RIDGWAY
CAPITAL PROJECTS

Preparation of Operation and Rates Analysis

Final Report

Pohnpei Utilities Corporation

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Final Report

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Pohnpei Utilities Corporation

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Abbreviations

ACP	African, Caribbean and Pacific Group of States
ADB	Asian Development Bank
ADF	Asian Development Fund of the ADB which provides concessional loans to beneficiary countries
AUSAID	Australian Government Overseas Aid Program
CAPM	Capital Asset Pricing Model
Cashpower	Cashpower prepaid electricity metering system supplied by Landis and Gyr
CO_2	Carbon dioxide
COM	College of Micronesia
Compact	The first Compact of Free Association with the United States as part of the FSM's constitutional confederation in free association with the U.S. which entered into force in 1986.
Compact II	An amended Compact, which took effect from June 30, 2004
CPUC	Chuuk Public Utility Commission
CSPU	ADB's Country Strategy and Program Update (2006-2007) for the FSM
DCF	Discounted Cash Flow
EDF	European Development Fund
EU	European Union
EUEF	EU Energy Facility
FPA	Fiscal Procedures Agreement
FSM	Federated States of Micronesia
GEF	Global Environment Facility
GHG	Greenhouse Gas
GMO	General Manager's Office
GDP	Gross Domestic Product
IDC	Interest During Construction
IDP	FSM Infrastructure Development Plan, December 2003
IMF	International Monetary Fund
IPIC	Infrastructure Planning Implementation Committees
JEMCO	US – FSM Joint Economic Management Committee
JICA	Japan International Cooperation Agency
LRMC	Long Run Marginal Cost
LRMCC	Long Run Marginal Capital Cost
LRMOC	Long Run Marginal Operating Cost
MDG	Millennium Development Goals
MOMI	Mobil Oil of Micronesia Incorporated
National Government	Government of the Federated States of Micronesia
NZAID	New Zealand's International Aid and Development Agency
NPV	Net Present Value
OCR	Ordinary Capital Resources, a non concessional loan from the ADB
ODA	Official Development Assistance
OIDP	Omnibus Infrastructure Development Project
O&M	Operation and Maintenance
OMIP	Operations and Maintenance Improvement Programme
PIGGAREP	Pacific Islands Greenhouse Gas Abatement through Renewable Energy Project

Pohnpei Government	Pohnpei State Government
PPIAF	Private Participation in Infrastructure Advisory Facility
PUC	Pohnpei Utilities Corporation
RDEP	Rural Development Electric Program
Reporting Date	The date on which this report's information and assumptions are primarily based
RMB	Renminbi (or yuan), is the official currency in the Mainland of the People's Republic of China (PRC)
ROI	Return on Investment
RPPU	Board of Residential Properties and Public Utilities
RUS	Rural Utilities Service of the USDA
SEFP	Sustainable Energy Finance Project
SOPAC	South Pacific Applied Geoscience Commission
SRMC	Short run marginal cost
TOR	Terms of Reference
UFW	Unaccounted-for Water Loss
US	United States of America
USAID	US Agency for International Development
USDA	US Department of Agriculture
UNDP	United Nations Development Programme
WACC	Weighted Average Cost of Capital
WEP	Water and Environmental Programs
WHO	World Health Organisation

Measures

¢	USD cents
Gal	US Gallon
GWh	Gigawatt hours
Hz	Hertz
ktons	1000 tons
KVA	Kilovolt-ampere
KW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hours
USD	United States Dollar
W	Watt

1 Executive Summary

1.1 Introduction

The purpose of the Operation and Rates Analysis is to independently recommend a tariff structure. This is to be based on the electricity, water and sewer rates that Pohnpei Utilities Corporation needs to cover operating expenses and finance long term growth. Assistance is also required in the presentation of the findings to the Government and certain representatives of the public.

1.2 Background

The Federated States of Micronesia (FSM) is a republic located in the Pacific Ocean. It operates in free association with the United States. The FSM is a U.S Dollar based economy and economic activity consists primarily of subsistence farming and fishing. The population of the FSM is about 107,000 according to the 2000 census. Pohnpei is one of the FSM's four island states. It has a population of about 34,500 people.

The FSM and Pohnpei are small, isolated economies that depend on the United States. The US underpins the economy, but it draws working age people to the US and domestically there is much public employment. However, with Gross Domestic Product (GDP) of around USD 2,100 per capita, pay standards in the FSM are relatively low. This means that affordability of basic services such as electricity, water and sewerage is difficult for many consumers. PUC's sales in the 2005 financial year amounted to approximately USD 262 per capita, which is about 12.5% of FSM GDP on a per capita basis.

Until 1991, Electricity, water and waste-water on Pohnpei were managed by the State Department of Public Works. At that time, the US Department of Interior found some limitations in electricity supply. In response, the Pohnpei Government set up PUC as a government corporation responsible for electricity. Two years later, PUC became responsible for water and sewer services.

PUC improved generating capacity, the distribution system and staff training levels, which led to substantial improvements in production, sales and collections. Until 1995, tariffs were heavily subsidized and an independent report at that time recommended that electricity tariffs be increased and its rate structure be altered to cover the cost of fuel supplies. Those rates and the rate structure have remained unchanged since then, although the overall cost of electricity has increased markedly as a direct result of increasing fuel prices. This situation is further compounded by there being a single supplier of fuel to Pohnpei.

The tariff increase caused revenue collection to become a problem for PUC. The corporation put prepaid Landis and Gyr Cashpower meters into operation for most electricity and water customers from 1998. This has noticeably improved arrears.

PUC now provides water and power to some 3,428 and 6,496 customers in that order on Pohnpei. It sells potable water, sewerage and electricity services to 53%, 27% and 96% of the population respectively.

1.3 Current Tariffs

Electricity

The current electricity tariff structure is summarized as:

Category	Structure	Tariff (USD)
Residential Power	Minimum Charge All Usage	USD 4.00 USD (0.10 + Fuel Cost) per kWh
Small general Power	Minimum Charge All Usage	USD 4.00 USD (0.10 + Fuel Cost) per kWh
Large Power	Minimum Charge All Usage All Demand	USD 10.00 USD (0.10 + Fuel Cost) per kWh USD 9.00 per kW
Industrial Power	Minimum Charge 0 to 100,000 kWh Over 100,000 kWh All Demand	USD 25.00 USD (0.08 + Fuel Cost) per kWh USD (0.06 + Fuel Cost) per kWh USD 9.00 per kW

Since 1996, a constant factor of 0.082 gallons per kWh has been used to calculate the surcharge. At the Reporting Date the fuel surcharge was 18.73¢/kWh. The price of diesel has recently risen to around USD 2.85 per gallon, which would increase the surcharge to around 23.37¢/kWh.

Water and Wastewater

The current water tariff is USD 1.80 per 1000 gallons, with a minimum charge USD 5.00. There is no separate tariff for wastewater. Instead, the water tariff is set to over-recover water costs to defray wastewater costs. This introduces a bias because costs are over-recovered from those water users that do not have a wastewater connection.

PUC charges connection fees of USD 15 and USD 30 for water and wastewater respectively. As actual hook-up costs are in the range of USD 105 to USD 630 for water (depending on whether the connection crosses a road) and USD 105 to USD 1,075 for wastewater, the connection fees set are heavily subsidised and provide an incentive for property owners to connect.

1.4 Required Revenue Analysis

Methodology

In markets with only one supplier, prices are usually set through regulation in a way that attempts to emulate how prices are determined in a more competitive environment. This usually means permitting the utility to charge enough to cover its operating costs, recover depreciation and receive a fair return on capital.

Efficient pricing bears some relation to the marginal cost of supply. Marginal cost refers to the relationship between total costs and output, and how costs change as output increases or decreases. As some costs are fixed in the short run while others are completely variable, marginal cost can be considered from a short run or long run perspective. Short run marginal cost is the cost of meeting an additional unit of demand while holding capacity constant, whereas long run marginal cost assumes all factors of production can be varied. The Terms of Reference (TOR) requires a Long Run Marginal Cost (LRMC) analysis.

The Consultant has been provided with PUC's projected capital expenditure for electricity, water and wastewater, but it has not been in a position to determine whether this is the optimal capital expenditure programme for the utility.

A key issue with marginal cost exercises is that the total revenue from tariffs based on marginal cost does not normally equal the revenue required by the utility. In general, required revenue is the sum of the forecast operating expenditure plus depreciation and a fair return on capital of the assets associated with providing the services. When estimating required revenue, the values of the assets currently employed are not regarded as a sunk cost but are recognized as having a positive opportunity cost.

To bridge the gap between marginal cost and required revenue some form of adjustment to the marginal cost based tariffs is needed so that the tariff structure can be financially sustainable and produce total revenues equal to the required revenues. The overall objective of any form of adjustment is to preserve as much of the LRMC type price signals as possible while permitting PUC to be financially sustainable. The approach taken in this Study has been to been to scale the tariffs to meet the required revenue objective. The Consultant has used a 20 year discounted cash flow model to estimate the required revenue for each part of PUC's business including water, waste water and power generation and supply. This approach captures more of the economic benefits of PUC's planned capital projects.

Under the approach adopted, PUC will earn its cost of capital, on average, over the twenty year period. The required rate of return reflects the opportunity cost of capital invested in a project. The weighted average cost of capital (WACC) is now the most commonly used and recommended approach for determining the appropriate cost of capital for firms. WACC is underpinned by the idea that if an investment generates enough return to pay the interest on the debt used to finance it, and also generates a satisfactory expected return on equity, then the project is acceptable. Consequently, the WACC is a blended composite of the costs of equity and the debt capital.

Based on the inputs set out above, we have used a required rate of return estimate of around 2.4% in estimating PUC's required revenue for electricity water and waste water. It should be noted that a commercial estimate of 6.5% has been used in estimating the LRMC of the various generation options because, at worst, these projects could be expected to be fully financed with interest bearing debt. If, however, these projects are funded with grants and concessional finance, it is expected that capital intensive projects like hydro would be favoured even more.

Electricity Service

PUC has 15.4 MW of installed capacity, comprising the 13.4 MW Nanpohnmal diesel facility and the 2.0 MW Nanpil hydro facility. Demand ranges between 2.5 MW and 7 MW at peak times.

The Nanpohnmal facility is well managed. Fuel efficiency averages 14.5 kWh/Gal, which is equivalent to 40% plant efficiency and very satisfactory for diesel plant of this size and age. Auxiliary power demand of the diesel units, has averaged around 4.65%, although this is higher than the industry norm of 3-3.5% for similar generating units. It is suggested that PUC explore ways to reduce this demand.

Nanpil hydro power plant has been out of service since August 2001 due to flooding of the powerhouse and associated facilities. PUC engaged Parsons of the USA for the USD 1.5 million rehabilitation of the scheme, half of which is being funded with grants. At current diesel fuel prices the outage of the Nanpil hydro power plant adds around USD 500,000 to the annual operating cost of PUC, so the nominal payback period for the rehabilitation is about three years. The rehabilitation will include updated control systems that will increase utilisation of low river flows. The plant is scheduled for recommissioning around late 2006.

The two existing power stations supply a 120 km long, 13.8 kV 3 phase, 60 Hz, overhead distribution system that comprises four main feeders. One supplies Kolonia, while a western and eastern feeder loop around the island and a fourth runs to Dekehtik Island. Technical losses in the distribution system average around 10.5% and are at an acceptable level, especially since they are understood to include around 2.5% for supplies to street lighting.

Overall operation and maintenance costs (excluding fuel) for generation activities were the equivalent of USD 2.26¢/kWh in 2004. Distribution costs in the same period were the equivalent of 1.23¢/kWh. These non fuel O&M (Operation and Maintenance) costs are considered to be rather high, mainly due to a relatively large salary and wage bill. Non fuel costs might be somewhat high, but they account for between 25% - 35% of electricity tariffs costs while fuel accounts for the 65% - 75% of these tariffs. Therefore, PUC's management should look to contain non fuel O&M costs but most effort should be directed toward reducing diesel consumption and prices if tariffs are to be minimised.

Water Services

PUC's water business has the capacity to produce 1,250 million gallons of potable water per year and demand is about half this amount. The water system covers approximately 54% of the Island's population and around 30% of the Island's area. The FSM Infrastructure Development Plan (IDP) states that the water system has sufficient capacity to serve existing demand levels. The World Health Organisation (WHO) reports that the proportion of the FSM's population that has access to an improved water source is 94% as of 2002. PUC plans to provide the Island with a single integrated system that delivers potable water to all developed areas.

PUC charges for water but not for waste water and sewerage treatment. The current tariff of USD 1.80 per 1000 gallons of water applies to around 2,900 residential connections and almost 400 government and commercial connections.

As PUC plans to extend water supply to the entire island, a comprehensive capital works programme has been planned which will involve spending just over USD 37 million on five main projects.

The challenge for setting tariffs in such circumstances is to match the forecast capital expenditure and operating costs to the forecast increases in connections and water demand. If the capital expenditure is too early, the burden of providing the required revenue falls on too few customers; if too late, there is insufficient capacity to service the demand for potable water

Sewerage Services

The Kolonia sewerage system covers approximately a quarter of the population of Pohnpei. The existing system involves a single wastewater treatment plant that operates close to its design limits and is close to the end of its economic life. The existing outfall requires upgrading to improve water quality in the outfall area. The WHO rates the FSM as having only 28% of the population with sustainable access to an improved sanitation system in 2002. The FSM does not rate well in this regard when compared amongst other Pacific Island nations. In May 2000 a cholera outbreak occurred in the Kitti municipality and a review of Millennium Development Goals (MDG) by the Asian Development Bank (ADB) highlighted the need for improved sewerage services to meet environmental sustainability goals. The ADB, under the Omnibus Infrastructure Development Project (OIDP), approved a loan of USD 10.2 million to be applied to Pohnpei wastewater improvements.

PUC does not charge for waste water and sewerage treatment. Therefore any charge will be a further cost increase for consumers. The total proposed capital works programme, excluding the OIDP, amounts to around USD 54.2 million. This expenditure is expected to service around 3,445 extra connections in the Kolonia, Kitti and Madolenihmw areas. This amounts to a capital cost of approximately USD 15,700 per connection, on average. Overall, this appears to be high and suggests that there may be lower cost options for providing some parts of the service.

Streetlighting

The PUC provides street lighting to around 828 streetlights and billing data suggests there are at least 185 metered streetlights that are billed. Billing data also suggests that current street lighting demand on Pohnpei is less than 500 MWh annually although a calculation of likely actual consumption is close to double this amount. Demand for street lighting is expected to remain virtually static with increased demand being offset by energy efficient lights.

A streetlight survey made by PUC in late 2004 estimated that 673 streetlights go unbilled and lost revenue amounts to around USD 295,000 and that total revenues from streetlights ought to be USD 363,000 per annum.

The Consultant assesses that 828 streetlights would consume around 970 MWh. If streetlights are billed at the marginal cost of electricity production of around 19¢/kWh plus an allowance for O&M of USD 27,000 then revenue from streetlights would be USD 250,000 per annum. There would not be an allowance for depreciation and the WACC for streetlighting because the Consultant understands these assets are not currently owned by PUC.

Unless Pohnpei State Government recompenses PUC for an amount set around this level for the provision of street lighting, these costs would need to be spread across PUC's customers. That costs, allowing for some capital expenditure to allow some extension to the existing streetlighting assets. Further increments of 0.5¢/kWh are suggested to cover capital expenditure beyond this.

1.5 Customer Opportunity Cost for Electricity

As of the Reporting Date, Residential customers have a levelized opportunity cost of electricity of 38.1¢/kWh. This is based on the best alternative of petrol based generation. Their cost of electricity from PUC is 29¢/kWh, which is 31.4% lower than their next cheapest option.

For small commercial customers, the best option is to generate electricity with diesel generators at a levelized cost of 33.2¢/kWh. Their cost of electricity from PUC is also 29¢/kWh, which is 14.5% lower than their next cheapest option.

For large customers, the best option is to generate electricity with medium sized diesel generators at a levelized cost of 30.8¢/kWh. Like residential and small commercial customers, their cost of electricity from PUC is 29¢/kWh, which is 6.2% lower than their next cheapest option.

For industrial customers, their best option is to generate electricity with medium size diesel generators also at a levelized cost of 30.8¢/kWh. Their cost of electricity from PUC is between 25¢/kWh and 27¢/kWh, which is between 14.1% and 23.2% lower than their next cheapest option.

Large governmental customers, however, have a lower opportunity cost of electricity than the rate charged by PUC. This is because these customers receive the same fuel discount for governmental organisations as PUC. This means that their opportunity cost of electricity is 22.5 ¢/kWh compared to PUC's lowest charge of 25 ¢/kWh.

Therefore, all customers other than large governmental customers are unlikely to find alternative sources of electricity cheaper than PUC's service. These consumers can, however, manage some of their demand by using electricity more selectively and by installing energy efficient light bulbs.

There is a significant risk of large government owned customers generating their own electricity. The loss of these customers would lead to the average cost of electricity rising for PUC's remaining customers. Those customers do not have more cost effective alternatives for power generation themselves. Being residential and small business consumers, they also have limited capacity to pay for energy. This in turn is likely to lead to increased arrears and has a political dimension too. Ultimately, those with the greatest capacity to pay for electricity also have the most cost-effective generation alternatives.

While PUC's governmental customers are exercising a social conscience by remaining connected to PUC, there may be a need for legislation to ensure the continued patronage by this important group of consumers.

1.6 Alternative Electricity Supply Options

Addressing PUC's power sector challenges involves resolving, as a first priority, PUC's high fuel costs by considering whether the current diesel/hydro mix is the least cost generation option for PUC. The report analyses alternative electricity supply options and considers hydropower, diesel generation and fuel supply possibilities, wind power, biomass plants and solar photovoltaic options.

Regarding hydropower, climate statistics for Pohnpei indicate that hydro resources are substantial. The main river systems have been investigated previously and pre-investment type studies have identified 6 to 8 MW of generation potential at seven locations. Of these, the most promising hydro schemes are Lehnmesi 1 and 2, Mahnd 1, Senipen/Riohk/Lehdau and Nanpil 2.

Studies have also been undertaken previously to boost the Nanpil plant's output. One proposal anticipates raising the dam height, sealing the reservoir and excavating upstream to create storage for an additional twenty minutes of plant operation. Sealing the reservoir would reduce under-dam leakage but this would not be economic for losses of less than ten percent. It is recommended that PUC set up stream flow gauges above and below the dam to establish if losses are greater than 10%. If so, the project might become economically viable.

Regarding diesel generation, the existing diesel units have remaining economic lives of around ten years. Replacement by fuel efficient diesel generators on a new site close to the tank farm has been considered. These units should not have capacity of more than 3.5 MW per unit because of system constraints, but they would improve average fuel consumption from 14.5 kWh/gallon to 15.5 kWh/gallon. Locating the new facility close to the tank farm could also avoid the current USD 0.1¢/gallon fuel delivery charge, subject to negotiations with Mobil.

Waste heat recovery on the existing diesel units was also considered. While technically feasible, there is no demand for process hot water or steam. Alternatively, generating electricity from recovered heat would yield only a small amount of additional electrical capacity given a relatively high capital cost. For these reasons, waste heat recovery is not considered as an economic option.

The high cost of diesel encourages PUC to import its own diesel to lower the cost per gallon. Previous studies have considered the economics of PUC building its own tank farm. Potential savings of USD 0.3 million per year need to be weighed against a capital cost of approximately USD 5.0 million. On this basis, a tank farm would not be economic.

Another option would be for PUC to purchase the existing MOMI tank farm, although this might mean PUC would become responsible for distributing various fuels to all customers on Pohnpei. PUC would then become involved in business outside its core activity and legislative remit. It would also act as a catalyst for more customers to disconnect from the grid by lowering their opportunity cost of generating electricity themselves.

Other possible generating options for the PUC include wind generators, biomass plants and solar photovoltaic plants. Of these, average wind speeds are considered too low to make wind power economic for a grid based system. For biomass, no concentrated and readily available source of digestible green matter exists and transportation using diesel fuelled vehicles makes such schemes uneconomic. Solar photovoltaic systems, on the other hand, are technically feasible and although their capital costs are very high their operating costs are low. A 3.5 MW peak solar photovoltaic plant would be a good fit for the PUC system.

The most promising generating options discussed above are: (a) a 3.5 MW diesel generating plant on a new site; (b) development of hydro power plants - for which the 2.8 MW Lehnmesi and 0.6 MW Mahnd projects were used for the purposes of analysis, and; (c) a 3.5 MW Solar photovoltaic power plant.

A conservative Weighted Average Cost of Capital (WACC) rate of 6.5% has been used to assess these projects on the basis that they could be funded on commercial terms (as a worst case). On this basis, the levelized unit generation cost for each option is 12.6¢/kWh for new hydro, 18.1¢/kWh for new diesel plant, 18.5¢/kWh for the existing diesel facility and 40.5¢/kWh for the photovoltaic option. This ranking is unlikely to change even if grant and concessional loans are made available to PUC.

Consequently, constructing all the new hydro plants is the least cost option for PUC in the long term. New diesel plants are not favoured since the improvement in fuel efficiency is offset by the capital cost of new plant. Solar photovoltaic plants are the most expensive option, mainly due their high capital cost and relatively low annual plant factor.

Overall, the preferred generation expansion option would see all hydro projects being developed in a sequence and the Nanpohnmal facility would be replaced by a diesel facility of around 7 MW in 2016. On this basis, the LRMC of electricity supply has been computed at the distribution or sales level by allowing for annual distribution losses of 10.5%. On this basis the LRMC, based on ten year time horizon, is estimated to be 21.1 ¢/kWh. By comparison, if PUC continues the status quo and replaces the existing diesel plant in 2016 with a larger facility as currently proposed, the LRMC is estimated to be 20.7¢/kWh. Furthermore, if over the next few years the real cost of diesel increases, the hydro option will become increasingly attractive. In addition, as the time horizon for calculating LRMC extends beyond ten years, hydro development is more economic because low operating costs offset high capital costs.

1.7 Funding Options

There are a range of sources of finance that PUC can consider financing its projects. These fall into two groups: bilateral support and multilateral support. Bilateral sources include: the US (Compact, RUS and OMIP); European Union (EDF, EUEF and PIEPSAP); Australia (AUSAID); and, New Zealand (NZAID).

Multilateral sources include: the Asian Development Bank (ADF and OCR Loan); The World Bank (grants, loans, SEFP and PPIAF); and, UNDP's PIGGAREP facility.

These sources provide a range of grants, concessional loans, commercial loans and technical assistance facilities. For capital expenditure, PUC would want to maximise access to grants from the Compact, RUS and the EUEF first, followed by concessional facilities from Japan, China, the ADB and the World Bank.

While the ADB's OCR non concessional loan is not the cheapest source of finance, the least cost expansion planning has been based on such a loan to be prudent. PUC would naturally want to minimise its cost of finance when developing specific financing plans for its capital expenditure.

1.8 Tariff Structures and Rate Determination

Tariff Structures

PUC has authority to set tariffs after consultation with the Board of Residential Properties and Public Utilities (RPPU). However, both the RPPU and the Commission on Energy also appear to have a charter to propose new tariffs. The tariff setting process is unclear from a legislative standpoint, although the RPPU and PUC have a common understanding of the process at a practical level. There is merit in ensuring that the law and practice for tariff setting is aligned.

The report considers a range of tariff mechanisms such as multipart prices, price discrimination, optional tariffs and volume based prices. Multipart prices with price discrimination are employed by PUC for electricity and there is economic rationale to do so. However, PUC's electricity pricing regime might be less politically acceptable because those who pay the most for electricity can least afford those rates.

PUC'S management have indicated a preference for a single electricity tariff that applies to all. There is a case for such an arrangement, which would have the effect of raising rates for large consumers to the marginal cost of production and lowering residential rates to this level.

If the tariff regime were adopted, PUC should continue with the two part charge (fuel plus non fuel O&M) for consumption. This arrangement would need to be reviewed as the fuel mix for generation changes, if the Consultant's recommendation regarding hydropower implementation is adopted.

Streetlighting is a further cost that PUC is being asked to bear and if it is not able to recover the cost of this service from the State Government then, under its mandate to be a commercial organisation that recovers its costs of operation, PUC has no option but to spread the cost across consumers.

Indicative Rate Structure

The tariff structure recommended to be adopted by PUC is a three part tariff that is equal for all customer classes. The three components would be: (a) a base rate of 11.3¢/kWh; (b) a fuel surcharge (as of September 2006) of 20.5¢/kWh and (c) a streetlighting surcharge of 1¢/kWh per 1,000 streetlights in 2006 money. The uniform tariff as of September 2006 would therefore be 32.8¢/kWh.

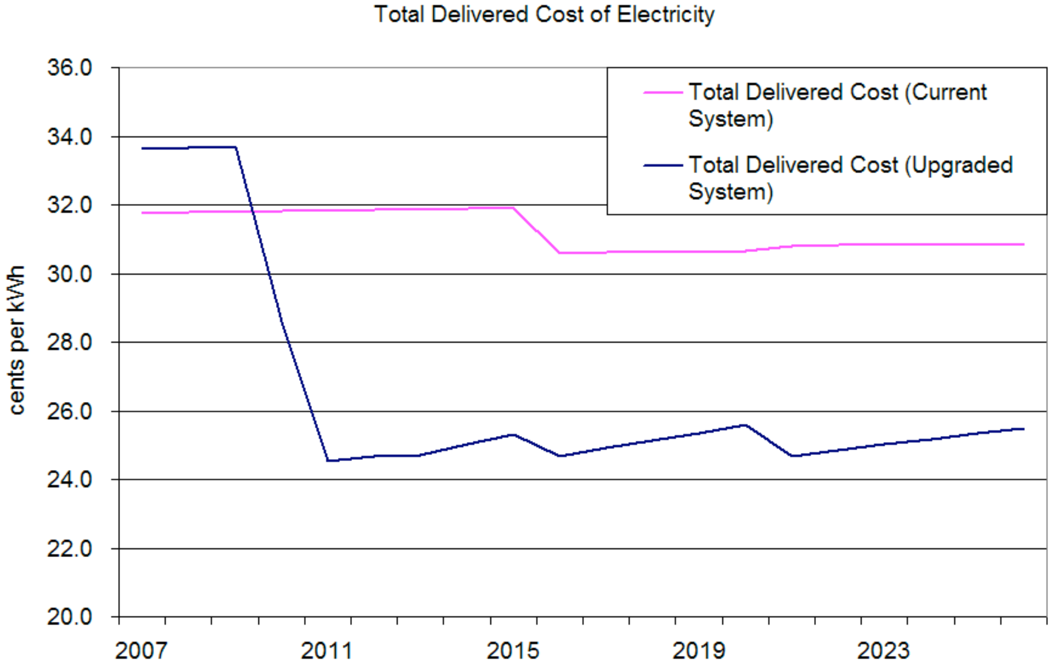
A comparison of PUC's electricity tariffs has been made with ASPA (American Samoa) and UNELCO (Vanuatu). The most recent reliable tariff information is based on March 2006 data for PUC, May 2006 rates from ASPA and July 2006 rates from UNELCO. Of the Benchmark Utilities, tariffs ranged between 18.6 ¢/kWh to 29.3 ¢/kWh and PUC's tariffs of 25 ¢/kWh to 29 ¢/kWh were at the high end of (but within) the range.

PUC and UNELCO have comparable residential power rates, although UNELCO charges commercial and industrial consumers at relatively lower rates. ASPA has lower tariffs overall, due partly to non fuel O&M costs that are lower than PUC because of ASPA's economies of scale, but mostly because fuel costs of 13.8 ¢/kWh are exceptionally low. This is due to competition in the fuel market and the high volumes of fuel sold in American Samoa. PUC should continue striving to reduce non fuel O&M costs by increasing productivity and its fuel related costs by devising a workable fuel strategy and adopting least cost generation planning principles.

The new tariffs suggested above are based on the current electricity supply arrangements remaining in force, referred to above as the Current System. If, however, PUC is able to implement least cost generation planning principles outlined in this report by exploring the Upgraded System, a significant reduction in the overall electricity tariff profile is possible. In fact, the Upgraded System Scenario potentially offers tariffs in 2011 that are around 7.5¢/kWh lower than the Current System.

If PUC plans for and is able to implement the Upgraded System, the average weighted tariff would be initially higher than the Current System until the impact of cheaper hydro generation is felt in 2010 and 2011. PUC's customers would therefore need to accept some "short term pain" for the "longer term gain" this scenario could bring.

Figure 1 - Total Delivered Cost of Energy



Regarding the water service, the average water tariff needs to increase by around 32% from USD 1.80 per 1000 gallons to around USD 2.37 per 1000 gallons if PUC is to recover its water costs. Assuming an average residential consumption of around 450 gallons per day, the average annual cost of water would increase from USD 295.65 to USD 389.27. It should be noted that the Pacific Benchmark[1] for water service is between USD 1.21 and USD 2.50 per 1,000 gallons, so the recommended tariff of USD 2.37 per 1,000 gallons falls within this range.

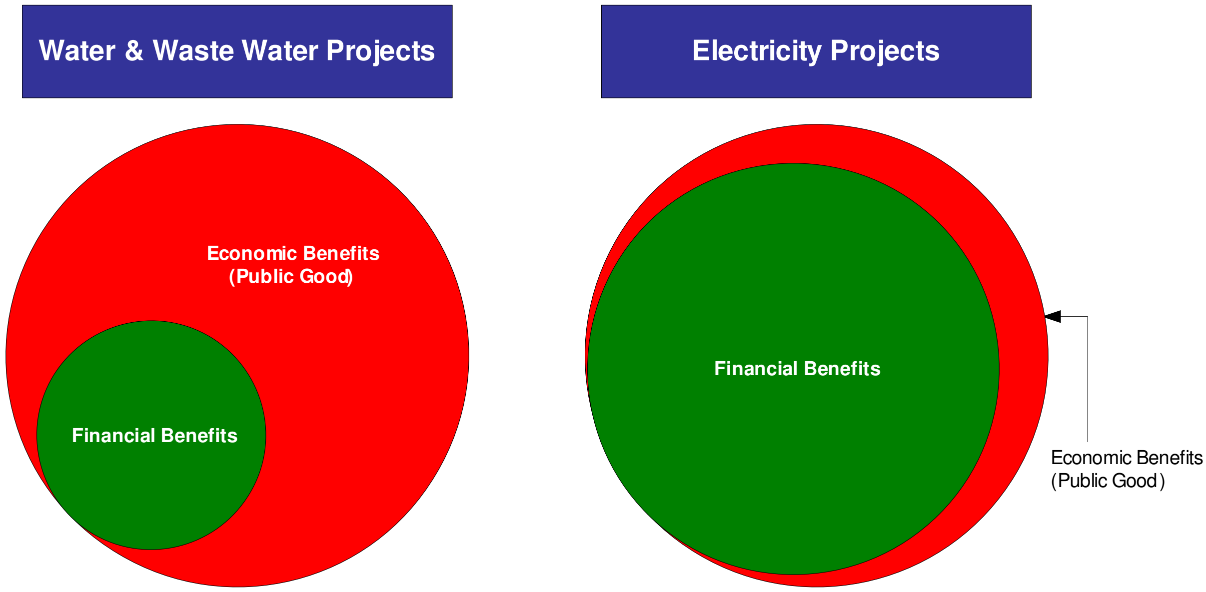
A connection charge is the most effective way to collect revenues for waste water services. However, based on the assumed capital expenditure programme, the annual charge per residential connection would amount to around USD 338 per annum. This is approximately equal to USD 4.70 per 1,000 gallons of sewer service. By comparison, the Pacific Benchmark[2] for water service is up to USD 1.50 per 1,000 gallons, so the recommended tariff does not fall within this range.

When combined with the increase in water charges, a residential consumer currently connected to water and waste water would face an increase in charges from USD 296.65 to around USD 727.00 per annum. The Consultant believes an increase of this magnitude is unsustainable and that a charge equivalent to no more than USD 1.50 per 1,000 gallons be levied on sewer connected customers. The balance of USD 3.20 per 1,000 gallons could therefore be seen as a "public good" component that might instead be borne by the State Government. Alternatively, water and waste water projects should be re-examined and ranked in order of Benefit: Cost ratios to set priorities. Some projects might also be delayed or cancelled.

[1] Asian Development Bank: Performance Benchmarking for Pacific Power and Water Utilities, December 2005.

[2] Asian Development Bank: Performance Benchmarking for Pacific Power and Water Utilities, December 2005

The following chart illustrates the difference in the public good element of electricity versus water and waste water projects. With electricity projects, much of the cost can be recovered cost-effectively from consumers, but in the case of water and, especially, waste water services this is not the case. The additional benefits to society from these projects often cannot be fully recovered from the public in low income countries because the benefits take a long time to be felt in macro-economic terms, especially when substantial capital expenditure is planned.



Overall, one possible tariff structure that the Consultant believes is worth discussing further with PUC and stakeholders is the concept of:

- Pricing water and sewerage tariffs as suggested above, but subject to further review regarding the sustainability of some of PUC's water and wastewater projects;
- Pricing electricity with a single tariff based on the marginal cost of production. Residential consumers would pay relatively less for electricity while business and governmental customers would pay relatively more for electricity;
- Retain the two part fixed cost and fuel per kWh electricity tariff;
- The single tariff not being set higher than the electricity opportunity cost for businesses. However, that rate would be greater than the electricity opportunity cost for Governmental customers, so these important consumers might need to be required to remain connected to PUC's system;

1.9 Benchmarking

The TOR asks for at least two utilities to be benchmarked and American Samoa Power Authority (ASPA) and UNELCO of Vanuatu are considered by the Consultant to be the most comparable. Four other pacific utilities are also similar with respect to PUC's electricity supply business, so these have been considered in the report as well. ASPA and UNELCO are referred to as the Benchmark Utilities and these utilities and these together with the other comparable utilities are referred to I the report as the Comparison Utilities.

The Pacific Power Association and the ADB produced a utility benchmarking report that is widely regarded as the best electricity benchmarking survey in the Pacific to date. A further report on water utilities was published in late 2005. These reports go further than comparisons of two utilities.

For water and wastewater, all of the eight utilities surveyed in the ADB's 2005 report have been considered for benchmarking purposes.

Electricity

Regarding electricity customer classes, it is noted that the theme for the Benchmark Utilities is to have four customer classes of residential, business, industrial and government. These classes might be adopted by PUC instead of its existing classification so that government customers are more distinct. Notably, the Benchmark Utilities have a higher proportion of non-residential customers and consumption by these groups highlights the relatively small size of commerce and industry on Pohnpei and consequent reliance on residential customers.

PUC has 50 electricity customers per electricity related employee compared to 558 for UNELCO, an average of 58 for Comparison Utilities and 71 for ASPA. ASPA has the benefits of scale, but a target of between 55-58 customers per electricity related employee might be sought by PUC, suggesting a reduction in staff of up to 10 percent over time unless genuine customer numbers increase.

Electricity employee payroll costs were found to be lower than rates these staff could obtain elsewhere with their skills, particularly the United States. However, employees obtain fringe benefits that PUC's management might review.

Regarding operating costs, PUC's generation O&M costs are higher than benchmark utilities and this is in part attributed to diesel auxiliary costs that might be reviewed. However, distribution costs per kilometre are reasonable. Overall, PUC rated very well regarding system efficiencies such as fuel efficiencies and losses.

Financially, PUC has an operating ratio that is consistent with pacific utilities, although improvements in this area should always be sought. PUC's debtor days continue to be a challenge however, and PUC is encouraged to minimise arrears further if it is to compare more favourably to other pacific utilities. Additionally, PUC has tight payment terms with suppliers, which means it has a significant working capital burden. Reducing debtor days payable and increasing credit terms with suppliers would benefit PUC.

With respect to tariffs, PUC tariffs were compared with ASPA and UNELCO. Earlier in 2006, when the analysis was made, these utilities had tariffs between 18.6 c/kWh to 29.5c/kWh and PUC's tariffs were at the high end of this range. It is suggested that PUC continue to reduce non fuel O&M costs through productivity increases, but that most effort go into reducing fuel costs by devising a workable fuel strategy and adopting least cost generation principles.

Waste and Wastewater

PUC has a relatively high proportion of residential customers, consistent with power consumption. Importantly, PUC lacks the base of business and industrial customers that other pacific utilities enjoy.

Pacific utilities have water consumption of between 340-752 gallons per connection day and PUC had 540 gallons per connection day in 2005. PUC'S water consumption per connection is therefore average.

PUC also has an average staffing level per customer for both its water and wastewater divisions and its payroll costs are comparable with rates achievable for PUC staff elsewhere.

PUC has a high level of unaccounted for water. Pacific utilities have UFW rates of between 24% - 47% and PUC's UFW last year was 48%. This needs to reduce and PUC is taking steps to achieve this. PUC rates very well, however, on the level of metering it has deployed.

PUC's operating costs as a ratio of revenues was 0.97 overall for 2005, meaning it is only just recovering its current costs. Return on total assets is –9.9%, which is within the pacific benchmark range of –20%-+5%. This is forecast to move closer to zero over time, indicating that PUC is achieving full cost recovery.

PUC has a very high current ratio because it has a very high level of customer arrears and possibly higher inventory levels than are desirable from an accounting viewpoint. Arrears need to be reduced for assets to be utilised more effectively. Regarding inventory, PUC's remoteness and the high cost of spares for the Daihatsu plant go some way to explain this high level.

With regard to PUC's tariffs for water, the acceptable Pacific Benchmark for water service is for charges of up to USD 2.50/1000 gallons. PUC's existing water tariff of USD 1.80/1000 gallons is well below this level but the Consultant found that PUC is undercharging for the service and not recovering costs. A water tariff of USD 2.37 is needed to achieve this.

Wastewater tariffs in the Pacific do not exceed USD 1.50 per 1000 gallons and at present PUC does not charge for this service at all. Taking PUC's planned sewage expansion into account, a sewer charge of USD 4.70 per 1000 gallons is calculated as being required. There is no doubt that sanitation levels on Pohnpei need to improve, but the cost cannot be recovered commercially if PUC is to charge rates comparable to other utilities for this service. Consequently, either projects are reviewed or deployed more cost effectively, or the State might consider providing support to reflect the public good nature of these projects.

With these matters in mind, PUC requested that the Consultant conduct some further analysis to assess the likely water and waste water tariffs resulting from a range of scenarios. The results of that analysis are set out in the following table.

Water Tariff Scenarios

Capital Expenditure Scenario	New Customers	Required Total Water Tariff ($/1000 gal)
No further capital expenditure	-	$ 1.49
ADD: Extension/ upgrading of Palikir water system from Sekere-Diadi	307	$ 1.70
ADD: FSM well drilling	655	$ 1.60
ADD: Rehabilitation of 2 - 1.0M gal tank and 1 -0.5M gal water tank	-	$ 1.63
ADD: New south west water supply system (Kitti)	491	$ 1.99
ADD: New south east water supply system (Madolenihmw)	491	$ 2.37

Wastewater Tariff Scenarios

Capital Expenditure Scenario	New Customers	Required Total Wastewater Tariff ($/1000 gal)*	Required Total Wastewater Tariff ($/1000 gal)**
No further capital expenditure	-	$ 2.56	$ 0.73
ADD: Omnibus Project	507	$ 3.40	$ 0.97
ADD: Extension of Kolonia system	2,050	$ 2.75	$ 0.78
ADD: South west disposal system- Kitti	698	$ 3.75	$ 1.18
ADD: South east disposal system- Madolenihmw	698	$ 4.70	$ 1.62

* If tariff levied only on sewer connected customers
** If tariff levied on all water connected customers

From this it can be seen that the water capital expenditure programme, excluding the new South West and South East water supplies leads to a water tariff of some $1.63 per 1,000 gallons. This is well within the Pacific Benchmark of $2.50 per 1,000 gallons.

Regarding wastewater, all scenarios lead to substantial increases in sewage service unless it is considered acceptable for this levy to be spread across all water customers on the basis that everyone benefits from the improved sanitation. If this were the case and the South West and South East disposal systems were not to proceed for the time being, then the combined water and sewage charge for all water connected customers would become $2.41 per 1,000 gallons. That charge would still be lower than benchmarked Pacific utilities, whilst enabling a substantial improvement in sanitation levels.

1.10 Private Sector Participation in the Provision of Utility Services

End users expect to receive a reasonable level of service in terms of quality and quantity that the utility will have a reasonable capital expenditure programme to meet new demands and services will be cost-effective.

Governments typically bear some of the utility’s costs. These subsidized tariffs are good for consumers who are better off but they are not good for the poor. While PUC must run efficiently and reduce costs by as much as reasonably possible, PUC must also generate revenues to cover its expansion plans if those plans are the best economic options for the State. In short, PUC is a long term business and political decisions surrounding PUC's activities must also be made on a long term basis, not based on voter pressures or electoral cycles.

The answer does not necessarily lie in private participation. Restructuring, technical assistance, appointment of the best possible board members and management, development-agency assistance, and other measures can achieve these objectives just as (or even more) effectively. Reform measures that include adequate stakeholder consultation, setting upstream policy, and defining service standards, tariffs, and subsidies should probably be applied first before looking to the private sector. If, after that process, the results the State Government have not been achieved, then opening aspects of the utility's business to the private sector is worth considering, but that approach needs careful advance planning.

Private involvement in PUC's business might bring new skills, create a focus on service and commercial performance and ease access to finance but clear policy would need to be established by the State Government first. To engage with the private sector before doing the hard and expensive work needed to establish that policy is almost certain to lead to failure.

Private firms would seek a higher weighted average cost of capital than the 2.4% assessed by the Consultant for PUC, so the only way that a private operator could reduce tariffs and improve service levels is through efficiency gains. If this is so, then it is best that PUC under State ownership strives to achieve those potential gains first.

If a private firm is involved in the delivery of services, the government remains ultimately accountable for service delivery. Therefore, government must ensure that it: (a) sets the right performance criteria for the private partner to meet, (b) satisfies itself that that the cost and quality of service meets the reasonable standards set by the government, (c) monitors the performance of the contract and (d) enforces the agreement should the private partner fail to perform satisfactorily.

The State Government would need to have a well qualified unit to carry out the functions listed above and, at present, the closest entity within Pohnpei is the RPPU. Members if the RPPU have said, however, that they do not possess all the skills required to interface with PUC and so there would need to be substantial capacity building and the creation of several full time positions for the RPPU to function as a counterparty to a private sector partner. These costs would need to be built into the tariffs and be borne by consumers.

Insofar as PUC's electricity business is concerned, there is no practical scope for competition in distribution, but there might be some limited scope in existing generation (eg. along the lines of the Telesource proposal, if properly prepared and competitively bid) or new generation (eg new hydro run on a concession basis).

Regarding water, the same lack of competition stands in the way of private involvement in distribution and wastewater collection, but there is some scope in water abstraction (eg wells being run privately) and in water sewage and treatment. Having a single entity like PUC to carry out all functions is the most commonly adopted model because the economies of scale are better, it is easier to coordinate interrelated decisions and because private sector options with a larger operation are likely to attract higher private sector interest.

Several ways of engaging with the private sector were considered, as shown in the following table.

Option	Ownership	Financing	Operations
Service Contract	Public	Public	Public and then some Private
Management Contract	Public	Public	Private
Lease Contract	Public	Public	Private
Concession	Public	Private	Private
Build-Operate-Transfer Contract	Private then Public	Private	Private
Build-Own-Operate-Transfer Contract	Private then Public	Private	Private
Joint Ownership	Private and Public	Private and Public	Private and Public
Sale	Private	Private	Private

Of these, Competitive Procurement of specific functions such as tree-trimming, line maintenance, pipe laying and maintenance should be considered. Competitive contracting is the easiest way to get the private sector involved in PUC's business, while leaving the utility to run the majority of its operations, manage its assets and serve its clients.

Competition in the Market options such as having competing generation facilities was considered, but this is unlikely to be effective other than for the possibility of contracting out the development and operation of new hydro facilities. This should be considered but it should also be borne in mind that the proposed facilities are small and might not attract build operate transfer type bidders. Other options such as opening the bottled water business to competition were considered but thought to require a regulatory framework that would not be cost-effective.

Competition in the Market options such as concessions, lease-affermage contracts and management contracts were also considered. Like privatization, these arrangements see the transfer of long term control of the utility assets to third parties. In the absence of competition in the market, strong regulation arrangements would need to be in place and the cost of establishing this in a small market is not considered pragmatic by the Consultant because the substantial establishment and ongoing costs would need to borne by end users, eroding the benefits.

The Telesource proposal was reviewed and found to be 6% more expensive than the cost of service currently provided by PUC. Of further concern is (a) the lack of competition when an unsolicited proposal is received and (b) the requirement for PUC to take and pay for more power than it needs for the next few years and (c) the reduced flexibility PUC would have regarding the running of the Nampil Hydro Plant and in developing new hydro facilities to reduce diesel costs.

Overall, the Consultant considers that the State Government would be better to encourage (a) PUC to continue improving its productivity; (b) the introduction of the private sector through the outsourcing of specific PUC functions, while allowing PUC to operate the bulk of its business as it does currently and (c) to consider helping bolster the capacity of the RPPU so that it can assume more regulatory capabilities over time.

2 Terms of Reference Requirements

In general terms, the TOR requires the Consultant to review or develop financial and statistical information supporting the current electricity and water and sewer rates, example operating expenses, generation, and load statistics, water production and loss statistics and so forth.

A review of PUC's operations, budgets, revenues and revenue requirements for power, water and sewer is also required. PUC expects that the Consultant will conduct field inspections of the PUC's operations, including interviews with staff, governmental agencies, major customers and others.

Further, a review of operational plans and manpower, equipment and supply requirements is required by function and cost. A comparison of actual operations to PUC's present budget on a year to date and latest twelve month basis is required.

The methodology for responding to these requirements is discussed in the following sections. The TOR is divided into fifteen components and several of these are inter-related, so components have been amalgamated into the nine sections below. Where components have been merged, the rationale for doing so is discussed in the relevant section below.

2.1 Information Gathering and Review

The first stage of the assignment involved collecting and collating some base information and refining aspects of the project as necessary. While Section 2 addresses these introductory matters, the key stages in this process involved:

- Establishing an information base of key documents for review, referring as required to PUC for clarification;
- Meeting with PUC to further establish & refine goals, objectives, timetable & process;
- Revising the Work Plan to reflect needs of the Project Timetable and Process. In this respect, the timetable was amended to reflect PUC's original timetable of the assignment being conducted over at least a six month period.
- Gathering and reviewing information supporting current tariffs;
- Reviewing costs and functional operational plans, human and physical resources.

The second group of activities undertaken by the Consultant involved identification of key stakeholders and commencement of the consultation process. In this respect, the Consultant completed field inspections, developed a consultation list with PUC and undertook initial consultation with major energy users and other organisations.

From its home office, the Consultant analysed the data and information collected in the field, from which the levels of required revenues and tariffs for different groups of consumers have been estimated.

2.2 Evaluate Required Revenue and Tariff Levels

TOR items 2, 3, 4 and 15 are interrelated and the Consultant has brought these together and responded in Section 6 (Required Revenue Analysis).

Item Two of the TOR requires that the Consultant evaluate current electricity rates and water and sewer rates to determine if the rates cover costs and provide an appropriate contribution towards internally funded capital improvement projects. A determination of the adequacy of the present revenues from rates and other sources is required for the short and long term revenue requirements for electricity and water and sewer utilities based on present operation.

Item Three of the TOR involves the determination of long run marginal cost of electricity supply (LRMC) based on averaging LRMC considering all major capital projects over a ten year period. LRMC is to be determined for generation and electricity supply to major consumer groups. A problem with this approach is that such a short period does not capture enough of the economic benefits of planned capital projects.

An analysis of the revenue requirements for capital projects based on varying scenarios for financing including internally generated financing, long term loan and government grant funding is required under Item Four of the TOR. Financing options for PUC are discussed in detail in Section 10.

Item Four of the TOR also anticipates the development of pro-forma budgets for the power, water and sewer utilities, that include the operating and capital budget requirement is also required and these are set out in Attachment 3.

Finally, Item Fifteen of the TOR requires an analysis of the revenue requirement for streetlights using various scenarios, whether these revenues are internally generated or through a government subsidy. Section 6.5 contains the Consultant's discussion regarding street lighting.

2.3 Customer Opportunity Cost Analysis

The TOR requires the Consultant to determine the opportunity cost for customers to satisfy their utility needs without connecting to the PUC. It also requires analysis of the impact on PUC of the largest customers leaving the system and the advent of PUC stand-by generators. It is implied that the opportunity cost analysis relates to electricity only.

The opportunity cost to consumers of alternative sources of supply is a key issue that affects how tariffs might be set. This task group addresses this issue and involves determining the opportunity cost by consumer group and considering the impact on PUC if major users choose alternative supply. The Consultant discusses this issue in Section 7.

2.4 Rate Determination

Item Six of the TOR requires the Consultant to evaluate the current electricity, water and sewer rates structure and identify alternative rate structures for the electricity and water and sewer operations. These questions are addressed in Section 8.

The Consultant is also to develop rates for power, water and sewer services that will satisfy the PUC revenue requirements on present PUC operations. Ideally, these rates should be set such that customers are discouraged from leaving the public utility system. These matters are considered in Section 6.

2.5 Benchmarking Analysis

TOR Items Seven and Eight are interrelated and the Consultant has brought these together.

Item Seven asks the Consultant to obtain financial, statistical and rate information from comparable operations. In particular, the Consultant is to seek demand information by customer class from comparable operations. In this regard, it is expected that the Consultant will consider at least two separate comparable utilities to gather information and compare expenses and operating conditions for both power and water and sewer operations.

The Consultant is to consider the number of customers by class, sales by class, recent growth and capital expenditures, number of employees by function, payroll costs, costs of supplies, government subsidies, and other sources of income beside rates, system efficiencies including fuel efficiencies and losses.

A comparison of the key financial and statistical ratios and the rate structure of PUC for electricity and water and sewer operations is to be made to the comparable operations to identify significant variations. Significant variations in the financial and statistical or the rate structure for electricity and water and sewer operations separately, is also to be made to determine the cause for any such variations. Based on this comparative study, and the Consultants own experience, advice as to where PUC may be able to improve its operations is to be provided by the Consultant. The cost and savings to the utility are to be estimated. The rates that could be implemented if these savings were put in place are to also be provided.

2.6 Alternative Supply Impact Analysis

The potential impacts and conservation effects of the alternative electricity and water and sewer rate structures are to be assessed. Government and Business Officials are to be interviewed to determine the political impact of the alternative rates. Customer impact analysis for both electricity and water and sewer customers to assess the impact on each class relative to existing electricity rates and water and sewer rates is to be performed by the Consultant.

2.7 Development & Presentation of Findings

TOR Items Ten, Eleven, Twelve and Fourteen are interrelated and the Consultant has brought these together.

Item Ten of the TOR requires the Consultant to develop and present its findings and provide assistance in presenting the Study findings and recommendations to the Governor, the Legislature, PUC Boards, RPPU Boards (if any), Chamber of Commerce and to the public at large. It is expected that this dialogue will be undertaken during the Consultant's third and final field trip to Pohnpei.

Item Eleven of the TOR states that the Consultant is to make an overall recommendation on the reasonableness of the current electricity rates and water and sewer rates. It is also to provide findings on the causes of variations and areas that require further management review are to form part of the findings.

Item Twelve of the TOR requires that the findings also provide a separate comprehensive revenue requirement, rate for power and water and sewer separately, based on present revenue requirements. Rate scenarios for full cost recovery over a 3 to 5 year periods are required. A study comparing PUC operations to other comparable utilities is required, highlighting potential gains from operational improvements.

Item Fourteen of the TOR sets out the requirement that a report of the deficiency of the rate study and how future rate studies should be improved. The Consultant is to make recommendations on how stakeholders and citizen involvement can be achieved in future rate studies.

2.8 Develop Communications Materials for Public

The TOR requires the Consultant, under Item 13, to develop pamphlets of the recommended tariff and any necessary information for education and dissemination of the effected change to the general public. This document is available seperately.

3 Introduction to the Report

3.1 Background

Pohnpei Utilities Corporation (PUC) is a government owned authority providing electricity, water and wastewater services for the State of Pohnpei. In 1991 PUC was established to take responsibility for the electricity system that was previously managed by the Pohnpei State Department of Public Works. Two years later, PUC also became responsible for the provision of water and sewer services.

Authority was given to the Board of Directors and management to determine and set tariffs necessary to operate the utility on a cost-recovery basis. The PUC is under the governance of a seven member Board of Directors, appointed by the Governor and approved by the Legislature of Pohnpei State. The General Manager, who is hired by the Board of Directors, oversees the daily operation of the Corporation and its 160 staff members.

As at 30 September 2005, PUC provided water and power to some 3,428 and 6,496 customers respectively on Pohnpei. Electricity sales are made to around 96% of the population and account for some 85% of PUC's revenues, with the balance being made up primarily through water sales to a little over half the Pohnpei populace. Customers purchase approximately 39 GWh of energy billed mostly through pre-paid metering. Water sales of some 727 million gallons in 2005 were made.

Regarding PUC's electricity operations, demand ranges between 2.5 MW and 7 MW at peak times. PUC's installed capacity is some 15.5 MW, which allows a high level of redundancy that is attractive from an operational viewpoint but not from a financial standpoint. PUC's generation capacity comprises mainly of six small caterpillar units and four 2.5 MW Daihatsu units.

With respect to PUC's water business, PUC has the capacity to produce 4.72 million gallons per day of potable water per year, yet produced 1.4 billion gallons in 2005 and sold 727 million gallons in that year. This suggests unaccounted water of some 48% through technical losses and illegal connections.

A major factor affecting PUC's operations is the cost of diesel fuel, a situation that is further compounded by there being a single supplier of fuel to Pohnpei. In light of the current cost of diesel fuel and expectations regarding future oil prices, the fuel component of electricity charges is on an upward trend.

Total budgeted revenue from power and water sales in 2006 is USD 10,738,000, 76% of which is from power sales.

PUC passes fuel costs through to electricity consumers and, on the face of things, this is an appropriate mechanism. However, with electricity tariffs around the 30¢/kWh level, the rate of arrears is at a very high level. In 2005, PUC's accounts receivable amounted to USD 3.05 million, equivalent to 34% of revenues for that year. This was significantly lower than the 2004 result, reflecting a bad debt write-off of USD 1.9 million. However, the underlying level of debtors still increased by USD 169,000 on an increase in revenue of USD 810,000.

PUC requires advice to assist it in determining the revenue requirements needed to recover its operating costs and to finance its long-term capital expenditure requirements. Also required by the PUC is assistance from the selected Consultant in presenting to the PUC board, the government and wider public. In connection with public relations, it will be necessary to develop a communication strategy and written materials that can be used to disseminate information.

The Study is being supported by the Pacific Islands Energy Policy and Strategic Action Plan (PIEPSAP), which is funded by the Danish Government under the EU Energy Initiative. In turn, the Study is being facilitated by the South Pacific Applied Geoscience Commission (SOPAC), which is an inter-governmental regional organisation dedicated to promoting sustainable development.

3.2 Appointment of the Consultant

On 15 August 2005, PUC invited proposals on an open competitive basis from Consultants for the provision of consulting services to carry out the services set out in Section 4. To maintain this Study's independence, proposals were also evaluated by the Treasury Department of Pohnpei Government and SOPAC, which assisted PUC in the selection process.

On 16 January 2006, following, evaluation of the technical and financial proposals received, and completion of contract negotiations, a contract award for the services was made to Ridgway Capital Projects Limited, of Christchurch, New Zealand ("Ridgway"). Ridgway's proposal was made in association with Maunsell Limited, a consulting engineering firm with offices in New Zealand, for the provision of technical support.

The Ridgway team comprises two specialists from Ridgway and two from Maunsell Limited. The team is comprised as follows:

Table 1 - Consultant Team Composition

Name	Position	Firm
Peter Seed	Economic and Financial Analyst	Ridgway
Richard MacGeorge	Project Finance Specialist	Ridgway
Frans van de Wydeven	Thermal Generation Engineer Power System Planner	Maunsell
Graeme Hughson	Water Asset Specialist	Maunsell

The contract is administered and supervised by the General Manager's Office (GMO) of PUC, and is being overseen by the Pohnpei State Treasury Department, through Director Finley Perman, and SOPAC, through Gerhard Zieroth - Manager, PIEPSAP.

3.3 Objectives of the Assignment

Electricity, water and wastewater networks employ assets that have long economic lives and that require maintenance at periodic intervals. PUC requires advice and recommendations on a tariff structure that will enable it to manage and maintain, in an economically sustainable way, its electricity, water and wastewater networks.

To be operationally viable, PUC must recover its operating costs and also recover an amount sufficient to replace assets that wear out or become obsolete (usually as approximated by depreciation). To be financially viable, PUC needs also to recover the opportunity cost of the capital it has employed in its networks. The opportunity cost of capital reflects the returns that PUC could earn by investing the funds it has employed in another investment with similar risk. The opportunity cost could also reflect an objective set by shareholders and other stakeholders.

Therefore, the process of determining tariffs is highly iterative to the extent that it involves optimising an outcome constrained by:

- A minimum required rate of return objective by the ultimate owners of the network supplier, and
- The price that consumers can afford to pay based on the cost of the next best alternative supply of electricity, water and wastewater services.

Our understanding is that the objective of the project is to derive a set of tariffs that reconcile these two competing objectives.

3.4 Consultations and Fact Finding

The Study involves a multi-disciplinary exercise and involves the coordination of financial, technical and economic issues. To ensure that implementation of the Study is balanced amongst all stakeholders, close cooperation between relevant Pohnpei Government agencies is essential. The participation of key agencies in the execution of this assignment has therefore been given priority and opportunities to provide feedback have been elicited in the Consultant's first field visit.

The TOR makes provision for the Consultant to conduct field inspections of PUC's operations, including interviews with staff, governmental agencies, major customers and others.

With regard to field inspections, on 6 March 2006, Mr. Graeme Hughson of Maunsell visited PUC's key water and wastewater assets and was accompanied by Airens Leerenson of PUC. On 8 March 2006, Mr. Frans van de Wydeven, Peter Seed and Richard MacGeorge visited the Nampohnmal and Nampil power stations.

Figure 2 - Photos From Site Visits

Regarding interviews with governmental agencies and major customers, the following meetings were held between the Consultant and other parties during the Consultant's first field trip between 5 March – 11 March, 2006. PUC did not attend any customer consultations because its staff were conscious of the need for customers to be able to speak openly.

Table 2 - Trip 1 Consultations List

Date of Meeting	Organization	Role	Representatives Met	Other Attendees
Friday, 3 March 2006	State Treasury Department	Project Sponsor	Finley Perman, (Director)	Kelly Keller (PUC), Richard MacGeorge (Ridgway), Peter Seed (Ridgway), Graeme Hughson (Maunsell)
Tuesday, 7 March 2006	Pohnpei Ace Hardware	PUC Customer	Larry Adams, (General Manager)	Richard MacGeorge (Ridgway), Peter Seed (Ridgway), Graeme Hughson (Maunsell)
Tuesday, 7 March 2006	FSM Finance Department	PUC Customer/ Compact Funding	Nick Andron, (Secretary of Finance)	Kelly Keller (PUC), Richard MacGeorge (Ridgway), Peter Seed (Ridgway), Graeme Hughson (Maunsell), Frans van de Wydeven (Maunsell)
Thursday, 9 March 2006	Department of Health Services (State Hospital)	PUC Customer	Wincener J. David, (Director)	Richard MacGeorge (Ridgway)
Thursday, 9 March 2006	FSM Telecom-munications Corporation	PUC Customer	Takuro Akinaga, (CEO and General Manager)	Richard MacGeorge (Ridgway)
Thursday, 9 March 2006	PUC Board of Directors	PUC	Anna Mendiola, (Chairman and President of the FSM Development Bank)	Kelly Keller (PUC), Richard MacGeorge (Ridgway)
Thursday, 9 March 2006	Pohnpei State Governor's Office	State Government	The Hon. Jack Yakana, (Lieutenant Governor of Pohnpei State)	Finley Perman (State Treasury), Kelly Keller (PUC), Richard MacGeorge (Ridgway)
Thursday, 9 March 2006	Compact - IPIC Representative for Pohnpei State	State Government	Yubert Yamada (IPIC Rep for Pohnpei State)	Kelly Keller (PUC), Robert Harman (PUC), Esmond Moses (PUC), Richard MacGeorge (Ridgway), Frans van de Wydeven (Maunsell)
Friday, 10 March 2006	Residential Property and Public Utility Commission (RPPU)	State Government Consumer's Representat ive	Yosuo Phillip (Chairman and head of the Economic Development Authority), Keropin David (Vice Chairman) Peter Aron Member	Kelly Keller (PUC), Richard MacGeorge (Ridgway)

Staff consultations were held with Ms Daisy Cantero (AGM – Administration and Acting General Manager in Mr. Aktoulea's absence), Mr. Kelly Keller (AGM – Budget and Finance), Mr. Robert Hadley (AGM – Water and Sewerage Department), Mr. Esmond Moses (Special Assistant – Strategic Planning), Mr. Joseph Phillip (Legal Counsel), Mr. Johnny Adolph (Manger, Accounting), Bob Godson (Manager, Division of Diesel Generation) and Alberita Likor (Assistant to the General Manager).

In addition to visiting Pohnpei, Mr. Peter Seed visited Fiji and met with Mr. Jared Morris of the Pacific Islands Forum and MR. Gordon Change of the Pacific Power Association. The purpose of these meetings was to discuss fuel supply and benchmarking matters.

The Consultant also conducted a second field visit to Pohnpei between 4 and 7 September 2006 to further develop the study.

3.5 Structure of the Final Report

This Final Report explains the Consultant's general approach to the issues raised in the TOR and to describe how each of the Terms of Reference (TOR) tasks will be completed. The report is organized under the following sections:

Section 1 – Executive Summary: This section sets out the principal findings of the Study.

Section 2 - Introduction, (this section): This section states the objectives of the Study, describes its context and the background to the Consultant's appointment. It outlines the organization of the Study and records some administrative matters.

Section 3 – Setting: Describes the principal geographic and economic features of the FSM, Pohnpei and the water and power sectors as they relate to the Study.

Section 4 – Terms of Reference (TOR) Requirements: Describes the requirements of the Terms of Reference regarding information gathering, tariff level evaluation, opportunity cost analysis and alternative supplies.

Section 5 – Current PUC Tariffs: Examines the current tariff levels and structure for water, wastewater and electricity.

Section 6 – Required Revenue Analysis: Reviews the revenue that PUC reasonably needs to operate on a cost recovery basis. This is achieved through an examination of Long Run Marginal Cost methodology that is then applied to each of electricity, water, wastewater and street light services to estimate the required revenue for each.

Section 7 – Customer Opportunity Cost of Electricity: Evaluates the by-pass pricing of alternatives to PUC service provision.

Section 8 – Tariff Structures and Rate Determination: Deals with two issues. The first involves tariff design questions and considers other tariff structures that might be applied to PUC's services. Particular consideration is given to life line tariff approaches and their potential application in PUC's situation. The second recommends a rate structure that might be adopted by PUC for its water, wastewater and electricity services.

Section 9 – Analysis of Alternative Electricity Supply Options discusses a range of alternative options that PUC might adopt for power generation, together with an analysis of which of these are likely to provide PUC with the lowest cost of generation.

Section 10 – Funding Options considers the implications of the Alternative Electricity Supply Options evaluated in Section 9. It reviews the availability of finance for PUC with respect to its electricity supply system, together with consideration of financing options for PUC's water supply activities.

3.6 Implementation Schedule and Deliverables

The Consultant mobilised on its first field trip to Pohnpei on 3 March 2006. This Report is based on that visit and subsequent analysis of the information gathered.

The Consultant shall agree a mutually convenient time with PUC and other stakeholders for the Consultant's second field trip. Suggested tentative timing for this trip is late July or early August 2006. During the second site visit, the Consultant suggests that a one-day Stakeholder Workshop is held to communicate issues and to obtain feedback on the Study's findings to that date. The Second site visit would also provide an opportunity to meet with PUC and the Pohnpei Government to discuss the Study. The Consultant would then return to its home office to complete the Final Report and pamphlet design for dissemination.

3.7 Acknowledgments

This Report was prepared by the Consultant's team, namely Richard MacGeorge, Peter Seed, Frans van de Wydeven and Graeme Hughson. The authors wish to give general thanks to the staff of Pohnpei Utilities Corporation and the Department of Finance for their generous cooperation and support, and to express particular gratitude for the assistance of Mrs. Anna Mendiola, Mr. Marcelino Actouka, Mr. Kelly Keller, Mr. Esmond Moses, Mr. Robert Hadley, Mr. Joseph Phillip, Ms. Daisy Cantero, Mr. Johnny Adolph and Mr. Bob Godson.

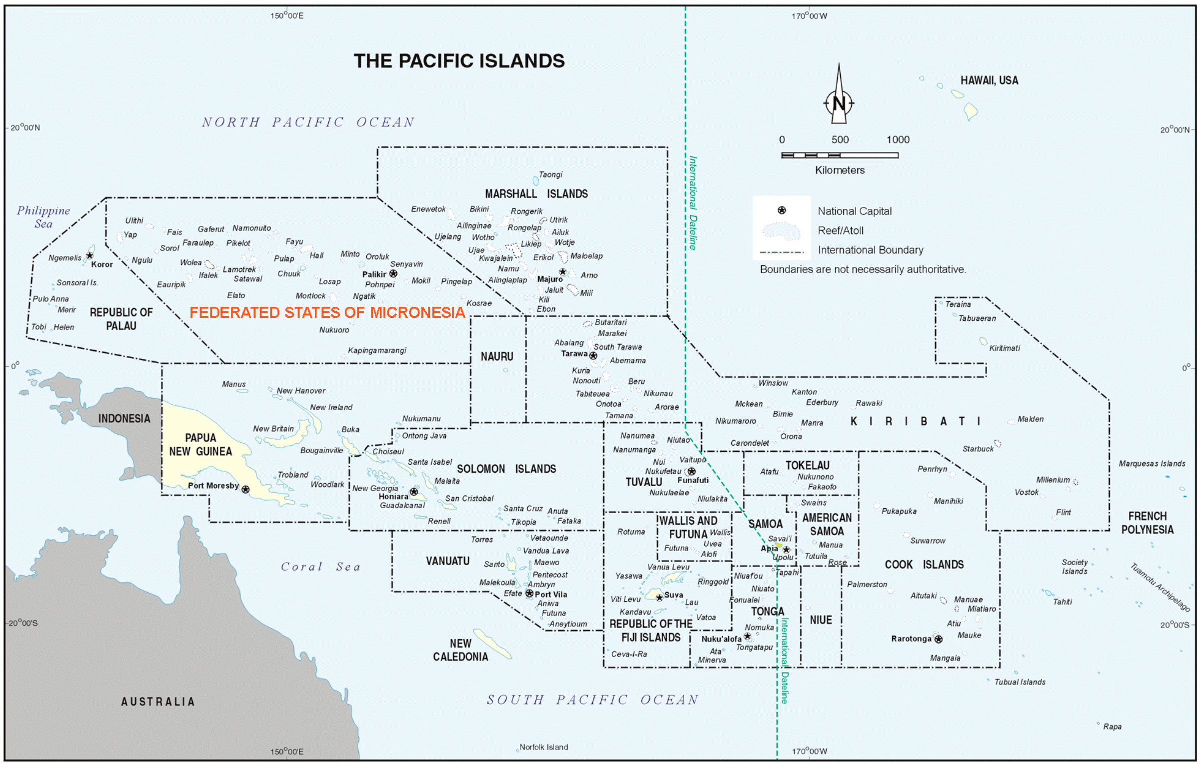
The authors also wish to express gratitude to The Hon. Jack E Yakana – Lieutenant Governor of Pohnpei State, Finley Perman – Director of the State Treasury Department and Nick Andron – Secretary of Finance for the National Government for their assistance in developing this report.

4 Setting

4.1 Country Profile

The Federated States of Micronesia (FSM) is a republic located in the Pacific Ocean, northeast of Papua New Guinea. The country is a sovereign state in free association with the United States. The FSM is made up from the four island states of Pohnpei, Chuuk, Kosrae and Yap. The state of Pohnpei consists of the largest island of Pohnpei together with eight smaller outer islands that are between 33 and 650 miles away.

Figure 3 - Map of the Pacific Islands



Source: Asian Development Bank (ADB)

The FSM is governed by a 1979 constitution through a unicameral Congress that has fourteen members elected by popular vote. Four senators - one from each state, serve four-year terms; the remaining ten senators represent districts based on population, and serve two-year terms. The President and vice president are elected by Congress from among the four state-based senators to serve four-year terms in the executive branch. Their congressional seats are then filled by special elections. The president and vice president have a cabinet.

The FSM is a U.S Dollar based economy. Economic activity consists primarily of subsistence farming and fishing. The islands have few mineral deposits, except for high-grade phosphate. The potential for a tourist industry exists, but the remoteness of the location and limited infrastructure hinder development. Financial assistance from the United States is the primary source of revenue, with the United States spending USD 1.3 billion in the islands under the Compact between 1986 and 2001.

The population of the FSM is about 107,000 according to the 2000 census, including about 34,500 on Pohnpei, the second most populated island. The FSM has a relatively high birth rate of some 25/1000 people and a relatively low death rate of approximately 5/1000 people. The population is young, however, with 37% being under age fourteen and only 3% being over age 65.

4.2 Overview of FSM and Pohnpei Economy

According to the IMF, the FSM had a Gross Domestic Product (GDP) of USD 277 million in 2004, which placed the economy by this measure at 215th in the world. On a per capital basis, the World Bank estimated in 2004 that the FSM had a GDP of USD 2,090.56 per capita, placing it 101st of the 184 countries surveyed.

The FSM is a small country that is heavily reliant on external assistance, especially through the Compact (1987 – 2001) and Compact II (2004 – 2023). However, Compact grants have been declining and currently amount to approximate one third of GDP, or USD 700 per capita. Total funding under Compact II is USD 92.7 million a year from grants and trust fund contributions.

The grant component of Compact II funding amounts to USD 76.2 million per year during the period between 2003 and 2005, falling by USD 0.8 million per year thereafter. Grant and trust fund contributions are indexed to 2/3rd of US inflation or 5%, whichever is lower.

The Trust Fund component amounts to USD 16 million as of 2004 and this rises to USD 29.6 million by 2023. The Trust Fund cannot be used for spending or borrowing until 2024, so it is not available for annual government expenditure. From 2024, the FSM will be able to draw on this trust fund.

The Compact II is administered by a US – FSM Joint Economic Management Committee (JEMCO) that approves grant allocations. It has identified six priority sectors, including infrastructure. There is no clear formula for determining allocations, but the JEMCO has decided that at least thirty percent of annual grants should be directed to infrastructure. The implications of this for PUC are discussed further under Section 9.

Each state within the FSM has its own administration, legislature and sets its own budget. Each state also levies taxes, reducing the degree of influence that the National Government has on fiscal policy. In part, this has led to differences between the economic performance of the individual states. Government borrowing and inflation in the FSM remain low however, despite rising oil prices that have contributed to a widening trade deficit.

Public expenditure accounts for over sixty per cent of GDP and the National and State governments employ half of those in full time employment. Public sector wages are roughly double those of the private sector and this hinders private sector development. Export oriented sectors account for only six per cent of employment, although some improvements have resulted from the ADB's Private Sector Development Programme.

The Compact allows FSM citizens to emigrate to the United States to work and this, combined with limited employment opportunities in the FSM, has encouraged up to a quarter of the population to leave the FSM for the United States or its territories. Population growth has slowed to around 0.2% per annum since the mid 1990s when it was around 2% per annum. Remittances from overseas residents officially account for about 1 per cent of GDP, but are probably higher than this figure, providing additional support for the economy.

Further support for the FSM is becoming evident following a USD 2.5 million grant from China, which has recently agreed a framework for economic development and fisheries. China, Europe and Japan are also very supportive of FSM economic development and stand to provide a degree of support that might lessen the impact of declining Compact funding.

Regarding the Pohnpei economy, including the hosting of the National Government which accounts for 45% of national GDP, a contraction of an estimated 2.8% occurred in 2004 because of declining private sector and public enterprise activity, while the government sector expanded. By contrast, Chuuk (which accounts for around 30% of GDP), Yap (17%) and Kosrae (9%) experienced a greater level of economic contraction of 4.5%.

In summary, the FSM and Pohnpei are small economies that face the dual challenge of geographic isolation and dependence on support from the United States. The US support underpins the economy, but it has the affect of drawing working age people to the US and skews the labour market toward public employment. However, pay standards in even the public sector are relatively low, however and this means that affordability of basic services such as electricity, water and sewerage services is a challenge for many of PUC's customers.

4.3 PUC and its Objectives

PUC's objectives are stated clearly in its strategic plan. This sets out PUC's mission, which is to improve the quality of life in Pohnpei. This vision is to be a quality service institution that is focussed and responsible.

Within this broad framework, PUC has a series of specific goals, which include:

- providing state wide water and sewers;
- automated water vending machines where necessary;
- maximising power generation from renewable sources;
- developing an underground power distribution system.

PUC also aims to be a profitable organisation whose practices meet best practice reference points. It plans to expand Cashpower to all its electricity customers and it would like to extend pre-payments to water and sewer services as well, collecting 75% and 50% respectively. These measures are designed towards having no accounts receivable.

Ultimately, PUC intends to serve a contented customer base and to support its staff through, for instance, the development of a new administration building. There are, however, some challenges that the Corporation faces and these stand in the way of PUC fully meeting its objectives. PUC has ranked these issues in order of importance to be:

- the high cost and dependence on imported diesel fuel;
- customer arrears;
- spare part costs;
- legislation;
- absenteeism amongst staff and punctuality;
- political influence;
- the Compact;
- litigation against the Corporation;
- availability of skilled labour;
- land access rights, and;
- competition (presumably by customers making their own power, water and sewer arrangements)

4.4 Power Sector Development

The PUC provides electricity 24 hours per day to some 6,500 households, most of them being billed through pre-paid metering. The PUC client base covers more than 96% of Pohnpei's approximately 35,000 population. New diesel generation capacity was constructed in the early nineties with Japanese aid, providing a much needed addition to PUC's generating capacity, improving generation efficiency and reliability of supply. Also constructed with Japanese aid were 13.8 kV distribution lines right around the island that contributed to a considerable reduction of technical line losses.

Historically, Pohnpei prospered during the Japanese Civilian administration of the FSM, under the League of Nations between 1914 and the start of World War II. During this period, the administration, through the Pohnpei Public Works Department, developed a small dam and reservoir to serve the local community with domestic water and hydro electricity. The small turbine-generator sets installed at that time were able to supply residents of Kolonia with a continuous supply of electricity. The powerhouse was, however, destroyed at the end of WWII during the closing stages of that conflict.

It was not until 1986 that Pohnpei was again able to enjoy reliable mains power. At that time, an ALCO barge with three diesel units (excluding one non operational unit) having a total capacity of 1.7 MW was delivered to Pohnpei. In the following year, the US Army Corps of Engineers built a 1.7 MW hydro electric facility at Nampil, adjacent to the Japanese built facility. The sizing of the Nampil facility and intermittent river flows have not, however, permitted the continuous supply of electricity from this station.

During 1989 and 1990, the Pohnpeian State Department of Public Works installed six caterpillar generating sets (of 1.4 MW capacity) at Nanpohnmal. In 1991, a report conducted for the US Department of Interior identified major shortcomings in the electricity supply services provided by the Pohnpei State Department of Public Works. The report found that power outages were common and generation supply was unable to meet demand. Staff, it was reported, did not possess the skills to run the system safely and reliably. Moreover, electricity tariffs were heavily subsidized, with the retail tariff being set around 3.5¢/kWh when the actual cost of production was closer to 21.5¢/kWh.

In response to the report, the State Government established PUC as a wholly owned government corporation to take responsibility for electricity supply. Following PUC's incorporation, a further four diesel generators of 5 MW capacity were installed in 1992 and 1994. These generators were donated to the National Government by the Government of Japan as part of its aid programme. Strictly speaking, these units remain the property of the National Government, but they are controlled, operated and maintained by PUC. Japanese grant monies also enabled the expansion of the Nanpohnmal facility to accommodate the extra generating sets and evacuation of electricity via feeder circuits to Kolonia and by linking the Eastern and Western circuits to the distribution system running around the island.

The establishment of PUC, improvements to generating capacity and the distribution system along with staff training between 1991 and 1995 led to substantial improvements in production, sales and collections. Financial management of PUC improved and from 1992, PUC's auditors were able to provide unqualified opinions regarding PUC's accounts.

In 1994, PUC's board (being concerned that tariffs for electricity sales were insufficient to recover costs) appointed Prospect Electricity and the American Samoa Power Authority to undertake an independent rate study. The board asked the Consultant to review PUC's operations, and assess whether operating costs were reasonable and to see if cost savings might be identified. The Consultant was asked to reference point the costs and rates of three other Pacific Island utilities to assist it in making its determination.

The Consultants recommended in their 1995 report that PUC raise its electricity tariffs by 39% and that PUC alter its rate structure. In this respect, it was suggested that PUC have a two part tariff to cover fixed costs of operation and a fuel surcharge (of 0.82 x the price, from time to time, of 1 gallon of diesel) to cover the cost of fuel supplies. It was also suggested that PUC add demand charges for larger customers to cover standby availability, together with the addition of several other charges to cover, amongst other things, connection and disconnection fees. In aggregate, a base tariff of 10¢/kWh and a fuel surcharge of 6.56¢/kWh amounted to an average retail tariff of 16.56¢/kWh.

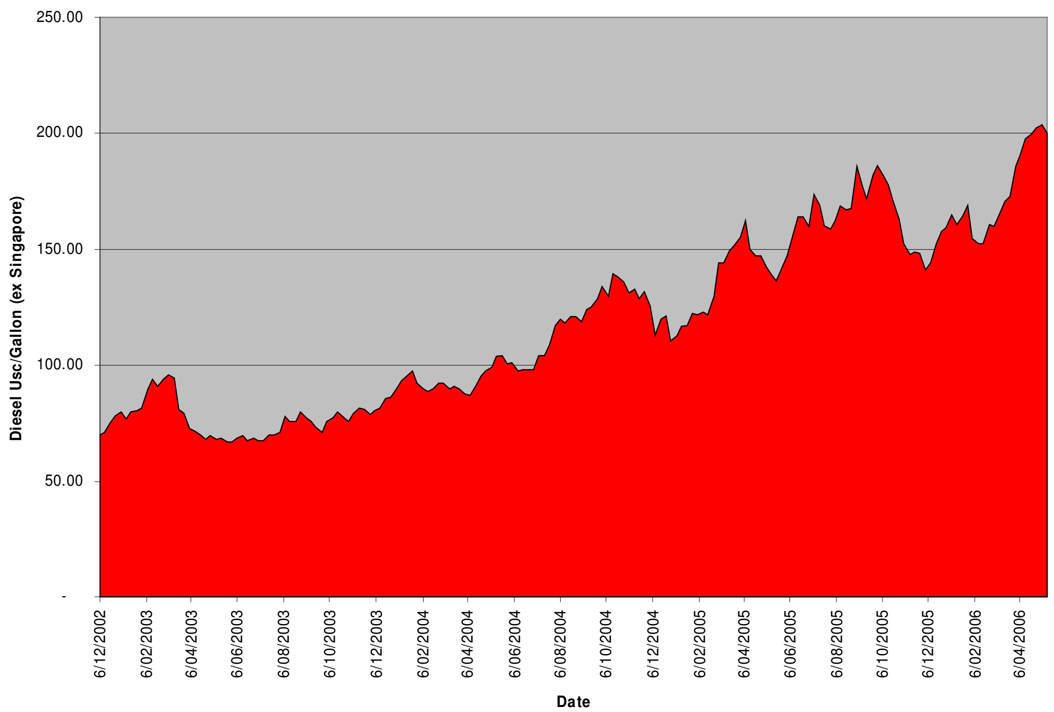
Regarding the benchmarking of PUC's proposed new tariffs to other pacific utilities, the Solomon Island Electric Authority, the Molokai Division of the Maui Electric Company and the American Samoa Power Authority were chosen for the analysis. The Consultants found that PUC's new tariffs would be lower than the Solomons and Molokai but higher than American Samoa.

The recommended rates and rate structure were adopted by PUC's board, leading to the tariff rate table contained in Section 5.1.

Having implemented a tariff increase, collection of revenues became an acute problem for PUC. The utility found, for instance, that a limited number of postal addresses for customers meant many consumers were not receiving power bills. Recovery of the higher tariff was also more difficult because power was being paid for after it was consumed and many poorer customers found it difficult to prioritise payments. Consequently, arrears increased dramatically and the number of days payable for accounts receivable increased from around thirty to ninety days. PUC implemented prepaid Landis and Gyr Cashpower meters for most customers from 1998 and this has had a marked positive effect on arrears.

The tariff structure adopted in 1996 has remained unchanged since that time, although the overall cost of electricity has increased markedly as a direct result of increasing fuel prices that are passed through to consumers as fuel prices change. To illustrate this increase, the cost of diesel ex Singapore between 2002-2005 is shown in the following chart

Figure 4 – Diesel Prices ex Singapore (2000-2005)



Fuel prices have more than doubled during this period, meaning prices have increased at a compound rate of some 36% per annum. Ex Singapore prices at the time of the Consultant's first field visit to Pohnpei in March 2006 were around USD 1.65 per gallon and PUC's purchase price was around USD 2.30 per gallon. Fuel prices have increased by a further 21% since that time. It is also understood that MOMI increased fuel prices by one USD per gallon on 1 June 2006, which would have the effect of increasing tariffs by a further 8¢/kWh. Further increases again might occur because the FSM Fuel Task Force has agreed that Kosrae will be included in the blanket fuel supply arrangement and the extra transport cost will be borne by all FSM States.

PUC's fuel consumption increased from August 2001 when the 2 MW Nampil hydro facility was flooded. The facility has been out of commission since that time, but it was expected the station would be re-commissioned in mid to late 2006. The additional cost of fuel as a result of this incident is estimated to be around USD 500,000 per annum.

PUC is considering becoming a fuel retailer, taking advantage of the arbitrage between the price it pays for fuel as a government purchaser and the retail price of diesel. Care needs to be taken, however, that PUC does not branch out into an activity that it has limited experience in. Furthermore, MOMI as the sole supplier would have the ability to compete with PUC because (a) the government price will still have a MOMI profit margin and (b) MOMI is skilled in fuel distribution. Consequently, it is likely that MOMI can compete effectively on fuel pricing, which might have the effect of lowering fuel costs to Pohnpei customers but could lead PUC into a loss making venture for itself. Another unintentional side effect of PUC retailing diesel is that the opportunity cost of electricity production by PUC's customers would fall, encouraging them to disconnect from the PUC system.

Current tariff levels range between 25 - 29¢/kWh depending on the type of consumer. This is made up of fixed charges of between 6-10¢/kWh and a fuel surcharge of some 19¢/kWh as at the Reporting Date. While there may be some operational improvements that might enable the fixed charge to be contained, the fuel surcharge poses the greatest challenge. This leads to tariffs that are high, which would be higher still if the State Government required a return of its capital invested in PUC. This is discussed in more detail under Section 8 but amounts to State support of around 1.7¢/kWh.

Addressing PUC's power sector challenges involves resolving as a first priority, PUC's high fuel costs by considering whether the current diesel/hydro mix is the least cost generation option for PUC. Where diesel fuel must be used, the issue then becomes a question of reducing consumption by increasing operating efficiencies insofar as possible, encouraging demand side savings and reducing the cost of fuel where this can be achieved. On this latter point, the FSM has established a Fuel Task Force and it is this entity that should guide this process with input from PUC as a major user.

In short, PUC's power system is generally well developed with regard to power distribution and retailing using Cashpower meters. However, Generation poses the greatest challenge. PUC's operation relies heavily on monopoly supplied and imported diesel for aging but well run diesel generators. Hydro power potential exists through the rehabilitation of the Nampil facility and the development of further sites, but these bring a financing challenge in order to reduce operating costs. This challenge is discussed in Section 9.

4.5 Water Sector Development

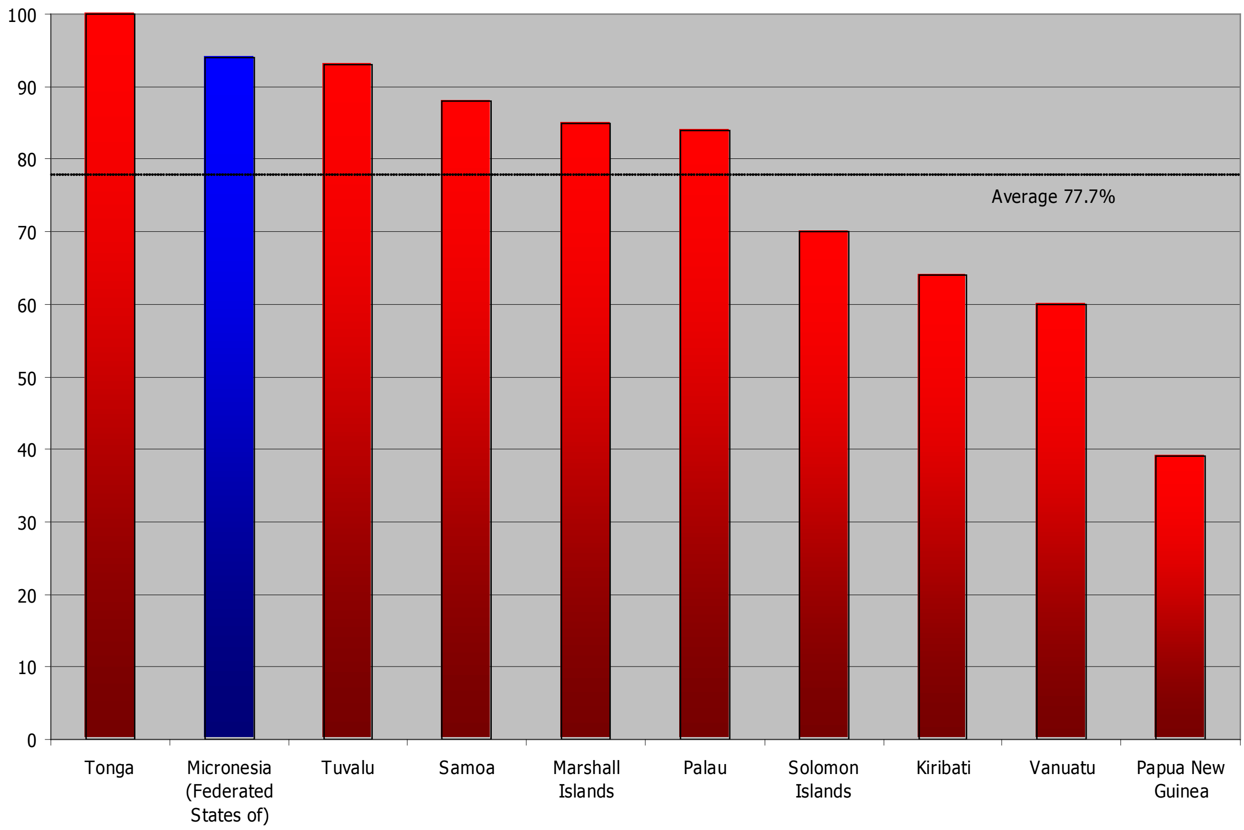
The PUC currently provides water and waste services 24 hours per day to approximately 2,882 and 1,020 households respectively. Connections to commercial, government, state and PUC number 395 for water and 191 for wastewater. Most households are billed through pre-paid metering. There are currently no charges for wastewater services.

PUC is responsible for the majority of Pohnpei's water and wastewater systems. As with electricity, it took over the State's water and sewerage assets in 1993. Services have been expanded significantly into the peri-urban and rural areas around Kolonia over the past 5 years. Wastewater services are provided in Kolonia and a small part of Nett to approximately 8,000 residents, 27% of the population. PUC's water system covers approximately 54% of the Island's population and around 30% of the Island's area. In addition to this network, there are approximately forty small community based water systems that are outside the area served by PUC. The National Government, based at Palikir, also has its own water system to supply government offices and the College of Micronesia (COM). This system has recently been incorporated into PUC's system which lowers PUC's overall asset quality.

The IDP for the period between 2004-2023 states that the water system has sufficient capacity to serve existing demand levels and that water assets are generally in good condition. However, the IDP also states that programmes to provide for coverage over the whole island, including development of new water sources, treatment and distribution facilities are needed.

The WHO reports that the proportion of the FSM's population that has access to an improved water source is 94% as of 2002. The chart below shows how the FSM compares favourably in this respect against other Pacific Island nations.

Figure 5 – Population with Access to Improved Water Facilities



Source: WHO Statistics 2006 and WHO Report 2006

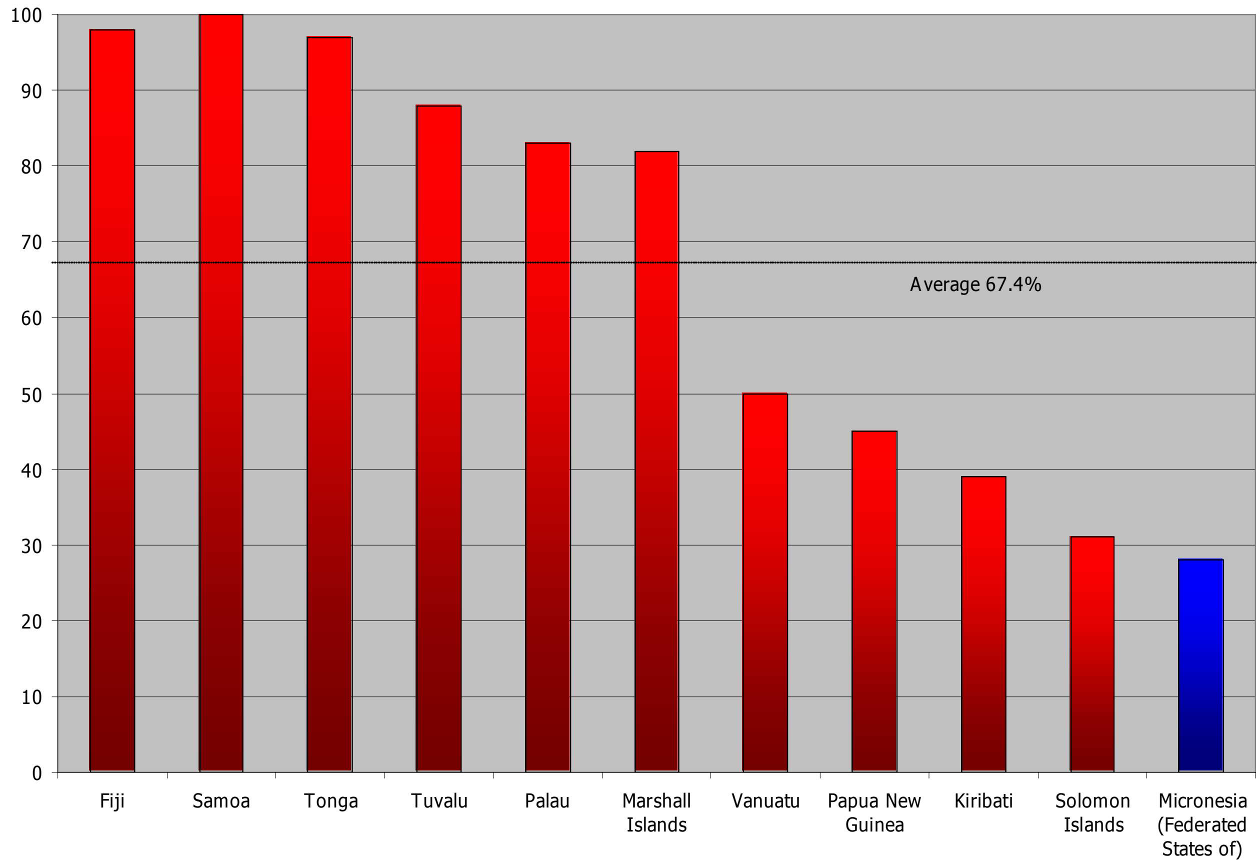
Most of Pohnpei's fresh water is sourced from rainfall catchments or shallow wells, where the water quality is reasonable. PUC plans to provide the island with a single integrated system that delivers potable water to all developed areas. PUC's existing water assets and development plans are discussed more fully in Section 6.3.

Regarding wastewater management on Pohnpei, principally this comprises the Kolonia sewerage system covering approximately a quarter of the population of Pohnpei. The existing system involves a single wastewater treatment plant that operates close to its design limits and is close to the end of its economic life. Operating costs and maintenance difficulties reflect this, particularly because the treatment plant is located on elevated land in a residential area. This means substantial pumping of wastewater to the facility is needed and some low lying areas do not receive service.

The ADB, in its Omnibus Development Project, also found that the sewerage collection system has deteriorated to a point where leaks occur at a higher rate than is needed to maintain acceptable sanitation levels. A further issue facing PUC is the island's high rainfall, which causes system overflows and sewage ingress into surface water from time to time. Beyond the water treatment plant, the ADB found that the existing outfall requires upgrading to improve water quality in the outfall area.

The WHO rates the FSM as having only 28% of the population with sustainable access to an improved sanitation system in 2002. The FSM does not rate well in this regard when compared amongst other Pacific Island nations, where the average proportion of those with acceptable sanitation systems is 67.4% (as of 2002).

Figure 6 - Population with sustainable access to improved sanitation



Source: WHO Statistics 2006 and WHO Report 2006

In May 2000, the Governor of Pohnpei State declared a State of Emergency when twenty-nine people with cholera were hospitalized. An outbreak of intestinal flu occurred at the same time and during the course of the next month, some 600 cases of cholera/flu had been reported. The outbreak occurred in the Kitti municipality and was thought to have related to the close proximity of pig husbandry and the production of Sakau (Kava).

A review of MDGs in the Pacific by the ADB in 2003 highlighted the need for improved sewerage services to meet the MDG regarding environmental sustainability. In response, the IDP anticipated USD 11.6 million between 2004-2023 being spent on upgrades to the Kolonia wastewater treatment plant, a sewerage system extension for Kolonia and an ocean outfall extension.

It was anticipated in the IDP that funding for these projects would come from sources other than Compact II funding. Potential sources included the National Government, State Government, US Government bi-lateral aid, the ADB, Japanese aid, the EU and other donors.

It transpired that the ADB, under the OIDP, approved a loan with part of the proceeds (referred to as "Component A") amounting to USD 10.2 million to be applied to Pohnpei wastewater improvements. These are to include upgrades to the wastewater treatment plant, development of a sewerage system at Sokehs, modifications to the balance of the sewerage system, development of tertiary wetlands, improvement to inflow and infiltration systems, a causeway lift station and other lift station modifications.

The intended outcomes from this facility are to raise effluent quality from the wastewater treatment plant to Environmental Protection Agency standards by 2009, cut sewage overflows in half by 2009 and expand the wastewater collection system to Sokehs so as to service an additional 300 households.

The ODIP loan requires that PUC undertake a comprehensive tariff study for all the services it provides, involving wastewater services. At present, PUC charges USD 5.00 per month for consumption of less than 2,500 gallons and USD 1.80 per 1,000 gallons. There is no specific sewerage charge, so an allocation of water revenues is made to cover the cost of wastewater service provision, irrespective of whether customers have a sewerage connection or not.

In conclusion, Pohnpei has a relatively well developed water treatment and reticulation system with approximately half of the population accessing this service and most others receiving bottled water from PUC. PUC plans to extend the water reticulation system to those customers, but the capital cost to do so is high and cost benefit analysis is needed to determine the financial and economic rationale for taking this step. Regarding wastewater, Pohnpei has a relatively poor service, with only around a quarter of the population being connected to the sewer network. The ADB has provided funding at USD 10 million to help address this issue, but significant additional funding will be required to achieve this objective.

The implication for PUC and customers is that sewer tariffs will need to increase substantially if PUC is to recover capex and opex associated with these new assets. These tariffs are unlikely to be affordable by customers and this raises the question about whether the proposed wastewater capex is commercially sustainable. If the proposed wastewater projects are cost-beneficial to Pohnpei, PUC might need governmental support to fund these projects. If the projects are not cost-beneficial, then alternative projects need to be considered.

4.6 Current PUC Tariffs

4.6.1 Electricity

The current electricity tariff structure is summarized below:

Table 3 – PUC's Current Electricity Tariff Structure

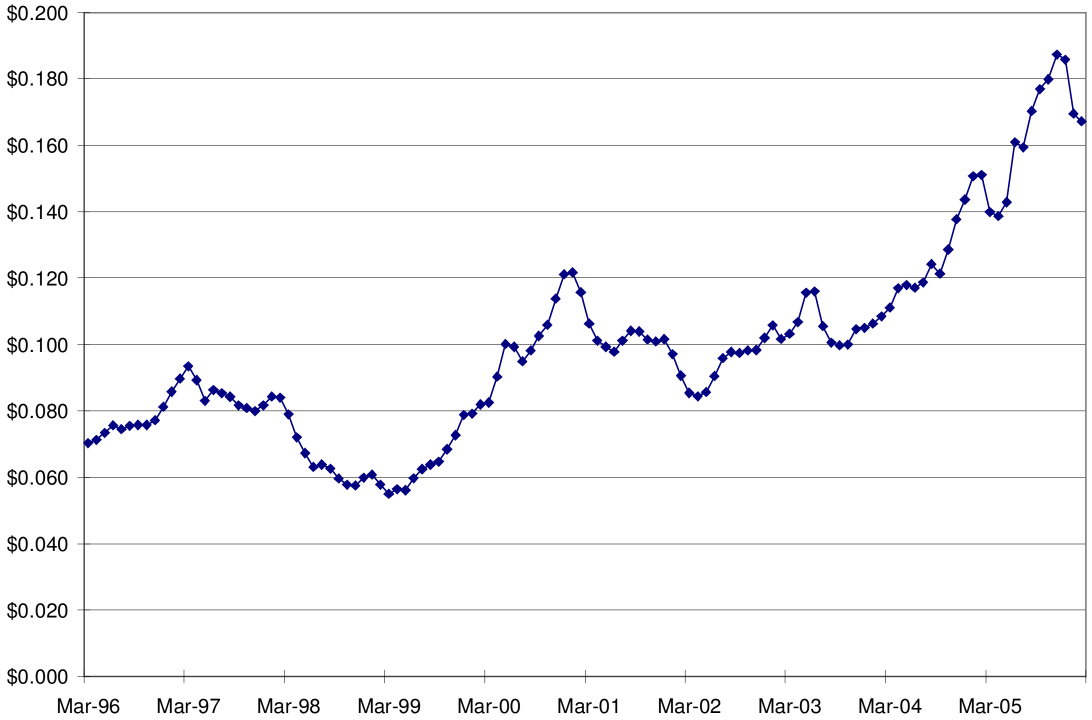
Category	Structure	Tariff (USD)
Residential Power	Minimum Charge All Usage	USD 4.00 USD (0.10 + Fuel Cost) per kWh
Small general Power	Minimum Charge All Usage	USD 4.00 USD (0.10 + Fuel Cost) per kWh
Large Power	Minimum Charge All Usage All Demand	USD 10.00 USD (0.10 + Fuel Cost) per kWh USD 9.00 per kW
Industrial Power	Minimum Charge 0 to 100,000 kWh Over 100,000 kWh All Demand	USD 25.00 USD (0.08 + Fuel Cost) per kWh USD (0.06 + Fuel Cost) per kWh USD 9.00 per kW

The key features of the current tariff structure are:

- All tariff groups pay a variable tariff made up of a base tariff plus a surcharge or pass-through of fuel costs;
- Residential and small general consumers pay on a variable tariff with no fixed component and a relatively lower minimum charge;
- Large and industrial power users have a multipart tariff structure comprising a fixed capacity charge and a variable tariff per unit of consumption;
- Industrial power users pay a progressively lower variable charge.

PUC faces fuel costs that are uncertain and outside its control. Therefore it has decided to pass these through to its customers by way of a fuel surcharge. The current fuel surcharge is a full pass-through of the cost of diesel and is calculated by PUC each month. From April 1996 to March 2006, the surcharge varied between a low of 5.5¢ and a high 18.73¢/kWh. The Consultant understands that the price of diesel has recently risen to around USD 3.30. This would suggest a surcharge, based on the current calculation approach, of around 27.1¢/kWh.

Figure 7 - PUC Fuel Surcharge (¢/kWh)



The surcharge is calculated as the product of a base diesel price and a plant efficiency factor. The diesel price is the weighted average cost of the imported diesel as landed in Kolonia.

The surcharge itself is calculated by applying a plant factor to the base diesel price. Since 1996, a constant plant efficiency factor of 0.082 gallons per kWh or 12.195 kWh per gallon has been used to calculate the pass through. However, the current diesel plant is estimated to generate with a fuel efficiency of around 14.5 kWh per gallon. Therefore, based on a diesel price of USD 3.30, the fuel surcharge would be calculated as 27.1¢/kWh. However, a fuel efficiency factor of 14.5 kWh per gallon would imply a surcharge of 22.8¢, suggesting that the current approach may overstate the surcharge by around 4.3¢/kWh.

As noted in section 8.1, the principles of marginal cost pricing suggest that the prices should reflect the opportunity costs of the various groups of consumers. Therefore, if one group of customers has a lower or higher opportunity cost of electricity than others, then a tariff design would reflect this. Overall, we would expect that larger industrial power users would have alternatives to purchasing power from PUC, and in fact this is the case. Large customers such as FSM Telecom and the State Hospital both have their own generators. Therefore their opportunity cost of power is the cost of generation using those generators. Small customers also have the option of using generators or alternative energy sources. However, as discussed in Section 7, the opportunity cost of doing this is significantly higher for small customers than for large industrial power users. Therefore, the current tariff structure is consistent with the fact that larger industrial power users have a lower opportunity cost of generation, even if this arrangement might be seen as inequitable.

4.6.2 Water and Wastewater

The current water tariff is USD 1.80 per 1000 gallons, with a minimum charge USD 5.00. There is no separate tariff for wastewater, and the water tariff is set to over-recover water costs to defray wastewater costs. This introduces an inequity in the over-recovery of costs from water users without a wastewater connection.

PUC charges connection fees of USD 15 and USD 30 for water and wastewater respectively. As actual hook-up costs are in the range of USD 105 to USD 630 for water (depending on whether the connection crosses a road) and USD 105 to USD 1,075 for wastewater, the connection fees set are heavily subsidised and provide an incentive for property owners to connect.

It is intended that the expansion of the water supply to circle the main island will reduce operating costs per connection, improving the sustainability of PUC and the affordability of the services provided.

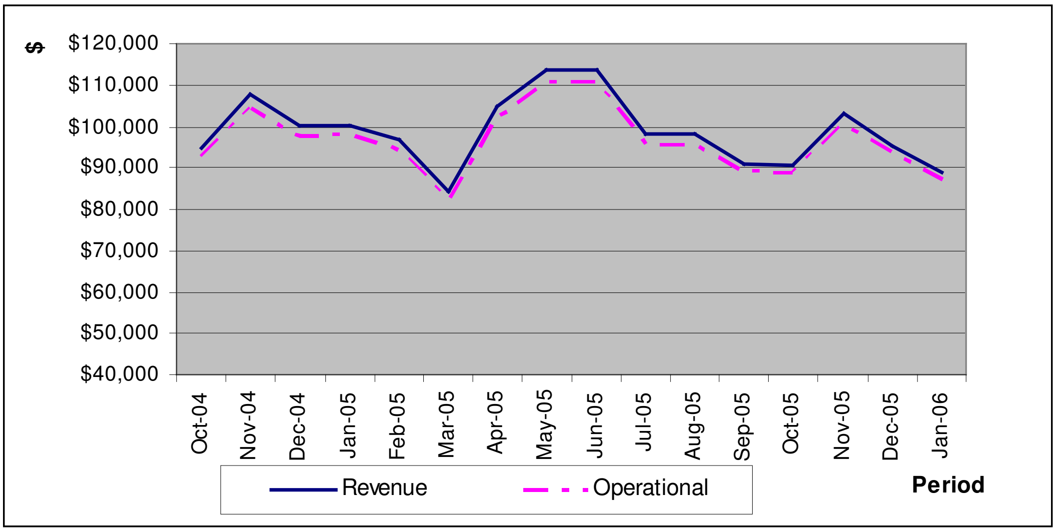
Components of the tariff are:

- Salaries of 29 staff directly involved in water and wastewater activity;
- Capitalisation - which includes cost of materials for new hook ups, system extensions, assets renewals and vehicles;
- Operation - consumables, annual required materials for repairs, and other costs of doing business; and,
- Power.

The construction of the tariff incorporates an element of cross-subsidisation from the power sector in that all corporate management and administration overheads are assigned to the power budget.

PUC figures indicate that cash collection averages 102% over operational costs (including capital expenditure but excluding depreciation) as shown in the figure below.

Figure 8 - Cash collection versus operating expenditure



The construction of water and wastewater capital pipe extension works is undertaken by the PUC workforce. The construction of intakes, wells, pumping stations, treatment plants, storage tanks and access roads is contracted out to experienced contractors. There is scope to make greater use of the private sector to increase efficiencies.

5 Required Revenue Analysis

5.1 Methodology

In a market with workable and efficient competition, the price of products or services are largely the result of the interaction of supply and demand. However, where competition is limited or there is only one supplier of the good or service, prices are usually set through regulation in a way that attempts to mimic how prices are determined in a more competitive environment. This usually means that the entity supplying the good or service is permitted to charge enough to cover its operating costs as well as recovering depreciation and a fair return on the capital employed in providing the service.

To provide efficient pricing signals about the cost of providing the services, prices should bear some relation to the marginal cost of supply. Marginal cost refers to relationship between total costs and output and how costs change as output increases or decreases. As some costs are fixed in the short run while others are completely variable, marginal cost can be considered from a short run or long run perspective. In very general terms:

- Short run marginal cost (SRMC) is the cost of meeting an additional unit of demand holding capacity constant; and,
- Long run marginal cost (LRMC) is the cost of meeting an additional unit of demand assuming that all factors of production can be varied.

This analysis focuses on the assessment of long run marginal cost as the TOR requires.

5.1.1 Long Run Marginal Cost Methodology

Long Run Marginal Cost (LRMC) can be thought of as the levelized cost of meeting an increase in demand over an extended period of time. In effect it is the net present value (NPV) of the change in generation or production load, divided by the NPV of the increase in load. Therefore LRMC estimates the marginal cost of meeting additional demand when all of the factors of production, including capital, are variable.

In effect, LRMC is the sum of the long run marginal operating cost (LRMOC) and the long run marginal capital cost (LRMCC).

The LRMOC is estimated as the NPV of the forecast operating cost over the forecast time horizon, divided by the present value of the forecast output. Therefore, the LRMOC of electricity generation or water supply can be expressed in terms of ¢/kWh or USD/1000 gallons respectively.

The LRMCC is estimated in a similar fashion however, in this case, the LRMCC is the present value of the optimal capital expenditure, all divided by the present value of the output over the time period. The LRMCC treats the existing plant and equipment as a sunk cost.

The capital expenditure used in the forecasts should be optimized insofar as the capital program should provide the least cost solution to the supply demand imbalance.

Therefore, the steps in determining the LRMCC are:

- Forecast the demand over a suitable time horizon – between ten and 20 years;
- Identify the possible capital projects that could be implemented to meet the demand;
- Select the least cost combination of projects; and
- Estimate the LRMCC as:

$$\mathrm{LRMC} = \frac{\mathrm{NPV(Optimal\ \ Capex)}}{\mathrm{NPV(Forecast\ Demand)}}$$

The Consultant has been provided with PUC's projected capital expenditure for electricity, water and wastewater, but it is not able to determine whether this is the optimal capital expenditure programme for the utility.

Therefore the LRMCC of electricity or water supply expresses the capital "used up" over the period of the analysis on a ¢/kWh or USD/100 gallons basis as appropriate.

- The required inputs for the analysis of LRMC comprise:
- Forecasts of demand over the nominated time horizon;
- Capital expenditure profiles and forecasts for projects that have the capacity to provide the required supply;
- Operating expenditure forecasts associated with each capital expenditure scenario; and,
- An estimate of required return on investment.

Based on these inputs it is possible to estimate the LRMCC and LRMOC for a range of possible options for the supply of either electricity or water or wastewater services.

5.1.2 Marginal Cost and Required Revenue

The two broad approaches that can be taken when reviewing tariffs are an embedded cost (sometimes called an average historical cost) tariff analysis or a marginal cost study. The terms of reference for this study required a marginal cost approach be used.

An average historical cost approach takes the revenue requirement for a given year and allocated it between customers based on a number of identified cost drivers. However a marginal cost approach attempts to identify the incremental costs associated with a marginal increase in throughput or load. In contrast to the embedded approach, the marginal cost approach is a forward-looking but largely hypothetical exercise.

5.1.3 Reconciling marginal cost and Required Revenue

One of the key issues with a marginal cost exercise is that the total revenue from tariffs based on marginal cost does not normally equal the revenue required by the utility. In general, required revenue is the sum of the forecast operating expenditure plus depreciation and a fair return on capital of the assets associated with providing the services. When estimating required revenue, the values of the assets currently employed are not regarded as a sunk cost but are recognized as having a positive opportunity cost.

Therefore to bridge the gap between marginal cost and required revenue some form of adjustment to the marginal cost based tariffs is needed so that the tariff structure can be financially sustainable and produce total revenues equal to the required revenues.

The overall objective of any form of adjustment is to preserve as much of the LRMC type price signals as possible while permitting the PUC to be financially sustainable. The LMRC type tariffs can be adjusted in a number of ways, including:

- The inclusion of fixed charges as part of the tariff;
- Scaling of the variable component of the charge, or;
- A fixed increase in tariffs.

The approach taken in this study has been to been, in effect, to scale the tariffs to meet the required revenue objective. The Consultant has used a 20 year discounted cash flow model to estimate the required revenue for each part of PUC's business including water, wastewater and power generation and supply.

The steps in estimating the required revenue for each part of the PUC business are as follows:

- Forecast demand over the nominated time horizon;
- Estimate the value of the existing assets that are required to provide the service;
- Forecast the capital expenditure profile associated with the least cost generation or supply options;
- Forecast operating expenditure;
- Estimate the level of tariff in each year of the forecast that results in a zero NPV when the cash flows are when discounted at the required rate of return.

Under this approach PUC will earn its cost of capital, on average, over the twenty year period. The tariffs estimated in the approach are higher than those estimated in the pure marginal cost approach but are scaled uniformly.

5.1.4 Rate of return assumptions

The required rate of return reflects the opportunity cost of capital invested in a project. In the case of a specific project, the required rate of return should reflect the relative riskiness of the investment and the cost of financing. The weighted average cost of capital (WACC) is now the most commonly used and recommended approach for determining the appropriate cost of capital for firms and hurdle rates, or acceptable rates of return, for projects.

The key concept underpinning WACC is that if an investment generates enough return to pay the interest on the debt used to finance it, and also generates a satisfactory expected return on equity, then the project is acceptable.

A firm's cost of capital is not a cash cost but rather the opportunity cost of the capital that is tied up in the business or the asset that is being bought. The cost of capital is, in effect, a market based measure of the notional rate of return that could be earned on a portfolio of shares and debt instruments with the same risk as the investment under consideration.

The cost of capital reflects the trade-off between risk and return undertaken by the providers of both equity and debt capital. Put simply, the greater the risk, the greater the required return of both shareholders and lenders.

WACC components

By definition, the capital employed in a project is provided from either

- Debt, from banks or other lenders, or
- Equity from shareholders or new capital introduced by grants.

The WACC is, in effect, a blended composite of the costs of equity and the debt capital. Therefore it is calculated as:

$$\boxed{WACC = Re \times E + Rd \times D}$$

where:

Re = the required post tax return on equity,

Rd = the cost of debt,

E = the proportion of equity in the target or long-term capital structure,

D = the proportion of debt in the target or long-term capital structure.

The cost of equity

For commercial entities the capital asset pricing model (CAPM) is the model most commonly used for deriving risk-adjusted rates of return on equity. The CAPM expresses the rate of return on equity as: (a) the rate of return on a risk free investment, plus, (b) a risk premium. The risk premium is scaled up or down depending upon the riskiness of the project.

In the case of PUC, the Consultant has been advised by the shareholder's representative that the appropriate rate of return on equity is zero.

The cost of debt

The after tax required return on debt is the rate on fixed rate debt, such as the swap rate, plus the appropriate margin. In general, for the purposes of calculating WACC, the maturity of the debt should match the time horizon of the project or investment of the assets.

Capital structure

More debt, all other things being equal, means a higher required return on equity. Debt introduces interest into the analysis, and interest on debt is another fixed cost. In general, firms with higher levels of fixed costs have higher risk, once again, all other things being equal. Therefore, firms with more debt have higher fixed costs, and more risk, from an equity investor's point of view.

However, one of the key principles of corporate finance is that "capital structure does not matter" in so far as the value of operating assets is concerned. The intuition behind this is that as firm takes on more debt, any benefits associated with the lower cost of capital are offset by the increase in the required return on equity.

Therefore, we should expect the WACC, which is the return on all of the capital employed, to be the same, irrespective of the level of leverage.

Key Parameters

The values of the key parameters are summarized below:

Table 4 - Key parameters for WACC Calculation

Parameter		
Required Return on Equity	Re	0%
Cost of debt	Rd	3%
Debt to Debt plus Equity	D	80%
Equity to Debt plus Equity	E	20%

WACC Estimate

The cost of debt is a weighted estimate based on the expected mix of funding.

Based on the inputs set out above we have used a required rate of return estimate of around 2.4% in estimating PUC's required revenue for electricity water and wastewater. As previously noted, a commercial estimate of 6.5% has been used in estimating the LRMC of the various generation options.

5.2 Electricity

5.2.1 Operational review of current system

Power generation on the island is provided mainly by the Nanpohnmal diesel power station with installed capacity of 13.4 MW and supplemented by the run-of-river Nanpil mini hydro power plant with installed capacity of 2.0 MW. Summary details of the PUC generating plant are given in Table 6.

Nanpil hydro power plant has been out of service since August 2001, due to flooding of the powerhouse, damage to the underground penstock approximately 100 meters upstream from the powerhouse and also damage to the intake and the automatic intake screen rake. The PUC engaged Parsons of the USA for the rehabilitation and financing of the scheme. Rehabilitation costs are in the order of USD 1.5 million, approximately 50% of which is provided in the form of grants. At current diesel fuel prices the outage of the Nanpil hydro power plant adds USD 500,000 to the annual operating cost of the PUC, and the payback period for the rehabilitation works is therefore just under three years.

The Nanpil rehabilitation works will include a new level sensor at the intake. Replacement controls will have provision for local operator adjustment of the minimum load of each turbine and the level control start and stop set points. This will increase the utilisation of low river flows, since the small turbine can operate satisfactorily at loads as low as 200 kW. The plant is scheduled for recommissioning in mid to late 2006.

Table 5 - Details of PUC Generating Plan

Unit	Make	Year Installed	Installed Capacity (kW)	Firm Capacity (kW)
Nanpohnmal Diesel Power Station				
No 4	Caterpillar	1989	1,135	900
No 5	Caterpillar	1989	1,135	900
No 6	Caterpillar	1989	1,135	900
No 7	Daihatsu	1992	2,500	2,200
No 8	Daihatsu	1992	2,500	2,200
No 9	Daihatsu	1994	2,500	2,400
No 10	Daihatsu	1994	2,500	2,400
Nanpil Hydro Power Plant				
No 1	Boving	1987	725	650
No 2	Boving	1987	1,333	1,150

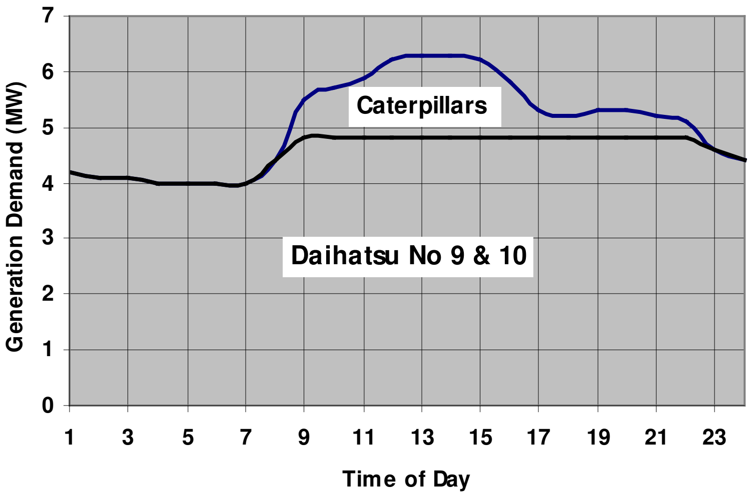
Current maximum generation demand is around 6.5 MW. However, with 11.9 MW available for firm thermal generating capacity plus on average 0.5 MW firm hydro capacity, the PUC is more than able to satisfy the island's electrical load requirements. While no new generating capacity is therefore required in the foreseeable future to meet the projected increased demand (Refer Section 6.2.2), new diesel plant could be installed to take advantage of better plant efficiencies or new mini hydro plant could be constructed (albeit at some considerable expense) to displace diesel generation. Decision criteria regarding the least cost generation option for PUC is contained in Section 9.

The two existing power stations supply a 13.8 kV 3 phase, 60 Hz, bare wire overhead distribution system, comprising four main feeders originating from Nanpohnmal power station. One feeder supplies Kolonia township, while a western and eastern feeder loop around the island and a fourth runs to Dekehtik, the airport area. The total length of the distribution system is approximately 120 km.

The overhead distribution system is a three phase, 336 mm2, four wire type with the fourth wire serving as both the high voltage and low voltage neutral. This neutral wire is earthed at regular intervals along the distribution line – typically at every second pole. Customers are supplied either at 120 V AC single phase or 208 V AC three phase depending on the load requirements of each connected customer, via insulated service drop wires from distribution transformers. While this is generally the case, some customers are connected to distribution transformers via low voltage underground cables.

The annual system load factor is around 70% and the typical system daily load curve in the figure below shows that the peak period occurs late morning to mid afternoon.

Figure 9 - Typical System Daily Load Curve in 2006



Base load generation demand on Pohnpei is met by the two newest Daihatsu diesels, because of their better fuel efficiency over the other diesel units. One or two of the older Caterpillar units are operated only for a few hours each day to meet the peak demand. After recommissioning of the Nanpil hydro power plant, some of the base load will again be provided by the hydro units and this is expected to result in annual fuel savings of USD 500,000 to the PUC.

Fuel efficiency of the existing generating units averages 14.5 kWh/Gal, which is equivalent to 40% plant efficiency and very satisfactory for diesel plant of this size and age.

Auxiliary power demand of the diesel units has averaged around 4.65% and is higher than the industry norm of 3-3.5% for similar generating units. . Technical losses in the distribution system average around 10.5% and are acceptable, especially since they are understood to include about 2.5% as power supplied for street lighting.

5.2.2 Assessment of future demand growth and asset/capacity requirements

The number of PUC's customers has been growing steadily since 1992, but has been decreasing slightly since a peak in 2003. Power generation and electricity sales reached a peak in the mid nineties, but then dropped back somewhat with growth rates virtually unchanged since 1998 and because of Pohnpei's economic conditions, tariff increases and the introduction of Cashpower meters. A summary of peak demand, gross generation, power sales and customer numbers since 1992 is provided in the table below.

Table 6 - Historic Electricity Generation and Sales

Year	Generation (GWh)	Sales (GWh)	Peak Demand (MW)	No of Customers
1992	29.7	23.0	6.4	2,243
1993	33.9	28.6	6.0	3,183
1994	38.3	32.3	6.4	3,686
1995	44.5	37.7	6.4	4,098
1996	44.9	38.7	7.3	4,535
1997	41.1	35.1	6.8	4,806
1998	39.8	34.2	6.9	5,157

Year	Generation (GWh)	Sales (GWh)	Peak Demand (MW)	No of Customers
1999	40.6	35.8	6.9	5,505
2000	40.1	34.6	6.4	5,590
2001	39.9	34.4	6.7	(no data)
2002	39.3	33.6	7.1	6,181
2003	39.8	34.4	6.6	6,410
2004	40.5	34.1	6.5	6,382
2005	39.4	29.4	6.5	6,143

For the purpose of the Study, a demand forecast until the year 2016 has been formulated as input to the generation expansion planning exercise that the Consultant has carried out. Generation and peak demand on Pohnpei is forecast to grow only very slowly at around 1 – 1.5% per annum until 2009 and then forecast to increase gradually to 3.5% per annum by 2016. This would result in the peak demand increasing from 6.5 MW to 8.2 MW in 2016. On this basis and assuming the system load factor will remain at around 70%, the corresponding increase in generation demand would be from the current 39.4 GWh to 50 GWh in 2016.

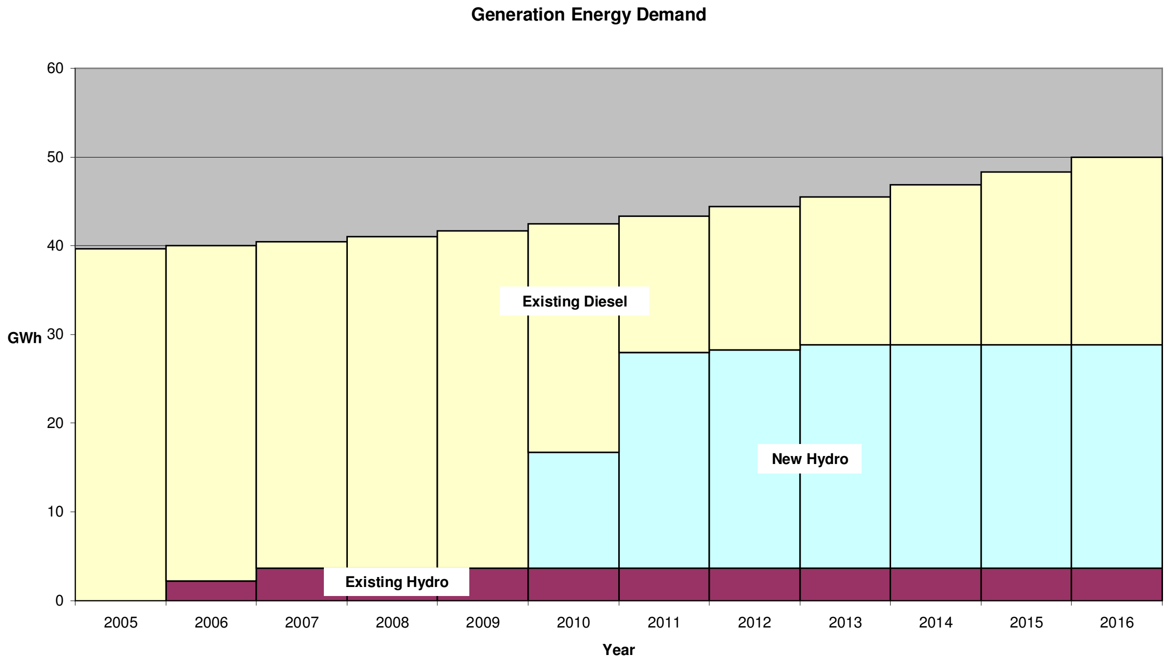
Based on the above demand forecast, it is concluded that the existing PUC generation plants can easily meet the electricity demand for Pohnpei over the next ten years and no new generation capacity is required. However, by 2016 the existing diesel units will have reached the end of their economic life and operation and maintenance costs will need to have increased considerably to ensure acceptable plant reliability and availability. To minimise the cost of electricity generation in future years, the long term least cost option for the PUC is to construct several mini hydro power plants as discussed in Section 9. The earliest that these new hydro power plants could be commissioned is around 2010 and the generation expansion scenario included in Attachment 1 is based on adding 6.34 MW of hydro generating capacity as detailed in the table below:

Table 7 - Proposed New Hydro Power Generating Capacity

Year	Station	Installed Capacity (kW)	Annual Generation (GWh)
2010	Lehnmesi 1	1,500	7.0
2010	Lehnmesi 2	1,300	6.1
2011	Mahnd 1	600	2.4
2011	Senipen/Riohk/Lehdau	940	3.7
2011	Nanpil 2	2,000	6.1
TOTAL		6,340	

Assuming that this new hydro generating capacity is installed in 2010 - 2011, the PUC generation mix would change drastically with up to 60% of diesel generation being displaced by hydro generation (Figure 9) leading to greatly reduced diesel fuel consumption (Refer Section 6.2.3).

Figure 10 - Forecast Generation Mix for PUC Power Plants



Full details of the generation scenario for the Pohnpei system are included in Attachment 1.

5.2.3 Expected operating costs

The audited September 2004 financial statements provide a breakdown of operating and maintenance costs for electricity generation and distribution as follows:

Table 8 - 2004 Operating and Maintenance Costs (Electricity Generation and Distribution)

Description	Generation USD	Distribution USD	Total USD	Generation US ¢/kWh	Distribution US ¢/kWh	Total US ¢/kWh	% of Total
Diesel Fuel	4,130,792		4,130,792	10.2		10.2	74.4
Salaries and Wages	399,894	390,516	790,410	0.99	0.96	1.95	14.2
Repairs and Maintenance	505,313	108,604	613,917	1.25	0.27	1.52	11.1
Other Production Costs	13,835		13,835	0.03		0.03	0.2
TOTAL	**5,049,834**	**499,120**	**5,548,954**	**12.47**	**1.23**	**13.70**	**100**

Operation and maintenance costs (excluding fuel) for generation activities were the equivalent of USD 2.26¢/kWh, which is rather high for a diesel based system in a developing country. It is noted that the fixed O&M component comprising salaries and wages is high for the relatively few generating units owned by the PUC. On the assumption that PUC will start to operate new hydro power plants from 2010 and consequently the running hours of diesel plant will reduce, less frequent diesel plant maintenance will be required. The resulting cost savings, however, would most likely be offset by the increased difficulty and cost of procuring spares for the aging diesel units. For Long Run Marginal Cost (LRMC) calculations (Refer Section 6.1), it has been assumed by the Consultant that the average generation O&M cost remains at around 2.3¢/kWh, although management would want to minimise this component insofar as reasonably possible.

Distribution costs in 2004 were the equivalent of 1.23¢/kWh and are also rather high, mainly due to a relatively large salary and wage bill. It is suspected that the main reason for the high distribution cost is the need for frequent tree trimming underneath the 120 km long distribution network, caused by the very rapid growth of vegetation in a wet tropical climate. For LRMC calculations it is therefore assumed that the average generation O&M cost remains at around 1.2¢/kWh.

However, it should be noted that while non fuel O&M costs are considered to be somewhat high, these costs account for around a quarter of total electricity production costs and fuel accounts for around three quarters of these costs. Management should look to contain non fuel O&M costs but most effort should be directed toward reducing diesel consumption if tariffs are to be minimised.

The generation expansion scenario outlined by the Consultant in Attachment 1 predicts that diesel fuel consumption will rise slightly until 2010 and then drop drastically with the introduction of new hydro power plants. Load growth in subsequent years is expected to see a gradual increase in diesel fuel consumption until 2016. For the purposes of the Study, the cost of diesel fuel is assumed to remain at around USD 2.30 per gallon in real terms and the projected annual diesel fuel cost to PUC for the period 2006 – 2016 is tabulated in the table below:

Table 9 - Projected PUC Annual Diesel Fuel Cost (in 2006 USD)

Year	Diesel Fuel Cost USD (million)
2006	6.00
2007	5.83
2008	5.93
2009	6.03
2010	4.09
2011	2.44
2012	2.57
2013	2.65
2014	2.87
2015	3.09
2016	3.36

5.2.4 Future Capital Requirements

On the assumption that the new hydro power plants are constructed as outlined in Section 6.2.2 capital requirements over the next four years will be significant. It is beyond the scope of this Study to prepare cost estimates for the designated projects but the cost estimates prepared in previous 1993 and 1994 studies have been updated by applying an overall escalation factor of approximately 30%.

In addition to the capital requirements for the suggested new power plants, there will also be a requirement to augment the distribution system. An allowance of USD 400,000 has been made for this in both 2009 and 2010.

Assuming a typical three year project implementation period, the projected capital requirements are tabulated in Table 11 and include estimates for engineering, contingencies and Interest During Construction (IDC), but exclude taxes and financing charges.

Table 10 - Capital Requirements Generating Plant and Distribution System (in USD)

	2007 (USD million)	2008 (USD million)	2009 (USD million)	2010 (USD million)	2011 (USD million)	Total (USD million)
Lehnmesi 1	1.32	3.52	3.08	0.88		8.80
Lehnmesi 2	1.26	3.36	2.94	0.84		8.40
Mahnd 1	0.26	0.52	0.52	1.04	0.26	2.60
Senipen/Riohk/Lehdau	0.84	1.68	1.68	3.36	0.84	8.40
Nanpil 2	1.79	3.58	3.58	7.16	1.79	17.90
Distribution System			0.40	0.40		0.80
Total	5.47	12.66	12.20	13.68	2.89	46.90

The Consultant's suggestions regarding the financing options for this capital expenditure programme are contained in Section 10.

5.2.5 Current asset values

The September 2004 PUC Fixed Asset Register and Depreciation Schedule provides a breakdown of depreciable generation and distribution assets as follows:

Table 11 - PUC Fixed Asset Register and Depreciation Schedule (2004)

	Acquisition Cost (USD million)	Accumulated Depreciation (USD million)	Value at Sept 2004 (USD million)
Generation Plant	22.09	13.07	9.02
Distribution Plant	13.28	4.87	8.41
General Plant	1.85	1.67	0.18
Total	37.22	19.61	17.61

Based on the general condition, age and type of the assets observed by the Consultant, the PUC stated value of USD 17.61 million for all power system assets is considered realistic.

5.2.6 Estimated required revenue

As discussed in section 6.1, the required revenue for PUC's electricity business has been estimated using a discounted cash flow (DCF) approach. The required revenue for the PUC electricity business has been estimated for the ten years from 2007 to 2016 given assumptions regarding forecast operating expenses, capital expenditure, current asset values and demand growth.

The DCF analysis currently assumes that prices are reviewed five yearly and that the price path for tariffs results in close to a break even return on investment (ROI) over time. The resulting required revenue for all electricity generation is summarized in the following table.

Table 12 - Required Revenue– All Generation

	Required Revenue (USD million)	GWh Sold
2007	10.4	34.6
2008	10.6	35.1
2009	10.7	35.7
2010	9.8	36.8
2011	9.0	37.9
2012	9.2	38.8
2013	9.5	39.8
2014	9.9	41.0
2015	10.2	42.2
2016	10.3	43.6

Note that the total required revenue reflects the forecast mix of hydro and diesel generation. The proportion of diesel generation falls as new hydro capacity comes on stream in 2010 and 2011. The hydro generation is assumed to provide PUC's base generation load. The introduction of more hydro capacity results in a drop in required revenue in those years as the total fuel cost falls as new hydro capacity is introduced. From 2011 required revenue then increases as the diesel generation increases to keep pace with the forecast demand.

Required revenue for diesel and hydro generation, and distribution are summarized in the following tables.

Table 13 - Required Revenue and Tariff Path - Diesel

	Required Revenue (USD million)	GWh Diesel
2007	8.9	31.4
2008	9.0	31.9
2009	9.1	32.4
2010	6.2	22.0
2011	3.7	13.1
2012	3.9	13.8
2013	4.0	14.3
2014	4.3	15.4
2015	4.7	16.6
2016	4.7	18.1

This analysis assumes new diesel plant will replace the existing Nampohnmal units which are expected to be at the end of their economic lives by that time. The analysis also assumes that the new plant has a higher fuel efficiency (15.5 kWh per gallon compared to the current 14.5 kWh per gallon) and that the diesel price is constant at USD 2.30 per gallon in nominal terms.

The required revenue for the diesel generation plant falls in 2016 but increases steadily, reflecting the fact that diesel generation satisfies any future increase in demand in excess of the base hydro capacity.

Hydro required revenue is relatively constant until 2010 and 2011 when the first and second tranche of new generation come on line.

Table 14 - Required Revenue - Hydro

	Required Revenue (USD million)	GWh Hydro
2007	0.5	3.2
2008	0.5	3.2
2009	0.5	3.2
2010	2.5	14.8
2011	4.2	24.8
2012	4.2	25.0
2013	4.3	25.5
2014	4.3	25.5
2015	4.3	25.5
2016	4.3	25.5

The Consultant has estimated the required revenue for distribution separately. The increase in required revenue reflects the underlying growth in throughput.

Table 15 - Required Revenue - Distribution

	Required Revenue (USD million)	GWh Carried
2007	1.0	34.6
2008	1.0	35.1
2009	1.0	35.7
2010	1.1	36.8
2011	1.1	37.9
2012	1.1	38.8
2013	1.2	39.8
2014	1.2	41.0
2015	1.2	42.2
2016	1.3	43.6

5.3 Water

5.3.1 Operational review of current system

The PUC currently provides water services 24 hours per day to approximately 3,428 households in Kolonia, Nett, Sokehs, the Government area in Palikir and the rural area to the east of Kolonia. Connections to commercial, government, state and PUC number 395.

The water supply has recently been extended from Awak to Kinakapw to service an additional 5,000 people (14% of the total population) in rural areas of the U municipality east of Kolonia.

The ownership of the Palikir water supply serving the government offices has been transferred to PUC from the government. This system was extended in 2003 to double the number of consumers.

The source of water for the main central Kolonia water supply is from a dam on the Nanpil river. Raw water is transported to the Nanpohnmal water treatment plant built in the 1970s. Treated water is supplied to reservoirs to normalise network pressures and provide storage to equalise peak flows and allow service to be continued in periods on water shortage or water production outages. A second facility that treats bore water is located adjacent to the medical school.

The Nanpil River source has limited storage potential and a strategy of well development, introduced in 1984/85, has continued with all water supply extension projects. Water is distributed to consumers through a network of pipes of sizes varying between 4 and 12 inches.

Water quality monitoring shows that water supplied meets the WHO International Standard for Drinking Water. PUC consistently provides a 24 hour service, although there are complaints of low pressure at times from consumers residing in high areas.

There are water losses from the pipe distribution system in the order of 48% and there are works planned to reduce these losses to an economic level. These problems are predominantly associated with the poor condition of asbestos cement pipes, which will all be replaced over the next 10 to 15 years.

In the rural areas there are forty-one small community water supply systems and the water used is untreated. The provision of potable water supply has been a problem in many of these areas, with risks of cross contamination from livestock and severe shortages in times of drought (when PUC provides tankered supplies).

Customers have indicated a willingness to have a public treated water supply and have requested the Pohnpei Government and PUC to expand the PUC water system. However, this needs to be balanced against the economic rationale for doing so. To do otherwise could mean that projects are implemented without consideration of whether the resulting tariffs are sustainable.

System management, operation and maintenance are undertaken by PUC staff. The O&M budget for 2006 is shown in the table below. 64% of the water and wastewater budget is allocated to water supply activities. The budget excludes the CIP team, which is assigned to maintenance work when there are not capital projects, and corporate management and administration costs.

Table 16 - Operation and Maintenance Budget (2006)

Expenditure category	Water	Wastewater
Salaries and wages		
- Division of Water	164,313	87,587
- Engineering & survey	14,985	8,575
- Equipment & vehicle maintenance	10,035	10,035
- Overtime	4,805	2,695
Total- Salary & wages	**194,137**	**108,892**
Corporate o/heads	**-**	**-**
Employee benefits	43,565	24,435
Training, safety, office supply	14,799	8,301
Chemicals	50,000	0
Repair and maintenance- system	40,000	15,000
Repair and maintenance- vehicles	12,813	7,187
Repair and maintenance- trenches	12,813	7,187
Consumerables	10,000	4,500
Computers & records	1,345	755
Electricity	20,000	40,000
Miscellaneous	1,345	755
Total expenditure	**400,818** **64%**	**217,011** **36%**

A total of eighteen staff (or staff equivalents) are engaged in the water activity. These include four management personnel, eleven system operators, two engineering/ survey staff and one equipment/ vehicle maintenance employee.

5.3.2 Assessment of future demand growth and asset/capacity requirements

The PUC strategic plan has the goal of providing potable water to 100% of households and businesses on Pohnpei by 2020 to improve the health and welfare of all Pohnpeians.

There are currently 3,428 residential connections to the public water supply, including 390 connections resulting from the recently completed Awak to Kinakapw extension.

The number of potential new connections on the main island is estimated to be 1,851 excluding the currently serviced area. This assumes that:

- the current population is 37,000;
- There is an occupancy ratio of 6.5 people per household;
- 10% of residents are remote from the proposed water supply extensions and will never be serviced;
- There is a 100% uptake in the new serviced areas.

PUC has undertaken investigations and prepared plans to develop water supplies to achieve this goal, with the following broad projects programmed:

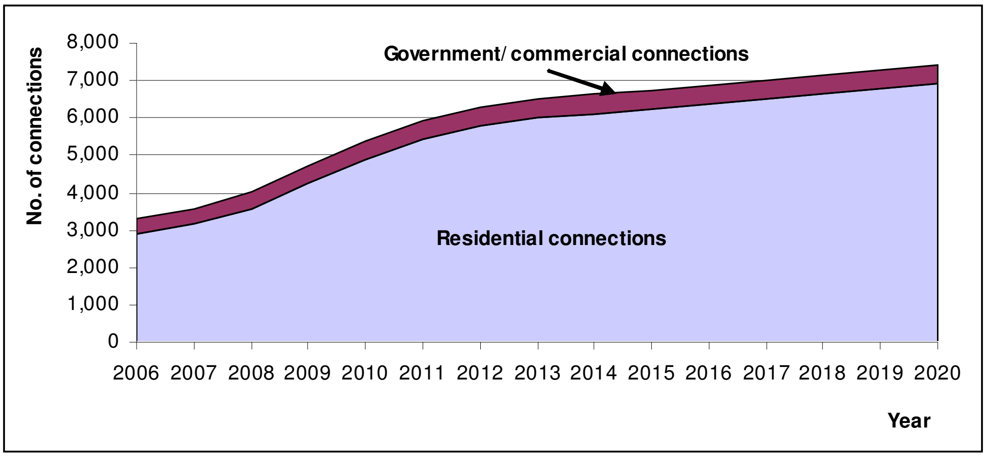
- A FSM well drilling project;
- Thirty wells to be constructed by the US Army Engineers; costs for mobilisation, well connections and hydrological survey are to be funded by PUC from Compact II allocations;
- Estimated new connections – 624 in the more densely populated areas near to the wells in the Madolenihmw and Kitti municipalities;
- Extension/upgrading of Palikir water system from Sokere-Diadi with 292 estimated new connections;
- New South West Water Supply System (Kitti) - Extension of supply to rural areas with the construction of a ring main around the island. This is estimated to create 468 new connections (assumed the rural extension to Kitti/ Madolenihmw is 50/50);
- New South East Water Supply System (Madolenihmw) with 468 estimated new connections.

Over the 15 year planning period to 2020, the total number of connections is estimated to increase 126% from 3,277 to 7,402 (refer to the table below). The increase for residential connections is expected to be 139% from 2,882 to 6,895 and 28% for government/commercial connections from 395 to 507.

Assumptions underlying these projects are:

- Population growth of 2% per annum;
- 100% residential uptake in areas with access to the public water supply;
- That commercial and government consumption will grow at a rate of 5% of new residential connections in the new areas (currently 10%).
- That the commercial and government usage will increase at 2% per annum

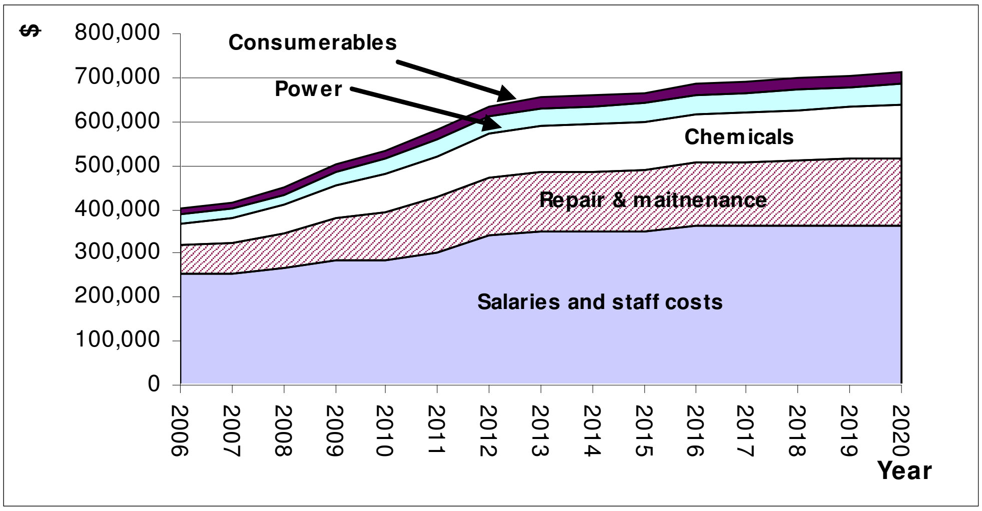
Figure 11 - Projected Number of Water Connections



5.3.3 Expected operating costs

Our assessment of operational and maintenance costs associated with the proposed capital works programme above is that costs would increase by 76% from the current level of USD 400,818 per annum to USD 705,000 per annum in the year 2020. In the same period the number of connections is calculated to increase 122%. Allowance has been made for some operational efficiencies to be made, with the ratio of connections per water staff declining.

Figure 12 - Projected Operations and Maintenance Costs



5.3.4 Future Capital Requirements

The capital works programme planned by PUC to implement its goal of extending water supply services to all the population on the main island's whole population is shown in the table below. The current programme includes an item for the rehabilitation of two reservoirs in 2008, but makes no allowance for any asset renewals after that date.

Table 17 - Water Supply Capital Investment Programme

Project description	Timing	Total (USD)
Extension/ upgrading of Palikir water system from Sokere-Diadi	2007- 2009	6,297,000
FSM well drilling	2006 - 2007	1,734,000
Rehabilitation of 2- 1.0M gal tank and 1-0.5M gal water tank	2008	767,000
New south west water supply system (Kitti)	2008 - 2012	13,798,000
New south east water supply system (Madolenihmw)	2008 - 2013	16,237,000
Total water capital improvement programme		37,099,000

5.3.5 Current asset values

Current September 2004 PUC fixed asset register and depreciation schedule provides a breakdown of depreciable wastewater assets as follows:

Table 18 - Water System Asset Book values as at September 2004

Asset class	Acquisition Cost (USD)	Accumulation depreciation (USD)	Value at Sept 2004 (USD)	Annual depreciation (USD)
Water production	5,383,152	2,006,946	3,376,206	189,768
Water distribution	8,100,421	2,130,407	5,970,014	226,044
General plant Note	53,212	53,212	0	0
Tools & equipment Note	57,778	57,778	0	0
	8,211,411	2,241,397	5,970,014	226,044

Note: Assumed to be 60% of total water and wastewater activity values

The headworks, raw water pipes, reservoirs and distribution network constructed prior to 1983, which represents a substantial proportion of the total network replacement value, has been written off in PUC's accounts. These assets still have a residual service life.

An indicative optimised depreciated replacement cost has been prepared based on an assessment of the current asset replacement costs and residual asset lives (condition based). The valuation includes the Palikir water system now under PUC ownership and the recently completed Awak to Kinakapw RUS funded extension. Assumptions have been made regarding asset quantities, sizes and construction date where PUC records are incomplete. The calculated values are shown in the table below.

Table 19 - Indicative Current Water System Value

Asset group	Replacement cost (USD)	Fair value (USD)	Annual depreciation (USD)
Headworks	187,000	123,888	2,338
Wells	1,237,500	1,072,702	24,475
Raw water pipes	1,868,944	1,296,288	29,244
Water treatment plants	1,513,600	1,161,403	25,171
Reservoirs	6,402,000	4,627,700	106,700
Distribution system (pipes, fittings)	12,758,743	7,524,097	240,241
Total	23,967,787	15,806,077	428,168

5.3.6 Estimated required revenue

The required revenue for PUC's water supply and reticulation business has been estimated using a discounted cash flow approach. The estimates for the ten years from 2007 to 2016 are made, given assumptions regarding forecast operating expenses, capital expenditure, current asset values and demand growth.

The DCF analysis currently assumes that prices are reviewed five yearly and that the price path for tariffs results in close to a break even return on investment (ROI) over time. The tariff paths and the resulting required revenue for water supply are summarized in the following table.

Table 20 - Required Revenue - Water

	Required Revenue (USD)	Throughput Gallons Million
2007	1.7	698.4
2008	1.8	776.5
2009	2.1	904.5
2010	2.4	1023.2
2011	2.7	1126.2
2012	2.8	1191.9
2013	2.9	1236.0
2014	3.0	1260.7
2015	3.0	1286.0
2016	3.1	1311.7

5.4 Wastewater

5.4.1 Operational review of current system

The PUC currently provides wastewater collection services 24 hours per day to approximately 1,020 households in Kolonia and a small part of the Nett municipal area, representing approximately 27% of the total population. Connections to commercial, government, state and PUC number 240. There are currently no charges for wastewater services.

The wastewater system consists of 12 miles of collection and force mains, seven pumping stations and the main sewage treatment plant located at Kepinle in central Kolonia. Treated sewage from the Kepinle treatment plant discharges into the inner harbour.

A second plant located in the industrial area on Dekehtik Island, built to treat effluent from the Tuna cannery (now inoperative) is maintained.

The Kepinle treatment plant is operating at capacity and has reached the end of its economic life. The location of this facility in the centre of the Kolonia urban area is suboptimal.

There is a high level of stormwater infiltration into the pipe reticulation which results in sewage surcharging in wet weather, and a pipe rehabilitation programme is planned to address this problem.

System management, operation and maintenance are undertaken by PUC staff. The O&M budget for 2006 is shown in the table in Section 6.3.1. Of the water and wastewater budget, 36% is allocated to wastewater supply activities. The budget excludes the CIP team, which is assigned to maintenance work when there are not capital projects, and corporate management and administration costs.

A total of eleven staff (or staff equivalents) are engaged in the wastewater activity. These include two management personnel, seven system operators, one engineering/survey staff and one equipment/ vehicle maintenance employee.

5.4.2 Assessment of future demand growth and asset/capacity requirements

The PUC strategic plan has the goal of providing a wastewater collection and disposal service to 100% of households and businesses on Pohnpei by 2020 to improve the health and welfare of Pohnpeians.

There are currently 1,020 residential connections to the public water supply. The number of potential new connections on the main island is estimated to be 4,110, excluding currently serviced areas. This assumes that:

- the current population is 37,000;
- an occupancy ratio of 6.5 people per household;
- 10% of residents are remote form proposed service extensions and will never be serviced;
- A 100% uptake in the new serviced areas.

This optimistic scenario is consistent with the strategic objectives of PUC and the planned capital improvement works programme.

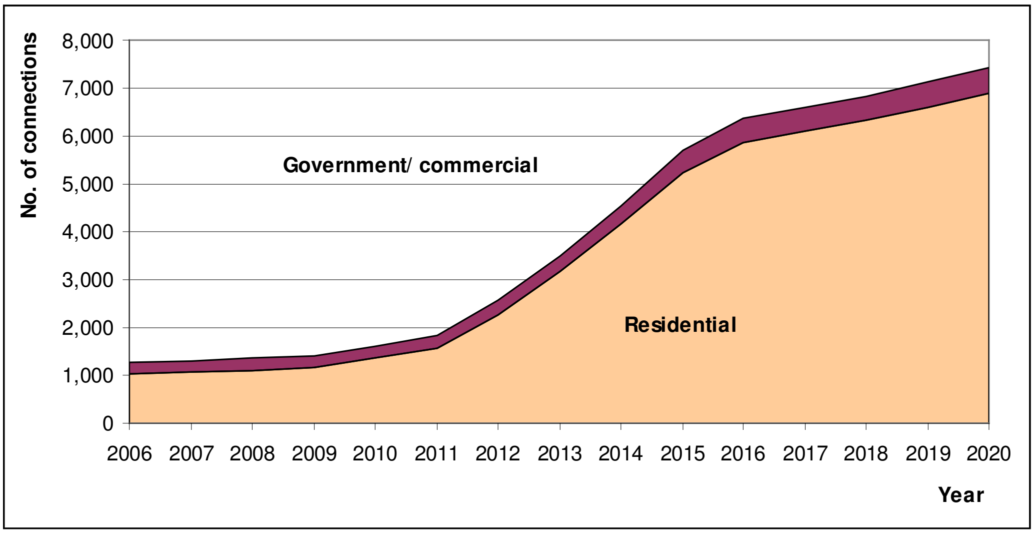
PUC has undertaken investigations and prepared plans to develop water supplies to achieve this goal, with the following broad projects programmed:

- Omnibus Development Programme;
- Construction of a new activated wastewater plant and wetlands on Dekehtik Island and outfall;
- A new pumping station to transfer sewage to the new treatment plant;
- Modifications and improvements to existing pumping stations;
- Rehabilitation works to the pipe reticulation system to reduce inflow and infiltration;
- Extension of wastewater services to Sokehs Islands (estimated new connections – 450 (Sokehs Islands);
- Extension of the Kolonia System;
- Extension of supply to the urban areas and rural areas to the East and West of Kolonia in the Nett and U municipalities (estimated new connections – 2,100);
- New South West Water Supply System (Kitti) - Extension of supply to rural areas with the construction of a ring main around the island (estimated new connections: 780 - assumed rural extension to Kitti/ Madolenihmw is 50/50);
- New South East Water Supply System (Madolenihmw) - Estimated new connections - 780

Over the 15 year planning period to 2020 the total number of connections is estimated to increase nearly five fold from 1,260 to 7,400 (refer to the figure below). The increase for residential connections is from 1,020 to 6,895. Assumptions made are that:

- Population growth will be 2% per annum;
- There will be 100% residential uptake in areas with access to the wastewater system;
- Commercial government will grow at a rate of 5% of new residential connections in the new areas;
- Commercial and government usage will increase at 2% per annum.

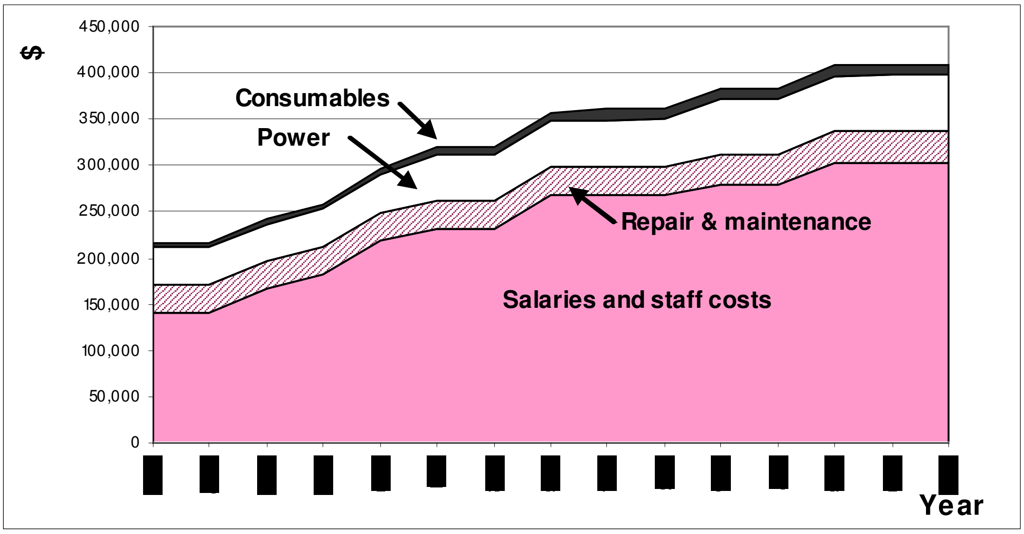
Figure 13 - Projected Number of Water Connections



5.4.3 Expected operating costs

Using the assumptions in Section 6.4.2, the Consultant's assessment of operational and maintenance costs associated with the proposed capital works programme above is that costs would increase by 114% from the current level of USD 217,000 per annum to USD 463,000 per annum in the year 2020. Allowance has been made for some operational efficiencies to be made, with the ratio of connections per water staff declining, and for the increased chemical and power associated with new treatment plants and pumping stations.

Figure 14 - Projected Operations and Maintenance Costs



5.4.4 Future Capital Requirements

The capital works programme planned by PUC to implement its goal of extending wastewater supply services to all the population on the main island is shown in the table below. The current programme makes no allowance for any asset renewals after the infiltration/ inflow investigations and remedial works programmed for 2007 and 2008.

Table 21 - Wastewater Capital Investment Programme

Project description	Timing	Total (USD)
Omnibus project		
Modifications to existing sewerage collection system	2007 - 2008	850,000
I/I investigation and control	2008	200,000
New causeway lift station	2009	102,000
Modifications to existing lift stations	2009 - 2010	75,000
Sokehs Island sewerage system	2008 - 2009	2,500,000
Wastewater treatment plant - activated sludge	2009	4,554,000
Wetlands disposal	2007 - 2010	617,500
Contingencies	2007 - 2010	757,721
Engineering design & supervision	2007 - 2010	657,567
Total -Omnibus Project		10,313,788
Extension of Kolonia system	2011 - 2020	16,660,000
South west disposal system- Kitti	2010 - 2020	16,308,000
South east disposal system- Madolenihmw	2007 - 2008	21,196,000
Total		64,477,788

The Omnibus project being funded by the ADB has been subject to its evaluation of economic and financial rates of return and found to be viable. However, the Consultant has not seen similar analysis for the USD 54.164 million that is projected to be spent on the further extension of the Kolonia system, the Southwest disposal system at Kitti or the Southeast disposal system at Madolenihmw. These projects should be subject to rigorous cost benefit and financial analysis to assess their economic and financial viability. As Section 6.4 shows, the wastewater tariff required to fund these projects is unlikely to be affordable by customers if all project costs are to be recovered commercially.

5.4.5 Current asset values

The September 2004 PUC fixed asset register and depreciation schedule provides a breakdown of depreciable wastewater assets as follows.

Table 22 - Wastewater System Asset Book Values as at September 2004

Asset class	Acquisition Cost (USD)	Accumulation depreciation (USD)	Value at Sept 2004 (USD)	Annual depreciation (USD)
Sewage collection & treatment	8,100,421	2,130,407	5,970,014	226,044
General plant [Note]	53,212	53,212	0	0
Tools & equipment [Note]	57,778	57,778	0	0
Total	8,211,411	2,241,397	5,970,014	226,044

Note: Assumed to be 40% of total water and wastewater activity values

The treatment plant, pipe collection network and pumping stations constructed prior to 1983, which represents a substantial proportion of the total network replacement value, has been written off. These assets still have a residual service life.

An indicative optimised depreciated replacement cost has been prepared based on an assessment of the current asset replacement costs and residual asset lives (condition based). The PUC asset register for the wastewater assets is unsuitable for valuation purposes, and broad assumptions have been made necessarily regarding asset quantities, sizes and construction dates.

The calculated values are shown in the table below.

Table 23 - Indicative Current Wastewater System Value

Asset group	Replacement cost (USD)	Fair value (USD)	Annual depreciation (USD)
Pipe network	3,733,969	2,083,448	62,233
Pumping stations	351,890	164,660	7,953
Kepinle treatment plant	1,270,500	154,000	38,500
Fisheries treatment plant	755,700	167,933	41,983
Total	6,112,059	2,570,041	150,669

The valuation is based on the known system parameters of 12 miles of collection and force main pipes, 7 pump stations and 2 treatment plants and inspections undertaken. The reason for the lower replacement cost as compared to the book value cannot be determined due to the lack of system information. Longer lives have been assigned than in the PUC valuation, reducing the annual depreciation cost.

5.4.6 Estimated required revenue

The required revenue estimates for water, the required revenue for PUC's wastewater treatment and reticulation business has been estimated using a discounted cash flow approach. The estimates for the ten years from 2007 to 2016 are made, given assumptions regarding forecast operating expenses, capital expenditure, current asset values and number of connections.

The DCF analysis currently assumes that prices are reviewed five yearly and that the price path for tariffs results in close to a break even return on investment (ROI) over time. The tariff paths and the resulting required revenue for wastewater are summarized in the following table.

Table 24 - Required Revenue - Wastewater

	Required Revenue (USD)	Equivalent Residential Connections
2007	1.31	3,887
2008	1.32	3,899
2009	1.32	3,911
2010	1.43	4,238
2011	1.54	4,565
2012	1.94	5,733
2013	2.41	7,145
2014	2.92	8,642
2015	3.43	10,139
2016	3.66	10,835

5.5 Street Lighting

5.5.1 Operational review of current system

The PUC provides street lighting to around 828 streetlights and billing data suggests there are at least 185 metered street lights that are billed. No separate demand data is available and the PUC includes this with the distribution system losses. From available billing data, it is estimated that current street lighting demand on Pohnpei is around 1 Gwh annually. In tropical zones, street lights are energised on average 12 hours daily.

A streetlight survey made by PUC in late 2004 found that 187 billed streetlights yielded USD 5,662.78 per month and this amounted to revenue of USD 36.53 per streetlight per month. On this basis, there are some 673 streetlights that go unbilled and at USD 36.53 per streetlight month, this forgone income equals USD 24,584.69 per month. Annually, this lost revenue amounts to around USD 295,000.

5.5.2 Assessment of future demand growth and asset/capacity requirements

Demand for street lighting is expected to grow at a low level with increased demand from new street lighting projects being offset to some degree by replacing incandescent light bulbs with energy efficient fluorescent light bulbs or sodium/mercury vapour lights.

5.5.3 Expected operating costs and Required Revenue

The streetlight survey referred to in Section 6.5.1 above suggests lost revenues of USD 295,000 per annum and that total revenues ought to be USD 363,000 per annum.

However, assuming 828 x 250W lights are energised for 12 hours a day, every day of the year, then 500 MWh would be consumed. This consumption is consistent with the billing data.

Operating costs for street lighting consist of the marginal cost of electricity production, which are essentially the cost of diesel fuel, plus the cost of replacing expired light bulbs. At current diesel fuel prices the energy cost is around 23¢/kWh and for an annual demand of 1 GWh this amounts to USD 221,000. The annual cost of replacing light bulbs is estimated at USD 27,000, which means that the total annual cost to the PUC of providing street lighting on Pohnpei is around USD 248,000.

The Pohnpei State Government might recompense PUC for an amount set around this level for the provision of street lighting unless it is agreed that this should be levied across PUC's customers.

5.5.4 Current asset values

Street lighting is not separately identified in the PUC Fixed Asset Register and Depreciation Schedule and insufficient data is available to estimate the current asset value. However, as most streetlights are installed by customers and consist of "barnlights" attached to various fittings, the value of existing streetlights is negligible. These lights will ultimately need to be replaced with more permanent arrangements.

6 Customer Opportunity Cost for Electricity

6.1 Electricity generation options

6.1.1 Residential customers

Residential customers on Pohnpei have very limited options to generate their own electricity. Wind power is not feasible due to the low average wind speeds on Pohnpei. Solar power using photovoltaic cells and storage batteries is technically feasible, but the efficiency of such systems is reduced somewhat by the relatively high incidence of cloud cover on the island. While running costs for photovoltaic solar systems are negligible, the relatively high capital cost (USD 10,000 - 15,000 per kW) would be a major barrier for most households with minimal savings and little borrowing capacity.

The most likely option for residential customers is to purchase a small (0.5 - 1.5 kW) petrol driven generator to supply their daily needs. Those that did would most likely run their generator only in the evening to supply lighting and power for appliances such as lighting and a TV. As such, their quality of electricity supply would be inferior to using continuous PUC supplied electricity and these residential customers would also have to purchase special appliances, such as kerosene driven fridges or freezers.

All calculations below are based on costs as of the Reporting Date.

6.1.2 Small commercial customers

Electricity generation options for small commercial customers are very similar to those for residential customers and consist of installing a photovoltaic solar system or a petrol or diesel driven generator. Commercial organizations in rural areas and located near a stream may be able to supply electricity from a run of river micro hydro power scheme (5 - 10 kW), although suitable locations would be strictly limited.

Photovoltaic solar systems will only favour organizations with a relatively low energy requirement such as shops, offices and hotels and not energy intensive organizations such as larger shops, offices, welding and fabrication facilities. Commercial customers are likely to be in a better position than residential customers to finance generation plant, but few are likely to commit to the high purchase cost of a photovoltaic solar system with storage batteries.

Those commercial customers that do install a petrol or diesel generator will most likely run it during business hours only, unless their business activities require a 24 hour supply such as required by hotels or refrigeration processes.

6.1.3 Large customers

Large customers on Pohnpei, such as Telecom and the State Hospital already own standby diesel generating assets (200 - 400 kW) and most likely would use these assets rather than install a new photovoltaic solar system. Even if they did invest in a photovoltaic solar system, the high level of demand would require operating a diesel generator in parallel to minimise battery storage capacity for rainy and night time periods.

6.2 Estimated opportunity costs

6.2.1 Residential customers

Residential customers currently pay a minimum charge of USD 4 per month for electricity. Usage is charged at 10¢/kWh plus the cost of fuel, which was 19¢/kWh at the time of the Consultant's first field visit. On this basis, the residential tariff of 29¢/kWh sets the threshold for determining whether alternative electricity generation options are more attractive than electricity budget from PUC.

For residential customers the opportunity cost of electricity generation using either a photovoltaic solar system or a petrol driven generator has been calculated using the following parameters:

Table 25 - Opportunity Cost Parameters for Electricity Generation - Residential

	Photovoltaic System	Petrol Generator
Installed Capacity	1,000 W	1,500 W
Capital Cost	USD 11,000	USD 650
Annual Generation	1,825 kWh	1,825 kWh
Useful System Life	15 yrs	10 yrs
Fuel Consumption	NA	9 kWh/Gal
Fuel Cost	NA	USD 3.30 /Gal
O&M Cost	negligible	USD 25 /yr

A 1,000 W solar voltaic system with storage batteries would be able to supply an evening demand of 1,500 W for a few hours, equivalent to a 1,500 W petrol generator. No allowance has been made for providing standby capacity and the customer would be without power if their generating plant is out of action. Using a discount rate of 10% the levelised opportunity cost is as follows:

Table 26 - Levelised Opportunity Cost for Electricity Generation - Residential

	Photovoltaic System (¢/kWh)	Petrol Generator (¢/kWh)
Capital	76.6	1.9
Fuel	0.0	36.7
O&M	0.0	0.5
Total	76.6	38.1

Clearly the photovoltaic system would not be favoured under these conditions by residential customers and even petrol generators will not provide customers with a reduced power bill. Private fuel purchased at a Mobil garage which is the monopoly petrol supplier on Pohnpei, does not attract the discount that PUC achieves as a government fuel purchaser.

6.2.2 Small commercial customers

Small commercial customers fall under the Small General Power Service charge, which is equivalent to the Residential tariff of 29¢/kWh. For small commercial customers, the opportunity cost of electricity generation using either a photovoltaic solar system or a diesel driven generator has been calculated using the following parameters:

Table 27 - Opportunity Cost Parameters for Electricity Generation - Small Commercial

	Photovoltaic System	Diesel Generator
Installed Capacity	8 kW	10 kW
Capital Cost	USD 80,000	USD 6,000
Annual Generation	14,600 kWh	14,600 kWh
Useful System Life	20 yrs	15 yrs
Fuel Consumption	NA	10 kWh/Gal
Fuel Cost	NA	USD 3.30 /Gal
O&M Cost	negligible	USD 550 /yr

An 8 kW solar voltaic system with storage batteries would be able to supply a peak demand of 10 kW for short periods, equivalent to a 10 kW diesel generator. No allowance has been made for providing standby capacity and the customer would be without power if their generating plant is out of action. Using a discount rate of 10% the levelised opportunity cost is as follows:

Table 28 - Levelised Opportunity Cost for Electricity Generation - Small Commercial

	Photovoltaic System (¢/kWh)	Diesel Generator (¢/kWh)
Capital	62.6	1.8
Fuel	0.0	30.0
O&M	0.0	1.4
Total	62.6	33.2

As for residential customers, small commercial customers would find solar photovoltaic and diesel generation too expensive to justify not sourcing electricity from PUC.

6.2.3 Large customers

PUC has two tariff arrangements that affect large customers. Those on PUC's "Large Power Service" tariff pay 29¢/kWh (10¢ + fuel of 19¢) and pay a USD 9.00 monthly charge per kW of capacity provided. Larger customers on PUC's "Industrial Power Service" pay 27¢ per kWh (8¢ + fuel of 19¢) for monthly consumption of under 100,000 per kWh. If consumption exceeds 100,000 per kWh, then the tariff reduces by a further 2¢ to 25¢/kWh.

For large customers, the only practical option as an alternative to mains supply power is to operate medium size diesel generators. Assuming customers need to purchase new generating equipment the opportunity cost of electricity generation has been calculated using the following parameters:

Table 29 - Opportunity Cost Parameters for Electricity Generation - Large Customers

	Diesel Generator
Installed Capacity	2 x 250 kW
Capital Cost	USD 300,000
Annual Generation	1,300 MWh
Useful System Life	20 yrs
Fuel Consumption	12.5 kWh/Gal
Fuel Cost	USD 3.30 /Gal
O&M Cost	USD 14,000 /yr

Allowance has been made for providing standby plant of equal capacity to provide power when one diesel generator fails or is undergoing maintenance. Using a discount rate of 10% the levelised opportunity cost is as follows:

Table 30 - Levelised Opportunity Cost for Electricity Generation - Large Customers

	Diesel Generator (¢/kWh)
Capital	2.5
Fuel	27.2
O&M	1.1
Total	30.8

For customers that are able to purchase diesel fuel at the same price as the PUC (such as Telcomm FSM and the State Hospital) at USD 2.30/Gal, the opportunity cost reduces to 22.5¢/kWh.

PUC's tariff for large customers is 8¢/kWh plus fuel of 19¢/kWh, which is an aggregate tariff of USD 27¢/kWh. The opportunity cost above shows that non government large customers are best to retain PUC as their electricity service provider. However, large government consumers are well positioned to generate their own electricity.

6.3 Implications for PUC

From the analysis above, it can be seen that customers on the Residential Power service and Small General Power Service are unlikely to find alternative sources of electricity that are cheaper than the service delivered by PUC. These consumers can, however, manage their demand by using electricity more selectively and by installing energy efficient light bulbs.

From a public relations perspective and given the not for profit nature of PUC's business, PUC might well consider developing a programme to provide energy efficient light bulbs to its customers. It is understood that PUC has offered such bulbs to customers before with limited take-up, but such a programme might be more successful now given the substantial increases in electricity generating costs during the last two years.

There is a significant risk of government owned customers that are on the Large Power Service and Industrial Power Service tariffs generating their own electricity. This would be of concern to PUC because the loss of such customers would lead to the average cost of electricity rising for PUC's remaining customers.

Those customers are unlikely to have more cost effective alternatives for power generation themselves but, being residential and small business consumers, they have limited capacity to pay for energy. This in turn is likely to lead to increased arrears and has a political dimension too. It is an unfortunate irony that those with the greatest capacity to pay for electricity also have the most cost-effective generation alternatives.

PUC's three largest customers (being the State Hospital, the FSM National Government and Telecomm FSM) are all government owned. They account for some 25% of PUC's electricity sales and are therefore key customers. Both the State Hospital and FSM Telcomm stated during consultations that they are aware that they could generate electricity more cost-effectively themselves, but they feel a social obligation to remain grid connected. Nonetheless, if there are not regulatory requirements for the continued patronage of governmental consumers (which would be needed at state and national levels) then PUC needs to ensure that its tariffs are set at a competitive level.

7 Tariff Structures and Rate Determination

7.1 Tariff Structures

7.1.1 Introduction

PUC obtains its authority to set tariffs from its establishing Act, SL 2L-171-91 of 9 February 1991. The Act provides under its Section 2(4) that PUC is *"to publish and implement a structure of rates for services rendered by the Corporation. Such rates are to be determined by the Board of Directors after consultation with the Board of Residential Properties and Public Utilities (RPPU), and calculated to ensure that, to the extent practicable, adequate and equitable charges are imposed for services and that the fee structure promotes increased use of public electrical services; PROVIDED that nothing in this Subsection shall prevent the Corporation from using subsidies received from governmental, international or private sources to reduce the overall costs charged to users of electrical services."*

However, D.L. No. 4L-191-79 §1, 8/9/79 provides that the RPPU is to "constantly monitor the use of these facilities and services, and to propose rates for the use or consumption of the same by both the public and private sectors, the payment of which will be devoted to new, better maintained, and improved facilities and services."

Consequently, it is not clear whether (a) PUC may set tariffs provided it has consulted (and presumably agreed) with the RPPU regarding tariff structure and rates or (b) the RPPU itself is to propose rates for public utility services.

State legislation becomes less clear when the Commission on Energy rules are considered. These rules (34 PC 2-103) provide that the Commission *"thoroughly review and continuously monitor existing power generation facilities and distribution lines as well as current rate structures and make recommendations regarding the same"*.

The RPPU Board of Directors consists of seven members, five of whom are: Murphy Panuelo, Perdus Ehsa, Keropin David, Gaius Saick and Resio Wichep. The two other positions are occupied by the Administrator of the Office of Transportation and Infrastructure, and the Executive Director of the EDA. These latter appointees are also appointed to serve on the Energy Commission, alongside the Director of the Department of Resource Management and Development and a member appointed by the Speaker of the Legislature.

The Consultant met with the RPPU and the RPPU advised that tariff setting in practice would involve PUC proposing new rates to the State Legislature and the Governor, consulting with consumers and then agreeing the proposed tariffs with the RPPU. The position of the RPPU is that it prefers PUC to be able to operate on a commercial basis but with no more than reasonable profits. The RPPU also requires that PUC is an efficient operator and has a prudent capital expenditure programme.

It is not within the Study's scope of work to comment on the process of tariff setting on Pohnpei State and the Consultant does not seek to do so, other than to note that there should be an unambiguous process for tariff setting that is reflected uniformly across all legislation regarding PUC.

7.1.2 Issues in Tariff Design

General Principles Underlying Tariff Design

Tariff design deals with the link between the individual prices that PUC charges each class of customer and the manner in which these tariffs are structured. As PUC is generally considered to be responsible for proposing tariffs and there is no set regulator in place, it is important that the conditions for tariff setting are known so that outcomes acceptable to the government and PUC are achieved.

Usually it is fair to say that utilities have a profit maximisation objective, but in the case of PUC the State Government does not expect any return on its equity in the business so PUC effectively acts in a not for profit capacity. In essence, because the government does not assign an equity return on capital objective, it provides PUC and end consumers with an implicit subsidy in the tariff.

The State Government's interest in tariff design is in ensuring that welfare is maximized and that an affordable service is provided to customers, especially the poor. Both PUC and the State Government also have an aligned interest in ensuring that tariffs are set so that a stable political environment is maintained.

Optimal pricing decisions are based on marginal cost so that under perfectly competitive conditions the price that is charged is equal to the marginal cost of producing a single further unit of water, electricity or sewerage collection and treatment (as the case may be). This concept of marginal cost pricing is allied to the objective of maximizing welfare, so governments favour market conditions that are very competitive.

The creation of a competitive market on Pohnpei is not a realistic goal, however, because the diseconomies of scale that would occur are likely to far outweigh the benefits of competition. In the absence of competition, a degree of price control is needed and to make recommendations in this regard, consideration of the methods of price control and how they might be applied in the case of PUC's case is needed.

PUC has a dominant market position but it is State government owned and pricing is subject to RPPU's consent on a case by case basis. The 1994 tariff increase took some time to be finally approved and part of the reason for this might be because of the unclear process discussed above in the introduction and because RPPU is charged with the difficult task of reconciling the conflicting objectives set out in the Act. These require that PUC imposes "*adequate charges*" (to ensure that PUC is able to recover its reasonable costs of operation) that are also *equitable* (to consumers) and that the *fee structure promotes increased use of public electrical services* (which implies lowering the cost of services to increase demand).

Overall, price determination needs to strike a balance between excessively low prices that might be politically driven and yet protect consumers from excessively high prices and the loss of associated macro-economic gains to Pohnpei. Price determination also needs to ensure that PUC is delivering services efficiently. Price controls are usually managed by placing limits on the overall revenues that a utility can receive and these are discussed in the following section.

Approaches to Limiting Revenues

There are following three main approaches to price setting and these are (a) rate of return pricing; (b) price cap pricing and (c) benchmark pricing.

Rate of return pricing sets prices based on permitted costs, which include a return on the capital invested. When the utility seeks a tariff change a review is made of the reasonableness of its costs and its weighted average cost of capital might also be considered. This method matches costs and revenues well but does not offer much incentive for efficient operation or development of the system;

Price cap pricing is also sometimes called RPI-X regulation and was developed in the United Kingdom as a counter to rate of return pricing. Under this regime, utilities can change tariffs and tariff structures as long as they do not exceed revenues adjusted against an index that is made up of an inflation allowance and an efficiency factor. This arrangement disconnects costs and revenues and places further pressure on utilities to become more efficient. However, it is possible to place undue pressure on utilities if the "X" factor is misjudged. It also assumes that the base revenue that is to be indexed is calculated fairly.

Benchmarking pricing is an assessment of the reasonableness of tariffs by comparison to comparable utilities. It presumes that truly comparable utilities can be found, although there is an incentive if the target utility is able to be more efficient than its benchmark counterparts because it will realise additional profits. It is accepted, however, that it is difficult to rely on benchmarking because the conditions of other utilities often differ quite markedly. If adjustments need to be made to help align the benchmarking assignment, this can call the exercise into further question.

The Study employs a combination of the above methods (especially rate of return pricing and benchmarking) because it requires the Consultant to consider the reasonableness of PUC's costs, its cost of capital and to refer to comparable utilities.

7.1.3 Alternative Tariff Structures

The previous section deals with marginal cost as a basis for determining tariffs and also several means through which overall revenues to a utility can be limited. Marginal cost pricing at its simplest level results in a linear price for all users. However, there are several forms of non-linear pricing and these include: (a) multipart prices; (b) price discrimination; (c) optional tariffs (d) volume based pricing and (e) peak load pricing.

Multipart prices are where a utility charges different prices for different parts of the service, such as charging a monthly connection fee and then a fee for consumption. Multipart prices are very common and PUC employs this arrangement for electricity and water. In the case of electricity, PUC charges a minimum charge and, for large users it charges a price per kW or KVA. It then charges for the consumption of kWh based on further parts for non fuel operating costs and a fuel surcharge and this is an appropriate charging mechanism. For water, charges are based on a connection charge and then a usage charge per 1,000 gallons.

Price Discrimination involves different prices being charged to different customer classes even though the cost of providing the service to those customers is the same.

Price discrimination is also called Ramsay Pricing and the premise that underlies the practice is that pricing is based on the elasticity of demand displayed by each customer class. Customers whose demand is relatively inelastic are charged at rates above the marginal cost of providing the service, whereas customers whose demand is relatively elastic are charged tariffs that are closer to the marginal cost.

When Ramsay pricing is applied, the result is usually that those who can afford to pay more for the services (such as businesses) are charged more and other users (such as residential consumers) can be charged at lower rates. These lower rates can sometimes be lower than the marginal cost of providing the service, creating a cross subsidization from one customer group to another.

Price discrimination often appears to be unfair to customers and this can make the practice politically difficult. However, price discrimination can also be consistent with government policy of providing more affordable services to the poor. Therefore, while price discrimination can help deliver a fair balance to consumers if it is well structured, customers need to be informed through a consultative process as to why this arrangement is in the collective best interests of end users.

PUC does price discriminate for electricity sales, but not for water sales. Residential and small power users pay a lower minimum charge than large and industrial consumers. The minimum charge equals just fourteen units of power for residential and small customers, thirty-five units for large power users and either ninety-two or one hundred units for industrial power service customers (depending on their level of consumption).

While the minimum charge for residential and small customers is lower than larger customers, residential, small general power consumers and large power customers pay more per unit of electricity consumed than industrial power customers. This approach is consistent with Ramsay Pricing because, as Section 7 discusses, residential and small general power service customers have an opportunity cost that is higher than the rates charged by PUC. While residential consumers might reduce consumption to a degree, their elasticity of demand is relatively inelastic and so they are charged more than other users.

However, while higher pricing for residential and small customers is consistent with the philosophy underlying Ramsay pricing, it does not necessarily promote equitable treatment between customer classes and this question is discussed further in the next section.

Ramsay pricing principles do not support the lower prices that private sector large customers pay because their opportunity cost of electricity is around 30.8¢/kWh, which is higher than the 25¢/kWh to 29¢/kWh they currently pay.

For governmental customers, however, pricing could be reduced further because their opportunity cost of electricity of 22.5¢/kWh is lower than all other users since they also have access to the government rates for fuel. However, price reductions for this group would satisfy the need to keep these customers connected to the grid, but it would be a decision that might be politically unacceptable because private sector consumers would feel that they are being unfairly discriminated against. Instead, government customers should be encouraged to stay connected to the grid, possibly through the implementation of appropriate legislation. There is also value in discussing whether State Government and National Government customers should enjoy the same rates between themselves or whether the more financially strong of these two pay a relatively higher rate.

The issues discussed above describe why it is difficult to resolve the issue of whether price discrimination should be applied to the tariff regime or not. PUC's price discrimination can be supported from an economic viewpoint, but Ramsay style discriminatory pricing (that leads to higher rates for large institutions in other markets) is not economically sustainable on Pohnpei because these organisations have cheaper power generation options. Consequently, PUC has discriminatory pricing that is rational from an economic perspective, but it may have lower political acceptability because those who pay the most for electricity can least afford those rates.

PUC's management have stated that they would prefer to see uniform pricing amongst all classes of customer. Given the unique situation on Pohnpei, until alternatives to diesel fired generation become available, it is possible that a case for non discriminatory pricing can be made.

Optional Tariffs are like multipart tariffs in that services are priced in a variety of ways. They differ in that customers choose from a "menu" of options that suit their consumption style best. Optional tariffs can work well if tariffs are set at levels above marginal cost, but require considerable thought if a utility is seeking to simply recover its costs, as in the case of PUC. Optional tariffs would be a move away from PUC management's ideal of having a single tariff across all customer classes and are likely to be difficult to manage given PUC's existing resources.

Volume based pricing sees tariffs being based on the level of consumption, with higher levels of consumption being charged at higher rates than lower levels of consumption. This approach is helpful as a means of demand side management, provided consumers are able to judge when they are being charged the higher rate.

Regarding PUC's electricity supply, it does not have capacity constraints and there is a fuel cost pass-through in the tariff, so there is no particular incentive for PUC to introduce volume based pricing for electricity other than for general demand side management.

For water and wastewater, PUC faces substantial capital expenditure for development of its water reticulation system around the island and in the development of its sewerage network. Charging that created an incentive to reduce demand would be an attractive option if this displaced the need for some of this capital expenditure.

Peak load pricing is useful when a network has been built to meet demand at peak times of the day. PUC's generation capacity is approximately twice its peak load, so it would be inappropriate to price on this basis. As for water and wastewater, the metering requirements for peak load pricing would be unduly complex for the benefits gained and, furthermore, such a pricing arrangement would not be consistent with international practice.

7.1.4 Tariff Setting for the Poor

One area where governments and utilities have difficulty in reaching agreement is on how pricing for the poor is best achieved. Utilities see subsidized pricing for this group as a means of government implementation of a social policy that potentially comes at the expense of the utility.

Whatever the mechanism that is employed, pro-poor utility pricing involves a subsidy that is funded either internally by the utility or by external sources. If funded within the utility, decapitalization (as the utility makes losses and its balance sheet shrinks) or price discrimination are the two ways that are usually used to fund the subsidy. If funded externally, this is usually from governments that have a policy of lowering pricing for the poor.

Decapitalization is not a recommended approach because the financial wellbeing of the utility deteriorates with time, ultimately damaging overall service levels. Price discrimination works if other customer classes have reasonably inelastic demand. On Pohnpei, business customers have relatively inelastic demand, but governmental customers have elastic demand because they also enjoy the government fuel rate. Therefore, subsidization of some or all residential consumers could only work equitably if all non residential customers shared the additional pricing burden. This may require legislation to ensure that governmental customers stay connected to the PUC system.

The key determinants of a successful subsidy scheme involve: (a) coverage; (b) targeting; (c) measuring the benefits to the poor; (d) what price distortions and other side effects might be caused by the subsidy and (e) the administration cost and difficulty of implementing the scheme.

Increasingly, the consensus on tariffs and the provision of subsidies for the poor is that they should be avoided because often the poor do not receive the benefit from broadly based schemes. Targeted schemes deliver greater benefit to the poor but these schemes need to be designed carefully so that establishment and administrative costs are not unduly costly. There are a number of ways that subsidies can be delivered, including:

No disconnection – which involves the utility not having the authority to disconnect non paying customers. This arrangement provides coverage to all and targets defaulters (who should be the poor but this is not always the case). However, while a no disconnection policy is easy to administer, it encourages arrears that cannot be easily predicted and significant price distortions can occur;

Across the board price subsidies - entail all customers paying a price for service that is lower than the marginal cost of production. This approach is contrary to PUC's commercial mandate. Broad brushed schemes are also usually so expensive that they are generally not employed now. Implicitly, Pohnpei State and PUC have been providing across the board subsidies to consumers for some time, as the corporation has not made an operating profit since at least 1999;

Lifeline tariffs - involve certain customers being given a certain amount of free electricity per household per month. The amount is usually based on the minimal amount that consumers need to maintain a household. It is understood that PUC's Cashpower meters supplied by Landis and Gyr have a built in lifeline tariff function. This function is modelled on South Africa's "Electricity Basic Services Support Policy" (EBSST) for free basic electricity;

Price discounts for privileged customers – is a further form of price discrimination because this scheme sees certain types of customers (often based on occupation) receiving discounts on their services. This approach can be seen by those not receiving the subsidy as being highly discriminatory and therefore inequitable. In this respect, PUC's employees are privileged because they receive small contributions toward their electricity bills. This fringe benefit makes it difficult to assess overall wage packets for PUC's staff and is seen by some as providing undue benefits to staff. From a political standpoint, price discounts for privileged customers can lead to negative perceptions that outweigh the benefits;

Burden limits – involve selecting poorer households whose utility bills exceed a set percentage of household income. A calculation is made by considering actual utility bills as a percentage of household income as verified by employer certificates. However, burden limits are difficult to police and the administrative costs are high;

Other earmarked cash transfers – are the reverse of Burden Limits because this form of subsidy is based on households having a certain level of "non utility" income. This means of subsidy has similar drawbacks to Burden Limits;

Non earmarked cash transfers – are general social assistance provided to help households meet their utility bills. These transfers can be made directly by the State and can be targeted but are generally only recommended where connection levels amongst the poor and metering levels are low.

There is general accord, if subsidies must be provided to the poor to assist them with their utility bills, that lifeline tariffs are the most expedient method. These tariffs can have several forms, but two stage and three stage tariffs are the most popular. The two stage lifeline tariff has a free block of service for the first stage and a non subsidized tariff as its second stage. Three stage tariffs have an additional stage that has a penalty tariff for higher levels of consumption as a means of dissuading poor customers from consuming too much service.

It is not clear whether PUC's Cashpower meters can be configured to manage a three stage lifeline tariff. However, the attraction of a three stage lifeline tariff is that the tariff can be made available to all households. The more affluent households are likely to consume power that is charged at the penalty rate (if set at the right level) and this 'repays' part or all of the subsidy. A three stage lifeline tariff can also be made optional so that residential customers can decide for themselves whether the scheme is worthwhile.

PUC has already adopted a further way of helping the poor through the introduction of Cashpower meters for electricity. Although this arrangement helps the utility's own arrears problem, it also helps customers who have difficulty managing their consumption under a post-paid regime. It is also possible that connection fees and arrears can be paid over time using pre-paid meters, so this system brings this additional flexibility. Prepaid metering also lowers the cost of collection for a utility, generating savings that can be spread across all customers and making it easier to service poorer customers.

7.1.5 Conclusions

PUC has authority to set tariffs after consultation with the RPPU, yet the RPPU also appears to have a charter to propose new tariffs and the Commission on Energy has similar rights. Consequently, the tariff setting process appears to be unclear from a legislative standpoint, although the RPPU and PUC have a common understanding of the process at a practical level. There is merit in ensuring that the law and practice for tariff setting is aligned.

Tariffs are ideally determined by a market operating in a competitive environment so that rates equal marginal cost as closely as possible. In the absence of a market, a degree of price regulation and control is necessary and this is usually achieved through rate of return pricing, the imposition of price caps or by reference to comparable utilities through benchmarking. The Study employs a combination of these approaches and this is a reasonable basis for price determination.

The report considers a range of tariff mechanisms such as multipart prices, price discrimination, optional tariffs and volume based prices. Analysis of these approaches suggests that multipart prices with price discrimination is employed by PUC for electricity and that there is economic rationale to do so. However, PUC's electricity pricing regime might have a lower level of political acceptability because those who pay the most for electricity can least afford those rates.

PUC'S management have indicated a preference for a single electricity tariff that applies to all. There is a case for such an arrangement, which would have the affect of raising rates for large consumers to the marginal cost of production and lowering residential rates to this level. If this arrangement were implemented, governmental consumers are likely to be the only group whose tariff exceeds the opportunity cost of electricity, so consideration might be given to legislating to ensure these customers remain connected to the PUC system.

If the tariff regime were adopted, it would be appropriate to continue with a two part charge (fuel or non fuel O&M) for consumption. This arrangement would need to be reviewed as the fuel mix for generation changes if the Consultant's recommendation regarding hydropower implementation is adopted.

PUC and stakeholders might wish to consider further relief for residential customers by introducing subsidies, but these would need to be funded largely by the Pohnpei Government as a matter of policy.

Several pro-poor tariffs have been considered, including:

- no disconnection;
- across the board price subsidies;
- lifeline tariffs;
- price discounts for privileged customers;
- burden limits; and
- cash transfers.

Of these tariffs, only lifeline tariffs, that provide some free basic electricity, have particular merit, especially a three stage arrangement that has a penalty for high levels of consumption. However, if a tariff common to all consumers is employed, a lifeline tariff has very limited merit.

7.2 Recommended rate structure

7.2.1 Electricity

The suggested least cost generation plan discussed above promotes the maximization of hydro resources and eventual replacement of the Nanpohnmahl facility with a smaller and more efficient diesel plant located near the tank farm. This plan is referred to as the Upgraded System. This option carries a higher risk than the status quo option discussed below because it is subject to (a) satisfactory completion of detailed feasibility studies; (b) Suitable funding availability and (c) successful implementation of the proposed new schemes.

The next best generation alternative is to continue using PUC's Nanpohnmal facility until the end of its economic life around 2016. That facility would then be replaced by a diesel plant at the tank farm that is similar to the arrangement currently proposed by PUC, although its unit sizes would not exceed 3.5 MW. This option is referred to as the Current System.

The tariff profiles that result from the Upgraded System differ markedly from the Current System. Tariffs are based on the information available to the Consultant as of the Reporting Date although diesel fuel price data was updated in September 2006.

7.2.1.1 Tariff analysis

The following analysis sets out the tariff paths for the preferred generation configuration. The analysis assumes that prices are reviewed five yearly and that the price path for tariffs results in close to a break even return on investment (ROI) over time. As mentioned previously, the profile of the total electricity tariff for the preferred generation configuration reflects the forecast mix of hydro and diesel generation. The follow table and chart demonstrate how this varies in response to the changing mix of generation capacity.

Table 31 - Tariff Profile – Upgraded System

	Average Tariff ¢/ kWh Nominal	Average Tariff ¢/ kWh Real
2007	33.6	32.7
2008	33.7	31.7
2009	33.7	30.8
2010	28.6	25.4
2011	24.5	21.1
2012	24.7	20.7
2013	24.7	20.1
2014	25.0	19.7
2015	25.3	19.4
2016	24.7	18.4

The proportion of diesel generation falls as new hydro capacity comes on stream in 2010 and 2011. The hydro generation is assumed to provide PUC's base generation load. The introduction of more hydro capacity results in a drop in required revenue in those years as the total fuel cost falls as new hydro capacity is introduced. From 2011 required revenue then increases as the diesel generation increases to keep pace with the forecast demand.

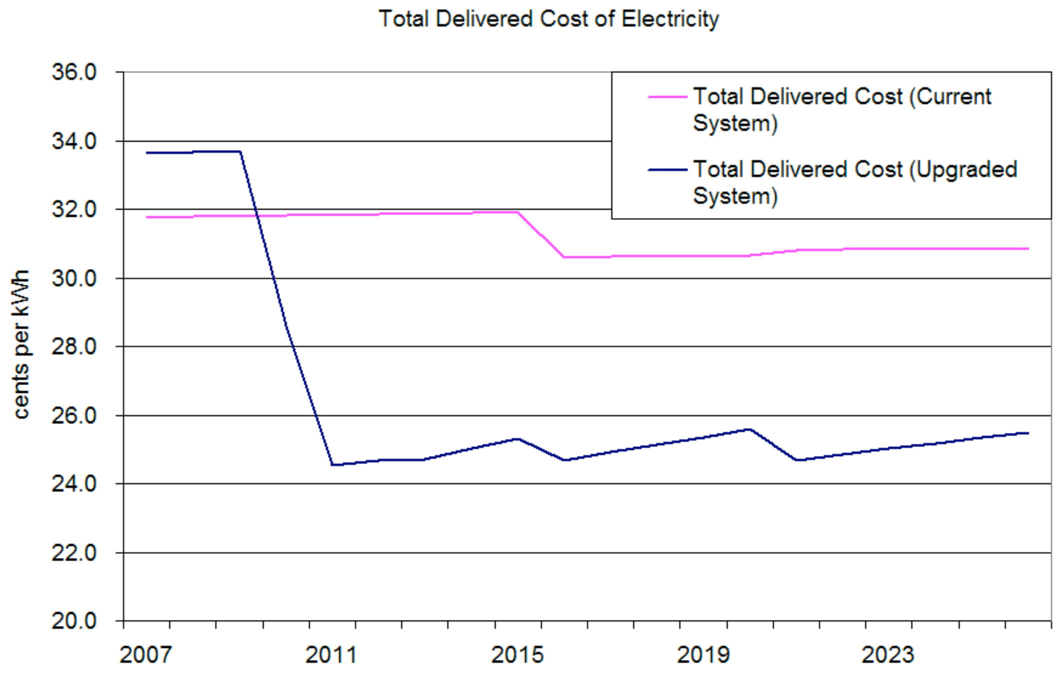
As the Current System involves no new capital expenditure, apart from investment in new diesel plant in 2016, the nominal tariff is constant from 2007 to 2015 at 31.8¢/kWh plus 1c/kWh for street lighting.

Table 32 - Tariff Profile- Current System

	Average Tariff ¢/ kWh Nominal	Average Tariff ¢/ kWh Real
2007	31.8	30.8
2008	31.8	30.0
2009	31.8	29.1
2010	31.8	28.3
2011	31.8	27.5
2012	31.9	26.7
2013	31.9	25.9
2014	31.9	25.2
2015	31.9	24.5
2016	30.6	22.8

The following chart clearly demonstrates the difference between the Upgraded System and the Current System. While the optimal generation option has higher tariffs from 2007 to 2009, there is a substantial reduction in tariff following 2009.

Figure 15 - Total Delivered Cost of Energy



7.2.2 Water

7.2.2.1 Tariff analysis

The tariff structure for water is assumed to be the same as that used currently. Based on the current capital programme and estimated number of connections and usage, the nominal tariff is estimated at USD 2.37 per 1000 gallons, compared to the current tariff of USD 1.80 per 1000 gallons.

Table 33 - Tariff Profile - Water

	Tariff USD/1000 Gallons Nominal	Tariff USD/1000 Gallons Real
2007	2.37	2.30
2008	2.37	2.23
2009	2.37	2.17
2010	2.37	2.10
2011	2.37	2.04
2012	2.37	1.98
2013	2.37	1.93
2014	2.37	1.87
2015	2.37	1.82
2016	2.37	1.76

7.2.3 Wastewater

7.2.3.1 Tariff analysis

The tariff paths and the resulting required revenue for waste water are summarized in the following table.

Table 34 - Tariff Profile - Wastewater

	Tariff USD/Connection Nominal	Tariff USD/Connection Real
2007	337.84	328.00
2008	337.84	318.45
2009	337.84	309.17
2010	337.84	300.17
2011	337.84	291.42
2012	337.84	282.94
2013	337.84	274.70
2014	337.84	266.69
2015	337.84	58.93
2016	337.84	251.39

PUC does not presently charge for waste water treatment. This analysis has based the tariff on a charge per connection as it is impractical for PUC to employ a volumetric waste water charge. Therefore the nominal estimated tariff is based on a fixed charge per "residential equivalent" connection.

In the analysis underpinning this interim report multiples have been applied to the number of commercial and institutional connections to arrive at an estimate of the number of "residential equivalent" connections. The analysis has assumed that a commercial connection is equivalent to 10 residential connections while an institutional connection is equivalent to 20 residential connections. While this is a broad approximation, and an area that will be refined in the final report, it does reflect the extra waste water production of larger users. There are a number of alternatives to this simple weighting such as the number of toilets or the number of sumps.

Based on this approach the nominal tariff is an annual connection charge of around USD 338 per equivalent residential connection per year.

7.2.4 Conclusions

Based on the interim analysis, the Upgraded System, involving investment in 6.34 MW of new hydro capacity, delivers a significant reduction in the overall electricity tariff profile. In fact, the Upgraded System delivers tariffs in 2011 which are around 4.5 ¢/kWh lower than the Current System. However, initially, the average weighted tariff of the Upgraded System is higher than the Current System until the impact of cheaper hydro generation is felt in 2010 and 2011.

The analysis suggests an increase in the average water tariff of around 32% from USD 1.80 per 1000 gallons to around USD 2.37 per 1000 gallons. Assuming an average residential consumption of around 450 gallons per day, the average annual cost of water would increase from USD 295.65 to USD 389.27.

This interim report has suggested a connection charge as the most efficient way of collecting the waste water required revenues. Alternatively, this could be charged as a supplemental charge to the water service charge per 1000 gallons. On this basis, the waste water charge would amount to USD 4.70 per 1000 gallons. Either way, based on the assumed capital expenditure programme, the annual charge per residential connection would amount to around USD 338 per annum. When combined with the increase in water charges, a residential consumer currently connected to water and waste water would face an increase in charges from USD 296.65 to around USD 727.00 per annum. The Consultant believes an increase of this magnitude is unsustainable. The maximum waste water and service charge that the Consultant believes should be sustained by customers is USD 1.50 per 1000 gallons based on benchmarking analysis set out in Section 8.

The preceding discussion has concentrated on estimating an average tariff and the impact on that tariff of various generation and water and waste water supply options. The final report will address tariff structure in more detail.

Overall, one possible tariff structure that the Consultant believes is worth discussing further with PUC and stakeholders is the concept of:

- Pricing water and sewerage tariffs as tentatively suggested above, but subject to further review regarding the sustainability of certain of these projects;

- Pricing electricity with a single tariff based on the marginal cost of production. Residential consumers would pay relatively less for electricity while business and governmental customers would pay relatively more for electricity;

- PUC employees would receive no support for their electricity bills;

- The single tariff should not be set higher than the electricity opportunity cost for businesses. However, that rate would be greater than the electricity opportunity cost for Governmental customers, so these consumers might need to be required to remain connected to PUC's system;

As a further option, the introduction of a three stage lifeline tariff for all residential customers. To qualify, households might, for example, be required to purchase a certain number of energy efficient light bulbs. The funding of the lifeline tariff might come from a premium added to the base tariff and through the penalties in the third block of the lifeline. Alternatively, support for any lifeline tariff could also need external funding from the Pohnpei Government. Overall, however, a lifeline tariff for electricity is not recommended if a common tariff for all consumers is employed.

8 Benchmarking Analysis

8.1 Requirements of the Consultant

PUC would like to benchmark itself against at least two other similar utilities. In doing so it would like expenses and operating conditions for both power and water and sewer operations to be compared. Financial, statistical and rate information is to be obtained for this purpose,

Customer Analysis – such as (i) demand information by customer class; (ii) the number of customers by class and; (iii) sales by class. For the purposes of this study, demand and sales are treated as the same as there is no evidence to suggest that the two differ.

Employee Analysis – including (i) the number of employees by function and; (ii) payroll costs.

Operating Cost Analysis – including (i) a comparison of expenses and operating conditions for both power and water and sewer operations; (ii) costs of supplies and; (iii) system efficiencies such as fuel efficiencies and losses. In this report, costs of supplies are analyzed as an integral part of section (i), above.

Financial Analysis – including (i) key financial and statistical ratios; (ii) the rate structure; (iii) other sources of income beside rates; (iv) recent growth and capital expenditures, and; (iv) government subsidies.

These analyses are to be carried out separately for electricity, water and wastewater to identify significant variations and their causes. PUC has also asked for advice about where it could improve its operations and what costs and savings these improvements might involve.

8.2 Benchmarking Reference Material

A range of material has been used to perform the benchmarking analysis. However, two reports have been especially important. The first is the PPA/ADB *Final Report on Performance Benchmarking (October 2002).* The second is the ADB's *Performance Benchmarking for Pacific Power and Water Utilities – Draft Final Report (December 2005).* These reports are referred to as the First Benchmarking Report and Second Benchmarking Report respectively.

8.3 Selection of Benchmarking Candidates

The Consultant infers that it is preferred that comparison utilities are integrated power and water/wastewater providers rather than single utilities. Preference has been given to integrated utilities for this reason.

PUC's 1995 Tariff Study, the First Benchmarking Report and the Second Benchmarking Report were reviewed to identify potential benchmarking candidates.

PUC's 1995 Tariff Study compared PUC against the Molokai Division of the Maui Electric Company, the Solomon Island Electric Authority and the American Samoa Power Authority.

The Maui Electric Company is not an integrated utility. It was not reviewed in either the First Benchmarking Report or the Second Benchmarking Report. There is also limited information available to consider the company. For these reasons, the company has been excluded as a benchmarking candidate.

The Solomon Island Electric Authority is an electricity utility only but it is comparable to PUC concerning gross generation, maximum demand and customer numbers.

When considering the ADB/PPA Report, twenty-one Pacific utilities were reviewed. Of these, the following utilities are comparable to PUC. These utilities are referred to in this section as the "Comparison Utilities".

Table 35 - Comparison Utilities

Utility Name	Electricity Service Provider	Water Services Provider
American Samoa Power Authority (ASPA)	**Yes**	**Yes**
Electric Power Corporation, Samoa	Yes	No
Palau Public Utilities Corporation (PPUC)	Yes	No
Solomon Island Electricity Authority (SIEA)	Yes	No
Te Aponga Ulra O Tumu-Te-Carovaro (TAU), Cook Islands	Yes	No
Societie d'Union Electrique du Vanuatu	**Yes**	**Yes**

While the Palau Public Utility Corporation (PPUC) is not an integrated utility, it is comparable in size to PUC and it has the lowest tariffs in Micronesia. For this reason, PPUC requires special mention and further analysis to determine whether it should be a comparison candidate for the Study.

PPUC was established in 1994 by the Government of Palau as a commercial business, the intention being that the government would subsidize the tariff for as long as necessary. It is unclear whether the tariff remains subsidized because PPUC's CEO advised SOPAC in April 2005 that it does not, while a PPUC presentation to e7 in March 2005 suggested that tariff subsidies are a barrier to the implementation of wind power and other renewable electricity options.

Based on a diesel price of USD 2.30 per gallon, PPUC's tariff to residential consumers ranges between 21.13 ¢/kWh for consumption of 500 kWh/ month and 25.13 ¢/kWh for consumption of over 2,000 kWh per month. Commercial and government consumers pay 23.13 ¢/kWh for the first 2,000 kWh per month and then 25.13 ¢/kWh for higher amounts. By comparison, PUC customers pay between 24.73 ¢/kWh and 28.73 ¢/kWh as of the Reporting Date. PUC's tariffs are therefore between 6.9% and 14.3% higher than PPUC's tariffs on this basis.

PPUC's directors and management resigned from the company pending rationalisation of PPUC's operations. In view of the uncertainty regarding the level of subsidization that PPUC receives, it not being an integrated utility and uncertainty regarding PPUC's general performance, the Consultant does not consider that PPUC is a comparable benchmark candidate.

The American Samoa Power Authority (ASPA) and Societie d'Union Electrique du Vanuatu (UNELCO) are both integrated utilities and are comparable in other respects. For this reason they have been selected as the principal comparison utilities for the Study. In this section of the report, these two utilities are referred to as the Benchmark Utilities.

The First Benchmarking Report provides valuable data on each of the utilities in the table and Pacific benchmarks that all Pacific utilities should aim to achieve. When dealing with electricity sector comparisons, this section compares PUC not only to APSA and UNELCO, it also accounts for the Pacific Benchmarks set down in the First Benchmarking Report that PUC should aim to be achieving.

8.4 Electricity Benchmarking Results

8.4.1 Customer Analysis

(i) Number of Customers by Class

Broadly speaking, electricity customers for the benchmarked utilities fall into the four categories of residential, business, industrial and government customers. PUC might consider re-classifying its customers in this way.

PUC has 6,496 electricity customers and these are divided into the four classes of Residential, Small General Power, Large Power and Industrial Power Consumers.

In 2005, PUC had 203 Residential Customers and 5,641 customers using CashPower meters, most of which are assumed to be residential. It had 157 Commercial customers. Industrial customers numbered seven, with four billed and three using three-phase CashPower meters. Government customers numbered 135.

Consequently, PUC's customers are comprised 15.62% Residential, 7.71% Commercial, 1.26% Industrial, 7.03% Government and 0.76% PUC Internal customers by number.

ASPA has 11,335 electricity customers and these are divided into the five classes of Residential & Debit Meter Customers, Commercial, Industrial, Government and ASPA Customers.

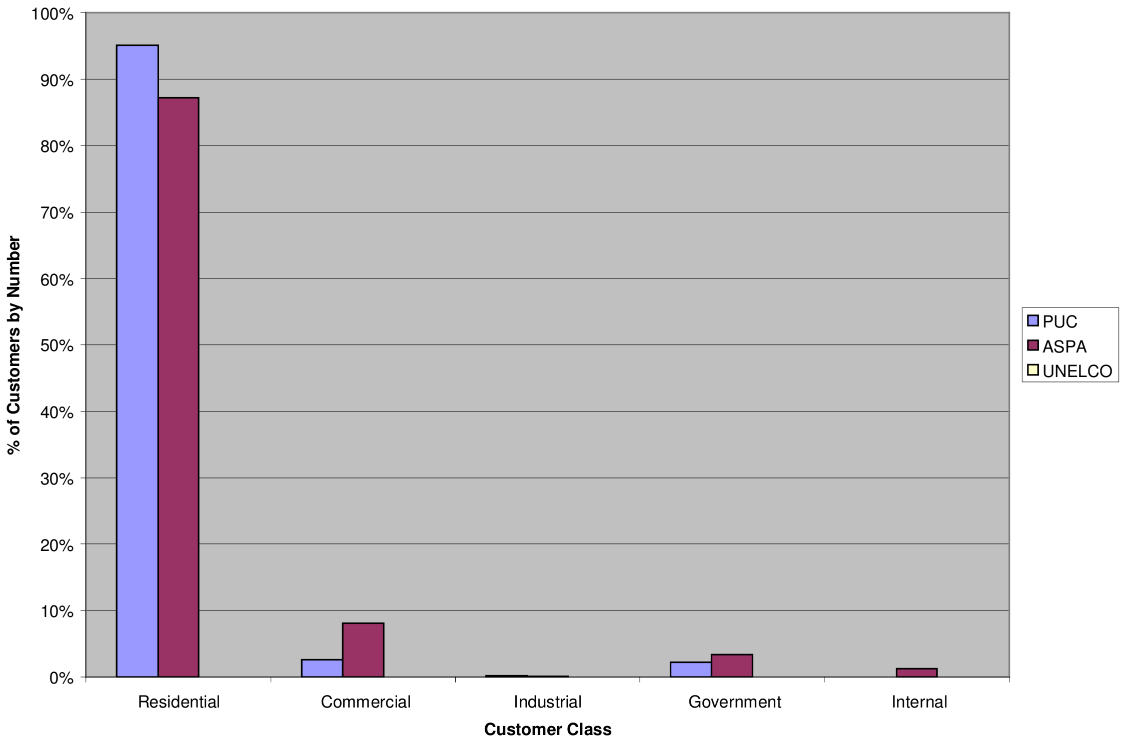
In 2005, ASPA had 11,335 customers. These comprised: 9,889 Residential and Debit Meter customers; 920 Commercial customers; 6 Industrial customers; 383 Government customers; and 137 ASPA Internal customers.

Consequently, ASPA's customers are comprised 87.2% Residential and Debit Meter, 8.1% Commercial, 0.1% Industrial, 3.4% Government and 1.2% ASPA Internal customers.

UNELCO has 5,745 electricity customers and these are divided into the three classes of Domestic, Business and High Voltage Consumers.

Taking each of the comparison utilities together, it can be seen from the chart below that PUC has relatively more residential customers than ASPA and UNELCO, whilst ASPA in particular has a relatively strong base of government and commercial customers. These classes of customer generally have a higher capacity to pay for electricity than residential consumers, which helps explain why the cost of electricity is felt particularly on Pohnpei.

Figure 16 - % of Customers by Number



(ii) Sales information by customer class

PUC's customers demanded 32.39 GWh during 2005. Of this, Residential customers consumed 15.62 GWh; Commercial customers consumed 7.71 GWh; Industrial customers consumed 1.26 GWh; Government customers consumed 7.03 GWh; and PUC customers consumed 0.76 GWh.

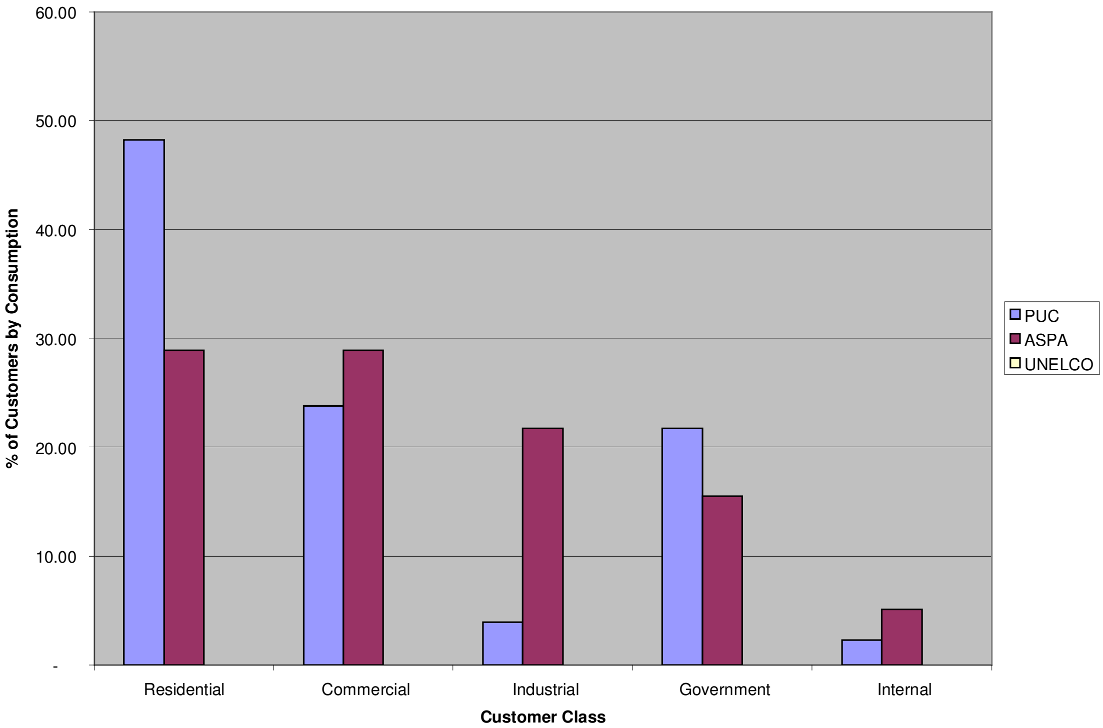
Consequently, PUC's residential, commercial, industrial, government and internal customers consumed 48.2%, 23.8%, 3.9%, 21.7% and 2.4% respectively of electricity sent out.

ASPA's customers demanded 167.3 GWh during 2005. Of this: Residential and Debit Meter customers consumed 48.35 GWh; Commercial customers consumed 48.34 GWh; Industrial customers consumed 36.27 GWh; Government customers consumed 25.88 GWh; and ASPA Internal customers consumed 8.45 GWh;

Consequently, ASPA's Residential and Debit Meter, Commercial, Industrial, Government and ASPA Internal customers consumed 28.9%, 28.9%, 21.7%, 15.5% and 5.1% respectively of electricity sent out.

Taking each of the comparison utilities together, it can be seen from the chart below that PUC has relatively much more residential consumption than ASPA and UNELCO, whilst ASPA in particular has a relatively strong demand from commercial and industrial customers, but not government as the number of these customers might suggest. As residential consumers account for a relatively high proportion of PUC's customer number, but an even higher proportion of consumption, a case for a single tariff across customer classes is strengthened.

Figure 17 - % of Customers by Consumption



8.4.2 Employee Analysis

(i) Number of employees by function

PUC has 131 electricity related staff and 6,496 electricity customers. This means that PUC has 50 electricity customers/ electricity related employee.

At the time of the First Benchmarking Report, ASPA had 140 electricity related staff and 10,000 electricity customers. This means that ASPA had 71 electricity customers/ electricity related employee.

At the time of the First Benchmarking Report, UNELCO had 105 electricity related staff and 5745 electricity customers. This means that UNELCO had 55 electricity customers/ electricity related employee.

The range of electricity customers/ electricity related employee for the benchmarked utilities is between 55 and 71. For reference, the Comparison Utilities have an average of 58 electricity customers/ electricity related employee.

The PUC has fewer customers per employee than the Benchmark Utilities and the average for the Comparison Utilities. This suggests that PUC might aim to improve its employee efficiency by at least ten per cent.

(ii) Payroll costs

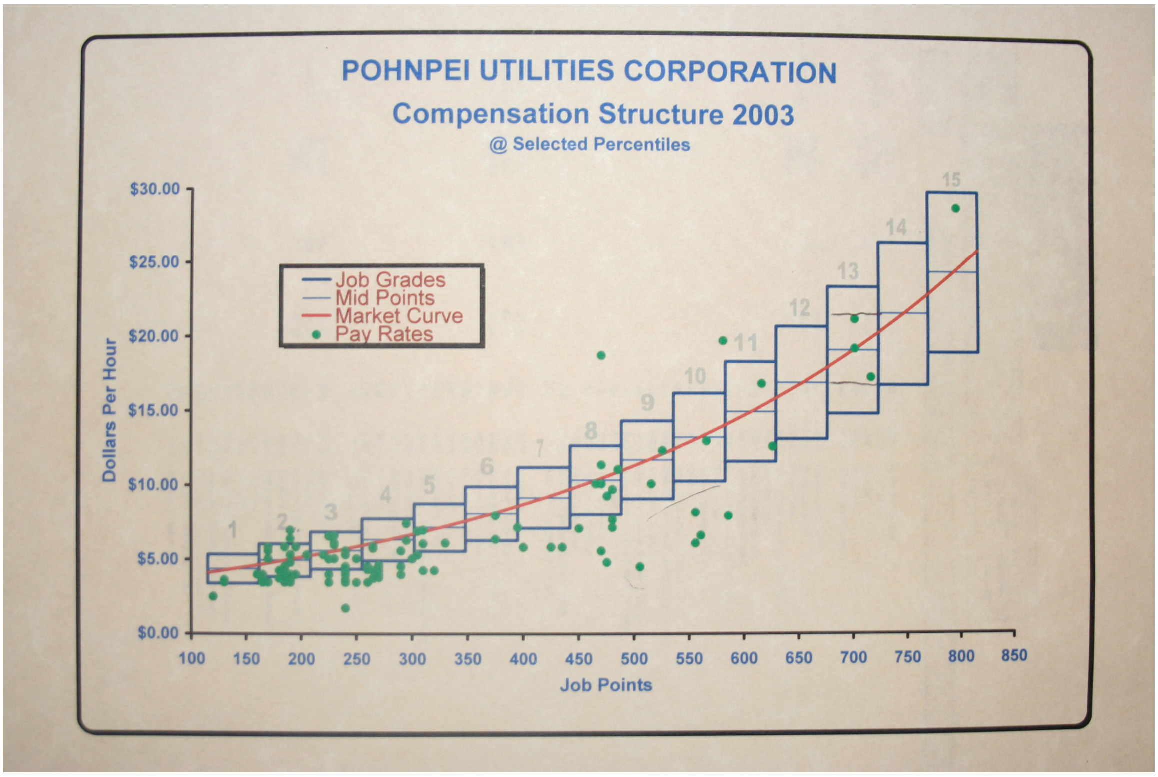
Payroll costs are difficult to obtain and this was found to be the case in both the First Benchmarking Report and the Second Benchmarking Report. PUC does, however, have useful data of its own regarding payroll costs through a report conducted by Andrus Associates in 2003.

The Wage and Salary Management Report benchmarked PUC's salaries against other comparable salaries payable on Pohnpei and elsewhere where PUC's staff are qualified to work, such as in the USA. The chart below summarizes the results of this review.

The chart shows the pay ranges by job grade, the salary mid points for each job grade and the pay rates offered by PUC. In short, it can be seen that rates by and large fall considerably below the rates that are otherwise available to PUC staff through other employers on Pohnpei and, in particular, the United States.

Care needs to be taken, however, regarding non wage employee benefits. One of these is credits that are available to PUC employees towards their electricity usage. It is thought that this amounts to around USD20 per employee per fortnight, amounting to around 24 ¢ per employee hour over a forty hour week. While this is not a considerable amount, PUC internal electricity use data that includes corporate and employee consumption suggests that employee consumption might be up to double this level. The perception of customers might outweigh the reality of these benefits, but PUC might consider whether it should manage this perception by reducing fringe benefits and paying staff solely through wages and salaries.

Figure 18 - PUC Compensation Structure 2003



8.4.3 Operating Cost Analysis

(i) Comparison of expenses and operating conditions

Generation - As of when the First Benchmarking Report was compiled, PUC had a O&M Cost of USD 99.26 /MWh, while ASPA had a O&M Cost of USD 18/MWh. The First Benchmarking Report did not calculate such a value for UNELCO, but the average of the Comparison Utilities was an O&M Cost of USD 76.29/MWh.

Distribution - As of when the First Benchmarking Report was compiled, PUC had a an average distribution cost of USD1560 per kilometre, compared to USD 882 for ASPA and USD 2907 for the Comparison Utilities. The distribution cost per MWh of gross energy was USD 16 for PUC, USD 17 for ASPA and USD 15.89 for the Comparison Utilities. Consequently, PUC fared well regarding its distribution costs, especially given the economy of scale benefits that ASPA enjoys.

(ii) System efficiencies such as fuel efficiencies and losses

The chart below shows the load and capacity factors, reserve plant margins and availability factors for each of the Comparison Utilities, the Benchmark Utilities and the average of all Pacific Utilities surveyed for the First Benchmarking Report. They show that PUC has a load factor that is better than the Comparison Utilities and the average of all Pacific Utilities. The load factor also sits well within the range for international best practice.

PUC has a low capacity factor, which is a symptom of the utility receiving granted equipment that came with no capital cost but also is less than optimal for the size of PUC's system. This issue cannot be corrected until PUC implements its long term least cost generation expansion plan. The reserve plant margin goes hand in hand with this issue.

PUC has enjoyed an availability factor of 82% at the time of the first benchmarking report. While this is lower than that enjoyed by the Benchmark Utilities and the Comparison Utilities, it is just within the Pacific Benchmark range suggested in the First Benchmarking Report.

Table 36 - Utilties Comparison Factors

	Load Factor	Capacity Factor	Reserve Plant Margin	Availability Factor
	%	%	%	%
ASPA	79.76	48.00	66.00	96.90
Electric Power Corporation, Samoa	56.90	31.10	83.30	94.20
Palau Public Utilities Corporation (PPUC)	73.77	46.13	59.91	92.25
PUC	**69.00**	**22.00**	**218.00**	**82.00**
Solomon Island Electricity Authority (SIEA)	54.80	24.05	128.00	98.00
Te Aponga Ulra O Tumu-Te-Carovaro (TAU), Cook Islands	69.46	31.78	118.58	98.63
UNELCO	55.81	24.40	128.75	99.04
Average: Comparison Companies	65.64	32.49	114.65	94.43
Average: Pacific Utilities	67.00	34.00	109.69	93.20
Range: International Best	50-80	35-65		10-65
Range: Pacific Benchmark Reference (Low	50.00	40.00		80.00
Range: Pacific Benchmark Reference (High	80.00	999.00		90.00

The following table illustrates the fuel consumption and lube oil consumption for each of the Comparison Utilities, the Benchmark Utilities and the average of all Pacific Utilities surveyed for the First Benchmarking Report. In summary, PUC fares particularly well in the consumption of fuel and this is been reaffirmed during the Consultant's field visits to Pohnpei. Regarding lube oil consumption, this was actually below the Pacific Benchmark range suggested as part of the First Benchmarking Report, possibly because of the recycling process for waste oil that PUC employed at that time.

Table 37 - Utilities Fuel and Lube Oil Consumption Comparison

	SFOC	LOC
	kWh/ Gallon	Gal/Hr
ASPA	15.26	2.48
Electric Power Corporation, Samoa	14.46	0.43
Palau Public Utilities Corporation (PPUC)	14.08	0.63
PUC	**14.61**	**0.77**
Solomon Island Electricity Authority (SIEA)	14.01	1.35
Te Aponga Ulra O Tumu-Te-Carovaro (TAU), Cook Islands	14.69	0.47
UNELCO	15.11	0.80
Average: Comparison Companies	14.60	0.99
Average: Pacific Utilities	14.35	0.92
Range: International Best Practice		
Range: Pacific Benchmark Reference (Low Value)	11.36	0.85
Range: Pacific Benchmark Reference (High Value)	15.14	0.92

8.4.4 Financial Analysis

(i) Key financial and statistical ratios

The table below shows the operating ratio and debt to equity ratio for PUC, the Comparison Utilities, the Benchmark Utilities and the average of all Pacific Utilities surveyed for the First Benchmarking Report.

The operating ratio is a function of total operating expenses plus depreciation divided by operating revenue. The Debt – Equity ratio is the amount of term debt divided by the sum of equity and term debt.

PUC's operating ratio was consistent with the average of Pacific Utilities but not the Comparison Utilities or Benchmark Utilities.

The table does not show a debt to equity ratio for PUC, although in 2005 this was 14%, which is a low level that has been maintained by the provision of substantial grants over time. If these grants are not forthcoming over the course of the next few years and PUC continues with its expansion plans, its debt to debt plus equity ratio could well exceed the recommended benchmark limit of 50%.

Table 38 - Utilities Key Financial and Statistical ratios

	Op. Ratio	D-E Ratio
American Samoa Power Authority (ASPA)	99.00	10.00
Electric Power Corporation, Samoa	103.00	45.00
Palau Public Utilities Corporation (PPUC)	123.00	0.50
Pohnpei Utilities Corporation (PUC), FSM	**142.00**	
Solomon Island Electricity Authority (SIEA)		
Te Aponga Ulra O Tumu-Te-Carovaro (TAU), Cook Islands	91.00	28.00
Societie d'Union Electrique du Vanuatu	74.00	48.00
Average: Comparison Companies	105.33	26.30
Average: Pacific Utilities	186	26.07
Range: International Best Practice	>-10%	<50%
Range: Pacific Benchmark Reference (Low Value)	0.00	0.00
Range: Pacific Benchmark Reference (High Value)	0.00	50.00

Regarding other financial benchmarks, PUC has consistently struggled with debtor days because customers (including the State and National Governments) have consistently paid late for electricity supplies. At the time of the First Benchmarking Report, PUC's debtor days were 100, against a recommended Pacific Benchmark of no more than 50. ASPA and UNELCO at that time enjoyed debtor days of 43 and 33 respectively. The situation should have improved with Cashpower meters being installed, but the 2005 accounts suggest that debtor days still average 120.

PUC pays its creditors within this 120 day period however. On average, oil suppliers receive payment in 33 days (given the importance of consistent oil supplies) and other creditors are paid on average after 51 days. Consequently, PUC is carrying the working capital cost of arrears for up to 90 days.

(ii) Rate structure

Each of the Benchmark Utilities employs a base tariff plus fuel recovery tariff structure. The First Benchmarking Report was completed in 2002 and the tariff data in that report is out of date because of the substantial increase in fuel prices. The most recent consistent data is based on March 2006 data for PUC, May 2006 rates from ASPA and July 2006 rates from UNELCO.

Table 39 - Utilities Rate Structures

Category	**PUC Tariff** Base + Fuel charge (USD)	**ASPA Tariff** Base + Fuel charge (USD)	**UNELCO Tariff** Base + Fuel charge (USD)
Residential Power	10 + 19 ¢/kWh = **29 ¢/kWh**	8.2 + 13.8 = **22.0 ¢/kWh**	**29.3 ¢/kWh**
Small general Power	10 + 19 ¢/kWh = **29 ¢/kWh**	9.9 + 13.8 = **23.7 ¢/kWh**	**26.5 ¢/kWh**
Large Power	10 + 19 ¢/kWh = **29 ¢/kWh**	7.2 + 13.8 = **21 ¢/kWh**	**21.3 ¢/kWh**
Industrial Power	6 to 8 + 19 ¢/kWh = **25 to 27 ¢/kWh**	4.8 + 13.6 = **18.6 ¢/kWh**	**21.3 ¢/kWh**

Of the Benchmark utilities, tariffs range between 18.6 ¢/kWh to 29.3 ¢/kWh and PUC's tariffs are at the high end of the range. PUC and UNELCO have comparable residential power rates, although UNELCO charges commercial and industrial consumers at relatively lower rates. ASPA has lower tariffs overall, due partly to non fuel O&M costs that are up to 20% lower than PUC, but mostly because fuel costs of 13.8 ¢/kWh are exceptionally low. This is because American Samoa imports a very high volume of diesel to support its fishing industry and consequently ASPA benefits from this arrangement.

PUC should continue striving to reduce non fuel O&M costs by increasing productivity and its fuel related costs by devising a workable fuel strategy and adopting least cost generation planning principles. On this basis, the two options set out in Section 8.1.1 in the report (the optimal option and the status quo option) deliver average tariffs that are 30.5 ¢/kWh and 28.4 ¢/kWh respectively. The optimal option is initially above the range (but the tariff falls quickly thereafter as the benefits of new capacity is felt). The Status Quo option tariff sits at a lower level but is still at the high end of the range and does not fall in nominal terms.

(iii) Other sources of income beside rates and government subsidies

PUC does not have income sources other than rates and it does not receive explicit government subsidies. It benefits from an implicit subsidy because the corporation is not required to return dividends to the State Government.

(iv) Recent growth and capital expenditures

PUC's capital expenditure programme is set out in the financial model attached to this report of this report.

8.5 Water and Waste Benchmarking Results

To assess the reasonableness of PUC's water tariff's, the Consultant reviewed the Asian Development Bank's December 2005 report called "Performance Benchmarking for Pacific Power and Water Utilities". This Second Benchmarking Report includes information dating back to 2002 for electricity utilities and 2005 information with regard to Pacific water utilities.

The Second Benchmarking Report compares the eight utilities of the Cook Islands, Fiji, Kosrae (FSM), Yap (FSM), Papua New Guinea, American Samoa and Vanuatu. The report is the most recent and comprehensive work of its type and is the best tool available for the purposes of water utility benchmarking.

8.5.1 Customer Analysis

(i) Number of customers by class;

in 2005, PUC had 2,882 residential water connections and 395 non residential water connections. Therefore, the utility had a total number of water connections of 3,277, which is comparable with most other Pacific utilities other than for PNG and Fiji (which has an excess of 120,000 connections).

Of PUC's water connections, 88% are residential which is a relatively high proportion by contrast to other Pacific utilities. These utilities have around 80% of their connections as residential. The benchmark range of 83% to 93%.

In 2005 PUC had 1227 waste water connections. Of these 1015 were residential connections, 138 were commercial and 74 were institutional. Across the Pacific between 0% and 100% of the population were supplied by pacific utilities. By comparison, 39% of the population of Pohnpei had access to sewer connections.

(ii) Sales by class.

PUC's residential and institutional customers consumed 450 gallons per day and 1,200 gallons per day respectively. On a connection basis, this amounts to 540 gallons per day per connection. By comparison, the Pacific utility benchmark range is between 340 and 752 gallons per day per connection. On this basis PUCs customers consume an average amount of water.

8.5.2 Employee Analysis

(i) Number of employees by function;

PUC employs twenty-nine staff in water and waste water division, eighteen of whom are assigned to the water service and eleven are responsible for waste-water.

The utilities surveyed in the second benchmarking report have between 67 and 337 water supply connections per staff member. By comparison, in 2005 PUC had 182 connections per staff member. Therefore, PUC has an average staffing level by comparison to its Pacific counterparts.

Pacific utilities have between 88 and 242 sewer connections per staff member, whereas PUC had 112 connections per staff member in the wastewater division. Consequently, PUC's level of staff efficiency is comparable with other pacific utilities.

(ii) Payroll costs.

Payroll costs are discussed under the Employee Analysis section above. In short, PUC's rates of pay are comparable with other employers on Pohnpei and, in particular, the United States. The United States is an important wage market because Micronesians are able to work there without visa requirements.

8.5.3 Operating Cost Analysis

(i) Comparison of expenses and operating conditions for water and sewer operations

PUC has unaccounted for water of approximately 48%, although there are plans to reduce these losses to an economic level. By comparison, utility studies and the Pacific benchmarking report in a range of unaccounted for water of between 24% and 47%. Consequently, PUC's unaccounted for water exceeds the outside range of pacific utilities. This is an area that requires addressing.

Pacific utilities have between 0% and 100% of their water volume sold on a metered basis. Of the eight utilities that took part in the benchmarking study to do not metered consumption, five provide 100% metering and one meters 93% of supply. By comparison, PUC meters virtually all of its customers.

(ii) Operating Ratios

An indicator of financial performance is the operating ratio, which is measured by dividing operating expenses by operating revenues. For a utility to be profitable, the ratio must be less than one.

Americans Samoa and Fiji have operating ratios exceeding two times, which means that their water and wastewater operations do not operate profitably. UNELCO has an operating ratio of 0.90 and Samoa has an operating ratio of 0.50.

PUC, by comparison, has a forecast operating ratio of 0.56 for its water business. For its waste water division, PUC has a forecast operating ratio of 0.35. Both of these measures indicate that PUC is operating efficiently from a financial perspective. When PUC's water and waste businesses are combined for 2005, they have an operating ratio of 0.97. This is more comparable with the operating ratio displayed by ASPA, but is forecast to reduce to around 0.6 over the next few years.

8.5.4 Financial Analysis

(i) Key financial and statistical ratios

The Pacific water sector benchmarking survey 2005 established a range of financial measures against which the financial performance of paper so that utilities were benchmarked. These are water supply and wastewater service average costs, return on total assets, the current ratio and annual arrears.

PUC's return on total assets was -9.9% in 2005. While this return is negative, it is comparable to other utilities in the Pacific. For example, ASPA had a similar return on total assets and the Fiji Water and Sewerage Department had a return on total assets of almost -20%. The utility UNELCO in Vanuatu and the water and sewer department in Samoa had returns on total assets of 5% and 2% respectively. Assuming PUC does not change its current system, it is forecast that return on total assets will improve over time and on average over the next 20 years will be between 0% and -1%. A ROTA above 0% should be targeted but generally this is consistent with PUC's charter to work on the basis of cost recovery but to not deliver dividends to the State government.

The current ratio is Current Assets/Current Liabilities. This ratio should be 1.0 or greater for liquidity. If it drops below 1.0, the ability to pay bills is impaired. If it is greater than 1.0, there is a possibility that assets are not being used efficiently to generate new revenue. In 2005, PUC's current ratio was 8.67 times, indicating that there is substantial inefficiency in the way that PUC's current assets are deployed. If debtors are excluded from the calculation, the current ratio drops to 2.86. This means that the inefficiencies in PUC's current assets are caused by its high level of accounts receivable. The pacific benchmarked utilities had a current ratio of 0.4 to 1.76, so PUC would do well to concentrate on its arrears and possibly consider whether its inventory levels are appropriate for the business.

And 2005, PUC had arrears as measured by debtor days outstanding of 123 days. By comparison to other pacific utilities, ASPA and UNELCO had 10 or less debtor days. However, the Fiji Water and Sewerage Department had debtor days of over 100 and in Samoa were close to 275. Therefore, there is a wide variation in the level of annual arrears, although PUC would do well to reduce its arrears as can be seen by the discussion regarding current ratio above.

(ii) Rate structure

PUC charges USD 1.80 per 1,000 gallons compared to ASPA's charge of USD 7 per 1,000 gallons and UNELCO's charge of USD 1.82 per 1,000 gallons. The average cost per 1,000 gallons on Pacific utilities surveyed in the Second Benchmarking Report fell within a range of USD 1.20 to USD 2.50, so PUC's existing water charge fits squarely within this range.

However, as PUC does not currently charge for waste water, PUC's tariff needs to be considered in light of the aggregated costs of providing water and waste water services.

The average cost per 1,000 gallons of waste water service on Pacific utilities surveyed in the Second Benchmarking Report fell within a range of USD 0.01 to USD 1.50, so PUC's combined water and sewer charge could be expected to be between USD 1.21 and USD 4.00 per 1,000 gallons. On this basis, PUC's water and waste service charge is only 45% of the top end of this range.

The tariff analysis set out in section 8.2.2 of the Final Report suggests a new water tariff of USD 2.37 per 1,000 gallons, which is still within the recently determined range of Pacific water charges determined in the Second Benchmarking Report.

(iii) Other sources of income beside rates and government subsidies

PUC does not have any sources of income other than revenue charged to customers through its tariffs.

Regarding government subsidies, PUC does not receive explicit government subsidies, although the benefits from implicit subsidies. These include the State government as shareholder not requiring dividends, which reduces on the weighted average cost of capital borne by the utility. A further implied subsidy is made to the utility through the State government's waiver of interest payments required to be made under ADB Omnibus facility

(iv) Recent growth and capital expenditures

PUC's growth in capital expenditures are set out in the financial model attached to this report.

8.6 Summary and Conclusions

The Pacific Power Association and the ADB produced a utility benchmarking report that is widely regarded as the best benchmarking survey in the Pacific to date. A further report on water utilities was published in late 2005. These reports go further than comparisons of two utilities.

However, the TOR asks for at least two utilities to be benchmarked and American Samoa Power Authority (ASPA) and UNELCO of Vanuatu are considered to be the most comparable. Four other pacific utilities are also similar with respect to PUC's electricity supply business, so these have been considered in the report as well. ASPA and UNELCO are referred to as the Benchmark Utilities and these utilities and these together with the other comparable utilities are referred to I the report as the Comparison Utilities.

For water and wastewater, all of the eight utilities surveyed in the ADB's 2005 report have been considered for benchmarking purposes.

Regarding electricity customer classes, it is noted that the theme for the Benchmark Utilities is to have four customer classes of residential, business, industrial and government. These classes might be adopted by PUC instead of its existing classification so that government customers are more distinct. Notably, the Benchmark Utilities have a higher proportion of non-residential customers and consumption by these groups, highlights the relatively small size of commerce and industry on Pohnpei and consequent reliance on residential customers.

PUC has 50 electricity customers per electricity related employee compared to 558 for UNELCO, an average of 58 for Comparison Utilities and 71 for ASPA. ASPA has the benefits of scale, but a target of between 55-58 customers per electricity related employee might be sought by PUC, suggesting a reduction in staff of up to 10 percent over time unless genuine customer numbers increase.

Electricity employee payroll costs were found to be lower than rates these staff could obtain elsewhere with their skills, particularly the United States. However, employees obtain fringe benefits that PUC's management might review.

Regarding operating costs, PUC's generation O&M costs are higher than benchmark utilities and this is in part attributed to diesel auxiliary costs that might be reviewed. However, distribution costs per kilometre are reasonable. Overall, PUC rated very well regarding system efficiencies such as fuel efficiencies and losses.

Financially, PUC has an operating ration that is consistent with pacific utilities, although improvements in this area should always be sought. PUC's debtor days continue to be a challenge however, and PUC is encouraged to minimise arrears further if it is to compare more favourably to other pacific utilities. Additionally, PUC has tight payment terms with suppliers, which means it has significant working capital burden. Reducing debtor days payable and increasing credit terms with suppliers would benefit PUC.

With respect to tariffs, PUC tariffs were compared with ASPA and UNELCO. Earlier in 2006, when the analysis was made, these utilities had tariffs between 18.6 c/kWh to 29.5c/kWh and PUC's tariffs were at the high end of this range. It is suggested that PUC continue to reduce non fuel O&M costs through productivity increases, but the most effort should to into reducing fuel costs by devising a workable fuel strategy and adopting least cost generating principles.

When PUC's water and waste businesses are considered, it can be seen that PUC has a relatively high proportion of residential customers, consistent with power consumption. Importantly, PUC lacks the base of business and industrial customers that other pacific utilities enjoy.

Pacific utilities have water consumption of between 340-752 gallons per connection day and PUC had 540 gallons per connection day in 2005. PUC'S water consumption per connection is therefore average.

PUC also has an average staffing level per customer for both its water and wastewater divisions and its payroll costs are comparable with rates achievable for PUC staff elsewhere.

PUC does have a high level of unaccounted for water. Pacific utilities have UFW rates of between 24% - 47% and PUC's UFW last year was 48%. This needs to reduce and PUC is taking steps to achieve this. PUC rates very well, however, on the level of metering it has deployed.

PUC's operating costs as a ratio of revenues was 0.97 overall for 2005, meaning it is only just recovering its current costs. Return on total assets is –9.9%, which is within the pacific benchmark range of –20%-+5%. This is forecast to move closer to zero over time, indicating that PUC is achieving full cost recovery.

PUC has a very high current ratio because it has a very high level of customer arrears and possibly higher inventory levels than are desirable from an accounting viewpoint. Arrears need to be reduced for assets to be utilised more effectively. Regarding inventory, PUC's remoteness and the high cost of spares for the Daihatsu plant go some way to explain this high level.

With regard to PUC's tariffs for water, the acceptable Pacific Benchmark for water service is for charges of up to USD 2.50/1000 gallons. PUC's existing water tariff of USD 1.80/1000 is well below this level but the Consultant found that PUC is undercharging for the service and not recovering costs. A water tariff of USD 2.37 is needed to achieve this.

Wastewater tariffs in the Pacific do not exceed USD 1.50 per 1000 gallons and at present PUC does not charge for this service at all. Taking PUC's planned sewage expansion into account, a sewer charge of USD 4.70 per 1000 gallons is calculated as being required. There is no doubt that sanitation levels on Pohnpei need to improve, but the cost cannot be recovered commercially if PUC is to charge rates comparable to other utilities for this service. Consequently, either projects are reviewed or deployed more cost effectively, or the State might consider providing support to reflect the public good nature of these projects.

9 Analysis of Alternative Electricity Supply Options

9.1 Introduction

In this section a review is presented of generation options available to the PUC followed by a least cost analysis of favourable options. The results of the least cost analysis provide the input for the generation expansion scenario discussed in Section 6.

9.2 Options

9.2.1 Hydro

Pohnpei is the highest of the Caroline Islands and has eleven peaks over 750ft. There are approximately 35 perennial streams on the island that are maintained by the relatively high rainfall encountered in the island's interior. Annual rainfall in Kolonia is about 180 inches and in the interior this increases to about 400 inches. Evaporation is estimated at around 70 inches/yr. Rainfall is fairly evenly distributed throughout the year although the average for the months of January and February is about 30% less than the other months. The above statistics are indicators that hydro resources on Pohnpei are substantial.

The main river systems on Pohnpei are Nanpil/Keipw, Lehnmesi, Riohk/Senipen, Lehdau and Mahnd, which have been investigated by various organisations[3] over the past 15 years. Several pre-investment type studies have been completed that have identified 6 to 8 MW of generation potential at seven locations. Brief details of the most promising hydro schemes identified previously are given in the table below:

Table 40 - Proposed New Hydro Power Plants on Pohnpei

Station	Installed Capacity (kW)	Annual Generation (GWh)
Lehnmesi 1	1,500	7.0
Lehnmesi 2	1,300	6.1
Mahnd 1	600	2.4
Senipen/Riohk/Lehdau	940	3.7
Nanpil 2	2,000	6.1

Studies have also been undertaken previously to boost the annual generating output of the existing 2 MW Nanpil hydro power plant. One proposal prepared in 2002[4] is to raise the height of the existing dam by about one metre, slurry seal the bottom of the existing reservoir and to excavate an area upstream of the dam to create a small storage reservoir.

The proposed additional storage is the equivalent of only 20 minutes of plant operation and the resulting increase in annual generation is expected to be minimal. However, slightly better controllability of the two generating units would be a benefit.

[3] Power Sector Development Study, ADB TA No: 1827-FSM, 1994 and Lehnmesi 1 HEP Pre-Investment Report by Knight Piesold, August 2004

[4] Nanpil Dam Expansion Report by J Gentry, April 2002

The effect of slurry sealing the reservoir bottom to reduce under-dam leakage has not been quantified, but if for the purposes of this Study it is assumed that a 10% increase in annual generation is possible, this would represent an increase in generation of around 300 MWh. At current diesel fuel costs the PUC would save around USD 50,000 per year, but the required estimated capital cost of USD 600,000 would not make the project economically viable on this basis. It is recommended, however, that the PUC set up stream flow gauges upstream and downstream of the dam and measure the under-dam leakage to establish if losses are more substantial than 10%, which could make the project economically viable.

9.2.2 Diesel

Options available to and previously explored by the PUC to provide electricity generation from diesel fuelled sources are:

(a) New and more fuel efficient diesel generators on a new site close to the tank farm;
(b) Waste heat recovery on existing diesel units;

Installing new and more efficient diesel generators would improve the average fuel consumption from 14.5 kWh/gallon to 15.5 kWh/gallon. It is not recommended that the new diesel units are larger than about 3.5 MW, because for a small power system like on Pohnpei the spinning reserve and standby capacity requirements would become disproportionably large. It would be best if the new diesel units are installed on a new site close to the tank farm and the current USD 0.1¢/gallon fuel delivery charge should be avoided.

Installing waste heat recovery units on the exhaust of existing diesel generators is technically feasible, however there is no demand in the area for process hot water or for low pressure steam for use in desalination plants. Generating steam for electricity generation from the relatively low temperature exhaust gases, would yield only a small (around 500 kW) amount of additional electrical capacity. Given the need for capital intensive and complex condensing type steam turbine equipment, this option is not considered economical.

The high cost of diesel fuel is an incentive for the PUC to import diesel fuel into Pohnpei to try and lower the cost per gallon. Previous studies have looked at the economics for PUC to construct, own and operate its own tank farm. The economics of such an option are unclear, because data presented in a 1997 report[5] suggests a potential saving to the PUC of only about 13 to 17 ¢/gallon on the assumption the PUC does not need to pay taxes. Based on a current annual diesel consumption of 2.7 million gallons the potential savings to the PUC would be in the order of USD 300,000 per year. The 1996 capital cost of a 4 x 500,000 gallon tank farm including unloading facilities was estimated at USD 3.8 million, but this is estimated to increase to close to USD 5 million in 2006 dollars.

Another option would be for the PUC to purchase and operate the existing Mobil tank farm, although this would make the PUC responsible for distribution of various liquid fuels to all customers on Pohnpei.

The Marshalls Energy Company, for example, sells diesel to fishing boat operators from its Majuro Tank farm, but this is a general energy business. For PUC to do the same would cause it to become involved in business outside its core activity and legislative remit. It would also act as a catalyst for more customers to disconnect from the grid.

[5] Feasibility Study of Alternative Diesel Fuel Supplies for PUC, June 1997

9.2.3 Other Possible Generating Options

Other possible generating options for the PUC include:

(a) Wind generators;
(b) Biomass plants;
(c) Solar photovoltaic plants;

Information on wind resources on Pohnpei are scarce, but in general the average wind speeds are considered too low to make wind power economic for a grid based system.

The potential for biomass plants producing methane that fuel gas generators is not clear. No concentrated readily available source of digestible green matter exists and transportation for large volumes of digestible green matter, using diesel fuelled vehicles, across the island quickly makes such schemes uneconomic.

Solar photovoltaic systems are technically feasible and although their capital costs are very high their operating costs are low. A grid based system would also avoid having to install expensive storage batteries, provided the generating capacity of the photovoltaic plant is less than the daytime minimum system demand. A 3.5 MW peak solar photovoltaic plant would be a good fit for the PUC system. A big challenge would be to secure suitable land that is large enough to house the solar cells. An area of approximately 10 hectares would be required for a 3.5 MW solar photovoltaic power plant.

9.3 Least Cost Analysis

For the most promising generating options discussed above a levelised unit generation cost has been calculated and which is compared with the unit generation cost from existing diesel units. The options analysed are:

(a) 3.5 MW diesel generating plant on a new site;
(b) 2.8 MW Lehnmesi and 0.6 MW Mahnd hydro power plant;
(c) 3.5 MW Solar photovoltaic power plant.

Parameters used in the least cost analysis are summarised in the table below:

Table 41 - Planning Parameters for Generation Options on Pohnpei

Parameter	New Diesel	New Hydro	Photovoltaic	Existing Diesel
Installed Capacity (MW)	3.5	3.4	3.5	3.6
Capital Cost (USD million)	3.5	19.8	24.5	0
Annual Net Generation (GWh)	23.7	15.3	6.4	6.4-23.7
Useful Life (yrs)	25	40	20	15
Fuel Consumption (kWh/Gal)	15.5	0	0	14.5
Fuel Cost (USD/Gal)	2.29	0	0	2.30
Fixed O&M Cost (USD/kW/yr)	25	15	15	25
Variable O&M Cost (¢/kWh)	1.0	0.5	0	1.3

The solar photovoltaic option has the lowest annual plant factor and while such a plant is valuable in providing peaking power during daylight hours, there would be no generation output for up to 13 hours per day. Capital cost estimates include contingencies and IDC, but exclude taxes and duties.

A weighted average cost of capital of 6.5% has been assumed for the purposes of evaluating different generation options. This is equal to the incremental cost to PUC of financing these projects on a non concessional basis from the ADB. The rationale for selecting ADB "OCR" finance costs as a reference point is set out in more detail in Section 10. Current ADB OCR rates are 6.0% fixed for ten years. A further 0.5% has been added to reflect contingency and other financing costs that an ADB loan might attract.

Using a conservative Weighted Average Cost of Capital (WACC) rate of 6.5%, the levelised unit generation cost for each option is calculated as shown in the table below. The impact of possible CO2 credits has not been included. The results show that constructing new hydro plants is the least cost option for the PUC in the long term. New diesel plants are not favoured since the improvement in fuel efficiency is offset by the capital cost of new plant. Solar photovoltaic plants are the most expensive option, mainly due their high capital cost and relatively low annual plant factor. At lower WACC rates, hydro is still the best option.

Table 42 - Levelised Unit Generation Cost

Parameter	New Diesel	New Hydro	Photovoltaic	Existing Diesel
Capital Cost (¢/kWh)	1.4	11.8	39.7	0
Fuel Cost (¢/kWh))	15.3	0	0	16.6
O&M Cost (¢/kWh)	1.4	0.8	0.8	1.9
Total Cost (¢/kWh)	18.1	12.6	40.5	18.5

9.4 Financial Implications of Alternatives

The least cost generation expansion option for the PUC discussed in Section 9 points to constructing new hydro power plants and therefore minimising expensive diesel generation. The candidate hydro projects and the timing for their implementation are discussed in Section 9 together with the generation expansion scenario for the next 10 years. Using the generation expansion scenario as a basis the LRMC of electricity supply has been computed at the distribution or sales level by allowing for annual distribution losses of 10.5%.

The impact of possible CO2 credits has not been included. Complete details of the LRMC analysis are included in Attachment 2 and are summarised as follows:

Table 43 - LRMC of Electricity Supply

	LRMC of Electricity Supply (¢/kWh)
Capital	6.0
Fuel	11.5
O&M	3.6
Total	21.1

By comparison, if the PUC continues the status quo and does not construct the proposed hydro power plants the LRMC is estimated to remain at around 20.1¢/kWh. While this rate is slightly lower than the LRMC for the hydro option, it can only be sustained for about 10 years while still operating the existing diesel units. If over the next few years there are further price rises (in real terms) in the cost of diesel fuel, the gap in LRMC between the status quo and the hydro option will narrow and long term the hydro option is expected to yield the lowest LRMC of electricity supply for the PUC.

10 Funding options

Item D.4 of the TOR requires that the Consultant analyse the revenue requirements for capital projects based on varying scenarios for financing including internally generated financing, long term loan and government grant funding. These scenarios are examined in this section, starting with consideration of how PUC has funded itself to date. The likelihood of future funding from these and new sources is then examined. Finally, these funding options are used to arrive at a suggested plan for funding PUC's growth strategy.

10.1 PUC Current Term Funding

10.1.1 Grants

Historically, PUC has received a range of grants, subsidies and capital contributions from the United States Federal Government, the State of Pohnpei and the Japanese International Cooperative Agency (JICA). A major source of financial support came from the Japanese Foreign Aid Programme, which donated two 4.5 MW Daihatsu diesel generators to the FSM in 1995. The National Government retains ownership of these units and effectively licenses their use to PUC, which is responsible for all operating and maintenance costs.

Since 1999, grants, subsidies and capital contributions to PUC amount to USD 3,050,910. The table below shows the support PUC has received from 1 October 1998 to 30 September 2004 as audited.

Table 44 - Grants and Subsidies received by PUC

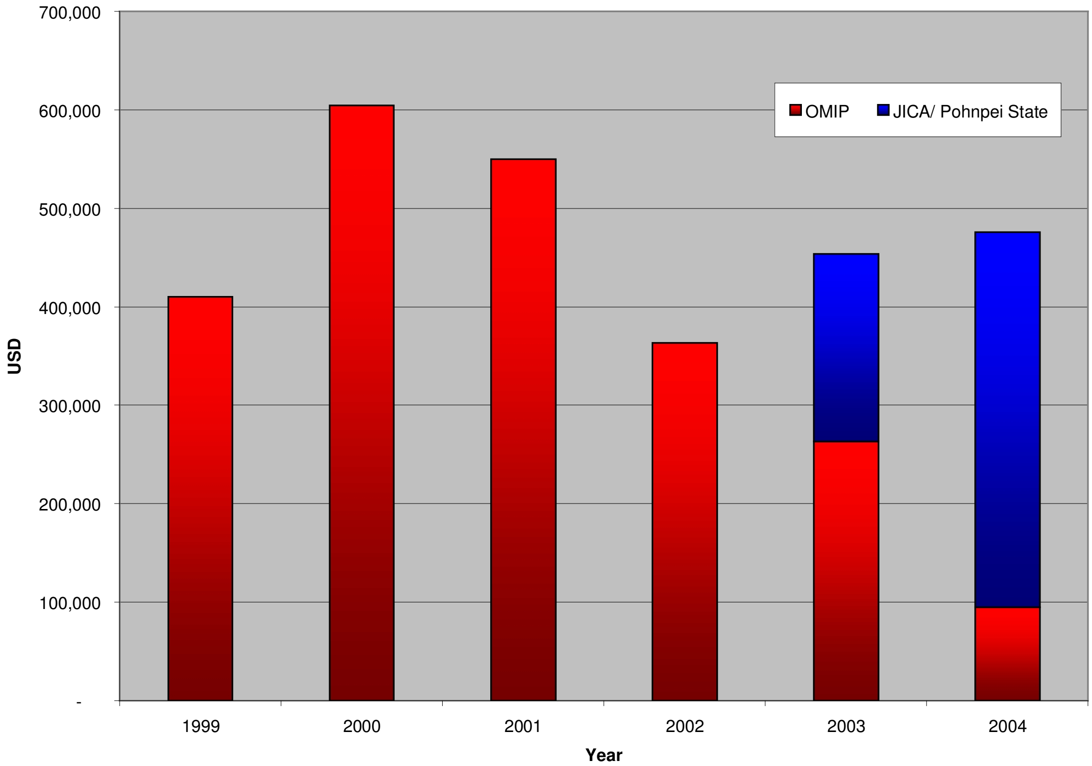
Year	Total	1999	2000	2001	2002	2003	2004
Grants and Subsidies							
US Dept. of Interior: Operations and Maintenance Improvement Programme (OMIP)							
Water	694,785	170,623	225,686	206,681	91,795	-	75,788
Electricity	649,958	183,702	378,712	79,889	-	7,655	-
US Dept. of Interior: Technical Assistance	55,665	55,665	-	-	-	-	-
Continuation of Prepaid Metering Programme	250,000	-	-	250,000	-	-	-
Utility Development	533,536	-	-	13,412	271,807	248,317	17,655
Human Resources Development	7,380	-	-	-	-	7,380	1,500
Total Grants and Subsidies	**2,191,324**	**409,990**	**604,398**	**549,982**	**363,602**	**263,352**	**94,943**
Capital Contributions							
Pohnpei State Grant	190,184	-	-	-	-	190,184	-
Japanese International Cooperative Agency	-	-	-	-	-	-	381,000
Total Capital Contributions	**190,184**	**-**	**-**	**-**	**-**	**190,184**	**381,000**
Total Grants, Subsidies & Capital Contributions	**2,381,508**	**409,990**	**604,398**	**549,982**	**363,602**	**453,536**	**475,943**

In addition, PUC's unaudited financial statements state that PUC received USD 193,459 in grants and subsidies in the year to 30 September 2005.

The most significant source of grant related support has come from the Office of Territorial and International Affairs of the US Department of Interior. The department maintains an Operations and Maintenance Improvement Programme (OMIP) for the purposes of providing technical support on the operation and maintenance of water and wastewater assets. The chart below illustrates the reduction in OMIP support for PUC over the last few years and PUC's budget for the 2006 financial year projects no OMIP financial support.

In 2003 and 2004, PUC received assistance from the Pohnpei Government and JICA amounting to USD 190,000 and USD 381,000 respectively.

Figure 19 - Total Grants, Subsidises and Capital Contributions



10.1.2 Borrowings

PUC is a public corporation established by an act of the Pohnpei Legislature. As such, it is permitted to borrow, but PUC's debts are not those of the Pohnpei State Government. As of September 30, 2004, had two term facilities with the FSM Development Bank and indirectly with the Asian Development Bank (ADB). The amount outstanding under these facilities at that time amounted to USD 2,400,724, against assets of USD 36,005,143 (6.7%).

The FSM Development Bank facility amounts to USD 150,000 and was entered into by PUC in 2001. The loan carries an interest rate of nine per cent and has a five year term, maturing in 2006. Security for the facility was made through PUC making a time deposit of USD 150,000 with FSM Development Bank. The rationale for cash collateralising a loan with an equal time deposit is unclear, since the deposit should earn less interest than PUC is paying to the Development Bank.

The ADB facility was made to the FSM in 2002, on lent to the State of Pohnpei and on lent again to PUC. Security for the facility is by way of a pledge of the Pohnpei State's share of the Compact of Free Association revenues due to the FSM. The State of Pohnpei has not imposed this security on PUC and, in addition, has waived its right to receive 6.82% per annum in interest under the on lending arrangement which is effectively a form of a tariff subsidy. The loan agreement between the FSM and the State of Pohnpei carries an interest charge of 1% per annum, capitalised during the grace period. The loan has a term of 40 years and a grace period of 5 years.

In the 2005 and 2006 financial years, PUC is projected to have debt service obligations of some USD 170,000 and USD 212,000 respectively. This burden is expected to reduce to around USD 65,000 during the 2007 and 2008 financial years, rising to USD 335,000 per annum between 2009 and 2043. The ADB facility is to be repaid on an annuity basis, meaning that each year's principal and interest repayments are equal in aggregate. Of this, the interest component projected to be waived by the State of Pohnpei amounts to USD 100,000 in 2009.

10.2 Future Support from Capital Providers

10.2.1 Bilateral Support

United States

Compact: The original 1986 Compact of Free Association was revised in December 2003. Compact II is provided as a Grant Fund and a Trust Fund. The Grant Fund amounts to some USD 76 million a year, decreasing by USD 0.8 million per annum. Funds are allocated to activities in six priority sectors, including infrastructure. The Trust Fund accrues by approximately USD 16 million per annum, rising by USD 0.8 million per annum until the Compact concludes in 2023. Then it is planned that the accumulated Trust Funds will replace the grant component.

The means of applying Grant Funds to infrastructure is set out in a Fiscal Procedures Agreement (FPA). The FPA does not set the amount of annual grants that can be allocated to infrastructure, but the Infrastructure Development Plan indicates that the amount will be around USD 20 per annum. The FPA gives highest priority to water and waste projects, amongst others, but energy projects have second priority unless they employ renewable energy that cannot be funded through the tariff structure. This arrangement is unclear, because cost recovery might be made through tariffs but this does not help PUC raise the initial capital to finance the capital expenditure of such projects. For this reason, PUC anticipates financing its proposed 10 MW diesel fired power station on Dekehtik Island with funds other than from the Compact.

Importantly, the FPA does not impose any requirement that projects that are proposed for Compact assistance pass particular financial criteria, such as projects having a positive benefit/cost ratio. This can lead to projects being proposed that will attract Compact funding even if they do not use the FSM's scarce resources efficiently.

Even though Compact funding favours water and wastewater projects, the IDP does not contemplate that PUC's projects (extension of the water supply system, Kolonia wastewater treatment and sewerage extension projects) will be funded by the Compact.

USDA: PUC is eligible to borrow from two of the USDA's Rural Utilities Services (RUS) programs. These are the:

- Water and Environmental Programs (WEP); and the,
- Rural Development Electric Program (RDEP).

Water and Wastewater

The WEP provides loans, grants and loan guarantees for drinking water, sanitary sewer, solid waste and storm drainage facilities in rural areas and cities and towns of 10,000 or less. Public bodies, such as PUC may qualify for assistance, provided the funding is used for capital expenditure.

RUS can provide loans, grants and loan guarantees, as follows:

- Loans: Recipients can only apply for funding if they can demonstrate that they are unable to obtain funds from commercial sources at reasonable rates and terms, It is unclear whether RUS funding can be applied to shortfalls after other sources have been exhausted (i.e. co-financing);

- Grants: can be extended to a recipient if this is needed to lower its costs to a reasonable level. Grants can cover up to 75% of project costs. The balance is usually provided by a RUS loan (20%) and the utility (5%);

- Guarantees: may be available for up to 90 % of any eligible loss incurred by the lender. Lenders pay a 1% guarantee fee (although it is unclear whether this is paid annually or on a one time basis), which may be passed on to the loan recipient.

Where loans and guarantees are provided, RUS will lend for up to forty years or the economic life of the asset being funded, whichever comes first. Interest on loans is charged at one of three rates, being a poverty rate, a market rate or an intermediate rate. It is assumed that PUC would be eligible for the poverty rate, which is currently set at 4.5% per annum. A typical RUS WEP facility for PUC would comprise 75% grant, 20% loan for 40 years with a 5% interest rate and 5% being funded internally by PUC. The effective cost of borrowing on this basis is 0.9% per annum.

Electricity

The RDEP offers: Hardship Loans, Municipal Rate Loans, Treasury Rate Loans, Guaranteed Loans, and Assistance to Rural Communities with Extremely High Energy Costs (loans and grant assistance). It is understood that Hardship Loans and Assistance to Rural Communities with Extremely High Energy Costs are the two facilities that apply to PUC's activities.

Hardship Loans are used to finance distribution facilities at a 5% interest rate, fixed for the term of the facility, which may not exceed 35 years.

Assistance to Rural Communities with Extremely High Energy Costs provides grants and loans to for capital expenditure to improve generation, transmission or distribution facilities where average residential energy expenditure for home energy is at least 275 % of the national average.

In March 2006, the average retail price of electricity to ultimate customers in the US was 9.86¢/kWh and 275% of this equals 27.12¢/kWh. As PUC's residential electricity tariff is above this level, Pohnpei State might be eligible for assistance under this program.

The effective cost of borrowing under the RDEP is 2.5% if funded as a 50/50 Grant/Loan but 50% if totally debt funded.

Operations and Maintenance Improvement Program (OMIP): The U.S. Department of Interior is the promoter for the Operations and Maintenance Improvement Program (OMIP). OMIP is a program that provides funds for unifying improvements to the operation and maintenance of the infrastructure in the U.S. areas. OMIP funds are matched, dollar for dollar, by beneficiary government's funding. The Army Corps of Engineers is the technical manager of OMIP for the Department of the Interior.

OMIP funding to PUC has fallen to nothing since 2003, but there is discussion of a second stage of training and technical assistance at some future date.

Japan: Japanese aid to the FSM and the Pacific Islands has generally fallen since 2000. JICA supports the FSM through volunteer-led programs in the areas of primary and secondary education, industrial development, development planning, environment, and regional health. In addition, the Ministry of Foreign Affairs provided USD 3.62 million in grant funding. However, it is understood that the Government of Japan plans to announce new aid to the Pacific Islands worth close to USD 400 million for the 2006 – 2009 period, an increase in Japanese aid for the Pacific by one third.

Further examination of Japanese support is needed, but if this is provided as a JBIC Official Development Assistance (ODA) Loan, typically these facilities carry an interest rate of 0.75 - 1.5% with a term of up to forty years.

China: China is expanding its interests in the Pacific and announced in April 2006, a USD 375 million package of concessional loans over the next three years. This included the FSM being the beneficiary of a USD 2.5 million grant and agreeing a framework for economic development and fisheries.

Chinese Government concessional loans are extended by the China Eximbank. China Eximbank usually lends amounts of greater than USD 2.5 million per borrowing and the terms depend on the accord reached between the Government of China and the beneficiary country. Usually, China Eximbank concessional loans are denominated in Renminbi (RMB), carry an interest rate of 2-3%, loans have maturities of up to 15 years and a grace period of up to five years. Loan covenants are usually reasonable.

Candidate projects can be proposed to the Chinese Government or China Eximbank by the borrowing country based on its development plan and strategy. In the case of PUC, this would be the IDP. China Eximbank then conducts an appraisal and reports its findings to the Chinese Government. If the project is accepted, an Inter-governmental Framework Agreement is signed by the two Governments and this specifies the loan purpose, amount, maturity period and interest rate of the facility. A loan agreement is also entered into by the borrower (the FSM).

European Union (EU): Under the EU's 9th European Development Fund (EDF), FSM has been allocated Euro 4.8 million under an A-envelope for financial and technical co-operation and Euro 1.4 million under a B-envelope for the period 2002- 2007. The program aims to contribute to outer island development through the identification and use of new and renewable sources of energy, and support to the work of non-state actors in the areas of conservation and environmental protection. Tentatively the 9th EDF project among others will provide support for photovoltaic and bio-fuel generation options in FSM.

The EU also has the EU Energy Facility (EUEF). In June 2005, the ACP-EU Council approved the creation of an Energy Facility with a total fund amount of EUR 220 million which was finally approved on 2nd June 2006. Of the fund, EUR 198 million has been allocated to a single Call for Proposals which was launched on 19th June 2006, with a single call for proposals being due for submission on 19th September 2006.

Infrastructure Projects that cost more than 2.5 million Euros (~USD 3.15 million) can be 50% funded by a grant of up to 10 million Euros (~USD 12.6 million). This implies non ODA co-financing with other organisations, but there are a number of options in this respect.

Pacific Islands Energy Policy and Strategic Action Plan (PIEPSAP): is a technical assistance initiative funded by the Danish Government under the EU Energy Initiative. PIEPSAP was created following the World Summit on Sustainable Development in Johannesburg in 2000. The Study is being funded by PIEPSAP and facilitated by SOPAC, the South Pacific Applied Geoscience Commission.

PIEPSAP started in August 2004 and it is planned to be available until August 2007. Aside from assisting with the Study, PIEPSAP is providing assistance in sourcing concessionary finance for PUC's medium term hydropower development, in the development of a FSM National Energy Policy with a guideline for renewable energy development and in providing advisory assistance in developing EUEF proposals.

Australia: In 2006-07 Australia will assist the FSM with border security as well as tertiary scholarships for study in Australia and the Pacific region. In addition, a small grants scheme supports the work of community organizations and some government initiatives. Australian input is estimated at around AUD 800,000.

PUC's activities do not appear to be eligible for direct AUSAID support in the near term. However, Australian Government Overseas Aid Program (AUSAID) is providing USD 0.45 million toward the USD 30.0 million Sustainable Energy Finance Project discussed under the World Bank, below.

New Zealand's Support to the FSM is included within New Zealand's International Aid and Development Agency's (NZAID) program to other Micronesian states, with an allocation of NZD 0.8 million in 2004-05, but no identified support for 2006-07. The focus is on education and with limited grant funds for self-standing community development initiatives. PUC's activities are unlikely to attract support from NZAID.

10.2.2 Multilateral Support

Asian Development Bank (ADB): The ADB identifies three strategic areas of support for the FSM, being: good governance; inclusive social development; and, pro-poor economic growth.

An indicative ADF allocation of USD 8 million has been set for FSM over the coming period to 2008. ADB has two active lending operations in FSM totalling USD 33.8 million in ADF credits for the Basic Social Services Project, the Private Sector Development Program and a program loan.

Of most significance to PUC is the Omnibus Infrastructure Development Loan Project (OIDP), which was declared effective on 23 March 2006. The total project cost is estimated at USD 30.2 million, of which USD 19 million equivalent was financed by ADB and USD 11.2 million by the National Government.

The State Government will borrow from the National Government and lend PUC USD 10.7 million for "Component A" of the Loan from the State Government. Component A involves improvements to the Pohnpei wastewater system as outlined in Section 6.4. Disbursements for Component A will be made from effectiveness until mid 2009.

PUC's borrowings in respect of Component A are expected to be funded as outlined in the following table.

Table 45 - PUC's borrowings for "Component A" of the Omnibus Loan

	ADB (USD million)	Government (USD million)	Total (USD million)
Asian Development Funds (ADF)	5.5	1.4	6.9
Ordinary Cash Resources (OCR)	2.0	1.8	3.8
Total	7.5	3.2	10.7

ADF funding is concessional finance made available for forty years, including an eight year grace period. The OCR facility is made available on non concessional terms for a period of twenty five years, including a five year grace period. Should PUC default on payments under either of these facilities, the State Government will be responsible for payment to the National Government. The National Government has the power to withhold tax revenues or Compact funding if the State Government defaults on payments. There was some doubt within the National Government that State utilities such as Chuuk Public Utility Commission (CPUC) and PUC would be able to meet their debt service obligations, according to Standing Committee Report 14-66 of the FSM Committee on Ways and Means dated November 2005.

Usual ADF lending to the FSM is in the order of USD 5 million every two to three years. However, the ADB is encouraging the graduation of the FSM from being "ADF-only" to "ADF with limited OCR". The Omnibus loan is an example of this transition.

The ADB intends to alter the project cost-sharing limits for ADF loans in future. Where it currently funds 80% of ADF projects, this proportion will reduce to 70% in future. When that will be is unclear because the ADB's Country Strategy and Program Update (2006-2007) for the FSM ("CSPU") affirms that there will be no ADB loans processed for the FSM during the 2006-2007 period so that the National Government is able to focus on existing loan programmes. This means that a loan for solid waste management (in addition to the funding for this purpose made available under the Omnibus loan) that was planned for 2007 is now likely to be delayed.

It is not clear whether applications for OCR funding can be made to the ADB for PUC's commercial activities during the loan moratorium period or whether only ADF applications are affected. For instance, if PUC decides to develop the 2.8 MW Lehnmesi and 0.6 MW Mahnd hydro facilities, an ADB OCR loan would be a possible source of finance for the funding of those projects.

The World Bank Group: The World Bank has limited activities in the Pacific, with current commitments of around USD 50 million to ten projects in Kiribati, Tonga, Samoa and the Solomons. The Bank is prepared to assist the FSM but is conscious of the substantial grant assistance the FSM has had from the US and Japan. Any support is likely to be targeted at private sector development and enhancing the government's ability to maintain key assets. This would appear to preclude assistance for asset growth.

The World Bank is also formulating the Sustainable Energy Finance Project (SEFP). This is a pipeline project to provide USD 30.0 million over a seven year period toward renewable energy projects as a means of displacing diesel generation in Pacific Island Countries. The Bank recognises that the introduction of Renewable Energy schemes faces the barriers of initial investment, limited experience of local financial institutions in energy lending and technical capacity that is in short supply. The SEFP includes the FSM but is more targeted toward Papua New Guinea, Fiji and the Solomon Islands where the World Bank has experience. In addition, the SEFP is aimed at Solar PV, pico hydro (under 5 kW) and locally produced bio-fuels using coconut oil, although other projects will be considered.

Overall, the focus of the fund is unlikely to be particularly helpful to PUC if the least cost generation options recommended in Section 9 are pursued, but it might be helpful if PUC were to assist customers (who are necessarily off-grid) to develop a small scale generation capability.

The World Bank also has a facility called the Private Participation in Infrastructure Advisory Facility (PPIAF) that can be applied to finance advisory services aimed at increasing private sector involvement in infrastructure. This facility might have some value if PUC decided to proceed with a private financing model for the development of the 2.8 MW Lehnmesi and 0.6 MW Mahnd hydro facilities. The Bank, through its Project Finance and Guarantees Division of the Infrastructure Economics and Finance Department, also has the capacity to provide partial risk guarantees to cover country risks that commercial lenders are unable to accept. PUC could consider these forms of support if the proposed hydro facilities were to be procured on a build-own-operate or build-operate-transfer. Alternatively, PUC might develop the projects itself and then transfer the assets to the private sector through a partial privatisation that leaves it simply contracting for electricity through a power purchase agreement, whilst not taking the risks associate with control of the assets. This is considered to be an unlikely route given the scale of the projects.

United Nations Development Programme (UNDP): The United Nations Development Programme, under its Global Environment Facility (GEF) has a Pacific Islands Greenhouse Gas Abatement through Renewable Energy Project (PIGGAREP). This USD 26.0 million project is aimed at reducing the Greenhouse Gas (GHG) emission growth by displacing fossil fuel use in the Pacific by promoting renewable energy options.

The project is expected to expand the renewable energy market by increasing the number of successful commercial renewable energy projects. It aims to achieve this by: (a) enhancing institutional capacity, (b) increasing the availability of financing to renewable energy projects; (c) strengthening relevant legal and regulatory environments; and, (d) raising the understanding of renewable energy among key stakeholders.

The FSM is identified by the PIGGAREP as having 2.86 MW of potential renewable capacity, and that the greatest greenhouse gas savings are likely to come from increasing hydro (saving 14.2 ktons CO_2), followed by bio-diesel (2.3 ktons CO_2) and PV (0.3 ktons CO_2).

Cook Islands, Fiji, Kiribati, Nauru, Niue, Papua New Guinea, Samoa, Solomon Island, Tonga, Tuvalu and Vanuatu). The FSM is not a signatory to PIGGAREP, but it is identified by the project as being a potential beneficiary.

10.3 Conclusions

There are a range of sources of finance that PUC can consider financing its projects. These fall into two groups: bilateral support and multilateral support.

Bilateral sources include:

- The US (Compact, RUS and OMIP);
- European Union (EDF, EUEF and PIEPSAP);
- Australia (AUSAID); and,
- New Zealand (NZAID).

Multilateral sources include:

- The Asian Development Bank (ADF and OCR Loan);
- The World Bank (grants, loans, SEFP and PPIAF); and,
- UNDP’s PIGGAREP facility.

These sources provide a range of grants, concessional loans, commercial loans and technical assistance facilities. For capital expenditure, PUC would want to maximise access to grants from the Compact, RUS and the EUEF first, followed by concessional facilities from Japan, China, the ADB and the World Bank.

While the ADB's OCR non concessional loan is not the cheapest source of finance, the least cost expansion planning has been based on such a loan to be prudent. PUC would naturally want to minimise its cost of finance when developing specific financing plans for its capital expenditure. These issues will be developed further in the final report.

11 Alternative Financing and Ownership Models

11.1 Introduction

Following the Consultant's submission of the draft version of the Final Report of the Operation and Rates Analysis study it became clear to PUC that there was a need for some further analysis.

Given that PUC is currently wholly owned by the state of Pohnpei, PUC considered that a review of how its assets are owned and managed should be undertaken. The purpose of the review is to see whether there are other financing and ownership modalities that might be adopted to deliver the services PUC provides more cost effectively.

The additional analysis required is:

- To review the various forms of financing modalities to determine which of these might deliver better value for money to consumers than the current arrangements;
- To assess in general terms the framework and costs associated with establishing a framework for implementing these modalities, assuming that international best practices are followed;
- To advise which, if any, of these models should be considered in further detail by PUC and the State Government, and;
- To suggest the likely tariffs that would result from each of the proposed models.

This section has been prepared by reference to a range of best practice materials, including the World Bank Toolkits, "Granting and Negotiating Infrastructure Concessions" and "Reforming Infrastructure".

11.2 Drivers for Reform

The challenges that PUC faces are not unusual. This is because electricity, water and wastewater services serve basic needs, but some people do not have access to safe and reliable services. End users expect to receive a reasonable level of service in terms of quality and quantity, that the utility will have a reasonable capital expenditure programme to meet new demands and services will be cost-effective.

Often though, people in developing countries do not have their expectations met and this can be because tariffs simply cover operating costs because the government wants to keep services affordable. Governments typically bear some of the utility's costs by writing off debt, waiving interest payments or not requiring a dividend - as is the case with Pohnpei State and PUC. The problem is that these subsidized tariffs are good for consumers who are better off but they are not good for the poor. Therefore, tariff subsidies mainly benefit wealthier people who are connected to the existing network. People who are not connected do not get the benefit of subsidies and might not have good prospects for receiving any service because the utility does not have the revenues to expand.

PUC is affected by these characteristics to some degree because it has limited revenues that can be applied to expanding its service. It relies on grants or loans that have interest payment waivers to roll out new services, but then it must bear the maintenance costs of keeping its assets in service. While it must run efficiently and reduce costs by as much as reasonably possible, PUC must also generate revenues to cover its expansion plans if those plans are the best economic options for the State. In short, PUC is a long term business and political decisions surrounding PUC's activities must also be made on a long term basis, not based on voter pressures or electoral cycles.

A solution to the problems faced by utilities like PUC cannot be found unless there is understanding of their root causes. Usually these causes are not simply a matter of cutting costs, collecting arrears, increasing tariffs or improving the utility's skill and productivity levels? For example, we have found that pay levels at PUC are reasonable given the alternatives open to PUC staff and that there is active training of staff. We have also found that there could be staff reductions in certain areas by up to ten percent and that productivity levels could also be improved over time, but we have also suggested that this is unlikely to materially reduce tariffs.

Instead, the State Government needs to encourage a structure, whether it is provided by the public or private sector that:

- Encourages the utilities assets to be managed by good quality people that can manage without political interference;

- Ensures the utility is run efficiently, both in terms of its day to day operations and new investments;

- Generates enough cash to maintain its assets and build new assets so that as many people as reasonably possible receive service.

This does not automatically mean that the answer lies in private participation. Restructuring, technical assistance, appointment of the best possible board members and management, development-agency assistance, and other measures can achieve these objectives just as (or even more) effectively. Reform measures that include adequate stakeholder consultation, setting upstream policy, and defining service standards, tariffs, and subsidies should probably be applied first before looking to the private sector. If, after that process, the results the State Government have not been achieved, then opening aspects of the utility's business to the private sector is worth considering, but that approach needs careful advance planning.

Private involvement in PUC's business might bring new skills, create a focus on service and commercial performance and ease access to finance but clear policy would need to be established by the State Government first. To engage with the private sector before doing the hard and expensive work needed to establish that policy is almost certain to lead to failure and that is why the Telesource proposal should not be considered by the State Government at this juncture, irrespective of the proposal's merits (which the Consultant questions in any event).

Private sector firms involved in the delivery of electricity, water and wastewater services do so provided the risk-return balance meets their criteria. Private firms would seek a higher weighted average cost of capital than the 2.4% assessed by the Consultant for PUC, so the only way that a private operator could reduce tariffs and improve service levels is through efficiency gains. If this is so, then it is best that PUC under State ownership strives to achieve those potential gains first.

If a private firm is involved in the delivery of services, the government remains ultimately accountable for service delivery. Therefore, government must ensure that it: (a) sets the right performance criteria for the private partner to meet, (b) satisfies itself that that the cost and quality of service meets the reasonable standards set by the government, (c) monitors the performance of the contract and (d) enforces the agreement should the private partner fail to perform satisfactorily.

The State Government would need to have a well qualified unit to carry out the functions listed above and, at present, the closest entity within Pohnpei is the RPPU. Members if the RPPU have said, however, that they do not possess all the skills required to interface with PUC and so there would need to be substantial capacity building and the creation of several full time positions for the RPPU to function as a counterparty to a private sector partner. These costs would need to be built into the tariffs and be borne by consumers.

11.3 Process and Models for Private Sector Engagement

11.3.1 Establishing a Framework for Engaging with the Private Sector

For any private sector involvement in PUC's activities to be successful, a range of pre-requisite conditions would need to exist. These are: (a) suitable, market friendly institutions being in present; (b) the legal system being suitably well developed; (c) that there is a private sector well geared toward competition and; (d) there is effective regulation in place. That regulation, in turn, needs to be coherent, truly independent, accountable, transparent and predictable in its actions. Not all of these components are developed to the stage needed for substantial private sector involvement, so the State Government would have some preparatory work to do before embarking too far down that path.

Provided the above conditions exist, the options available to the State Government depend on the level of competition there might be in each of PUC's activities. Insofar as PUC's electricity business is concerned, there is no practical scope for competition in distribution, but there might be some limited scope in existing generation (eg along the lines of the Telesource proposal, if properly prepared and competitively bid) or new generation (eg new hydro run on a concession basis).

Regarding water, the same lack of competition stands in the way of private involvement in distribution and wastewater collection, but there is some scope in water abstraction (eg wells being run privately) and in water sewage and treatment.

Firstly though, the State Government would need to decide how many utilities there might be for the provision of the services that PUC currently provides. The discrete aspects of PUC's business are:

- Electricity – generation, distribution and retail;
- Water – abstraction, treatment, distribution and retail;
- Wastewater – collection, treatment, discharge and retail.

Having a separate electricity utility is possible and is, of course, how PUC started life. This would mean, then, that PUC's water and wastewater businesses would need to be run as a separate utility and this would bring about duplication of common services. It would also be also be difficult to open the State's water and wastewater activities to the private sector fully because of the substantial social nature of this business.

It would also be theoretically possible to go further than separating the electricity and water businesses into separate entities by unbundling all the sub-components of those businesses, but in practical terms this would not be workable on Pohnpei because the business is too small for any net benefits to be derived.

Therefore, having a single entity to carry out all functions is the most commonly adopted model because the economies of scale are better, it is easier to coordinate interrelated decisions and because private sector options with a larger operation are likely to attract higher private sector interest.

11.3.2 Models

It would be unusual to move from the current fully public model to engaging with the private sector without some intermediate steps. The State Government has taken the first of these steps by creating PUC as an autonomous, self-financing commercial utility. This arrangement offers the minimum conditions for competition by making utility supply commercial and transparent.

Competitive Procurement - The next step along the public-private path is to encourage competitive procurement of specific functions such as tree-trimming, line maintenance, pipe laying and maintenance. The functions that are best suited to outsourcing have a reasonably low level of skill in the initial stages so that there is a reasonable pool of competitors to bid for work. Standards, procurement and contract management would need to be set by PUC with care and a level of training would also be required to help the private sector upskill and engage with PUC most effectively. In any event, bidding for service contracts needs to be open and transparent, with contract periods being set either project by project or for short periods of 1-2 years.

Competitive contracting is the easiest way to get the private sector involved in PUC's business, while leaving the utility to run the majority of its operations, manage its assets and serve its clients. It is a useful stepping stone toward more involved methods of private sector participation.

Competition in the Market – A further level of private sector involvement might involve what is called competition in the market and two examples are: (a) division of generation into different units that might compete or, more practically; (b) splitting off PUC's bottled water business and allowing the service to compete with PUC by serving customers on PUC's piped network that seek a higher quality of water than the network can provide. Care would need to be taken to ensure that unconnected customers are protected because the bottled water business has a natural monopoly in those areas, so its activities would need to be regulated. The cost of doing so might well outweigh the benefits.

Competition for the Market – The penultimate step toward full private sector engagement is to create a competition for the right to provide part or all of the utility's services to the market. There are a number of ways that this can be done, as follows:

Concessions - The government might want the operator to be responsible for all aspects of the service. The operator would be legally bound to meet the specified service standards, and to make and finance the investments necessary to improve service. In return the operator would be entitled to the tariff revenue (and perhaps also subsidies). Concessions are usually long term with contracts of 25 years being reasonably common, can involve all the business being managed by the private partner or an operating concession for part or all of the business. The Telesource proposal is an example of a potential operating concession for an aspect of PUC's business.

Lease-affermage contracts - These make the private operator responsible for everything except new investment. This can make sense where the risks make private finance expensive or impossible to obtain. Such risks could include a likelihood that tariffs would not yield enough revenue to pay for investments, or that subsequent governments would not stick to the rules originally agreed.

Management contracts - These are usually shorter-term arrangements in which a private operator is paid a fee for providing a management team to run the public utility. In this case, most of the risk stays with government. For example, if the utility cannot cover its costs, the government bears the loss, not the operator. The contract usually provides for bonuses in the event that the management team helps the utility to meet or exceed specified performance targets.

Privatisation – This final step in the public-private spectrum is privatisation, which involves the transfer of ownership and control of hitherto public assets to the private sector. From experience, it has been learnt that the benefits of privatisation have come less from the transfer of ownership and more from the sectoral reforms that preceded the transfer. Privatisations have had their place and have been common for electricity assets, but less so for water assets. In any event, they rely on there being suitable competition in the market for the provision of services so that consumers have choice. This is not a realistic outcome on Pohnpei because of economies of scale, so clear regulation would be needed instead. While PUC's electricity assets might be a candidate for privatisation, the State Government does not currently have the capacity it needs to set up the necessary framework and then procure a private partner, not does the Consultant believe there are net benefits in this approach.

Overall, the Consultant considers that the State Government would be better to encourage (a) PUC to continue improving its productivity; (b) the introduction of the private sector through the outsourcing of specific PUC functions, while allowing PUC to operate the bulk of its business as it does currently and (c) to consider helping bolster the capacity of the RPPU so that it can assume more regulatory capabilities over time.

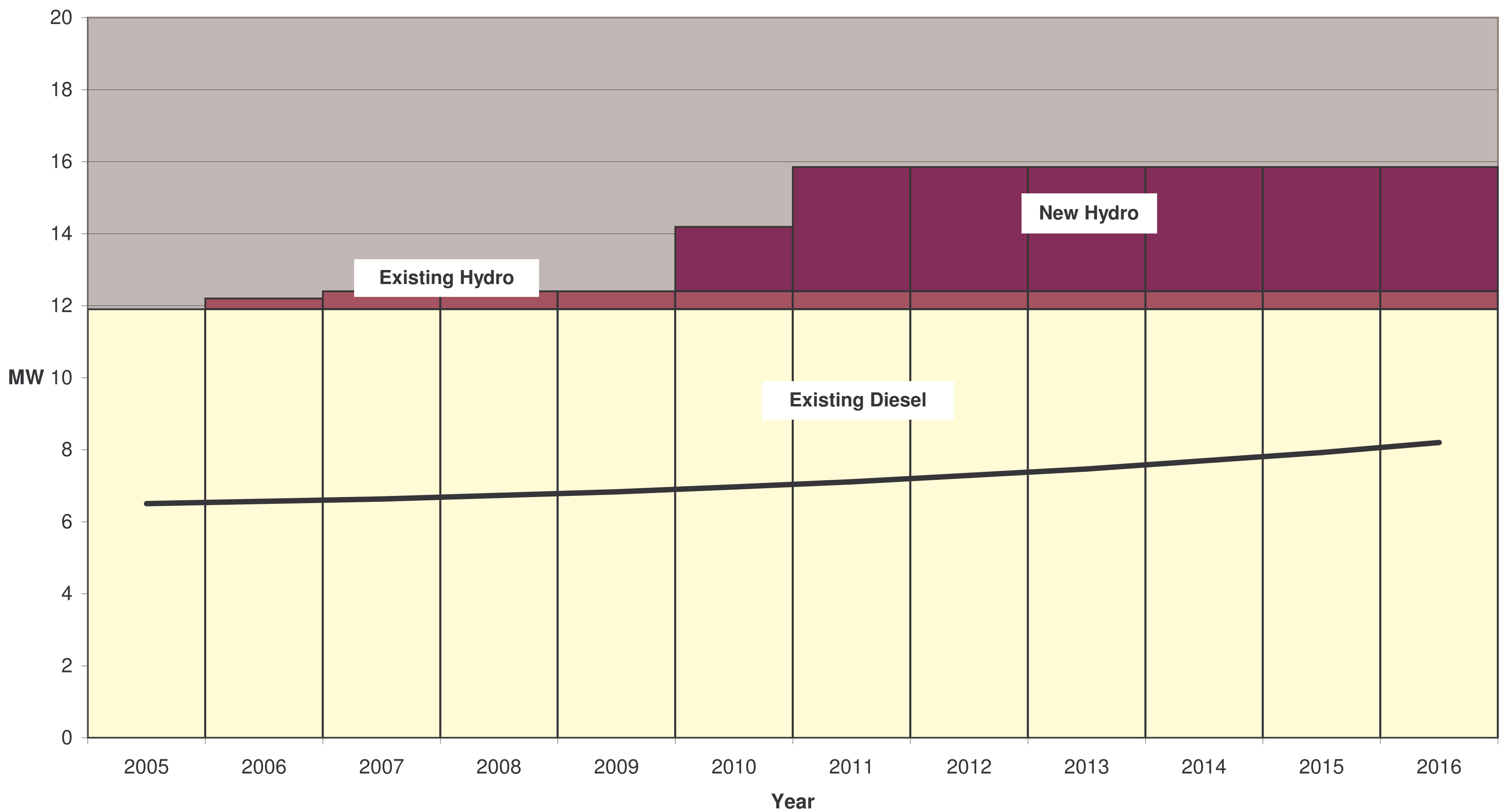
ATTACHMENT 1

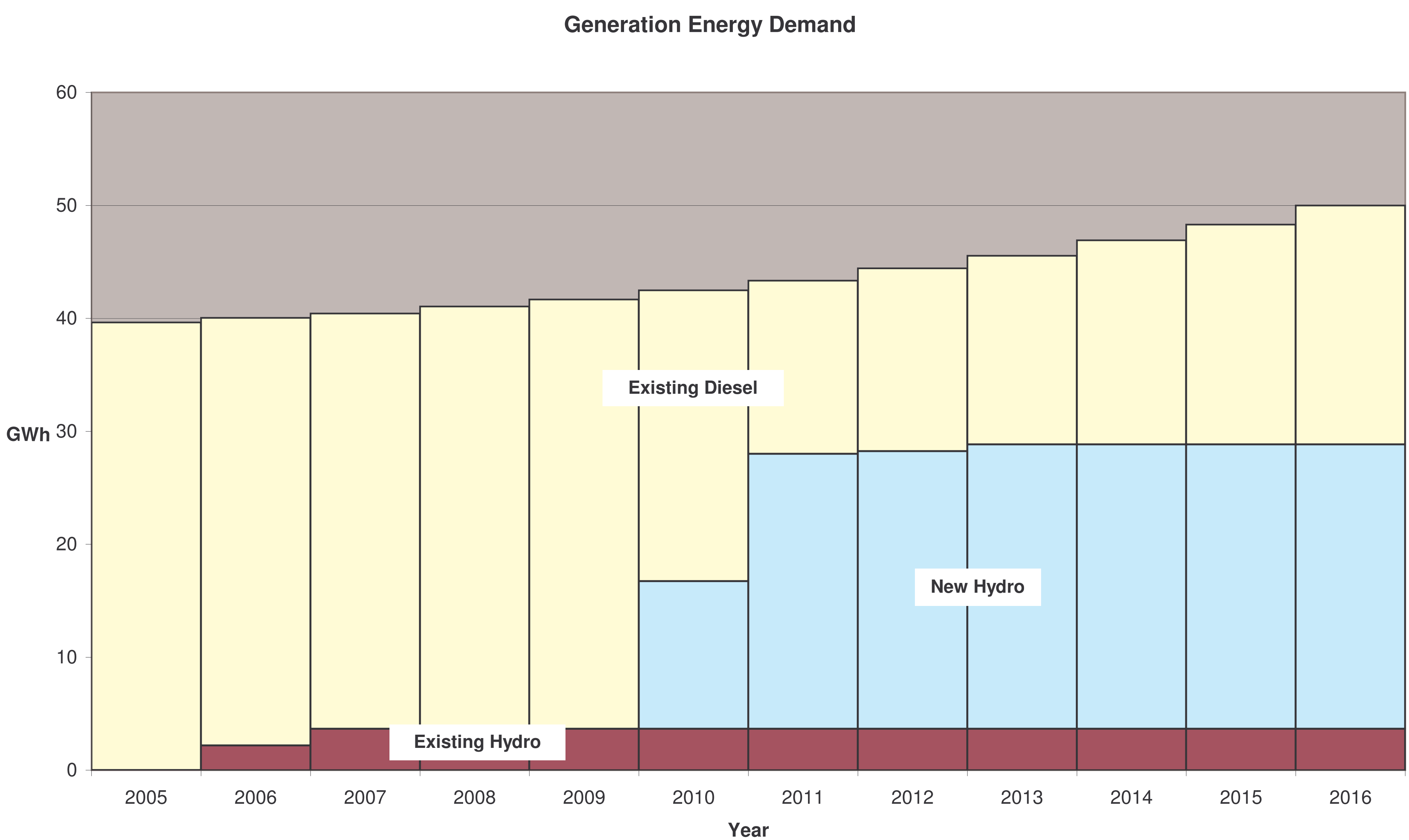
Generation Expansion Scenario

Generation Expansion in Pohnpei System

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Peak Demand (MW)	6.5	6.6	6.6	6.7	6.8	7.0	7.1	7.3	7.5	7.7	7.9	8.2
Energy Demand (GWh)	39.6	40.0	40.4	41.0	41.7	42.5	43.3	44.4	45.5	46.9	48.3	50.0
System Load Factor (%)	69.6	69.6	69.6	69.6	69.6	69.6	69.6	69.6	69.6	69.6	69.6	69.6
Existing Diesel Plants												
Firm Capacity (MW)	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Energy (GWh)	39.6	37.8	36.8	37.4	38.0	25.8	15.4	16.2	16.7	18.1	19.5	21.2
Capacity Factor (%)	38.0	36.3	35.3	35.9	36.5	24.7	14.7	15.5	16.0	17.3	18.7	20.3
Existing Hydro Plant												
Firm Capacity (MW)	0.0	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Energy (GWh)	0.0	2.2	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Capacity Factor (%)	0.0	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3
New Hydro Plant												
Firm Capacity (MW)	0.0	0.0	0.0	0.0	0.0	1.8	3.5	3.5	3.5	3.5	3.5	3.5
Energy (GWh)	0.0	0.0	0.0	0.0	0.0	13.1	24.3	24.6	25.2	25.2	25.2	25.2
Capacity Factor (%)	0.0	0.0	0.0	0.0	0.0	83.3	80.5	81.4	83.3	83.3	83.3	83.3

Generation Peak Demand and Firm Capacity



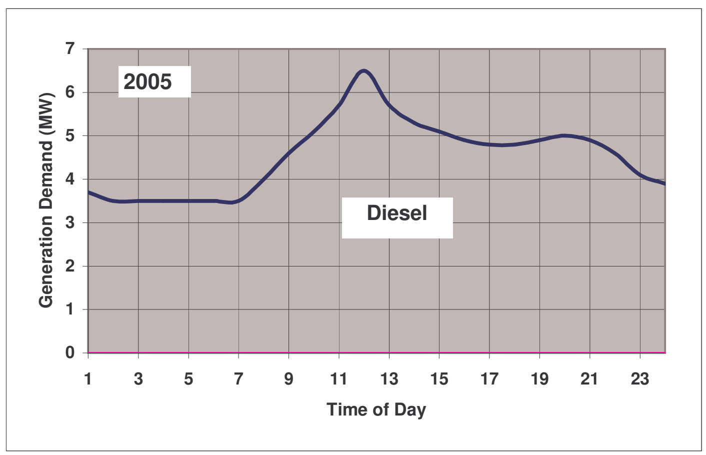

Generation Energy Demand
60
50
40
GWh 30
20
10
0
Existing Diesel
New Hydro
Existing Hydro
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
Year

Pohnpei System Generation Dispatch

Maunsell Ltd

			Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
Generator Name	**Inst Cap**	**Firm Cap**	**Class**	**Generation Demand (MW)**																								**GWh**	**%**
	MW	**MW**		3.7	3.5	3.5	3.5	3.5	3.5	3.5	4.0	4.6	5.1	5.7	6.5	5.7	5.3	5.1	4.9	4.8	4.8	4.9	5.0	4.9	4.6	4.1	3.9	39.6	69.6
Existing Generators																													
CAT-4	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.5	0.9	0.5	0.3	0.9	0.8	0.7	0.7	0.8	0.8	0.8	0.0	0.0	0.0	3.0	38.5
CAT-5	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.5	0.9	0.5	0.3	0.9	0.8	0.7	0.7	0.8	0.8	0.8	0.0	0.0	0.0	3.0	38.5
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	BI	1.9	1.8	1.8	1.8	1.8	1.8	1.8	2.0	2.3	1.7	2.4	2.4	2.4	2.4	1.7	1.7	1.7	1.7	1.7	1.7	1.7	2.3	2.1	2.0	16.8	79.8
DAI-10	2.500	2.400	BI	1.9	1.8	1.8	1.8	1.8	1.8	1.8	2.0	2.3	1.7	2.4	2.4	2.4	2.4	1.7	1.7	1.7	1.7	1.7	1.7	1.7	2.3	2.1	2.0	16.8	79.8
Hydro #1	0.725	0.000	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro #2	1.333	0.000	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**15.463**	**11.900**		3.7	3.5	3.5	3.5	3.5	3.5	3.5	4.0	4.6	5.1	5.7	6.5	5.7	5.3	5.1	4.9	4.8	4.8	4.9	5.0	4.9	4.6	4.1	3.9	39.6	

Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**3.0**
MW Growth (%)	**base**
GWh Growth (%)	**base**
Total Base Capacity (MW)	**0.0**
Total Base/Interm Cap (MW)	**4.8**
Total Intermediate Cap (MW)	**1.8**
Total Peak Capacity (MW)	**5.3**
	11.9
Peak to Base Load Ratio	**0.8**

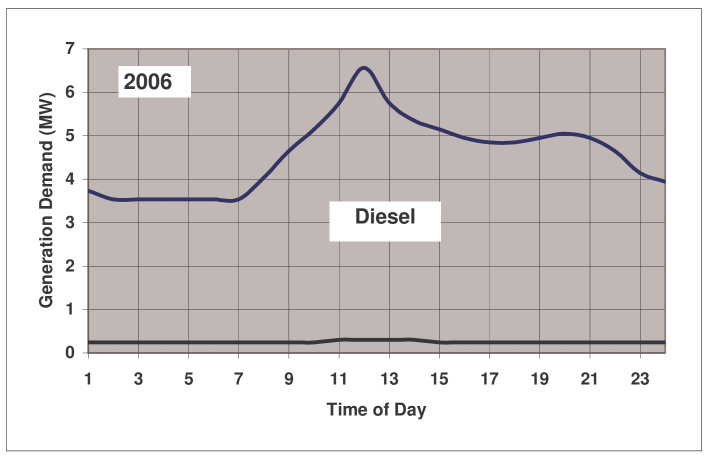


Notes:

Generator Name	Inst Cap	Firm Cap	Class	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
			Time of Day												Generation Demand (MW)													GWh	%
	MW	MW		3.7	3.5	3.5	3.5	3.5	3.5	3.5	4.0	4.6	5.2	5.8	6.6	5.8	5.4	5.2	4.9	4.8	4.8	4.9	5.1	4.9	4.6	4.1	3.9	40.0	69.6
Existing Generators																													
CAT-4	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3	0.7	0.3	0.1	0.8	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	1.4	17.6
CAT-5	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3	0.7	0.3	0.1	0.8	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	1.4	17.6
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.9	2.2	1.7	2.4	2.4	2.4	2.4	1.7	2.4	2.3	2.3	2.4	1.7	2.4	2.2	2.0	1.8	17.5	83.4
DAI-10	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.9	2.2	1.7	2.4	2.4	2.4	2.4	1.7	2.4	2.3	2.3	2.4	1.7	2.4	2.2	2.0	1.8	17.5	83.4
Hydro #1	0.725	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
Hydro #2	1.333	0.000	B	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**15.463**	**12.200**		3.7	3.5	3.5	3.5	3.5	3.5	3.5	4.0	4.6	5.2	5.8	6.6	5.8	5.4	5.2	4.9	4.8	4.8	4.9	5.1	4.9	4.6	4.1	3.9	40.0	

Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**3.2**
MW Growth (%)	**1**
GWh Growth (%)	**1**
Total Base Capacity (MW)	**0.3**
Total Base/Interm Cap (MW)	**4.8**
Total Intermediate Cap (MW)	**1.8**
Total Peak Capacity (MW)	**5.3**
	12.2
Peak to Base Load Ratio	**0.8**

Notes:



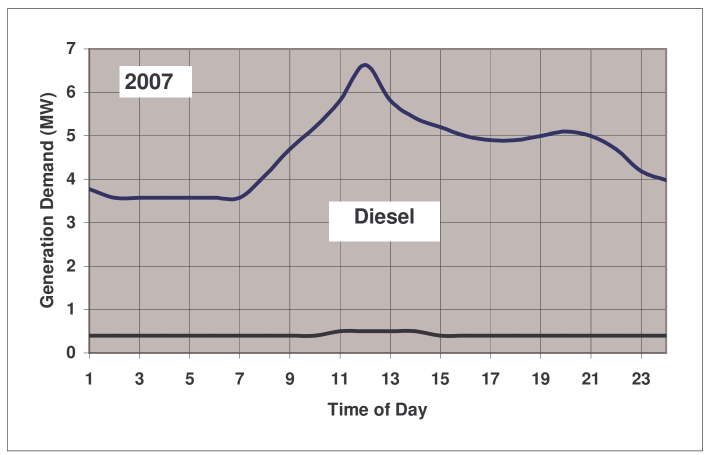
Pohnpei System Generation Dispatch

Maunsell Ltd

Generator Name	Inst Cap MW	Firm Cap MW	Class / Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total GWh	LF/CF %
				Generation Demand (MW)																									
				3.8	3.6	3.6	3.6	3.6	3.6	3.6	4.1	4.7	5.2	5.8	6.6	5.8	5.4	5.2	5.0	4.9	4.9	5.0	5.1	5.0	4.7	4.2	4.0	40.4	69.6
Existing Generators																													
CAT-4	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.3	0.7	0.3	0.1	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	12.4
CAT-5	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.3	0.7	0.3	0.1	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	12.4
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.8	2.1	1.7	2.4	2.4	2.4	2.4	1.7	2.3	2.2	2.2	2.3	2.4	2.3	2.1	1.9	1.8	17.4	82.8
DAI-10	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.8	2.1	1.7	2.4	2.4	2.4	2.4	1.7	2.3	2.2	2.2	2.3	2.4	2.3	2.1	1.9	1.8	17.4	82.8
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**15.463**	**12.400**		3.8	3.6	3.6	3.6	3.6	3.6	3.6	4.1	4.7	5.2	5.8	6.6	5.8	5.4	5.2	5.0	4.9	4.9	5.0	5.1	5.0	4.7	4.2	4.0	40.4	

Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**3.4**
MW Growth (%)	**1.0**
GWh Growth (%)	**1.0**
Total Base Capacity (MW)	**0.5**
Total Base/Interm Cap (MW)	**4.8**
Total Intermediate Cap (MW)	**1.8**
Total Peak Capacity (MW)	**5.3**
	12.4
Peak to Base Load Ratio	**0.8**

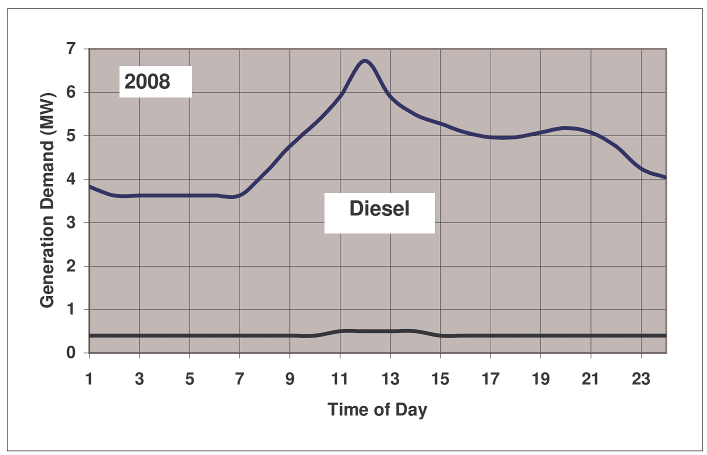
Notes:



Generator Name	Inst Cap MW	Firm Cap MW	Class	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total GWh	LF/CF %
			Time of Day / Generation Demand (MW)	3.8	3.6	3.6	3.6	3.6	3.6	3.6	4.1	4.8	5.3	5.9	6.7	5.9	5.5	5.3	5.1	5.0	5.0	5.1	5.2	5.1	4.8	4.2	4.0	41.0	69.6
Existing Generators																													
CAT-4	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3	0.7	0.3	0.1	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	13.6
CAT-5	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3	0.7	0.3	0.1	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	13.6
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.9	2.2	1.7	2.4	2.4	2.4	2.4	1.7	2.3	2.3	2.3	2.3	2.4	2.3	2.2	1.9	1.8	17.6	83.8
DAI-10	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.9	2.2	1.7	2.4	2.4	2.4	2.4	1.7	2.3	2.3	2.3	2.3	2.4	2.3	2.2	1.9	1.8	17.6	83.8
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**15.463**	**12.400**		3.8	3.6	3.6	3.6	3.6	3.6	3.6	4.1	4.8	5.3	5.9	6.7	5.9	5.5	5.3	5.1	5.0	5.0	5.1	5.2	5.1	4.8	4.2	4.0	41.0	

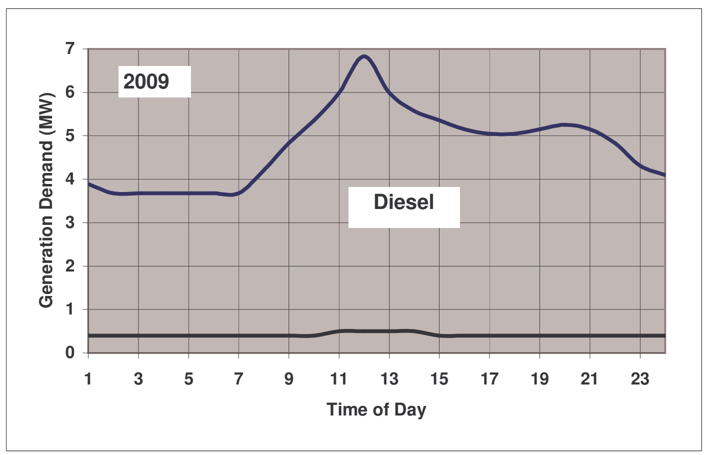
Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**3.3**
MW Growth (%)	**1.5**
GWh Growth (%)	**1.5**
Total Base Capacity (MW)	**0.5**
Total Base/Interm Cap (MW)	**4.8**
Total Intermediate Cap (MW)	**1.8**
Total Peak Capacity (MW)	**5.3**
	12.4
Peak to Base Load Ratio	**0.8**

Notes:



			Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
Generator Name	**Inst Cap**	**Firm Cap**	**Class**	**Generation Demand (MW)**																								**GWh**	**%**
	MW	**MW**		3.9	3.7	3.7	3.7	3.7	3.7	3.7	4.2	4.8	5.4	6.0	6.8	6.0	5.6	5.4	5.1	5.0	5.0	5.1	5.3	5.1	4.8	4.3	4.1	41.7	69.6
Existing Generators																													
CAT-4	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3	0.8	0.3	0.1	0.8	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	1.4	18.2
CAT-5	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3	0.8	0.3	0.1	0.8	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	1.4	18.2
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.9	2.2	1.7	2.4	2.4	2.4	2.4	1.7	2.4	2.3	2.3	2.4	1.7	2.4	2.2	2.0	1.8	17.6	83.6
DAI-10	2.500	2.400	BI	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.9	2.2	1.7	2.4	2.4	2.4	2.4	1.7	2.4	2.3	2.3	2.4	1.7	2.4	2.2	2.0	1.8	17.6	83.6
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**15.463**	**12.400**		3.9	3.7	3.7	3.7	3.7	3.7	3.7	4.2	4.8	5.4	6.0	6.8	6.0	5.6	5.4	5.1	5.0	5.0	5.1	5.3	5.1	4.8	4.3	4.1	41.7	

Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**3.2**
MW Growth (%)	**1.5**
GWh Growth (%)	**1.5**
Total Base Capacity (MW)	**0.5**
Total Base/Interm Cap (MW)	**4.8**
Total Intermediate Cap (MW)	**1.8**
Total Peak Capacity (MW)	**5.3**
	12.4
Peak to Base Load Ratio	**0.8**

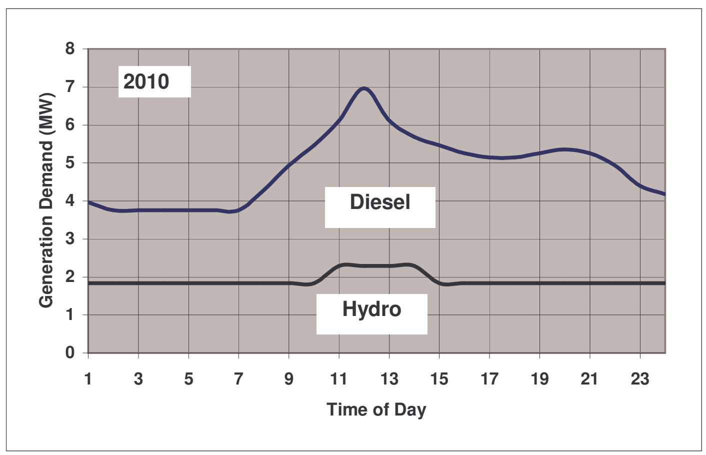


Notes:

Generator Name	Inst Cap MW	Firm Cap MW	Class	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total GWh	LF/CF %
			Time of Day	Generation Demand (MW)																									
				4.0	3.8	3.8	3.8	3.8	3.8	3.8	4.3	4.9	5.5	6.1	7.0	6.1	5.7	5.5	5.3	5.1	5.1	5.3	5.4	5.3	4.9	4.4	4.2	42.5	69.6
Existing Generators																													
CAT-4	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-5	1.135	0.900	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	BI	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.2	1.5	1.8	1.9	2.3	1.9	1.7	1.8	1.7	1.7	1.7	1.7	1.8	1.7	1.5	1.3	1.2	12.9	61.3
DAI-10	2.500	2.400	BI	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.2	1.5	1.8	1.9	2.3	1.9	1.7	1.8	1.7	1.7	1.7	1.7	1.8	1.7	1.5	1.3	1.2	12.9	61.3
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
Lehnmesi 1	1.500	0.970	B	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.1	83.3
Lehnmesi 2	1.300	0.820	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.0	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	18.263	14.190		4.0	3.8	3.8	3.8	3.8	3.8	3.8	4.3	4.9	5.5	6.1	7.0	6.1	5.7	5.5	5.3	5.1	5.1	5.3	5.4	5.3	4.9	4.4	4.2	42.5	

Largest Unit in System (MW)	2.40
Reserve Capacity (MW)	4.8
MW Growth (%)	2.0
GWh Growth (%)	2.0
Total Base Capacity (MW)	2.3
Total Base/Interm Cap (MW)	4.8
Total Intermediate Cap (MW)	1.8
Total Peak Capacity (MW)	5.3
	14.2
Peak to Base Load Ratio	0.8

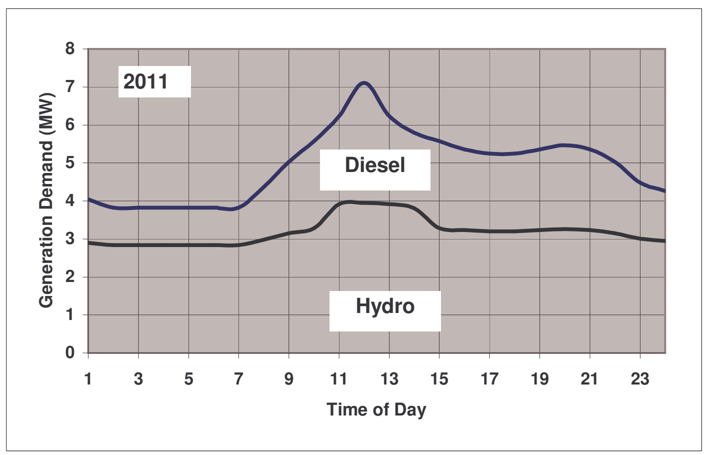
Notes:



			Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
Generator Name	**Inst Cap**	**Firm Cap**	**Class**	Generation Demand (MW)																								**GWh**	**%**
	MW	**MW**		4.0	3.8	3.8	3.8	3.8	3.8	3.8	4.4	5.0	5.6	6.2	7.1	6.2	5.8	5.6	5.4	5.2	5.2	5.4	5.5	5.4	5.0	4.5	4.3	43.3	69.6
Existing Generators																													
CAT-4	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-5	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.3
DAI-10	2.500	2.400	BI	1.2	1.0	1.0	1.0	1.0	1.0	1.0	1.4	1.9	2.3	2.3	2.4	2.3	2.0	2.3	2.1	2.0	2.0	2.1	2.2	2.1	1.9	1.5	1.3	15.1	71.7
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
Lehnmesi 1	1.500	0.970	B	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.1	83.3
Lehnmesi 2	1.300	0.820	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.0	83.3
Mahnd 1	0.600	0.330	B	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.4	83.3
Senipen/Riohk/Lehdau	0.940	0.500	B	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.7	83.3
Nanpil 2	2.000	0.830	BI	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.5	0.5	5.2	71.7
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**21.803**	**15.850**		4.0	3.8	3.8	3.8	3.8	3.8	3.8	4.4	5.0	5.6	6.2	7.1	6.2	5.8	5.6	5.4	5.2	5.2	5.4	5.5	5.4	5.0	4.5	4.3	43.3	

Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**6.3**
MW Growth (%)	**2.0**
GWh Growth (%)	**2.0**
Total Base Capacity (MW)	**3.1**
Total Base/Interm Cap (MW)	**3.2**
Total Intermediate Cap (MW)	**2.4**
Total Peak Capacity (MW)	**7.1**
	15.9
Peak to Base Load Ratio	**0.8**

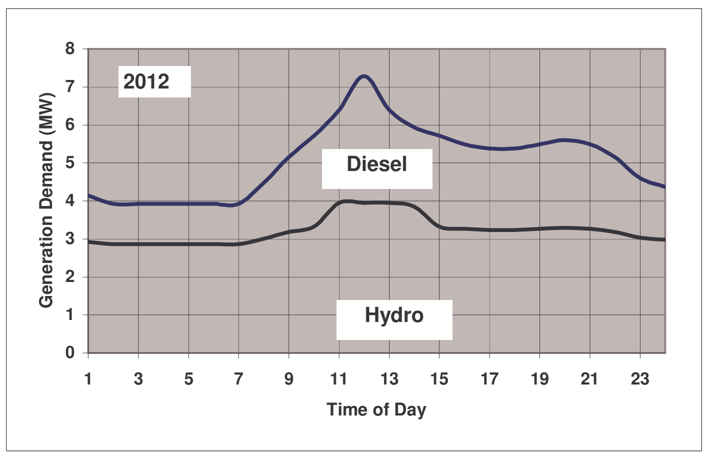
Notes:



			Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
Generator Name	**Inst Cap**	**Firm Cap**	**Class**	**Generation Demand (MW)**																								**GWh**	**%**
	MW	**MW**		4.1	3.9	3.9	3.9	3.9	3.9	3.9	4.5	5.2	5.7	6.4	7.3	6.4	5.9	5.7	5.5	5.4	5.4	5.5	5.6	5.5	5.2	4.6	4.4	44.4	69.6
Existing Generators																													
CAT-4	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-5	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.8
DAI-10	2.500	2.400	BI	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.5	2.0	2.4	2.4	2.4	2.4	2.1	2.4	2.2	2.1	2.1	2.2	2.3	2.2	2.0	1.6	1.4	15.8	75.2
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
Lehnmesi 1	1.500	0.970	B	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.1	83.3
Lehnmesi 2	1.300	0.820	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.0	83.3
Mahnd 1	0.600	0.330	B	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.4	83.3
Senipen/Riohk/Lehdau	0.940	0.500	B	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.7	83.3
Nanpil 2	2.000	0.830	BI	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.7	0.7	0.8	0.8	0.8	0.7	0.5	0.5	5.5	75.2
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**21.803**	**15.850**		4.1	3.9	3.9	3.9	3.9	3.9	3.9	4.5	5.2	5.7	6.4	7.3	6.4	5.9	5.7	5.5	5.4	5.4	5.5	5.6	5.5	5.2	4.6	4.4	44.4	

Largest Unit in System (MW)	2.40
Reserve Capacity (MW)	6.2
MW Growth (%)	2.5
GWh Growth (%)	2.5
Total Base Capacity (MW)	3.1
Total Base/Interm Cap (MW)	3.2
Total Intermediate Cap (MW)	2.4
Total Peak Capacity (MW)	7.1
	15.9
Peak to Base Load Ratio	0.8

Notes:

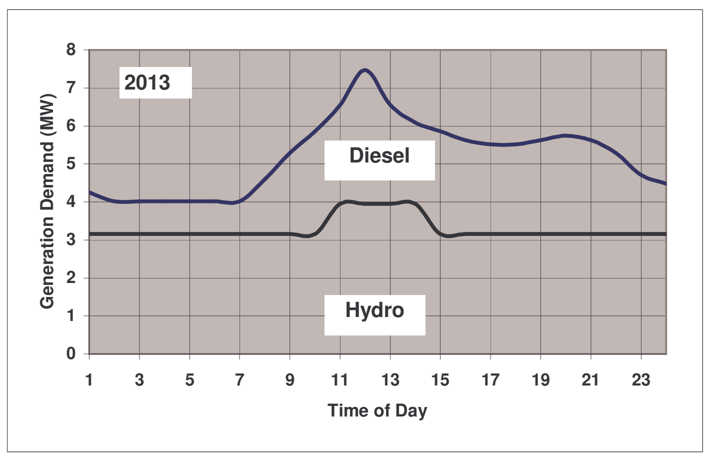


Pohnpei System Generation Dispatch

Maunsell Ltd

			Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
Generator Name	**Inst Cap**	**Firm Cap**	**Class**	**Generation Demand (MW)**																								**GWh**	**%**
	MW	**MW**		4.3	4.0	4.0	4.0	4.0	4.0	4.0	4.6	5.3	5.9	6.5	7.5	6.5	6.1	5.9	5.6	5.5	5.5	5.6	5.7	5.6	5.3	4.7	4.5	45.5	69.6
Existing Generators																													
CAT-4	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-5	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.2	1.1	0.2	0.0	1.0	0.8	0.0	0.0	0.8	0.9	0.8	0.0	0.0	0.0	2.5	11.8
DAI-10	2.500	2.400	BI	1.1	0.9	0.9	0.9	0.9	0.9	0.9	1.4	2.1	1.7	2.4	2.4	2.4	2.1	1.7	1.7	2.4	2.4	1.7	1.7	1.7	2.1	1.5	1.3	14.2	67.6
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
Lehnmesi 1	1.500	0.970	B	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.1	83.3
Lehnmesi 2	1.300	0.820	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.0	83.3
Mahnd 1	0.600	0.330	B	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.4	83.3
Senipen/Riohk/Lehdau	0.940	0.500	B	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.7	83.3
Nanpil 2	2.000	0.830	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.1	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**21.803**	**15.850**		4.3	4.0	4.0	4.0	4.0	4.0	4.0	4.6	5.3	5.9	6.5	7.5	6.5	6.1	5.9	5.6	5.5	5.5	5.6	5.7	5.6	5.3	4.7	4.5	45.5	

Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**6.0**
MW Growth (%)	**2.5**
GWh Growth (%)	**2.5**
Total Base Capacity (MW)	**4.0**
Total Base/Interm Cap (MW)	**2.4**
Total Intermediate Cap (MW)	**2.4**
Total Peak Capacity (MW)	**7.1**
	15.9
Peak to Base Load Ratio	**0.8**



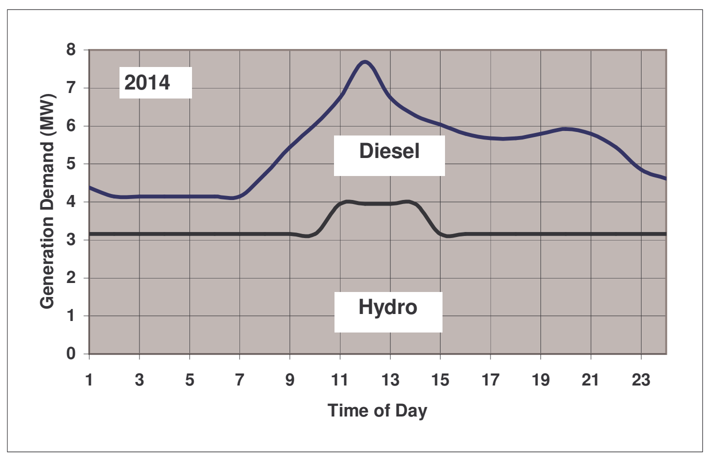
Notes:

Pohnpei System Generation Dispatch Maunsell Ltd

Generator Name	Inst Cap	Firm Cap	Class	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
			Time of Day	Generation Demand (MW)																								GWh	%
	MW	MW		4.4	4.1	4.1	4.1	4.1	4.1	4.1	4.7	5.4	6.0	6.7	7.7	6.7	6.3	6.0	5.8	5.7	5.7	5.8	5.9	5.8	5.4	4.9	4.6	46.9	69.6
Existing Generators																													
CAT-4	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-5	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.4	1.3	0.4	0.0	1.2	1.0	0.8	0.8	1.0	1.1	1.0	0.0	0.0	0.0	3.7	17.6
DAI-10	2.500	2.400	BI	1.2	1.0	1.0	1.0	1.0	1.0	1.0	1.6	2.3	1.7	2.4	2.4	2.4	2.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	2.3	1.7	1.5	14.4	68.3
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
Lehnmesi 1	1.500	0.970	B	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.1	83.3
Lehnmesi 2	1.300	0.820	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.0	83.3
Mahnd 1	0.600	0.330	B	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.4	83.3
Senipen/Riohk/Lehdau	0.940	0.500	B	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.7	83.3
Nanpil 2	2.000	0.830	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.1	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	21.803	15.850		4.4	4.1	4.1	4.1	4.1	4.1	4.1	4.7	5.4	6.0	6.7	7.7	6.7	6.3	6.0	5.8	5.7	5.7	5.8	5.9	5.8	5.4	4.9	4.6	46.9	

Largest Unit in System (MW)	2.40
Reserve Capacity (MW)	5.8
MW Growth (%)	3.0
GWh Growth (%)	3.0
Total Base Capacity (MW)	4.0
Total Base/Interm Cap (MW)	2.4
Total Intermediate Cap (MW)	2.4
Total Peak Capacity (MW)	7.1
	15.9
Peak to Base Load Ratio	0.8

Notes:



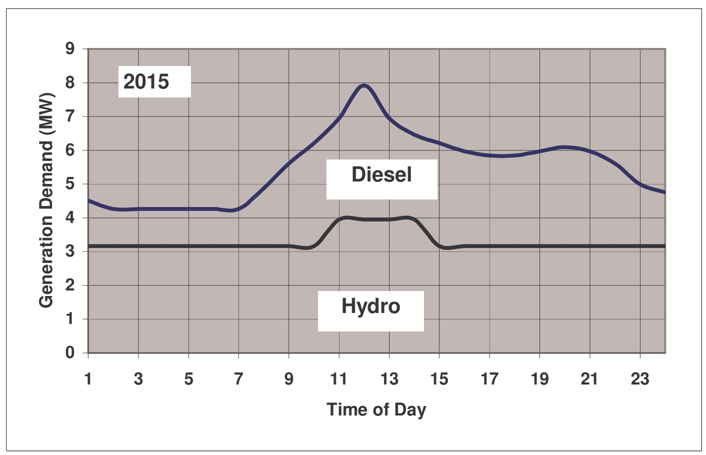
Pohnpei System Generation Dispatch

Maunsell Ltd

			Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
Generator Name	**Inst Cap**	**Firm Cap**	**Class**												**Generation Demand (MW)**													**GWh**	**%**
	MW	**MW**		4.5	4.3	4.3	4.3	4.3	4.3	4.3	4.9	5.6	6.2	6.9	7.9	6.9	6.5	6.2	6.0	5.8	5.8	6.0	6.1	6.0	5.6	5.0	4.8	48.3	69.6
Existing Generators																													
CAT-4	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-5	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.4	0.6	1.6	0.6	0.1	1.4	1.1	1.0	1.0	1.1	1.3	1.1	0.8	0.0	0.0	5.0	24.0
DAI-10	2.500	2.400	BI	1.3	1.1	1.1	1.1	1.1	1.1	1.1	1.7	1.7	1.7	2.4	2.4	2.4	2.4	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.6	14.4	68.6
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
Lehnmesi 1	1.500	0.970	B	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.1	83.3
Lehnmesi 2	1.300	0.820	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.0	83.3
Mahnd 1	0.600	0.330	B	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.4	83.3
Senipen/Riohk/Lehdau	0.940	0.500	B	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.7	83.3
Nanpil 2	2.000	0.830	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.1	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**21.803**	**15.850**		4.5	4.3	4.3	4.3	4.3	4.3	4.3	4.9	5.6	6.2	6.9	7.9	6.9	6.5	6.2	6.0	5.8	5.8	6.0	6.1	6.0	5.6	5.0	4.8	48.3	

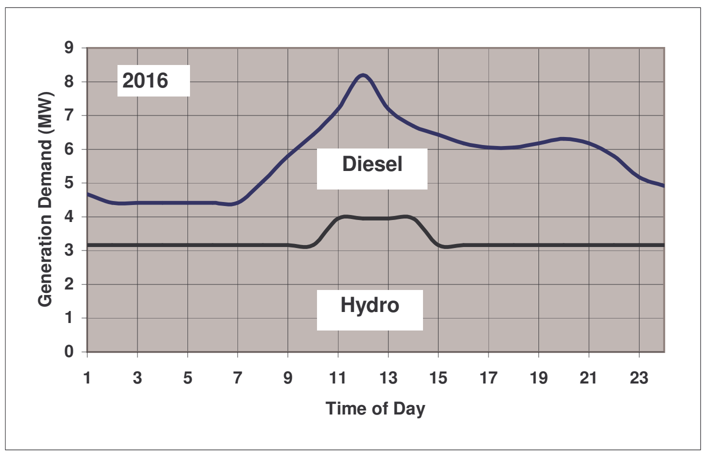
Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**5.5**
MW Growth (%)	**3.0**
GWh Growth (%)	**3.0**
Total Base Capacity (MW)	**4.0**
Total Base/Interm Cap (MW)	**2.4**
Total Intermediate Cap (MW)	**2.4**
Total Peak Capacity (MW)	**7.1**
	15.9
Peak to Base Load Ratio	**0.8**

Notes:



			Time of Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total	LF/CF
Generator Name	**Inst Cap**	**Firm Cap**	**Class**	**Generation Demand (MW)**																								**GWh**	**%**
	MW	**MW**		4.7	4.4	4.4	4.4	4.4	4.4	4.4	5.0	5.8	6.4	7.2	8.2	7.2	6.7	6.4	6.2	6.1	6.1	6.2	6.3	6.2	5.8	5.2	4.9	50.0	69.6
Existing Generators																													
CAT-4	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-5	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAT-6	1.135	0.900	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-7	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-8	2.500	2.200	P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAI-9	2.500	2.400	I	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.6	0.8	1.8	0.8	0.3	1.6	1.3	1.2	1.2	1.3	1.5	1.3	1.0	0.0	0.0	6.2	29.3
DAI-10	2.500	2.400	BI	1.5	1.3	1.3	1.3	1.3	1.3	1.3	1.9	1.7	1.7	2.4	2.4	2.4	2.4	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	2.0	1.8	15.0	71.3
Hydro #1	0.725	0.200	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.5	83.3
Hydro #2	1.333	0.300	B	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Generators																													
Lehnmesi 1	1.500	0.970	B	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.1	83.3
Lehnmesi 2	1.300	0.820	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.0	83.3
Mahnd 1	0.600	0.330	B	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	2.4	83.3
Senipen/Riohk/Lehdau	0.940	0.500	B	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.7	83.3
Nanpil 2	2.000	0.830	B	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	6.1	83.3
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**21.803**	**15.850**		4.7	4.4	4.4	4.4	4.4	4.4	4.4	5.0	5.8	6.4	7.2	8.2	7.2	6.7	6.4	6.2	6.1	6.1	6.2	6.3	6.2	5.8	5.2	4.9	50.0	

Largest Unit in System (MW)	**2.40**
Reserve Capacity (MW)	**5.3**
MW Growth (%)	**3.5**
GWh Growth (%)	**3.5**
Total Base Capacity (MW)	**4.0**
Total Base/Interm Cap (MW)	**2.4**
Total Intermediate Cap (MW)	**2.4**
Total Peak Capacity (MW)	**7.1**
	15.9
Peak to Base Load Ratio	**0.8**



Notes:

ATTACHMENT 2

LRMC Analysis of Electricity Supply

ATTACHMENT 2

Long Run Marginal Cost Analysis on an Economic Basis

All costs in 2006 dollars

Base Date: 1-Jan-06
WACC: 6.5 %

	HYDRO		DIESEL	
Parasitic Power:	1	% of Installed Capacity	4.65	% of Installed Capacity
Fuel Cost:	-	US$ / US Gal (incl 4% sales tax)	2.30	US$ / US Gal (incl 4% sales tax)
Fuel Cost:	0.00	US$ / litre (incl 4% sales tax)	0.66	US$ / litre (incl 4% sales tax)
Fuel Consumption:	0.00	kWh / US Gal	14.50	kWh / US Gal
Fuel Consumption:	0.000	Litre / kWh	0.240	Litre / kWh
Operational Lifetime:	40	Years	25	Years
Fixed O&M Cost:	15	US$ / kW / yr	25	US$ / kW / yr
Variable O&M Cost:	0.005	US$ / kWh	0.013	US$ / kWh
Monetarised CO_2 Saving*:	0	US$ / kWh		

* Equivalent to US$ 7.00 / tonne carbon saved / year.

Item	Units	Year 1 2006	Year 2 2007	Year 3 2008	Year 4 2009	Year 5 2010	Year 6 2011	Year 7 2012	Year 8 2013	Year 9 2014	Year 10 2015	Year 11 2016
Installed Diesel Capacity	kW	13,405	13,405	13,405	13,405	13,405	13,405	13,405	13,405	13,405	13,405	13,405
Installed Hydro Capacity	kW	2,058	2,058	2,058	2,058	4,858	8,398	8,398	8,398	8,398	8,398	8,398
Generation Output	MWh / yr	40,035	40,436	41,042	41,658	42,491	43,341	44,424	45,535	46,901	48,308	49,999
Diesel Generation	MWh / yr	37,845	36,786	37,392	38,008	25,774	15,351	16,180	16,700	18,066	19,473	21,164
Hydro Generation	MWh / yr	2,190	3,650	3,650	3,650	16,717	27,989	28,244	28,835	28,835	28,835	28,835
Net Energy Fed into Transmission Grid	MWh / yr	38,254	38,689	39,267	39,854	41,125	42,347	43,390	44,470	45,773	47,114	48,726
Distribution Losses	%	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Electricity Sales	MWh / yr	34,237	34,626	35,144	35,669	36,807	37,901	38,834	39,801	40,967	42,167	43,610
Capital Expenditure **												Residual Value
Lehnmesi 1 Hydro (1.5 MW, US$ 8.8 million)	US$ '000		1,320	3,520	3,080	880						- 7,000
Lehnmesi 2 Hydro (1.3 MW, US$ 8.2 million)	US$ '000		1,260	3,360	2,940	840						- 6,800
Mahnd 1 Hydro (0.6 MW, US$ 2.6 million)	US$ '000		260	520	520	1,040	260	-	-	-	-	- 2,200
Senipen/Riohk/Lehdau Hydro (0.94 MW, US$ 8.4 million)	US$ '000		840	1,680	1,680	3,360	840					- 7,200
Nanpil 2 Hydro (2 MW, US$ 17.9 million)	US$ '000		1,790	3,580	3,580	7,160	1,790					- 15,000
Distribution System	US$ '000				400	400						- 680
Sub-Total	US$ '000	-	5,470	12,660	12,200	13,680	2,890	-	-	-	-	- 38,880
Operation and Maintenance Costs												
- Fuel	US$ '000	6,003	5,835	5,931	6,029	4,088	2,435	2,567	2,649	2,866	3,089	3,357
- Fixed O & M	US$ '000	366	366	366	366	408	461	461	461	461	461	461
- Variable O & M	US$ '000	503	496	504	512	419	340	352	361	379	397	419
- Distribution O & M	US$ '000	500	500	500	500	500	500	500	500	500	500	500
- CO_2 Credits	US$ '000	-	-	-	-	-	-	-	-	-	-	-
Sub-Total	US$ '000	6,872	6,697	6,802	6,907	4,915	3,236	3,379	3,471	3,706	3,947	4,237
Capital plus Operating Costs	US$ '000	6,872	12,167	19,462	19,107	18,595	6,126	3,379	3,471	3,706	3,947	- 34,643

PV of Costs $57,063 US$ '000 (calculated at WACC)

Long Run Marginal Cost at WACC

Capital	0.060	US$ / kWh
Fuel	0.115	US$ / kWh
O&M	0.036	US$ / kWh
CO_2 Credit	0.000	US$ / kWh
Total	0.211	US$ / kWh

** Excl. taxes and duties but incl contingencies and IDC

ATTACHMENT 3

Projected Financial Statements

Pohnepei Utilities Corporation

Years ended 30 September

Statement of Financial Performance

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Operating Revenue												
Electricity Sales	7,920	9,918	11,649	11,832	12,016	10,532	9,292	9,583	9,838	10,248	10,670	10,760
Water Sales	1,187	1,080	1,654	1,839	2,142	2,424	2,668	2,823	2,928	2,986	3,046	3,107
Waste Sales		-	1,313	1,317	1,321	1,432	1,542	1,937	2,414	2,920	3,425	3,660
Other	(65)	(155)										
Total Gross Operating Revenue	9,042	10,843	14,616	14,988	15,479	14,388	13,502	14,343	15,180	16,154	17,142	17,528
Expenses												
Payroll	1,919	2,056	2,118	2,182	2,247	2,315	2,384	2,456	2,529	2,605	2,683	2,764
Administration	390	395	406	419	431	444	457	471	485	500	515	530
Fuel	5,355	7,305	7,092	7,210	7,328	4,890	2,811	2,970	3,067	3,332	3,603	3,680
Operating costs	456	190	196	202	208	214	221	227	234	241	248	256
Maintenance	608	524	540	556	573	590	608	626	645	664	684	705
Other Expenses	1,962	-	-	-	-	-	-	-	-	-	-	-
Total Expenses	10,691	10,471	10,353	10,568	10,788	8,453	6,481	6,750	6,961	7,342	7,734	7,934
EBITDA	(1,648)	372	4,264	4,420	4,692	5,935	7,021	7,593	8,219	8,812	9,408	9,594
less Depreciation	1,909	2,024	2,303	3,149	3,955	4,047	4,622	5,083	5,470	5,766	6,232	6,366
EBIT	(3,557)	(1,652)	1,961	1,271	737	1,888	2,399	2,510	2,749	3,046	3,176	3,227
less Net Interest Paid		(39)	(137)	(463)	(999)	(1,593)	(2,107)	(2,448)	(2,703)	(2,865)	(3,023)	(3,095)
Net Operating Profit	(3,557)	(1,691)	1,824	808	(262)	295	292	62	47	181	153	133
Non operating revenues												
Grants and subsidies	193											
Other projects	23											
Other Income	55											
Sub-total	271	-	-	-	-	-	-	-	-	-	-	-
Net Profit (loss) before Capital Contributions	**(3,285)**	**(1,691)**	**1,824**	**808**	**(262)**	**295**	**292**	**62**	**47**	**181**	**153**	**133**

Pohnepei Utilities Corporation

Years ended 30 September

Statement of Financial Position

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Current Assets												
Cash	333	-	364	420	489	514	489	456	424	395	368	341
Debtors	3,048	3,048	3,604	2,464	2,545	2,365	2,220	2,358	2,495	2,655	2,818	2,881
Inventory	1,523	1,523	2,026	2,060	2,094	1,397	803	849	876	952	1,030	1,051
Other	825											
	5,730	4,571	5,994	4,943	5,127	4,276	3,511	3,663	3,796	4,002	4,215	4,274
Investments	778											
Investments - current	601	601	601	601	601	601	601	601	601	601	601	601
Investments - noncurrent	483	483	483	483	483	483	483	483	483	483	483	483
	1,084	1,084	1,084	1,084	1,084	1,084	1,084	1,084	1,084	1,084	1,084	1,084
Fixed & Intangible Assets												
Gross Assets	50,730	54,273	62,782	88,175	112,339	138,685	155,926	170,277	181,868	190,753	189,270	193,300
Less Accum. Depreciation	24,545	26,377	28,680	31,829	35,784	39,831	44,453	49,536	55,006	60,772	53,467	59,833
Net Assets	26,185	27,896	34,102	56,345	76,555	98,854	111,473	120,741	126,862	129,981	135,802	133,466
Work in Progress	2,534											
Total Fixed Assets	28,719	27,896	34,102	56,345	76,555	98,854	111,473	120,741	126,862	129,981	135,802	133,466
Total Assets	**35,533**	**33,550**	**41,180**	**62,372**	**82,766**	**104,213**	**116,068**	**125,488**	**131,742**	**135,067**	**141,102**	**138,824**
Current Liabilities												
Overdraft		233	-	-	-	-	-	-	-	-	-	-
Trade creditors - oil	483	660	641	652	663	442	254	269	277	301	326	333
Trade creditors - other	746	434	447	460	474	488	503	518	533	549	566	583
Sundry Creditors & Accruals	353	217	223	230	237	244	251	259	267	275	283	291
Tax payable												
Short Term Borrowings		-	-	-	-	-	-	-	-	-	-	-
	1,582	1,544	1,311	1,342	1,373	1,174	1,008	1,045	1,077	1,125	1,175	1,207
Term Liabilities												
Bank LC	100	-	-	-	-	-	-	-	-	-	-	-
RUS Water Extensions Loan	578	578	572	567	561	554	548	541	534	526	518	510
ADB Water Extension Loan	2,119	2,119	2,052	1,985	1,918	1,851	1,784	1,716	1,649	1,582	1,515	1,448
Omnibus Loan		-	58	4,401	8,709	8,883	7,995	7,107	6,218	5,330	4,442	3,553
Investment Company Debt	407	366	326	285	244	203	163	122	81	41	-	-
FSM	181	67	-	-	-	-	-	-	-	-	-	-
New Debt		-	6,161	22,285	38,715	60,007	72,739	83,062	90,241	94,340	101,177	99,698
	3,384	3,130	9,169	29,523	50,147	71,499	83,228	92,548	98,724	101,819	107,652	105,209
Sub total	4,966	4,674	10,480	30,865	51,520	72,673	84,236	93,593	99,801	102,945	108,826	106,416
Shareholders Funds												
Net Assets	30,567	28,876	30,700	31,508	31,245	31,540	31,832	31,894	31,941	32,122	32,276	32,408
Total Liabilities	**35,533**	**33,550**	**41,180**	**62,372**	**82,766**	**104,213**	**116,068**	**125,488**	**131,742**	**135,067**	**141,102**	**138,824**
	-	-	-	-	-	-	-	-	-	-	-	-

Pohnepei Utilities Corporation

Years ended 30 September

Statement of Cash Flows

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Cash flows from operating activities												
Reported profit/(loss)	(3,557)	(1,691)	1,824	808	(262)	295	292	62	47	181	153	133
Add Non cash Items												
Depreciation	1,909	2,024	2,303	3,149	3,955	4,047	4,622	5,083	5,470	5,766	6,232	6,366
Other	1,962											
	314	333	4,126	3,957	3,693	4,342	4,913	5,145	5,516	5,947	6,385	6,499
Add/(Less) Movements in Working Capital Items												
Increase/(Decrease) in Creditors	748	(271)	0	31	31	(199)	(166)	37	32	48	49	32
Decrease/(Increase) in Debtors	(169)	825	(556)	1,140	(81)	179	146	(138)	(138)	(160)	(162)	(63)
Decrease/(Increase) in Inventory	(67)	-	(503)	(34)	(34)	697	594	(45)	(28)	(75)	(78)	(22)
Increase/(Decrease) in Taxes Payable	-	-	-	-	-	-	-	-	-	-	-	-
Other	(175)	2,534	-	-	-	-	-	-	-	-	-	-
	337	3,089	(1,059)	1,137	(83)	677	573	(147)	(133)	(188)	(191)	(53)
Net Cash from Operating Activities	651	3,422	3,067	5,094	3,609	5,019	5,487	4,999	5,383	5,760	6,194	6,446
Cashflows from Noncapital Financing Activities												
Operating grants received	193	-	-	-	-	-	-	-	-	-	-	-
Spurline Projects	23	-	-	-	-	-	-	-	-	-	-	-
	216	-	-	-	-	-	-	-	-	-	-	-
Cash Flows from Investing Activities												
Cash was provided by:												
Sale of assets	51											
Sale of Investment												
Cash was applied to:												
(Increase) decrease in fixed deposit	(203)	-	-	-	-	-	-	-	-	-	-	-
Purchase of fixed assets	(1,949)	(3,734)	(8,509)	(25,393)	(24,164)	(26,346)	(17,241)	(14,351)	(11,591)	(8,885)	(12,053)	(4,030)
Net Cash From Investing Activities	(2,101)	(3,734)	(8,509)	(25,393)	(24,164)	(26,346)	(17,241)	(14,351)	(11,591)	(8,885)	(12,053)	(4,030)
Cash Flows from Financing												
Cash was (applied to) provided from:												
Net Increase in Long Term Debt	517	-	6,038	20,354	20,624	21,352	11,729	9,320	6,175	3,096	5,832	-
(Net Repayment of Long Term Debt)	-	(254)	-	-	-	-	-	-	-	-	-	(2,443)
Capirtal Contributions	723	-	-	-	-	-	-	-	-	-	-	-
Net Cash From Financing Activities	1,239	(254)	6,038	20,354	20,624	21,352	11,729	9,320	6,175	3,096	5,832	(2,443)
Net Increase/(Decrease) in Cash Held	**6**	**(566)**	**597**	**56**	**70**	**24**	**(25)**	**(32)**	**(32)**	**(30)**	**(27)**	**(27)**
Opening Cash	327	333	(233)	364	420	489	514	489	456	424	395	368
Add Increase/(Decrease) in Cash	6	(566)	597	56	70	24	(25)	(32)	(32)	(30)	(27)	(27)
Closing Cash	333	(233)	364	420	489	514	489	456	424	395	368	341