DRUK GREEN POWER CORPORATION LIMITED

PROPOSAL FOR REVISION OF TARIFF
(July 2016-June 2019)

April 2016

CONTENTS

1. EXECUTIVE SUMMARY

This is a proposal for the revision of Domestic Generation Tariff for the tariff period (July 2016-June 2019). Druk Green Power Corporation Limited (Druk Green) has prepared this proposal as required by the Bhutan Electricity Authority (BEA) in line with the Bhutan Domestic Electricity Tariff (BDET) Policy 2015 and the Tariff Determination Regulation (TDR) reflecting the actual cost of efficient business operation of Druk Green.

The tariff has been calculated using the BEA's Generation Tariff Model and the parameters as given in the policy directives of the BDET Policy 2015. The generation tariff for Druk Green for domestic consumption has been arrived at by using a cost of equity as 15.5%, cost of debt of 9.81%, gearing ratio of 50%, and net average annual energy of 6,282 GWh based on which the domestic generation tariff works out to Nu. 1.84 per kWh.

The tariff is higher than the existing generation tariff of Nu. 1.39 per kWh prevailing since October 2013. Therefore, this proposal is submitted to the BEA for consideration for an upward review of the domestic generation tariff. An increase in generation tariff, as proposed by Druk Green, would provide a steady revenue stream to the Royal Government of Bhutan (RGOB) from the hydropower sector and spur further growth in this very important and strategic sector.

2. INTRODUCTION

This proposal for the revision of generation tariff has been prepared in keeping with the TDR and incorporating the proposed changes in the parameters used for tariff calculation methodology as per the BDET Policy 2015. The tariff proposal is prepared keeping in mind the following principles for tariff determination:

i) Fairness to both service customers and service providers;
ii) No unjust discrimination against service providers or those who wish to use the services;
iii) Reflect the actual cost of efficient business operation;
iv) Conducive to efficiency improvement in business operation;
v) Enhance efficient and adequate supply to satisfy the domestic demand; and
vi) Transparency in the determination and presentation of tariffs.

The BEA revised the generation tariffs in 2013 from Nu. 1.20 per kWh to Nu. 1.39 kWh for the tariff period from 1st October 2013 till 30th June 2016. The tariff for Royalty Energy (15% of total generation) was set as Nu. zero per kWh and supplied to Bhutan Power Corporation Ltd (BPC). Since the existing tariff is approved till 30th June 2016, the tariff proposal for upward revision of tariff considering the updated investment plans from July 2016-June 2019 as well as the updated historical O&M costs is submitted for the tariff period 2016-2019.

3. PARAMETERS USED FOR TARIFF DETERMINATION

The Generation Tariff Model provided by the BEA is used to calculate the average cost of supply for Druk Green. The average cost of supply for Druk Green was determined based on the cost of supply methodology and using the principles to reflect the actual cost of efficient business operation.

The various inputs used in the generation tariff model in keeping with the BDET Policy 2015 and TDR are as given below:

4.1 Tariff Period

The total cost and the total energy is discounted over the tariff period using the Weighted Average Cost of Capital (WACC). The tariff period is proposed as three years as per the provisions of the BDET Policy. The audited financial figures for the year 2015 have been used with 2015 as the reference year for the calculations. The 2015 audited financial statements are given in ***Annexure I.***

4.2 Cost Parameters

The total cost comprises of O&M cost, depreciation, return on assets and returns on working capital. The cost components used as input in the tariff model are as below:

4.2.1 Cost of Equity

The Cost of Equity of 15.5% has been proposed based on the average lending rates of the financial institutions, which for the manufacturing sector is 13%. As per BDET Policy, the BEA could allow a reasonable premium up to a maximum of 250 basis points on the above rates depending on the domestic market situation and gearing ratio applied. Therefore, a 15.5% post tax cost of equity is proposed.

4.2.2 Cost of Debt

As per the BDET Policy 2015, the actual cost of debt is to be used. Hence, the cost of debt is calculated as a weighted average of the interest rates of the loan balance amount of the Druk Green power plants and the addition of the institutional investments to be funded through new loans during the tariff period. The proposed debt for financing the institutional investments are as given in Table 1 below:

Table 1. Debt and Loan Detail

SN	Loan particulars	Year of Loan disbursement	Principle Amount (Mill Nu.)	Interest rate	Repay-ment period	Loan balance 31.12.2016 (Mill Nu.)	Loan balance 31.12.2017 (Mill Nu.)	Loan balance 31.12.2018 (Mill Nu.)
1	BHP Lower Stage	2 April 2002 to 17 June 2005	1,648.87	6.00%	15	879.4	769.47	659.55
2	BHP Upper Stage	30 Dec 1997 to 14 Oct 2007	708	6.00%	20	318.6	283.2	247.8
3	KHP	18 Sep 1997 to 28 Mar 2003	2,240.00	10.75%	12	-	-	-
4	THP	31 Mar 1997 to 31 Dec 2006	15,588.56	9.00%	12	2,532.71	1,266.35	-
5	CHP		983.64	5.00%	15	-	-	-
6	Proposed Loans		811.76	13.00%	10	811.75	767.68	717.88
7	Proposed Loans		470.84	13.0 %	10	-	470.84	445.28
8	Proposed Loans		1,111.12	13.0 %	10	-	-	1,111.12
	Total		**23,562.79**			**4,542.46**	**3,557.54**	**3,181.63**

The weighted average cost of debt for tariff period using the total loan balance is 9.81%.

4.2.3 *Gearing Ratio*

The gearing ratio has been calculated as defined in the TDR using the Debt to Net Fixed Assets. In order to ensure competitive and efficient pricing through an optimal capital structure, the BDET Policy provides that the gearing ratio for computation of WACC shall be higher than the actual gearing ratio and up to a maximum of 70:30. During the tariff period DGPC's average gearing ratio is 9.36%. However, for the purpose of tariff determination, a gearing ratio of 50% is proposed.

4.2.4 *Weighted Average Cost of Capital (WACC)*

The WACC is determined using the cost of equity and the cost of debt as proposed above. The cost of equity of 15.5%, cost of debt of 9.81%, and the prevailing corporate income tax rate of 30% has been used. The resulting WACC of 15.98% is as given in Table 2 below:

Table 2. WACC

Particular	Percentage
Gearing	50%
Cost of Equity	15.5%
Cost of Debt	9.81%
WACC	**15.98%**

4.3 Return on Assets

The return on assets is determined by the Net Assets multiplied by the WACC. The asset schedule as given below has been used in the tariff model.

4.3.1 Fixed Assets

The asset schedule as of December 2015 derived as per the depreciation rates given in Schedule B of the TDR is used for tariff calculation.

Table 3. Asset Schedule

	Gross value	Acc. Dep	Net value	Depreciation
Land	118.37	-	118.37	-
Buildings	1,524.17	308.35	1,215.81	50.81
Civil structures	3,154.04	648.99	2,505.05	105.13
Dam complex	12,019.52	3,472.45	8,547.07	400.65
Water conductor	23,564.48	5,514.09	18,050.39	785.48
Power house	19,749.99	7,350.16	12,399.83	1,427.88
Transmission equipment	350.18	135.14	215.04	11.67
Equipment	885.89	648.39	237.50	113.11
Office equipment	508.71	335.23	173.48	96.54
Total	**61,875.35**	**18,412.80**	**43,462.55**	**2,991.28**

The BDET Policy mentions that for the regulatory asset base used for tariff determination, assets owned by the utilities but not in use and/or which are not utilized for generation, transmission and distribution of electricity shall not be considered. Therefore, the asset schedule used for tariff determination is net of the following assets and accumulated depreciation given below. These assets constructed by the project authorities were handed over to the various other agencies but still exist in the books of Accounts of DGPC.

Table 4. Deductions in Assets Schedule

	Cost as per THPA report (Mill Nu.)	Cost with IDC (Mill Nu.)	Cost with IDC andDep (Mill Nu.)	Dep: 1/4/2009 - 31/12/2015
Gaeddu College of Business Studies	933.41	1,094.89	1,097.88	246.10
Gedu Middle Secondary School	61.36	71.97	72.17	16.18
Bhutan Telecom	7.61	8.93	8.95	2.01
Royal Bhutan Police	5.62	6.60	6.61	1.48
Gedu Hospital	69.27	81.25	81.42	18.26
Total	**1,077.27**	**1,263.64**	**1,267.03**	**284.03**

The THP Distribution assets, amounting to Nu.123.58 million (31st December 2015 net asset values), is to be transferred to BPC as on 30th June 2016. Hence, the gross asset values and accumulated depreciation for the THP distribution assets as given below has also been deducted from the DGPC's asset values for tariff calculation.

Table 5. THP Distribution Assets

	Asset Value (Million Nu.)	Accumulated Dep (Million Nu.)
THP Distribution Assets	166.840	43.256

The following land assets of DGPC as given in Table 6, which are not utilized for generation, transmission and distribution of electricity but leased to the Bhutan Hydropower Services Limited (BHSL), is also not included in the above Asset Schedule.

Table 6.Deductions in Assets

Asset Location	Nu. Mill
Land at Jigmiling	32.00

4.3.2 *Investments*

The investment schedule has been prepared using the 2015 approved Druk Green Investment Plan 2016-2019 (revised according to Budget 2016). The investment schedule given below was prepared based on the capitalization schedule and is used for tariff calculation.

Table 7. Investment Schedule

Project/Activity	2016	2017	2018	2019
Land	-	-	-	-
Buildings	177.87	16.39	207.11	622.39
Civil structures	53.11	67.80	10.00	-
Dam complex	5.00	-	184.22	-
Water conductor	-	20.00	35.00	35.00
Power house	406.72	188.96	103.38	1,504.88
Transmission equipment	-	20.00	207.50	-
Equipment	-	-	-	-
Office equipment	169.05	157.69	363.91	171.95
TOTAL (Nu. Mill)	**811.75**	**470.84**	**1,111.12**	**2,334.22**

The detailed Investment Plan for 2016-19 for DGPC is included in ***Annexure II.*** The Investment Plan includes only the institutional investments pertaining to the existing Plants and the Corporate Office, and not the investments in new generation capacity addition.

4.4 O&M Allowance

The O&M cost comprises of operations and maintenance costs, employee costs, and other expenses. The wheeling charges and power import costs have not been included. The O&M cost of the Fleet Management Division has been apportioned to the O&M cost of the Plants. The O&M allowance of 1,368.98 Million, considering the historical average of past three years adjusted for inflation, is used in the tariff model.

4.4.1 Historical O&M Costs

The historical O&M cost and the 2015 O&M cost as per the audited 2015 annual accounts is given below:

Table 8.Consolidated Historical O&M costs for Druk Green

Total Expenses	2013	2014	2015
O&M Costs	509.10	453.24	449.60
Employee Costs	690.21	649.16	802.94
Other Expenses	89.07	29.98	145.86
Total	***1,288.38***	***1,132.37***	***1,398.40***

As per the BDET Policy, the costs related to CSR and income from rental and hire charges, if any, are to be excluded from the tariff calculations. Therefore, the following costs have been removed from the O&M cost.

Table 9. Deductions from O&M Allowances

Expenses	2013	2014	2015
Corporate Social Responsibility	7.13	8.38	25.62
Foreign Exchange Gain/Loss	227.43	102.21	60.62
House Rent Income	13.52	12.65	13.34
Total (Nu. Millions)	**248.07**	**123.23**	**99.59**

4.4.2 Benchmark O&M Cost

The TDR allows a benchmark operation and maintenance (O&M) cost of 1% to 1.5% of the capital cost adjusted by consumer price index since installation or the revalued capital cost.

The proposed average O&M allowance of Nu. 1,368.98 million, which is 1.02% of the capital cost (replacement value), is within the range of 1 to 1.5% of the capital cost set for the benchmark O&M cost. This is much lower compared to benchmarks set by the Indian Central Electricity Regulatory Commission. The CERC norms allow for 2% of capital cost for projects commissioned before 2014. For projects commissioned after

2014, CERC allows for 4% of original capital cost for projects less than 200 MW and 2.5% for projects more than 200 MW.

The BDET Policy states that the O&M benchmarks for the new investments shall be maintained lower than that of older assets. Therefore, the O&M cost of 1% has been considered in the tariff model for subsequent O&M allowances for the new investments capitalized during the tariff period.

The revalued asset cost of Druk Green during the tariff period is Nu.134,598.58 million. The revalued asset cost of the power plants under Druk Green, valued by Cunningham Lindsey International Private Ltd on the asset values as on 31 December 2011 to derive the replacement value as on 1st October 2012, was escalated by inflation to arrive at the 2015 revalued asset cost (***Annexure III***). The benchmark O&M cost taken at 1.0% of capital cost works out to Nu. 1,346 million.

Table 10. New Replacement Cost (2015)

Plants	New Replacement Value (Nu.)
Basochhu Hydropower Plant	7,088,724,775.93
Chhukha Hydropower Plant	26,869,194,312.02
Tala Hydropower Plant	10,324,488,580.47
Kurichhu Hydropower Plant	90,316,176,364.05
Total Assets (Nu. Replacement Cost)	**134,598,584,032.46**
O&M Benchmark Cost (1%)	1,345,985,840.32

4.4.3 Corporate Office Costs

With the four power plants under Druk Green, it is proposed that the entire cost of the Corporate Office be considered for tariff calculation unlike in the past reviews where only 1/3rd of the cost was considered by the BEA. The cost of the Projects Department in Corporate Office which is mainly involved in investigation and construction of new hydropower projects is directly booked to new projects and is accounted separately to be capitalized as part of the costs of those specific projects. There is a clear cost separation between the cost intended for new projects and the costs towards operation and maintenance of the Plants. Further, Druk Green has no other mandate but to develop, operate and maintain hydropower plants.

4.4.4 Regulatory Fees

Regulatory fees to the BEA has not been added separately as the annual regulatory fee of Nu. 14.8 million is already accounted under O&M expenses.

4.4.5 *Inflation*

The historical inflation figures are taken from the Consumer Price Index bulletin of the National Statistics Bureau (***Annexure IV***). The average inflation rate of the last three years is used to calculate the historical average O&M cost and to escalate the yearly O&M allowance over the tariff period. The average annual inflation rate of 7.09% for the past three years as detailed below is used for the tariff period.

Table 11. Historical Inflation on Non Food Item

Year	2013	2014	2015	Average
Inflation figures	8.75%	6.91%	5.62%	**7.09%**

Source: Consumer Price Index Bulletin, National Accounts and Price Division, National Statistical Bureau.

4.5 *Cost of Working Capital*

The calculation of the cost of working capital uses the annual inventories and arrears.

4.5.1 *Inventories*

The average inventories for the years 2013 to 2015 amounting to Nu. 557.08 million has been used in the calculation as shown below:

Table 12.Historical Inventories

	2013	2014	2015	Average
Inventories (Mill Nu.)	526.03	560.78	584.29	557.03

4.5.2 *Arrears*

The weighted average arrears of 60 days is used for tariff calculation. This is compiled from the different Memorandum of Understandings (MoU) signed between BPC and Tala (THP), Chhukha (CHP), Basochhu (BHP) and Kurichhu (KHP) Hydropower Plants. The bill preparation and delivery duration is the same for all plants, whilst the bill payment durations vary. The average consumption period of 15 days is also added to arrive at the arrears. The weighted average arrear is calculated using the generation forecast for 2016 as shown below:

Table 13. Weighted Average of Arrears

Arrears (No of Days)	BHP	CHP	KHP	THP	Average
2016 Generation Forecast (GWh)	317	1,858	375	4,841	
Average Energy consumption duration	15	15	15	15	
Bill preparation and delivery duration	10	10	10	10	
Bill payment due date	30	45	45	30	
Arrears	**55**	**70**	**70**	**55**	**60**

Source: 1. MoU on bulk sale and purchase of electrical energy signed between BPC, CHP and THPA effective from 31/7/2006.2. MoU signed between BPC and KHPC effective from 1/1/2004.

4.6 Energy Volumes

The average mean annual generation for the past 3 years less the 15% royalty energy volumes is used for energy volumes.

4.6.1 Annual Energy Generation Forecast

The total annual energy generation forecast for the tariff period is 7,390.38 GWh as given below:

Table 14. 2016 Generation Forecast

Average Annual Energy for the year 2016 to 2019 in MU					
	BHP	**CHP**	**KHP**	**THP**	**Total**
Energy Generation	316.96	1,857.54	375.22	4,840.66	7,390.38

Forecast based on average of past three years and addition of TDS

This was forecasted based on past 3 years' generation as detailed in Table 15with the addition of the additional generation from the Tsibjalumchhu Diversion Scheme.

Table 15.Historical Energy Generation

Year	Generation Projection for 2016-2019 (GWh)						
	BHP	CHP	KHP	THP	TDS	THP-TDS	Druk Green
2013	331.77	1,907.44	378.60	4,913.63	-	4,913.63	7,531.45
2014	306.35	1,797.83	368.03	4,674.89	23.69	4,651.20	7,123.40
2015	312.75	1,867.36	379.02	4,822.47	67.35	4,755.13	7,314.26
Average Generation (without TDS)	**316.96**	**1,857.54**	**375.22**	**4,803.66**		**4,773.32**	**7,323.03**
Tsibjalumchhu Diversion Scheme (TDS)						67.35	67.35
Average Generation (with TDS)	**316.96**	**1,857.54**	**375.22**	**4,803.66**		**4,840.66**	**7,390.38**

4.6.2 Annual Energy Volumes

As per the BDET Policy 2015, the royalty energy volume is deducted from the total energy volumes for tariff computation. The energy volume net of the 15% royalty energy is 6,282 GWh. This energy volume, net of the auxiliary losses, computed to be 6,206 GWh as given in Table 16 below is used for tariff computation.

Table 16. Energy Volumes

Year	2016	2017	2018	2019
ENERGY (GWh)	6,282	6,282	6,282	6,282
ENERGY net of Losses (GWh)	6,206	6,206	6,206	6,206
ROYALTY ENERGY (GWh)	1,095	1,095	1,095	1,095

4.6.3 Royalty Energy Volumes

The 15% royalty energy corresponds to an energy volume of 1,095 GWh annually during the tariff period.

4.6.4 Auxiliary Consumption and Plant Availability

The auxiliary consumption of 1.2% and power plant availability of 100% is considered in the tariff model as the actual average energy generated is used. Druk Green's past three years average auxiliary consumption inclusive of transformation losses is 1.12% of the total energy generated at average power plant availability (for four months) of 98.70% as shown below:

Table 17.Power Plant Availability

Year	2013	2014	2015	Average
Power Plant Availability (%)	98.95	98.94	98.20	98.70
Auxilliary +Transformation loss (%)	1.21	1.12	1.02	1.12

4.6.5 O&M Efficiency Gain

An O&M efficiency gains target of 2% has been considered in the tariff model. This was based on the previous tariff reviews by the BEA. It is observed that there is an average increase of 14% in the O&M cost of Druk Green over the period from 2012 to 2015. Considering this it is seen that the percentage increase in O&M cost is much higher than the inflation. Therefore, the efficiency gain of at least 2% used is reasonable.

Table 18.*Historical O&M Costs*

Year	2012	2013	2014	2015	Average
O&M Cost	***986.31***	***1,288.38***	***1,132.37***	***1,398.40***	
% Increase		31%	-12%	23%	14%
Inflation		8.75%	6.91%	5.62%	7.09%

4.6.6 Import of Energy

The BDET Policy 2015 states that the import of energy shall be on net monthly import basis to meet the shortfall of domestic supply to be allocated to industries (HV customers).

Anet import of energy by the Kurichhu Hydropower Plant is expected during the tariff period as shown in table below. This is calculated based on the average trends over the past 5 years. The imports are to be made at the export rate which is Nu. 1.98 for 2016-17, Nu. 2.178 for 2017-2019 period.

Table 19. Import for Domestic Consumption

Months	Generation Projection (GWh)	Demand Projection (GWh)				Net Import (GWh)			
	2016-2019	2016	2017	2018	2019	2016	2017	2018	2019
January	13.91		45.96	53.70	62.75		-32.06	-39.80	-48.84
February	11.28		42.91	53.08	65.66		-31.64	-41.80	-54.38
March	15.04		48.29	58.75	71.47		-33.25	-43.71	-56.43
April	22.85		38.54	42.78	47.49		-15.69	-19.93	-24.64
May	39.35		42.00	46.22	50.86		-2.65	-6.86	-11.51
June	44.26		37.58	40.41	43.45				
July	48.58	30.76	31.90	33.08					
August	48.27	35.71	39.09	42.78					
September	47.02	21.84	22.36	22.90					
October	41.08	23.85	24.12	24.40					
November	25.20	33.53	36.39	39.49		-8.33	-11.19	-14.29	
December	18.38	36.17	39.63	43.42		-17.79	-21.25	-25.05	
Total (GWh)	**375.22**					**-26.12**	**-147.72**	**-191.44**	**-195.80**
Rate (Nu/unit)						1.98	2.178	2.178	2.178
Total (Mill. Nu.)						**-51.72**	**-321.73**	**-416.96**	**-426.45**

4. GENERATION TARIFFS

The average cost of generation for Druk Green is calculated from the tariff model. The tariff was determined using debt inclusive of envisaged investment in the tariff period. The gearing ratio of 50% is being used. The summary of the output of the Tariff Model is given below:

Table 20. Summary of the Cost of Generation

Tariff period	Inputs	1	2	3
Cost of Equity	15.5%			
Cost of Debt	9.81%			
Gearing Ratio	50%			
WACC	15.98%			
Discounted Total Cost		10,047	18,528	25,726
Discounted ENERGY		5,351	9,966	13,944
Average Cost		1.84	Nu/kWh	

The tariff calculations result in anaverage cost of generation during the July 2016-June 2019 tariff period of Nu. 1.84 per kWh, which is higher than the current approved tariff of Nu. 1.39 per kWh.

The detailed output of the tariff model is given in ***Annexure V.*** The output of the average cost of supply for the individual plants have also been prepared as required by BEA and is attached in ***Annexure V***.

5. CONCLUSION

The tariff proposal has been prepared in line with the policy provisions of the BDET Policy 2015 and the TDR. From the results presented above, the cost of generation of Nu. 1.84 per kWh is higher than the existing generation tariff set by BEA in 2013 of Nu. 1.39 per kWh. Therefore, it is proposed that the BEA consider the upward revision of the domestic generation tariff to Nu. 1.84 per kWh for the July 2016-June 2019 tariff period.

The increase in tariff will allow Druk Green to earn returns as permissible within the BDET Policy and the regulatory framework, and to maintain satisfactory levels of profitability. This will also safeguard revenues from export from being eroded by domestic sales and ensure steady flow of revenues to the Royalty Government of Bhutan from the hydropower sector.

ANNEXURES

ANNEXURE I. ANNUAL ACCOUNTS 2015

DRUK GREEN POWER CORPORATION LIMITED

Statement of Financial Position as at 31st December 2015

Amount in Nu.

Particulars	Note	2015	2014
ASSETS			
Non- Current Assets			
Property,Plant & Equipment	1	44,530,318,923.46	45,737,658,469.62
Intangible Assets	1	67,427,364.22	41,057,059.55
Capital Work in Progress	1	388,093,190.80	791,258,725.09
Long-Term Investments	2	5,132,418,852.07	4,035,675,082.30
Total Non - Current Assets		**50,118,258,330.55**	**50,605,649,336.56**
Current Assets			
Cash and Bank Balance	5	327,474,496.15	693,596,340.44
Short Term Investments	6	3,043,000,000.00	3,715,101,722.20
Inventories	7	584,286,338.50	560,782,465.61
Sundry Debtors	8	967,584,630.26	1,191,209,108.31
Short Term Loans and Advances	9	352,779,979.59	424,434,042.36
Other Current Assets	10	197,500,293.88	283,432,456.68
Total Current Assets		**5,472,625,738.38**	**6,868,556,135.60**
TOTAL ASSETS		**55,590,884,068.93**	**57,474,205,472.16**
EQUITY AND LIABILITIES:			
Shareholder's Equity			
Share Capital	11	30,712,866,000.00	30,508,291,000.00
General Reserves		8,600,844,795.11	8,162,735,630.49
Retained Earnings		3,315,748,593.03	3,311,582,828.88
Accumulated Other Comprehensive Income		58,101,290.00	36,039,560.00
Group Investment Reserve		190,000,000.00	190,000,000.00
Total Shareholders' Equity		**42,877,560,678.15**	**42,208,649,019.37**
Non- Current Liabilities			
Long- Term Borrowings	12	7,769,695,310.40	10,215,298,542.83
Long Term Provisions	13	417,194,422.02	332,052,470.01
Deferred Tax Liability	4	53,018,834.66	(37,054,364.18)
Total Non Current Liabilities		**8,239,908,567.08**	**10,510,296,648.66**
Current Liabilities			
Short - Term Borrowings	14	2,291,529,714.45	2,556,703,493.45
Short - Term Provisions	15	1,636,966,816.91	1,812,889,164.95
Other Current Liabilities	16	544,918,292.34	385,667,145.73
Total Current Liabilities		**4,473,414,823.70**	**4,755,259,804.13**
Total Liabilities		**12,713,323,390.78**	**15,265,556,452.79**
TOTAL SHAREHOLDERS' EQUITY & LIABILITIES		**55,590,884,068.93**	**57,474,205,472.16**

DRUK GREEN POWER CORPORATION LIMITED

Statement of Comprehensive Income for the year ended 31st December 2015

Amount in Nu.

Particulars	Note No.	2015	2014
Income			
Electricity Revenue	17	14,058,058,253.05	13,656,772,624.43
Interest Earned	18	154,143,864.38	204,418,362.09
Other Income	19	45,883,343.91	44,580,955.47
		14,258,085,461.34	13,905,771,941.99
Expenditure			
Wheeling charges		592,984,484.74	575,053,223.42
Royalty Expense		1,520,595,229.77	1,472,287,438.14
Insurance		114,506,467.10	113,792,128.54
Running and Maintenance Expenses	20	335,093,540.50	339,445,049.51
Employees' Remuneration and Benefits	21	802,940,040.88	649,155,369.44
Purchase of Energy	22	314,512,552.02	371,285,817.48
Interest on Borrowings	23	622,014,081.21	751,503,584.92
Depreciation/Amortisation		2,307,439,218.08	2,260,530,905.72
Other Expenses	24	245,449,437.61	153,211,046.71
		6,855,535,051.91	6,686,264,563.88
Operating Profit		**7,402,550,409.43**	7,219,507,378.11
Less:			
Profit Before Tax		**7,402,550,409.43**	7,219,507,378.11
Tax Expense			
Current Tax		2,161,528,617.56	2,188,780,827.77
Deferred Tax (Income)/Expense		90,073,198.83	(656,278.54)
Income Tax for earlier years		-	-
Profit for the Year		**5,150,948,593.04**	5,031,382,828.88
Other comprehensive income:			
Actuarial gains (losses) on defined benefit pension plans		22,061,730.00	37,336,730.00
Total Other Comprehensive Income for the Year		**22,061,730.00**	37,336,730.00
COMPREHENSIVE INCOME FOR THE YEAR		**5,173,010,323.04**	5,068,719,558.88
Basic & Diluted Earnings Per Share		**168.43**	166.14

ANNEXURE II. INVESTMENT PLANS 2016-2019

As per Capitalization Schedule

Total Investments/ Project Cost (Million Nu.)

Particulars	Total: 2016-2019	2016	2017	2018	2019
Corporate Office					
Druk Green Corporate Office Building	357.50				357.50
Construction of P/Ling Integrated Service Centre.	184.61			184.61	
R&D Centre	255.00				255.00
Networking	31.60	11.60			20.00
Other Asset*	280.78	65.14	68.40	71.82	75.41
Total	**1,109.49**	**76.74**	**68.40**	**256.43**	**707.91**
THP	**Total: 2016-2019**	**2016**	**2017**	**2018**	**2019**
II. E&M EQUIPMENT					
Purchase of Two Forged/Forged fabricated runners and Hard-coating on the Runners	71.38			71.38	
Reclamation and Hard coating of Runners	149.90	55.90	38.00	28.00	28.00
Upgradation of Computerised Control System (CCS) including MIV and Governing System	-				
Purchase of modified/upgraded Nozzle Assembly	840.00				840.00
400kV GIS System(12 year maintenance)	100.00			100.00	
Supply and Installation of 20T EOT crane at TRT Store	15.00		15.00		
Improvement of Ventilition system and replacement of existing Air Conditions at Power House	80.00	80.00			
III. CIVIL WORKS					
Buildings	65.94	65.94	-	-	-
Walls and Fencing	1.50	-	1.50	-	-
Road and Culverts	22.50	5.00	17.50	-	-
Water Supply and Sanitation	12.17	12.17	-	-	-
Other Civil Structure	73.45	73.45	-	-	-
Power House Stabilisation Work/Rock bolt installation Including Consultancy	273.35	-			273.35
Networking	10.63	10.63	-	-	-
Other Assets*	73.71	17.10	17.96	18.85	19.80
Total: THP	**1,789.54**	**320.20**	**89.96**	**218.24**	**1,161.15**
CHP	**Total: 2016-2019**	**2016**	**2017**	**2018**	**2019**
I. DAM WORKS					
Replacement of present Radial Gate Hoisting mechanism with Hydraulic system.	182.22			182.22	
Modification of intake and sediment flushing system at Lubichu Diversion Scheme	3.00	3.00			
Civil Rehabilitation of CHP Dam	-				
Provide Additional Log Booms	2.00			2.00	
II. E&M EQUIPMENT					
Generator and Power transformer protection of four units	13.82	13.82			
Implementation of SCADA System	108.10			108.10	
Replacement of Generator Stator and Field Coil	361.03				361.03
Purchase 4 New Runners with Hard Coating option	235.16	235.16			
Reclamation of Runners	97.63		97.63		

Upgradation of current open loop Cooling Water System of Units to Closed Loop System, including Replacement of Existing Cooling Water pipes with Stainless Steel Pipes	35.00			35.00	
Install online partial discharge monitoring system for Generator Transformers	4.00			4.00	
III. CIVIL WORKS					
Buildings	44.39	10.61	16.39	15.00	2.39
Walls and Fencing	1.44	1.44	-	-	-
Road and Culverts	17.30	1.50	15.80	-	-
Water Supply and Sanitation	-	-	-	-	-
Other Civil Structure	47.90	20.90	17.00	10.00	-
Networking and Installation of comprehensive CCTV surveillance for CHP.	7.52	7.52	-	-	-
Other Assets*	117.12	27.17	28.53	29.96	31.46
Total: CHP	**1,277.64**	**321.13**	**175.35**	**386.28**	**394.88**
BHP	**Total: 2016-2019**	**2016**	**2017**	**2018**	**2019**
I. E&M EQUIPMENT					
Purchase of one spare Runners for each Plant (Phase-3)	30.00		30.00		
Upgradation of SCADA System for both Plants and Switchyard.	103.50			103.50	
Reclamation of Runners and Accessories	14.70	6.20	2.00	4.00	2.50
Transformer for Upper Stage (15 MVA GT)	20.00		20.00		
II. CIVIL WORKS					
Walls and Fencing	6.90	6.90	-	-	-
Buildings	5.37	5.37	-	-	-
Road and Culverts	0.20	0.20	-	-	-
Rectification of Penstock of Stage 2	35.00				35.00
Networking	13.00	3.13	6.87	3.00	-
Other Assets*	32.50	7.54	7.92	8.31	8.73
Total: BHP	**261.18**	**29.35**	**66.79**	**118.81**	**46.23**
KHP	**Total: 2016-2019**	**2016**	**2017**	**2018**	**2019**
I. DAM WORKS					
Radial Gate Rectification	-				
Dam Instrumentation Analysis	2.00	2.00			
II. E&M EQUIPMENT					
Uprgadation of Protection relays of generator and feeders	15.64	15.64			
Changing of Runners Servo Motor for Unit III	6.33		6.33		
Implementation of SCADA System	108.10			108.10	
Upgradation of closed loop cooling water system	20.00		20.00		
installation of remote water monitoring system at SumpaLhuentse	1.60	1.60			
III. CIVIL WORKS					
Buildings	37.50	22.50	-	7.50	7.50
Walls and Fencing	2.00	2.00	-	-	-
Road and Culverts	-	-	-	-	-
Water Supply and Sanitation	17.50	1.50	16.00	-	-
Other Civil Structure	1.50	1.50	-	-	-
Networking and Installation of comprehensive CCTV surveillance for KHP	16.30	3.30	13.00	-	-
Other Assets*	61.62	14.30	15.01	15.76	16.55
Total: KHP	**290.09**	**64.33**	**70.34**	**131.36**	**24.05**
DGPC	**4,727.92**	**811.75**	**470.84**	**1,111.12**	**2,334.22**

ANNEXURE III. REVALUED CAPITAL COSTS

Valuation of Assets (2015)			2013 Price level	2014 Price Level	2015 Price Level
Plants	**Original Capitalisation(Mill. Nu.)**	**New Replacement Value (Mill.Nu.)**	8.75%	6.91%	5.62%
BHP	3,764.75	5,772.64	6,277.74	6,711.54	7,088.72
CHP	3,694.35	21,880.68	23,795.24	25,439.49	26,869.19
KHP	6,060.78	8,407.65	9,143.32	9,775.13	10,324.49
THP	46,981.17	73,548.16	79,983.62	85,510.49	90,316.18
Total	**60,501.05**	**109,609.13**	**119,199.93**	**127,436.64**	**134,598.58**

ANNEXURE IV. INFLATION

Year	Period	Food	Non-Food	Year-on-Year Non-Food Inflation	Average Inflation Non-Food
2013	Jan	101.25	102.59	9.01%	8.75%
	Feb	102.29	103.12	9.56%	
	Mar	102.42	104.03	10.53%	
	Apr	104.12	104.49	6.38%	
	May	104.16	104.97	6.87%	
	Jun	106.04	106.23	8.15%	
	Jul	107.87	108.88	9.40%	
	Aug	109.66	107.85	8.36%	
	Sep	110.78	108.40	8.92%	
	Oct	113.48	109.06	9.06%	
	Nov	114.40	109.30	9.30%	
	Dec	115.49	109.44	9.44%	
2014	Jan	115.34	110.29	7.50%	6.91%
	Feb	115.60	110.45	7.11%	
	Mar	115.60	110.75	6.46%	
	Apr	116.71	111.11	6.34%	
	May	117.54	111.77	6.47%	
	Jun	118.81	112.10	5.52%	
	Jul	119.80	115.54	6.12%	
	Aug	120.25	116.56	8.08%	
	Sep	120.90	116.90	7.84%	
	Oct	120.98	117.04	7.31%	
	Nov	121.39	116.91	6.96%	
	Dec	121.42	117.36	7.23%	
2015	Jan	121.04	118.17	7.15%	5.62%
	Feb	121.11	118.59	7.37%	
	Mar	121.12	118.81	7.28%	
	Apr	121.21	118.82	6.93%	
	May	120.89	119.04	6.50%	
	Jun	121.27	119.44	6.55%	
	Jul	122.10	120.69	4.46%	
	Aug	123.00	120.80	3.64%	
	Sep	123.73	121.19	3.67%	
	Oct	124.45	121.75	4.03%	
	Nov	124.60	121.85	4.23%	
	Dec				

ANNEXURE V. GENERATION TARIFF

DGPC: Total Cost of Supply (mill Nu.)					
	2016	2017	2018	2019	2020
OM	1,446.8	1,525.2	1,614.0	1,719.6	1,807.2
DEP	3,046.9	3,107.3	3,208.3	3,316.1	3,357.7
RoA	6,767.4	6,383.1	6,013.0	5,775.6	5,432.3
RoWC	391.1	391.4	393.9	401.0	403.7
Total Cost	11,652.2	11,407.0	11,229.2	11,212.3	11,000.9

Energy volumes (GWh)					
	2016	2017	2018	2019	2020
$ENERGY_i$	6,282	6,282	6,282	6,282	6,282
ENERGY	6,206	6,206	6,206	6,206	6,206
ROYALTY	1,095	1,095	1,095	1,095	1,095

Average Cost of Supply					
Tariff period	1	2	3	4	5
Discounted Total Cost	10,047	18,528	25,726	31,923	37,166
Discounted ENERGY	5,351	9,966	13,944	17,375	20,333
Average Cost	1.84	Nu/kWh			

BHP: Total Cost of Supply (mill Nu.)					
	2016	2017	2018	2019	2020
OM	114.5	121.0	128.5	136.0	142.9
DEP	235.8	241.3	247.7	252.2	253.5
RoA	380.8	349.2	325.4	302.2	266.6
RoWC	26.8	26.9	27.2	27.5	27.5
Total Cost	757.9	738.4	728.8	717.9	690.5

Energy volumes (GWh)					
	2016	2017	2018	2019	2020
$ENERGY_i$	269	269	269	269	269
ENERGY	266	266	266	266	266
ROYALTY	47	47	47	47	47

Average Cost of Supply					
Tariff period	1	2	3	4	5
Discounted Total Cost	647	1,184	1,637	2,017	2,329
Discounted ENERGY	227	421	586	727	848
Average Cost	2.79	Nu/kWh			

CHP: Total Cost of Supply (mill Nu.)					
	2016	2017	2018	2019	2020
OM	444.3	468.9	497.3	528.6	555.6
DEP	264.7	288.2	335.1	390.5	412.9
RoA	328.9	329.6	336.3	369.5	353.6
RoWC	61.8	65.3	70.1	76.3	79.8
Total Cost	1,099.6	1,152.0	1,238.9	1,364.9	1,402.0

Energy volumes (GWh)					
	2016	2017	2018	2019	2020
$ENERGY_i$	1,579	1,579	1,579	1,579	1,579
ENERGY	1,560	1,560	1,560	1,560	1,560
ROYALTY	275	275	275	275	275

Average Cost of Supply					
Tariff period	1	2	3	4	5
Discounted Total Cost	938	1,777	2,546	3,269	3,903
Discounted ENERGY	1,331	2,466	3,435	4,262	4,967
Average Cost	0.74	Nu/kWh			

KHP: Total Cost of Supply (mill Nu.)					
	2016	2017	2018	2019	2020
OM	176.8	186.5	197.6	208.5	219.1
DEP	343.4	356.6	373.8	384.0	385.8
RoA	506.9	460.5	418.9	375.2	316.6
RoWC	48.7	48.9	49.6	50.1	49.8
Total Cost	1,075.7	1,052.5	1,039.9	1,017.8	971.2

Energy volumes (GWh)					
	2016	2017	2018	2019	2020
$ENERGY_i$	319	319	319	319	319
ENERGY	315	315	315	315	315
ROYALTY	56	56	56	56	56

Average Cost of Supply					
Tariff period	1	2	3	4	5
Discounted Total Cost	918	1,684	2,330	2,869	3,308
Discounted ENERGY	269	498	694	861	1,003
Average Cost	3.36	Nu/kWh			

THP: Total Cost of Supply (mill Nu.)					
	2016	2017	2018	2019	2020
OM	779.3	820.3	865.7	925.4	972.5
DEP	2,202.9	2,221.2	2,251.8	2,289.4	2,305.5
RoA	6,073.1	5,736.4	5,396.4	5,174.4	4,914.7
RoWC	287.4	283.9	281.1	282.1	281.6
Total Cost	9,342.7	9,061.8	8,794.9	8,671.3	8,474.3

Energy volumes (GWh)					
	2016	2017	2018	2019	2020
$ENERGY_i$	4,115	4,115	4,115	4,115	4,115
ENERGY	4,065	4,065	4,065	4,065	4,065
ROYALTY	717	717	717	717	717

Average Cost of Supply					
Tariff period	1	2	3	4	5
Discounted Total Cost	7,971	14,567	20,029	24,623	28,454
Discounted ENERGY	3,468	6,427	8,952	11,106	12,944
Average Cost	2.24	Nu/kWh			