt service reserve at that time. The subordinate-lien bonds will be on parity with those that GPA issued in 2010 to create a working capital fund and that also converted to long-term debt a loan associated with GPA's now closed commercial paper (CP) program.

Securing the senior-lien bonds is a first-lien pledge on the net revenues of the approximately 47,500-customer vertically integrated electric system. A debt service reserve fund, cash funded at maximum annual debt service (MADS), provides additional liquidity.

A second-lien pledge of net revenues secures the subordinate lien bonds. The senior-lien bonds will remain GPA's working lien. While a subordinate-lien pledge of net revenues provides security, GPA also received PUC-Guam approval to implement a 2% bill surcharge, which went into effect in April 2011, to (by practice) provide a dedicated stream of revenues for that portion of the subordinate-lien bonds. A debt service reserve, fully funded at MADS, provides additional liquidity on the subordinate-lien bonds.

GPA's financial performance continues to stabilize as various actions just in the past several years have improved cash flow certainty, buoyed by support from the PUC-Guam. This includes allowing GPA to recover not just fuel costs but also related out-of-the-money hedges through its LEAC, which is implemented every six months, as well as the aforementioned surcharge. All of these actions should boost liquidity to management's eventual goal of 60 days' operating expenses, from 45 days currently. Fixed charge coverage has rebounded as well, at 1.2x in both fiscals 2011 and 2010; fixed charge coverage is Standard & Poor's internally adjusted debt service coverage (DSC) metric that imputes certain recurring debt-like obligations into the calculation in order to treat them as if they were long-term debt. Actual annual DSC for GPA has been less consistent over the past five years, but still generally strong at between

1.3x and 1.7x. Fiscal 2009 was an exception at 0.97x, mainly as fuel costs rose quicker than GPA could recover them even through an interim LEAC. GPA expects the PUC-Guam to rule by the end of 2012 on a request to change the frequency of the LEAC from bi-annual to quarterly. The PUC-Guam has already approved--in May 2012--GPA's latest rate case, which included 6% base rate adjustments for the remainder of fiscal 2012 and all of fiscal 2013 and the continued buildup of GPA's cash reserves, as well as separately allowing GPA's self-insurance fund to build up to $20 million. Additional changes to the rate structure, including the introduction of an explicit demand charge to certain customer classes, are pending based on the PUC-Guam's August 2012 order for further study on the matter and additional phase-in time if implemented.

The 2012 stipulation on rates, plus the working capital reserves funded from bond proceeds in 2010, has allowed GPA to maintain available reserves at about 45 days' operating expenses, even if GPA is currently projecting to be slightly below that level for fiscal 2012. GPA, in order to further preserve liquidity, has moved to safer--if more expensive--fuel hedging arrangements that aim to minimize margin calls and collateral posting exposure. GPA currently does not have any collateral posted with the only one of the three counterparts to which it could even be subject to a margin call, as it trades within a specified credit limit.

The ongoing U.S. military buildup, while still an enormous undertaking, has been greatly scaled back in size as well as timeline. Originally as many as 9,000 troops and their dependents were to relocate to the island, mainly from Japan, by 2014 to 2017. Recently, however, the DOD has indicated that the number would be closer to 4,700 active duty personnel, along with family members, support and civilian staff, vendors, and suppliers. The timeline would be less certain, but likely more protracted. All facets of Guam's government, from the general government to utilities, the port, and airport have reached a general understanding with DOD that any impacts from the relocation would be cost-neutral to Guam, even if many of the details are still to be determined.

However, the benefit to GPA from the lessened and protracted military relocation is that it can complete its recent emphasis on transmission and distribution system reliability improvements, including undergrounding of key lines and reinforcement of above-ground assets. GPA management expects to be largely done with these efforts by the end of 2015 at a cost of almost $80 million. The future plans for generation are mainly based on a goal of increased fuel diversity, as capacity is currently ample for the 275 MW load that GPA currently serves plus any growth-related impacts. This could include a number of options, even LNG importation, a small portfolio of renewable energy options, or other options.

Guam Power Authority is a vertically integrated, 270 megawatt-peak load electric utility that provides service to approximately 48,000 customers on the island of Guam, the largest and southernmost of the Mariana archipelago, approximately 1,500 miles southeast of Tokyo. GPA is a statutorily autonomous component unit of the government and, as such, if it were ever to transfer or loan money to GovGuam, it would be only at the discretion of the CCU; surplus net revenues otherwise stay within GPA's coffers.

Outlook

The stable outlook reflects Standard & Poor's opinion that GPA's financial performance is sustainable given the improvements to its operations and to Guam's economy and the successful trend of rate cases with PUC-Guam. Some uncertainty regarding GovGuam's fiscal consistency and its periodic ability to meet its obligations to GPA on a timely basis still preclude a higher rating. The territory will always face risks associated with vulnerability to the tourism industry, due to factors such as economic cycles (especially in Asia) and severe weather events. We also expect some slippage in the timeline of the U.S. Marine relocation, likely well beyond the current 2017 working target, but that the overall impact to GPA will be neutral from a cost and infrastructure requirements standpoint. Should GPA's strong and supportive relationship with its regulatory body deteriorate to the point where it materially affects its improved financial performance, a negative credit action might be warranted.

Power Supply Portfolio: Strong Performing Assets, Fuel Remains a Risk

GPA relies almost entirely on eight units at four different sites across the island. All together, the units have a combined name plate capacity of about 352 MW, compared to a system peak of 267 MW in 2011. Five of the units are owned by GPA but run by private operators under three-year performance management contracts. Two of the other three key units are owned and operated by an independent power producer under a lease-purchase agreement that is being defeased with the series 2012A bond proceeds. These two units, nos. 8 and 9 at the Piti site, were installed in 1999 with a nominal 88 MW capacity. All eight units run on residual no. 6 fuel oil that is imported from Singapore on a contract that runs through the end of February 2013; management generally maintains a one- to two-month fuel inventory on hand. GPA management's long-term integrated resources plan has identified some future options that could help diversify the fuel supply and possibly even save on operating costs, such as LNG, but carry very high capital costs. In the near term, GPA will continue to rely on fuel oil but attempt to hedge as carefully as possible, generally locking in 50% of its requirements for the upcoming fiscal year. GPA's hedging strategy is to minimize the potential for margin calls and collateral call risk; only once in the past five years has GPA had to post collateral. GPA also will introduce small amounts of renewable energy options into its portfolio, but by way of purchased power agreements rather than direct ownership of assets such as wind or even solar.

Financial Performance: Short-Term Fixes Providing Long-Term Stability

While fiscal 2009 audited results represented a challenging year for GPA, reflected in fixed charge coverage of 0.95x, we believe this was an anomaly from the trend of consistently sound financial performance, given a number of nonrecurring obligations that were booked in 2009. Fiscal 2010 and 2011 results showed a bounce-back to 1.2x. Since 2008, GPA has received PUC-Guam approval to incorporate virtually all fuel-related costs beyond just direct fuel expenses into its LEAC, including commodity hedges. In recent years, PUC-Guam has generally approved base rate adjustment requests, even if not all have been always exactly as requested. This includes a multiyear rate case filed by GPA with adjustments through fiscal 2014 that included a more explicit demand charge for certain commercial customers. GPA later refiled in April 2012; that stipulation was approved a month later to include 6% base rate increases for the remainder of fiscal 2012 and all of fiscal 2013 that also was supportive of GPA further building up its cash reserves. A decision on the demand charges was deferred for further study. GPA also expects PUC-Guam to rule before the end of calendar year 2012 on its request to move the frequency of the LEAC to quarterly from its current twice yearly. PUC-Guam reviews rates with an assumption of annual DSC of 1.75x in mind.

The approval of enhanced GPA liquidity is important to credit quality. With the eventual goal of maintaining at least 60 days' cash on hand at all times, GPA implemented a 2% bill surcharge, effective April 2011, specifically dedicated to maintaining consistently better levels of liquidity. The historically thin available working capital was only exacerbated in fiscal 2009 by a fuel purchase margin call and an $8 million collateral posting attributed to the CP-related bank loan. Management has represented that it currently has no plans to request a new CP authorization. GPA also has a $35 million (USD) line of credit related to fuel purchases.

In June 2011, GPA entered into two new guaranteed investment contracts (GIC) with Natixis Funding Corp. (A/Stable/A-1) for each of GPA's two main restricted cash accounts: the construction and debt service reserve funds. Because GPA by definition has recurring operating revenues and other noninvestment sources of liquidity readily available based on "prudent practices" of cash management, and therefore does not rely on investment earnings or the GICs to make full and timely payments on its bonds, we do not believe there to be a credit impact associated with the GICs. For additional information, see "Public Finance Criteria: Review of Investment Agreements for Municipal Revenue Bond Financings," published on June 26, 2007, on RatingsDirect on the Global Credit Portal.

Related Criteria And Research

USPF Criteria: Electric Utility Ratings, June 15, 2007

Ratings Detail (As Of September 25, 2012)		
Guam Pwr Auth subord ln		
Long Term Rating	BBB-/Stable	Affirmed
Guam Pwr Auth (AGM)		
Unenhanced Rating	BBB(SPUR)/Stable	Affirmed
Guam Pwr Auth		
Unenhanced Rating	BBB(SPUR)/Stable	Affirmed

Many issues are enhanced by bond insurance.

MOODY'S
INVESTORS SERVICE

New Issue: Moody's assigns Baa3 ratings to Guam Power Authority's 2012 Senior Lien Revenue Bonds

Global Credit Research - 24 Sep 2012

Existing Revenue Bonds upgraded to Baa3, Subordinate Revenue Bonds upgraded to Ba1

GUAM POWER AUTHORITY
Electric Distribution and Generation
GU

Moody's Rating

ISSUE		**RATING**
Revenue Bonds, 2012 Series A		Baa3
Sale Amount	$370,000,000	
Expected Sale Date	10/05/12	
Rating Description	Revenue: Government Enterprise	

Moody's Outlook STA

Opinion

NEW YORK, September 24, 2012 --

Moody's Investors Service has assigned a Baa3 rating to the 2012 Series A Bonds to be issued by the Guam Power Authority (GPA). At the same time, the ratings of the existing revenue bonds have been upgraded from Ba1 to Baa3, and the existing subordinate revenue bonds have been upgraded from Ba2 to Ba1. The rating outlook is stable.

SUMMARY RATING RATIONALE

The rating of GPA's Revenue Bonds reflects its dominant market position as the sole provider of electricity to a diversified customer base comprising residential, business and government customers including both the Government of Guam as well as the U.S. Navy.

The rating upgrade reflects improved financial performance, as measured by debt service coverage levels and liquidity held in the form of days cash on hand. The rating upgrade also reflects approval of multi-year rate increase requests and the signing of a new long term power supply contract with the U.S. Navy, GPA's largest customer.

Outlook

The rating outlook is stable, reflecting the certainty of rates over the next few years as well as GPA's improved operational profile.

What could move the rating - UP

The rating could be upgraded if the financial profile materially improves and GPA's resource mix gains greater diversity.

What could move the rating - DOWN

The rating could be downgraded if GPA's financial profile deteriorates such that debt service coverage, inclusive of all debt and lease obligations, falls below 1.1x on a consistent basis.

USE OF PROCEEDS:

The bonds will be issued to refund a portion GPA's outstanding Revenue Bonds.

LEGAL SECURITY:

The Revenue Bonds 2012 Series A are secured by a pledge of revenues from the electric power system. GPA covenants to fix rates which will be sufficient to yield 1.3x debt service coverage on the Revenue Bonds. A debt service reserve will be funded by an amount equal to maximum annual debt service.

INTEREST RATE DERIVATIVES:

None

DETAILED RATING CONSIDERATIONS

MONOPOLY POWER PROVIDER FOR THE ISLAND OF GUAM, A STRATEGICALLY IMPORTANT TERRITORY OF THE UNITED STATES

Guam Power Authority ("GPA") is a publicly owned monopoly provider of electricity on the island of Guam, an un-incorporated territory of the United States, located in Micronesia.

A major economic growth driver of Guam is tourism, which largely originates from Japan but is increasingly diversifying to include other countries in Asia.

U.S. military expenditures also contribute to the island's economy, as the U.S military maintains a significant presence on Guam through the Andersen Air Force Base as well as other military installations on the island. The U.S. Navy (which also contracts for the Air Force) has recently contracted with GPA to power their provider on Guam for the next 10 years, which Moody's views as positive.

The U.S Department of Defense plans to move approximately 5,000 additional marines to Guam by 2014, which is expected to lead to increases in GPA's peak demand. We note that this is lower than the original plan of more than 8,000 marines and that the final number and timing is subject to change.

As a result of the anticipated military buildup, we expect the U.S Government to become a larger customer as measured by revenues, which due to its Aaa credit rating, is beneficial for GPA. The additional generation requirement is expected to be met largely by current generation capabilities.

GREATER REGULATION THAN OTHER RATED PUBLIC POWER ENTITIES

Unlike much of the rated public power entities, GPA is subject to rate regulation from the Guam Public Utilities Commission ("GPUC"). The GPUC is governed by seven commissioners who are appointed by the Governor of Guam, with the GPUC mandated by law to set rates to meet costs and debt service obligations.

The GPUC has typically approved all rate increases, however a multi-year rate increase plan in 2011 required changes which were not completed before the fiscal year end, and instead were approved in August 2012. This shows that despite the strong relationship between GPA and the GPUC, the rate making process can encounter delays which may temporarily depress GPA's financial profile.

GPA has structured its rates such that various cost elements such as fuel costs are not included in the base rate but rather as surcharges which are adjusted every six months and do not require approval from the regulator. Moody's understands that GPA expects this surcharge adjustment to shorten from six months to three months, which Moody's considers positive as it reduces GPA's working capital requirements.

LACK OF FUEL SUPPLY DIVERSITY GRADUALLY BEING ADDRESSED

All of GPA's generation facilities are oil fueled, with oil supplies delivered by Petrobras under a three year agreement based on market oil prices. The lack of fuel source diversity exposes GPA's fuel costs to potential spikes in oil prices, which is a weakness relative to utilities which have a number of different fuel sources.

GPA's exposure to oil prices is somewhat offset through the fuel adjustment surcharge, which passes through the cost impact of oil price increases to customers every six months rather than embedding such costs within the base rate.

As part of better resource diversification, GPA has entered into a PPA to purchase 30MW of solar and wind resource to come online in 2013 / 2014, which is equivalent to around 11% of 2011 peak demand of 272MW.

In addition, GPA is considering adding additional wind resource, and has also commissioned a study considering conversion of certain oil powered facilities to gas fired facilities, which would improve the current oil concentration in the resource mix.

IMPROVED RECENT FINANCIAL PERFORMANCE

The financial performance of GPA has demonstrated improvement over the last two years. Debt service coverage inclusive of subordinated debt and lease payments improved from 1.0x in 2009 to 1.2x in 2010 and 2011 following the successful implementation of rate increases in 2010.

When last rated in 2010, GPA's liquidity position was challenged as a result of [1] defaulting under agreements with its standby bank facility provider and [2] cash on balance sheet pledged under derivative agreements.

This position has since improved as a result of [1] funding of a new working capital fund and [2] revising fuel hedging policies which have reduced out of the money positions requiring cash pledging. As a result, days cash on hand have increased from 28 days in 2009 to 62 days in 2011, which is supportive of the rating.

Over the next few years, Moody's expects GPA to maintain consolidated debt service coverage levels around 1.2x -1.3x, as a multiyear rate increase already approved is enacted.

RISK OF EXTREME WEATHER EVENTS WELL MITIGATED

Guam is periodically subject to Typhoons and tropical storms - since 1962 seven storms have caused damage great enough to result in federal disaster relief, the last of which occurred in 2004.

GPA manages risks associated with natural disasters by running cabling underground for its major customers such as the Guam Airport and Hospital - at present over 60% of KWh sales are provided through such arrangements. A major initiative has also been undertaken to replace poles from wood to concrete. The financial impact of extreme weather events has declined over time as a result of these initiatives.

As insurance for natural disasters cannot be obtained on reasonable terms, GPA retains a self insurance fund for such events.

CAPITAL PROGRAM MANAGEABLE WITHIN THE RATING

Relative to other rated publicly owned utilities, GPA's capital program is less focused on adding generation, as a result of the substantial reserve margins presently in the system. The focuses of the capital improvement program reflect aims to [i] diversify fuel source, [ii] meet environmental standards and [ii] strengthen and maintain the existing generation, transmission and distribution assets.

Over the next few years, GPA may face additional capex spend as a result of [i] meeting heightened environmental standards and [ii] conversion of certain generation facilities to run on different fuel sources, in order to diversify its fuel mix. Moody's will monitor this going forward and notes that there are different structuring options for this from GPA's perspective (such as entering off-take contracts or self building), which will have different impacts on GPA's financial profile. Moody's notes that due to the high variable costs of some of GPA's assets, additional capex may not necessarily increase GPA's costs to its customers.

KEY STATISTICS:

Electric System Debt Service Coverage, 2011 (per resolution): 2.5x

Consolidated Debt Service Coverage Ratio, 2011 (Moody's): 1.2x

Consolidated Debt Ratio, 2011: 84%

Days Cash on Hand, 2011: 62

Total Cash and Cash Equivalents, 2011; 228M

Electric System Revenue Bonds, 9/30/2011: 560M

The principal methodology used in this rating was U.S. Public Power Electric Utilities With Generation Ownership

Exposure published in November 2011. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

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For ratings issued on a program, series or category/class of debt, this announcement provides relevant regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides relevant regulatory disclosures in relation to the rating action on the support provider and in relation to each particular rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides relevant regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

Information sources used to prepare the rating are the following: parties involved in the ratings, parties not involved in the ratings, and public information.

Moody's considers the quality of information available on the rated entity, obligation or credit satisfactory for the purposes of issuing a rating.

Moody's adopts all necessary measures so that the information it uses in assigning a rating is of sufficient quality and from sources Moody's considers to be reliable including, when appropriate, independent third-party sources. However, Moody's is not an auditor and cannot in every instance independently verify or validate information received in the rating process.

Please see the ratings disclosure page on www.moodys.com for general disclosure on potential conflicts of interests.

Please see the ratings disclosure page on www.moodys.com for information on (A) MCO's major shareholders (above 5%) and for (B) further information regarding certain affiliations that may exist between directors of MCO and rated entities as well as (C) the names of entities that hold ratings from MIS that have also publicly reported to the SEC an ownership interest in MCO of more than 5%. A member of the board of directors of this rated entity may also be a member of the board of directors of a shareholder of Moody's Corporation; however, Moody's has not independently verified this matter.

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Please see ratings tab on the issuer/entity page on www.moodys.com for the last rating action and the rating history.

The date on which some ratings were first released goes back to a time before Moody's ratings were fully digitized and accurate data may not be available. Consequently, Moody's provides a date that it believes is the most reliable and accurate based on the information that is available to it. Please see the ratings disclosure page on our website www.moodys.com for further information.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

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EXHIBIT B

ATTACHMENT I

CURRENT PERIOD

AUGUST 2012 TO JANUARY 2013

LEAC RECONCILIATION

GUAM POWER AUTHORITY
Fuel Clause Reconciliation

Schedule 1

		Total FY 13	FY 13 Civilian	FY 13 Navy
1	Start Date			
2	Total Sales	1,571,884	1,261,087.00	310,797.00
3	Daily Sales	4,306.53	3,455.03	851.50
4	Plant Use	6.25%	215.99	53.23
5	Transmission Loss	3.38%	116.85	28.80
6	Distribution Loss	4.12%	142.30	-
7	Company Use	0.19%	6.50	1.60
8	Total Daily Demand		3,936.67	935.13

			Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	TOTALS	% To Total
9	Month		Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	TOTALS	
10	Days		31	30	31	30	31	31		
			Actual	Actual	Actual	Actual/Forecast	Forecast	Forecast		
11	Required Generation-Civilian		117,057	120,087	120,706	119,811	122,037	122,037	721,735	80.749%
12	Required Generation-Navy		28,989	28,054	28,989	28,054	28,989	28,989	172,064	19.251%
13	TOTAL REQUIRED GENERATION		146,046	148,141	149,695	147,865	151,026	151,026	893,799	
14	Number 6 (HSFO/LSFO)		$ 22,159,166	$ 22,814,028	$23,335,710	$ 23,733,427	$ 24,840,022	$ 23,451,984	$140,334,337	Schedule 2
15	Number 2 (GPA)		1,204,172	400,786	590,416	386,642	709,956	419,255	3,711,228	Schedule 3
16	Number 2 (USN)		0	0	0	0	0	0	0	Schedule 4
17	TOTAL COST		$ 23,363,338	$ 23,214,814	$23,926,126	$ 24,120,069	$ 25,549,978	$ 23,871,239	$144,045,564	
18	Handling Costs		1,399,357	1,826,092	970,701	(827,157)	(826,670)	(826,932)	1,715,391	Schedule 5
19	TOTAL EXPENSE		$ 24,762,695	$ 25,040,906	$24,896,827	$ 23,292,912	$ 24,723,308	$ 23,044,307	$145,760,955	
	Calculation of Civilian Factor									
20	Sales-Civilian		97,612	99,007	107,106	103,651	107,106	107,106	621,588	
20a	Sales-At Transmission Level		5,379	5,189	5,334	5,268	5,443	5,443	32,056	
20b	Sales @ 13.8 kV		92,233	93,818	101,772	98,383	101,663	101,663	589,532	
21a	Fuel Cost Recovery @ 13.8 kV	$186.834	17,577,865	17,539,558	18,351,556	18,381,343	18,994,054	18,994,054	109,838,430	
21b	Fuel Cost Recovery @ "Transmission"		968,804	934,581	960,924	948,749	980,374	980,374	5,773,807	
21c	Total Recovery		18,546,668	18,474,139	19,312,480	19,330,092	19,974,429	19,974,429	115,612,237	
22	Civilian Costs (Total Expense x %)	80.749%	19,522,712	20,040,354	19,620,073	18,808,829	19,963,862	18,608,083	116,563,913	
22a	Deferred Fuel Amort.								0	
23	Under/(Over)		976,043	1,566,215	307,593	(521,263)	(10,567)	(1,366,346)	951,675	
24	Estimated Under/(Over)									
25	Net Recovery Under/(Over)									
									$ 192.7604	Proposed Rate Without Discount
26	Proposed Fuel Cost Recovery									
	Civilian Clause Reconciliation:									
27	Opening Recovery Balance-Aug. 1, 2012		3,253,634	4,229,677	5,795,892	6,103,486	5,582,222	5,571,655		
	Under/(Over)		976,043	1,566,215	307,593	(521,263)	(10,567)	(1,366,346)		
29	Closing Recovery Balance		4,229,677	5,795,892	6,103,486	5,582,222	5,571,655	4,205,309	(951,675.41)	Decrease/(Increase) in Deferred F
	GL balance		4,229,648	5,795,863	6,103,456					
	Variance		29	30	29					

Bills Computed at 1000 kWh/month	Current Rates (1)	Current Bill	Rate to fully recover	Increase (Decrease)
Customer Charge $/month	$ 10.00	$ 10.00	$ 10.00	$ -
Non Fuel Energy Charges ($/Kwh)				
Lifeline Usage (500 Kwh)	0.03644	$ 18.22	$ 18.22	$ -
Non Lifeline Usage	0.09545	$ 47.73	$ 47.73	$ -
WaterWell Charge				
Lifeline Usage (500 Kwh)	0.00000	$ -	$ -	$ -
Non Lifeline Usage	0.00279	$ 1.40	$ 1.40	$ -
Insurance Charge	0.0029	$ 2.90	$ 2.90	$ -
WCF Surcharge	0.00749	$ 7.49	$ 7.49	
Fuel Recovery Charge		$186.834	$193.119	$ 6.28
TOTAL Bill		$ 274.56	$ 280.85	$ 6.28
Increase (Decrease) From Current Bill			$ 6.28	
Percent Increase (Decrease)			2.29%	
Increase (Decrease) From Current Leac Factor			$ 6.28	
Percent Increase (Decrease)			3.36%	

Adjusted LEAC Rate:	Updated Rate	Effective	
Customer	Aug-12	Aug-12	
Secondary - 13.8 KV	$ 0.193119	$ 0.186834	
Primary - 13.8 KV	$ 0.186978	$ 0.180900	97%
34.5 KV	$ 0.185050	$ 0.179035	96%
115 KV	$ 0.183122	$ 0.177170	95%

C:\Guam\GPA\LEACs\Mar02\LEAC Aug 12 thru Jan 13 rev

Schedule 2

Baseload Unit Forecast
Cost of Number 6 Oil

IWPS TOTAL GENERATIOI	146,046	148,141	149,695	147,865	151,026	151,026	893,799
	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Total
Cabras #1							
Generation (Mwh)	19,530	36,861	26,350	33,348	33,574	35,750	185,412
Kwh/Barrel	626	638	650	617	617	617	
Barrels	31,215	57,753	40,524	54,049	54,415	57,941	295,896
Mmbtu/Kwh (Heat Rate)	9,750	9,557	9,381	9,887	9,887	9,887	
Cabras #2							
Generation (Mwh)	31,540	30,968	25,227	28,469	25,264	27,044	168,512
Kwh/Barrel	594	591	572	601	601	601	
Barrels	53,073	52,379	44,113	47,369	42,037	44,999	283,970
Mmbtu/Kwh (Heat Rate)	10,265	10,317	10,667	10,150	10,150	10,150	
Cabras #3							
Generation (Mwh)	15,442	16,172	22,561	5,269	0	0	59,444
Kwh/Barrel	764	637	728	718	718	718	
Barrels	20,209	25,370	30,993	7,338	0	0	83,910
Mmbtu/Kwh (Heat Rate)	7,983	9,569	8,380	8,496	0	0	
Cabras #4							
Generation (Mwh)	22,846	2,544	19,227	23,676	23,784	20,369	112,446
Kwh/Barrel	741	606	730	712	712	712	
Barrels	30,845	4,200	26,346	33,253	33,405	28,608	156,657
Mmbtu/Kwh (Heat Rate)	8,236	10,071	8,359	8,567	8,567	8,567	
Tanguisson #1							
Generation (Mwh)	7,151	7,009	2,566	370	3,415	5,146	25,657
Kwh/Barrel	483	499	508	481	481	481	
Barrels	14,809	14,041	5,053	769	7,100	10,698	52,471
Mmbtu/Kwh (Heat Rate)	12,632	12,220	12,011	12,682	12,682	12,682	
Tanguisson #2							
Generation (Mwh)	7,901	4,634	1,927	91	8,558	9,002	32,113
Kwh/Barrel	470	484	497	475	475	475	
Barrels	16,802	9,570	3,875	192	18,016	18,952	67,406
Mmbtu/Kwh (Heat Rate)	12,972	12,598	12,266	12,842	12,842	12,842	
Piti Power Plant 4 & 5							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	463	463	463	463	463	463	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Enron (IPP) Piti #8							
Generation (Mwh)	14,113	27,892	27,817	26,847	26,967	25,617	149,253
Kwh/Barrel	744	742	746	734	734	734	
Barrels	18,979	37,571	37,306	36,576	36,740	34,900	202,072
Mmbtu/Kwh (Heat Rate)	8,203	8,217	8,181	8,311	8,311	8,311	
Enron (IPP) Piti #9							
Generation (Mwh)	23,474	20,439	21,714	28,435	26,991	26,588	147,641
Kwh/Barrel	728	725	727	730	730	730	
Barrels	32,242	28,199	29,855	38,952	36,974	36,422	202,644
Mmbtu/Kwh (Heat Rate)	8,378	8,416	8,387	8,356	8,356	8,356	
Total Generation (Mwh)	141,997	146,519	147,389	146,505	148,553	149,515	880,478
Total Barrels	218,174	229,083	218,065	218,498	228,686	232,520	1,345,026
Price/Barrel	$101.57	$99.59	$107.01	$108.62	$108.62	$100.86	$104.34
Total Cost (Sch. 6)	$22,159,166	$22,814,028	$23,335,710	$23,733,427	$24,840,022	$23,451,984	$140,334,337
% to Total MWH Generation	97%	99%	98%	99%	98%	99%	99%
% to Fuel Cost	95%	98%	98%	98%	97%	98%	97%
						$	104.34

THE GUAM POWER AUTHORITY
GPA Diesel Unit Forecast
Cost of Number 2 Oil

Remaining Demand	4,049	1,622	2,306	1,360	2,473	1,510	13,320
	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Total
Dededo CT #1							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	297	297	297	297	297	297	
Barrels	16	6	0	0	0	0	22
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Dededo CT #2							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	374	374	374	374	374	374	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Macheche CT							
Generation (Mwh)	115	216	482	14	0	0	827
Kwh/Barrel	408	450	452	454	454	454	
Barrels	282	480	1,065	31	0	0	1,858
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Yigo CT							
Generation (Mwh)	425	742	326	387	977	467	3,324
Kwh/Barrel	435	452	459	457	457	457	
Barrels	976	1,640	710	847	2,138	1,022	7,333
Mmbtu/Kwh (Heat Rate)	13,320	0	0	0	12,691	12,691	
Tenjo Vista							
Generation (Mwh)	1,598	479	1,038	644	1,496	1,043	6,298
Kwh/Barrel	420	601	613	595	595	595	
Barrels	3,804	797	1,694	1,082	2,514	1,753	11,645
Mmbtu/Kwh (Heat Rate)	13,807	9,651	9,465	9,748	9,748	9,748	
TEMES							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	327	327	327	327	327	327	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	

	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Total
Manengon (MDI)							
Generation (Mwh)	1,124	89	255	178	0	0	1,646
Kwh/Barrel	619	618	620	613	613	613	
Barrels	1,817	144	411	290	0	0	2,663
Mmbtu/Kwh (Heat Rate)	9,376	9,384	9,358	9,462	0	0	
Talofofo							
Generation (Mwh)	787	96	194	119	0	0	1,196
Kwh/Barrel	589	582	681	571	571	571	
Barrels	1,337	165	285	208	0	0	1,995
Mmbtu/Kwh (Heat Rate)	9,853	9,969	8,513	10,158	0	0	
Marbo CT							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	293	293	293	293	293	293	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Dededo Diesel							
Generation (Mwh)	0	0	11	18	0	0	29
Kwh/Barrel	525	525	525	530	530	530	
Barrels	0	0	7	34	0	0	41
Mmbtu/Kwh (Heat Rate)	0	0	3,870	10,943	0	0	
Total Generation (MWH) #2 Units	4,049	1,622	2,306	1,360	2,473	1,510	
Total Barrels	8,232	3,232	4,173	2,493	4,652	2,776	25,557
Price/Barrel-See Schedule 7	$ 146.28	$ 124.01	$ 141.49	$ 155.11	$ 152.61	$ 151.04	$ 145.21
Total Cost	$1,204,172	$400,786	$590,416	$386,642	$709,956	$419,255	$3,711,228
Total Gross Generation	146,046	148,141	149,695	147,865	151,026	151,026	
Total Barrels	226,406	232,315	222,237	220,991	233,338	235,296	
% to Total MWH Generation	3%	1%	2%	1%	2%	1%	
% to Fuel Cost	5%	2%	2%	2%	3%	2%	

GUAM POWER AUTHORITY
Navy Dispatch

Schedule 4

	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Total
Remaining Demand	0	0	0	0	(0)	0	
New Orote Plant							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	600	600	600	600	600	600	
Barrels	0	0	0	0	0	0	0
Radio Barrigada Muse							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	550	550	550	550	550	550	
Barrels	0	0	0	0	0	0	0
Naval Hospital Muse							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	550	550	550	550	550	550	
Barrels	0	0	0	0	0	0	0
Total Barrels	0	0	0	0	0	0	0
Price/Barrel	$ 146.28	$ 124.01	$ 141.49	$ 155.11	$ 152.61	$ 151.04	
Total Cost	$0	$0	$0	$0	$0	$0	$0
Remaining Demand	0	0	0	0	(0)	0	0

GUAM POWER AUTHORITY
Fuel Handling and Other Costs

Schedule 5

	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Total
Total Number Six Consumption	218,174	229,083	218,065	218,498	228,686	232,520	1,345,026
Dock Usage Fee/Barrel	$0.58	$0.52	$0.53	$0.56	$0.53	$0.52	
Total Dock Fee-Tristar (FY 13 Budget)	$126,129	$118,418	$115,764	$122,036	$122,036	$122,036	$726,418
A) Excess Laytime/Overtime-Tristar	2,029	855	1,816	1,786	1,869	1,901	10,256
Storage Tank Rental-Tristar (FY 13 Budget)	87,826	87,826	87,826	115,560	115,560	115,560	610,157
Pipeline Fee-Tristar (FY 13 Budget)	36,302	40,984	41,969	69,646	69,646	69,646	328,194
TOTAL Tristar Costs	$252,285	$248,083	$247,375	$309,028	$309,111	$309,143	$1,675,025
Tank Farm Management Fee (Based on contract with Vital)	56,273	56,273	56,273	56,273	56,273	56,273	337,637
Ship Demurrage Cost (Budget and FY 13 Budget)	-	-	-	13,443	13,443	13,443	40,328
D) Fuel Hedging loss/gain (estimated	**(61,030)**	**(176,100)**	**(42,360)**	**0**	**0**	**0**	**(279,490)**
E) Lube Oil (Budget and FY 13 Budget)	148,953	84,230	126,370	177,870	177,870	177,870	893,162
Subscription Delivery fee, Vacuum Rental, Hauling (FY 13 Budget)	1,350	8,888	7,867	5,500	5,500	5,500	34,605
F) Sale of fuel to Matson	(37,338)	(61,408)	(72,201)	(69,634)	(69,231)	(69,524)	(379,336)
G) Inventory growth to be recovered this period 07/31/12 vs 01/31/13	1,020,316	1,644,367	640,092	(1,354,348)	(1,354,348)	(1,354,348)	(758,270)
SGS Inspection (FY 13 Budget)	12,590	16,876	0	19,231	19,231	19,231	87,159
C) Labor charges (FY 13 Budget)	5,958	4,884	7,286	15,481	15,481	15,481	64,570
B) Interest Charges	-	-	-	-	-	-	-
TOTAL Handling Costs	1,399,357	$1,826,092	$970,701	($827,157)	($826,670)	($826,932)	$1,715,391
	379,041	181,725	330,609				
	1,020,316	(1,644,367)	(640,092)				1,715,391

Notes:

(A) Total Excess Laytime & O/T Charges for period 10/11 thru 09/12 — $ 21,837.35
Total barrels offloaded FY 2012 — 2,671,520
Rate per barrel — $0.0082

(B) Total Bank Charges (commission, issuance, LC fees) — N/A
LC charges rate per annum — 2.35%
# of months charged by ANZ Bank — 2

(c) Fiscal Year 12 budget for Labo — $ 166,240.38
Divided by 12 months — 12.00
Estimated labor charges Fy12 — $ 13,853.37
Fiscal Year 13 budget for Labor — $ 185,769.23
Divided by 12 months — 12.00
Estimated labor charges Fy 13 — $ 15,480.77

(D) Fuel Hedging Gain/loss - Hedging Contract is in place thru 09.30.12

(E) Lube oil is based on FY 13 Budget of $2,134,440.

(F) Sale to Matson
Average No. of Barrels for FY 2012 — 3181
Multiplied by $2.03 for handling fee and $4.20 for bunker fee plus 15% mark

G) Inventory Growth calculated as follows:
07/31/12 vs. 01/31/13

Description	Barrels	Unit cost	Amount
Estimated ending inventory as of 01/31/13	489,199	100.315	$ 49,074,039
Estimated ending inventory as of 010/31/12	489,199	108.621	$ 53,137,084
Change in fuel inventory	-	(8.306)	$ (4,063,045)
Amount recoverable for 3 months			$ (4,063,045)
Divided by 3 months-to recover every month			$ (1,354,348.30)

GUAM POWER AUTHORITY
Inventory Effect of Number Six Costs

		Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Ending
Layer 1	Inventory (bbls)	0	-	-	483,356	264,857	36,171	-
	Price/Bbl	-	-	-	108.62	108.62	108.62	108.62
Layer 2	Inventory (bbls)	0	-	-	239,291	239,291	239,291	42,943
	Price/Bbl	-	-	-	99.43	99.43	99.43	99.43
Layer 3	Inventory (bbls)	0	-	-	240,000	240,000	240,000	240,000
	Price/Bbl	-	-	-	100.74	100.74	100.74	100.74
Layer 4	Inventory (bbls)	0	-	-	240,000	240,000	240,000	240,000
	Price/Bbl	-	-	-	99.89	99.89	99.89	99.89
Layer 5	Inventory (bbls)	0	-	-	240,000	240,000	240,000	240,000
	Price/Bbl	-	-	-	100.51	100.51	100.51	100.51
Layer 6	Inventory (bbls)	0	-	-	240,000	240,000	240,000	240,000
	Price/Bbl	-	-	-	101.01	101.01	101.01	101.01
Layer 7	Inventory (bbls)	0	-	-	240,000	240,000	240,000	240,000
	Price/Bbl	-	-	-	111.76	111.76	111.76	111.76
Total Consumption (bbls)		218,174	229,083	218,085	218,498	228,686	232,520	1,345,025.92
Total Barrels	Layer 1	0	0	0	218,498	228,686	36,171	
	Layer 2	0	0	0	0	0	196,348	
	Layer 3	0	0	0	0	0	0	
	Layer 4	0	0	0	0	0	0	
	Layer 5	0	0	0	0	0	0	
	Layer 6	0	0	0	0	0	0	
	Layer 7	0	0	0	0	0	0	
	Total	0	0	0	218,498	228,686	232,520	
Cost	Layer 1	$0	$0	$0	$23,733,427	$24,840,022	$3,928,956	
	Layer 2	-	-	-	-	-	19,523,028	
	Layer 3	-	-	-	-	-	-	
	Layer 4	-	-	-	-	-	-	
	Layer 5	-	-	-	-	-	-	
	Layer 6	-	-	-	-	-	-	
	Layer 7	-	-	-	-	-	-	
	Total	$0	$0	$0	$23,733,427	$24,840,022	$23,451,984	$72,025,433
	Price Per Barrel	$0.00	$0.00	$0.00	$108.62	$108.62	$100.86	$53.55

	$/Bbl											
				-	4.499	6.501	5.200	1.00	-	-	5.20
Oct-12	108.62	Actual	Latest Platts——	-	4.499	6.501	5.200	1.00	-	-	5.20
Nov-12	99.43	Actual		612.50	4.499	6.501	5.200	1.00	612.50	94.23	99.43
Dec-12	100.74	Forecast		621.00	4.499	6.501	5.200	1.00	621.00	95.54	100.74
Jan-13	99.89	Forecast		615.50	4.499	6.501	5.200	1.00	615.50	94.69	99.89
Feb-13	100.51	Forecast		619.50	4.499	6.501	5.200	1.00	619.50	95.31	100.51
Mar-13	101.01	Forecast		622.75	4.499	6.501	5.200	1.00	622.75	95.61	101.01
Apr-13	111.76	Forecast		626.17	14.10	17.89	15.424	1.00	626.17	96.33	111.76
May-13	111.76	Forecast		626.17	14.10	17.89	15.424	1.00	626.17	96.33	111.76
Jun-13	111.76	Forecast		626.17	14.10	17.89	15.424	1.00	626.17	96.33	111.76
Jul-13	112.08	Forecast		628.27	14.10	17.89	15.424	1.00	628.27	96.66	112.08
Aug-13	112.08	Forecast		628.27	14.10	17.89	15.424	1.00	628.27	96.66	112.08
Sep-13	112.08	Forecast		628.27	14.10	17.89	15.424	1.00	628.27	96.66	112.08

Note: Fuel forecast was based Morgan Stanley
Energy Noon Call Asia on Sing HSFO 180CST
dated 12/05/12

Balance as of 10.31.12	HSFO	213,996.94	110.03	23,546,186.02		
	LSFO	269,358.97	107.50	28,956,218.28		
		483,355.91	108.62	52,502,404.30		
Shipments for November 2012	HSFO	186,495.00	99.11	18,484,405.82	29,224.13	6.38
	LSFO	52,796.00	100.55	5,308,417.80	8,104.76	6.51
		239,291.00	99.43	23,792,823.62		

Workpaper for Number 2 oil pricing:

	May-11
Actual Invoice	Shell
CT	3.4060
Diesel	3.7880
Tenjo	3.7890
Cabras 1&2/Tango	3.7890
Total	14.7720
Average	3.6930
Multiplied by 42	**$ 155.106**

Premium fee $ 26.96 Effective March 2010

Note: Fuel forecast was based on Morgan Stanley
Gasoil swaps .5%S dated 12/05/12

				Forecast		
Aug-12	$	-	Actual	-	1	-
Sep-12	$	-	Actual	-	1	-
Oct-12	$	-	Actual	-	1	-
Nov-12	$	155.11	Actual	-	1	-
Dec-12	$	152.61	Forecast	**125.65**	1	125.65
Jan-13	$	151.04	Forecast	**124.08**	1	124.08

FUEL HEDGING PROGRAM
GAIN/(LOSS)

					Platt's Posted Price HSFO 180 cst	GPA HEDGING CALCULATION Diff. between Platts Price vs. Cap/Floor	Contract Quantity	GPA GAIN / (LOSS)
FY 2012	Trade Date	Month	Cap. Price	Floor Price	$/MT	$	MT	($)
J Aron	19-Aug-11	August	667.00	558.50	673.103	$6.103	10,000	$ 61,030.00
J Aron	18-May-12	August	712.00	569.5	673.103	$0.000	10,000	$ -
	ACTUAL NET GPA GAIN/(LOSS)							$ 61,030.00
J Aron	19-Aug-11	September	667.00	558.50	684.610	$17.610	10,000	$ 176,100.00
J Aron	18-May-12	September	712.00	569.5	684.610	$0.000	10,000	$ -
	ACTUAL NET GPA GAIN/(LOSS)							$ 176,100.00
FY 2013								
ANZ	6/4/2012	October	670.00	525.25	650.236	$0.000	10,000	$ -
Goldman Sachs	6/8/2012	October	646.00	523.50	650.236	$4.236	10,000	$ 42,360.00
	PROJECTED NET GPA GAIN/(LOSS)							$ 42,360.00
ANZ	6/4/2012	November	670.00	525.25	612.495	$0.000	10,000	$ -
Goldman Sachs	6/8/2012	November	646.00	523.50	612.495	$0.000	10,000	$ -
	PROJECTED NET GPA GAIN/(LOSS)							$ -
ANZ	6/4/2012	December	670.00	525.25	621.000	$0.000	10,000	$ -
Goldman Sachs	6/8/2012	December	646.00	523.50	621.000	$0.000	10,000	$ -
	PROJECTED NET GPA GAIN/(LOSS)							$ -
Morgan Stanley	6/4/2012	January	640.00	511.00	615.500	$0.000	10,000	$ -
	PROJECTED NET GPA GAIN/(LOSS)							$ -
	Grand Total							$ 279,490.00

Schedule 8b

GPA HEDGE CONTRACTS							
	Trade	Quantity	Period	Ceiling		Floor	
J Aron	8/19/2011	10,000	07/01/12-09/30/12	667.00	101.06	558.50	84.62
J Aron	5/18/2012	10,000	07/01/12-09/30/12	712.00	107.88	569.50	86.29
ANZ	6/4/2012	10,000	10/01/12-12/31/12	670.00	101.52	525.25	79.58
Goldman Sachs	6/8/2012	10,000	10/01/12-12/31/12	646.00	97.88	523.50	79.32
Morgan Stanley	6/4/2012	10,000	01/01/13-03/31/13	640.00	96.97	511.00	77.42

Schedule 9

IWPS TOTAL GENERATION (MW		146,046		148,141		149,695		147,865		151,026		151,026	747,753
	Forecast by Generation		Forecast by Generation		Forecast by Generation		Forecast by Generation		Forecast by Generation		Forecast by Generation		
	Aug-12	Aug-12	Sep-12	Sep-12	Oct-12	Oct-12	Nov-12	Nov-12	Dec-12	Dec-12	Jan-13	Jan-13	
Cabras 1		#DIV/0!		#DIV/0!		#DIV/0!	39,351	34,389	31,110	33,574	32,913	35,750	
Cabras 2		#DIV/0!		#DIV/0!		#DIV/0!	9,142	7,989	23,410	25,264	24,898	27,044	
Cabras 3		#DIV/0!		#DIV/0!		#DIV/0!	20,038	17,511	-	-	-	-	
Cabras 4		#DIV/0!		#DIV/0!		#DIV/0!	25,911	22,644	22,039	23,784	18,753	20,369	
ENRON 1		#DIV/0!		#DIV/0!		#DIV/0!	25,801	22,547	24,988	26,967	23,584	25,617	
ENRON 2		#DIV/0!		#DIV/0!		#DIV/0!	30,624	26,763	25,010	26,991	24,478	26,588	
HEI 1		#DIV/0!		#DIV/0!		#DIV/0!	8,441	7,376	3,165	3,415	4,738	5,146	
HEI 2		#DIV/0!		#DIV/0!		#DIV/0!	922	806	7,930	8,558	8,288	9,002	
Dededo CT 1		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Dededo CT 2		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Macheche CT		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Marbo CT		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Yigo CT		#DIV/0!		#DIV/0!		#DIV/0!	-	-	905	977	430	467	
TEMES CT		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Dededo Diesel 1		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Dededo Diesel 2		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Dededo Diesel 3		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Dededo Diesel 4		#DIV/0!		#DIV/0!		#DIV/0!	-	-	-	-	-	-	
Pulantat Diesel 1		#DIV/0!		#DIV/0!		#DIV/0!	252	220	-	-	-	-	
Pulantat Diesel 2		#DIV/0!		#DIV/0!		#DIV/0!	168	147	-	-	-	-	
Talofofo Diesel 1		#DIV/0!		#DIV/0!		#DIV/0!	776	678	-	-	-	-	
Talofofo Diesel 2		#DIV/0!		#DIV/0!		#DIV/0!	260	227	-	-	-	-	
Tenjo Diesel 1		#DIV/0!		#DIV/0!		#DIV/0!	1,664	1,454	353	381	316	343	
Tenjo Diesel 2		#DIV/0!		#DIV/0!		#DIV/0!	1,368	1,196	294	318	253	274	
Tenjo Diesel 3		#DIV/0!		#DIV/0!		#DIV/0!	1,348	1,178	235	254	90	97	
Tenjo Diesel 4		#DIV/0!		#DIV/0!		#DIV/0!	1,224	1,070	131	141	123	134	
Tenjo Diesel 5		#DIV/0!		#DIV/0!		#DIV/0!	1,048	916	141	152	63	69	
Tenjo Diesel 6		#DIV/0!		#DIV/0!		#DIV/0!	864	755	232	250	116	126	
	-		-		-	#DIV/0!	-	-	-	-	-	-	
	-	#DIV/0!	-	#DIV/0!	-	#DIV/0!	169,200	147,865	139,941	151,026	139,043	151,026	

GUAM POWER AUTHORITY
LEVELIZED ENERGY ADJUSMENT CLAUSE

ASSUMPTIONS/ADD'L INFORMATION:

1. Total sales (Civilian & Navy) same as used in the Docket 98-002.
2. Plant use, losses and company use as a ratio to sales are calculated as follows.

	Mwh	Ratio to Sales	Ratio to Sendout	
Total Mwh Sales -FY12	1,563,474			Ratio to net send out **
Plant Use - (FY 12)	97,739	6.25%		1,683,686
Transmission Losses	52,876	3.38%	3.14%	6.97%
Distribution losses	64,393	4.12%	3.82%	
Company use (FY12)	2,943	0.19%	0.17%	

**tie in to report GPA 318 as of 09.30.08

Note A:	Mwh	Ratio	Allocated FY08 T&D Losses	
Total T&D losses FY12	117,269		7.50%	(Ratio to sales)
Transmission losses-9/30/91	48,579	45.09%	52,876	
Distribution losses- 9/30/91	59,160	54.91%	64,393	
	107,739		117,269	

Net Plant Output	1,683,686
T&D Losses	117,269
Interim PUC adopted line loss standard	6.97%

LEAC Rates Applicable to Different Sales Level
August 2012 to January 2013

		Adjusted LEAC Rate			Cost Shift
1	Total Sales -MWH			621,588	
2	Less: Sales				
3	Primary (3% Discount) (Line 18*.97)	$	0.186978	18,632	$ 3,483,735
4	34.5 (4% Discount) (Line 18*.96)	$	0.185050	13,413	2,482,119
5	115 (5% Discount) (Line 18 * .95)	$	0.183122	11	1,923
6	Net Sales - MWh			589,532	$ 5,967,777
7					
8	Total Civilian Fuel Cost		$	116,563,913	
9	Over/(Under) Recovery			3,253,634	
10	Less: Fuel Costs Recovery from Discounted Customers			(5,967,777)	
11					
12	Civilian Fuel Cost (Net of Discounted Customers)		$	113,849,769	
13					
14	LEAC Rate without discount(Line 8 +9/Line 5)		$	0.192760	
15	LEAC Rate with discount(Line12//Line 6)		$	0.193119	

ATTACHMENT II

PROJECTED SPREADSHEETS

FEBRUARY 2013
TO
JULY 2013

LEAC RECONCILIATION

GUAM POWER AUTHORITY
Fuel Clause Reconciliation

Schedule 1

	Total FY 13	FY 13 Civilian	FY 13 Navy
1 Start Date			
2 Total Sales	1,571,884	1,261,087.00	310,797.00
3 Daily Sales	4,306.53	3,455.03	851.50
4 Plant Use	6.25%	215.99	53.23
5 Transmission Loss	3.38%	116.85	
Transmission Loss Above 13.8kV	2.97%		25.33
6 Distribution Loss	4.12%	142.30	-
7 Company Use	0.19%	6.50	1.60
8 Total Daily Demand		3,936.67	931.66

		Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	TOTALS	% To Total
9 Month		Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	TOTALS	
10 Days		28	31	30	31	30	31		
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast		
11 Required Generation-Civilian		110,227	122,037	118,100	122,037	118,100	122,037	712,537	80.863%
12 Required Generation-Navy		26,086	28,881	27,950	28,881	27,950	28,881	168,630	19.137%
13 TOTAL REQUIRED GENERATION		136,313	150,918	146,050	150,918	146,050	150,918	881,167	
14 Number 6 (HSFO/LSFO)		$ 20,724,925	$ 23,198,031	$ 22,662,901	$ 22,464,487	$ 22,551,315	$ 26,029,835	$ 137,631,495	Schedule 2
15 Number 2 (GPA)		439,908	227,253	580,758	2,619,624	4,050,096	138,000	8,055,639	Schedule 3
16 Number 2 (USN)		0	0	0	0	0	0	0	Schedule 4
17 TOTAL COST		$ 21,164,833	$ 23,425,285	$ 23,243,659	$ 25,084,111	$ 26,601,411	$ 26,167,835	$ 145,687,134	
18 Handling Costs		1,554,503	1,564,158	1,556,894	1,556,090	1,556,299	1,569,976	9,357,922	Schedule 5
19 TOTAL EXPENSE		$ 22,719,337	$ 24,989,443	$ 24,800,553	$ 26,640,201	$ 28,157,711	$ 27,737,811	$ 155,045,055	
Calculation of Civilian Factor									
20 Sales-Civilian		96,741	107,106	103,651	107,106	103,651	107,106	625,361	
20a Sales-At Transmission Level		4,917	5,443	5,268	5,443	5,268	5,443	31,782	
20b Sales @ 13.8 kV		91,824	101,663	98,383	101,663	98,383	101,663	593,579	
21a Fuel Cost Recovery @ 13.8 kV	$207.683	19,070,394	21,113,651	20,432,565	21,113,651	20,432,565	21,113,651	123,276,476	
21b Fuel Cost Recovery @ "Transmission"		975,010	1,079,476	1,044,654	1,079,476	1,044,654	1,079,476	6,302,745	
21c Total Recovery		20,045,404	22,193,126	21,477,219	22,193,126	21,477,219	22,193,126	129,579,220	
22 Civilian Costs (Total Expense x %)	80.863%	18,371,512	20,207,185	20,054,444	21,542,037	22,769,138	22,429,595	125,373,911	
22a Deferred Fuel Amort.								0	
23 Under/(Over)		(1,673,892)	(1,985,941)	(1,422,775)	(651,090)	1,291,919	236,469	(4,205,309)	
24 Estimated Under/(Over)									
25 Net Recovery Under/(Over)									
								$ 207.2071	Proposed Rate Without Discount
26 Proposed Fuel Cost Recovery									
Half of Navy Adjustment		0							
Civilian Clause Reconciliation:									
27 Opening Recovery Balance-Jan. 31, 2013		4,205,309	2,531,417	545,476	(877,299)	(1,528,389)	(236,469)		
Under/(Over)		(1,673,892)	(1,985,941)	(1,422,775)	(651,090)	1,291,919	236,469		
29 Closing Recovery Balance		2,531,417	545,476	(877,299)	(1,528,389)	(236,469)	0	4,205,309.03	Decrease/(Increase) in Deferred Fu

Bills Computed at 1000 kWh/month	Current Rates [1]	Current Bill	Rate to fully recover	Increase (Decrease)
Customer Charge $/month	$ 10.00	$ 10.00	$ 10.00	$ -
Non Fuel Energy Charges ($/Kwh)				
Lifeline Usage (500 Kwh)	0.03644	$ 18.22	$ 18.22	$ -
Non Lifeline Usage	0.09545	$ 47.73	$ 47.73	$ -
WaterWell Charge				
Lifeline Usage (500 Kwh)	0.00000	$ -	$ -	$ -
Non Lifeline Usage	0.00279	$ 1.40	$ 1.40	$ -
Insurance Charge	0.0029	$ 2.90	$ 2.90	$ -
WCF Surcharge	0.00749	$ 7.49	$ 8.39	$ 0.90
Roll Back Credit (RBC)	-0.00618	$ (6.18)	$ (6.18)	$ -
Fuel Recovery Charge		$ 186.83	$ 207.68	$ 20.85
TOTAL Bill		$ 268.38	$ 290.13	$ 21.75
Increase (Decrease) From Current Bill			$ 21.75	
Percent Increase (Decrease)			8.10%	
Increase (Decrease) From Current Leac Factor			$ 20.85	
Percent Increase (Decrease)			11.16%	

Adjusted LEAC Rate: Customer	Effective Feb-13	
Secondary - 13.8 KV	$ 0.207683	
Primary - 13.8 KV	$ 0.198673	96%
34.5 KV	$ 0.197828	95%
115 KV	$ 0.194228	94%

Schedule 2

Baseload Unit Forecast
Cost of Number 6 Oil

IWPS TOTAL GENERATIOI	136,313	150,918	146,050	150,918	146,050	150,918	881,167
	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Total
Cabras #1							
Generation (Mwh)	32,378	36,609	36,951	19,354	0	36,671	161,963
Kwh/Barrel	617	617	617	617	617	617	
Barrels	52,476	59,333	59,889	31,368	0	59,435	262,501
Mmbtu/Kwh (Heat Rate)	9,887	9,887	9,887	9,887	0	9,887	
Cabras #2							
Generation (Mwh)	19,731	24,741	26,710	31,378	31,884	27,151	161,594
Kwh/Barrel	601	601	601	601	601	601	
Barrels	32,830	41,166	44,443	52,209	53,051	45,176	268,875
Mmbtu/Kwh (Heat Rate)	10,150	10,150	10,150	10,150	10,150	10,150	
Cabras #3							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	718	718	718	718	718	718	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Cabras #4							
Generation (Mwh)	21,885	20,650	21,897	23,213	22,632	20,447	130,724
Kwh/Barrel	712	712	712	712	712	712	
Barrels	30,738	29,002	30,755	32,603	31,787	28,717	183,601
Mmbtu/Kwh (Heat Rate)	8,567	8,567	8,567	8,567	8,567	8,567	
Tanguisson #1							
Generation (Mwh)	2,533	3,711	7,545	9,442	11,517	4,325	39,073
Kwh/Barrel	481	481	481	481	481	481	
Barrels	5,266	7,716	15,687	19,629	23,944	8,991	81,233
Mmbtu/Kwh (Heat Rate)	12,682	12,682	12,682	12,682	12,682	12,682	
Tanguisson #2							
Generation (Mwh)	7,201	8,581	9,076	11,059	11,336	8,411	55,664
Kwh/Barrel	475	475	475	475	475	475	
Barrels	15,160	18,065	19,107	23,283	23,865	17,707	117,187
Mmbtu/Kwh (Heat Rate)	12,842	12,842	12,842	12,842	12,842	12,842	
Piti Power Plant 4 & 5							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	463	463	463	463	463	463	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Enron (IPP) Piti #8							
Generation (Mwh)	26,496	27,915	15,141	20,876	27,433	27,627	145,487
Kwh/Barrel	734	734	734	734	734	734	
Barrels	36,098	38,032	20,627	28,442	37,375	37,638	198,212
Mmbtu/Kwh (Heat Rate)	8,311	8,311	8,311	8,311	8,311	8,311	
Enron (IPP) Piti #9							
Generation (Mwh)	24,616	27,935	26,548	26,322	27,433	25,732	158,586
Kwh/Barrel	730	730	730	730	730	730	
Barrels	33,721	38,267	36,367	36,058	37,580	35,249	217,241
Mmbtu/Kwh (Heat Rate)	8,356	8,356	8,356	8,356	8,356	8,356	
Total Generation (Mwh)	134,839	150,142	143,868	141,644	132,235	150,362	853,091
Total Barrels	206,288	231,582	226,874	223,591	207,602	232,913	1,328,850
Price/Barrel	$100.47	$100.17	$99.89	$100.47	$108.63	$111.76	$103.57
Total Cost (Sch. 6)	$20,724,925	$23,198,031	$22,662,901	$22,464,487	$22,551,315	$26,029,835	$137,631,495
% to Total MWH Generation	99%	99%	99%	94%	91%	100%	97%
% to Fuel Cost	98%	99%	98%	90%	85%	99%	94%
						$	103.57

THE GUAM POWER AUTHORITY
GPA Diesel Unit Forecast
Cost of Number 2 Oil

	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Total
Remaining Demand	1,474	776	2,182	9,274	13,815	556	28,076
Dededo CT #1							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	297	297	297	297	297	297	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Dededo CT #2							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	374	374	374	374	374	374	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Macheche CT							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	454	454	454	454	454	454	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	
Yigo CT							
Generation (Mwh)	876	412	441	3,821	7,684	0	13,233
Kwh/Barrel	457	457	457	457	457	457	
Barrels	1,916	901	965	8,362	16,813	0	28,956
Mmbtu/Kwh (Heat Rate)	12,691	12,691	12,691	12,691	12,691	0	
Tenjo Vista							
Generation (Mwh)	598	365	1,741	5,126	5,923	556	14,309
Kwh/Barrel	595	595	595	595	595	595	
Barrels	1,005	613	2,926	8,616	9,955	934	24,048
Mmbtu/Kwh (Heat Rate)	9,748	9,748	9,748	9,748	9,748	9,748	
TEMES							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	364	364	364	364	364	364	
Barrels	0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)	0	0	0	0	0	0	

		Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Total
Manengon (MDI)								
Generation (Mwh)		0	0	0	0	0	0	0
Kwh/Barrel		613	613	613	613	613	613	
Barrels		0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)		0	0	0	0	0	0	
Talofofo								
Generation (Mwh)		0	0	0	327	208	0	534
Kwh/Barrel		571	571	571	571	571	571	
Barrels		0	0	0	572	364	0	936
Mmbtu/Kwh (Heat Rate)		0	0	0	10,158	10,158	0	
Marbo CT								
Generation (Mwh)		0	0	0	0	0	0	0
Kwh/Barrel		293	293	293	293	293	293	
Barrels		0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)		0	0	0	0	0	0	
Dededo Diesel								
Generation (Mwh)		0	0	0	0	0	0	0
Kwh/Barrel		530	530	530	530	530	530	
Barrels		0	0	0	0	0	0	0
Mmbtu/Kwh (Heat Rate)		0	0	0	0	0	0	
Total Generation (MWH) #2 Units		1,474	776	2,182	9,274	13,815	556	
Total Barrels		2,921	1,514	3,891	17,549	27,132	934	53,940
Price/Barrel-See Schedule 7	$	150.59	$ 150.14	$ 149.27	$ 149.27	$ 149.27	$ 147.72	$ 149.34
Total Cost		$439,908	$227,253	$580,758	$2,619,624	$4,050,096	$138,000	$8,055,639
Total Gross Generation		136,313	150,918	146,050	150,918	146,050	150,918	
Total Barrels		209,209	233,095	230,765	241,140	234,734	233,847	
% to Total MWH Generation		1%	1%	1%	6%	9%	0%	
% to Fuel Cost		2%	1%	2%	10%	15%	1%	

GUAM POWER AUTHORITY
Navy Dispatch

Schedule 4

	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Total
Remaining Demand	0	0	0	(0)	(0)	0	
New Orote Plant							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	600	600	600	600	600	600	
Barrels	0	0	0	0	0	0	0
Radio Barrigada Muse							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	550	550	550	550	550	550	
Barrels	0	0	0	0	0	0	0
Naval Hospital Muse							
Generation (Mwh)	0	0	0	0	0	0	0
Kwh/Barrel	550	550	550	550	550	550	
Barrels	0	0	0	0	0	0	0
Total Barrels	0	0	0	0	0	0	0
Price/Barrel	$ 150.59	$ 150.14	$ 149.27	$ 149.27	$ 149.27	$ 147.72	
Total Cost	$0	$0	$0	$0	$0	$0	$0
Remaining Demand	0	0	0	(0)	(0)	0	0

GUAM POWER AUTHORITY
Fuel Handling and Other Costs

Schedule 5

	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Total
Total Number Six Consumption	206,288	231,582	226,874	223,591	207,602	232,913	1,328,850
Dock Usage Fee/Barrel	$0.59	$0.53	$0.54	$0.55	$0.59	$0.52	
Total Dock Fee-Tristar (FY 13 Budget)	$122,036	$122,036	$122,036	$122,036	$122,036	$122,036	$732,213
A) Excess Laytime/Overtime-Tristar	1,686	1,893	1,854	1,828	1,697	1,904	10,862
Storage Tank Rental-Tristar (FY 13 Budget)	115,560	115,560	115,560	115,560	115,560	115,560	693,360
Pipeline Fee-Tristar (FY 13 Budget)	69,646	69,646	69,646	69,646	69,646	69,646	417,879
TOTAL Tristar Costs	$308,928	$309,135	$309,096	$309,070	$308,939	$309,146	$1,854,314
Tank Farm Management Fee (Based on contract with Vital)	56,273	56,273	56,273	56,273	56,273	56,273	337,637
Ship Demurrage Cost (FY 13 Budget)	13,443	13,443	13,443	13,443	13,443	13,443	80,656
D) Fuel Hedging loss/gain (estimated	0	0	0	0	0	0	0
E) Lube Oil (FY 13 Budget)	177,870	177,870	177,870	177,870	177,870	177,870	1,067,220
Subscription Delivery fee, Vacuum Rental, Hauling (FY 13 Budget)	5,500	5,500	5,500	5,500	5,500	5,500	33,000
F) Sale of fuel to Matson	(69,524)	(69,763)	(74,892)	(74,892)	(74,892)	(75,047)	(439,011)
G) Inventory growth to be recovered this period 01/31/13 vs 07/31/13	946,129	946,129	946,129	946,129	946,129	946,129	5,676,776
SGS Inspection (FY 13 Budget)	19,231	19,231	19,231	19,231	19,231	19,231	115,388
C) Labor charges (FY 13 Budget)	15,481	15,481	15,481	15,481	15,481	15,481	92,885
B) Interest Charges/LC Charges	81,173	90,859	88,763	87,986	88,326	101,950	539,057
TOTAL Handling Costs	1,554,503	$1,564,158	$1,556,894	$1,556,090	$1,556,299	$1,569,976	$9,357,922
							9,357,922

Notes:

(A) Total Excess Laytime & O/T Charges for period 10/11 thru 09/12	$ 21,837.35
Total barrels offloaded FY 2012	2,671,520
Rate per barrel	$0.0082
(B) Total Bank Charges (commission, issuance, LC fees)	N/A
LC charges rate per annum	2.35%
# of months charged by ANZ Bank	2

(c) Fiscal Year 12 budget for Labo	$ 166,240.38
Divided by 12 months	12.00
Estimated labor charges Fy12	$ 13,853.37
Fiscal Year 13 budget for Laboı	$ 185,769.23
Divided by 12 months	12.00
Estimated labor charges Fy 13	$ 15,480.77

(D) Fuel Hedging Gain/loss - Hedging Contract is in place thru 03.31.13

(E) Lube oil is based on FY 13 Budget of $2,134,440.

(F) Sale to Matson
Average No. of Barrels for FY 2012 3181
Multiplied by $2.03 for handling fee and $4.20 for bunker fee plus 15% mark

G) Inventory Growth calculated as follows:
07/31/13 vs. 01/31/13

Description	Barrels	Unit cost	Amount
Estimated ending inventory as of 07/31/13	489,199	111.919	$ 54,750,815
Estimated ending inventory as of 01/31/13	489,199	100.315	$ 49,074,039
Change in fuel inventory	-	11.604	$ 5,676,776
Amount recoverable for 6 months			$ 5,676,776
Divided by 6 months-to recover every month			$ 946,129.40

GUAM POWER AUTHORITY
Inventory Effect of Number Six Costs

		Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Ending
Layer 1	Inventory (bbls)	42,943	-	-	-	-	-	-
	Price/Bbl	99.43	99.43	99.43	99.43	99.43	99.43	99.43
Layer 2	Inventory (bbls)	240,000	76,854	-	-	-	-	0
	Price/Bbl	100.74	100.74	100.74	100.74	100.74	100.74	100.74
Layer 3	Inventory (bbls)	240,000	240,000	240,000	13,125.98	-	-	-
	Price/Bbl	99.89	99.89	99.89	99.89	99.89	99.89	99.89
Layer 4	Inventory (bbls)	240,000	240,000	240,000	240,000	29,534.82	-	0
	Price/Bbl	100.51	100.51	100.51	100.51	100.51	100.51	100.51
Layer 5	Inventory (bbls)	240,000	240,000	240,000	240,000	29,535	-	0
	Price/Bbl	101.01	101.01	101.01	101.01	101.01	101.01	101.01
Layer 6	Inventory (bbls)	240,000	240,000	240,000	240,000	240,000	91,468	0
	Price/Bbl	111.76	111.76	111.76	111.76	111.76	111.76	111.78
Layer 7	Inventory (bbls)	240,000	240,000	240,000	240,000	240,000	240,000	98,555
	Price/Bbl	111.76	111.76	111.76	111.76	111.76	111.76	111.76
Total Consumption (bbls)		206,266	231,582	226,874	223,591	207,602	232,913	1,328,849.70
Total Barrels	Layer 1	42,943	0	0	0	0	0	
	Layer 2	163,348	76,654	0	0	0	0	
	Layer 3	0	154,927	226,874	13,126	0	0	
	Layer 4	0	0	0	210,465	29,535	0	
	Layer 5	0	0	0	0	29,535	0	
	Layer 6	0	0	0	0	148,532	91,468	
	Layer 7	0	0	0	0	0	141,445	
	Total	206,288	231,582	226,874	223,591	207,602	232,913	
Cost	Layer 1	$4,269,795	$0	$0	$0	$0	$0	
	Layer 2	16,455,130	7,722,029	-	-	-	-	
	Layer 3	-	15,476,002	22,662,901	1,311,181	-	-	
	Layer 4	-	-	-	21,153,307	2,968,468	-	
	Layer 5	-	-	-	-	2,983,235	-	
	Layer 6	-	-	-	-	16,599,813	10,222,253	
	Layer 7	-	-	-	-	-	15,607,582	
	Total	$20,724,925	$23,198,031	$22,662,901	$22,464,487	$22,551,315	$26,029,835	$137,631,495
	Price Per Barrel	$100.47	$100.17	$99.69	$100.47	$108.63	$111.76	$103.57

	$/Bbl										
				-	4.499	6.501	5.200	1.00	-	-	5.20
Oct-12	108.62	Actual	Latest Platts-------	-	4.499	6.501	5.200	1.00	-	-	5.20
Nov-12	99.43	Actual		612.50	4.499	6.501	5.200	1.00	612.50	94.23	99.43
Dec-12	100.74	Forecast		621.00	4.499	6.501	5.200	1.00	621.00	95.54	100.74
Jan-13	99.89	Forecast		615.50	4.499	6.501	5.200	1.00	615.50	94.69	99.89
Feb-13	100.51	Forecast		619.50	4.499	6.501	5.200	1.00	619.50	95.31	100.51
Mar-13	101.01	Forecast		622.75	4.499	6.501	5.200	1.00	622.75	95.81	101.01
Apr-13	111.76	Forecast		626.17	14.10	17.89	15.424	1.00	626.17	96.33	111.76
May-13	111.76	Forecast		626.17	14.10	17.89	15.424	1.00	626.17	96.33	111.76
Jun-13	111.76	Forecast		626.17	14.10	17.89	15.424	1.00	626.17	96.33	111.76
Jul-13	112.08	Forecast		628.27	14.10	17.89	15.424	1.00	628.27	96.66	112.08
Aug-13	112.08	Forecast		628.27	14.10	17.89	15.424	1.00	628.27	96.66	112.08
Sep-13	112.08	Forecast		628.27	14.10	17.89	15.424	1.00	628.27	96.66	112.08

Note: Fuel forecast was based Morgan Stanley
Energy Noon Call Asia on Sing HSFO 180CST
dated 12/06/12

Balance as of 10.31.12	HSFO	213,996.94	110.03	23,546,186.02
	LSFO	269,358.97	107.50	28,956,218.28
		483,355.91	108.62	52,502,404.30

Workpaper for Number 2 oil pricing:

	May-11
Actual Invoice	Shell
Temes	0.0000
Diesel	0.0000
Tenjo	0.0000
Cabras 1&2/Tango	0.0000
Total	0.0000
Average	0.0000
Multiplied by 42	$ -

Premium fee $ 26.96 Effective March 2010

Note: Fuel forecast was based on Morgan Stanley
Gasoil swaps .5%S dated 12/06/12

				Forecast		
Feb-13	$	150.59	Forecast	123.63	1	123.63
Mar-13	$	150.14	Forecast	123.18	1	123.18
Apr-13	$	149.27	Forecast	122.31	1	122.31
May-13	$	149.27	Forecast	122.31	1	122.31
Jun-13	$	149.27	Forecast	122.31	1	122.31
Jul-13	$	147.72	Forecast	120.76	1	120.76

Schedule 8a

FUEL HEDGING PROGRAM
GAIN/(LOSS)

FY 2013	Trade Date	Month	Cap. Price	Floor Price		Platt's Posted Price HSFO 180 cst $/MT	GPA HEDGING CALCULATION Diff. between Platts Price vs. Cap/Floor $	Contract Quantity MT	GPA GAIN / (LOSS) ($)
Morgan Stanley	6/4/2012	February	640.00	511.00		619.500	$0.000	10,000	$ -
	PROJECTED NET GPA GAIN/(LOSS)								$ -
Morgan Stanley	6/4/2012	March	640.00	511.00		622.750	$0.000	10,000	$ -
	PROJECTED NET GPA GAIN/(LOSS)								$ -
	Grand Total								$ -

Schedule 8b

GPA HEDGE CONTRACTS							
	Trade	Quantity	Period	Ceiling		Floor	
Morgan Stanley	6/4/2012	10,000	01/01/13-03/31/13	640.00	96.97	511.00	77.42

Schedule 9

IWPS TOTAL GENERATION (MW		136,313		150,918		146,050		150,918		146,050		150,918	744,854
	Forecast by Generation Feb-13	Feb-13	Forecast by Generation Mar-13	Mar-13	Forecast by Generation Apr-13	Apr-13	Forecast by Generation May-13	May-13	Forecast by Generation Jun-13	Jun-13	Forecast by Generation Jul-13	Jul-13	
Cabras 1	30,242	32,378	32,893	36,609	35,372	36,951	17,908	19,354	-	-	34,439	36,671	
Cabras 2	18,429	19,731	22,230	24,741	25,569	26,710	29,034	31,378	30,877	31,884	25,498	27,151	
Cabras 3	0	-	0	-	-	-	-	-	-	-	-	-	
Cabras 4	20,442	21,885	18,554	20,650	20,962	21,897	21,479	23,213	21,918	22,632	19,202	20,447	
ENRON 1	24,748	26,496	25,082	27,915	14,494	15,141	19,317	20,876	26,567	27,433	25,945	27,627	
ENRON 2	22,993	24,616	25,100	27,935	25,413	26,548	24,356	26,322	26,567	27,433	24,166	25,732	
HEI 1	2,366	2,533	3,335	3,711	7,223	7,545	8,736	9,442	11,153	11,517	4,062	4,325	
HEI 2	6,726	7,201	7,710	8,581	8,688	9,076	10,233	11,059	10,978	11,336	7,899	8,411	
Dededo CT 1	0	-	0	-	-	-	-	-	-	-	-	-	
Dededo CT 2	0	-	0	-	-	-	-	-	-	-	-	-	
Macheche CT	0	-	0	-	-	-	-	-	-	-	-	-	
Marbo CT	0	-	0	-	-	-	-	-	-	-	-	-	
Yigo CT	818	876	370	412	422	441	3,536	3,821	7,441	7,684	-	-	
TEMES CT	0	-	0	-	-	-	-	-	-	-	-	-	
Dededo Diesel 1	0	-	0	-	-	-	-	-	-	-	-	-	
Dededo Diesel 2	0	-	0	-	-	-	-	-	-	-	-	-	
Dededo Diesel 3	0	-	0	-	-	-	-	-	-	-	-	-	
Dededo Diesel 4	0	-	0	-	-	-	-	-	-	-	-	-	
Pulantat Diesel 1	0	-	0	-	-	-	-	-	-	-	-	-	
Pulantat Diesel 2	0	-	0	-	-	-	-	-	-	-	-	-	
Talofofo Diesel 1	0	-	0	-	-	-	207	223	201	208	-	-	
Talofofo Diesel 2	0	-	0	-	-	-	95	103	-	-	-	-	
Tenjo Diesel 1	236	252	126	140	647	676	1,082	1,169	1,409	1,455	205	218	
Tenjo Diesel 2	175	187	60	66	551	575	1,028	1,110	1,208	1,247	96	102	
Tenjo Diesel 3	61	65	46	52	186	194	923	997	1,107	1,143	61	65	
Tenjo Diesel 4	61	65	13	15	200	209	834	901	1,006	1,039	58	62	
Tenjo Diesel 5	27	29	33	37	34	36	582	629	704	727	51	55	
Tenjo Diesel 6	0	-	50	55	48	50	296	320	302	312	51	55	
	-		-		-	-	-	-	-	-	-	-	
	127,323	136,313	135,601	150,918	139,809	146,050	139,644	150,918	141,439	146,050	141,732	150,918	

Note: Cabras Unit #3 tripped off line on November 8, 2012 due to damaged/burned bus bars on the 13.8 KV side (High side) on auxiliary transformer and cracks on the generator shaft (engine side). Investigation/damage assessment work are still ongoing.

Schedule 10

GUAM POWER AUTHORITY
LEVELIZED ENERGY ADJUSMENT CLAUSE

ASSUMPTIONS/ADD'L INFORMATION:
1. Losses Allocated using FY 2012 Rate Case Loss Percentages

	Mwh	Ratio to Sales	Discount Percentage	Ratio to net send out **
Total Mwh Sales -FY12	1,563,474			1,683,686
Plant Use - (FY 12)	97,739	6.25%		
Transmission Total		3.38%		
Transmission Losses-115		1.24%	93.74%	
Transmission Losses-34.4		1.74%	95.47%	
Primary Losses-13.8		0.41%	95.88%	
Distribution losses		4.12%		
Company use (FY12)	2,943	0.19%		

Note A:	Mwh	Ratio	Allocated FY12 T&D Losses	
Total T&D losses FY12	117,269		7.50%	6.97%

Loss Allocation from FY2011 Rate Case (1)

	Case Losses	Allocator	Current Losses
Transmission	3.40%	45.09%	3.38%
Transmission-115	1.24%	16.49%	1.24%
Transmission-34.4	1.75%	23.17%	1.74%
Transmission-13.8	0.41%	5.44%	0.41%
Distribution			
Total:	4.14%	54.91%	4.12%
Primary	1.41%	18.64%	1.40%
Secondary	1.03%	13.64%	1.02%
Transformer	1.71%	22.62%	1.70%
Total Loss	7.55%		7.50%

ATTACHMENT III

FY12 ACTUAL
LEAC RECOVERY

Guam Power Authority
Actual Generation, Fuel, Sales & Losses
Fiscal Year 2012

Description	Actual Oct-11	Actual Nov-11	Actual Dec-11	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Actual Jul-12	Actual Aug-12	Actual Sep-12	Actual TOTAL
Cabras #1													
Generation (Kwh)	21,240,900	30,155,100	29,440,600	31,111,300	21,363,600	11,526,900	13,160,700	29,749,300	34,338,000	30,990,500	19,529,600	36,860,600	309,467,100
Kwh/Barrel	605	613	608	604	514	643	637	674	632	621	626	638	617
Total Barrels	35,098	49,179	48,433	51,542	41,555	17,924	20,670	44,109	54,363	49,934	31,215	57,753	501,773
Mmbtu/Kwh (Heat Rate)	10,080	9,948	10,035	10,106	11,865	9,485	9,580	9,044	9,657	9,829	9,750	9,557	9,891
Cabras #2													
Generation (Kwh)	7,079,800	15,074,400	22,347,800	0	14,948,600	36,479,100	29,497,900	31,595,100	26,393,900	36,153,800	31,539,900	30,968,500	282,078,800
Kwh/Barrel	558	564	580	0	777	608	617	594	587	595	594	591	601
Total Barrels	12,680	26,721	38,541	14	19,236	60,010	47,792	53,181	44,939	60,787	53,073	52,379	469,350
Mmbtu/Kwh (Heat Rate)	10,925	10,813	10,520		7,850	10,035	9,883	10,267	10,386	10,256	10,265	10,317	10,150
Cabras #3													
Generation (Kwh)	26,039,771	17,997,702	24,289,753	26,130,975	22,824,647	21,152,715	24,072,040	21,833,698	21,515,761	3,310,451	15,442,461	16,172,041	240,782,015
Kwh/Barrel	735	734	728	734	722	720	717	713	694	700	764	637	718
Total Barrels	35,450	24,505	33,367	35,622	31,610	29,395	33,563	30,609	31,020	4,732	20,209	25,370	335,452
Mmbtu/Kwh (Heat Rate)	8,304	8,306	8,380	8,316	8,448	8,477	8,505	8,552	8,795	8,719	7,983	9,569	8,498
Cabras #4													
Generation (Kwh)	22,982,190	22,295,442	18,546,743	19,947,845	22,824,204	25,251,101	24,312,178	19,866,255	25,684,524	25,417,575	22,845,685	2,543,692	252,517,434
Kwh/Barrel	712	700	703	710	720	718	707	715	709	713	741	606	712
Total Barrels	32,298	31,837	26,383	28,103	31,704	35,178	34,404	27,783	36,205	35,658	30,845	4,200	354,598
Mmbtu/Kwh (Heat Rate)	8,573	8,711	8,677	8,594	8,473	8,498	8,632	8,531	8,599	8,558	8,236	10,072	8,566
Tanguisson #1													
Generation (Kwh)	2,402,700	4,454,200	1,561,100	0	1,693,000	1,100,900	3,352,500	7,540,400	8,218,700	3,384,400	7,151,100	7,008,500	47,867,500
Kwh/Barrel	501	478	449	0	467	478	484	477	477	473	483	499	481
Total Barrels	4,793	9,318	3,476	2	3,628	2,303	6,931	15,811	17,212	7,148	14,809	14,041	99,472
Mmbtu/Kwh (Heat Rate)	12,169	12,761	13,582		13,072	12,761	12,611	12,791	12,775	12,883	12,632	12,221	12,676
Tanguisson #2													
Generation (Kwh)	6,307,000	8,443,000	7,266,600	8,800,200	5,526,100	8,227,700	7,712,200	2,632,000	7,789,200	8,309,300	7,900,700	4,633,600	83,547,600
Kwh/Barrel	490	477	469	475	469	473	477	466	469	477	470	484	475
Total Barrels	12,864	17,694	15,479	18,540	11,787	17,386	16,169	5,653	16,623	17,425	16,802	9,570	175,991
Mmbtu/Kwh (Heat Rate)	12,442	12,784	12,994	12,851	13,011	12,890	12,789	13,101	13,018	12,792	12,973	12,599	12,850
Piti Plant (Navy)													
Generation (Kwh)	0	0	0	0	0	0	0	0	0				0
Kwh/Barrel	0	0	0	0	0	0							0
Total Barrels	0												0
Mmbtu/Kwh (Heat Rate)													
Piti #8 (MEC/Enron)													
Generation (Kwh)	29,522,600	14,851,600	20,089,500	27,772,700	24,840,200	10,746,500	17,203,740	22,787,000	19,557,600	20,136,600	14,112,600	27,891,900	249,512,540
Kwh/Barrel	739	724	724	721	732	727	736	742	736	743	744	742	734
Total Barrels	39,963	20,526	27,745	38,508	33,921	14,780	23,387	30,729	26,569	27,105	18,979	37,571	339,783
Mmbtu/Kwh (Heat Rate)	8,257	8,431	8,425	8,458	8,330	8,390	8,292	8,226	8,287	8,211	8,203	8,217	8,307
Piti #9 (MEC/Enron)													
Generation (Kwh)	28,189,200	29,624,800	27,636,500	27,997,300	24,235,800	28,442,900	26,123,300	20,180,600	8,311,200	21,061,800	23,473,900	20,439,400	285,716,700
Kwh/Barrel	741	724	731	731	734	733	735	726	713	729	728	725	730
Total Barrels	38,037	40,911	37,806	38,279	33,029	38,782	35,562	27,799	11,662	28,884	32,242	28,199	391,192
Mmbtu/Kwh (Heat Rate)	8,231	8,424	8,345	8,340	8,313	8,317	8,304	8,403	8,559	8,365	8,379	8,416	8,352
Total Gen.Kwh (B/load)	143,764,161	142,896,244	151,178,596	141,760,320	138,256,151	142,927,816	145,434,558	156,184,353	151,808,885	148,764,426	141,995,946	146,518,233	1,751,489,689
Total Barrels	211,183	220,691	231,229	210,609	206,470	215,758	218,477	235,674	238,592	231,673	218,173	229,082	2,667,611
Price per Barrel	105.76	106.53	109.52	110.10	109.89	112.04	116.66	113.19	115.45	114.32	101.57	99.01	109.56
Total Cost	22,333,664.00	23,509,637	25,325,061	23,189,054	22,689,320	24,173,279	25,486,438	26,676,408	27,544,558	26,485,454	22,159,166	22,682,212	292,254,251

Description	Actual Oct-11	Actual Nov-11	Actual Dec-11	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Actual Jul-12	Actual Aug-12	Actual Sep-12	Actual TOTAL
Cabras #1													
					0								
Dededo CT #1													
Generation (Kwh)	0	0	0		0	0	0		0	0	0	0	0
Kwh/Barrel	0	0	0	#DIV/0!	0	0	0	0	#DIV/0!	#DIV/0!	0	0	0
Total Barrels	9	57	7	0	0	0	6	0	0	0	16	6	101
Mmbtu/Kwh (Heat Rate)													
Dededo CT #2													
Generation (Kwh)	0	0	0	0	0	0	0	0	0	0	0	0	0
Kwh/Barrel	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Barrels	0	0	0	0	0	0	0	0				0	0
Mmbtu/Kwh (Heat Rate)													
Macheche CT													
Generation (Kwh)	129,600	111,600	0	0	46,800	198,000	0	0	0	0	115,200	216,000	817,200
Kwh/Barrel	468	494	0	#DIV/0!	433	510	0	0	#DIV/0!	0	409	450	454
Total Barrels	277	226	5	0	108	388	4	26	0	5	282	480	1,801
Mmbtu/Kwh (Heat Rate)	12,397	11,746			13,385	11,364					14,198	12,889	12,783
Yigo CT													
Generation (Kwh)	14,400	680,400	0	39,600	50,400	198,000	280,800	0	259,200	241,200	424,800	741,600	2,930,400
Kwh/Barrel	576	488	0	457	400	486	501	0	493	410	435	452	457
Total Barrels	25	1,395	1	87	126	408	560	78	526	589	976	1,640	6,410
Mmbtu/Kwh (Heat Rate)	10,069	11,892		12,687	14,500	11,942	11,567		11,770	14,163	13,326	12,826	12,688
TEMES CT (Piti #7)													
Generation (Kwh)	21,883	108,181	34,668	20,688	132,618	916,925	0	0	0	0	0	0	1,234,963
Kwh/Barrel	281	367	244	272	374	375	0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	0	364
Total Barrels	78	295	142	76	355	2,446	0	0	0	0	0	0	3,392
Mmbtu/Kwh (Heat Rate)	20,674	15,816	23,757	21,335	15,526	15,471							15,930
Tenjo Vista													
Generation (Kwh)	1,337,040	2,720,880	1,431,360	1,410,480	1,049,760	2,593,440	1,553,040	1,020,960	921,600	732,240	1,597,680	479,520	16,848,000
Kwh/Barrel	601	740	530	640	600	611	629	592	604	606	420	602	595
Total Barrels	2,227	3,677	2,701	2,204	1,749	4,242	2,471	1,726	1,527	1,208	3,804	797	28,332
Mmbtu/Kwh (Heat Rate)	9,659	7,838	10,945	9,063	9,663	9,487	9,228	9,803	9,610	9,568	13,810	9,640	9,754
Manengon (MDI)													
Generation (Kwh)	245,150	499,111	192,195	179,684	197,975	545,812	308,716	165,913	398,503	747,925	1,123,905	89,367	4,694,256
Kwh/Barrel	562	503	691	617	559	576	810	984	620	620	619	621	613
Total Barrels	436	992	278	291	354	948	381	169	643	1,207	1,817	144	7,660
Mmbtu/Kwh (Heat Rate)	10,316	11,528	8,389	9,402	10,371	10,074	7,158	5,893	9,359	9,360	9,377	9,346	9,464
Talofofo													
Generation (Kwh)	288,000	432,000	72,720	180,720	159,840	388,800	234,720	107,280	203,040	450,720	786,960	96,480	3,401,280
Kwh/Barrel	589	548	551	599	561	595	558	360	583	610	589	585	571
Total Barrels	489	789	132	302	285	654	421	298	348	739	1,337	165	5,958
Mmbtu/Kwh (Heat Rate)	9,842	10,593	10,528	9,679	10,342	9,749	10,403	16,105				9,919	10,159
Dededo Diesel													
Generation (Kwh)	10,600	0						0		0	0	0	10,600
Kwh/Barrel	530	#DIV/0!	0	0	0	0	0	#DIV/0!	#DIV/0!	#DIV/01	0	0	530
Total Barrels	20	0						0		0	0		20
Mmbtu/Kwh (Heat Rate)	10,943												10,943
Marbo CT													
Generation (Kwh)	0			0							0	0	0
Kwh/Barrel	0	0	0	0	0	0						0	0
Total Barrels	6	0	0		0					0	0	0	6
Mmbtu/Kwh (Heat Rate)													
Orote Diesel (Navy)													
Generation (Kwh)													
Kwh/Barrel													
Total Barrels													

Description	Actual Oct-11	Actual Nov-11	Actual Dec-11	Actual Jan-12	Actual Feb-12	Actual Mar-12	Actual Apr-12	Actual May-12	Actual Jun-12	Actual Jul-12	Actual Aug-12	Actual Sep-12	Actual TOTAL
Cabras #1													
Total Gen.Kwh (CT/DSL)	2,046,673	4,552,172	1,730,943	1,831,172	1,637,393	4,840,977	2,377,276	1,294,153	1,782,343	2,172,085	4,048,545	1,622,967	29,936,699
Total Barrels	3,566	7,431	3,266	2,960	2,977	9,085	3,843	2,296	3,044	3,748	8,232	3,232	53,680
Price per Barrel	146.26	147.76	149.78	152.41	152.74	153.33	159.17	157.00	159.73	158.50	146.28	138.03	151.09
Total Cost	521,598	1,098,013	489,187	451,069	454,700	1,393,075	611,681	360,495	486,214	594,065	1,204,172	446,121	8,110,391
Total Gross Generation	145,810,834	147,448,416	152,909,539	143,591,492	139,893,544	147,768,793	147,811,834	157,478,506	153,591,228	150,936,511	146,044,491	148,141,200	1,781,426,388
Total Barrels	214,749	228,122	234,495	213,569	209,447	224,843	222,320	237,970	241,636	235,421	226,405	232,314	2,721,291
Total Fuel Costs	22,855,262	24,607,650	25,814,248	23,640,124	23,144,020	25,566,354	26,098,119	27,036,902	28,030,772	27,079,519	23,363,338	23,128,333	300,364,642
	0	17	9	14	0	0	8	17	7	15	32	9	
		0											
Sales (Kwh):													
Civilian	102,524,919	97,683,741	106,122,279	100,460,150	90,970,451	105,002,783	100,524,538	111,360,018	102,293,360	106,201,745	97,612,051	99,007,813	1,219,763,848
Navy	28,240,511	29,162,647	29,845,990	27,914,531	26,897,674	27,138,054	25,529,822	30,154,655	30,467,265	29,475,103	29,509,561	29,375,333	343,711,146
Sub-Total	130,765,430	126,846,388	135,968,269	128,374,681	117,868,125	132,140,837	126,054,360	141,514,673	132,760,625	135,676,848	127,121,612	128,383,146	1,563,474,994
Plant Use	7,303,496	8,105,821	8,493,907	7,237,545	7,241,236	7,914,558	7,863,370	9,231,680	8,998,066	8,427,914	8,828,796	8,092,862	97,739,251
T & D Losses	7,504,152	12,242,357	8,203,573	7,736,314	14,549,210	7,464,438	13,649,928	6,485,000	11,575,816	6,578,984	9,852,970	11,425,953	117,268,695
Company Use	237,756	253,850	243,790	242,952	234,973	248,960	244,176	247,153	256,721	252,765	241,113	239,239	2,943,448
Gross Generation	145,810,834	147,448,416	152,909,539	143,591,492	139,893,544	147,768,793	147,811,834	157,478,506	153,591,228	150,936,511	146,044,491	148,141,200	117,268,695
							0	0	0	0	0	0	
Fuel Expense:													
Total Fuel Costs	22,855,262	24,607,650	25,814,248	23,640,124	23,144,020	25,566,354	26,098,119	27,036,902	28,030,772	27,079,519	23,363,338	23,128,333	300,364,642
Fuel Handling	422,140	233,345	380,165	(26,517)	(120,003)	(356,099)	(782,677)	201,913	367,245	425,740	379,041	181,725	1,306,017
Sounding Variance/Pipeline Adj.	-	-	-		-	-	-	-		-	-	86,481	86,481
Total Fuel Expense	23,277,402	24,840,995	26,194,413	23,613,607	23,024,017	25,210,255	25,315,442	27,238,815	28,398,017	27,505,259	23,742,379	23,396,539	301,757,139
Recoveries from Navy	(4,767,930)	(5,338,193)	(5,557,204)	(4,962,701)	(4,783,321)	(5,022,765)	(4,743,722)	(5,686,746)	(6,149,817)	$ (5,835,540)	(5,239,983)	(5,000,552)	(63,088,474)
Net Fuel Expense	18,509,472	19,502,802	20,637,209	18,650,906	18,240,696	20,187,490	20,571,720	21,552,069	22,248,200	21,669,719	18,502,396	18,395,987	238,668,665
Civilian Recovery:													
Beg. Recovery Balance	(10,775,556)	(12,085,416)	(11,466,098)	(11,343,627)	(12,159,879)	(9,084,725)	(7,218,406)	(4,961,169)	(3,419,135)	451,462	3,040,390	2,716,135	(10,775,556)
Net Fuel Expense	18,509,472	19,502,802	20,637,209	18,650,906	18,240,696	20,187,490	20,571,720	21,552,069	22,248,200	21,669,719	18,502,396	18,395,987	238,668,665
Current Fuel Cost Rec.-Civilian	(19,819,332)	(18,883,484)	(20,514,738)	(19,467,157)	(15,165,542)	(18,321,171)	(18,314,483)	(20,010,035)	(18,377,603)	(19,080,791)	(18,826,651)	(18,732,796)	(225,513,783)
Current Fuel Cost Rec.-Invty	(111,754)	(106,477)	(115,675)	(109,768)	$ 1,633,489.20	$ 1,885,058.77	1,237,306	1,370,870	1,259,037	$ 1,307,208.00	(279,983)	(258,657)	7,710,657
Current Fuel Cost Rec.	(19,707,578)	(18,777,007)	(20,399,063)	(19,357,389)	(16,799,031)	$ (20,206,229.77)	(19,551,789)	(21,380,905)	(19,636,640)	(20,387,999)	(18,546,668)	(18,474,139)	(233,224,440)
Monthly (over)/under	(1,309,860)	619,318	122,471	(816,251)	3,075,154	1,866,319	2,257,237	1,542,034	3,870,597	2,588,928	(324,255)	(336,809)	13,154,882
Navy Adjustment	-	-	-			-					-		-
End Recovery Balance, Fuel	(12,085,416)	(11,466,098)	(11,343,627)	(12,159,879)	(9,084,725)	(7,218,406)	(4,961,169)	(3,419,135)	451,462	3,040,390	2,716,135	2,379,326	2,379,326
	12,523,629	11,466,101	11,343,630	12,159,881	9,084,728	7,218,408	4961171.359	3,419,137	(451,459)	(3,040,388)	(2,716,133)	(2,379,323)	4,758,649
Actual inventory change:											2		7,137,975
GL Balance, Beg. Invty. Cost Change	11,141,174	10,987,118	12,264,193	12,312,710	12,601,156	11,902,145	11,001,364	10,164,262	9,283,946	4,826,831	213,217	1,513,515	11,141,174
Inventory Cost- Revenue	111,754	106,477	115,675	109,768	(1,633,489)	(1,885,059)	(1,237,306)	(1,370,870)	(1,259,037)	(1,307,208)	279,983	258,657	(7,710,657)
Inventory Cost- Actual Change	(265,810)	1,170,599	(67,157)	178,678.39	934,477.90	984,278.05	400,203.72	490,553.95	(3,198,078)	(3,306,406)	1,020,315.88	1,644,367	(13,978)
GL Balance, End. Invty. Cost Change	10,987,118	12,264,193	12,312,710	12,601,156	11,902,145	11,001,364	10,164,262	9,283,946	4,826,831	213,217	1,513,515	3,416,539	3,416,539

GL Balance -09.30.12 186000.60	2,379,324
GL Balance -09.30.12 186000.66	3,416,538
Total	5,795,862
Variance	3

Notes:

a) Company Use is excluded from the calculation of T and D Losses as such KWH are already part of Civilian Sales.

b) These figures are unaudited

ATTACHMENT IV

SUPPORT FOR DISPATCH ASSUMPTION

LEAC Forecast

	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13
Generation Forecast (MWh)								
Cabras 1	31,110	32,913	30,242	32,893	35,372	17,908	0	34,439
Cabras 2	23,410	24,898	18,429	22,230	25,569	29,034	30,877	25,498
Cabras 3	0	0	0	0	0	0	0	0
Cabras 4	22,039	18,753	20,442	18,554	20,962	21,479	21,918	19,202
ENRON 1	24,988	23,584	24,748	25,082	14,494	19,317	26,567	25,945
ENRON 2	25,010	24,478	22,993	25,100	25,413	24,356	26,567	24,166
HEI 1	3,165	4,738	2,366	3,335	7,223	8,736	11,153	4,062
HEI 2	7,930	8,288	6,726	7,710	8,688	10,233	10,978	7,899
Dededo CT 1	0	0	0	0	0	0	0	0
Dededo CT 2	0	0	0	0	0	0	0	0
Macheche Ct	0	0	0	0	0	0	0	0
Marbo CT	0	0	0	0	0	0	0	0
Yigo CT	905	430	818	370	422	3,536	7,441	0
TEMES CT	0	0	0	0	0	0	0	0
Dededo Diesel 1	0	0	0	0	0	0	0	0
Dededo Diesel 2	0	0	0	0	0	0	0	0
Dededo Diesel 3	0	0	0	0	0	0	0	0
Dededo Diesel 4	0	0	0	0	0	0	0	0
Pulantat Diesel 1	0	0	0	0	0	0	0	0
Pulantat Diesel 2	0	0	0	0	0	0	0	0
Talofofo Diesel 1	0	0	0	0	0	207	201	0
Talofofo Diesel 2	0	0	0	0	0	95	0	0
Tenjo Diesel 1	353	316	236	126	647	1,082	1,409	205
Tenjo Diesel 2	294	253	175	60	551	1,028	1,208	96
Tenjo Diesel 3	235	90	61	46	186	923	1,107	61
Tenjo Diesel 4	131	123	61	13	200	834	1,006	58
Tenjo Diesel 5	141	63	27	33	34	582	704	51
Tenjo Diesel 6	232	116	0	50	48	296	302	51
Total MWh	139,941	139,043	127,323	135,601	139,809	139,644	141,439	141,732
Total Baseload MWh	137,650	137,652	125,946	134,903	137,721	131,063	128,060	141,210
Total Peaking MWh	2,291	1,391	1,377	698	2,089	8,581	13,378	522

Total Baseload MWh (%)	98.4%	99.0%	98.9%	99.5%	98.5%	93.9%	90.5%	99.6%
Total Peaking MWh (%)	1.6%	1.0%	1.1%	0.5%	1.5%	6.1%	9.5%	0.4%

ATTACHMENT V

SUPPORT FOR FUEL PRICE PER BARREL

TAX INVOICE

PETROBRAS SINGAPORE PRIVATE LTD.

8 Eu Tong Sen Street - The Central - #22-89
Singapore 059818

TAX INVOICE Nº 425926
GST REG. Nº 200604967H
CO. REG. Nº 200604967H

DATE: 21 NOVEMBER 2012

BUYER

GUAM POWER AUTHORITY
PO BOX 2977
HAGATNA GUAM 96932-2977 GUAM (US)
UNITED STATES

SELLER	DESCRIPTION OF GOODS
PETROBRAS SINGAPORE PRIVATE LTD	LOW SULPHUR FUEL OIL
ORIGIN COUNTRY	**DELIVERY**
SINGAPORE	DAP, GUAM
VESSEL/TRANSPORTATION MEANS	**BILL OF LADING DATE**
NORDROSE	12-Nov-2012

PAYMENT INSTRUCTIONS

PAYMENT TO BE MADE BY TELEGRAPHIC TRANSFER WITHOUT DISCOUNT ON MATURITY DATE FOR CREDIT TO PETROBRAS SINGAPORE PRIVATE LTD., ACCOUNT Nº 2506681055 AT DEUTSCHE BANK AG SINGAPORE (SWIFT: DEUTSGSG) THROUGH DEUTSCHE BANK TRUST COMPANY AMERICAS NEW YORK U.S.A.
(SWIFT: BKTRUS33 - CHIP UID: 061968)
PLEASE REQUEST YOUR BANK TO FILL IN "SHA" (INSTEAD OF "OUR" OR "BEN") AT THE MONEY ORDER FIELD 71A - DETAIL OF CHARGES.

DUE DATE

11-Dec-2012

QUANTITY	SGD EQUIVALENT	UNIT PRICE US$/MT	TOTAL AMOUNT US$
LOW SULPHUR FUEL OIL NET VOLUME METRIC TONNES 8,104.764		654.975	5,308,417.80
GST - OUT OF SCOPE			
TOTAL AMOUNT DUE:			5,308,417.80

PLEASE PAY US$ 5,308,417.80 . THANK YOU.

REMARKS

PSPL REF:
Invoice prepared by - JUNKO NAKANO - junko.nakano@petrobras.com - DDI +65 6550-5677

LEANDRO PASSOS
FUEL OIL TRADER
PETROBRAS SINGAPORE PRIVATE LIMITED
Reg. No. 200604967H

Paulo Canabrava

PETROBRAS SINGAPORE PTE. LTD.
Paulo Canabrava
Trading Manager
Fuel Oil, Bunker and Feedstocks
Petrobras Singapore Private Limited
Reg. No. 200604967H

TAX INVOICE

PETROBRAS
SINGAPORE PRIVATE LTD.

8 Eu Tong Sen Street - The Central - #22-89
Singapore 059818

TAX INVOICE Nº 426927
GST REG. Nº 200604967H
CO. REG. Nº 200604967H

DATE: 21 NOVEMBER 2012

BUYER

GUAM POWER AUTHORITY
PO BOX 2977
HAGATNA GUAM 96932-2977 GUAM (US)
UNITED STATES

SELLER PETROBRAS SINGAPORE PRIVATE LTD	**DESCRIPTION OF GOODS** HIGH SULPHUR FUEL OIL
ORIGIN COUNTRY SINGAPORE	**DELIVERY** DAP, GUAM
VESSEL/TRANSPORTATION MEANS NORDROSE	**BILL OF LADING DATE** 12-Nov-2012

PAYMENT INSTRUCTIONS

PAYMENT TO BE MADE BY TELEGRAPHIC TRANSFER WITHOUT DISCOUNT ON MATURITY DATE FOR CREDIT TO PETROBRAS SINGAPORE PRIVATE LTD., ACCOUNT Nº 2506681055 AT DEUTSCHE BANK AG SINGAPORE (SWIFT: DEUTSGSG) THROUGH DEUTSCHE BANK TRUST COMPANY AMERICAS NEW YORK U.S.A. (SWIFT: BKTRUS33 - CHIP UID: 061968)
PLEASE REQUEST YOUR BANK TO FILL IN "SHA" (INSTEAD OF "OUR" OR "BEN") AT THE MONEY ORDER FIELD 71A - DETAIL OF CHARGES.

DUE DATE

11-Dec-2012

QUANTITY	SGD EQUIVALENT	UNIT PRICE US$/MT	TOTAL AMOUNT US$
HIGH SULPHUR FUEL OIL NET VOLUME METRIC TONNES 29,224.126 GST - OUT OF SCOPE		632.505	18,484,405.82
TOTAL AMOUNT DUE:			18,484,405.82

PLEASE PAY US$ 18,484,405.82 . THANK YOU.

REMARKS

PSPL REF:
Invoice prepared by - JUNKO NAKANO - junko.nakano@petrobras.com - DDI +65 6550-5677

Paulo Carvalho
PETROBRAS SINGAPORE PTE. LTD.

LEANDRO PASSOS
~~FUEL OIL TRADER~~
PETROBRAS SINGAPORE PRIVATE LIMITED
Reg. No. 200604967H

IP&E HOLDINGS, LLC.
dba IP&E GUAM
643 Chalan San Antonio, Ste. 100
Tamuning, Guam 96913-3644
Main Office: 647-0000 / 647-0123
Dispatch: 565-2949 / 565-2916
Fax: 565-2913

Fueling Excellence

Periodic Invoice

WHOLESALE
GUAM BUSINESS LICENSE NO.

I CERTIFY THAT I HAVE READ THE GUAM RESALE CERTIFICATE OVERPAGE AND DECLARE IT TO BE TRUE & CORRECT UNDER PENALTY OF PERJURY.
Executed on date: ____________
By: ____________
(Customer's Signature)
____
(Print Name)

Invoice Date : 1
Invoice Number: 1278
Depot :
Page Number :

Customer Nbr: 6418598

Sold To: GUAM POWER AUTHORITY-GPA049-09CAB/MEC/TA
P.O.BOX 2977
ATTN: ROD BUMAGAT
PO# 18467 OP
HAGATNA GU 96932

Description	Delivered Qty	UM	Price	Extended Price
DIESEL 3 NA1993 PGIII	4445.10	GA	4.8300	21,469.83
DIESEL 3 NA1993 PGIII	4445.10	GA	3.7890	16,842.48

Cabrera 1/2

Invoice Summary

Product	100183 DIESEL 3 NA1993 PGIII	Total	8890.20 GA	38,312.31
Invoice Subtotal				38,312.31

ms Net 30 Days Net Due Date 12/27/12 Invoice Cycle WKY Weekly

*****************FINAL******************

RECEIVED
DEC - 6 2012
GPA
ACCOUNTS PAYABLE

CERTIFIED TRUE CO

DIP READING GAL
AFTER ______ = ______
BEFORE ______ = ______

METER READING
CLOSING ______
OPENING ______

nal - Processing • Yellow - Accounting • Pink - Customer

SEE REVERSE PAGE FOR CONDITIO

IP&E HOLDINGS, LLC.
dba IP&E GUAM
643 Chalan San Antonio, Ste. 100
Tamuning, Guam 96913-3644
Main Office: 647-0000 / 647-0123
Dispatch: 565-2949 / 565-2916
Fax: 565-2913

Fueling Excellence

Periodic Invoice

WHOLESALE
GUAM BUSINESS LICENSE NO.
I CERTIFY THAT I HAVE READ THE GUAM RESALE CERTIFICATE OVERPAGE AND DECLARE IT TO BE TRUE & CORRECT UNDER PENALTY OF PERJURY.
Executed on date: ____________
By: ____________
(Customer's Signature)
____
(Print Name)

Invoice Date : 11/
Invoice Number: 12788
Depot :
Page Number :

Customer Nbr: 6419929

Sold To: GUAM POWER AUTHORITY-GPA050-09 CT PLANTS
P.O. BOX 2977
PO#18464 OP
ATTN: ROD BUMAGAT- ACCOUNTING
Agana-P.O. Box GU 96932

Description	Delivered Qty	UM	Price	Extended Price
DIESEL 3 NA1993 PGIII	9385.89	GA	3.4060	31,968.34

Invoice Summary

Product	100183 DIESEL 3 NA1993 PGIII	Total	9385.89 GA	31,968.34
Invoice Subtotal				31,968.34

ms Net 30 Days   Net Due Date 12/27/12   Invoice Cycle WKY Weekly

****************FINAL*****************

RECEIVED
DEC - 6 2012
GPA
ACCOUNTS PAYABLE

CERTIFIED TRUE COPY

DIP READING GAL
AFTER ______ = ______
BEFORE ______ = ______

METER READING
CLOSING ______
OPENING ______

inal - Processing • Yellow - Accounting • Pink - Customer

SEE REVERSE PAGE FOR CONDITIO

ATTACHMENT VI

DOCUMENTATION ON ALL FUEL HANDLING EXPENSES (EXISTING CONTRACTS SUBMITTED IN THE PREVIOUS LEAC FILING)

ATTACHMENT VII

BILLING ILLUSTRATIONS – Residential, Large Power Service, Large Government Service

GUAM POWER AUTHORITY
BILL ILLUSTRATION RATE SCHEDULE R - RESIDENTIAL

	RATE SCHEDULE R			
	Existing Rate		Effective 02-01-13	
KWH		500		500
Monthly Charge	$ 10.00	$ 10.00	$ 10.00	$ 10.00
Non-Fuel Energy Charge				
First 500 KWH	0.036440	18.22	0.036440	18.22
Over 500 KWH	0.095850	-	0.095850	-
Emergency Water-well charge	0.002790	-	0.002790	-
Insurance Charge	0.002900	1.45	0.002900	1.45
Working Capital Fund Surcharge	0.007780	3.89	0.008390	4.20
Roll Back Credit (RBC)	-0.006180	(3.09)	-0.006180	(3.09)
Total Electric Charge before Fuel Recovery Charges		30.47		30.78
Fuel Recovery Charge	0.186834	93.42	0.207683	103.84
Total Electric Charge		$ 123.89		$ 134.62
Increase/(Decrease) in Total Bill				$ 10.73
% Increase/(Decrease) in Total Bill				8.66%
% Increase/(Decrease) in LEAC rate				11.16%

	RATE SCHEDULE R				
	Existing Rate		Effective 02-01-13		
KWH		1,000		1,000	
Monthly Charge	$ 10.00	$ 10.00	$ 10.00	$ 10.00	
Non-Fuel Energy Charge					
First 500 KWH	0.036440	18.22	0.036440	18.22	
Over 500 KWH	0.095850	47.93	0.095850	47.93	
Emergency Water-well charge	0.002790	1.40	0.002790	1.40	
Insurance Charge	0.002900	2.90	0.002900	2.90	
Working Capital Fund Surcharge	0.007780	7.78	0.008390	8.39	
Roll Back Credit (RBC)	-0.006180	(6.18)	-0.006180	(6.18)	
Total Electric Charge before Fuel Recovery Charges		82.04		82.65	
Fuel Recovery Charge	0.186834	186.83	0.207683	207.68	
Total Electric Charge		$ 268.87		$ 290.33	
Increase/(Decrease) in Total Bill				$ 21.46	
% Increase/(Decrease) in Total Bill				7.98%	XXX
% Increase/(Decrease) in LEAC rate				11.16%	

	RATE SCHEDULE R			
	Existing Rate		Effective 02-01-13	
KWH		1,500		1,500
Monthly Charge	$ 10.00	$ 10.00	$ 10.00	$ 10.00
Non-Fuel Energy Charge				
First 500 KWH	0.036440	18.22	0.036440	18.22
Over 500 KWH	0.095850	95.85	0.095850	95.85
Emergency Water-well charge	0.002790	2.79	0.002790	2.79
Insurance Charge	0.002900	4.35	0.002900	4.35
Working Capital Fund Surcharge	0.007780	11.67	0.008390	12.59
Roll Back Credit (RBC)	-0.006180	(9.27)	-0.006180	(9.27)
Total Electric Charge before Fuel Recovery Charges		133.61		134.53
Fuel Recovery Charge	0.186834	280.25	0.207683	311.52
Total Electric Charge		$ 413.86		$ 446.05
Increase/(Decrease) in Total Bill				$ 32.19
% Increase/(Decrease) in Total Bill				7.78%
% Increase/(Decrease) in LEAC rate				11.16%

	RATE SCHEDULE R			
	Existing Rate		Effective 02-01-13	
KWH		2,000		2,000
Monthly Charge	$ 10.00	$ 10.00	$ 10.00	$ 10.00
Non-Fuel Energy Charge				
First 500 KWH	0.036440	18.22	0.036440	18.22
Over 500 KWH	0.095850	143.78	0.095850	143.78
Emergency Water-well charge	0.002790	4.19	0.002790	4.19
Insurance Charge	0.002900	5.80	0.002900	5.80
Working Capital Fund Surcharge	0.007780	15.56	0.008390	16.78
Roll Back Credit (RBC)	-0.006180	(12.36)	-0.006180	(12.36)
Total Electric Charge before Fuel Recovery Charges		185.18		186.40
Fuel Recovery Charge	0.186834	373.67	0.207683	415.37
Total Electric Charge		$ 558.85		$ 601.77
Increase/(Decrease) in Total Bill				$ 42.92
% Increase/(Decrease) in Total Bill				7.68%
% Increase/(Decrease) in LEAC rate				11.16%

	RATE SCHEDULE R			
	Existing Rate		Effective 02-01-13	
KWH		2,500		2,500
Monthly Charge	$ 10.00	$ 10.00	$ 10.00	$ 10.00
Non-Fuel Energy Charge				
First 500 KWH	0.036440	18.22	0.036440	18.22
Over 500 KWH	0.095850	191.70	0.095850	191.70
Emergency Water-well charge	0.002790	5.58	0.002790	5.58
Insurance Charge	0.002900	7.25	0.002900	7.25
Working Capital Fund Surcharge	0.007780	19.45	0.008390	20.98
Roll Back Credit (RBC)	-0.006180	(15.45)	-0.006180	(15.45)
Total Electric Charge before Fuel Recovery Charges		236.75		238.28
Fuel Recovery Charge	0.186834	467.09	0.207683	519.21
Total Electric Charge		$ 703.84		$ 757.48
Increase/(Decrease) in Total Bill				$ 53.65
% Increase/(Decrease) in Total Bill				7.62%
% Increase/(Decrease) in LEAC rate				11.16%

GUAM POWER AUTHORITY
BILL ILLUSTRATION RATE SCHEDULE P - LARGE POWER SERVICE (THREE PHASE

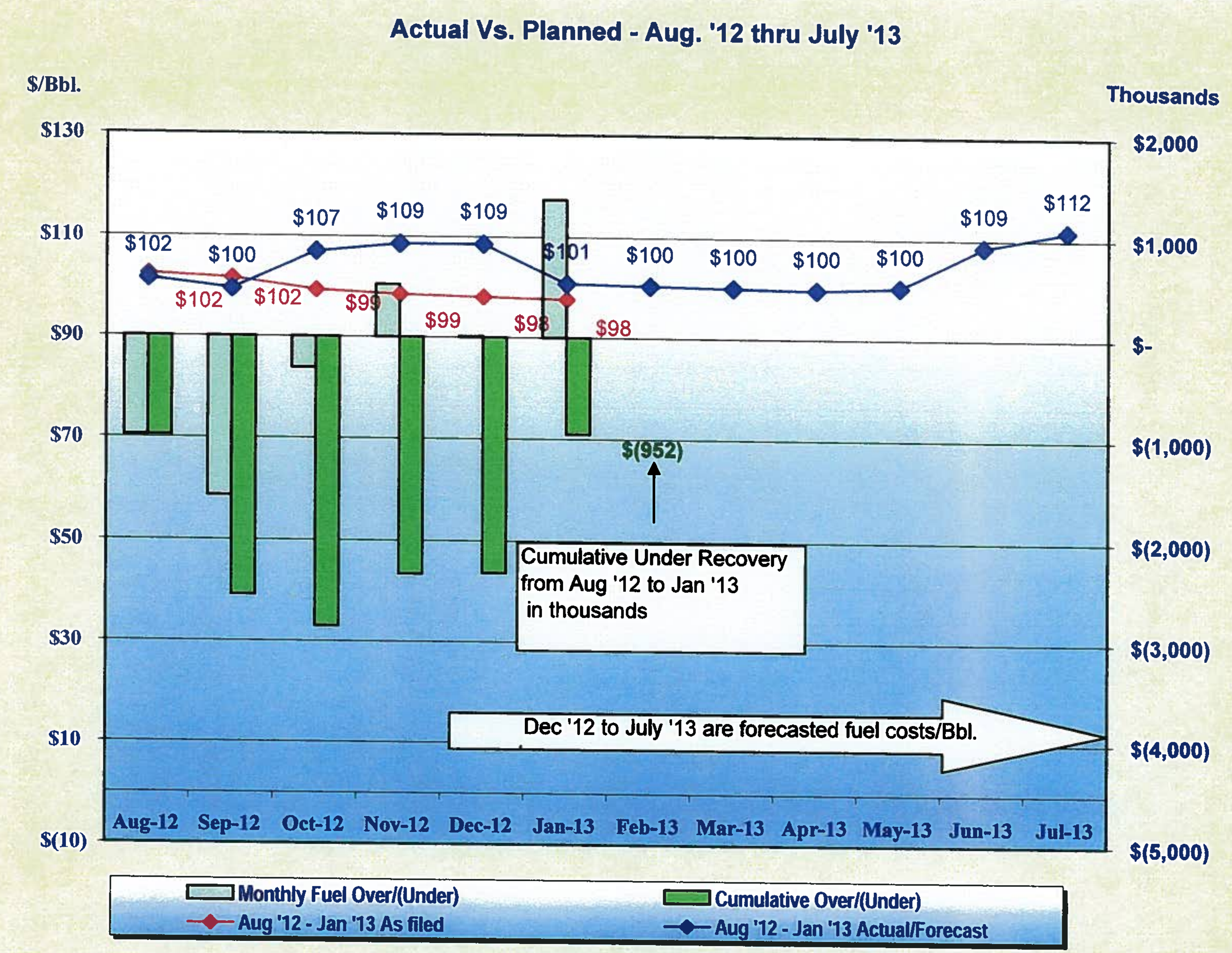
			RATE SCHEDULE P			
		kW/kWh Billed	Existing Rate		Effective 02-01-13	
THREE PHASE						
KWH				101,400		101,400
MINIMUM DEMAND	200					
Monthly Charge			47.40	47.40	47.40	47.40
Demand Charge ($/kW-month)		210	13.43	2,820.30	13.43	2,820.30
Energy Charge ($/kWh-month)						
First Block - First 45,000 kWh per month ($/kWh)		45,000	0.152200	6,849.00	0.15220	6,849.00
Second Block - > 45,000 kWh per month ($/kWh)		56,400	0.045110	2,544.20	0.04511	2,544.20
Emergency Water-well charge		101,400	0.002790	282.91	0.00279	282.91
Insurance Charge		101,400	0.002900	294.06	0.00290	294.06
WCF Surcharge		101,400	0.007780	788.89	0.00839	850.75
Roll Back Credit (RBC)		101,400	(0.006180)	(626.65)	(0.00618)	(626.65)
Total Electric Charge before Fuel Recovery Charges				13,000.11		13,061.96
Fuel Recovery Charge		101,400	0.186834	18,944.97	0.207683	21,059.06
Total Electric Charge				$31,945.08		$34,121.02
Increase/(Decrease) in Total Bill						$2,175.94
% Increase/(Decrease) in Total Bill				$31,638.73		6.81%
% Increase/(Decrease) in LEAC rate						11.16%

GUAM POWER AUTHORITY
BILL ILLUSTRATION RATE SCHEDULE L - LARGE GOVT SERVICE (THREE PHASE

			RATE SCHEDULE L			
		kW/kWh Billed	Existing Rate		Effective 02-01-13	
THREE PHASE						
KWH				634,200		634,200
MINIMUM DEMAND	200	1,158				
Monthly Charge			$ 47.40	47.40	$ 47.40	47.40
Demand Charge ($/kW-month)		1,158	13.55	15,690.90	13.55	15,690.90
Energy Charge ($/kWh-month)						
First Block - First 24,000 kWh per month ($/kWh)		24,000	0.23980	5,755.20	0.23980	5,755.20
Second Block - > 24,000 kWh per month ($/kWh)		610,200	0.04786	29,204.17	0.04786	29,204.17
Emergency Water-well charge		634,200	0.00279	1,769.42	0.00279	1,769.42
Insurance Charge		634,200	0.00290	1,839.18	0.00290	1,839.18
WCF Surcharge		634,200	0.00778	4,934.08	0.00839	5,320.94
Roll Back Credit (RBC)		634,200	(0.00618)	(3,919.36)	(0.00618)	(3,919.36)
Total Electric Charge before Fuel Recovery Charges				55,320.99		55,707.85
Fuel Recovery Charge		634,200	0.186834	118,490.12	0.207683	131,712.56
Total Electric Charge				$173,811.11		$187,420.41
Increase/(Decrease) in Total Bill						$13,609.30
% Increase/(Decrease) in Total Bill						7.83%
% Increase/(Decrease) in LEAC rate						11.16%

ATTACHMENT VIII

Actual vs. Planned Fuel Cost per Barrel



Actual Vs. Planned - Aug. '12 thru July '13
$/Bbl.
Thousands
$130
$110
$90
$70
$50
$30
$10
$(10)
$2,000
$1,000
$-
$(1,000)
$(2,000)
$(3,000)
$(4,000)
$(5,000)
$102
$100
$107
$109
$109
$101
$100
$100
$100
$100
$109
$112
$102
$102
$99
$99
$98
$98
$(952)
Cumulative Under Recovery from Aug '12 to Jan '13 in thousands
Dec '12 to July '13 are forecasted fuel costs/Bbl.
Aug-12
Sep-12
Oct-12
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
Jul-13
Monthly Fuel Over/(Under)
Cumulative Over/(Under)
Aug '12 - Jan '13 As filed
Aug '12 - Jan '13 Actual/Forecast

ATTACHMENT IX

Working Capital Fund Surcharge Adjustment

Guam Power Authority
Working Capital Fund Requirement-Fuel Portion

		Additional FY 2013	Additional FY 2012	Original Eff 4/1/12	Total WCF Surcharge Eff 5/1/12	Total WCF Surcharge Eff 2/1/13
A	Current Year Fuel Costs Budget	$ 316,595,000	$ 305,450,000			
B	Prior Year Fuel Costs Budget	$ 305,450,000	$ 247,191,000			
C	Increase in Fuel Costs	$ 11,145,000	$ 58,259,000			
D	Working Capital Fund Requirement (1/12 of Line C Increase In Fuel Costs)	$ 928,750	$ 4,854,917			
E	Navy Share [1]	17.0%	17.0%			
F	Civilian Share [1]	83.0%	83.0%			
G	Navy Additional WCF Surcharge Share (Line D x Line E)	$ 157,888	$ 825,336			
H	**Navy WCF Surcharge (Line G / 12)**	**$ 13,157**	**$ 68,778**	$ 110,374	$ 179,152	$ 192,309
I	Civilian Additional WCF Surcharge Share (Line D x Line F)	$ 770,863	$ 4,029,581			
J	Kwh Sales Forecast (May 2012 through April 2013)		1,288,180,143			
J1	Kwh Sales Forecast (Feb 2013 through Jan 2014)	1,264,016,864				
K	**Civilian WCF Surcharge (Line I / Line J)**	**$ 0.00061**	**$ 0.00313**	$ 0.00466	$ 0.00778	$ 0.00839
				Note (2)	Note (3)	Note (4)

(1) Per PUC Order dated 6/10/11. (FY 10 TLCOS Rate base allocator)
(2) This surcharge is effective from April 1, 2012 through September 30, 2015 (42 months amortization)
(3) This surcharge is effective May 1, 2012 through April 30, 2013 (12 months amortization)
(4) This surcharge is effective February 1, 2013 through Jan 31, 2014 (12 months amortization)

ATTACHMENT X

Excess Bond Fund Transactions

GPA

Excess Bond Fund Cash Flow

	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Transactions March 1, 2008 to October 31, 2012
1 Beginning Balance - March 1, 2008	$ 511,592	$ 509,960	$ 509,960	$ 509,960	$ 509,960	$ 510,155	$ 510,188	$ 510,223	$ 510,257	$ 510,290	$ 510,322	$ 510,298	$ 510,302	$ 4,636,497
2														
3 Add Interest Earnings					194	34	35	35	32	32	(25)	4	4	127,178
4 Transfer to Revenue Account	(1,632)													(1,632)
5 Add Payback from LEAC*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 823,746
6 Total Cash balance	$ 509,960	$ 509,960	$ 509,960	$ 509,960	$ 510,155	$ 510,188	$ 510,223	$ 510,257	$ 510,290	$ 510,322	$ 510,298	$ 510,302	$ 510,306	$ 5,585,790
7														
8 Less Disbursements:														
9 Macheche to San Vitores	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,537,464
10 Macheche to GAA	-	-	-	-	-	-	-	-	-	-	-	-	-	1,528,982
11 Integrated Resource Plan	-	-	-	-	-	-	-	-	-	-	-	-	-	257,362
12 Transmission Study	-	-	-	-	-	-	-	-	-	-	-	-	-	150,000
13 Load Research & Cost of Service Study	-	-	-	-	-	-	-	-	-	-	-	-	-	457,929
14 Wind Study*	-	-	-	-	-	-	-	-	-	-	-	-	-	143,746
15 Total Disbursements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,075,484
16														
17 **Ending Balance - September 30, 2011**	**$ 509,960**	**$ 509,960**	**$ 509,960**	**$ 509,960**	**$ 510,155**	**$ 510,188**	**$ 510,223**	**$ 510,257**	**$ 510,290**	**$ 510,322**	**$ 510,298**	**$ 510,302**	**$ 510,306**	**$ 510,306**
18														
19 Ending Balance per account														
20 Merrill Lynch	$ 509,961	$ 509,961	$ 509,961	$ 509,961	$ 510,155	$ 510,188	$ 510,223	$ 510,258	$ 510,290	$ 510,323	$ (0)	$ -	$ -	$ -
21 JP Morgan	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22 Bank of Guam	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	510,298	510,302	510,306	510,306
23 **Total account balances at September 30, 2011**	**$ 509,961**	**$ 509,961**	**$ 509,961**	**$ 509,961**	**$ 510,155**	**$ 510,188**	**$ 510,223**	**$ 510,258**	**$ 510,290**	**$ 510,323**	**$ 510,298**	**$ 510,302**	**$ 510,306**	**$ 510,306**

EXHIBIT C

APPENDIX A

Progress Reporting for June 2012 – Nov 2012

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
1	**Accurate metering and billing of the U.S. Navy**		
1.1	Process Ongoing	Navy account set in Utiligy for electronic meters (Q220 and Q1000) at all Navy metering points.	• Actual billing of Navy is reviewed by GPA prior to issuing to Navy. • GPA uses handheld devices to read the Navy quantum meters for upload to Utiligy. • No changes during the period of June 2012 through Nov 2012. • GPA has determined that it will acquire and implement the Customer Care & Billing software from Oracle within the next three years. The issue of the Navy will be posed to the software vendor during the implementation period.
1.2	Pending	Exploring the feasibility of aggregate reading	• Currently unavailable; working with software developer; will not be available until the next release. • Harmon Substation & Tanguisson Substation WAN link ordered to provide capability of remote Navy Metering. This is a work in progress and estimated completion time is one year. • No changes during the period of June 2012 through Nov 2012. • GPA has determined that it will acquire and implement the Customer Care & Billing software from Oracle within the next three years. The issue of the Navy will be posed to the software vendor during the implementation period.
2	**Accurate metering and billing of civilian loads**		

2.1	Process Ongoing	Meter Task Force (MTFC) continues to oversee, assess, and issue recommendations for QA/QC of metering and billing accuracy	<u>System Losses Report Data</u>
			• June 2012-Nov 2012
			  o Three-Phase meter accounts (MTF)
			    ▪ Accounts investigated with meter discrepancies found and corrected: 18
			    ▪ Accounts investigated with no meter discrepancy: 154
			  o Ongoing Single & Three phase meter field investigations (MFI)
			    ▪ Accounts with meter discrepancies found and corrected: 248
			    ▪ Accounts with no meter discrepancy: 159

2.2	Process Ongoing	Customer service continuing to resolve issues for hard to read or inaccessible meters	<u>Hard to read or inaccessible meters (unsafe conditions, gate lock, vicious dog, etc.)</u> • June 2012: 321 accounts • July 2012: 319 accounts • Aug 2012: 312 accounts • Sept 2012: 331 accounts • Oct 2012: 310 accounts

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
	Process Ongoing	Customer service continuing to resolve issues for hard to read or inaccessible meters	• Nov 2012: 272 accounts • GPA coordinating with Customers for actual readings on a monthly basis after billings estimated three times their average consumption. Adjustments are made based on actual/verified readings and consumptions. • GPA now notifies customers through system generated letters. 1st Notice given informs the customer to coordinate for a verified reading or apply for relocation of meter within 10 days. Final notice given to inform the customer that service can be terminated. • First and final notices mailed out to customers with inaccessible meters: June 2012: 203 accounts July 2012: 219 accounts Aug 2012: 200 accounts Sept 2012: 242 accounts Oct 2012: 151 accounts Nov 2012: 123 accounts Tracking of letters sent and acknowledgement of customers' response will be done via cat codes in the service connection window of Utiligy.
2.3	Process Ongoing	Identify all zero consumption billings and perform required field investigations	• For June 2012 thru Nov 2012: ○ 747 accounts identified with zero consumption and 116 accounts have been investigated and processed for corrective action they include: ▪ 89 accounts revealed vacant units (no load/minimal consumption) ▪ 12 accounts have field testing/pending investigation ▪ 10 accounts have meter change-outs; pending backbilling ▪ 5 accounts have pending work clearances/meter removed A report is created to identify age of the meters servicing these addresses for possible testing whether they are defective, etc. and also to monitor previous consumption history.
3	**Systematic analysis of billing accounts for possible outliers**		
3.1	Process Ongoing	Documentation for systematic billing analysis	• Descriptive statistics are performed to identify customer accounts for further investigations. • Analysis/refinements addressed on a monthly basis as problems are encountered. • Both the reading exception and billing exception reports are being reviewed and scrutinized for each billing cycle monthly. These reports indicate all the possible

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
			reading and billing exception that warrants review and attention. Analysis continues to be performed each month as the bills are reviewed and processed.
3.2	Process Ongoing	Monitoring of reading exception reports in Utiligy system	• Reading exception reports are verified for accuracy and statistics of reading exception errors are tracked by Accounting. Any item requiring service order or investigations are being routinely communicated to Customer Svs. This process continued during the period of June – November 2012.
3.3	Process Ongoing	Additional reports generated monthly in Utiligy system to assist in billing analysis	• Reports are generated monthly to assist in billing analysis.
4	**Accurate Monitoring, Measurement and Reporting of System Losses**		
4.1	Process Ongoing	Civilian load recovery reported by the MTFC monthly on a system losses report	• April 2012 o Single & Three phase Meter Field Investigations accounts w/adjustments for backbilling (includes Jan-Mar mtr change-outs) ▪ Revenue recovery: $92,185.43 ▪ kWh recovery: 312,673 • May 2012 o Single & Three phase Meter Field Investigations accounts w/adjustments for backbilling ▪ Revenue recovery: $31,949.09 ▪ kWh recovery: 107,191 • June 2012 o Single & Three phase Meter Field Investigations accounts w/adjustments for backbilling ▪ Revenue recovery: $14,214.30 ▪ kWh recovery: 50,497 • July 2012 o Single & Three phase Meter Field Investigations accounts w/adjustments for backbilling ▪ Revenue recovery: $41,039.42 ▪ kWh recovery: 146,710 • Aug 2012 o Single & Three phase Meter Field Investigations accounts w/adjustments for backbilling ▪ Revenue recovery: $7,299.02 ▪ kWh recovery: 26,366 *Report changed to reflect the month of each mtr change out period for backbilling rev & kWh recovery beginning Apr 2012. Pending Sept-November back-bill from mtr change-out.

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
4.2	Process Ongoing	Identify present metering discrepancies	• June 2012 ▪ Meter Discrepancies: 50 ▪ Meter investigation MFI:73 ▪ Meter investigation INV: 182 ▪ Meter Task Force: 9 ▪ Meter change outs: 120 • July 2012: ▪ Meter Discrepancies: 47 ▪ Meter investigations MFI: 73 ▪ Meter investigation INV: 192 ▪ Meter Task Force: 35 ▪ Meter change outs: 119 • Aug 2012: ▪ Meter Discrepancies: 64 ▪ Meter investigation MFI: 79 ▪ Meter investigation INV: 118 ▪ Meter Task Force: 18 ▪ Meter change outs: 118 • Sept 2012: ▪ Meter Discrepancies: 30 ▪ Meter investigation MFI: 100 ▪ Meter investigation INV: 31 ▪ Meter Task Force: 125 ▪ Meter change outs: 77 • Oct 2012: ▪ Meter Discrepancies: 37 ▪ Meter investigation MFI: 54 ▪ Meter investigation INV: 40 ▪ Meter change outs: 71 • Nov 2012 ▪ Meter Discrepancies: 42 ▪ Meter investigation MFI: 110 ▪ Meter investigation: INV: 18 ▪ Meter Task Force: 11 ▪ Meter change outs: 84

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
4.3	Process Ongoing	Procure equipment & systems	• New utility trucks – 2 ea.
4.4	Process Ongoing	Replace, install, upgrade substation metering reporting systems	June 2012 • Task force,scheduled outage for GITC primary metering trouble shoot and conduct PM with underground crew found defective secondary fuse on customer side and made corrections. • Task force,Investigations/meter testing for customers' accounts consuming below 100 kwh per month -ongoing. • Radio Barrigada Sub, T-23/T-24 Q-1000 meters trouble shoot replace defective Secondary PT fuses.conduct load Analysis. Navy request load transfer from T-8 to T-7 transformer via Buss-tie breaker isolate 34.5kv line side,transformer maintenance PM verify and download metering before and after for billing purposes. July 2012 • Task force,Investigations/meter testing for customers' accounts consuming below 100 kwh per month, ongoing & investigate complaints on demand readings. • GPA contractor request to Transfer load from P-322 to P-52, installation. New X-185,X-183, 34.5Kv Riser, download metering to capture reads before and after load transfer for billing. Aug 2012 • Marbo Sub T-14 rack out Q1000 high end meter for calibration. • Macheche/Yigo/Dededo Combustion Turbine plants conduct PM on Gen/station power meters.calibrate for accuracy. • Tanguissan Breaker failure,assist clean up and verify health of gen meters, X101, X-101,X103,X-105 • Cabras Unit number 3,SEL-734 meter trouble shoot and make adjustment due to miss wired by contractors, conduct load analysis to insure meters are functioning properly. • Apra P223 upgrade from electro mechanical meter DG meter to new electronic meter for 13.8 kv feeder. • Verify Customers with Demand charges rate schedule J&P. • Task Force, Verify GWA pump site with low to no consumptions. Sept 2012 • Agana Monmong Sub TP-14,DZSP request assistance to rack out Breaker request meter shop to verify health of meter and programing..

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
4.4	Process Ongoing		• Smart meter training for Appex hired Employees conducted by Appex and GPA meter shop. • Harmon SubStation coordinate with Hardy contractor Rack out Q-1000 meter for T-22 and reconfigurefrom FM5s meter to FM 9s for upgrade ongoing project,pending replacement of PTs. <u>Oct 2012</u> • Cabras unit number 4 coordinate with cabras instrument tech.,relay and control meter health check on SEL-734 meters. • Network communications application training,Smart meter crew.attended. • Post pre storm,secure all Primary/metering for navy sites. • Barrigada/Tamuning, Substation mechanical meter replacement to new SEL-735 meters all 13.8Kva feeders. • Witness FATS testing of new meters for deployment. • Coordinate with UOG personnel replace complete metering outfit for pump house and marine lab due to heavy corrosion. <u>Nov 2012</u> • Cabras unit number 4 trouble shoot communications with SEL-734 unable to down load reprogram meter. • Ongoing Substation meter upgrades from mechanical to new SEL-735 meters Tamuning and Machche sub. • Coordinate with GWA crew, mechanical meter replacement to new three phase Smart meters 6 each sites using pro field hand held device. • Harmon Sub T-22 work on cubicle for T-22 upgrades,breaker PTs & CTs ongoing. • Marbo Substation T-14 replace defective CTs, coordinate with Relay and substation personnel.

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
5	**Identification of unlisted electric energy consumer**		
5.1	Process Ongoing	Process in place to identify and minimize occurrences in Unlisted consuming meters. Various reports are generated to identify unlisted energy consumers (i.e., exception, UNLISTEDMTR report for meter readings that were not captured in Utiligy and therefore ran after each upload).	**June 2012** • RPS conducted 36 inspections of meters from the Active Accounts <100 KWH Report. Findings included the following: 2 meters were terminated (not in use), 20 meters were vacant facilities (houses/units/buildings), 10 meters were seldom used, 3 were for businesses that are no longer in operation, and 1 meter was removed by RPS due to a previously investigated wire theft (customer side wirings were removed by unknown). • RPS also inspected 2 meters from the Active Accounts Billed Minimum Report: 1 meter was determined to be seldom used and the other 1 meter is terminated. No discrepancies were discovered at either location. **July 2012** • RPS did not investigate any meters on the Active Accounts Billed Minimum, Active Accounts <100 KWH, or the Unlisted – Consuming Meters Report. **August 2012** • RPS conducted 10 investigations of meters randomly selected from the Billed Accounts with Minimum Billing Report. Of that number, 6 locations were vacant, 1 service was not in use, 1 unit is being renovated and 2 locations had new tenants (still moving in). All inspections were documented. • RPS also conducted 49 verifications of meters selected from the Active Accounts <100 KWH Report. Investigations yielded the following: 37 locations are vacant or abandoned, 4 sites were in use but only minimal load, 4 businesses closed down, 3 provisions are in use (no infractions), and 1 location was just occupied. No irregularities were noted. All investigations were documented and reported to the Executive Division. **September 2012** • RPS conducted 9 inspections of meters selected from the Active Accounts <100 KWH report. Of this, we found: 6 meters were found at vacant facilities, 1 provision was not in use, 1 service is verified for low usage, and 1 location was just being occupied. No irregularities were noted. All investigations were documented and reported to the Executive Division. **October 2012** • RPS conducted 29 inspections of meters from the Active Accounts <100 KWH report. 2 meters were terminated and no longer in use, 12 meters were found at vacant facilities, 4 meters were not in use, 1 location was under renovation (no power in use), 2 locations were just being occupied, and 8 meters were found registering slowly indicating low usage. No irregularities were noted. All investigations were documented and reported to the Executive Division.

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
			November 2012 • RPS conducted 6 inspections of meters from the Active Accounts <100 KWH report. 2 meters were terminated and no longer in use, 3 meters were assigned to vacant facilities, and 1 meter was found registering slowly indicating low usage. No irregularities were noted. All investigations were documented and reported to the Executive Division.
5.2	Process Ongoing	Tampering and illegal connections investigated and documented through GPA Revenue Protection Section, Internal Audit Section.	**June 2012** • RPS conducted 11 verifications of reported/suspected meter tampering or theft of service/property incidents. Of that number, 6 were confirmed violations involving: 1 meter with a plastic unknown object inside the meter glass used to stop disk rotation, 2 direct hookups at the service entrance, 1 stolen meter found in an unassigned location, and 2 jumpered meter sockets. All cases were reported to GPD and services isolated from the IWPS. The 5 remaining sites were investigated but yielded no findings of tamper or theft. • RPS also conducted 10 onsite inspections while at Mike's Apartments in Anigua: 5 meters were found terminated and sealing devices not compromised. All meters were removed and returned to Meter Shop for evaluation. The remaining 5 meters were active accounts and physical inspections did not yield any infractions. **July 2012** • RPS conducted 10 investigations of meters reported/suspected of tampering or Theft of service. Of that number, 3 were reported to GPD as confirmed violations involving cut termination seals, a damaged strap and a swapped meter. All services were isolated from the IWPS. The remaining 7 inspections yielded no findings of confirmed tamper, discrepancies were corrected and documented. **August 2012** • RPS conducted 8 investigations of meters reported/suspected of tampering or theft of service. Of that number, 5 were reported to GPD as confirmed violations involving the following: 2 discoveries of jumpered meter sockets and 3 direct taps on the service line at the entrance or mid-span. All 5 services were isolated from the IWPS. The remaining 3 inspections yielded negative findings of tamper or theft. **September 2012** • RPS conducted 6 investigations of meters reported tampering or for theft of service. Of that number, 4 locations were reported to GPD as confirmed violations for tampering involving an inverted (upside down) meter, jumpered temporary provision, a cut termination (red) seal, and a missing nonpayment disconnect (green) seal. The remaining 2 were negative for tampering or theft of service. **October 2012** • RPS conducted 15 inspections of meters reported to the IAO for meter tampering or theft of service. Of that number, 8 meters were confirmed as violations involving:

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
5.2	Process Ongoing		4 jumpered meter socket discoveries, 1 meter swapping incident, 2 damaged/cut seal and straps, and 1 damaged meter. All cases were reported to GPD and service isolated to all locations. The remaining 7 investigations yielded negative findings for tamper or theft. **November 2012** • RPS conducted 6 suspected/reported meter tampering and theft of service cases. Of that number, 5 investigations yielded confirmed violations for the following: 3 disconnected meters were found with seals or straps cut/damaged/missing, 1 meter socket was found jumpered and 1 meter was upside down. 1 reported possible illegal hookup involved an internal hook up to a generator; a main line to the generator was stolen (customer side). No discrepancy found on GPA's system. • RPS performed a work clearance (removal of meter & isolated service) for a damaged weather head condition. Customer was ready to make needed repairs.
6	**Power system design and procurement guides considering optimization of system costs and losses**		
6.1	Process Ongoing	Prepare conductor economics selection and evaluation guidelines	• Conductor sizing guidelines based on voltage drop prepared for single-phase loads is completed. Three-phase guidelines are still being finalized. Analysis of existing system will be conducted through the Medium Range Plan that was completed back in April 2010. • 17 out of the 63 distribution feeders will be re-conductored based on back-feeding capability, loading, voltage drop, and line losses. To date, P-111, P-261, P-046, P-205, P-087 and part of P-283 have been completed.
6.2	Process Ongoing	Stock appropriate transformers	• Engineering will identify oversized transformers to be changed out. Analysis will commence after metering data is mapped and modeled to determine actual consumption from CIS data. Under the Meter ID project, 30,000 of 45,053 meters have been updated and mapped.
7	**Metering assessment and correction of customer power factor**		
7.1	Process Ongoing	Evaluating large demand customers to define magnitude of power factor problem.	• AMX software is still resolving issues on 5 individual accounts out of 176 accounts in cycle 23 as of 6/4/2010. No changes occurred during the period of June 2012 through Dec 2012. GPA has not received instructions to apply the changes from DV to the PD environment • AMX software developer has completed the power factor program based on the KVAH reads. • GPA has determined that it will acquire and implement the Customer Care &

	KEY MANAGEMENT OBJECTIVE	TASK DESCRIPTION	STATUS
			Billing software from Oracle within the next three years. The issue of processing power factor readings from digital meters will be posed to the software vendor during the implementation period.
7.2	Process Ongoing	Evaluating economics of power factor improvement	• Evaluation of economics of power factor improvement completed. Engineering will order capacitors as part of the Distribution capital improvement project program in accordance with the Medium Range Plan completed back in April 2010. • 19 of the 63 distribution feeders were estimated to need capacitor placement. However, this number will change due to recent re-configuring and transferring of load between critical feeders.
8	**Cost effective reactive power compensation**		
8.1	Process Ongoing	Procure and install distribution capacitors	• Engineering will order capacitors as part of the Distribution capital improvement project program in accordance with the Medium Range Plan completed April 2010. • Procurement of 2 each switched capacitor banks is ongoing and is being planned for installation on P-330 and P-322. • P-331, P-250 and P-330 capacitor bank installations in the design stage. • To date, capacitor installations for P-323 and P-281 are completed, and a capacitor bank on P-206 was removed due to excess VAR contribution. • 17 Feeders affected by the Smart Grid Initiative (Volt/VAR) optimization will be removed from the Medium Range Plan.
9	**Quality Systems Design & Implementation**		
9.1		Documentation including supporting documents is regularly updated & maintained	• Documents updated and submitted semi-annually.

EXHIBIT C - Line Losses & Quarterly Management Plan Progress Report

GROSS GENERATION, SALES, LINE LOSSES

	24-Month	12-Month	Oct-12	Sep-12	Aug-12	Jul-12	Jun-12	May-12
Gross Generation	3,603,759,781	1,785,311,240	149,695,687	148,141,200	146,044,491	150,936,511	153,591,228	157,478,506
Station Use	193,900,936	98,687,282	8,251,528	8,092,862	8,828,796	8,427,914	8,998,066	9,231,680
Net Send Out (A-B)	3,409,858,846	1,686,623,958	141,444,159	140,048,338	137,215,695	142,508,597	144,593,162	148,246,826
Sales to Navy (@34.5Kv)	701,351,134	345,424,451	29,953,816	29,375,333	29,509,561	29,475,103	30,467,265	30,154,655
GPA-metered (C-D)	2,708,507,712	1,341,199,507	111,490,343	110,673,005	107,706,134	113,033,494	114,125,897	118,092,171
Power factor adj.	0	0						
Adjusted (E-F)	2,708,507,712	1,341,199,507	111,490,343	110,673,005	107,706,134	113,033,494	114,125,897	118,092,171
GPA KWH Accountability:								
Sales to customers								
(accrual basis)	2,475,498,941	1,220,832,833	103,593,904	99,007,813	97,612,051	106,201,745	102,293,360	111,360,018
GPA use-KWH	5,885,541	2,950,079	244,387	239,239	241,113	252,765	256,721	247,153
No of days	731	366	31	30	31	31	30	31
Unaccounted for KWH (G-H)	227,123,230	117,416,595	7,652,052	11,425,953	9,852,970	6,578,984	11,575,816	6,485,000
Ratio of Unaccounted KWH:								
Ratio to Gross Generation (J/A)	6.30%	6.58%	5.11%	7.71%	6.75%	4.36%	7.54%	4.12%
Ratio to Net Generation (J/C)	6.66%	6.96%	5.41%	8.16%	7.18%	4.62%	8.01%	4.37%

Note: Beginning in October 2007 Company use is no longer part of Civilian sales; GPA use starting October 2007 is being deducted to calculate unaccounted KWH.

12/18/2012

EXHIBIT D

GUAM CONSOLIDATED COMMISSION ON UTILITIES

RESOLUTION NO.: 2012-77

AUTHORIZING THE MANAGEMENT OF THE GUAM POWER AUTHORITY TO PETITION THE PUBLIC UTILITIES COMMISSION FOR A CHANGE IN THE LEVELIZED ENERGY ADJUSTMENT CLAUSE

WHEREAS, the Public Utilities Commission has established a Tariff under which the Guam Power Authority (GPA) is allowed to recover its fuel costs and fuel related costs under a factor which is reset and trued up every (6) six months through the Levelized Energy Adjustment Clause (LEAC); and

WHEREAS, the deadline for the next filing is on December 15, 2012; and

WHEREAS, the world wide cost of fuel has been very volatile since the rate was last adjusted; and

WHEREAS, for the (6) six month period ending January 31, 2013, the initial forecast was a per barrel fuel index average of $103.12 and the revised estimate including actual data into November, 2012 is for a per barrel fuel cost of approximately $104.34; and

WHEREAS, GPA's estimated per barrel cost of fuel for the period ending August 31, 2013 is approximately $103.58; and

WHEREAS, GPA's existing Fuel Supplier – Petrobras – has had significant difficulty meeting GPA's fuel specifications and has advised GPA it is unwilling to continue the contract beyond the initial termination date; and

WHEREAS, in the aftermath of the problems at the disaster at the Fukushima nuclear power plant in northern Japan, utilities in Japan have dramatically increased their use of liquefied natural gas; and

WHEREAS, this increased usage of gas has increased the market price for gas and has therefore increased the cost of an important blending component of GPA's oil; and

WHEREAS, while the market price of high sulfur fuel oil has remained relatively stable over the period, the cost of blending has increased and has forced Petrobras into a situation whereas it is losing money on every GPA shipment; and

WHEREAS, GPA has issued a new Invitation for Bids for its fuel supply contract and believes the increased blending costs will lead to an increase in fuel costs of approximately 10%; and

WHEREAS, although this increase will not have significant impact of the cost of fuel burned during the upcoming LEAC period, it will have a significant impact on the carrying cost of inventory which GPA is allowed to recover through the period; and

WHEREAS, GPA is forecasting increased burning of diesel fuel in light of the fact that Cabras #3 will be unavailable for the upcoming LEAC period; and

WHEREAS, GPA has determined that the Levelized Energy Adjustment Clause factor for secondary voltage service customers will need to be increased from $0.18683/kWh to $0.20768/kWh for the period of February 1, 2013 to July 31, 2013; and

WHEREAS, this change in the LEAC factor to $0.20768/kWh would result in an increase of 7.59% of the total bill or $20.85/month for a residential customer utilizing an average of 1,000 kilowatt hours per month; and

WHEREAS, the PUC adopted a Working Capital Fund Surcharge in June, 2011 that included a mechanism wherein GPA would be allowed to recover the change in the Working Capital Fund Requirement attributable to fuel by adjusting the surcharge with every LEAC filing; and

WHEREAS, the forecast of the Working Capital Fund Requirement is for an increase of $0.00061/kWh for a total of $0.00839/kWh which equates to a change of 0.22% or $.61per month for a residential customer utilizing an average of 1,000 kWh per month and will result in a monthly increase of $13,157 to Navy Billings for a total charge of $192,309 per month; and

WHEREAS, as a result of a cash study completed for the Authority in 2009, GPA has been pursuing a move from a bi-annual LEAC filing to a quarterly LEAC filing and GPA is including in its petition a request to effect this change; and

WHEREAS, GPA now is requesting the Consolidated Commission on Utilities to authorize the Authority to file such petition with the Public Utilities Commission; and

NOW, THEREFORE BE IT RESOLVED, by the Consolidated Commission on Utilities as follows:

1. The General Manager of the Guam Power Authority is authorized to petition the Public Utilities Commission for a increase in the Levelized Energy Adjustment Clause (LEAC) factor for secondary voltage service customers from $0.18683/kWh to $0.20768 to be effective for the period from February 1, 2013 thru July 31, 2013. (LEAC factors for alternative voltage levels are as reflected in the attached spreadsheets.)

2. The General Manager is further authorized to petition for a change in the Working Capital Fund Surcharge factor from $0.00778/kWh to $0.00839/kWh for civilian customers and an increase in the monthly surcharge amount of $13,157 to the U.S. Navy for a total fee of $192,309.

3. The General Manager is also authorized to petition the PUC for a change from a bi-annual LEAC process to a quarterly LEAC process.

RESOLVED, that the Chairman certifies and the Board Secretary attests to the adoption of this Resolution.

DULY AND REGULARLY ADOPTED AND APPROVED THIS 12th DAY OF DECEMBER, 2012.

Certified by:	Attested by:
SIMON A. SANCHEZ, II	**JOSEPH (JOEY) T. DUENAS**
Chairperson	CCU Board Secretary

I, Joseph (Joey) T. Duenas, Board Secretary for the Consolidated Commission on Utilities do hereby certify that the foregoing is a full, true, and correct copy of the resolution duly adopted at a regular meeting of the members of Guam's Consolidated Commission on Utilities, duly and legally held at the meeting place thereof on December 12, 2012, at which meeting of all said members had due notice and at which at least a majority thereof were present, and

At said meeting said resolution was adopted by the following vote:

Ayes: 4

Nays: 0

Absent: 0

Abstain: 0

As of the date of this certification, said original resolution has not been amended, modified, or rescinded since the date of its adoption, and the same is now in full force and effect.

SO CERTIFIED this 12th day of December 2012.

JOSEPH (JOEY) T. DUENAS
Board Secretary
Consolidated Commission on Utilities

EXHIBIT E

Recommendation	Evaluation and Implementation Plan	Original Due Date	Update
R1. Target hedges for 100% of consumption prior to each 6-month LEAC period using fixed prices, swaps, calls, puts, participating swaps, and collars.	Task R1.1. Under the management of GPA's CFO engage hedge counterparts (Counterparts) to better understand what instruments, execution constraints, and margin requirements (if any) are available for GPA's needs.	4/30/2012	GPA and Hedge consultant had a call with Goldman Sachs on June 6, 2012.
	Task R1.2. Consolidate and review historical consumption figures and establish integration between forecasted consumption and execution of the risk management strategy.	3/31/2012	Structured draft position report to include this information. New deadline 09/30/2013
R2. Execute hedges using GPA personnel to run models, execute trades, and report positions and risk. Activities to be shadowed by SAIC for the first six-12 months.	Task R2.3. Establish Interim Program to ensure models are fully integrated, personnel adequately trained, and resources available.	3/31/2013	GPA is running model and Hedge consultant is shadowing results. New deadline 09/30/2013
R3. Ensure separation of duties	Task R3.0. Establish Management Directive to fund and ensure resources for the execution of the Risk Management Program	3/31/2012	Revised organizational structure to clearly reflect separation of duties. SOP has been developed in draft form. New deadline 03/31/2012
	Task R3.4. Review with CCU GPA's evaluation and implementation of the 14 recommendations made by GCG.	2/28/2013	
R4. Independent audit every two years. Initial conduct audit on a shorter interval Schedule to verify or update the models at least annually Modify procedures as needed as credit and margin changes.	Task R4.5. Conduct an audit at least every two years of the execution of the risk management program	3/31/2014	This will be discussed with D&T as part of the Audit Engagement to commence in October (after end of fiscal year ending in September)

Recommendation	Evaluation and Implementation Plan	Original Due Date	Update
	Task R4.6. Conduct an audit at least once a year of the models and reports supporting the risk management program.	2/28/2013	GPA has entered into a contract that will include periodic audits of GPA's hedging transactions..
R5. Identify new positions and hire personnel needed to execute on plan	See Task R3.0		Requested 1 FTE to General Manager. The person will devote 20-30% of his/her time to hedging.
R6. Devise plan to train new personnel needed to execute on plan	See Task R3.0 and R4.5		Trip to DC from CMontellanos and trip to Guam sometime in the next year by consultant to do some additional training..
R7. Develop user manual based on Appendix F	Task R7.7 Develop user manual based on Appendix F of Procedures Manual	6/30/2012	New position report enhances the information and will include an executive dashboard for senior management consumption New deadline 03/31/2013
R8. Design a simple interim plan to protect GPA LEAC from price volatility until personnel, models, and reporting infrastructures are in place	See Task R3.0		We have increased hedges through the end of the Summer 2012. Increased training for ACFO to utilize the different models.

Recommendation	Evaluation and Implementation Plan	Original Due Date	Update
R9. Engage counterparties in exploratory discussions	See Task R1.1		GPA and Hedge consultant had a call with Goldman Sachs on June 6, 2012.
R10. Create Quarterly reporting to CCU physical/financial, buy/sell, mark-to-market, hedge effectiveness, Value at Risk (VaR), credit exposure (CDF spreads) / potential margin requirements	Task R10.8. Develop a specific report template, format, content that is meaningful to GPA and CCU	4/30/2012	ACFO to discuss with GPA senior management on what is appropriate/desirable. New deadline 09/30/2013
R11. Integrate Models	Task R11.9. GPA to devise a plan for implementation process to integrate, maintain, and audit models and reporting to support Risk Management Policies and Procedures	4/30/2012	Position report will integrate all these models. New deadline 09/30/2013
R12. Enhance reporting capabilities and process	See Task R3.0, R10.8, and R11.9		The procedures manual will be enhanced to include backup and maintenance of the model. This includes archiving each individual run and checking for the integrity of the model at least on a quarterly basis. New deadline 09/30/2013

Recommendation	Evaluation and Implementation Plan	Original Due Date	Update
R13. Include backup plan to manage personnel risk	See Tasks R3.0 and R3.4		Requested new staff. Alternatively exploring training of somebody from Finance or from SPORD.

EXHIBIT F

GPA Docket 12-06
July 30, 2012

Line Item #6: GPA should in their next LEAC rate filing address those actions it is taking to reduce the forced outages incurred by Cabras 2 and to meet its availability standard.

GPA Response: On February, 2012, the Authority performed a boiler overhaul of Cabras Unit #2 as part of our routine O&M and boiler integrity and also to address boiler issues that were causing force outages.

The major work and replacement are as follows:

- Replaced section of the burner front wall tubes
- Complete replacement of re-heater tubes
- Replaced lower hopper headers
- Completed UT of the archway, side wall and rear walls to determine wall thickness. Replaced all tubes that were below nominal tube thickness