PACIFIC POWER ASSOCIATION

PACIFIC REGION INFRASTRUCTURE FACILITY

Power Benchmarking Manual

PERFORMANCE BENCHMARKING FOR PACIFIC POWER UTILITIES

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This Manual is a joint publication of the Pacific Power Association (PPA) and the Pacific Region Infrastructure Facility (PRIF).

This edition of the Power Benchmarking Manual draws upon the original Benchmarking Manual published by the Pacific Power Association in 2002 and funded by the Asian Development Bank. The contents of the 2002 version form the basis of Section 1 of this edition. In response to feedback received through the 2011 Benchmarking Report, sections have been added to cover the benchmarking questionnaire, explanation of key performance indicators and sample calculations, and an introduction to Performance Improvement Plans.

Development of the Power Benchmarking Manual was overseen by the Pacific Infrastructure Advisory Centre (PIAC) based in Sydney, Australia and the Pacific Power Association based in Suva, Fiji. The Manual was prepared by PIAC's Energy Specialist, Pauline Muscat, with input from the Regional Benchmarking Specialist, consultant, Abraham Simpson and the Benchmarking Team Leader, consultant, Derek Todd, under the Power Benchmarking Project managed by Maria Corazon Alejandrino-Yap. The Manual is endorsed by PPA's Executive Director, Andrew Daka and PIAC Manager, John Austin.

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).

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Edited by Catherine Holden.

Printed in Sydney, Australia
September 2012

Foreword

It is our pleasure to introduce this revised edition of the Benchmarking Manual in support of the performance benchmarking initiative for power utilities in the Pacific region. The overarching goal of the benchmarking initiative is to assist power utilities lift their performance and contribute to improved economic and social development through improved service delivery. The benchmarking program will result in increased efficiency and improved delivery of power operations.

This Manual revision builds on the 2002 edition and was initiated in response to the recommendations made in the 2011 Power Benchmarking Report. The report highlighted a need for training and support material to increase understanding and appreciation of benchmarking as a tool for improving utility performance. This Manual provides an overview of the benchmarking process, an explanation of the benchmarking questionnaire and the Key Performance Indicators (with examples), and an introduction to the use of benchmarking results for the development of Performance Improvement Plans.

With the recent commitment from Pacific Power Association utility CEOs to sustain an annual benchmarking activity, it is anticipated that this Manual will be an integral supporting resource for years to come.

Mr. John Austin
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Pacific Infrastructure Advisory Center

Mr. Andrew Daka
Executive Director
Pacific Power Association

September 2012

The Pacific power benchmarking program is co-ordinated through the Pacific Power Association (PPA) with the support of the Pacific Infrastructure Advisory Center (PIAC). It is funded and supported by the Pacific Region Infrastructure Facility (PRIF) partners; the Asian Development Bank, the Australian Agency for International Development, the New Zealand Ministry of Foreign Affairs and Trade, the European Commission, the European Investment Bank, and the World Bank Group.

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Introduction

Purpose

This Manual was designed to encourage Pacific power utilities to continue undertaking benchmarking activities. The Manual is comprised of easy-to-follow guidelines to ensure benchmarking participation is effective and efficient and results in maximum on-going benefits.

Structure

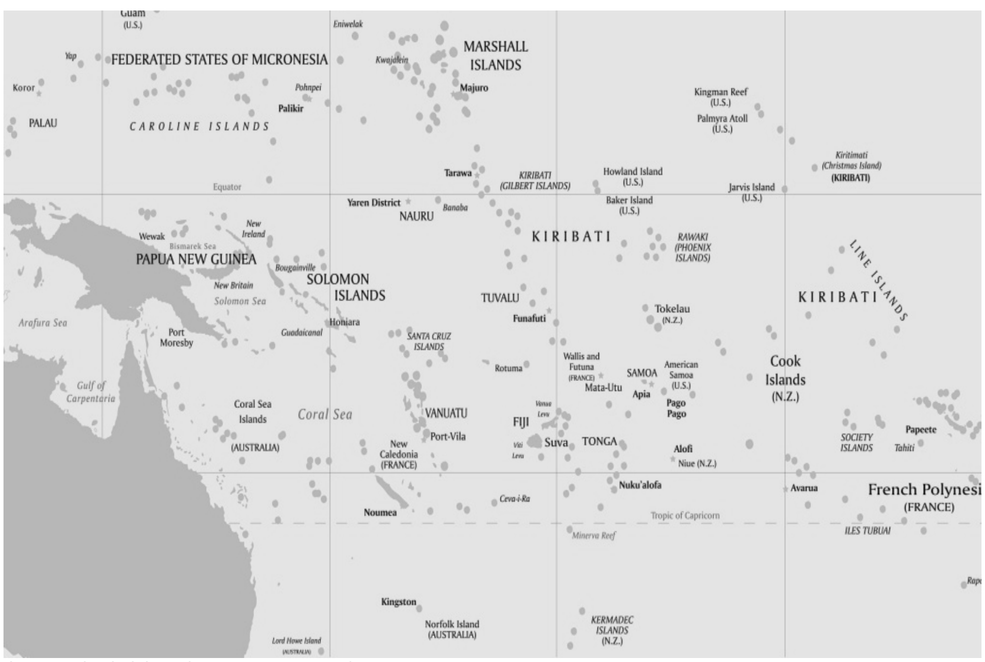
This Manual is structured as follows:

Section 1:	The Benchmarking Process
Section 2:	Benchmarking Questionnaire
Section 3:	Key Performance Indicators (KPIs)
Section 4:	Examples of KPI Calculations
Section 5:	Data Reliability Assessment
Section 6:	Performance Improvement Plans

Pacific Region Benchmarking Background

The Pacific Ocean is 166 million square kilometres and occupies about one third of the globe.

Figure I: Pacific Island Map



Source: SPC-SOPAC. 2012. Member Countries. *http://www.sopac.org/index.php/member-countries*

Across the Pacific, the Pacific Power Association (PPA) has 25 member utilities and of these, 21 participated in the 2011 benchmarking exercise. (However, 19 provided sufficient data to allow the calculation of a reasonable number of key performance indicators). The Pacific Island utilities are listed in Table I. General operating characteristics of utilities that participated in the 2011 benchmarking exercise are provided in Appendix A.

Table I: 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)
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.

All Pacific power utilities are invited to participate in the Pacific benchmarking exercise, ensuring more comprehensive benchmarking data and a better quality result for all.

The majority, but not all power utilities servicing the Pacific Islands are publicly owned. In some of the cases where public ownership is retained, private enterprises are sometimes contracted to provide generation or distribution services.

The price of electricity tends to be high in the region, typically around US$ 0.41 per kWh for domestic consumers. This is due to the heavy reliance upon expensive diesel generation. Fuel costs for Pacific power utilities are extremely high due to the compounded effect of both remoteness from suppliers and relatively small purchase volumes. Often these utilities receive grant assistance. Generation is small compared to mainland utilities, with installed capacity being typically 100MW or less and in the order of 10,000 customers served, though substantial variations exist. In general, there appear to be opportunities to improve the effectiveness, efficiency and overall commercial performance of these power utilities.

Performance benchmarking promotes improvement because it provides a way to learn from better performers. Furthermore, benchmarking reports can act as comprehensive policy instruments, in a region and industry where such resources tend to be lacking. Benchmarking can serve as a useful surrogate to competition, which is a major driver of improvement in larger mainland economies.

To maximize efficiencies and knowledge sharing, Pacific island power utilities are encouraged to use this Manual as a resource for developing and implementing industry best practice.

SECTION 1: The Benchmarking Process

What is Benchmarking?

Benchmarking is the systematic comparison and evaluation of businesses, either as a whole or at an individual functional level, to identify differences in performance and therefore opportunities for either breakthrough or continuous improvement towards best practice.

Benchmarking has four key elements:

1. Systematic – needs be part of an on-going disciplined program in order to maximise results;
2. Comparative – involves evaluating relative performance;
3. Focussed on best practice – looks towards examples set by best performers;
4. About achieving quantum breakthrough or incremental continuous improvements.

Types of Benchmarking

Methodologies for benchmarking generally fall into two groups:

1. Statistical Benchmarking

Statistical benchmarking focuses on statistical relationships between resources consumed (e.g. labour or materials) and outputs delivered (kWh of electricity distributed or kms of distribution line). This form of benchmarking is favoured by some regulators because it is comprehensive and facilitates the prescription of best practice results to other utilities; i.e. for regulating prices and service levels. The disadvantage of statistical benchmarking is that it can become overly complex. As a result, regulators also tend to rely upon management benchmarking.

2. Management Benchmarking

Management benchmarking involves the use of comparisons. For example, key performance indicators (KPIs) are compared with performance indicators (IPs), to measure differences in the relative performance of both service levels and the efficiencies of various power utility functions. Management benchmarking is essentially operational and is much easier to understand and explain, especially in respect of the causes and effects of differences in practices and performances.

Management benchmarking may be undertaken at two levels:

1. Overview–a general assessment of the overall service levels and/or efficiency across all or most power utility functions. The current round of PPA Pacific utility benchmarking is of the “overview” type;
2. Detailed–conducted at a process level in order to specifically assess particular service levels and/or efficiencies of individual processes.

Notwithstanding the merits of management benchmarking, it does have its drawbacks. Its inherent weakness is a focus on one KPI at a time providing a partial rather than a complete overview.

This drawback can be at least partially if not substantially compensated for by use of:

1. Balanced scorecards;
2. Performance quadrants.

Balanced scorecards require that KPIs and PIs be considered as balanced baskets of measures and not be considered individually. Performance quadrants require costs and service levels to be considered together in order to identify benchmarked performance. Both balanced scorecards and performance quadrants are discussed in more detail below under ‘How to Benchmark’.

Management benchmarking can also be conducted internally and/or externally:

1. Internally from one period to another; or
2. Externally, either comprehensively between organisations (typically in the power or related industries) or between individual functions (by comparing similar functions in different industries).

This Manual focuses on management benchmarking as a practical way of enabling Pacific power utilities to learn from best practices and improve performance.

Why Benchmark?

Benchmarking is a powerful management and operational resource that allows Pacific power utilities to improve their performance and gain efficiencies. It is a persuasive tool that involves power utility managers and operators in the process and demonstrates the possibilities for better performance through actual working examples. By discovering and reporting on the facts themselves, utility managers and operators are involved in and contribute to the process from the ground up, rather than being instructed from the top down. This involvement and buy-in fosters ownership and is more motivating and engaging than the latter approach.

Benchmarking is best used to plan improvements rather than to assess past performance. Benchmarking can be used as a planning tool together with balanced scorecards, whereby corporate targets are benchmarked against best practice and plans are put in place to progress towards and surpass those targets.

The long-term benefits of benchmarking include:

1. Increased levels of effectiveness (i.e. producing required outputs and achieving expected outcomes);
2. Increased levels of efficiency;

3. Empowerment of employees, particularly when benchmarking is extended to analysis and improvement by teams of employees;
4. Promotion of the "learning organisation" whereby staff are taught to manage core competencies in a disciplined way and can then adapt, adopt and innovate to suit their needs.

It is therefore important that benchmarking not be seen as a finish line, but as a way to empower staff to look for breakthroughs and opportunities for continuous improvement.

When to Benchmark

Box 1.1 When to Benchmark

- Start at Overview level
- Join in with other utilities in the Pacific
- Prioritise benchmarking activities - do the most important things first
- Complete a benchmarking cycle
- Decide whether to continue benchmarking or use other improvement tools

It is important for Pacific power utilities to continue performance benchmarking in order to capitalise on the potential gains identified in the first round of benchmarking and to sustain further on-going improvements in the coming years.

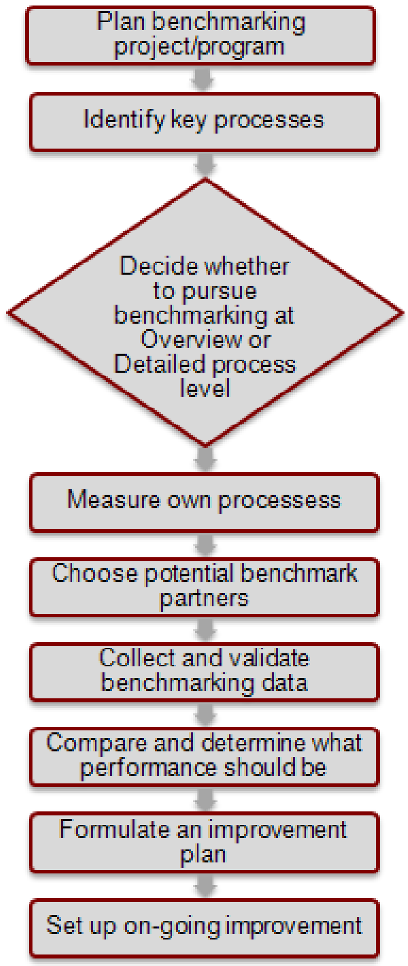
Such improvements will help meet the increasing expectations of customers, owners and regulators for better power utility performance, especially in terms of better prices, services, safety and environmental outcomes.

It is recommended utilities commence with overview benchmarking (as presently conducted through the PPA) and over time, progress along the lines of detailed benchmarking. The results of initiatives implemented because of benchmarking will demonstrate whether there is value in investing in another cycle of benchmarking or whether individual utilities should adopt a different strategy would more appropriately achieve future organisational goals.

How to Benchmark

Benchmarking is an intuitively simple process. The purpose of this Manual is to make the benefits of experience available to help streamline the reader's approach and to pursue uniformity in the benchmarking of Pacific power utilities. The following graphic provides an overview illustration of the benchmarking process. Each of these steps are expanded upon below

Figure 1.1: Benchmarking Methodology



Plan Benchmarking Project/Program

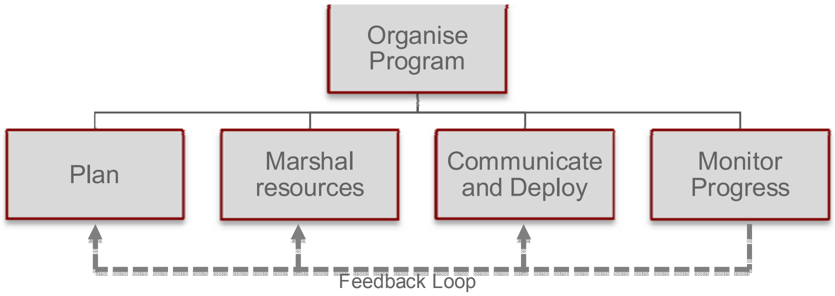
Box 1.2: Plan Approach

Consider applying the following techniques when benchmarking:

- Identify customer requirements;
- Include in planning cycle the use of benchmarks and balanced scorecards;
- Use performance quadrants.

To organise the benchmarking project/program, formulate a project and resourcing plan in consultation with staff and managers. Explain objectives in the planning phase and assign responsibilities with the appropriate authority and associated accountabilities. Marshal resources and build support. Ensure effective communication throughout the benchmarking project/program and monitor progress. See the following illustration outlining benchmark project management.

Figure 1.2: Identify Benchmarking Project/Program



Identify the Required Approach

In planning the benchmarking project/program, it is recommended that the operator consider using the following approaches/techniques:

1. Identify requirements of customers in order to focus benchmarking on what customers want;
2. Use balanced scorecards to ensure other important stakeholders and aspects are considered;
3. Use performance quadrants to ensure that both service levels and efficiencies are considered.

Identify What Customers Want

Identify the requirements of customers through for example, workshop sessions with staff and/or customers, or by undertaking a customer survey. Knowing customer requirements will help prioritise what is important for benchmarking. The following table is an example of common customer priorities for electricity services.

Table 1.1: Contents of Balanced Scorecards

What Customers Typically Rank as Important (in descending order from most to least important)	How Typically Measured	
	KPIs (examples)	**Survey**
Reliability of supply	System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI)	Survey Results
Price	Price comparisons	
Clear cost/pricing structures	Compare structures	
Bill clarity	Compare formats	
24 hour customer service; ease of contact	Compare service standards	

Good customer service	As above, compare service standards	
Accuracy of billing	Billing errors	
Individual treatment	% implementation of customer relationship management (CRM)	
Price guarantees	Comparisons	

Identify Overall Business Needs

Balanced scorecards allow power utilities to contextualise customer and other important stakeholder requirements, particularly shareholders, staff and the community. Knowing these requirements allow managers and operators to maximise results by focusing benchmarking activities on areas of importance.

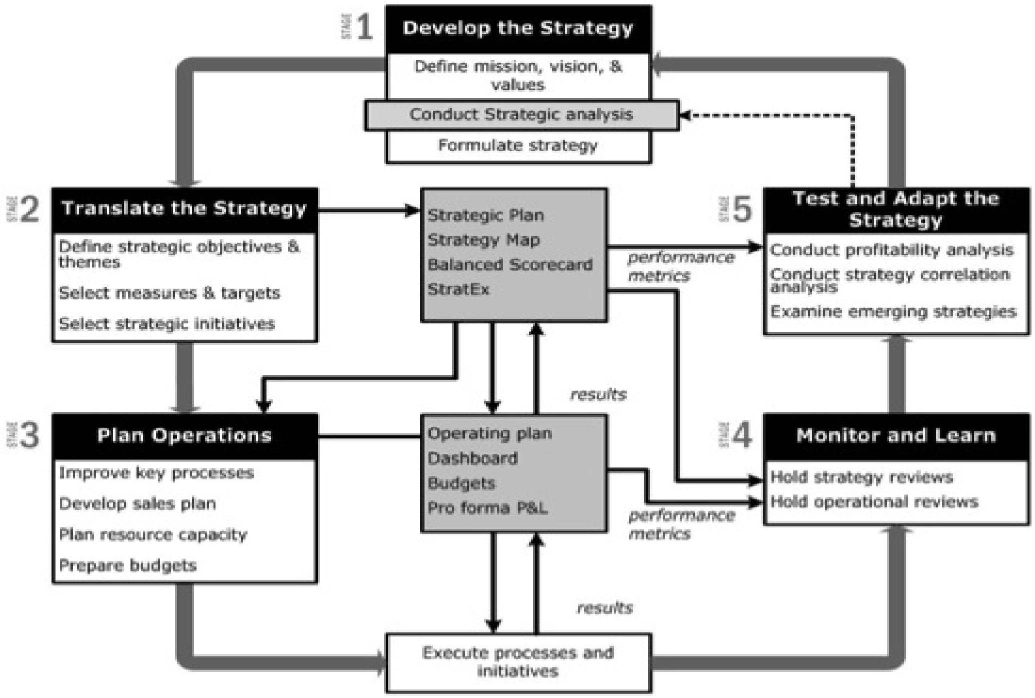
The balanced scorecard approach seeks to address four basic questions, as summarised in the following table.

Table 1.2: Contents of Balanced Scorecards

Four Basic Questions	Aspects to be Measured	Typical Measures
What do we look like to our shareholders?	Profitability, growth and shareholder value	Return on equity
How does the customer see us?	Time, quality, service and cost/price	Customer satisfaction
What must we excel at? What are our core competencies?	Process measures of outputs, efficiencies, cycle times, defect rates.	• SAIDI • SAIFI • Plant availability • Capacity factor
Can we continue to improve and create value?	Extent of innovation and improvement (highly reliant on staff contributions)	• % of revenue from new products • % of savings achieved • Lost time injury duration (LTID) • Lost time injury frequency (LTIF) • Total lost time due to industrial disputes (TLID)

Ideally the balanced scorecard approach encourages managers to focus on the handful of measures which are most critical (i.e. most relating to results for key stakeholders and customers) as well as some important key operational indicators. Importantly, strategy and vision (not control) are seen to be at the centre of successfully implementing balanced scorecards, as illustrated in the following diagram.

Figure 1.3: How the Closed Loop Management System Links Strategy and Operations



Source: Kaplan & Norton, Harvard Business Review, January 2008

The balanced scorecard helps:

- Translate the strategy into operational plans;
- Overtime, identify emerging business strategies; and
- Adapt and refine the strategy as experience is accumulated.

Format of balanced scorecard / action plan are as follows:

Table 1.3: Balanced Score Card Format

Focus Area	Strategic Intent	Vision, Mission, Values	Strategies	Measures and Targets	
				Budget Year	In 3 Years
Finance					
Customer					
Business Process					
Learning and Growth					

Use Benchmarking and Balanced Scorecards as Planning Tools

Concentrate on using benchmarking for planning. Balanced scorecards can be used to include planning targets benchmarked against best practice.

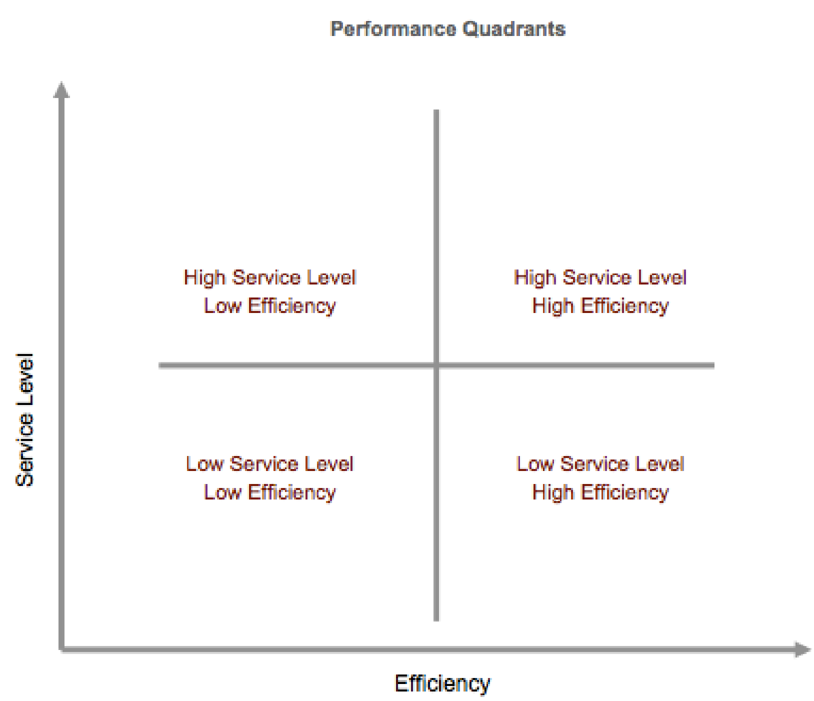
Use Performance Quadrants

The use of performance quadrants helps overcome potentially partial views only being considered in management benchmarking. In this case, use of performance quadrants forces concurrent consideration of service levels and unit costs. For example, what is the value of having extremely low unit costs (possibly reflecting efficiency) when service levels are low and customers are complaining. Performance quadrant analysis helps overcome this. When graphed, performance quadrants relate measures of relative efficiency along one axis and relative service levels along the other, with points of intersection falling into one of four performance quadrants:

1. Low efficiency, low service levels – (lower left) worst performance quadrant;
2. Low efficiency, high service levels– (higher left) high service priority quadrant;
3. High efficiency, low service levels – (lower right) low cost priority quadrant;
4. High efficiency, high service levels – (higher right) the best performance quadrant.

These trade-offs between service levels and efficiencies can relate to one service and related costs, or a basket of products and services and related costs.

Figure 1.4: Service Cost Trade-offs and Best Performance Quadrants



Identify Key Processes

Box 1.3: Identify Key Processes

- Consult the power utility process map provided
- Amend the process map to suit individual power utilities
- Choose which process areas to measure and benchmark

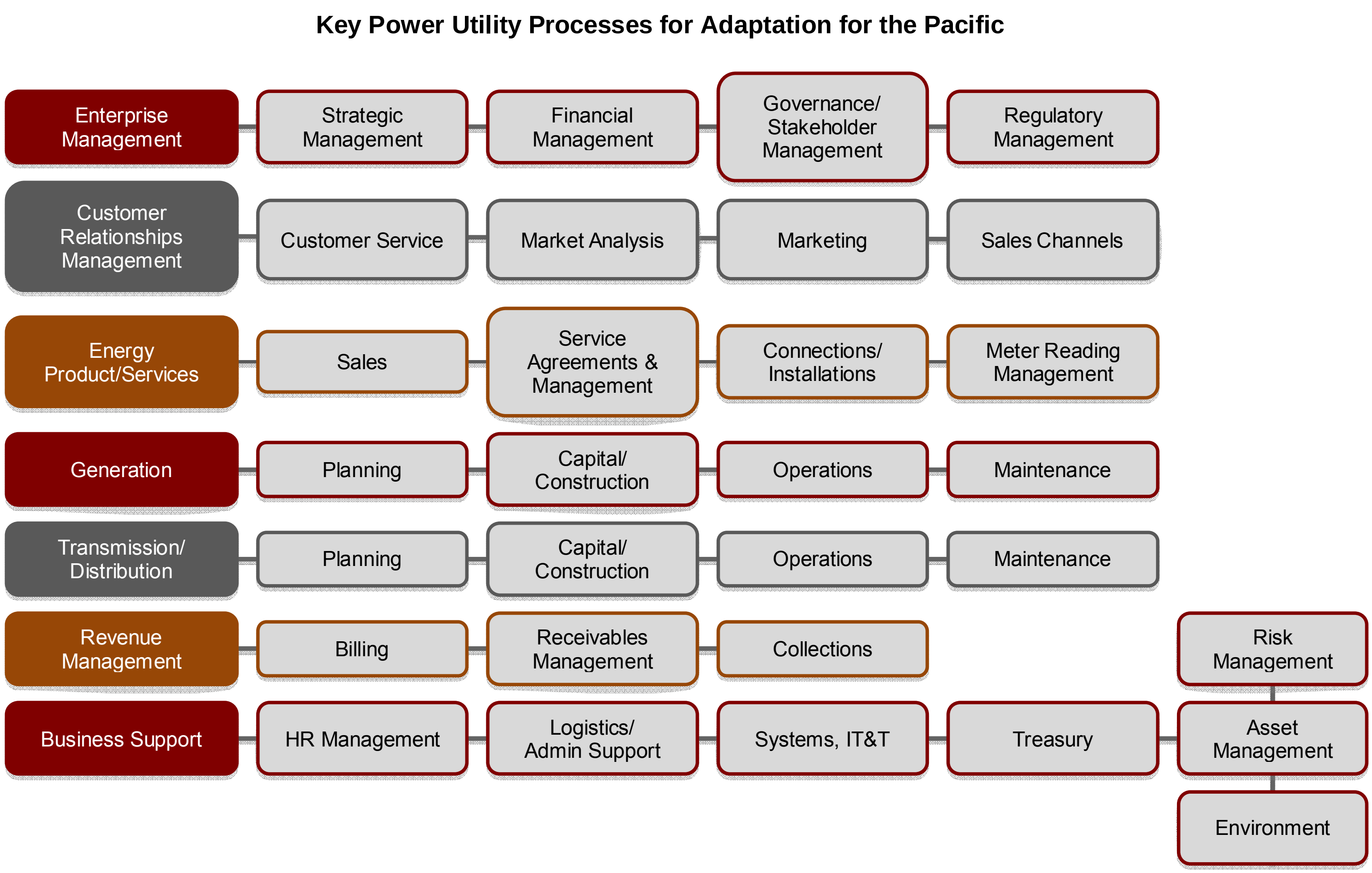
As a preliminary step, identify key (overview) organisational processes. Identify key processes by drawing an overview process map. This will provide the foundation for determining what to benchmark and will subsequently make evident what has been omitted from benchmarking. Knowing both is important for interpreting results.

An overview organisational process map adapted from a competitive, best practice, power utility is provided below. Notice that customer relationship management functions, typically associated with competitive markets, has been retained because customers like to be treated individually and at high customer care levels, whatever the type of market they are served in.

After completing the overview process map, two options will emerge:

1. Extend the current scope of benchmarking into other areas (for example, environmental management); and/or
2. Conduct a more detailed analysis of what has already been benchmarked.

Figure 1.5: Model Process Overview Map



Decide Whether to Pursue Benchmarking at Overview or Detailed Process Level

Box 1.4: Decide whether to pursue benchmarking at Overview or Detailed process level

Start with overview benchmarking, then do detailed benchmarking.

Detailed benchmarking can be done:

1. With a few selective processes (i.e. as flagged by overview benchmarking)
2. Cyclically including all processes over a number of years
3. All processes at one time.

Consider using teams, particularly for detailed benchmarking.

A utility would generally start with overview benchmarking and then proceed, possibly on a selective basis, with detailed benchmarking. The recent rounds of benchmarking involving Pacific power utilities are overview benchmarking. Overview benchmarking identifies where problems exist and the general magnitude of improvement required. Detailed process benchmarking will achieve the same result but also provides the basis for cause and effect analysis and thereby how to resolve problems. Detailed process benchmarking can be time and resource intensive but can represent good value and investment if it results in substantial and sustained improvements. It is the prerogative of each utility to determine whether to engage in detailed process mapping and analysis in support of benchmarking.

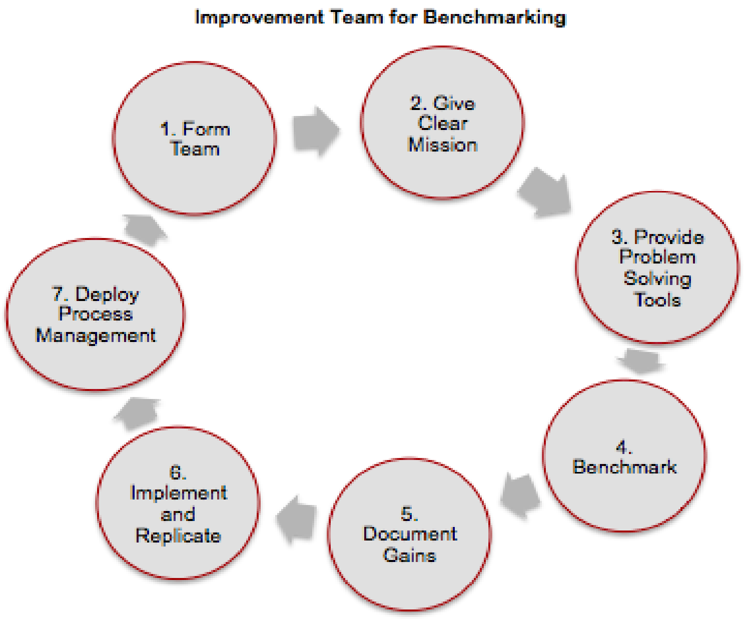
Consider Setting Up Improvement Teams

Once a utility decides to undertake detailed analysis and/or process mapping for benchmarking, it is both appropriate and effective to set up teams to address each component. For example, to improve the System Average Interruption Duration Index (SAIDI) the following more detailed aspects will need to be analysed and strengthened:

1. Generation performance;
2. Distribution performance;
   a) Planning (e.g., in regard to design & construction standards or security and other planning criteria);
   b) Operations (e.g., in regard to practices regarding re-closing after trips);
   c) Maintenance (e.g., in regard to live-line working).

Typically no one unit within a utility would have all of the skills required to address a comprehensive range of contributing factors. It is therefore often appropriate to establish a team (including representatives from generation and distribution) to address and resolve the problem. An illustration of team arrangement is provided below.

Figure 1.6: Improvement Team for Benchmarking



Guidelines for setting up improvement teams:

1. Form the team;
2. Provide a clear mission;
3. Give the team problem solving tools (it is best if they can drill down to process levels – as depicted at the centre of the diagram – in order to analyse and create improvements taking into account "cause and effect" relationships);
4. Undertake benchmarking;
5. Quantify and document the gains to be made;
6. Implement and replicate across other areas to be improved;
7. Allocate on-going improvement target paths to the various process managers involved.

Measure and Analyse Own Processes

Box 1.5: Measure and Analyse Processes

Measures can be qualitative, for example:

1. Photographs,
2. Observational, or
3. Assessments.

Or measures can be quantitative and of the following types:

1. Effectiveness,
2. Efficiency, and
3. Volume.

Analysis can be done using the "six tools of quality."

The next step is to identify the critical success factors for functions (overview or detailed) under review, and to then decide which measures best reflect success (or failure) in performance.

It is important to be able to characterise measures, because this will influence the interpretation of results produced. There are two types of measures for benchmarking purposes:

1. Qualitative measures, which for example can include:
    a) Image based, e.g. comparing photographs of different facilities; or
    b) Observational, e.g. comparing clarity of different billing forms.

2. Quantitative measures, which can be classified as:
    a) Effectiveness (e.g. achievement of service levels, such as SAIDI);
    b) Efficiency (e.g. economy in use of resources such as O&M costs/km of distribution line); or
    c) Volume (e.g. activity levels, typically used for planning purposes such as for inventory levels).

Note: It is possible that the more important functions are more difficult to measure and are therefore often the least benchmarked. It is better to imperfectly measure what is important than to precisely measure the barely relevant or irrelevant.

Analysis of the data can be done using process management tools (i.e. the six tools of quality):

1. Check sheets
2. Cause and effect (fish bone) diagrams
3. Graphing
4. Pareto charts
5. Solution matrixes
6. Financial tools

These are generally simple but useful techniques. Some financial and other technical tools may involve some complexity however relevant skills are usually available within a utility to help with their application.

As indicated previously, it is important to interpret results within the context of a basket of indicators in order to ensure proper balance of view (i.e. through use of balanced scorecards) and through relating costs to service levels and the trade-offs inevitably involved (i.e. through use of performance quadrants).

Choose Potential Benchmark Partners

Partners can be from the same or similar industries, or if benchmarking a particular function, partners can be from dissimilar industries.

While overall comparisons of key performance indicators must generally be made between utilities in the same field, benchmarking of individual functions need not be. Indeed the most interesting and potentially the most rewarding comparisons are likely to be between same/similar functions in dissimilar industries where participants are not conditioned by similar experiences and expectations. In Island economies, there would generally be scope for benchmarking of individual functions between dissimilar industries, including private/public sector exchanges. For the purposes of the PPA-

ADB current round of benchmarking, this has been determined as other Pacific island utilities.

Generally or for more detailed process benchmarking, Pacific utilities might like to take the following into account when selecting potential benchmark partners:

1. It is worthwhile to properly research which organisations might be good benchmark partners because the costs of on-going benchmarking can be substantial and should not be invalidated or diminished in value by poor partner choice;
2. The Pacific will probably provide good like-to-like comparisons which will make benchmarking easy;
3. However, benchmarking outside the Pacific is more likely to reveal best-practice comparisons;
4. The largely investor owned Caribbean utilities might make interesting comparisons;
5. Proximity might allow good access to Australian or New Zealand statistics. Good Australasian utilities performing close to international best practices make some comparisons appealing, as does the potential to make comparisons with both public and privately owned Australasian utilities. Though it should be noted that generalisations may be limited as the scale of operations in Australasia is far greater;
6. Utilities in the American Public Power Association often share small scale and public ownership characteristics with Pacific utilities. Additionally, these utilities often need to directly compete or come under peer pressure to perform as well as private utilities. Comparisons with these utilities could be interesting, however, more likely than not they directly take power or back-up from a regional grid making many comparisons less useful;
7. Asian utilities are generally on a much bigger scale, however Malaysia’s Tenaga National’s (TNB) service levels could make interesting comparisons. TNB is now competing with independent power utilities (IPUs), which are typically very small, and the IPUs are now compelled as part of their franchise commitment to provide equal to or better than TNB’s service levels.

Collect and Validate Data

Data can be collected in one or more of the following ways:

- Internet searches
- Annual reports (which often include KPI results)
- Trade shows
- Public addresses
- Journal articles
- Telephone survey
- Questionnaire survey
- Exchange of information (e.g. process maps and statistics)
- Inter-utility visits

Methods of collection should be tailored to suit needs and budget. Generally, it is best to identify needs and then exchange as much information as possible before making a field visits (visits should not be “fishing expeditions” or “industrial tourism”).

Figure 1.7: Steps for Validation

When comparing data between benchmarking partners, considerable effort needs to be undertaken in confirming definitions and trying to achieve comparability.

Overview benchmarking can use more general data such as those reflected in commonly used power industry KPIs and PIs, taking into account at least some of the above factors.

However, detailed benchmarking needs to “drill down” into specific differences such as relativities in:

- Systems maintained, e.g. numbers of poles inspected, transformers maintained etc.;
- Costs incurred, e.g. labour, materials and ownership costs such as leasing;
- Processes used;
- Demographic differences, such as customer density, customer characteristics (such as a dominant High Voltage user), vegetation, accessibility, etc.

Data needs to be normalised to facilitate comparability, e.g. cost/km, revenue/unit etc. Differences between utilities in benchmark data can generally be attributed to one or more of four factors:

1. Demography differences;
2. Accounting/statistical differences (i.e. in the way data is measured and collected);
3. Service level differences;
4. Efficiency differences.

These differences need to be analysed to ensure demographic differences are understood and appreciated, accounting/statistical differences are minimised and service level and efficiency differences are accurate – as a basis for assessment of benchmark performance. In large, well developed benchmark databases, demographic differences will often be quantified and used to adjust raw data as a means of facilitating comparisons. The problem with this is that such weighting can often “drive” a large part of benchmark performance outcomes. The Pacific power utility benchmark database has not been developed to the extent that this needs to be taken into account as of yet.

Generally there is a “healthy” scepticism regarding benchmark data, i.e. not really meaning what it purportedly portrays. Therefore, it is important in the collection and validation process to involve potential users of the data. Below is a series of steps which should be considered in benchmark data collection and validation. These steps are designed to obtain commitment from participants and promote confidence in data and validation. It is suggested that:

1. Improvement team participants workshop both data and process differences perhaps over a series of at least two workshops; and that
2. Executive representatives get involved in at least a combined workshop of data and process differences so that their objectives and concerns can be fully addressed in benchmark outcomes.

Compare and Determine What Performance Should Be

Box 1.6: Compare and Determine Performance

Compare performance:

- Service levels
- Efficiency

Identify gaps between current and better performance.

Project trends, i.e. will gap get bigger or smaller over time?

Establish targets for closing gaps, near and longer terms.

Data can be divided into overview KPIs for use in balanced scorecards and overview benchmarking and PIs for more detailed process analysis and benchmarking.

These KPIs and PIs set out:

1. Purpose of indicators;
2. Data required;
3. How to calculate; and
4. Suggested benchmarks and reference values.

In analysis, data should be:

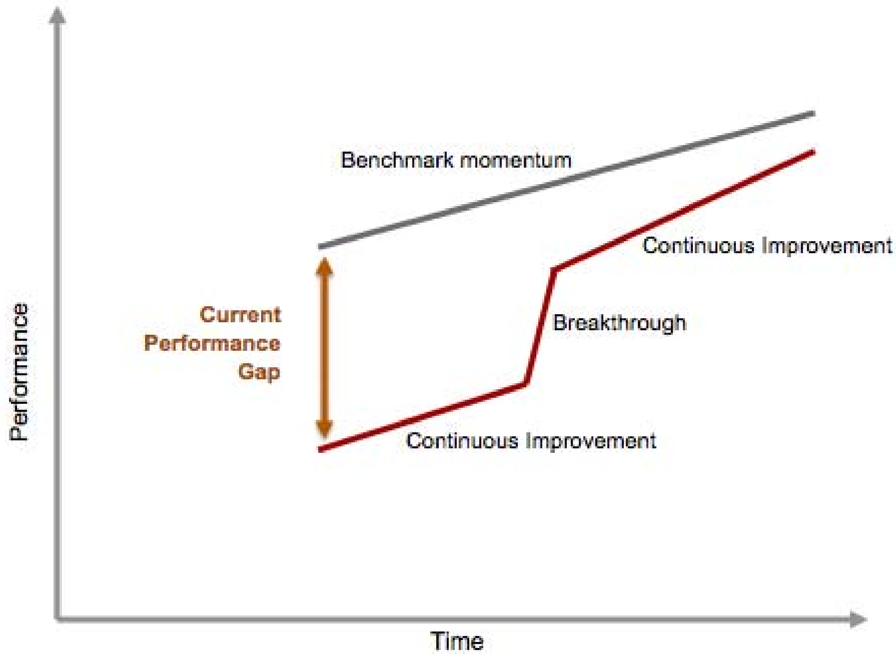
1. Considered in the context of balanced scorecards to ensure a properly balanced view is considered;
2. Also analysed, at least selectively, in terms of "performance quadrants" to determine more comprehensively where the utility is situated regarding both service levels and efficiency; remembering it is best to be in the high service level-high efficiency quadrant.

Determine What Performance Should Be

The next step is to measure the difference between benchmark and current performance. This gap needs to be evaluated in terms of:

1. Quantum of difference;
2. Prospects for the future, i.e. is the momentum actually closing or widening the gap over time. Consideration of this will determine the extent and nature of improvement required.

Figure 1.8: Momentum Line and Performance Gap



Formulate an Improvement Plan and Set Up On-Going Improvement

Box 1.7: Formulate an Improvement Plan

An improvement plan will probably include:

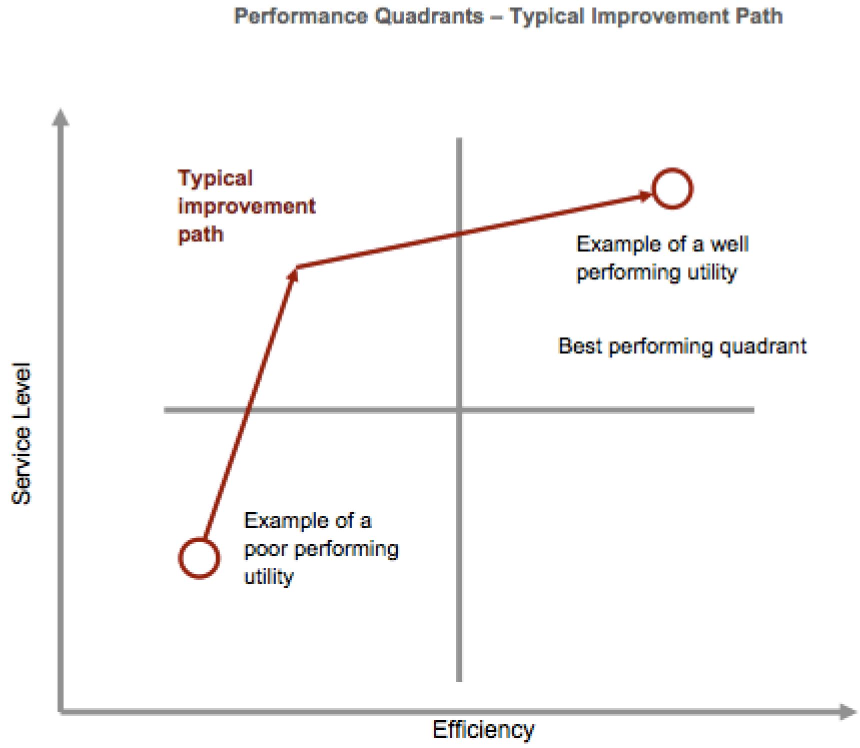
1. Improving service levels
2. Improving efficiency

This is likely to be achieved through a combination of:

1. Breakthrough improvements
2. Continuous improvements

Actions need to be planned and acted upon to achieve improvement towards best-practice benchmarked performance. A typical improvement path for a utility (as illustrated below) might be to concentrate first upon achieving improved service levels and then improving efficiencies.

Figure 1.9: Service and Cost Trade-offs and Best Performance Quadrants



However, individual utilities will need to choose improvement paths suitable to their own particular circumstances. Indeed, utilities may choose as a matter of strategy to be in the low service level, efficient quadrant. Such choices are entirely up to them, their customers and other stakeholders.

In undertaking the benchmarking exercise, managers and staff should be looking at measuring and improving processes. By repeating this cycle, breakthrough and continuous improvement may be possible.

As indicated above, improvements can be breakthrough or continuous. Breakthrough improvements are more likely to occur as a result of strategic, overview benchmarking where possibly new and different approaches may be considered. Continuous improvement is more likely to occur in operational benchmarking where decision considerations are more likely to be tactical than strategic.

It is important to consider both possible improvement paths because sometimes the largest and most intractable problems can only be solved by applying a multitude of small improvement steps, all of which add up to a required sizeable solution.

SECTION 2: Benchmarking Questionnaire

The current Benchmarking exercise consists of two sections. Section 1 seeks to gain background information into the operations of the utility, while Section 2 forms the basis of the Key Performance Indicator derivations. Feedback received from previous rounds of benchmarking indicates that utilities found Section 1 self-explanatory and did not encounter difficulties in completing the required information. See Appendix B for Section 1 of the Benchmarking questionnaire. This Manual focuses on Section 2 and is intended to assist users in understanding, completion and application of the benchmarking performance data.

The Benchmarking Questionnaire (Section 2) requests data inputs from the utilities. The data inputs are divided into the following categories:

- Generation
- Transmission
- Distribution
- Demand Side Management
- Human Resources / Safety
- Customers / General
- Finance

The current benchmarking round (2012) builds and improves upon the previous benchmarking exercises. In response to feedback received through the 2011 round, and in order to simplify the process of reporting data for the utilities, data inputs were separated from KPI calculations.

The Benchmarking Questionnaire (Section 2) can be found on the pages that follow. A short explanation of each data input is provided in the 'Explanation' column, and the required units for the data input are specified.

The 'Data Input Explanations' section that follows provides more detailed information on each input and where relevant, examples.

PACIFIC POWER ASSOCIATION
PACIFIC POWER UTILITY BENCHMARKING STUDY
QUESTIONNAIRE SECTION 2: BENCHMARKING INFORMATION

2012 Version:17 August 2012

Instructions:

1. Please see the attached Word document file "PPA Benchmarking 2012 - Intro and Section 1" for the Background, Introduction and Section 1 of the Questionnaire.
2. The attached word document "Explanations of Input Data 1" provides explanation of each input, with practical examples and sample calculations.
3. Both Section 1 (Word document) and Section 2 (Excel spreadsheet) will need to be completed for the 2012 Benchmarking Exercise.
4. Please enter the data or information requested in the yellow boxes indicated.
5. Reference unit conversion charts are provided on the Sheet "Reference Unit Conversion"
6. Where appropriate, please mark as follows: n.av. = not available; N/Ap = not applicable
7. All information requested (employment, costs, revenue, etc.) ***refers only to electricity operations*** . Do not include information for other services the utility may provide such as water, waste management, telecommunications, fuel supply etc.
8. Before returning the completed questionnaire, **please change the filename to indicate the utility, e.g. TAU, FEA, PNG Power, etc.**

SECTION 2: Introductory Questions

Information on person providing the information:

If the same person has completed both Section 1 and Section 2, indicate the name and then 'same as Section 1' below.

Completed by Benchmarking Liaison Officer (name):	
Position / Title:	
Endorsed by CEO (name):	
Country or territory:	
Name of utility:	
Postal address:	
E-mail address:	
Back up e-mail address:	
Telephone number:	
Skype address (if any):	

Benchmarking Period:		
Start Date for Benchmarking Data Collection Period (Benchmarking Period)		Calendar year is preferred, otherwise use relevant financial/reporting year
End Date for Benchmarking Data Collection Period (Benchmarking Period)		
Date questionnaire completed		
Currency Used by Utility to Report Costs:		All costs are to be provided in this currency

Ref	Input Name	Units	Explanation	System Data					Comments
	Generation			**Generation information is to be provided for the ENTIRE UTILITY SYSTEM**					
				Main Grid 1	Grid 2	Grid 3	Others		
1	Name of the Grid		Brief name or description of each grid						
2	Total Utility Generation	MWh	Total utility generation for each grid					MWh	
3	Total IPP Generation Purchased	MWh	Purchases from IPPs for each grid					MWh	
4	Maximum Demand / Peak Generation	MW	Maximum demand for each grid					MW	
5	Minimum Demand Generation	MW	Minimum demand for the each grid					MW	
6	Guaranteed/Contracted IPP Generation Capacity	MW	The capacity guaranteed by an IPP under contract					MW	
7	Generator 1 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 2 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 3 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 4 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 5 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 6 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 7 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 8 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 9 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 10 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 11 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 12 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 13 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 14 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 15 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 16 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
7	Generator 17 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW	
	(add more as required)							MW	
8	Generation by Source (MWh)	MWh	Use the total for Utility for each grid						
8a	Distillate (ADO or IDO)	MWh	Total Utility generation from distillate per grid					MWh	
8b	Heavy fuel oil (HFO or IFO)	MWh	Total Utility generation from heavy fuel oil per grid					MWh	
8c	Biofuels	MWh	Total Utility generation from biofuel per grid					MWh	
8d	Mixed Fuel	MWh	Total Utility generation from mixed fuel (eg coconut oil and diesel) for each grid. Provide details of mixture, fuels used and % of each in Comments column.					MWh	
8e	LNG	MWh	Total Utility generation from liquid natural gas for each grid					MWh	
8f	Hydropower	MWh	Total Utility generation from hydro resources for each grid					MWh	
8g	Wind energy	MWh	Total Utility generation from wind energy for each grid					MWh	
8h	Solar Photovoltaics	MWh	Total Utility generation from solar PV for each grid					MWh	
8i	Biomass	MWh	Total Utility generation from wood or other biomass for each grid					MWh	
8j	Geothermal	MWh	Total Utility generation from geothermal for each grid					MWh	
8k	Other	MWh	Any other sources of generation on each grid. Please specify in Comments column.					MWh	
9	Fuel Usage	L / kL / ML							
9a	Distillate (ADO or IDO)	L / kL / ML	Total Distillate usage per year per grid. Select the units used (L/kL/ML)					L or kL or ML?	
9b	Heavy fuel oil (HFO or IFO)	L / kL / ML	Total HFO/IDO usage per year per grid. Select the units used (L/kL/ML)					L or kL or ML?	
9c	Biofuels	L / kL / ML	Total Biofuel usage per year per grid. Select the units used (L/kL/ML)					L or kL or ML?	
9d	Mixed fuel	L / kL / ML	Total Mixed Fuel usage per year per grid. Select the units used (L/kL/ML). Indicate details of mixture in Comments column					L or kL or ML?	
9e	LNG	L / kL / ML	Total LNG Usage per year per grid. Select the units used (L/kL/ML)					L or kL or ML?	
10	Total Lubricants Used in Generation	L / kL / ML	Total lubricants used in generation from ADO/IDO, HFO/IFO, Biofuels, Fuel Mixtures, LNG. Select the units used (L/kL/ML)					L or kL or ML?	
11	Utility Capacity Hours Out of Service Due to Generation Forced Outage Events	MWh	Sum of (Utility Generation Forced Outage Duration multiplied by Capacity Rating)					MWh	
12	Utility Capacity Hours Out of Service Due to Generation Planned Outage Events	MWh	Sum of (Utility Generation Planned Outage Duration multiplied by Capacity Rating)					MWh	
13	Utility Capacity Hours Out of Service Due to Generation De-rated Events	MWh	Sum of (Utility Generation De-rated Outage Duration multiplied by Capacity Rating)					MWh	
14	IPP Capacity Hours Out of Service Due to Generation Forced Outage Events	MWh	Sum of (IPP Generation Forced Outage Duration multiplied by Capacity Rating)					MWh	
15	IPP Capacity Hours Out of Service Due to Generation Planned Outage Events	MWh	Sum of (IPP Generation Planned Outage Duration multiplied by Capacity Rating)					MWh	
16	IPP Capacity Hours Out of Service Due to Generation De-rated Events	MWh	Sum of (IPP Generation De-rated Outage Duration multiplied by Capacity Rating)					MWh	
17	Power Station Usage / Station Auxiliaries	MWh	Total energy used in the power stations operated by the utility					MWh	
18	Enabling Framework for Private Sector Participation IPP/ PPA Arrangement?	Y/N	Enabling framework includes procedures, processes etc. Provide details in Comments column.	Y/N					

Ref	Input Name	Units	Explanation	System Data		Comments
	Transmission			**Transmission information is to be provided for the MAIN GRID ONLY**		
	Transmission refers only to network of **above 34.5kV**					
19	Does your system have a transmission network?	Y/N	Applies only to Fiji, Guam, PNG and Saipan. Other utilities answer "No" and proceed to 'Distribution'.	Y/N		
20	Number of Unplanned Transmission Outage Events	events	Number of times in the period when a transmission system fault resulted in an unplanned outage		events	
21	Total Duration of Unplanned Transmission Outage Events	hrs	The total sum of the duracion of all unplanned transmissionn system outages in the period		hrs	
22	Length of Transmission Line	km / miles	Total length of all transmission lines and cables in each network		km or miles?	
23	Electricity delivered to distribution system	MWh	Total electricity delivered to the distribution system in MWh		MWh	
	Distribution			**Distribution information is to be provided for the MAIN GRID ONLY**		
	Distribution refers only to power sent through the grid **at or below 34.5 kV**					
	All utilities should complete this section					
24	Number of Distribution Forced Outage Events	events	The total number of outages due to faults in the distribution network		events	
25	Length of Distribution Line	km / miles	The total length of all distribution lines and cables in the distribution network		km or miles?	
26	Total Distribution Transformer Capacity	MVA	The sum of all distribution transformer capacity on the network		MVA	
27	Total Customer Interruptions	interruptions	Total number of customer connections affected by distribution outages (both plannd and unplanned) in the period		interruptions	
28	Total Customer Duration Interrupted	customer hrs	Sum of (Custom Interruption x Duration of Interruption)		customer hrs	
	Demand Side Management			**Demand Side Management information is to be provided for the ENTIRE UTILITY SYSTEM**		
29	Does the utility actively engaged in any demand side management initiatives?	Y/N	This includes initiatives acorss all grid. Select Yes/No for this question and for the following activities. If other activities that are not specified, please specify below in 'Others'.	Y/N		
30a	Replacing incandescent lighting with compact fluorescent lighting	Y/N		Y/N		
29a	Installing sensors on lighting or other	Y/N		Y/N		
29b	Replacing old inefficient air conditioners with high-efficiency units	Y/N		Y/N		
29c	Performance testing of appliances and equipment	Y/N		Y/N		
29d	Replacing old refrigerators and freezers with new, high-efficiency units	Y/N		Y/N		
29e	Have varying rates for peak and off peak electricity usage	Y/N		Y/N		
29f	Educational program to consumers	Y/N		Y/N		
29g	Other 1 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 1 - Specify here:	
29h	Other 2 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 2- Specify here:	
29i	Other 3 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 3 - Specify here:	
29j	Other 4 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 4 - Specify here:	
29k	Other 5 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 5 - Specify here:	
30	What is the budget for DSM?	0	Specify DSM budget for reporting period. If no DSM budget, type "0"		0	
31	How many employees are engaged in DSM?	employees	Provide total number of employees. Provide details in the comments column		employees	
32	Has there been recorded savings by consumers? How much?	MWh (total)	Select "Yes" or "No". If "Yes", indicate how much in the local currency		MWh (total)	
33	What power Quality Standard applies, if any?		Provide name of the standard. If none applies, type "None".			

Ref	Input Name	Units	Explanation	System Data					Comments
	Human Resources / Safety			**Human Resource / Safety information is to be combined for the ENTIRE UTILITY SYSTEM**					
34	Total Days Lost Due to Work Injury During Period (excludes contractors)	days	The sum of work days/shifts an employee is unable to report to work due to injury sustained at work. Excludes contractors.		days				
35	Number of Lost Time Injuries During Period (excludes contractors)	LTIs	Total employee LTIs. Contractor injuries are not counted towards LTIs.		LTIs				
36	Total Number of Employees (excludes contractors)	employees	The total number of employees. This factor excludes contractors		employees				
37	Total number of employees in Distribution & Customer Service at Start of Period	employees	Total number of employees in Distribution & Customer Service at Start of Period	0		employees			
38	Total number of employees in Distribution & Customer Service at End of Period	employees	Total number of employees in Distribution & Customer Service at End of Period	0		employees			
39	Total Hours Worked (excludes contractors)	hrs	The total hours worked by employees		hrs				
40	Paid Hours Utility Generation Labour	hrs	Total paid hours for generation labour, taking into account overtime rates					hrs	
41	Paid Hours Utility Distribution Labour	hrs	Total paid hours labour to maintain and operate the utility's distribution network.		hrs				
42	Total Paid Hours Employees Including Contractors	hrs	The total paid hours for employee labour. This takes overtime (double timeetc) into account		hrs				
	Customers / Gen			**Customer information is to be combined for the ENTIRE UTILITY SYSTEM, except for Electricity Sold which is per grid**					
				Main Grid 1	Grid 2	Grid 3	Others		
43	Electricity Sold	MWh	Total electricity billed to customers in MWh for each grid					MWh	
44	Total Number of Customers at Start of Benchmarking Period	connections	Number of customers at the start of the benchmarking period. Include total of all customer classes for all the networks.	0		connections			
45	Total Number of Customers at End of Benchmarking Period	connections	Number of customers at the end of the benchmarking period. Include total of all customer classes for all the networks.	0		connections			
46	Number of Households Supplied (Domestic Connections)	connections	Combined number of domestic connections across all grids, taken at end of benchmarking period		connections				
47	Total Number of Households in the Country	households	The total number of households in the country.		households				
48	Lifeline Tariff Available?	Y/N	Indicate Yes or No	Y/N					
49	Maximum Threshold for Monthly Consumption Under Tariff	kWh/mth	Provide the tariff threshold in kWh/month		kWh/mth				
50	Tariff Schedule / Tariff Table Attached?	Y/N	Please attach tariff schedule/table and indicate Yes when this is done.	Y/N					
51	Total Electricity Billed under Lifeline Tariff	MWh	The total electricity billed to customers under Lifeline Tariff in MWh.		MWh				
52	Total Domestic Electricity Billed	MWh	The total electricity billed to customers under domestic tariff in MWh.		MWh				
53	Total Commercial Electricity Billed	MWh	The total electricity billed to customers under the commercial tariff in MWh.		MWh				
54	Total Industrial Electricity Billed	MWh	The total electricity billed to customers under the industrial or maximum demand tariff in MWh.		MWh				
55	Total Other Electricity Billed	MWh	The total electricity billed to customers under the industrial or maximum demand tariff in MWh. Please specify		MWh				
56	Total Unbilled Electricity Usage	MWh	e.g Head Office, Water Services, Street Lighting etc. (This does not include power station usage/station auxiliiaries)		MWh				
57	Is the utility self regulated or externally regulated?	self / external	Select self regulated or externally regulated. Provide any details	self / external ?					
58	Do you have a maintenance plan for your utility?	Y/N	This may cover generation, transmission, distribution. Please attach plan.	Y/N					

Ref	Input Name	Units	Explanation	System Data	Comments
	Finance			**Finance information is to be combined for the ENTIRE UTILITY SYSTEM**	
59	Depreciation Generation Assets		Total depreciation of generation assets over the benchmark period		
60	Depreciation Transmission & Distribution Assets		Total depreciation of transmission & distribution assets over the benchmark period		
61	Other Depreciation		Total depreciation on other electricity assets excluding generation, transmission & distribution assets for benchmarking period.		
62	Total Operating Revenue		Total Operating Revenue earned from electricity sales.		
63	Total Operating Expenses		Total Operating Expenses excluding depreciation, interest and tax.		
64	Earnings Before Interest and Tax (EBIT) / Operating Profit		Sales revenue minus the cost of goods sold and all expenses except for interest and taxes		
65	Profit After Tax (PAT) / Earnings After Tax (EAT)		Sales revenue after deducting all expenses, including taxes		
66	Long Term Debt / Non Current Liability		Funds obtained from loans, mortgages, bonds, etc. that have repayment terms longer than one year		
67	Equity / Net Assets / Capital and Reserves		Equity / Net Assets / Capital & Reserves represents the owner's funds or claims the owners have on the business.		
68	Non Current Asset at End of Previous Period		The assets that are consumed over a period of more than a year taken from end of prev period		
69	Non Current Asset at End of Benchmarking Period		The assets that are consumed over a period of more than a year taken from end of benchmarking period		
70	Current Assets		Value of all assets that are reasonably expected to be converted into cash within one year		
71	Current Liabilities		Company's debts or obligations that are due within one year		
72	Debtors/Receivables at Period End		Money owed to a business by its clients (customers) and shown on its Balance Sheet as an asset		
73	Are utility finances independently audited?	Y/N	If Yes, indicate who the auditor was in Comments column	Y/N	
74	What is the accounting standard used by the utility?		eg US GAP, IAS, IPSA, None etc		
	Generation Expenditure				
75	Hydrocarbon Based Fuel & Lubrication Oil Expenditure		Total expenditure on distillate fuel oil, heavy fuel oil, coconut oil, other hydro carbon based fuels, and lubricating oil		
76	Duty and Taxes on Hydrocarbon Based Fuel & Lubricating Oil		Total duty and taxes paid hydrocarbon based fuel & lubricating oil		
77	Generation O&M Costs (utility)		Total cost for operations and maintenance of the Utility. This excludes all IPP generation costs, labour costs and fuel and oil costs.		
78	Generation Labour		Total expenditure on labour associated with the generation of electricity		
	Transmission/ Distribution Expenditure				
79	Transmission/ Distribution O&M Cost		Total expenses incurred in the operations and maintenance of the distribution network		
80	Transmission/ Distribution Labour		Total expenditure on labour for transmission & distribution operations		
	Overheads/ Other Expenditure				
81	Other Labour Expenditure (Customer Service, Head Office, Finance, HR, others)		Total labour expenditure for head office and other labour for electricity operations		
82	Other Duty/ Taxes		All duty and taxes paid to government for equipment and supplies. Do not include personal income tax and other taxes applicable to workers remuneration. GST, VAT or other forms of sales tax is also excluded		
83	Other Expenditure		Total expenditure on items not included in any of the above.		

Please go to 'Data Reliability' Sheet and complete.

Data Input Explanations

Introductory Questions

Please provide all of the contact information requested in the table.

1) Benchmarking Period

The Benchmarking Period is a 12 months period to be determined by the utility. The 2011 calendar year is preferred, however, for utilities whose financial year does not correspond with the calendar year, the latest complete financial year may be selected as the benchmarking period.

Enter the start and end dates of the annual benchmarking period in the space provided.

The dates that are entered here will be automatically referred to in the spreadsheet. An example is provided below:

Figure 2.10: Example showing benchmarking period 1 July 2011 - 30 June 2012

Benchmarking Period		
Start Date for Benchmarking Data Collection Period	1 July 2011	Calendar yr is preferred, otherwise use relevant financial/reporting yr
End Date for Benchmarking Data Collection Period	30 June 2012	

Filling in the benchmarking period information will automatically populate the fields of the spreadsheet where the start and end date of the benchmarking period are referred to, such as Inputs # 44 and 45 in the 'Customer' section:

44	Total Number of Customers at Start of Benchmarking Period	connections	Number of customers at start of period. Includes total of all customer classes for all networks	1 July 2011		connections
45	Total Number of Customers at End of Benchmarking Period	connections	Number of customers at end of period. Includes total of all customer classes for all networks	30 June 2012		connections

2) Date Questionnaire Completed

Enter the date that the 2012 Benchmarking spreadsheet was filled out.

3) Currency Used by Utility to Report on Costs

Enter the currency in which the utility will report all financial figures (use local currency for example, FJD). The currency that is entered here will be automatically referred to in the spreadsheet whereever a monetary figure is requested. For example, where Generation O&M Costs are requested, the currency entered will populate as the Currency Used by Utility to Report on Costs. An example is provided below:

Figure 2.11: Example of Currency Used by Utility to Report on Costs

Currency Used by Utility to Report Costs	FJD	All costs are provided in this currency

Filling in the Currency Used by Utility to Report on Costs will automatically make all fields where a monetary value is requested populate in the currency units specified.

				Main Grid 1	Grid 2	Grid 3	Other	
77	Generation O&M Costs (utility)	FJD	Total cost for operations and maintenance of the utility. Excludes all IPP generation costs, labour costs, fuel and oil costs.					FJD

Utilities are not required to convert currency as any conversion required will be undertaken by those who collate and analyse the benchmarking results.

Generation

Please provide the information requested for each of the utility's grid systems. If there is a single grid, then only the first column for Main Grid needs to be completed. If there are more than 3 grids, the smaller ones can be combined into 'Other'.

1) Name of the Grid

Identify the grid(s) by name or location.

For example, for FEA this could be: Viti Levu, Vanua Levu N, Vanua Levu S, Ovalau. For PNG Power: PM, Ramu, Gazelle, Other. For TAU: Rarotonga, Aitutaki, Other etc.

2) Total Utility Generation (MWh)

Total Utility Generation is the sum of the energy, in megawatt hours (MWh), generated by the utility's generating plants for each grid. This is the energy that a generator injects into the bus to which it is connected and is most likely measured by an energy meter located on the generator circuit breaker that connects the generator to the bus.

3) Total IPP Generation Purchased (MWh)

Total IPP Generation is the sum of the energy purchased in MWh from Independent Power Producers for each grid.

4) Maximum Demand / Peak Generation (MW)

The peak or maximum demand experienced during the benchmark period. That is, the maximum demand experienced during the year.

5) Minimum Demand Generation (MW)

The minimum demand experienced during the benchmark period. That is the minimum demand experienced for normal supply. Do not include abnormal situations such as total system blackouts.

6) Guaranteed / Contracted IPP Generation Capacity (MW)

The Guaranteed / Contracted IPP Capacity is the capacity guaranteed by an IPP under contract to supply the utility.

7) Generator Nameplate Capacity Rating (MW)

The Generator Nameplate Capacity Rating is the capacity for a generator as stated on the nameplate on the generator; or, where a generating plant has been permanently de-rated than the de-rated capacity should be used in place of the nameplate rating. Add a comment to show what the nameplate rating was, and what it was de-rated to. Refer to the example provided in *Figure 2.12*, Generator 4 Nameplate Capacity Rating comment.

A table is provided to list each generator with its nameplate rating and also where applicable to list its de-rated capacity.

Generators that are kept for standby purposes are to be included. Black start station generators are not to be included.

Fill in the table with the details for each generator.

An example is provided below. This example shows a utility with 3 grids, with 5 generators on the Main Grid, 2 generators on Grid 2, and 3 generators on Grid 3. Generator 4 shows a de-rated capacity of 0.375MW. The nameplate capacity is provided in the comments column, 0.5MW.

Figure 2.12: Example of Generator Nameplate Capacity Rating Table

			Main Grid 1	Grid 2	Grid 3	Others		Comments
7	Generator 1 Nameplate Capacity Rating	MW	0.500				MW	
7	Generator 2 Nameplate Capacity Rating	MW	0.500				MW	
7	Generator 3 Nameplate Capacity Rating	MW	0.500				MW	
7	Generator 4 Nameplate Capacity Rating	MW	0.375				MW	0.5MW generator derated to 0.375MW
7	Generator 5 Nameplate Capacity Rating	MW	0.375				MW	
7	Generator 6 Nameplate Capacity Rating	MW		0.375			MW	
7	Generator 7 Nameplate Capacity Rating	MW		0.325			MW	
7	Generator 8 Nameplate Capacity Rating	MW			0.225		MW	
7	Generator 9 Nameplate Capacity Rating	MW			0.225		MW	
7	Generator 10 Nameplate Capacity Rating	MW			0.175		MW	
7	Generator 11 Nameplate Capacity Rating	MW					MW	
7	Generator 12 Nameplate Capacity Rating	MW					MW	
7	Generator 13 Nameplate Capacity Rating	MW					MW	
7	Generator 14 Nameplate Capacity Rating	MW					MW	
7	Generator 15 Nameplate Capacity Rating	MW					MW	
7	Generator 16 Nameplate Capacity Rating	MW					MW	
7	Generator 17 Nameplate Capacity Rating	MW					MW	
	(add more as required)						MW	

8) Generation by Source (MWh)

Here the generation is divided into the different fuel sources (non renewable and renewable). A table is provided to list the MWh generation from each fuel source. The total utility generation is to be included for each grid. IPP generation is not to be included.

Fill out the table for each grid.

An example is provided below. This example shows a utility with 3 grids. The Main Grid has generation from ADO, HFO, Mixed Fuel (60% diesel, 40% coconut oil), Hydropower and Solar PV. Grid 2 has generation using ADO, HFO, Hydropower and Biomass. Grid 3 has generation from Solar PV and Biomass.

Figure 2.13: Example of Generation by Source Table (MWh)

			Main Grid 1	Grid 2	Grid 3	Others		Comments
8	Generation by Source (MWh)	MWh						
8a	Distillate (ADO or IDO)	MWh	55,040	13,040			MWh	
8b	Heavy fuel oil (HFO or IFO)	MWh	16,200	15,100			MWh	
8c	Biofuels	MWh					MWh	
8d	Mixed Fuel	MWh	20,220				MWh	60% diesel, 40% coconut oil
8e	LNG	MWh					MWh	
8f	Hydropower	MWh	151,600	42,500			MWh	
8g	Wind energy	MWh					MWh	
8h	Solar Photovoltaics	MWh	60		220		MWh	
8i	Biomass	MWh		20,086	140		MWh	
8j	Geothermal	MWh					MWh	
8k	Other	MWh					MWh	

a) Generation by Distillate (ADO/IDO) (MWh)

Electricity generated by all Automotive Diesel Oil / Industrial Diesel Oil (ADO/IDO) generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

The example shown in Figure 2.4 above shows that for Grid 1, ADO generation was made up of 55,040 MWh utility generation.

b) Generation by Heavy Fuel (HFO/IFO) (MWh)

Electricity generated by all Heavy Fuel Oil / Industrial Fuel Oil (HFO/IFO) generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

c) Generation by Biofuels (MWh)

Electricity generated by all biofuel generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

d) Generation by Mixed Fuel (MWh)

Electricity generated by all mixed fuel generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

If biofuel is used, provide the percentage (%) of each component fuel.

In the example shown in Figure 2.4 above, Grid 1 has 20,220 MWh mixed fuel generation, made up of 60% diesel and 40% coconut oil, as shown in the comments column.

e) Generation by LNG (MWh)

Electricity generated by all Liquid Natural Gas (LNG) generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

f) Generation by Hydropower (MWh)

Electricity generated by all hydro generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

g) Generation by Wind (MWh)

Electricity generated by all wind generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

h) Generation by Solar (MWh)

Electricity generated by all solar generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

i) Generation by Biomass (MWh)

Electricity generated by all Biomass generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

j) Generation by Geothermal (MWh)

Electricity generated by all geothermal generating plants supplying the grids. The total generated by the utility's generators is to be entered into the table provided.

k) Generation by Other (MWh)

Electricity generated by other generating plants than those above supplying the grids. The total generated by the utility's generators is to be entered into the table provided. Please specify what is meant by 'Other' in the Comments column.

9) Fuel Usage (L / kL / ML)

Here a table is provided to list the annual fuel usage of the various hydrocarbon fuels sources: Distillate (ADO/IDO), HFO/IFO, Biofuels, Mixed Fuels and LNG turbine. Fuel Usage can be expressed in L, kL or ML. The user will need to select the units being used.

Fill out the table showing the quantity of usage of each fuel source for each grid.

An example is provided below. This example shows a utility with 2 grids. The Main Grid uses Distillate and HFO. Grid 2 uses Distillate, HFO and Biofuels. Distillate and HFO are shown in kL, whereas Biofuel usage is expressed in L.

Figure 2.14: Example of Fuel Usage Table

			Main Grid 1	Grid 2	Grid 3	Others		Comments
9	Fuel Usage	L / kL / ML						
9a	Distillate (ADO or IDO)	L / kL / ML	19,100	34,330			kL	
9b	Heavy fuel oil (HFO or IFO)	L / kL / ML	41,090	11,000			kL	
9c	Biofuels	L / kL / ML		35,080			L	
9d	Mixed fuel	L / kL / ML					L or kL or ML?	
9e	LNG	L / kL / ML					L or kL or ML?	

a) ADO/ IDO Fuel Usage

ADO/IDO is the total diesel fuel oil consumed for generating electricity is to be provided. The user will need to select the units being used (L, kL or ML).

b) HFO / IFO Fuel Usage

The total HFO/IFO consumed for the generation of electricity. The user will need to select the units being used (L, kL or ML).

c) Biofuel Usage

The total biofuel used to generate electricity. The user will need to select the units being used (L, kL or ML).

d) Mixed Fuel Usage

Where biofuel, such as coconut oil, is mixed with ADO/IDO, the Mixed Fuel Usage is the total quantity (L/kL/ML) used for the generation of electricity. The user will need to select the units being used (L, kL, or ML)

e) LNG Usage

The total LNG used to generate electricity. The user will need to select the units being used (L, kL or ML).

10) Total Lubricants Used In Generators using Hydrocarbon Fuels (kL)

Hydrocarbon fuels are ADO/IDO, HFO/IFO, biofuels, mixed fuels and LNG. The lubricants referred to here are the total lubricants consumed for the generation of electricity using these fuels.

Total Lubricant Used can be expressed in L, kL or ML. The user will need to select the units being used.

11) Utility Capacity Hours Out of Service Due to Generation Forced Outage Events (MWh)

Utility generators are at times forced out of service due to faults on the engine or electrical systems. The Utility Capacity Hours Out of Service for an event can be determined by the duration during which time the generator is not available multiplied by the capacity of the generator. The sum of the Capacity Hours Out of Service for each forced event is the data required for this project.

For example, in June 2011, a 5MW generator on a utility's Main Grid had an oil system failure that led to a 48 hour out of service to repair the fault. In August 2011, the same utility had an electrical fault in a 2.7MW generator also on the Main Grid that resulted in a 4 day unplanned shutdown. The Utility Capacity Hours Out of Service is calculated:

$$5\text{MW} \times 48\text{hrs} + 2.7\text{MW} \times (4 \times 24 \text{ hrs}) = 240 + 259.2 = 499.2 \text{ MWh}$$

12) Utility Capacity Hours Out of Service Due to Generation Planned Outage Events (MWh)

The Utility Capacity Hours Out of Service Due to Planned Events is the sum of the Capacity Hours Out of Service for each planned event. A planned outage event is where a utility generating unit is taken out of service as scheduled for maintenance such as overhauls, servicing, etc.

The method of calculation is the same as for Forced Outage Events so refer to the example for Utility Capacity Hours Out of Service Due to Generation Forced Outage Events for instructions on how to calculate the Utility Capacity Hours Out of Service Due to Planned Outages Events.

13) Utility Capacity Hours Out of Service Due to Generation De-rated Events (MWh)

At times a generating unit may be de-rated for various reasons. In this instance the generator is available for service up to a limited capacity. The Utility Capacity Out of Service for a De-rated Event is the difference between the generator's full rated capacity (as shown on the generator nameplate) and the limited capacity multiplied by the duration during which the generator is de-rated.

For example, where a 5 MW generator is de-rated to 4 MW for 100 hours, the Capacity Out of Service for this event is:

$$(5-4) \text{ MW} \times 100 \text{ Hours} = 100 \text{ MWh}$$

14) IPP Capacity Hours Out of Service Due to Generation Forced Outage Events (MWh)

IPP generators are at times forced out of service due to faults on the engine or electrical systems. The IPP Capacity Hours Out of Service for an event can be determined by the duration during which time the generator is not available multiplied by the guaranteed / contracted capacity. The sum of the IPP Capacity Hours Out of Service for each Forced Event is the data required for this project.

Refer to the example provided under Utility Capacity Hours Out of Service Due to Generation Forced Outage Events for the method to calculate the same factor for the IPP forced outages.

15) IPP Capacity Hours Out of Service Due to Generation Planned Outage Events (MWh)

The IPP Capacity Hours Out of Service Due to Planned Events is the sum of the Capacity Hours Out of Service for each planned event. A planned outage event is where an IPP generating unit is taken out of service as scheduled for maintenance such as overhauls, servicing, etc.

The method of calculation is the same as for Forced Outage Events therefore refer to the example for Utility Capacity Hours Out of Service Due to Generation Forced Outage Events for instructions on how to calculate the IPP Capacity Hours Out of Service Due to Planned Outages Events.

16) IPP Capacity Hours Out of Service Due to Generation De-rated Events (MWh)

At times an IPP generating unit may be de-rated for various reasons. When de-rated the generator is available for service up to a limited capacity. The IPP Capacity Out of Service for a De-rated Event is the difference between the IPP's Guaranteed / Contracted Generation Capacity and the limited capacity, multiplied by the duration during which the IPP guaranteed / contracted capacity is de-rated.

For example: Where an IPP is contracted to make available 10MW of capacity and this is de-rated to 6.5 MW for 100 hours. The IPP Capacity Out of Service for this event is:

$$(10 - 6.5) \text{ MW} \times 100 \text{ hrs} = 350 \text{ MWh}$$

17) Power Station Usage / Station Auxiliaries (MWh)

Power Station Usage / Station Auxiliaries is the total energy used in the power stations operated by the utility. This includes electricity for auxiliary supply to the generators and all other activities carried out in the power station. This is typically unbilled supply that is metered.

18) Framework for Private Sector Participation

Here the response is a "Yes" if the utility has in place a framework and policies and procedures for incorporating private sector participation in the generation of electricity. Where there is no framework, policies and procedures the answer is "No". Where there is some progress toward this goal of encouraging private sector participation, briefly describe what is being done in the Comments column.

Transmission

For the purpose of this benchmarking exercise, the transmission network is defined as comprising any lines, cables, and equipment operating at a voltage greater than 34.5 kV.

19) Does Your System Have a Transmission System?

With reference to the above definition, if the utility's system includes any lines, cables, and equipment operating at a voltage greater than 34.5 kV, "Yes" should be selected and the transmission questions that follow answered. If the utility's system operates at or below 34.5kV, "No" should be selected and the user can skip to 'DISTRIBUTION' (data input number 24).

20) Number of Unplanned Outage Events (events)

An unplanned outage event on the transmission network is where a transmission line, underground cable or connecting equipment is taken out of service by a fault. The total number of such events is the 'Number of Unplanned Outage Events'.

For example, a utility with a 66kV transmission system, whose benchmarking period was 1 January 2011 to 31 December 2011 incurred two unplanned outages in January 2011 and one unplanned outage in September 2011. The total Number of Unplanned Outage Events for the benchmarking period is 3.

An outage event is an outage that lasts more than a minute in duration. If the utility defines an outage differently, please state this in the comment cell.

21) Total Duration of Unplanned Outage Events (hours)

Total Duration of Unplanned Outage Events is the sum of the duration of unplanned outage events in hours.

For example, building on the example provided in input number 20, if the first unplanned outage lasted for 24 hours, the second for 5 days, and the third for 3 days, the Total Duration of Unplanned Outage Events is calculated as:

$$24 + (5 \times 24) + (3 \times 24) = 216 \text{ hrs}$$

22) Length of Transmission Lines (km / miles)

The Length of Transmission Lines is the total length of all transmission lines and cables in the transmission network. This measure may be expressed in km or miles. The units used will need to be indicated by using the km / miles selection box provided.

23) Electricity Delivered to Distribution System (MWh)

The Electricity Delivered to Distribution System is the total electricity delivered to the distribution system by the transmission network in MWh. This is the sum of all electricity injected into the distribution network from the transmission network irrespective of whether it is generated by the utility or IPP. It excludes any losses that have been incurred between generation and delivery to the distribution system and any electricity used in the substations for the delivery of electricity.

Distribution

For the purpose of this benchmarking exercise, the distribution network is defined as comprising any lines, cables, and equipment operating at a voltage at 34.5 kV or below. The 415/ 240 volts or lower voltage network is not to be included.

24) Number of Distribution Forced Outage Events (events)

The total number of outages due to faults in the distribution network.

25) Length of Distribution Lines (km / miles)

The total length of all distribution lines and cables in the distribution network. This measure may be expressed in km or miles. The units used will need to be indicated by using the km / miles selection box provided.

26) Total Distribution Transformer Capacity (MVA)

The sum of all distribution transformer capacity on the network. Transformers on the transmission network or in the power stations for stepping up the voltage or for power station supply are not to be included.

27) Total Customer Interruptions

A customer interruption is defined as one customer (connection) whose power has been interrupted once. Usually when an outage occurs, a number of customers have their power interrupted. The number of connections affected will depend on where the fault was isolated. The number of customers affected is the Customer Interruptions for that outage. All Customer Interruptions are included irrespective of whether it is caused by a planned or forced outage. The sum of all the Customer Interruptions in the benchmarking period will provide the Total Customer Interruptions.

For example, a distribution feeder trips and 150 customers are affected. The Customer Interruptions for that outage is 150. If the feeder trips a second time, the customer interruptions is again 150. The total customer interruption for both trips is 300.

Total Customer Interruptions and Total Customer Duration interrupted are determined for:

1. Outages caused by faults and planned maintenance work on the high voltage distribution network, transmission lines and generators that result in interruption to power supplied to a customer. Outages on the low voltage network are to be excluded.
2. Outages of more than a minute are to be considered. Momentary outages such as those caused by an auto-recloser which has successfully reclosed should be excluded. However, where the recloser has locked out, the outage should be included.

28) Total Customer Duration Interrupted

The Total Customer Duration Interrupted is determined by summing the Customer Duration Interrupted for each event. For each event the Customer Duration Interrupted is determined by the number of customers affected multiplied by the duration in hours the customers were affected (see Reference 27 for the types of outages to be included). Take the example given above under Total Customer Interruptions. If the first feeder trip took 30 minutes to restore, and the second took 12 hours, the Customer Duration Interrupted is calculated as:

$$150 \times 0.5\text{hrs} + 150 \times 12 = 75 + 1800 = 1875 \text{ customer hours}$$

Demand Side Management

Demand Side Management (DSM) initiatives across all grids should be included.

29) Does the utility actively engage in DSM initiatives?

Indicate “Yes” or “No”. The following questions provide some examples of DSM activities. If the answer to this question is “Yes”, indicate which of the below activities are actively being undertaken by the utility. If the initiatives are not listed, include details under Other 1, Other 2, Other 3..etc.

30) What is the budget for DSM?

Specify DSM budget for reporting period. If no DSM budget, type “0”.

31) How many employees are engaged in DSM?

Provide total number of employees. Provide details in the comments column.

32) Has there been recorded savings by customers?

Select “Yes” or “No”. If “Yes”, indicate how much in MWh.

33) What power quality standard applies, if any?

Provide name of the standard. If none applies, type “None”.

Human Resources & Safety

Human Resource and Safety inputs are to be combined across all grids.

34) Total Days Lost Due to Work Injury During Period (days)

The sum of work days/shifts an employee is unable to report to work due to injury sustained at work. The Australian Standards defines such occurrences as those ‘that resulted in a fatality, permanent disability or time lost from work of one day/shift or more. AS 1885.1 1990.

This factor does not include days lost due to contractor work injuries.

35) Number of Lost Time Injuries During Period

A Lost Time Injury (LTI) is an incident of employee injury incurred at work that immediately results in the employee’s incapacity to report to work for the following shift. Contractor injuries are not counted towards LTIs.

36) Total Number of Employees

The total number of employees engaged in electricity generation, transmission, distribution and supporting activities. This factor excludes contractors.

Where the utility is involved in other services such as water supply, sewerage, etc. then the CEO and the executive/ manager responsible for electricity supply is to be counted along with the staff engaged in electricity supply. Staff engaged for the other utility activities besides electricity supply are not to be counted.

37) Total Number of Employees in Distribution & Customer Service at Start of Period

The total number of employees in distribution and customer service at the start of the benchmarking period.

This includes:

- Employees whose job responsibilities are mainly related to the operations and maintenance of the distribution network.
- Employees employed mainly for the distribution network although they may also be required for work on the transmission network.
- Workers involve in customer service including customer connections/disconnections, etc.

This should not include:

- Generation employees
- Employees mainly employed for the transmission network
- Head office staff
- HR and Finance staff
- Support staff
- Employees engaged in other utility activities such as water supply, etc.

38) Total Number of Employees in Distribution & Customer Service at End of Period

The number of employees in distribution and customer service at the end of the benchmarking Period.

Refer data input 37 for whom to include and whom to exclude in this number.

39) Total Hours Worked (hours)

The total hours worked by employees engaged in electricity supply. This does not factor in any time-and-a-half or double-time; it is simply the total actual hours worked. Contractors are to be excluded.

For example, where a person worked 3 hours overtime at a rate of double time, the hours worked is 3 hours.

40) Paid Hours Utility Generation Labour (hours)

The Paid Hours Utility Generation Labour is the total hours paid for labour to maintain and operate the utility's power stations. For normal hours the hours worked is equal to the hours paid for. Where overtime is worked the hours paid for may be greater than the hours worked should the overtime rate be time-and-a-half or double-time. The hours paid for in overtime are to be included in this data.

For example, a utility has 100 employees who each work a 40 hour standard week. This equates to 2000 hours per year for each employee. If 20 employees worked 10 hours overtime, paid at double-time (x2) and 10 employees worked 10 hours overtime at time-and-a-half (1.5x), the Paid Hours Utility Generation Labour for the year will be calculated as such:

Paid Hours Utility Generation Labour = Normal paid hours + Overtime paid hours

Normal paid hours = 100 employees x 40hrs x 50wks = 200,000 hrs

Overtime paid hours = (20 employees x 10hrs x 2) + (10 employees x 10hrs x 1.5)
= 400 + 150 = 550 hrs

Therefore Paid Hours Utility Generation Labour = 200,550 hrs

41) Paid Hours Utility Distribution Labour (hours)

The total hours paid for labour to maintain and operate the utility's distribution network. For normal hours, the hours worked is equal to the hours paid for. Where overtime is worked the hours paid for may be greater than the hours worked should the overtime rate be time-and-a-half or double-time. The hours paid for in overtime are to be included in this data.

Refer to the example provided in data input 40 for methodology on how to calculate this figure.

42) Total Paid Hours Employees (hours)

The total paid hours for employee labour. For normal hours the hours worked is equal to the hours paid for. Where overtime is worked the hours paid for may be greater than the hours worked should the overtime rate be time-and-a-half or double-time. The hours paid for in overtime are to be included in this data.

For example where a person works 3 hours overtime at a rate of double-time, the hours paid is 6 hours.

Refer to data input 40 for another example of how to calculate this.

Customer / General

Customer information is taken from combining the entire utility system (across all grids).

43) Electricity Sold (MWh)

Electricity Sold is the total electricity billed to customers in MWh.

44) Total Number of Customers at Start of Benchmarking Period

This is the number of customers at the start of the benchmarking period. A customer is defined here as a connection, therefore the total number of customer connections to the grid is to be provided.

45) Total Number of Customers at End of Benchmarking Period

This is the total number of customers (connections) at the end of the benchmarking period.

46) Number of Households (Domestic Customers) Supplied

The number of domestic connections to the network. This includes domestic customers across all grids. Take the number of domestic connections at the end of the reporting period.

47) Total Number of Households in the Country

The total number of households in the country. This may be obtained from the government entity responsible for national statistics/census.

48) Lifeline Tariff Usage

A Lifeline Tariff is a reduced electricity rate provided for households to assist the poor with basic electricity needs. Indicate if a lifeline tariff exists by selecting “Yes” or “No”.

49) Lifeline Tariff – Maximum Threshold for Monthly Consumption

The threshold monthly consumption is the maximum kWh consumption below which the lifeline tariff applies.

For example, a lifeline tariff rate (that may be significantly cheaper than the general rate) may be applied for domestic users who use less than, for example 150kWh/month.

Please indicate the tariff rate in the space provided in the spreadsheet.

50) Tariff Schedule

A copy of the tariff schedule for the utility should be provided. Select “Yes” once the tariff schedule has been attached.

51) Total Electricity Billed Under Lifeline Tariff (MWh)

The total electricity billed to customers under Lifeline Tariff in MWh.

52) Total Domestic Electricity Billed (MWh)

The total electricity billed to customers under domestic tariff in MWh.

53) Total Commercial Electricity Billed (MWh)

The total electricity billed to customers under the commercial tariff in MWh.

54) Total Industrial Electricity Billed (MWh)

The total electricity billed to customers under the industrial or maximum demand tariff in MWh.

55) Total Other Electricity Billed (MWh)

The total electricity billed to customers under the industrial or maximum demand tariff in MWh.

56) Total Unbilled Usage (MWh)

This includes any metered but unbilled electricity usage, such as unbilled electricity used by Head Office, Depots, Water Services, street lights, etc. Where a utility is involved in other services such as water supply, and the other service has not been billed internally, the energy provided for this service is to be included here.

57) Self Regulated or External Regulated

In some countries, the Act gives the utility the power to regulate the electricity supply industry in said country. This is self-regulation. External regulation is where the regulation of the electricity supply industry is the responsibility of an entity or a government department separately operated from the utility.

Indicate if the utility is self regulated or externally regulated by using the selection box provided.

58) Do you have a maintenance plan for your utility?

Please indicate if the utility has a maintenance plan by selecting “Yes” or “No”. This may cover generation, transmission, or distribution; and it may be in the form of a report, schedule or tabulation. If a maintenance plan exists, please attach it with the utility’s submission.

Finance

The financial results take into account both utility and IPP generation and expenses, across all grid networks.

All financial inputs are expressed in local currency as specified by the user.

Refer to Appendix C for financial inputs that can be sourced from the utility's Profit and Loss Statement and Balance Sheet. The financial reports for the Fiji Electricity Authority 2010 are used for this illustration. The Profit & Loss statement is referred to as the Statement of Comprehensive Income and the Balance Sheet as Statement of Financial Position.

Depreciation

Depreciation (or amortisation) is a method of allocating the cost of a tangible asset over its useful life. Businesses depreciate long-term assets for both tax and accounting purposes.

Depreciation is used in accounting to try and match the expense of an asset to the income that the asset helps the company earn. For example, if a company buys a piece of equipment for $1 million and expects it to have a useful life of 10 years, it will be depreciated over 10 years. Every accounting year, the company will expense $100,000 of the value of the equipment (assuming straight-line depreciation), which will be matched with the money that the equipment helps to make each year.[1]

59) Depreciation Generation Assets (Local Currency)

The value by which generation assets have been depreciated over the benchmarking period.

60) Depreciation Transmission & Distribution Assets (Local Currency)

The value by which all transmission and distribution assets have been depreciated over the benchmarking period.

61) Other Depreciation (Local Currency)

All depreciation costs not included in Generation, Transmission or Distribution.

62) Total Operating Revenue (Local Currency)

Total Operating Revenue is revenue earned from electricity sales. This data can be found in the Profit & Loss Statement.

[1] Reference: http://www.investopedia.com/terms/d/depreciation.asp#ixzz1zYO6UHCe

63) Total Operating Expenses (Local Currency)

Total Operating Expenses excluding depreciation, interest and tax. This can be obtained from the Profit and Loss Statement.

64) Earnings Before Interest & Tax (EBIT) / Operating Profit (Local Currency)

Earnings Before Interest and Taxes (EBIT) or Operating Profit equals the sales revenue minus the cost of goods sold and all expenses except for interest and taxes. This is the surplus generated by operations. It can be obtained from the Profit and Loss Statement and represents the Operating Profit earned by the business after employing capital provided by owners and long-term lenders. It is also known as 'Operating Profit' Before Interest and Taxes (OPBIT) or simply Profit before Interest and Taxes (PBIT).[2]

65) Profit After Tax (PAT) / Earnings After Tax (EAT) (Local Currency)

Profit after Tax (NPAT) or Earnings after Tax (EAT) equals sales revenue after deducting all expenses, including interests and taxes.[3] It represents the earning generated by the business for the owners of the business and can be obtained from the Profit and Loss Statement.

66) Long Term Debt / Non Current Liability (Local Currency)

Long Term Debt / Non Current Liability represents the funds obtained from loans, mortgages, bonds, etc. that have repayment terms longer than one year. This data can be obtained from the Balance Sheet.

67) Equity / Net Assets / Capital & Reserves (Local Currency)

Equity / Net Assets / Capital & Reserves represent the owner's funds or claims the owners have on the business. In many Pacific Island utilities the government is the owner of the business.

68) Non Current Assets at End of Previous Period (Local Currency)

This represents the assets that are consumed over a period of more than a year. Land, buildings, machinery, generators, transformers, cables, overhead lines and transport equipment are examples of such assets. Also referred to as Fixed Assets, this data can be obtained from the Balance Sheet for the end of the period previous to the benchmarking period.

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[2] Reference: Wikipedia – EBIT
[3] Reference: Wikipedia – Profit after Tax

69) Non Current Assets at End of Benchmarking Period (Local Currency)

This represents the assets that are consumed over a period of more than a year. This data can be obtained from the Balance Sheet at the end of the benchmarking period.

70) Current Assets (Local Currency)

Current Assets represent the value of all assets that are reasonably expected to be converted into cash within one year in the normal course of business. Current assets include cash, accounts receivable, inventory, marketable securities, prepaid expenses and other liquid assets that can be readily converted to cash. Current Assets are reported on the Balance Sheet.[4]

71) Current Liabilities (Local Currency)

Current Liabilities represent a company's debts or obligations that are due within one year. Current Liabilities include short-term debt, accounts payable, accrued liabilities and other debts. Current Liabilities are reported on the Balance Sheet.[5]

72) Debtors / Receivables at Period End (Local Currency)

Accounts Receivable also known as Debtors, is money owed to a business by its clients (customers) and shown on its Balance Sheet as an asset.[6]

73) Are Utility Finances Independently Audited?

Indicate if the utility finances are independently audited, and if so, by whom. Chose Y for yes and N for No.

74) What is the Accounting Standard Used By the Utility?

Indicate the accounting standard used. For example US GAP, IAS, IPSA. If no standard is used type “None”.

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[4] Reference: http://www.investopedia.com/terms/c/currentassets.asp#ixzz1zZjl8RzZ
[5] Reference: http://www.investopedia.com/terms/c/currentliabilities.asp#ixzz1zZkBiBCy
[6] Reference: Wikipedia – Debtors

Generation Expenditure

75) Hydrocarbon Based Fuel & Lubricating Oil Expenditure (Local Currency)

Hydrocarbon based fuels are Distillate Fuel Oil, Heavy Fuel Oil, Biofuels and Coconut oil. The total expenditure would include:

1. Total costs of purchasing these fuels for electricity production.
2. Where the fuel, such as coconut oil is produced internally, then the total costs of purchasing copra and extracting the oil for use as fuel.
3. The expenditure for Lubricating oil.

Bio-mass and LNG for electricity generation is to be excluded.

76) Duty on Hydrocarbon Based Fuel & Lubricating Oil (Local Currency)

Some governments charge duty and other taxes on fuel while others allow the utility to purchase fuel at duty free rates. This input includes duty and any other taxes applicable to fuel and lubricating oil.

77) Total Generation O&M Costs (Local Currency)

The Total Generation Operations and Maintenance (O&M) Costs is the total cost for the operations and maintenance of the utility generation assets in the local currency. This includes the costs for parts, repair and maintenance activities, supplies for power stations and other costs incurred by generation operations and maintenance.

These costs do not include:

- Fuel and lubricating oil, labour and staffing costs;
- IPP costs;
- Depreciation of generation assets;
- Financing costs;
- Transmission & Distribution costs;
- Overheads and any other costs not incurred by generation operations and maintenance.

78) Generation Labour (Local Currency)

Generation labour includes all expenditure on labour incurred in the generation of electricity. This includes all normal hours of work, overtime, allowances, statutory deductions such as pension deductions and training expenses.

Transmission/ Distribution Expenditure

79) Transmission & Distribution O&M Costs (Local Currency)

The Distribution Operations and Maintenance (O&M) Costs is the total expenses incurred in the operations and maintenance of the distribution network, expressed in the local currency. This includes all vehicle operating costs and all other costs related to distribution operations.

Cost to be excluded are:

- Labour costs,
- Depreciation,
- Generation costs,
- Head office costs, and
- Other costs not related to distribution operations and maintenance.

80) Transmission and Distribution Labour (Local Currency)

This input includes all costs related to labour associated with the operations and maintenance of the transmission and distribution network.

Overheads/Other Expenditure

81) Other Labour Expenditure (Local Currency)

All labour expenses not included in 'Generation Labour' and 'Transmission and Distribution Labour' associated with electricity operations. Include overheads, customer service, finance, human resources, information technology and any other relevant departments.

82) Other Taxes & Duty (Local Currency)

This input includes all taxes and duty paid on supplies, equipment and services.

Do not include:

1. Personal income tax and other taxes paid on the workers behalf.
2. GST, VAT or any other form of sales tax.
3. Duty and Taxes on fuel and oil.

83) Other Expenditure (Local Currency)

All other expenditure not included in any of the previous data inputs.

SECTION 3: Key Performance Indicators

The Key Performance Indicators (KPIs) that are being calculated in the 2012 Benchmarking round are provided in the table below. This list was determined upon review of the 2011 Benchmarking Report recommendations for improving the quality of information in future benchmarking exercises.

The KPIs are presented in the following categories:

- Generation
- Transmission
- Distribution
- Demand Side Management
- Human Resources / Safety
- Customers / General
- Finance

The 2012 benchmarking KPIs are provided in Table 3.1.

Table 3.1: 2012 Benchmarking KPIs

KPI #	Indicator Name	Value	Unit
	Generation		
1	Load Factor		%
2	Capacity Factor		%
3	Availability Factor		%
4	Generation Labour Productivity		GWh/FTE generation employee
5	Specific Fuel Oil Consumption		kWh/L
6	Lube Oil Consumption		kWh/L
7	Forced Outage		%
8	Planned Outage		%
9	Generation O&M Costs		USD/MWh
10	Power Station Usage		%
11	Renewable Energy to Grid		%
12	IPP Energy Generation		%
13a	Distillate Generation		%
13b	Heavy Fuel Oil Generation		%
13c	Biofuel Generation		%
13d	Mixed Fuel Generation		%

13e	LNG Generation		%
14	Enabling Framework for Private Sector		
	Transmission		
15	Transmission Losses		%
16	Transmission Reliability		outage events/km
17	Average Transmission Outage Duration		h
	Distribution		
18	Network Delivery Losses		%
19	Distribution Losses		%
20	Customers per Distribution Employees		customers/distribution employee
21	Distribution Reliability		events/100km
22	Distribution Transformer Utilisation		%
23	Transmission/Distribution O&M Cost		USD/km
24	SAIDI		customer-mins
25	SAIFI		customer interruptions
	Demand Side Management		
26	DSM Initiatives		
27	DSM Budget		USD
28	DSM FTE Employees		#
29	DSM MWh Savings		MWh
30	Power Quality Standards		
	Human Resources / Safety		
31	Lost Time Injury Duration		days/ employee
32	Lost Time Injury Frequency Rate		events per million hours worked
33	Labour Productivity		%
	Customers / General		
34	Service Coverage		%
35	Productive Electricity Usage		%
36a	Lifeline Tariff Usage		%
36b	Domestic Usage		%
36c	Commercial Usage		%
36d	Industrial Usage		%
36e	Other Usage		%
37	Customer Unbilled Electricity		%
38	Self Regulated or Externally Regulated		
	Financial Indicators		
39	Operating Ratio		%
40	Debt to Equity Ratio		%
41	Rate of Return on Assets		%
42	Return on Equity		%
43	Current Ratio		%
44	Debtor Days		days
45	Average Supply Cost		US c /kWh
46	Per Unit Costs Breakdown		

a	Depreciation Generation Assets		%
b	Hydrocarbon Based Fuel & Lube Oil Expenditure		%
c	Duty and Taxes on Hydrocarbon Based Fuel & Lube Oil		%
d	Generation O&M Costs (utility)		%
e	Generation Labour		%
f	Transmission/ Distribution O&M Cost		%
g	Transmission/ Distribution Labour		%
h	Depreciation Transmission & Distribution Assets		%
i	Other Labour Expenditure		%
j	Other Duty/ Taxes		%
k	Other Expenditure		%
l	Other Depreciation		%

Colour Code

Data that is **bold and in maroon font** is inputted directly from the 2012 Questionnaire Data Inputs Sheet. Data that is **bold and in grey font** is a factor calculated using inputs from the 2012 Questionnaire Data Inputs Sheet. Some of the equations require that local currency be converted to USD for the calculation of the KPI. Where this is the case, the currency inputs are shown in **bold and in grey font**, as the other calculated factors.

Generation

I) Load Factor (%)

$$\text{Load Factor (\%)} = \frac{[\mathbf{Gross\ Generation\ (MWh)}] * 100}{\mathbf{Maximum\ Demand\ (MW)} * 8{,}760\ \text{h}}$$

Demand for electricity varies throughout the day and this necessitates scheduling of generating units to match demand. The ‘Load Factor’ indicates a key characteristic of demand. A high load factor indicates a lower variation in demand with respect to time, and vice-versa. In a graph of demand against time, a load factor of 100% would be a straight line.

A low load factor may mean generators more frequently start and stop, resulting in lower efficiency.

Investment in capacity is largely determined by the maximum demand. For loads with equal maximum demand but different load factors, the load with a higher load factor would produce a better utilization of the generating capacity and subsequently a higher return on investment in generation capacity.

The higher the load factor the better the economics of operating the system.

Load factor can be influenced by lower off peak tariffs/ higher peak demand tariffs, demand side management and peak load shedding.

Target: 50% to 80%

2) Capacity Factor (%)

$$\text{Capacity Factor (\%)} = \frac{[\textbf{Gross Generation (MWh)}] * 100}{\textbf{Total Installed Generation Capacity(MW)} * 8760\text{ h}}$$

The investment in generation capacity is determined by several factors:

- Maximum demand
- Redundant capacity to enable outages for planned maintenance
- Spinning reserve policy
- Capacity required for standby purposes
- Other factors such as transmission capabilities and risks

Total Installed Generation Capacity includes both the utilities' generators and that of Independent Power Producers' (IPPs). Capacity factor indicates capacity utilisation and the risk of insufficient capacity. A higher utilisation is desirable - it indicates better use of the generating capacity to produce energy. On the other hand, too high of a capacity factor would indicate a high risk of insufficient capacity to meet demand during the peak.

Target: ≈ 40%

3) Availability Factor (%)

$$\text{Availability Factor (\%)} = \frac{\left[\begin{array}{c}(\textbf{Total Installed Generation Capacity (MW)} * 8760\text{h}) - \\ \textbf{Total Capacity Hours Out of Service (MWh)}\end{array}\right] * 100}{\textbf{Total Installed Generation Capacity (MW)} * 8{,}760\text{ h}}$$

Generation capacity may become unavailable for operation due to various reasons, such as:

- Forced outages: due to faults on the generator, connecting equipment or transmission network, breakdowns of the diesel engine and instability that may require the generator to be taken out for repairs.
- Planned outages: due to routine maintenance of the generator and engine, connecting equipment or transmission network.
- De-rating of the generator or connection equipment. Here the generator is available to supply the network however due to temporary limitations it cannot generate up to full capacity. The capacity by which the generator is de-rated becomes unavailable for generation until such time as it is restored to full capacity generation.

Note: where a generator is de-rated permanently, the de-rated capacity becomes the rating of that generator when determining the "Installed Generation Capacity".

Target: 80% to 90%

4) Generation Labour Productivity (GWh/FTE Generation employee)

$$\text{Generation Labour Productivity (GWh/generation employee)} = \frac{[\textbf{Total Utility Generation (MWh)}]\ /\ 1000}{\textbf{Number of Full Time Equivalent (FTE) Generation Employees}}$$

"Full Time Equivalent (FTE)" is defined as the total number of hours paid for over a period divided by the normal hours of work for one person over that same period.

For this exercise, 40 hours per week and 50 weeks per annum (or 2000 hours per annum) is taken as equal to one FTE.

To derive the FTE Generation Employees, add the number of hours paid for generation employees. Overtime is to be included as the equation is based on hours paid for. For example, if a person works 1 hour of overtime and is paid double-time, the FTE Generation is calculated using 2 hours.

Paid hours data can be sourced from payroll records.

5) Specific Fuel Oil Consumption (kWh/L)

$$\text{Specific Fuel Oil Consumption (kWh/L)} = \frac{\textbf{Total Fuel Oil Generation (kWh)}}{\textbf{Total Fuel Usage (L)}}$$

Specific Fuel Oil consumption monitors the efficiency of generating units using hydro-carbon based fuels such as Heavy Fuel Oil (HFO), Industrial Diesel Oil (IDO), bio-diesel and mixed Biofuel/ Automotive Diesel Oil (ADO).

Specific fuel consumption is normally given in grams per kWh or (kg/kWh or Tonne/MWH) as this includes the impact of the specific gravity of fuel and more closely relates to the energy content of the fuel. The definition used for this exercise uses kWh per Litre as it is the definition used for the previous two benchmarking exercises.

The temperature at which the volume of fuel oil is measured is important. At higher temperatures the fuel expands. If not compensated for, a higher volume would be recorded and if paid for 'per litre', a higher payment for the same amount of energy would be made. This would not be an issue for fuel meters that are temperature compensated. Where temperature is not compensated, it could be adjusted manually by adjusting the volume to the standard 15˚C (59˚F) temperature. For diesel fuels the temperature coefficient would be 0.08% volume per ˚C temperature change.

Some utilities pay for fuel on a tonnage basis. This is preferable as it considers the specific gravity of fuel and the required temperature compensation is accounted for. In this way payment is directly correlated with the energy content of the fuel. Utilities are expected to provide fuel oil usage data at the standard 15˚C.

The 'Total Fuel Oil Generation' is the total kWh generated in all plants operating on HFO, ADO and Bio-diesel and mixed biodiesel/ADO.

Utilities are advised to also determine the specific fuel consumption for light diesel and HFO separately, in order to identify which machines (if any) are operating inefficiently.

HFO despite having a lower heating value has a higher specific gravity and thus will produce up to 10% more kWh per litre of fuel.

Benchmark: > 4 kWh/ Litre

6) Lubricating Oil Consumption (kWh/L)

$$\text{Lubricating Oil Consumption (kWh/L)} = \frac{\textbf{Total Fuel Oil Generation (MWh)} * 1000}{\textbf{Total Lubricants Used in Generation (L)}}$$

This indicator is also best limited to carbon-based fuel oil generating units, which are the major 'consumers' of lubricating oil.

This indicator is only useful over a long period such as a year. On a monthly basis it can have large variation as servicing may occur every several months depending on hours of operations.

On an annual basis, the lubricating oil consumption figure indicates the quality of maintenance done on a generating unit.

Benchmark: 500 to 700 kWh/Litre for units up to 1 MW capacity
1,000 to 1,300 kWh/ Litre for units of 4-5 MW capacity

7) Forced Outage (%)

$$\text{Forced Outage (\%)} = \frac{\left[\sum_{n=\text{Utility}}^{[\text{Utility,IPP}]} \left(\begin{array}{l}\textbf{n Capacity Hours Out of Service Due to Generation Forced Outage Events(MWh)} + \\ \textbf{n Capacity Hours Out of Service Due to Generation Derated Outage Events(MWh)}\end{array}\right)\right] * 100}{\textbf{Total Installed System Generation Capacity (MW)} * \textbf{8760h}}$$

Forced outages are:

- Outages due to unplanned events such as faults on the generating unit or connecting equipment to the grid;
- Outages as a result of human or operator error; or
- De-rated capacity as a result of temporary limitation imposed on the generating unit.

To determine Unavailable Capacity Forced, a record of every fault event needs to be kept. The key data to be extracted from the report is the length of time the generator was unavailable. This would extend from the time of the fault to the time the unit is restored and made available for operations, or for de-rating events, from the time the unit was de-rated to the time it was restored to full capacity.

The Unavailable Capacity Forced for a generator is the capacity of the generator multiplied by the hours unavailable.

The sum of unavailable capacity in MWh for all events during the period is the ‘Unavailable Capacity Forced’ used to determine this indicator.

Benchmark: less than 5%

8) Planned Outage (%)

$$\text{Planned Outage (\%)} = \frac{\sum_{n=\text{Utility}}^{[\text{Utility,IPP}]} \left(\textbf{n Capacity Hours Out of Service Due to Generation Planned Outage Events (MWh)}\right) * 100}{\textbf{Total Installed System Generation Capacity (MW)} * 8760\text{h}}$$

A planned outage is the time a generator is down as a result of planned maintenance such as servicing and overhauls on the generating unit or equipment connecting it to the grid. To calculate the numerator for this indicator, determine and sum the unavailable capacity hours out of service for each outage event.

Benchmark: less than 5%

9) Generation Operations and Maintenance (O&M) Cost (USD per MWh)

$$\text{Generation O\&}M\ (\text{USD}/MWh) = \frac{\textbf{Total Generation O\&}\mathit{M\ Costs}\ \textbf{(USD)}}{\textbf{Total Utility Generation (MWh)}}$$

Costs are to be provided in the local currency. Conversion to USD will be performed by the Benchmarking Team who will prepare the final benchmarking report.

Generation Expenditure includes all costs related to generation such as labour/staffing, repairs, parts, etc.

This cost does not include fuel, oil and IPP purchases as other indicators capture these costs . This indicator may be used to monitor all other generation costs.

Benchmark: $18.00 per MWh

10) Power Station Usage (%)

$$\text{Power Station Usage (\%)} = \frac{\textbf{Power Station Usage / Station Auxiliaries (MWh)} * 100}{\textbf{Total Utility Generation (MWh)}}$$

This indicator looks at the energy consumed in utility operated power stations (including auxiliaries) as a percentage of Total Utility Generation.

Where the power station is supplied from the power station bus through a separate circuit breaker from the generator main circuit breaker, the meter (if available) on the power station supply circuit breaker would provide the Power Station-Auxiliary Power.

This indicator may be used to monitor the energy used in power stations to generate the energy for customers.

Benchmark: Less than 5%

11) Renewable Energy to Grid (%)

$$\text{Renewable Energy to Grid (\%)} = \frac{\textbf{Total Renewable Energy Generation (MWh)}}{\textbf{Gross Generation (MWh)}}$$

Renewable Energy Generated is the total energy generated from renewable sources such a hydro, wind, solar, bio-mass, bio-fuels, etc.

This includes all utility generated and IPP generated renewable energy. The unit of measure is MWh.

Benchmark specific to each utility.

12) IPP Energy Generation (%)

$$\text{IPP Energy Generation (\%)} = \frac{\textbf{Total IPP Generation Purchased (MWh)} * 100}{\textbf{Gross Generation (MWh)}}$$

IPP Energy Generation is the total energy purchased from IPPs. This indicates the level of participation of the private sector in energy generation for the utilities.

Benchmark specific to each utility.

13) Generation by Source

a) Distillate Generation (%)

$$\text{Distillate Generation } (\%) = \frac{\textbf{Distillate Energy Generation (MWh)} * 100}{\textbf{Gross Generation (MWh)}}$$

Distillate Generation is the total energy generated by ADO/IDO fuelled generators. This indicator looks at the percentage of the total generation generated from distillate fuel.

Benchmark: Individually set by each utility. In general, the desire is to reduce this generation as fuel costs are high.

b) Heavy Fuel Oil Generation (%)

$$\text{Heavy Fuel Oil Generation } (\%) = \frac{\textbf{Heavy Fuel Oil Generation (MWh)} * 100}{\textbf{Gross Generation (MWh)}}$$

Heavy Fuel Oil (HFO) generation is the total energy generated using heavy fuel oil as a percentage of total Generation. HFO is usually installed as a cheaper alternative to distillate.

Benchmark specific to each utility.

c) Biofuel Generation (%)

$$\text{Biofuel Generation } (\%) = \frac{\textbf{Biofuel Generation (MWh)} * 100}{\textbf{Gross Generation (MWh)}}$$

Biofuel generation is the total energy generated using biofuels. The biofuel is usually bio-diesel.

Benchmark specific to each utility.

d) Mixed Fuel Generation (%)

$$\text{Mixed Fuel Generation } (\%) = \frac{\textbf{Mixed Fuel Generation (MWh)} * 100}{\textbf{Gross Generation (MWh)}}$$

Mixed Fuel Generation refers to fuels that comprise a mix of bio-fuel and distillate. This is typically coconut oil or bio-diesel mixed with IDO/ADO.

Benchmark is specific to each utility.

e) LNG Generation (%)

$$\text{LNG Generation } (\%) = \frac{\textbf{LNG Generation (MWh)} * 100}{\textbf{Gross Generation (MWh)}}$$

Liquid Natural Gas (LNG) generation is the energy generated from LNG.

Benchmark is specific to each utility as it is dependent on the availability of resources.

14) Enabling Framework for Private Sector Participation

This looks at whether a utility has in place a framework for facilitating the participation of the private sector in power generation.

Transmission

15) Transmission Losses (%)

$$\text{Transmission Losses } (\%) = \frac{[\textbf{Net Generation (MWh)} - \textbf{Electricity Delivered to Distribution Network (MWh)}] * 100}{\textbf{Net Generation (MWh)}}$$

This indicator looks at the energy losses resulting from the delivery of electricity across the transmission network. This would include energy consumed in the utilities substations if this is not metered and accounted for.

Net Generation is the total energy delivered to the transmission network from the generating stations and IPPs.

Electricity Delivered to the Distribution Network is the total energy measured at the demarcation points between transmission and distribution networks flowing in the direction of the distribution network from the transmission network.

16) Transmission Reliability (events per 100 km of line)

$$\text{Transmission Reliability (outage events per 100 km of line)} = \frac{\textbf{Number of Unplanned Transmission Outage Events (events)} * 100}{\textbf{Length of Transmission Line (km)}}$$

This indicator looks at the reliability of the transmission network in terms of unplanned or forced outages as a result of faults on the transmission network.

The indicator is faults per 100 km of transmission line.

17) Average Transmission Outage Duration (hrs per event)

$$\text{Average Transmission Outage Duration(hrs)} = \frac{\textbf{Total Duration of Unplanned Transmission Outage Events (events)}}{\textbf{Number of Unplanned Transmission Outage Events (events)}}$$

Distribution

18) Network Delivery Losses (%)

$$\text{Network Delivery Losses (\%)} = \frac{[\textbf{Net Generation (MWh)} - \textbf{Electricity Sold (MWh)}] * 100}{\textbf{Electricity Sold (MWh)}}$$

Where a utility cannot separate transmission and distribution losses, the combined losses can be determined by this indicator.

19) Distribution Losses (%)

$$\text{Distribution Losses (\%)} = \frac{[\textbf{Electricity Delivered to Distribution Network (MWh)} - \textbf{Electricity Sold (MWh)}] * 100}{\textbf{Electricity Delivered to Distribution Network (MWh)}}$$

This indicator looks at the energy losses resulting from the delivery of electricity across the distribution network. This would include energy consumed in the utilities substations if it is not metered and accounted for.

Electricity Delivered to the Distribution Network is the total energy measured at the demarcation points between transmission and distribution. Where a utility does not have a transmission network, the electricity delivered to the Distribution Network would be equal to the Net Generation.

Benchmark: Less than 5%

20) Customers Per Distribution Employee

$$\text{Customers Per Distribution Employee (customers per distribution employee)} = \frac{\textbf{Average Number of Customers (connections)}}{\textbf{Average Number of Distribution and Customer Service Employees (employees)}}$$

The greater the customers per distribution employee, the better labour is utilised and more efficient the operation.

Benchmark is specific to each utility.

21) Distribution Reliability (events per 100 km of line)

$$\text{Distribution Reliability (events per 100 km of line)} = \frac{\textbf{Number of Distribution Forced Outage Events (events)} * 100}{\textbf{Length of Distribution Line (km)}}$$

This indicator looks at forced outage events per 100 km of distribution lines and cables.

22) Distribution Transformer Utilisation (%)

$$\text{Distribution Transformer Utilisation (\%)} = \frac{\textbf{Electricty Sold (MWh)} * 100}{\textbf{Total Distribution Transformer Capcity (MVA)} * 8760\text{h}}$$

This indicator looks at the total energy delivered to consumers on the low voltage network through distribution transformers.

Total Distribution Transformer Capacity is calculated by adding up the capacity (nameplate rating) of all distribution transformers installed on the distribution network.

The Distribution Transformer Utilisation indicates the effectiveness of distribution planning in matching transformer capacity with demand. A low utilisation implies a greater investment in distribution transformers. A higher utilisation implies higher efficiency in capital outlay on the distribution network (or on the other side of the scale, deferred capacity upgrade and erosion of security margins)

Benchmark: Greater than 30%.

23) Transmission/Distribution Operations and Maintenance Costs (USD per km line)

$$T\&D\ Operations\ \&\ Maintenance\ Cost(USD/km) = \frac{\mathrm{T\&D}\ O\&M\ \mathbf{Costs\ (USD)}}{\mathbf{Length\ of\ Distribution\ Line\ (km)}}$$

The total cost of operating and maintaining the distribution network on a per km line (overhead line and underground cable).

24) System Average Interruption Duration Index (SAIDI) (mins per customer)

$$\mathrm{SAIDI\ (minutes)} = \frac{\mathbf{Total\ Customer\ Interruptions\ Duration\ Interrupted\ (cust\ hr)} * 60}{\mathbf{Average\ Number\ of\ Customers\ (connections)}}$$

Total Customer Interruptions Duration Index is found by summing the customer interruptions duration for each customer interruption event. This includes both planned and forced events. For example, if a forced outage causes 10 customers to experience a power cut of 2 hours, the Customer Interruptions Duration for this event is 10 x 2 = 20 customer hours. If another outage affects 20 customers for 3 hours, Customer Interruptions Duration is 60 customer hours.

The total Customer Interruptions Duration Interrupted for these two events is 20 + 60 = 80 customer hours.

SAIDI indicates the average power outage duration experienced by a customer during the benchmarking period. When determining SAIDI and SAIFI the following internationally accepted convention applies:

1. Only outages caused by faults and planned outages on the high voltage distribution network, transmission lines and generators that result in interruption to power supplied to a customer is to be taken into consideration. Outages on the low voltage network are to be excluded.
2. Only outages of more than a minute are to be considered. Momentary outages such as those caused by an auto-recloser which has successfully reclosed should be excluded. However, where the recloser has locked out, then the outage should be included.

Benchmark: 200 customer minutes

25) System Average Interruption Frequency Index (SAIFI) (events per customer)

$$\text{SAIFI } (\%) = \frac{\textbf{Total Customer Interruptions}}{\textbf{Average Number of Customers (connections)}}$$

The 'Total Customer Interruptions' is the sum of the customer interruptions for each outage including both forced and planned interruptions. A customer interruption for a power outage is the total customers interrupted for the event. For example, if two power outages affect 300 and 500 customers respectively, the total customer interruption is 300 + 500 = 800.

SAIFI indicates the average number of outages a customer experienced for the period.

Demand Side Management

These indicators reflect the extent to which demand side management is undertaken by each utility.

26) Actively Engaged in Demand Side Management Initiatives

A utility's engagement in Demand Side Management (DSM) initiatives indicates a proactive approach to changing consumer behaviour and reducing electricity demand. When applied to unbilled electricity consumption, such as power station auxiliary usage and the consumption in head office or government buildings, this will have a positive affect reducing Power Station Usage (KPI 10) and reducing Customer Unbilled Electricity Usage (KPI 37), with subsequent reduction in fuel usage translating to an increased profit margin. When applied to domestic, commercial or industrial consumers, behaviour can be changed to result in a lower demand being placed on overloaded generator resources and to change the demand profile to achieve a demand that can be met with more efficient operation.

27) Demand Side Management Budget

A utility's DSM budget is reflective of the focus being placed on DSM activities. Goals for changing consumer behaviour to reduce demand or change consumption patterns require resourcing and adequate budgeting.

28) Full Time Equivalent Employees Involved in Demand Side Management Initiatives

Like the DSM budget, a utility's number of FTE employees involved in DSM activities indicates the focus being placed on DSM activities. Goals for changing consumer behaviour require adequate human resourcing.

29) Recorded Savings By Consumers Through Demand Side Management Initiatives

A successful DSM Program will be shown through a reduction of power usage and recorded savings.

30) Power Quality Standards

Power quality standards are important in determining the degree that power reflects the ideal electricity signal with constant magnitude and frequency sinusoid voltage wavelength. Having a power quality standard provides a method to monitor power quality. Good network power quality will result in efficient distribution. Poor network power quality will ultimately result in financial loss through increased distribution losses, damage to equipment and unplanned outages.

Human Resources

31) Lost Time Injury Duration Rate (Days per employee)

$$\text{Lost Time Injury Duration Rate (days)} = \frac{\text{Total Days Lost Due to Work Injury During Period (days)}}{\textbf{Total Number of Employees (employees)}}$$

A Lost Time Injury (LTI) is defined as an incident where an employee is absent from work for one day/shift due to injury. Australian Standards AS18851 provides guidelines for this indicator.

Benchmark: less than 5 days

32) Lost Time Injury Frequency Rate (Injuries per million hours)

$$\text{Lost Time Injury Frequency Rate} = \frac{\text{Number of Lost Time Injuries During Period (LTIs)} * 1{,}000{,}000\ \text{h}}{\textbf{Total Hours Worked (h)}}$$

The frequency rate is the number of injuries resulting in lost time, for each one million hours worked.

Benchmark: less than 2 per million hours

33) Labour Productivity (customers per employee)

$$\text{Labour Productivity } (\%) = \frac{\textbf{Average Number of Customers (customers)} * 100}{\textbf{FTE Utility}}$$

Labour Productivity looks at the number of customers per FTE Utility. Paid hours is the total hours paid for labour and includes contractors engaged in the operations and maintenance of the system. FTE is the full time equivalent determined by the total paid normal hours for one person for one year (2000 hours). The total paid hours divided by FTE gives the FTE Utility. The total paid hours does not include the labour hours engaged for capital expenditure projects.

Customers

34) Service Coverage (%)

$$\text{Service Coverage } (\%) = \frac{\textbf{Number of Households Supplied (Domestic Connections)(households)} * 100}{\textbf{Total Number of Households in Country (households)}}$$

This indicator looks at the electricity coverage with respect to the country served by the utility. It also indicates the potential market yet to be served by the utility.

35) Productive Electricity Usage (%)

$$\text{Productive Electricty Usage } (\%) = \frac{\begin{gathered}\textbf{Total Commercial Electricty Billed (MWh)} + \\ \textbf{Total Industrial Electricty Billed (MWh)} \\ \textbf{Total Other (Productive) Electricity Billed (MWh)} * 100\end{gathered}}{\textbf{Electricty Sold (MWh)}}$$

It is assumed that the electricity billed to commercial and industrial customers is productive for the economy. Based on this assumption, this indicator captures the productive economic impact of electricity supply. It ignores the economic impact of domestic supply and other categories.

36) Customer Usage

a) Lifeline Tariff Usage (%)

$$\text{Lifeline Tariff Usage (\%)} = \frac{\textbf{Total Electricty Billed Under Lifeline Tariff (MWh)} * 100}{\textbf{Electricty Sold (MWh)}}$$

Lifeline tariff is usually a lower price to assist low income household customers. Lifeline tariff is applied differently by utilities that offer this category. Some utilities only bill customers with this tariff whose monthly usage is below the threshold, while other utilities provide this tariff to all customers up to the threshold and the normal tariff for the additional units consumed above the threshold.

This indicator looks at the percentage (%) of electricity sold under the lifeline tariff.

b) Domestic Usage (%)

$$\text{Domestic Usage (\%)} = \frac{\textbf{Total Domestic Electricty Billed (MWh)} * 100}{\textbf{Electricty Sold (MWh)}}$$

The portion of electricity sold for domestic use.

c) Industrial Usage (%)

$$\text{Industrial Usage (\%)} = \frac{\textbf{Total Industrial Electricty Billed (MWh)} * 100}{\textbf{Electricty Sold (MWh)}}$$

The portion of electricity sold for industrial use. This includes customers on the maximum demand tariff.

d) Commercial Usage (%)

$$\text{Commercial Usage (\%)} = \frac{\textbf{Total Commercial Electricty Billed(MWh)} * 100}{\textbf{Electricty Sold (MWh)}}$$

The portion of electricity sold to commercial customers.

e) Other Usage (%)

$$\text{Other Usage (\%)} = \frac{\textbf{Total Other Electricty Billed (MWh)} * 100}{\textbf{Electricty Sold (MWh)}}$$

The portion of electricity sold to customers other than any of the customers in a) to d).

37) Customer Unbilled Electricity Usage (%)

$$\text{Customer Unbilled Elecricity Usage(\%)} = \frac{\textbf{Total Unbilled Electricity Usage (MWh)}}{\textbf{Electricity Sold (MWh)} + \textbf{Total Unbilled Electricty Usage (MWh)}}$$

This represents the electricity that is metered but is not billed to any consumer. This would include utility head office and depot electricity usage, public goods such as street lights or water supply where the utility is responsible for them, and any other activity that the utility may be responsible for.

38) Self Regulated or Externally Regulated

External regulation is usually indicative of higher quality standards being imposed on a utility than when a utility is self regulated.

Financial

39) Operating Ratio (%)

$$\text{Operating Ratio} = \frac{\textbf{Total Operating Expenses(local currency)} + \textbf{Depreciation (local currency)} * 100}{\text{Total Operating Revenue (local currency)}}$$

A measure of how much income is consumed by the business to produce and supply electricity.

40) Debt to Equity Ratio (%)

$$\text{Debt to Equity Ratio (\%)} = \frac{\textbf{Long Term Debt/Non Current Liability (local currency)}}{\text{Equity/Net Assets/Capital Reserves (local currency)} + \textbf{Long Term Debt/Non Current Liability (local currency)}} * 100$$

This looks at the gearing of the business. Gearing is a measure of financial leverage, demonstrating the degree to which a firm's activities are funded by the owner's funds versus creditor's funds. The higher the gearing, the greater the risk. When the business is performing well higher returns are generated for the owners. When losses are incurred the impact on the owner is increased.[7]

The optimum gearing ratio is specific for each industry. For the utility business in the Pacific a Benchmark of 50% is deemed suitable.

41) Rate of Return on Assets (%)

$$\text{Rate of Return on Assets(\%)} = \frac{\textbf{Earnings Before Interest and Tax EBIT/Operating Profit (local currency)} * 100}{\text{Average Non Current Assets (local currency)}}$$

The rate of return on assets is the return generated from the investment in the assets of the business.

Earnings Before Interest Tax (EBIT) is the operating profit generated by the business after all operating costs including depreciation have been deducted from the income.

42) Return on Equity (%)

$$\text{Return on Equity (\%)} = \frac{\textbf{Profit After Tax/Earnings After Tax (local currency)} * 100}{\text{Equity/Net Assets/Capital Reserves (local currency)}}$$

Return on Equity is the returns generated by the business for the owners of the business. In most utilities in the Pacific the owners of the utility is the government.

Profit after tax (PAT) is the profit after interest is paid on funds from debt financiers and tax is paid to Government.

[7] http://www.investopedia.com/terms/g/gearingratio.asp#ixzz20LyA4V1V

43) Current Ratio (%)

$$\text{Current Ratio (\%)} = \frac{\textbf{Current Assets (local currency)} * 100}{\text{Current Liabilities (local currency)}}$$

Current ratio indicates the ability of a utility to meet its short term liabilities (liabilities due within 12 months).

Where the ratio is less than 100%, there is a risk that should the suppliers and liability owners' call on payment the utility would not be able to make all payments.

44) Debtor Days (%)

$$\text{Debtor Days (days)} = \frac{\textbf{Debtors/Receivables at Period End (local currency)} * 365}{\text{Total Operating Revenue (local currency)}}$$

Debtor days measure the effectiveness of collecting revenue for electricity sold. A high debtor days indicates that bills are not being paid in time and this would put pressure on the utility in terms of working capital demand.

Benchmark is less than 50 days.

45) Average Supply Cost (USD per MWh)

$$\text{Average Supply Cost (USD/MWh)} = \frac{\textbf{Total Operating Expenses (USD)}}{\text{Electricity Sold (MWh)}}$$

The unit costs of supplying electricity.

46) Per Unit Breakdown of costs (%/unit)

$$\text{component (local currency/MWh)} = \frac{\text{Costs (local currency)}}{\text{Electricity Sold (MWh)}}$$

$$\text{\% component} = \frac{\text{component (local currency)} * 100}{\text{Sum of components}}$$

The per unit costs breakdown of supplying electricity.

Components are:

- Hydro-carbon based fuel & oil expenditure
- Duty & taxes on fuel & oil
- Generation O&M utility
- Generation labour
- Depreciation generation assets
- Transmission/ distribution O&M cost
- Transmission/ distribution labour
- Depreciation transmission and distribution assets
- Other labour expenditure (customer service, head office, finance, HR, others)
- Other expenditure
- Other duty/ taxes
- Other depreciation

Calculated Factors

A. Gross Generation

$$\text{Gross Generation (MWh)} = [\textbf{Total Utility Generation Capacity (MWh)} + \textbf{Total IPP Generation Purchased (MWh)}]$$

The total energy generated to meet system demand.

B. Net Generation

$$\text{Net Generation (MWh)} = [\textbf{Gross Generation (MWh)} - \textbf{Power Station Usage(MWh)}]$$

The total energy provided by the power stations and IPPs after deducting the energy consumed in the power stations.

C. Total Utility Generation Capacity

$$\text{Total Utility Generation Capacity (MW)} = \left[\sum_{n=1}^{\substack{\text{Total number}\\ \text{of generators}}} \left(\textbf{Generator}_{\mathbf{n}}\ \textbf{Nameplate Capacity Rating (MW)}\right)\right]$$

Utility Generation Capacity is the nameplate rating of generators. Where a generator has been permanently de-rated then the de-rated capacity should be used in place of the nameplate rating.

D. Total Installed Generation Capacity

$$\begin{aligned}\text{Total Installed Generation Capacity(MW)} &= \textbf{Total Utility Generation (MW)} \\ &+ \textbf{Total Guaranteed/Contracted IPP Generation Capacity (MW)}\end{aligned}$$

The total of the utility generator's and IPP's contracted capacity.

E. Number of Full Time Equivalent (FTE) Generation Employees

$$\text{Number of Full Time Equivalent (FTE) Generation Employees} = \frac{\textbf{Paid Hours Utility Generation Labour(h)}}{2000\ \text{(h)}}$$

The FTE number of generation employees.

F. Total Fuel Oil Generation

$$\text{Total Fuel Oil Generation (MWh)} = \sum_{n=\text{distillate}}^{[\text{distillate,HFO,biofuel,mixed fuel}]} \textbf{Generation by n (MWh)}$$

Total generation by generators operated on distillate, HFO, biofuels and mixed biofuel.

G. Total Fuel Usage

$$\text{Total Fuel Usage (L)} = \sum_{n=\text{distillate}}^{[\text{distillate,HFO,biofuel,mixed fuel,LNG}]} \textbf{Fuel Usage by n (L)}$$

See comment on F. The litres should be temperature compensated data at 15˚C (59˚F). Where a meter has temperature compensation then the meter reading is the correct data.

H. Total Utility Capacity Hours Out of Service

$$\begin{aligned}&\text{Total Utility Capacity Hours Out of Service (MWh)}\\&= \textbf{Utility Capacity Hours Out of Service Due to Generation Forced Outage Events(MWh)}\\&+ \textbf{Utility Capacity Hours Out of Service Due to Generation Planned Outage Events(MWh)}\\&+ \textbf{Utility Capacity Hours Out of Service Due to Generation Derated Outage Events(MWh)}\end{aligned}$$

Capacity hours out of service due to utility forced events, planned events and temporarily generator de-rating events.

I. Total IPP Capacity Hours Out of Service

$$\begin{aligned}&\text{Total IPP Capacity Hours Out of Service (MWh)}\\&= \textbf{Utility IPP Hours Out of Service Due to Generation Forced Outage Events(MWh)}\\&+ \textbf{Utility IPP Hours Out of Service Due to Generation Planned Outage Events(MWh)}\\&+ \textbf{Utility IPP Hours Out of Service Due to Generation Derated Outage Events(MWh)}\end{aligned}$$

Capacity hours out of service due to IPP forced events, planned events and temporarily contracted capacity de-rating events.

J. Total Capacity Hours Out of Service

$$\begin{aligned}&\text{Total Capacity Hours Out of Service (MWh)}\\&\qquad = \textbf{Total Utility Capacity Hours Out of Service (MWh)}\\&\qquad + \textbf{Total IPP Capacity Hours Out of Service (MWh)}\end{aligned}$$

Capacity hours out of service for utility and IPP generators.

K. Average Number of Distribution and Customer Service Employees

$$\text{Average Number of Distribution and Customer Service Employees (employees)} = \frac{\begin{array}{c}\textbf{Total Num. of Employees in Distribution and Customer Service at Start of Period (employees)} + \\ \textbf{Total Num. of Employees in Distribution and Customer Service at End of Period (employees)}\end{array}}{2}$$

Average number of distribution and customer service employees for the benchmarking period.

L. Average Number of Customers

$$\text{Average Number of Customers (connections)} = \frac{\begin{array}{c}\textbf{Total Number of Customers at Start of Period (connections)} + \\ \textbf{Total Number of Customers at End of Period (connections)}\end{array}}{2}$$

Average number of customers for the benchmarking period.

M. Full Time Equivalent (FTE) Utility

$$\text{FTE Utility} = \frac{\text{Total Paid Hours Employees including contractors}}{\text{FTE Annual Hours (2000)}}$$

Full Time Equivalent number of total utility employees.

N. Average Non Current Assets

$$\text{Average Non Current Assets (local currency)} = \frac{\begin{array}{c}\text{Non Current Assets at End of Previous Period (local currency)} + \\ \textbf{Non Current Assets at End of Benchmarking Period (local currency)}\end{array}}{2}$$

Average noncurrent assets for the benchmarking period.

O. Total Renewable Energy Generation

$$\text{Total Renewable Energy Generation (MWh)} = \sum_{n=\text{hydro}}^{[\text{hydro,wind,solar,biomass, geothermal,biofuel,other renewable}]} \textbf{Total Generation by n (MWh)}$$

Total energy generated by renewable sources such as solar, wind, bio-mass, bio-fuels, hydro, geothermal.

P. Total Billed Electricity Usage

$$\begin{aligned}\text{Total Billed Electricty Usage (MWh)} &= \textbf{Total Electricty Billed Under Lifeline Tariff (MWh)} \\ &+ \textbf{Total Domestic Electricty Billed (MWh)} \\ &+ \textbf{Total Comercial Electricty Billed (MWh)} \\ &+ \textbf{Total Industrial Electricty Billed (MWh)} \\ &+ \textbf{Total Other Electricity Billed (MWh)}\end{aligned}$$

Total energy billed to customers.

Q. Total Generation Costs (USD)

$$\begin{aligned}\text{Total Generation Costs (USD)} &= \textbf{Generation O\&M Costs (Utility)(USD)} \\ &+ \textbf{Generation Labour (USD)}\end{aligned}$$

R. Total Transmission and Distribution Costs (USD)

$$\begin{aligned}\text{Total Transmission and Distribution } Costs \text{ (USD)} &= \textbf{T}\&D\ O\&M\ Costs(USD) \\ &+ \textbf{Transmission/Distribution Labour (USD)}\end{aligned}$$

SECTION 4: Examples of KPI Calculations

The following section provides worked solutions to selected KPIs using the sample data provided in the questionnaire below.

Working through the results of individual utility data will assist in identifying priority areas for improvement and the formulation of the utility's Performance Improvement Plan, which is further addressed in Section 6.

PACIFIC POWER ASSOCIATION
PACIFIC POWER UTILITY BENCHMARKING STUDY
QUESTIONNAIRE SECTION 2: BENCHMARKING INFORMATION

2012 Version:17 August 2012

PACIFIC REGION INFRASTRUCTURE FACILITY
A partnership for better infrastructure services in Pacific Island Countries

Instructions:

1. Please see the attached Word document file "PPA Benchmarking 2012 - Intro and Section 1" for the Background, Introduction and Section 1 of the Questionnaire.
2. The attached word document "Explanations of Input Data 1" provides explanation of each input, with practical examples and sample calculations.
3. Both Section 1 (Word document) and Section 2 (Excel spreadsheet) will need to be completed for the 2012 Benchmarking Exercise.
4. Please enter the data or information requested in the yellow boxes indicated.
5. Reference unit conversion charts are provided on the Sheet "Reference Unit Conversion"
6. Where appropriate, please mark as follows: n.av. = not available; N/Ap = not applicable
7. All information requested (employment, costs, revenue, etc.) ***refers only to electricity operations*** . Do not include information for other services the utility may provide such as water, waste management, telecommunications, fuel supply etc.
8. Before returning the completed questionnaire, **please change the filename to indicate the utility, e.g. TAU, FEA, PNG Power, etc.**

SECTION 2: Introductory Questions

Information on person providing the information:

If the same person has completed both Section 1 and Section 2, indicate the name and then 'same as Section 1' below.

Completed by Benchmarking Liaison Officer (name):	
Position / Title:	
Endorsed by CEO (name):	
Country or territory:	
Name of utility:	SAMPLE for Exercise
Postal address:	
E-mail address:	
Back up e-mail address:	
Telephone number:	
Skype address (if any):	

Benchmarking Period:		
Start Date for Benchmarking Data Collection Period (Benchmarking Period)	1/1/2011	Calendar year is preferred, otherwise use relevant financial/reporting year
End Date for Benchmarking Data Collection Period (Benchmarking Period)	31/12/2011	
Date questionnaire completed		
Currency Used by Utility to Report Costs:	USD	All costs are to be provided in this currency

Ref	Input Name	Units	Explanation	System Data				
	Generation			**Generation information is to be provided for the ENTIRE UTILITY SYSTEM**				
				Main Grid 1	Grid 2	Grid 3	Others	
1	Name of the Grid		Brief name or description of each grid					
2	Total Utility Generation	MWh	Total utility generation for each grid	91,980				MWh
3	Total IPP Generation Purchased	MWh	Purchases from IPPs for each grid	39,240				MWh
4	Maximum Demand / Peak Generation	MW	Maximum demand for each grid	30				MW
5	Minimum Demand Generation	MW	Minimum demand for the each grid	15				MW
6	Guaranteed/Contracted IPP Generation Capacity	MW	The capacity guaranteed by an IPP under contract	5				MW
7	Generator 1 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	5				MW
7	Generator 2 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	10				MW
7	Generator 3 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	10				MW
7	Generator 4 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	7				MW
7	Generator 5 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	7				MW
7	Generator 6 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate	10				MW
7	Generator 7 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 8 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 9 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 10 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 11 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 12 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 13 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 14 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 15 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 16 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
7	Generator 17 Nameplate Capacity Rating	MW	The capacity for the generator as stated by the nameplate					MW
	(add more as required)							MW
8	Generation by Source (MWh)	MWh	Use the total for Utility for each grid					
8a	Distillate (ADO or IDO)	MWh	Total Utility generation from distillate per grid	45,990				MWh
8b	Heavy fuel oil (HFO or IFO)	MWh	Total Utility generation from heavy fuel oil per grid	13,797				MWh
8c	Biofuels	MWh	Total Utility generation from biofuel per grid	940				MWh
8d	Mixed Fuel	MWh	Total Utility generation from mixed fuel (eg coconut oil and diesel) for each grid. Provide details of mixture, fuels used and % of each in Comments column.	920				MWh
8e	LNG	MWh	Total Utility generation from liquid natural gas for each grid	1,820				MWh
8f	Hydropower	MWh	Total Utility generation from hydro resources for each grid	13,797				MWh
8g	Wind energy	MWh	Total Utility generation from wind energy for each grid	4,599				MWh
8h	Solar Photovoltaics	MWh	Total Utility generation from solar PV for each grid	920				MWh
8i	Biomass	MWh	Total Utility generation from wood or other biomass for each grid	2,759				MWh
8j	Geothermal	MWh	Total Utility generation from geothermal for each grid	5,518				MWh
8k	Other	MWh	Any other sources of generation on each grid. Please specify in Comments column.	920				MWh
9	Fuel Usage	L / kL / ML						
9a	Distillate (ADO or IDO)	L / kL / ML	Total Distillate usage per year per grid. Select the units used (L/kL/ML)	13,500,000				L or kL or ML?
9b	Heavy fuel oil (HFO or IFO)	L / kL / ML	Total HFO/IDO usage per year per grid. Select the units used (L/kL/ML)	4,100,000				L or kL or ML?
9c	Biofuels	L / kL / ML	Total Biofuel usage per year per grid. Select the units used (L/kL/ML)	230,000				L or kL or ML?
9d	Mixed fuel	L / kL / ML	Total Mixed Fuel usage per year per grid. Select the units used (L/kL/ML). Indicate details of mixture in Comments column	220,000				L or kL or ML?
9e	LNG	L / kL / ML	Total LNG Usage per year per grid. Select the units used (L/kL/ML)					L or kL or ML?
10	Total Lubricants Used in Generation	L / kL / ML	Total lubricants used in generation from ADO/IDO, HFO/IFO, Biofuels, Fuel Mixtures, LNG. Select the units used (L/kL/ML)	70,000				L or kL or ML?
11	Utility Capacity Hours Out of Service Due to Generation Forced Outage Events	MWh	Sum of (Utility Generation Forced Outage Duration multiplied by Capacity Rating)	31,332.5				MWh
12	Utility Capacity Hours Out of Service Due to Generation Planned Outage Events	MWh	Sum of (Utility Generation Planned Outage Duration multiplied by Capacity Rating)	56,600				MWh
13	Utility Capacity Hours Out of Service Due to Generation De-rated Events	MWh	Sum of (Utility Generation De-rated Outage Duration multiplied by Capacity Rating)	2,065.5				MWh
14	IPP Capacity Hours Out of Service Due to Generation Forced Outage Events	MWh	Sum of (IPP Generation Forced Outage Duration multiplied by Capacity Rating)	100				MWh
15	IPP Capacity Hours Out of Service Due to Generation Planned Outage Events	MWh	Sum of (IPP Generation Planned Outage Duration multiplied by Capacity Rating)	2,000				MWh
16	IPP Capacity Hours Out of Service Due to Generation De-rated Events	MWh	Sum of (IPP Generation De-rated Outage Duration multiplied by Capacity Rating)	50				MWh
17	Power Station Usage / Station Auxiliaries	MWh	Total energy used in the power stations operated by the utility	4,600				MWh
18	Enabling Framework for Private Sector Participation IPP/ PPA Arrangement?	Y/N	Enabling framework includes procedures, processes etc. Provide details in Comments column.	Y/N				

Ref	Input Name	Units	Explanation	System Data		Comments
	Transmission			**Transmission information is to be provided for the MAIN GRID ONLY**		
	Transmission refers only to network of **above 34.5kV**					
19	Does your system have a transmission network?	Y/N	Applies only to Fiji, Guam, PNG and Saipan. Other utilities answer "No" and proceed to 'Distribution'.	Y/N		
20	Number of Unplanned Transmission Outage Events	events	Number of times in the period when a transmission system fault resulted in an unplanned outage	10	events	
21	Total Duration of Unplanned Transmission Outage Events	hrs	The total sum of the duracion of all unplanned transmissionn system outages in the period	168	hrs	
22	Length of Transmission Line	km / miles	Total length of all transmission lines and cables in each network	300	km	
23	Electricity delivered to distribution system	MWh	Total electricity delivered to the distribution system in MWh	124,620	MWh	
	Distribution			**Distribution information is to be provided for the MAIN GRID ONLY**		
	Distribution refers only to power sent through the grid **at or below 34.5 kV**					
	All utilities should complete this section					
24	Number of Distribution Forced Outage Events	events	The total number of outages due to faults in the distribution network	1,000	events	
25	Length of Distribution Line	km / miles	The total length of all distribution lines and cables in the distribution network	100,000	km	
26	Total Distribution Transformer Capacity	MVA	The sum of all distribution transformer capacity on the network	60	MVA	
27	Total Customer Interruptions	interruptions	Total number of customer connections affected by distribution outages (both plannd and unplanned) in the period	3,227,150	interruptions	
28	Total Customer Duration Interrupted	customer hrs	Sum of (Custom Interruption x Duration of Interruption)	1,415,400	customer hrs	
	Demand Side Management			**Demand Side Management information is to be provided for the ENTIRE UTILITY SYSTEM**		
29	Does the utility actively engaged in any demand side management initiatives?	Y/N	This includes initiatives acorss all grid. Select Yes/No for this question and for the following activities. If other activities that are not specified, please specify below in 'Others'.	Y/N		
30a	Replacing incandescent lighting with compact fluorescent lighting	Y/N		Y/N		
29a	Installing sensors on lighting or other	Y/N		Y/N		
29b	Replacing old inefficient air conditioners with high-efficiency units	Y/N		Y/N		
29c	Performance testing of appliances and equipment	Y/N		Y/N		
29d	Replacing old refrigerators and freezers with new, high-efficiency units	Y/N		Y/N		
29e	Have varying rates for peak and off peak electricity usage	Y/N		Y/N		
29f	Educational program to consumers	Y/N		Y/N		
29g	Other 1 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 1 - Specify here:	
29h	Other 2 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 2- Specify here:	
29i	Other 3 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 3 - Specify here:	
29j	Other 4 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 4 - Specify here:	
29k	Other 5 (please specify)	Y/N	Any other DSM initiavites. Please specify.	Y/N	Other 5 - Specify here:	
30	What is the budget for DSM?	0	Specify DSM budget for reporting period. If no DSM budget, type "0"		0	
31	How many employees are engaged in DSM?	employees	Provide total number of employees. Provide details in the comments column		employees	
32	Has there been recorded savings by consumers? How much?	MWh (total)	Select "Yes" or "No". If "Yes", indicate how much in the local currency		MWh (total)	
33	What power Quality Standard applies, if any?		Provide name of the standard. If none applies, type "None".			

Ref	Input Name	Units	Explanation	System Data					Comments
	Human Resources / Safety			**Human Resource / Safety information is to be combined for the ENTIRE UTILITY SYSTEM**					
34	Total Days Lost Due to Work Injury During Period (excludes contractors)	days	The sum of work days/shifts an employee is unable to report to work due to injury sustained at work. Excludes contractors.	80.00	days				
35	Number of Lost Time Injuries During Period (excludes contractors)	LTIs	Total employee LTIs. Contractor injuries are not counted towards LTIs.	15	LTIs				
36	Total Number of Employees (excludes contractors)	employees	The total number of employees. This factor excludes contractors	800	employees				
37	Total number of employees in Distribution & Customer Service at Start of Period	employees	Total number of employees in Distribution & Customer Service at Start of Period	0	480	employees			
38	Total number of employees in Distribution & Customer Service at End of Period	employees	Total number of employees in Distribution & Customer Service at End of Period	0	530	employees			
39	Total Hours Worked (excludes contractors)	hrs	The total hours worked by employees	1,600,000.0	hrs				
40	Paid Hours Utility Generation Labour	hrs	Total paid hours for generation labour, taking into account overtime rates	100,000.0				hrs	
41	Paid Hours Utility Distribution Labour	hrs	Total paid hours labour to maintain and operate the utility's distribution network.	1,166,000.0	hrs				
42	Total Paid Hours Employees Including Contractors	hrs	The total paid hours for employee labour. This takes overtime (double timeetc) into account	1,800,000.0	hrs				
	Customers / General			**Customer information is to be combined for the ENTIRE UTILITY SYSTEM, except for Electricity Sold which is per grid**					
				Main Grid 1	Grid 2	Grid 3	Others		
43	Electricity Sold	MWh	Total electricity billed to customers in MWh for each grid	100,000				MWh	
44	Total Number of Customers at Start of Benchmarking Period	connections	Number of customers at the start of the benchmarking period. Include total of all customer classes for all the networks.	0	165,400	connections			
45	Total Number of Customers at End of Benchmarking Period	connections	Number of customers at the end of the benchmarking period. Include total of all customer classes for all the networks.	0	174,300	connections			
46	Number of Households Supplied (Domestic Connections)	connections	Combined number of domestic connections across all grids, taken at end of benchmarking period	151,300	connections				
47	Total Number of Households in the Country	households	The total number of households in the country.	300,000	households				
48	Lifeline Tariff Available?	Y/N	Indicate Yes or No	Y/N					
49	Maximum Threshold for Monthly Consumption Under Tariff	kWh/mth	Provide the tariff threshold in kWh/month		kWh/mth				
50	Tariff Schedule / Tariff Table Attached?	Y/N	Please attach tariff schedule/table and indicate Yes when this is done.	Y/N					
51	Total Electricity Billed under Lifeline Tariff	MWh	The total electricity billed to customers under Lifeline Tariff in MWh.	2,000	MWh				
52	Total Domestic Electricity Billed	MWh	The total electricity billed to customers under domestic tariff in MWh.	50,000	MWh				
53	Total Commercial Electricity Billed	MWh	The total electricity billed to customers under the commercial tariff in MWh.	10,000	MWh				
54	Total Industrial Electricity Billed	MWh	The total electricity billed to customers under the industrial or maximum demand tariff in MWh.	23,000	MWh				
55	Total Other Electricity Billed	MWh	The total electricity billed to customers under the industrial or maximum demand tariff in MWh. Please specify	15,000	MWh				
56	Total Unbilled Electricity Usage	MWh	e.g Head Office, Water Services, Street Lighting etc. (This does not include power station usage/station auxiliiaries)	5,000	MWh				
57	Is the utility self regulated or externally regulated?	self / external	Select self regulated or externally regulated. Provide any details	self / external ?					
58	Do you have a maintenance plan for your utility?	Y/N	This may cover generation, transmission, distribution. Please attach plan.	Y/N					

	Finance			**Finance information is to be combined for the ENTIRE UTILITY SYSTEM**		
59	Depreciation Generation Assets	USD	Total depreciation of generation assets over the benchmark period	3,500,000	USD	
60	Depreciation Transmission & Distribution Assets	USD	Total depreciation of transmission & distribution assets over the benchmark period	1,000,000	USD	
61	Other Depreciation	USD	Total depreciation on other electricity assets excluding generation, transmission & distribution assets for benchmarking period.	500,000	USD	
62	Total Operating Revenue	USD	Total Operating Revenue earned from electricity sales.	70,000,000	USD	
63	Total Operating Expenses	USD	Total Operating Expenses excluding depreciation, interest and tax.	46,600,000	USD	
64	Earnings Before Interest and Tax (EBIT) / Operating Profit	USD	Sales revenue minus the cost of goods sold and all expenses except for interest and taxes	18,400,000	USD	
65	Profit After Tax (PAT) / Earnings After Tax (EAT)	USD	Sales revenue after deducting all expenses, including taxes	5,000,000	USD	
66	Long Term Debt / Non Current Liability	USD	Funds obtained from loans, mortgages, bonds, etc. that have repayment terms longer than one year	100,000,000	USD	
67	Equity / Net Assets / Capital and Reserves	USD	Equity / Net Assets / Capital & Reserves represents the owner's funds or claims the owners have on the business.	50,000,000	USD	
68	Non Current Asset at End of Previous Period	USD	The assets that are consumed over a period of more than a year taken from end of prev period	120,000,000	USD	
69	Non Current Asset at End of Benchmarking Period	USD	The assets that are consumed over a period of more than a year taken from end of benchmarking period	140,000,000	USD	
70	Current Assets	USD	Value of all assets that are reasonably expected to be converted into cash within one year	50,000,000	USD	
71	Current Liabilities	USD	Company's debts or obligations that are due within one year	40,000,000	USD	
72	Debtors/Receivables at Period End	USD	Money owed to a business by its clients (customers) and shown on its Balance Sheet as an asset	25,000,000	USD	
73	Are utility finances independently audited?	Y/N	If Yes, indicate who the auditor was in Comments column	Y/N		
74	What is the accounting standard used by the utility?		eg US GAP, IAS, IPSA, None etc			
	Generation Expenditure					
75	Hydrocarbon Based Fuel & Lubrication Oil Expenditure	USD	Total expenditure on distillate fuel oil, heavy fuel oil, coconut oil, other hydro carbon based fuels, and lubricating oil	17,000,000	USD	
76	Duty and Taxes on Hydrocarbon Based Fuel & Lubricating Oil	USD	Total duty and taxes paid hydrocarbon based fuel & lubricating oil	1,760,000		
77	Generation O&M Costs (utility)	USD	Total cost for operations and maintenance of the Utility. This excludes all IPP generation costs, labour costs and fuel and oil costs.	3,000,000		USD
78	Generation Labour	USD	Total expenditure on labour associated with the generation of electricity	2,000,000		
	Transmission/ Distribution Expenditure					
79	Transmission/ Distribution O&M Cost	USD	Total expenses incurred in the operations and maintenance of the distribution network		USD	
80	Transmission/ Distribution Labour	USD	Total expenditure on labour for transmission & distribution operations		USD	
	Overheads/ Other Expenditure					
81	Other Labour Expenditure (Customer Service, Head Office, Finance, HR, others)	USD	Total labour expenditure for head office and other labour for electricity operations		USD	
82	Other Duty/ Taxes	USD	All duty and taxes paid to government for equipment and supplies. Do not include personal income tax and other taxes applicable to workers remuneration. GST, VAT or other forms of sales tax is also excluded		USD	
83	Other Expenditure	USD	Total expenditure on items not included in any of the above.		USD	

Please go to 'Data Reliability' Sheet and complete.

Colour Code

Data that is **bold and in maroon font** is inputted directly from the 2012 Questionnaire Data Inputs Sheet. Data that is **bold and in grey font** is a factor calculated using inputs from the 2012 Questionnaire Inputs Sheet.

Generation Indicators

1) KPI 1: Load Factor

$$\text{Load Factor (\%)} = \frac{[\textbf{Gross Generation (MWh)}] * 100}{\textbf{Maximum Demand (MW)} * 8{,}760 \text{ h}}$$

$$\text{Gross Generation (MWh)} = [\textbf{Total Utility Generation Capacity (MWh)} + \textbf{Total IPP Generation Purchased (MWh)}]$$

Example Using Sample Data:

$$\textit{Gross Generation} = 91{,}980 + 39240 = 131{,}220 \text{ MWh}$$

$$\textit{Load Factor} = \frac{131{,}220 * 100}{30 * 8760} = 49.9\%$$

Benchmark: 50% to 80%

Therefore the Load Factor is 49.9%.

2) KPI 2: Capacity Factor

$$\text{Capacity Factor (\%)} = \frac{[\textbf{Gross Generation (MWh)}] * 100}{\textbf{Total Installed Generation Capacity (MW)} * 8760 \text{ h}}$$

$$\text{Total Installed Generation Capacity(MW)} = \textbf{Total Utility Generation (MW)} + \textbf{Total Guaranteed/Contracted IPP Generation Capacity (MW)}$$

Calculated for Sample Data:

$$\textit{Installed Generation Capacity} = 5 + 10 + 10 + 7 + 7 + 10 + 5 = 54\text{MW}$$

$$\textit{Capacity Factor} = \frac{(131{,}220 * 100)}{[54 * 8760]} = 27.7\%$$

Benchmark: > 40%

Therefore the Capacity Factor is 27.7%.

3) KPI 3: Availability Factor

$$\text{Availability Factor (\%)} = \frac{\left[\begin{array}{c}(\textbf{Total Installed Generation Capacity (MW)} * 8760\text{ h}) - \\ \textbf{Total Capacity Hours Out of Service (MWh)}\end{array}\right] * 100}{\textbf{Total Installed Generation Capacity (MW)} * 8{,}760\text{ h}}$$

$$\text{Total Installed Generation Capacity(MW)} = \textbf{Total Utility Generation (MW)} + \textbf{Total Guaranteed/Contracted IPP Generation Capacity (MW)}$$

$$\text{Total Capacity Hours Out of Service (MWh)} = \textbf{Total Utility Capacity Hours Out of Service(MWh)} + \textbf{Total IPP Capacity Hours Out of Service (MWh)}$$

Calculated for Sample Data:

$$Total\ Installed\ Generation\ Capacity = 5 + 10 + 10 + 7 + 7 + 10 + \\ = 54\text{MW}$$

Benchmark: 80% to 90%

$$Total\ Capacity\ Hours\ Out\ of\ Service = 31{,}332.5 + 56{,}600 + 2{,}065.5 + 100 + 2000 + 50 = 92{,}148\text{ MWh}$$

$$Availability\ Factor = \frac{((54 * 8760) - 92{,}148) * 100}{(54 * 8760)} = 80.5\%$$

Therefore the Availability Factor is 80.5%.

4) KPI 4: Generation Labour Productivity

$$\text{Generation Labour Productivity (GWh/generation employee)} = \frac{[\textbf{Total Utility Generation (MWh)}]\ /\ 1000}{\textbf{Number of Full Time Equivalent (FTE) Generation Employees}}$$

$$\text{Number of Full Time Equivalent (FTE) Generation Employees} = \frac{\textbf{Paid Hours Utility Generation Labour(h)}}{2000\text{ (h)}}$$

Calculated for Sample Data:

Benchmark: 22GWh/FTE_{Gen}

$$FTE\ Generation\ Employee = \frac{100{,}000}{2000} = 50$$

$$Generation\ Labour\ Productivity = \frac{91{,}980}{50 * 1000} = 1.8\text{ GWH/FTEGen}$$

Therefore Generation Labour Productivity is 1.8 GWH/FTE_{Gen}.

5) KPI 5: Specific Fuel Oil Consumption

$$\text{Specific Fuel Oil Consumption (kWh/L)} = \frac{\textbf{Total Fuel Oil Generation (kWh)}}{\textbf{Total Fuel Usage (L)}}$$

$$\text{Total Fuel Oil Generation (MWh)} = \sum_{\text{n=distillate}}^{\text{[distillate,HFO,biofuel,mixed fuel]}} \textbf{Generation by n (MWh)}$$

$$\text{Total Fuel Usage (L)} = \sum_{\text{n=distillate}}^{\text{[distillate,HFO,biofuel,mixed fuel,LNG]}} \textbf{Fuel Usage by n (L)}$$

Calculated for Sample Data:

$$\begin{aligned} Total\ \ Fuel\ Usage &= 13{,}500{,}000 + 4{,}100{,}000 + 230{,}000 + 220{,}000 \\ &= 18{,}050{,}000 \text{ Ltrs} \end{aligned}$$

Benchmark:
> 4 kWh/L

$$\begin{aligned} Total\ Fuel\ Oil\ Generation &= 45{,}990 + 13{,}797 + 940 + 920 \\ &= 61{,}647 \text{ MWh} \end{aligned}$$

$$Specific\ Fuel\ Consumption = \frac{61{,}647 * 1000}{18{,}050{,}000} = 3.42 \text{ kWh/Ltrs}$$

Therefore Specific Fuel Oil Consumption is 3.42 kWh per Litre.

6) KPI 6: Lube Oil Consumption

$$\text{Lubricating Oil Consumption (kWh/L)} = \frac{\textbf{Total Fuel Oil Generation (MWh)} * 1000}{\textbf{Total Lubricants Used in Generation (L)}}$$

Calculated for Sample Data:

$$\begin{aligned} Lubricating\ Oil\ Consumption &= \frac{61{,}647\ *\ 100}{70{,}000} \\ &= 880.67 \text{ kWh/L} \end{aligned}$$

Benchmark:
500 to 700 kWh/L or
1000 to 1300 kWh/L

Therefore Lube Oil Consumption is 880.67 kWh per Litre.

7) KPI 9: Generation O&M Costs

$$\text{Generation O\&}M\ (USD/MWh) = \frac{\textbf{Total Generation O\&M Costs (USD)}}{\textbf{Total Utility Generation (MWh)}}$$

Calculated for Sample Data:

$$Generation\ O\&M\ Costs = \frac{5{,}000{,}000}{91{,}980} = \$54.36/\text{MWh}$$

Benchmark:
> US $18.00/ MWh

Therefore Generation O&M Costs is $54.36 per MWh.

8) KPI 10: Power Station Usage

$$\text{Power Station Usage (\%)} = \frac{\textbf{Power Station Usage / Station Auxiliaries (MWh)} * 100}{\textbf{Total Utility Generation (MWh)}}$$

Calculated for Sample Data:

$$Utility\ Power\ Station\ Usage = \frac{4{,}600 * 100}{91{,}980} = 5\%$$

Benchmark:
< 5%

Therefore Utility Power Station Usage is 5%.

9) KPI 11: Renewable Energy to Grid

$$\text{Renewable Energy to Grid (\%)} = \frac{\textbf{Total Renewable Energy Generation (MWh)}}{\textbf{Gross Generation (MWh)}}$$

$$\text{Total Renewable Energy Generation (MWh)} = \sum_{\text{n=hydro}}^{\substack{\text{[hydro,wind,solar,biomass,} \\ \text{geothermal,biofuel,other renewable]}}} \textbf{Total Generation by n (MWh)}$$

Calculated for Sample Data:

$$Total\ Renewable\ Energy\ Generated = 13{,}797 + 4{,}599 + 920 + 2{,}759 + 5{,}519 = 27{,}594\ \text{MWh}$$

$$Renewable\ Energy\ to\ Grid = \frac{27{,}594 * 100}{131{,}240} = 21\%$$

Benchmark:
To be determined by utility

Therefore Renewable Energy to Grid is 21%.

10) KPI 12: IPP Energy Generation

$$\text{IPP Energy Generation (\%)} = \frac{\textbf{Total IPP Generation Purchased (MWh)} * 100}{\textbf{Gross Generation (MWh)}}$$

Calculated for Sample Data:

$$IPP\ Energy\ Purchase = \frac{39{,}240 * 100}{131{,}220} = 29.9\%$$

Benchmark:
To be determined by utility

Therefore IPP Energy Purchase is 29.9%.

Transmission Indicators

11) KPI 15: Transmission Losses

$$\text{Transmission Losses (\%)} = \frac{[\textbf{Net Generation (MWh)} - \textbf{Electricity Delivered to Distribution Network (MWh)}] * 100}{\textbf{Net Generation (MWh)}}$$

$$\text{Net Generation (MWh)} = [\text{Gross Generation (MWh)} - \textbf{Power Station Usage(MWh)}]$$

Calculated for Sample Data:

$$Net\ Generation = 131{,}220 - 4{,}600 = 126{,}620$$

$$Transmission\ Loss = \frac{[126{,}620 - 124{,}620] * 100}{126{,}620}$$

Benchmark:
< 2%

Therefore Transmission Loss is 1.58%.

12) KPI 16: Transmission Reliability

$$\text{Transmission Reliability (outage events per 100 km of line)} = \frac{\textbf{Number of Unplanned Transmission Outage Events (events)} * 100}{\textbf{Length of Transmission Line (km)}}$$

Calculated for Sample Data:

$$Transmission\ Reliability = \frac{10 * 100}{300} = 3.3\ \text{events/100 km}$$

Benchmark:
< 2 events per 100km

Therefore Transmission Reliability is 3.3 events per 100km of line.

Distribution Indicators

13) KPI 20: Customers per Distribution Employee

$$\text{Customers Per Distribution Employee (customers per distribution employee)} = \frac{\textbf{Average Number of Customers (connections)}}{\textbf{Average Number of Distribution and Customer Service Employees (employees)}}$$

$$\text{Average Number of Customers (connections)} = \frac{\textbf{Total Number of Customers at Start of Period (connections)} + \textbf{Total Number of Customers at End of Period (connections)}}{2}$$

Calculated for Sample Data:

$$Average\ Distribution\ Employees = \frac{[480 + 530]}{2} = 505\ \text{employees}$$

$$Average\ Customers = \frac{[165{,}400 + 174{,}300]}{2} = 169{,}850\ \text{customers}$$

$$Customers\ per\ Distribution\ Employee = \frac{169{,}850}{505} = 336\ \text{customers/employee}$$

Benchmark: To be determined by utility

Therefore there are 336 customers per distribution employee.

14) KPI 22: Distribution Transformer Utilisation

$$\text{Distribution Transformer Utilisation (\%)} = \frac{\textbf{Electricty Sold (MWh)} * 100}{\textbf{Total Distribution Transformer Capcity (MVA)} * 8760\text{h}}$$

Calculated for Sample Data:

$$Distribution\ Transformer\ Utilisation = \frac{100{,}000 * 100}{60 * 8760} = 19\%$$

Benchmark: > 30%

Therefore Distribution Transformer Utilisation is 19%.

15) KPI 24: System Average Interruption Duration Index

$$\text{SAIDI (minutes)} = \frac{\textbf{Total Customer Interruptions Duration Interrupted (cust hr)} * 60}{\textbf{Average Number of Customers (connections)}}$$

Calculated for Sample Data:

$$SAIDI = \frac{1{,}415{,}400 * 60}{169{,}850} = 500 \text{ customer minutes}$$

Benchmark:
200 customer minutes

Therefore SAIDI is 500 customer minutes.

16) KPI 25: System Average Interruption Frequency Index

$$\text{SAIFI (\%)} = \frac{\textbf{Total Customer Interruptions}}{\textbf{Average Number of Customers (connections)}}$$

Calculated for Sample Data:

$$SAIFI = \frac{3{,}227{,}150}{169{,}850} = 19 \text{ interruptions per customer}$$

Therefore SAIFI is 19 interruptions per customer.

Human Resource/Safety Indicators

17) KPI 31: Loss Time Injury Duration Rate

$$\text{Lost Time Injury Duration Rate (days)} = \frac{\text{Total Days Lost Due to Work Injury During Period (days)}}{\textbf{Total Number of Employees (employees)}}$$

Calculated for Sample Data:

$$LTID = \frac{80}{800} = 0.1 \text{ days per employee}$$

Benchmark:
< 5 days

Therefore LTID is 0.1 days per employee.

18) KPI 32: Loss Time Injury Frequency Rate

$$\text{Lost Time Injury Frequency Rate} = \frac{\text{Number of Lost Time Injuries During Period (LTIs)} * 1{,}000{,}000\ \text{h}}{\textbf{Total Hours Worked (h)}}$$

Calculated for Sample Data:

$$LTIFR = \frac{15 * 1{,}000{,}000}{1{,}600{,}000} = 9.38\ \text{LTIs/million hours}$$

Benchmark: < 2 per million hours

Therefore LTIFR is 9.38 LTIs per million hours.

19) KPI 33: Labour Productivity

$$\text{Labour Productivity (\%)} = \frac{\textbf{Average Number of Customers (customers)} * 100}{\text{FTE Utility}}$$

$$\text{FTE Utility} = \frac{\text{Total Paid Hours Employees including contractors}}{\text{FTE Annual Hours (2000)}}$$

Calculated for Sample Data:

$$FTE\ Utility = \frac{1{,}800{,}000}{2000} = 900$$

$$Overall\ Labour\ Productivity = \frac{169{,}850}{900} = 189\ \text{customers per FTE}$$

Therefore Overall Labour Productivity is 189 customers per FTE.

Customer Indicators

20) KPI 34: Service Coverage

$$\text{Service Coverage (\%)} = \frac{\textbf{Number of Households Supplied (Domestic Connections)(households)} * 100}{\textbf{Total Number of Households in Country (households)}}$$

Calculated for Sample Data:

$$Service\ Coverage = \frac{151{,}300 * 100}{300{,}000} = 50.4\%$$

Therefore Service Coverage is 50.4%.

21) KPI 35: Productive Electricity Usage

$$\text{Productive Electricty Usage } (\%) = \frac{\begin{array}{c}\textbf{Total Commercial Electricty Billed (MWh)} + \\ \textbf{Total Industrial Electricty Billed (MWh)} \\ \text{Total Other (Productive) Electricty Billed (MWh)} * 100\end{array}}{\textbf{Electricty Sold (MWh)}}$$

Calculated for Sample Data:

$$Productive\ Electricty\ Usage = \frac{[10{,}000 + 23{,}000] * 100}{100{,}000} = 33\%$$

Therefore Productive Electricity Usage is 33%.

22) KPI 36a: Lifeline Tariff Usage

$$\text{Lifeline Tariff Usage } (\%) = \frac{\textbf{Total Electricty Billed Under Lifeline Tariff (MWh)} * 100}{\textbf{Electricty Sold (MWh)}}$$

Calculated for Sample Data:

$$Lifeline\ Tariff\ Usage = \frac{2000 * 100}{100{,}000} = 2\%$$

Therefore Lifeline Tariff Usage is 2%.

Financial Indicators

23) KPI 40: Debt to Equity Ratio

$$\text{Debt to Equity Ratio } (\%) = \frac{\textbf{Long Term Debt/Non Current Liability (local currency)} * 100}{\begin{array}{c}\text{Equity/Net Assets/Capital Reserves (local currency)} + \\ \textbf{Long Term Debt/Non Current Liability (local currency)}\end{array}}$$

Calculated for Sample Data:

$$Debt\ to\ Equity\ Ratio = \frac{100{,}000{,}000 * 100}{50{,}000{,}000 + 100{,}000{,}000} = 66.7\%$$

Benchmark: 50%

Therefore the Debt to Equity Ratio is 66.7%.

24) KPI 41: Rate of Return on Assets

$$\text{Rate of Return on Assets}(\%) = \frac{\textbf{Earnings Before Interest and Tax EBIT/Operating Profit (local currency)} * 100}{\text{Average Non Current Assets (local currency)}}$$

$$\text{Average Non Current Assets (local currency)} = \frac{\text{Non Current Assets at End of Previous Period (local currency)} + \textbf{Non Current Assets at End of Benchmarking Period (local currency)}}{2}$$

Calculated for Sample Data:

$$Average\ Non\ Current\ Assets = \frac{120{,}000{,}000 + 140{,}000{,}000}{2} = 130{,}000{,}000$$

$$Rate\ of\ Return\ on\ Assets = \frac{18{,}400{,}000 * 100}{130{,}000{,}000} = 14.15\%$$

Therefore the Rate of Return on Assets is 14.15%.

25) KPI 42: Return on Equity

$$\text{Return on Equity }(\%) = \frac{\textbf{Profit After Tax/Earnings After Tax (local currency)} * 100}{\text{Equity/Net Assets/Capital Reserves (local currency)}}$$

Calculated for Sample Data:

$$Rate\ of\ Return\ on\ Equity = \frac{5{,}000{,}000 * 100}{50{,}000{,}000} = 10\%$$

Therefore the Rate of Return on Equity is 10%.

26) KPI 43: Current Ratio

$$\text{Current Ratio }(\%) = \frac{\textbf{Current Assets (local currency)} * 100}{\text{Current Liabilities (local currency)}}$$

Calculated for Sample Data:

$$Current\ Ratio = \frac{50{,}000{,}000 * 100}{40{,}000{,}000} = 125\%$$

Therefore the Current Ratio is 125%.

27) KPI 44: Debtor Days

$$\text{Debtor Days (days)} = \frac{\textbf{Debtors/Receivables at Period End (local currency)} * 365}{\text{Total Operating Revenue (local currency)}}$$

Calculated for Sample Data:

$$Debtor\ Days = \frac{25{,}000{,}000 * 365}{70{,}000{,}000} = 130\ \text{days}$$

Benchmark: < 50 days

Therefore there are 130 Debtor Days.

28) KPI 45: Average Supply Costs

$$\text{Average Supply Cost (USD/MWh)} = \frac{\textbf{Total Operating Expenses (USD)}}{\text{Electricity Sold (MWh)}}$$

Calculated for Sample Data:

$$Average\ Supply\ Costs = \frac{46{,}600{,}000}{100{,}000} = \$466/\text{MWh}$$

Therefore Average Supply Costs is $466 per MWh or 46.6 cents per kWh.

SECTION 5:
Data Reliability Assessment

The quality of the benchmarking data is critical to the validity of the benchmarking results. In the 2012 round of benchmarking, and for future rounds, a separate sheet within the questionnaire requires utilities to provide a self-assessed reliability grade for six key components of the primary data (Table 5.2) in order to better understand data quality issues and encourage improvements in data reliability.

Table 5.2: Key Data Component Reliability Assessment Questions

Question	Description	Reliability Grade (A, B, C or D)
i.	How is fuel consumption calculated or derived?	
ii.	How are generation quantities calculated or derived?	
iii.	How are customer outage impacts calculated or derived?	
iv.	How are network demands and capacity utilisation calculated or derived?	
v.	How are the number of connections or customers calculated?	
vi.	Where is financial information sourced from?	

The general reliability expectations of each grade are described below in *Table 5.3*, where A represents the most reliable data and D the least reliable data.

Table 5.3: General Reliability Evaluation

Reliability Grade	Reliability	Description
A	Highly Reliable	Data is based on sound records, procedures, investigations or analyses that are properly documented and recognised as the best available assessment methods. Effective metering or measurement systems exist.
B	Reliable	Generally as in Category A, but with minor shortcomings, e.g. some of the documentation is missing, the assessment is old or some reliance on unconfirmed reports; or there is some extrapolation made (e.g. extrapolations from records that cover more than 50 percent of the utility system).
C	Unreliable	Generally as in Category B, but data is based on extrapolations from records that cover more than 30 per cent (but less than 50 per cent) of the utility system.
D	Highly Unreliable	Data is based on unconfirmed verbal reports and/or cursory inspections or analysis, including extrapolations from such reports/inspections/analysis. There are no reliable metering or measurement systems.

Further guidance for each component is given in *Table 5.4*, although this is not intended to be a detailed specification. Self-assessments will remain at least partially subjective as a result of variations in circumstances and scale. Please select the Reliability Grade that best represents the reliability for each component in *Table 5.2* and provide any additional comments on that selection.

Table 5.4: Reliability Grading Guidance

Reliability Grade	Description		
i.	**How is fuel consumption calculated or derived?**	**Related Questionnaire Data Inputs**	**Comments**
A	Accurate records are kept of deliveries, inventory and consumption of oil and fuel type by location, station and unit. Fuel consumption measurement equipment is temperature compensated. Monthly fuel consumption measurement is taken for each unit and fuel consumption audits are regularly undertaken and reconciled by unit. Audits are carried out by both internal and external parties.	9, 10	[Please insert any comments on your self assessed data reliability grading here]
B	Records are kept of deliveries, inventory and consumption of oil and fuel type by location and station. Fuel consumption measurement equipment is not temperature compensated. Fuel consumption measurement is taken for power stations and fuel consumption audits are undertaken and reconciled by power stations. Audits are carried out by internal and external parties.		
C	Some records are kept of deliveries, inventory and consumption of oil and fuel type by location and station. Fuel consumption measurement are done by dip stick. Fuel consumption audits are only undertaken by an external party annually and reconciled by power stations.		
D	Some records are kept of deliveries, inventory and consumption of oil and fuel type by location and station. Fuel consumption measurement are done by dip stick. Fuel consumption audits are rarely undertaken or irregular. Heavy reliance on fuel supplier information.		

ii.	**How are generation quantities calculated or derived?**	**Related Questionnaire Data Inputs**	**Comments**
A	Generation quantities are computed on the basis of measurement by station, unit and auxiliary metering at all grid connected generation points, which are calibrated / verified for accuracy regularly. Generation profiles are monitored continuously and there is an established process for reporting capacity factors. There is an established process for derating of generators and reporting of all related volumes.	2 to 8 inclusive 11 to 17 inclusive	[Please insert any comments on your self assessed data reliability grading here]
B	Generation quantities are computed on the basis of measurement by unit and station metering at all grid connected generation points. Meters may not be calibrated or verified for accuracy. Reliable generation profiles are available. More manual processing and interpretation of records may be required than A.		
C	Reliable and calibrated metering is not available at all grid connected generation points. Generation profiles are estimated or extrapolated. Derating information is not routinely recorded.		
D	Aggregated generation information is available, with limited information available on unit and station profiles and capacity factors. No reliable calibrated metering systems exist.		

iii.	How are customer outage impacts calculated or derived?	**Related Questionnaire Data Inputs**	**Comments**
A	Details of individual HV network or generation outages are available and used to calculate customer impact measures and reliability statistics. Records of trip times, restoration sequences, and affected customer numbers are available from SCADA, generator, substation, operating or other records. Outage records are suitable for causal analysis and performance improvement. An established and auditable process is used for evaluation of outage impacts.	11 to 16 inclusive 20,21 24, 27, 28	[Please insert any comments on your self assessed data reliability grading here]
B	Reliable assessment of HV network and generation outages are available, but may require more manual processing of information from source records than in A. Customer numbers for network segments and affected areas are used to derive reliability statistics but may not be up to date at all times.		
C	Where outage impacts are assessed, they use estimates of outage durations and affected customer numbers. It is likely that not all outages are captured in reporting statistics. Limited processes exist for fault causal analysis and reporting.		
D	Outage analysis may only be performed for large outages, if at all. Outage details are not recorded consistently or for reporting purposes. It may be difficult to extract information from generator, substation and operating records. There are no established processes related to customer outage analysis.		

iv.	How are network demands and capacity utilisation calculated or derived?	Related Questionnaire Data Inputs	Comments
A	Calibrated metering equipment is installed at all zone and distribution substations and at consumer's premises for all categories of consumers. Demand information is captured throughout the network. Records are up to date and identify installed capacity of lines and transformers. Billing records and databases reveal regular reading of meters. Established processes exist and are used for reporting of capacity utilisation, losses and network demand profiles. Power system anaysis software may be in use and routinely undertaken. Detailed loss breakdowns are regularly updated and available.	4, 5, 23, 26, 32	[Please insert any comments on your self assessed data reliability grading here]
B	Generally as per A, although processes and systems are not as developed. Limitations of installed metering and substation equipment will require more manual processing of information. Asset records are missing information requiring some extrapolation for assessment purposes. Power system analysis software or studies may be undertaken from time to time.		
C	Metering is not comprehensive enough to allow evaluation of demand and losses easily throughout the network. There may be significant limitations in the records of installed assets. Billing records and aggregate consumption information is incomplete.		
D	Asset records may be well out of date and metering coverage of the network poor. Major assumptions required for evaluation of utilisation at an aggregate level. No meaningful loss breakdown possible. No recent power system analysis completed.		

v.	How are the number of connections or customers calculated?	Related Questionnaire Data Inputs	Comments
A	Billing records and databases clearly identify customer specific meters. Billing processes reveal regular reading of meters and meter readings are the basis for charging consumers. Databases of electricity connections and meters are complete. There is a mechanism to identify faulty meters and repair meters. Processes for installation of new connections, installation of meters and generation of bills based on this are interlinked with a robust process.	43 to 56 inclusive	[Please insert any comments on your self assessed data reliability grading here]
B	Database/ records reveal the list of customers that have meters installed in their electricity connections. Meter data and associated customer databases may be limited and the linkage with the billing system harder to demonstrate.		
C	Records do not reveal the exact number of connections which are metered . Not all billing is based on metered quantities. Processes associated with new connections and metering management may not be robust.		
D	No formalised processes for metering and connection management. Number of current connections estimated with poor linkages to billing system and database coverage.		

vi.	Where is financial information sourced from?	Related Questionnaire Data Inputs	Comments
A	Major budget and functional reporting categories identified and separated. Cost allocation standards for common costs are in place. An accrual based double entry accounting system is practiced. Accounting standards are comparable to commercial accounting standards with clear guidelines for recognition of income and expenditure. Accounting and budgeting manuals are in place and are adhered to. Financial statements have full disclosure and are audited regularly and on time.	59 to 83 inclusive	[Please insert any comments on your self assessed data reliability grading here]
B	Key costs related to generation and distribution are identifiable, although complete segregation is not practiced. Key income and expenditure is recognised based on accrual principles, but accounting standards may not be comparable to commercial accounting standards. Disclosures are complete and are timely and audits undertaken.		
C	Major budget and functional reporting categories are not clearly separated, eg, between electricity power supply costs and costs for other utility functions such as water, sewerage, etc. Limited useful functional reporting and cost allocation principles in place. Audits may have a significant time lag or may be irregular.		
D	There is no segregation of major budget and functional categories, eg, no clear distinction between electricity power supply costs and costs for other utlity functions such as water, sewerage, etc. A cash-based accounting system may be practiced. There are no clear systems for reporting unpaid expenditure or revenues that are due. Disclosures and reporting may not be timely.		

This will be followed up by data reliability audits conducted by the Benchmarking Team when given opportunity through site visits.

SECTION 6: Performance Improvement Plans

Ultimately, the value of benchmarking is in utilising the results to develop and implement an action plan that will lift performance. Areas of priority and KPI performance targets will be different for each utility.

Broad areas of focus could be:

- Improving customer service
- Lifting operational performance
- Lifting financial performance

Various approaches could be used to select KPIs such as:

- Alignment with utility strategy/focus
- Least cost option
- Risk assessment
- Improving data collection & reporting

Benchmarking exercises and data will provide utility managers with the tools necessary for developing improvement initiatives. Where data collection and storage are seen to be inadequate, setting up data recording systems will be a positive first step. Templates for some of the major areas of data collection are provided in Appendix D.

KPIs that relate to the focus areas need to be identified, targets set for improvement and then strategic initiatives developed and implemented to achieve the target set.

Table 6.1: Priority Improvement Plan Template

Priority Improvement Plan			
Priority KPI	**Current Benchmark**	**Target**	**Improvement Initiatives**
KPI A			
KPI B			
KPI C			
…			

A table showing examples of improvement initiatives is provided below. Each utility will need to consider the initiatives that will best address the KPIs they are targeting within their own context.

Table 6.2: Performance Improvement Plan Initiatives

KPI #	Indicator Name	Value	Unit	Improvement Initiative
	Generation			
1	Load Factor		%	• Implement measures to shift demand from peak to off peak e.g. tariffs, DSM initiatives
2	Capacity Factor		%	• Review/set spinning reserve policy/operational philosophy • Improve generation reliability to enable less standby capacity
3	Availability Factor		%	• Preventative maintenance • Improve planned outages to reduce forced outages
4	Generation Labour Productivity		GWh/FTE generation employee	• Human Resources management strategies
5	Specific Fuel Oil Consumption		kWh/L	• Maintenance of engines • Review generation dispatch policy
6	Lube Oil Consumption		kWh/L	• Check quality of oil
7	Forced Outage		%	• Maintenance Plan • Regular Inspections/Test to detect need for maintenance - include this in Operator duties
8	Planned Outage		%	• Incentivise Employee Performance, Templates/Recording Systems to record data • Publicise data
9	Generation O&M Costs		USD/MWh	• Review staffing requirements • Address losses • Reduce unbilled usage
10	Power Station Usage		%	• Employ DSM activities in Power Station
11	Renewable Energy to Grid		%	• Conduct a resource review on renewable energy options • Progress with studies already completed
12	IPP Energy Generation		%	• Consider IPP agreements
13a	Distillate Generation		%	• Review fuel mix • Consider RE options.
13b	Heavy Fuel Oil Generation		%	
13c	Biofuel Generation		%	

KPI #	Indicator Name	Value	Unit	Improvement Initiative
13d	Mixed Fuel Generation		%	
13e	LNG Generation		%	
14	Enabling Framework for Private Sector			• Develop enabling environment
	Transmission			
15	Transmission Losses		%	• Redesign of transmission network • Consider installing capacitors
16	Transmission Reliability		outage events/km	• Preventative maintenance
17	Average Transmission Outage Duration		h	• Preventative maintenance
	Distribution			
18	Network Delivery Losses		%	• Phase balancing • Proper design and planning.
19	Distribution Losses		%	• Determine proportion of technical and non-technical losses • Address issues of theft, faulty meters, lack of metering
20	Customers per Distribution Employees		customers/ distribution employee	• Human Resource Management Plan • Increase customer connections.
21	Distribution Reliability		events/100 km	• Preventative maintenance
22	Distribution Transformer Utilisation		%	• Ensure adequate planning for distribution expansion • Correct sizing of new transformers.
23	Distribution O&M Cost		USD/km	• Review staffing requirements • Address losses • Reduce unbilled usage • Consider automation • Fault locators.
24	SAIDI		%	• Preventative maintenance • Review/improve network redundancy • Automate switching • Improved recording of outage data
25	SAIFI		%	• Preventative maintenance • Review/improve network redundancy • Automate switching • Improved recording of outage data
	Demand Side Management			
26	DSM Initiatives			
27	DSM Budget		USD	• Set budget for DSM • Link Budget to expected outcomes Reward employees for successful implementation/performance based

KPI #	Indicator Name	Value	Unit	Improvement Initiative
				remuneration/bonuses
28	DSM FTE Employees		#	
29	DSM MWh Savings		MWh	
30	Power Quality Standards			
	Human Resources / Safety			
31	Lost Time Injury Duration		days	• Human Resources Management Plan
32	Lost Time Injury Frequency Rate			• Safety Initiatives • Use of Safety Standards • PPE • Training
33	Labour Productivity		%	• Performance Based Remuneration
	Customers / General			
34	Service Coverage		%	
35	Productive Electricity Usage		%	• DSM
36a	Lifeline Tariff Usage		%	
36b	Domestic Usage		%	
36c	Commercial Usage		%	
36d	Industrial Usage		%	
36e	Other Usage		%	
37	Customer Unbilled Electricity		%	• Install/repair meters • Prepaid meters • Implement DSM activities for legitimate unbilled customers
38	Self Regulated or Externally Regulated			
	Financial Indicators			
39	Operating Ratio			• Reduce costs • Increase revenue
40	Debt to Equity Ratio		%	
41	Rate of Return on Assets		%	• Increase profits
42	Return on Equity		%	• Increase profits
43	Current Ratio		%	• Maintain sufficient current assets to cover liabilities
44	Debtor Days		days	• Incentivise Payment by Due Date • Ensure access to pay bills is easy • Pre-paid metering
45	Average Supply Cost		US c /kWh	• Cost management • Improve utilisation of assets.

Once a Priority Improvement Plan has been formed, it is then resourced, planned and implemented. Regular review of the KPIs will help guide the implementation and pre-empt adjustments where necessary.

For some utilities the priority initiatives would be improving data collection. Templates that facilitate the collection of key data elements for calculation of KPIs are provided in Appendix D. These include templates for:

- Lost Time Injury Recording
- Generation Power Outage Recording
- Transmission Power Outage Recording
- Distribution Power Outage Recording

APPENDIX A:
Pacific Power Utilities Data

Table A: Basic Information on Participating Utilities in 2011 Benchmarking Round

Abbreviation & Country	Utitlity	Installed Capacity (MW)	Gross Generation (Excludes IPPs) (MWh)	Maximum Demand (MW)	Customers (Number)	Employees FTE
ASPA (A.Samoa)	American Samoa Power Authority	47.7	159,113	24.8	11,884	209
CPUC (Chuuk, FSM)	Chuuk Public Utility Corporation	2	9,768	4	1,634	56
CUC (Saipan)	Commonwealth Utilities Corporation, Saipan	106.7	216,541	44.9	15,500	242
EDT (Tahiti)	Electricite de Tahiti	235.3	688,853	101.4	81,044	487
EPC (Samoa)	Electric Power Corporation	37.5	111,353	18	38,158	602
FEA (Fiji)	Fiji Electricity Authority	211.2	835,169	139.6	151,410	673
GPA (Guam)	Guam Power Authority	552.8	1,252,672	272	47,333	522
KAJUR (Ebeye, RMI)	Kwajalein Atoll Joint Utility Resources	3.6	14,183	2	-	-
KUA (Kosrae, FSM)	Kosrae Utilities Authority	5	6,504	1.1	1,845	23
MEC (Majuro, RMI)	Marshalls Energy Company	28	75,747	8.9	4,832	180
NPC (Niue)	Niue Power Corporation	2.1	3,000	0.6	870	21
NUA (Nauru)	Nauru Utilities Authority	8	17,103	3.3	1,918	70
PPL (PNG)	PNG Power Limited	292	796,610	92.9	91,173	1412
PPUC (Palau)	Palau Public Utilities Corporation	18.9	84860	15.4	6,417	70
PUB (Kiribati)	Public Utilities Board	5.5	21,641	5.3	8,337	57
SIEA (Solomon Isl)	Solomon Islands Electricity Authority	25.6	83,600	13.8	13,753	-
TAU (Cook Islands)	Te Aponga Uira O Tumu Te-Varovaro	10.36	27,763	4.9	5,249	54
TEC (Tuvalu)	Tuvalu Electricity Corporation	5.1	11,800	1	2,210	59
TPL (Tonga)	Tonga Power Limited	15.3	52,609	7.7	14,000	104
UNELCO (Vanuatu)	UNELCO Vanuatu Limited	23.6	60,360	11.3	10,571	106
YSPSC (Yap, FSM)	Yap State Public Service Corporation	6.6	13,000	2.3	1,900	23
Average		80	219200	38	26200	265
Median		17	56500	8	8300	87
Non-Participating Utilities						
EEC (New Caledonia)	Electricite et Eau de Caledonie					
EEWF (Wallis et Futuna)	Electricite et Eau de Wallis et Futuna					
ENERCAL (New Caledonia)	Societe Neo-Caledonenne D'Energie					
PUC (Pohnpei, FSM)	Pohnpei Utilities Corporation					

Notes: 1. Data were provided by the utilities in response to the Benchmarking exercise 2011. 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.

APPENDIX B: Section 1 of Benchmarking Questionnaire (2012)

1.0: GENERAL UTILITY INFORMATION

Information on the person providing the information

Lead utility coordinator: (who completes the form)	
Approved by utility CEO:	
Position:	
Reporting period:	
Country or territory:	
Name of utility	
Postal address of utility	
E-mail address:	
Back up e-mail address:	
Telephone number:	
Skype address (if any):	

1.1: Electricity services through the grid

Does utility supply the entire country (or state or locality where relevant)?	
If the reply is no, what are the main islands or island groups served by the utility?	
Rural electrification through the grid. Is the utility responsible for supply to rural consumers? If so, how is 'rural' defined? *	
Rural electrification: stand-alone or not grid-connected Is the utility responsible for small mini-grid supply (e.g. village supply, stand-alone solar PV, etc.) If so, explain briefly	

* Connections per km^2 (or per square mile) or other criteria

1.2: Utility ownership, services provided and institutional arrangements

Government ownership (%)	
Private ownership (%)	
Other (%)	

Service other than electricity	**Yes/ No**	**Year's turnover as % of total***
Water supply		
Waste management		
Telecommunications		
Petroleum or LPG supply		
Other (indicate service)		

Utility operates under:	**Yes/ No**	**Date in effect; date of expiry or comments**
An Act of legislature (or equiv.)?		
A concession agreement or license (or concessions/licenses)?		
Other legal framework (for example, part of Public Works?		
Is Government represented on board? (If so indicate if through Finance Ministry., Public Works, Energy Dept., etc.?)		
Does the Government decide tariff levels?		

Regulatory & service framework	Yes/No and Comment
Is utility self-regulating? (If yes, for technical standards or policies on IPPs, PPAs, FITs, etc.? *	

* IPP = Independent power producer; PPA = Power purchase agreement; FIT = Feed-in tariff

Is there an external or independent utility regulator?	
If yes, name & year established and make-up of regulatory members	
If yes, legal responsibilities (e.g. tariffs, tech standards, etc.)	
If yes, regulator's relationship with the Government (govt department, independent govt agency, etc.)	
If no, is an independent regulator being considered by the Government or is it under development ?	
Is there a legal requirement, regulation, decree etc. on power quality (e.g. voltage or frequency tolerance)? If yes, briefly describe	

Is there a service obligation (e.g. mandatory supply to rural areas near grid)? If so explain briefly	
Are clear regulations in place to allow independent power supply to the grid by Independent Power Producers (IPPs)? If so, when did this enter into force & is there any formal regulation?	
Is there a feed-in tariff policy (e.g. for private solar PV systems to feed to the grid)? If so, describe briefly	
Is there a requirement to provide demand side management (DSM) energy efficiency services to commercial &/or household consumers? If so, describe briefly.	
Is there a formal national goal for generation from renewable energy? (If so, is this government or utility goal? Briefly describe (e.g. 10% of generation by 2020)	

1.3: Tariff schedule and taxes

Tariff schedule	**Other information**
The final tariff change introduced in 2010	Date change came into effect
All tariff changes in 2011	Date change came into effect
Fuel surcharge and dates of any change	Fuel surcharge, if not included in tariff schedule
Tax on consumers	Indicate if the published tariff includes Value added tax (VAT) or other taxes

Fuel import duty & taxes	**Other information**
Import duty on fuel use	Provide % of CIF value, cents/litre, cents/gallon, etc. as appropriate. Note if utility fuel use is free of import duty
Other tax on fuel use for generation	Provide any additional tax, if any on fuel used for electricity generation. Note if utility fuel use is free of any normal fuel tax
Tax concessions for utility equipment	Provide information on any reduced tax or other concessions for equipment imported by the utility

APPENDIX C: Financial Statements

Statement of Comprehensive Income

For the year ended 31 December 2010

Notes
2009

		2010	2010	
		$'000	% Revenue	
				$'000
Revenue - electricity sales	5	226,945		169,049
Other operating revenue	5	4,654		10,556
Total revenue		**231,599**		**179,605**

Total Operating Revenue

Personnel costs		(17,447)	(17,993)
Fuel costs		(126,756)	(77,270)
Electricity purchases		(12,611)	(12,027)
Lease and rent expenses		(1,688)	(1,721)
Depreciation on property, plant and equipment		(29,655)	(28,819)
Amortisation of intangible assets		(528)	(543)
Losses due to flooding -		(1,140)	
Cyclone Mick & Tomas - Restoration costs		(1,445)	(2,157)
Other operating expenses		(24,652)	(24,315)
Total expenses		**(214,782)**	**(165,985)**

Total Operating Expenses

Profit before finance costs, income tax and interest in joint venture		**16,817**	**13,620**

EBIT

Finance Cost			
Finance cost		(12,631)	(10,176)
Interest income		1,278	2,309
Unrealised foreign exchange gain / (loss), net		7,534	(5,322)
Profit before income tax and interest in joint venture	6	**12,998**	**431**
Share of profit of joint venture		192	499
Profit before income tax		**13,190**	**930**
Income tax (expense/benefit)	7(a)	(4,786)	1,515
Profit after income tax		**8,404**	**2,445**
Other comprehensive income		-	-
Total comprehensive income for the year		**8,404**	**2,445**

EAT

The above statement of comprehensive income has been prepared in accordance with the International Financial Reporting Standards (IFRS) and should be read in conjunction with the accompanying notes.

Statement of Financial Position

For the year ended 31 December 2010

Notes	2010 $'000	% Total $'000	2009
CAPITAL AND RESERVES			
Retained profits		351,501	343,097
Capital contribution		63,199	58,943
		414,700	402,040

Equity

Represented by:

Debtor
Year End

CURRENT ASSETS			
Cash on hand and at bank	8		- 36,490
Held to maturity financial assets	13(b)	55,837	57,859
Receivables and prepayments	9	32,617	27,714
Inventories	10	16,142	15,166
Loans receivable	12	-	621
Withholding income tax recoverable		328	330
	104,924	**138,180**	

Current
Assets

NON-CURRENT ASSETS			
Property, plant and equipment	11	809,081	716,537
Loans receivable	12	-	9,735
Available for sale financial assets	13(a)	233	2,270
Intangible assets	14(b)	2,502	2,560
Deferred tax assets	7(b)	8,834	10,997
	820,650	**742,099**	
TOTAL ASSETS		**925,574**	**880,279**

Non Current assets
End of Benchmark
period

Non Current assets
End of Previous
period

CURRENT LIABILITIES			
Bank overdraft	8		
Trade and other payables	15	59,063	23,638
Provision for employee entitlements	16	1,710	1,641
Interest bearing borrowings	17	71,628	116,435
	132,677	**141,714**	

Current Liabilities

NON-CURRENT LIABILITIES			
Trade and other payables	15	30,610	26,927
Provision for employee entitlements	16	4,670	5,398
Interest bearing borrowings	17	280,181	243,232
Deferred income	18	11,563	12,419
Deferred tax liabilities	7(c)	51,173	48,549
	378,197	**336,525**	
TOTAL LIABILITIES		**510,874**	**478,239**
NET ASSETS		414,700	402,040

Long
Term
Debt

Equity

The above statement of financial position has been prepared in accordance with the International Financial Reporting Standards (IFRS) and should be read in conjunction with the accompanying notes.

APPENDIX D:
Data Recording Templates

1) Lost Time Injury Recording

LOST TIME INJURY RECORDING						
				Absent from Work		Total Days Absent
Date of Injury	Name of Employee	Department	Nature of Injury	Start Date	End Date	due to Injury

2) Generation Power Outage Recording

GENERATION POWER OUTAGE RECORDING						
	Outage		Duration of	Number of		Planned or
Date of Outage	Start Time	End Time	Outage	Customers Affected	Cause of Outage	Forced Outage?

3) Transmission Power Outage Recording

TRANSMISSION POWER OUTAGE RECORDING						
	Outage		Duration of	Number of		Planned or
Date of Outage	Start Time	End Time	Outage	Customers Affected	Cause of Outage	Forced Outage?

4) Distribution Power Outage Recording

DISTRIBUTION POWER OUTAGE RECORDING						
	Outage		Duration of	Number of		Planned or
Date of Outage	Start Time	End Time	Outage	Customers Affected	Cause of Outage	Forced Outage?