Report #3: Final Independent Expert Report of TPL proposal

Updated Version

Technical Assistance to strengthen the capacity of the Tonga Electricity Commission in promoting private sector investments in Tonga's Power Sector

SUBMITTED TO:

Pacific Community (SPC)

Tonga Electricity Commission (TEC)

SUBMITTED BY:

ENERGY & ECONOMICS CONSULTING

04 August 2020

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LIST OF ACRONYMS

CAIDI	Customer Average Interruption Duration Index
Capex	Capital expenditures
ECC	Electricity Concession Contract
EEC	Energy & Economics Consulting
ERP	Equity Risk Premium
IMF	International Monetary Fund
INDC	Intended Nationally Determined Contributions
IPP	Independent Power Producer
Opex	Operational expenditures
PCREEE	Pacific Centre for Renewable Energy and Energy Efficiency
PPA	Pacific Power Association
PPA	Power Purchase Agreement
RAV	Regulatory Asset Value
RE	Renewable Energy
ROR	Rate of Return
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SPC	Pacific Community
TEC	Tonga Electricity Commission
TPL	Tonga Power Limited
WACC	Weighted Average Cost of Capital

1. INTRODUCTION

1.1. Background and Objectives

The Tonga Electricity Commission (TEC) is responsible for the regulation of the electricity sector in the Kingdom of Tonga. Tonga Power Limited (TPL) is the main actor in the sector and is operating under the framework of an Electricity Concession Contract (ECC).[1]

An important element of the ECC is the so-called Regulatory Reset. The coming Regulatory Reset, which is to be completed by 30 June 2020, consists of two main elements. First, the determination of the electricity tariffs applicable to TPL in the next ECC period. This is to be done on the basis of the methodologies set out in the current ECC. Second, the negotiating and determination of the third ECC – which then will prescribe the applicable regulatory framework after July 2020.

To assist TEC in carrying out the Regulatory Reset, assistance from suitable consultants was procured through support from the Pacific Centre for Renewable Energy and Energy Efficiency (PCREEE). Energy & Economics Consulting (EEC) was selected to carry out this important assignment.

1.2. Purpose of this report

The assignment consists of the following deliverables:

Nr	Deliverable	Description
1	Report #1: Review of the ECC	Desk study review of the current ECC
2	Report #2: Initial Independent Expert Report of TPL proposal	Review of TPL proposal as per Schedule 11 – para 3 of the ECC
3	**Report #3: Final Independent Expert Report of TPL proposal**	**Revised report on TPL's resubmission, meetings and training report**
4	Report #4: Independent Expert Report on submissions and consultations	Review report on Government reset submission (if any) and feedback from public consultations
5	Report #5: Meetings and Training Report	Reports on meetings (between TEC, Government and TPL) and training report

1 The current ECC can be accessed at: http://www.tongapower.to/Portals/2/Docs/concession_contract/The%202nd%20ECC%20No.%201.pdf

6	Report #6: Final Report	End of contract Report (report containing all materials produced in the assignment) and the Tariff Model

In the previously submitted Report #2, the Independent Expert (EEC) presented its view on TPL's Proposals and developed a series of recommendations for the tariff setting. TPL responded to Report #2 and addressed the recommendations that were made. In this report, the response from TPL is reviewed and final recommendations are presented.

Furthermore, this report also includes the results of the training that has been carried out so far. Due to the COVID-19 pandemic however, it was not possible to undertake a visit to Tonga yet. Therefore, two online training sessions were carried out.

1.3. Report outline

This report is structured as follows:

- Section 2 presents an overview of the final recommendations with respect to the non-fuel tariff.
- Section 3 presents an overview of the final recommendations with respect to the fuel tariff.
- Section 3 presents an overview of the final recommendations with respect to the service standards.

Furthermore:

- Annex 1 presents the detailed results from the WACC analysis (as previously reported in Report #1).
- Annex 2 contains the revised Schedule 6 of the ECC, based on the recommended changes to the fuel tariff i.e. split into a Diesel Component and RE Component.
- Annex 3 contains a draft for the PPA Guideline Protocol.

2. NON-FUEL TARIFF

2.1. Time period

TPL had proposed to set the duration of Period 3 to five years i.e. 2020 to 2025. The current regulatory Period 2 is set at five years. This seems to be a reasonable period and strikes a good balance between risks and incentives. Given that TPL also prefers a period of 5 years, there is no reason to opt for a different time period. As such a time period of 5 years is thus recommended and was agreed to with TPL.

2.2. Demand forecast

TPL had proposes a demand forecast growth of 2.78% per annum. This is based on a forecast for TBU of 3% and for the Outer Islands of 1.5%. The weighted average then (based on 86/14 weights) comes down to 2.78%.

Table 1: TPL demand forecast. Source: TPL Proposal.

Demand Forecast (kWh per year)	2020	2021	2022	2023	2024	2025
TPL Proposal	64,800,000	66,598,200	68,446,300	70,345,685	72,297,778	74,304,041

Between 2015 and 2019 the compounded growth was 6.3%. This is more than twice the proposed rate of 2.78%. Also, TPL's assumption that growth in TBU is higher than the outer islands is incorrect. Historical data show growth levels in outer island to be higher on average.

Therefore, an alternative demand forecast was been carried out based on economic analysis. The main principle of the model is that there is a close relation between economic growth and electricity consumption. This method is based on the relationship between GDP and sales: As the economy grows, the level of electricity consumption will naturally increase and hence sales for the utility will also increase. The causal relationship between electricity consumption and GDP, which is also widely accepted in the literature, can be clearly seen in Figure 1. This Figure shows the relationship for a sample of countries worldwide. As may be observed, the electricity consumption clearly increases at higher levels of economic development.

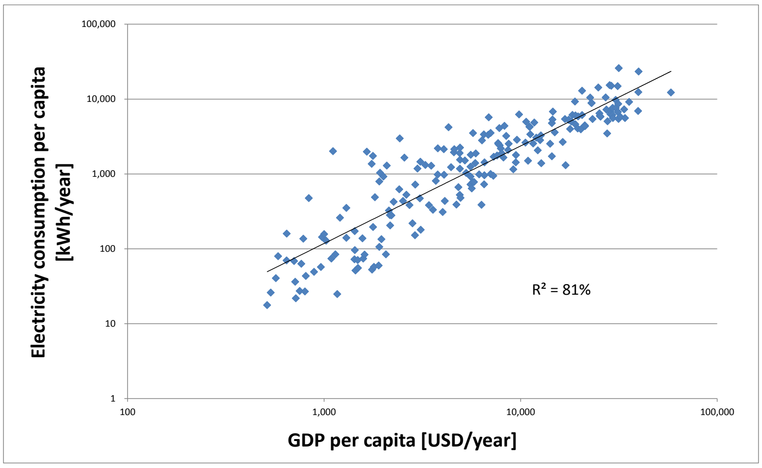


Figure 1: Relationship between economic development and electricity consumption data for an international sample of countries. Source: World Bank data.

The relationship between the change in GDP and the change in kWh consumption is however not one-to-one. A given percentage change in GDP will not result in the same level of growth, but only to some degree. This is expressed in terms of an elasticity factor (ε):

$$\varepsilon_{kWh} = \frac{\overline{kWh}_t / \overline{kWh}_{t-1} - 1}{GDP_t \,/\, GDP_{t-1} - 1}$$

Where:

- i: Customer category
- t: year
- $\overline{kWh}$: Energy consumption
- ε_{kWh}: Elasticity for kWh
- GDP: Gross Domestic Product

For deriving the elasticity factor, historical data has been used as reported by TPL. Data on GDP has been obtained from the IMF. The correlation between the two variables is shown in Figure 2. From the historical data the elasticity factor was estimated to be 1.05. This implies that a 1% increase (decrease) in GDP results in a 1.05% increase (decrease) in the level of consumption.

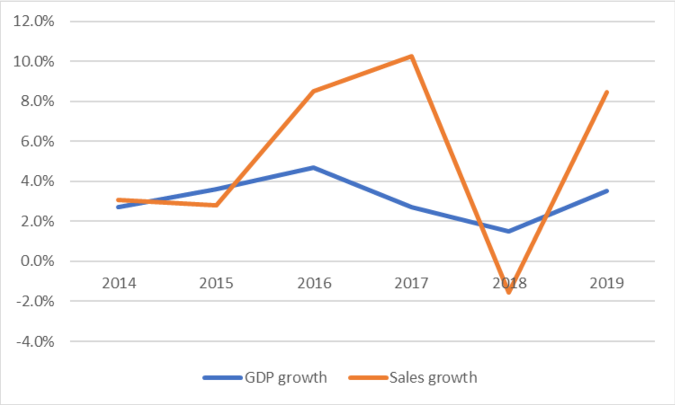


Figure 2: Historical correlation between change in GDP and electricity sales.

The forecast for sales can be derived from the expected changes in GDP. For this the IMF forecasts have been used.

Table 2: GDP growth projections by IMF.[2]

Year	2020	2021	2022	2023	2024	2025
GDP Growth	3.7%	2.9%	2.4%	2.1%	2.0%	2.0%

The results of the demand forecast on the basis of the GDP method is presented in Table 3. This is based on the methodology and estimated economic parameters as discussed in the previous sections. As can be seen, there is a difference in the sense that the economic forecast is based on an annually different growth factor, while TPL's forecast has assumed a compounded growth.

Table 3: Demand forecast on the basis of the economic model and comparison with TPL forecasts

Demand Forecast (kWh per year)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Economic Model	65,184,313	67,146,361	68,865,308	70,407,890	71,893,497	73,410,450
TPL Proposal	64,800,000	66,598,200	68,446,300	70,345,685	72,297,778	74,304,041
Difference	384,313	548,161	419,008	62,205	(404,281)	(893,591)

2.3. Non-fuel opex

2.3.1. TPL Proposal

For the opex forecast in Period 3, TPL has developed the projections as shown in the below Table. As mentioned by TPL, these projections show a downward trend compared to the actual opex in period

[2] See: https://www.imf.org/external/datamapper/NGDP_RPCH@WEO/OEMDC/TON

2 of -1.56%. In its projections, TPL notes, cost efficiencies equal or greater than the rate of inflation have also been incorporated.

Table 4: Opex projections for period 3. Source: TPL Proposals, p. 16.

OPEX by REGULATED DIVISION	2020/21	2021/22	2022/23	2023/24	2024/25	Total	%
Distribution	3,224,552	3,109,586	3,148,136	3,195,755	3,118,842	15,796,871	18.2%
Generation	4,844,316	4,321,996	4,902,856	4,787,191	4,995,107	23,851,466	27.5%
Retail	1,650,306	1,650,306	1,650,306	1,650,306	1,650,306	8,251,530	9.5%
Indirect/ Corporate	7,521,268	7,569,693	7,721,087	7,875,509	8,133,019	38,820,577	44.8%
	17,240,442	16,651,582	17,422,385	17,508,761	17,897,275	86,720,445	100.0%

When evaluating opex it is important that this is done on a per-unit basis i.e. opex per unit of output (kWh). The reason for this is that the absolute opex is strongly dependent on the size of the operations which is represented by the sales base of the company. The following Figure shows the projected opex per kWh for each category. For 2015/16 till 2018/19 the data is based on actuals. After that, the data are projections (indicated by years with a "*"). Also, the costs have been converted into United States Dollars to accommodate the analysis that will be presented further.

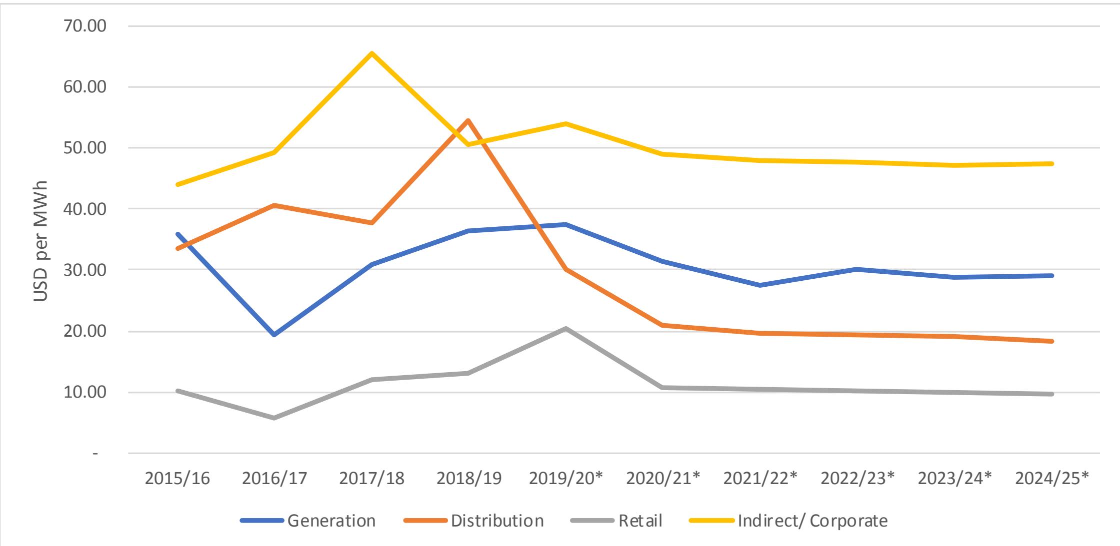


Figure 3: Historic opex and proposed opex by TPL per category. Source: TPL Proposals, p. 15-16.

For reference the cost per category are also shown below in tabular format.

Table 5: Historic opex and proposed opex by TPL per category. Source: TPL Proposals, p. 15-16.

USD/MWh	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Generation	35.9	19.2	30.8	36.5	37.5	31.6	27.4	30.2	28.7	29.2

Distribution	33.4	40.5	37.7	54.6	30.0	21.0	19.7	19.4	19.2	18.2
Retail	10.3	5.7	12.1	12.9	20.3	10.7	10.5	10.2	9.9	9.6
Indirect/Corporate	44.0	49.3	65.5	50.6	53.9	49.0	48.0	47.6	47.3	47.5
Total	**123.5**	**114.8**	**146.1**	**154.6**	**141.7**	**112.3**	**105.5**	**107.4**	**105.1**	**104.5**

As can be observed in Figure 1, opex levels have sharply increased in period 2 and are projected to remain at a more or less stable level during period 3. The total opex, as shown in Figure 2, remains constant at a level of around 105 USD per MWh.

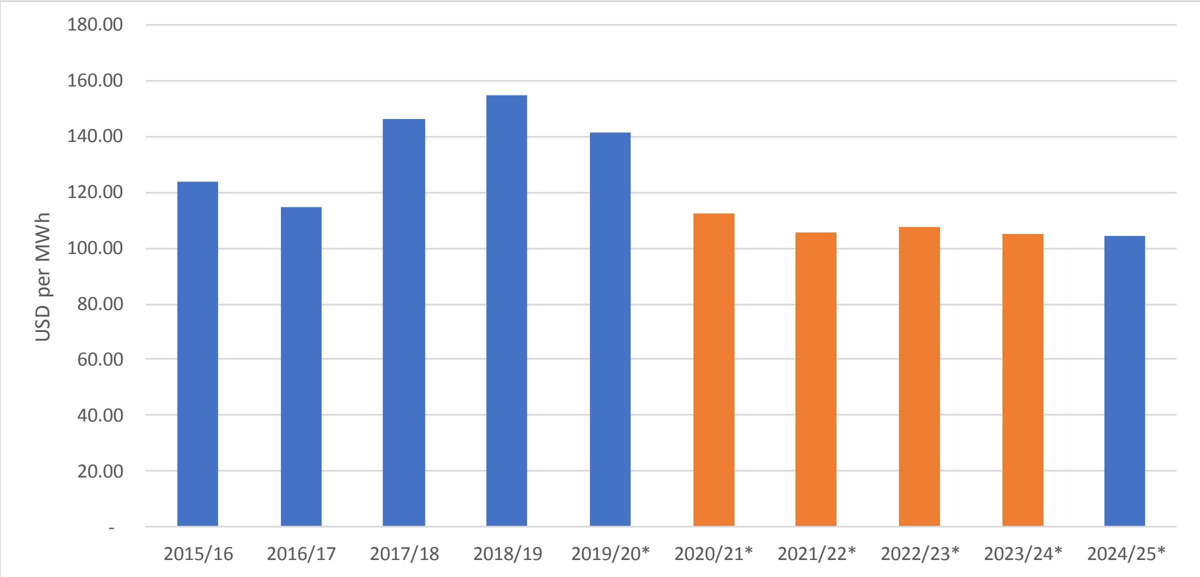


Figure 4: Historic opex and proposed total opex. Source: TPL Proposals, p. 15-16.

When reviewing opex proposals part of a regulatory process, any regulator is faced with the challenge of how to evaluate what the appropriate allowed "efficient" level of opex is. If the allowed opex is set too high, then this results in excessive profits to the company. On the other hand, a too low opex allowance may negatively affect the financial performance of the company. Faced with this issue, it is important to make a clear distinction between two separate issues.

First, the question comes up what the efficient opex is i.e. what level of opex can be considered being reflective of an efficiency mode of operations, considering the environment that the company operates in and any constraints faced. For example, the fact that TPL is an island utility already imposes a constraint in the sense that the possibility to enhance efficiency through scale effects is very limited. Larger utilities, such as those operating on the mainland, generally have more scope for scale efficiency improvement as compared to island utilities.

The standard approach followed by regulators to assess opex proposals is benchmarking. Benchmarking is the process of comparing cost in a given utility with the cost incurred by other – more or less similar- utilities in other jurisdictions. The basic idea is that if one utility is able to reach a certain level of high efficiency, any other similar utility would in principle be expected to do the same.

Of course, benchmarking has its limitations in the sense that no company is fully comparable to another. There will always be certain factors that drive the cost of a given company, and which may not be applicable to the other company. However, benchmarking is a useful tool to at least get quantitative information about relative levels of performance. The constraints of benchmarking are therefore not so much its application itself, but rather the way in which the results of the benchmarking analysis are used.

The second issue is how much time will be needed for a utility to improve its cost from the current level to the perceived efficient level. It cannot be expected that full efficiency will be achieved overnight. Improvements will require great efforts which will only materialize over time. When setting opex allowances therefore, the regulator needs to account for the fact that opex efficiency achievements will happen in a gradual fashion. This needs to be reflected in the setting of the allowed opex.

TPL's proposed opex for period 3 are reviewed in the next section. For the benchmarking analysis, two sets of data samples have been used. First, the data published by the PPA in their Benchmarking Report.[3] Second data set consisting of 12 Caribbean utilities. Data for these have been collected from their financial statements and/or regulatory statements.

2.3.2. Benchmarking using PPA data

PPA publishes two sets of comparisons regarding costs in their benchmarking report: Generation O&M cost per MWh, and T&D cost per km of network. The results are shown in the following figures.

[3] PPA Pacific Utilities Benchmarking Report, PPA, 2018.

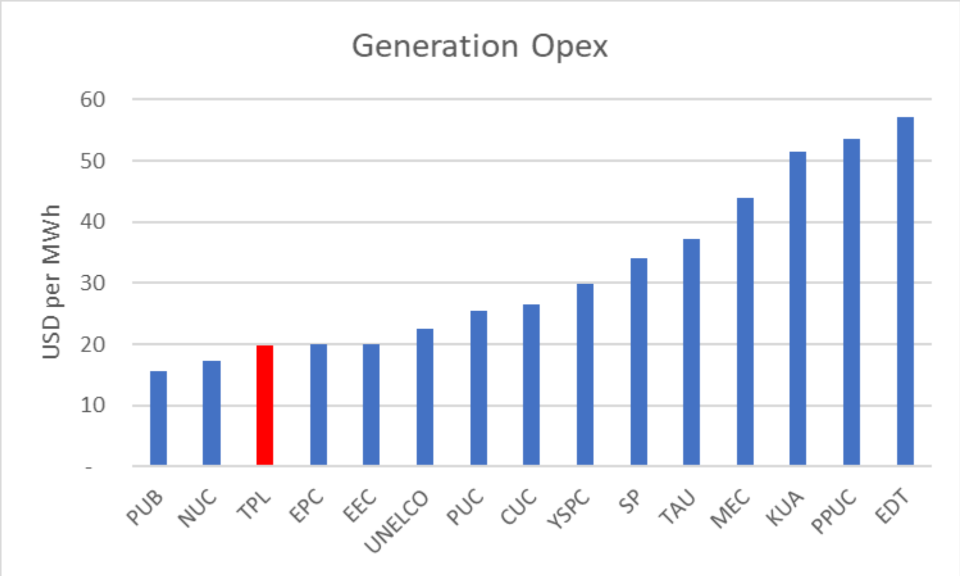


Figure 5: Comparison of generation opex for TPL versus peers in the Pacific region. Source: PPA benchmarking report 2018.

As may be observed, TPL has relatively low cost compared to others in the PPA sample. Its cost is shown as around 20 USD per MWh and is among the lowest in the sample. However, is it unclear how this indicator is defined, given that in the data reported in TPL's proposals, the generation cost is around 30 – 35 USD per MWh in the period 2017/18 till 2018/19. As the PPA data refers to the year 2018, there seems to be a difference in definition applied in the PPA data and the data shown here. It is unclear what the source of this substantial difference is.

For distribution cost, TPL is located in the middle of the sample with a cost of around 4,000 USD per km of network. This is more than twice as high as the least cost company in the sample.

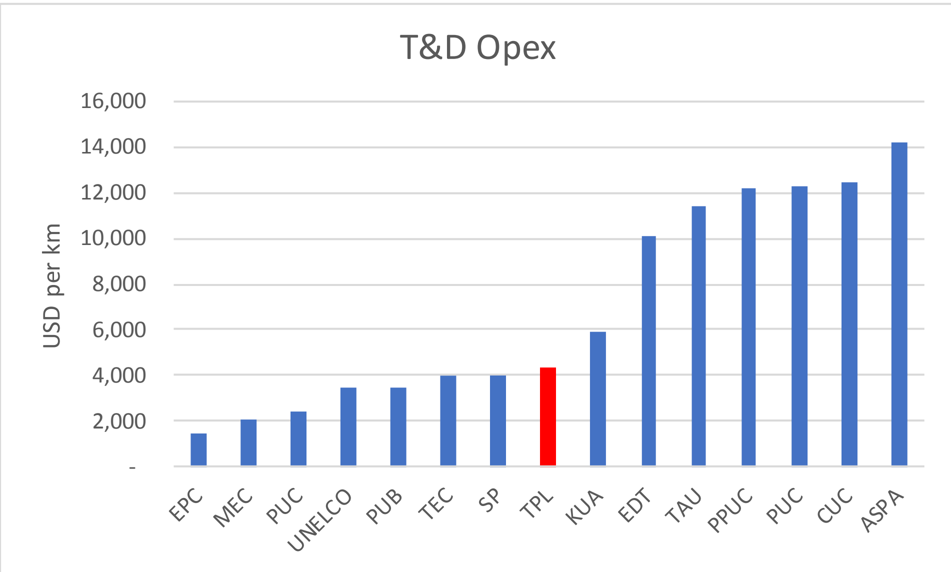


Figure 6: Comparison of distribution opex for TPL versus peers in the Pacific region. Source: PPA benchmarking report 2018.

2.3.3. Benchmarking using Caribbean data

The PPA benchmarking are a useful reference but do not provide sufficient information to determine what adequate opex levels for TPL are. Therefore, supplemental benchmarking has been undertaken using a set of Caribbean utilities as comparators. These utilities are very similar to TPL in the sense that they are island utilities operating relatively small systems. These utilities can thus be considered an appropriate reference. However, it should also be recognized that any benchmarking effort is imperfect by definition and therefore the results of the analysis are not to be taken as the target itself, but rather should act as guidance in the setting of the opex targets.

When comparing the total opex for TPL against peer (island) utilities in the Caribbean, a distinction is made between the four cost categories (generation, distribution, retail, and indirect). For each cost category, the cost per MWh has been computed.

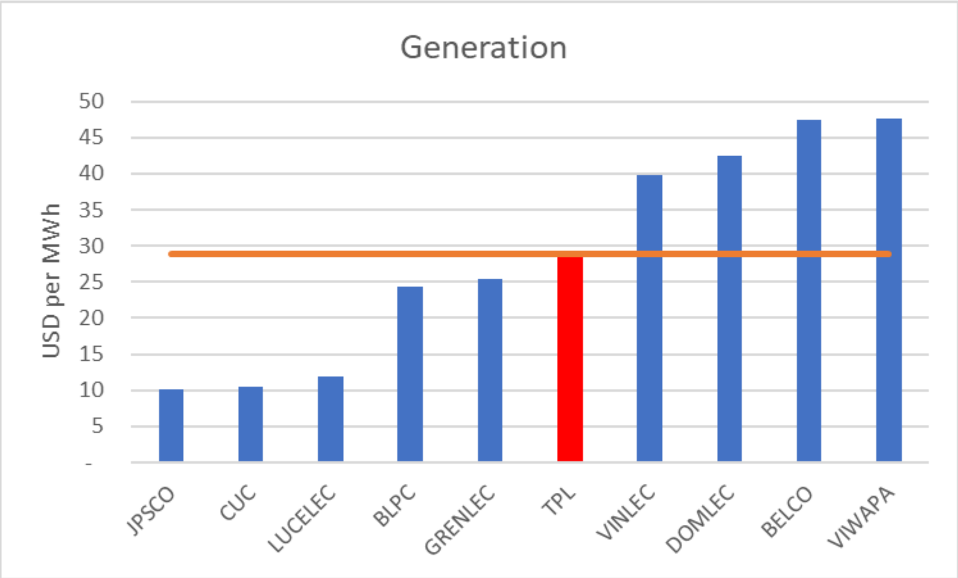


Figure 7: Comparison of generation opex for TPL versus peers in the Caribbean region. Source: Company annual reports

Generation opex in TPL is more or less average as can be seen in Figure 7. There is a considerable difference between the best performer (JPSCO from Jamaica) and TPL, however. TPL's cost is almost three times as high.

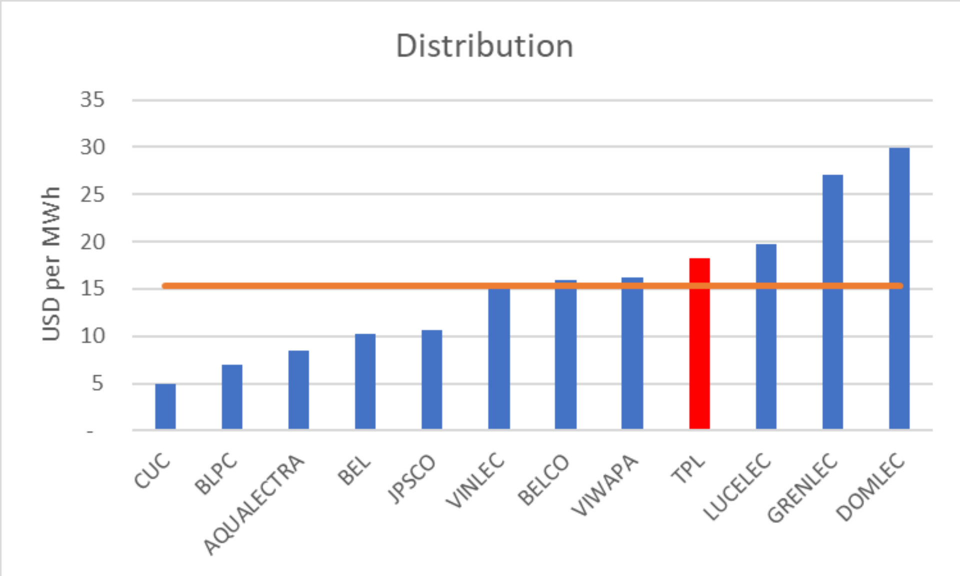


Figure 8: Comparison of distribution opex for TPL versus peers in the Caribbean region. Source: Company annual reports

For distribution a similar trend can be observed with TPL's cost being higher than average, and a relatively big gap between TPL and the best performers.

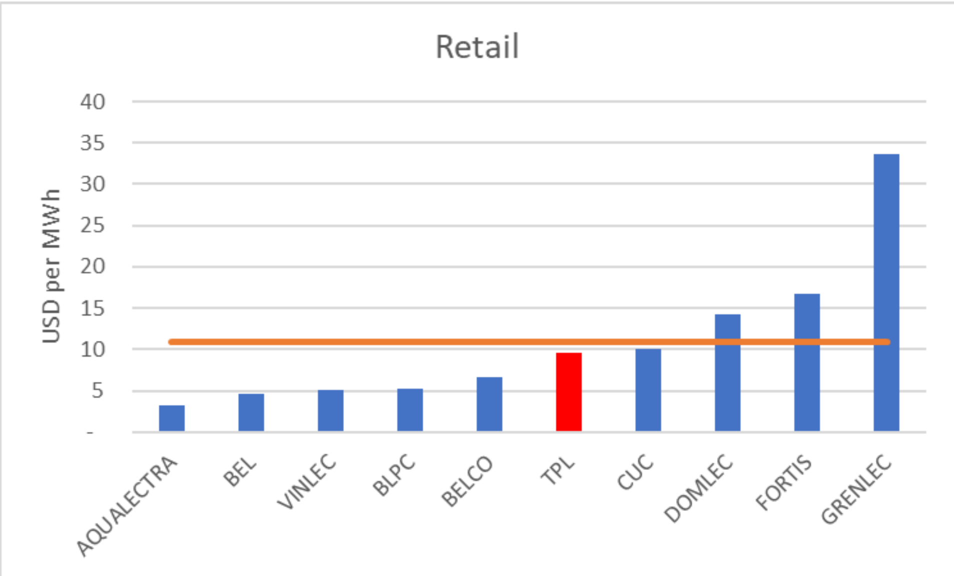


Figure 9: Comparison of retail opex for TPL versus peers in the Caribbean region. Source: Company annual reports

For retail, it is observed that TPL's cost is below average. At the same time, however, there again is a big gap between the best performers and TPL.

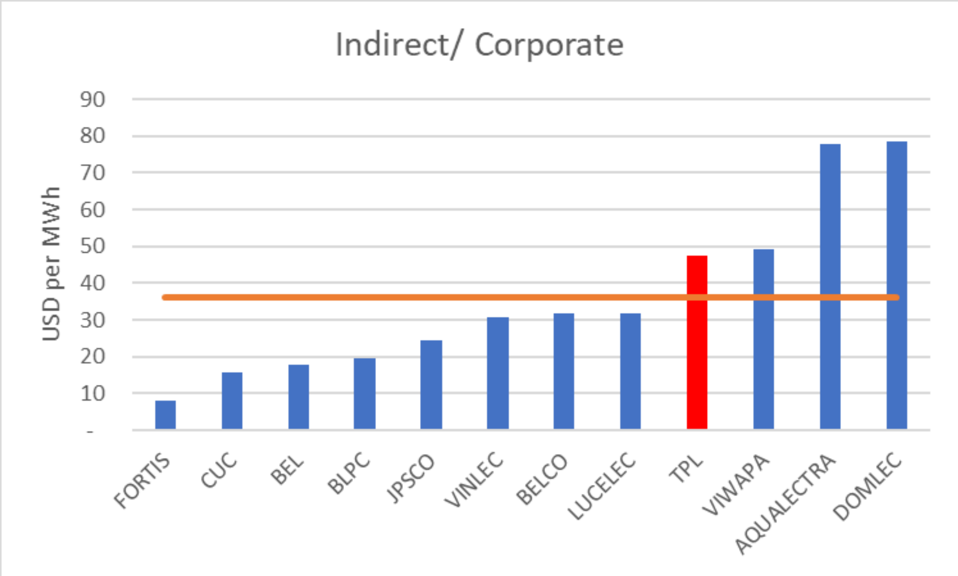


Figure 10: Comparison of indirect/corporate opex for TPL versus peers in the Caribbean region. Source: Company annual reports

Finally, for indirect cost TPL's cost are again higher than average while the gap between best performers is substantial.

2.3.4. Development of recommendations

The results so far suggest that TPL's opex is generally speaking higher than the average of the Caribbean sample of peer utilities. This is also clearly shown in Figure 11 where a comparison of the total opex is shown. Within the sample, roughly speaking, three categories of companies can be identified. First, a middle group to which TPL belongs and where the opex is around 100 USD per MWh. Then a group of worse performers with higher opex levels. And finally, a group of best performance with opex levels down to below 50 USD per MWh.

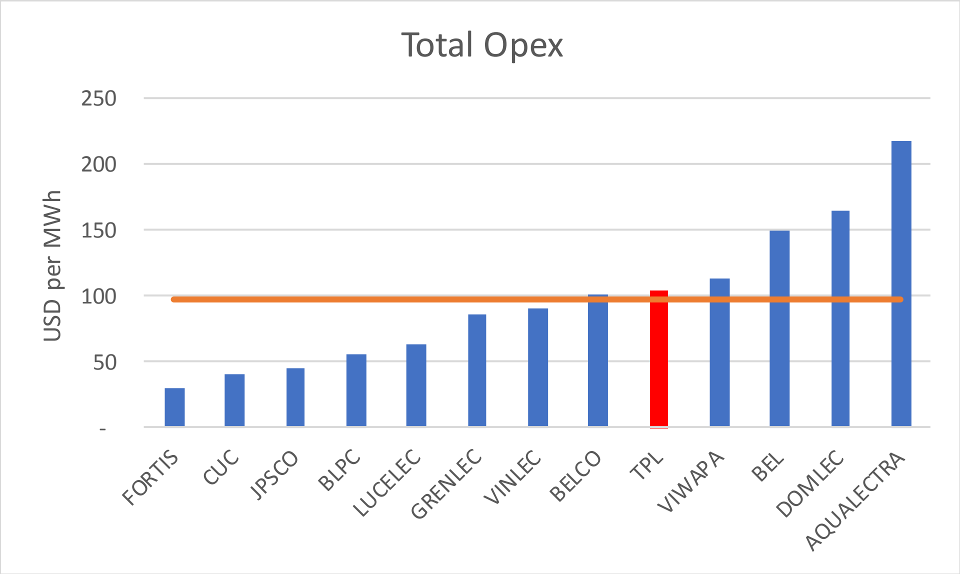


Figure 11: Comparison of opex for TPL versus peers in the Caribbean region. Source: Company annual reports

The utilities in the middle-performers and worse-performer groups and typically companies with a mainly government ownership structure. These companies tend to be less efficient than the mainly privately-owned companies such as those in the best-performer group. Although it cannot be stated conclusively, it appears that ownership does have an impact on the efficiency of the utilities.

When considering the picture per cost category, it appears that TPL's cost are particularly higher in the area of indirect/corporate cost. Interestingly, TPL cost in generation, distribution and retail combined would be the Caribbean average. This is not to say that this is an efficient level, as average performance by definition is not best performance. The point therefore rather is that the inefficiencies in TPL seems to be particularly in the area of indirect cost.

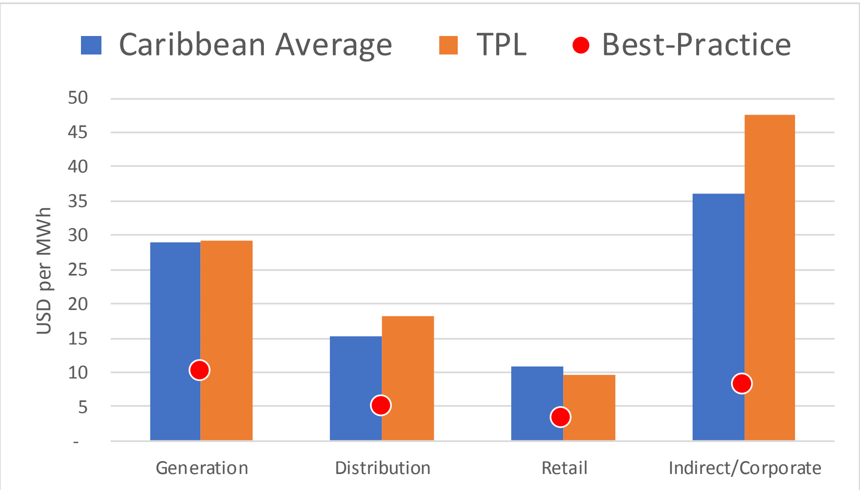


Figure 12: Comparison of opex components for TPL versus peers in the Caribbean region. Source: Company annual reports

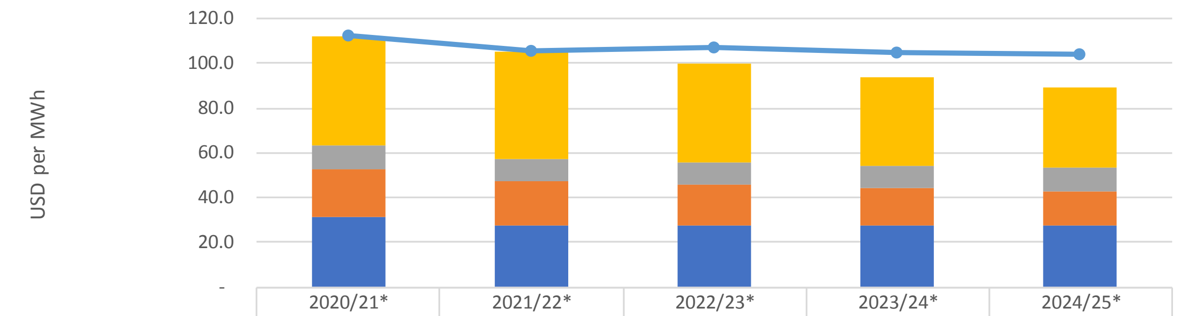
To develop a measure of what a reasonable opex allowance for TPL could be, as mentioned before, two issues should be considered namely (1) what an efficient level of cost is, and (2) how quick this level can be achieved. As can be seen in Figure 12 there is a considerable difference between average and best performance in the sample. It is not realistic to expect that TPL would be able to reduce its cost to this level within a period of five years. But, some degree of improvement is certainly possible and bringing costs at least to the average level can be considered a reasonable target.

For the determination of suitable opex allowances, the following principles have been followed:

- For each year, an opex target is defined in terms of T$/ MWh and this is done for each of the four opex categories separately.
    - The target for year 2020/21 is set equal to TPL's projections
    - The target for year 2024/25 is set as the average of the benchmarking sample
    - In case TPL's proposal is lower than the above average, TPL's proposal is used
- Between 2020/21 and 2024/25 each year the opex target is reduced by a fixed percentage

With the opex target (T$/MWh) set for each year, the opex allowances (T$) can subsequently be computed for each year.

The resulting per-unit opex allowances are also shown in Figure 13 and compared with the projections made by TPL.



	2020/21*	2021/22*	2022/23*	2023/24*	2024/25*
Indirect/ Corporate	49.0	48.0	43.6	39.7	36.1
Retail	10.7	10.5	10.5	10.5	10.5
Distribution	21.0	19.7	18.1	16.6	15.3
Generation	31.6	27.4	27.4	27.4	27.4
Allowance Total	112.3	105.5	99.6	94.2	89.2
TPL projection total	112.3	105.5	107.4	105.1	104.5

Generation Distribution Retail Indirect/ Corporate TPL projection total Allowance Total

Figure 13: Resulting opex allowances after benchmarking and comparison with TPL projections.

The resulting path in terms of T$ per annum can be derived by multiplying the T$/MWh targets with the sales forecast for the year. The results are shown in Table 6.

Table 6: Benchmarking results for opex (Model 1).

T$	2020/21	2021/22	2022/23	2023/24	2024/25
Generation	4,844,316	4,321,996	4,441,931	4,565,195	4,691,879
Distribution	3,224,552	3,109,586	2,935,774	2,771,677	2,616,753
Retail	1,650,306	1,650,306	1,696,102	1,743,169	1,791,542
Indirect/Corporate	7,521,268	7,569,693	7,075,714	6,613,970	6,182,359
Total	**17,240,442**	**16,651,582**	**16,149,521**	**15,694,011**	**15,282,532**

2.3.5. Additional analysis

TPL had recognized that the benchmarking results as shown in the previous Section (see also Report #2) hand, were mainly explained by the high costs is in the area of Indirect/Corporate. At the same time, TPL also noted that there is some degree of substitution between cost items. Following this further analysis has been done by splitting these into two components namely for Generation/Distribution/Retail on the one hand, and Indirect/Corporate on the other hand.

Separate targets are developed for each of these two categories. In doing so, the following approach has been followed:

- For each year, an opex target is defined in terms of USD/MWh:
    - The target for year 2020/21 is set equal to TPL's projections
    - The target for year 2024/25 is set as the average of the benchmarking sample
    - In case TPL's proposal is lower than the target, TPL's proposal is used
- Between 2020/21 and 2024/25 each year the opex target is reduced by a fixed percentage

The Caribbean averages, which acts as the targets, are shown in the following Table.

Table 7: Targets for opex in 2024/25 based on benchmarking results. Amounts in USD per MWh.

Caribbean average			
Generation	USD/MWh	28.86	
Distribution	USD/MWh	15.28	55.03
Retail	USD/MWh	10.89	
Indirect/ Corporate	USD/MWh	36.09	36.09

The resulting target per year are then derived for each of the two components.

Table 8: Development of opex targets for generation/transmission/distribution.

Opex part 1: Generation, Distrubution, Retail			2020-21	2021-22	2022-23	2023-24	2024-25
TPL Proposal	T$		9,719,174	9,081,888	9,701,298	9,633,252	9,764,255
TPL Proposal	USD/MWh		65.07	57.56	59.83	57.80	57.01
Opex in 2020/21	USD/MWh	65.07					
Target in 2024/25	USD/MWh	55.03					
Annual reduction	%	-4.1%					
Target	USD/MWh		65.07	57.56	59.83	57.38	55.03
Target	T$		9,719,174	9,081,888	9,701,298	9,562,825	9,424,884

Table 9: Development of opex targets for indirect/corporate

Opex part 2: Indirect/Corporate			2020-21	2021-22	2022-23	2023-24	2024-25
TPL Proposal	T$		7,521,268	7,569,693	7,721,087	7,875,509	8,133,019
TPL Proposal	USD/MWh		50.35	47.98	47.61	47.26	47.48
Opex in 2020/21	USD/MWh	50.35					
Target in 2024/25	USD/MWh	36.09					
Annual reduction	%	-8.0%					
Target	USD/MWh		50.35	46.33	42.63	39.23	36.09
Target	T$		7,521,268	7,310,086	6,912,997	6,537,479	6,182,359

Table 10: Benchmarking results for opex (Model 2).

T$	2020/21	2021/22	2022/23	2023/24	2024/25
Gen/Dis/Ret	9,719,174	9,081,888	9,701,298	9,562,825	9,424,884
Indirect/Corporate	7,521,268	7,310,086	6,912,997	6,537,479	6,182,359
Total	17,240,442	16,391,974	16,614,295	16,100,304	15,607,243

2.3.6. Final Non-Fuel Opex recommendations

Following the comparative analysis of TPL's opex two model outcomes have been reached, which will both be used in the analysis of the non-fuel tariff.

Table 11: Final opex projections for non-fuel tariff analysis.

Opex	2020-21	2021-22	2022-23	2023-24	2024-25
TPL Proposal	17,240,442	16,651,582	17,422,385	17,508,761	17,897,275
Benchmarking model 1	17,240,442	16,651,582	16,149,521	15,694,011	15,282,532
Benchmarking model 2	17,240,442	16,391,974	16,614,295	16,100,304	15,607,243

2.4. Capex projections

TPL had presented its projections for investment during the next Period 3. As mentioned by TPL, the capex forecast in Period 3 are lower than in Period 2. In Period 2 the average annual capex was 8.7 mln while in the proposed Period 3 it is 6.7 million. It is noted that – as also confirmed by TPL - these capex projections are in nominal terms and exclude any donated assets.

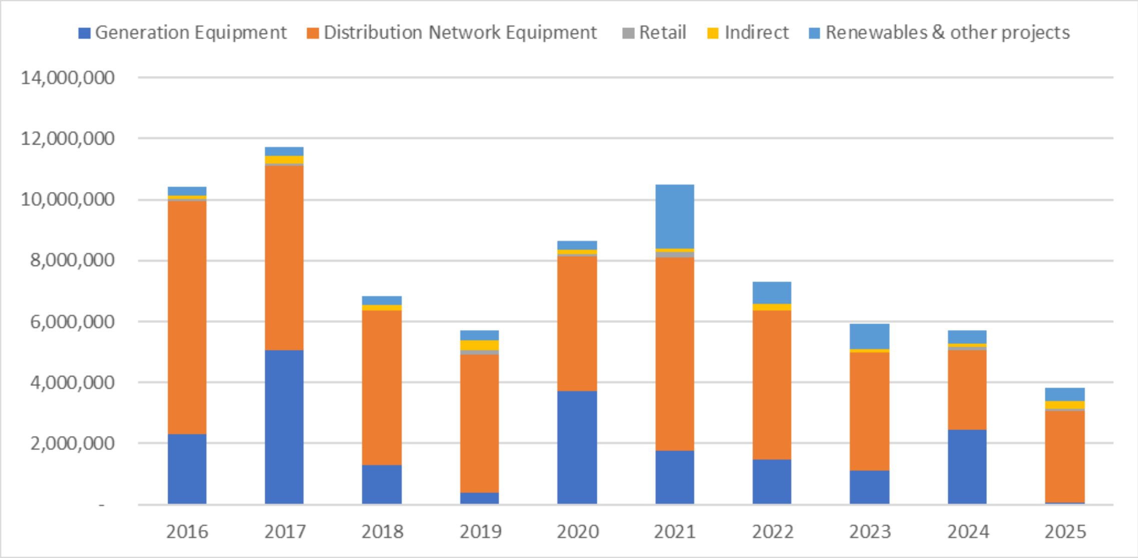


Figure 14: TPL capex in Period 2 and TPL projections for Period 3. Source: TPL Proposal.

After requests, TPL had provided more detailed breakdowns of its investments. Also, background information was provided in the 2019-2024 Business Plan. After review of this information it appears that TPL's capex projections can be considered reasonable. Therefore, the final recommendation is to adopt TPL's proposed capex.

Table 12: Final recommended capex.

	2020/21	2021/22	2022/23	2023/24	2024/25	2020 - 25
Generation Capital Expenditure	1,758,125	1,467,837	1,102,000	2,439,721	72,000	6,839,683
Distribution Capital Expenditure	5,105,290	3,983,813	3,606,922	2,457,949	2,684,631	17,838,605
Smart Grid						-
Office Computers & Equipment	121,054	124,203	123,814	133,889	119,096	622,056
Furniture & Fixtures	3,378	5,490	17,084	5,903	2,970	34,824
Tools & Equipment	37,406	61,481	36,646	44,647	120,827	301,008
Vehicles	1,090,000	705,000	170,000	185,000	380,000	2,530,000
Other Auxiliary Equipment						-
Land & Building	290,000	220,000	50,000	-	-	560,000
Renewables	2,097,423	741,600	841,129	448,761	448,761	4,577,674
TOTAL	**10,502,677**	**7,309,424**	**5,947,595**	**5,715,870**	**3,828,284**	**33,303,850**

2.5. Depreciation

TPL's proposed depreciation expenses consist of three categories:

1. Depreciation on net capex end of Period 1
2. Depreciation on net capex end of Period 2
3. Depreciation on new assets in Period 3 ("new assets this year & prior yr dep")

Table 13: TPL proposed depreciation. Source: TPL proposals, p. 11.

	2020/21	2021/22	2022/23	2023/24	2024/25	2020 - 25
Depreciation on						
Net Capex end of Period I	(1,631,893)	(1,631,893)	(1,631,893)	(1,631,893)	(1,631,893)	(8,159,466)
Net Capex end of Period 2	(1,041,611)	(1,041,611)	(1,041,611)	(1,041,611)	(1,041,611)	(5,208,057)
New assets this year & prior yr dep	(571,567)	(401,552)	(260,066)	(278,836)	(220,389)	(1,732,410)
Total	**(3,245,072)**	**(3,075,056)**	**(2,933,571)**	**(2,952,340)**	**(2,893,893)**	**(15,099,933)**

With respect to the depreciation on Period 3 assets, it was noted that in the TPL data table, the annual depreciation amount for that particular year only are shown, and not the accumulated depreciation. For example, for 2020/21 the charge is 571,567 and in 2021/22 it is 401,552. But, the total depreciation charge in 2021/22 should be the sum of 2020/21 and 2021/22. That is, it should be 973,119 rather than 401,552.

The annual depreciation charges were therefore recomputed. First, the proposed investments by TPL are shown in Table 14 per category and per year.

CAPEX			2020-21	2021-22	2022-23	2023-24	2024-25
Generation Capital Expenditure	T$		1,758,125	1,467,837	1,102,000	2,439,721	72,000
Distribution Capital Expenditure	T$		5,105,290	3,983,813	3,606,922	2,457,949	2,684,631
Smart Grid	T$						
Office Computers & Equipment	T$		121,054	124,203	123,814	133,889	119,096
Furniture & Fixtures	T$		3,378	5,490	17,084	5,903	2,970
Tools & Equipment	T$		37,406	61,481	36,646	44,647	120,827
Vehicles	T$		1,090,000	705,000	170,000	185,000	380,000
Other Auxiliary Equipment	T$						
Land & Building	T$		290,000	220,000	50,000	-	-
Renewables	T$		2,097,423	741,600	841,129	448,761	448,761
Total	**T$**		**10,502,677**	**7,309,424**	**5,947,595**	**5,715,870**	**3,828,284**

Table 14: TPL projected investment in Period 3.

From the investment summary, the annual depreciation charge per category and per year can be derived. From these annual charges the total depreciation per year can then be established. This is shown in Table 15.

DEPRECIATION			2020-21	2021-22	2022-23	2023-24	2024-25
Generation Capital Expenditure	T$	5.0%	87,906	73,392	55,100	121,986	3,600
Distribution Capital Expenditure	T$	3.3%	170,006	132,661	120,111	81,850	89,398
Smart Grid	T$	8.0%	-	-	-	-	-
Office Computers & Equipment	T$	10.0%	12,105	12,420	12,381	13,389	11,910
Furniture & Fixtures	T$	12.5%	422	686	2,136	738	371
Tools & Equipment	T$	20.0%	7,481	12,296	7,329	8,929	24,165
Vehicles	T$	20.0%	218,002	141,001	34,000	37,000	76,001
Other Auxiliary Equipment	T$	20.0%	-	-	-	-	-
Land & Building	T$	2.0%	5,800	4,400	1,000	-	-
Renewables	T$	3.3%	69,844	24,695	28,010	14,944	14,944
Depreciation for the year	**T$**		**571,567**	**401,552**	**260,066**	**278,836**	**220,389**
Accumulated depreciation	**T$**		**571,567**	**973,119**	**1,233,185**	**1,512,021**	**1,732,410**

Table 15: Final annual depreciation charge per category and per year for Period 3 investments.

Combining this with the depreciation for existing investment, the final depreciation figures for Period 3 are shown in the following Table.

			2020-21	2021-22	2022-23	2023-24	2024-25
Depreciation - Period 1	T$		1,631,893	1,631,893	1,631,893	1,631,893	1,631,893
Depreciation - Period 2	T$		1,177,385	1,177,385	1,177,385	1,177,385	1,177,385
Depreciation - Period 3	T$		571,567	973,119	1,233,185	1,512,021	1,732,410
Total Depreciation	**T$**		**3,380,845**	**3,782,397**	**4,042,464**	**4,321,300**	**4,541,688**

Table 16: Final annual depreciation charge

2.6. WACC

TPL had proposed to maintain the WACC of 8.5% from Period 2. TPL had included in its proposals a table setting out the underlying WACC parameters and computations. This table is reproduced below.

Table 17: Parameters presented by TPL for WACC computation. Source: TPL Proposal.

Asset beta	0.65
Risk free rate	4%
Tax -equity	25%
Equity beta	1.3
Market Risk Premium	7%
Cost of equity	**12.10%**
Tax - debt	25%
Debt premium	1.47%
Debt issuance cost	0.50%
Debt margin	1.97%
Cost of debt	**6.47%**
Leverage	50%
WACC	**8.5%**

TPL's proposed 8.5% was evaluated through a WACC analysis. This showed the range for the real pre-tax WACC to be located between 7.6% and 10%. Notably, TPL's proposed 8.5% is located within this band. This range is subsequently recommended to be used for the computation of the non-fuel tariff. As these computations are based on a nominal post tax WACC, the real WACC above is converted accordingly as shown in Table 18.

For the tariff computations a range for the WACC will be used, based on a lower, upper, and mid-point whereby the mid-point is represented by TPL's estimate.

Table 18: Nominal post-tax WACC.

WACC Range	**Lower**	**TPL**	**Upper**
WACC (Post-Tax Real)	7.6%	8.5%	10.0%
Corporate Tax Rate	25.0%	25.0%	25.0%
Inflation Escalation Factor	102.9%	102.9%	102.9%

WACC (Post-Tax Nominal)	10.7%	11.6%	13.2%
Rate of Return	**14.3%**	**15.5%**	**17.6%**

2.7. Inflation Forecast

TPL has proposed the use of IMF inflation forecasts and arrives at a compound annual inflation of 2.92%. It is common to use inflation forecasts by an authority such as the IMF. These forecasts, as shown in the following Table, can therefore be considered appropriate and recommended to be used.

Table 19: Proposed inflation forecast based on IMF projections.

Year	2020	2021	2022	2023	2024	2025	Compound
Inflation forecast (IMF)	3.89%	4.15%	2.94%	2.50%	2.50%	2.50%	2.92%

2.8. Regulated Asset Value

The Regulated Asset Value (RAV) is driven by two factors namely the investment (capex) and the depreciation.

- The initial RAV is taken from TPL's proposals and is set at T$ 67,591,956.
- For the capex, the projections by TPL have been used. As mentioned before, the capex allowances are still subject to detailed analysis and can change as a result of this.
- For the depreciation amounts refer to Table 16.

The resulting RAV per annum is shown in the following Table.

Table 20: RAV computation to use in the non-fuel tariff computation

REGULATED ASSET VALUE			2020-21	2021-22	2022-23	2023-24	2024-25
Starting RAV	T$		67,591,956	74,713,788	78,240,815	80,145,946	81,540,516
Investment	T$		10,502,677	7,309,424	5,947,595	5,715,870	3,828,284
Depreciation - Period 1	T$		(1,631,893)	(1,631,893)	(1,631,893)	(1,631,893)	(1,631,893)
Depreciation - Period 2	T$		(1,177,385)	(1,177,385)	(1,177,385)	(1,177,385)	(1,177,385)
Depreciation - Period 3	T$		(571,567)	(973,119)	(1,233,185)	(1,512,021)	(1,732,410)
Ending RAV	T$		74,713,788	78,240,815	80,145,946	81,540,516	80,827,112

2.9. Non-Fuel Tariff Computation

The non-fuel tariff is now computed based on the updated recommendations as presented in this report. The computations are also contained in a Draft Tariff Model, which is attached to this report.

The allowed cost can now be determined by summing up the three components (opex, depreciation, and return) for each year. This provides an annual allowed cost per year. The non-fuel tariff for Period 3 now needs to be computed, such that the income generated by this tariff is equal to the allowed cost. In doing so, the time-value of the cost and revenues need to be considered. This is done by discounting income and cost. The logical discount factor in this case is the ROR (15.53%).

In carrying out the non-fuel tariff computation, it must be taken into account that, following the analysis as presented earlier in this section, different scenarios can be identified with respect to some numbers to be used for the computation. A summary is shown in Table 21.

Table 21: Summary of underlying data for non-fuel tariff computation and basis for possible scenarios.

Item	Nr options	Options	Remark
Demand forecast	2	• TPL Proposal • Economic forecast	• See Table 3
Non-Fuel Opex	3	• TPL Proposal • Benchmark model 1 • Benchmark model 2	• Table 11
Capex	1	• TPL Proposal	• Table 12
Depreciation	2	• TPL Proposal • Adjusted	• Table 16
WACC	3	• TPL Proposal (15.5%) • Low 14.3% • High 17.6%	• Table 18
Inflation	1	• TPL Proposal (IMF)	• Table 19

As may be seen, there are a total of 6 items, each with a number of options. Each combination of options (which is denoted as a “scenario”) will result in a certain non-fuel tariff level. The total number of scenarios is equal to: 2 x 3 x 1 x 2 x 3 x 1 = 36. For each of these 36 scenarios, the resulting non-fuel tariff is shown in Figure 15.

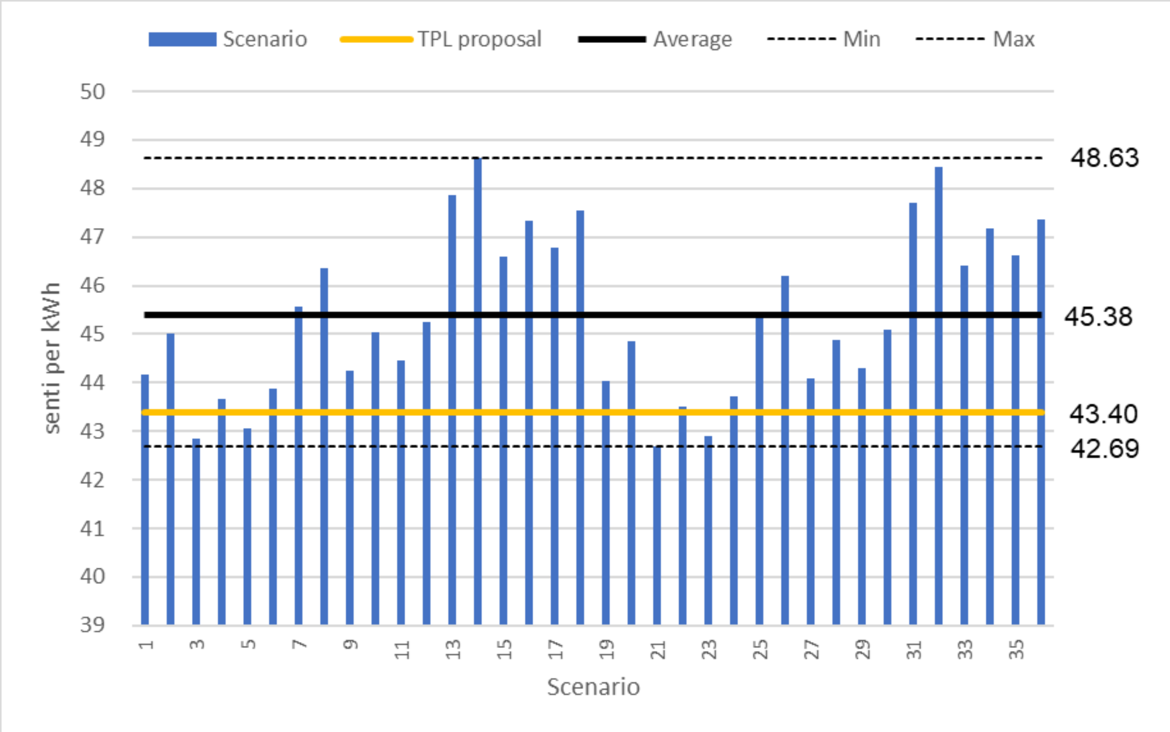


Figure 15: Non-fuel tariff computed under different scenarios.

The tariffs for the scenarios range between a level of minimum 42.69 and maximum 48.63 senti per kWh. The average tariff for the scenarios is 45.38 senti per kWh and is indicated by the line in Figure 15. TPL has proposed a non-fuel tariff of 43.40 senti per kWh[4]; this is indicated in the Figure by the orange line. As can be seen, TPL's proposal is located within the minimum and maximum tariff for the scenarios. Furthermore, TPL's proposal is located below the average for the scenarios.

Given that TPL's proposed number is within the range of the scenario outcomes and also below the average, it is recommended that the non-fuel tariff for Period 3 is set at 43.40 senti per kWh.

[4] Final Proposals, page 5.

3. FUEL TARIFF

3.1. Fuel type and generation mix

The generation mix for TPL has substantially changed in the recent years. The share of renewable energy has steadily increased and is expected to reach 50% by end of 2020. The effect of this is that less diesel fuel is consumed and hence generation costs are less sensitive to changes in international fuel prices.

The move to an important role for renewable energy directly follows from the Government of Tonga's policy and hence is taken as given. With respect to the electricity sector, these are contained in Tonga's Intended Nationally Determined Contributions (INDC):[5]

- 50% of electricity generation from renewable sources by 2020;
- 70% of electricity generation from renewable sources by 2030;
- Improve energy efficiency through reduction of electricity line losses to 9 percent by 2020 (from a baseline of 18 percent in 2010).

TPL's projections of increased shares of renewable energy are thus in line with the INDC and hence considered appropriate.

To support the share of RE increase battery systems will be installed. This appears to be a logical consequence, as a 50% share and ultimately 70% share of RE in a relatively small system like TPL would not be possible without this (i.e. would result in an instable power system). In this respect the introduction of batteries in the system seems appropriate.

The following final recommendations are made:

- Adopt the projected change in TPL's renewable energy generation share in line with the INDC i.e. 50% by 2020 and further towards 70% by 2030.
- Adopt the introduction of batteries in the system.

[5] Intended Nationally Determined Contributions, Kingdom of Tonga, 4 December 2015.

3.2. Split of Fuel Tariff Formula into Fuel and RE components

The concept of the current fuel tariff is to set a monthly tariff based on forecast of sales and forecast fuel price. Afterwards, differences between the forecast and outturn sales and fuel price are compensated in the next month. This compensation consists of two elements namely (1) a periodic adjustment for the difference, and (2) interest compensation for the ongoing balance between forecast and outturn volumes and prices. Furthermore, the cost of non-diesel (RE) generation are also corrected for in the fuel tariff whereby the assumption is that the cost of RE generation is the same as diesel generation.

The fuel tariff system can be considered in line with the best-practices observed in island utilities such as TPL. However, there is an important issue to consider which is that the current specification assumes that any RE generation that takes place, is undertaken by the concessionaire (TPL). This thus excludes the cost of "energy generated by third parties (e.g. independent power producers) and then sold to the Concessionaire".[6]

This creates a problem that – in principle – TPL cannot pass through the cost of any purchased RE into the fuel tariff. TPL can only pass through the cost of RE that is produced by the company itself and this can happen at the cost of diesel. The logic is that if TPL can utilize other generation sources than diesel and produce at lower cost, these costs can be recouped at the price of diesel fuel. This thus creates a strong incentive for TPL to investigate possibilities to bring down generation cost.

However, in the current formulation of the ECC, any RE purchased from external parties is not to be included in the fuel tariff. It is however a fact that TPL purchases energy from IPPs and will increase to do so in future. Therefore, a suitable adjustment to the fuel tariff specification is in order.

As mentioned earlier, the mechanism of forecasting and adjusting the fuel tariff adjustments on its own is proper and in line with best practices. The issue to be resolved is to allow purchased RE energy (through PPAs) also to be recouped in the fuel tariff. The following is therefore recommended:

1. Rename the "Fuel Tariff" to "Fuel/RE Tariff"
2. This Fuel/RE Tariff will then allow the concessionaire to recoup the cost of diesel generation as well as RE generation;
3. The new RE tariff can be based on the same principles as the current fuel tariff i.e. forecasts of sales and prices, and adjustments afterwards.

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[6] ECC, part 2, p. 56.

The formulation of the new Fuel/RE Tariff – which is to be integrated into the updated Schedule 6 of the ECC for Period 3 – is included in Annex 2.

3.3. Diesel efficiency targets

For Period 2, the target set for fuel (diesel) efficiency in TPL has been set at 4 kWh/l. This target represents the kWh of gross generation that TPL should achieve for each liter of fuel consumed. Note that these targets only apply to the diesel fuel component of generated electricity and not to the renewable energy portion of generation.

In its proposal, TPL mentions that the outturn fuel efficiency for Tongatapu has been 4.09 kWh/l, thus a slight overperformance compared to the 4.05. A graph has been included where the efficiency – only for Tongatapu – is shown to reduce from around 4.15 in January 2014 to 4.00 kWh/l in November 2019.[7] No mentioning is however made of the performance in the outer islands. TPL's proposal for Period 3 is to maintain the same efficiency standards i.e. 4.05 for Tongatapu, 3.75 kWh/l for Vava'u, and 3.55 for Hathe.

[7] TPL Proposals, p. 17.

Based on performance data provided by TPL as part of its Progress Reports, it was observed that the fuel efficiency was in the order of 4.5 kWh/l.[8] TPL however indicated that these data were based on all generation i.e. for both diesel and RE together. Subsequently, more detailed information was provided by TPL showing the split in generation between diesel and RE.[9] These data were received on a monthly basis from July 2017 till April 2020 and showed:

- Diesel fuel consumption per island
- Gross generation per island and per type (diesel, RE, total)
- Net generation per island and per type (diesel, RE, total)
- Total parasitic consumption (plant consumption)
- Diesel fuel efficiency per island (including RE generation)
- Diesel fuel efficiency per island (excluding RE generation)

From these data the diesel fuel efficiency for the TPL system has been computed and is shown in Figure 16. In line with the definition of fuel efficiency, this has been done exclusive of RE generation. Thus, the indicator is computed as the gross kWh produced by diesel units, divided by the total fuel consumed. For reference, the target of 4 kWh/l for Period 2 as well as the 12-month average is also shown.

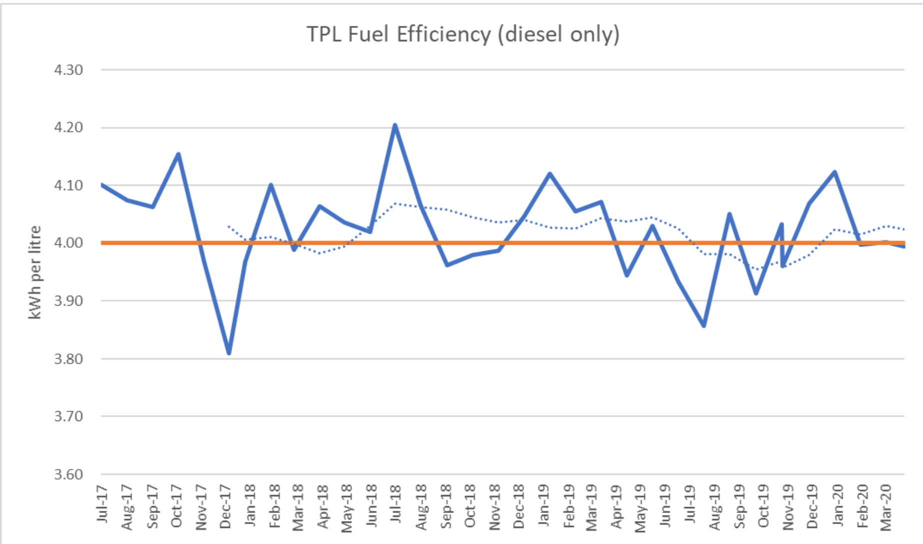

Figure 16: Diesel efficiency performance of TPL. Computed using TPL data.

[8] See Report #2, page 23.

[9] Excel file "FOR EC FUEL EFFICIENCY (3).xlsx" which was submitted through Dropbox.

TPL has been able to beat the Period 2 target most of the time. On average, the fuel efficiency since July 2017 has been 4.02 kW/l. TPL exhibits a downward trend in fuel efficiency. The reason for this given by TPL is that due to increased RE production, the loading of the diesel units is lower and hence the efficiency tends to drop.[10] Given the historical performance of 4.02 kWh/l, maintaining the diesel efficiency target of 4.0 kWh/l would seem to be suitable.

3.4. System Loss Target

The system loss target for the last year of Period 2 is set at 10%. This consists of:[11]

- parasitic losses, being the losses incurred in the generation stations. These are also referred to as "generation losses";
- non-technical losses, being the theft of electricity; and
- line losses, being the losses in the network due to heat dissipation.

According to TPL, the current split of losses is 3% parasitic and 7% transmission (being non-technical and line losses).[12] For Period 3, TPL proposes that the losses will be based on the following:

- Fuel generation: 3% parasitic, 7% line
- RE generation: 3% parasitic, 7% line
- RE-battery stored generation: 7-11% parasitic, 7% line

A fundamental issue is that the system loss target is defined as the sum of generation and network (line) losses. Any change in the generation portfolio – due to increased RE penetration – will cause a change in generation losses but not in line losses. Therefore, it seems appropriate that in the determination of the system loss target, each individual type of losses area is assessed separately.

3.4.1. Line losses

Figure 17 shows the trend in the losses (including the line losses) as reported by TPL in its Progress Reports. Since July 2016 the level of line losses has fluctuated between 5% and 10%. Notably, in the period between roughly February 2018 and January 2019, the line losses were at a relatively low level of between 6% and 7%. After that, the line losses have increased sharply.

[10] TPL letter of 20 March 2020 to TEC, Appendix A (Fuel efficiency)

[11] Electricity Commission, Electricity Reset 2015 - Decision Number 1, 29 June 2015, p. 18.

[12] TPL Proposals, p.18.

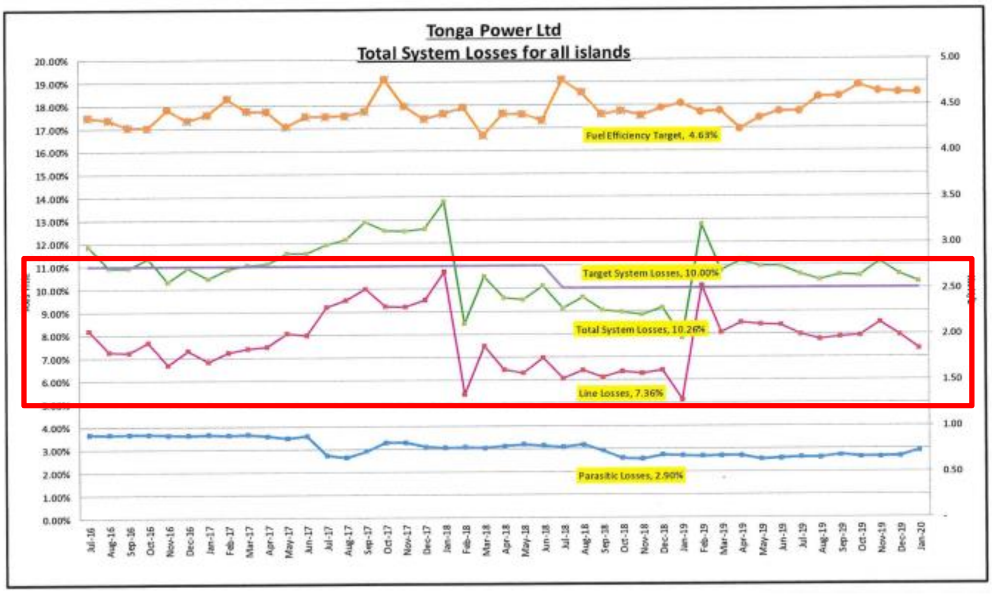

Figure 17: Line losses reported by TPL in the period July 2016 till January 2020. Source: TPL Progress Report January 2020, p.4.

The explanation for the low losses down to 5% in some months provided by TPL was as follows: “It has been a combination of CT meter and three phase meter issues when combined with the read period being longer, and or shorter than other months”.[13] If such monthly variations are accounted for, the average line losses in the period can be computed to be in the order of 7.5%. In its January 2020 Progress Report, TPL reports that line losses in that month are 7.36%.[14]

TPL is planning investments in its network system including upgrading of conductors. Furthermore, TPL has carried out modeling of system losses and the results of this analysis were provided.[15] In its own projection, TPL has projected line losses to go down from 7.5% in 2021 to 5.5% in 2025. These projections are therefore adopted as the targets for line losses, as shown in the following Table.

Table 22: Target for line losses. Based on TPL system loss modeling.

	2021	2022	2023	2024	2025
Line losses	7.5%	6.5%	6.5%	5.5%	5.5%

[13] TPL letter of 20 March 2020 to TEC.

[14] TPL Progress Report for January 2020, p. 1.

[15] Excel file “System Loss (Entura May20 data) V2 (1)” which was submitted through Dropbox.

3.4.2. Parasitic losses - Fuel

According to the PPA benchmarking report, the present level of diesel parasitic losses in TPL (2018) is 3.342%.[16] This is a performance that is less efficient than the 3% reported by TPL in its proposal. The results of the PPA benchmarking analysis are shown in Figure 4. The average for the sample is 3.5%. TPL's performance can thus be considered a bit better than the Pacific region average.

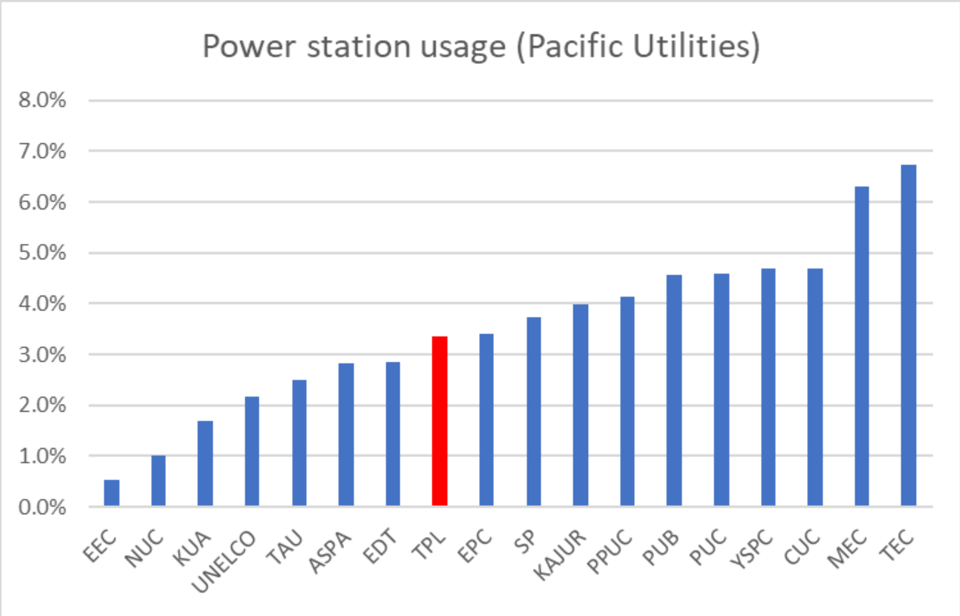

Figure 18: Comparison of diesel generation losses of TPL versus peers in the Pacific region. Source: PPA benchmarking report 2018.

When TPL is compared to Caribbean island utilities, a similar pattern emerges with TPL. The average performance in the Caribbean is 4.2%. TPL is below the average but still worse than the best performers in the sample.

[16] PPA Pacific Utilities Benchmarking Report, PPA, 2018.

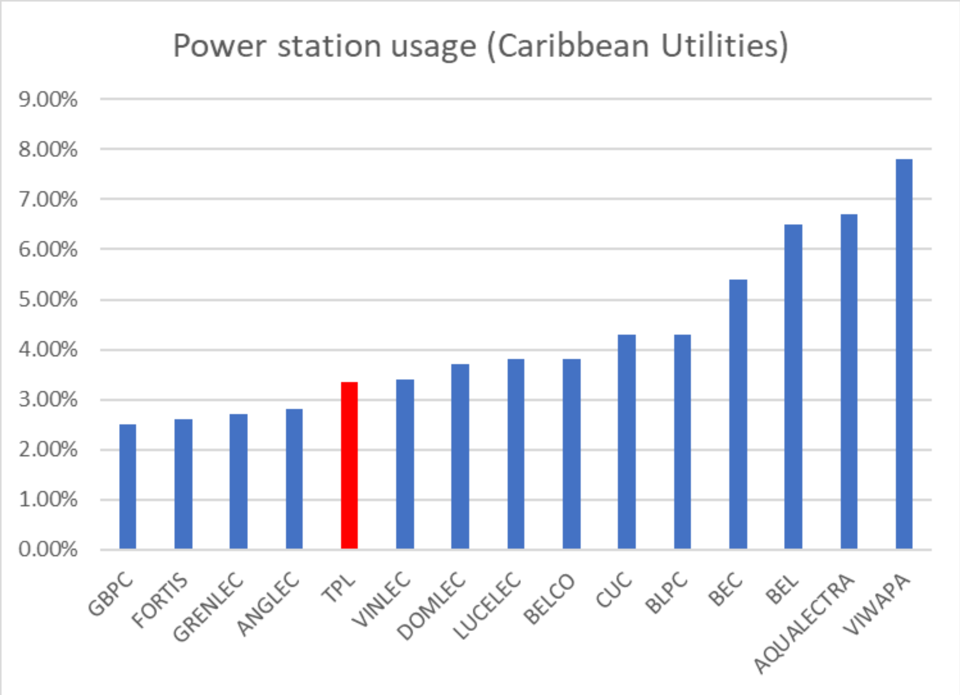

Figure 19: Comparison of diesel generation losses of TPL versus peers in the Caribbean region. Source: CARILEC benchmarking report 2015.

Overall, it appears that TPL's performance is somewhat better than its peers in the Pacific and Caribbean region, but still worse than the perceived best-practice target of 2.5%.

It should be noted though that the target of 2.5% is defined as the percentage of losses occurring in the diesel power station only. Thus, the target does not apply to the total generation, but only to the diesel component of gross generation.

Table 23: Recommended Loss Targets for Fuel in Period 3.

	Line Loss Target	Parasitic - Fuel	Total Loss Target - Fuel
2021	7.5%	2.5%	10.0%
2022	6.5%	2.5%	9.0%
2023	6.5%	2.5%	9.0%
2024	5.5%	2.5%	8.0%
2025	5.5%	2.5%	8.0%

3.4.3. Parasitic Losses – RE

For RE, a distinction is made between RE energy generated using facilities of TPL, and RE that is purchased from IPPs on the basis of PPAs. For RE parasitic losses, it should be considered that TPL does not purchase gross energy from RE IPPs, but rather net energy i.e. the costs of parasitic losses are incurred by the IPP and not TPL. Therefore, RE parasitic losses from TPL's point of view are zero.

For RE facilities owned by TPL, parasitic losses will apply and for this is it reasonable to allow the same target as for diesel fuel.

Furthermore, because the share of RE in the generation portfolio in the TPL system will be significant (more than half), an important issue will emerge. There may be hours during which the amount of produced energy will be more than the demand. This can for example happen during hours where demand is relatively low, but RE generation is high due to favorable sunlight. At the same time, the ability to reduce diesel generation is limited as this is constrained by the requirement of maintaining stability in the system. To solve the problem of overproduction, the excess energy can be stored in batteries. This however creates additional losses which must be considered.

Table 24: Projections for additional losses due to increased RE penetration. Computations based on TPL data.

	Gross Generation (kWh)	RE Spill (kWh)	BESS RTE Loss (kWh)	RE Spill	BESS RTE Loss	Additional Losses
2021	59,957,736	626,727	751,650	1.0%	1.3%	2.3%
2022	62,895,624	457,608	682,021	0.7%	1.1%	1.8%
2023	65,872,372	324,823	614,907	0.5%	0.9%	1.4%
2024	68,905,140	224,106	547,120	0.3%	0.8%	1.1%
2025	71,989,980	157,578	477,936	0.2%	0.7%	0.9%

Based on TPL analysis, additional losses in 2021 of 2.3% will occur and this will then gradually reduce over time, as the gap between available generation and demand will narrow down. Average additional losses will be 1.5% per year, but as can be seen there is high variability from year to year. In this respect and taking into account that there is at this point little experience in Tonga in this area, it seems appropriate not to impose a target for the additional losses in the coming Period 3. Instead it is recommended that the additional losses are set on the basis of actually incurred losses. For practical purposes, the actual losses from the previous year can be used for this.

Table 25: Recommended Loss Targets for RE-TPL in Period 3.

	Line Losses Target	Parasitic Target - RE_{TPL}	RE Loss Target
2021	7.5%	2.5%	10% + actual Spill/Battery losses in 2020
2022	6.5%	2.5%	9% + actual Spill/Battery losses in 2021
2023	6.5%	2.5%	9% + actual Spill/Battery losses in 2022
2024	5.5%	2.5%	8% + actual Spill/Battery losses in 2023
2025	5.5%	2.5%	8% + actual Spill/Battery losses in 2024

Table 26: Recommended Loss Targets for RE-PPA in Period 3.

	Line Losses Target	Parasitic Target – RE_{PPA}	RE Loss Target
2021	7.5%	0%	7.5% + actual Spill/Battery losses in 2020
2022	6.5%	0%	6.5% + actual Spill/Battery losses in 2021
2023	6.5%	0%	6.5% + actual Spill/Battery losses in 2022
2024	5.5%	0%	5.5% + actual Spill/Battery losses in 2023
2025	5.5%	0%	5.5% + actual Spill/Battery losses in 2024

3.5. PPA Guidelines

Section 2.16 of Part 2 of the ECC for Period 2 mentions the following:

> **Power Purchase Agreements**
>
> 2.16 Within six months of the coming into force of this Regulatory Addendum the Commission after consultation with the Concessionaire and the Kingdom shall propose a Protocol for the review of proposed Power Purchase Agreements and any Protocol agreed to in writing by the Commission, the Concessionaire and the Kingdom shall be deemed to be an integral part of the Regulatory Addendum.

The protocol mentioned in Section 2.16 has so far not been developed. A draft Protocol has been included in Annex 3 of this report for further discussion between TEC and TPL.

4. RELIABILITY INDICATORS

4.1. Possible inclusion of reliability indicators

As mentioned in Report #1, the list of standards is quite comprehensive and follow more or less the standards in use by regulators in Europe. Nevertheless, an important set of standards missing in this list relates to reliability. System reliability is an important indicator of performance and measures the frequency and duration of interruptions experienced by customers. The typical indicators used for this purpose are:

- SAIFI measures the probability that a customer will experience an outage. It is calculated by dividing the number of customer interruptions by the total number of customers served. The number of customer interruptions is the total number of interrupted customers for each interruption. This is typically measured over the period of a calendar year.
- SAIDI provides a measure for the average time that customers are interrupted. It is calculated by dividing the total customer interruption duration by the total number of customers. The customer interruption duration is defined as the aggregated time that all customers were interrupted. SAIDI is also known as Customer Minutes Lost (CML).
- CAIDI is defined as SAIDI divided by SAIFI and is a measure for the average time required restoring service to the average customer per interruption. It is calculated by dividing the total interruption duration by the total number of interruptions.

It is noted that presently already reports SAIDI/SAIFI/CAIDI to TEC and has also set internal targets as shown below. Given the importance of these indicators, it seems appropriate to consider to also include these in the regulatory framework. Whether this is possible however depends strongly on the quality of the reported data. This is investigated more closely further.

4.2. Analysis of TPL reported data

TPL provided information about the level of its reliability indicators in the Progress Reports. Also, in these reports the company has indicated what its targets are.

4. SYSTEM RELIABILITY

There are no service standards for reliability imposed upon Tonga Power in the 2015 Regulatory Addendum. However for 2018-19, the Concessionaire has set itself the following TARGETS, namely:-

SAIDI1[1]	-	1,080 minutes per annum
CAIDI2[2]	-	870 minutes per annum
SAIFI3[3]	-	14

Appendix 3 hereto gives details of TPL's present and recent past performance for system reliability.

Figure 20: Excerpt from TPL Progress Report for August 2019 (page 2).

It is noted though that the targets set by TPL do not appear to be consistent. As SAIDI by definition is SAIFI x CAIDI, the 1,080-minute target for SAIDI does not corresponds with 870 x 14.

It should be mentioned further that for CAIDI, TPL has used “minutes per annum” as the dimension. But this should be “minutes per interruption”. For SAIFI, no dimension is provided, but it is assumed that this is “interruptions per year per annum”

The performance for Tonga as a whole was not reported, only for individual islands. In order to arrive at a national figure, the indices for the different islands would need to be weighted by the number of customers. This information was not available. Nevertheless, given the relatively large size of Tongatapu, the above reported figures can be considered indicative for Tonga as a whole.

The reported performance for Tongatapu the period July 2018 – June 2019 was as follows:[17]

- SAIDI: 877
- CAIDI: 1179
- SAIFI: 10.69

The actual performance as reported by TPL thus seems to be better than the targets currently internally set, except for CAIDI.

It is however observed that (similar as with the targets) there is an internal discrepancy between the reported performance. According to the standard formulas, it should always hold that:

SAIDI = SAIFI x CAIDI

When this is applied to the targets and actual performance, the above requirement does not hold. For the targets: 14 x 870 = 12,108 ≠ 1,080. Similarly, for the actual performance, 10.69 x 1178 = 12,592 ≠ 877.

4.3. Inconsistency with IEEE formula

The standard reference for the computation of the reliability indicators is provided by IEEE.[18] These are as follow:

[17] Progress Report January 2020, p. 9.

$$\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

$$\text{CAIDI} = \frac{\sum \text{Customer Interruption Duration}}{\text{Total Number of Customers Interrupted}}$$

$$\text{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\sum \text{Total Number of Customers Interrupted}}$$

From this it follows that it should always hold that SAIDI = SAIFI x CAIDI. If this condition is not satisfied, this is an indication that the underlying data, reporting systems, or calculation procedures are not robust. As mentioned above, the TPL targets as well as reported figures do not comply with the condition that SAIDI = SAIFI x CAIDI.

In response this observation TPL indicated that:

> *"TPL has provided the "IEEE-1366-Reliability-Indices-2-2019" presentation as supporting clarification that the formulae that SAIDI = SAIFI x CAIDI does not always hold due to the network complexity (Automation vs Manual)"* [19]

However, this argument is flawed as the condition SAIDI = SAIFI x CAIDI should hold in all cases, whether restoration is automatic or manual, or done in stages etc. Network complexity has impact on the level of the indicators, but not on their definitions.

Further information provided by TPL[20] (through Dropbox) could also not help to reveal the reason for the discrepancy in TPL's numbers. The data provided were hard numbers and did not show the exact way in which the indicators had been computed.

Based on the above it can be concluded that TPL's currently reported data is not sufficiently robust to be included as part of the ECC's reporting framework in Period 3. It is recommended that an audit is carried out of TPL's reliability reporting systems and that reporting practices are aligned with

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[18] IEEE, 1366-2012 - IEEE Guide for Electric Power Distribution Reliability Indices.

[19] TPL letter of 20 March 2020 to TEC.

[20] The following spreadsheet files were provided: HV_Faults_2020_01.xlsx, HV_Saidi Report_2020_01.xlsx, TPL_Reliability Graphs_2020_04_EC Submission_05062020.xlsx

international standards as per IEEE guidelines. After that, these indicators can be included in the ECC Period 4 round.

5. FINAL RECOMMENDATIONS

TPL's Proposal for Period 3 were reviewed and based on this the following main recommendations are made for Period 3:

1. **Adopt a non-fuel tariff of 43.40 senti per kWh;**

2. **Update the Fuel Tariff into a Fuel/RE Tariff, to assure consistent incorporation of the introduction of Renewable Energy. For this Schedule 6 of the ECC can be substituted by the text in Annex 2.**
3. **Adopt a fuel efficiency target as follows:**

	Fuel Efficiency Target (kWh/liter)
2021	4.0
2022	4.0
2023	4.0
2024	4.0
2025	4.0

4. **Adopt Loss Targets as follows:**

	Loss Target – Fuel	**Loss Target - RE_{TPL}**	**Loss Target – RE_{PPA}**
2021	9.0%	10% + actual Spill/Battery losses in 2020	7.5% + actual Spill/Battery losses in 2020
2022	9.5%	9% + actual Spill/Battery losses in 2021	6.5% + actual Spill/Battery losses in 2021
2023	9.5%	9% + actual Spill/Battery losses in 2022	6.5% + actual Spill/Battery losses in 2022
2024	8.5%	8% + actual Spill/Battery losses in 2023	5.5% + actual Spill/Battery losses in 2023
2025	8.5%	8% + actual Spill/Battery losses in 2024	5.5% + actual Spill/Battery losses in 2024

5. **Consider formal introduction of SAIDI/SAIFI/CAIDI indicators in Period 4. Improve the data collection and reporting processes of these indicators during Period 3.**

ANNEX 1: WACC ESTIMATION

Concept of the WACC

Estimation of a company's cost of capital is an important element of the regulatory process of price-setting. The cost of capital forms an integral part of the company's total costs and hence, should also be incorporated in the level of the tariff. The Weighted Average Cost of Capital, WACC, is the most common method used for calculating the minimum rate of return of a business.[21] The WACC is the average of the cost of each component of the capital structure of the company, debt and equity, weighted by their share on total capital. It is therefore the weighted average of the return required by lenders and shareholders of the company, who are the providers of capital.

For calculating the WACC we have adopted the following standard formula:

$$WACC = g \times R_D + R_E\,(1 - g)$$

where g is gearing ratio; R_D is the cost of debt; R_E the cost of equity.

For the cost of debt (R_D), the following formula is used:

$$R_D = R_F + DRP$$

where R_F is the risk-free rate and DRP is the Debt Risk Premium

The principal methodology for estimating the cost of equity (R_E) is the Capital Asset Pricing Methodology (CAPM) formula:

$$R_E = R_F + \beta \times (R_M - R_F)$$

where R_F is the risk-free rate; β is the equity Beta (the measure of non-diversifiable risk of the company); and $(R_M - R_F)$ is the equity risk premium (ERP).

The estimation of the WACC then comes down to the estimation of the Costs of Debt and Equity, which are in turn estimated based on empirical data for each of the parameters. This process is schematically shown in Figure 21.

[21] It should be noted that estimating the rate of return using the Discounted Cash Flow (DCF) method is not practical in this case as this will result in circularity: The future expected returns would be based on allowances set today by the regulator, which in turn would be derived from expected returns in the future. See for example Cannon, B. (2009), "Cost of Capital", Camput's 2009 Energy Regulation Conference, Queen's University School of Business.

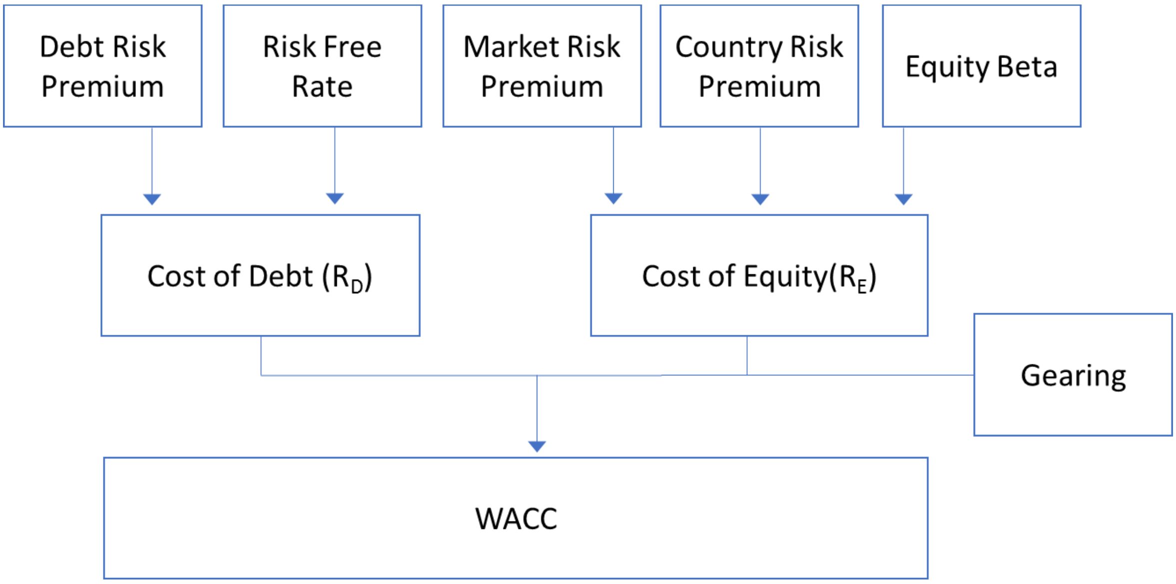

Figure 21. Underlying parameters for the WACC estimation

Cost of Debt (R_D)

For the estimation of the cost of debt the actual debt paid can be considered here. It is assumed that TPL's estimation of 6.47% is valid.

Risk-free rate

The risk-free rate is that which would apply to riskless investments. Securities issued by the government of the country concerned are usually taken as the lowest risk securities available in that country. Hence the rate on government bonds is often taken as an indication of the risk-free rate. Ideally, the bonds should be freely traded in liquid markets with a term matching the expected life of the infrastructure assets to be financed.

Based on data from the Tonga Central Bank, yields on government bonds vary between 3% and 3.5%. This range has therefore been adopted as the estimation for the risk-free rate.

Equity Risk Premium (ERP)

The ERP is often referred to as the "market risk premium" for the market. It is the risk premium for an investment in a market portfolio of shares in relation to an investment in risk-free securities. Here, the market rate of return is the expected return on the market portfolio.

Due to lack of a financial market for utilities in Tonga, a direct estimate could not be made from Tonga market data. In the absence of this, an alternative approach has been followed by using data from the United States and converting this into a figure representative for the Tonga situation.

The standard reference for the country risk premium on the basis of the above approach is the data published by professor Damodaran. The ERP for the United States was estimated to be 5.69%. To this, a country risk premium should be added. As Tonga has no sovereign rating, the risk-free rate as represented by the Tonga government bonds has been adopted as a proxy.

Table A1: Country Risk Premium (Damodaran)[22]

Country	Moody's rating	Country Risk Premium	Total Equity Risk Premium
United States of America	Aaa	0.00%	5.69%
Tonga	Not available	3% - 3.5%	***8.69% - 9.19%***

Beta

A central feature of the CAPM is the use of a measure of the relationship between the risks attributed to investments in a specific firm and the risks associated with the capital market as a whole. This is known as beta risk.

The equity beta of a company's shares is a measure of the degree of risk (i.e. the volatility) of those shares and is an indication of the degree to which the company is sensitive to cyclical trends. The equity beta is computed as the covariance of the return on the stock market and the return on the individual share. If a company has a beta of 1, this means that the company's sensitivity to cyclical trends matches that of the market portfolio. The general factors that affect the equity beta include: the financial structure (degree of financial leverage); the company's sensitivity to cyclical trends; the relationship between the company's fixed and variable costs (operational leverage); the level of business risk; the supervisory system in the country where the business operates; and the number and nature of the sectors in which the company is active.

Equity betas can be observed in the market and various financial information providers publish information on equity betas. For those companies for which such data are not available, the beta of

[22] Source: http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html

other companies doing similar business could be taken. Here it is important to note the distinction between the equity beta and the asset beta. When comparing betas, this should be done based on the asset beta (rather than the equity beta). The asset beta assumes that a company is 100% financed by equity. Thus, comparisons are not influenced by the fact that different companies will tend to have different financing structures. Once an appropriate asset beta is set, this can then be converted into an equity beta.

For identifying the range for the asset beta, it is useful to consider regulatory precedence. Table A2: provides an overview of recent regulatory decisions in this regard.

Table A2: Asset betas used by Regulators. Compiled from data published by respective regulating authorities.

Regulator	Decision	Date of decision	Parameter estimate
Australian Energy Regulator (AER)	Networks NSW: distribution, 2014-19	April 2015	0.34
New Zealand Commerce Commission	Electricity Distribution: CPP, five-year WACC	September 2016	0.39
Australian Energy Regulator (AER)	TasNetworks: Draft Decision, 2017-19	September 2016	0.34
Northern Ireland Utility Regulator (NIAUR)	NIE Networks: Draft Decision, 2017-24	March 2017	0.38

On the basis of the international experience, an asset beta between 0.34 and 0.38 can be considered as a suitable range to be applied. The asset beta can be converted into the equity beta of between 0.68 and 0.76 by applying the Miller formula:

$$\beta_{Equity} = \frac{\beta_{Asset}}{(1-g)}$$

Gearing (g)

Gearing calculates as debt / (debt + equity). The appropriate level of gearing for the WACC can be determined based on either the actual gearing of the Licensees; or based on a notional capital structure. Regulators typically prefer notional gearing structures, as setting the gearing assumption equal to actual gearing increases the risk that the decision could be viewed as an endorsement of their capital structure decisions. This may lead to adopting riskier capital structures.

Information about some recent regulatory decisions on gearing assumptions is shown in the following Table. As can be seen the range is between 44% and 60%. This range has therefore been adopted.

Table A3: Recent regulatory applications of gearing decisions

Regulator	Decision	Date	Gearing
Australian Energy Regulator (AER)	Networks NSW: distribution, 2014- 19	April 2015	60%
New Zealand Commerce Commission	Electricity Distribution: CPP, five-year WACC	September 2016	44%
Australian Energy Regulator (AER)	TasNetworks: Draft Decision, 2017-19	September 2016	60%
Northern Ireland Utility Regulator (NIAUR)	NIE Networks: Draft Decision, 2017-24	March 2017	45%

WACC Computation

In the preceding sections the different parameters for the WACC computation were estimated. Based on this, the resulting WACC can now be estimated in terms of a range between a lower and higher boundary.

Table A4: Computation of the WACC on the basis of estimated parameters

	Low estimate	High estimate
Cost of Debt	**6.47%**	**6.47%**
Risk free rate	3.00%	3.50%
Asset beta	0.34	0.38
Equity beta (pre-tax)	0.57	0.95
ERP	5.69%	5.69%
CRP	3.00%	3.50%
Cost of Equity	**9.2%**	**12.4%**

Gearing		
Debt	60%	40%
Equity	40%	60%
WACC	**7.6%**	**10.0%**

ANNEX 2: REVISED SCHEDULE 6 OF THE ECC

Note: Text in red indicate the main changes to the existing Schedule 6 of ECC 2.

1. Regulated Tariff

1.1. The Regulated Tariff shall comprise two elements (a) a Non-Fuel component, (b) a Fuel/RE component. Each element shall be computed in accordance with the provisions of this Schedule.

1.2. During the Regulatory Period referred to in Clause 3.2(a) of the Addendum (the period from 1st July 2020 until 30 June 2025 the Regulated Tariff for each Island Group shall be the same.

1.3. The Regulated Tariff as at the Reset Date of 1st July 2020 shall be: -

a) Non-Fuel Tariff component (senti/kWh billed): 43.40

b) Fuel/RE Tariff component (senti/kWh billed): Y

c) REGULATED TARIFF (senti/kWh billed): X + Y

2. Adjustment of Regulated Tariff

2.1. The Non-Fuel component of the Regulated Tariff may be adjusted during the Regulatory Period only:-

a) Annually on the 1st of January in each year, commencing 1st January 2021, in accordance with the indexation provisions of paragraph 5 of this Schedule; or

b) In the event of an Extraordinary Event having given rise to an Extraordinary Review and Adjustment, all in accordance with Clause 4 and Schedule 8 of this Addendum.

2.2. The Fuel/RE component of the Regulated Tariff ordinarily shall be adjusted during the Reset Period on a quarterly basis (on 1 July, 1 October, 1 January, and 1 April) in accordance with this Schedule but the Commission, in their absolute discretion may consent to an ad hoc request from the Concessionaire to an adjustment within each quarter were there is an upward spike in the landed cost of diesel at Nuku'alofa OR may require an adjustment within each quarter where there is a significant reduction in the laded cost of diesel at Nuku'alofa.

2.3. In respect of any proposed adjustment under paragraph 2.1(a) of this Schedule the Concessionaire shall submit an Application for such an adjustment, together with all relevant documents and evidence, on or before 15th November in each year. The Commission reasonably may require the Concessionaire to explain further its method of calculation of the Proposed Tariff Adjustment and, if so required, the Concessionaire promptly shall provide to the Commission such additional information or explanations sought by the Commission.

2.4. In respect of any proposed adjustment under paragraph 2.2. of this Schedule the Concessionaire shall submit an Application for such an adjustment, together with all relevant documentation and evidence, at least one calendar month prior to the quarterly adjustment dates referred to in paragraph 2.2. (e.g. no later than 1st June in respect of an adjustment to be effective from 1sth July).

3. Approval by the Commission of the Proposed Adjusted Tariff

3.1. If the Commission advises the Concessionaire in writing within 15 Business Days of receipt of an application under Paragraph 2.1(a) or 2.2 of this Schedule to adjust the Regulated Tariff that: -

a) The Commission agrees with the Concessionaire's calculation of the Proposed Adjusted Tariff, the Regulated Tariff will, from the commencement of the next Tariff Period, be the Proposed Adjusted Tariff applied for by the Concessionaire;

b) The Commission disagrees with the Concessionaire's calculation of the Proposed Adjusted Tariff, which disagreement must be on reasonable grounds and must specify which aspect(s) of the Concessionaire's calculation the Commission disagrees with, the Concessionaire and the Commission will endeavor to agree on the correct calculation of the Tariff Adjustment as soon as reasonably possible. If the Concessionaire and the Commission fail to agree on the Tariff Adjustment prior to the commencement of the next Tariff Period:

i. Forthwith they will submit the calculation of the Tariff Adjustment for Arbitration under Clause 14.2 of the Addendum; and

ii. The Proposed Tariff Adjustment shall not take effect except to the extent that it is approved by the Arbitrator.

3.2. If the Commission does not advise the Concessionaire in writing within 15 Business Days of receipt of the application under paragraph 2.1(a) or 2.2. of this Schedule to adjust the Regulated Tariff that the Commission either agrees or disagrees with the Concessionaire's calculation or that the Commission requires the Concessionaire to further explain the Concessionaire's calculation, the Regulated Tariff will be the Proposed Adjusted Tariff as at the commencement of the next Tariff Period.

4. New Regulated Tariff to be effective from the commencement of the new Tariff Period

4.1. Once the Tariff Adjustment has been agreed or determined under paragraph 3 of this Schedule:

a) The Concessionaire promptly shall give notice to the public of the Tariff Adjustment, in such reasonable manner as has been agreed in writing between the Concessionaire and the Commission; and

b) The adjusted Regulated Tariff will take effect as form the start of the next Tariff Period and the Concessionaire may invoice Customers paying the Regulated Tariff accordingly (and, to the extent that this requires any correction to any invoice issued by the Concessionaire to a customer, for amounts invoiced at the pre-adjustment Regulated Tariff, this correction will be made on the next invoice issued to the Customer).

5. Indexation of the Non-Fuel Component of the Regulated Tariff

5.1. The annual adjustment of the non-fuel component of the Regulated Tariff shall be calculated according to the following Formula:-

$$Non\ Fuel\ Component_p = Non\ Fuel\ Component_{p-1} \times \frac{CPI_p}{CPI_{p-1}}$$

Where:

p = the next Tariff Period

CPI_p = the CPI at the start of the next Tariff Period

CPI_{p-1} = the CPI used in the non-fuel adjustment at the start of the current Tariff Period

6. Fuel/RE Tariff

6.1. At the start of the first Tariff Period of the Regulatory Period, a twelve-month forecast is made for the *PermittedCost* and the sales. The Fuel/RE component is then computed by dividing the Net Present Value (NPV) of the monthly forecast for *PermittedCost* by the NPV of the monthly forecast for the sales, for the period of the next twelve months:

$$Fuel/RE\ Component_0 = \frac{NPV(PermittedCost^*)}{NPV(Sales^*)}$$

Where

- the subscript "$_*$" denotes a forecast
- *Fuel/RE Component$_0$* = the Fuel/RE Component at the start of the first Tariff Period.
- *PermittedCost* =* the monthly forecast for the PermittedCost for the next twelve months
- *Sales* = the* monthly forecast for the sales for the next twelve months

6.2. Forecasts for electricity sales are based on a reasonable growth in demand for electricity.

6.3. Forecasts for PermittedCost are based on the methodology described in paragraph 7 of this Schedule.

6.4. At the start of each new Tariff Period, two adjustments are applied, as described in paragraph 8 of this Schedule, to the Fuel/RE Component of the previous Tariff Period:

a) Adjustment (1): An update of the Fuel/RE Component to take into account updated forecasts for the *PermittedCost* in the next Tariff Period.

b) Adjustment (2): Related to the compensation for differences between forecast and outturn *PermittedCost* in previous Tariff Period.

7. Permitted cost

7.1. The Permitted Cost (*PermittedCost*) for the Concessionaire involved in the generation or purchase of electricity is equal to:

$$PermittedCost = PermittedCost_{Fuel} + PermittedCost_{RE\text{-}TPL} + PermittedCost_{RE\text{-}PPA}$$

Where:

- $PermittedCost_{Fuel}$ = the permitted cost of generation using fuel;
- $PermittedCost_{RE\text{-}TPL}$ = the permitted cost of generation using RE installations owned by the concessionaire
- $PermittedCost_{RE\text{-}PPA}$ = the permitted cost of purchasing RE energy from Independent Power Producers through a Power Purchase Agreement

7.2. Permitted cost for fuel (*PermittedCost*$_{Fuel}$)

a) The $PermittedGeneration_{Fuel}$ is the permitted amount of electricity produced using diesel fuel generators and is calculated as:

$$PermittedGeneration_{Fuel} = \frac{Sales \cdot Share_{Fuel}}{1 - LossTarget_{Fuel}}$$

Where:

- *Sales* = electricity sales
- $LossTarget_{Fuel}$ = the loss target for fuel generation
- $Share_{Fuel}$ = the share of net fuel generation in the total net generation

b) $PermittedCost_{Fuel}$ is the permitted cost for the generation using fuel and is calculated as:

$$PermittedCost_{Fuel} = \frac{PermittedGeneration_{Fuel}}{FuelEfficiencyTarget} \cdot Price_{Fuel}$$

Where:

- *FuelEfficiencyTarget* = the fuel efficiency rate target for fuel generation.
- $Price_{Fuel}$ = the price of fuel per litre

7.3. Permitted cost for Renewable Energy purchased from IPPs through a PPA (*PermittedCost$_{RE\text{-}PPA}$*)

a) The *PermittedGeneration$_{RE\text{-}PPA}$* is the permitted amount of electricity produced using RE facilities owned by the Concessionaire and is calculated as:

$$PermittedGeneration_{RE-PPA} = \frac{Sales \cdot Share_{RE-PPA}}{1 - LossTarget_{RE-PPA}}$$

Where:

- *Sales* = electricity sales
- *LossTarget$_{RE\text{-}PPA}$* = the loss target for RE-PPA generation
- *Share$_{RE\text{-}PPA}$* = the share of net RE-PPA generation in the total net generation

b) *PermittedCost$_{RE\text{-}PPA}$* is the permitted cost for the purchase of electricity through PPAs and is calculated as:

$$PermittedCost_{RE-PPA} = PermittedGeneration_{RE-PPA} \cdot Price_{RE-PPA}$$

Where:

- *Price$_{RE\text{-}PPAl}$* = the price of RE-PPA electricity per kWh

7.4. Permitted cost for Renewable Energy using facilities owned by Concessionaire (*PermittedCost$_{RE\text{-}TPL}$*)

a) The *PermittedGeneration$_{RE\text{-}TPL}$* is the permitted amount of electricity produced using RE facilities owned by the Concessionaire and is calculated as:

$$PermittedGeneration_{RE-TPL} = \frac{Sales \cdot Share_{RE-TPL}}{1 - LossTarget_{RE-TPL}}$$

Where:

- *Sales* = electricity sales
- *LossTarget$_{RE\text{-}TPL}$* = the loss target for RE-TPL generation
- *Share$_{RE\text{-}TPL}$* = the share of net RE-TPL generation in the total net generation

b) *PermittedCost$_{RE\text{-}TPL}$* is the permitted cost for the generation using RE-TPL and is calculated as:

$$PermittedCost_{RE-TPL} = PermittedGeneration_{RE-TPL} \cdot Price_{RE-TPL}$$

Where:

- *Price$_{RE\text{-}TPLl}$* = the price of RE-TPL electricity per kWh

8. Adjustments to the Fuel/RE Component

8.1. Adjustment (1)

The Fuel/RE Component in the new Tariff Period *p+1* is adjusted as follows:

$$Adjustment(1)_{p+1} = \frac{NPV(PermittedCost^{*})}{NPV(Sales^{*})} - Fuel/RE\ Component_{p}$$

Where:

- *NPV* = Net Present Value of the values of that variable for each month of the next Twelve-Month Period using the Allowed Rate of Return as the discount rate
- *PermittedCost** = the monthly forecast for the PermittedCost for the next twelve months
- *Sales* = the* monthly forecast for the sales for the next twelve months
- *Fuel/RE Component$_p$* = Fuel/RE Component in the present previous Tariff Period.

8.2. Adjustment (2)

The balance at the end of each month *m* of over/under recovered *PermittedCost* is calculated as:

$$\begin{aligned} Balance_{m} &\\ &= (1 + ROR) \times Balance_{m-1} + Fuel/RE\ Component\ _{m-1} \times Sales_{m-1} \\ &- PermittedCost_{m-1} \end{aligned}$$

Where

- ROR = the Allowed Rate of Return

The Fuel/RE Component in the new Tariff Period *p+1* is adjusted as follows:

$$Adjustment(2)_{p+1} = \frac{-Balance_{M}}{NPV(Sales_{*})}$$

Where

- *Balance$_M$* = the balance at the end of the last month of the present Tariff Period p
- *Sales* = the* monthly forecast for the sales for the next twelve months

9. Targets

The targets to be applicable during the Regulatory Period shall be as follows:

a) Fuel Efficiency Target (*FuelEfficiencyTarget*) shall be 4.0 kWh per liter

b) The Losses Targets shall be as follows:

	Fuel ***LossTarget$_{Fuel}$***	**RE – Concessionaire owned** ***LossTarget$_{RE\text{-}TPL}$***	**RE – Purchased** ***LossTarget$_{RE\text{-}PPA}$***
2021	9.0%	10% + actual Spill/Battery losses in 2020	7.5% + actual Spill/Battery losses in 2020
2022	9.5%	9% + actual Spill/Battery losses in 2021	6.5% + actual Spill/Battery losses in 2021
2023	9.5%	9% + actual Spill/Battery losses in 2022	6.5% + actual Spill/Battery losses in 2022
2024	8.5%	8% + actual Spill/Battery losses in 2023	5.5% + actual Spill/Battery losses in 2023
2025	8.5%	8% + actual Spill/Battery losses in 2024	5.5% + actual Spill/Battery losses in 2024

ANNEX 3: PPA GUIDELINE PROTOCOL

The following sets out the recommended procedure for the identification and selection of an IPP and the subsequent entry into a PPA with the Concessionaire.

Definitions

““IPP selection process” means the competitive process of selecting a preferred bidder;

“independent power producer” means a body corporate established for the purpose of building, owning and operating a generating facility and selling all generated energy to the Concessionaire under a power purchase agreement;

“Power Purchase Agreement” means an agreement between the Concessionaire and an independent power producer with commercial and technical terms and conditions for supply of electricity generated by the independent power producer to the Concessionaire;”

Procedures for tendering new generation capacity

(1) The Concessionaire shall develop comprehensive IPP Selection Procedures that shall guide the IPP selection process and which shall be

- in accordance with a system that is fair, equitable, transparent, competitive and cost-effective;
- in accordance with objective, clear, transparent and non-discriminatory criteria which may relate to the safety, reliability and security of the power system, land use and sitting, the protection of the environment, energy efficiency, the nature and availability of primary energy resources, and any other criteria set forth in the IPP Selection Procedures;

(1) The IPP Selection Procedures shall include a standard Power Purchasing Agreement to be issued as part of the IPP selection process.

(3) The Concessionaire shall submit the IPP Selection Procedures mentioned under subsection (1) for approval by the Commission.

Identification of new generation capacity

(3) The Concessionaire shall

a) identify any shortfall in generation capacity to assure the reliable and secure supply of electricity;

b) determine the type and amount of generation capacity necessary to be added to assure the reliable, cost effective, and secure supply of electricity;

(4) Necessary renewable generation capacity mentioned under subsection (3) shall be installed by a preferred bidder selected during an IPP selection process and who shall sell energy to the Concessionaire under a power purchase agreement;

IPP Selection process

(5) The Concessionaire shall organize an IPP selection process and shall

a) invite persons who wish to build, own and operate generating facilities and who meet the conditions specified in the IPP Selection Procedures, to participate in the process of competitive procurement of new generation capacity;
b) evaluate the received bids and identify the preferred bidder;
c) issue an Award Letter to the preferred bidder;
d) enter into a Power Purchase Agreement with the preferred bidder;
e) maintain, in such form as it may prescribe, a register of all power purchase agreements entered into under this section.

Approval and award letter

(6) After the evaluation of the bids and the identification of the preferred bidder, but prior to issuing the Award Letter to the preferred bidder, the Concessionaire must submit a report to the Commission for approval, demonstrating how the criteria of value for money and the substantial technical, operational and financial risk transfer were applied in the evaluation of the bids, demonstrating how these criteria were satisfied in the preferred bid and including any other information as required by the Commission.

(7) After having received the approval mentioned under subsection 1, the Concessionaire shall issue an Award Letter to the preferred bidder.

Obligations on the preferred bidder

(8) Within 30 days after the grant of an Award Letter, the preferred bidder shall enter into a Power Purchase Agreement with the Concessionaire for the supply of electricity generated to the Concessionaire.