PACIFIC POWER ASSOCIATION

PERFORMANCE BENCHMARKING FOR PACIFIC POWER UTILITIES

Benchmarking Report

PREPARED BY THE PACIFIC POWER ASSOCIATION (PPA) WITH THE SUPPORT OF THE PACIFIC INFRASTRUCTURE ADVISORY CENTRE (PIAC) AND THE SECRETARIAT OF THE PACIFIC COMMUNITY (SPC).

December

2011

This is a publication of the Pacific Power Association

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PIAC operates under the Pacific Region Infrastructure Facility (PRIF) a multi-partner infrastructure coordination and financing mechanism for the Pacific region. The partners are the Asian Development Bank (ADB), the Australian Agency for International Development (AusAID), the New Zealand Ministry for Foreign Affairs and Trade (NZMFAT), the World Bank Group (WBG), the European Commission (EC) and the European Investment Bank (EIB). Financial support came from technical assistance grant TA 6522 REG, establishment of PIAC.

Acknowledgments

The following have contributed significantly to the 2011 Pacific power utility performance benchmarking exercise.

On behalf of the Pacific Region Infrastructure Facility (PRIF), the Asian Development Bank (ADB) provided funding and overall support in the preparation of this report through the Pacific Infrastructure Advisory Center (PIAC). The PRIF partners are the Asian Development Bank (ADB), the Australian Agency for International Development (AusAID), the New Zealand Ministry for Foreign Affairs and Trade (NZMFAT), the World Bank Group (WBG), the European Commission (EC) and the European Investment Bank (EIB).

The Pacific Power Association (PPA) provided overall coordination and acted as the link between the ADB consultants and the participating PPA member utilities. PPA arranged support for Steering Committee meetings held in Nadi, Fiji in April and in Guam in July 2011. PPA also provided the services of its Renewable Energy Adviser, Faumui Iese Toimoana during a critical period from late June through mid-July 2011. The exercise would not have been possible without PPA's input and strong support.

The project Steering Committee, consisting of the CEOs of three participating utilities (TAU of the Cook Islands, FEA of Fiji and PPUC of Palau) and representatives of ADB, the EC, the Secretariat of the Pacific Community (SPC), PPA and the WB, provided guidance.

The twenty one participating utilities graciously complied with repeated requests for information and clarification, extending in several cases until early November 2011. Their honest responses regarding the difficulties faced in providing the information will improve future benchmarking efforts. CEOs and other utility staff made helpful comments on a draft benchmarking questionnaire tested by seven utilities in March 2011 and then revised, and on the draft benchmarking report released in July 2011. Mr Solomone Fifita of the SPC and Mr Thomas Jensen of the United Nations Development Program (UNDP) also provided useful comments on the draft report.

Several organisations kindly provided access to recent benchmarking reports covering other island or small electric power utilities. These are: (1) the Caribbean Electric Utility Services Corporation (CARILEC) serving the Caribbean islands, (2) the Network of Experts of Small Island System Managers (NESIS) for island utilities associated with the European utility association Eurelectric, and; (3) the American Public Power Association (APPA) whose series of Selected Financial and Operational Ratios distinguishes between indicators of smaller Pacific-sized public utilities in the USA and larger ones. These reports allowed comparisons of some indicators of performance for Pacific and other similar utilities.

Finally, a draft final report of 22 November 2011 was reviewed by two external evaluators, both of whom have held senior positions within Pacific power utilities: Mr Ken Uyehara of Palau and Mr Abraham Simpson of Fiji. Valuable comments from the evaluators have been incorporated into this final report. The final report also benefited from comments on the draft provided by Corazon Alejandrino-Yap and John Austin of PIAC, Andrew Daka of PPA; and Robert Kesterton and Martina Tonizzo of the ADB.

Preface

The Pacific Power Association (PPA) is the regional organisation representing 25 electric power utilities in 20 Pacific Islands Countries and Territories (PICTs) in energy fora. At its Annual Conference held at the Warwick Hotel on the Coral Coast in Fiji in August 2006, the Board resolved to recommence the Regional Power Utilities Benchmarking which had started under ADB funding in 2000.

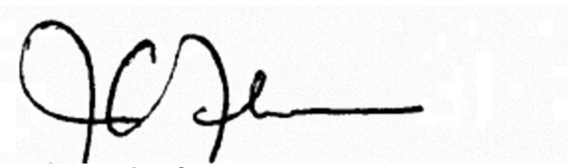
The endorsement by regional leaders in 2010 of the *Framework for Action on Energy Security in the Pacific*, a policy and strategy for energy sector action at the regional level, mandated the PPA to undertake a regional benchmarking exercise for all member Utilities.

This report presents the findings of the exercise and it is anticipated that this will be used as the baseline indicator for the next rounds of annual benchmarking.

The results of the benchmarking can be utilised by the power utilities to formulate performance improvement programs (PIPs) to improve the overall performance of the utilities making them more sustainable. This process, which will involve consultants in the initial phase, will gradually be taken up by the utilities themselves once benchmarking has been mainstreamed into the utility operations.

The PPA appreciates the support provided by the Pacific Region Infrastructure Facility (PRIF) in this first benchmarking exercise. The PRIF is supported by five partners: the Asian Development Bank (ADB), the Australian Agency for International Development (AusAID), the European Union (EU) and the European Investment Bank (EIB), the New Zealand Ministry for Foreign Affairs and Trade (NZMFAT) and the World Bank (WB).

The PPA, in partnership with the PRIF and Secretariat for the Pacific Community (SPC) looks forward to the second round of the benchmarking exercise in 2012.



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January 2012

Table of Contents

List of Figures

Notes

1. Costs for 2010 utility operations were converted to US dollars using the average exchange rate from Table A19 of *Asian Development Outlook 2011* (Asian Development Bank, 2011) except French Polynesia from ExchangeRate.com for average 2010 value.
2. The graphs in this report use a **black broken line** to mark out ***average*** values and a **red broken line** to mark out ***median*** values. Colour-coded labels are also included beside the graphs.

List of Tables

List of Boxes

Abbreviations

ADB	Asian Development Bank
ADO, IDO	Automotive Diesel Oil; Industrial Diesel Oil (light petroleum fuels)
AGM	Annual General Meeting
APPA	American Public Power Association (of which PPA is a member)
AusAID	Australian Agency for International Development
BMEP	Brake Mean Effective Pressure
BSC	Balanced Scorecard Approach
CARICOM	Caribbean Community
CARILEC	The Caribbean Electric Utility Services Corporation
CEO	Chief Executive Officer
CROP	Council of Regional Organisations of the Pacific
DSM	Demand Side Management (improved energy efficiency for customers)
EC	European Commission
Eurelectric	European Electrical Utility Association
Feed-in tariff (FIT)	Terms and conditions for private producer to sell renewable energy to the grid, typically varies by type of technology, and typically under a long-term contract
FTE	Full Time Equivalent
GDP	Gross Domestic Product
GNP	Gross National Product
GST	Goods and Services Tax
GW, MW, kW	Gigawatt, Megawatt, kilowatt; (1 GW = 1,000 MW = 1,000 kW)
GWh, MWh, kWh	Gigawatt hours; Megawatt hours; kilowatt hours; (1 GWh = 1,000 MWh = 1,000,000 KWh)
HFO/IFO	Heavy Fuel Oil; Industrial Fuel Oil (heavy petroleum fuels)
HV	High voltage
ICT	Information and Communications Technology
IPP	Independent Power Producer, usually private sector
KEMA	Dutch consulting firm (and PPA Allied Member)
kV	kilovolt (1,000 volts)
MVA	Megavolt ampere
NESIS	Network of Experts of Small Island System Managers (European utilities)
Net metering	RE incentive, usually allowing consumers to sell renewable-based electricity net of consumption from the grid at agreed price and duration
NZMFAT	New Zealand Ministry for Foreign Affairs and Trade
O&M	Operations and Maintenance
PIAC	Pacific Infrastructure Advisory Center
PIC	Pacific Island Country
PICTs	Pacific Island Countries and Territories
PIFS	Pacific Islands Forum Secretariat
PIP	Performance Improvement Plan
PIPIs	Pacific Infrastructure Performance Indicators (PIAC)
PPA	Pacific Power Association; also Power Purchase Agreement
PRIF	Pacific Region Infrastructure Facility
PV	Photovoltaic
RE	Renewable Energy
RHC	Return on Human Capital
RORA	Rate of Return on Assets
SAIDI	System Average Outage Duration

SAIFI	System Average Interruption Frequency Index
SFC	Specific Fuel Consumption
SHS	Solar Home Systems (low voltage, usually direct current, photovoltaic systems)
SOE	State Owned Enterprise
SPC	Secretariat of the Pacific Community
T&D	Transmission and Distribution
USDOI	United States Department of the Interior
VAT	Value Added Tax
WBG	World Bank Group

Executive Summary

The previous, and until now only, performance benchmarking study for Pacific Island power utilities was carried out a decade ago, based on information provided by twenty utilities. The current exercise intended to adopt the same basic indicators presented in the earlier effort, in part because the utilities had some familiarity with the approach but also to allow comparisons between past (2000 utility operations) and present (2010) performance. Additional indicators were added to include information about grid-connected renewable energy, utility energy efficiency efforts, electricity supply to grids from independent suppliers, regulatory arrangements, and others.

During 2011, twenty-one utilities—varying substantially in size, staffing, resources, customer base and geographical coverage—participated in the benchmarking project. The effort was coordinated by the Pacific Power Association (PPA) with financial assistance from development partners through the Sydney-based Pacific Infrastructure Advisory Center (PIAC) under an agreement between PPA, PIAC and the Secretariat of the Pacific Community (SPC), which coordinates Pacific regional energy matters. The 2011 benchmarking was conceived as a baseline for a series of future benchmarking efforts to be carried out annually, as a mechanism to improve the pool of information available about the region's utilities and as a tool to assist utilities to improve their technical and financial performance. Several recent (2006–2009) power utility benchmarking studies have been carried out in islands or small utilities in other regions of the world, and Pacific results have been compared to these.

Project Background

Information on utility operations during 2010 was provided to the PPA and benchmarking consultants through a two–part questionnaire (basic utility information and detailed data) which was tested with seven utilities, slightly modified and sent electronically to the PPA's member utilities in April 2011. Responses from 16 utilities were assessed in May and June, and some utilities resubmitted data based on requests for clarification. Preliminary results were reported to CEOs, other utility staff and others during the PPA's Annual General Meeting (AGM) in Guam in July 2011, which also served as the venue for numerous discussions and several workshops to further clarify data to improve final results. An additional five utilities subsequently decided to participate and provided data between August and November 2011. A final draft report was completed in late November, reviewed externally by two independent Pacific power experts who have served as senior staff of Pacific utilities, reviewed by a project Steering Committee, and finalized in December 2011.

Key Findings and Observations

Results are presented in 32 charts with explanatory text and 16 tables. The earlier benchmarking report treated all results as confidential: individual utility results were not identified. In 2011, the CEOs agreed that utilities could be identified for most performance indicators, the exceptions being certain financial information which some utilities considered to be sensitive.

In brief, comparisons between utility operations for 2000 and 2010 are as follows:

Comparisons 2000 to 2010

- Indicators of generation performance are similar for both periods, suggesting no substantial improvement or decline in load factor, capacity factor or specific fuel consumption. Availability of generating plants has improved slightly. Maintenance planning and its implementation may have worsened.
- Transmission and distribution losses reported by utilities are about the same for both periods. Because of issues in the reporting of system losses, it is difficult to conclude that performance has improved or declined, but results suggest that reporting of losses needs to be better addressed in future benchmarking.
- Distribution transformer utilisation is essentially unchanged since 2000, remaining very low, suggesting that utilities are not properly sizing transformers and perhaps not maintaining them well. Distribution productivity reported by utilities, as measured by customers per distribution employee, has improved considerably.
- Indicators of interruptions to supply were probably estimated, not measured, for most utilities during both reporting periods. It is unclear whether performance has improved.
- Financial indicators are only indicative for both periods. Nonetheless, rates of return on assets, current ratios and debt/equity ratios all appear to have improved. Timely collection of debt (debtor days) has worsened.

Several performance measures not included a decade ago were added for the 2011 report:

New 2011 Performance Measures

- In terms of renewable energy fed into the main grid systems of the utilities, overwhelmingly hydro-power, constituted 22 per cent of total generation, but 16 of 21 participating utilities remained almost totally petroleum-dependent in 2010.
- There was some limited reporting of utility efforts to assist customers to reduce electricity use (improved end-use energy efficiency) but most utilities either did not have, or did not report on these initiatives.
- An attempt was made to develop an overall composite indicator of Pacific power utility technical performance. The initial results are only indicative but may serve as a starting point for an improved future technical and financial composite.

There were only a few indicators common to Pacific utilities and those of other island regions. In brief:

Common Indicators

- Load factors and capacity factors are considerably better for the Caribbean island utilities but the Pacific reported better reserve plant margins and generating equipment availability factors.
- Overall system losses and technical losses are almost identical for the Pacific and Caribbean utilities. However, non-technical losses (such as theft or bad metering) are significantly higher in the Pacific. System losses for the NESIS group of island utilities, part of the European utility association Eurelectric, are lower than those of the Pacific or the Caribbean.

- The small American cooperative utilities which usually purchase and then distribute power had the same average distribution productivity (customers per distribution employee) in 2006 as the PPA members did in 2010.
- Reported customer supply interruption indicators were similar for the Pacific and Caribbean but in both regions, reporting accuracy was questionable.
- The rate of return on assets was higher for the Pacific than the Caribbean utilities but the very low median Pacific value suggests that Pacific results are not necessarily better.
- The average household tariff in the Pacific is roughly the same as the Caribbean considering the different reporting years. Commercial tariffs, however, seem to be somewhat higher in the Pacific.
- Overall labour productivity, measured by customers per full-time equivalent employee, is very low for the Pacific utilities: only 85 compared to 135 for the Caribbean and 125 for the smallest European island utilities. Low productivity suggests that Pacific utility staff generally require skill upgrading and could possibly benefit from more remote monitoring of isolated systems, which has become more cost-effective in recent years with improved communication and control systems.

It is implicit in this report, but as noted by an external reviewer of the draft final report, not explicitly stated, that public utilities are expected to operate on a commercial basis. A number of recommendations are made for follow-up activities to improve benchmarking, which in turn should allow better management decisions and help utilities become more commercially sustainable over time. There are three interrelated, overlapping areas in which recommendations are made for the consideration of the utility CEOs, PPA and development partners, arising from the experiences of the 2011 benchmarking exercise. In brief these are in three interlinking areas of improving (a) Pacific power utility performance; (b) quality of information in future benchmarking and; (c) usefulness of benchmarking to utilities.

1 Broad areas for improving Pacific power utility performance such as improving low labor productivity, reducing high non-technical losses, improving low levels of maintenance, improving outage indicators, improving knowledge of customer perceptions, and improving the effectiveness of life-line tariffs.

2 Improving the quality of information in future benchmarking through more rigorous and better-defined performance indicators (and regional goals for those indicators) and the overall questionnaire, providing practical benchmarking training to utility staff, developing a new manual of performance benchmarking, and assisting utilities collect and analyze data for benchmarking.

3 Improving the usefulness of benchmarking to utilities through practical training in benchmarking as an ongoing management tool for decision-making, use of Pacific utility staff for mentoring other utilities, consideration of performance-based employee contracts, and assistance to selected utilities for benchmarking performance improvement plans.

1 Introduction and Background

1.1 Objectives

Performance indicators can help utilities monitor, assess and improve their performance over time by identifying any worrying technical or financial trends within the utility, and by comparing performance with other similar utilities in the Pacific and elsewhere.

...benchmarking is a tool to help improve the quality of service and lift operational and financial performance of the utilities...

In short, benchmarking is a tool to help improve the quality of service and lift operational and financial performance of the utilities and this is the main objective of this exercise. There are several key objectives behind the 2011 benchmarking initiative:

Key Objectives

- To provide a baseline of indicators based on 2010 operational data, against which to measure future changes in technical and financial performance of Pacific Island electric power utilities.
- To compare Pacific performance in 2010 with results from a decade ago (2000 operational data) and with recent results of similar island utilities and small utilities elsewhere.
- To work with selected utilities to assist them to develop and implement benchmarking performance improvement plans (PIPs).

- To contribute to the Pacific energy sector database being developed by the SPC and the Pacific Infrastructure Performance Indicators (PIPIs) for energy developed by PIAC.[1]

1.2 Background, Approach and Extent of Participation

Recent studies in the Pacific region have identified the poor quality of national and regional energy sector data as a constraint to effective analyses of issues, opportunities for improved decision-making and to future improvement. This is true for energy broadly and for the electric power sector. There is limited reliable, consistent, up-to-date information on the technical and economic performance of the region's power utilities and no time-series data allowing comparisons over time. This constrains attempts to improve services, and document the improvements, within the power sector.

In August 2010, the PPA, SPC, and PIAC signed a Memorandum of Understanding (MOU) to establish a sustainable benchmarking system for the power utilities of the Pacific Island Countries and Territories (PICTs). Within the Council of Regional Organisations of the Pacific (CROP), the PPA is the lead CROP implementing agency responsible for electric power assistance activities, with twenty-five member utilities among the PICTs. The SPC signed the MOU as the lead CROP coordinating agency for energy and PIAC acted on behalf of PRIF.

This benchmarking initiative is linked to the *Framework for Action on Energy Security in the Pacific*, a policy and strategy for energy sector action at the regional level, which was endorsed by regional leaders in 2010, and which recognizes the development of improved energy data as a high priority at both national and regional levels. Accordingly, data collected for the 2011 and future benchmarking exercises was designed in part to provide selected power sector data for the SPC's initiatives to improve energy data.

PRIF partners provided an oversight function to guide and monitor project implementation. A Project Steering Committee chaired by PIAC and comprising representatives from SPC, PPA, PRIF partner agencies and CEOs of three PPA member power utilities, met three times during the exercise.

The approach and methodology of the exercise are described in Appendix 1 of this report.

All 25 PPA member utilities (listed in Appendix 2) were eligible for participation in the benchmarking exercise (although only countries eligible for PRIF assistance can receive follow-up support). By late July 2011, 16 utilities had provided sufficient information for preliminary results to be reported in a draft report presented to utility chief executive officers (CEOs) during the PPA's Annual General Meeting (AGM) held in Guam. At the AGM or shortly afterwards, an additional six utilities indicated their wish to participate, of which five provided data by November 2011. Appendix 3 is a list of the final 21 participating utilities, along with those which took part in the initial benchmarking exercise a decade earlier.

1.3 Data and Other Information Used

A list of spreadsheets summarising the data and data sources used to prepare this report is attached as Appendix 4. The key data are those from the returned questionnaires and some of these had data gaps, which are summarised in Appendix 5. In addition, a number of general reports on benchmarking

[1] These have been completed but are not covered in this report.

were reviewed, as well as similar reports prepared for other small utilities or island utilities elsewhere in the world. These, and other materials used in this report, are listed in Appendix 6.

Appendix 7 lists key persons consulted during the study. Some information used in this report on recommendations for follow-up and future benchmarking is from Appendix 8, which is a brief summary of a benchmarking workshop for utility staff held in July in conjunction with the PPA's AGM.

Except where noted, the information used in this report was provided by the participating utilities through a questionnaire[2] (Appendix 9 and Appendix 10) prepared by the consultants, reviewed by a group of utility CEOs and subsequently modified and distributed to utilities by email. The questionnaires were completed by designated benchmarking liaison officers, submitted by the utilities to PPA and/or the consultants, reviewed for consistency, and in some cases resubmitted by utilities. The consultants have tried to verify the validity and consistency of the data through written requests for clarification of apparent errors, dialogue with the utilities, and where possible, comparisons with recent development agency or utility reports.

The data sheets are attached as Appendix 11. Appendix 12 describes the Balanced Scorecard Approach to benchmarking, which may help the PPA and utility CEOs in the process of determining appropriate revisions to indicators for the next benchmarking questionnaire.

[2] The questionnaire is in two parts: (1) "PPA benchmarking 2011 - Intro & Section 1.doc" finalised on 4 April 2001 (Appendix 9); and (2) "PPA Benchmarking Section 2 final version.xls" finalised on 5 April (Appendix 10).
Section 1 covers background and basic utility information. Section 2 is for detailed data and indicators.

2 Regional and Utility Overview

2.1 The Regional Context

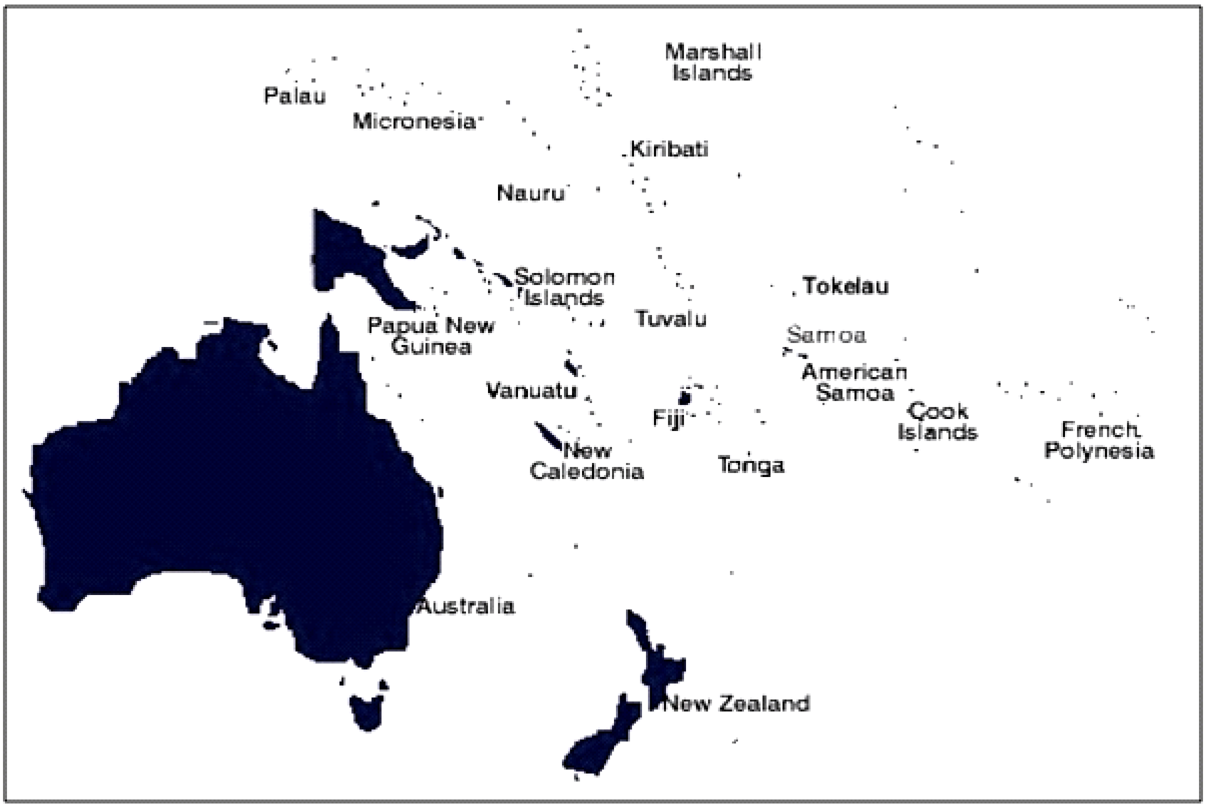
The Pacific Island Countries and Territories (PICTs), shown in Figure 2.1.1, have an estimated mid-2011 population of 10.0 million people living on 553,519 km^2 of land.[3] One country, Papua New Guinea (PNG), dominates, with over two-thirds of the population and occupying nearly 84 per cent of land area.

Distances between and within PICTs can be enormous – Kiribati, for example has only 103,000 people living on 33 widely scattered atolls on 811 km^2 of land extending over 4,200 km from east to west and 2,000 km from north to south. Although this example may be extreme, it demonstrates the challenges faced by the PICTs in providing affordable services of reasonable quality – including electricity – in the region.

Tables 2.1 and 2.2 summarise some economic and demographic characteristics of the countries and territories in which the utilities that participated in this exercise operate.

[3] Secretariat of the Pacific Community (SPC). *Pacific Regional Information System*. http://www.spc.int/prism/.

Figure 2.1.1 Map of the area served by the Pacific Power Association



Note: Australian & New Zealand utilities are not Active Members of PPA
Source: University of Texas: www.lib.utexas.edu/maps

Table 2.1 Economies and populations of independent Pacific Island countries

Country	Population Mid-2011	Land area km²	GNP per capita US$; 2009	GDP per capita US$	Year	GDP growth rate per capita % 2010	%2011	Current account balance % GDP; 2010	High exposure to fuel price rises
Cook Isl.	15,576	237	n.a.	10,875	2008	-2.2	-0.8	4.9	√
Fiji	851,745	18,273	3,840	3,499	2008	-0.3	0.0	-2.3	√
Kiribati	102,697	811	1,830	1,490	2008	-1.2	0.1	-13.7	√
Marshall Islands	54,999	181	3,060	2,851	2007	-1.0	0.0	-10.5	√
Micronesia, Fed. States	102,360	701	2,500	2,183	2007	-7.6	n.a.	-17.0	√
Nauru	10,185	21	n.a.	2,071	2006/7	0.0	1.9	n.a.	√
Palau	20,643	444	6,220	8,423	2007	1.4	n.a.	-9.5	√
PNG	6,888,297	462,840	1,180	897	2006	4.8	6.2	-26.6	√
Samoa	183,617	2,785	2,840	2,672	2008	-0.3	2.7	-8.1	√
Solomon Islands	553,254	30,407	n.a.	1,014	2008	1.6	5.2	-20.0	√
Tonga	103,682	650	3,260	2,629	2007/8	-1.5	0.2	-5.6	√
Tuvalu	11,206	26	n.a.	1,831	2002	-0.5	-0.5	n.a.	√
Vanuatu	251,784	12,281	2,620	2,218	2007	0.7	1.2	-2.4%	√
PIC average			*3,039*	*3,281*		*-0.5*	*1.5%*		
CARICOM average				*11,632*	*various*				

Notes: **1.** *e* = estimated **2.** n.a. = not available **3.** Utilities from all above PICs above participated in 2011 benchmarking.

Sources: 1. Asian Development Bank (ADB). 2011. *Asian Development Outlook* **2.** ADB. 2011. *Pacific Economic Monitor* **3.** GNPs from ADB; GDPs from Secretariat of the Pacific Community (SPC). 2010. Pocket Summary **4.** SPC. 2011. Populations from Pacific Island Populations: Estimates and Projections **5.** CARICOM GDPs sourced from CIA. 2011. *The World Factbook*. https://www.cia.gov/library/publications/the-world-factbook/geos/xx.html

Table 2.1 illustrates the wide variation in populations, land areas, per capita Gross National Product (GNP) and Gross Domestic Product (GDP), and recent economic growth rates per capita:

- Recent per capita PIC GNPs and GDPs have averaged roughly USD$3,000 and $3,300 respectively but in 2010 per capita 'growth' was negative 0.5 per cent and is estimated by the ADB to be only +1.5 per cent in 2011, due in part to the impacts on the Pacific of the global financial crisis. With slow economic growth in many PICs, governments may be reluctant to adjust power tariffs sufficiently to meet the actual cost of supply, and many already charge less than full cost.
- All PICs, even PNG with indigenous resources, are highly vulnerable[4] to the effects of high-cost petroleum fuels, with the smaller north Pacific PICs and other atoll countries being particularly vulnerable. Fuel dominates the operating costs of most of the region's utilities.

PICs and Caribbean island utility benchmarking indicators are compared later in this report. When comparing PIC utilities with those in the Caribbean, it should be noted that average per capita GDP in the Caribbean region is about 3.5 times that of the PICs, suggesting that more resources are likely to be available to the Caribbean utilities for overall operations and maintenance.

The Pacific territories and dependencies (Table 2.2) have far higher GDP/capita than the independent PICs, and consumers can presumably afford higher electricity charges.

Table 2.2: Economies and populations of Pacific Island territories or dependencies[5]

Dependency or Territory	Population Mid-2011	Land area km^2	GDP per capita US$	Year
American Samoa	66,692	199	9,041	2005
Guam	192,090	541	22,661	2005
Niue	1,446	259	9,618	2006
Northern Mariana Isl	63,517	457	12,638	2005
New Caledonia	252,331	18,576	37,993	2008
French Polynesia	271,831	3,521	21,071	2006
Wallis & Futuna	13,193	142	n.a.	n.a.
Average			*18,837*	

Sources: As for Table 1.1

2.2 The Participating Utilities

Of the PPA's 25 member utilities, 21 participated in the 2011 benchmarking exercise, as shown in Table 2.3 below. Of these, 19 provided sufficient data to allow the calculation of a reasonable number of key performance indicators.

[4] Theodore Levantis. 2008. 'Oil price vulnerability in the Pacific.' *Pacific Economic Bulletin*, vol 23, no. 2; AusAID. 2008. *Australian Aid Program Perspectives on Rising Fuel Prices in the Pacific*; Asian Development Bank (ADB). 2009. *Taking Control of Oil;* United Nations Development Program (UNDP). 2007. *Overcoming Vulnerability to Rising Oil Prices: Options for Asia and the Pacific*.

[5] French Polynesia was designated as an overseas territory, in 2003 became an overseas collectively (*collectivités d'outre-mer* or *COM*) and in 2004 an overseas country inside the French Republic (*pays d'outre-mer au sein de la République*, or POM), with considerable autonomy but without a legal modification of its status. New Caledonia was also an overseas territory but gained a special status *(statut particulier* or *statut original*) in 1999, with New Caledonian citizenship and a gradual transfer of power from France to New Caledonia itself.

Table 2.3 Utility participation in 2011 benchmarking

Abbreviation	Utility	Country or Territory
Participating Utilities		
ASPA	American Samoa Power Authority	American Samoa (US territory)
CPUC	Chuuk Public Utility Corporation	Federated States of Micronesia (FSM)
CUC	Commonwealth Utilities Corporation, Saipan	Commonwealth of Northern Marianas
EDT	Electricite de Tahiti	French Polynesia (Polynésie Française) (COM)**
EPC	Electric Power Corporation	Samoa (SAM)
FEA	Fiji Electricity Authority	Fiji (FIJ)
GPA	Guam Power Authority	Guam (US territory)
KAJUR *	Kwajalein Atoll Joint Utility Resources	Marshall Islands (RMI)
KUA	Kosrae Utilities Authority	Federated States of Micronesia (FSM)
MEC *	Marshalls Energy Company	Marshall Islands (RMI)
NPC	Niue Power Corporation	Niue
NUA	Nauru Utilities Authority	Nauru (NAU)
PPL	PNG Power Limited	Papua New Guinea (PNG)
PPUC	Palau Public Utilities Corporation	Palau (PAL)
PUB	Public Utilities Board	Kiribati (KIR)
SIEA	Solomon Islands Electricity Authority	Solomon Islands (SOL)
TAU	Te Aponga Uira O Tumu Te-Varovaro	Cook Islands (COO)
TEC	Tuvalu Electricity Corporation	Tuvalu (TUV)
TPL	Tonga Power Limited	Tonga (TON)
UNELCO	UNELCO Vanuatu Limited	Vanuatu
YSPSC	Yap State Public Service Corporation	Federated States of Micronesia (FSM)
Non-Participating Utilities		
EEC	Electricite et Eau de Caledonie	New Caledonia (Nouvelle Calédonie)
EEWF	Electricite et Eau de Wallis et Futuna	Wallis and Futuna (Wallis et Futuna)
ENERCAL	Societe Neo-Caledonenne D'Energie	New Caledonia (Nouvelle Calédonie)
PUC	Pohnpei Utilities Corporation	Federated States of Micronesia (FSM)

Notes: **1.** The bracketed abbreviations are ADB designations for its Pacific developing member countries **2.** * Indicates that limited data were provided so some key indicators could not be calculated **3.** ** For explanation of the designation 'COM', see footnote 5.

2.3 Characteristics of the Participating Utilities

As Table 2.4 illustrates, the utilities vary widely in terms of installed capacity (2 to over 550 MW), gross generation (3–1253 GWh), maximum demand (0.6–72 MW), customer base (about 900-150,000) and employees (20–1400).

Clearly performance indicators would be expected to vary widely, even if each utility is managed equally well. With such a wide range of utility sizes, very small or very large values can distort the average. For example, the average installed capacity is 80 MW but the median (or middle) value is only 17 MW.

Table 2.4: Basic information on participating utilities in 2010

Utility	Installed Capacity (MW)	Gross Generation Excludes IPPs (MWh)	Maximum Demand (MW)	Minimum Demand (MW)	Customers (Number)	Employees (full-time equivalent)
ASPA (A .Samoa)	47.7	159,113	24.8	13.0	11,884	209
CPUC (Chuuk, FSM)	2.0	9,768	4.0	-	1,634	56
CUC (Saipan)	106.7	216,541	44.9	37.0	15,500	242
EDT (Tahiti)	235.3	688,853	101.4	44.8	81,044	487
EPC (Samoa)	37.5	111,353	18.0	6.4	38,158	602
FEA (Fiji)	211.2	835,169	139.6	60.0	151,410	673
GPA (Guam)	552.8	1,252,672	272.0	139.0	47,333	522
KAJUR (Ebeye, RMI)	3.6	14,183	2.0	-	-	-
KUA (Kosrae, FSM)	5.0	6,504	1.1	0.6	1,845	23
MEC (Majuro, RMI)	28.0	75,747	8.9	6.5	4,832	180
NPC (Niue)	2.1	3,000	0.6	0.3	870	21
NUA (Nauru)	8.0	17,103	3.3	1.7	1,918	70
PPL (PNG)	292.0	796,610	92.9	33.0	91,173	1,412
PPUC (Palau)	18.9	84,860	15.4	-	6,417	70
PUB (Kiribati)	5.5	21,641	5.3	2.0	8,337	57
SIEA (Solomon Isl)	25.6	83,600	13.8	4.9	13,753	-
TAU (Cook Islands)	10.36	27,763	4.9	3.4	5,249	54
TEC (Tuvalu)	5.1	11,800	1.0	0.5	2,210	59
TPL (Tonga)	15.3	52,609	7.7	3.1	14,000	104
UNELCO (Vanuatu)	23.6	60,360	11.3	2.4	10,571	106
YSPSC (Yap, FSM)	6.6	13,000	2.3	1.3	1,900	23
Average	*80*	*219,200*	*37.5*	*20.4*	*26,200*	*265*
Median	*17*	*56,500*	*8.3*	*3.4*	*8,300*	*87*

Notes: 1. For Tables 2.4 - 2.7 data were provided by the utilities. However some data provided were inconsistent (or reported differently in different parts of the questionnaire) so some data in other tables may differ **2.** Blank cells = data were unavailable in time for this draft report **3.** Averages & medians only calculated for those with data in the cells, and are rounded off.

Figure 2.1.2 Funafuti Power Plant, TEC Tuvalu (Photo: PPA)

The above photo shows the main power plant of TEC, a participating utility. Tables 2.5 and 2.6 also show various differences among the utilities. Table 2.5 indicates that about 29 per cent of sales are to households, 39 per cent to commerce, 16 per cent to industry and 16 per cent to other consumers including government.

Table 2.5: Utility electricity sales in 2010 (GWh)

Utility	Household	Commercial	Industry	Other (include govt)	Total
ASPA (A. Samoa)	45.3	40.6	20.6	35.4	141.9
CPUC (Chuuk, FSM)	3.20	2.30	0.0	0.90	6.40
CUC (Saipan)	77.74	131.10	0.0	63.0	271.84
EDT (Tahiti)	229.7	105.3	292.1	9.0	636.2
EPC (Samoa)	25.70	52.90	4.8	8.30	91.70
FEA (Fiji)	215.80	336.70	190.2	12.1	754.8
GPA (Guam)	487.0	578.3	0.0	572.3	1,637.6
KAJUR (Ebeye, RMI)	n.a	n.a	n.a	n.a	n.a
KUA (Kosrae, FSM)	2.20	1.48	0.33	1.53	5.53
MEC (Majuro, RMI)	n.a	n.a	n.a	n.a	55.38**
NPC (Niue)	n.a.	n.a	n.a	n.a	2.79**
NUA (Nauru)	n.a	n.a	n.a	n.a	13.27**
PPL (PNG)	147.0	444.0	166.0	0.0	757.00
PPUC (Palau)	22.8	24.6	0.0	19.7	67.1
PUB (Kiribati)	7.14	3.00	7.0	3.40	20.54
SIEA (Solomon Isl.)	9.6	29.7	7.8	10.1	57.2
TAU (Cook Isl.)	8.11	16.46	0.0	0.28	24.85
TEC (Tuvalu)	2.43	1.52	0.0	1.46	5.41
TPL (Tonga)	17.90	17.05	2.98	4.69	42.62
UNELCO (Vanuatu)	17	14	21	5	57
YSPSC (Yap, FSM)	2.18	1.48	0.33	1.53	5.51
% of total *	*29%*	*39%*	*16%*	*16%*	*100%*

Notes: 1. * Calculated only for utilities that provided sales by customer **category 2.** ** Data from annual reports, donor studies, governments, etc., not from utility benchmark questionnaire **3.** The definition of 'commercial' differs by utility: some include government sales within commercial **4. n**.a. = not available from utility data provided.

For the main transmission/distribution grids of the participating utilities (Table 2.6), 78 per cent of generation is from petroleum fuels (light and heavy fuel combined).[6] About 22 per cent of main grid utility generation is from renewable energy sources, overwhelmingly through hydroelectric power. However, there are some discrepancies in the way utilities reported renewable energy, so the RE percentages are indicative only, as discussed further in Section 4 of this report.

[6] This may not be indicative of renewable energy penetration for the utility (or the country) overall. For example, Papua New Guinea's Port Moresby grid system accounts for well under 50% of PPL's generation and sales; the RE component of 85.5% reported in Table 2.6 would be much lower for PPL overall. PNG also has considerable geothermal generation but this is private mining company generation, not PPL.

Table 2.6: Gross generation by source - *for main grid only* - in 2010 (MWh)

Utility	Distillate ADO / IDO**	Heavy fuel HFO / IFO***	Hydro	Wind	Solar PV	Biomass & Biofuel	Total	% RE+
ASPA (A. Samoa)	159,113	-	-	-	-	-	159,113	0.0
CPUC (Chuuk, FSM)	-	9,798	-	-	-	-	9,798	0.0
CUC (Saipan) *	208,446	-	-	-	-	-	208,446	0.0
EDT (Tahiti)	4,245	336,002	209,145			-	549,392	38.1
EPC (Samoa)	51,663		47,738		4	156	99561	48.1
FEA (Fiji) *	236,356	126,237	413,619	6,420		16,207	798,839	54.6
GPA (Guam)	26,122	1,835,881	-	-	-	-	1,862,003	0.0
KAJUR (Ebeye, RMI)	-	-	-	-	-	-		0.0
KUA (Kosrae, FSM)	6,504	-	-	-	56	-	6,560	0.9
MEC (Majuro, RMI)	62,912	-	-	-	-	-	62,912	0.0
NPC (Niue)	3,000	-	-	-	3	-	3003	0.1
NUA (Nauru)	23,187	-	-	-	53	-	23,240	0.2
PPL (PNG)	31,734	16,333	283,454	-	-	-	331,521	85.5
PPUC (Palau)	83,075	-	-	-	-	-	83,075	0.0
PUB (Kiribati)	21,641	-	-	-	-	-	21,641	0.0
SIEA (Solomon. Isl)	83,623	-	-	-	-	180	83,803	0.2
TAU (Cook Isl)	27,763	-	-	-	-	-	27,763	0.0
TEC (Tuvalu)	6,278	-	-	-	135	-	6,413	2.1
TPL (Tonga)	45,214	-	-	-	-	-	45,214	0.0
UNELCO (Vanuatu)	53,274	-	-	5,388	-	571	59,233	10.1
YSPSC (Yap, FSM)	13,000	-	-	-	-	-	13,000	0.0
Total	*1,147,150*	*2,324,251*	*953,956*	*11,808*	*251*	*17,114*	*4,454,530*	
% of total	*25.8%*	*52.2%*	*21.4%*	*0.3%*	*0.01%*	*0.7%*	*100%*	*22.1*

Notes: 1. Total is for *main grid system only*, not entire utility generation. Blank spaces = zero **2.** Data as reported by the utilities; for some (e.g. PPUC, TAU) there may be some unreported PV **3.** * Excludes CUC power purchases of 74,864 MWh; includes FEA biomass energy purchase. **4.** ** ADO/IDO = Automotive Diesel Oil; Industrial Diesel Oil (light petroleum fuels) **5.** *** HFO/IDO = Heavy Fuel Oil; Industrial Fuel Oil (heavy petroleum fuels) **6.** + RE = Renewable Energy

Table 2.7, which is spread over the next three pages, summarises information about utility ownership, the range of services provided, policies, power sector legislation, national goals for electrification through renewable energy, regulations that encourage (or at least permit) private supply to the grid, and the extent of coverage of each utility's electrification services. All of the utilities generate power, transmit it through grids of various voltages (see Table 2.8) and distribute to customers. A few purchase relatively small amounts of electricity but most generate nearly all of the power fed into the grids.

Table 2.7a: Utility structures, ownership, policies, regulation and coverage

Utility	Govt ownership	Provides non-electric services? y or n?	If yes, type	Non-grid or rural supply	Govt / Cabinet appoints board?	Electricity legislation?	External regulation?	
							Technical?	Commercial?
CPUC (Chuuk, FSM)	100%	Yes	water supply	Standalone PV & SHS *	Yes	CPUC Act 1996	No	No
CUC (Saipan)	100%	Yes	Water; waste management	No	No	Public Law 4-47 enacted by Legislature	Yes both: Commonwealth Public Utility Commission	
EDT (Tahiti)	99.99% private	No	N/A	A few mini-grids; no obligation to develop more	No but represented by Energy Ministry	No	SEM is technical regulator Tariff set by Concession formula negotiated every 5 years	
EPC (Samoa)	100%	No	N/A	Grid extension, standalone PV and PV mini-grid (Apolima)	Yes	Yes, various Acts 1972-2010	Regulator created under Electricity Act of 2010 but not yet implemented	
FEA (Fiji)	100%	No	N/A	Rural grid extensions only	Minister for Utilities	Yes	Not at present but Govt regulation anticipated	
GPA (Guam)	100%	No	N/A	Single grid	General public	Public Law 9-189, May 1968	Regulated by Guam Public Utilities Commission; follow national standards & policies.	
KUA (Kosrae, FSM)	100%	No	N/A	Single grid; Kosrae is all rural	Governor, legislature	Yes, state law Nov 1991	No	No
MEC (Majuro, RMI)	100%	Yes	fuel sales	Manage rural PV	Yes	Yes	No	No
NPC (Niue)	100%	No	N/A	Rural grid extensions only	No board	No, part of Public Works	No	No, only Cabinet
NUA (Nauru)	100%	Yes <1%	Water, fuel	N/A	No board	Yes, June 2011	Planned	Planned
PPL (PNG)	100%	No	N/A			Yes		
PPUC (Palau)	100%	No	N/A	Standalone PV & diesel systems; grid-connected PV	No	Yes	No	No
PUB (Kiribati)	100%	Yes	Water supply & sewage	Standalone PV & SHS	Yes	Public Utility Act 1997, revised 1998		Environment regulation 2001
SIEA (Solomon Isl.)	100%	No	N/A	Diesel, Hydro, Standalone & SHS	Yes	Electricity Act 2007, State Enterprises Act 2009	Yes	No
TAU (Cook Isl.)	100%	No	N/A	Diesel & solar PV on Pukapuka	Yes	Yes	No	No
TEC (Tuvalu)	100%	No	N/A	Standalone PV, diesel & SHS	Yes	Electricity Act 1991, Public Enterprises Act 2010	No	yes - National energy Policy
TPL (Tonga)	100%	No	N/A	Standalone PV, Diesel and SHS	Yes	Electricity Act 2007	Yes, Utilities Regulation Authority	Yes, UTA
UNELCO (Vanuatu)	No; 100% private	No		Rural connections within concession area; no stand-alone	No but one representative from Energy Minister	No national legislation	Yes	Yes, external monitor & control
YSPC (Yap, FSM)	100%	Yes	Water; waste management	All of Yap is essentially rural	Yes, represented by state agencies	Yes, Yap State Law 4-4	No, self-regulating	Yes; state energy policy

Notes: 1. * SHS = Solar Home Systems (low voltage DC photovoltaic systems) **2.** N/A = Not Applicable **3.** Data not provided by ASPA & KAJUR

Table 2.7b Utility structures, ownership, policies, regulation and coverage

Utility	Power quality law /regulation	Service obligation	Regulation or requirement for:			National RE goal (electricity)	Tariff		Tax on electricity inputs or supply?			National utility or specified service areas?
			IPPs / PPAs *	FIT** or net metering	DSM ***		Determined by	Fuel surcharge	On electricity sold?	On utility equipment?	On fuel for power?	
CPUC (Chuuk, FSM)	No- patterned on US regulations	No	No	No	Being considered for future	30% RE by 2020	Board	No	USD 0.128/gal	4% tax on all imported goods	USD 0.128/gal	Weno and 4 outer islands
CUC (Saipan)	US standard	No	Yes - Public Law 16-17 (Privatization Law	Net Energy Metering Policy (PL 15-87)	No	40% RE by 2012	Utility Board	Yes	No	Yes	Yes	Saipan, Tinian and Rota
EDT (Tahiti)	LV 10% HV 7-10% freq. 5%	Every paid extension must be connected	French standards	Yes clear policy & tariffs for PV & wind	No; DSM services are provided	50% RE by 2020	Concession agreement	No	Territorial & city taxes + 5% VAT		Taxed but varying subsidies to stabilise cost	20 islands; 90% of population of French Polynesia
EPC (Samoa)	No	Yes	No	No	No	20% RE by 2030	Government	Yes	No	No(?)	S$0.4/l of IDO + 15% VAT	National; 97% coverage
FEA (Fiji)	distribution voltage 6%; freq. 2%	No	FEA grid code for IPPs	yes; currently F$0.23 / kWh	commercial audits at FEA cost	90% RE by 2015	Commerce Commission	Not currently	12.5% VAT added to bill	No duty for RE equipment	F$0.18/litre for IDO; F$0.10/l HFO	Main island of Viti Levu + Vanua Levu & Ovalau
GPA (Guam)	US standard	Yes - On Utility approval	No	Net metering	Yes	5% net sales from RE by 2015	Guam Public Utilities Commission	Yes	No	No	No	Throughout Guam
KUA (Kosrae, FSM)	voltage ±5%; 7.5% for industry	No	Under consideration	No	No	No; state energy plan being developed	Board of Directors	Yes	No	4%	No	State of Kosrae, FSM
MEC (Majuro, RMI)	No	planning only	No	No	No	20% RE by 2020	Cabinet	No	No	8%	No	Majuro, Jaluit and Wotje
NPC (Niue)	NZ but no compliance	Safety only	No	No	Only with donor $	100% carbon neutral 2013	Government	No	Yes; 12.5% paid by utility	No	No	National, single island
NUA (Nauru)	Being considered	No	Being prepared	No	No	50% RE by 2015	Government	No	No	No	No	National, single island

Notes: 1. * IPPs = Independent Power Producers (usually private sector) PPAs= Power Purchase Agreements **2.** ** FIT = Feed-in tariff **3.** *** DSM = Demand Side Management **4. (?)** questionable result

Table 2.7c Utility structures, ownership, policies, regulation and coverage

Utility	Power quality law regulation	Service obligation	Regulation or requirement for:			National RE$^+$goal electricity	Tariff		Tax on electricity inputs or supply?			National utility or specified service areas?
			IPPs / PPAs**	FIT** or net metering	DSM***		Determined by	Fuel surcharge	On electr. sold?	on utility equipment?	On fuel for electr.?	
PPL (PNG)	AS/NZS 3000:2007								10% GST added to bill			
PPUC (Palau)	Yes	No but PUC task is to electrify all of Palau	Yes, within the confines of the law which created the utility. Net metering expected to be approved during 2011			20% RE by 2020	Utility Board	Yes		No	USD 0.05/gal	Main Island & three other outlying states
PUB (Kiribati)	AS/NZS 3000:2007					Reach 70% of population with RE; date ?	Price Ord. Act 1976, rev 1981			No		South Tarawa
SIEA (Solomon Isl.)	AS/NZS 3000:2007	Community Service Obligation Regulation	Yes - technical standard requirements	No	No	20% RE by 2018	Govt under Electricity Tariff Regulation 2005	Yes		Yes	SBD$0.22/litre plus 10% GST	Auki, Malu'u, Gizo, Noro, Munda, Kirakira, Lata, Buala, Tulagi and Honiara
TAU (Cook Isl.)	AS/NZS 3000:2007	Yes - on Government approval	Yes	Net metering	no	50% RE by 2015; 100% by 2020	Board	No		100% levy exemptions	Port charges and VAT	Rarotonga
TEC (Tuvalu)	AS/NZS 3000:2007	No	No	No	Being consider-ed	100% RE by 2020	Board	Yes	3% for > 50kWh /my consumption	No	0.05 cent rebate per litre of fuel purchase	Funafuti & all outer islands except Niulakita
TPL (Tonga)	AS/NZS 3000:2007					50% RE for main grid by 2012	Electricity Commission and TPL	Yes				Tongatapu, Vavau, Haapai and Eua
UNELCO (Vanuatu)	Yes under concession agreement	Yes, any customer request within concession	No	No	No	No RE goal	Regulated under concession agreement	No	12.5% value added tax	No concessions on import duty	15 vatu/litre	Islands of Efate, Tanna & Malekula
YSPSC (Yap, FSM)	No but quality is good	Legally no; 100% electrification goal; so yes in practice.	No	Soon net metering to be introduced	No but comm.& house-holds	State goal of 28% with ADB support	Board	No, built into tariff	No	4% national import duty; exempt from Yap state tax	0.05 US$ per US gallon duty; 0.05 US$/USG Yap excise tax	75% of state: Yap Proper, Ulithi Atoll, Falalop, Woleai

Notes: 1. * IPP = Independent Power Producer; PPA = Power Purchase agreement **2.** ** FIT = Feed-in tariff **3.** *** DSM = demand side management (for customer energy efficiency services) **4.** $^+$ RE = Renewable Energy **5.** GST = Goods & Services Tax **6.** VAT = Value Added Tax **7.** No data provided by ASPA and KAJUR

Information from Table 2.7a-c is summarised below for the utilities that provided information:[7]

Ownership	19 of the 21 utilities that participated in the 2011 benchmarking exercise were 100% government owned in 2010.
Utility services	Six of 19 utilities that responded provided non-electricity services such as water supply, sewerage, and waste management and/or fuel sales. In some cases, some costs of these services are charged to electricity operations, or not adequately accounted for. This can lead to reported costs (and losses) that should be charged to the water, waste or sewerage operations. Utilities should better allocate costs among services to accurately reflect the actual costs of the services and clearly show subsidies or cross-subsidies where these exist.
Off-grid supply	Over half of the utilities have some responsibility for off-grid supply away from a main grid, usually stand-alone rural low-voltage DC photovoltaic systems but in some cases small diesel or hydro mini-grid systems. These remote systems often require considerable time and resources, without sufficient compensation to fully cover utility costs. For some utilities, governments have established artificially low users' fees for off-grid supply, imposing additional costs on the utility or resulting in poor operations and maintenance of the systems.
Boards	In general the government appoints most or all members of the utility board of directors but two of the utilities have no formal board.
Legislation	All but two utilities operate under formal power sector legislation (although some legislation is quite out-dated).
Regulation	Most of the utilities have no formal system of external regulation (technical or commercial) but commercial regulation exists (e.g. Fiji, PNG, Vanuatu) or is under development or consideration in several PICTs (e.g. Samoa, Tonga). External regulators in other regions of the world often encourage or require a regular performance benchmarking programme. Most Pacific utilities are the only organisations in the country with technical knowledge of the power sector and are self-regulating technically, but with strong government influence on the level of tariffs.
Service obligations	Most have no formal public service obligation.
Quality standards	Many have some form of regulation of power standards (voltage fluctuations and/or frequency) but not all are enforced.
Private supply regulations	Only three of the 19 utilities have formal regulations for Independent Power Producers (IPPs) and utility Power Purchase Agreements (PPAs) from IPPs (with others under consideration), so some proposed IPP arrangements can be *ad hoc* and may be difficult to negotiate, limiting the potential for cost-effective independent supply.

[7] ASPA and KAJUR did not provide responses to Section 1 of the questionnaire. For some questions, information available from other sources was included in the summary.

Net metering or feed-in tariffs	Only five of the 19 utilities that responded have either net metering regulations or feed-in tariffs (FITs)[8] so it can be difficult for consumers or small businesses to legally provide power to the grid with clear rules, from renewable (or other) energy systems, such as household PV systems being installed or considered in some PICTs (and increasingly common outside of the Pacific).
Renewable energy goals	Most of the governments have established specific national goals and timetables for electrification through renewable energy. These tend to be very ambitious and many have been developed with little substantive utility input or serious consideration of practicality. They tend to be statements of broad intent.
Tariff determination	About half of the electricity tariffs are ostensibly established by the board of directors or external independent commissions. In practice, the governments have a very strong influence on – or in some cases effectively decide – tariff levels.
Charges to Consumers (tariffs)	It can be difficult to compare costs of supply on a consistent basis as some of the utilities pay import duty or tax on fuel and/or equipment, but others do not. Similarly, published tariff schedules do not always clearly indicate all charges to consumers. Some add government taxes and a range of other charges (e.g. insurance) to the bill, but others include these in the tariff schedule. Some tariffs indicate only a 'base charge' with additional fuel surcharges that often change frequently and can be difficult for consumers to understand or challenge.
Service coverage	Finally, the systems range from a single distribution voltage grid covering customers on only a single island to those covering many islands and dispersed rural communities with several main grids, a number of smaller isolated grids, and stand-alone systems. A few have national coverage but others (e.g. in the FSM) only cover specific states.

Some of the technical and financial benchmarking indicators measured in this report may appear to be poor for a specific utility but this does not necessarily indicate poor planning or management. The value for line loses, for example, may be due more to the characteristics of the grid (low voltage, long length, low customer density, low customer demand) than to inadequate operations, management or maintenance. Some financial indicators may be poor due to government-established tariffs that do not cover full costs.

[8] Net metering is a renewable energy production incentive, usually allowing consumers to sell renewable-based electricity to the grid (net of consumption from the grid) at an agreed price and duration. A FIT provides terms and conditions for a private producer to sell renewable energy to the grid, typically varying by type of technology, and typically under a long-term contract.

Table 2.8 summarises information on PICT utility transmission and distribution systems.

Table 2.8 Utility transmission and distribution voltages (kV)

Utility	Transmission	Distribution	Frequency (Hz)
CUC * (Saipan)	34.5	13.8	60
EDT (Tahiti)	30, 90	11; 14; 20	50
EPC (Samoa)	22; 33	6.6; 22	50
FEA (Fiji)	33; 132	11	50
GPA (Guam)	110 & above	13.8	60
RMI & FSM **	None	13.8	60
NPC (Niue), NUA (Nauru), PUB (Kiribati), TAU (Cook Isl.), TEC (Tuvalu), TPL (Tonga)	33	11	50
PPUC (Palau)	34.5	13.8	60
UNELCO (Vanuatu)	None	5.5	50

Notes: 1. * In Rota & Tinian, 13.8 kV distribution only **2.** ** RMI = MEC and KAJUR; FSM = PUC, CPUC, KUA & YSPSC

3 The Benchmark Indicators

When this initiative was planned in late 2010, it was the intention of the PPA to retain, as far as practical, the indicators and reporting style used in the earlier benchmarking effort of a decade ago. Table 3.1 lists the key indicators used for 2000 data (reported in the 2002 report) along with goals agreed by CEOs at that time for future benchmarking. With one exception,[9] these indicators have been retained for this report, with several additions shown in Table 3.2.

Table 3.1: Key benchmark indicators (2000 and 2010)

Key Indicators* Used in 2002 report	Explanation or definition from the 2002 report	Average for 2002	Goals for future as agreed in 2002
Generation			
Load factor	Annual Generation (MWh) * 100 Peak generated load (MW) * Period hours (8,760)	67%	50-80%
Capacity factor	Annual Generation (MWh) * 100 Installed plant capacity (MW) * Period hours (8,760)	34%	> 40%
Availability factor	Installed plant capacity (MW) * hours (8,760) - MWh losses * 100 Installed capacity (MW) * Period hours (8,760)	93%	80%-90%
Specific fuel oil consumption (kWh / litre)	Units Generated / Fuel Used	3.79	3 - 4
Lube oil consumption (litres / hour)	Lubricants used (volume) Hours of operation	3.50	3.2 - 3.5
Forced outage	MWh out of service due to forced outages * 100 Installed plant capacity (MW) * Period hours (8,760)	7.93%	3-5%
Planned outage factor	MWh out of service due to planned outages * 100 Installed plant capacity (MW) * Period hours (8,760)	4.30%	3%
O&M cost per /MWh	Total operation and maintenance costs Electricity sent out to grid (MWh)		$18

[9] As discussed in Section 4 of the report next section, lubricating oil use (show under generation in Table 3.1) was changed from litres per hour to litres per MWh generated, which is more indicative of performance.

Transmission**			
Reliability	Unplanned outage * 100 / Length of line	Not available	
Transmission Losses	Energy sent out - Energy sent to distribution system / Energy sent to distribution system	8.02%	5%
Distribution			
Customers/employee	Average total number of customers / Average no. of employees in distribution & consumer services	242	240
Reliability / km	No of unplanned outages * 100 / Total length of line		
Transformer utilisation	Total energy sold (MWh) * 100 / Distribution transformer capacity (MVA) * 8760 hr	18.14%	30%
Distribution Losses	Electricity sent out - electricity sold / Electricity sent out	12.34%	5%
SAIFI (interruptions/customer)	Total number of customer interruptions / Average total number of customers	19.00	10
SAIDI (hours/customer)	Total customer hours interrupted * 60 / Average total number of customers	592	200
Distribution O&M US$/km ***	Distribution operation and maintenance costs / Total circuit kilometres or miles	$2,478	$800
Corporate / financial			
Operating ratio	Total operating expenses + depreciation / Operating revenue	186%	0%
Debt to equity ratio	Long term debt / (Equity + long term debt)	26.07%	<50%
Rate of return	Operating income / Average net fixed assets in operation	- 16.80%	> 0%
Current ratio	Current assets / Current liabilities	3:1	>1:1
Debtor days	Debtors at year end * 365 / Total revenue	79 days	< 50 days

Notes: 1. * Slightly edited from 2002 benchmarking summary report. Several indicators slightly renamed or formulas modified for clarity. **2.** ** In effect 'transmission' refers only to the utilities with high-voltage supply above 33 or 34.5 kV. **3**. ***This was reported to be a questionable result in 2002.

Some new indicators have been added for several reasons (discussed in detail in Appendix 1):

- Utility operations in the Pacific have evolved in the past decade with the introduction of grid-connected renewable energy, independent suppliers, new regulatory arrangements, etc.
- A review of recent power sector benchmarking experience in relatively small utilities elsewhere – particularly other island regions such as those of the Caribbean Electric Utility Services Corporation (CARILEC) – suggested some useful additions.
- A 2010 Memorandum of Understanding between the PPA, SPC, and PIAC (on behalf of the PRIF development agency partners) specified the collection of some broad energy data for use by the SPC and PRIF for their own energy statistics efforts.

The new indicators, and other information requested from utilities, are listed in Table 3.2 below. It was appreciated that some utilities may not be able to provide all of the data requested but the results were meant to serve as a baseline for future Pacific power utility benchmarking.

...utility operations in the Pacific have evolved in the past decade with the introduction of grid-connected renewable energy, independent suppliers and new regulatory arrangements.

Table 3.2: Additional indicators or information requested for 2011 benchmarking

Added indicator	What information it provides	Comment
Service coverage (electrification rate through the grid, %)	Population (i.e. residential connections) with utility-based electricity service / total population (i.e. total households) Comment: Most utilities will not have this information	SPC* PRIF** CARILEC***
Lifeline tariff ($ / kWh)	Lifeline Tariff for residential consumers $/kWh compared to average tariff Comment: Indicate savings for low-income consumers compared to the normal residential charge	SPC
Productive electricity use	Commercial & industrial electricity billed/total electricity billed	SPC
Regulation	Indication of extent of self-regulation (standards, tariffs, IPPS) or external regulation (government or independent commission)	SPC, CARILEC
Enabling Framework for Private Sector Participation	Existence of standard IPP / PPA arrangements	SPC
Private sector contribution	Total annual kWh supplied by IPP/Total kWh sent out Comment: May only be available for the main utility grid	SPC
Renewable energy	% of energy generated or sent out (in case of energy purchased from external IPPs) by renewable sources as follows: Biofuel, Wind, Solar PV, Hydro, Geothermal, Biomass/bagasse, Other Comment: biofuel to exclude any petroleum fuel content	SPC
Average generation cost ($ / MWh)	Total annual costs / gross energy entering the system (excluding power station auxiliary usage)	CARILEC
Average supply cost ($ / MWh)	Total annual costs / energy delivered to customers	CARILEC
Electricity charge (tariff by customer class) ($/kWh; $/kW)	Charge to consumer by consumer category (not just overall) Comment: preferably average for the year (2010), not latest charges	CARILEC
Power quality	Existence of a national standard for voltage and frequency fluctuations	CARILEC
Fuel used	For diesel systems, per cent of total generation which is light (IDO, ADO) and heavy petroleum fuel (HFO)	New
Demand side management	Budget if any for DSM; Full-time equivalent employees engaged in DSM; MWh saved by consumer from utility DSM initiative	New
Composite indicator	Overall indicator of utility performance	New

Notes: 1. * SPC indicates utility data SPC hopes to include in the Pacific energy sector database it is developing. **2.** ** PRIF = PRIF energy indicator, which is part of a PRIF basic data set. **3.** *** CARILEC = indicators in recent CARILEC benchmarking reports which seem to be appropriate for the Pacific.

4 Results

4.1 Introduction

This section provides performance indicators for 2010 operations in the form of a series of charts comparing the participating utilities. There is a brief explanation of the relevance of each indicator with both average and median[10] values and a comparison of results to those of a decade ago. In addition, the electricity charges per kWh for typical levels of household and commercial consumption in late 2010/early 2011 are compared for those utilities where data was available, based on publicly available information. Where the text refers to the 'Pacific benchmark' or 'regional benchmark', these are the future goals agreed to by utility CEOs in 2002. All quotations referring to the indicators for operational year 2000 are from the 2002 final report. The format of this section broadly follows the style of the 2002 report.

Table 4.1: Utility participation 2010 & 2000

Abbrev.	2010	2000
ASPA	√	√
CPUC	√	√
CUC	√	no
EDT	√	√
EEC	no	√
EEWF	no	√
ENERCAL	no	√
EPC	√	√
FEA	√	√
GPA	√	√
KAJUR	√	√
KUA	√	√
MEC	√	no
NPC	√	√
NUA	√	no
PPL	√	√
PPUC	√	√
PUB	√	√
PUC	no	√
SIEA	√	√
TAU	√	√
TEC	√	no
TPL	√	√
UNELCO	√	√
YSPSC	√	no

As shown in Table 4.1, the earlier benchmarking study for utility operations during 2000 covered 20 utilities; the current one effectively covers 19 (there are 21 participants in total but KAJUR[11] and MEC provided only limited data). Sixteen utilities took part in both years so comparing results for the two reporting periods should be reasonably accurate, despite somewhat different utility coverage, with more participation by Francophone utilities in 2000.

In the 2002 report, the average (arithmetic mean) values reported for all utilities were used for most indicators. However, the median (the middle value in the series) is probably more appropriate because a single utility

[10] The 2002 report did not include any median values. Unfortunately the old 2002 datasheets that are still available covered only 16 utilities, not all 20 participants, so it was not possible to calculate the median values for 2000 operations and compare them to 2010 operations. In some cases, it was possible to estimate a median value from the charts.

[11] Additional financial data was provided for KAJUR by ADB staff in mid-December 2011, too late for inclusion in this report.

reporting a very high or low value can skew the overall average results considerably. Where available, the 2002 data has been reworked to provide both median and average values for key indicators for those utilities that participated in both studies.

For technical performance indicators, the utilities are identified by name. The financial indicators are not reported by utilities consistently and, in some cases, are less accurate. In addition, some utilities specified that financial data not be made public, so individual utilities are identified by alphabetic codes (A, B, C, etc.),[12] not utility names.

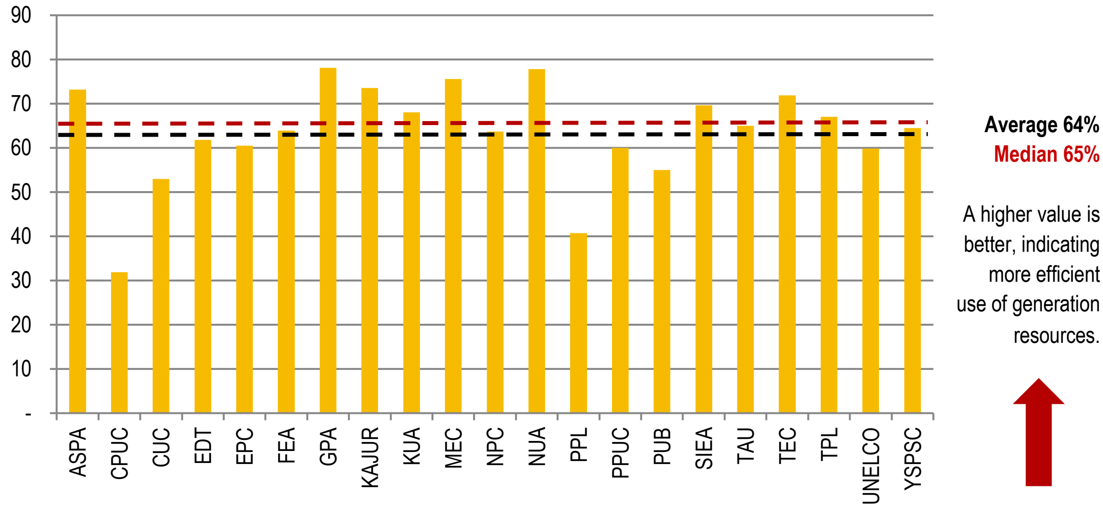
4.2 Generation Indicators

(i) Load Factor

Load factor (LF) is a measure of the effectiveness of the use of utility generation resources. It is the ratio of system average power generated to peak power demand over a period of time. A lower LF indicates greater fluctuation in the use of generators throughout the reporting period, sometimes (but not necessarily) resulting in higher losses. A high LF implies a relatively flat demand for electricity and relatively constant utilisation of generators, transformers and related equipment operating at efficient levels.

In 2000, the load factor was rated as a "relatively good average [of] 67 per cent, compared to an international range of 65-80 per cent".[13] At the time, Pacific utility CEOs selected "a high benchmark of 80 per cent indicating that in future, demand management should play an increasingly important part in Pacific power sector policies."[14] In 2010, however, the reported results are slightly lower than those of a decade ago as shown in Figure 4.2.1. One external reviewer of the draft final report expressed doubt that a LF of 80 per cent is achievable in practice, suggesting 70-75 per cent as more realistic for the Pacific.

Figure 4.2.1 Load factor 2010 (%)



[12] There are gaps among the letters chosen because the same code is used as that of the 2002 report, but with new letters added for new participants. The code used for each utility has been provided to the CEO of that utility.
[13] Pacific Power Association (PPA) and Asian Development Bank (ADB). 2002. *Final Report Performance Benchmarking October 2002: Pacific Power Utilities.* Sydney, p. 5-1.
[14] PPA and ADB, *Pacific Power Utilities,* p. 5-1.

(ii) Capacity Factor

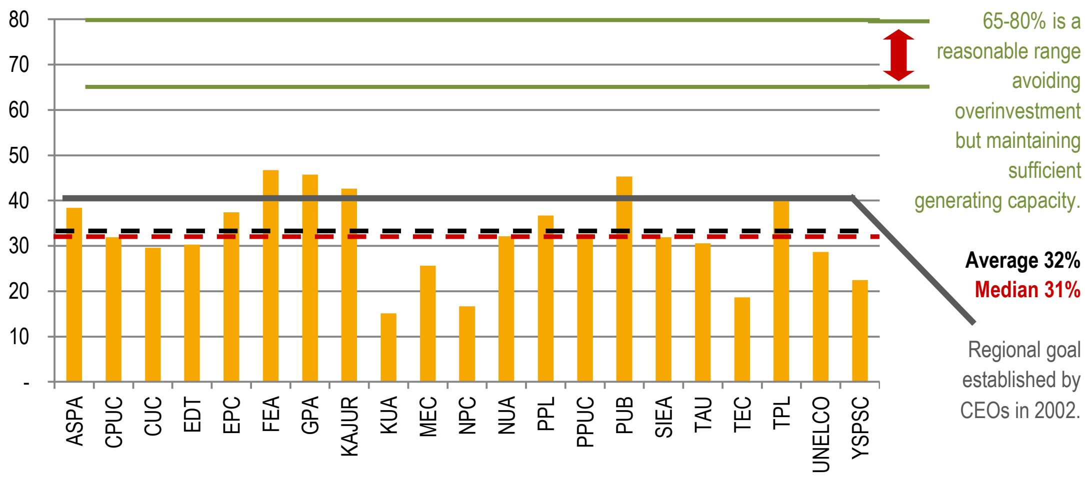
Capacity factor (CF) is also an indicator of effectiveness in relation to the use of generation resources. It is a similar measure to LF. Where LF measures average power as a percentage of maximum demand, CF measures average power demand as a percentage of installed capacity.[15] A lower CF means that there is adequate reserve capacity to meet future load growth or demand when some generation is shut down for maintenance or down due to faults. It also suggests over-investment in generation capacity. A higher CF means demand is closer to available capacity, which can cause difficulties in scheduling maintenance of generating plants. Furthermore, available capacity may not meet future load increases. Improving the CF can require major capital investment in new generating plants. Utilities with a CF of nearly 1.0 tend to have an inadequate capacity to meet demand, which can result in power rationing.

For operations during 2000, the capacity factor averaged at 34 per cent compared to a regional goal of 40 per cent and international best practice of 50-60 per cent "reflecting … isolation, need for reserve margins and indivisibility of plant serving "pockets" of small loads. Discussions with CEO's … indicate that they believe this … will be difficult to improve."[16]

In 2010 the capacity factor averaged only 32 per cent - this is slightly lower on average than a decade ago and well below the regional goal of 40 per cent.

In 2010, as shown in Figure 4.2.2, the capacity factor averaged only 32 per cent (median 31 per cent), with wide variation in reported results. This is slightly lower on average than a decade ago, and well below the regional goal of 40 per cent.

Figure 4.2.2 Capacity factor 2010 (%)



(iii) Availability Factor

The **availability factor** (AF) of a power plant is the amount of time it is able to produce electricity (taking into account outage times) over a specified period, divided by the installed capacity, times the length of the period.

[15] Note that some sources (e.g. Wikipedia) use the terms load factor and capacity factor interchangeably, both used as this paper defines CF. Several commentators suggest a desirability to separately report on (or at least carefully distinguish between) firm and non-firm capacity. This issue is discussed later under results and recommendations.

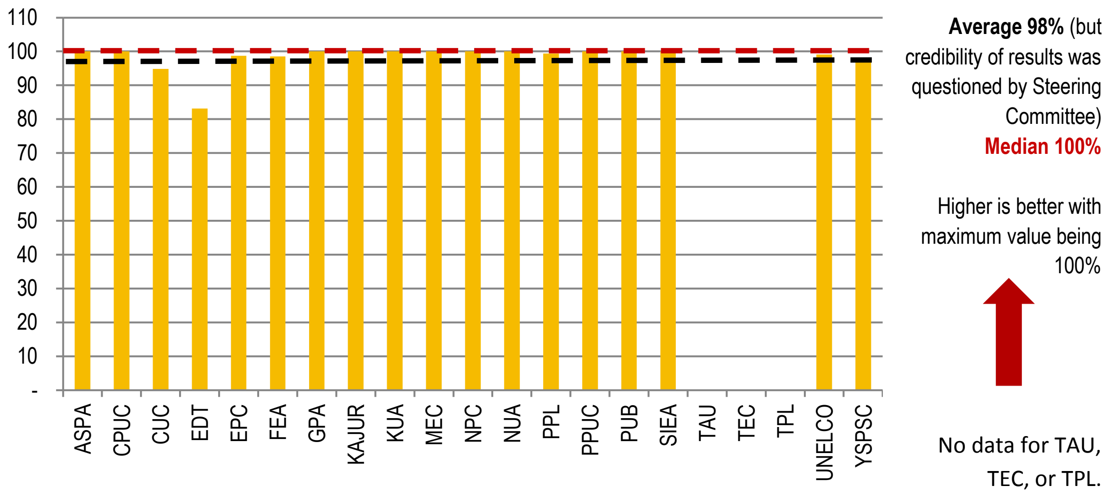
[16] PPA and ADB, *Pacific Power Utilities,* p. 5-1.

The availability of a power plant varies depending on outages due to failure or maintenance. Plants that run less frequently (e.g. plants brought on line for meeting peak demand only) have higher availability factors because they are generally in good operating condition. Plants that frequently experience breakdowns have low AF. Thermal power stations generally have availability factors between 70 per cent and 90 per cent. Newer plants, and those that are well-maintained, tend to have significantly higher availability factors.

For utility operations during 2000, the reported availability of generating plant in the Pacific averaged 93 per cent “compared to the Pacific benchmark of 90 per cent and typical international practice of 65 per cent.”[17] In 2010, the results reported by utilities (Figure 4.2.3) are higher, with average and median values both exceeding the regional benchmark.

At least one Steering Committee member felt that the results are not credible, with presumed uncertainty in reporting. One external reviewer noted that the questionnaire definition includes station auxiliaries in losses and argued that: (a) these should be excluded, and, (b) the AF should take into account non-availability due to forced outages, planned outages, and periods when generating plant is de-rated. These issues should be addressed and resolved before the next benchmarking planned for 2012. The AF would be considerably lower if based on firm continuous capacity.

Figure 4.2.3 Availability factor 2010 (%)



(iv) Generation Labour Productivity

Generation labour productivity is a measure of the services produced per employee, i.e. productivity of staff engaged to operate and maintain generating plants. It is a ratio of total electricity generation to the number of full-time equivalent (FTE) employees who operate and maintain the system’s generating plant. For power utilities, the indicator of service has traditionally been the amount of electricity generated per employee, but this may change over time as Pacific utilities provide more energy efficiency services to customers.

In 2000, Pacific utilities generated about 3 GWh for each employee involved primarily in power generation (with a range of 0.5-10), compared to typically 22 GWh in larger utilities, which is considered to be international best practice. In 2002, the CEOs argued that this is not an appropriate indicator for comparison: comparing “large base-load on mainland [utilities] compared to island

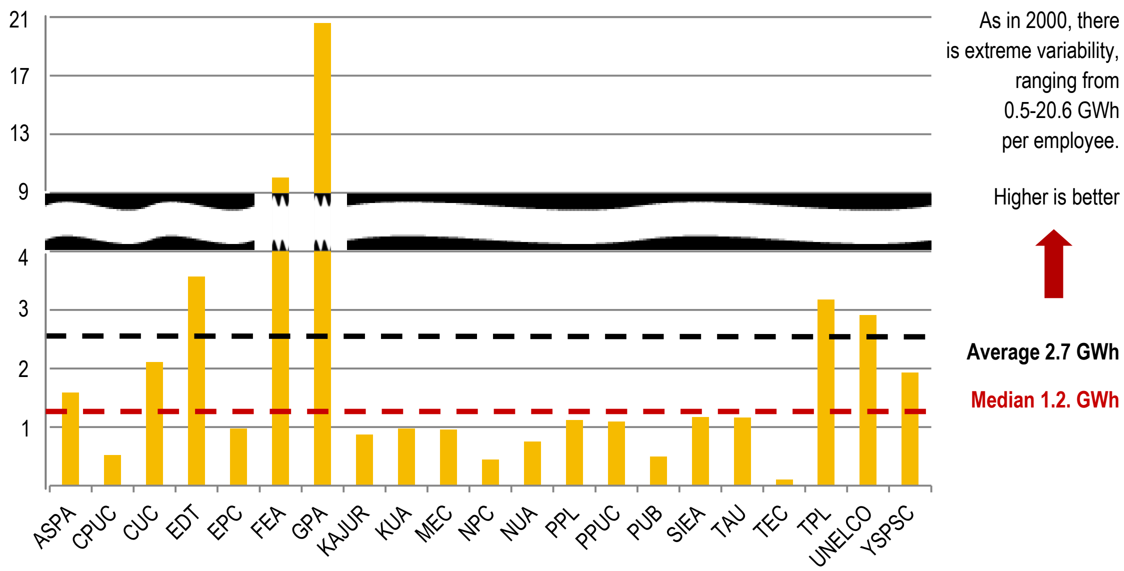
[17] PPA and ADB, *Pacific Power Utilities,* p. 5-2.

generation stations. However, considering the worldwide emphasis on productivity improvement in the power sector, there may also be opportunities in this regard in the Pacific."[18]

In 2010, the range (Figure 4.2.4) was wider than that reported in 2002 but the average had declined to 2.7 GWh per generation employee, with the median of 1.2 even lower. The reported productivity per FTE generation employee has apparently declined in the past decade.[19] However, it may be appropriate to reconsider the usefulness of this indicator for future benchmarking.

The reported productivity per FTE generation employee has apparently declined in the past decade.

Figure 4.2.4 Generation labour productivity 2010 (GWh/generation employee)



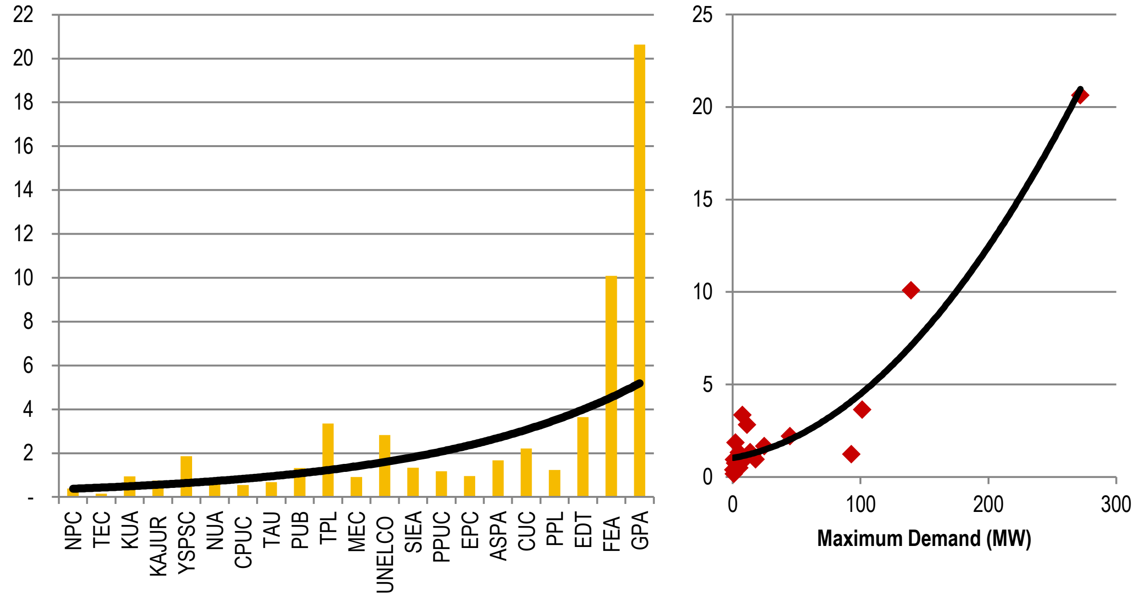
The smaller utilities will tend to have lower generation productivity because of a low level of GWh generated but a high number of semi-skilled staff to operate and maintain the generating plant, regardless of utility size. As shown in the left side of Figure 4.2.5, this is generally true for the Pacific utilities, with a clear trend (the thick black exponential trend line) of increasing labour productivity as the utility maximum demand increases.

The generation productivity of YSPSC, TPL and UNELCO stand out relative to others. Figure 4.2.5 indicates that they have the highest labour productivity among the smaller utilities in the group. The same data is presented in the form of a scatter chart at the right-hand portion of Figure 4.2.5, for which the best trend line fit appears to be quadratic. There does not appear to be, as questioned by a Steering Committee member, a clear cut-off point above which productivity tends to improve due to economies of scale.

[18] PPA and ADB, *Pacific Power Utilities,* p. 5-2.

[19] 'Apparently declined': as one external reviewer suspects, some utilities do not understand or accurately report on FTE employees or do not accurately allocate them to generation, distribution, etc. A Steering Committee member asked whether total FTE employment levels rose between 2000 and 2011. The original datasheets for 2000 are no longer available but for the 12 utilities for which reported FTE is available for both years (total, not generation), seven indicated fewer total employees in 2010 than in 2000, whereas five reported an increase, with an overall decline of 3 per cent. For the same utilities, generation reportedly grew by 41 per cent during the same period.

Figure 4.2.5 Labour productivity 2010 (GWh/generation employee)



(v) Specific Fuel Consumption

Specific fuel consumption (SFC) is a measure of the efficiency of fuel use for power generation, often reported in kWh/gallon or kWh/litre of fuel used. SFC is a key performance indicator because fuel accounts for the overwhelming bulk of generation costs in a typical PPA–member diesel based power utility. It refers to the efficiency of utility generation only – it does not include purchased energy from Independent Power Producers (IPPs).

In technical specifications, fuel efficiency is generally reported in kilograms (kg) or grams (g) of fuel per kWh of power produced, which takes into consideration the different densities and energy content of lighter and heavier petroleum fuels. The type of fuel used thus has a bearing on SFC.

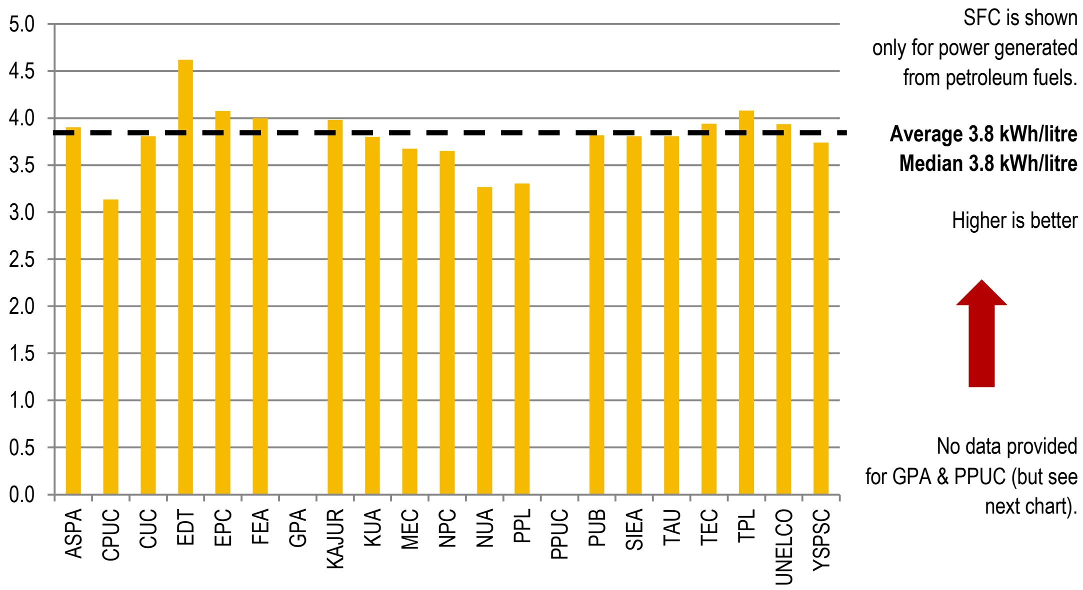
Specific fuel consumption is a measure of the efficiency of fuel use for power generation. During 2010 operations, the reported average (and median) of 3.8 kWh per litre has hardly changed over the decade.

For operations during 2000, it was reported that “Pacific practice … (average of 3.79 kWh per litre) is already close to … the Pacific benchmark of 4.0 kWh per litre indicating … good performance.” [20]

During 2010 operations, as shown below in Figure 4.2.6, the reported average (and median) of 3.8 kWh per litre has hardly changed over the decade.

[20] PPA and ADB, *Pacific Power Utilities,* p. 5-3. A SFC of 3.79 kWh per litre is 4.512 kWh/kg at a specific gravity of fuel of 0.84 kg per litre. This is equivalent to 221.6 g per kWh.

Figure 4.2.6 Specific fuel consumption in 2010 (kWh/litre)



Note that specific fuel consumption is only comparable for similar sized engines operating at similar loads. A large modern slow-speed or medium-speed engine with a high BMEP[21] value generally has a higher SFC (about 30 per cent higher) than a small high-speed or low BMEP medium-speed engine at similar loads and with similar maintenance standards. It was not possible to separate the data by engine type or size (which would be useful in future benchmarking exercises) and operating conditions.

EDT, EPC and TPL – especially EDT – stand out as the only utilities generating over 4 kWh per litre of fuel. FEA and KAJUR report 4.0 kWh per litre (but actual KAJUR efficiency is believed to be less.) The type and quality of fuel used also has a significant effect on SPC. Engines using heavier fuel with high calorific values will normally have a higher SFC compared to lower density fuels.

Larger utilities such as GPA and (to a lesser extent) FEA with large generating plants use heavier fuel, which suggests that it may be appropriate in future benchmarking to consider measuring SFC in g/kWh or kg/kWh to provide more meaningful comparisons of fuel use efficiency that account for different petroleum fuels.

For Pacific utilities studied on behalf of the PPA by the Dutch consulting firm KEMA (for which data were available when this report was prepared), the average SFC for 2009 or 2010 operations[22] was 3.71 kWh per litre and the median was 3.66 kWh per litre (Figure 4.2.7) – results that KEMA considered to be low.

Fuel efficiency should be improved, generally through more cost-effective maintenance, but is probably not unreasonable considering that most PICT utilities use small high-speed diesel generators.

Fuel efficiency should be improved, generally through more cost-effective maintenance, but is probably not unreasonable considering that most PICT utilities use small high-speed diesel generators. New low and medium speed engines should achieve 4-5 kWh per litre.

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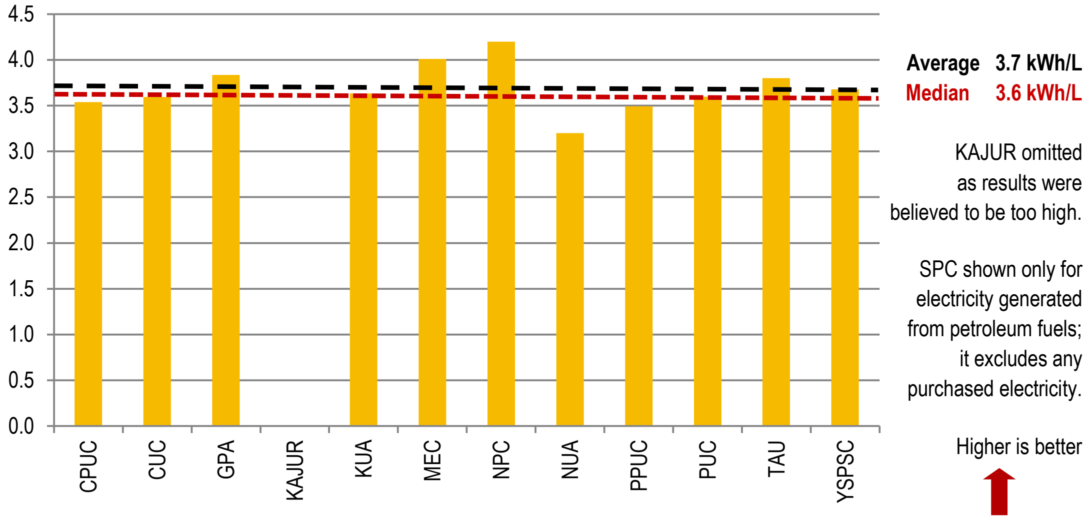
[21] BMEP is Brake Mean Effective Pressure, the average effective pressure of all stroke cycles. BMEP is a function of temperature of the gases in the cylinder.

[22] KEMA provided preliminary 2010 data for NPC, NUA & TAU. All others are for 2009.

Note that the data in Figure 4.2.7 is a bit lower than the utilities reported (Figure 4.2.6).[23] NPC had the best 2010 fuel efficiency of the eleven utilities (4.2 kWh per litre), which is considerably higher than that reported in Figure 4.2.6 (3.65 kWh per litre). The reason for the discrepancy is unknown. MEC was second among the eleven (4.0 kWh per litre).

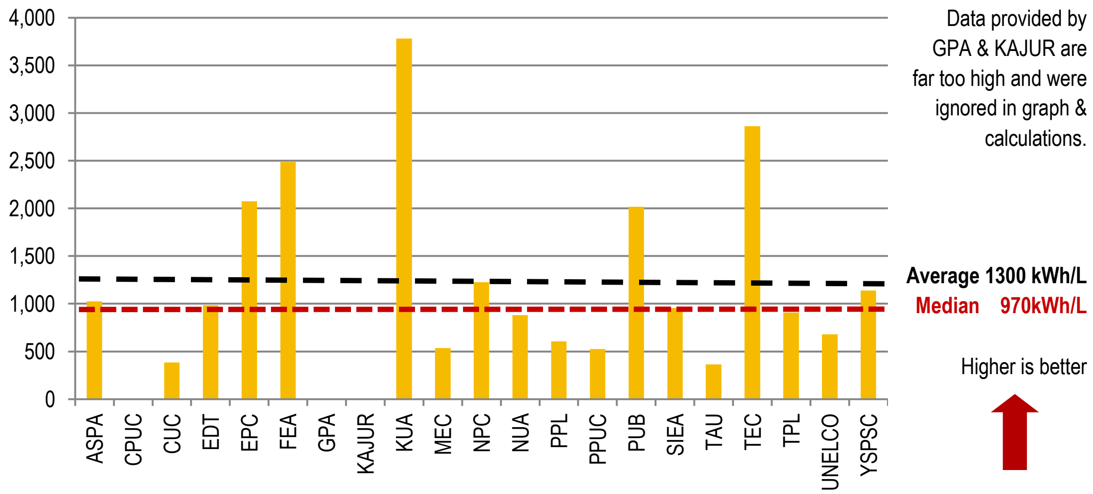
Figure 4.2.7 Fuel efficiency for 11 Pacific utilities (kWh/litre) based on KEMA data



(vi) Lubricating Oil Consumption[24]

Another useful measure of the efficiency of petroleum-fuelled generation is the number of kWh generated per litre of **lubricating oil consumed**, with the benchmark varying according to the size and condition of the engine. Lower lubricating oil efficiency can be attributed to poor maintenance, e.g. due to worn piston rings. Discussions with several Pacific utility engineers suggests that reasonable values are about 500–700 kWh per litre for a 1 MW engine and 1,000–1,300 kWh per litre for a 4–5 MW engine. In 2010, the average (Figure 4.2.8) was 1300 kWh per litre, with a median value of 970 kWh per litre, but it was not possible to separate these by engine size.

Figure 4.2.8 Lubricating oil consumption in 2010 (kWh/litre)



[23] Part of the difference may be because KEMA data was for 2009 or 2010 operations, depending on the utility, whereas all other data was for 2010. KEMA may also have had time to resolve inconstancies in the data during field visits.

[24] For operations in 2000, the 2002 benchmarking exercise reported lubricating oil consumption for petroleum fuelled gensets in litres per hour. However this is not a particularly meaningful indicator so it has been dropped for the current exercise and replaced with kWh per litre of lubricating oil.

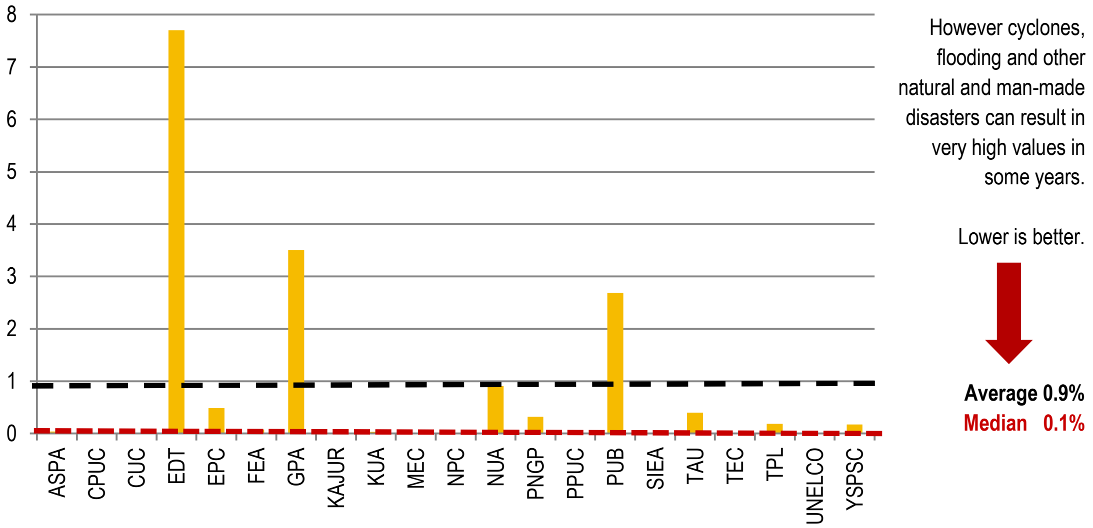
(vii) Forced Outage

Forced outage is unplanned outage (or generator downtime) that has been forced on the utility. It is total unplanned loss of generation capacity as a percentage of maximum available generation from installed capacity. Unplanned outages are attributable to problems with generators that forced the utility to take them out of service. In 2002, for operations during 2000, it was reported that "some improvement is required … regarding forced outage"[25] with an average of 7.93 percent compared to a Pacific benchmark of 5 per cent.

In 2010 (Figure 4.2.9), the utilities reported average forced outage of under one per cent and a median value under 0.1 per cent. Although the median is consistent with the reported Availability Factors in Figure 4.2.3, the data for both indicators appears to be questionable.[26] Reporting may need to improve in the future for meaningful comparisons to be drawn among utilities.

In 2010 the utilities reported average forced outage of under one per cent – reporting may need to improve in the future for meaningful comparisons to be drawn among utilities.

Figure 4.2.9 Forced outage reported for 2010 (%)



(viii) Planned Outage

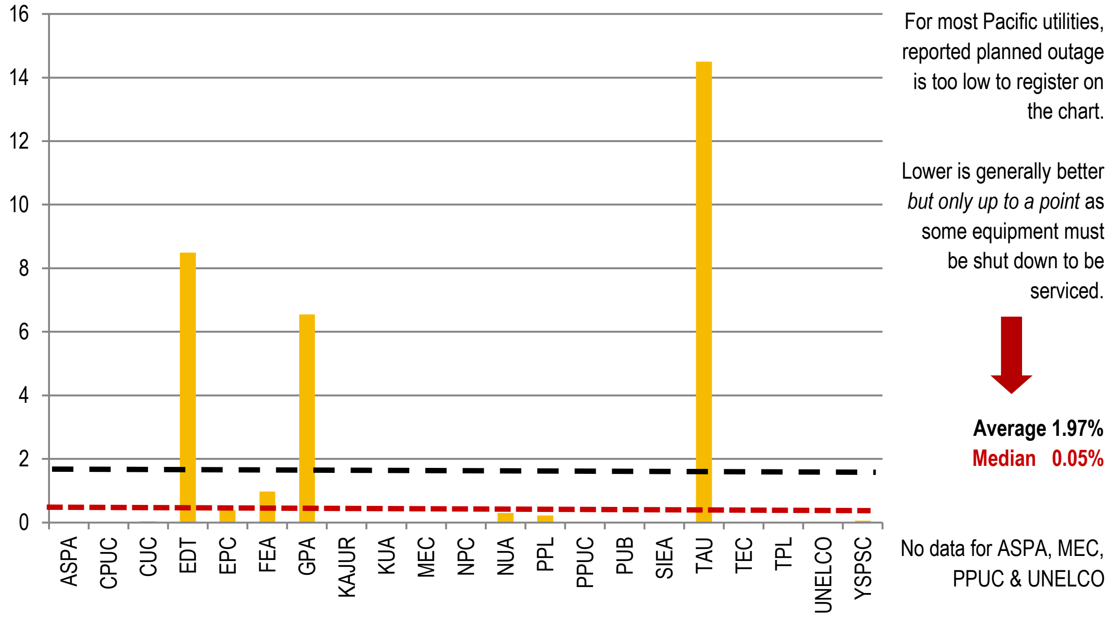
Planned or scheduled outage is downtime for planned maintenance or other activities requiring equipment to be shut down. It is a scheduled loss of generating capacity as a percentage of installed capacity to generate energy. In 2000, planned outage was reported to be acceptable, averaging 4.3 per cent compared to the Pacific benchmark of 3 per cent.

In 2010, the reported average (Figure 4.2.10) was under 2 per cent but the median was well under 1 per cent, which appears to be far too low. It suggests that very little planned maintenance of generating equipment occurs in most of the Pacific utilities, often due to insufficient reserve capacity to allow the shutdown of generators due for scheduled maintenance and a lack of spare parts. Unfortunately, when maintenance periods are extended, the probability that generators may break down increase.

[25] PPA and ADB, *Pacific Power Utilities,* p. 5-4.

[26] Possibly, some utilities' calculations were based on available capacity rather than installed capacity.

Figure 4.2.10 Planned outage in 2010 (%)

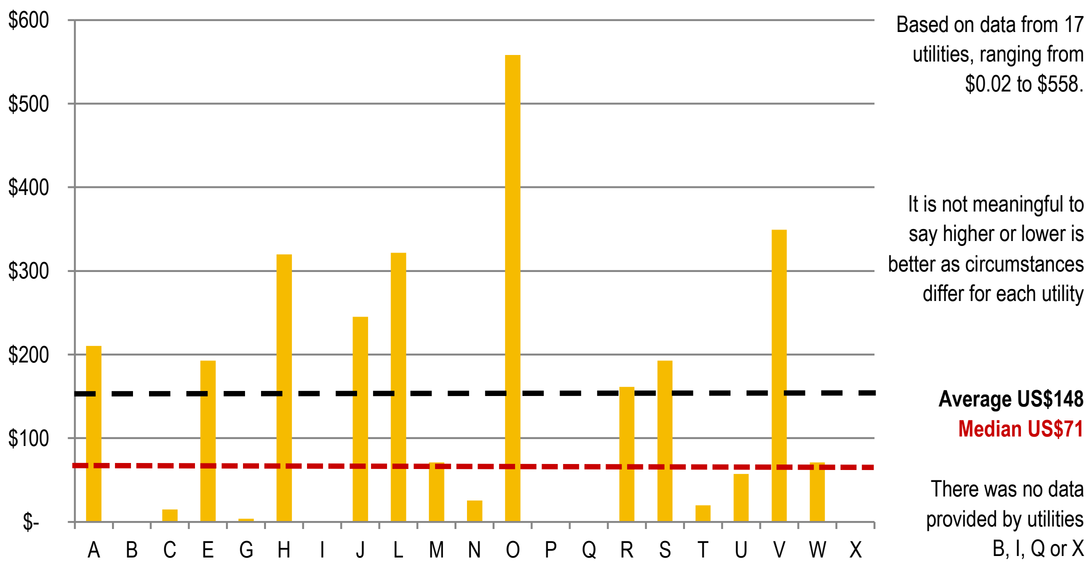


(ix) Generation Operations and Maintenance (O&M) Costs

The indicator used is simply the expenditure on **O&M** of generating equipment in US$ per MWh generated. The 2002 report did not provide data on generation O&M expenditures but chose a benchmark of US$18 per MWh, excluding fuel and lubrication oil expenditures. Considering inflation over the past decade, a comparable benchmark would be far higher today.

For operations during 2010, shown in Figure 4.2.11 below, the reported average was US$148 per MWh with a median of US$71. Note that some utilities did not want cost data to be made public so utilities are identified by alphabetic code, rather than the utility abbreviation (the codes assigned are not in the same order as the utility abbreviations or names).

Figure 4.2.11 Generation O&M expenditures in 2010 (US$/MWh)



4.3 Generation Indicators

(i) Losses (General)

In 2000, six participating utilities provided data for “transmission functions (defined as 33 kV and above).”[27] On average, there were 35 outages per 100km of transmission line per annum; labour productivity was 24 GWh per transmission employee (compared to an Australian mainland average of 70 GWh).

Reported transmission losses as a percentage of energy generated were typically around 8 per cent (compared to an Australian mainland average of 19 per cent[28] and a Pacific benchmark of 5 per cent). The 2002 report concluded that “there is scope in the Pacific to improve transmission line losses”.[29]

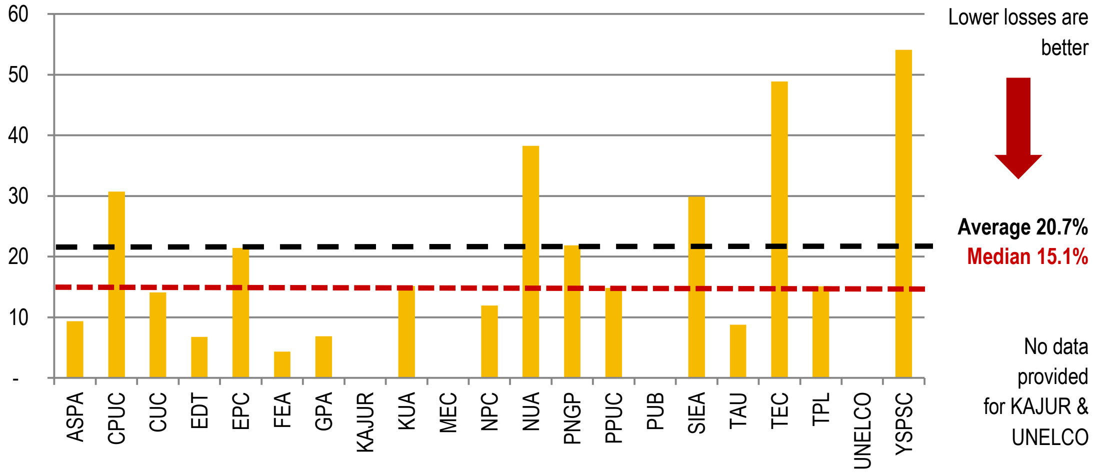
In 2010, five participating utilities reported that they operate transmission networks (33 kV for southern Pacific utilities, 34.5 kV for those following US standards, and one reporting HV transmission at 30 kV and 90 kV.

Pacific utilities reported average transmission and distribution losses in 2010 of nearly 21 per cent [and] a median value of 15 per cent...

Comparable data was not provided for all five utilities (some appear to have reported transmission and distribution combined), and there appear to be some inconsistencies in reporting, so these indicators have not been compared or charted.

If transmission and distribution losses (as a percentage of electricity generated) are combined, Pacific utilities reported average T&D losses in 2010 of nearly 21 per cent, a median value of 15 per cent, with some (CPUC, NUA, TEC & YSSPC) much higher. However, this data, shown in Figure 4.3.1, should be considered as being only roughly indicative. Some utilities included station losses and some financial losses among non-technical losses. The distinction is discussed below Figure 4.3.1.

Figure 4.3.1 Combined transmission and distribution losses as reported by utilities 2010 (%)



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[27] PPA and ADB, *Pacific Power Utilities,* p. 6-1.
[28] PPA and ADB, *Pacific Power Utilities,* p. 6-1.
Note however, that energy data (2001-2002) from the Australian Bureau of Statistics presents the following figures in relation to losses in Australia: “In 2001-02, 26,907 GWh was used or lost during supply of electricity to users. Initial losses by generators accounted for 12,082 GWh, transmission losses accounted for 6,301 GWh, and distribution losses accounted for 8,524 GWh. These losses represent around **13.1%** of total electricity generated for sale.”
Australian Bureau of Statistics. 2003. *Energy Statistics, Australia, 2001-02*.
http://www.abs.gov.au/ausstats/abs@.nsf/0/1DD46A713657BA33CA256E000075736B?OpenDocument.
[29] PPA and ADB, *Pacific Power Utilities,* p. 6-1.

(ii) Distribution Losses

Distribution losses are those that occur from the high voltage substations to the consumer meters. For those PICT utilities without HV transmission grids, distribution losses are those from circuit breakers of feeders inside power plants to consumer meters. These losses are classified as technical and non-technical:

Technical and Non-Technical Losses

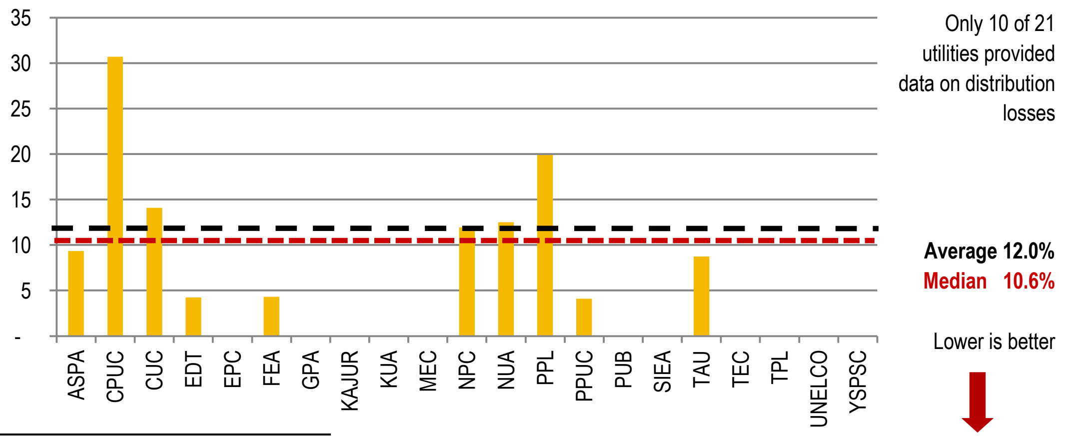
- Technical losses are mainly caused by unbalances in the distribution system and/or too high resistance in the system. These depend on distribution voltages, sizes and kinds of conductors or cables used; transformer types, condition and loading and the wire sizes of service feeds to consumers' meters.
- Non-technical losses are those due to electricity used by a consumer but not paid for, including theft, computer programming errors, unmetered, metering errors, etc. This category should not include the use of electricity within the utility itself (power station use, other facility use), free provision of street lighting, or electricity provided to the water, waste management or sewerage section of the utility, but not paid for. These are financial, not non-technical, losses.

For 2010, reported distribution losses for those utilities that provided data remained high at 12 per cent.

For utility operations in 2000, the report of 2002 stated that "Pacific distribution losses on average at 12 per cent are far too high (compared to the regional and international benchmark of 5 per cent). This is a priority area for improvement."[30] The reported losses in 2000 apparently included both technical and non-technical losses; the definitions used may have been unclear. For 2010, as shown in Figure 4.3.2, reported distribution losses for those utilities that provided data remained high at 12 per cent, with a median value of 10.6 per cent. However, some reported losses that appear to be very high (e.g. CPUC) may be the result of including some financial losses within the non-technical losses.

These are comparable to total system losses, T&D, as reported by KEMA (see Figure 4.3.3). However, these are based on modelling the grid and calculating losses, not actual metered losses, so results will differ from those reported by utilities.

Figure 4.3.2 Distribution losses as reported by utilities in 2010 (%)



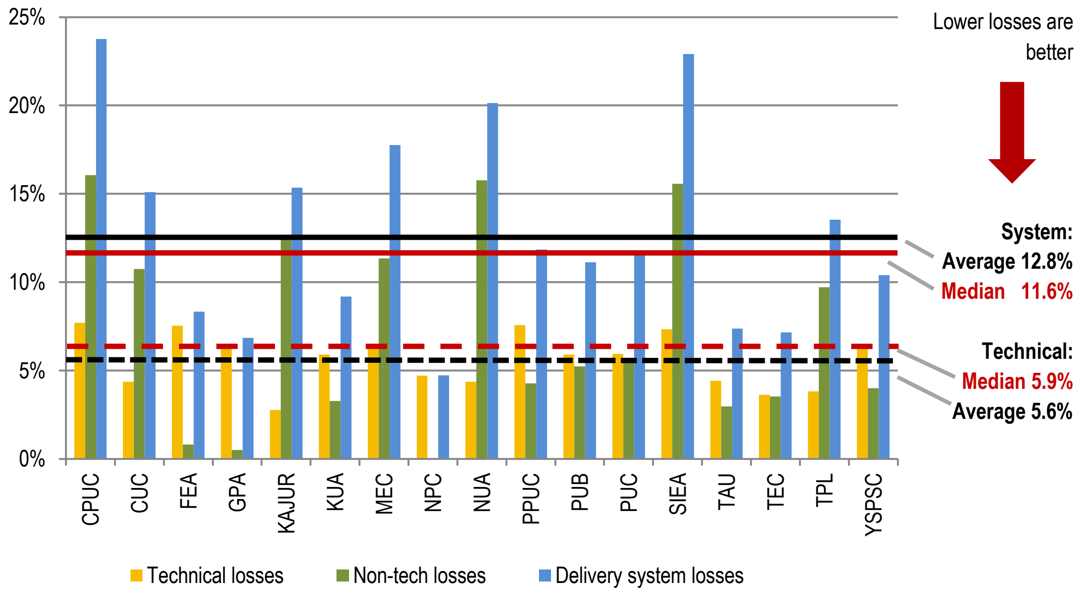
[30] PPA and ADB, *Pacific Power Utilities,* p. 7-2.

(iii) The KEMA System Loss Studies[31]

As noted, most Pacific utilities do not operate true transmission systems but rather medium and low voltage distribution grids. The losses as reported by utilities in the 2011 questionnaires did not always clearly distinguish between transmission and distribution. Some utilities entered data in the wrong section of the spreadsheet and it is not always apparent how this should be corrected. For seventeen Pacific utilities, data on total delivery system losses (transmission plus distribution) are available from a series of KEMA technical reports. Some results are summarised in Figure 4.3.3 below. Although some results are preliminary and will be finalised in early 2012, they clearly distinguish between technical and non-technical losses, with internal power station use and financial losses excluded.

Total system losses during 2009 (northern utilities) and 2010 (southern utilities) vary widely, but averaged 12.8 per cent (median 11.6 per cent). This is a bit higher than those of a considerably smaller number of utilities (10 versus 17) as reported by utilities (Figure 4.3.3). Technical losses averaged 5.6 per cent with a median value of 5.9 per cent. These numbers would normally be expected to be 3–5 per cent, preferably closer to 3 per cent. Only five PIC utilities[32] have technical losses below 5 per cent: CUC, NPC, NUA, TEC and TPL.

Figure 4.3.3 Losses for 17 Pacific utilities as reported by KEMA (2009-2010 operations)



Non-technical losses (the broken black line in Figure 4.3.3 for each utility) were higher on average than technical losses, averaging 7.2 per cent of electricity generated, with a median value of 5.2 per cent. There should be considerable opportunity to reduce this level. Finally, KEMA reports total losses (technical, non-technical, station use, provision to water and sewerage utility divisions, etc. combined) as 17.9 per cent (both

Non-technical losses were higher on average than technical losses, averaging 7.2 per cent of electricity generated – there should be considerable opportunity to reduce this level.

[31] PPA and KEMA. 2011. *Quantification of Energy Efficiency in the Utilities of the South Pacific*. (Draft 2011 reports for NPC, NUA and TAU for 2010 losses); PPA and KEMA. 2010. *Quantification of Energy Efficiency in the Utilities of the U.S. Affiliate States Excluding US Virgin Islands: Final Data Handbook and Final Report*. (2010 reports for the northern utilities providing 2009 losses; and preliminary spread sheets with losses for other southern utilities). These were all prepared for the PPA by the Dutch consulting firm KEMA, with support from the USDOI, the EC and the New Zealand government.

[32] This excludes KAJUR, for which some data appears to be wrong.

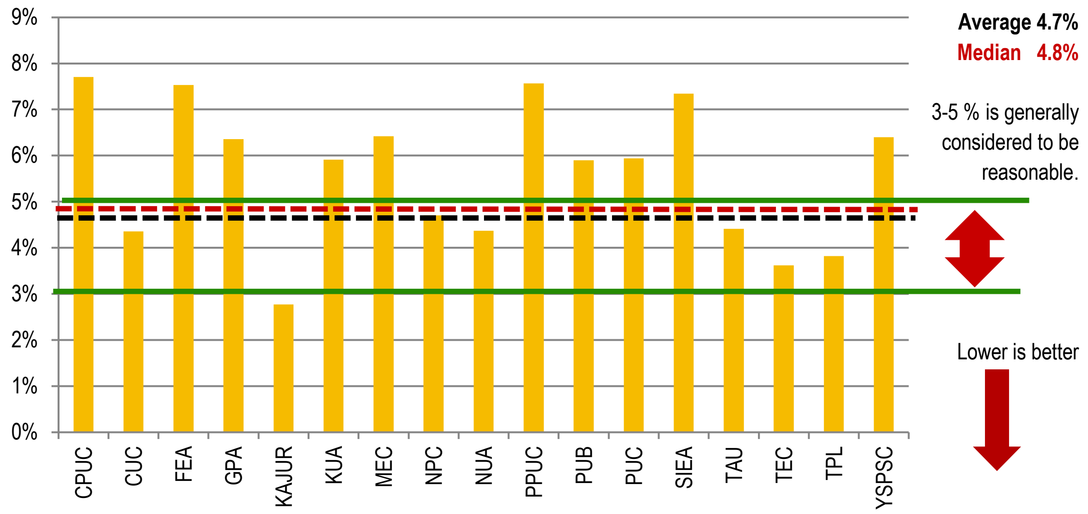
average and median). This is lower than the total T&D losses reported by utilities (Figure 4.3.2) averaging at 20.7 per cent, but higher than the median of 15 per cent. As noted earlier, the difference may be due to the different number of utilities covered and different ways of allocating non-technical losses; or in some cases, weak reporting.

The KEMA studies modelled utility transmission and distribution systems where measured data was unavailable or inaccurate. It is probably the most complete and accurate recent data available for most Pacific power utilities. The differences between the data reported by utilities and that calculated or measured by KEMA suggest that there were misunderstandings in the use of the 2011 questionnaire. For future benchmarking exercises, clarification of the questionnaire may be required.

(iv) Station Auxiliaries

A generating station's use of electricity, often referred to (perhaps misleadingly) as station losses, is usually indicated by the percentage of MWh generation used internally in the power station. Generally 3-5 per cent is considered to be acceptable internationally. The average value was 4.7 per cent and the median was 4.8 per cent, but as shown in Figure 4.3.4, only about 40 per cent of the 17 PICT utilities for which data was available are within or below the preferred range.

Figure 4.3.4 Station energy use for Pacific utilities as reported by KEMA (2009-2010 operations)



4.4 Other Distribution Indicators

(i) Customers per Distribution Employee

In 2000, there were on average 242 customers for each FTE utility employee working on distribution, which was considered by the report authors at the time to be good.

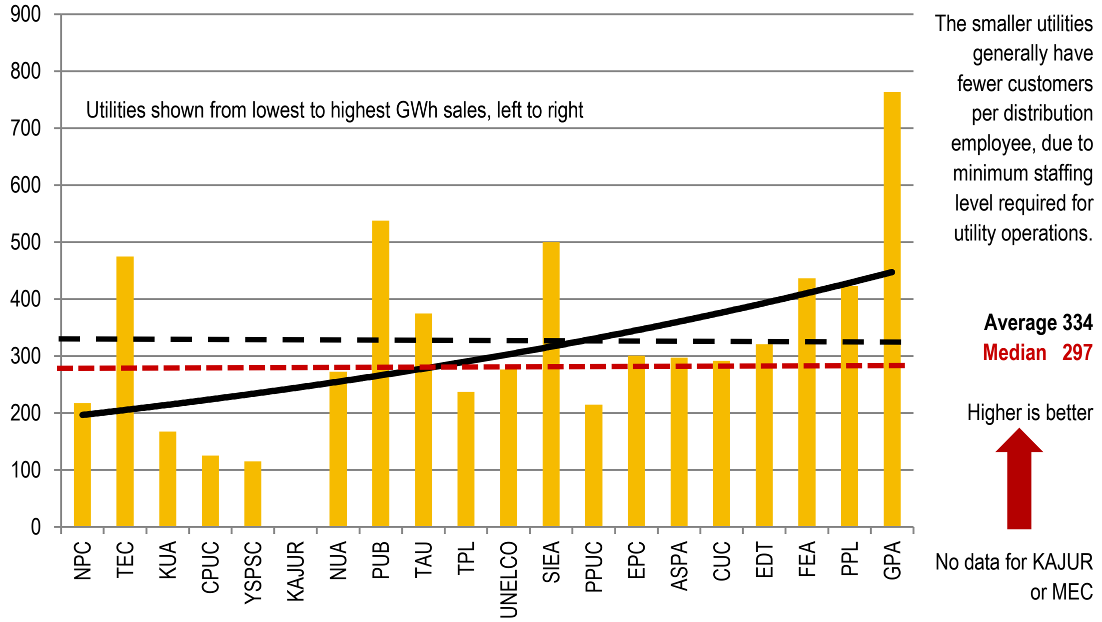
In 2010 (Figure 4.4.1), the reported average was 334 and the median was 297. This marks an impressive improvement of nearly 40 per cent for the average if

There is a clear trend: Pacific utilities with higher total sales generally serve more customers per distribution employee.

accurate.[33] There is a clear trend (continuous black trend line in Figure 4.4.1): Pacific utilities with higher total sales generally serve more customers per distribution employee.

If Figure 4.3.5 had charted customers per distribution employee with the utilities ranked according to the total length of the distribution network, it might be expected to show an even better correlation. However, this was not the case: the trend was less clear (and the chart has not been included).

Figure 4.4.1 Customers per distribution employee in 2010



(ii) Distribution Transformer Utilisation

This indicator measures the transformer load in MVA, i.e. the energy used by customers connected to the transformers as a percentage of distribution transformer capacity. High utilisation implies an efficient capital expenditure process for investing in distribution transformer capacity to meet the demands of customers. This process takes into consideration demand, demand growth and contingency requirements to improve supply security and reliability.

In 2000, utilisation was low, averaging 18 per cent compared to a regional goal of 30 per cent. The report noted that “this can only be achieved in the long term because of the usually long lead times required to improve usage of capital assets.”[34]

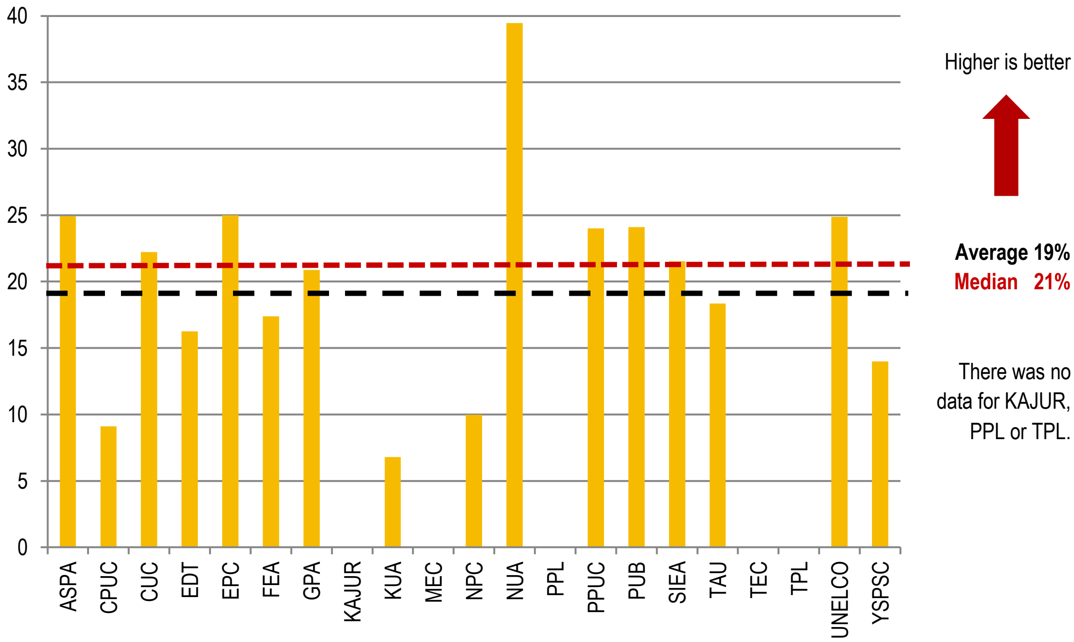
In 2010, the reported average as shown in Figure 4.4.3 was 19 per cent, with a median value of 21 per cent, which represents no significant improvement. Discussions with some utility engineering staff and others suggest that utilities may be ordering the same sized transformers used in the past, rather than reviewing the load distribution along the grid and ordering transformer sizes accordingly. Only NUA exceeds the Pacific goal.

In 2000, (distribution transformer) utilisation was low, averaging 18 percent compared to a regional goal of 30 per cent. In 2010, the reported average was 19 per cent, which represents no significant improvement.

[33] As noted by an external reviewer, for some utilities, the reported improvement may be due to outsourcing of functions such as vegetation control, etc. In this case, FTE should include contractor hours within paid hours for distribution work.
[34] PPA and ADB, *Pacific Power Utilities,* p. 7-1.

Figure 4.4.2 PPUC Distribution, Palau (Photo: KEMA 2010)

Figure 4.4.3 Distribution transformer utilisation in 2010 (%)



(iii) Interruption Duration

The 'System Average Interruption Duration Index' (SAIDI) is commonly used as a reliability indicator measuring hours of interruptions per customer. In the 2002 report, SAIDI was considered to be "a priority area for improvement considering that current performance is not good (average of 592 minutes per year compared to [the] Pacific benchmark of 200) and customers typically rank reliability of supply as very important."[35]

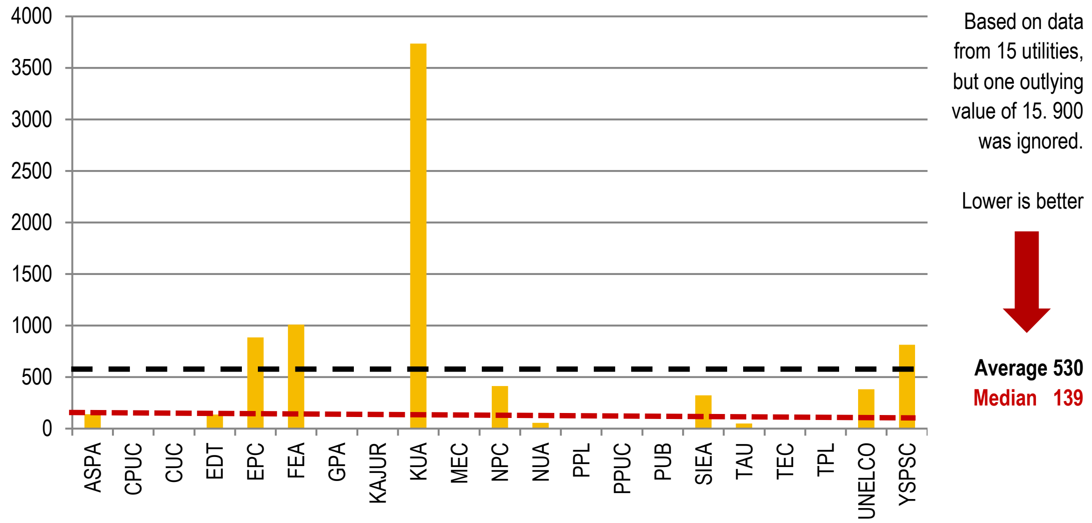
For 2010 (Figure 4.4.4), the reported average was 530 minutes (with one very high value ignored) with a median of only 139 minutes, well within the Pacific goal of 200. However, within PICT utilities, SAIDI

[35] PPA and ADB, *Pacific Power Utilities,* p. 7-2.

tends to be estimated or only measured in part, so the reported results for some utilities are unlikely to be indicative of actual performance.

The weak reporting of forced outages (Figure 4.2.9) affects the calculation of SAIDI and 'System Average Interruption Frequency Index' (SAIFI) (Figure 4.4.5) further suggesting that reported outage data is unlikely to be reliable.

Figure 4.4.4 SAIDI interruptions in 2010 (minutes per customer)

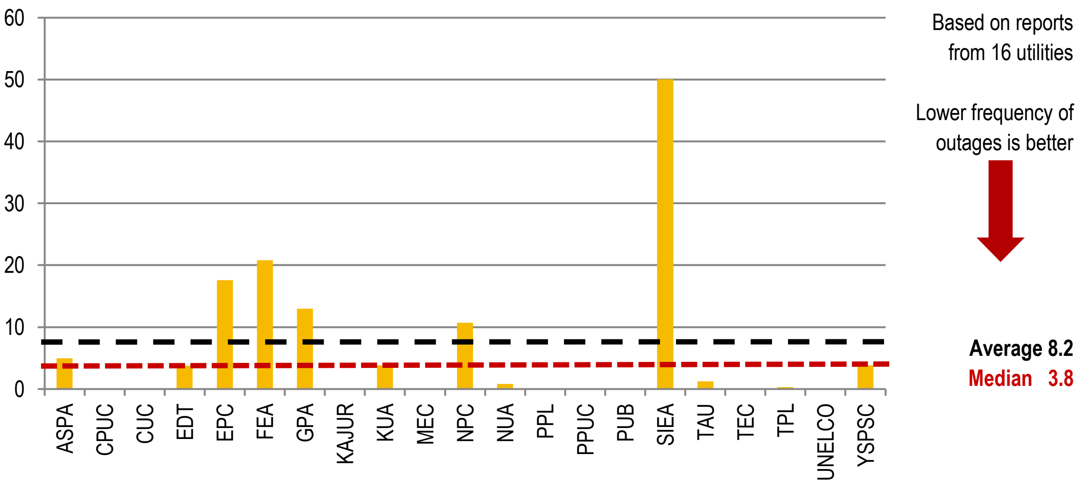


(iv) Interruption Frequency

The 'System Average Interruption Frequency Index' (SAIFI) is also used as a reliability indicator, measuring the number of interruptions per customer. In 2000, the reported average was 19 compared to a regional benchmark of 10 and international best practice of 0.9.

For 2010, reported data suggests that SAIFI has dropped to about 8 with a median of less than 4 interruptions per customer per year. As with SAIDI, SAIFI tends to be estimated by utilities or only partly recorded so the reported improvement may not reflect actual changes in performance.

Figure 4.4.5 SAIFI: interruption frequency in 2010 (interruptions per customer)



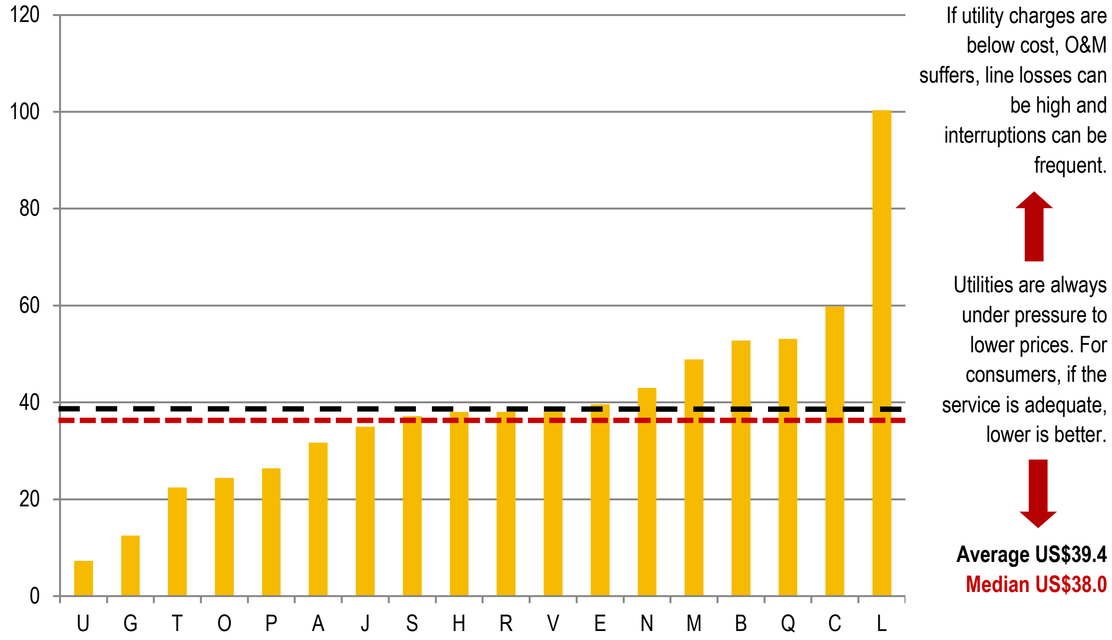
4.5 Financial Indicators

(i) Price of Electricity

Financial data in this report has been converted to US dollars. In the 2002 report (i.e. for electricity sales in 2000), the average selling price of electricity (overall electricity sales divided by revenue from sales) to all consumers was US$0.154 per kWh ranging from 3¢-42¢. This was apparently not weighted according to utility size, for example by sales.

In 2010 (Figure 4.5.1), the reported average was US$0.394 per kWh with a median value of US$0.380 ranging from 7¢ to US$1.00. This is in current costs, with no attempt to adjust for inflation during the intervening period of time.[36] The price charged by a utility does not, of course, necessarily correlate with costs for the same utility. Utilities have not been identified at the request of some CEOs.

Figure 4.5.1 Reported average selling price in 2010 (¢/kWh)



(ii) Household and Commercial Tariffs

The utilities (Figure 4.5.1) reported the average price charged to all classes of consumers during the year (i.e. total revenue over total sales). It can be difficult to accurately compare the electricity charges of different utilities to different consumer classes solely through published tariff structures. Some have minimum monthly charges, a few have fuel surcharges that change monthly and can be difficult to interpret, some have goods and services taxes (GST) or value added taxes (VAT) included in published tariff schedules, whereas others have no GST/VAT or include them in the schedules.

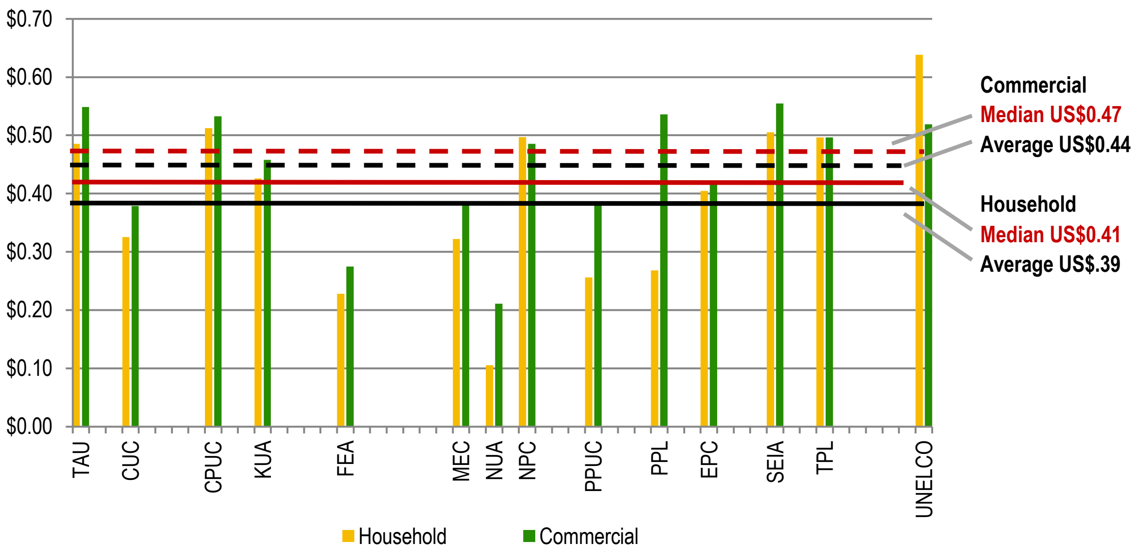
Where there is a fuel cost surcharge, the amount is not always indicated. Figure 4.5.2 below attempts to compare costs charged to households consuming 200 kWh per month (yellow columns) and

[36] One Steering Committee member asked whether prices were adjusted for inflation, and if not, why not. Data on inflation (e.g. through consumer price indices) may have been available for each country but the authors did not seek such data or feel that the additional information justified the effort.

commercial enterprises consuming 500 kWh per month (green columns) with all known charges included. However, this is only indicative as it was not possible to determine tariffs for the same time period for all utilities. The dates range from the last half of 2010 through early 2011, when tariffs for some utilities increased by 20 per cent or more. Households consuming 200 kWh per month paid on average US$0.39 per kWh (median US$0.41). For small commercial customers consuming 500 kWh per month, the average charge was US$0.44 per kWh (median US$0.47). Many, if not most, Pacific utilities, charge consumers less than the full cost of supply.

These charges are higher than those indicated in Figure 4.5.1 which does not cover exactly the same utilities or time period.

Figure 4.5.2 Electricity charge (US$/kWh) – Household 200 kWh/month – Commercial 500 kWh/month



Note: Gaps due to unavailable data from some utilities

(iii) Lifeline Tariffs

Seven Pacific utilities have 'lifeline tariffs', which are meant to support low-income household consumers through reduced (subsidised) rates, generally for a modest consumption level sufficient for basic needs (typically lighting, fans, radio and other small loads, and sometimes television). From a utility perspective, the maximum allowable consumption under lifeline tariff rates should be set at a relatively low level (generally under 100 kWh per month) so that the impact on utility income is modest. For maximum benefits to low-income households, the lifeline rate should be well below the average household tariff, and the full tariff should preferably apply to all consumption by households that exceed the lifeline limit.

As shown in Figure 4.5.3, the maximum allowable monthly consumption under tariffs classified as 'lifeline' rates ranges from 30 to 500 kWh per month, per household; and savings compared to the normal household tariff (Figure 4.5.4) range from only 9 per cent to 65 per cent.

The lifeline rate should be well below the average household tariff and the full tariff should preferably apply to all consumption by households that exceed the lifeline limit.

One utility (MEC) has (or had in 2010) a lifeline limit that was probably higher than median consumption and savings are too low to be of much benefit to poorer families. It is a lifeline in name only.

UNELCO has a modest but reasonable lifeline limit of 60 kWh per month with savings to consumers within the lifeline category of 65 per cent. Along with FEA, PPL and EPC, it is well designed to benefit low-income people without much negative impact on utility revenue. The structure with the lowest impact on utility revenue, while genuinely assisting low-income families, is FEA: all consumers exceeding the lifeline limit pay the full charge for all units consumed, not just those units exceeding the lifeline maximum of 75 kWh per month.

There was insufficient information available to calculate the number or percentage of households covered by a lifeline tariff, although it is quite high in several countries. Similarly, the amount of subsidy provided by the government and/or the cross-subsidy provided by some consumers to others is not known. This information would be useful if utilities are to develop and adopt lifeline tariffs that meet government objectives with minimal revenue loss for the utility.

Figure 4.5.3 Maximum lifeline consumption (kWh/month)

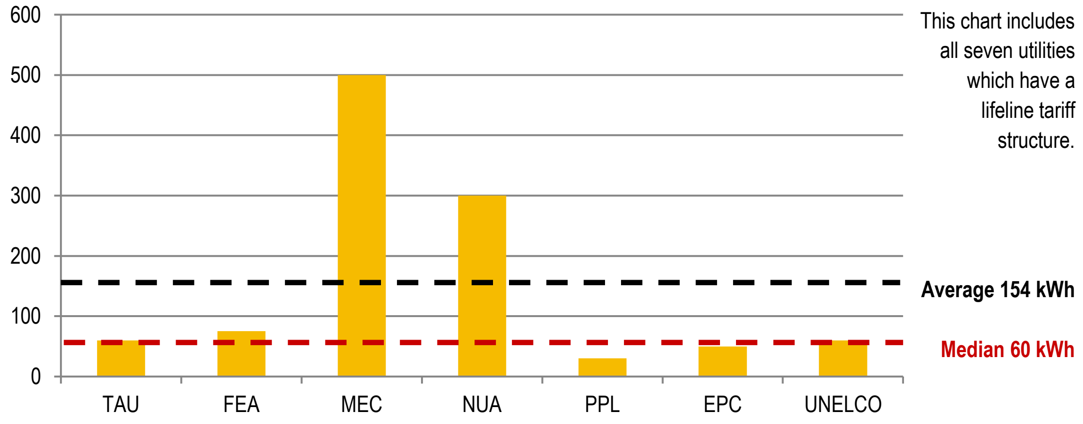
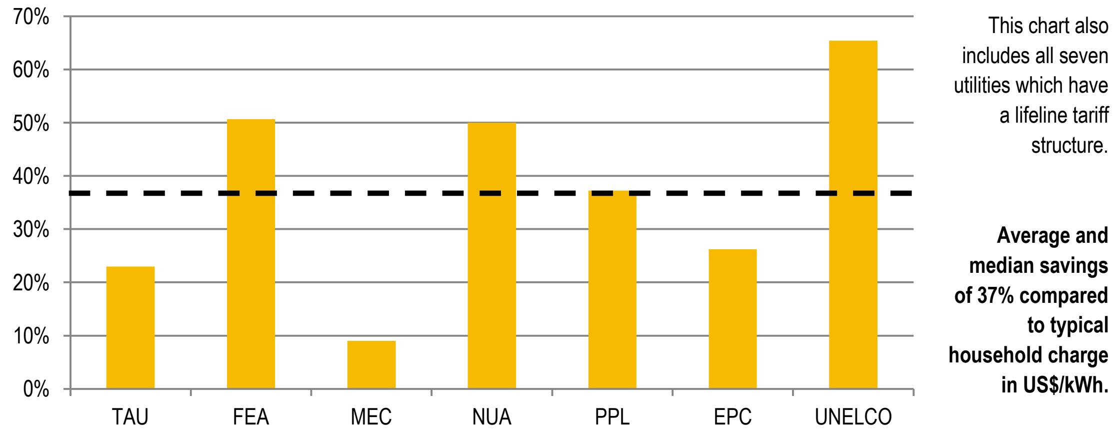


Figure 4.5.4 Lifeline savings (% of normal household tariff)



(iv) Financial Indicators: General Comments

For some of the following financial indicators, utilities have requested that data not be made public. As such, alphabetic codes are used in place of utility abbreviations. It should be noted that financial reporting is in some cases not indicative of actual utility costs. In some PICTs, equipment and services provided by donor grants are not included or costed in the asset base. Some utilities provide independently audited accounts but others do not. In general, the financial data should be considered indicative only.

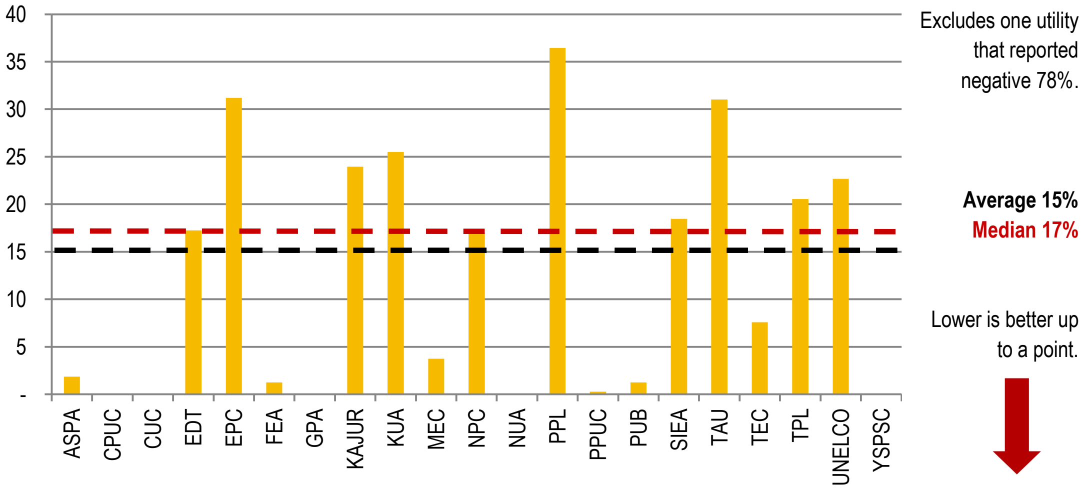
(v) Debt to Equity Ratio[37]

The indicator used for the level of utility debt is the ratio of long term debt to equity, plus long term debt, expressed as a percentage. In 2000, Pacific utilities generally had low levels of debt, with an average ratio of 26 per cent compared to a regional and international benchmark of a maximum of 50 per cent.

For 2010, as shown in Figure 4.5.5, the reported debt equity ratio declined further to an average of 15 per cent (median 17 per cent) suggesting that debt is generally not a serious issue for the region's power utilities. Some utilities can afford to borrow more to improve their service to customers.

For 2010, the reported debt equity ratio declined further to an average of 15 per cent, suggesting that debt is generally not a serious issue for the region's power utilities.

Figure 4.5.5 Debt to equity ratio in 2010 (%)



(vi) Rate of Return on Assets

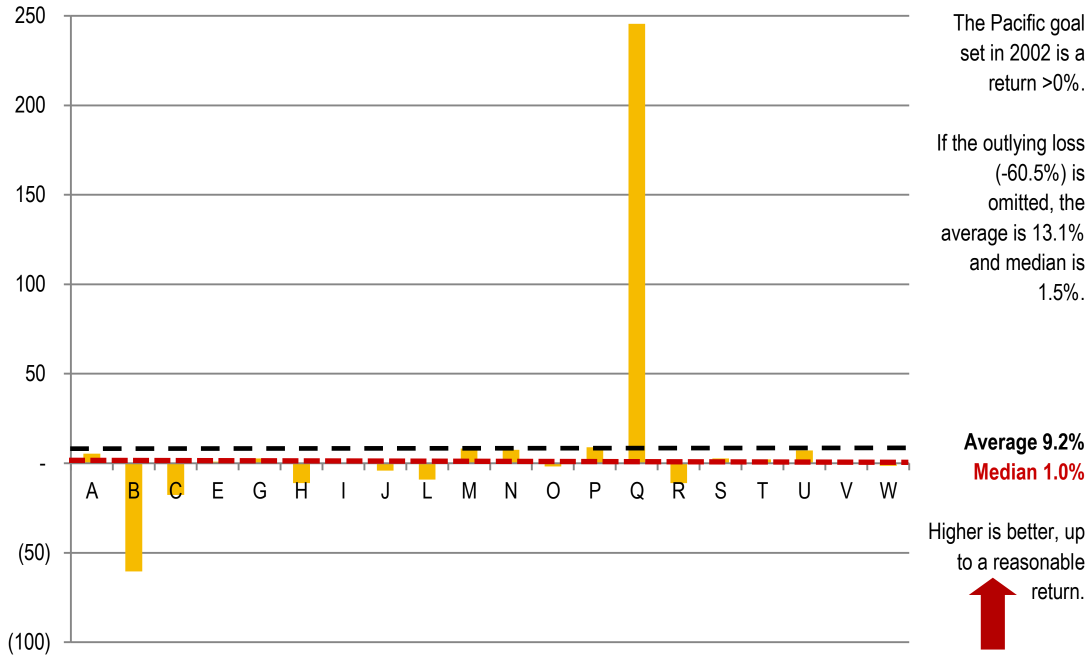
The RORA indicator, chosen a decade ago, was defined as the ratio of operating income to the average value of net fixed assets in operation. The 2002 report stated that "generally, Pacific power utilities do not earn commercial rates of return (the Pacific average is minus 16 per cent compared to typical commercial returns of plus 10 per cent). Commercial development is a potential area for improvement in the Pacific."[38]

[37] One Steering Committee member suggested that "a discussion on cost is needed before analysing indicators." If there are additional utility cost data which could serve as an introduction to this section, the authors are unaware of it.
[38] PPA and ADB, *Pacific Power Utilities,* p. 8.1.

Although the average reported rate of return on assets in 2000 was -16 per cent, this was skewed by the extreme results of one utility. The median value was about +4 per cent and this is probably more indicative than the average of typical utility performance decade ago. [39]

For 2010 (Figure 4.5.6), the average reported return was 9 per cent (skewed upwards by one very high reported value) but with a low median of only 1 per cent.

Figure 4.5.6 Return on total operating assets in 2010 (%)



(vii) Return on Equity

Return on equity measures financial returns on owners' funds invested,[40] where the average owners funds = contributed equity + reserves + retained profits/losses. This indicator was calculated in 2002 but not provided in the 2002 report.

For 2010 (Figure 4.5.7), the reported return on equity – which covered a slightly different set of utilities than Figure 4.5.6 – was 8 per cent with a median value of 6 per cent, with considerable variation among utilities. However, if one outlying value (utility C with 100 per cent) is ignored, the average and median drop to 1 per cent and 3 per cent respectively as shown in Figure 4.5.7 below.

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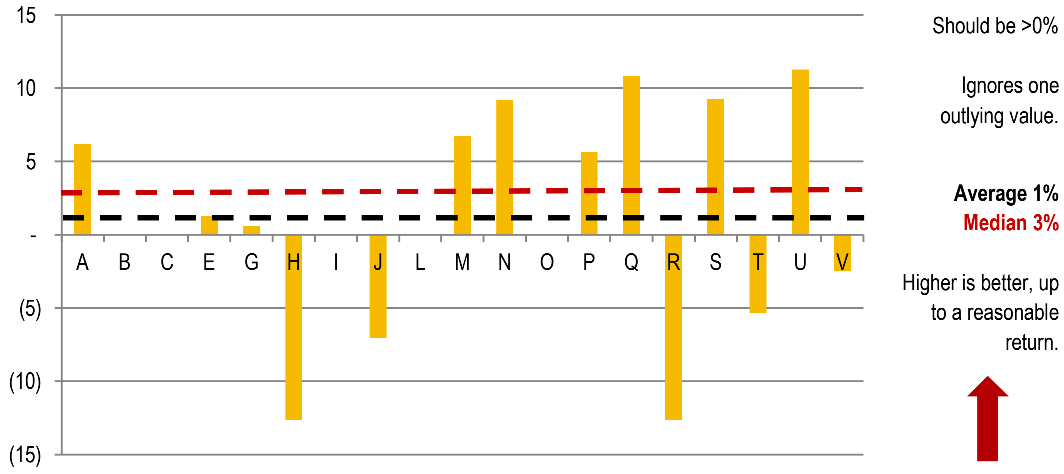
[39] One Steering Committee member noted that it "would be useful to comment on how RORA relates to asset valuation and accounting policy. Do all utilities have the same accounting policy? Do any regularly revalue assets?" Unfortunately, we do not have the information to answer this question but suspect that asset revaluation is not done regularly in many utilities and accounting policies reportedly differ.

[40] "In accounting and finance, equity is the residual claim or interest of the most junior class of investors in assets, after all liabilities are paid. If liability exceeds assets, negative equity exists. In an accounting context, Shareholders' equity (or stockholders' equity, shareholders' funds, shareholders' capital or similar terms) represents the remaining interest in assets of a company, spread among individual shareholders of common or preferred stock."

Sourced from: Wikipedia. 2010. 'Equity (finance).' http://en.wikipedia.org/wiki/Equity_(finance).

Figure 4.5.7 Return on equity in 2010 (%)



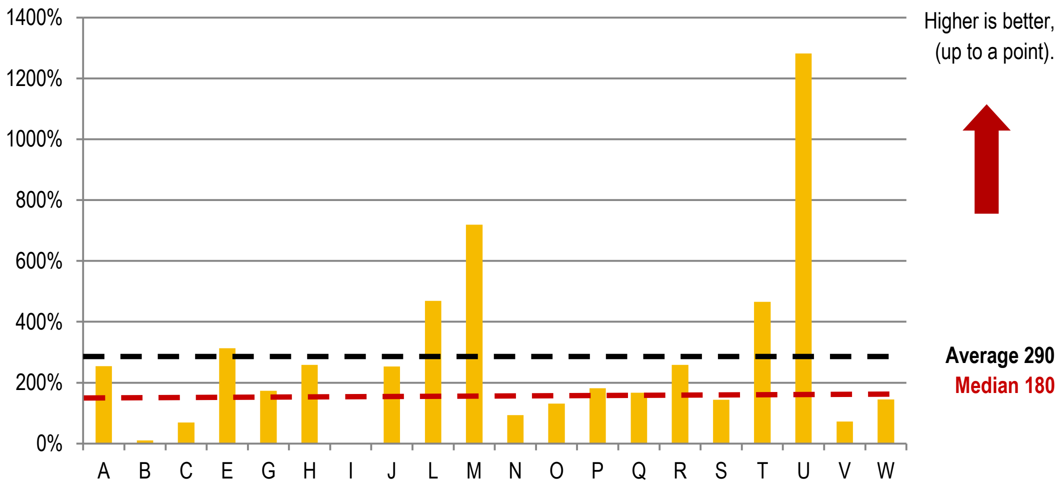
(viii) Current Ratio

The current ratio (current assets divided by current liabilities, expressed as a percentage) measures the ability of business to pay its creditors within the next 12 months, i.e. the ability of the utility to meet its current liabilities from current assets.

For 2000, it was reported that generally, "Pacific power utilities have adequate liquidity indicating probably grant support and effective rate recoveries (Pacific average is 327 per cent compared to Pacific benchmark of 100 per cent)."[41]

However, as for some other indicators, the results were skewed by the extremely high reported ratio of one utility. If the outlier is ignored, the average in the earlier 2002 benchmarking report was 214 per cent with a median of 105 per cent. For 2010 as shown below in Figure 4.5.8, the average was slightly higher at 290 per cent, with a median of 180 per cent.

Figure 4.5.8 Reported current ratio in 2010 (current assets/current liabilities)



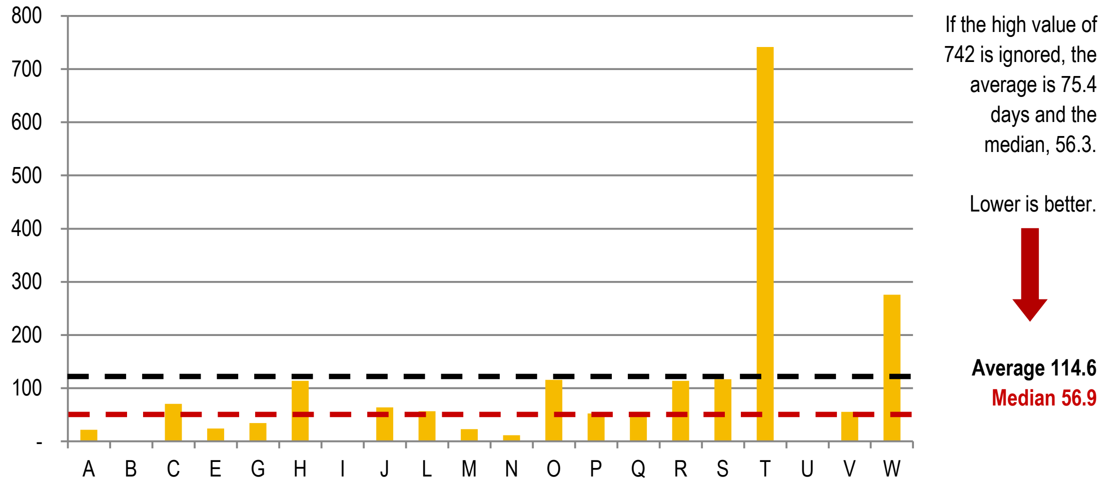
[41] PPA and ADB, *Pacific Power Utilities,* p. 8-2.

(ix) Debtor Days

This indicator measures how long it takes, on average, for the utility to collect debts. In 2000, "generally, revenue collection [was] good with a few exceptions making the average worse than the benchmark (Pacific average is 79 days compared to the Pacific benchmark of 50)."[42] In 2002 the median value was about the same as the benchmark of 50 days.

Reported data for 2010 is shown in Figure 4.5.9 below. The average is considerably higher than a decade ago at 115 days because of one very high value, but the median value of 57 is not far above the Pacific benchmark of 50 days established in 2002.

Figure 4.5.9 Reported debtor days in 2010



4.6 Other General Indicators

The 2002 report included additional indicators for (i) duration of lost time due to accidents; (ii) frequency of lost time accidents; and (iii) training expenditure from own resources. These are also covered for 2010 operations but definitions (the same used a decade ago) are not consistent with any international standards.

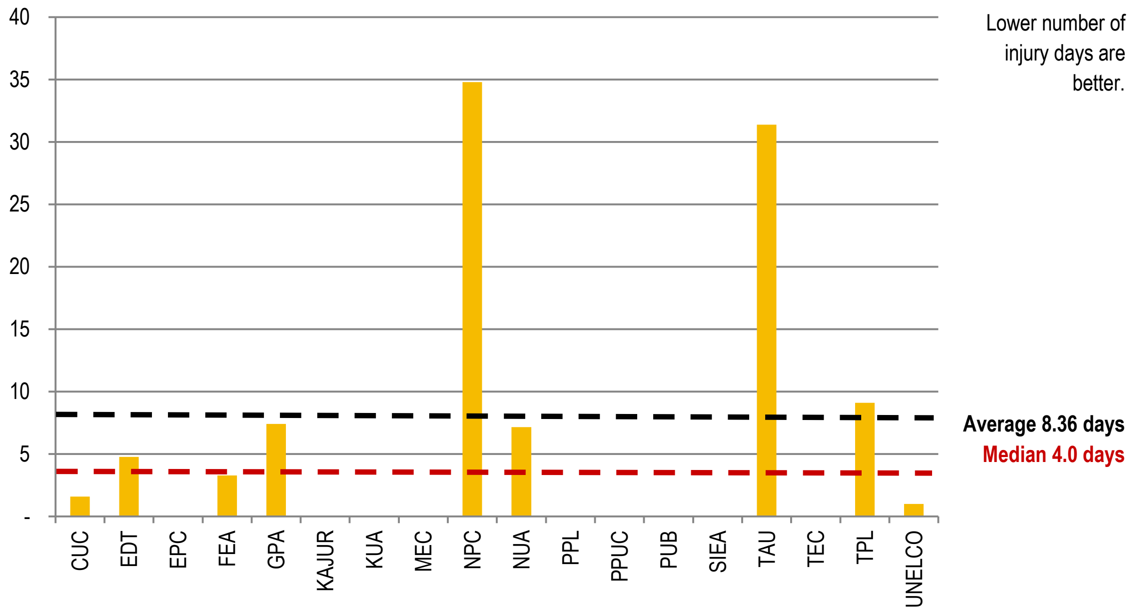
(i) Lost Time Injury Duration Rate

The 2002 report suggests an average of about 500 workdays lost to injuries, which is untenable, with two utilities far worse than the others. The report suggested that several utilities "could well benefit from pro-actively managing duration of absences caused by accidents."[43]

For 2010 (Figure 4.6.1), only 10 utilities reported data. With one very high outlying report omitted, the average lost time due to injuries is about eight days per employee with a median of four.

[42] PPA and ADB, *Pacific Power Utilities,* p. 8-2.
[43] PPA and ADB, *Pacific Power Utilities,* p. 9-1.

Figure 4.6.1 Lost time injury duration rate (days per FTE employee)



(ii) Lost Time Injury Frequency Rate

The reported frequency of accidents resulting in lost days in the 2002 report averages about 2.5 per million hours, per utility, with a wide range; two utilities (not the same ones as for injury duration) were far in excess of the others. The 2002 report noted that "some utilities appear to have a high frequency of accidents which generally may not be severe; i.e. duration and frequency do not appear to be greatly correlated."[44]

For 2010, no chart has been prepared as few utilities reported data and some reports seem to be far too high, several at or above 6,000. There may be a need for improved reporting for future benchmarking.

(iii) Renewable Energy to Grid

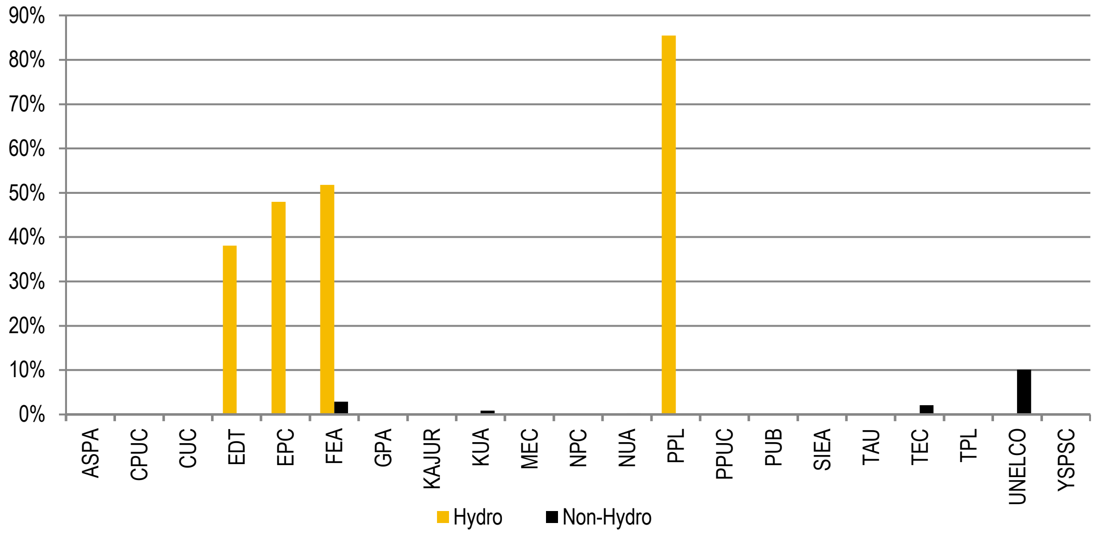
The 2002 report did not cover utility generation from renewable energy sources. Figure 4.6.2 provides an indication of renewable energy generation in 2010 *but only energy fed into the main grid system of each utility*. Renewable energy accounted for 22 per cent of generation, 97 per cent of which was from hydropower. There were small amounts of solar PV, wind and bio-energy, e.g. biomass in the form of wood waste and sugar cane waste (bagasse), and bio-fuels.

A figure of 22 per cent of renewable energy into the main grids may seem impressive, but it is heavily concentrated in a small number of PICTs countries with hydropower resources: 16 of the 21 participating utilities still provide about 98 per cent or more of electricity from petroleum fuel.

Renewable energy accounted for 22 per cent of generation, 97 per cent of which was from hydropower.

[44] PPA and ADB, *Pacific Power Utilities,* p. 9-1.

Figure 4.6.2 Renewable energy generation in 2010 for main utility grid (roughly indicative only) (%)



The estimates in Figure 4.6.2 are only approximate and indicative of the extent of use of renewable energy by PICT utilities for several reasons:

- For PPL in Papua New Guinea, which has a number of grids, the percentage of hydropower would be far less if all major grids, not just Port Moresby, were included. PNG also has many large private power suppliers some of which use wood, hydropower or geothermal, and data on these is unavailable or inaccurate.
- For those Pacific countries with hydropower resources, the hydropower contribution to total generation varies very substantially from year to year depending on rainfall patterns and storage capacity.
- Countries were inconsistent in reporting, some including purchases from IPPs while others did not. FEA of Fiji for example, provided data on purchases of power generated from wood but omitted bagasse (waste from sugar cane). Several other utilities with small amounts of solar energy supplied by private or government institutions to the grid neglected to report it.
- Non-grid connected renewable energy, which some PICT utilities install and manage, is omitted.

A number of grid-connected installations have been installed or planned since 2010. The information in this report provides a useful baseline for future benchmarking. UNELCO's wind farm is illustrated in Figure 4.6.3.

Figure 4.6.3 UNELCO wind farm near Port Vila, Vanuatu (Photo: UNELCO)

(iv) Demand Side Management

There is likely to be an increase in the future in demand-side management (DSM) services to large consumers, small businesses and households. DSM services entail utility involvement in efforts to assist customers to reduce electricity consumption or change the pattern of demand in ways that could benefit the utility, such as reducing the rate of growth of maximum demand or shifting loads to different times of day.

As shown in Table 4.2, only 10 utilities provided a response, or under 50 per cent. Six utilities reported that they have no DSM activities and four reported that they have one or two staff members assigned to DSM with budgets ranging from US$5,000-$75,000. Only one utility reported savings through DSM efforts.

There is likely to be an increase in the future in demand-side management (DSM) services to large consumers, small businesses and households.

There is likely to be more DSM activity than utilities reported. Several were involved to some extent in 2010 in donor-supported and/or government DSM efforts (e.g. refitting of energy efficient lights, improving air conditioning efficiency, etc.) but did not report this.

Table 4.2 Utility demand side management efforts in 2010

Response from utilities	No of utilities reporting	Comments
No response	11	DSM section of questionnaire left blank
No DSM staff or N/A	6	As above
Some Full time DSM staff	4	Either one or two staff
Budget for DSM	5	Ranges from $0-75,000 *
Savings made in 2010	1	1 MWh

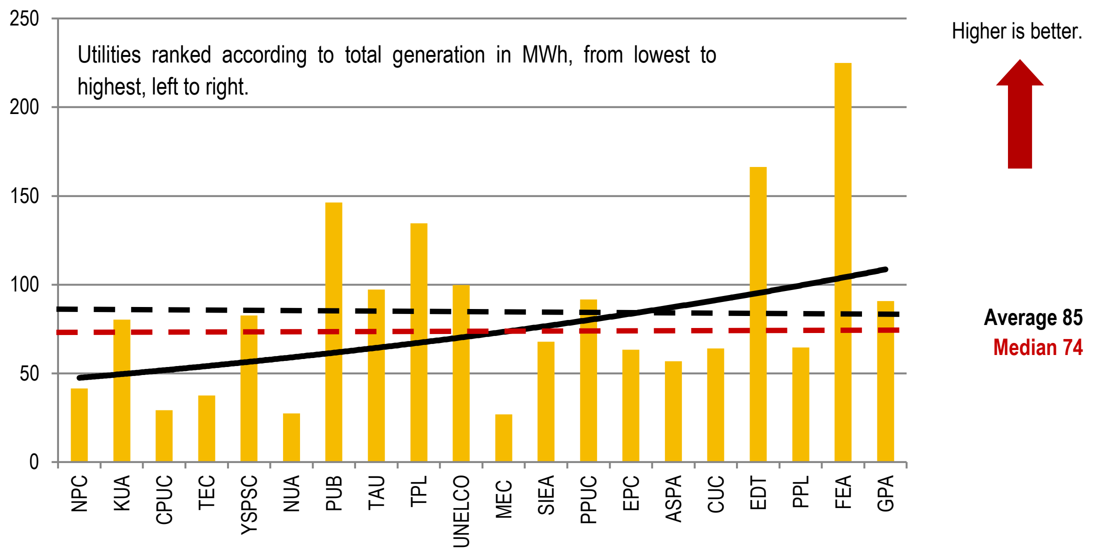
Notes: **1.** N/A = not applicable **2.** * Average = US$35,000

(v) Overall Labour Productivity

The 2002 report did not include an indicator of overall labour productivity, measured by the number of customers per total FTE utility employee. This has been included in the current report in part because productivity appears to be quite low compared to similar sized island utilities elsewhere, as shown in Section 5 of this report.

As shown below in Figure 4.6.4, on average, there were 85 customers per employee, with a median value of only 74. There is a trend of better performance for the larger utilities, as ranked by their total generation. There is wide variation in results, with KUA, YSSPC, TPL, EDT and FEA all well above average for their size.

Figure 4.6.4 Overall labour productivity in 2010 (customers per utility employee)



4.7 An Overall Composite Indicator

For this report, there was an attempt to develop an overall composite indicator of utility performance. To be useful, this should include the following characteristics:

Characteristics of Composite Indicator

- It should cover a wide enough range of indicators to be reasonably comprehensive, preferably including measures for generation efficiency, utilisation of assets and equipment, transmission/distribution performance, quality of service to consumers, and financial performance;
- The number of indicators used should be relatively few (perhaps 3-5), be available for all or most participating utilities, and be based on accurate information from utilities (or other sources); and
- Each indicator used should be a good measure of a key aspect of utility performance.

Based on the information available, it has not been possible to develop an overall composite indicator based on both financial and technical indicators:

Overall Composite Indicator

- The financial data overall is believed to be less reliable than technical data and was thus omitted from consideration for inclusion.

- Even for technical data (as summarised in Appendix 5) there were significant gaps in the amount of data submitted by some utilities. There were also some issues regarding the quality of some technical data.
- The indicators of service quality, such as customer interruptions (SAIDI and SAIFI), were reported by 15 and 16 utilities respectively, but much of the data provided was suspect, and they are not sufficiently reliable for use. There are no available indicators of the quality of power (e.g. variations in distribution voltage and frequency).

For the 2010 benchmarking, a preliminary and only roughly indicative composite indicator of technical performance has been prepared based on four specific indicators, with these explanations and caveats:

Components of Composite Indicator

- **Generation efficiency:** the indicator used for generation efficiency is specific fuel consumption, which may bias results against those with a high level of hydropower.
- **Efficient utilisation of assets**: the indicator used for utilisation of assets is capacity factor.
- **System losses:** the indicator used for transmission and distribution performance is overall system losses (data of Figure 4.3.3 if available or if not Figure 4.3.1).
- **Overall labour productivity:** the indicator used is customers per full time utility employee. Although this may bias results against the smaller utilities, and does not account for the extent of automation in some systems (e.g. GPA's generators), the results would be similar if only the above three indicators are used.[45]

Results are summarised in Table 4.3 and Figure 4.7.1, with equal weightings for each indicator.[46] However, this is only a very rough indication of technical performance and is meant primarily as an initial attempt only. The indicators are to be developed and improved, if CEOs feel it is useful, in future benchmarking efforts.

Table 4.3 Composite indicator suggestive of utility technical performance

Overall Ranking	Utilities	Score (Maximum of 4.0)
Higher	EDT, FEA, GPA, PPUC, PUB, TPL	3.0 - 3.8
Medium	CUC, EPC, PPL, SIEA, TAU, TEC, YSPSC	2.6 - 2.8
Lower	CPUC, KUA, MEC, NPC, NUA	2.2 - 2.5

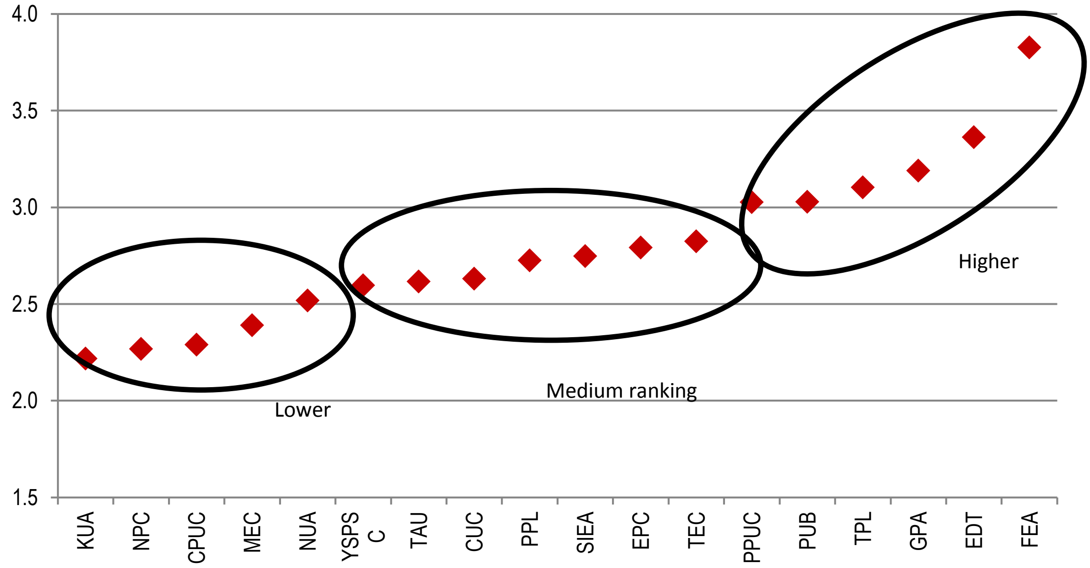
Notes: 1. For Higher, Medium & Lower ranking, utilities are listed in alphabetical order, not by score **2.** Insufficient data for KAJUR and UNELCO so they were not included.

[45] Using only the first three indicators, PPUC, TEC and YSPC would each move down one category.

[46] The four measures used were each adjusted to a score of 1.0 for the best performance, and then weighted equally to calculate the composite. The maximum score is 4.0. Details are provided in Appendix 11.

As Table 4.3 and Figure 4.7.1 show, seven of the 18 utilities were grouped within a fairly narrow band with a score of 2.6 to 2.8, with five utilities scoring lower and six higher.

Figure 4.7.1 Composite technical indicator (maximum value of 4.0)



5 Comparing Pacific Results with Other Benchmarking Studies

5.1 Comparing the 2002 and 2011 Benchmarking Results

As noted in Section 4, an earlier Pacific power utility benchmarking exercise was carried out in 2001-2002. The data collected was for utility operations during the calendar – or in some cases fiscal – year, 2000. A project report was completed in October 2002, although the project was not formally concluded until 2005.

The questionnaire developed and used to collect data in 2001-2002 was subsequently revised slightly in 2003 to incorporate suggestions for better explaining the indicators and other minor improvements. Apparently, the revised 2003 version was intended to be used for proposed annual benchmarking from 2004 onwards but this did not occur.

Table 5.1 compares the average results of the current exercise with that of a decade ago, based on data provided by the utilities.

Table 5.1 Key indicators compared for 2002 & 2011 Pacific benchmarking reports (2002 report based on 2000 data) (2011 report based on 2010 data)

Key Indicators (of 2002 report)		**2002 Results** (Ave Median)	**Future Goals** (agreed in 2002)	**International Best Practice** (2002 report)	**2011 Results** (Ave Median)
Generation					
Load factor (%)	↑ better	67 66	50-80	50-80	64 65
Capacity factor (%)	↑ better	34 33.	> 40	35-65	32 31
Availability factor (%)	↑ better	93 97	80-90	10-65	98 100
Specific fuel oil consumption (kWh/ litre)	↑ better	3.8 3.7.	4	over 4	3.8 3.8
Lube oil consumption (litres/hour)	↓ better	3.5 2.0	3.2 - 3.5	No standard	Not useful; not calculated
Forced outage factor (%)	↓ better	7.9 3.2	3-5	0	0.9 0.1
Planned outage factor (%)	↓ better	4.3 3.9	3	3	2 ~0 (?)
O&M (US$ per MWh)	varies	58 14	18		148 (?) 71 (?)
Transmission					
Transmission losses (%)	↓ better	8 n.a.	5	5	? data errors
Distribution					
Customers/employee	↑ better	242 224	240	350	334 297
Transformer utilisation (%)	↑ better	18 18	30	50	19 21
Distribution losses (%)	↓ better	12 (?) n.a.	5	5	12? (10 replies)
SAIFI (interruptions/cust.)	↓ better	19 8	10	0.9	8.2 (?) 3.8 (?)
SAIDI (hours/customer)	↓ better	592 33	200	47	530 (?) 139
Distribution O&M ($/km)	varies	2,478 (?)	800	167	?
Corporate / financial					
Debt to equity ratio (%)	↓ better	26 n.a.	< 50	< 50	15 17
Rate of return on assets (%)	↑ better	- 16.8	> 0	> 10	9.2 (?) 1 (?)
Current ratio	↑ better	3:1 1.3	>1:1	1:1	2.9:1 1.8
Debtor days	↓ better	79 51	< 50 days	30 days	115 57
Comment		*20 utilities*			*21 utilities*

Notes: 1. n.a. = not available **2.** (**?**) = questionable result **3.** See Table 3.1 for definitions of the indicators

5.2 Comparing Pacific Indicators to those of Other Small Utilities

Some Pacific utility staff questioned the value of comparing PICT indicators to those considered to be international best practice, which generally apply to large, well-resourced utilities in richer countries. Accordingly, for 2011, there was an attempt to compare Pacific performance to those utilities that share PICT characteristics: small, remote locations and (for most utilities) extreme dependence on petroleum fuel. Where comparable indicators were available, and these were limited, those of Pacific utilities have been compared to the following:

Comparison to Other Small Island Utilities

- ***Benchmark Study of Caribbean Utilities, Final Report Fifth Update – Year 2008)***[47] of April 2010 was prepared for the Caribbean Electric Utility Services Corporation (CARILEC) in which 21 Caribbean island utilities participated. Like the PICTs, the CARILEC members rely overwhelming on petroleum fuel and are small, remote utilities. In general, they have higher electricity coverage and better maintenance budgets than PPA members and the countries have considerably higher per capita GDPs. As there have been five Caribbean regional benchmarking exercises from 2002 to 2008, the utilities are quite familiar with the approach so data collection and reporting are probably better than in the Pacific.
- ***Small Island Systems Second Benchmarking Report of the Network of Experts of Small Island System Managers***, 2009.[48] This was based mostly on 2006 data and covers island utilities associated with the European utility association Eurelectric. The study covers 17 utility groups operating in 73 islands. The 17 groups include GDF-SUEZ Energy Services within which EDT Polynésie Française, EEC Nouvelle Calédonie, EEWF Wallis et Futuna and UNELCO Vanuatu were included as one group. Also included were utilities of high-income islands such as Malta, Jersey, Guernsey, Cyprus and the Isle of Man. Nonetheless, like utilities of the PICTs, these are mostly small, remote, high-cost, petroleum-dependent operations.
- ***Selected Financial and Operational Ratios 2009***[49] of the American Public Power Association was included as the coverage separates indicators for its smaller Pacific-sized member utilities from the larger ones. Of the 170 utilities participating, 82 per cent have less than 50,000 customers and 54 per cent less than 20,000. However, half of the utilities do not generate electricity (and 70 per cent generate 10 per cent or less of energy supplied to customers), but only distribute it, so most indicators may be of limited comparative value.

Table 5.2 attempts to compare Pacific performance with that of recent benchmarking reports for these other small utilities, but there were fewer common indicators available than expected. Some of these are only indicative, as the definitions of some indicators differ. Averages were used (CARILEC & NESIS) where median values were not available. Some observations from Table 5.2 are covered in Section 6 of this report.

[47] Caribbean Electric Utility Services Corporation (CARILEC) and KEMA. 2010. *Benchmark Study of Caribbean Utilities (Fifth Update – Year 2008).* Final Report (Anonymous Version: April).
[48] Network of Experts of Small Island System Managers (NESIS), 2009. *Small Island Systems Second Benchmarking Report of the Network of Experts of Small Island System Managers – 2004, 2005, 2006 Data.* (14 April).
[49] American Public Power Association (APPA). 2010. *APPA Selected Financial and Operating Ratios of Public Power Systems, 2009 Data.* (November).

Table 5.2 Key indicators compared for Pacific and other small utilities

Indicator	Pacific (Average & Median)		CARILEC (Average)	NESIS (Average)			APPA (Median)
Data for operational year	**2010**		**2008**	**2006**			**2009**
No. of participating utilities	21 (but limited data for 2)		21	17 groups; 73 islands			170
Utility characteristics	Most small, remote & oil dependent; most 100% govt-owned. Range of 900 -150,000+ customers, with median of 8,300		Most small, remote & oil dependent; much higher GDP/capita than PICs; Govt, private & mixed ownership	EU-linked; much higher GDP/capita than PIC;; Govt, private & mixed ownership. Islands are listed in 3 categories below.(14 of 21 PICTs<100 GWh)			US public-owned; typically generation < 10% of supply; 82% have < 50,000 customers
Generation	**Average**	**Median**		**> 1000 GWh**	**< 1000 GWh**	**< 100 GWh**	
Load factor (%)	64	65	74.2				54.8
Capacity (utilisation) factor (%)	32	31	42.4				
Reserve plant margin (%)	114	91	60.5				
Availability factor (%)	98	100	82.9				
Fuel consumption (kWh / litre)	3.8	3.8					
Lube oil use (kWh / litre)	1300	970					
Forced outage factor (%)	0.9	0.1					
Planned outage factor (%)	2	0					
O&M (US$ per kWh)	148	71					
Transmission & distribution losses*							
System losses (%)	12.8	11.6	13	9.7	6.9	9.0	
T & D technical losses (%)	5.6	5.9	6				
Non-technical losses (%)	7.2	5.2	3				
Distribution							
Customers/employee	334	297					333
Unplanned outages / km	(?)	(?)					
Transformer utilisation (%)	19	21					
Distribution losses (%)	12 ?	?					3.93
SAIFI (see note 3)**	8.2	3.8	6.38				
SAIDI(min/year/employee)**	530	139	580	176	77	309	
Distribution O&M (US$/km)	(?)	(?)					3,738
Distribution O&M (US$/kWh)	(?)	(?)					0.078
Corporate / financial / misc							
Debt to equity ratio (%)	15	17					
Rate of return on assets (%)	9.2	1	6.4				
Current ratio	2.9:1	1.8:1					2.02
Debtor days	115	57					
Gen. cost (US$/kWh)***	(?)	(?)	0.264	0.126	0.169	0.274	
Tariff (US$/kWh) household + commercial	0.39 0.47	0.41 0.44	0.366 0.387				0.094 0.092
Customers/employee (total)	85	74	135	278	167	125	
Work incidents/100 employees	(?)	(?)	3.0				

Notes: **1.** *From KEMA supply side loss reports. **2.** **PICT data are comparable to the region's total system losses and presumably wrongly reported **3.** SAIFI & SAIDI: Data insufficient for benchmarking & some are inconsistent for CARILEC (and probably PICTs). **4.** ***Generation costs for NESIS & APPA include purchased electricity; NESIS costs based on €1.0 = US$1.25 in 2006. **5.** **+**PICTs based on 200 kWh per m for households, 500 kWh per m commercial; CARILEC 100 & 2000 respectively. **6.** (**?**) indicates data may not be sufficiently reliable for meaningful comparisons.

6 Discussion and Lessons Learned

6.1 Discussion of Results

This exercise is intended to be the first in a series of annual benchmarking exercises that the PPA hopes to carry out with support from development partners. Issues and difficulties faced in completing the 2011 benchmarking exercise are summarised below.

(i) Questionnaire Design

Although the 2002 questionnaire was the basis for the 2011 questionnaire, it was revised substantially to account for various changes in utility operations over the past decade. Since no funding was available for a training workshop to introduce utility staff to the new version, the revised questionnaire included considerably expanded explanatory notes and was tested by seven utilities in March 2011. CEOs reported that the design was clear and could be understood and used by their staff. A slightly modified final version was circulated for utility use in early April.

There were hundreds of email exchanges and a number of telephone conservations between utilities and the regional consultant to explain and clarify questionnaire use. Most misunderstandings involved the distinction between transmission systems (defined in the spreadsheet as high voltage of about 33 kV or above) and distribution (below 33 kV) regardless of whether electricity was sent to distribution transformers or directly to customers. This affected the calculation of some transmission and distribution system indices, particularly those involving system losses. A simpler questionnaire with fewer key indicators would have been easier to use and in retrospect may have been preferable.

One of the external reviewers of the draft final report of November 2011 felt that there should be more clarity in the explanations and definitions of indicators in future benchmarking: “clear definitions need to be established, agreed upon, documented and signed off by the utilities.” For example, SAIDI and

SAIFI indicate the impact of outages on customers in terms of duration and frequency respectively, but the definition does not clarify that the indicators should cover both transmission and distribution, not distribution only.

Box 6.1 provides another specific example, the definition of FTE employment.

Box 6.1: Clear definitions of indicators - utility employment levels

A final comment on the indicators is that there is a need to properly document the definitions of the indicators, especially those that are formulated for Pacific Island utilities. For example, the report refers to number of employees while the questionnaire refers to Full time Equivalents. The questionnaire also defines an average FTE as the average of the FTE at the beginning and end of the period. FTE may be defined as:

> "The ratio of the total number of paid hours during a period (part time, full time, contracted) by the number of working hours in that period Mondays through Fridays. The ratio units are FTE units or equivalent employees working full-time. In other words, one FTE is equivalent to one employee working full-time.
>
> For example: You have three employees and they work 50 hours, 40 hours, and 10 hours per week – totalling 100 hours. Assuming a full-time employee works 40 hours per week, your full time equivalent calculation is 100 hours divided by 40 hours, or 2.5 FTE."

If this definition of FTE is accepted then there is no need for an average FTE. Secondly, I sense that the difference between FTE and number of employees may not be fully understood by some utilities and this may result in differing interpretations and application of data. For example, some utilities may outsource functions such as vegetation control for distribution lines. Should FTE include the labour hours paid for by the utility for this work done by contractors? I would suggest it should.

Source: Excerpted from Simpson, Abraham. 2011. *Review of the Draft Final Benchmarking Report on Performance Benchmarking for Pacific Power Utilities*. (November).

(ii) Data Collection

Since most utilities, or their CEOs, were broadly familiar with benchmarking from participation in the earlier exercise, utilities were expected to be able to provide reasonably good data without any initial training or the need for visits to the utilities to assist staff in the identification of what data already exists and what may need to be collected for the exercise.

...the absence of data or incomplete data can affect the ability of utilities to measure performance and establish meaningful internal goals.

In fact, it proved difficult to obtain reliable, consistent and reasonably complete data through email and telecom exchanges. Both external reviewers noted that the absence of data or incomplete data can affect the ability of utilities to measure performance and establish meaningful internal goals.

(iii) Resubmissions of Data and Quality of Results

It was anticipated that the initial submissions of data from a number of utilities would contain gaps and inconsistencies, and as expected there were significant gaps and/or errors in every returned questionnaire. These were assessed, and brief reports sent to utilities indicating specific omissions and data requiring clarification. This resulted in a second round of submissions from about half of the utilities with some improvements. There were subsequent face-to-face discussions about the data with utility staff during the PPA's AGM in Guam in late July, and these talks were invaluable. These resulted in further improvement in the data provided from several utilities.

Four utilities provided data too late to allow any analysis and, if required, subsequent re-submission. Despite these issues, an informal review of available data from the 2002 report suggests that the results are probably no less accurate than those of a decade ago.

(iv) Cross-Checking Data

Staff of the PRIF partners and others, were asked to provide any recent PICT power sector studies that might provide additional data or allow checking of data submitted. In general, reports were too dated to be of use.

The most useful source was the KEMA series of supply side loss studies – supported by the EC, the USDOI and NZMFAT – which provided information on losses (technical, non-technical, and station auxiliary use) for 17 utilities for 2009 or 2010 operations and fuel consumption data for 11 utilities. The PPA provided assurance that the consultants had access to all available data, including preliminary results for some southern Pacific utilities. This data was quite valuable.

(v) Perceived Value of Benchmarking to the Utilities

During the 2010 and 2011 PPA AGMs, CEOs expressed strong support for this benchmarking exercise. During discussions with utility staff that collected and submitted data, some stated in private that their utility did not use benchmarking data for day-to-day management decisions and some respondents felt it may be of more interest to development agencies than practical and useful for utilities.

Others acknowledged the usefulness of the exercise but said they did not have the time or resources to devote to collecting much of the data requested. In general, discussions with non-CEO utility staff suggest that they see value in annual benchmarking and would like to see the work continue on a regular basis.

CEOs expressed strong support for this benchmarking exercise [and] in general, discussions with non-CEO utility staff suggest that they see value in annual benchmarking.

(vi) Comparing Findings of the 2002 and 2011 Reports

Nearly the same number of utilities participated in both benchmarking studies and the same definitions were used for indicators. However the original data used to calculate the indicators for 2000 operations were unavailable for several utilities, so comparing results for the two periods is reasonably accurate but not exact.

Comparing Results of 2002 and 2011 Reports

- Generation indicators are quite similar, suggesting no substantial improvement (or decline) in load factor, capacity factor or specific fuel consumption. The fuel consumption data were aggregates for each utility: there was insufficient information on generator sizes and loading to determine whether they operated within efficient ranges for their sizes. Availability of generating plant has improved slightly. Outage indicators suggest that maintenance planning and implementation may have declined.
- T&D losses as reported by utilities are about the same for both time periods. Because of issues in the reporting of system losses for 2010 (and possibly 2000), it is difficult to conclude that performance has improved or declined. The results suggest that reporting of losses needs to be better addressed in future benchmarking efforts.
- Distribution transformer utilisation is essentially unchanged and remains low, suggesting that utilities are not properly sizing transformers (when they are ordered) and perhaps not maintaining them well. Distribution productivity, as measured by customers per distribution employee, has improved.
- Indicators of interruptions to supply (SAIDI and SAIDI) were at least in part estimated, not measured, for many of the utilities during both reporting periods. Reported results may not be indicative of actual performance so it is unclear whether performance has improved.
- Reporting standards for financial data are not consistent in the region (e.g. reporting of assets, separation of some electricity from water and sewerage costs) and some reporting was not based on independently audited accounts, so financial indicators are probably only indicative for both periods. The authors are not aware of which accounting standards are most common or have been adopted by which utilities.[50] Nonetheless, rates of return on assets, current ratio and debt/equity ratios all appear to have improved. Timely collection of debt (debtor days) has worsened.

(vii) Comparing Pacific Results with Those of Other Small Utilities

There were fewer comparable indicators than expected available from benchmarking studies carried out in non-Pacific island utilities or other small utilities. In some cases the definitions of indicators differed, but often different indicators were used. Nonetheless:

Comparing Pacific Results to Other Small Utilities

- Load factors and capacity factors are considerably better for the Caribbean island utilities (CARILEC members) but the Pacific (PPA members) reported better reserve plant margins and availability factors.

[50] These include the U.S., Generally Accepted Accounting Principles (US GAPP), International Accounting Standards (IAS), International Public Sector Accounting Standards (IPSAS) based on French GAAP, etc. Future benchmarking should ask utilities to specify the standards they use.

- Overall system losses and technical losses (as calculated, not measured, by KEMA in both regions) are almost identical for the PPA and CARILEC utilities. However, non-technical losses are significantly higher in the Pacific and there appear to be good opportunities for cost-effective reductions in these losses. System losses for the European-linked island utilities (NESIS members) are lower than those of the Pacific and the Caribbean.
- The small American cooperative utilities (APPA) which largely purchase power and then distribute it had the same average distribution productivity (customers per distribution employee) in 2006 as the PPA members did in 2010.
- Reported SAIDI and SAIFI customer supply interruption indicators were similar for the PPA and CARILEC members but in both regions, reporting accuracy was questionable.
- The reported rate of return on assets was higher for PPA members than those of CARILEC. However, the median for the PPA (not available for CARILEC) was very low so the Pacific results are not necessarily better.
- The average household and commercial tariffs in the Pacific are higher than those of the Caribbean, but this is probably more the result of the calculations being made in different reporting years (2010 and 2008 respectively) rather than indicating a real difference.
- Overall labour productivity, measured by customers per FTE employee, is very low for the PPA members – an average of only 85 compared to 135 for CARILEC members and 125 for the smallest utilities (under 100 GWh per year of generation) of the NESIS group. It would be worthwhile determining why overall productivity is so much lower in the Pacific than in other similar utilities. Low productivity suggests that PICT utilities staff probably generally require skill upgrading and could possibly benefit from more remote monitoring of isolated systems, which has become more cost-effective in recent years with improved ICT and control systems.

(viii) New Indicators in 2011 and Beyond

Several performance measures not included a decade ago were added for the 2011 report:

New Indicators in 2011 Report

- Renewable energy fed into the main grid systems of the utilities comprised 22 per cent of total generation, overwhelmingly hydropower (with some wind, solar, biomass and bio-fuels), but 16 of the 21 participating utilities remained almost totally petroleum-dependent in 2010.
- There was some, but very limited, reporting of utility efforts to assist customers to reduce electricity use (demand side management energy efficiency), but about half of the utilities (11 of 21) either did not have or did not report such initiatives. For this indicator to have any value, reporting of utility efforts to assist customers to reduce electricity use need to be improved in the future.

- The average cost per unit (kWh) to household and commercial consumers was added, including costs that may not be explicit in the published tariff. Lifeline tariffs were compared for those utilities that have adopted them. A number of lifeline tariffs reduce utility revenue but do not appear to appreciably assist low-income consumers; their effectiveness can be improved.
- An attempt was made to develop an overall composite indicator of Pacific power utility technical performance. As this is an initial effort only, the results are only indicative with components and weightings of the composite. If it continues to be used, it is likely to change in the future.

Commentators and evaluators suggested consideration of several additional indicators for future benchmarking:

Future Benchmarking Indicators

- Emissions from power plants (carbon dioxide, sulphur oxides and nitrogen oxides).[51]
- A measure of consumer perceptions of the quality of service provided by the utilities through, for example, a simple and low cost internet based survey targeting selected key customers with internet access. This would be separate from the questionnaire (as results would come from customers, not the utility) but with results incorporated into the benchmarking report.
- Service coverage showing the extent to which electricity is provided throughout the country, which could indicate the potential customers not currently connected to the grid.
- Return on Human Capital (RHC), which equals Competence times Engagement times Organisational Opportunity. Competence refers to the organisation's collective ability to do the job, Engagement measures an employees' willingness to do the job and; Organisational opportunity refers to giving the right people the job they love doing. (It was noted that this is complex. Current indicators for safety and productivity are adequate for the present, but might be considered in the longer term.)

(ix) Follow-up Including Performance Improvement Plans

During the 2011 PPA AGM, there was a workshop with utility staff and agencies (summarised in Appendix 8) organised by PIAC to discuss future benchmarking and possible follow-up assistance to help selected utilities improve performance. The conclusions[52] in brief were:

[51] From the review report: "I would suggest consideration of emissions indicators from power stations. The Pacific Islands are most vulnerable to global warming and while our emissions are tiny compared to major nations this could be used to show we are doing what we can to help the situation and thus give us stronger moral grounds on which to urge larger nations to do their part. These could include emissions of CO_2, NO_X and SO_X."
Simpson, Abraham. 2011. *Review of the Draft Final Benchmarking Report on Performance Benchmarking for Pacific Power Utilities*. (November).

[52] It was also agreed that all data would be provided by utilities by mid-August so the report could be completed by the end of September. However, data (mostly from additional utilities) continued to arrive until early November, and completion was delayed.

Conclusions

- The PPA should coordinate annual practical benchmarking studies, retaining a broad range of indicators (but merging T&D loss indicators), keeping the current Steering Committee mechanism, and working with CROP agencies and development partners to secure sufficient funding, including for utility training in data collection and its use.
- The consultants would work with selected utilities on their needs and priorities for short-term follow-up assistance, to help utilities use benchmarking to improve performance (but the choice of utilities has yet to be finalised).
- Development agencies, the PPA and CROP agencies indicated their willingness to support future benchmarking. PIAC noted PRIF's willingness to support a small number of utilities to develop mechanisms to improve their performance through benchmarking in the near future, and this could be extended to other utilities over the next several years.

6.2 Lessons Learned

When this exercise began, there was an attempt to apply a number of lessons learned from benchmarking experiences in other small utilities (both power and water) in relatively remote less-developed countries. These have proved to be applicable to the Pacific[53] and further lessons have been learned during the 2011 benchmarking process:

Lessons Learned

- In at least some utilities, CEOs apparently did not discuss the exercise and its priority with those given responsibility for data collection and reporting, and some staff did not put in sufficient time and effort to provide the most accurate available information. This reduced the value of the resulting reports to utilities. Benchmarking success requires visible support and continuous leadership of the CEOs and allocation of adequate staff time and skills to obtain and report the data.
- Although the 2011 questionnaire contained far more text to define and explain indicators than the earlier 2002 questionnaire, it nonetheless proved to be insufficient. More clarity is needed, supported by a benchmarking manual with calculations of practical examples.
- Data collection is a key challenge, perhaps even more than those involved in this exercise realised at the outset, and requires diligence and commitment from all participating utilities. Lack of incentives and accountability for collecting and regularly reporting reliable performance data seems to be a contributing issue.

[53] These are discussed in Appendix 1. For example, utilities tend to prefer home-grown indicators that they can easily identify with, and comparisons with similar utilities, not internationally accepted indicators to benchmark against. Also, a series of regular benchmarking exercises is far more valuable than a one-off exercise. Repeated observations of a utility over time allows a better understanding of utility-specific issues.

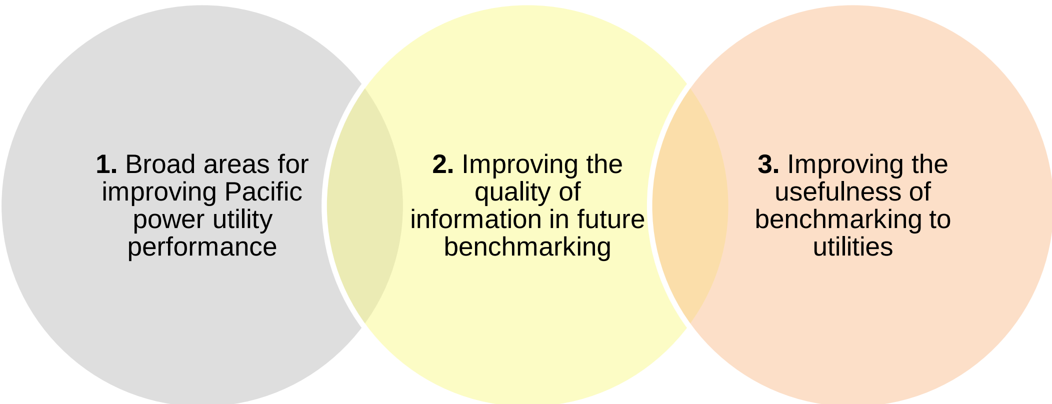
- Benchmarking generally has both short-term objectives for the organisations undertaking it (improved delivery of selected services or operational processes) and medium-term objectives (institutionalised process of change, better capacity of staff to initiate change). However, in the Pacific, it seems to be seen by senior staff of many utilities as primarily a mechanism for comparing their performance with regional peers, rather than a management tool for use within the utility. This reduces the value of benchmarking as a source of information for internal utility decision-making.
- Training of utility staff to introduce – or reintroduce – benchmarking concepts and mechanisms would have been appropriate to improve the capacity of staff to provide appropriate data and improve the quality of results. The lack of practical training exacerbated the difficulty in obtaining good data and resulted in more time being required to complete the work. Utility staff would also have been more aware of the use of benchmarking for improving utility performance.
- "Reporting fatigue" – as consultants and the PPA request corrections to questionable data – can lead to inaccurate data, rendering the benchmarking system of limited practical use. Some utilities may have been burdened with unrealistic reporting requirements.
- Data sources should be reliable and, ideally, cross-checked. In 2011, there were limited recent reports available for cross-checking.
- For useful results, the cost of utility resources, primarily in the form of staff time, can be considerable, and this was probably underestimated during project design.
- Visits to the utilities to assist staff locate data, assess its' accuracy, and perhaps collect some additional information, would have improved the reliability of results, although it would of course have added considerably to costs.
- Although there were a series of discussions with utility staff during the PPA's AGM on preliminary results (the July draft report), there was no opportunity during a presentation to CEOs to get substantive feedback from them. More feedback may have improved the final reporting.
- In the past there has been some sensitivity among some utilities regarding the public release of data or indicators that are considered sensitive. For the 2011 exercise, most indicators identify each utility. Experience elsewhere suggests that this is likely to improve the impact of benchmarking on utility service over time.
- The range of utility sizes and the wide service area covered by some utilities suggests that they cannot always be lumped into a one size fits all analysis. This in turn has led to a suggestion that for future benchmarking, questionnaires should be specifically tailored to each utility, rather than use a generic Pacific questionnaire.
- The active support of PPA, which has been evident during 2011, is essential for successful power sector benchmarking.

7 Recommendations

Discussions during the 2011 benchmarking effort have consistently confirmed that utility CEOs and senior staff feel that benchmarking is valuable and should continue, preferably on an annual basis. The Steering Committee unanimously agreed during its December 2011 meeting that regular benchmarking is critical and should continue in 2012.

It is recommended that power utility benchmarking be carried out each year with financial and technical support from development agencies, at least during the next several years. If there are insufficient funds to do so yearly, benchmarking should be carried out every second year.

There are three areas in which recommendations are made for the consideration of the utility CEOs, PPA and development partners, arising from the experiences of the 2011 benchmarking exercise. These are interrelated and overlapping, not completely distinct from each other:



(i) Broad Areas for Improving Pacific Power Utility Performance

The benchmarking effort in 2011 did not include field visits to participating utilities and did not generate the level of practical understanding of utility operations, constraints and issues required to recommend areas of improvement for individual utilities. Detailed recommendations are not appropriate. Nonetheless, there are several broad areas of concern for a number of participating utilities:

Broad Areas of Concern

- **Low labour productivity.** The Caribbean utilities have 60 per cent more customers per FTE employee than those of the Pacific and the smallest NESIS island utilities have nearly 50 per cent more. It would be worthwhile to determine the key reasons for this so that appropriate improvement initiatives can be developed and implemented. Are there generally low skill levels among staff, inadequate technical and management training programmes, rapid turn-over and/or emigration of key staff, low levels of investment in cost-effective remote monitoring and control systems, etc.? There have been assessments of the effectiveness of a number of state owned enterprises (SOEs) in the Pacific by PRIF partners. It is recommended that the findings of such studies be consolidated into a utility-specific report, discussed during PPA's 2012 AGM, and used to inform and improve PPA (and other) assistance efforts for utilities.

- **High non-technical losses.** Overall system losses do not appear to have improved within the Pacific in the past decade and non-technical losses are considerably higher than those of the Caribbean. A regional loss-reduction programme based on cost-effective improvements should be developed by the PPA, including discussions with PRIF partners on grant and loan assistance to specific utilities for implementation.

- **Low levels of maintenance.** Although the indicators in this report are not always clear or consistent, it appears that planning and implementation of maintenance of generating plants, transformers and other equipment, has not improved in the past decade. In some cases, a key contributing factor is that revenues are insufficient to cover full costs, leaving inadequate funds for cost-effective maintenance programmes. It is recommended that several case studies be prepared for selected utilities (based on available information from recent technical reports of PRIF partners and others) which can be used to demonstrate to government decision-makers and/or boards of directors of utilities that a properly resourced maintenance programme, and full-cost tariffs, should reduce medium-long term operating costs to the utility and consumer.

- **Poor knowledge of outages.** The SAIDI and SAIFI indicators of the duration and frequency of customer outages appear to be questionable. It is recommended that a study be carried out covering several selected utilities on how the data required to produce the indicators can be improved, and the benefits and costs of an improvement programme.

- **Knowledge of customer perceptions.** With several exceptions, Pacific utilities do not appear to have reliable mechanisms for determining customer perceptions of the quality of the service provided, and trends over time of changes in perceptions, which can help utilities identify areas of improvement in these services. It is recommended that advice be sought by the PPA on low-cost mechanism to determine the perceptions of (at least) key customers.[54]

[54] The advice should not be costly. One of the external reviewers has carried out surveys of this type for several SOEs and private companies.

- **Inappropriate life-line tariffs.** In some Pacific island countries, life-line tariffs are required by governments to lower the cost of electricity used for basic services by low-income households. However, these tariffs are often poorly designed, may provide only limited relief to low-income persons, reduce utility income, and require subsidies and/or cross-subsidies that are often not transparent. It is recommended that a study be carried out about the effectiveness of life-line tariffs in the region (benefits to low-income persons, benefits to other electricity consumers, number of consumers benefitting, level of revenue lost, cost and source of subsidies, and recommendations for improved mechanisms which deliver benefits to low-income households with less negative impact on utility revenues).

The costs of carrying out the above recommendations, possible sources of funding, responsibility for action, and priorities, have not been addressed. However, these could be considered when the PPA Secretariat discusses the themes, findings and recommendations of this report with its' directors, and subsequently advises PIAC of initiatives that might form the basis for collaboration with PRIF regarding future support and assistance at a regional level and to specific utilities.

(ii) Improving the Quality of Information in Future Benchmarking

The PPA decided early during this exercise, and PIAC agreed, to keep the indicators and analysis as close as practical to the approach used in the 2002 report, both to reduce the reporting burden on utilities and to allow better comparisons of performance between the two reporting periods. Based on this year's experience, it is recommended that a number of changes be made to improve the quality and accuracy of future reports. The bulk of recommendations in this report are made under this heading. Some can be easily incorporated into the 2012 exercise without the need for extensive resources but others may be impractical unless substantial levels of financial support are available.

Improving the indicators and questionnaire.

The indicators and questionnaire format should be carefully reviewed by the PPA and CEOs in early 2012 to agree on changes to make it more user-friendly and improve the resulting data. Specific recommendations for consideration follow.

Improving Indicators and Questionnaire

- **General.** The definitions and formulas for all indicators should be reviewed for accuracy, clarity, and relevance as useful indicators of performance for Pacific power utilities. They should be modified as required.
- **Losses.** The questionnaire should continue to distinguish between transmission and distribution for some indicators (e.g. transformer utilisation, customers per distribution employee, etc.) but should not try to report separately on transmission and distribution losses. Instead these should be combined into a single measure of delivery system losses. Delivery losses should be divided into technical losses and non-technical losses with each clearly defined and described. Station use (station auxiliaries) should be measured and treated separately as an operating cost, not incorporated into technical losses.

- **Financial reporting.** The questionnaire should include a question on the accounting standard used by the utility (e.g. US GAP, IAS, IPSA, etc.) and whether the information provided is from independently audited accounts. Utilities should separate financial losses due to electricity not paid for, from non-technical losses. For example, there may be financial losses from free provision of street lighting or cross-subsidisation of the utilities' water, waste and/or sewage operations (if any) which are beyond the utilities' control. The questionnaire should be structured to more easily identify and report utility costs for non-power operations. The PPA should discuss with its PRIF partners whether the current corporate and financial indicators are still appropriate, and how they might be improved for more consistent and reliable reporting. If useful, improved indicators should be developed.
- **Genset sizes.** It may be possible to develop a reporting system to indicate the size and loading of individual generator engines, in order to distinguish between those with higher or lower design efficiencies. This would allow a more meaningful comparison of the specific fuel consumption of different utilities. CEOs should consider whether this information can be readily provided and if reporting on fuel use of individual generators is useful and practical.
- **Availability factor.** The definition should exclude power station auxiliary consumption. Consider whether it should be redefined in the Pacific to take into consideration non availability due to forced and planned outages and periods when a generating unit is de-rated. In any case, clearly distinguish between continuous available generating capacity rather than installed capacity.
- **Outages.** The data required to generate indicators of supply interruptions (SAIDI and SAIFI) are time consuming to collect and are generally incomplete. Depending on the findings of the SAIDI/SAFI study recommended under (i) Broad Areas for Improving Pacific Power Utility Performance, it may be useful to develop a format for utilities collect sufficient data for reasonable estimates. The definitions of SAIDI/SAIFI should be clarified, e.g. including both transmission and distribution system outages.
- **Renewable energy.** The percentage of RE calculated in this report is based on energy fed into the main grid (with the main grid as defined and reported by the utility). For some PICs, this is not indicative of the level of grid-connected RE for the utility's service area (country, state, etc.). An improved indicator may be appropriate and if so, should be developed.
- **Energy efficiency.** The utility-based DSM initiatives as reported by some utilities were incomplete and only half of participants responded. As national interest in improved energy efficiency is likely to grow in the Pacific, and more resources are expected to be available to improve the efficiency of energy use, an improved method of reporting energy efficiency efforts should be developed, along with an indicator, if practical.
- **Composite indicator.** The usefulness of an overall composite indicator of utility performance should be considered. If it is to be continued, the relevant component indicators and their weightings should be decided by CEOs. It is suggested that either the composite should include a financial component or there should be separate technical and financial composite indicators.

- **New indicators.** Consider whether new indicators suggested by various commentators should be added, and if so carefully define them and how they are to be measured, e.g.:
    - Emissions from power plants, and if so, should this be restricted to carbon dioxide or include others such as sulphur and nitrogen oxides;
    - Consumer perceptions of the quality of service provided by the utilities; and
    - Service coverage showing the extent to which electricity is provided throughout the service area (though this may be impractical, as accurate data are generally restricted to 10-yearly census reports).

- **Pacific regional targets for specific indicators.** The regional goals for individual indicators were decided by the utility CEOs a decade ago and should be reconsidered. During the preparation of this report, it was apparent that opinions differ on appropriate and achievable goals, so no firm recommendations for changes are made. However, Table 7.1 provides a starting point for consideration by CEOs.

- **Customised questionnaire/template.** It has been suggested that customised templates be developed for each utility. This is not recommended for several reasons. During the PPA 2011 AGM, CEOs agreed that the full set of standard questions should be provided to all utilities, but utilities would respond to those they felt were appropriate for their situation. In addition, it would be impractical to compare performance among utilities if different indicators were used for some utilities.

An approach called the Balanced Score Card (BSC) framework was used by an external reviewer when evaluating the usefulness and relevance of the November 2011 draft of this report. The approach is briefly summarised in Box 7.1 and covered in more detail in Appendix 12. This may be a useful framework for the PPA and CEOs to decide on appropriate changes to the indicators to be used in the next benchmarking exercise.

Box 7.1: The Balanced Scorecard Approach to choosing indicators

Appendix12, excerpted from the Review of Draft Final Benchmarking Report[55] discusses the BSC approach linking performance measures to business strategy execution and assessing the relevance and usefulness of the indicators. In brief, the BSC framework answers the following questions:

- What critical areas of measurement are needed to provide a complete picture of the state of strategy?
- What strategic objectives will the firm pursue in each critical performance area and how will they link?
- Which measures and targets are needed to track the progress of these objectives
- Who will be responsible for collecting data, reporting and answering queries concerning the measures?

The framework generally considers the business, in this case a Pacific power utility, from four perspectives, the first two being external perspectives on the organisation while the latter two are internal:

- **Financial (**what does the owner - usually the government - want?).

[55] Simpson, *Review of the Draft Final Benchmarking Report on Performance*.

- **Customer** (for a Pacific utility, price, power quality, power availability and customer service as perceived by the customer are assumed to be priorities).
- **Process** (the four basic processes are customer management, operations, innovation/business development, and community/regulatory).
- **Learning & Growth** (what objectives does the utility need to pursue to develop its' people, information systems and leadership for the future? There are three areas of interest: human capital, information capital and organisational capital)

Appendix 12 includes a number of questions within the above perspectives and suggests that the BSC approach can help CEOs in the identification of gaps among the performance indicators, and the choice of indicators that might be most relevant and useful. The appendix also includes a schematic illustration to help visually identify gaps.

Table 7.1 Revised Pacific regional benchmarking indicators and goals for CEOs consideration

Key Indicator	Goals for future agreed by CEOs in 2002	International Best Practice (2002 report)	Reported Results in 2011 (Median)	Goals for future?
Generation				
Load factor	50-80%	65-80%	65%	70-75%
Capacity factor	> 40%	35-65%	31%	60%
Availability factor	80%-90%	10-65%	100%	Overall: 60% New plant: >70%
Reserve margin		30 – 60%	91%	60%
Lubricating oil (litres / hour)	3.2-3.5	No standard	Not used	Not useful
Lubricating oil (kWh/litre)	-	-	970	~1 MW: 500-600 ~4-5 MW: 1000-1300
Specific fuel consumption medium speed 750 rpm (kWh / l)	4.0	4.5	3.6-3.8 *	> 4.0
Forced outage	3-5%	3%	0.1%	3 – 5%
Planned outage factor	3%	3%	0.05%	3 – 5%
O&M cost per MWh	$18	-	$71	Report but no goal**
Transmission & Distribution (T&D)				
Transmission Losses	5%	5%	n.a.	< 10% T&D combined
Delivery system losses Technical Non-technical			5.9% 5.2%	< 5% < 3 %
Station auxiliary use	None	-	4.8%	< 5.0
Customers/distribution employee	240	350	297	300
Distribution transformer utilisation	30%	50%	21%	< 50%
Distribution losses	5%	5%	12%(?)	Combine with T** losses
SAIFI	10	0.9	3.8	6-10
SAIDI	200	47	139	100
Distribution O&M US$/km	$800	$167	-	Report but no goal***
Corporate / Financial				
Debt to equity ratio	<50%	< 50%	17%	20-30%
Rate of return on assets	> 0%	> 10%	1%	10%
Current ratio	>1:1	1:1	1.8	2:1 – 3:1
Debtor days	< 50 days	30 days	57	< 30 days
Customers / total employees	None	-	74	>100 (?)

Notes: 1. * Median differs according to source (questionnaires or KEMA) **2.** ** T= Transmission losses **3.** *** Or possibly goal using constant $. The old indicators not mentioned in this table remain unchanged but CEOs should consider them as well **4. (?)** questionable result

Training.

Considering the difficulty that some utilities had in understanding and using the questionnaire, there should be some form of practical training provided to relevant utility staff in the value of benchmarking and in the questionnaire's use. This will be expensive but costs can be reduced by having separate north and south Pacific workshops and/or combining the training with another utility workshop or meeting. It may be practical to reduce costs, adjust training to individual utility needs, and provide training to more utility staff by having one or two trainers travel to each utility, rather than through subregional training. It is also recommend that a technical workshop on benchmarking be held during the PPA's AGM in Vanuatu in July 2012.

Benchmarking manual.

The earlier benchmarking exercise a decade ago included the development of a *Manual of Performance Benchmarking for Pacific Power Utilities*[56] which is still available in electronic form from the PPA. It is recommended that an improved and updated version of this be developed for use in 2012 and subsequent benchmarking. It should include practical examples of calculations of indicators and explain their value to the utility.

Visits to utilities for data collection.

Considering numerous past difficulties in energy data collection in the Pacific (not specific to power utilities or the broader energy sector), it is recommended that visits be made to at least some utilities to assist in the collection and initial analysis of data, and the development of templates for data collection and storage. It may be possible to combine this with data collection for other purposes, such as the SPC's energy data system, and this should be encouraged.

Financial support for data collection.

In past regional studies, it is has been common to engage local consultants for initial data collection and some analysis. Some support should be considered for the smaller utilities (and perhaps other poorly-resourced utilities) to assist them to collect the necessary data. Funds might appropriately be allocated from the PPA's benchmarking allocation beginning in 2012, assuming timely approval by the EC.[57] Assistance should be provided to smaller or poorly-resourced utilities to collect and maintain benchmarking data useful for internal management decisions.

PRIF requirements.

Where the PRIF partners arrange power sector technical assistance grants or loans, they should consider including the collection of specific benchmarking data in their covenants, provide financial support for the data collection, and provide all reports electronically to the PPA. In return, the development partners should have access to PPA data.

PPA database.

The PPA should develop a benchmarking database that is updated annually, including all benchmarking indicators, to allow easier comparison of trends over time and comparisons among utilities. The data for the 2011 benchmarking should form the baseline.

[56] PPA and ADB. 2002. *Manual of Performance Benchmarking for Pacific Power Utilities.* July.
[57] The PPA does not have the resources to develop a regular data collection mechanism but could perhaps support an annual exercise to help collect and assess whatever data exist.

(iii) Improving the Usefulness of Benchmarking to Utilities

Benchmarking generally has short-term objectives for improved delivery of selected services and longer-term objectives such as institutionalising a process of change. However, as noted, most Pacific utilities appear to consider it primarily a tool for comparing performance with that of their peers, which is a useful, but limited objective.

The recommendations discussed in (ii) Improving the Quality of Information in Future Benchmarking, to improve the information generated by the exercise should, of course, improve the usefulness of benchmarking for the utilities. In addition, the following recommendations are made:

Benchmarking for ongoing management decision-making.

A workshop should be arranged for senior utility staff on the practical use of benchmarking for identifying performance shortcomings, implementing practical improvements (initially those with high returns for low costs) and monitoring changes in performance, as part of routine management processes. This would require systematic collection and analysis of data for key indicators (perhaps monthly or quarterly).

Mentoring of utility staff in practical benchmarking.

Formal or informal arrangements should be made to tap into the experience of utilities that have successfully used benchmarking/key result areas internally, and applied findings to improve performance, for other Pacific utilities. This could be in association with, or in addition to the above recommendation.

Performance-based employee contracts.

Utilities which already use benchmarking as a management tool, and are comfortable with it, might consider extending the approach to employee contracts, with salary increments and advancements based in part on success in meeting agreed key performance indicators.

Performance Improvement Plans.

Initial follow-up assistance to utilities to help them develop PIPs should be focused, practical and address areas of improvement that the utilities themselves have identified, rather than try to improve overall utility performance, which can be a huge undertaking.

This report has identified delivery system (supply side) losses as an area where most PIC power utilities can make substantive improvements. It is recommended that initial support should focus on assisting utilities improve their performance by identifying and reducing:

- Non-technical losses, which are higher than those of similar Caribbean island utilities. These could include faulty metering, theft, and non-payments of bills. A related area, reducing debtor days, should be included.
- Financial losses due to free services to municipalities such as street lighting, and non-payment of services to associated non-electrical services such as water, sewerage, etc. operations.
- Technical losses which can be reduced cost-effectively, which will vary by utility but might include excessive transformer losses or poor fuel consumption.

An advantage of this approach is that PRIF-partner supported studies have been completed, or are nearing completion, for almost all PPA member utilities and these suggest specific supply-side loss improvements for each utility, and provide estimates of the financial costs and benefits of specific improvements.