Hawaii Electric Light Company, Inc. • PO Box 1027 • Hilo, HI 96721-1027

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Warren H. W. Lee, P.E.
President

January 30, 2007

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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaii Electric Light Company, Inc.

In accordance with paragraph 5.3a of General Order No. 7, the following information is respectfully submitted.

HELCO's 2006 total system capability was 266,600 kW net (271,000 kW gross) and included firm capacity power purchases of 24,700 kW from Puna Geothermal Venture ("PGV")[1] and 60,000 kW from Hamakua Energy Partners, L.P. ("HEP"). HELCO's system peak of 201,300 kW net (206,500 kW gross) occurred on December 27, 2006, at approximately 6:34 p.m. The 2006 reserve margin was 32.4% over the system peak.

Load Management/DSM

At the time of the system peak, HELCO had in place 27 load management contracts totaling 6,367 kW under Rider M and Schedule U, which reduced the evening peak by approximately 6,000 kW. In addition, HELCO has had residential and commercial & industrial demand side management ("DSM") programs in place since 1996, which reduced the system peak by an estimated 7,700 net kW (net of free riders). Without the load management and DSM impacts, the system peak would have been approximately 215,000 kW net, with a 24.0% reserve margin.

[1] PGV's normal rating is 30 MW. In July 2006, PGV began experiencing problems with well production. At the time of the system peak, PGV's output was 24.7 MW. PGV has represented that it expects to be restored to the contract export of 30 MW by April 2007.

Distributed Generation ("DG") and Combined Heat and Power ("CHP")

Firm DG resources can provide generating capacity if dispatchable by the utility, or can reduce peak loads if operated by customers. HELCO has been including forecasted firm DG resources, namely CHP, in its Adequacy of Supply ("AOS") evaluations for the past several years. The updated short-term CHP forecast (dated January 12, 2007) used for this 2007 AOS report projects that the peak reduction impacts of CHP installations will be slightly lower than the impacts projected for the 2006 AOS report.[2] This comes as a result of (1) new rules issued by the U.S. Environmental Protection Agency ("EPA") which will require more stringent emission controls for stationary diesel engines in the near future, (2) Commission criteria required to be met by HELCO in order to provide customer-sited DG projects on a regulated utility basis, and (3) other uncertainties concerning customer-sited DG. A further explanation of these factors is provided in Attachment 1.

Because the CHP impacts contained in this analysis are small relative to HELCO's reserve margin, the effects of the updated short-term forecast are not significant.

Reserve Margins

Attachment 2 shows the expected reserve margin over the next three years, based on HELCO's 2006-2011 Sales and Peak Forecast, dated June 20, 2006, HELCO's latest estimate of forecasted DSM impacts, and HELCO latest estimate of forecasted CHP impacts. (Attachment 2 also shows the estimated reserve margins without future DSM.) Attachment 3 details the gross and net ratings of HELCO units and Independent Power Producer ("IPP") units.

The following capacity planning criterion is used to determine the need for additional generation:

> *The sum of the reserve ratings of all available units, minus the reserve rating of the largest available unit, minus the reserve ratings of any units on maintenance, must be equal to or greater than the system peak load to be supplied*[3].

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[2] For example, in the 2006 AOS report, the peak reduction impact of CHP in the year 2008 was forecasted to be 4.9 MW. In this 2007 AOS report, the peak reduction impact of CHP in the year 2008 is forecasted to be 2.0 MW.

[3] HELCO is evaluating whether and to what extent reserve margins higher than those produced by application of the capacity planning criteria should be targeted based on factors (such as unit availabilities and the need to account for fluctuations in intermittent generation on the system) not explicitly considered by the criteria.

HELCO's generation capacity for the Big Island for the next three years is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Very truly yours,

Attachments

cc: Division of Consumer Advocacy

Factors Affecting CHP Forecast

New EPA Requirements

On July 11, 2005, the EPA issued interim New Source Performance Standards ("NSPS") requiring lower nitrogen oxides ("NOx") emission levels for stationary diesel engines manufactured after April 1, 2006. On July 11, 2006, the EPA issued the final NSPS for stationary diesel engines, specifying the lower NOx emission requirements to take effect in January 2011. The NSPS also requires the use of lower sulfur diesel fuel, with the most stringent requirements taking effect in late 2010 for units built after April 1, 2006. Based on HELCO's understanding, the new NSPS could significantly increase the costs of future DG installations. This would especially impact the feasibility of future customer DG installations, including CHP.

Limitations on Utility DG at Customer Sites

In October 2003, the Commission opened a DG Investigative Docket No. 03-0371 to determine DG's potential benefits to, and impact on, Hawaii's electric distribution systems and markets, and to develop policies and a framework for DG projects deployed in Hawaii.

On January 27, 2006, the Commission issued Decision and Order No. 22248 ("D&O 22248") in its DG Investigative Docket. In D&O 22248, the PUC indicated that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system.

With regard to DG ownership, D&O 22248 affirmed the ability of the electric utilities to procure and operate DG for utility purposes at utility sites. The Commission also indicated its desire to promote the development of a competitive market for customer-sited DG. In weighing the general advantages and disadvantages of allowing a utility to provide DG services on a customer's site, the Commission found that the "disadvantages outweigh the advantages." However, the Commission also found that the utility "is the most informed potential provider of DG" and it would not be in the public interest to exclude the electric utilities from providing DG services at this early stage of DG market development.

Therefore, D&O 22248 allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need, (2) the DG is the lowest cost alternative to meet that need, and (3) it can be shown that, in an open and competitive process acceptable to the Commission, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility's offering.

On March 1, 2006, HELCO (along with HECO and MECO, collectively, the "Companies") filed a Motion for Clarification and/or Partial Reconsideration ("DG Motion"), requesting that the Commission clarify how the three conditions under which electric utilities are allowed to provide regulated DG services at customer-owned sites will be administered, in order to better determine the impacts the conditions may have on the Companies' DG plans. On April 6, 2006, the Commission issued Order No. 22375 on the DG Motion and provided clarification to the conditions under which electric utilities are allowed to provide regulated DG services (e.g., utilities can use a portfolio perspective—a DG project aggregated with other DG systems and other supply-side and demand-side options—to support a finding that utility-owned customer-sited DG projects fulfill a legitimate system need, and the economic standard of "least cost" in the order means "lowest reasonable cost" consistent with the standard in the IRP framework), and affirmed that the electric utility has the responsibility to demonstrate that it meets all applicable criteria included in D&O 22248 in its application for Commission approval to proceed with a specific DG project.

Prior to opening of the investigative DG proceeding, in October 2003, the Companies filed an application for approval of CHP tariffs, under which they would own, operate and maintain customer-sited, packaged CHP systems (and certain ancillary equipment) pursuant to standard form contracts with eligible commercial customers. The CHP tariff application (Docket No. 03-0366), was suspended by the Commission in March 2004 until, at a minimum, the matters in Docket No. 03-0371 were adequately addressed.

By letter dated November 2, 2006, the Commission requested that the Companies state their intentions with regard to pursuing the CHP tariff application, given the Commission criteria for allowing regulated utility-owned DG stated in D&O 22248, as clarified by Order No. 22375. On December 29, 2006, the Companies withdrew their CHP tariff application, based on the determination that it would be difficult to implement CHP projects on a programmatic basis given the criteria of D&O 22248, as clarified. The Companies will continue to consider CHP projects on a case-by-case basis, and if a decision is made to pursue the implementation of a CHP project, then an application would be filed requesting Commission approval of such CHP project.

On December 17, 2004, HELCO filed an application for a CHP project with Koa Hotel, LLC ("Koa Hotel"), Docket No. 04-0366. On January 21, 2005, the Commission issued Order No. 21554, suspending the Koa Hotel application pending the resolution of its Distributed Generation Investigation, Docket No. 03-0371. Following the Commission's issuance of D&O 22248, as clarified, HELCO determined that it would need to work with Koa Hotel further to re-evaluate CHP. Accordingly, on December 29, 2006, HELCO filed a Withdrawal of Application for its proposed Koa Hotel CHP System. On January 16, 2007, the Commission issued Order No. 23197 approving HELCO's Withdrawal of Application and closed Docket No. 04-0366. By letter dated January 17, 2007, HELCO gave notice to Koa Hotel that it was terminating the CHP Agreement governing the proposed Koa Hotel CHP System. HELCO will continue to work with Koa Hotel with respect to energy cost savings alternatives, and if a decision is made to pursue the implementation of a CHP System, then an application would be filed requesting Commission approval of a new CHP Agreement.

D&O 22248 also required the Companies to file tariffs, establish reliability and safety requirements for DG, establish a non-discriminatory DG interconnection policy, develop a standardized interconnection agreement to streamline the DG application review process, establish standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services), and establish detailed affiliate requirements should the utility choose to sell DG through an affiliate. The Companies filed their proposed modifications to existing DG interconnection tariffs and their proposed unbundled standby rates for Commission approval in July and August 2006, respectively. By Order No. 23171, dated December 28, 2006, the Commission opened a new proceeding, Docket No. 2006-0497, to investigate the Companies' proposed DG interconnection tariff modifications and standby rate tariffs. The Commission will conduct public hearings in the first quarter of 2007, and thereafter a procedural schedule will be developed.

Other Uncertainties Associated with Customer DG

There is a significant degree of uncertainty in forecasting the customer DG market. On a macro-scale, the economic viability of CHP is highly sensitive to fuel and electricity prices. The energy efficiency benefits of a CHP system may not translate to overall cost savings for a customer if the CHP fuel cost (for diesel fuel oil, propane or synthetic natural gas) is significantly higher than the cost of fuel used to generate grid electricity. Furthermore, prospective CHP projects are subject to customer desire and support, which can be extremely variable. Finally, it should be noted that until Docket No. 2006-0497 is completed, the impacts, if any, of the pending DG interconnection and standby rate tariffs on customer DG development cannot be determined.

Table 1
Adequacy of Supply

	With 3rd Party CHP [I]					
			Without Future DSM (Includes Acquired DSM) [II]		With Future DSM (Includes Acquired DSM) [III]	
Year	System Capability at Annual Peak Load (net kW) [A]	Notes	System Peak (net kW) [B] [IV]	Reserve Margin (%) [[A-B]/B] [IX]	System Peak (net kW) [C] [IV]	Reserve Margin (%) [[A-C]/C] [IX]
Recorded 2006	266,600	(V)	201,300	32.4%	N/A	N/A
Future 2007	271,900	(VI)	207,400	31.1%	206,400	31.7%
2008	271,900	(VII)	212,400	28.0%	210,800	29.0%
2009	288,200	(VIII)	217,600	32.4%	215,500	33.7%

Notes:

(I) With 3rd Party CHP:
- Forecasted system peaks include reduction for forecasted system level third party CHP impacts.[1]

(II) System Peaks (Without Future Peak Reduction Benefits of DSM Programs):
- Implementation of full-scale DSM programs began in the first quarter of 1996 following Commission approval of the programs.
- The forecasted system peak values for the years 2007-2009 include the actual peak reduction benefits acquired in 1996-2005 and the estimated peak reduction benefits acquired in 2006, as well as the benefits of the Rider M and Schedule U contracts, and third party CHP impacts.

[1] 3rd Party CHP impacts are from a CHP forecast dated January 12, 2007. These impacts are included in the system peak. The impacts are at system level based on a loss factor of 8.39% and include an availability factor to account for periods when the 3rd Party CHP is unavailable due to forced outage and maintenance.

(III) System Peaks (With Future Peak Reduction Benefits of DSM Programs):

- The forecasted system peaks for 2007-2009 include the peak reduction benefits of the DSM programs (acquired and future) and the Rider M and Schedule U contracts, and third party CHP impacts.

(IV) The 2007-2009 annual forecasted system peaks are based on

- HELCO's 2006-2011 Sales and Peak Forecast, dated June 20, 2006. The HELCO annual forecasted system peak is expected to occur in the month of December.

(V) System Capability for 2006 includes:

- HELCO units at a total of 181,900 kW net (186,300 kW gross).

- Firm power purchase contracts with a combined net total of 84,700 kW from PGV (24,700 kW)[2] and HEP (60,000 kW).

(VI) System Capability for 2007 includes

- HELCO units at a total of 181,900 kW net (186,300 kW gross).

- Firm power purchase contracts with a combined net total of 90,000 kW from PGV (30,000 kW) and HEP (60,000 kW).

(VII) System Capability for 2008 includes:

- HELCO units at a total of 181,900 kW net (186,300 kW gross).

- Firm power purchase contracts with a combined net total of 90,000 kW from PGV (30,000 kW) and HEP (60,000 kW).

(VIII) System Capability for 2009 includes:

- HELCO units at a total of 198,200 kW net (204,600 kW gross). This includes the anticipated installation of Keahole ST-7, a nominal 16,300 kW (net) steam turbine generator (Phase III of a nominal 60,300 kW (net) dual train combined-cycle unit). In August 2006, HELCO awarded the engineering consultant contract to design the conversion to a dual train combined cycle unit. Equipment procurement and construction is currently underway for ST-7and all the discretionary permits have been received for the project, which is scheduled for commercial operation in December 2009. The expeditious installation of ST-7 is one of the conditions specified in the settlement agreement reached on November 6, 2003 between

[2] PGV's normal rating is 30 MW. In July 2006, PGV began experiencing problems with well production. At the time of the system peak, PGV's output was 24.7 MW. PGV has represented that it expects to be restored to the contract export of 30 MW by April 2007.

HELCO, the Keahole Defense Coalition, the State Department of Hawaiian Home Lands, the State Department of Land and Natural Resources, the State Department of Health, Peggy Ratliff, and Mahi Cooper, which in turn was incorporated among the conditions in the State Land Use Commission Decision and Order (November 7, 2005) reclassifying the Keahole site as Urban, and in the County ordinance (May 2, 2006) rezoning the site to General Industrial.

- Firm power purchase contracts with a combined net total of 90,000 kW from PGV (30,000 kW) and HEP (60,000 kW).

(IX) Reserve Margin

- The reserve margins shown for 2007-2009 assume that HEP and PGV are at full ratings.

HELCO Adequacy of Supply
2006 Unit Ratings (Firm Capacity at Actual System Peak in December 2006)

	(Gross MW)		(Net MW)	
Unit	Reserve Rating (MW)	NTL Rating (MW)	Reserve Rating (MW)	NTL Rating (MW)
Shipman 3	7.50	7.50	7.10	7.10
Shipman 4	7.70	7.70	7.30	7.30
Hill 5	14.10	14.10	13.50	13.50
Hill 6	21.40	21.40	20.20	20.20
Puna	15.50	15.50	14.10	14.10
Kanoelehua D11	2.00	2.00	2.00	2.00
Waimea D12	2.75	2.50	2.75	2.50
Waimea D13	2.75	2.50	2.75	2.50
Waimea D14	2.75	2.50	2.75	2.50
Kanoelehua D15	2.75	2.50	2.75	2.50
Kanoelehua D16	2.75	2.50	2.75	2.50
Kanoelehua D17	2.75	2.50	2.75	2.50
Keahole D21	2.75	2.50	2.75	2.50
Keahole D22	2.75	2.50	2.75	2.50
Keahole D23	2.75	2.50	2.75	2.50
Kanoelehua CT-1	11.50	11.50	11.50	11.50
Keahole CT-2	13.00	13.00	13.00	13.00
Puna CT-3	20.80	20.80	20.40	20.40
Keahole CT-4	22	22	22	22
Keahole CT-5	22	22	22	22
Panaewa D24	1.00	1.00	1.00	1.00
Ouli D25	1.00	1.00	1.00	1.00
Punaluu D26	1.00	1.00	1.00	1.00
Kapua D27	1.00	1.00	1.00	1.00
HELCO Total	186.25	184.00	181.85	179.60
PGV	24.70 (1)	24.70 (1)	24.70 (1)	24.70 (1)
HEP	60.00	60.00	60.00	60.00
IPP Total	84.70	84.70	84.70	84.70
System Total	270.95	268.70	266.55	264.30

Notes:

(1) PGV's normal rating is 30 MW. In July 2006, PGV began experiencing problems with well production. At the time of the system peak, PGV's output was 24.7 MW. PGV has represented that it expects to be restored to the contract export of 30 MW by April 2007.

HELCO Adequacy of Supply
2007-2008 Unit Ratings (Firm Capacity at Forecasted System Peak in December 2007-2008)

	(Gross MW)		(Net MW)	
Unit	·Reserve Rating (MW)	NTL Rating (MW)	Reserve Rating (MW)	NTL Rating (MW)
Shipman 3	7.50	7.50	7.10	7.10
Shipman 4	7.70	7.70	7.30	7.30
Hill 5	14.10	14.10	13.50	13.50
Hill 6	21.40	21.40	20.20	20.20
Puna	15.50	15.50	14.10	14.10
Kanoelehua D11	2.00	2.00	2.00	2.00
Waimea D12	2.75	2.50	2.75	2.50
Waimea D13	2.75	2.50	2.75	2.50
Waimea D14	2.75	2.50	2.75	2.50
Kanoelehua D15	2.75	2.50	2.75	2.50
Kanoelehua D16	2.75	2.50	2.75	2.50
Kanoelehua D17	2.75	2.50	2.75	2.50
Keahole D21	2.75	2.50	2.75	2.50
Keahole D22	2.75	2.50	2.75	2.50
Keahole D23	2.75	2.50	2.75	2.50
Kanoelehua CT-1	11.50	11.50	11.50	11.50
Keahole CT-2	13.00	13.00	13.00	13.00
Puna CT-3	20.80	20.80	20.40	20.40
Keahole CT-4	22	22	22	22
Keahole CT-5	22	22	22	22
Panaewa D24	1.00	1.00	1.00	1.00
Ouli D25	1.00	1.00	1.00	1.00
Punaluu D26	1.00	1.00	1.00	1.00
Kapua D27	1.00	1.00	1.00	1.00
HELCO Total	186.25	184.00	181.85	179.60
PGV	30.00	30.00	30.00	30.00
HEP	60.00	60.00	60.00	60.00
IPP Total	90.00	90.00	90.00	90.00
System Total	276.25	274.00	271.85	269.60

Notes:

HELCO Adequacy of Supply
2009 Unit Ratings (Firm Capacity at Forecasted System Peak in December 2009)

	(Gross MW)		(Net MW)	
Unit	Reserve Rating (MW)	NTL Rating (MW)	Reserve Rating (MW)	NTL Rating (MW)
Shipman 3	7.50	7.50	7.10	7.10
Shipman 4	7.70	7.70	7.30	7.30
Hill 5	14.10	14.10	13.50	13.50
Hill 6	21.40	21.40	20.20	20.20
Puna	15.50	15.50	14.10	14.10
Kanoelehua D11	2.00	2.00	2.00	2.00
Waimea D12	2.75	2.50	2.75	2.50
Waimea D13	2.75	2.50	2.75	2.50
Waimea D14	2.75	2.50	2.75	2.50
Kanoelehua D15	2.75	2.50	2.75	2.50
Kanoelehua D16	2.75	2.50	2.75	2.50
Kanoelehua D17	2.75	2.50	2.75	2.50
Keahole D21	2.75	2.50	2.75	2.50
Keahole D22	2.75	2.50	2.75	2.50
Keahole D23	2.75	2.50	2.75	2.50
Kanoelehua CT-1	11.50	11.50	11.50	11.50
Keahole CT-2	13.00	13.00	13.00	13.00
Puna CT-3	20.80	20.80	20.40	20.40
Keahole CT-4	- (I)	- (I)	- (I)	- (I)
Keahole CT-5	- (I)	- (I)	- (I)	- (I)
Keahole DTCC	62.36 (I)	62.36 (I)	60.30 (I)	60.30 (I)
Panaewa D24	1.00	1.00	1.00	1.00
Ouli D25	1.00	1.00	1.00	1.00
Punaluu D26	1.00	1.00	1.00	1.00
Kapua D27	1.00	1.00	1.00	1.00
HELCO Total	204.61	202.36	198.15	195.90
PGV	30.00	30.00	30.00	30.00
HEP	60.00	60.00	60.00	60.00
IPP Total	90.00	90.00	90.00	90.00
System Total	294.61	292.36	288.15	285.90

Notes:

(I) Conversion of Keahole CT-4 and CT-5 to dual train combined cycle (DTCC) with the addition of Keahole ST-7.