Summary of Upfront Tariff for RLNG based Power Projects

Particulars	60% Plant Factor				92% Plant Factor			
	Foreign Financing		Local Financing		Foreign Financing		Local Financing	
	Rs/kWh	Cents/kWh	Rs/kWh	Cents/kWh	Rs/kWh	Cents/kWh	Rs/kWh	Cents/kWh
30 Years Project Life	**RLNG Price US$ 10/MMBTU**							
700-900 MW (Combined Cycle)	8.85	8.88	9.58	9.61	7.90	7.93	8.37	8.40
20 Years Project Life								
700-900 MW (Combined Cycle)	9.04	9.07	9.84	9.87	8.02	8.05	8.54	8.57
30 Years Project Life	**RLNG Price US$ 11/MMBTU**							
700-900 MW (Combined Cycle)	9.47	9.50	10.20	10.23	8.51	8.54	8.99	9.02
20 Years Project Life								
700-900 MW (Combined Cycle)	9.66	9.69	10.46	10.50	8.64	8.66	9.16	9.19
30 Years Project Life	**RLNG Price US$ 12/MMBTU**							
700-900 MW (Combined Cycle)	10.09	10.13	10.82	10.86	9.13	9.16	9.60	9.63
20 Years Project Life								
700-900 MW (Combined Cycle)	10.28	10.32	11.09	11.12	9.25	9.28	9.77	9.81

Introduction:

1. The Government of Pakistan (GoP) is making all out efforts to reduce the electricity demand-supply gap in the country, by adopting multi-pronged strategy. GoP has initiated Clean, Affordable and Reliable Energy ("**CARE**") Program which is an integrated approach towards Sustainable Energy for Pakistan through import of R-LNG for setting up of power plants. It is anticipated that 600 MMSCFD of R-LNG would be available for the power generation projects in 2017-18 for which Ministry of Water & Power and Ministry of Petroleum & Natural Resources are in close coordination to finalize the modalities.

2. As per decision of the CCOE, 3,600 MW RLNG based power plants will be located at Bhikki, Balloki and Haveli Bahadur Shah etc. Exact sites and power plant capacities at each location will be finalized by NTDCL considering the feasibility, demand supply, power evacuation and system studies. In this respect, plant capacities in the range of 700-900MW for IPPs are being prepared in the Upfront Tariff.

3. The process would entail the sponsors to submit proposal to PPIB in response to the advertisement published after announcement of Upfront Tariff by NEPRA. The Sponsors' technical and financial strength as well as proposed project details will be evaluated by PPIB for issuance of Letter of Intent (LOI) after which the sponsors will apply to NEPRA for tariff acceptance and generation license.

4. Projects will be approved by the NEPRA such that for each site, defined capacity cutoff is reached subject to a maximum cap of approximately 3,600 -4,000 MW.

Basis for Upfront Tariff

The upfront tariff is worked out on the following basis:

1) Price and Quality of Gas:

LNG price is assumed at US$ 10, US$ 11 and US$ 12 per MMBTU on LHV basis. Actual price of LNG for Power Plants will be based and indexed to the LNG prices to be determined by OGRA/GOP.

- Gas shall be of pipeline quality;
- Calorific value: [950 BTUs]

Ref: Estimated/to be confirmed by the Government.

2) Plant Size:

a. The upfront tariff has been determined for the plants with the capacities of 800 MW Net at Site.

b. The actual net capacity of the complex will be determined on the basis of Initial Dependable Capacity (IDC) Test at the time of COD and the relevant tariff components will be adjusted downward. However, upward adjustment in tariff will not be allowed if the IDC established lower than the benchmarks stated above.

Ref: GTW Handbook 2013 ***(Annex-I)***

3) Project Location:

a. Projects are required to be established within the Punjab and exact location of the sites will be finalized with the concurrence of NTDCL.

4) Plant Specifications:

a. The sponsors of the plant will be at liberty to select plant of any manufacturer based on Combined Cycle Gas Turbine technology as long as minimum efficiency and availability thresholds are ensured for the life of the project.

5) Exchange Rate:

a. Reference exchange rate of Rs. 99.6750/US$ (2nd January 2015) has been used in calculating the reference tariff and the same shall be used for indexations/adjustments where applicable.

Ref: www.oanda.com ***(Annex-II)***

6) Total Project Cost:

a. The capital cost includes cost of Main Plant Equipment System, Gas turbines including Auxiliaries, STG. & Auxiliaries, Balance of Plant Equipment System, Other Mechanical Equipment System, Electrical Equipment System, Gas Handling Infrastructure, Engineering & Project Management, Erection & Commissioning, land, site development and civil works, transportation and evacuation cost up to inter-connection point.

b. The Total Project Costs are as follows:

- 800 MW Net at Foreign Financing US$ 863.386 Million
- 800 MW Net Local Financing US$ 938.097 Million

c. The 800MW tariff will be applicable to the projects with the capacities of 700MW – 900MW respectively.

d. Tariff for Simple Cycle has also been calculated for ten (10) months and on the following basis:

- Net Capacity assumed to be 60% of the Combined Cycle Operation;
- Fuel Cost Component is calculated at Net Efficiency of 37%;
- Variable O&M Component is calculated at 60% of the CC Capacity;
- Fixed O&M and ROE to be 50% of the Combined Cycle Operation as an incentive to operate.

Ref: PJM report, EIA report and NEPRA's indexed tariff ***(Annex-III)***

Capital Cost Indexation Mechanism

The following indexation mechanism shall be applicable for adjustments in capital cost during the validity period with the changes in Producers Price Index (PPI) for Steel and Electrical Machinery.

CC(n)	=	(cc(0) * 51*ΔSI) + (CC(0) * 38% *ΔEI) + (CC(0) * 11%)

Where:

CC(n) = Capital Cost at the time of acceptance of the tariff during the control period

CC(0)	=	Capital Cost at the beginning of the control period
ΔSI	=	Variation in US PPI for Steel i.e. SI(n)/SI(0)
SI(n)	=	PPI Steel at the time of acceptance of the tariff
SI(0)	=	PPI Steel for the month of January 2015
ΔEI	=	Variation in US PPI for Electrical Machinery i.e. EI(n)/EI(0)
EI(n)	=	PPI Electrical Machinery at the time of acceptance of the tariff
EI(0)	=	PPI Electrical Machinery for the month of January 2015

Ref: NEPRA's Upfront Tariff for Coal

7) Customs Duties, Cess and Withholding Tax:

a. Customs duties & cess @ 5.95% of the 66.75% of the capital cost has been assumed in the project cost which will be adjusted at the time of COD on actual basis. No withholding tax on local foreign contractors, sub-contractors, supervisory services and technical services provided by foreign (non-residents) entities has been assumed. Actual expenditure, if any, on this account will be included in the project cost at the time of COD on the basis of verifiable documentary evidence.

Ref: NEPRA's Upfront Tariff for Coal

8) Construction Period:

(i) The targeted maximum construction period after financial close is 18 months for simple cycle operation and 28 months for combined cycle operation. No adjustment will be allowed in this tariff to account for financial impact of any delay in project construction;

9) Financing of Projects:

a. The sponsor of the project can arrange foreign financing in American Dollar ($), British Pound Sterling (£), Euro (€) and Japanese Yen (Y) or in any currency as the Government of Pakistan may allow.

b. The Upfront Tariff has been determined on the basis of debt equity ratio of 75:25; the minimum equity shall be 20% and the maximum equity shall be 30%; if the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as loan.

Ref: NEPRA's Upfront Tariff for Coal

10) Financial Charges:

For the purpose of determination of upfront tariff loan tenure of 10 years plus grace period equivalent to construction period has been considered.

a. Interest Rate:

i. The reference three (3) Months Karachi Inter Bank Offer Rate (KIBOR) of 9.57% plus 300 basis points has been used for calculating the financial charges.

ii. The reference three (3) Months London Inter-Bank Offer Rate (LIBOR) of 0.2556% plus 450 basis points has been used for calculating the financial charges.

b. The interest calculated in the reference debt service schedule shall be subjected to adjustment for variation in quarterly-KIBOR in the case of local loan and quarterly-LIBOR in the case of foreign loan on quarterly basis. The adjustment shall be made on 1st July, 1st October, 1st January and 1st April based on latest available TT&OD selling rate and KIBOR notified by the National Bank of Pakistan and Reuters for the purpose of LIBOR.

c. The maximum allowed premium on LIBOR and KIBOR is 4.5% and 3.0% respectively and there will be no adjustment on the basis of actual higher premium than the maximum allowed limit. In case spread negotiated is less than the said limit, the saving will be shared in the ratio of 60:40 between power purchaser and the power producer respectively.

d. The repayment of loan shall be considered from the first year of commercial operation.

Ref: State Bank of Pakistan, http://www.global-rates.com/interest-rates/libor/american-dollar/usd-libor-interest-rate-3-months.aspx and NEPRA's Upfront Tariff for Coal.

11) Financing Fees & Charges:

a. Financing fee & charges are taken @3.5% of the borrowing to cater for the upfront fee, commitment fee, lenders' technical, financial and legal consultants' fee etc.

b. During various discussions and meetings between Ministry of Water & Power, Ministry of Finance, Ministry of Petroleum and Natural Resources and stakeholders, keeping in view that LNG is an imported commodity that attracts various uncertainties, an amount of one month gas price at full load is required to be placed in an Escrow Account to be arranged by the Project Company and it will be exclusively utilized upon payment default by the Power Purchaser under the Power Purchase Agreement in respect of Fuel Cost Component (FCC). Further, this cash margin amount will be adjusted in the tariff in the last agreement year of the project. In case of any earlier termination of the project agreements, this amount will be adjusted in the payment if required for which a mechanism / protocol will be included in the project agreements.

12) Political Risk Insurance:

a. In case of foreign financing that originates outside Pakistan, political risk insurance fee such as export credit agency fee or sinosure fee etc. @7% on the total debt servicing would be included in the project cost. Project cost will be adjusted at the time of COD on the basis of actual fee subject to maximum cap of 7% of the total debt servicing. In case the sponsor managed better alternative fee arrangement, the same will be considered at the time of COD.

Ref: NEPRA's Upfront Tariff for Coal

13) Interest During Construction (IDC):

Interest During Construction (IDC) has been calculated on the basis of 75% of the CAPEX including customs duties as per the following reference parameters:

Table

Year	800 MW
1st Year	40.00%
2nd Year	40.00%
3rd Year	20.00%

a. IDC shall not be adjusted for any variation on account of actual expenditure / disbursement percentage during the construction period;

b. At the time of COD, IDC shall be reestablished on the basis of indexed capital cost, actual custom duties & cess, withholding tax on contracts/services, actual premium on LIBOR & KIBOR subject to maximum of 4.5% and 3.0% respectively and the impact of export credit agency fee or, sinosure fee, if any, subject to maximum cap of 7% of the total debt service;

c. In case of more than one financing plans, separate IDC shall be calculated for each plan on reference parameters;

d. IDC shall be recalculated on the basis of weighted average quarterly LIBOR/KIBOR during the construction period plus actual premium subject to maximum limit on reference parameters.

Ref: NEPRA's Upfront Tariff for Coal

14) Return on Equity (ROE):

a. The Return on Equity shall be 15% per annum (IRR based) for the projects.

Ref: NEPRA's determination for Gas based IPPs

15) Thermal Efficiency:

a. The minimum reference net LHV thermal efficiency 57% for 800 MW has been assumed for calculating reference fuel cost component;

b. The fuel cost component will be subject to downward revision on the basis of actual heat rates established as a result of heat rate test conducted at the time of COD in accordance with the established benchmarks in the presence of the representatives of the power purchaser. For acceptance of the test, approval of the power purchaser will be mandatory. Upward revision in the fuel cost component will not be allowed in case the net LHV heat rates are established higher than the heat rate at which minimum thermal efficiency specified above and the financial impact, if any, of lower thermal efficiency over the term of the Agreement will be borne by the power producer. However the [60:40] sharing mechanism between Power Purchaser and Power Producer will be applicable only in case the efficiency, approved by the Authority for different capacities is established higher as a result of heat rate tests carried out at the time of COD.

Ref: GTW Handbook 2013 and NEPRA's Upfront Tariff for Coal

16) Insurance Cost During Operation:

a. During the term of the Agreement, insurance component of tariff will be adjusted on the basis of actual insurance cost with a cap of 1.35% of the EPC Cost.

Ref: NEPRA's determination for Gas based IPPs

17) Interest on Working Capital:

a. The Working Capital requirement has been worked out in accordance discussions held with various stakeholders wherein SBLC charges @ 1.5% of the price of two months Gas requirement at 100% plant load has been allowed.

b. Further, the cost of working capital required to fill receivable gap of 45 days has been allowed. The interest on Working Capital has been calculated on the basis of quarterly-KIBOR of 9.57% plus 200 basis points, which will be adjusted for variation in quarterly-KIBOR.

18) Operation and Maintenance (O & M) Expenses:

a. Operation and Maintenance or O&M expenses comprises of repair and maintenance, establishment including employee expenses, administrative & general expenses.

b. 46% of the fixed O&M expenses shall be indexed with local CPI whereas 54% shall be indexed with USCPI and Exchange rate (PKR/US$) variation.

c. 39% of the variable O&M shall be indexed with local CPI whereas 61% shall be indexed with USCPI and exchange rate (PKR/US$) variation.

d. The reference Local CPI and US CPI will be of January 2015.

e. Variable O & M expenses have been assumed in the ratio of 39% Local and 61% Foreign.

f. Fixed O & M expenses have been assumed in the ratio of 54% Local and 46% Foreign.

*Ref: EIA report, Black & Veatch report and NEPRA's indexed tariff for Gas based IPPs. **(Annex-IV)***

20) <u>Tariff Structure:</u>

The tariff shall be two-part consisting of the following:

i. Energy Purchase Price

a) Fuel Cost Component;

b) Variable O&M Local;

c) Variable O&M Foreign;

ii. Capacity Purchase Price

a) Fixed O&M (Local);

b) Fixed O&M (Foreign);

c) Insurance Cost;

d) Cost of Working Capital;

e) Return on equity; and

f) Debt Service (Principal Repayment and Interest Charges).

21) Tariff Design:

(i) The tariff will be applicable for a period of thirty (30) years from the commencement of the commercial operations;

(ii) The upfront tariff has been determined for two periods i.e. for the period of first ten years when the project will be paying its debt and the remaining period of ten years without debt servicing.

(iii) For the purpose of comparison, levelized tariff assuming 10% discount factor has also been worked out.

(iv) Levelization has been carried out for the "useful life" of the project which in the instant case is equivalent to "Tariff Period".

22) Dispatch Criteria:

a. The sole criterion for dispatch of all the power plants shall be the "merit order dispatch".

23) Plant Availability:

a. After COD, the minimum annual availability of the plant will be 92%.

24) General Conditions:

a. No provision for Workers Welfare Fund and Workers Profit Participation Fund has been made in the tariff. If there is any such obligation it shall be treated as Pass-Through under Power Purchase Agreement to be reimbursed in 12 months as Supplementary Tariff.

b. In case of mix (foreign & local) financing, separate debt service schedules shall be developed using the annuity method at COD;

c. At the time of COD, project cost will be converted into Pak Rupees using the Average of the Exchange Rates prevailing on 1st day of each month during construction period.

d. During life of the project operations, quarterly adjustments/indexations for local inflation, foreign inflation, exchange rate variations and interest rate variations will be made on 1st July, 1st October, 1st January and 1st April each year based on latest available date with respect to CPI notified by the Federal Board of Statistics (FBS), USCPI issued by US Bureau of Labor Statistics and revised TT&OD selling rate of foreign currencies (US Dollar, British Pound Sterling, Euro and Japanese Yen) notified by the National Bank of Pakistan. The method of indexation will be as follows:

Tariff Components	**Tariff Indexation & Adjustment**
Fuel Cost Component	Delivered Fuel Price (inclusive of Transportation) at the power Plant
Variable O&M (Foreign)	US$ to Pak Rupees & US CPI
Variable O&M (Local)	Pakistan CPI
Fixed O&M (Foreign)	US$ to Pak Rupees & US CPI
Fixed O&M (Local)	Pakistan CPI
Cost of Working Capital	Adjustments for relevant KIBOR Variations
Return on Equity	US$ to Pak Rupees
Principal Repayment (Foreign Currency Loan)	US$/Euro/Yen/Pound to Pak Rupees (based on borrowing by the Company)
Interest//Mark-Up payment	Adjustments for relevant LIBOR or other applicable interest (Foreign Currency Loan rate benchmark Adjustments for Variation in Rs./Foreign Currency (US$/Euro/Yen/Pound) rate as applicable
Interest//Mark-Up payment	Adjustments for relevant KIBOR Variations (Local Currency Loan)

Ref: NEPRA's Upfront Tariff for Coal

25) <u>Validity of Tariff:</u>

The choice to opt for this tariff will only be available upto 90 days from the date of its determination by the Authority and Notification. Further, this tariff will only be valid for approvals given for the first 3600 MW-4000 MW of companies.

26) Scope and extent of application:

This tariff shall apply in all cases for a RLNG generating facility or a unit thereof based subject to fulfillment of eligibility criteria.

27) Eligibility Criteria:

(v) Only RLNG power generation companies meeting the following conditions will be eligible for this tariff;

- Companies issued LOI by the PPIB for the grant of upfront tariff;
- Companies who confirm that brand new plant & machinery shall be installed. The plant & machinery shall be designed, manufactured and tested in accordance with the latest parameters and standards to be specified in this tariff determination and PPA;
- Companies proposing the net capacity in the range of 700 MW to 900 MW;
- Companies who have the consent of the power purchaser for procurement of electricity, along with a certificate from the power purchaser that it will have the necessary infrastructure ready and in place to evacuate all the power supplied by the applicant.

28) Financial Closing:

The companies opting for this tariff will have to achieve financial close by [five (5) months from issuance of LOS]. The upfront tariff granted to any company will no longer remain applicable / valid if financial close is not achieved by the relevant company by financial closing date or a generation license is declined to that company;

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 10 USD 60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.5359	1.2269	2.6873	4.4788	10.5992	10.6338
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.6066	1.1563	2.6873	4.4788	10.5992	10.6338
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.6865	1.0763	2.6873	4.4788	10.5992	10.6338
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.7769	0.9859	2.6873	4.4788	10.5992	10.6338
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.8793	0.8836	2.6873	4.4788	10.5992	10.6338
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.9951	0.7677	2.6873	4.4788	10.5992	10.6338
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.1262	0.6366	2.6873	4.4788	10.5992	10.6338
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.2746	0.4882	2.6873	4.4788	10.5992	10.6338
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.4425	0.3203	2.6873	4.4788	10.5992	10.6338
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.6326	0.1302	2.6873	4.4788	10.5992	10.6338
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
21	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
22	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
23	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
24	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
25	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
26	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
27	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
28	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
29	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.9956	0.7672	2.6873	4.4788	10.5992	10.6338
11-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.5408	7.6612	7.6862
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.3319	0.2557	1.5121	2.5201	8.6405	8.6687
Levelized															
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.5894	0.5596	2.0735	3.4558	9.5762	9.6075

Levelized Tariff = 9.5762 Rs./kWh 9.6075 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total	Total
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total	Tariff	Tariff
Year	Component	Foreign	Local	EPP	Local	Foreign		CPP	Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.2987	0.3606	9.8085	9.8405

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - KIBOR	9.57%	
Spread Over and above KIBOR	3.00%	
Total Interest Rate	12.57%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	30.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		LNG	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		108.632	Million US $
One Month Escrow Account - LNG		34.489	Million US $
Sub total		163.334	Million US $
Total Project Cost		**933.334**	Million US $
Cost per MW - Gross		1.130	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	700.000	Million US $
Equity	25%	233.333	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		18%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		60.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
KIBOR - 3 Months	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Quarterly Int. Rate	3.14%	

	Construction Period			Debt		
				Principal	IDC	Fin. Chrg.
Year	**1st Year**	**2nd Year**	**4 Months**			
Opening Balance	-	**249.73**	**532.36**			
1st Quarter	10.00%	10%	10%			
Principal Amount	**57.75**	**57.75**	**57.75**	173.250		
Financing Fee 3.5%	**20.21**	-	0.00			20.21
Interest	**1.8148**	**9.6625**	**18.5441**		30.02	
Closing Balance	**59.56**	**317.14**	**608.65**			
Opening Balance	**59.56**	**317.14**	**608.65**			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	**3.6866**	**11.7809**	**19.7318**		35.20	
Closing Balance	**121.00**	**386.67**	**686.13**			
Opening Balance	**121.00**	**386.67**	-			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**5.6173**	**13.9659**	-		19.58	
Closing Balance	**184.37**	**458.39**	-			
Opening Balance	**184.37**	**458.39**	-			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**7.6086**	**16.2196**	-		23.83	
Closing Balance	**249.73**	**532.36**	-			
Total Debt Incl. IDC				**577.50**	**108.63**	**20.21**
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000	MWs
Equity Investment	23,258	Rs. Million
Return on Equity	18.00%	
IRR	15.00%	

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(9,303.00)	
31-Dec-12	(1.00)	(9,303.00)	
30-Apr-13	-	(4,651.50)	
30-Apr-14	1	4,186.35	0.5974
30-Apr-15	2	4,186.35	0.5974
30-Apr-16	3	4,186.35	0.5974
30-Apr-17	4	4,186.35	0.5974
30-Apr-18	5	4,186.35	0.5974
30-Apr-19	6	4,186.35	0.5974
30-Apr-20	7	4,186.35	0.5974
30-Apr-21	8	4,186.35	0.5974
30-Apr-22	9	4,186.35	0.5974
30-Apr-23	10	4,186.35	0.5974
30-Apr-24	11	4,186.35	0.5974
30-Apr-25	12	4,186.35	0.5974
30-Apr-26	13	4,186.35	0.5974
30-Apr-27	14	4,186.35	0.5974
30-Apr-28	15	4,186.35	0.5974
30-Apr-29	16	4,186.35	0.5974
30-Apr-30	17	4,186.35	0.5974
30-Apr-31	18	4,186.35	0.5974
30-Apr-32	19	4,186.35	0.5974
30-Apr-33	20	4,186.35	0.5974
30-Apr-34	21	4,186.35	0.5974
30-Apr-35	22	4,186.35	0.5974
30-Apr-36	23	4,186.35	0.5974
30-Apr-37	24	4,186.35	0.5974
30-Apr-38	25	4,186.35	0.5974
30-Apr-39	26	4,186.35	0.5974
30-Apr-40	27	4,186.35	0.5974
30-Apr-41	28	4,186.35	0.5974
30-Apr-42	29	4,186.35	0.5974
30-Apr-43	30	15,815.11	0.5974
	XIRR	**16.13%**	
	IRR	**15.00%**	

Upfront Tariff RLNG- Debt Servicing on Local Financing

Net Capacity	800.000	MWs
KIBOR	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Debt 75.00%	700.00	US$ Million
Exchange Rate	99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	700.0	9.0	22.0	691.0	30.99			
2	691.0	9.3	21.7	681.7	30.99			
3	681.7	9.6	21.4	672.2	30.99			
4	672.2	9.9	21.1	662.3	30.99	0.5359	1.2269	1.7628
5	662	10.2	20.8	652.1	30.99			
6	652.1	10.5	20.5	641.7	30.99			
7	641.7	10.8	20.2	630.8	30.99			
8	630.8	11.2	19.8	619.7	30.99	0.6066	1.1563	1.7628
9	619.7	11.5	19.5	608.2	30.99			
10	608.2	11.9	19.1	596.3	30.99			
11	596.3	12.2	18.7	584.0	30.99			
12	584.0	12.6	18.4	571.4	30.99	0.6865	1.0763	1.7628
13	571.4	13.0	18.0	558.4	30.99			
14	558.4	13.4	17.5	544.9	30.99			
15	544.9	13.9	17.1	531.1	30.99			
16	531.1	14.3	16.7	516.8	30.99	0.7769	0.9859	1.7628
17	516.8	14.7	16.2	502.0	30.99			
18	502.0	15.2	15.8	486.8	30.99			
19	486.8	15.7	15.3	471.1	30.99			
20	471.1	16.2	14.8	455.0	30.99	0.8793	0.8836	1.7628
21	455.0	16.7	14.3	438.3	30.99			
22	438.3	17.2	13.8	421.1	30.99			
23	421.1	17.8	13.2	403.3	30.99			
24	403.3	18.3	12.7	385.0	30.99	0.9951	0.7677	1.7628
25	385.0	18.9	12.1	366.1	30.99			
26	366.1	19.5	11.5	346.6	30.99			
27	346.6	20.1	10.9	326.5	30.99			
28	326.5	20.7	10.3	305.8	30.99	1.1262	0.6366	1.7628
29	305.8	21.4	9.6	284.4	30.99			
30	284.4	22.0	8.9	262.4	30.99			
31	262.4	22.7	8.2	239.7	30.99			
32	239.7	23.5	7.5	216.2	30.99	1.2746	0.4882	1.7628
33	216.2	24.2	6.8	192.0	30.99			
34	192.0	25.0	6.0	167.1	30.99			
35	167.1	25.7	5.2	141.3	30.99			
36	141.3	26.5	4.4	114.8	30.99	1.4425	0.3203	1.7628
37	114.8	27.4	3.6	87.4	30.99			
38	87.4	28.2	2.7	59.2	30.99			
39	59.2	29.1	1.9	30.0	30.99			
40	30.0	30.0	0.9	0.0	30.99	1.6326	0.1302	1.7628
		$700.00	$539.41		$1,239.41			

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 11 USD — 60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel	Var. O&M		Total	Fixed O&M		Cost of		ROE	Debt	Interest	Total			
	Component	Foreign	Local	EPP	Local	Foreign	W/C	Insurance		Repayment	Charges	CPP		Rs. /kWh	Cents/kWh
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.5379	1.2314	2.7060	4.5100	11.2272	11.2638
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.6088	1.1605	2.7060	4.5100	11.2272	11.2638
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.6890	1.0803	2.7060	4.5100	11.2272	11.2638
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.7798	0.9896	2.7060	4.5100	11.2272	11.2638
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.8825	0.8868	2.7060	4.5100	11.2272	11.2638
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.9988	0.7705	2.7060	4.5100	11.2272	11.2638
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.1304	0.6390	2.7060	4.5100	11.2272	11.2638
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.2793	0.4900	2.7060	4.5100	11.2272	11.2638
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.4478	0.3215	2.7060	4.5100	11.2272	11.2638
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.6386	0.1307	2.7060	4.5100	11.2272	11.2638
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
21	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
22	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
23	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
24	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
25	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
26	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
27	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
28	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
29	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.9993	0.7700	2.7060	4.5100	11.2272	11.2638
11-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.5611	8.2783	8.3053
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.3331	0.2567	1.5264	2.5440	9.2613	9.2915
Levelized															
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.5916	0.5617	2.0899	3.4832	10.2005	10.2337

Levelized Tariff = 10.2005 Rs./kWh 10.2337 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 12 USD

60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (P[illegible]W/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel	Var. O&M		Total	Fixed O&M		Cost of		ROE	Debt	Interest	Total			
	Component	Foreign	Local	EPP	Local	Foreign	W/C	Insurance		Repayment	Charges	CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.5399	1.2359	2.7247	4.5411	11.8552	11.8939
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.6110	1.1648	2.7247	4.5411	11.8552	11.8939
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.6915	1.0843	2.7247	4.5411	11.8552	11.8939
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.7826	0.9932	2.7247	4.5411	11.8552	11.8939
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.8858	0.8901	2.7247	4.5411	11.8552	11.8939
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.0025	0.7734	2.7247	4.5411	11.8552	11.8939
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.1345	0.6413	2.7247	4.5411	11.8552	11.8939
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.2840	0.4918	2.7247	4.5411	11.8552	11.8939
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.4532	0.3227	2.7247	4.5411	11.8552	11.8939
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.6446	0.1312	2.7247	4.5411	11.8552	11.8939
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
21	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
22	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
23	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
24	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
25	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
26	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
27	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
28	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
29	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.0030	0.7729	2.7247	4.5411	11.8552	11.8939
11-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.5814	8.8955	8.9245
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.3343	0.2576	1.5408	2.5680	9.8821	9.9143
Levelized															
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.5938	0.5638	2.1063	3.5106	10.8247	10.8600

Levelized Tariff = 10.8247 Rs./kWh 10.8600 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 10 USD

60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.7377	0.4250	2.0423	3.4039	9.5243	9.5554
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.7734	0.3893	2.0423	3.4039	9.5243	9.5554
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.8108	0.3518	2.0423	3.4039	9.5243	9.5554
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.8501	0.3126	2.0423	3.4039	9.5243	9.5554
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.8912	0.2714	2.0423	3.4039	9.5243	9.5554
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.9344	0.2283	2.0423	3.4039	9.5243	9.5554
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.9796	0.1830	2.0423	3.4039	9.5243	9.5554
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	1.0270	0.1356	2.0423	3.4039	9.5243	9.5554
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	1.0768	0.0859	2.0423	3.4039	9.5243	9.5554
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	1.1289	0.0338	2.0423	3.4039	9.5243	9.5554
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
21	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
22	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
23	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
24	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
25	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
26	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
27	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
28	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
29	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.9210	0.2417	2.0423	3.4039	9.5243	9.5554
11-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	1.4661	7.5866	7.6113
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.3070	0.0806	1.2672	2.1121	8.2325	8.2593
Levelized															
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.5786	0.1793	1.6375	2.7292	8.8496	8.8785

Levelized Tariff = 8.8496 Rs./kWh 8.8785 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total	Total
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total	Tariff	Tariff
Year	Component	Foreign	Local	EPP	Local	Foreign		CPP	Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.2763	0.3382	9.7862	9.8181

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - LIBOR	0.26%	
Spread Over and above LIBOR	4.50%	
Total Interest Rate	4.76%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	30.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		LNG	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		38.684	Million US $
One Month Escrow Account - LNG		34.489	Million US $
Sub total		93.386	Million US $
Total Project Cost		**863.386**	Million US $
Cost per MW - Gross		1.046	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	647.539	Million US $
Equity	25%	215.846	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		18%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		60.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
LIBOR - 3 Months	0.26%	
Spread over LIBOR	4.50%	
Total Interest Rate	4.76%	
Quarterly Int. Rate	1.19%	

	Construction Period			Debt Principal	IDC	Fin. Chrg.
Year	**1st Year**	**2nd Year**	**4 Months**			
Opening Balance	-	**237.95**	**487.42**			
1st Quarter	10.00%	10%	10%			
Principal Amount	**57.75**	**57.75**	**57.75**	173.250		
Financing Fee 3.5%	**20.21**	-	0.00			20.21
Interest	**0.6866**	**3.5156**	**6.4815**		10.68	
Closing Balance	**58.44**	**299.21**	**551.65**			
Opening Balance	**58.44**	**299.21**	**551.65**			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	**1.3813**	**4.2439**	**6.7874**		12.41	
Closing Balance	**117.57**	**361.21**	**616.18**			
Opening Balance	**117.57**	**361.21**	-			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**2.0844**	**4.9810**	-		7.07	
Closing Balance	**177.40**	**423.94**	-			
Opening Balance	**177.40**	**423.94**	-			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**2.7957**	**5.7268**	-		8.52	
Closing Balance	**237.95**	**487.42**	-			
Total Debt Incl. IDC				**577.50**	**38.68**	**20.21**
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000	MWs
Equity Investment	21,514	Rs. Million
Return on Equity	18.00%	
IRR	15.00%	

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(8,605.80)	
31-Dec-12	(1.00)	(8,605.80)	
30-Apr-13	-	(4,302.90)	
30-Apr-14	1	3,872.61	0.5526
30-Apr-15	2	3,872.61	0.5526
30-Apr-16	3	3,872.61	0.5526
30-Apr-17	4	3,872.61	0.5526
30-Apr-18	5	3,872.61	0.5526
30-Apr-19	6	3,872.61	0.5526
30-Apr-20	7	3,872.61	0.5526
30-Apr-21	8	3,872.61	0.5526
30-Apr-22	9	3,872.61	0.5526
30-Apr-23	10	3,872.61	0.5526
30-Apr-24	11	3,872.61	0.5526
30-Apr-25	12	3,872.61	0.5526
30-Apr-26	13	3,872.61	0.5526
30-Apr-27	14	3,872.61	0.5526
30-Apr-28	15	3,872.61	0.5526
30-Apr-29	16	3,872.61	0.5526
30-Apr-30	17	3,872.61	0.5526
30-Apr-31	18	3,872.61	0.5526
30-Apr-32	19	3,872.61	0.5526
30-Apr-33	20	3,872.61	0.5526
30-Apr-34	21	3,872.61	0.5526
30-Apr-35	22	3,872.61	0.5526
30-Apr-36	23	3,872.61	0.5526
30-Apr-37	24	3,872.61	0.5526
30-Apr-38	25	3,872.61	0.5526
30-Apr-39	26	3,872.61	0.5526
30-Apr-40	27	3,872.61	0.5526
30-Apr-41	28	3,872.61	0.5526
30-Apr-42	29	3,872.61	0.5526
30-Apr-43	30	14,629.86	0.5526
	XIRR	16.13%	
	IRR	15.00%	

Upfront Tariff RLNG- Debt Servicing on Foreign Financing

Net Capacity	800.000	MWs
LIBOR	0.26%	
Spread over LIBOR	4.50%	
Total Interest Rate	4.76%	
Debt 75.00%	647.54	US$ Million
Exchange Rate	99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	647.5	12.7	7.7	634.8	20.44			
2	634.8	12.9	7.5	621.9	20.44			
3	621.9	13.0	7.4	608.9	20.44			
4	608.9	13.2	7.2	595.7	20.44	0.7377	0.4250	1.1626
5	596	13.4	7.1	582.3	20.44			
6	582.3	13.5	6.9	568.8	20.44			
7	568.8	13.7	6.8	555.1	20.44			
8	555.1	13.8	6.6	541.3	20.44	0.7734	0.3893	1.1626
9	541.3	14.0	6.4	527.3	20.44			
10	527.3	14.2	6.3	513.1	20.44			
11	513.1	14.3	6.1	498.8	20.44			
12	498.8	14.5	5.9	484.3	20.44	0.8108	0.3518	1.162
13	484.3	14.7	5.8	469.6	20.44			
14	469.6	14.9	5.6	454.8	20.44			
15	454.8	15.0	5.4	439.7	20.44			
16	439.7	15.2	5.2	424.5	20.44	0.8501	0.3126	1.1626
17	424.5	15.4	5.0	409.1	20.44			
18	409.1	15.6	4.9	393.6	20.44			
19	393.6	15.8	4.7	377.8	20.44			
20	377.8	15.9	4.5	361.9	20.44	0.8912	0.2714	1.1626
21	361.9	16.1	4.3	345.7	20.44			
22	345.7	16.3	4.1	329.4	20.44			
23	329.4	16.5	3.9	312.9	20.44			
24	312.9	16.7	3.7	296.2	20.44	0.9344	0.2283	1.1626
25	296.2	16.9	3.5	279.2	20.44			
26	279.2	17.1	3.3	262.1	20.44			
27	262.1	17.3	3.1	244.8	20.44			
28	244.8	17.5	2.9	227.3	20.44	0.9796	0.1830	1.1626
29	227.3	17.7	2.7	209.6	20.44			
30	209.6	17.9	2.5	191.6	20.44			
31	191.6	18.2	2.3	173.5	20.44			
32	173.5	18.4	2.1	155.1	20.44	1.0270	0.1356	1.1626
33	155.1	18.6	1.8	136.5	20.44			
34	136.5	18.8	1.6	117.7	20.44			
35	117.7	19.0	1.4	98.6	20.44			
36	98.6	19.3	1.2	79.4	20.44	1.0768	0.0859	1.1626
37	79.4	19.5	0.9	59.9	20.44			
38	59.9	19.7	0.7	40.2	20.44			
39	40.2	20.0	0.5	20.2	20.44			
40	20.2	20.2	0.2	0.0	20.44	1.1289	0.0338	1.1626
		$647.54	$169.90		$817.44			

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 11 USD 60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel	Var. O&M		Total	Fixed O&M		Cost of		ROE	Debt	Interest	Total			
	Component	Foreign	Local	EPP	Local	Foreign	W/C	Insurance		Repayment	Charges	CPP		Rs. /kWh	Cents/kWh
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.7406	0.4267	2.0592	3.4319	10.1492	10.1823
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.7765	0.3908	2.0592	3.4319	10.1492	10.1823
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.8141	0.3532	2.0592	3.4319	10.1492	10.1823
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.8535	0.3138	2.0592	3.4319	10.1492	10.1823
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.8948	0.2725	2.0592	3.4319	10.1492	10.1823
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.9381	0.2292	2.0592	3.4319	10.1492	10.1823
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.9835	0.1838	2.0592	3.4319	10.1492	10.1823
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	1.0312	0.1361	2.0592	3.4319	10.1492	10.1823
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	1.0811	0.0862	2.0592	3.4319	10.1492	10.1823
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	1.1334	0.0339	2.0592	3.4319	10.1492	10.1823
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
21	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
22	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
23	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
24	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
25	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
26	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
27	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
28	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
29	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.9247	0.2426	2.0592	3.4319	10.1492	10.1823
11-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	1.4865	8.2037	8.2305
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.3082	0.0809	1.2810	2.1350	8.8522	8.8811
Levelized															
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.5809	0.1800	1.6527	2.7545	9.4718	9.5027

Levelized Tariff = 9.4718 Rs./kWh 9.5027 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 12 USD

60%

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (Rs./kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
Year	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.7436	0.4284	2.0760	3.4600	10.7741	10.8092
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.7796	0.3924	2.0760	3.4600	10.7741	10.8092
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.8173	0.3546	2.0760	3.4600	10.7741	10.8092
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.8569	0.3151	2.0760	3.4600	10.7741	10.8092
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.8984	0.2736	2.0760	3.4600	10.7741	10.8092
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.9419	0.2301	2.0760	3.4600	10.7741	10.8092
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.9875	0.1845	2.0760	3.4600	10.7741	10.8092
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	1.0353	0.1367	2.0760	3.4600	10.7741	10.8092
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	1.0854	0.0866	2.0760	3.4600	10.7741	10.8092
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	1.1379	0.0340	2.0760	3.4600	10.7741	10.8092
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
21	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
22	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
23	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
24	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
25	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
26	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
27	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
28	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
29	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.9284	0.2436	2.0760	3.4600	10.7741	10.8092
11-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	1.5068	8.8209	8.8496
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.3095	0.0812	1.2947	2.1579	9.4720	9.5028
Levelized															
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.5832	0.1807	1.6679	2.7799	10.0940	10.1269

Levelized Tariff = 10.0940 Rs./kWh 10.1269 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 10 USD 92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)									Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel	Var. O&M		Total	Fixed O&M		Cost of		ROE	Debt	Interest	Total			
	Component	Foreign	Local	EPP	Local	Foreign	W/C	Insurance		Repayment	Charges	CPP		Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.5359	1.2269	2.6873	2.9209	9.0414	9.0709
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.6066	1.1563	2.6873	2.9209	9.0414	9.0709
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.6865	1.0763	2.6873	2.9209	9.0414	9.0709
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.7769	0.9859	2.6873	2.9209	9.0414	9.0709
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.8793	0.8836	2.6873	2.9209	9.0414	9.0709
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.9951	0.7677	2.6873	2.9209	9.0414	9.0709
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.1262	0.6366	2.6873	2.9209	9.0414	9.0709
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.2746	0.4882	2.6873	2.9209	9.0414	9.0709
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.4425	0.3203	2.6873	2.9209	9.0414	9.0709
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	1.6326	0.1302	2.6873	2.9209	9.0414	9.0709
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
21	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
22	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
23	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
24	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
25	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
26	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
27	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
28	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
29	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.9956	0.7672	2.6873	2.9209	9.0414	9.0709
11-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.0000	0.0000	0.9245	1.0048	7.1253	7.1485
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.3319	0.2557	1.5121	1.6435	7.7640	7.7893
Levelized															
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5974	0.5894	0.5596	2.0735	2.2538	**8.3742**	**8.4015**

Levelized Tariff = 8.3742 Rs./kWh 8.4015 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total	Total
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total	Tariff	Tariff
Year	Component	Foreign	Local	EPP	Local	Foreign		CPP	Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.2987	0.3606	9.8085	9.8405

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - KIBOR	9.57%	
Spread Over and above KIBOR	3.00%	
Total Interest Rate	12.57%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	30.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		**LNG**	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		108.632	Million US $
One Month Escrow Account - LNG		34.489	Million US $
Sub total		163.334	Million US $
Total Project Cost		**933.334**	Million US $
Cost per MW - Gross		1.130	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	700.000	Million US $
Equity	25%	233.333	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		18%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		92.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
KIBOR - 3 Months	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Quarterly Int. Rate	3.14%	

	Construction Period			Debt Principal	IDC	Fin. Chrg.
Year	**1st Year**	**2nd Year**	**4 Months**			
Opening Balance	-	**249.73**	**532.36**			
1st Quarter	10.00%	10%	10%			
Principal Amount	**57.75**	**57.75**	**57.75**	173.250		
Financing Fee 3.5%	**20.21**	-	0.00			20.21
Interest	**1.8148**	**9.6625**	**18.5441**		30.02	
Closing Balance	**59.56**	**317.14**	**608.65**			
Opening Balance	**59.56**	**317.14**	**608.65**			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	**3.6866**	**11.7809**	**19.7318**		35.20	
Closing Balance	**121.00**	**386.67**	**686.13**			
Opening Balance	**121.00**	**386.67**	-			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**5.6173**	**13.9659**	-		19.58	
Closing Balance	**184.37**	**458.39**	-			
Opening Balance	**184.37**	**458.39**	-			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**7.6086**	**16.2196**	-		23.83	
Closing Balance	**249.73**	**532.36**	-			
Total Debt Incl. IDC				**577.50**	**108.63**	**20.21**
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000	MWs
Equity Investment	23,258	Rs. Million
Return on Equity	18.00%	
IRR	15.00%	

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(9,303.00)	
31-Dec-12	(1.00)	(9,303.00)	
30-Apr-13	-	(4,651.50)	
30-Apr-14	1	4,186.35	0.5974
30-Apr-15	2	4,186.35	0.5974
30-Apr-16	3	4,186.35	0.5974
30-Apr-17	4	4,186.35	0.5974
30-Apr-18	5	4,186.35	0.5974
30-Apr-19	6	4,186.35	0.5974
30-Apr-20	7	4,186.35	0.5974
30-Apr-21	8	4,186.35	0.5974
30-Apr-22	9	4,186.35	0.5974
30-Apr-23	10	4,186.35	0.5974
30-Apr-24	11	4,186.35	0.5974
30-Apr-25	12	4,186.35	0.5974
30-Apr-26	13	4,186.35	0.5974
30-Apr-27	14	4,186.35	0.5974
30-Apr-28	15	4,186.35	0.5974
30-Apr-29	16	4,186.35	0.5974
30-Apr-30	17	4,186.35	0.5974
30-Apr-31	18	4,186.35	0.5974
30-Apr-32	19	4,186.35	0.5974
30-Apr-33	20	4,186.35	0.5974
30-Apr-34	21	4,186.35	0.5974
30-Apr-35	22	4,186.35	0.5974
30-Apr-36	23	4,186.35	0.5974
30-Apr-37	24	4,186.35	0.5974
30-Apr-38	25	4,186.35	0.5974
30-Apr-39	26	4,186.35	0.5974
30-Apr-40	27	4,186.35	0.5974
30-Apr-41	28	4,186.35	0.5974
30-Apr-42	29	4,186.35	0.5974
30-Apr-43	30	15,815.11	0.5974
	XIRR	**16.13%**	
	IRR	**15.00%**	

Upfront Tariff RLNG- Debt Servicing on Local Financing

Net Capacity	800.000	MWs
KIBOR	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Debt 75.00%	700.00	US$ Million
Exchange Rate	99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	700.0	9.0	22.0	691.0	30.99			
2	691.0	9.3	21.7	681.7	30.99			
3	681.7	9.6	21.4	672.2	30.99			
4	672.2	9.9	21.1	662.3	30.99	0.5359	1.2269	1.7628
5	662	10.2	20.8	652.1	30.99			
6	652.1	10.5	20.5	641.7	30.99			
7	641.7	10.8	20.2	630.8	30.99			
8	630.8	11.2	19.8	619.7	30.99	0.6066	1.1563	1.7628
9	619.7	11.5	19.5	608.2	30.99			
10	608.2	11.9	19.1	596.3	30.99			
11	596.3	12.2	18.7	584.0	30.99			
12	584.0	12.6	18.4	571.4	30.99	0.6865	1.0763	1.762
13	571.4	13.0	18.0	558.4	30.99			
14	558.4	13.4	17.5	544.9	30.99			
15	544.9	13.9	17.1	531.1	30.99			
16	531.1	14.3	16.7	516.8	30.99	0.7769	0.9859	1.7628
17	516.8	14.7	16.2	502.0	30.99			
18	502.0	15.2	15.8	486.8	30.99			
19	486.8	15.7	15.3	471.1	30.99			
20	471.1	16.2	14.8	455.0	30.99	0.8793	0.8836	1.7628
21	455.0	16.7	14.3	438.3	30.99			
22	438.3	17.2	13.8	421.1	30.99			
23	421.1	17.8	13.2	403.3	30.99			
24	403.3	18.3	12.7	385.0	30.99	0.9951	0.7677	1.7628
25	385.0	18.9	12.1	366.1	30.99			
26	366.1	19.5	11.5	346.6	30.99			
27	346.6	20.1	10.9	326.5	30.99			
28	326.5	20.7	10.3	305.8	30.99	1.1262	0.6366	1.7628
29	305.8	21.4	9.6	284.4	30.99			
30	284.4	22.0	8.9	262.4	30.99			
31	262.4	22.7	8.2	239.7	30.99			
32	239.7	23.5	7.5	216.2	30.99	1.2746	0.4882	1.7628
33	216.2	24.2	6.8	192.0	30.99			
34	192.0	25.0	6.0	167.1	30.99			
35	167.1	25.7	5.2	141.3	30.99			
36	141.3	26.5	4.4	114.8	30.99	1.4425	0.3203	1.7628
37	114.8	27.4	3.6	87.4	30.99			
38	87.4	28.2	2.7	59.2	30.99			
39	59.2	29.1	1.9	30.0	30.99			
40	30.0	30.0	0.9	0.0	30.99	1.6326	0.1302	1.7628
		$700.00	$539.41		$1,239.41			

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 11 USD — 92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel	Var. O&M		Total	Fixed O&M		Cost of		ROE	Debt	Interest	Total			
	Component	Foreign	Local	EPP	Local	Foreign	W/C	Insurance		Repayment	Charges	CPP		Rs. /kWh	Cents/kWh
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.5379	1.2314	2.7060	2.9413	9.6585	9.6900
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.6088	1.1605	2.7060	2.9413	9.6585	9.6900
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.6890	1.0803	2.7060	2.9413	9.6585	9.6900
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.7798	0.9896	2.7060	2.9413	9.6585	9.6900
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.8825	0.8868	2.7060	2.9413	9.6585	9.6900
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.9988	0.7705	2.7060	2.9413	9.6585	9.6900
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.1304	0.6390	2.7060	2.9413	9.6585	9.6900
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.2793	0.4900	2.7060	2.9413	9.6585	9.6900
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.4478	0.3215	2.7060	2.9413	9.6585	9.6900
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	1.6386	0.1307	2.7060	2.9413	9.6585	9.6900
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
21	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
22	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
23	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
24	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
25	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
26	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
27	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
28	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
29	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.9993	0.7700	2.7060	2.9413	9.6585	9.6900
11-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.0000	0.0000	0.9366	1.0181	7.7354	7.7606
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.3331	0.2567	1.5264	1.6592	8.3764	8.4037
Levelized															
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5996	0.5916	0.5617	2.0899	2.2716	**8.9889**	**9.0182**

Levelized Tariff = 8.9889 Rs./kWh 9.0182 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 12 USD

92%

Year	Energy Purchase Price (Rs./kW[illegible]				Capacity Purchase Price (P[illegible]W/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.5399	1.2359	2.7247	2.9616	10.2757	10.3092
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.6110	1.1648	2.7247	2.9616	10.2757	10.3092
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.6915	1.0843	2.7247	2.9616	10.2757	10.3092
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.7826	0.9932	2.7247	2.9616	10.2757	10.3092
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.8858	0.8901	2.7247	2.9616	10.2757	10.3092
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.0025	0.7734	2.7247	2.9616	10.2757	10.3092
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.1345	0.6413	2.7247	2.9616	10.2757	10.3092
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.2840	0.4918	2.7247	2.9616	10.2757	10.3092
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.4532	0.3227	2.7247	2.9616	10.2757	10.3092
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.6446	0.1312	2.7247	2.9616	10.2757	10.3092
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
21	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
22	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
23	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
24	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
25	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
26	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
27	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
28	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
29	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	1.0030	0.7729	2.7247	2.9616	10.2757	10.3092
11-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.0000	0.0000	0.9488	1.0313	8.3454	8.3727
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.3343	0.2576	1.5408	1.6748	8.9889	9.0182
Levelized															
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6018	0.5938	0.5638	2.1063	2.2895	9.6036	9.6349

Levelized Tariff = 9.6036 Rs./kWh 9.6349 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 10 USD

92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.7377	0.4250	2.0423	2.2199	8.3404	8.3676
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.7734	0.3893	2.0423	2.2199	8.3404	8.3676
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.8108	0.3518	2.0423	2.2199	8.3404	8.3676
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.8501	0.3126	2.0423	2.2199	8.3404	8.3676
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.8912	0.2714	2.0423	2.2199	8.3404	8.3676
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.9344	0.2283	2.0423	2.2199	8.3404	8.3676
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.9796	0.1830	2.0423	2.2199	8.3404	8.3676
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	1.0270	0.1356	2.0423	2.2199	8.3404	8.3676
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	1.0768	0.0859	2.0423	2.2199	8.3404	8.3676
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	1.1289	0.0338	2.0423	2.2199	8.3404	8.3676
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
21	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
22	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
23	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
24	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
25	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
26	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
27	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
28	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
29	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.9210	0.2417	2.0423	2.2199	8.3404	8.3676
11-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.0000	0.0000	0.8797	0.9562	7.0766	7.0997
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.3070	0.0806	1.2672	1.3774	7.4979	7.5223
Levelized															
1-30	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5526	0.5786	0.1793	1.6375	1.7799	7.9003	7.9261

Levelized Tariff = 7.9003 Rs./kWh 7.9261 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total	Total
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total	Tariff	Tariff
Year	Component	Foreign	Local	EPP	Local	Foreign		CPP	Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.2763	0.3382	9.7862	9.8181

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - LIBOR	0.26%	
Spread Over and above LIBOR	4.50%	
Total Interest Rate	4.76%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	30.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		LNG	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		38.684	Million US $
One Month Escrow Account - LNG		34.489	Million US $
Sub total		93.386	Million US $
Total Project Cost		**863.386**	Million US $
Cost per MW - Gross		1.046	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	647.539	Million US $
Equity	25%	215.846	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		18%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		92.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
LIBOR - 3 Months	0.26%	
Spread over LIBOR	4.50%	
Total Interest Rate	4.76%	
Quarterly Int. Rate	1.19%	

	Construction Period			Debt		
				Principal	IDC	Fin. Chrg.
Year	1st Year	2nd Year	4 Months			
Opening Balance	-	237.95	487.42			
1st Quarter	10.00%	10%	10%			
Principal Amount	57.75	57.75	57.75	173.250		
Financing Fee 3.5%	20.21	-	0.00			20.21
Interest	0.6866	3.5156	6.4815		10.68	
Closing Balance	58.44	299.21	551.65			
Opening Balance	58.44	299.21	551.65			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	1.3813	4.2439	6.7874		12.41	
Closing Balance	117.57	361.21	616.18			
Opening Balance	117.57	361.21	-			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	2.0844	4.9810	-		7.07	
Closing Balance	177.40	423.94	-			
Opening Balance	177.40	423.94	-			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	2.7957	5.7268	-		8.52	
Closing Balance	237.95	487.42	-			
Total Debt Incl. IDC				577.50	38.68	20.21
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000 MWs
Equity Investment	21,514 Rs. Million
Return on Equity	18.00%
IRR	15.00%

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(8,605.80)	
31-Dec-12	(1.00)	(8,605.80)	
30-Apr-13	-	(4,302.90)	
30-Apr-14	1	3,872.61	0.5526
30-Apr-15	2	3,872.61	0.5526
30-Apr-16	3	3,872.61	0.5526
30-Apr-17	4	3,872.61	0.5526
30-Apr-18	5	3,872.61	0.5526
30-Apr-19	6	3,872.61	0.5526
30-Apr-20	7	3,872.61	0.5526
30-Apr-21	8	3,872.61	0.5526
30-Apr-22	9	3,872.61	0.5526
30-Apr-23	10	3,872.61	0.5526
30-Apr-24	11	3,872.61	0.5526
30-Apr-25	12	3,872.61	0.5526
30-Apr-26	13	3,872.61	0.5526
30-Apr-27	14	3,872.61	0.5526
30-Apr-28	15	3,872.61	0.5526
30-Apr-29	16	3,872.61	0.5526
30-Apr-30	17	3,872.61	0.5526
30-Apr-31	18	3,872.61	0.5526
30-Apr-32	19	3,872.61	0.5526
30-Apr-33	20	3,872.61	0.5526
30-Apr-34	21	3,872.61	0.5526
30-Apr-35	22	3,872.61	0.5526
30-Apr-36	23	3,872.61	0.5526
30-Apr-37	24	3,872.61	0.5526
30-Apr-38	25	3,872.61	0.5526
30-Apr-39	26	3,872.61	0.5526
30-Apr-40	27	3,872.61	0.5526
30-Apr-41	28	3,872.61	0.5526
30-Apr-42	29	3,872.61	0.5526
30-Apr-43	30	14,629.86	0.5526
	XIRR	**16.13%**	
	IRR	**15.00%**	

Upfront Tariff RLNG- Debt Servicing on Foreign Financing

Net Capacity		800.000	MWs
LIBOR		0.26%	
Spread over LIBOR		4.50%	
Total Interest Rate		4.76%	
Debt	75.00%	647.54	US$ Million
Exchange Rate		99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	647.5	12.7	7.7	634.8	20.44			
2	634.8	12.9	7.5	621.9	20.44			
3	621.9	13.0	7.4	608.9	20.44			
4	608.9	13.2	7.2	595.7	20.44	0.7377	0.4250	1.1626
5	596	13.4	7.1	582.3	20.44			
6	582.3	13.5	6.9	568.8	20.44			
7	568.8	13.7	6.8	555.1	20.44			
8	555.1	13.8	6.6	541.3	20.44	0.7734	0.3893	1.1626
9	541.3	14.0	6.4	527.3	20.44			
10	527.3	14.2	6.3	513.1	20.44			
11	513.1	14.3	6.1	498.8	20.44			
12	498.8	14.5	5.9	484.3	20.44	0.8108	0.3518	1.162[illegible]
13	484.3	14.7	5.8	469.6	20.44			
14	469.6	14.9	5.6	454.8	20.44			
15	454.8	15.0	5.4	439.7	20.44			
16	439.7	15.2	5.2	424.5	20.44	0.8501	0.3126	1.1626
17	424.5	15.4	5.0	409.1	20.44			
18	409.1	15.6	4.9	393.6	20.44			
19	393.6	15.8	4.7	377.8	20.44			
20	377.8	15.9	4.5	361.9	20.44	0.8912	0.2714	1.1626
21	361.9	16.1	4.3	345.7	20.44			
22	345.7	16.3	4.1	329.4	20.44			
23	329.4	16.5	3.9	312.9	20.44			
24	312.9	16.7	3.7	296.2	20.44	0.9344	0.2283	1.1626
25	296.2	16.9	3.5	279.2	20.44			
26	279.2	17.1	3.3	262.1	20.44			
27	262.1	17.3	3.1	244.8	20.44			
28	244.8	17.5	2.9	227.3	20.44	0.9796	0.1830	1.1626
29	227.3	17.7	2.7	209.6	20.44			
30	209.6	17.9	2.5	191.6	20.44			
31	191.6	18.2	2.3	173.5	20.44			
32	173.5	18.4	2.1	155.1	20.44	1.0270	0.1356	1.1626
33	155.1	18.6	1.8	136.5	20.44			
34	136.5	18.8	1.6	117.7	20.44			
35	117.7	19.0	1.4	98.6	20.44			
36	98.6	19.3	1.2	79.4	20.44	1.0768	0.0859	1.1626
37	79.4	19.5	0.9	59.9	20.44			
38	59.9	19.7	0.7	40.2	20.44			
39	40.2	20.0	0.5	20.2	20.44			
40	20.2	20.2	0.2	0.0	20.44	1.1289	0.0338	1.1626
		$647.54	$169.90		$817.44			

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 11 USD — 92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.7406	0.4267	2.0592	2.2382	8.9555	8.9847
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.7765	0.3908	2.0592	2.2382	8.9555	8.9847
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.8141	0.3532	2.0592	2.2382	8.9555	8.9847
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.8535	0.3138	2.0592	2.2382	8.9555	8.9847
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.8948	0.2725	2.0592	2.2382	8.9555	8.9847
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.9381	0.2292	2.0592	2.2382	8.9555	8.9847
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.9835	0.1838	2.0592	2.2382	8.9555	8.9847
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	1.0312	0.1361	2.0592	2.2382	8.9555	8.9847
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	1.0811	0.0862	2.0592	2.2382	8.9555	8.9847
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	1.1334	0.0339	2.0592	2.2382	8.9555	8.9847
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
21	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
22	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
23	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
24	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
25	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
26	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
27	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
28	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
29	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.9247	0.2426	2.0592	2.2382	8.9555	8.9847
11-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.0000	0.0000	0.8919	0.9694	7.6867	7.7118
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.3082	0.0809	1.2810	1.3924	8.1096	8.1361
Levelized															
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5548	0.5809	0.1800	1.6527	1.7964	**8.5137**	**8.5415**

Levelized Tariff = 8.5137 Rs./kWh 8.5415 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 12 USD

92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (Rs./kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.7436	0.4284	2.0760	2.2565	9.5706	9.6018
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.7796	0.3924	2.0760	2.2565	9.5706	9.6018
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.8173	0.3546	2.0760	2.2565	9.5706	9.6018
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.8569	0.3151	2.0760	2.2565	9.5706	9.6018
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.8984	0.2736	2.0760	2.2565	9.5706	9.6018
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.9419	0.2301	2.0760	2.2565	9.5706	9.6018
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.9875	0.1845	2.0760	2.2565	9.5706	9.6018
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	1.0353	0.1367	2.0760	2.2565	9.5706	9.6018
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	1.0854	0.0866	2.0760	2.2565	9.5706	9.6018
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	1.1379	0.0340	2.0760	2.2565	9.5706	9.6018
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
21	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
22	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
23	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
24	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
25	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
26	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
27	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
28	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
29	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.9284	0.2436	2.0760	2.2565	9.5706	9.6018
11-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.0000	0.0000	0.9041	0.9827	8.2968	8.3238
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.3095	0.0812	1.2947	1.4073	8.7214	8.7498
Levelized															
1-30	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5570	0.5832	0.1807	1.6679	1.8130	9.1271	9.1568

Levelized Tariff = 9.1271 Rs./kWh 9.1568 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 10 USD

60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.5359	1.2269	2.7205	4.5341	10.6545	10.6893
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.6066	1.1563	2.7205	4.5341	10.6545	10.6893
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.6865	1.0763	2.7205	4.5341	10.6545	10.6893
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.7769	0.9859	2.7205	4.5341	10.6545	10.6893
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.8793	0.8836	2.7205	4.5341	10.6545	10.6893
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.9951	0.7677	2.7205	4.5341	10.6545	10.6893
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.1262	0.6366	2.7205	4.5341	10.6545	10.6893
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.2746	0.4882	2.7205	4.5341	10.6545	10.6893
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.4425	0.3203	2.7205	4.5341	10.6545	10.6893
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.6326	0.1302	2.7205	4.5341	10.6545	10.6893
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.9956	0.7672	2.7205	4.5341	10.6545	10.6893
11-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.5961	7.7165	7.7417
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.4978	0.3836	1.8390	3.0651	9.1855	9.2155
Levelized															
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.6526	0.6197	2.2299	3.7165	**9.8370**	**9.8691**

Levelized Tariff = 9.8370 Rs./kWh 9.8691 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total	Total
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total	Tariff	Tariff
Year	Component	Foreign	Local	EPP	Local	Foreign		CPP	Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.3153	0.3771	9.8251	9.8572

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - KIBOR	9.57%	
Spread Over and above KIBOR	3.00%	
Total Interest Rate	12.57%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	20.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		LNG	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		108.632	Million US $
One Month Cash Margin - LNG		34.489	Million US $
Sub total		163.334	Million US $
Total Project Cost		**933.334**	Million US $
Cost per MW - Gross		1.130	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	700.000	Million US $
Equity	25%	233.333	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		19%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		60.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
KIBOR - 3 Months	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Quarterly Int. Rate	3.14%	

	Construction Period			Debt Principal	IDC	Fin. Chrg.
Year	**1st Year**	**2nd Year**	**4 Months**			
Opening Balance	-	**249.73**	**532.36**			
1st Quarter	10.00%	10%	10%			
Principal Amount	**57.75**	**57.75**	**57.75**	173.250		
Financing Fee 3.5%	**20.21**	-	0.00			20.21
Interest	**1.8148**	**9.6625**	**18.5441**		30.02	
Closing Balance	**59.56**	**317.14**	**608.65**			
Opening Balance	**59.56**	**317.14**	**608.65**			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	**3.6866**	**11.7809**	**19.7318**		35.20	
Closing Balance	**121.00**	**386.67**	**686.13**			
Opening Balance	**121.00**	**386.67**	-			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**5.6173**	**13.9659**	-		19.58	
Closing Balance	**184.37**	**458.39**	-			
Opening Balance	**184.37**	**458.39**	-			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**7.6086**	**16.2196**	-		23.83	
Closing Balance	**249.73**	**532.36**	-			
Total Debt Incl. IDC				577.50	108.63	20.21
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000	MWs
Equity Investment	23,258	Rs. Million
Return on Equity	19.00%	
IRR	15.00%	

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(9,303.00)	
31-Dec-12	(1.00)	(9,303.00)	
30-Apr-13	-	(4,651.50)	
30-Apr-14	1	4,418.93	0.6306
30-Apr-15	2	4,418.93	0.6306
30-Apr-16	3	4,418.93	0.6306
30-Apr-17	4	4,418.93	0.6306
30-Apr-18	5	4,418.93	0.6306
30-Apr-19	6	4,418.93	0.6306
30-Apr-20	7	4,418.93	0.6306
30-Apr-21	8	4,418.93	0.6306
30-Apr-22	9	4,418.93	0.6306
30-Apr-23	10	4,418.93	0.6306
30-Apr-24	11	4,418.93	0.6306
30-Apr-25	12	4,418.93	0.6306
30-Apr-26	13	4,418.93	0.6306
30-Apr-27	14	4,418.93	0.6306
30-Apr-28	15	4,418.93	0.6306
30-Apr-29	16	4,418.93	0.6306
30-Apr-30	17	4,418.93	0.6306
30-Apr-31	18	4,418.93	0.6306
30-Apr-32	19	4,418.93	0.6306
30-Apr-33	20	4,418.93	0.6306
	XIRR	**16.28%**	
	IRR	**15.00%**	

Upfront Tariff RLNG- Debt Servicing on Local Financing

Net Capacity	800.000	MWs
KIBOR	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Debt 75.00%	700.00	US$ Million
Exchange Rate	99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	700.0	9.0	22.0	691.0	30.99			
2	691.0	9.3	21.7	681.7	30.99			
3	681.7	9.6	21.4	672.2	30.99			
4	672.2	9.9	21.1	662.3	30.99	0.5359	1.2269	1.7628
5	662	10.2	20.8	652.1	30.99			
6	652.1	10.5	20.5	641.7	30.99			
7	641.7	10.8	20.2	630.8	30.99			
8	630.8	11.2	19.8	619.7	30.99	0.6066	1.1563	1.7628
9	619.7	11.5	19.5	608.2	30.99			
10	608.2	11.9	19.1	596.3	30.99			
11	596.3	12.2	18.7	584.0	30.99			
12	584.0	12.6	18.4	571.4	30.99	0.6865	1.0763	1.762[illegible]
13	571.4	13.0	18.0	558.4	30.99			
14	558.4	13.4	17.5	544.9	30.99			
15	544.9	13.9	17.1	531.1	30.99			
16	531.1	14.3	16.7	516.8	30.99	0.7769	0.9859	1.7628
17	516.8	14.7	16.2	502.0	30.99			
18	502.0	15.2	15.8	486.8	30.99			
19	486.8	15.7	15.3	471.1	30.99			
20	471.1	16.2	14.8	455.0	30.99	0.8793	0.8836	1.7628
21	455.0	16.7	14.3	438.3	30.99			
22	438.3	17.2	13.8	421.1	30.99			
23	421.1	17.8	13.2	403.3	30.99			
24	403.3	18.3	12.7	385.0	30.99	0.9951	0.7677	1.7628
25	385.0	18.9	12.1	366.1	30.99			
26	366.1	19.5	11.5	346.6	30.99			
27	346.6	20.1	10.9	326.5	30.99			
28	326.5	20.7	10.3	305.8	30.99	1.1262	0.6366	1.7628
29	305.8	21.4	9.6	284.4	30.99			
30	284.4	22.0	8.9	262.4	30.99			
31	262.4	22.7	8.2	239.7	30.99			
32	239.7	23.5	7.5	216.2	30.99	1.2746	0.4882	1.7628
33	216.2	24.2	6.8	192.0	30.99			
34	192.0	25.0	6.0	167.1	30.99			
35	167.1	25.7	5.2	141.3	30.99			
36	141.3	26.5	4.4	114.8	30.99	1.4425	0.3203	1.7628
37	114.8	27.4	3.6	87.4	30.99			
38	87.4	28.2	2.7	59.2	30.99			
39	59.2	29.1	1.9	30.0	30.99			
40	30.0	30.0	0.9	0.0	30.99	1.6326	0.1302	1.7628
		$700.00	$539.41		$1,239.41			

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 11 USD — 60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 60%	Total Tariff Rs. /kWh	Total Tariff Cents/kWh
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP			
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.5379	1.2314	2.7393	4.5655	11.2827	11.3195
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.6088	1.1605	2.7393	4.5655	11.2827	11.3195
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.6890	1.0803	2.7393	4.5655	11.2827	11.3195
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.7798	0.9896	2.7393	4.5655	11.2827	11.3195
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.8825	0.8868	2.7393	4.5655	11.2827	11.3195
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.9988	0.7705	2.7393	4.5655	11.2827	11.3195
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.1304	0.6390	2.7393	4.5655	11.2827	11.3195
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.2793	0.4900	2.7393	4.5655	11.2827	11.3195
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.4478	0.3215	2.7393	4.5655	11.2827	11.3195
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.6386	0.1307	2.7393	4.5655	11.2827	11.3195
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.9993	0.7700	2.7393	4.5655	11.2827	11.3195
11-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.6166	8.3339	8.3610
1-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.4996	0.3850	1.8546	3.0910	9.8083	9.8403
Levelized															
1-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.6551	0.6219	2.2469	3.7449	**10.4622**	**10.4963**

Levelized Tariff = 10.4622 Rs./kWh 10.4963 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 12 USD

60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (Rs./kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.5399	1.2359	2.7581	4.5969	11.9109	11.9498
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.6110	1.1648	2.7581	4.5969	11.9109	11.9498
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.6915	1.0843	2.7581	4.5969	11.9109	11.9498
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.7826	0.9932	2.7581	4.5969	11.9109	11.9498
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.8858	0.8901	2.7581	4.5969	11.9109	11.9498
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.0025	0.7734	2.7581	4.5969	11.9109	11.9498
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.1345	0.6413	2.7581	4.5969	11.9109	11.9498
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.2840	0.4918	2.7581	4.5969	11.9109	11.9498
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.4532	0.3227	2.7581	4.5969	11.9109	11.9498
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.6446	0.1312	2.7581	4.5969	11.9109	11.9498
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.0030	0.7729	2.7581	4.5969	11.9109	11.9498
11-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.6371	8.9512	8.9804
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.5015	0.3864	1.8702	3.1170	10.4311	10.4651
Levelized															
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.6575	0.6242	2.2640	3.7733	11.0874	11.1235

Levelized Tariff = 11.0874 Rs./kWh 11.1235 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 10 USD — 60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.7377	0.4250	2.0730	3.4550	9.5755	9.6067
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.7734	0.3893	2.0730	3.4550	9.5755	9.6067
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.8108	0.3518	2.0730	3.4550	9.5755	9.6067
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.8501	0.3126	2.0730	3.4550	9.5755	9.6067
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.8912	0.2714	2.0730	3.4550	9.5755	9.6067
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.9344	0.2283	2.0730	3.4550	9.5755	9.6067
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.9796	0.1830	2.0730	3.4550	9.5755	9.6067
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	1.0270	0.1356	2.0730	3.4550	9.5755	9.6067
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	1.0768	0.0859	2.0730	3.4550	9.5755	9.6067
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	1.1289	0.0338	2.0730	3.4550	9.5755	9.6067
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.9210	0.2417	2.0730	3.4550	9.5755	9.6067
11-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	1.5173	7.6377	7.6627
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.4605	0.1208	1.4917	2.4862	8.6066	8.6347
Levelized															
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.6406	0.1985	1.7495	2.9158	**9.0363**	**9.0658**

Levelized Tariff = 9.0363 Rs./kWh 9.0658 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total	Total
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total	Tariff	Tariff
Year	Component	Foreign	Local	EPP	Local	Foreign		CPP	Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.2916	0.3535	9.8015	9.8335

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - LIBOR	0.26%	
Spread Over and above LIBOR	4.50%	
Total Interest Rate	4.76%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	20.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		**LNG**	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		38.684	Million US $
One Month Cash Margin - LNG		34.489	Million US $
Sub total		93.386	Million US $
Total Project Cost		**863.386**	Million US $
Cost per MW - Gross		1.046	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	647.539	Million US $
Equity	25%	215.846	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		19%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		60.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
LIBOR - 3 Months	0.26%	
Spread over LIBOR	4.50%	
Total Interest Rate	4.76%	
Quarterly Int. Rate	1.19%	

	Construction Period			Debt		
Year	**1st Year**	**2nd Year**	**4 Months**	**Principal**	**IDC**	**Fin. Chrg.**
Opening Balance	-	**237.95**	**487.42**			
1st Quarter	10.00%	10%	10%			
Principal Amount	**57.75**	**57.75**	**57.75**	173.250		
Financing Fee 3.5%	**20.21**	-	0.00			20.21
Interest	**0.6866**	**3.5156**	**6.4815**		10.68	
Closing Balance	**58.44**	**299.21**	**551.65**			
Opening Balance	**58.44**	**299.21**	**551.65**			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	**1.3813**	**4.2439**	**6.7874**		12.41	
Closing Balance	**117.57**	**361.21**	**616.18**			
Opening Balance	**117.57**	**361.21**	-			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**2.0844**	**4.9810**	-		7.07	
Closing Balance	**177.40**	**423.94**	-			
Opening Balance	**177.40**	**423.94**	-			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**2.7957**	**5.7268**	-		8.52	
Closing Balance	**237.95**	**487.42**	-			
Total Debt Incl. IDC				**577.50**	**38.68**	**20.21**
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000	MWs
Equity Investment	21,514	Rs. Million
Return on Equity	19.00%	
IRR	15.00%	

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(8,605.80)	
31-Dec-12	(1.00)	(8,605.80)	
30-Apr-13	-	(4,302.90)	
30-Apr-14	1	4,087.75	0.5833
30-Apr-15	2	4,087.75	0.5833
30-Apr-16	3	4,087.75	0.5833
30-Apr-17	4	4,087.75	0.5833
30-Apr-18	5	4,087.75	0.5833
30-Apr-19	6	4,087.75	0.5833
30-Apr-20	7	4,087.75	0.5833
30-Apr-21	8	4,087.75	0.5833
30-Apr-22	9	4,087.75	0.5833
30-Apr-23	10	4,087.75	0.5833
30-Apr-24	11	4,087.75	0.5833
30-Apr-25	12	4,087.75	0.5833
30-Apr-26	13	4,087.75	0.5833
30-Apr-27	14	4,087.75	0.5833
30-Apr-28	15	4,087.75	0.5833
30-Apr-29	16	4,087.75	0.5833
30-Apr-30	17	4,087.75	0.5833
30-Apr-31	18	4,087.75	0.5833
30-Apr-32	19	4,087.75	0.5833
30-Apr-33	20	4,087.75	0.5833
	XIRR	**16.28%**	
	IRR	**15.00%**	

Upfront Tariff RLNG- Debt Servicing on Foreign Financing

Net Capacity		800.000	MWs
LIBOR		0.26%	
Spread over LIBOR		4.50%	
Total Interest Rate		4.76%	
Debt	75.00%	647.54	US$ Million
Exchange Rate		99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	647.5	12.7	7.7	634.8	20.44			
2	634.8	12.9	7.5	621.9	20.44			
3	621.9	13.0	7.4	608.9	20.44			
4	608.9	13.2	7.2	595.7	20.44	0.7377	0.4250	1.1626
5	596	13.4	7.1	582.3	20.44			
6	582.3	13.5	6.9	568.8	20.44			
7	568.8	13.7	6.8	555.1	20.44			
8	555.1	13.8	6.6	541.3	20.44	0.7734	0.3893	1.1626
9	541.3	14.0	6.4	527.3	20.44			
10	527.3	14.2	6.3	513.1	20.44			
11	513.1	14.3	6.1	498.8	20.44			
12	498.8	14.5	5.9	484.3	20.44	0.8108	0.3518	1.162[illegible]
13	484.3	14.7	5.8	469.6	20.44			
14	469.6	14.9	5.6	454.8	20.44			
15	454.8	15.0	5.4	439.7	20.44			
16	439.7	15.2	5.2	424.5	20.44	0.8501	0.3126	1.1626
17	424.5	15.4	5.0	409.1	20.44			
18	409.1	15.6	4.9	393.6	20.44			
19	393.6	15.8	4.7	377.8	20.44			
20	377.8	15.9	4.5	361.9	20.44	0.8912	0.2714	1.1626
21	361.9	16.1	4.3	345.7	20.44			
22	345.7	16.3	4.1	329.4	20.44			
23	329.4	16.5	3.9	312.9	20.44			
24	312.9	16.7	3.7	296.2	20.44	0.9344	0.2283	1.1626
25	296.2	16.9	3.5	279.2	20.44			
26	279.2	17.1	3.3	262.1	20.44			
27	262.1	17.3	3.1	244.8	20.44			
28	244.8	17.5	2.9	227.3	20.44	0.9796	0.1830	1.1626
29	227.3	17.7	2.7	209.6	20.44			
30	209.6	17.9	2.5	191.6	20.44			
31	191.6	18.2	2.3	173.5	20.44			
32	173.5	18.4	2.1	155.1	20.44	1.0270	0.1356	1.1626
33	155.1	18.6	1.8	136.5	20.44			
34	136.5	18.8	1.6	117.7	20.44			
35	117.7	19.0	1.4	98.6	20.44			
36	98.6	19.3	1.2	79.4	20.44	1.0768	0.0859	1.1626
37	79.4	19.5	0.9	59.9	20.44			
38	59.9	19.7	0.7	40.2	20.44			
39	40.2	20.0	0.5	20.2	20.44			
40	20.2	20.2	0.2	0.0	20.44	1.1289	0.0338	1.1626
		$647.54	$169.90		$817.44			

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 11 USD — 60%

Year	Energy Purchase Price (Rs./kWh) Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Capacity Purchase Price (PKR/kW/Hour) Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP	Capacity Charge@ 60%	Total Tariff Rs. /kWh	Total Tariff Cents/kWh
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.7406	0.4267	2.0900	3.4833	10.2006	10.2338
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.7765	0.3908	2.0900	3.4833	10.2006	10.2338
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.8141	0.3532	2.0900	3.4833	10.2006	10.2338
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.8535	0.3138	2.0900	3.4833	10.2006	10.2338
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.8948	0.2725	2.0900	3.4833	10.2006	10.2338
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.9381	0.2292	2.0900	3.4833	10.2006	10.2338
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.9835	0.1838	2.0900	3.4833	10.2006	10.2338
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	1.0312	0.1361	2.0900	3.4833	10.2006	10.2338
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	1.0811	0.0862	2.0900	3.4833	10.2006	10.2338
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	1.1334	0.0339	2.0900	3.4833	10.2006	10.2338
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.9247	0.2426	2.0900	3.4833	10.2006	10.2338
11-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.5378	8.2551	8.2820
1-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.4623	0.1213	1.5063	2.5106	9.2278	9.2579
Levelized															
1-30	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.6432	0.1993	1.7652	2.9420	**9.6592**	**9.6907**

Levelized Tariff = 9.6592 Rs./kWh 9.6907 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 12 USD

60%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price ([illegible]R/kW/Hour)								Capacity Charge@ 60%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.7436	0.4284	2.1069	3.5116	10.8257	10.8610
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.7796	0.3924	2.1069	3.5116	10.8257	10.8610
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.8173	0.3546	2.1069	3.5116	10.8257	10.8610
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.8569	0.3151	2.1069	3.5116	10.8257	10.8610
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.8984	0.2736	2.1069	3.5116	10.8257	10.8610
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.9419	0.2301	2.1069	3.5116	10.8257	10.8610
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.9875	0.1845	2.1069	3.5116	10.8257	10.8610
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	1.0353	0.1367	2.1069	3.5116	10.8257	10.8610
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	1.0854	0.0866	2.1069	3.5116	10.8257	10.8610
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	1.1379	0.0340	2.1069	3.5116	10.8257	10.8610
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.9284	0.2436	2.1069	3.5116	10.8257	10.8610
11-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.5584	8.8725	8.9014
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.4642	0.1218	1.5210	2.5350	9.8491	9.8812
Levelized															
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.6458	0.2001	1.7808	2.9681	**10.2822**	10.3157

Levelized Tariff = 10.2822 Rs./kWh 10.3157 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 10 USD — 92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel	Var. O&M		Total	Fixed O&M		Cost of		ROE	Debt	Interest	Total			
	Component	Foreign	Local	EPP	Local	Foreign	W/C	Insurance		Repayment	Charges	CPP		Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.5359	1.2269	2.7205	2.9570	9.0775	9.1071
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.6066	1.1563	2.7205	2.9570	9.0775	9.1071
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.6865	1.0763	2.7205	2.9570	9.0775	9.1071
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.7769	0.9859	2.7205	2.9570	9.0775	9.1071
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.8793	0.8836	2.7205	2.9570	9.0775	9.1071
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.9951	0.7677	2.7205	2.9570	9.0775	9.1071
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.1262	0.6366	2.7205	2.9570	9.0775	9.1071
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.2746	0.4882	2.7205	2.9570	9.0775	9.1071
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.4425	0.3203	2.7205	2.9570	9.0775	9.1071
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	1.6326	0.1302	2.7205	2.9570	9.0775	9.1071
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.9956	0.7672	2.7205	2.9570	9.0775	9.1071
11-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.0000	0.0000	0.9576	1.0409	7.1614	7.1847
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.4978	0.3836	1.8390	1.9990	8.1194	8.1459
Levelized															
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.6306	0.6526	0.6197	2.2299	2.4238	**8.5443**	**8.5721**

Levelized Tariff = 8.5443 Rs./kWh 8.5721 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total	Total
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total	Tariff	Tariff
Year	Component	Foreign	Local	EPP	Local	Foreign		CPP	Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.3153	0.3771	9.8251	9.8572

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - KIBOR	9.57%	
Spread Over and above KIBOR	3.00%	
Total Interest Rate	12.57%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	20.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		LNG	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		108.632	Million US $
One Month Escrow Account - LNG		34.489	Million US $
Sub total		163.334	Million US $
Total Project Cost		**933.334**	Million US $
Cost per MW - Gross		1.130	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	700.000	Million US $
Equity	25%	233.333	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		19%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		92.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
KIBOR - 3 Months	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Quarterly Int. Rate	3.14%	

	Construction Period			Debt Principal	IDC	Fin. Chrg.
Year	**1st Year**	**2nd Year**	**4 Months**			
Opening Balance	**-**	**249.73**	**532.36**			
1st Quarter	10.00%	10%	10%			
Principal Amount	**57.75**	**57.75**	**57.75**	173.250		
Financing Fee 3.5%	**20.21**	-	0.00			20.21
Interest	**1.8148**	**9.6625**	**18.5441**		30.02	
Closing Balance	**59.56**	**317.14**	**608.65**			
Opening Balance	**59.56**	**317.14**	**608.65**			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	**3.6866**	**11.7809**	**19.7318**		35.20	
Closing Balance	**121.00**	**386.67**	**686.13**			
Opening Balance	**121.00**	**386.67**	**-**			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**5.6173**	**13.9659**	**-**		19.58	
Closing Balance	**184.37**	**458.39**	**-**			
Opening Balance	**184.37**	**458.39**	**-**			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**7.6086**	**16.2196**	**-**		23.83	
Closing Balance	**249.73**	**532.36**	**-**			
Total Debt Incl. IDC				**577.50**	**108.63**	**20.21**
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000	MWs
Equity Investment	23,258	Rs. Million
Return on Equity	19.00%	
IRR	15.00%	

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(9,303.00)	
31-Dec-12	(1.00)	(9,303.00)	
30-Apr-13	-	(4,651.50)	
30-Apr-14	1	4,418.93	0.6306
30-Apr-15	2	4,418.93	0.6306
30-Apr-16	3	4,418.93	0.6306
30-Apr-17	4	4,418.93	0.6306
30-Apr-18	5	4,418.93	0.6306
30-Apr-19	6	4,418.93	0.6306
30-Apr-20	7	4,418.93	0.6306
30-Apr-21	8	4,418.93	0.6306
30-Apr-22	9	4,418.93	0.6306
30-Apr-23	10	4,418.93	0.6306
30-Apr-24	11	4,418.93	0.6306
30-Apr-25	12	4,418.93	0.6306
30-Apr-26	13	4,418.93	0.6306
30-Apr-27	14	4,418.93	0.6306
30-Apr-28	15	4,418.93	0.6306
30-Apr-29	16	4,418.93	0.6306
30-Apr-30	17	4,418.93	0.6306
30-Apr-31	18	4,418.93	0.6306
30-Apr-32	19	4,418.93	0.6306
30-Apr-33	20	4,418.93	0.6306
	XIRR	**16.28%**	
	IRR	**15.00%**	

Upfront Tariff RLNG- Debt Servicing on Local Financing

Net Capacity	800.000	MWs
KIBOR	9.57%	
Spread over KIBOR	3.00%	
Total Interest Rate	12.57%	
Debt 75.00%	700.00	US$ Million
Exchange Rate	99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	700.0	9.0	22.0	691.0	30.99			
2	691.0	9.3	21.7	681.7	30.99			
3	681.7	9.6	21.4	672.2	30.99			
4	672.2	9.9	21.1	662.3	30.99	0.5359	1.2269	1.7628
5	662	10.2	20.8	652.1	30.99			
6	652.1	10.5	20.5	641.7	30.99			
7	641.7	10.8	20.2	630.8	30.99			
8	630.8	11.2	19.8	619.7	30.99	0.6066	1.1563	1.7628
9	619.7	11.5	19.5	608.2	30.99			
10	608.2	11.9	19.1	596.3	30.99			
11	596.3	12.2	18.7	584.0	30.99			
12	584.0	12.6	18.4	571.4	30.99	0.6865	1.0763	1.762
13	571.4	13.0	18.0	558.4	30.99			
14	558.4	13.4	17.5	544.9	30.99			
15	544.9	13.9	17.1	531.1	30.99			
16	531.1	14.3	16.7	516.8	30.99	0.7769	0.9859	1.7628
17	516.8	14.7	16.2	502.0	30.99			
18	502.0	15.2	15.8	486.8	30.99			
19	486.8	15.7	15.3	471.1	30.99			
20	471.1	16.2	14.8	455.0	30.99	0.8793	0.8836	1.7628
21	455.0	16.7	14.3	438.3	30.99			
22	438.3	17.2	13.8	421.1	30.99			
23	421.1	17.8	13.2	403.3	30.99			
24	403.3	18.3	12.7	385.0	30.99	0.9951	0.7677	1.7628
25	385.0	18.9	12.1	366.1	30.99			
26	366.1	19.5	11.5	346.6	30.99			
27	346.6	20.1	10.9	326.5	30.99			
28	326.5	20.7	10.3	305.8	30.99	1.1262	0.6366	1.7628
29	305.8	21.4	9.6	284.4	30.99			
30	284.4	22.0	8.9	262.4	30.99			
31	262.4	22.7	8.2	239.7	30.99			
32	239.7	23.5	7.5	216.2	30.99	1.2746	0.4882	1.7628
33	216.2	24.2	6.8	192.0	30.99			
34	192.0	25.0	6.0	167.1	30.99			
35	167.1	25.7	5.2	141.3	30.99			
36	141.3	26.5	4.4	114.8	30.99	1.4425	0.3203	1.7628
37	114.8	27.4	3.6	87.4	30.99			
38	87.4	28.2	2.7	59.2	30.99			
39	59.2	29.1	1.9	30.0	30.99			
40	30.0	30.0	0.9	0.0	30.99	1.6326	0.1302	1.7628
		$700.00	$539.41		$1,239.41			

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 11 USD — 92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 92%	Total Tariff Rs. /kWh	Total Tariff Cents/kWh
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP			
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.5379	1.2314	2.7393	2.9775	9.6948	9.7264
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.6088	1.1605	2.7393	2.9775	9.6948	9.7264
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.6890	1.0803	2.7393	2.9775	9.6948	9.7264
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.7798	0.9896	2.7393	2.9775	9.6948	9.7264
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.8825	0.8868	2.7393	2.9775	9.6948	9.7264
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.9988	0.7705	2.7393	2.9775	9.6948	9.7264
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.1304	0.6390	2.7393	2.9775	9.6948	9.7264
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.2793	0.4900	2.7393	2.9775	9.6948	9.7264
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.4478	0.3215	2.7393	2.9775	9.6948	9.7264
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	1.6386	0.1307	2.7393	2.9775	9.6948	9.7264
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.9993	0.7700	2.7393	2.9775	9.6948	9.7264
11-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.0000	0.0000	0.9700	1.0543	7.7716	7.7969
1-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.4996	0.3850	1.8546	2.0159	8.7332	8.7616
Levelized															
1-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.6329	0.6551	0.6219	2.2469	2.4423	**9.1596**	**9.1895**

Levelized Tariff = 9.1596 Rs./kWh 9.1895 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Local Financing (Combined Cycle) @ RLNG Price - 12 USD

92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price ([illegible]R/kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.5399	1.2359	2.7581	2.9979	10.3120	10.3457
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.6110	1.1648	2.7581	2.9979	10.3120	10.3457
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.6915	1.0843	2.7581	2.9979	10.3120	10.3457
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.7826	0.9932	2.7581	2.9979	10.3120	10.3457
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.8858	0.8901	2.7581	2.9979	10.3120	10.3457
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.0025	0.7734	2.7581	2.9979	10.3120	10.3457
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.1345	0.6413	2.7581	2.9979	10.3120	10.3457
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.2840	0.4918	2.7581	2.9979	10.3120	10.3457
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.4532	0.3227	2.7581	2.9979	10.3120	10.3457
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.6446	0.1312	2.7581	2.9979	10.3120	10.3457
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	1.0030	0.7729	2.7581	2.9979	10.3120	10.3457
11-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.0000	0.0000	0.9823	1.0677	8.3818	8.4091
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.5015	0.3864	1.8702	2.0328	9.3469	9.3774
Levelized															
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.6352	0.6575	0.6242	2.2640	2.4608	**9.7749**	**9.8068**

Levelized Tariff = 9.7749 Rs./kWh 9.8068 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 10 USD 92%

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity	Total	Total
Year	Fuel	Var. O&M		Total	Fixed O&M		Cost of		ROE	Debt	Interest	Total	Charge@	Tariff	Tariff
	Component	Foreign	Local	EPP	Local	Foreign	W/C	Insurance		Repayment	Charges	CPP	92%	Rs. /kWh	Cents/kWh
1	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.7377	0.4250	2.0730	2.2533	8.3737	8.4010
2	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.7734	0.3893	2.0730	2.2533	8.3737	8.4010
3	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.8108	0.3518	2.0730	2.2533	8.3737	8.4010
4	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.8501	0.3126	2.0730	2.2533	8.3737	8.4010
5	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.8912	0.2714	2.0730	2.2533	8.3737	8.4010
6	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.9344	0.2283	2.0730	2.2533	8.3737	8.4010
7	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.9796	0.1830	2.0730	2.2533	8.3737	8.4010
8	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	1.0270	0.1356	2.0730	2.2533	8.3737	8.4010
9	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	1.0768	0.0859	2.0730	2.2533	8.3737	8.4010
10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	1.1289	0.0338	2.0730	2.2533	8.3737	8.4010
11	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
12	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
13	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
14	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
15	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
16	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
17	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
18	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
19	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
Average															
1-10	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.9210	0.2417	2.0730	2.2533	8.3737	8.4010
11-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.0000	0.0000	0.9104	0.9895	7.1100	7.1332
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.4605	0.1208	1.4917	1.6214	7.7419	7.7671
Levelized															
1-20	5.9683	0.0924	0.0597	6.1204	0.0569	0.0668	0.0998	0.1035	0.5833	0.6406	0.1985	1.7495	1.9016	8.0221	8.0482

Levelized Tariff = 8.0221 Rs./kWh 8.0482 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Simple Cycle)

	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)				Total Tariff	Total Tariff
	Fuel	Var. O&M		Total	Fixed O&M		ROE	Total CPP		
Year	Component	Foreign	Local	EPP	Local	Foreign			Rs. /kWh	Cents/kWh
1	9.1943	0.1541	0.0996	9.4480	0.0284	0.0334	0.2916	0.3535	9.8015	9.8335

Upfront Tariff - RLNG 800 MW

Assumptions for the Plant		
Interest Rate % per annum - LIBOR	0.26%	
Spread Over and above LIBOR	4.50%	
Total Interest Rate	4.76%	
Withholding Tax on Dividends	7.50%	
Discount Rate	10%	
HHV-LHV Factor	1.10760	
LNG Price LHV - US$/MMBTU	10.00	
LNG Price LHV - Rs./MMBTU	**996.75**	
Project Life	20.00	Years
Capital Structure:		
Debt % of Total Project Cost	75%	
Equity % of Total Project Cost	25%	
Equity Draw down		
1st Year of Construction Period	40%	
2nd Year of Construction Period	40%	
4 Months of Construction Period	20%	

ASSUMPTIONS - RLNG

Basis for Tariff		LNG	
Gross Capacity at Mean Site conditions		825.806	
Net Capacity at Site conditions		800.000	MWs
Net Capacity for Open Cycle	60.00%	480.000	MWs
EPC Cost (70% of CAPEX)		**539.00**	Million US $
Project Development Costs			
CAPEX		**770.000**	Million US $
Financial Charges			
Financing Fees & Charges		20.213	Million US $
Interest During Construction		38.684	Million US $
One Month Escrow Account - LNG		34.489	Million US $
Sub total		93.386	Million US $
Total Project Cost		**863.386**	Million US $
Cost per MW - Gross		1.046	Million US $
Exchange Rate per US $		99.675	Rs.
Financing Plan			
Debt	75%	647.539	Million US $
Equity	25%	215.846	Million US $
Construction Period		28	Months
Grace Period		28	Months
Loan Repayment Period - Years		10	
Return on Equity		19%	
Return on IRR basis		15%	
Variable O & M - Local		4.200	US $ Million
Variable O & M - Foreign		6.500	US $ Million
Total Variable O&M		**10.700**	**US $ Million**
Fixed O & M Amount - Foreign		4.700	US $ Million
Fixed O & M Amount - Local		4.000	US $ Million
Total Fixed O&M Amount		**8.700**	**US $ Million**
Insurance Cost	1.35%	7.277	US $ Million
Working Capital Amount - Local		7.020	US$ Million
Thermal efficiency, LHV Net at Site for CCGT		57.00%	
Thermal efficiency, LHV Net at Site for OCGT		37.00%	
Plant Factor		92.00%	

Upfront Tariff - IDC Calculation RLNG

Debt Amount	**577.500**	US$ Million
LIBOR - 3 Months	0.26%	
Spread over LIBOR	4.50%	
Total Interest Rate	4.76%	
Quarterly Int. Rate	1.19%	

	Construction Period			Debt Principal	IDC	Fin. Chrg.
Year	**1st Year**	**2nd Year**	**4 Months**			
Opening Balance	-	**237.95**	**487.42**			
1st Quarter	10.00%	10%	10%			
Principal Amount	**57.75**	**57.75**	**57.75**	173.250		
Financing Fee 3.5%	**20.21**	-	0.00			20.21
Interest	**0.6866**	**3.5156**	**6.4815**		10.68	
Closing Balance	**58.44**	**299.21**	**551.65**			
Opening Balance	**58.44**	**299.21**	**551.65**			
2nd Quarter	10.00%	10.00%	10.00%			
Principal Amount	57.75	57.75	57.75	173.250		
Interest	**1.3813**	**4.2439**	**6.7874**		12.41	
Closing Balance	**117.57**	**361.21**	**616.18**			
Opening Balance	**117.57**	**361.21**	-			
3rd Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**2.0844**	**4.9810**	-		7.07	
Closing Balance	**177.40**	**423.94**	-			
Opening Balance	**177.40**	**423.94**	-			
4th Quarter	10.00%	10.00%	0.00%			
Principal Amount	57.75	57.75	-	115.500		
Interest	**2.7957**	**5.7268**	-		8.52	
Closing Balance	**237.95**	**487.42**	-			
Total Debt Incl. IDC				**577.50**	**38.68**	**20.21**
	40.00%	40.00%	20.00%	100.00%		

Upfront Tariff - Cost of Working Capital Component		
Net Capacity	800.00	MW
Hours per Day	24.00	
Heat rate	5987.72	
Gas Price Incld. GST	996.75	PKR
Daily Quantity	114964	MMBTU
Period Required	60	Days
2 Months Gas Quantity required	6,897,852.63	MMBTU
2 Months Gas invoice at full load	6,875,434,611	PKR
SBLC charges	1.50%	
Cost of SBLC Amount	**103,131,519**	PKR
Working Capital Receivable Cycle		
Receivable gap allowed	45	Days
Amount required for 45 Days	5,156,575,958	PKR
Base Rate of KIBOR	9.57%	
Spread over KIBOR	2.00%	
Total Interest Rate	11.57%	
Cost of Total Working Capital allowed	**699,747,357**	PKR
Cost of Working Capital Component	**0.0998**	Rs./kW/h

Upfront Tariff - Return on Equity

Project Capacity Net	800.000	MWs
Equity Investment	21,514	Rs. Million
Return on Equity	19.00%	
IRR	15.00%	

Date of Investment	Year	ROE Rs. Million	ROE kW/h
31-Dec-11	(2.00)	(8,605.80)	
31-Dec-12	(1.00)	(8,605.80)	
30-Apr-13	-	(4,302.90)	
30-Apr-14	1	4,087.75	0.5833
30-Apr-15	2	4,087.75	0.5833
30-Apr-16	3	4,087.75	0.5833
30-Apr-17	4	4,087.75	0.5833
30-Apr-18	5	4,087.75	0.5833
30-Apr-19	6	4,087.75	0.5833
30-Apr-20	7	4,087.75	0.5833
30-Apr-21	8	4,087.75	0.5833
30-Apr-22	9	4,087.75	0.5833
30-Apr-23	10	4,087.75	0.5833
30-Apr-24	11	4,087.75	0.5833
30-Apr-25	12	4,087.75	0.5833
30-Apr-26	13	4,087.75	0.5833
30-Apr-27	14	4,087.75	0.5833
30-Apr-28	15	4,087.75	0.5833
30-Apr-29	16	4,087.75	0.5833
30-Apr-30	17	4,087.75	0.5833
30-Apr-31	18	4,087.75	0.5833
30-Apr-32	19	4,087.75	0.5833
30-Apr-33	20	4,087.75	0.5833
	XIRR	16.28%	
	IRR	15.00%	

Upfront Tariff RLNG- Debt Servicing on Foreign Financing

Net Capacity	800.000	MWs
LIBOR	0.26%	
Spread over LIBOR	4.50%	
Total Interest Rate	4.76%	
Debt 75.00%	647.54	US$ Million
Exchange Rate	99.68	

Period	Principal Million $	Principal Repayment Million $	Interest Million $	Balance Million $	Debt Service Million $	Principal Rep'ment Rs./kW/h	Interest Rs./kW/h	Debt Servicing Rs./kW/h
1	647.5	12.7	7.7	634.8	20.44			
2	634.8	12.9	7.5	621.9	20.44			
3	621.9	13.0	7.4	608.9	20.44			
4	608.9	13.2	7.2	595.7	20.44	0.7377	0.4250	1.1626
5	596	13.4	7.1	582.3	20.44			
6	582.3	13.5	6.9	568.8	20.44			
7	568.8	13.7	6.8	555.1	20.44			
8	555.1	13.8	6.6	541.3	20.44	0.7734	0.3893	1.1626
9	541.3	14.0	6.4	527.3	20.44			
10	527.3	14.2	6.3	513.1	20.44			
11	513.1	14.3	6.1	498.8	20.44			
12	498.8	14.5	5.9	484.3	20.44	0.8108	0.3518	1.162[illegible]
13	484.3	14.7	5.8	469.6	20.44			
14	469.6	14.9	5.6	454.8	20.44			
15	454.8	15.0	5.4	439.7	20.44			
16	439.7	15.2	5.2	424.5	20.44	0.8501	0.3126	1.1626
17	424.5	15.4	5.0	409.1	20.44			
18	409.1	15.6	4.9	393.6	20.44			
19	393.6	15.8	4.7	377.8	20.44			
20	377.8	15.9	4.5	361.9	20.44	0.8912	0.2714	1.1626
21	361.9	16.1	4.3	345.7	20.44			
22	345.7	16.3	4.1	329.4	20.44			
23	329.4	16.5	3.9	312.9	20.44			
24	312.9	16.7	3.7	296.2	20.44	0.9344	0.2283	1.1626
25	296.2	16.9	3.5	279.2	20.44			
26	279.2	17.1	3.3	262.1	20.44			
27	262.1	17.3	3.1	244.8	20.44			
28	244.8	17.5	2.9	227.3	20.44	0.9796	0.1830	1.1626
29	227.3	17.7	2.7	209.6	20.44			
30	209.6	17.9	2.5	191.6	20.44			
31	191.6	18.2	2.3	173.5	20.44			
32	173.5	18.4	2.1	155.1	20.44	1.0270	0.1356	1.1626
33	155.1	18.6	1.8	136.5	20.44			
34	136.5	18.8	1.6	117.7	20.44			
35	117.7	19.0	1.4	98.6	20.44			
36	98.6	19.3	1.2	79.4	20.44	1.0768	0.0859	1.1626
37	79.4	19.5	0.9	59.9	20.44			
38	59.9	19.7	0.7	40.2	20.44			
39	40.2	20.0	0.5	20.2	20.44			
40	20.2	20.2	0.2	0.0	20.44	1.1289	0.0338	1.1626
		$647.54	$169.90		$817.44			

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 11 USD 92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.7406	0.4267	2.0900	2.2717	8.9890	9.0183
2	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.7765	0.3908	2.0900	2.2717	8.9890	9.0183
3	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.8141	0.3532	2.0900	2.2717	8.9890	9.0183
4	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.8535	0.3138	2.0900	2.2717	8.9890	9.0183
5	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.8948	0.2725	2.0900	2.2717	8.9890	9.0183
6	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.9381	0.2292	2.0900	2.2717	8.9890	9.0183
7	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.9835	0.1838	2.0900	2.2717	8.9890	9.0183
8	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	1.0312	0.1361	2.0900	2.2717	8.9890	9.0183
9	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	1.0811	0.0862	2.0900	2.2717	8.9890	9.0183
10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	1.1334	0.0339	2.0900	2.2717	8.9890	9.0183
11	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
12	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
13	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
14	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
15	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
16	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
17	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
18	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
19	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
Average															
1-10	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.9247	0.2426	2.0900	2.2717	8.9890	9.0183
11-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.0000	0.0000	0.9227	1.0029	7.7202	7.7454
1-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.4623	0.1213	1.5063	1.6373	8.3546	8.3818
Levelized															
1-20	6.5651	0.0924	0.0597	6.7173	0.0569	0.0668	0.1098	0.1035	0.5856	0.6432	0.1993	1.7652	1.9187	**8.6359**	**8.6641**

Levelized Tariff = 8.6359 Rs./kWh 8.6641 US Cents/kWh

Upfront Tariff for 800 MW RLNG Projects on Foreign Financing (Combined Cycle) @ RLNG Price - 12 USD

92%

Year	Energy Purchase Price (Rs./kWh)				Capacity Purchase Price (PKR/kW/Hour)								Capacity Charge@ 92%	Total Tariff	Total Tariff
	Fuel Component	Var. O&M Foreign	Var. O&M Local	Total EPP	Fixed O&M Local	Fixed O&M Foreign	Cost of W/C	Insurance	ROE	Debt Repayment	Interest Charges	Total CPP		Rs. /kWh	Cents/kWh
1	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.7436	0.4284	2.1069	2.2902	9.6043	9.6356
2	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.7796	0.3924	2.1069	2.2902	9.6043	9.6356
3	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.8173	0.3546	2.1069	2.2902	9.6043	9.6356
4	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.8569	0.3151	2.1069	2.2902	9.6043	9.6356
5	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.8984	0.2736	2.1069	2.2902	9.6043	9.6356
6	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.9419	0.2301	2.1069	2.2902	9.6043	9.6356
7	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.9875	0.1845	2.1069	2.2902	9.6043	9.6356
8	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	1.0353	0.1367	2.1069	2.2902	9.6043	9.6356
9	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	1.0854	0.0866	2.1069	2.2902	9.6043	9.6356
10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	1.1379	0.0340	2.1069	2.2902	9.6043	9.6356
11	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
12	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
13	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
14	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
15	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
16	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
17	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
18	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
19	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
Average															
1-10	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.9284	0.2436	2.1069	2.2902	9.6043	9.6356
11-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.0000	0.0000	0.9350	1.0163	8.3304	8.3576
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.4642	0.1218	1.5210	1.6532	8.9673	8.9966
Levelized															
1-20	7.1619	0.0924	0.0597	7.3141	0.0569	0.0668	0.1198	0.1035	0.5880	0.6458	0.2001	1.7808	1.9357	9.2498	9.2800

Levelized Tariff = 9.2498 Rs./kWh 9.2800 US Cents/kWh

Annexures & References

Annex-I

2013 GTW Combined Cycle Specs

Model	First Year in Service	Net Plant Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	Comments
Alstom (50 Hz)										
KA11N2-2	1993	345 000 kW	6652 Btu	51.3%	7018 kJ	1.3 inch Hg	*****	*****	2 x GT11N2	dual pressure non-reheat HRSG
KA13E2-1	2012	281 000 kW	6378 Btu	53.5%	6729 kJ	1.3 inch Hg	*****	*****	1 x GT13E2	dual pressure non-reheat HRSG
KA13E2-2	2012	565 000 kW	6343 Btu	53.8%	6691 kJ	1.3 inch Hg	*****	*****	2 x GT13E2	dual pressure non-reheat HRSG
KA13E2-3	2012	850 000 kW	6331 Btu	53.9%	6679 kJ	1.3 inch Hg	*****	*****	3 x GT13E2	dual pressure non-reheat HRSG
KA26-1	2011	467 000 kW	5739 Btu	59.5%	6055 kJ	1.3 inch Hg	*****	*****	1 x GT26	triple pressure reheat HRSG
KA26-2	2011	935 000 kW	5735 Btu	59.5%	6050 kJ	1.3 inch Hg	*****	*****	2 x GT26	triple pressure reheat HRSG
Alstom (60 Hz)										
KA11N2-2	2001	349 000 kW	6587 Btu	51.8%	6950 kJ	1.3 inch Hg	*****	*****	2 x GT11N2	dual pressure non-reheat HRSG
KA24-2	1996	664 000 kW	5853 Btu	58.4%	6164 kJ	1.3 inch Hg	*****	*****	2 x GT24	triple pressure reheat HRSG
Ansaldo Energia (50 Hz)										
1AE643-CC1M	1996	111 700 kW	6348 Btu	53.8%	6698 kJ	*****	73 600 kW	40 200 kW	1 x AE64.3A	
2AE643-CC1M	1996	223 700 kW	6340 Btu	53.8%	6689 kJ	*****	147 100 kW	80 600 kW	2 x AE64.3A	
1AE942-CC1M	1981	258 400 kW	6421 Btu	53.1%	6775 kJ	*****	165 800 kW	96 600 kW	1 x AE94.2	
2AE942-CC1M	1981	518 000 kW	6408 Btu	53.2%	6761 kJ	*****	331 600 kW	192 900 kW	2 x AE94.2	
1AE943-CC1M	1995	456 400 kW	5797 Btu	58.9%	6116 kJ	*****	306 000 kW	157 900 kW	1 x AE94.3A	
2AE943-CC1M	1995	913 200 kW	5795 Btu	58.9%	6114 kJ	*****	610 400 kW	317 800 kW	2 x AE94.3A	
Note: ISO conditions with sea water condenser										
Bharat Heavy Electricals (50 Hz)										
CC105P	1988	38 040 kW	8273 Btu	41.3%	8728 kJ	*****	25 800 kW	13 416 kW	1 x MS5001	dual pressure
CC205P	1988	76 329 kW	8246 Btu	41.4%	8700 kJ	*****	51 600 kW	27 090 kW	2 x MS5001	dual pressure
CC305P	1988	114 869 kW	8219 Btu	41.5%	8671 kJ	*****	77 400 kW	41 022 kW	3 x MS5001	dual pressure
CC106B	1997	62 662 kW	7071 Btu	48.3%	7460 kJ	*****	42 500 kW	22 100 kW	1 x MS6001B	dual pressure
CC206B	1997	125 571 kW	7057 Btu	48.4%	7446 kJ	*****	85 000 kW	44 455 kW	2 x MS6001B	dual pressure
CC106FA	2003	114 944 kW	6441 Btu	53.0%	6795 kJ	*****	76 500 kW	41 999 kW	1 x MS6001FA	triple pressure, non reheat
CC206FA	2003	235 823 kW	6278 Btu	54.4%	6624 kJ	*****	153 000 kW	90 117 kW	2 x MS6001FA	triple pressure, reheat

Model	First Year in Service	Net Plant Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	
Bharat Heavy Electricals (50 Hz) (cont'd)										
CC109E	2003	192 900 kW	6640 Btu	51.4%	7000 kJ	*****	127 700 kW	68 200 kW	1 x MS9001E	dual pressure, non reheat
CC209E	2003	399 300 kW	6600 Btu	51.7%	6960 kJ	*****	255 400 kW	138 700 kW	2 x MS9001E	dual pressure, non reheat
CC309E	2003	585 500 kW	6560 Btu	52.0%	6920 kJ	*****	383 100 kW	211 000 kW	3 x MS9001E	dual pressure, non reheat
CC1.942	1998	232 500 kW	6630 Btu	51.5%	6990 kJ	*****	152 000 kW	85 500 kW	1 x V94.2	dual pressure
CC2.942	1998	467 500 kW	6600 Btu	51.7%	6960 kJ	*****	304 000 kW	173 000 kW	2 x V94.2	dual pressure
CC3.942	1998	701 000 kW	6600 Btu	51.7%	6960 kJ	*****	456 000 kW	259 000 kW	3 x V94.2	dual pressure
CC109FA	2003	394 900 kW	5995 Btu	56.9%	6325 kJ	*****	258 700 kW	141 500 kW	1 x MS9001FA	triple pressure reheat
CC209FA	2003	794 100 kW	5965 Btu	57.2%	6290 kJ	*****	517 400 kW	287 000 kW	2 x MS9001FA	triple pressure reheat
CC109FB	2012	452 600 kW	5765 Btu	59.2%	6080 kJ	*****	295 300 kW	164 000 kW	1 x MS9001FB	triple pressure reheat
CC209FB	2012	910 100 kW	5735 Btu	59.5%	6050 kJ	*****	590 600 kW	332 500 kW	2 x MS9001FB	triple pressure reheat
GE Energy Aeroderivative (50 Hz)										
LM2000PS	2000	24 123 kW	7682 Btu	44.4%	8105 kJ	1.0 inch Hg	18 275 kW	6 417 kW	1 x LM2000PS	water injection
LM2000PJ	2000	24 410 kW	7231 Btu	47.2%	7629 kJ	1.0 inch Hg	17 769 kW	7 222 kW	1 x LM2000PJ	DLE
LM2500PE	1981	31 147 kW	6909 Btu	49.4%	7289 kJ	1.0 inch Hg	22 374 kW	9 481 kW	1 x LM2500PE	dry
LM2500PE	1981	31 553 kW	7338 Btu	46.5%	7742 kJ	1.0 inch Hg	23 091 kW	9 227 kW	1 x LM2500PE	water injection
LM2500PJ	1995	30 559 kW	6894 Btu	49.5%	7274 kJ	1.0 inch Hg	21 846 kW	9 415 kW	1 x LM2500PJ	DLE
LM2500+ PK	1995	38 533 kW	7322 Btu	46.6%	7725 kJ	1.0 inch Hg	29 316 kW	10 104 kW	1 x LM2500+ PK	water injection
LM2500+ PR	1995	40 905 kW	6726 Btu	50.7%	7096 kJ	1.0 inch Hg	29.962 kW	11 790 kW	1 x LM2500+ PR	DLE
LM2500+ G4 RC	2005	47 045 kW	7093 Btu	48.1%	7484 kJ	1.0 inch Hg	36 024 kW	12 028 kW	1 x LM2500+ G4 RC	water injection
LM2500+ G4 RC	2005	48 702 kW	6793 Btu	50.2%	7167 kJ	1.0 inch Hg	36 024 kW	13 740 kW	1 x LM2500+ G4 RC	water injection
LM2500+ G4 RD	2005	44 001 kW	6613 Btu	51.6%	6977 kJ	1.0 inch Hg	32 881 kW	12 008 kW	1 x LM2500+ G4 RD	DLE
LM2500+ G4 RD	2005	45 457 kW	6402 Btu	53.3%	6754 kJ	1.0 inch Hg	32 881 kW	13 515 kW	1 x LM2500+ G4 RD	DLE
LM6000PC	1997	55 110 kW	6740 Btu	50.6%	7111 kJ	1.0 inch Hg	43 339 kW	12 903 kW	1 x LM6000PC	water injection
LM6000PC Sprint	1998	64 599 kW	6672 Btu	51.1%	7039 kJ	1.0 inch Hg	50 836 kW	15 051 kW	1 x LM6000PC Sprint	water injection
LM6000PF	1997	55 435 kW	6338 Btu	53.8%	6687 kJ	1.0 inch Hg	42 732 kW	13 766 kW	1 x LM6000PF	DLE
LM6000PF liquid	2005	53 351 kW	6391 Btu	53.4%	6743 kJ	1.0 inch Hg	40 999 kW	13 668 kW	1 x LM6000PF	DLE
LM6000PF Sprint	2006	60 628 kW	6424 Btu	53.1%	6778 kJ	1.0 inch Hg	47 505 kW	14 341 kW	1 x LM6000PF	DLE, 15 ppm NOx
LM6000PF Sprint	2006	61 624 kW	6383 Btu	53.5%	6734 kJ	1.0 inch Hg	48 040 kW	14 819 kW	1 x LM6000PF	DLE, 25 ppm NOx
LM6000PG	2009	68 799 kW	6690 Btu	51.0%	7058 kJ	1.0 inch Hg	53 665 kW	16 534 kW	1 x LM6000PG	water injection
LMS100PA	2006	119 109 kW	6826 Btu	50.0%	7202 kJ	1.0 inch Hg	102 995 kW	19 342 kW	1 x LMS100PA	water injection
LMS100PB	TBD	115 420 kW	6577 Btu	51.9%	6939 kJ	1.0 inch Hg	99 044 kW	19 388 kW	1 x LMS100PB	DLE

Model	First Year In Service	Net Plant Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	Comments
GE Energy Aeroderivative (60 Hz)										
LM2000PS	2000	23 957 kW	7589 Btu	45.0%	8007 kJ	1.0 inch Hg	18 412 kW	6 102 kW	1 x LM2000PS	water injection
LM2000PJ	2000	23 911 kW	7168 Btu	47.6%	7563 kJ	1.0 inch Hg	17 657 kW	6 816 kW	1 x LM2000PJ	DLE
LM2500PE	1981	32 020 kW	6776 Btu	50.4%	7149 kJ	1.0 inch Hg	23 292 kW	9 444 kW	1 x LM2500PE	dry
LM2500PE	1981	32 269 kW	7242 Btu	47.1%	7641 kJ	1.0 inch Hg	24 049 kW	8 986 kW	1 x LM2500PE	water injection
LM2500PJ	1995	31 188 kW	6807 Btu	50.1%	7182 kJ	1.0 inch Hg	22 719 kW	9 173 kW	1 x LM2500PJ	DLE
LM2500+ PK	1995	40 073 kW	7180 Btu	47.5%	7575 kJ	1.0 inch Hg	30 982 kW	9 966 kW	1 x LM2500+ PK	water injection
LM2500+ PR	1995	40 579 kW	6647 Btu	51.3%	7013 kJ	1.0 inch Hg	30 464 kW	10 945 kW	1 x LM2500+ PR	DLE
LM2500+ G4 RC	2005	47 406 kW	7039 Btu	48.5%	7427 kJ	1.0 inch Hg	36 333 kW	12 081 kW	1 x LM2500+ G4 RC	water injection
LM2500+ G4 RC	2005	48 935 kW	6819 Btu	50.0%	7194 kJ	1.0 inch Hg	36 333 kW	13 666 kW	1 x LM2500+ G4 RC	water injection
LM2500+ G4 RD	2005	44 331 kW	6564 Btu	53.6%	6925 kJ	1.0 inch Hg	33 165 kW	13 449 kW	1 x LM2500+ G4 RD	DLE
LM2500+ G4 RD	2005	45 673 kW	6371 Btu	53.6%	6722 kJ	1.0 inch Hg	33 165 kW	13 449 kW	1 x LM2500+ G4 RD	DLE
LM6000PC	1997	55 704 kW	6705 Btu	50.9%	7074 kJ	1.0 inch Hg	43 843 kW	13 000 kW	1 x LM6000PC	water injection
LM6000PC Sprint	1998	64 167 kW	6660 Btu	51.2%	7027 kJ	1.0 inch Hg	50 526 kW	14 909 kW	1 x LM6000PC	water injection
LM6000PF	1997	55 804 kW	6308 Btu	54.1%	6655 kJ	1.0 inch Hg	43 068 kW	13 798 kW	1 x LM6000PF	DLE
LM6000PF liquid	2005	53 094 kW	6376 Btu	53.5%	6727 kJ	1.0 inch Hg	40 712 kW	13 505 kW	1 x LM6000PF	DLE
LM6000PF Sprint	2006	60 357 kW	6408 Btu	53.2%	6761 kJ	1.0 inch Hg	47 383 kW	14 181 kW	1 x LM6000PF	DLE, 15 ppm NOx
LM6000PF Sprint	2006	61 412 kW	6383 Btu	53.5%	6734 kJ	1.0 inch Hg	48 092 kW	14 539 kW	1 x LM6000PF	DLE, 25 ppm NOx
LMS100PA	2006	119 306 kW	6815 Btu	50.1%	7190 kJ	1.0 inch Hg	103 045 kW	19 484 kW	1 x LMS100PA	water injection
LMS100PB	TBD	115 573 kW	6569 Btu	51.9%	6931 kJ	1.0 inch Hg	99 012 kW	19 563 kW	1 x LMS100PB	DLE
GE Power & Water Heavy Duty (50/60 Hz										
6B 3-Series	1987	64 803 kW	6768 Btu	50.4%	7141 kJ	1.2 inch Hg	42 470 kW	23 298 kW	1 x 6B	non-reheat, 65.8 MW gross
6B 3-Series	1979	130 859 kW	6703 Btu	50.9%	7072 kJ	1.2 inch Hg	84 789 kW	47 789 kW	2 x 6B	non-reheat, 132.8 MW gross
6F 3-Series	1991	118 400 kW	6199 Btu	55.0%	6540 kJ	1.2 inch Hg	78 304 kW	41 629 kW	1 x 6FA	non-reheat, 120.2 MW gross
6F 3-Series	1991	239 400 kW	6132 Btu	55.6%	6470 kJ	1.2 inch Hg	156 871 kW	85 575 kW	2 x 6FA	non-reheat, 243.0 MW gross
GE Power & Water Heavy Duty (50 Hz)										
9E 3-Series	1979	193 200 kW	6570 Btu	51.9%	6932 kJ	1.2 inch Hg	129 379 kW	66 828 kW	1 x 9E	non-reheat, 196.1 MW gross
9E 3-Series	1979	391 400 kW	6480 Btu	52.7%	6837 kJ	1.2 inch Hg	259 803 kW	137 406 kW	2 x 9E	non-reheat, 397.1 MW gross
9F 3-Series	1994	397 104 kW	5966 Btu	57.2%	6295 kJ	1.2 inch Hg	259 800 kW	142 419 kW	1 x 9FA	reheat, 402.2 MW gross
9F 3-Series	1994	798 702 kW	5933 Btu	57.5%	6260 kJ	1.2 inch Hg	519 539 kW	288 805 kW	2 x 9FA	reheat, 808.4 MW gross
9F 5-Series	2003	454 094 kW	5757 Btu	59.3%	6074 kJ	1.2 inch Hg	295 550 kW	164 638 kW	1 x 9FB	reheat, 460.2 MW gross
9F 5-Series	2003	913 619 kW	5712 Btu	59.7%	6027 kJ	1.2 inch Hg	592 [illegible] kW	337 318 kW	2 x 9FB	reheat, 925.0 MW gross

Nandipur

Model	First Year in Service	Net Plant Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	
GE Power & Water Heavy Duty (50 Hz)										
9F 7-Series	2011	512 037 kW	5594 Btu	61.0%	5902 kJ	1.2 inch Hg	338 700 kW	180 173 kW	1 x FE50	reheat, 518.9 MW gross
9F 7-Series	2011	1 025 553 kW	5586 Btu	61.1%	5892 kJ	1.2 inch Hg	679 400 kW	359 900 kW	2 x 9FB	reheat, 1039.3 MW gross
109H	1997	520 000 kW	5690 Btu	60.0%	6000 kJ	1.2 inch Hg	****	****	1 x 9001H	1 shaft, reheat, 527.0 MW gross
GE Power & Water Heavy Duty (60 Hz)										
7E 3-Series	1977	135 350 kW	6680 Btu	51.1%	7048 kJ	1.2 inch Hg	88 012 kW	49 144 kW	1 x 7EA	non-reheat, 137.2 MW gross
7E 3-Series	1979	270 128 kW	6695 Btu	51.0%	7063 kJ	1.2 inch Hg	176 024 kW	97 784 kW	2 x 7EA	non-reheat, 273.8 MW gross
7F 3-Series	2008	277 266 kW	5948 Btu	57.7%	6235 kJ	1.2 inch Hg	183 845 kW	96 632 kW	1 x 7F	reheat, 280.5 MW gross
7F 3-Series	2008	559 732 kW	5889 Btu	58.5%	6152 kJ	1.2 inch Hg	367 700 kW	199 005 kW	2 x 7F	reheat, 566.7 MW gross
7F 5-Series	2009	323 000 kW	5863 Btu	58.2%	6189 kJ	1.2 inch Hg	216 100 kW	112 000 kW	1 x 7F	reheat, 323.3 MW gross
7F 5-Series	2009	655 000 kW	5783 Btu	59.0%	6100 kJ	1.2 inch Hg	432 000 kW	232 000 kW	2 x 7FA.05	reheat, 656.4 MW gross
107H	1997	400 000 kW	5690 Btu	60.0%	6000 kJ	1.2 inch Hg	****	****	1 x 7001H	1 shaft, reheat, 405.4 MW gross
Hitachi (50/60 Hz)										
1025	1988	43 760 kW	6812 Btu	50.1%	7186 kJ	****	29 730 kW	14 030 kW	1 x H-25	
2025	1988	87 800 kW	6785 Btu	50.3%	7157 kJ	****	59 460 kW	28 340 kW	2 x H-25	
Hitachi (50 Hz)										
1080-50	2010	155 790 kW	6390 Btu	53.4%	6742 kJ	1.2 inch Hg	108 940 kW	46 850 kW	1x H-80	non-reheat, 1x1x1
2080-50	2010	322 830 kW	6170 Btu	55.3%	6510 kJ	1.2 inch Hg	217 880 kW	104 950 kW	2x H-80	reheat, 2x2x1
Hitachi (60 Hz)										
1080-60	2010	154 450 kW	6426 Btu	53.1%	6780 kJ	1.2 inch Hg	107 360 kW	47 090 kW	1x H-80	non-reheat, 1x1x1
2080-60	2010	321 150 kW	6181 Btu	55.2%	6522 kJ	1.2 inch Hg	214 720 kW	106 430 kW	2x H-80	reheat, 2x2x1
IHI Power Systems (50/60 Hz)										
LM2500PE	1986	31 790 kW	7093 Btu	48.1%	7484 kJ	****	22 230 kW	10 270 kW	1 x LM2500PE	
LM2500PK	1998	40 540 kW	6944 Btu	49.1%	7326 kJ	****	29 660 kW	11 730 kW	1 x LM2500PK	
LM2500RB	2006	43 120 kW	6497 Btu	52.5%	6855 kJ	****	31 430 kW	12 550 kW	1 x LM2500RB	
LM2500RC	2005	47 780 kW	6818 Btu	50.0%	7193 kJ	****	34 660 kW	14 100 kW	1 x LM2500RB	
LM2500RD	2005	43 900 kW	6533 Btu	52.2%	6893 kJ	****	31 350 kW	13 440 kW	1 x LM2500RB	
Note: All IHI ratings with inlet and exhaust losses										
IHI Power Systems (50 Hz)										
LM6000PC	1997	55 250 kW	6687 Btu	51.0%	7055 kJ	****	42 900 kW	13 420 kW	1 x LM6000PC	
LM6000PC	1997	111 130 kW	6649 Btu	51.3%	7015 kJ	****	85 800 kW	27 530 kW	2 x LM6000PC	

Model	First Year in Service	Net Plant Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	Comments
IHI Power Systems (50 Hz) (cont'd)										
LM6000PC Sprint	1997	62 120 kW	6655 Btu	51.3%	7021 kJ	••••	48 430 kW	14 860 kW	1 x LM6000PC Sprint	
LM6000PC Sprint	1997	124 820 kW	6623 Btu	51.5%	6988 kJ	••••	96 860 kW	30 380 kW	2 x LM6000PC Sprint	
LM6000PD	1997	55 180 kW	6402 Btu	53.3%	6754 kJ	••••	42 260 kW	13 960 kW	1 x LM6000PD	
LM6000PD	1997	110 970 kW	6366 Btu	53.6%	6717 kJ	••••	84 520 kW	28 590 kW	2 x LM6000PD	
LM6000PD Sprint	1997	59 820 kW	6475 Btu	52.7%	6831 kJ	••••	46 460 kW	14 470 kW	1 x LM6000PD Sprint	
LM6000PD Sprint	1997	120 220 kW	6443 Btu	53.0%	6798 kJ	••••	92 920 kW	29 610 kW	2 x LM6000PD Sprint	
LM6000PF	1997	55 180 kW	6402 Btu	53.3%	6754 kJ	••••	42 260 kW	13 960 kW	1 x LM6000PF	
LM6000PF	1997	110 970 kW	6366 Btu	53.6%	6717 kJ	••••	84 520 kW	28 590 kW	2 x LM6000PF	
LM6000PF Sprint	1997	59 830 kW	6474 Btu	52.7%	6830 kJ	••••	46 460 kW	14 470 kW	1 x LM6000PF Sprint	
LM6000PF Sprint	1997	120 220 kW	6443 Btu	53.0%	6798 kJ	••••	92 920 kW	29 610 kW	2 x LM6000PF Sprint	
LM6000PG	2009	70 000 kW	6524 Btu	52.3%	6883 kJ	••••	53 980 kW	17 330 kW	1 x LM6000PG	
LM6000PG	2009	140 600 kW	6495 Btu	52.5%	6853 kJ	••••	107 960 kW	35 330 kW	2 x LM6000PG	
LM6000PG Sprint	2009	72 320 kW	6559 Btu	52.0%	6920 kJ	••••	55 850 kW	17 820 kW	1 x LM6000PG Sprint	
LM6000PG Sprint	2009	145 230 kW	6532 Btu	52.2%	6892 kJ	••••	111 700 kW	36 300 kW	2 x LM6000PG Sprint	
LM6000PH	2011	63 660 kW	6335 Btu	53.9%	6684 kJ	••••	48 240 kW	16 610 kW	1 x LM6000PH	
LM6000PH	2011	127 890 kW	6307 Btu	54.1%	6654 kJ	••••	96 480 kW	33 880 kW	2 x LM6000PH	
LM6000PH Sprint	2011	66 080 kW	6389 Btu	53.4%	6741 kJ	••••	50 660 kW	16 640 kW	1 x LM6000PH Sprint	
LM6000PH Sprint	2011	108 450 kW	6360 Btu	53.7%	6710 kJ	••••	101 320 kW	33 960 kW	2 x LM6000PH Sprint	
Note: All IHI ratings with inlet and exhaust losses										
MAN Diesel & Turbo (50/60 Hz)										
THM 1304-12N	2004	35 400 kW	7160 Btu	47.7%	7550 kJ	1.0 Inch Hg	24 000 kW	11 400 kW	2 x THM 1304-12N	dual pressure HRSG
MAPNA Group (50Hz)										
SCC5 2x2	1981	465 900 kW	6836 Btu	49.9%	7210 kJ	••••	315 480 kW	159 800 kW	2 x SGT5-2000E	
Mitsubishi Heavy Industries (50 Hz)										
MPCP1(M701)	1981	212 500 kW	6635 Btu	51.4%	7000 kJ	1.5 inch Hg	142 100 kW	70 400 kW	1 x M701DA	
MPCP2(M701)	1981	426 600 kW	6610 Btu	51.6%	6974 kJ	1.5 inch Hg	284 200 kW	142 400 kW	2 x M701DA	
MPCP3(M701)	1981	645 000 kW	6585 Btu	51.8%	6947 kJ	1.5 inch Hg	426 300 kW	218 700 kW	3 x M701DA	
MPCP1(M701F4)	1992	477 900 kW	5687 Btu	60.0%	6000 kJ	1.5 inch Hg	319 900 kW	158 000 kW	1 x M701F4	
MPCP2(M701F4)	1992	958 800 kW	566[illegible] Btu	60.2%	5981 kJ	1.5 inch Hg	639[illegible] kW	319 000 kW	2 x M701F4	

Model	In Service	Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	Comments
Mitsubishi Heavy Industries (50 Hz) (cont'd)										
MPCP1(M701F5)	1992	525 000 kW	5594 Btu	61.0%	5902 kJ	1.5 inch Hg	354 000 kW	171 000 kW	1 x M701F5	
MPCP2(M701F5)	1992	1 053 300 kW	5576 Btu	61.2%	5883 kJ	1.5 inch Hg	708 000 kW	345 300 kW	2 x M701F5	
MPCP1(M701G)	1997	498 000 kW	5755 Btu	59.3%	6071 kJ	1.5 inch Hg	325 700 kW	172 300 kW	1 x M701G2	
MPCP2(M701G)	1997	999 400 kW	5735 Btu	59.5%	6051 kJ	1.5 inch Hg	651 400 kW	348 000 kW	2 x M701G2	
MPCP1(M701J)	2014	680 000 kW	5531 Btu	61.7%	5835 kJ	1.5 inch Hg	463 000 kW	217 000 kW	1 x M701J	
Mitsubishi Heavy Industries (60 Hz)										
MPCP1(M501)	1981	167 400 kW	6635 Btu	51.4%	7000 kJ	1.5 inch Hg	112 100 kW	55 300 kW	1 x M501DA	
MPCP2(M501)	1981	336 200 kW	6610 Btu	51.6%	6974 kJ	1.5 inch Hg	224 200 kW	112 000 kW	2 x M501DA	
MPCP3(M501)	1981	506 200 kW	6585 Btu	51.8%	6947 kJ	1.5 inch Hg	336 300 kW	169 900 kW	3 x M501DA	
MPCP1(M501F)	1994	285 100 kW	5976 Btu	57.1%	6305 kJ	1.5 inch Hg	182 700 kW	102 400 kW	1 x M501F3	
MPCP2(M501F)	1994	572 200 kW	5955 Btu	57.3%	6283 kJ	1.5 inch Hg	365 400 kW	206 800 kW	2 x M501F3	
MPCP1(M501G)	1995	398 900 kW	5843 Btu	58.4%	6165 kJ	1.5 inch Hg	264 400 kW	134 500 kW	1 x M501G1	
MPCP2(M501G)	1995	800 500 kW	5823 Btu	58.6%	6144 kJ	1.5 inch Hg	528 800 kW	271 700 kW	2 x M501G1	
MPCP1(M501GAC)	2011	412 400 kW	5735 Btu	59.5%	6051 kJ	1.5 inch Hg	273 600 kW	138 800 kW	1 x M501GAC	
MPCP2(M501GAC)	2011	826 100 kW	5726 Btu	59.6%	6041 kJ	1.5 inch Hg	547 200 kW	278 900 kW	2 x M501GAC	
MPCP1(M501J)	2011	470 000 kW	5549 Btu	61.5%	5854 kJ	1.5 inch Hg	322 000 kW	148 000 kW	1 x M501J	
MPCP2(M501J)	2011	942 900 kW	5531 Btu	61.7%	5835 kJ	1.5 inch Hg	644 000 kW	298 900 kW	2 x M501J	
MPCP1(M501JAC)	2015	450 000 kW	<5595 Btu	>61%	<5903 kJ	1.5 inch Hg	310 000 kW	140 000 kW	1 x M501JAC	
Note: All Mitsubishi ratings at electric generator terminals with inlet and exhaust losses										
Mitsui Engineering & Shipbuilding (50/60 Hz)										
MACS70	1997	10 210 kW	7668 Btu	44.5%	8090 kJ	****	7 700 kW	2 510 kW	1 x MSC70	
MACS90	1997	12 220 kW	8183 Btu	41.7%	8633 kJ	****	9 100 kW	3 120 kW	1 x MSC90	
MACS100	1997	14 540 kW	7991 Btu	42.7%	8431 kJ	****	10 960 kW	3 580 kW	1 x MSC100	
PW Power Systems (50/60 Hz)										
SwiftPac 30	1990	36 570 kW	6750 Btu	50.6%	7122 kJ	****	27 220 kW	10 006 kW	1 x FT8-3	
SwiftPac 60	1990	74 185 kW	6655 Btu	51.3%	7022 kJ	****	54 840 kW	20 597 kW	2 x FT8-3	
Rolls-Royce (50/60 Hz)										
RB211-G62 DLE	1993	37 725 kW	6801 Btu	50.2%	7175 kJ	1.9 inch Hg	26 716 kW	12 045 kW	1 x RB211	dual pressure
RB211-GT62 DLE	1999	39 760 kW	6639 Btu	51.4%	7005 kJ	1.9 inch Hg	28 626 kW	12 205 kW	1 x RB211	dual pressure
RB211-GT61 DLE	2000	42 640 kW	6464 Btu	52.8%	6820 kJ	1.9 inch Hg	31 171 kW	12 593 kW	1 x RB211	dual pressure

CC Ratings

Model	First Year in Service	Net Plant Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	Comments
Rolls-Royce (50/60 Hz) (cont'd)										
RB211-H63 WLE	2010	54 019 kW	6715 Btu	50.8%	7085 kJ	1.8 inch Hg	40 935 kW	14 189 kW	1 x RB211	dual pressure, water injection
RB211-H63 WLE	2010	68 398 kW	7040 Btu	48.5%	7428 kJ	1.8 inch Hg	40 935 kW	29 125 kW	1 x RB211	fired to 1346F, 1p, water inj
Rolls-Royce (50 Hz)										
Trent 60 DLE	1998	65,356 kW	6367 Btu	53.6%	6718 kJ	1.5 inch Hg	50,767 kW	15,820 kW	1 x Trent	2P unfired
Trent 60 DLE	1998	131,173 kW	6345 Btu	53.8%	6695 kJ	1.5 inch Hg	50,767 kW	32,125 kW	2 x Trent	
Trent 60 DLE	1998	78,373 kW	6574 Btu	51.9%	6936 kJ	1.5 inch Hg	50,767 kW	29,348 kW	1 x Trent	2P fired to 1007F
Trent 60 DLE	1998	157,352 kW	6548 Btu	52.1%	6909 kJ	1.5 inch Hg	50,767 kW	59,364 kW	2 x Trent	
Trent 60 DLE ISI	2010	77,673 kW	6384 Btu	53.4%	6736 kJ	1.5 inch Hg	61,978 kW	17,100 kW	1 x Trent	2P ISI unfired
Trent 60 DLE ISI	2010	155,585 kW	6375 Btu	53.5%	6726 kJ	1.5 inch Hg	61,978 kW	34,473 kW	2 x Trent	
Trent 60 DLE ISI	2010	94,151 kW	6627 Btu	51.5%	6992 kJ	1.5 inch Hg	61,978 kW	34,252 kW	1 x Trent	2P ISI fired to 1007F
Trent 60 DLE ISI	2010	188,697 kW	6613 Btu	51.6%	6977 kJ	1.5 inch Hg	61,978 kW	69,003 kW	2 x Trent	
Trent 60 WLE	2001	81,247 kW	6633 Btu	51.4%	6998 kJ	1.5 inch Hg	64,479 kW	18,291 kW	1 x Trent	2P unfired
Trent 60 WLE	2001	162,803 kW	6619 Btu	51.6%	6984 kJ	1.5 inch Hg	64,479 kW	36,935 kW	2 x Trent	
Trent 60 WLE	2001	107,233 kW	6956 Btu	49.1%	7339 kJ	1.5 inch Hg	64,479 kW	45,380 kW	1 x Trent	1P fired to 1300F
Trent 60 WLE	2001	214,952 kW	6941 Btu	49.2%	7323 kJ	1.5 inch Hg	64,479 kW	91,349 kW	2 x Trent	
Trent 60 WLE ISI	2011	82,885 kW	6655 Btu	51.3%	7022 kJ	1.5 inch Hg	66,000 kW	18,433 kW	1 x Trent	2P ISI unfired
Trent 60 WLE ISI	2011	166,065 kW	6643 Btu	51.4%	7009 kJ	1.5 inch Hg	66,000 kW	37,211 kW	2 x Trent	
Trent 60 WLE ISI	2011	109,567 kW	6971 Btu	49.0%	7355 kJ	1.5 inch Hg	66,000 kW	46,259 kW	1 x Trent	1P ISI fired to 1300F
Trent 60 WLE ISI	2011	219,593 kW	6957 Btu	49.1%	7340 kJ	1.5 inch Hg	66,000 kW	93,087 kW	2 x Trent	
Rolls-Royce (60 Hz)										
Trent 60 DLE	1998	66,438 kW	6374 Btu	53.5%	6725 kJ	1.5 inch Hg	51,674 kW	16,010 kW	1 x Trent	2P unfired
Trent 60 DLE	1998	133,276 kW	6354 Btu	53.7%	6704 kJ	1.5 inch Hg	51,674 kW	32,448 kW	2 x Trent	
Trent 60 DLE	1998	79,672 kW	6582 Btu	51.8%	6945 kJ	1.5 inch Hg	51,674 kW	29,786 kW	1 x Trent	2P fired to 1007F
Trent 60 DLE	1998	159,868 kW	6562 Btu	52.0%	6924 kJ	1.5 inch Hg	51,674 kW	60,124 kW	2 x Trent	
Trent 60 DLE ISI	2010	75,475 kW	6376 Btu	53.5%	6727 kJ	1.5 inch Hg	60,200 kW	16,641 kW	1 x Trent	2P ISI unfired
Trent 60 DLE ISI	2010	151,131 kW	6368 Btu	53.6%	6719 kJ	1.5 inch Hg	60,200 kW	33,501 kW	2 x Trent	
Trent 60 DLE ISI	2010	90,883 kW	6605 Btu	51.7%	6969 kJ	1.5 inch Hg	60,200 kW	32,682 kW	1 x Trent	2P ISI fired to 1007F
Trent 60 DLE ISI	2010	182,148 kW	6591 Btu	51.8%	6954 kJ	1.5 inch Hg	[illegible]	65,846 kW	2 x Trent	

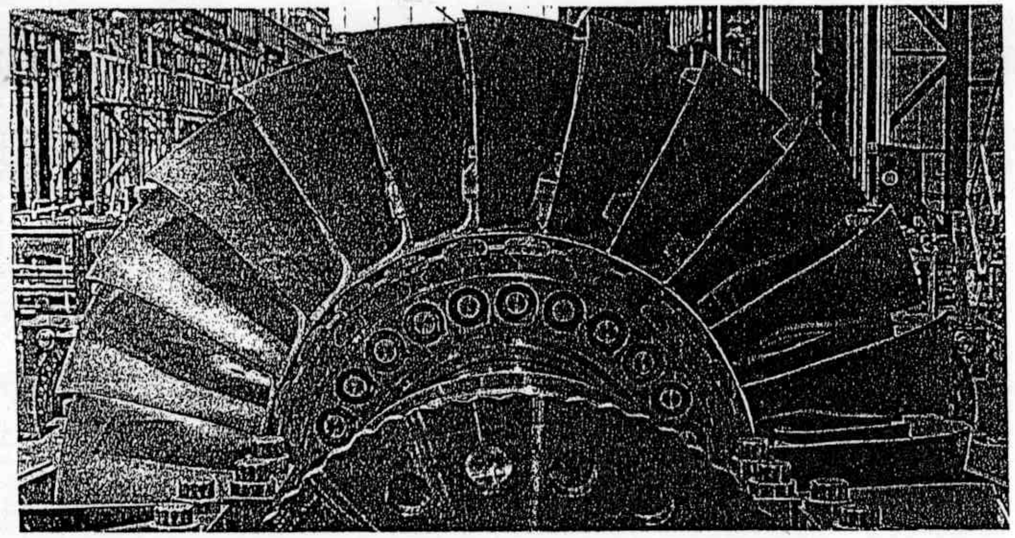
Model	First Year in Service	Net Plant Output (kW)	Heat Rate (Btu/kWh)	Net Plant Efficiency	Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. & Type Gas Turbine	Comments
Rolls-Royce (60 Hz) (cont'd)										
Trent 60 WLE	2001	77,952 kW	6633 Btu	51.4%	6998 kJ	1.5 inch Hg	61,754 kW	17,671 kW	1 x Trent	2P unfired
Trent 60 WLE	2001	156,160 kW	6621 Btu	51.5%	6986 kJ	1.5 inch Hg	61,754 kW	35,637 kW	2 x Trent	
Trent 60 WLE	2001	102,438 kW	6957 Btu	49.1%	7340 kJ	1.5 inch Hg	61,754 kW	43,199 kW	1 x Trent	1P fired to 1300F
Trent 60 WLE	2001	205,212 kW	6945 Btu	49.1%	7328 kJ	1.5 inch Hg	61,754 kW	86,824 kW	2 x Trent	
Trent 60 WLE ISI	2011	80,303 kW	6723 Btu	50.8%	7093 kJ	1.5 inch Hg	64,036 kW	17,798 kW	1 x Trent	2P ISI unfired
Trent 60 WLE ISI	2011	160,850 kW	6712 Btu	50.8%	7082 kJ	1.5 inch Hg	64,036 kW	35,883 kW	2 x Trent	
Trent 60 WLE ISI	2011	105,704 kW	7017 Btu	48.6%	7404 kJ	1.5 inch Hg	64,036 kW	44,273 kW	1 x Trent	1P ISI fired to 1300F
Trent 60 WLE ISI	2011	211,920 kW	7001 Btu	48.7%	7387 kJ	1.5 inch Hg	64,036 kW	89,157 kW	2 x Trent	
Siemens Energy (50/60 Hz)										
SCC-600 1x1	1981	35 900 kW	6843 Btu	49.9%	7220 kJ	****	23 880 kW	12 600 kW	1 x SGT-600	dual pressure, no reheat
SCC-600 2x1	1981	73 280 kW	6702 Btu	50.9%	7071 kJ	****	47 780 kW	26 450 kW	2 x SGT-600	dual pressure, no reheat
SCC-700 1x1	1999	45 160 kW	6517 Btu	52.3%	6876 kJ	****	31 300 kW	14 410 kW	1 x SGT-700	dual pressure, no reheat
SCC-700 2x1	1999	91 620 kW	6424 Btu	53.1%	6778 kJ	****	62 600 kW	30 040 kW	2 x SGT-700	dual pressure, no reheat
SCC-750 1X1	2012	47 340 kW	6684 Btu	51.0%	7052 kJ	****	34 840 kW	12 500 kW	1 x SGT-750	dual pressure, no reheat
SCC-750 2X1	2012	94 700 kW	6600 Btu	51.7%	6964 kJ	****	69 690 kW	26 020 kW	2 x SGT-750	dual pressure, no reheat
SCC-800 1x1	1998	66 570 kW	6344 Btu	53.8%	6693 kJ	****	46 300 kW	21 000 kW	1 x SGT-800	dual pressure, no reheat
SCC-800 2x1	1998	135 370 kW	6239 Btu	54.7%	6583 kJ	****	92 600 kW	44 200 kW	2 x SGT-800	dual pressure, no reheat
SCC-800 1x1	2010	71 400 kW	6189 Btu	55.1%	6530 kJ	****	49 100 kW	23 100 kW	1 x SGT-800	dual pressure, no reheat
SCC-800 2x1	2010	143 600 kW	6155 Btu	55.4%	6494 kJ	****	98 300 kW	46 800 kW	2 x SGT-800	dual pressure, no reheat
Siemens Energy (50 Hz)										
SCC5-2000E 1x1	1981	253 000 kW	6499 Btu	52.5%	6857 kJ	****	168 000 kW	89 000 kW	1 x SGT5-2000E	dual pressure, no reheat
SCC5-2000E 2x1	1981	512 000 kW	6426 Btu	53.1%	6780 kJ	****	336 000 kW	184 000 kW	2 x SGT5-2000E	dual pressure, no reheat
SCC5-4000F 1S*	1995	431 000 kW	5812 Btu	58.7%	6133 kJ	****	289 000 kW	138 000 kW	1 x SGT5-4000F	triple pressure, reheat
SCC5-4000F 2x1	1995	862 000 kW	5812 Btu	58.7%	6133 kJ	****	578 000 kW	296 000 kW	2 x SGT5-4000F	triple pressure, reheat
SCC5-8000H 1S*	2009	570 000 kW	<5687 Btu	>60.0%	<6000 kJ	****	375 000 kW	195 000 kW	1 x SGT5-8000H	triple pressure, reheat
SCC5-8000H 2x1	2010	1 140 000 kW	<5687 Btu	>60.0%	<6000 kJ	****	750 000 kW	390 000 kW	2 x SGT5-8000F	triple pressure, reheat

*Note: Siemens model 1S designates single shaft

2014 GAS TURBINE WORLD SIMPLE CYCLE SPECIFICATIONS

Model	Year	ISO Base Rating (kW)	Heat Rate (Btu/kWh)	Efficiency	Pressure Ratio	Exhaust Flow (lb/sec)	Turbine Speed (rpm)	Exhaust Temp (F)	Approx Weight (lb)	Approx. L x W x H	Comments
GE Power & Water Heavy Duty Simple Cycle											
6B.03	1978	43,100 kW	10,180 Btu	33.5%	12.7	320 lb	5,163 rpm	1,003 F	443,000 lb	79 x 13 x 14 ft	Available in 50 and 60 Hz
6F.03	2003	79,200 kW	9,470 Btu	36.0%	16.1	472 lb	5,231 rpm	1,097 F	508,000 lb	74 x 12 x 15 ft	Available in 50 and 60 Hz
7E.03	1984	90,000 kW	10,060 Btu	33.9%	12.8	644 lb	3,600 rpm	1,014 F	600,000 lb	66 x 12 x 12 ft	
7F.04	2009	187,000 kW	8,850 Btu	38.6%	16.2	993 lb	3,600 rpm	1,114 F	960,000 lb	78 x 24 x 14 ft	
7F.05	2009	227,000 kW	8,680 Btu	39.3%	18.4	1,174 lb	3,600 rpm	1,122 F	1,060,000 lb	78 x 24 x 14 ft	
7HA.01	2012	275,000 kW	8,240 Btu	41.4%	21.5	1,269 lb	3,600 rpm	1,145 F	1,200,000 lb	82 x 15 x 23 ft	
7HA.02	2014	330,000 kW	8,240 Btu	41.4%	21.5	1,522 lb	3,600 rpm	1,145 F	1,320,000 lb	90 x 17 x 20 ft	
9E.03	1992	130,000 kW	9,860 Btu	34.6%	12.9	917 lb	3,000 rpm	1,007 F	820,000 lb	70 x 17 x 17 ft	
9F.03	1996	265,000 kW	9,020 Btu	37.8%	16.7	1,466 lb	3,000 rpm	1,103 F	1,281,000 lb	92 X 17 X 17 ft	
9F.05	2003	299,000 kW	8,810 Btu	38.7%	18.3	1,470 lb	3,000 rpm	1,183 F	1,447,000 lb	93 x 17 x 17 ft	
9HA.01	2011	397,000 kW	8,220 Btu	41.5%	21.8	1,822 lb	3,000 rpm	1,146 F	1,900,000 lb	100 x 19 x 19 ft	
9HA.02	2014	470,000 kW	8,220 Btu	41.5%	21.8	2,157 lb	3,000 rpm	1,146 F	2,100,000 lb	109 x 20 x 21 ft	

Note: All GE Heavy Duty models with inlet loss, exhaust loss, and shaft driven auxiliary losses.



2014 GAS TURBINE WORLD COMBINED CYCLE SPECIFICATIONS

Model	Year	Gross Plant Output (kW)	Net Plant Output (kW)	Net Heat Rate (Btu/kWh)	Net Plant Efficiency	Net Heat Rate (kJ/kWh)	Condenser Pressure	Gas Turbine Power (kW)	Steam Turbine Power (kW)	No. and Type GT	Comments
GE Power & Water Heavy Duty Combined Cycle (50 Hz)											
1x1 6B.03	1987	66,000	64,800 kW	6,770 Btu	50.4%	7,141 kJ	1.2 inch Hg	42,578 kW	23,445 kW	1 x 6B.03	Non-reheat
2x1 6B.03	1979	133,100	130,900 kW	6,700 Btu	50.9%	7,069 kJ	1.2 inch Hg	85,156 kW	47,977 kW	2 x 6B.03	Non-reheat
1x1 6F.03	1991	120,400	118,400 kW	6,200 Btu	55.0%	6,540 kJ	1.2 inch Hg	78,619 kW	41,742 kW	1 x 6F.03	Non-reheat
2x1 6F.03	1991	243,100	239,400 kW	6,130 Btu	55.6%	6,470 kJ	1.2 inch Hg	157,237 kW	85,883 kW	2 x 6F.03	Non-reheat
1x1 9E.03	1979	198,100	195,000 kW	6,550 Btu	52.1%	6,911 kJ	1.2 inch Hg	128,650 kW	69,404 kW	1 x 9E.03	Non-reheat
2x1 9E.03	1979	398,400	392,500 kW	6,480 Btu	52.7%	6,837 kJ	1.2 inch Hg	257,301 kW	141,073 kW	2 x 9E.03	Non-reheat
1x1 9F.03	1994	408,000	403,000 kW	5,870 Btu	58.1%	6,194 kJ	1.2 inch Hg	262,864 kW	145,490 kW	1 x 9F.03	Reheat
2x1 9F.03	1994	822,000	811,000 kW	5,840 Btu	58.5%	6,158 kJ	1.2 inch Hg	525,728 kW	295,792 kW	2 x 9F.03	Reheat
1x1 9F.05	2002	461,000	455,000 kW	5,740 Btu	59.5%	6,055 kJ	1.2 inch Hg	297,521 kW	163,576 kW	1 x 9F.05	Reheat
2x1 9F.05	2002	926,000	914,000 kW	5,710 Btu	59.7%	6,027 kJ	1.2 inch Hg	595,038 kW	330,697 kW	2 x 9F.05	Reheat
1x1 9HA.01	2011	600,000	592,000 kW	5,560 Btu	61.4%	5,862 kJ	1.2 inch Hg	394,472 kW	205,191 kW	1 x 9HA.01	Reheat
2x1 9HA.01	2011	1,195,000	1,181,000 kW	5,570 Btu	61.2%	5,878 kJ	1.2 inch Hg	789,352 kW	405,920 kW	2 x 9HA.01	Reheat
1x1 9HA.02	2014	710,000	701,000 kW	5,560 Btu	61.4%	5,862 kJ	1.2 inch Hg	467,008 kW	242,922 kW	1 x 9HA.02	Reheat
2x1 9HA.02	2014	1,415,000	1,398,000 kW	5,570 Btu	61.2%	5,878 kJ	1.2 inch Hg	934,497 kW	480,560 kW	2 x 9HA.02	Reheat
GE Power & Water Heavy Duty Combined Cycle (60 Hz)											
1x1 6B.03	1987	66,000	64,800 kW	6,770 Btu	50.4%	7,141 kJ	1.2 inch Hg	42,578 kW	23,445 kW	1 x 6B.03	Non-reheat
2x1 6B.03	1979	133,100	130,900 kW	6,770 Btu	50.9%	7,069 kJ	1.2 inch Hg	85,156 kW	47,977 kW	2 x 6B.03	Non-reheat
1x1 6F.03	1991	120,400	118,400 kW	6,200 Btu	55.0%	6,540 kJ	1.2 inch Hg	78,619 kW	41,742 kW	1 x 6F.03	Non-reheat
2x1 6F.03	1991	243,100	239,400 kW	6,130 Btu	55.6%	6,470 kJ	1.2 inch Hg	157,237 kW	85,883 kW	2 x 6F.03	Non-reheat
1x1 7E.03	1977	137,600	135,400 kW	6,680 Btu	51.1%	7,048 kJ	1.2 inch Hg	89,148 kW	48,466 kW	1 x 7E.03	Non-reheat
2x1 7E.03	1979	276,800	272,600 kW	6,640 Btu	51.4%	7,007 kJ	1.2 inch Hg	178,296 kW	98,490 kW	2 x 7E.03	Non-reheat
1x1 7F.04	2009	286,000	283,000 kW	5,800 Btu	58.8%	6,120 kJ	1.2 inch Hg	185,903 kW	100,549 kW	1 x 7F.04	Reheat
2x1 7F.04	2009	574,000	567,000 kW	5,790 Btu	59.0%	6,107 kJ	1.2 inch Hg	371,805 kW	202,666 kW	2 x 7F.04	Reheat
1x1 7F.05	2009	347,000	343,000 kW	5,750 Btu	59.3%	6,068 kJ	1.2 inch Hg	226,234 kW	121,041 kW	1 x 7F.05	Reheat
2x1 7F.05	2009	697,000	688,000 kW	5,740 Btu	59.5%	6,054 kJ	1.2 inch Hg	452,468 kW	244,346 kW	2 x 7F.05	Reheat
1x1 7HA.01	2012	410,000	405,000 kW	5,580 Btu	61.1%	5,892 kJ	1.2 inch Hg	273,418 kW	136,782 kW	1 x 7HA.01	Reheat
2x1 7HA.01	2012	823,000	813,000 kW	5,570 Btu	61.2%	5,878 kJ	1.2 inch Hg	546,836 kW	276,028 kW	2 x 7HA.01	Reheat
1x1 7HA.02	2014	492,000	486,000 kW	5,580 Btu	61.1%	5,892 kJ	1.2 inch Hg	328,101 kW	164,138 kW	1 x 7HA.02	Reheat
2x1 7HA.02	2014	987,000	976,000 kW	5,570 Btu	61.2%	5,878 kJ	1.2 inch Hg	656,203 kW	331,233 kW	2 x 7HA.02	Reheat

Note: All GE Heavy Duty models with inlet loss, exhaust loss, and shaft driven auxiliary losses.

2013 GTW Simple Cycle Specs

Model	First Year in Service	ISO Base Rating (kW)	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed (rpm)	Exhaust Temp (F)	Approx Weight (lb)	Approx L x W x H	Comments
Alstom (50 Hz)											
GT11N2	1993	113 600 kW	10 247 Btu	33.3%	15.9	882.0 lb	3610 rpm	979 F	419 000 lb	43 x 18 x 33 ft	dual fuel burner available
GT13E2	2012	202 700 kW	8 980 Btu	38.0%	18.2	1376.0 lb	3000 rpm	934 F	772 000 lb	36 x 18 x 18 ft	dual fuel burner available
GT26	2011	326 000 kW	8 467 Btu	40.3%	35.0	1526.0 lb	3000 rpm	1117 F	895 000 lb	39 x 16 x 18 ft	dual fuel burner available
Alstom (60 Hz)											
GT11N2	1993	115 400 kW	10 066 Btu	33.9%	15.9	882.0 lb	3600 rpm	979 F	419 000 lb	31 x 18 x 33 ft	dual fuel burner available
GT24	2011	230 700 kW	8 531 Btu	40.0%	35.4	1113.0 lb	3600 rpm	1107 F	507 000 lb	35 x 13 x 15 ft	dual fuel burner available
Ansaldo Energia											
AE64.3A	1996	75 000 kW	9 505 Btu	35.9%	16.7	476.0 lb	3000/3600	1065 F	220 000 lb	36 x 13 x 16 ft	AE64.3A includes gear box
AE94.2	1981	170 000 kW	9 825 Btu	34.7%	11.5	1179.0 lb	3000 rpm	1026 F	617 000 lb	46 x 41 x 28 ft	
AE94.2K	1981	170 000 kW	9 348 Btu	36.5%	12.0	1190.0 lb	3000 rpm	1013 F	617 000 lb	46 x 41 x 28 ft	AE94.2K also burns syngas
AE94.3A	1995	310 000 kW	8 573 Btu	39.8%	19.5	1653.0 lb	3000 rpm	1069 F	794 000 lb	43 x 20 x 26 ft	all weights include auxiliaries
Aviadvigatel											
GTU-2.5P	1995	2 550 kW	16 160 Btu	21.1%	5.9	56.4 lb	5500 rpm	682 F	100 531 lb	43 x 10 x 9 ft	w/ gearbox and gen losses
GTU-4P	1997	4 130 kW	14 220 Btu	24.0%	7.3	65.7 lb	5500 rpm	777 F	150 928 lb	45 x 10 x 9 ft	w/ gearbox and gen losses
GTU-6P	2002	6 140 kW	13 032 Btu	26.2%	8.7	74.7 lb	6925 rpm	885 F	161 819 lb	45 x 10 x 9 ft	w/ gearbox and gen losses
GTU-12PG-2	2004	12 300 kW	10 469 Btu	32.6%	15.9	101.2 lb	6500 rpm	925 F	296 960 lb	59 x 10 x 14 ft	w/ gearbox and gen losses
GTE-16PA	2007	16 300 kW	9 614 Btu	35.5%	19.9	124.0 lb	3000 rpm	898 F	389 400 lb	64 x 10 x 9 ft	w/ gearbox and gen losses
GTU-25P	2008	23 000 kW	9 312 Btu	36.7%	27.3	169.1 lb	5000 rpm	883 F	467 710 lb	79 x 10 x 9 ft	w/ gearbox and gen losses
Bharat Heavy Electricals											
PG5371(PA)	1988	26 300 kW	11 990 Btu	28.5%	10.5	270.0 lb	5094 rpm	905 F	185 220 lb	38 x 11 x 12 ft	with standard combustor
PG6581(B)	2000	43 000 kW	10 303 Btu	33.1%	12.4	312.0 lb	5163 rpm	1008 F	200 655 lb	49 x 11 x 12 ft	with standard combustor
PG6111(FA)	2003	77 100 kW	9 611 Btu	35.5%	15.6	451.0 lb	5231 rpm	1109 F	231 525 lb	32 x 16 x 15 ft	with DLN combustor
PG9171(E)	1994	128 700 kW	9 952 Btu	34.3%	12.8	899.0 lb	3000 rpm	1012 F	617 400 lb	66 x 15 x 16 ft	with standard combustor
V94.2	1997	157 000 kW	9 920 Btu	34.4%	11.1	1132.0 lb	3000 rpm	1004 F	650 475 lb	46 x 41 x 28 ft	all ratings on natural gas
PG9351(FA)	1996	260 100 kW	9 099 Btu	37.5%	16.7	1430.0 lb	3000 rpm	1108 F	694 400 lb	74 x 16 x 18 ft	with DLN combustor
PG9371(FB)	2004	297 000 kW	8 782 Btu	38.9%	18.3	1420.0 lb	3000 rpm	1184 F	716 800 lb	74 x 16 x 18 ft	with DLN combustor

Model	First Year in Service	ISO Base Rating (kW)	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed (rpm)	Exhaust Temp (F)	Approx Weight (lb)	[illegible] L x [illegible]	
Capstone Turbine											
C30	1998	30 kW	13 100 Btu	26.0%	4.0	0.7 lb	96000 rpm	530 F	891 lb	30 x 60 x 70 in	all packaged [illegible]
C65	1999	65 kW	11 800 Btu	29.0%	4.0	1.1 lb	96000 rpm	588 F	1 671 lb	30 x 77 x 76 in	
C200	2008	200 kW	10 300 Btu	33.0%	4.0	2.9 lb	61000 rpm	535 F	6 120 lb	67 x 150 x 98 in	
C600	2010	600 kW	10 000 Btu	33.0%	4.0	8.8 lb	61000 rpm	535 F	27 700 lb	96 x 360 x 114 in	3xCC200
C800	2009	800 kW	10 300 Btu	33.0%	4.0	11.7 lb	61000 rpm	535 F	32 300 lb	96 x 360 x 114 in	4xCC200
C1000	2010	1 000 kW	10 300 Btu	33.0%	4.0	14.7 lb	61000 rpm	535 F	37 200 lb	96 x 360 x 114 in	5xCC200
Centrax Gas Turbine											
CX501-KB5	1992	3 897 kW	11 747 Btu	29.1%	10.3	33.9 lb	14200 rpm	1031 F	85 980 lb	30 x 9 x 10 ft	Rolls-Royce 501-KB5
CX501-KB7	1993	5 245 kW	10 848 Btu	31.5%	13.9	46.6 lb	14571 rpm	928 F	85 980 lb	30 x 9 x 10 ft	Rolls-Royce 501-KB7
CX300	2011	7 900 kW	11 158 Btu	31.0%	13.8	66.0 lb	14010 rpm	999 F	126 000 lb	40 x 8 x 12 ft	Siemens SGT-300
CX400	2011	12 900 kW	9 817 Btu	34.8%	16.9	87.0 lb	9500 rpm	1031 F	165 000 lb	61 x 9 x 13 ft	Siemens SGT-400
CXRB211	2010	32 130 kW	8 681 Btu	39.3%	21.5	206.9 lb	4850 rpm	949 F	200 000 lb	63 x 13 x 23 ft	Rolls-Royce GT61 DLE
Trent 60 DLE	2011	51 504 kw	8 104 Btu	42.1%	33.0	334.4 lb	3000 rpm	832 F	420 000 lb	67 x 15 x 17 ft	Rolls-Royce Trent 60
Trent 60 WLE ISI	2011	64 000 kw	8 273 Btu	41.2%	36.0	394.8 lb	3000 rpm	768 F	420 000 lb	67 x 15 x 17 ft	Rolls-Royce Trent 60
Dresser-Rand (50/60 Hz)											
KG2-3E	1989	1 895 kW	21 543 Btu	16.7%	4.7	33.0 lb	18800 rpm	1020 F	38 580 lb	22 x 7 x 9 ft	Dresser gas turbine
VECTRA 30G	2007	22 767 kW	9 428 Btu	36.2%	17.9	149.7 lb	6200 rpm	1017 F	88 200 lb	30 x 14 x 15 ft	LM2500 gas generator
VECTRA 40G	1998	30 460 kW	8 780 Btu	38.9%	22.4	190.2 lb	6200 rpm	979 F	88 200 lb	30 x 14 x 15 ft	LM2500+ gas generator
VECTRA 40G4	2007	33 209 kW	8 737 Btu	39.1%	23.6	198.4 lb	6200 rpm	1006 F	88 200 lb	30 x 14 x 15 ft	LM2500+G4 gas generator
Dresser-Rand (60 Hz)											
DR-61G	1981	23 394 kW	9 280 Btu	36.8%	18.2	153.1 lb	3600 rpm	992 F	88 200 lb	30 x 14 x 15 ft	LM2500 gas turbine
DR-61GP	1995	30 742 kW	8 821 Btu	38.7%	22.5	192.2 lb	3600 rpm	959 F	88 200 lb	30 x 14 x 15 ft	LM2500+ gas turbine
DR-61G4	2005	33 175 kW	8 811 Btu	38.7%	23.0	201.8 lb	3600 rpm	978 F	88 200 lb	30 x 14 x 15 ft	LM2500+G4 gas turbine
DR-63G PC	1994	43 738 kW	8 166 Btu	41.8%	27.8	279.1 lb	3600 rpm	848 F	83 800 lb	27 x 14 x 19 ft	LM6000PC gas turbine
DR-63G PG	2008	50 447 kW	8 213 Btu	41.6%	30.8	308.0 lb	3930 rpm	880 F	83 800 lb	27 x 14 x 19 ft	LM6000PG gas turbine
Note: All D-R models with standard annular combustor except KG2-3E											
GE Energy Aeroderivative (50 Hz)											
LM1800e	2011	18 100 kW	9 930 Btu	34.4%	15.6	131.0 lb	3000 rpm	916 F	210 000 lb	57 x 9 x 10 ft	
LM2000PS	2000	18 363 kW	9 874 Btu	34.6%	15.6	142.7 lb	3000 rpm	866 F	210 000 lb	57 x 9 x 10 ft	water injection
LM2000PJ	2000	17 855 kW	9 707 Btu	35.1%	15.6	136.1 lb	3000 rpm	925 F	210 000 lb	57 x 9 x 10 ft	DLE
LM2500PE	1981	23 091 kW	9 717 Btu	35.1%	19.1	157.4 lb	3000 rpm	963 F	250 000 lb	57 x 9 x 10 ft	water injection
LM2500PJ	1981	21 846 kW	9 345 Btu	36.5%	19.1	151.0 lb	3000 rpm	995 F	250 000 lb	57 x 9 x 10 ft	DLE

Model	First Year in Service	ISO Base Rating (kW)	[illegible]t Rate [illegible]/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbi[illegible] Speed ([illegible])	Exhaust Temp (F)	Approx Weight (lb)	[illegible]	
GE Energy Aeroderivative (50 Hz) (cont'd)											
LM2500PK	1995	29 316 kW	9 287 Btu	36.7%	19.1	196.6 lb	3000 rpm	911 F	250 000 lb	57 x 9 x 10 ft	water injection
LM2500PR	1981	29 962 kW	8 854 Btu	38.5%	19.4	191.3 lb	3000 rpm	982 F	250 000 lb	57 x 10 x 23 ft	DLE
LM2500+ RC	2005	36 024 kW	9 184 Btu	37.2%	23.0	213.0 lb	3000 rpm	945 F	250 000 lb	65 x 10 x 23 ft	water injection
LM2500+ RD	2005	32 881 kW	8 774 Btu	38.9%	23.0	201.0 lb	3000 rpm	977 F	250 000 lb	65 x 10 x 23 ft	DLE
LM6000PC	1997	43 339 kW	8 519 Btu	40.1%	29.8	283.2 lb	3000 rpm	803 F	673 370 lb	65 x 14 x 15 ft	water injection
LM6000PC Sprint	1998	50 836 kW	8 458 Btu	40.3%	31.9	296.9 lb	3000 rpm	835 F	673 370 lb	65 x 14 x 15 ft	water injection
LM6000PD	1997	42 732 kW	8 173 Btu	41.7%	29.8	274.8 lb	3000 rpm	844 F	673 370 lb	65 x 14 x 15 ft	DLE
LM6000PD Sprint	2000	47 505 kW	8 162 Btu	41.8%	31.7	290.0 lb	3000 rpm	835 F	673 370 lb	65 x 14 x 15 ft	DLE
LM6000PF	2006	42 732 kW	8 173 Btu	41.7%	29.8	274.8 lb	3000 rpm	844 F	673 370 lb	65 x 14 x 15 ft	DLE, 15 ppm NOx
LM6000PF Sprint	2006	48 040 kW	8 151 Btu	41.7%	31.9	290.8 lb	3000 rpm	840 F	673 370 lb	65 x 14 x 15 ft	DLE
LM6000PG	2008	53 500 kW	8 582 Btu	39.8%	30.0	317.3 lb	3000 rpm	862 F	673 370 lb	65 x 14 x 15 ft	water injection
LM6000PH	2009	51 000 kW	TBD	TBD	32.1	TBD	3000 rpm	TBD	673 370 lb	65 x 14 x 15 ft	DLE
LMS100PA	2006	103 200 kW	7 830 Btu	43.6%	41.0	482.8 lb	3000 rpm	756 F	TBD	130 x 20 x 54 ft	water injection
LMS100PB	2010	100 400 kW	7 730 Btu	44.1%	40.0	485.0 lb	3000 rpm	775 F	TBD	130 x 20 x 54 ft	DLE
GE Energy Aeroderivative (60 Hz)											
LM1800e	2011	18 100 kW	9 930 Btu	34.4%	15.6	131.0 lb	3000 rpm	916 F	210 000 lb	57 x 9 x 10 ft	
LM2000PS	2000	18 412 kW	9 874 Btu	34.6%	15.6	142.7 lb	3600 rpm	860 F	210 000 lb	57 x 9 x 10 ft	water injection
LM2000PJ	2000	17 657 kW	9 707 Btu	35.1%	15.6	136.1 lb	3600 rpm	918 F	210 000 lb	57 x 9 x 10 ft	DLE
LM2500PE	1981	24 049 kW	9 717 Btu	35.1%	19.1	157.4 lb	3600 rpm	955 F	250 000 lb	57 x 9 x 10 ft	water injection
LM2500PJ	1981	22 719 kW	9 345 Btu	36.5%	19.1	151.0 lb	3600 rpm	987 F	250 000 lb	57 x 9 x 10 ft	DLE
LM2500PK	1995	30 982 kW	9 287 Btu	36.7%	19.1	196.6 lb	3600 rpm	906 F	250 000 lb	57 x 9 x 10 ft	water injection
LM2500PR	1981	30 464 kW	8 854 Btu	38.5%	19.4	191.3 lb	3600 rpm	960 F	250 000 lb	57 x 9 x 10 ft	DLE
LM2500+ RC	2005	36 333 kW	9 184 Btu	37.2%	23.0	213.0 lb	3600 rpm	945 F	250 000 lb	65 x 10 x 10 ft	water injection
LM2500+ RD	2005	33 165 kW	8 774 Btu	38.9%	23.0	201.0 lb	3600 rpm	977 F	250 000 lb	65 x 10 x 10 ft	DLE
LM6000PC	1997	48 843 kW	8 519 Btu	40.1%	29.8	283.2 lb	3600 rpm	810 F	532 080 lb	56 x 14 x 15 ft	water injection
LM6000PC Sprint	1998	50 526 kW	8 458 Btu	40.3%	31.9	296.9 lb	3600 rpm	838 F	532 080 lb	56 x 14 x 15 ft	water injection
LM6000PD	1997	43 068 kW	8 173 Btu	41.7%	29.8	274.8 lb	3600 rpm	851 F	532 080 lb	56 x 14 x 15 ft	DLE
LM6000PD Sprint	2000	47 383 kW	8 162 Btu	41.8%	31.7	290.0 lb	3600 rpm	838 F	532 080 lb	56 x 14 x 15 ft	DLE
LM6000PF	2006	43 068 kW	8 173 Btu	41.7%	29.8	274.8 lb	3600 rpm	851 F	532 080 lb	56 x 14 x 15 ft	DLE, 15 ppm NOx
LM6000PF Sprint	2006	48 092 kW	8 151 Btu	41.9%	31.9	290.8 lb	3600 rpm	846 F	532 080 lb	56 x 14 x 15 ft	DLE
LM6000PG	2008	53 500 kW	8 582 Btu	39.8%	30.0	317.3 lb	3600 rpm	862 F	673 370 lb	65 x 14 x 15 ft	water injection
LM6000PH	2009	51 000 kW	8 020 Btu	TBD	32.1	300.0 lb	3600 rpm	896 F	TBD	TBD	DLE
LMS100PA	2006	103 500 kW	7 815 Btu	43.6%	41.0	480.0 lb	3600 rpm	760 F	TBD	109 x 78 x 54 ft	water injection
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	40.0	475.0 lb	[illegible]	[illegible]	TBD	[illegible]	[illegible]

Annex-II

OANDA

Historical Exchange Rates

Daily BID rates @ +/- 0%

DATE: Jan 1, 2015 › Jan 2, 2015
INTERBANK: +/- 0%
PRICE: Bid
VALUES: Rate
FREQUENCY: Daily

	USD / PKR
Period Average	99.6907
Period High	99.7063
Period Low	99.6750
Jan 2, 2015	99.6750
Jan 1, 2015	99.7063

› www.oanda.com/currency/historical-rates/

Annex-I

Halmore

Quarterly Indexation/Adjustment of Tariff

Halmore		
Quarterly Indexation/Adjustment of Tariff		
Tariff Components	Reference	Revised Oct-Dec 2014 Quarter
Capacity Charge (Rs./kW/Hour)		
Fixed O&M - Local	0.0713	0.0916
Fixed O&M - Foreign	0.1021	0.1327
Cost of Working Capital (Gas)	0.0561	0.0445
Cost of Working Capital (HSD)	0.1201	0.0952
ROE	0.4014	0.4799
ROEDC	0.1271	0.1520
Debt Servicing	1.6450	1.4329
Total-Gas	**2.4030**	**2.3336**
Total-HSD	**2.4670**	**2.3843**
Variable O&M (Rs./kWh)		
Variable O&M - Gas (foreign)	0.2737	0.3557
Variable O&M - HSD (foreign)	0.3951	0.5135
Total	**0.6688**	**0.8692**
Indexation Values		
Exchange Rate (Rs./USD)	85.900	102.700
US CPI (All Urban Consumers)	218.803	237.852
CPI (General) - Local	154.72	198.70
WPI(Manufacturer)-Local	193.440	
3 Monthly KIBOR	13.40%	10.18%
Outstanding Prinicipal (Rs. In Million)	14,683.00	12,158.00
Hours in the quarter		2,208.00

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Annex-I

Orient Power Company (Pvt.) Limited

Adjustment on account of Quarterly Indexations

Tariff Components	Reference Decision 12 Jan 2012	Revised Oct- Dec 2014 Quarter
Capacity Charge(Rs./kW/Hour)		
Fixed O&M – Local	0.1336	0.1716
Fixed O&M - Foreign	0.1065	0.1519
Cost of Working Capital-Gas	0.0473	0.0375
Cost of Working Capital-HSD	0.1013	0.0803
ROE	0.3964	0.5057
ROEDC	0.0795	0.1014
Debt Servicing	1.0298	0.9124
Total (Gas)	**1.7931**	**1.8805**
Total (HSD)	**1.8471**	**1.9233**
Variable O&M (Rs./kWh)		
Variable O&M – Gas (Foreign)	0.1459	0.2081
Variable O&M – HSD (Foreign)	0.2392	0.3412
Indexation Values		
CPI (General)	154.720	198.700
US CPI	212.709	237.852
Exchange Rate	80.500	102.700
KIBOR	13.39%	10.18%
Principal Outstanding (Rs. Mlns.)	9,358	6,868
Hours in the Quarter		2,208

Note:- Insurance component of capacity charge is not part of quarterly indexation. It is adjusted annualy on actual basis as per mechanism stipulated in the decision of the Authority.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
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Annex-I

Sapphire Electric Company Limited
Quarterly Indexation/Adjustment of Tariff

Tariff Components	Reference 23rd Nov. 2012	Revised Oct-Dec 2014
Capacity Charge(Rs./kW/Hour)		
Fixed O&M – Local	0.0762	0.0979
Fixed O&M - Foreign	0.0965	0.1308
Cost of Working Capital-Gas	0.0449	0.0375
Cost of Working Capital-HSD	0.0961	0.0802
Return on Equity	0.3964	0.4884
Return on Equity During Construction	0.1061	0.1307
Debt Servicing	1.3145	1.1900
Total (Gas)	**2.0346**	**2.0753**
Total (HSD)	**2.0858**	**2.1180**
Variable O&M (Rs./kWh)		
Variable O&M – Foreign -Gas	0.2583	0.3502
Variable O&M – Foreign -HSD	0.3728	0.5054
Indexation Values		
CPI (General)	154.720	198.700
US CPI	216.177	237.852
Exchange Rate	83.350	102.700
KIBOR	12.60%	10.18%
Principal Outstanding (Rs. in Million)	12,268	9,406
Hours in the Quarter		2,208

Note:- Insurance component of capacity charge is not part of quarterly indexation. It is adjusted annualy on actual basis as per mechanism stipulated in the decision of the Authority.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
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Annex-I

Saif Power Limited

Quarterly Indexation/Adjustment of Tariff

Tariff Components	Reference COD Decision 20 Jun 2011	Revised Oct-Dec 2014 Quarter
Capacity Charge(Rs./kW/Hour)		
Fixed O&M – Local	0.0792	0.1017
Fixed O&M - Foreign	0.1016	0.1358
Cost of Working Capital-Gas	0.0424	0.0361
Cost of Working Capital-HSD	0.0909	0.0773
Return on Equity	0.3824	0.4675
Return on Equity During Construction	0.1129	0.1380
Debt Servicing	1.3848	1.2759
Total (Gas)	**2.1033**	**2.1550**
Total (HSD)	**2.1518**	**2.1962**
Variable O&M (Rs./kWh)		
Variable O&M – Foreign -Gas	0.2650	0.3541
Variable O&M – Foreign -HSD	0.3825	0.5111
Indexation Values		
CPI (General)	154.720	198.700
US CPI	217.631	237.852
Exchange Rate	84.000	102.700
KIBOR	12.34%	10.18%
Principal Outstanding (Rs. Mlns.)	12,908	9,341
Hours in the Quarter		2,208

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
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Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM

With June 1, 2018 Online Date

PREPARED FOR

PJM Interconnection, L.L.C.

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May 15, 2014

This report was prepared for PJM Interconnection, L.L.C. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or Sargent & Lundy, or their clients.

The authors would like to thank PJM staff for their cooperation and responsiveness to our many questions and requests. We would also like to thank the PJM Independent Market Monitor for helpful discussions.

Table of Contents

Executive Summary

PJM Interconnection, L.L.C (PJM) retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review the Cost of New Entry (CONE) parameters and other elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff.[1] This report presents our estimates of the CONE parameters for consideration by PJM and stakeholders in advance of their upcoming capacity auctions. Our review of the other elements of RPM is presented separately, in a concurrently-released report, the "Third Triennial Review of PJM's Variable Resource Requirement Curve" ("2014 VRR Report").

CONE represents the first-year total net revenue (net of variable operating costs) a new generation resource would need in order to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. It is the starting point for estimating the *Net* Cost of New Entry (Net CONE). Net CONE is defined as the operating margins that a new resource would need to earn in the capacity market, after netting margins earned in markets for energy and ancillary services (E&AS).

Accurate estimates of CONE, E&AS, and ultimately Net CONE are critical to RPM meeting its objectives because they provide the benchmark prices that define the administratively-determined demand curve for capacity (*i.e.*, the variable resource requirements, or VRR, curves). Without accurate Net CONE estimates, the VRR curves cannot be expected to procure the target amounts of capacity needed to satisfy PJM's resource adequacy requirements. Net CONE values are also used to establish offer price screens for market mitigation purposes under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[2]

We developed CONE estimates for gas-fired simple-cycle combustion turbine (CT) and combined-cycle (CC) power plants in each of the five administrative CONE Areas, with an assumed online date of June 1, 2018. Our estimates are based on complete plant designs reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. For both the CT and CC plants, we specify two GE 7FA turbines, with the CC equipped with a single heat recovery steam generator and steam turbine ("2×1 configuration"), cooling towers, and supplemental duct-firing capacity. All plants have selective catalytic reduction (SCR) for controlling NO_x. Most have dual-fuel capability except in the Rest of RTO Area, where actual projects have generally not been designed with dual-fuel capability (however, we also provide an alternative estimate with dual fuel at PJM's request following the gas delivery challenges experienced this past winter). CCs in the Southwestern Mid-Atlantic Area Council (SWMAAC) Area are also assumed not to have dual-fuel capability, consistent with projects in development and an assumption that they pay for firm gas transportation service instead. There

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1 PJM Interconnection, L.L.C. (2014). Open Access Transmission Tariff, effective date 1/31/2014, ("PJM 2014 OATT"), accessed 5/1/2014 from http://www.pjm.com/~/media/documents/agreements/tariff.ashx, Section 5.10 a.

2 PJM 2014 OATT, Section 5.14 h.

are no other major differences in plant specifications among regions, although plant capacities and heat rates vary regionally with elevation and with ambient summer conditions.

For each plant specified, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimated annual fixed operating and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. We then translated the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to earn its required return on and of capital, assuming an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant investor, which we estimated based on various reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.8% at a 7% cost of debt and a 60/40 debt-to-equity capital structure.

Table 1 shows the resulting CONE values for CT plants in each CONE Area. We present the CONE estimates on both a "level-real" basis (a lower year-one cost recovery amount, assuming future contributions to cost recovery increase with inflation) and on a "level-nominal" basis (a higher year-one cost recovery requirement, assuming future contributions to cost recovery do *not* increase with inflation). As discussed in our 2014 VRR Report, we recommend that PJM transition from level-nominal to level-real CONE values. However, the following paragraphs discuss CONE in level-nominal terms to facilitate comparison to current parameter values.

Our CONE estimates vary by CONE Area due to differences in plant configuration and performance assumptions, labor rates, property tax laws, and other locational differences in capital and fixed O&M costs. The Eastern Mid-Atlantic Area Council (EMAAC) and SWMAAC Areas have the highest CT CONE estimates at $150,000/MW-year and $148,400/MW-year, respectively. Their higher CONE values reflect significantly higher labor costs in EMAAC and high property taxes in SWMAAC that are based on all property, not just land and buildings. The Western Mid-Atlantic Area Council (WMAAC) and Dominion Areas have the next highest CONE values of $143,500/MW-year and $141,200/MW-year, respectively. The Rest of RTO Area has the lowest CONE value of $138,000/MW-year due to the assumed absence of dual-fuel capability (consistent with observed development efforts) and lower labor costs. Under PJM's alternative assumption that future entrants there will invest in dual-fuel capability, the CT CONE value increases to $147,500.

Table 1 also compares these CT CONE estimates to two reference points: PJM's current parameters for the 2017/18 capacity auction and Brattle's prior estimates for the 2015/16 delivery year from its 2011 PJM CONE Study.[3] To produce a meaningful comparison, we show these reference points escalated to 2018 at 3% per year. As shown, our estimates are similar to the Brattle 2015/16 values, except in SWMAAC and Dominion where updated property tax calculations and labor costs contribute to increasing the CONE values by 9% and 15%, respectively. Our estimates in those

[3] Spees, Kathleen, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, (2011). *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, August 24, 2011, ("2011 PJM CONE Study"), available at http://www.pjm.com/documents/reports.aspx.

CONE Areas are closer to the PJM 2017/18 parameters (which are higher than the Brattle 2015/16 values largely because they were escalated from prior settlement values using a Handy-Whitman index that has risen significantly faster than actual plant costs, as noted in our 2014 VRR Report). In the other CONE Areas (EMAAC, Rest of RTO, and WMAAC), our estimates are lower than the 2017/18 parameters. Overall, our estimates are within -8% to +6% of PJM's current parameters, depending on the Area.

Table 1
Recommended CT CONE for 2018/19

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$400	$373	$348	$372	$364
Installed	*($m)*	$420	$391	$364	$390	$382
First Year FOM	*($m/yr)*	$6	$10	$7	$5	$8
Net Summer ICAP	***(MW)***	**396**	**393**	**385**	**383**	**391**
Unitized Costs						
Overnight	*($/kW)*	$1,012	$948	$903	$971	$931
Installed	*($/kW)*	$1,061	$994	$947	$1,018	$977
Levelized FOM	*($/MW-yr)*	$15,000	$25,600	$18,800	$13,700	$19,600
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$127,300**	**$126,000**	**$117,100**	**$121,800**	**$119,900**
Level-Nominal	***($/MW-yr)***	**$150,000**	**$148,400**	**$138,000**	**$143,500**	**$141,200**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$161,600	$150,700	$148,000	$155,200	$132,400
Brattle 2015/16 Estimate*	*($/MW-yr)*	$145,700	$134,400	$134,200	$141,400	$120,600
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	($11,600)	($2,300)	($10,000)	($11,700)	$8,800
Brattle 2015/16 Estimate	*($/MW-yr)*	$4,300	$14,000	$3,800	$2,000	$20,600
PJM 2017/18 Parameter	*(%)*	-8%	-2%	-7%	-8%	6%
Brattle 2015/16 Estimate	*(%)*	3%	9%	3%	1%	15%

Sources and Notes:
Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Table 2 shows the recommended CONE estimates for CC plants in each CONE Area, with comparisons to prior CONE values. EMAAC has the highest CONE estimates at $203,900/MW-year due to labor costs that are higher than the rest of PJM. SWMAAC and WMAAC have the next highest CC CONE estimates at $197,200/MW-year and $190,900/MW-year, respectively. The CONE

Areas with the lowest values are Rest of RTO (due to the lack of dual fuel) at $188,100/MW-year, and Dominion (as it has the lowest labor costs) at $182,400/MW-year. Under PJM's alternative assumption that future entrants will invest in dual-fuel capability in the Rest of RTO Area, the CC CONE value there increases to $193,700.

Compared to the Brattle 2015/16 values, the current CC CONE estimates are higher across all CONE Areas due to higher estimated costs of EPC contingency, owner's project development costs, and plant O&M costs. While the EPC contract costs increased in all Areas, the SWMAAC and Dominion values increased more due to higher estimated labor costs than in the previous analysis, as we found the prevailing wages in those regions include both union and non-union labor, whereas the previous analysis assumed strictly non-union labor.

Table 2
Recommended CC CONE for 2018/19

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$808	$707	$709	$737	$708
Installed	*($m)*	$885	$775	$777	$808	$776
First Year FOM	*($m/yr)*	$17	$30	$19	$15	$19
Net Summer ICAP	***(MW)***	**668**	**664**	**651**	**649**	**660**
Unitized Costs						
Overnight	*($/kW)*	$1,210	$1,065	$1,089	$1,137	$1,073
Installed	*($/kW)*	$1,326	$1,168	$1,193	$1,245	$1,176
Levelized FOM	*($/MW-yr)*	$26,000	$44,800	$29,500	$23,300	$28,300
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$173,100**	**$167,400**	**$159,700**	**$162,000**	**$154,800**
Level-Nominal	***($/MW-yr)***	**$203,900**	**$197,200**	**$188,100**	**$190,900**	**$182,400**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$199,900	$176,300	$192,900	$191,800	$170,100
Brattle 2015/16 Estimate*	*($/MW-yr)*	$183,700	$161,000	$177,100	$176,700	$157,000
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	$4,100	$20,900	($4,700)	($900)	$12,200
Brattle 2015/16 Estimate	*($/MW-yr)*	$20,300	$36,200	$11,100	$14,200	$25,400
PJM 2017/18 Parameter	*(%)*	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	*(%)*	10%	18%	6%	7%	14%

Sources and Notes:
Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

The updated CC CONE values have increased over the prior estimates more than the CT CONE values have, leading to a higher cost premium for CCs of $41,000–54,000/MW-year compared to $27,000-43,000/MW-year in our prior study. The most significant driver for the greater CC CONE increase is the relative difference in plant O&M costs estimated by S&L compared to the previous analysis. Fixed O&M costs decreased for CTs (with a larger fraction treated as variable costs) but increased for CCs. This difference explains approximately two-thirds of the increase in the CC premium over CTs. The rest of the difference is explained by higher labor rates and contingency and project development factors than in the prior study, which add more dollars to the cost of the more capital-intensive CC than the CT. In the Dominion CONE Area, the addition of the SCR to the CT largely offsets these differences.

The Brattle authors and Sargent & Lundy (S&L) collaborated in completing the CONE analysis and preparing this study. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M, and major maintenance costs and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

I. Introduction

A. Background and Objective

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which Variable Resource Requirement (VRR) curves set the "demand." The VRR curves are determined administratively based on a design objective to procure sufficient capacity for maintaining resource adequacy in all locations while also mitigating price volatility and susceptibility to market power abuse. To procure sufficient capacity, the VRR curves' price-quantity combinations are established to be consistent with the assumption that, in a long-term economic equilibrium, new entrants will set average capacity market prices at the Net Cost of New Entry (Net CONE). Net CONE is the first-year capacity revenue a new generation resource would need (in combination with expected energy and ancillary services margins) to recover its capital and fixed costs, given reasonable expectations about future cost recovery under continued equilibrium conditions. Thus, the sloped demand curve is assigned a price equal to Net CONE at approximately the point where the quantity equals the desired average reserve margin.[4] VRR curve prices are higher at lower reserve margins and lower at higher reserve margins, but all price points on the curve are indexed to Net CONE.

Just prior to each three-year forward auction, PJM determines Net CONE values for each of five CONE Areas, which are used to establish VRR curves for the system and for all Locational Deliverability Areas (LDAs). PJM calculates Net CONE for a defined "reference resource" by subtracting its estimated one-year energy and ancillary services (E&AS) net revenues from its estimated Cost of New Entry (CONE). CONE values are determined through triennial CONE studies (or litigated settlements), with escalation rates applied to the subsequent two auctions.[5] PJM separately estimates net E&AS revenue offsets annually for setting the Net CONE in each auction.

PJM has traditionally estimated CONE and Net CONE based on a gas-fired simple-cycle combustion turbine (CT) as the reference technology. However, as we explain in the concurrently-released 2014 VRR Report, we recommend defining the VRR curve based on the average Net CONE of a CT and a gas-fired combined-cycle gas turbine (CC).[6] If PJM and stakeholders accept this recommendation, they will need estimates for both a CT and a CC in setting the VRR curve. If they do not, PJM will still need both estimates for calculating offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[7]

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4 The exact quantity on the VRR curve where the price equals Net CONE is actually 1% above the IRM reliability requirement in order to reduce the likelihood of deficient outcomes. However, our concurrently-released VRR Curve report finds that even with this adjustment, the existing VRR curve is likely to fall short of reliability objectives. For more details, see 2014 VRR Report.

5 PJM 2014 OATT, Section 5.10 a.

6 2014 VRR Report.

7 PJM 2014 OATT, Section 5.14 h.

We were asked to assist PJM and stakeholders in this triennial review by developing CONE estimates for new CT and CC plants in each of the five CONE Areas. In this study, we define the CT and CC reference technologies and estimate their CONEs in the five CONE Areas.

B. Analytical Approach

Our analytical starting point for estimating CONE is a detailed characterization of the CC and CT plants in each CONE Area to reflect the technologies, plant configurations, and locations where developers are most likely to build. While the turbine technology for each plant is specified in the tariff (GE 7FA), we provide a review of the most recent gas-fired generation projects in PJM and the U.S. to determine whether this assumption is still relevant to the PJM market.[8] The key configuration variables we define for each plant include the number of gas and steam turbines, NO_x controls, duct firing and power augmentation, cooling systems, dual-fuel capability, and gas compression. We selected specific plant characteristics based on: our analysis of the predominant practices among recently-developed plants; our analysis of technologies, regulations, and infrastructure; and our experience with previous projects. Key site characteristics include proximity to high voltage transmission infrastructure and interstate gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant locations and technical specifications for each CONE Area is presented in Section II.

We developed comprehensive, bottom-up estimates of the costs of building and maintaining the specified plants in Section III. S&L estimated *plant proper* capital costs—equipment, materials, labor, and EPC contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the *owner's* capital costs, including gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component.

We estimated annual fixed operations and maintenance (fixed O&M) costs, including labor, materials, property tax, insurance, asset management costs, and working capital. The results of this analysis are presented in Section IV.

Next, we translated these costs into the capital and fixed cost recovery the plant would have to earn in its first year, which we call the "Cost of New Entry" ("CONE"). CONE depends on the estimated capital and fixed O&M costs as well as the estimated cost of capital consistent with the project's risk and the assumed economic life of the asset. CONE also depends on developers' long-term market view and how it impacts the cost recovery path for the plant, specifically whether they can expect to earn as much in later years as in earlier years. We present our financial assumptions for calculating CONE in Section V.

Finally, in Section VI, we offer CONE calculations based on two different assumed cost recovery paths: one in which future revenues are assumed to remain constant in real-terms, which we recommend, as explained in our 2014 VRR Report; and one in which future revenues are assumed to

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[8] PJM, *PJM Manual 18: PJM Capacity Market*, Revision: 22, p. 21.

remain constant in nominal terms, which PJM has historically assumed. The level-real assumption results in lower CONE values.

The Brattle authors and Sargent & Lundy collaborated on completing this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Determination of Reference Technologies

Similar to the 2011 PJM CONE Study, we determined the characteristics of the reference technology primarily based on a "revealed preferences" approach that relies on our review of the choices that actual developers found to be most feasible and economic. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional review of the underlying economics, regulations, and infrastructure, and S&L's experience. For selecting the reference technology location within each CONE Area, we modified our analysis from the 2011 PJM CONE Study to take into account a broader view of potential sites that can be considered feasible and favorable for new plant development. As the basis for determining most of the selected reference technology specifications, we updated our analysis from the 2011 study by examining CT and CC plants built in PJM and the U.S. since 2008, including plants currently under construction. We characterized these plants by size, plant configuration, turbine type, NO_x controls, CO catalyst, duct firing, dual-fuel capability, and cooling system.

A. Locational Screen

The Open Access Transmission Tariff (OATT) requires a separate CONE parameter in each of five CONE Areas as summarized in Table 3.[9]

Table 3
PJM CONE Areas

CONE Area	Transmission Zones	States
1 Eastern MAAC	AECO, DPL, JCPL, PECO, PSEG, RECO	NJ, MD, DE
2 Southwest MAAC	BGE, PEPCO	MD, DC
3 Rest of RTO	AEP, APS, ATSI, ComEd, DAY, DEOK, DQL	WV, VA, OH, IN, IL, KY, TN, MI
4 Western MAAC	MedEd, Penelec, PPL	PA
5 Dominion	Dominion	VA, NC

9 PJM 2014 OATT, Section 5.10 a.

We conducted a locational screening analysis to identify feasible and favorable locations for each of the five CONE Areas. Our approach for identifying the representative locations within each CONE Area included three steps:

1. We identified candidate locations based on revealed preference of actual plants built since 2002 or recently proposed plants to identify the areas of primary development, putting more weight on recent projects.

2. We sharpened the definition of likely areas for future development, depending on the extent of information available from the first step. For CONE Areas where recent projects provide a clear signal of favored locations, we only excluded counties that would appear to be less attractive going forward, based on environmental constraints or economic costs (absent special offsetting factors we would not know about). For CONE Areas where revealed preference data is weak or scattered, we identified promising locations from a developer perspective based on proximity to gas and electric interconnections and key economic factors such as labor rates and energy prices

3. This approach results in identifying a specified area that spans a wider range of counties than the previous CONE study. For this reason, we developed cost estimates for each CONE Area by taking the average of cost inputs (*e.g.*, labor rates) across the specified locations.

We describe next the results of the screening analysis that we used for determining the reference plant locations in each CONE Area. The locations chosen for each CONE Area are shown in Figure 1. To provide a more detailed description of the specified locations, we show the cities used for estimating labor rates in Table 4.

Our review of recent development in CONE Area 1 **Eastern MAAC (EMAAC)** resulted in identifying two areas where significant development has occurred since 2002. The first area is in northern New Jersey along the I-95 corridor, where four plants have been built since 2002, including the 2012 Kearny peaking facility, and three additional CC plants are in the planning phase. The second area includes Philadelphia and the southernmost New Jersey counties, where two CC plants have been built and three additional facilities are in the planning phase. With significant development in both areas and no reason for excluding either due to environmental or economic reasons, we include both as our reference locations.

In CONE Area 2 **Southwest MAAC (SWMAAC)**, four new projects are in various stages of development (three CCs and one CT) in the area around Waldorf, Maryland including portions of Charles and Prince George's counties. Despite the strong indication of developers' preferences to build in this area, limits on the existing gas infrastructure are expected to create gas supply challenges that will be addressed in the cost estimation section of this study. There is limited development in the rest of the region.

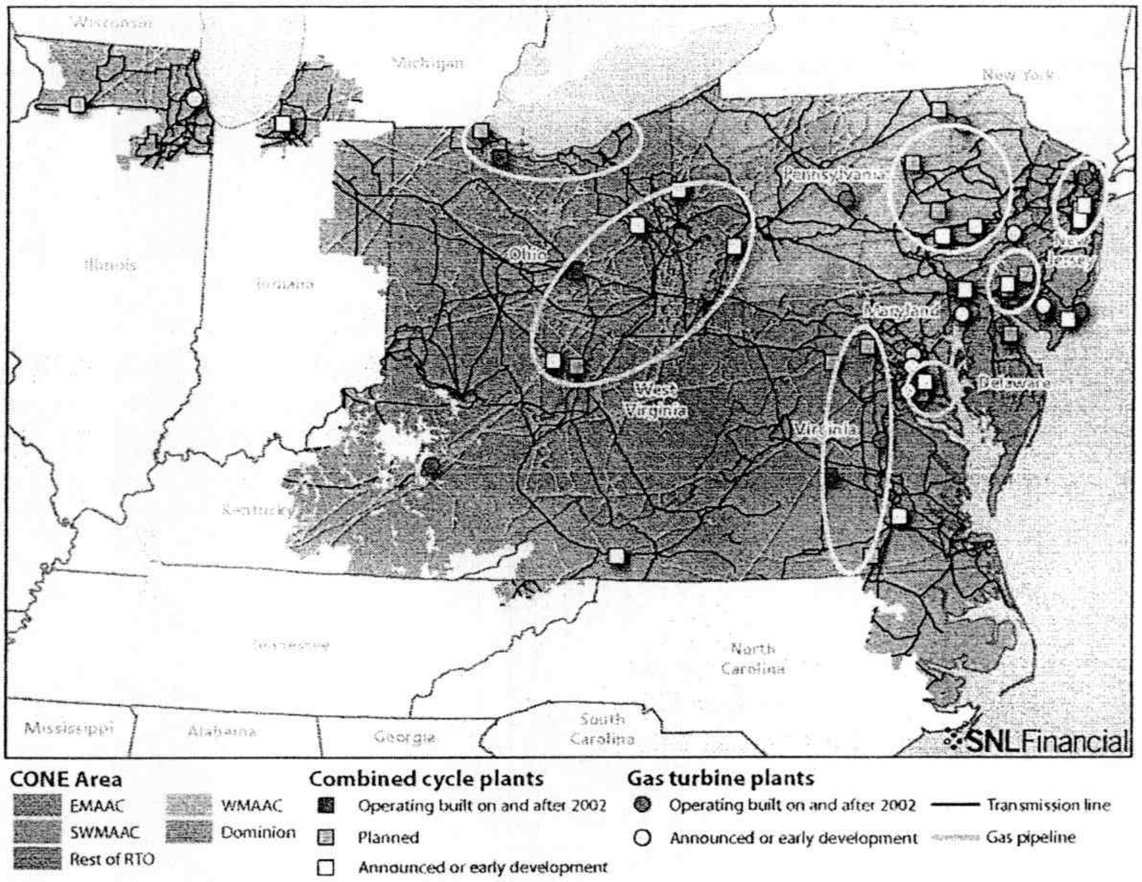
For the larger CONE Area 3 **Rest of RTO** CONE Area, the revealed preferences approach indicated three favored areas based on our review of recently built or in-development plants: northern Illinois, northwest Ohio, and the Pennsylvania, Ohio, and West Virginia portions of the Ohio River valley.

Further analysis resulted in excluding northern Illinois due to relatively low energy revenues and high labor costs, which disfavor this area relative to the others identified. For these reasons, we chose the counties in northwest Ohio and the Ohio River valley region for estimating costs in the Rest of RTO Area.

In CONE Area 4 **Western MAAC (WMAAC)**, developers have demonstrated a willingness to build primarily in mid-eastern Pennsylvania, including areas around Allentown, Scranton, and Lancaster. Projects include the Mehoopany peaking facilities added in 2013 and five CC facilities in different planning stages within this region. We found no reasons to narrow or expand the specified area further.

In CONE Area 5 **Dominion**, we identified two promising areas, one with several operating plants (in north-central Virginia) and the other with two proposed plants (south-central Virginia), both of which appear to meet developers' gas and electric infrastructure needs. We expanded the region considered to include both areas as well as the counties in between, which amounts to the counties along and just west of I-95 in Virginia.

Figure 1
Results of Locational Screening for each CONE Area



Source:
Map provided by SNL Financial
Data on operating and planned projects downloaded from SNL Financial between November 2013 and March 2014.

Table 4
CONE Area Labor Pools

CONE Area				
1 EMAAC	**2 SWMAAC**	**3 Rest of RTO**	**4 WMAAC**	**5 Dominion**
Jersey City, NJ	Washington, DC	Pittsburgh, PA	Reading, PA	Petersburg, VA
Newark, NJ	Annapolis, MD	New Castle, PA	Williamsport, PA	Richmond, VA
Camden, NJ	Alexandria, VA	Steubenville, OH	Wilkes-Barre, PA	Alexandria, VA
New Brunswick, NJ		Cleveland, OH		
Newark, DE		Lorain, OH		
Wilmington, DE		Toledo, OH		
Philadelphia, PA		Wheeling, WV		
		Parkersburg, WV		
		Huntington, WV		

We calculate the plant operating characteristics (*e.g.*, net capacity and heat rate) of the reference technologies using turbine vendors' performance estimation software for the combustion turbines output and GateCycle software for the remainder of the CC plant. For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[10] The assumed ambient conditions for each location are shown in Table 5.

Table 5
Assumed PJM CONE Area Ambient Conditions

CONE Area	Elevation *(ft)*	Max. Summer Temp *(deg F)*	Relative Humidity *(%RH)*
1 Eastern MAAC	110	94.0	44.2
2 Southwest MAAC	150	95.2	45.2
3 Rest of RTO	1,070	89.5	50.2
4 Western MAAC	1,200	91.0	46.0
5 Dominion	390	93.7	47.2

Source:
Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

B. Plant Size, Configuration and Turbine Model

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7FA as the turbine model), we provide a review of the most recent gas-fired generation projects in PJM and the U.S. to confirm this assumption.[11] We reviewed CT and CC projects built or currently proposed in PJM and across the U.S. to determine the configuration, size, and turbine types for the reference technologies.

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10 The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition, Dordrecht, Holland: D. Reidel Publishing Company, 1981.

11 PJM 2014 OATT, Attachment DD, Section 2, see definition for Reference Resource.

For the CT, we found that frame-type CTs (GE 7FA and Siemens-501) have been the predominant turbine types built in PJM and throughout the U.S. since 2002, as shown in Table 6. We also found a recent trend toward aeroderivative turbines (GE LMS100 and LM6000). The total capacity of new aeroderivative turbines built in PJM since 2008 is approximately the same as frame-type turbines over the same time period.

Table 6
Turbine Model of CT Turbines Built and Under Construction in PJM and the U.S.

Turbine Model	Turbine Class	Online After 2002				Online After 2008			
		PJM		U.S.		PJM		U.S.	
		(count)	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*
General Electric-7FA	Frame	31	4,807	105	16,132	3	481	16	2,518
General Electric-LM6000	Aeroderivative	11	1,615	27	4,088	7	317	80	3,669
General Electric-LMS100	Aeroderivative	15	1,165	135	10,057	3	273	28	2,606
Rolls Royce Corp-Trent 60	Aeroderivative	2	148	13	853	2	120	4	225
Siemens-501	Frame	22	949	198	8,784	0	0	0	0
Siemens-V84	Frame	3	273	29	2,688	0	0	0	0
General Electric-7EA	Small Frame	2	120	4	225	0	0	10	742
General Electric-MS6001	Small Frame	9	1,179	16	1,903	0	0	0	0

Source:
Data downloaded from Ventyx's *Energy Velocity Suite* between November 2013 and March 2014

We find that the frame-type GE 7FA turbine to be a reasonable choice for the PJM CT reference technology as it is the turbine model that has been built the most in PJM since 2008 and has a lower turbine cost per-kilowatt than the aeroderivative models. While we believe the turbine model should change if the market reveals such a preference, we do not find a basis to make a change in turbine model for PJM in the current study from the tariff specification. The reference CT plant configuration is assumed to have two turbines at one site (a "2×0") to capture savings from the economies of scale, which is also consistent with the tariff. We specify the CT reference technology capacity and heat rate in the CONE Areas based on the local conditions assumptions in Table 5, with the CT capacities ranging from 395 to 411 MW.

For the CC reference technology, the predominant size of recently developed CC plants is 500 to 700 MW (including duct firing capacity, if any), primarily in a 2×1 configuration, as shown in Table 7.

Table 7
PJM CC Under Construction or Built
(a) Since 2002

	< 300 (MW)	300-500 (MW)	500-700 (MW)	700-900 (MW)	> 900 (MW)	Total (MW)
1 x 1	1,902	1,839				**3,741**
2 x 1	42	466	11,186	700		**12,394**
3 x 1	198		2,240	3,060	2,255	**7,754**
Total	**2,141**	**2,305**	**13,426**	**3,760**	**2,255**	**23,888**

(b) Since 2010

	< 300 (MW)	300-500 (MW)	500-700 (MW)	700-900 (MW)	> 900 (MW)	Total (MW)
1 x 1	762	1,839				**2,601**
2 x 1			2,446	700		**3,146**
3 x 1			545		1,329	**1,874**
Total	**762**	**1,839**	**2,991**	**700**	**1,329**	**7,621**

Sources and Notes:
Data downloaded from Ventyx's Energy Velocity Suite between November 2013 and March 2014

The turbine model most often installed on recent CC plants is the GE 7FA, as shown in Table 8. The Siemens and GE turbines are similar designs that have both been competing for market share. While we find there are reasons to use either turbine manufacturer, we selected the GE 7FA for the PJM CONE due to its previous use in estimating CONE in PJM. Based on the local ambient condition assumptions in Table 5, we specify the 2×1 CC reference technology's summer capacity to range from 576–595 MW (prior to considering supplemental duct firing, as discussed in the next section).

Table 8
Turbine Model of CC Plants Built and Under Construction Combined Cycle Plants in PJM Online Since 2002

Turbine Model	Installed Capacity (MW)
General Electric 7FA	12,977
Siemens V84.2	2,240
Siemens SGT6-8000H	1,530
Siemens AG-501F	1,433
Mitsubishi M501GAC	1,329
Siemens SCC6-5000F	975
General Electric 7FB	758
Simens 501FD	559
General Electric Other	198
Other	1,889

Sources and Notes:
Data downloaded from Ventyx's Energy Velocity Suite between November 2013 and March 2014

We considered whether a flexible CC design, such as the GE Flex60, should be specified as the configuration of the CC reference technology. Our review of the performance of the conventional packages versus the flexibility package found that the benefits of the improved flexible design are largely offset by its incremental costs, such that the Net CONE calculation for the conventional and flexible designs would likely be similar. In addition, there is limited data available for accurately calculating either the capital costs or the E&AS revenues of the flexible design due to its recent introduction into the market. For these reasons, we assumed a conventional plant design for the CC. If the flexible design continues to be considered and built by developers in the next several years, PJM could consider using such a design in future CONE updates.

C. Detailed Technical Specifications

1. Combined Cycle Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower, based on the predominance of cooling towers among new CCs and S&L recommendation. Our review of EIA-860 data found that all CC plants with a specified cooling system had a cooling tower installed, as shown in Table 9.

Table 9
Cooling System for CC Plants in PJM Under Construction or Built Since 2008

State	Once-Through *(MW)*	Cooling Tower *(MW)*	Dry Cooling *(MW)*	Unknown *(MW)*
Pennsylvania	0	545	0	126
Virginia	0	589	0	1,329
New Jersey	0	1,350	0	0
Delaware	0	309	0	62
Ohio	0	1,207	0	0
Illinois	0	0	0	573
Indiana	0	0	0	0
Total	0	**4,001**	0	**2,091**

Sources and Notes:

Based on 2012 Form EIA-860 Data; cooling tower includes recirculating with forced, induced and natural cooling towers.

We reviewed whether reclaimed water from municipal waste treatment centers would be available for use in the cooling systems to avoid environmental issues with withdrawing fresh water. Our review of the availability of reclaimed water indicated that EMAAC and SWMAAC have at least one treatment center per county, such that reclaimed water can be considered generally available. In WMAAC and Dominion, we found that reclaimed water can be available on a site-specific basis. Although not every county has such a facility, we assume reclaimed water is prevalent enough for the reference technology to use reclaimed water in each of these CONE Areas. For the Rest of RTO Area, municipal waste treatment facilities are much less common such that withdrawals from ground or surface water would be necessary. In addition to environmental drivers for using reclaimed water, building the piping and treatment facilities required for ground or surface water costs $500k to $1 million more than for reclaimed water, depending on the location.

2. Combined-Cycle Duct Firing

For the reference CC plant, supplemental firing of the steam generator, also known as "duct firing," increases steam production and hence increases the output of the steam turbine. Duct firing is common, although there is no standard optimized design. The decision to incorporate supplemental firing with the plant configuration and the amount of firing depends on the owner's preference and perceived economic value.

We assumed the reference CC plant would add duct firing sufficient to increase the net plant capacity by 73 MW, or 12%. This is close to the average of CC plants constructed since 2002 or in development in the U.S. but less than in PJM, as shown in Table 10. Due to the relatively small number of plants built in PJM since 2002, we chose to weigh the U.S. value more heavily.

Table 10
Duct-Firing Capability of CC Plants Constructed Since 2002 and In Development

	Installed Capacity *(MW)*	No. of Plants *(count)*	Avg. Plant Size *(MW)*	Avg. Duct Fired Capacity *(MW)*	Duct Fired Addition % *(%)*
PJM	2,020	3	673	93	16%
U.S.	35,865	56	640	77	14%

Sources and Notes:
Data on duct firing capacities for CC plants downloaded from Ventyx's Energy Velocity Suite in 2014

Including duct firing increases the net capacity of the plant but reduces efficiency due to the higher incremental heat rate of the supplemental firing (when operating in duct firing mode) and the reduced efficiency of steam turbine (when not operating at full output). The estimated heat rates and capacities take account for this effect.

3. Power Augmentation

Based on our analysis in the 2011 PJM CONE Study, we included evaporative coolers downstream of the filtration system to lower the combustion turbine inlet air temperature during warm weather operation. This increases turbine output and efficiency for only a small increase in capital cost. In addition, the combustion turbines in both simple- and combined-cycle arrangements are equipped with an inlet filtration system to protect from airborne dirt and particles. Evaporative coolers and associated equipment add $3 million per combustion turbine to the capital costs.

4. Emissions Controls

Emission control technology requirements for new major stationary sources are determined through the New Source Review (NSR) pre-construction permitting program. The NSR permitting program evaluates the quantity of regulated air pollutants the proposed facility has the potential-to-emit and determines the appropriate emission control technology/practice required for each air pollutant. The regulated air pollutants that will have the most impact on emission control technology requirements for new CTs and CCs are nitrogen oxides (NO_x) and carbon monoxide (CO).

NO_x and CO emissions from proposed gas-fired facilities located in PJM will be evaluated through two different types of NSR permitting requirements:

- Non-attainment NSR (NNSR) for NO_x emissions; and
- Prevention of Significant Deterioration (PSD) for CO emissions.

NO_x emissions are evaluated through the NNSR permitting requirements, because NO_x (a precursor to ozone) is treated as a non-attainment air pollutant for all areas within the Ozone Transport Region

(OTR) regardless of ozone attainment status.[12] Except for Rest of RTO, all of the CONE Areas in PJM are within OTR, and thus, emissions of NO_x from proposed facilities are treated as a non-attainment air pollutant and evaluated through non-attainment new source review (NNSR). The Rest of RTO is currently non-attainment for 8-hour ozone.

New CTs and CCs with no federally enforceable restrictions on operating hours are deemed a major source of NO_x emissions, and therefore, trigger a Lowest Achievable Emission Rates (LAER) analysis to evaluate NO_x emission control technologies. The NO_x emission control technology required by the LAER analysis is likely to be a selective catalytic reduction (SCR) system. SCR systems are widely recognized as viable technology on aeroderivative and smaller E-class frame combustion turbines and have more recently been demonstrated on F-class frame turbines. Our assumptions of an SCR on the F-class turbine is supported by the Commission's recent determination in approving the NYISO's assumption of F-class turbine with SCR as the proxy unit for its proposed Demand Curves that "the record of evidence presented in support of the frame unit with SCR is adequate in order to find that NYISO reasonably concluded that the F class frame with SCR is a viable technology."[13] In addition, we assume inlet air filters and dry low NO_x burners, which are also necessary to achieve the required emissions reductions.

CO emissions are evaluated through the PSD permitting requirements, because PJM is designated as an attainment area for CO. New combustion turbine facilities with no operating hour restrictions have the potential-to-emit CO in a quantity that exceeds the significant emission threshold for CO, and therefore, trigger a Best Available Control Technology (BACT) analysis to evaluate CO emission control technologies. The CO emission control technology required as a result of a BACT analysis is likely to be an oxidation catalyst (CO Catalyst) system.

For these reasons, we assume an SCR and a CO Catalyst system as the likely requirements resulting from the NSR permitting program for new gas-fired facilities proposed in all CONE Areas. The most significant change from the 2011 PJM CONE Study is assuming an SCR on the CT in Dominion, which is being added due to additional consideration of the regulatory requirements of being located in the Ozone Transport Region. The CO Catalyst system in all areas is expected to increase costs of emissions control equipment by $2.4 million (in 2014 dollars) over the 2011 CONE study.

5. Dual Fuel Capability, Firm Gas Contracts, and Gas Compression

We largely maintained our assumption from the 2011 PJM CONE Study that the reference CT and CC plants would install dual-fuel capability in all CONE Areas except for the Rest of RTO Area, based on a review of recent projects. The Rest of RTO Area is assumed to be single-fuel, although at PJM's request we also calculated CONE estimates for Rest of RTO with dual-fuel capability in Section VI).

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12 The Ozone Transport Region (OTR) includes all of New England as well as Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and portions of Virginia.

13 Federal Energy Regulatory Commission (2014). Order 146 FERC ¶ 61,043, Issued January 28, 2014, at paragraph 58. Docket No. ER14-500-000.

Our assumptions have changed only for CCs in SWMAAC, where we do not assume dual fuel, consistent with the CPV St. Charles project under development there.[14] Instead, we assume firm transportation service on the Dominion Cove Point (DCP) pipeline. We understand from shippers that the DCP pipeline is capacity-constrained and also has limited operational flexibility. Firm transportation avoids interruptions, although it may not provide additional operational flexibility. Firm transportation also largely eliminates the value of dual-fuel capability (except when the three major interstate pipelines to which the DCP pipeline is connected become constrained). However, we do not assume firm transportation for the reference CT plant since firm gas is unlikely to be economic for a plant that operates at a low capacity factor. We assume the CT will have dual-fuel capability.

To be capable of firing gaseous and liquid fuels, the plants are assumed to be equipped with enough liquid fuel storage and infrastructure on-site for three days of continuous operation. Dual-fuel capability also requires the combustion turbines to have water injection nozzles to reduce NOx emissions while firing liquid fuel. These modifications as well as the costs associated with fuel oil testing, commissioning, inventory, and the capital carrying charges on the additional capital costs contribute to the overall costs for dual-fuel capability. The incremental cost is approximately $22 million for the CC and $24 million for the CT (in 2014 dollars), including equipment, labor, and materials, indirect costs, and fuel inventory.[15] That contributes approximately $9,500/MW-year to the CONE for the CT and $5,600/MW-year for the CC (in 2018 dollars and in level-nominal terms). For CCs in SWMAAC, firm transportation avoids these costs, but the firm transportation itself costs about twice as much, as discussed in Section IV.A.5.

Based on our analysis in the 2011 PJM CONE Study, we determined gas compression would not be needed for new gas plants with frame-type combustion turbines located near and/or along the major gas pipelines selected in our study. The frame machines generally operate at lower gas pressures than the gas pipelines.

6. Black Start Capability

Based on our analysis in the 2011 PJM CONE Study, we did not include black start capability in either the CC or CT reference units because few recently built gas units have this capability.

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14 Environmental Consulting & Technology, Inc. (2011), Demonstration of Compliance with Air Quality Control Requirements and Request for Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Approvals: CPV St. Charles Project, 725-MW Combined Cycle Project, Prepared for Competitive Power Ventures Maryland, LLC (CPV), ECT No. 110122-0200, August 2011.

15 The incremental cost of dual-fuel capability is higher for the CT due to the cost of the demineralized water package that is already assumed to be installed for the CC for its steam cycle.

7. Electrical Interconnection

While all CONE Areas have a variety of transmission voltages, both lower and higher than 345 kV, we selected 345 kV as the typical voltage for new CT and CC plants to interconnect to the transmission grid in PJM. The switchyard is assumed to be within the plant boundary and is counted as an EPC cost under "Other Equipment," including generator circuit breakers, main power and auxiliary generator step-up transformers, and switchgear. All other electric interconnection equipment, including generator lead and network upgrades, is included separately under Owner's Costs, as presented in Section III.B.4.

D. SUMMARY OF REFERENCE TECHNOLOGY SPECIFICATIONS

Based on the assumptions discussed above, the technical specifications for the CT and CC reference technology are shown in Table 11 and Table 12. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 5.

Table 11
Summary of CT Reference Technology Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7FA.05
Configuration	2 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	396 / 393 / 385 / 383 / 391 *
Net Heat Rate (HHV in Btu/kWh)	10,309 / 10,322 / 10,297 / 10,296 / 10,317 *
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Dual / Dual / Single / Dual / Dual *
Firm Gas Contract	No
Special Structural Req.	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes:
See Table 5 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* Power ratings and heat rates are for EMAAC, SWMAAC, Rest of RTO, WMAAC, and Dominion CONE Areas, respectively

Table 12
Summary of CC Reference Technology Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7FA.05
Configuration	2 x 1
Cooling System	Cooling Tower *
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
w/o Duct Firing	595 / 591 / 578 / 576 / 587 **
with Duct Firing	668 / 664 / 651 / 649 / 660 **
Net Heat Rate (HHV in Btu/kWh)	
w/o Duct Firing	6,800 / 6,811 / 6,791 / 6,792 / 6,808 **
with Duct Firing	7,028 / 7,041 / 7,026 / 7,027 / 7,039 **
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Dual / Single / Single / Dual / Dual **
Firm Transportation Service	No / Yes / No / No / No **
Special Structural Req.	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes:
See Table 5 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* CONE Area 3 uses ground/surface water; all others use reclaimed water for cooling
** For EMAAC, SWMAAC, Rest of RTO, WMAAC, and Dominion CONE Areas, respectively

III. Capital Cost Estimates

Capital costs are those costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs, include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2014 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct simple and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost in 2018 dollars by escalating the 2014 cost data using reasonable escalation rates. The 2018 "installed cost" is the present value of the construction period cash flows as of the end of the construction period and is calculated using the monthly drawdown schedule and the cost of capital for the project.

A. Plant Proper Capital Costs

1. Plant Developer and Contractor Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

2. Equipment and Sales Tax

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines, where applicable. The major equipment includes "owner-furnished equipment" (OFE) that the owner purchases through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. A sales tax rate specific to each CONE Area is applied to the sum of major equipment and other equipment to account for the sales tax on all equipment.

3. Labor and Materials

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, and field engineering, start-up, and commissioning services. "Materials" include all construction material associated with the EPC scope of work, material freight costs, and consumables during construction.

The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, the labor rates have been developed by S&L through a survey of the prevalent wages in each region in 2014, including both union and non-union labor. This approach differs from the 2011 PJM CONE Study, in which a single assumption of the labor type was specified for each CONE Area. The change in determining wages and productivity rates results in higher labor costs in SWMAAC and Dominion, which were assumed to use strictly non-union labor in the 2011 study. The updated approach provides a better representation of the labor force that will include labor from both pools. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type.

4. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. Capital cost estimates include an EPC contractor fee of 10% and 12% of EPC costs for CT and CC facilities, respectively.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of EPC costs.

The EPC contractor fee and contingency rates are based on S&L's proprietary project cost database. The EPC contingency rate (10%) is higher than the value used in the 2011 PJM CONE study (4% contingency charged by the EPC, plus an additional 3% of EPC costs for change orders that was included as part of the Owner's Contingency) due to input received from stakeholders following the issuance of that study. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.6% of the pre-contingency overnight capital costs, compared to 6.4% in the 2011 study.

B. Owner's Capital Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

1. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, legal fees, and emissions reductions credits that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

2. Net Start-Up Fuel Costs During Testing

Before commencing full commercial operations, new generation plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas and ultra-lower sulfur diesel (ULSD) if dual fuel capability is specified. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas and fuel oil consumption, and will receive revenues for its energy production. We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume Transco Zone 6 Non-New York (Z6 NNY) prices apply for all CONE Areas; forecast Z6 NNY natural gas prices using traded futures on NYMEX (CME Group) until March 2015 and grow the basis differentials at the rate of inflation into 2018.
- **Fuel Oil:** rely on No. 2 fuel oil futures for New York harbor through January 2018; escalate fuel oil prices between January 2018 and an assumed fuel delivery date of March and April 2018 based on the escalation in Brent crude oil futures over the same date range.[16]
- **Electric Energy:** estimate prices based on PJM Eastern Hub for EMAAC, and PJM Western Hub for all other CONE Areas; calculate monthly 2015 market heat rates based on electricity and gas futures in each location and assume market heat rates remain constant to 2018; average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

16 Data from Bloomberg, representing trade dates 12/22/2013 to 2/20/2014.

Table 13
Startup Production and Fuel Consumption During Testing

	Energy Production			Fuel Consumption						
	Energy Produced *(MWh)*	Energy Price *($/MWh)*	Energy Sales *($m)*	Natural Gas *(MMBtu)*	Natural Gas Price *($/MMBtu)*	NG Cost *($m)*	Fuel Oil *(MMBtu)*	Fuel Oil Price *($/MMBtu)*	Fuel Oil Cost *($m)*	Total Cost *($m)*
Gas CT										
1 Eastern MAAC	206,924	$42.3	$8.8	1,996,322	$5.49	$11.0	99,816	$17.9	$1.8	$4.0
2 Southwest MAAC	206,625	$38.7	$8.0	1,993,443	$5.49	$10.9	99,672	$17.9	$1.8	$4.7
3 Rest of RTO	190,360	$38.7	$7.4	1,928,726	$5.49	$10.6	n.a	$17.9	$0.0	$3.2
4 Western MAAC	198,935	$38.7	$7.7	1,919,816	$5.49	$10.5	95,991	$17.9	$1.7	$4.6
5 Dominion	204,852	$38.7	$7.9	1,976,332	$5.49	$10.9	98,817	$17.9	$1.8	$4.7
Gas CC										
1 Eastern MAAC	691,621	$42.3	$29.3	3,958,589	$5.49	$21.7	197,929	$18.0	$3.6	-$4.0
2 Southwest MAAC	657,777	$38.7	$25.4	3,952,938	$5.49	$21.7	n.a.	$18.0	$0.0	-$3.7
3 Rest of RTO	639,138	$38.7	$24.7	3,824,235	$5.49	$21.0	n.a.	$18.0	$0.0	-$3.7
4 Western MAAC	668,436	$38.7	$25.8	3,806,568	$5.49	$20.9	190,328	$18.0	$3.4	-$1.5
5 Dominion	685,484	$38.7	$26.5	3,918,677	$5.49	$21.5	195,934	$18.0	$3.5	-$1.5

Sources and Notes:
Energy production and fuel consumption estimated by S&L
Energy and fuel prices are forecasted based on futures downloaded from Ventyx's Energy Velocity Suite in 2014

3. Gas Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 14. We identified appropriate lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs.[17]

We assume the gas interconnection will require a metering station and a five mile lateral connection, similar to 2011 PJM CONE Study. From this data, we estimate that gas interconnection costs will be $20.5 million (in 2014 dollars) for all plants, as we found no relationship between pipeline width and per-mile costs in the project cost data.

[17] The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

Table 14
Gas Interconnection Costs

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(2014$)*	Pipeline Cost *($m/mile)*	Meter Station *(Y/N)*	Meter Station Cost *(2014m$)*
Delta Lateral Project	PA	2010	16	3.4	$9,944,085	$2.91	Y	$3.5
Carty Lateral Project	OR	2014	20	24.3	$52,032,000	$2.14	Y	$2.3
South Seattle Delivery Lateral Expansion	WA	2013	16	4.0	$13,788,201	$3.4	N	n.a.
Bayonne Delivery Lateral Project	NJ	2012	20	6.2	$13,891,136	$2.2	Y	$3.9
North Seattle Delivery Lateral Expansion	WA	2012	20	2.2	$11,792,028	$5.4	Y	$1.4
FGT Mobile Bay Lateral Expansion	AL	2011	24	8.8	$28,179,328	$3.2	Y	$2.6
Northeastern Tennessee Project	VA	2011	24	28.1	$133,734,240	$4.8	Y	$2.9
Hot Spring Lateral Project	TX,AR	2011	16	8.4	$34,261,849	$4.1	Y	$3.8
Average						$3.5		$2.9

Sources and Notes:

A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp)

4. Electric Interconnection

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs do not always occur, but are incurred when improvements, such as replacing substation transformers, are required.

In addition to the interconnection projects included in the 2011 PJM CONE study, we added projects recently constructed or under construction that are representative of interconnection costs for a new gas combined-cycle or combustion turbine. Table 15 summarizes the project costs used for estimating electric interconnection costs for this study. Based on the capacity-weighted average, electric interconnection cost is at approximately $12 million for CTs and $20 million for CCs, both expressed in 2014 dollars.

Table 15
Electric Interconnection Costs in PJM

Plant Size	Observations	Electrical Interconnection Cost	
		Average	Average
	(count)	*(2014\$m)*	*(2014\$/kW)*
100-300 MW	5	\$3.8	\$26.7
300-500 MW	3	\$11.3	\$31.4
500-800 MW	13	\$19.5	\$30.9
Capacity Weighted Average	**21**	**\$17.4**	**\$30.0**

Sources and Notes:
Confidential project-specific cost data provided by PJM.

5. Land

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 20 acres for sale in each selected county. There is a wide range of prices within the same CONE Area as shown in Table 16, which means that land costs can vary significantly among plants.

Table 16
Current Land Asking Prices

CONE Area	Current Asking Prices	
	Range	Observations
	(2013 \$000/acre)	*(count)*
1 EMAAC	\$10-\$119	8
2 SWMAAC	\$19-\$150	10
3 RTO	\$10-\$100	22
4 WMAAC	\$5-\$100	14
5 Dominion	\$13-\$163	9

Sources and Notes:
We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

Table 17 shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 30 acres of land are needed for CT and 40 acres for CC.

Table 17
Cost of Land Purchased

CONE Area	Land Price (\$/acre)	Plot Size		Cost	
		Gas CT (acres)	Gas CC (acres)	Gas CT (\$m)	Gas CC (\$m)
1 EMAAC	\$66,300	30	40	\$1.99	\$2.65
2 SWMAAC	\$73,900	30	40	\$2.22	\$2.96
3 RTO	\$38,100	30	40	\$1.14	\$1.52
4 WMAAC	\$41,600	30	40	\$1.25	\$1.66
5 Dominion	\$54,300	30	40	\$1.63	\$2.17

Sources and Notes:
We assume land is bought in 2014, *i.e.*, 6 months to 1 year before the start of construction.

6. Fuel and Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel working capital is 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

We calculated the cost of the fuel inventory in areas with dual-fuel capability assuming a three day supply of ULSD fuel will be purchased prior to operation at a cost of \$2.52/gallon, or \$18/MMBtu (in 2018 dollars), based on current futures prices.[18]

7. Owner's Contingency

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* We assumed an owner's contingency of 9% of Owner's Costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

8. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are also part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs.[19]

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18 EIA, Electric Power Monthly, 2013.

19 As discussed in the Financial Assumptions section, we assume the plant is financed through a 60% debt and 40% equity capital structure.

C. Escalation to 2018 Installed Costs

1. Escalation

We escalated the 2014 estimates of overnight capital cost components forward to the construction period for a June 2018 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for equipment and materials and labor. The real escalation rate for each cost category was then added to the assumed inflation rate of 2.25% (see Section V.A) to determine the nominal escalation rates, as shown in Table 18.

Table 18
Capital Cost Escalation Rates

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.40%	2.65%
Labor	1.50%	3.75%

Sources and Notes:
Escalation rates on equipment and materials costs are derived from the relevant BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from 2014 overnight costs using the monthly capital drawdown schedule developed by Sargent & Lundy for an online date in June 2018.

However, we escalated several cost items in a different manner:

- **Land**: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2018 online date, the land is thus assumed to be purchased in late 2014 such that current estimates do not require any additional escalation.
- **Net Start-Up Fuel and Fuel Inventories**: no escalation was needed since we forecasted fuel and electricity prices in 2018 dollars.
- **Electric and Gas Interconnection**: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior completion, consistent with the 2011 CONE Study; the interconnection costs have been escalated specifically to these months.

2. Cost of Capital During Construction

S&L has developed monthly capital drawdown schedules over the project development period for each technology. The drawdown schedule is important for calculating debt and equity costs during construction to arrive at a complete "installed cost."

The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2018 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate.[20] By using the ATWACC to calculate the present value, the installed costs will include both the interest during construction from the debt financed portion of the project and the cost of equity for the equity financed portion.

20 For CTs, the construction drawdown schedule occurs over 20 months with 80% of the costs incurred in the final 11 months prior to commercial operation. For CCs, the construction drawdown schedule occurs over 36 months with 80% of the costs incurred in the final 20 months prior to commercial operation.

D. CAPITAL COST SUMMARY

Based on the technical specifications for the reference CT and CC in Section II and the capital cost estimates in this section, a summary of the capital costs for an online date of June 1, 2018 is shown below in Table 19 and Table 20.

Table 19
Summary of Capital Costs for CT Reference Technology in Nominal $

	CONE Area				
	1	2	3	4	5
	EMAAC	SWMAAC	Rest of RTO	WMAAC	Dominion
Capital Costs (in $millions)	*396 MW*	*393 MW*	*385 MW*	*383 MW*	*391 MW*
Owner Furnished Equipment					
Gas Turbines	$98.8	$98.4	$94.0	$98.7	$98.6
SCR	$18.9	$18.7	$17.9	$18.8	$18.8
Sales Tax	$8.2	$7.0	$6.7	$7.1	$7.3
Total Owner Furnished Equipment	**$125.9**	**$124.1**	**$118.6**	**$124.6**	**$124.8**
EPC Costs					
Equipment	$30.9	$30.5	$25.5	$30.8	$30.7
Construction Labor	$71.7	$55.4	$55.3	$54.5	$48.2
Other Labor	$21.2	$19.6	$18.6	$19.6	$19.0
Materials	$9.7	$9.0	$8.6	$9.6	$9.4
Sales Tax	$2.8	$2.4	$2.0	$2.4	$2.5
EPC Contractor Fee	$26.2	$24.1	$22.9	$24.1	$23.5
EPC Contingency	$28.8	$26.5	$25.2	$26.6	$25.8
Total EPC Costs	**$191.4**	**$167.4**	**$158.1**	**$167.6**	**$159.2**
Non-EPC Costs					
Project Development	$15.9	$14.6	$13.8	$14.6	$14.2
Mobilization and Start-Up	$3.2	$2.9	$2.8	$2.9	$2.8
Net Start-Up Fuel Costs	$4.0	$4.7	$3.2	$4.6	$4.7
Electrical Interconnection	$13.0	$12.9	$12.7	$12.6	$12.9
Gas Interconnection	$22.6	$22.6	$22.6	$22.6	$22.6
Land	$2.0	$2.2	$1.1	$1.2	$1.6
Fuel Inventories	$5.3	$5.3	$0.0	$5.1	$5.2
Non-Fuel Inventories	$1.6	$1.5	$1.4	$1.5	$1.4
Owner's Contingency	$6.1	$6.0	$5.2	$5.9	$5.9
Financing Fees	$9.4	$8.7	$8.1	$8.7	$8.5
Total Non-EPC Costs	**$82.9**	**$81.4**	**$70.9**	**$79.6**	**$79.8**
Total Capital Costs	$400.2	**$372.9**	**$347.6**	**$371.8**	**$363.8**
Overnight Capital Costs ($million)	$400	$373	**$348**	$372	$364
Overnight Capital Costs ($/kW)	$1,012	$948	**$903**	$971	$931
Installed Cost ($/kW)	$1,061	$994	**$947**	$1,018	$977

Table 20
Summary of Capital Costs for CC Reference Technology in Nominal $

Capital Costs (in $millions)	1 EMAAC *595 MW*	2 SWMAAC *591 MW*	3 Rest of RTO *578 MW*	4 WMAAC *576 MW*	5 Dominion *587 MW*
	CONE Area				
Owner Furnished Equipment					
Gas Turbines	$97.3	$92.6	$92.6	$97.2	$97.2
HRSG / SCR	$43.5	$43.5	$43.5	$43.5	$43.5
Sales Tax	$9.9	$8.2	$8.2	$8.4	$8.8
Total Owner Furnished Equipment	**$150.7**	**$144.3**	**$144.3**	**$149.1**	**$149.5**
EPC Costs					
Equipment					
Condenser	$4.2	$4.2	$4.2	$4.2	$4.2
Steam Turbines	$35.5	$35.5	$35.5	$35.5	$35.5
Other Equipment	$60.6	$55.9	$56.4	$60.4	$60.3
Construction Labor	$213.8	$162.1	$164.5	$168.2	$146.9
Other Labor	$45.1	$39.6	$39.9	$41.0	$39.1
Materials	$37.8	$37.8	$37.8	$37.8	$37.8
Sales Tax	$9.7	$8.0	$8.0	$8.3	$8.6
EPC Contractor Fee	$66.9	$58.5	$58.9	$60.6	$57.8
EPC Contingency	$62.4	$54.6	$54.9	$56.5	$54.0
Total EPC Costs	**$536.1**	**$456.2**	**$460.1**	**$472.5**	**$444.3**
Non-EPC Costs					
Project Development	$34.3	$30.0	$30.2	$31.1	$29.7
Mobilization and Start-Up	$6.9	$6.0	$6.0	$6.2	$5.9
Net Start-Up Fuel Costs	-$4.0	-$3.7	-$3.7	-$1.5	-$1.5
Electrical Interconnection	$22.0	$21.8	$21.4	$21.3	$21.7
Gas Interconnection	$22.6	$22.6	$22.6	$22.6	$22.6
Land	$2.7	$3.0	$1.5	$1.7	$2.2
Fuel Inventories	$6.1	$0.0	$0.0	$5.9	$6.0
Non-Fuel Inventories	$3.4	$3.0	$3.0	$3.1	$3.0
Owner's Contingency	$8.5	$7.4	$7.3	$8.1	$8.1
Financing Fees	$18.9	$16.6	$16.6	$17.3	$16.6
Total Non-EPC Costs	**$121.3**	**$106.7**	**$105.0**	**$115.8**	**$114.2**
Total Capital Costs	**$808.0**	**$707.2**	**$709.4**	**$737.4**	**$708.0**
Overnight Capital Costs ($million)	**$808**	**$707**	**$709**	**$737**	**$708**
Overnight Capital Costs ($/kW)	**$1,210**	**$1,065**	**$1,089**	**$1,137**	**$1,073**
Installed Cost ($/kW)	**$1,326**	**$1,168**	**$1,193**	**$1,245**	**$1,176**

IV. Operation and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed operations and maintenance (O&M) costs each year, including property tax, insurance, labor, consumables, minor maintenance, and asset management. Annual fixed O&M costs add to CONE. Separately, we also calculated *variable* operations and maintenance costs (including maintenance, consumables, and waste disposal costs) to inform PJM's future E&AS calculations.

A. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

1. Plant Operation and Maintenance

We estimated the labor, consumables, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including the Electric Power Research Institute (EPRI) State-of-the-Art Power Plant Combustion Turbine Workstation v 9.0 data for existing plants reported on FERC Form 1, confidential data from other operating plants, and vendor publications for equipment maintenance.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. We include monthly LTSA payments as fixed O&M since they are not based on the operation of the plant, and all other costs under the LTSA are considered variable O&M.

2. Insurance and Asset Management Costs

We calculated insurance costs as 0.60% of the overnight capital cost per year, based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of CT and CC plants in operation.

3. Property Tax

To estimate property tax, we researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states. We estimated the property taxes through bottom-up cost estimates that separately evaluated taxes on real property (including land and structural improvements) and personal property (the remainder of the plant) in each location. In this study, we did not incorporate any assumed Payment in Lieu of Taxes (PILOT) agreements. Although PILOT agreements could be executed between an individual plant developer and a county, these agreements are individually negotiated and may not be available on a similar basis for all plants.

Real property is taxed in all states containing reference plant locations we selected for the CONE Area. Personal property is taxed only in SWMAAC (Maryland), Rest of RTO (the portion in Ohio), and Dominion (Virginia). For power plants, the value of personal property tends to be much higher than the value of real property, since equipment costs make up the majority of the total capital cost.

For this reason, property taxes for plants located in states that impose taxes on personal property will be significantly higher than plants located in states that do not.

To estimate real property taxes, we assumed the assessed value of land and structural improvements is the initial capital cost of these specific components. We determined assessment ratios and tax rates for each CONE Area by reviewing the publicly posted tax rates for several counties within the specified locations and by contacting county and state tax assessors (The tax rates assumed for each CONE Area is summarized in Table 21). We multiply the assessment ratio by the tax rate to determine the overall effective tax rate, and apply that rate to our estimate of assessed value. We assume that assessed value of real property will escalate in future years with inflation.

Personal property taxes in the states of Maryland, Ohio, and Virginia were estimated using a similar approach. As with real property, we multiply the local tax rate by the assessment ratio to determine the effective tax rate on assessed value. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years. For example, in Maryland, personal property is subject to straight-line depreciation of 3.3% per year down to a minimum of 25% of the original assessed value.[21]

21 Maryland Depreciation Regulation Chapter 18, Subtitle 03, Chapter 01, Depreciation .02B(2). Phone conversation with Laura Kittel (410-767-1897) at State Department of Assessments & Taxation in June 2012.

Table 21
Property Tax Rate Estimates for Each CONE Area

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
CONE Area		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
State		*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	
1 EMAAC								
New Jersey	[1]	4.6%	75.2%	3.3%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.8%	50.0%	1.4%	straight-line at 3.3%/yr to 25% min.
3 RTO								
Ohio	[3]	5.6%	35.0%	1.9%	5.6%	24.0%	1.3%	follow annual report "SchC-NewProd (NG)"
Pennsylvania	[4]	3.7%	100.0%	3.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[4]	3.7%	100.0%	3.7%	n/a	n/a	n/a	n/a
5 Dominion								
Virginia	[5]	1.0%	95.5%	0.9%	1.0%	95.5%	0.9%	ceiling at 90%; floor at 25%

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Middlesex and Camden Counties. For Middlesex County see: http://www.co.middlesex.nj.us/taxboard/rate_ratio.pdf, for Camden County see: [illegible] and [illegible]

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJSA § 54:4-1

[2a], [2c] Maryland tax rates estimated as the sum of county and state rates in Charles County and Prince George's County in 2013-2014. Data obtained from Maryland Department of Assessment & Taxation website: http://www.dat.state.md.us/sdatweb/taxrate.html

[2d] Md. Tax-Property Code Ann. 7-237

[2e] Maryland Depreciation Regulation Chapter 18, Subtitle 03, Chapter 01, Depreciation .02B(2). Phone conversation with State Department of Assessments & Taxation in June 2012.

[3a], [3c] Received "Rates of Taxation" from Morgan County auditor's office on Feb 27, 2014, which the auditor confirmed is applicable to both real and personal property; reviewed rates for Perry, Fairfield, and Athens counties, which range from 5–8%.

[3b], [3d] Assessment ratios for real property and electric companies' production personal property found on p. 91 and 95 of Ohio Department of Taxation 2012 Annual Report, http://www.tax.ohio.gov/portals/0/communications/publications/annual_reports/2012_annual_report/2012_AR_internet.pdf

[3e] Depreciation schedules for utility assets found in Form U-EL by Ohio Department of Taxation: http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2014/PU_EL_2014.xls

[4a] Berks county tax rates available at: http://www.co.berks.pa.us/Dept/Assessment/Documents/2014%20co%20twp%20%202013%20sch%20tax%20rate.pdf

[4b] Real properties assessed at 100% according to conversations with Chief Tax Assessor of Berks County.

[4c] - [4e]: According to *Pennsylvania Legislator's Municipal Deskbook*, only real estate tax assessed by local governments in Pennsylvania

[5a] Current real property rate in Fauquier County available at: http://www.fauquiercounty.gov/government/departments/commrev/index.cfm?action=rates. Reviewed property tax rates for Fairfax and Dinwiddie counties, which range from 0.8 – 1.1%.

[5b], [5d] Assessment ratio provided by Virginia State Corporation Commission Principal Utility Appraiser in March 2014.

[5c] Code of Virginia (§ 58.1-2606., Line C) states generating equipment shall not exceed the real estate rate applicable in the respective localities; we assume personal property tax rate equal to the real property tax rate in [5a].

[5e] Received depreciation for electric companies from Virginia State Corporation Commission by Principal Utility Appraiser via email; confirmed that depreciation ceiling of 90% and floor of 25% apply to personal property.

4. Working Capital

We estimated the cost of maintaining working capital requirements for the reference CT and CC by first estimating the working capital requirements (calculated as accounts receivable minus accounts payable) as a percent of gross profit for 3 merchant generation companies: NRG, Calpine, and Dynegy. The weighted average working capital requirement among these companies is 5.59% of gross profits.[22] Translated to the plant level, we estimate that the working capital requirement is approximately 0.7% of overnight costs in the first operating year (increasing with inflation thereafter). In the capital cost estimates, we do not include the working capital requirements but instead the cost of maintaining the working capital requirement based on the borrowing rate for short-term debt for BB rated companies 0.96%.[23]

5. Firm Transportation Service Contract in Southwest MAAC

The gas pipeline serving the part of SWMAAC we identified for the reference plants is the Dominion Cove Point (DCP) pipeline. We understand from shippers that they have had trouble obtaining gas on the DCP pipeline. Availability of interruptible service has been unreliable and inflexible with the pipeline being fully subscribed and also unable to absorb substantial swings in usage within a day. To at least partially address this problem, we assume new CC plants will sign up for firm transportation service on DCP. We assume that the new CT will not acquire firm service due to the relatively few hours such a plant is expected to operate.

To estimate the costs of acquiring firm transportation service on the DCP pipeline for a plant coming online in 2018, we assume the same transportation reservation rate on DCP as that filed for the proposed Dominion Cove LNG export project. That rate is $5.5260 per dekatherm per month for 2017,[24] which we escalate to 2018 dollars, resulting in a rate of $5.6503 per dekatherm.[25] We assume that the CC will reserve sufficient gas service to support baseload operation (without supplemental duct firing) as summarized in Table 22. This results in a $6.5 million annual cost, adding $11,100/MW-year to the CONE for CCs in SWMAAC.

Flexible, no-notice, non-ratable firm service would cost even more, but we do not have a basis for estimating such costs. Instead, we assume energy margin calculations would have to account for limited flexibility of gas service from the DCP (see Section III.B of the 2014 VRR Report).

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22 Gross profits are revenues minus cost of goods sold, including variable and fixed operation and maintenance costs.

23 15-day average 3-month bond yield as of February 14, 2014, BFV USD Composite (BB), from Bloomberg.

24 Application for Authority to Construct, Modify, and Operate Facilities Used for the Export of Natural Gas under Section 3 of the Natural Gas Act and Abbreviated Application for a Certificate of Public Convenience and Necessity under Section 7 of the Natural Gas Act, Volume 1 of III, Public, before the Federal Energy Regulatory Commission, in the matter of Dominion Cove Point LNG, LP, Cove Point Liquefaction Project, filed April 1, 2013. Docket No. CP13-___-000. Available at http://newsinteractive.post-gazette.com/20130401-5045(28233263).pdf.

25 This does not include variable charges, which should not be included in CONE but should be accounted for in estimating energy margins to calculate Net CONE.

Table 22

Estimated Cost of Procuring Firm Gas Service on DCP Pipeline

Component	Units	Gas CC
Plant Characteristics		
Summer ICAP (w/o duct-firing)	*(MW)*	591
Summer Heatrate at Baseload (HHV)	*(Btu/kWh)*	6,811
Gas Consumption at Baseload		
Maximum Hourly	*(MMBtu/hr)*	4,023
Maximum Daily	*(MMBtu/hr)*	96,563
Firm Gas Reservations		
Cost of Firm Gas Capacity per Month	*(2018$/Dth)*	$5.6503
Total Firm Gas Capacity Reservation	*(Dth)*	96,600
Total Cost of Firm Gas Reservations	***(2018$)***	**$6,550,000**
	(2018$/MW-year)	$11,100

Sources and Notes:
See footnote 24.
1 dekatherm (Dth) is equivalent to 1 MMBtu.

B. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they inform the E&AS revenue offset calculations performed annually by PJM. We provide an explanation of the costs here to clearly differentiate which O&M costs are considered fixed and which are variable.

- **Major Maintenance:** Over the long-term operating life of CT and CC plants, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the average variable O&M cost (in dollars per megawatt-hour, or $/MWh) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the plant capacity in megawatts. For starts-based major maintenance, the average variable O&M cost ($/factored start, per turbine) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls.
- **Other Variable O&M**: Other variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. These items are always expressed in $/MWh, regardless of whether the maintenance component is hours-based or starts-based.

C. Escalation to 2018

We escalated the components of the O&M cost estimates from 2014 to 2018 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 18) have been also used to escalate the O&M costs. The assumed real escalation rate for labor is 1.5% per year, while those for other O&M costs are 0.4%.

D. Summary of O&M Costs

Based on the technical specifications for the reference CT and CC in Section II and the O&M estimates in this section, a summary of the fixed and variable O&M for an online date of June 1, 2018 is shown below in Table 23 and Table 24.

Table 23
Summary of O&M Costs for CT Reference Technology

O&M Costs	CONE Area				
	1 EMAAC *396 MW*	2 SWMAAC *393 MW*	3 Rest of RTO *385 MW*	4 WMAAC *383 MW*	5 Dominion *391 MW*
Fixed O&M (2018$ million)					
LTSA	$0.3	$0.3	$0.3	$0.3	$0.2
Labor	$1.5	$1.1	$1.2	$1.1	$1.0
Consumables	$0.2	$0.2	$0.2	$0.2	$0.2
Maintenance and Minor Repairs	$0.4	$0.4	$0.4	$0.4	$0.4
Administrative and General	$0.2	$0.2	$0.2	$0.2	$0.2
Asset Management	$0.4	$0.4	$0.4	$0.4	$0.4
Property Taxes	$0.4	$5.3	$2.5	$0.4	$3.1
Insurance	$2.4	$2.2	$2.1	$2.2	$2.2
Firm Gas Contract	$0.0	$0.0	$0.0	$0.0	$0.0
Working Capital	$0.0	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2018$ million)	**$5.9**	**$10.1**	**$7.2**	**$5.2**	**$7.7**
Levelized Fixed O&M (2018$/MW-yr)	**$15,000**	**$25,600**	**$18,800**	**$13,700**	**$19,600**
Variable O&M (2018$/MWh)					
Major Maintenance - Hours Based	2.40	2.39	2.39	2.39	2.36
Consumables, Waste Disposal, Other VOM	1.89	1.89	1.89	1.89	1.89
Total Variable O&M (2018$/MWh)	**4.29**	**4.27**	**4.27**	**4.27**	**4.25**

Table 24
Summary of O&M Costs for CC Reference Technology

O&M Costs	CONE Area 1 EMAAC 595 MW	2 SWMAAC 591 MW	3 Rest of RTO 578 MW	4 WMAAC 576 MW	5 Dominion 587 MW
Fixed O&M (2018$ million)					
LTSA	$0.3	$0.3	$0.3	$0.3	$0.2
Labor	$4.6	$3.3	$3.6	$3.5	$3.0
Consumables	$0.3	$0.3	$0.3	$0.3	$0.3
Maintenance and Minor Repairs	$4.7	$4.1	$4.3	$4.2	$4.0
Administrative and General	$0.4	$0.3	$0.3	$0.3	$0.3
Asset Management	$0.7	$0.6	$0.7	$0.6	$0.6
Property Taxes	$1.4	$9.9	$5.5	$1.5	$6.0
Insurance	$4.8	$4.2	$4.3	$4.4	$4.2
Firm Gas Contract	$0.0	$6.6	$0.0	$0.0	$0.0
Working Capital	$0.1	$0.0	$0.0	$0.1	$0.0
Total Fixed O&M (2018$ million)	**$17.4**	**$29.7**	**$19.2**	**$15.1**	**$18.7**
Levelized Fixed O&M (2018$/MW-yr)	**$26,000**	**$44,800**	**$29,500**	**$23,300**	**$28,300**
Variable O&M (2018$/MWh)					
Major Maintenance - Hours Based	1.49	1.45	1.47	1.47	1.45
Consumables, Waste Disposal, Other VOM	1.14	1.14	1.14	1.14	1.14
Total Variable O&M (2018$/MWh)	**2.63**	**2.60**	**2.61**	**2.61**	**2.60**

V. Financial Assumptions

A. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[26] The appropriate ATWACC reflects the systemic financial market risks of the project's future cash flows as a merchant generating plant participating in the PJM markets. As a merchant project, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts and other hedges in place. This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

[26] The "after-tax weighted-average cost of capital" (ATWACC) is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

To estimate the cost of capital for such a project, we reviewed a broad range of reference points. As there is significant uncertainty in any single cost of capital estimate, we reviewed all of the available reference points and selected a level that is reasonable considering the wide range of values. The reference points that we are using include updated estimates for publicly-traded merchant generation companies (NRG, Calpine, and Dynegy), additional sources from previous analysis by Brattle, fairness opinions for merchant generation divestitures, and analyst estimates.[27] Supplementing our analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours. We derived each of the reference points as follows, with results summarized in Table 25.

- **Publicly Traded Companies**: we derived ATWACC estimates using the following standard techniques.
  - *Return on Equity:* We estimate the return on equity (ROE) using the Capital Asset Pricing Model (CAPM). The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta."[28] We calculated a risk-free rate of 3.4% using a 15-day average of 30-year U.S. treasuries as of February 2014.[29] We estimated the expected risk premium of the market to be 6.5% based on the long-term average of values provided by Credit Suisse and Ibbotson.[30] The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index. The resulting return on equity ranges from 7.1–11.9% for the companies included in the analysis, as shown in Table 25.[31]
  - *Cost of Debt:* We estimate the cost of debt (COD) by compiling the unsecured senior credit ratings for each merchant generation company and examining the bond yields associated with those credit ratings. In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments, with "AAA" being the highest rating and "D" being the lowest. Calpine and Dynegy's credit

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27 We do not include private equity investors in our sample because their cost of equity cannot be observed in market data. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses face lower risks and lower cost of capital than merchant generation.

28 Brealy, Richard, Stuart C. Myers, and Franklin Allen (2011). *Principles of Corporate Finance.* New York: McGraw-Hill/Irwin.

29 Bloomberg, Bloomberg Professional Service (2014). Data downloaded February 21, 2014. (Bloomberg, 2014). Risk free rate calculated based on 30 year U.S. bond yields.

30 The Ibbotson market risk premium is 6.7% and the Credit Suisse market risk premium is 6.2%. Ibbotson (2013), *SBBI 2013 Valuation Yearbook,* Chicago: Morningstar, 2013. Dimson, Elroy, Paul Marsh, and Mike Stauton (2013). *Credit Suisse Global Investment Returns Sourcebook 2013,* Zurich: Credit Suisse Research Institute, February 2013.

31 Dynegy financial characteristics are currently significantly different from Calpine and NRG as it is in the final stages of emerging from bankruptcy. However, we believe that it still can provide a useful reference point for estimating the cost of capital for a merchant generator.

ratings are "B," with an associated cost of debt of 8.7%, while NRG's is "BB" with a 7.5% cost of debt.[32]

- *Debt/Equity Ratio*: We estimate the five-year average debt/equity ratio for each merchant generation company using company 10-Ks for the debt value and Bloomberg for the market value of equity.

- **April 2011 Brattle Estimates** were calculated using a similar approach and have been adjusted downward by 0.9 percentage points for the current analysis based on the difference in the risk-free rate between April 2011 (4.3%) and February 2014 (3.4%).

- **The other reference points** come from publicly available values used by financial advisors and analysts in valuations associated with mergers and divestitures. For example, the financial advisors for the acquisition of GenOn by NRG used discount rates of 7.0–8.5% for NRG and 8.5–9.5% for GenOn in their discounted cash flow analyses associated with the merger. While there are no details provided on how these ranges were developed, we find these values provide useful reference points for estimating the cost of capital. The values in Table 25 have been adjusted upward by 0.7 percentage points due to the change in risk-free rates since the original estimates were developed by the financial analysts in 2012.

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[32] Data downloaded from Bloomberg in 2014.

Table 25

Summary of Cost of Capital Reference Points and Recommended ATWACC

Company	Brattle Updated ATWACC Estimates						Prior Estimates Adjusted to Feb 2014 Risk-Free Rate			
	S&P Credit Rating [1]	Equity Beta [2]	Return on Equity [3]	Cost of Debt [4]	Debt/ Equity Ratio [5]	After Tax WACC [6]	July 2012 Financial Advisor Estimates for NRG-GenOn Merger [7]	Apr 2011 Brattle Estimates [8]	2011 Analyst Estimates [9]	2011 Fairness Opinions [10]
Publicly Traded Companies										
Calpine	B	1.29	11.9%	8.7%	61/39	7.8%		6.7%	6.6%	
NRG	BB	1.04	10.4%	7.5%	73/27	6.1%	7.7 - 9.2%	6.3%	6.2%	
Dynegy	B	0.49	7.1%	8.7%	42/58	6.1%		7.4%	7.1 - 11.1%	
Acquired Companies (previously traded)										
GenOn Energy							9.2 - 10.2%	10.3%	7.6 - 9.6%	
Mirant								8.0%	7.6 - 8.6%	
Merchant Generation Divestitures										
FirstEnergy Merchant Generation										7.1 - 8.1%
Allgheny Merchant Generation										7.1 - 7.6%
Duke's Merchant Generation										7.3 - 8.3%
Recommendation			**13.8%**	**7.0%**	**60/40**			**8.0%**		

Sources and notes:
[1]: Bloomberg, 2014.
[2]: Brattle analysis.
[3] = Assumed risk-free rate (3.40%) + assumed market risk premium (6.50%) × [2].
[4]: Bloomberg, 2014.
[5]: Market structure calculated by Brattle using company 10-Ks for debt value and Bloomberg for market value of equity.
[6] = (% Debt) × [4] × (1 – [6]) + (% Equity) × [3]
[7] – [10]: 2011 and 2012 estimates have been adjusted based on changes in the risk-free rate. The risk-free rates were 4.3% in April 2011, 2.7% in July 2012, and 3.4% February 2014. (Bloomberg, 2014)
[7]: NRG Energy Inc. and GenOn Energy, *Joint Proxy Statement/Prospectus for Special Meeting of Stockholders to be Held on Friday, November 9, 2012*, October 5, 2012, pp. 63, 70, and 75.
[8] – [10]: 2011 PJM CONE Study contains original analysis for [8] and citations to original sources for [9] and [10].

Based on this set of reference points and our assumption of merchant entry risk that exceeds the average risk of the publicly-traded generation companies, we believe an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE. That value is above the cost of capital of Calpine and NRG, both of which have some long-term contracts and hedges in place, and it is near the mid-point of the range of the additional reference points.

Although the specific assumptions on capital structure, ROE, and COD corresponding to our ATWACC have almost no impact on the CONE calculation, we do need to assume specific values in order to quantify interest during construction and depreciable capital costs. We assumed a capital structure of 60/40 debt-equity ratio to reflect typical projects' capital structures and their associated ROE and COD. For a representative COD of 7.0% and a 60/40 debt-to-equity capital structure, the ATWACC of 8.0% translates to an ROE of 13.8%, as shown in Table 25. Note that the ATWACC applied to the five CONE Areas varies very slightly with applicable state income tax rates, as discussed in the following section.

B. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, and interest during construction.

Inflation rates affect our CONE estimates by forming the basis for projected increases in various FOM cost components over time. We also use the inflation rate as the cost escalation rate in our level-real CONE estimate. We estimated future twenty-year inflation rates based on bond market data, Federal Reserve estimates, and consensus U.S. economic projections. The implied inflation rate over twenty years from treasury yields is 2.2%, and the Cleveland Federal Reserve estimate of inflation expectations is 1.9% over twenty years.[33] The most forward looking forecast in the Blue Chip Economic Indicators report is 2.3%.[34] Based on these sources, we assumed for the Net CONE calculations an average long-term inflation rate of 2.25%.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal and state tax rates. The marginal federal corporate income tax rate for 2013 is 35%.[35] The state tax rates assumed for each CONE Area are shown in Table 26. Virginia's lower rate slightly reduces Dominion's CONE, although ATWACC there increases from 8.0% to 8.1% because the debt tax shield is less valuable.

[33] As stated on the Cleveland Federal Reserve website, "The Cleveland Fed's estimate of inflation expectations is based on a model that combines information from a number of sources to address the shortcomings of other, commonly used measures, such as the "break-even" rate derived from Treasury inflation protected securities (TIPS) or survey-based estimates. The Cleveland Fed model can produce estimates for many time horizons, and it isolates not only inflation expectations, but several other interesting variables, such as the real interest rate and the inflation risk premium." Federal Reserve Bank of Cleveland (2013), *Cleveland Fed Estimates of Inflation Expectations*, accessed July 16, 2013. Available at http://www.clevelandfed.org/research/data/inflation_expectations/.

[34] Blue Chip Economic Indicators (2013), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, March 2013. We used the consensus ten-year average consumer price index (CPI) for all urban consumers.

[35] Internal Revenue Service (2013), *2012 Instructions for Form 1120, U.S. Corporation Income Tax Return*, January 25, 2013. Available at http://www.irs.gov/pub/irs-pdf/i1120.pdf.

Table 26
State Corporate Income Tax Rates

CONE Area	Representative State	Corporate Income Tax Rate
1 Eastern MAAC	New Jersey	9.00%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Pennsylvania	9.99%
4 Western MAAC	Pennsylvania	9.99%
5 Dominion	Virginia	6.00%

Sources and notes:
State tax rates retrieved from www.taxfoundation.org

We calculated depreciation based on the current federal tax code, which allows generating companies to use the Modified Accelerated Cost Recovery System (MACRS) of 20 years for a CC plant and 15 years for a CT plant.[36]

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 60% debt and 7.0% COD.

VI. Summary of CONE Estimates

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how net revenues are received over time to recover capital and annual fixed costs. "Level-nominal" cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real dollars, inflation adjusted terms) over the 20-year economic life of the plant. A "level-real" cost recovery path starts lower then increases at the rate of inflation (*i.e.*, constant in real dollar terms).[37] As discussed in the 2014 VRR Report, we recommend that PJM adopt the level-real value as it is more consistent with our expected trajectory of operating margins from future capacity and net E&AS revenues. All descriptions below refer to level-nominal values to facilitate consistent comparison with parameters PJM is currently using.

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[36] Internal Revenue Service (2013), *Publication 946. How to Depreciate Property*, February 15, 2013. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

[37] Both cost recovery paths (level-real and level-nominal) are calculated such that the NPV of the project is zero over the 20-year economic life.

Table 27 and Table 28 show summaries of our capital costs, annual fixed costs, and levelized CONE estimates for the CT and CC reference plants for the 2018/19 delivery year. For comparison, the tables include the most recent 2017/18 PJM administrative CONE parameters and the results of the 2011 PJM CONE Study for the 2015/16 auction, with both escalated to a 2018/19 delivery year at 3% per year to reflect estimated historical escalation rates for generation.[38]

For the CT, our CONE estimates differ by CONE Area due to differences in plant configuration and performance assumptions, differences in labor rates, differences in property tax regulations, and other locational differences in capital and fixed O&M costs. EMAAC and SWMAAC have the highest CONE estimates at $150,000/MW-year and $148,400/MW-year, respectively, due to significantly higher labor costs in EMAAC and high property taxes in SWMAAC that are based on all property, not just land and buildings, as in some other areas. WMAAC and Dominion have the next highest CONE values of $143,500/MW-year and $141,200/MW-year, respectively. The Rest of RTO Area has the lowest CONE values of $138,000/MW-year due to the lack of dual-fuel capability and lower labor costs.

[38] The 3% escalation rate is based on a component-weighted average of the escalation rates in Table 1818.

Table 27
Recommended CONE for CT Plants in 2018/2019

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$400	$373	$348	$372	$364
Installed	*($m)*	$420	$391	$364	$390	$382
First Year FOM	*($m/yr)*	$6	$10	$7	$5	$8
Net Summer ICAP	***(MW)***	**396**	**393**	**385**	**383**	**391**
Unitized Costs						
Overnight	*($/kW)*	$1,012	$948	$903	$971	$931
Installed	*($/kW)*	$1,061	$994	$947	$1,018	$977
Levelized FOM	*($/MW-yr)*	$15,000	$25,600	$18,800	$13,700	$19,600
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$127,300**	**$126,000**	**$117,100**	**$121,800**	**$119,900**
Level-Nominal	***($/MW-yr)***	**$150,000**	**$148,400**	**$138,000**	**$143,500**	**$141,200**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$161,600	$150,700	$148,000	$155,200	$132,400
Brattle 2015/16 Estimate*	*($/MW-yr)*	$145,700	$134,400	$134,200	$141,400	$120,600
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	($11,600)	($2,300)	($10,000)	($11,700)	$8,800
Brattle 2015/16 Estimate	*($/MW-yr)*	$4,300	$14,000	$3,800	$2,000	$20,600
PJM 2017/18 Parameter	*(%)*	-8%	-2%	-7%	-8%	6%
Brattle 2015/16 Estimate	*(%)*	3%	9%	3%	1%	15%

Sources and Notes:

Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Table 27 compares these CONE estimates to two reference points: PJM's current parameters for the 2017/18 capacity auction and Brattle's prior estimates for the 2015/16 delivery year from its 2011 PJM CONE Study. To produce a meaningful comparison, we show these reference points escalated to 2018 at 3% per year. As shown, our estimates are similar to the Brattle 2015/16 values, except in SWMAAC and Dominion where updated property tax calculations and labor costs contribute to increasing the CONE values by 9% and 15%, respectively. Our estimates in those CONE Areas are closer to the PJM 2017/18 parameters (which are higher than the Brattle 2015/16 values largely because they were escalated from prior settlement values using a Handy-Whitman index that has risen significantly faster than actual plant costs, as noted in our 2014 VRR Report). In the other CONE Areas (EMAAC, Rest of RTO, and WMAAC), our estimates are lower than the 2017/18 parameters. Overall, our estimates are within -8% to +6% of PJM's current parameters, depending on the Area.

Comparing the current CT CONE estimates to the Brattle 2015/16 estimates, the CT CONE values are either approximately equal in EMAAC, Rest of RTO and WMAAC or higher by 9% in SWMAAC and higher by 15% in Dominion. The SWMAAC and Dominion values are higher for several reasons. First, we assumed higher labor rates, based on the prevailing wages in those Areas, which include a mix of union and non-union labor. Second, increased property tax estimates that now consider taxes on personal property (*i.e.*, the plant equipment) in accordance with state tax laws in both of these regions also lead to higher CONE estimates. Third, the assumed addition of an SCR on the Dominion CT increased the CONE estimates there. Other components of the estimate also changed there and in all the CONE Areas, but with increases in some categories offsetting decreases in others. Assumptions that increased CONE included higher EPC contract costs (mostly due to labor costs), EPC contingency costs, and owner's project development costs. On the other hand, a lower ATWACC and lower plant O&M estimates reduced CONE.

For the CC, EMAAC has the highest CONE estimates at $203,900/MW-year due to labor costs that are higher than the rest of PJM. SWMAAC and WMAAC have the next highest CC CONE at $197,200/MW-year and $190,900/MW-year, respectively. The CONE Areas with the lowest values are Rest of RTO (due to the lack of dual fuel) at $188,100/MW-yr and Dominion (as it has the lowest labor costs) at $182,400/MW-year.

Table 28
Recommended CONE for CC Plants in 2018/2019

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$808	$707	$709	$737	$708
Installed	*($m)*	$885	$775	$777	$808	$776
First Year FOM	*($m/yr)*	$17	$30	$19	$15	$19
Net Summer ICAP	***(MW)***	**668**	**664**	**651**	**649**	**660**
Unitized Costs						
Overnight	*($/kW)*	$1,210	$1,065	$1,089	$1,137	$1,073
Installed	*($/kW)*	$1,326	$1,168	$1,193	$1,245	$1,176
Levelized FOM	*($/MW-yr)*	$26,000	$44,800	$29,500	$23,300	$28,300
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$173,100**	**$167,400**	**$159,700**	**$162,000**	**$154,800**
Level-Nominal	***($/MW-yr)***	**$203,900**	**$197,200**	**$188,100**	**$190,900**	**$182,400**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$199,900	$176,300	$192,900	$191,800	$170,100
Brattle 2015/16 Estimate*	*($/MW-yr)*	$183,700	$161,000	$177,100	$176,700	$157,000
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	$4,100	$20,900	($4,700)	($900)	$12,200
Brattle 2015/16 Estimate	*($/MW-yr)*	$20,300	$36,200	$11,100	$14,200	$25,400
PJM 2017/18 Parameter	*(%)*	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	*(%)*	10%	18%	6%	7%	14%

Sources and Notes:

Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Compared to the Brattle 2015/16 values, the current CC CONE estimates are higher across all CONE Areas due to higher estimated costs of EPC contingency, owner's project development costs, and plant O&M costs. While the EPC contract cost increased in all cases, the SWMAAC and Dominion values increased more due to higher estimated labor costs than in the previous analysis, as we found the prevailing wages in those regions include both union and non-union labor, whereas the previous analysis assumed strictly non-union labor.

The updated CC CONE values have increased over the prior estimates more than the CT CONE values have, leading to a higher cost premium for CCs of $41,000-54,000/MW-year compared to $27,000-43,000/MW-year in our prior study. The most significant driver for the greater CC CONE increase is the relative difference in plant O&M costs estimated by S&L compared to the previous analysis. As noted earlier in this report, the CT fixed O&M in the current analysis is less than the 2011 value, with a larger fraction treated as variable costs; however, the fixed CC plant O&M is greater than the previous value. Combined, this difference explains approximately two-thirds of the increase in the CC premium. The rest of the difference is explained primarily by higher labor rates, and contingency and project development factors than in the prior study, which add more dollars to the cost of the more capital-intensive CC than the CT. In the Dominion CONE Area, the addition of the SCR to the CT largely offsets these differences.

At PJM's request, we are also providing estimates for the Rest of RTO CONE Area with dual-fuel capabilities, as shown in Table 29. Adding dual-fuel capabilities to the plant specifications increases the level-nominal value of the CT CONE by $9,500/MW-year and the CC CONE by $5,600/MW-year.

Table 29
Rest of RTO CONE Estimates for Different Fuel Configurations

		Gas CT		Gas CC	
Rest of RTO		**Single Fuel**	**Dual Fuel**	**Single Fuel**	**Dual Fuel**
Gross Costs					
Overnight	*($m)*	$348	$373	$709	$733
Installed	*($m)*	$364	$391	$777	$802
First Year FOM	*($m/yr)*	$7	$8	$19	$20
Net Summer ICAP	***(MW)***	**385**	**385**	**651**	**651**
Unitized Costs					
Overnight	*($/kW)*	$903	$969	$1,089	$1,125
Installed	*($/kW)*	$947	$1,016	$1,193	$1,232
Levelized FOM	*($/MW-yr)*	$18,800	$19,700	$29,500	$29,900
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**
Levelized Gross CONE					
Level-Real	***($/MW-yr)***	**$117,100**	**$125,100**	**$159,700**	**$164,400**
Level-Nominal	***($/MW-yr)***	**$138,000**	**$147,500**	**$188,100**	**$193,700**

List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
CAPM	Capital Asset Pricing Model
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CT	Combustion Turbine
DCP	Dominion Cove Point
DCR	Demand Curve Reset
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation and Maintenance
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System

MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NNY	Non-New York
NO_x	Nitrogen Oxides
NSR	New Source Review
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

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EIA Report

Independent Statistics & Analysis

U.S. Energy Information Administration

Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants

April 2013

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Contents

Tables

Introduction

The current and future projected cost and performance characteristics of new electric generating capacity are a critical input into the development of energy projections and analyses. The construction and operating costs, along with the performance characteristics of new generating plants, play an important role in determining the mix of capacity additions that will serve future demand for electricity. These parameters also help to determine how new capacity competes against existing capacity, and the response of the electric generators to the imposition of environmental controls on conventional pollutants or any limitations on greenhouse gas emissions.

In 2010, EIA commissioned an external consultant to develop up-to-date cost and performance estimates for utility-scale electric generating plants for *AEO 2011*.[1] This information allowed EIA to compare the costs of different power plant technologies on a standardized basis and was a key input enhancement to the National Energy Model System (NEMS). For the *AEO 2013* development, EIA commissioned the same consultant group to update the cost and performance estimates for each of the technologies evaluated in the original 2010 study. This paper summarizes the results of the findings and discusses how EIA uses the updated information to analyze the development of new capacity in the electric power sector.

Developing updated estimates: key design considerations

The focus of the 2013 update was to gather current information on the "overnight" construction costs, operating costs, and performance characteristics for a wide range of generating technologies.[2] The estimates were developed through costing exercises, using a common methodology across technologies. Comparing cost estimates developed on a similar basis using the same methodology is of particular importance to ensure modeling consistency.

Each technology is represented by a generic facility of a specific size and configuration, in a location that does not have unusual constraints or infrastructure requirements. Where possible, costs estimates were based on information derived from actual or planned projects known to the consultant. When this information was not available, the project costs were estimated using costing models that account for the current labor and materials rates necessary to complete the construction of a generic facility as well as consistent assumptions for the contractual relationship between the project owner and the construction contractor.

The specific overnight costs for each type of facility were broken down to include:

- **Civil and structural costs:** allowance for site preparation, drainage, the installation of underground utilities, structural steel supply, and construction of buildings on the site
- **Mechanical equipment supply and installation:** major equipment, including but not limited to, boilers, flue gas desulfurization scrubbers, cooling towers, steam turbine generators, condensers, photovoltaic modules, combustion turbines, and other auxiliary equipment
- **Electrical and instrumentation and control:** electrical transformers, switchgear, motor control centers, switchyards, distributed control systems, and other electrical commodities

[1] U.S. Energy Information Administration, Updated Capital Cost Estimates for Electricity Generation Plants November 2010
[2] The term "overnight" refers to the cost of the project as if no interest were incurred during its construction.

- **Project indirect costs**: engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management start up and commissioning, and fees for contingency[3]
- **Owners costs:** development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system

Non-fuel operations and maintenance (O&M) costs associated with each of the power plant technologies were evaluated as well. The O&M costs that do not vary significantly with a plant's electricity generation are classified as fixed, while the costs incurred to generate electricity are classified as variable. The heat rates[4] were also evaluated for the appropriate technologies.

It should be noted that all estimates provided in this report are broad in scope. A more in-depth cost assessment would require a more detailed level of engineering and design work, tailored to a specific site.

Findings

Table 1 summarizes updated cost estimates for generic utility-scale generating plants, including seven powered by coal, six by natural gas, three by solar energy, two each by wind, hydroelectric, biomass, and geothermal power, and one each by uranium and municipal solid waste. EIA does not model all of these generating plant types, but included them in the study in order to present consistent cost and performance information for a broad range of generating technologies. Additionally, while EIA does model new geothermal and hydroelectric capacity, site specific cost estimates from alternate sources are used in the NEMS model. The specific technologies represented in the NEMS model for *AEO2013* that use the cost data from this report are identified in the last column of Table 1.

Table 2 compares the updated overnight cost estimates to those developed for the 2010 report. To facilitate comparisons, the costs are expressed in 2012 dollars.[5] Notable changes include:

- **Integrated Gasification Combined Cycle (IGCC) Coal Plants with and without carbon capture and storage (CCS):** The updated overnight capital cost estimates for single unit IGCC plants with and without CCS both rose by approximately 19 percent. This change can be primarily attributed to more recent information from current IGCC projects in various stages of the development process.[6]

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[3] Fees for contingency include contractor overhead costs, fees, profit, and construction.
[4] Heat Rate is a measure of generating station thermal efficiency commonly stated as Btu per kilowatthour.
[5] U.S. Energy Information Administration, Annual Energy Outlook 2013, Table 20, GDP chain-type price index.
[6] The increase in cost for IGCC with CCS resulted in EIA revising its technology assumption for new coal plants with CCS in EIA's projections. EIA's National Energy Modeling System (NEMS) includes one option for coal with CCS, and in *AEO2012* new coal plants with CCS were assumed to have the characteristics consistent with those of an IGCC unit with CCS. However, due to the difference in costs between advanced pulverized coal (PC) with CCS and IGCC with CCS presented in the 2013 update, the assumed characteristics of a coal plant with CCS in NEMS were assumed to be consistent with those of an advanced PC plant with CCS for the *AEO2013*.

- **Conventional Natural Gas Combined Cycle (NGCC):** The updated overnight capital cost for conventional NGCC plants declined by 10 percent relative to the cost in the 2010 study. In addition, the assumed capacity of these units rose from 540 MW in the 2010 study to 620 MW.
- **Onshore Wind**: Overnight costs for onshore wind decreased by approximately 13 percent relative to the 2010 study, primarily due to lower wind turbine prices.
- **Solar Photovoltaic:** The overnight capital costs for solar photovoltaic technologies decreased by 22 percent for 150 MW photovoltaic units from the costs presented in the 2010 study. The size of the smaller photovoltaic units evaluated was increased from 7 MW in the 2010 study to 20 MW in the 2013 study. Although it is not entirely consistent to compare these two systems, there was a significant decline in costs on a $/kW basis from the 7 MW system to the 20 MW system. The overall decreases in costs can be attributed to a decline in the component costs and construction cost savings for the balance of plant.

As previously noted, costs are developed using a consistent methodology that includes a broad project scope and includes indirect and owners costs. The cost figures will not necessarily match those derived in other studies that employ different approaches to cost estimation.

It should also be noted that when modeling geothermal and hydroelectric power resources, EIA uses site-specific sources for the technology cost estimates, and not the estimates provided by the consultant, due to the site specific nature of those resource supply models.

EIA's analysis of technology choice in the electric power sector

EIA's modeling employs a net present value (NPV) capital budgeting methodology to evaluate different investment options for new power plants. Estimates of the overnight capital cost, fixed and variable operations and maintenance costs, and plant heat rates for generic generating technologies serve as a starting point for developing the total cost of new generating capacity. However, other parameters also play a key role in determining the total capital costs. Because several of these factors are dynamic, the realized overall capital cost for given technologies can vary based on a variety of circumstances. Five of the most notable parameters are:

- **Financing:** EIA determines the cost of capital required to build new power plants by calculating a weighted average cost of capital using a mix of macro-economic parameters determined through EIA's modeling and an assumed capital structure for the electric power industry.
- **Lead Time:** The amount of time needed to build a given type of power plant varies by technology. Projects with longer lead times increase financing costs. Each year of construction represents a year of additional interest charges before the plant is placed in service and starts generating revenue.

- **Inflation of material and construction costs:** The projected relationship between the rate of inflation for the overall economy and key drivers of plant costs, such as materials and construction, are important elements impacting overall plant costs. A projected economy-wide inflation rate that exceeds the projected inflation rate for materials and construction costs results in a projected decline in real (inflation-adjusted) capital costs and vice versa.
- **Resource Supply:** Technologies such as wind, geothermal, or hydroelectric must be sited in suitable locations to take advantage of the particular resource. In order to capture the site specific costs associated with these technologies, EIA develops upward sloping supply curves for each of these technologies. These curves assume that the lowest-cost, most-favorable resources will be developed first, and that costs associated with the technology will increase as only higher-cost, less-favorable sites are left to be developed.
- **Learning by doing:** The overnight capital costs developed for the report serve as an input to EIA's long term modeling and represent the cost of construction for a project that could begin as early as 2013. However, these costs are assumed to decrease over time in real terms as equipment manufacturers, power plant owners, and construction firms gain more experience with certain technologies. The rate at which these costs decline is often referred to as the learning rate.

EIA determines learning rates at the power plant component level, not for the power plant technology itself because some technologies share the same component types. It is assumed that the knowledge and experienced gained through the manufacture and installation of a given component in one type of power plant can be carried over to the same component in another type of plant. As an example, the experience gained through the construction of combined cycle natural gas plants can be leveraged to influence the overall cost of building an IGCC unit, which in part, includes the components of a combined cycle natural gas plant. Other technologies, such as nuclear power and pulverized coal (PC) plants without CCS, do not share component systems, and their learning rates are determined solely as a function of the amount of capacity built over time.

Technologies and their components are represented in the NEMS model at various stages of maturity. EIA classifies technologies into three such stages: mature, evolutionary, and revolutionary. The technology classification determines the rate of cost reduction that can be achieved through the learning function. Generally, overnight costs for technologies and associated components decline at a specified rate based on a doubling of new capacity. The cost decline is fastest for revolutionary technologies and slower for evolutionary and mature technologies.[7]

The capacity additions used to influence learning are primarily developed from NEMS results. However, external capacity additions from international projects are also included for some technologies, to account for additional learning from such projects. For power plant technologies with multiple components, the capacity additions are weighted by the contribution of each component to the overall plant construction cost.[8]

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[7] U.S. Energy Information Administration, AEO 2012 Electricity Market Module Assumptions Document, Table 8.3.
[8] U.S. Energy Information Administration, AEO 2012 Electricity Market Assumptions Document, Table 8.4.

Table 3 classifies the status of each technology and component as modeled in *AEO2013*.

The NEMS model also assumes that efficiency for all fossil-fueled plants improves as a result of learning by doing. The power plant heat rates provided by the consultant are intended to represent the characteristics of a plant that starts construction in 2013, referred to as "first-of-a-kind." NEMS assumes that the heat rate for all fossil fueled technologies declines over time to a level referred to as an "nth-of-a-kind" heat rate.[9] The magnitude of heat rate improvement depends on the current state of the technology, with revolutionary technologies seeing a more significant decline in heat rate than mature technologies. Heat rate improvements are independent to capacity expansion. Fixed and variable O&M are not assumed to achieve learning-related savings.

Impact of location on power plant capital costs

The estimates provided in this report are representative of a generic facility located in a region without any special issues that would alter its cost. However, the cost of building power plants in different regions of the United States can vary significantly. The report includes location-based cost adjustment tables for each technology in 64 metropolitan areas. These adjustments were made to reflect the impact of remote location costs, costs associated with seismic design that may vary by region, and labor wage and productivity differences by region. In order to reflect these costs in EIA's modeling, these adjustments were aggregated to represent the 22 Electricity Market Module regions. EIA also assumes that the development of certain technologies is not feasible in given regions for geographic, logistical, or regulatory reasons. The regional cost adjustments and development restrictions are summarized in Table 4.

Summary

The estimates provided by the consultant for this report are key inputs for EIA electric market projections, but they are not the sole driver of electric generation capacity expansion decisions. The evolution of the electricity mix in each of the 22 regions to be modeled in *AEO2013* is sensitive to many factors, including the projected evolution of capital costs over the modeling horizon, projected fuel costs, whether wholesale power markets are regulated or competitive, the existing generation mix, additional costs associated with environmental control requirements, and future electricity demand.

Users interested in additional details regarding these updated cost estimates should review the consultant study prepared by SAIC Energy Environment and Infrastructure in Appendix B.

[9] U.S. Energy Information Administration, AEO 2013 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies,, Table 8.2.

Table 1. Updated estimates of power plant capital and operating costs

	Plant Characteristics		Plant Costs (2012$)			
	Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	NEMS Input
Coal		38.78%				
Single Unit Advanced PC	650	8,800	$3,246	$37.80	$4.47	N
Dual Unit Advanced PC	1,300	8,800	$2,934	$31.18	$4.47	Y
Single Unit Advanced PC with CCS	650	12,000	$5,227	$80.53	$9.51	Y
Dual Unit Advanced PC with CCS	1,300	12,000	$4,724	$66.43	$9.51	N
Single Unit IGCC	600	8,700	$4,400	$62.25	$7.22	N
Dual Unit IGCC	1,200	8,700	$3,784	$51.39	$7.22	Y
Single Unit IGCC with CCS	520	10,700	$6,599	$72.83	$8.45	N
Natural Gas						
Conventional CC	620	7,050	$917	$13.17	$3.60	Y
Advanced CC	400	6,430	$1,023	$15.37	$3.27	Y
Advanced CC with CCS	340	7,525	$2,095	$31.79	$6.78	Y
Conventional CT	85	10,850	$973	$7.34	$15.45	Y
Advanced CT	210	9,750	$676	$7.04	$10.37	Y
Fuel Cells	10	9,500	$7,108	$0.00	$43.00	Y
Uranium						
Dual Unit Nuclear	2,234	N/A	$5,530	$93.28	$2.14	Y
Biomass						
Biomass CC	20	12,350	$8,180	$356.07	$17.49	N
Biomass BFB	50	13,500	$4,114	$105.63	$5.26	Y
Wind						
Onshore Wind	100	N/A	$2,213	$39.55	$0.00	Y
Offshore Wind	400	N/A	$6,230	$74.00	$0.00	Y
Solar						
Solar Thermal	100	N/A	$5,067	$67.26	$0.00	Y
Photovoltaic	20	N/A	$4,183	$27.75	$0.00	N
Photovoltaic	150	N/A	$3,873	$24.69	$0.00	Y
Geothermal						
Geothermal – Dual Flash	50	N/A	$6,243	$132.00	$0.00	N
Geothermal – Binary	50	N/A	$4,362	$100.00	$0.00	N
Municipal Solid Waste						
Municipal Solid Waste	50	18,000	$8,312	$392.82	$8.75	N
Hydroelectric						
Conventional Hydroelectric	500	N/A	$2,936	$14.13	$0.00	N
Pumped Storage	250	N/A	$5,288	$18.00	$0.00	N

Table 2. Overnight cost comparison with 2010 estimates

	Overnight Capital Costs (2012 $/kW)		
	2013 Report	2010 Report	% Difference
Coal			
Single Unit Advanced PC	$3,246	$3,292	-1%
Dual Unit Advanced PC	$2,934	$2,956	-1%
Single Unit Advanced PC with CCS	$5,227	$5,300	-1%
Dual Unit Advanced PC with CCS	$4,724	$4,760	-1%
Single Unit IGCC	$4,400	$3,706	19%
Dual Unit IGCC	$3,784	$3,348	13%
Single Unit IGCC with CCS	$6,599	$5,559	19%
Natural Gas			
Conventional CC	$917	$1,017	-10%
Advanced CC	$1,023	$1,043	-2%
Advanced CC with CCS	$2,095	$2,141	-2%
Conventional CT	$973	$1,012	-4%
Advanced CT	$676	$691	-2%
Fuel Cells	$7,108	$7,105	0%
Uranium			
Dual Unit Nuclear	$5,530	$5,546	0%
Biomass			
Biomass CC	$8,180	$8,205	0%
Biomass BFB	$4,114	$4,012	3%
Wind			
Onshore Wind	$2,213	$2,534	-13%
Offshore Wind	$6,230	$6,211	0%
Solar			
Solar Thermal	$5,067	$4,877	4%
Solar Photovoltaic (7 MW)	N/A	$6,289	N/A
Solar Photovoltaic (20 MW)	$4,183	N/A	N/A
Solar Photovoltaic (150 MW)	$3,873	$4,943	-22%
Geothermal			
Geothermal – Dual Flash	$6,243	$5,798	8%
Geothermal – Binary	$4,362	$4,304	1%
Municipal Solid Waste			
Municipal SolidWaste	$8,312	$8,557	-3%
Hydroelectric			
Conventional Hydroelectric	$2,936	$3,197	-8%
Pumped Storage	$5,288	$5,816	-9%

Table 3. Status of technologies and components modeled by EIA

	Revolutionary	Evolutionary	Mature
Pulverized Coal			X
Pulverized Coal with CCS			
- Non-CCS portion of Pulverized Coal Plant			X
- CCS	X		
Integrated Gasification Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Gasifier		X	
- Balance of Plant			X
Conventional Natural Gas Combined Cycle			
- Conventional Combustion Turbine			X
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle with CCS			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
- CCS	X		
Conventional Natural Gas Combustion Turbine			
- Conventional Combustion Turbine			X
- Balance of Plant			X
Advanced Natural Gas Combustion Turbine			
- Advanced Combustion Turbine		X	
- Balance of Plant			X
Advanced Nuclear	X		
Biomass			
- Pulverized Coal			X
- Fuel Preparation		X	
Geothermal		X	
Municipal Solid Waste/Landfill Gas			X
Conventional Hydroelectric			X

Table 3. Status of technologies and components modeled by EIA (cont.)

	Revolutionary	Evolutionary	Mature
Wind			
- Onshore/Common Components			X
- Offshore Components	X		
Solar Thermal	X		
Solar PV			
- Modules (Utility and End Use)		X	
- Utility Balance of Plant		X	

Table 4. Regional cost adjustments for technologies modeled by NEMS by Electric Market Module (EMM) region[10,11]

EMM Region	PC	IGCC	PC w/CCS	Conv. CT	Adv. CT	Conv. CC	Adv. CC	Adv. CC w/CCS	Fuel Cell	Nuclear	Biomass	MSW	On-shore Wind	Off-shore Wind	Solar Thermal	Solar PV
1 (ERCT)	0.91	0.92	0.92	0.93	0.95	0.91	0.92	0.90	0.96	0.96	0.93	0.93	0.95	0.92	0.86	0.87
2 (FRCC)	0.92	0.93	0.94	0.93	0.93	0.91	0.92	0.92	0.97	0.97	0.94	0.94	N/A	N/A	0.89	0.90
3 (MROE)	1.01	1.01	0.99	0.99	1.01	0.99	0.99	0.97	0.99	1.01	0.99	0.98	0.99	0.97	N/A	0.96
4 (MROW)	0.95	0.96	0.96	0.98	1.00	0.97	0.97	0.96	0.98	0.98	0.96	0.96	1.03	1.01	N/A	0.95
5 (NEWE)	1.10	1.09	1.05	1.16	1.20	1.16	1.15	1.08	1.01	1.05	1.04	1.02	1.06	1.03	N/A	1.03
6 (NYCW)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.50	1.14	N/A	1.26	1.26	N/A	1.29	N/A	N/A
7 (NYLI)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.50	1.14	N/A	1.26	1.26	1.25	1.29	N/A	1.45
8 (NYUP)	1.11	1.10	1.05	1.17	1.22	1.16	1.16	1.06	1.00	1.07	1.03	1.00	1.01	0.99	N/A	0.98
9 (RFCE)	1.15	1.14	1.09	1.21	1.25	1.21	1.21	1.12	1.02	1.08	1.07	1.03	1.05	1.03	N/A	1.05
10 (RFCM)	0.98	0.98	0.98	1.01	1.02	1.00	1.00	0.99	0.99	0.99	0.98	0.98	1.00	0.98	N/A	0.97
11 (RFCW)	1.05	1.04	1.02	1.05	1.06	1.04	1.04	1.02	1.00	1.03	1.02	1.00	1.02	1.01	N/A	1.00
12 (SRDA)	0.92	0.93	0.93	0.95	0.96	0.93	0.93	0.92	0.97	0.96	0.93	0.94	0.96	1.00	N/A	0.89
13 (SRGW)	1.07	1.06	1.05	1.05	1.05	1.06	1.05	1.04	1.02	1.03	1.03	1.03	1.04	1.00	N/A	1.05
14 (SRSE)	0.92	0.93	0.93	0.95	0.97	0.93	0.94	0.92	0.97	0.96	0.93	0.94	0.96	0.93	N/A	0.89
15 (SRCE)	0.93	0.94	0.94	0.94	0.95	0.93	0.93	0.92	0.97	0.97	0.94	0.94	0.96	1.00	N/A	0.89
16 (SRVC)	0.89	0.91	0.91	0.91	0.93	0.88	0.89	0.88	0.96	0.95	0.91	0.91	0.95	0.92	N/A	0.84
17 (SPNO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
18 (SPSO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
19 (AZNM)	1.00	1.00	0.99	1.03	1.04	1.02	1.02	1.00	0.99	1.00	1.00	0.99	1.03	1.00	0.99	0.99
20 (CAMX)	N/A	N/A	1.12	1.24	1.29	1.25	1.24	1.15	1.03	N/A	1.08	1.06	1.12	1.05	1.13	1.11
21 (NWPP)	1.01	1.01	1.00	1.02	1.03	1.01	1.01	0.99	0.99	1.01	1.00	0.98	1.05	1.02	0.99	0.99
22 (RMPA)	0.99	0.99	0.97	1.02	1.05	1.01	1.01	0.96	0.98	1.01	0.97	0.95	1.03	N/A	0.93	0.93

Note: Geothermal and Hydroelectric plants are not included in the table because EIA uses site specific cost estimates for these technologies which include regional factors.

[10] U.S. Energy Information Administration, AEO 2012 EMM Assumptions document, Figure 6.

[11] The regional tables in the report were aggregated to the appropriate Electricity Market Module region in order to represent regional cost factors in NEMS.

Appendix A - Acronym List

BFB - Bubbling Fluidized Bed

CC - Combined Cycle

CCS - Carbon Capture and Sequestration

CT - Combustion Turbine

IGCC - Integrated Gasification Combined Cycle

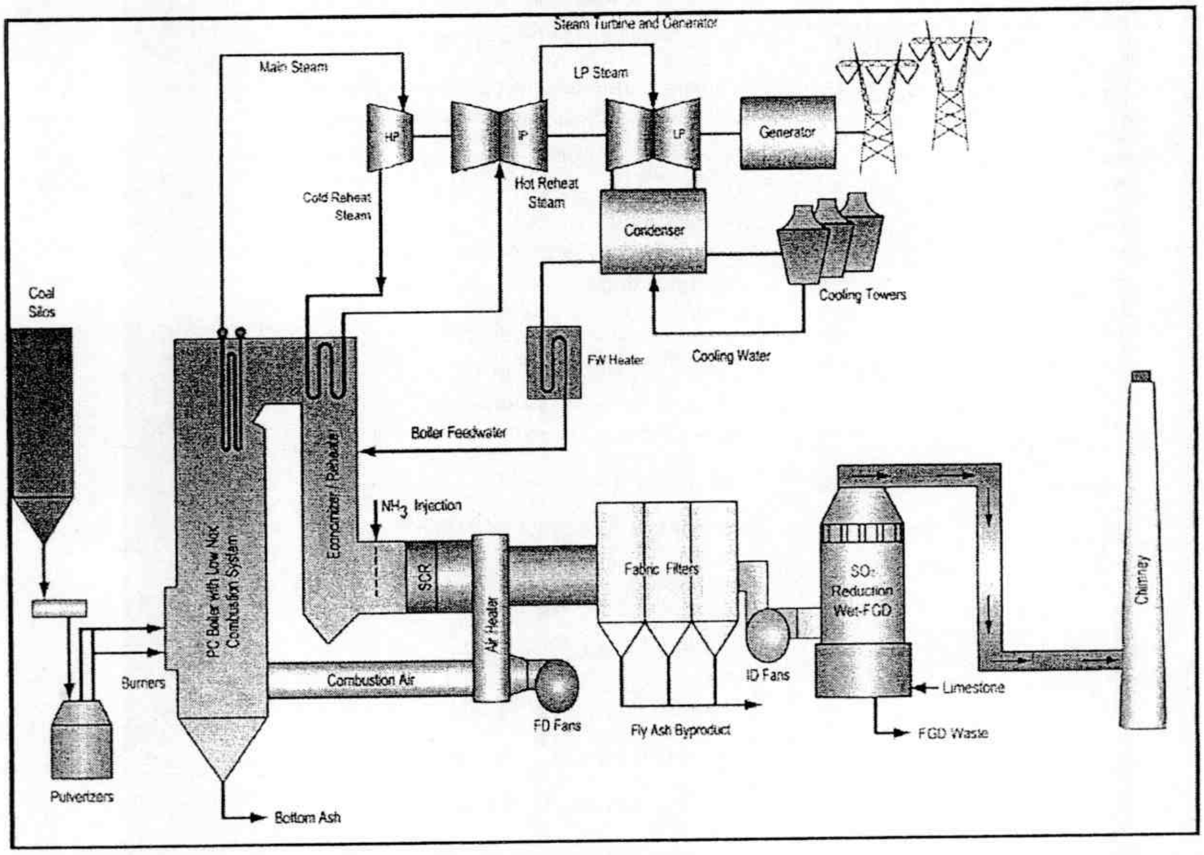
PC - Pulverized Coal

PV – Photovoltaic

TABLE 1-1 – LIST OF TECHNOLOGIES FOR REVIEW

TECHNOLOGY	DESCRIPTION	COMMENTS
Advanced Pulverized Coal	650 megawatt-electrical ("MWe") and 1,300 MWe; supercritical; all advanced pollution control technologies	Greenfield Installation
Advanced Pulverized Coal with Carbon Capture and Sequestration ("CCS")	650 MWe and 1,300 MWe; supercritical; all advanced pollution control technologies, including CCS technologies	Greenfield Installation
Conventional Natural Gas Combined Cycle ("NGCC")	620 MWe; F-Class system	
Advanced NGCC	400 MWe; H-Class system	
Advanced NGCC with CCS	340 MWe; H-Class system	
Conventional Combustion Turbine ("CT")	85 MWe; E-Class turbine	
Advanced CT	210 MWe; F-Class turbine	
Integrated Gasification Combined Cycle ("IGCC")	600 MWe and 1,200 MWe; F-Class-syngas system	
IGCC with CCS	520 MWe; F-Class-syngas system	
Advanced Nuclear	2,234 megawatt ("MW"); AP1000 PWR Basis	Brownfield Installation
Biomass Combined Cycle	20 MWe	Wood Fuel
Biomass Bubbling Fluidized Bed ("BBFB")	50 MWe	Wood Fuel
Fuel Cells	10 MWe	
Geothermal	50 MWe Dual Flash and Binary	
Municipal Solid Waste ("MSW")	50 MWe	
Hydroelectric	500 MWe	
Pumped Storage	250 MWe	
Wind Farm – Onshore	100 MWe	
Wind Farm – Offshore	400 MWe	
Solar Thermal – Central Station	100 MWe	
Photovoltaic – Central Station	20 MWe –AC and 150 MWe - AC	

FIGURE 3-1 – ADVANCED PULVERIZED COAL DESIGN CONFIGURATION



3.2 ELECTRICAL AND CONTROL SYSTEMS

The Advanced Pulverized Coal Facility has one ST electric generator. The generator is a 60 Hertz ("Hz") machine rated at approximately 800 mega-volt-amperes ("MVA") with an output voltage of 24 kilovolts ("kV"). The ST electric generator is directly connected to generator step-up transformer ("GSU"), which in turn is connected between two circuit breakers in the high-voltage bus in the Advanced Pulverized Coal Facility switchyard through a disconnect switch. The GSU increases the voltage from the electric generator from 24 kV to interconnected transmission system high voltage.

The Advanced Pulverized Coal Facility is controlled using a DCS. The DCS provides centralized control of the plant by integrating the control systems provided with the boiler, ST and associated electric generator and the control of BOP systems and equipment.

3.3 OFF-SITE REQUIREMENTS

Coal is delivered to the facility via rail, truck or barge. Water for all processes at the Advanced Pulverized Coal Facility can be obtained from one of a variety of sources; however, water is typically sourced from an adjacent river, when possible. The Advanced Pulverized Coal Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for boiler makeup. Wastewater is sent to an adjacent river or other approved alternative. Further, the electrical interconnection from the Advanced Pulverized Coal on-site switchyard is effectuated by a connection to an adjacent utility substation, assumed to be no more than 1 mile from the Advanced Pulverized Coal Facility.

3.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Advanced Pulverized Coal Facility ("APC") with a nominal capacity of 650 MW is \$3,246/kilowatt ("kW") and with a nominal capacity of 1,300 MW is \$2,934/kW. Table 3-1 and Table 3-2 summarize the Cost Estimate categories for the APC Facility.

TABLE 3-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR APC

Technology:	APC	
Nominal Capacity (ISO):	650,000 kW	
Nominal Heat Rate (ISO):	8,800 Btu/kWh-HHV	
Capital Cost Category		(000s) (October 1, 2012\$)
Civil Structural Material and Installation		230,000
Mechanical Equipment Supply and Installation		863,500
Electrical / I&C Supply and Installation		132,000
Project Indirects [1]		350,000
EPC Cost before Contingency and Fee		1,575,500
Fee and Contingency		183,000
Total Project EPC		1,758,500
Owner's Costs (excluding project finance)		351,700
Total Project Cost (excluding finance)		2,110,200
Total Project EPC	\$ / kW	2,705
Owner Costs 20% (excluding project finance)	\$ / kW	541
Total Project Cost (excluding project finance)	\$ / kW	3,246

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

TABLE 3-2 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR APC

Technology: APC Nominal Capacity (ISO): 1,300,000 kW Nominal Heat Rate (ISO): 8,800 Btu/kWh-HHV		
Capital Cost Category		(000s) (October 1, 2012$)
Civil Structural Material and Installation		413,140
Mechanical Equipment Supply and Installation		1,659,944
Electrical / I&C Supply and Installation		244,400
Project Indirects (1)		608,140
EPC Cost before Contingency and Fee		2,925,624
Fee and Contingency		307,191
Total Project EPC		3,232,815
Owner Costs (excluding project finance)		581,907
Total Project Cost (excluding finance)		3,814,722
Total Project EPC	$ / kW	2,486
Owner Costs 18% (excluding project finance)	$ / kW	448
Total Project Cost (excluding project finance)	$ / kW	2,934

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustment criteria.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that were included in outdoor installation are Alabama, Arizona, Arkansas, Florida, Georgia, Louisiana, Mississippi, New Mexico, and South Carolina.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the APC Facility include Fairbanks, Alaska; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 1.5.1, taking into consideration the amount of labor we estimated for the APC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 3-3 and Table 3-4 in the Appendix show the APC capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

3.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.5.2., the APC Facility includes the major maintenance for boiler, ST, associated generator, BOP, and emissions reduction catalysts. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the megawatt-hours ("MWh") incurred. Typically, significant overhauls on an APC Facility occur no less frequently than six or seven years. Table 3-5 presents the FOM and VOM expenses for the APC Facility. Table 3-5 and Table 3-6 present the O&M expenses for the APC Facility.

TABLE 3-5 – O&M EXPENSES FOR APC (650,000 KW)

Technology:	APC
Fixed O&M Expense	\$37.80/kW-year
Variable O&M Expense	\$4.47/MWh

TABLE 3-6 – O&M EXPENSES FOR APC (1,300,000 KW)

Technology:	APC
Fixed O&M Expense	\$31.18/kW-year
Variable O&M Expense	\$4.47/MWh

3.6 ENVIRONMENTAL COMPLIANCE INFORMATION

As mentioned in Section 3.1, the APC Facility is assumed to include low NO_X combustion burners in the boiler, SCR, and a flue gas desulfurization ("FGD") to further control the emissions of NO_X and SO_2, respectively. Table 3-7 presents the environmental emissions for the APC Facility.

TABLE 3-7 – ENVIRONMENTAL EMISSIONS FOR APC

Technology:	APC
NO_X	0.06 lb/MMBtu
SO_2	0.1 lb/MMBtu
CO_2	206 lb/MMBtu

COST REPORT

COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

Prepared for the
National Renewable Energy Laboratory

FEBRUARY 2012

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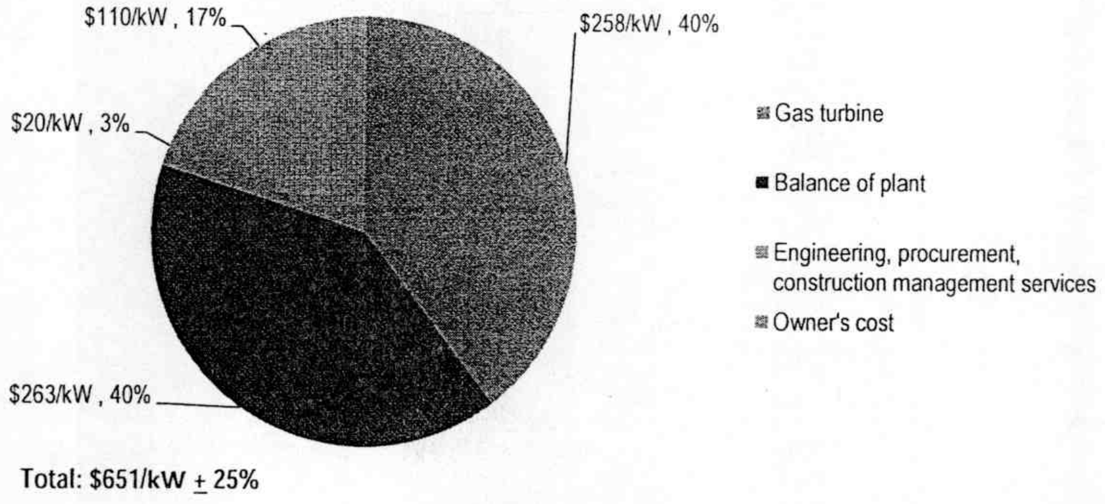

Figure 2. Capital cost breakdown for a gas turbine power plant

2.3 COMBINED-CYCLE TECHNOLOGY

Natural gas combined-cycle (CC) technology was represented by a 615- MW plant. Costs were based on two GE 7FA combustion turbines or equivalent, two heat recovery steam generators (HRSGs), a single reheat steam turbine and a wet mechanical draft cooling tower. The cost included a SCR/CO reactor housed within the HRSGs for NOx and CO reduction. The combustion turbine generator was assumed to include dry low NOx combustion system capable of realizing 9 ppmvd @ 15% O_2 at full load.

2010 capital cost was estimated to be 1,230 $/kW +25%. Cost uncertainty for CC technology is low. Although it is possible that advanced configurations for CC components will be developed over the next 40 years, the economic incentive for new development has not been apparent in the last few decades. The cost estimates did not include any cost reduction through 2050. Table 4 presents cost and performance data for combined-cycle technology. Table 5 presents emission data for the technology. The 2010 capital cost breakdown for the combined-cycle power plant is shown in Figure 3.

Table 4. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	1250	–	–	–	–	–	–	–	–	–
2010	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2015	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2020	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2025	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2030	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2035	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2040	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2045	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2050	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50

Table 5. Emission Rates for a Combined-Cycle Power Plant

SO_2 (Lb/mmbtu)	NO_X (LB/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.0073	0.0058	117

Guddu Power Project

FROM :GENCO HOLDING FAX NO. :0512287019 15 Jan. 2015 05:31PM P1

ATTN : MR JEHANZEB BHATTI

Attention: Mr. Mian Muhammad Imran, CEO
GENCO Holding Company Limited

From: Safeer Ahmed, Senior Manager Finance
PPIB

Dated: 15th January 2015

Subject: **Provision of data related to GUDU Power Project**

Please find attached herewith table showing the data required related to GUDU Power Project.

Best Regards,

Sr. No	Particulars	Comments
1.	Gross Capacity	747.005 MW at Average site conditions.
2.	Net Capacity	720.790 MW.
3.	Projected Availability	March, 2015
4.	USD Exchange rate	approved Cost as per PC-I USD = 45472.75 million PKR = 14302.66 million. 1USD = PKR 83.
5.	Reference date of the data	August, 2009.

Jehanzaib Bhatti
Assistant Manager (Finance)
Private Power & Infrastructure Board
Ministry of Water & Power
Government of Pakistan
50 Nazimuddin Road, F-7/4,
Islamabad. Pakistan.
Telephone: (92 51) 9100 118-129
Fax: (92 51) 9100 131-132

747 MW (GROSS) COMBINED CYCLE POWER PROJECT GUDDU

1.	Capacity - (ISO at Site)	• GT-14 = 255.6 MW • GT-15 = 255.6 MW
		• 2 Gas Turbines 243 MW each • 2 HRSGs • 1 Steam Turbine 261 MW
2.	Efficiency	• Gas Turbine = 36.69% • Combined Cycle ≅ 56.40%
3.	Committed Plant Availability	Dec. 2015
4.	Average Plant Factor	60%
5.	EPC Cost (Rs.in Million)	50938.84
6.	Non EPC Cost (Rs. in Million)	2745.13
7.	Interest During Construction (IDC) (Rs. in Million):	6091.44
8.	Total Project Cost (Rs. in Million)	59,775.410
9.	Capital Structure	• 15% of the Foreign Currency Component of EPC Cost Injected by GENCO-II whereas balance 85% financed by the consortium of China Exim Bank & HSBC. • 100% of Local Currency Component of EPC Cost and all over & above cost of PC-1 being financed by GENCO-II. • For the financing of GENCO-II's portion Finance Division provided CDL to the tune of PKR 7.6 Billion. •
11.	Total Construction Period	05 years
12.	Open Cycle Operation after Start of Construction	• The GT-14 was synchronized for the first time with National Grid on 10.03.2014 • The GT-15 was synchronized for the first time with National Grid on 07.04.2014
13.	Combined Cycle Operation after Start of Construction	The Steam Turbine was synchronized for the first time with National Grid on 04.06.2014

Summary of Average Costs for CCPP by NEPRA - Gas based IPPs

Particulars	Saif	Orient	Sapphire	Halmore	Average
Gross Capacity	225.00	229.00	235.00	285.00	243.50
Net Capacity	209.79	212.74	212.11	209.00	210.91
Project Cost $ Million	201.91	198.55	212.97	237.66	212.77
Project Cost PKR Million	16,960.67	15,983.11	17,750.80	20,415.08	17,777.42
Exchange Rate US$ / Rs.	84.00	80.50	83.35	85.90	83.44
Exchange Rate US$ / Rs. Present	99.68	99.68	99.68	99.68	99.68
Multiplier	1.19	1.24	1.20	1.16	1.20
Indexed Project Cost	239.59	245.84	254.68	275.77	253.97
Revised Cost/MW Gross $Mil	1.06	1.07	1.08	0.97	**1.05**

Interest & Exchange Rates – 2nd Jan-2015

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1) Due to a change of policy by the ICE Benchmark Administration, LIBOR rates are available with a 24 hour delay only. No website is allowed to publish real time rates anymore publically.

2) In 2013 the BBA (nowadays ICE) discontinued LIBOR fixing for a number of currencies (NZD, SEK, DKK, AUD and CAD) and maturities.

3 month US Dollar LIBOR interest rate

Charts USD LIBOR interest rates - maturity 3 months

Chart last month | Chart last year | Chart full term

The 3 month US Dollar (USD) LIBOR interest rate is the average interest rate at which a selection of banks in London are prepared to lend to one another in American dollars with a maturity of 3 months. Alongside the 3 month US Dollar (USD) LIBOR interest rate we also have a large number of other LIBOR interest rates for other maturities and/or in other currencies. See the links at the bottom of this page for a summary of all maturities, currencies and historic interest rates. The LIBOR interest rates are used by banks as the base rate in setting the level of their savings, mortgage and loan interest rates.

For a summary of all current LIBOR interest rates, click here.
For detailed background information about LIBOR, click here.

Tables USD LIBOR interest rates - maturity 3 months

Current interest rates	
january 20 2015	0.25670 %
january 19 2015	0.25620 %
january 16 2015	0.25660 %
january 15 2015	0.25260 %
january 14 2015	0.25360 %
january 13 2015	0.25330 %
january 12 2015	0.25280 %
january 09 2015	0.25410 %
january 08 2015	0.25210 %
january 07 2015	0.25210 %
january 06 2015	0.25110 %
january 05 2015	0.25360 %

First rate per month	
january 02 2015	0.25560 %
december 01 2014	0.23460 %
november 03 2014	0.23235 %
october 01 2014	0.23260 %
september 01 2014	0.23360 %
august 01 2014	0.23810 %
july 01 2014	0.23180 %
june 02 2014	0.22715 %
may 01 2014	0.22285 %
april 01 2014	0.22810 %
march 03 2014	0.23565 %
february 03 2014	0.23560 %

First rate per year	
january 02 2015	0.25560 %
january 02 2014	0.24285 %
january 02 2013	0.30500 %
january 03 2012	0.58250 %
january 04 2011	0.30281 %
january 04 2010	0.25438 %
january 02 2009	1.41250 %
january 02 2008	4.68063 %
january 02 2007	5.36000 %
january 03 2006	4.54438 %
january 04 2005	2.57000 %
january 02 2004	1.15000 %

LIBOR per currency
- American dollar LIBOR
- British pound sterling LIBOR
- European Euro LIBOR
- Japanese Yen LIBOR
- Swiss franc LIBOR

US dollar LIBOR interest rates
- American dollar LIBOR overnight
- American dollar LIBOR 1 week
- American dollar LIBOR 1 month
- American dollar LIBOR 2 months
- American dollar LIBOR 3 months
- American dollar LIBOR 6 months
- American dollar LIBOR 12 months

US dollar LIBOR history
- American dollar LIBOR 2014
- American dollar LIBOR 2013
- American dollar LIBOR 2012
- American dollar LIBOR 2011
- American dollar LIBOR 2010
- American dollar LIBOR 2009
- American dollar LIBOR 2008
- American dollar LIBOR 2007
- American dollar LIBOR 2006
- American dollar LIBOR 2005
- American dollar LIBOR 2004
- American dollar LIBOR 2003
- American dollar LIBOR 2002
- American dollar LIBOR 2001
- American dollar LIBOR 2000
- American dollar LIBOR 1999

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Overnight Euro LIBOR	-0.15643 %	01-20-2015	
JPY LIBOR - 1 week	0.04357 %	01-20-2015	
USD LIBOR - 1 month	0.16850 %	01-20-2015	
CHF LIBOR - 3 months	-0.66000 %	01-20-2015	
GBP LIBOR - 6 months	0.68781 %	01-20-2015	
USD LIBOR - 12 months	0.61590 %	01-20-2015	

All LIBOR interest rates, click here

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KIBOR

As on 2-Jan-15

Tenor	BID	OFFER
1 - Week	9.25	9.75
2 - Week	9.31	9.81
1 - Month	9.31	9.81
3 - Month	9.32	9.57
6 - Month	9.36	9.61
9 - Month	9.36	9.86
1 - Year	9.35	9.85
2 - Year	9.49	9.99
3 - Year	9.66	10.16

Data source: Reuters

Natural Gas Combined-Cycle Plant

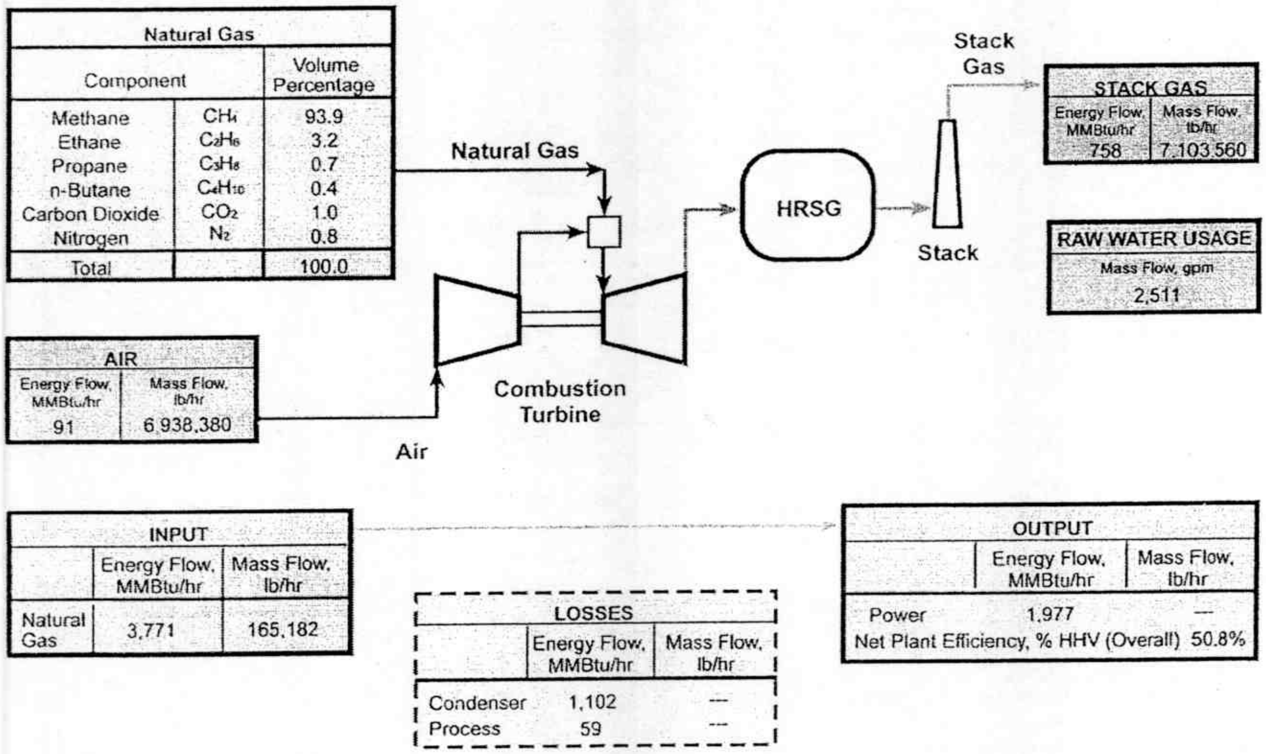
Plant Overview

This analysis is based on a 560 MWe (net power output) natural gas combined-cycle (NGCC) plant located at a greenfield site in the midwestern United States. This plant is designed to meet Best Available Control Technology (BACT) emission limits. The combination process, heat, and mass balance diagram for the NGCC plant is shown in Figure 1. The primary fuel is natural gas (NG) with a higher heating value (HHV) of 22,792 Btu/lb. The plant is assumed to operate in baseload mode at a capacity factor (CF) of 85 percent without sparing of major train components. A summary of plant performance data for the NGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	NGCC
Carbon capture	No
Net power output (kWe)	560,360
Net plant HHV efficiency (%)	50.8
Primary fuel (type)	Natural Gas
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	68.4
Total plant cost ($ x 1,000)	$310,710

Figure 1. Process Flow Diagram
NGCC



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 10.6 percent of the TPC.

No process contingency is included in this case because all elements of the technology are commercially proven.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for NGCC cases.

Table 4. Air Emissions Summary @ 85% Capacity Factor

Pollutant	NGCC Without CCS
CO_2	
• tons/year	1,661,720
• lb/MMBtu	119
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	Negligible
• lb/MMBtu	Negligible
NOx	
• tons/year	127
• lb/MMBtu	0.009
PM (filterable)	
• tons/year	Negligible
• lb/MMBtu	Negligible
Hg	
• tons/year	Negligible
• lb/TBtu	Negligible

The 560 (net) MWe NGCC plant was projected to have a TPC of $554/kWe, resulting in a 20-year LCOE of 68.4 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	**1x560 MWe net NGCC**				
Plant Size:	560.4	(MWe, net)	Heat Rate:	6,719	(Btu/kWh)
Primary/Secondary Fuel (type):	Natural Gas		Fuel Cost:	6.75	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	85	(%)	Capital Charge Factor:	16.4	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					12.2
Resulting Operating Costs (Levelized 2007 dollars)					**Mills/kWh**
Fixed Operating Cost					1.5
Variable Operating Cost					1.5
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					53.1
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					68.4

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

International Journal of Application or Innovation in Engineering & Management (IJAIEM)
Web Site: www.ijaiem.org Email: editor@ijaiem.org, editorijaiem@gmail.com
Volume 2, Issue 7, July 2013 ISSN 2319 - 4847

Techno-economic feasibility study for a peaking Gas Turbine power plant in Zimbabwe

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ABSTRACT

The research assessed the techno-economic viability of a Peaking Gas turbine Power Plant in Zimbabwe to partly address the 800MW energy deficit that the country is currently facing. The term "Peaking" describing the period of time at which the plant will operate, that is, it will only operate during periods of high electrical demand, and thus the plant will have a plant load factor of 20-33% as deduced in the Market Analysis. The deficit has resulted in erratic and unsustainable load shedding during peak hours which is costing the country's economy whereby the country is forced to import electricity, and companies are experiencing production disruptions as well as investing into costly backup power units. After carrying out an assessment of the several options to address the energy deficit the Gas turbine technology was chosen because of the nature of its design which is capable of addressing the requirements of a varying peak load. From the technical analysis the selected configuration is a Combined Cycle Gas Turbine (CCGT) Power Plant with a rated capacity of 120MW and a thermal efficiency of 57% which is comparable to expected performance from such a design. The economic analysis showed that the project will have a payback period of 7 years, and of importance is the project internal rate of return of 16.91% which is higher than the weighted average cost of capital (WACC) or the effective interest rate of 10%. Overally the feasibility study showed that not only is the project technically and economically sound, but shows sustainable development with its good environmental merits. The results from this study are proof that CCGT technology can be used to address the energy deficit currently being experienced in Zimbabwe and the Southern African Power Pool Region (SAPP).

Keywords: Combined Cycle Gas Turbine, Peaking Plant, Weighted Average Cost of Capital, Thermal efficiency

1. INTRODUCTION

1.1 Background

Energy is one of the pillars to economic and social development of a nation. The Industrial revolution is a testament to this fact and three factors provided the framework for it to occur. These were Energy, Labor and Technology. Hence the economy of a nation is dependent upon equitable access to sustainable, dependable and efficient energy sources.
Zimbabwe as a nation is facing challenges in meeting its power demand; this problem is not unique to Zimbabwe only as the Region itself has been faced with power challenges since 2007 (SAPP, 2011). Currently Zimbabwe's generating capacity is about 1400MW, with a maximum demand as high as 2200MW which will continue to escalate as the economy recovers (ZESA, 2013). The deficit is heavily experienced during peak periods, thus periods of high electrical energy demand. This deficit has resulted in erratic and sustained load shedding during peak hours. The current energy deficit as projected by ZESA to continue for the next 4-5years.

1.2 Justification

Reiterating the above said matter, it is all but clear that energy is of prime importance to Zimbabwe's socio-economic recovery and development. Load shedding has resulted in Agriculture, Industry and Mining suffering. Production levels in all sectors have been hit hard by the current energy situation. The power shortages have resulted in companies resorting to more expensive energy sources like the use of diesel generators to power their plants and production lines.
The so above said 800MW power shortage is heavily experienced during peak periods when the energy demand is higher than the available generation capacity (ZESA, 2013). Therefore in order to address this market or demand there is a need for a power station which can cater for the peak load.
The most obvious choice is a Gas turbine power plant, which traditionally has been used as a peaking plant all over the world. Several attributes of the Gas turbine make it a suitable technology as a peaking plant. These include its ability to achieve quick start-ups and shutdowns, the low initial investment capital required as compared to Coal fired power stations (Badeer.G, 2013). Furthermore, the energy deficit requires a swift means to address it; therefore the short construction period required for a Gas turbine power plant is also an additional advantage (Seebregts, 2010). In addition, Zimbabwe has sizeable natural gas reserves, and our neighboring country Mozambique has been discovered to have the third largest natural gas reserves in the world, making the required fuel for the plant readily available. It goes without saying that Gas turbine's ability to use multiple fuels is also another important factor, since it can also use ethanol which is also available in the country (Badeer.G, 2013).

Furthermore, it is also recommended that the plant will have a turbine inlet cooling system (TIC) which can use LNG as the coolant, as this will ensure uncompromised plant electrical output during warm periods. It also recommended for the plant to use the latest GE Mark V control system for the steam and gas turbine so as to ensure high plant thermal efficiency, low emissions, and overall securing high plant availability performance. It is also recommended that the GE LM6000PD Sprint Gas turbine be the gas turbine technology of choice due to its high thermal efficiency and low emission rates and from the technical analysis it had the best specifications.

8.2 Environmental Recommendations

Although the above recommended technical factors ensure protection for the environment, it is also recommended that several management technics must be adopted in the plant operation. These include implementation of a Cleaner Production (CP) strategy at the plant and using established international standards and overall using an Environmental Management System (EMS) so as to ensure that the environmental goals are achieved.

8.3 Economical Recommendations

In order to ensure that the project will attract financing the government might have to consider taxing the annual profits made from the project only after the return on investment has been realized as this will increase the project value to the investors.

8.4 Policy Recommendations

The plant will use fuel from Mozambique; therefore it is recommended that the government sticks to its energy policy measures especially its commitment in ensuring a solid bilateral business relationship with Mozambique. This is also pointed out in the energy policy where it's stated that the country is committed to regional power system integration through supporting initiatives on system integration, joint cross-border generation projects.

8.5 Overall Project Conclusion

Technical Performance	Plant Results	Required/World Class Standards
Plant Thermal Efficiency	57% (6300KJ/kWh)	55-60%
Plant Output	117MW	
Plant rated capacity	120MW	
Plant Load factor	25-33%	25-35%
Plant Availability Factor	85%	85%-95%
Environmental Performance		
NO_x	<30.4mg/m^3	<70mg/m^3 (S.I 72of 2009)
CO	<10mg/m^3	<40mg/m^3 (S.I 72of 2009)
Overall Environmental Grading of Project	Meets EMA requirements	
Economic Performance		
Expected Plant Life	25 years	<30 years
Investment requirement	($900/kW)108Million	$700-1150/kW
Plant O&M Cost	$33-45/kWh	$33-44/kWh
Fuel cost	$54.77/MWh	45/MWh
Project payback period	7.7 years	5-10 years
Project Internal rate of return	16.91%	10%
Project NPV after 25years	148 Million	
Total Production Cost	$73.81/MWh	$65-80/MWh

Therefore the feasibility study showed that there is a market for a peaking gas turbine power plant. Furthermore, there is technology capable of meeting the required technical and environmental performance. In addition, it is economically

PLANT RATINGS AND EFFICIENCIES

Efficiency
& Capacity

Vendor	Model	Net Output (MW)	Net Efficiency	Net Output (MW)	Net Efficiency
		1 GT + 1 ST		2 GT + 1 ST	
GE	S109F.03/S209F.03	403	> 58.0%	811	> 58.0%
	[illegible]/S209F.0[illegible]	[illegible]	> [illegible].0%	[illegible]	[illegible]
	S109HA.01/S209HA.01	592	> 61.0%	1181	> 61.0%
	S109HA.02/S209HA.02	701	> 61.0%	1398	> 61[illegible]
Alstom	KA26.1SS/KA26.2MS	500	60.0%	1000	60.0%
Siemens	SCC5-PAC4000F 1S/ SCC5-PAC4000F MS 2x1	445	58.7%	890	58.7%
	[illegible]-8000H	[illegible]	> 60.0%	[illegible]	[illegible]

[illegible] based on ISO conditions
[illegible] losses and Auxiliary [illegible]
[illegible]

Indexed Tariff

For Gas IPPs

Summary of Indexed Tariff for Combined Cycle IPPs up to October-December 2014

IPPs	Fuel	Variable O&M (foreign)	Total EPP (Rs./kWh)	Fixed O&M (Local)	Fixed O&M (foreign)	Insurance	Cost of W/C	ROE	ROEDC	WHT (@7.5%)	Debt Servicing	Total CPP (Rs./kWh)	Total Tariff (Rs./kWh)
Orient	4.3429	0.2081	**4.5510**	0.1716	0.1519	0.0559	0.0375	0.5057	0.1014	0.0455	0.9124	**1.9819**	6.5329
Saif	4.3432	0.3541	**4.6973**	0.1017	0.1358	0.0936	0.0361	0.4675	0.1380	0.0454	1.2759	**2.2940**	6.9913
Sapphire	4.3431	0.3502	**4.6933**	0.0979	0.1308	0.0994	0.0375	0.4884	0.1307	0.0464	1.1900	**2.2211**	6.9144
Halmore	4.3431	0.3557	**4.6988**	0.0916	0.1327	0.0781	0.0445	0.4799	0.1520	0.0474	1.4329	**2.4591**	7.1579
Average	4.3431	0.3170	**4.6601**	0.1157	0.1378	0.0818	0.0389	0.4854	0.1305	0.0462	1.2028	**2.2390**	6.8991