Office of Utilities Regulation

Least Cost Expansion Plan
ADDENDUM No.1 – March 8, 2005

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1. BACKGROUND

The Office of Utilities Regulation (OUR) has prepared a generation Least Cost Expansion Plan (LCEP) dated October 2004. This document constitutes Addendum No.1 to the LCEP and should be read and construed in conjunction with the text of the October 2004 Report.

The October LCEP reviewed an earlier analysis conducted by the Jamaica Public Service Company (JPS) dated February 2004 and made certain recommendations for optimizing generation capacity additions in order to meet the projected growth in electricity peak demand covering the period up to 2017.

The October 2004 LCEP identified the following capacity needs up to 2015 and the Base Case Plan contained in the study is summarized as follows:

- Approximately 230 MW of additional net generating capacity is required over the next three (3) years beginning in 2005 in order to avert significant power outages.

- The first block of 76 MW is required in 2005, the second block of 38 MW in 2006 and the remainder by 2007/08.

- Ideally, the additional capacity should be in the form of two (2) combined cycle plants burning liquefied natural gas (LNG) at the price agreed between the Governments of Jamaica and Trinidad and Tobago. This could be achieved by the following:
  - 2 x 38 MW of gas turbine capacity burning No. 2 Distillate in 2005;
  - 1 x 38 MW of gas turbine capacity burning No. 2 Distillate in 2006;
  - By 2007/08, combine these three (3) gas turbines with an additional gas turbine and two (2) heat recovery steam generators to create 2 x 115 MW combined cycle plants which would utilize LNG from Trinidad.

- Preparations be made for an additional base load plant of 115 MW to be installed in 2010. This plant would likely be another combined cycle plant, if LNG prices similar to those being offered by Trinidad and Tobago are available. For significantly higher LNG prices, coal fired steam plants would be the preferred option.

- The next block of generating capacity required after 2010 would be needed between 2013 and 2015, however, succeeding updates of the least cost plan will determine the optimal plant type prior to this date.

2. NEED FOR LCEP AMENDMENT

A number of important decisions have been taken subsequent to October 2005 and new factors introduced in respect of electricity generation, which have impacted on the LCEP. Therefore the need to revise the LCEP has arisen. The key considerations driving the revisions include the following:

1. As there was insufficient time to pursue a competitive tendering approach for the first tranche of capacity to be installed by 2005, the expansion of the Jamaica energy Partners (JEP) facilities at Old Harbour to add 49MW of medium speed diesel plant to the system by 2005 was approved.

2. In order for the gas strategy to be feasible, a partnership with the Government was seemingly established where Jamalco and JPS made indicative commitments for the off take of the LNG to be supplied from Trinidad and Tobago. Jamalco's commitment included the expansion of its alumina refinery. This expansion is capable of providing an additional 40 MW of capacity through cogeneration to the national grid by 2007. Government has approved the inclusion of this capacity inter-alia in keeping with its policy to encourage cogeneration and renewable sources of energy.

3. The gas strategy envisaged the conversion of the JPS existing steam generating units, GT10 to use LNG as well as installation of one (1) new 115MW combined cycle plant capable of utilizing LNG. Other plants including IPP facilities capable of being economically converted to using gas were not considered in the initial quantity of gas being negotiated and therefore, not included in the earlier analysis.

4. A modeling of the system indicated that JEP would be at a competitive disadvantage if it were not included in the gas strategy. JEP has indicated a commitment to the conversion of its existing and proposed new diesel plants totaling 124MW to burn LNG in 2008 if gas was made available to them. The amended LCEP now includes an assumption of the conversion of JEP plant to be capable of using gas.

5. The coincidence of conversion expenses and new plants in 2008 would create a temporary spike in the tariff to consumers given the significant investment stream in new generating capacity proposed. A delay of the installation of the second combined cycle plant until 2010 would create a smoother tariff path while still meeting the Loss of Load Probability (LOLP) criteria. This is possible as the second combined cycle plant is justified more on the basis of substitution/displacement of less economic plants than to meet the LOLP.

As a result of the above, a further study dated March 8, 2005 was undertaken by the OUR. The results and recommendations arising from the exercise are contained under Section 4 of this document.

3. THE KEY ASSUMPTIONS OF THE AMENDED BASE PLAN

The key assumptions for the amended Base Plan remain the same as outlined in section 2.3 of the October 2004 LCEP and is reproduced below for easy reference.

The Recommended Plan is based on the following assumptions:

- Planning objective of having a loss of load probability of no more than 0.55% (or 48 hours per year). This is a measure of system reliability and indicates the chance of having a power cut.
- Average growth in demand of 4.57% per year in accordance with the revised demand forecast.
- LNG fuel available from Trinidad at a price within the assumed range of $3.20 to $3.80 / Mbtu (Million British Thermal Units) at the power plant site in sufficient quantities to support two (2) combined cycle plants of 115 MW each.
- LNG from Trinidad can be made available in 2007 (or 2008).
- Additional LNG obtainable at an average market price of $4.3 / Mbtu.
- Coal available at plant at an average price of $1.5/Mbtu.
- The only plants retired during the planning horizon are JPPC (2015), JEP (2025) and Old Harbour No.1 (2015) based on the JPS retirement schedule.
- Medium speed diesels and gas turbines can be made available in 2005 and 2006. The gas turbines made available in these years can be converted to combined cycle plants in 2007 which can be run on the expected natural gas from Trinidad.

- Average discount rate of 12% for calculating present value of costs. This is based on the OUR's estimate of the weighted average cost of capital (WACC) of JPS used in the 2004 tariff review.

The fuel prices used in re-examining the LCEP is the same as that set out in Section 4 of the October 2004 study. It should be noted that the LCEP identifies generation requirements over a long term horizon and given the long operating life of typical power plants, it is not anticipated that short term movements in fuel prices will significantly impact the study outcome. Also, the price of the different fuels, relative to each other over the planning period, is of greater relevance in determining the least cost selection of generation type rather than the prevailing price of fuels.

4. AMENDED LEAST COST EXPLANSION PLAN

Economic studies have now been conducted and the amended LCEP arising from the above considerations has resulted in a new recommended Plan. The analysis was extended to the year 2027 so as to cover the LNG time frame of 20-years. The generation expansion plan detailed below emerged as the Base Case and is recommended for implementation by the OUR:

- Expansion of the existing Jamaica Energy Partner's barge mounted diesel plant located at Old Harbour by 49 MW in 2005/6 (already approved).

- Installation of 2 x 38 MW gas turbine plants in 2006.

- Addition of JAMALCO 40MW cogeneration in 2007 (already approved).

- Conversion of the 2 x 38 MW gas turbines (installed in 2006) to a 115 MW combined cycle plant burning LNG by adding a Heat Recovery Steam Generator in 2008.

- Addition of a second 115 MW combined cycle plant burning LNG in 2010.

- Conversion of all of JPS Oil-fired steam plants (Hunts Bay B6 and Old Harbour Units 1-4) as well as Hunts Bay GT10 to burn LNG in 2008.

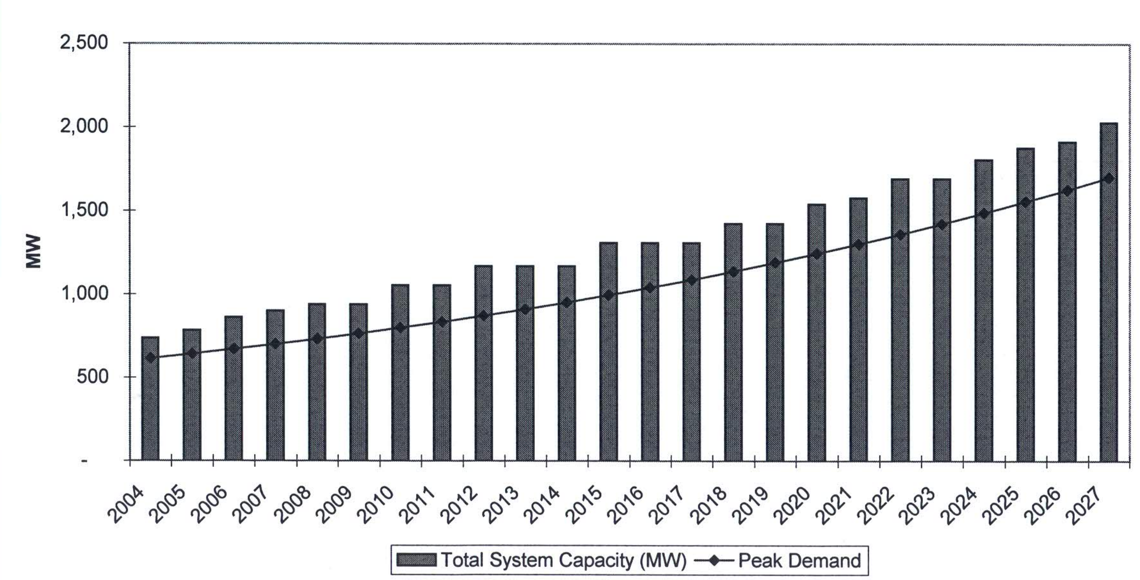
- Addition of the first in a series of 115 MW Coal fired steam fired plants in 2012.

This above plan fully utilizes the quantum of LNG allocated to the electricity sector. The 2x115MW combined cycle plants are expected to be sited at Hunts Bay or else where in the Kingston/ St. Catherine area given that 60% or more of the existing electricity load is located in this geographic region.

ESTIMATED ADDITIONAL COST COMPARED TO BASE CASE (US$ M)

Year	Plant Retired/ Converted	Plant Added	Fuel Type	Unit Net Output (MW)	No. of Units	Capacity Added (MW)	Capacity Retired/ Converted (MW)	Total System Capacity (MW)	Peak Demand	Reserve Capacity (MW)	Reserve Margin (%)	Loss of Load Probability (%)	Loss of Load Probability (hours/year)
2004								737	614	123	20.0%	1.126%	98.6
2005		JEP Medium Speed Diesel	No. 6 (2005-2008), NG from T&T (2008-2025)	16	3	48		785	642	143	22.3%	0.719%	63.0
2006		Gas Turbine	No. 2	38	2	76		861	671	190	28.4%	0.183%	16.0
2007		Jamalco	No. 2 (2007-2008), NG from T&T (As of 2008)	40	1	40		901	701	200	28.6%	0.145%	12.7
2008	2 GTs converted	Combine Cycle	NG from T&T	115	1	115	76	940	732	208	28.4%	0.178%	15.6
2009						-		940	765	175	22.9%	0.442%	38.7
2010		Combine Cycle	NG from T&T	115	1	115		1,055	799	256	32.1%	0.071%	6.2
2011						-		1,055	835	220	26.4%	0.191%	16.7
2012		Coal Fired Steam	Coal	115	1	115		1,170	872	298	34.2%	0.044%	3.9
2013								1,170	911	259	28.4%	0.122%	10.7
2014								1,170	952	218	22.9%	0.335%	29.3
2015	JPPC, OH1	Coal Fired Steam, Combine Cycle	Coal, NG from T&T	115	2	230	90	1,310	995	315	31.6%	0.059%	5.2
2016						-		1,310	1,041	269	25.9%	0.170%	14.9
2017						-		1,310	1,088	222	20.4%	0.470%	41.2
2018		Coal Fired Steam	Coal	115	1	115		1,425	1,138	287	25.2%	0.170%	14.9
2019						-		1,425	1,190	235	19.8%	0.482%	42.2
2020		Coal Fired Steam	Coal	115	1	115		1,540	1,244	296	23.8%	0.198%	17.3
2021		Gas Turbine	No. 2	38	1	38		1,578	1,301	277	21.3%	0.291%	25.5
2022		Coal Fired Steam	Coal	115	1	115		1,693	1,361	333	24.4%	0.134%	11.7
2023						-		1,693	1,423	270	19.0%	0.428%	37.5
2024		Coal Fired Steam	Coal	115	1	115		1,808	1,488	320	21.5%	0.226%	19.8
2025	JEP	Gas Turbine, Combine Cycle	No. 2, NG	38, 38, 115	3	191	122	1,877	1,556	321	20.7%	0.441%	38.6
2026		Gas Turbine	No. 2	38	1	38		1,915	1,627	288	17.7%	0.420%	36.8
2027		Coal Fired Steam	Coal	115	1	115		2,030	1,701	329	19.3%	0.267%	23.4
TOTAL					**21**	**1,581**	**288**						

OUR RECOMMENDED GENERATION EXPANSION PLAN



Parameter	US$ M
Plan cost from WASP	1,800.01
Adjustment for GTs	7.25
Conversion Cost	10.86
Total Cost	1,818.11
Base Case Cost	1,807.37
Cost over Base Case	**10.75**
% Over Base Case	0.59%

APPENDIX 1
EXPANSION TABLE

APPENDIX 2

WASP LCEP SCHEDULE

SOLUTION # 1 VARIABLE ALTERNATIVES BY YEAR

YEAR	PRESENT WORTH COST OF THE YEAR (K$) CONCST	SALVAL	OPCOST	ENSCST	TOTAL	OBJ.FUN. (CUMM.)	LOLP %	GTRB	CC#2	NGCC	CCFB	ORFS	MSDO	PFSM	NGC2
2027	9134	7884	18294	105	19650	2716761	0.267	4	1	1	7	0	0	0	3
2026	2818	2067	20138	193	21083	2697111	0.420	4	1	1	6	0	0	0	3
2025	8386	5253	21260	227	24621	2676029	0.441	2	1	1	6	0	0	0	3
2024	12833	7068	24580	115	30460	2651408	0.226	1	1	0	6	0	0	0	3
2023	0	0	27166	261	27427	2620947	0.428	1	1	0	5	0	0	0	3
2022	16097	6524	28944	80	38597	2593521	0.134	1	1	0	5	0	0	0	3
2021	2483	809	32120	205	33999	2554924	0.291	1	1	0	4	0	0	0	3
2020	20193	5981	34250	149	48611	2520925	0.198	0	1	0	4	0	0	0	3
2019	0	0	38206	435	38641	2472314	0.482	0	1	0	3	0	0	0	3
2018	25330	5437	40777	154	60824	2433673	0.170	0	1	0	3	0	0	0	3
2017	0	0	45791	499	46290	2372850	0.470	0	1	0	2	0	0	0	3
2016	0	0	48853	179	49032	2326560	0.170	0	1	0	2	0	0	0	3
2015	56729	6947	52294	58	102135	2277528	0.059	0	1	0	2	0	0	0	3
2014	0	0	68750	438	69188	2175394	0.335	0	1	0	1	0	0	0	2
2013	0	0	73795	162	73958	2106206	0.122	0	1	0	1	0	0	0	2
2012	49996	3806	79398	56	125644	2032248	0.044	0	1	0	1	0	0	0	2
2011	0	0	91337	307	91645	1906604	0.191	0	1	0	0	0	0	0	2
2010	37261	1357	98301	116	134321	1814960	0.071	0	1	0	0	0	0	0	2
2009	0	0	111770	903	112673	1680639	0.442	0	1	0	0	0	0	0	1
2008	46740	969	120407	372	166550	1567965	0.178	0	1	0	0	0	0	0	1
2007	0	0	148763	310	149073	1401415	0.145	0	1	0	0	0	0	0	0
2006	0	0	160234	443	160677	1252342	0.183	0	1	0	0	0	0	0	0
2005	0	0	172752	2163	174915	1091666	0.719	0	1	0	0	0	0	0	0
2004	0	0	181363	4031	185394	916751	1.126	0	1	0	0	0	0	0	0
2003	88404	0	194517	1192	284114	731357	0.342	0	1	0	0	0	0	0	0
2002	0	0	214965	438	215403	447244	0.146	0	0	0	0	0	0	0	0
2001	0	0	228930	2910	231840	231840	0.750	0	0	0	0	0	0	0	0

LEGEND

CCFB – **C**OAL FIRED STEAM PLANT (**C**IRCULATING **F**LUIDISED **B**ED TYPE)
CC#2 – **C**OMBINE **C**YCLE PLANT (BURNING **#2** DIESEL FUEL)
GTRB – **G**AS (COMBUSTION) **TURB**INE PLANT
MSDO – **M**EDIUM **S**PEED **D**IESEL PLANT
NGCC – **N**ATURAL **G**AS FIRED **C**OMBINE **C**YCLE PLANT (LNG AT MARKET PRICE)
NGC2 – **N**ATURAL **G**AS FIRED **C**OMBINE CYCLE PLANT (LNG AT TRINIDAD PRICE)
ORFS – **OR**IMULSION **F**IRED **S**TEAM PLANT
PFSM – **P**ETCOKE **F**IRED **S**TEAM PLANT
CONCST – **CON**STRUCTION **COST**
SALVAL – **SAL**VAGE **VAL**UE
OPCOST – **OP**ERATING **COST**
ENSCST – **E**NERGY **N**OT **S**ERVED (UNSERVED ENERGY) **COST**

NOTE

Two (2) Gas Turbine plants which are included in the WASP optimizing sequence and scheduled for installation in 2006, are not shown in the table above but however, form a part of the Combine Cycle Plant to be implemented in 2008.