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February 27, 2007

Edward L. Reinhardt
President

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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
Maui Electric Company, Limited ("MECO")

In accordance with paragraph 5.3a of General Order No. 7, the following information is respectfully submitted.[1]

This report will show that MECO has sufficient capacity to meet the forecasted loads on the islands of Maui, Lanai and Molokai. Although, MECO may not, at times, have sufficient capacity on the Maui system to cover for the loss of the largest unit, MECO will implement appropriate mitigation measures to overcome the insufficient reserve capacity situation.

1.0 Maui Division

1.1 Peak Demand and System Capability in 2006

Maui's 2006 system peak occurred on August 14, 2006, and was 206,400 kW (net) or 210,800 kW (gross). The total system capability of Maui had a reserve margin of approximately 13% over the 2006 system peak, as shown in Attachment 1.

[1] MECO's Adequacy of Supply ("AOS") report is due within 30 days after the end of the year. On January 26, 2007, MECO requested an extension to no later than March 30, 2007, to file its report to allow it to better assess and incorporate the impact of its most recent generation availability experience (for the calendar year 2006), recently updated maintenance schedules and an updated forecast for Combined Heat and Power on the Company's reserve capacity outlook for the 2007 – 2011 period to be covered by the 2007 AOS. On February 1, 2007, the Commission issued a letter granting MECO's request

1.2 Maui Division Capacity Planning Criteria

The following capacity planning criteria are used to determine the timing of an additional generating unit for the Maui Division:

New generation will be added to prevent the violation of the rule listed below where "units" mean all units and firm capacity suppliers physically connected to the system, and "available unit" means an operable unit not on scheduled maintenance.

The sum of the reserve ratings of all 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.

In addition, consideration will be given to maintaining a reserve margin of approximately 20 percent based on Reserve Ratings.

1.3 Projected Peak Demand

MECO's 2006 system peak of 210.8 MW (gross) or 206.4 MW (net) occurred on August 14, 2006. The 2006 annual peak was 4.3 MW higher than the 2005 system recorded peak of 206.5 MW (gross) or 202.1 MW (net) set on August 8, 2005.

MECO's higher system peak in 2006 compared to 2005 can be attributed in part to new load growth (i.e., increase in number of customers and new construction) from customers such as the Maui High Performance Computing Center's new building and Maui Memorial Medical Center's new wing, both of which opened in the third quarter of 2006, and new home construction in central, south, and west Maui. The growth from new load was partially offset by the continuation of cooler, less humid weather and the loss of load from the Kapalua Bay Hotel.

Peaks are expected to continue growing during the forecast horizon as new construction projects are completed and loads are added such as the expansion of the Kaanapali Ocean Resorts, Maui Ocean Club's new tower and several residential subdivisions throughout Maui. Offsets will occur with the loss of load from the Renaissance Wailea, which will be demolished in 2007 and expected to reopen as the St. Regis at the end of 2009. As shown in Table 1 in Attachment 1, peak demand is forecasted to continue to increase.

Recorded System Peak Demand

Year	Recorded System Peak, MW-Net
1997	170.9
1998	172.3
1999	176.3
2000	181.2
2001	187.0
2002	189.8
2003	197.7
2004	206.5
2005	202.1
2006	206.4

1.4 MECO's Portfolio Approach to Capacity Planning

Capacity planning in Hawaii has increased in complexity in recent years because of the myriad of resources that may be available to meet consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. Electric utilities must consider all feasible demand-side and supply-side resources in integrated resource planning under the Hawaii Public Utilities Commission's ("Commission") Integrated Resource Planning Framework. In addition, electric utilities in Hawaii must comply with Renewable Portfolio Standards established in Hawaii Revised Statutes, Sections 269-91 to 269-95. Moreover, MECO must comply with the requirements in the Commission's Competitive Bidding Framework, issued on December 8, 2006, in Docket No. 03-0372, to acquire new supply-side resources.

In accordance with MECO's preferred plan developed in IRP-2 and its modified preferred plan developed in its IRP-2 evaluation reports prepared in 2004 and 2005, MECO will rely upon a portfolio of demand-side and supply-side resources to meet the growing demand for electricity. This portfolio will consist of energy efficiency and load management demand-side management ("DSM") resources, renewable resources, distributed generation ("DG") resources, existing and future utility firm capacity generation, existing firm capacity non-utility generation, and potential firm capacity non-utility generation.

A portfolio approach to capacity planning is necessary because of the uncertainties associated with each type of resource. For example, the economic attractiveness of energy efficiency DSM measures is a function of actual fuel prices and tax credits, which may be affected by federal legislation to extend the "sunset date", the date at which the tax credits will no longer be available. For load management DSM programs, there is uncertainty as to when regulatory

approval will be received and the rate at which customers will choose to participate in the programs. Central station and distributed generation, whether utility or non-utility, are subject to the uncertainties of the permitting process. Furthermore, the actual impacts of customer-owned DG such as combined heat and power ("CHP") will be dependent upon actual and projected fuel prices and customer acceptance of the technology. Renewable energy projects are subject to the uncertainty of community acceptance, as demonstrated by Hawaiian Electric Company, Inc.'s ("HECO") experience in attempting to implement a wind energy project above Kahe on Oahu in 2005. Therefore, by pursuing an array of demand-side and supply-side resources with a portfolio approach, some of the uncertainty can be mitigated because the successes of some resources can offset the lower productivity of other resources.

1.5 HC&S Power Purchase Agreement ("PPA")

MECO filed a letter with the Commission in Docket No. 6616 (Hawaiian Commercial & Sugar Company ["HC&S"]), on July 27, 2005, which informed the Commission that MECO and HC&S agreed on June 28, 2005 not to issue a notice of termination of the PPA resulting in termination of the PPA prior to the end of the day on December 31, 2011. This agreement was reached so that HC&S will have more certainty as to the future revenue sources supporting its sugar business, MECO will be able to rely on the continued availability of power from HC&S (a firm, non-fossil fuel power producer) beyond the end of 2007 in planning MECO's generating system and in meeting its Renewable Portfolio Standards, and both parties will have additional time in which to consider HC&S' future plans before negotiating a new, long-term PPA. For planning purposes, MECO assumes the HC&S PPA will terminate at the end of 2011.

1.6 Kaheawa Wind Power ("KWP")

On June 9, 2006, KWP, an Independent Power Producer ("IPP"), completed construction of a 30 MW wind farm and began providing energy to the Maui system. Although the installation of this wind resource will provide the Maui system with up to 30 MW of additional energy production, the Maui system capability will not be affected because the wind resource is an as-available resource, which is not dispatchable and cannot provide given amounts of power at scheduled times.

1.7 Makila Hydro ("Makila")

On September 22, 2006, Makila, an IPP, completed construction of a 500 kW hydro-electric facility and began providing energy to the Maui system. MECO and Makila executed a PPA on May 10, 2005. MECO submitted an application to the Commission on June 28, 2005, which among other things, requested approval of the PPA. On May 10, 2006, the Commission issued Decision & Order No. 22460, approving the PPA. Although the installation of this hydro resource will provide the Maui system with up to 500 kW of additional energy production, the

Maui system capability will not be affected because the hydro resource is an as-available resource, which is not dispatchable and cannot provide given amounts of power at scheduled times.

1.8 Maalaea Unit 18 Status

On October 27, 2006, Maalaea Unit 18, a nominal 17,100 kW (net) steam turbine generator, was placed into commercial operation.[2] Maalaea Unit 18 is the third and final phase of a combined cycle unit that consists of two combustion turbines and the steam turbine generator totaling 56,780 kW (net).[3]

1.9 Maalaea Unit 13 Status

On December 9, 2005, Maalaea Unit 13, a 12.34 MW (net) Mitsubishi diesel engine generator, suffered equipment failure causing extensive damage to the engine crankshaft, frame, and cylinder blocks. The current repair schedule estimates that it will take approximately seventeen months to manufacture the necessary parts, assemble and test the parts at the manufacturing plant, disassemble and ship the parts to Maui, and finally reassemble and test the parts at Maalaea. Consequently, MECO projects Maalaea Unit 13 will be unavailable for service to the electrical system until approximately July 2007.

The impact of the unavailable capacity from Maalaea Unit 13 for the first six months of 2007 is shown in the system capability chart on page 1 of Attachment 2. Maui will also experience significant shortfalls in reserve capacity during this same period. MECO plans to implement one or more of the mitigation measures identified in Section 1.17 below during this period in order to mitigate the potential impact the reserve capacity shortfall may have on its system reliability.

1.10 Waena Unit 1 Status

Consistent with the conclusions of MECO's IRP-2 process, including the conclusions in its IRP-2 Evaluation Reports filed in 2004 and 2005, MECO is currently pursuing the permitting of a simple cycle combustion turbine at the Waena Generating Station. The property designated for the future Waena Generating Station is located in central Maui and was purchased by MECO from Alexander & Baldwin on November 26, 1996. On July 7, 2000, the Maui County Council approved MECO's Change in Zoning application (to change the zoning from Agricultural to

[2] Commission approval for the purchase and installation of Maalaea Unit 18 was received in Decision & Order No. 13730, filed January 11, 1995, in Docket No. 7744.

[3] The NTL rating for Maalaea Unit 18 of 17.1 MW reflects the expected output of the generating unit based on the output of Maalaea Unit 15. Testing of Maalaea Unit 18 to, among other things, establish a NTL rating for the unit is currently in progress and is expected to be completed in the second quarter of 2007.

Heavy Industrial) for the Waena Generating Station and the bill was subsequently approved by the Mayor on July 13, 2000.

MECO's IRP-2, 2005 Evaluation Report, submitted to the Commission on April 29, 2005 in Docket No. 99-0004, indicated that additional firm capacity would be needed in 2009, and that need for capacity would best be met by installing a 20 MW (nominal) simple cycle combustion turbine.

Because of the long lead time needed to install a new generating unit, air permitting activities were initiated in 2000 in order to be able to meet a commercial operation date in 2009. (Air permitting activities are the first critical path components in the schedule to install a generating unit.) A Prevention of Significant Deterioration/Covered Source ("PSD/CS") permit application (i.e., air permit application), was submitted to the State of Hawaii Department of Health ("DOH") on December 5, 2002.

As noted in Section 1.5, MECO and HC&S agreed on June 28, 2005 not to issue a notice of termination of the PPA resulting in termination of the PPA prior to the end of the day on December 31, 2011. With this extension of the PPA, the need date for new firm capacity was deferred from 2009 to 2011, based on forecasts for peak demand, energy efficiency DSM impacts, load management DSM impacts and CHP impacts in effect at that time.

Through negotiations with DOH in July 2005, MECO agreed to resubmit its air permit application with updates included in the Maalaea Unit 18 PSD/CS permit, which was approved on September 8, 2004. In compliance with this request, MECO resubmitted its air permit application in December 2005. On January 30, 2006, the DOH declared MECO's air permit application "complete," meaning that all information needed by DOH to review the application was contained within the application.

Based on current capacity planning analysis, which is discussed further in Sections 1.14 and 1.14.1 below, MECO needs additional firm generating capacity in 2011 in order to satisfy Rule 1 of its capacity planning criteria.[4] The Commission's Competitive Bidding Framework requires that MECO employ a competitive bidding process to acquire the needed capacity or seek a waiver from the competitive bidding requirement from the Commission. MECO will comply with the requirements of the Competitive Bidding Framework. MECO's IRP-3 report will be filed with the Commission no later than April 30, 2007.

[4] In 2010, based on forecasts for peak demand, energy efficiency DSM impacts, load management DSM impacts and CHP impacts in effect at this time, Maui's reserve margin is anticipated to fall below the 20% minimum reserve margin guideline (to 19 %) in its capacity planning criteria. MECO does not plan to advance the need date for firm generating capacity to 2010 based on its reserve margin being slightly less than 20% because MECO fully expects to be able to meet demand, even with a unit on maintenance and with the largest remaining available unit forced out of service at the time of the system peak in that year.

1.11 Hana Distributed Generation

In the previous Adequacy of Supply report that was filed on March 6, 2006, MECO's intended use of the two 1,000 kW standby diesel engine generators, located at Hana Substation No. 41, was for emergency conditions as a capacity source, if required. However, MECO plans to complete a communication and controls project in 2007, contingent upon Commission approval of the project that will allow the Hana units to be operated as dispatchable distributed generation units. As a result, the Hana units will be considered firm capacity and their capacity is included in the total reserve rating of the system capability.

1.12 Maui 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. MECO has been including forecasted firm DG resources, namely CHP, in its Adequacy of Supply ("AOS") evaluations for the past several years. The updated CHP forecast (dated January 9, 2007) used for this 2007 AOS report projects that the peak reduction impacts of CHP installations will be significantly lower than the impacts projected for the 2006 AOS report.[5] 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 MECO in order to provide customer-sited DG projects on a regulated utility basis, and (3) other uncertainties concerning customer-sited DG. Further detailed explanation of these factors is provided in Attachment 3.

Based on the events and uncertainties detailed in Attachment 3, a revised 20 year forecast for CHP was developed that reflects that CHP will be more limited compared to previous forecasts. The cumulative forecasted impacts for the years 2007-2011, are shown in the table below. No new CHP systems were commissioned on Maui in 2006. These forecasted impacts of the proposed CHP Program on future system peaks are also indicated in Attachment 1.[6]

[5] For example, in the 2006 AOS report, the peak reduction impact of CHP in the year 2008 was forecasted to be 3.0 MW. In this 2007 AOS report, the peak reduction impact of CHP in the year 2008 is forecast to be 1.0 MW.

[6] For purposes of this report, CHP systems are reflected in the System Peak numbers (based on the net equivalent capacity of the CHP system, taking into account the electrical capacity supplied to a customer, the reduction of the customer's electrical load through waste heat application for the system, and a reduction in line losses). The load reduction impacts of CHP systems and/or DG owned by third parties are also reflected in the System Peak numbers.

Year	Forecasted Impacts of Small CHP Market (MW Net)
2007	0.5
2008	1.0
2009	1.5
2010	1.9
2011	1.9

1.13 Maui Load Management DSM Program

In MECO's previous AOS, filed with the Commission on March 6, 2006, MECO assumed that their proposed load management DSM program applications would be filed in 2006, approved in 2007, with full-scale impacts realized in 2008. MECO now expects to file these program applications shortly for its residential and commercial and industrial direct load control programs, RDLC and CIDLC, respectively. The current forecast is that approval will now occur at the end of 2007, with full-scale impacts realized in 2008.

MECO's load control programs will be similar in design to HECO's programs. Although HECO's RDLC and CIDLC programs were approved in October 2004, HECO submitted requests for modifications to increase the budget of both programs in March 2006 for additional funding of equipment and installation costs and received approval in June 2006 and November 2006 for the CIDLC and RDLC programs respectively. MECO decided it would be prudent to assess HECO's program successes and challenges before filing its own applications and will be incorporating the proposed modifications in its load management programs, as appropriate for MECO's customer base. The following table shows the cumulative forecasted peak impacts of the load management DSM programs for years 2007-2011.

Year	Forecasted Impacts of Load Management DSM (MW Net)
2007	0.0
2008	3.1
2009	5.0
2010	6.5
2011	7.5

1.14 MECO's Energy Efficiency DSM Programs

On February 13, 2007, in the Energy Efficiency Docket (Docket No. 05-0069) the Commission issued Decision and Order No. 23258. The Commission ordered that the energy efficiency programs transition to a non-utility administrator by January 2009. The impact of the transition is unknown at this time and there are uncertainties associated with obtaining the peak reduction impacts from a new, yet to be defined market structure. Should customer participation in the DSM programs be lower than estimated or delayed, the peak forecast used in this AOS filing will result in higher peak loads.

The Commission intends to open another docket to examine the selection of the non-utility administrator and refine the details of the new market structure. It is MECO's intention to assist in the transition in order that it occurs as smoothly as possible. Thus, while MECO's estimate of energy efficiency program impacts was developed under the assumption that MECO was the program administrator throughout the AOS report horizon, and new programs identified in MECO's IRP-3 process were included beginning in 2008, the Company has not made any adjustments to the projections as the result of the Commission's order.

Unlike the Energy Efficiency DSM Programs, load management DSM programs will continue to be administered by the utilities.

1.15 Potential Maui Load Service Capability Shortfalls and Reserve Margin Shortfalls

A Load Service Capability ("LSC") margin shortfall is an indication that there is a reserve margin ("RM") shortfall. Reserve margin shortfall is defined as not having enough reserve margin from firm capacity resources on the system to cover for the loss of the largest unit (with a unit on

planned maintenance). The calculation of reserve margin shortfalls does not take into account the availability of as-available resources, such as the Kaheawa Wind Farm and Makila Hydro. Reserve margin shortfalls do not equate to rolling blackouts. Other factors must be considered when making an assessment of the possibility that available generation will be insufficient to serve the system load (i.e., that rolling blackouts will have to be implemented). These factors include the availability of non-firm resources (such as the wind farm and the hydro facility), differences between actual and forecast peaks (which are impacted by factors such as weather), differences between monthly peaks, and normal weekday and weekend peaks, differences between actual and normal unit capabilities (due to such factors as temporary unit deratings, ambient conditions in the case of Maalaea Units 14, 16, 17 and 19, and the overall condition of the units), differences between actual and planned maintenance schedules (maintenance outages may be extended or shortened, depending on circumstances), and the risk of multiple unit outages.

For planning purposes, *projections* are used to forecast the timing of future resource additions. The following factors affect reserve margin projections:

- System Capability – Long-term projections of unit capabilities based on normal top load ratings are required in addition to the committed capacity of firm power producers with existing Power Purchase Agreements.

- Monthly Peak Forecast – The base load forecast is used.

- Planned Maintenance Schedule – MECO's normal maintenance scheduling practices are used. Maintenance scheduling is performed by the MECO Power Supply Department. Scheduling involves many different operational factors. Maintenance scheduling can be expected to be adjusted several times over the year due to changing operational factors. In the event planned capacity is delayed, rearranging maintenance schedules should be considered as a measure to mitigate the effects of delays in installing generation or acquiring the peak reduction benefits of energy efficiency DSM, load management DSM or CHP.

- Loss of Largest Unit – The basis for providing sufficient reserve margin to cover this unit while another unit is on planned maintenance.

1.15.1 LSC Shortfalls and RM Shortfalls for the 2006 - 2011 Timeframe

Load Service Capability shortfalls for the year 2007 are primarily the result of the extended Maalaea Unit 13 unplanned outage until approximately July 2007. No LSC margin shortfalls or Reserve Margin shortfalls are expected to occur in 2008 or 2009. Although, LSC margin shortfalls are not expected to occur in 2010, RM shortfalls could occur. In 2010, Maui's RM is expected to be slightly less than the 20% minimum reserve margin guideline. See Attachment 1. MECO does

not plan to advance the need date for firm generating capacity to 2010 based on its reserve margin being slightly less than 20% because MECO fully expects to be able to meet demand, even with a unit on maintenance and with the largest remaining available unit forced out of service at the time of the system peak in that year (i.e., MECO will be able to satisfy Rule 1 of its capacity planning criteria). MECO may implement mitigation measures as detailed in Section 1.17, if the need arises.

On Maui, in 2007, without the benefit of Maalaea Unit 13 until July 2007, the Maui system could potentially experience LSC margin shortfalls, as shown in Attachment 2, page 1, unless the mitigation measures identified Section 1.17 of this report are taken to lessen the impacts to the system. Reserve margin is the difference between system generating capability and peak demand. The term "load service capability" is a measure of MECO's ability to meet system load requirements, accounting for both planned maintenance and the loss of its largest unit. LSC margin shortfalls (which are indicated by values less than zero) are used as a planning tool to identify potential conditions of generating reserve capacity shortfalls and do not equate to either service interruptions or rolling blackouts. During periods when LSC margin values are less than zero, there is a possibility that a service interruption could occur if the largest unit is lost from service during the peak period.

In 2007, without mitigation measures, LSC margin shortfalls could occur in May and June, as shown in Attachment 2, page 1.[7] In May, a LSC margin shortfall of 4.3 MW could occur when Maalaea Unit 3 (approximately 2.5 MW) and half of the Dual Train, Maalaea Unit 15&16 (approximately 28 MW) are taken out of service for planned maintenance. In June, a LSC margin shortfall of 2.1 MW could occur when half of the Dual Train, Maalaea Unit 14 and 15 (approximately 28 MW) is taken out of service for planned maintenance.

In years 2008, 2009, and 2010, Maui is not expected to experience LCS margin shortfalls based on current forecasts.

In 2010, while Maui is not expected to experience LSC margin shortfalls, it may experience a RM shortfall, where the reserve margin at the time of the peak may be less than the 20% guideline in MECO's capacity planning criteria. MECO does not plan to advance the need date for firm generating capacity to 2010 based on its reserve margin being slightly less than 20% because MECO will be able to satisfy Rule 1 of its capacity planning criteria.

In 2011, without mitigation measures or additional generation, LSC margin shortfalls could occur in May, June, October, and November as shown in Attachment 2, page 2. In May, a LSC margin shortfall of 2.5 MW could occur when half of the Dual Train, Maalaea Unit 17&18 or

[7] In January 2007, the Maui system did experience a LSC margin shortfall, as shown in Attachment 2, page 1. However, the system did not experience a generation shortfall, because Maui's largest unit remained on-line.

Maalaea Unit 18&19 (both approximately 28 MW) is taken out of service for planned maintenance during separate times of the month. Similarly, in June, a LSC margin shortfall of 2.9 MW could occur when half of the Dual Train, Maalaea Unit 14&15 or Maalaea Unit 15&16 (both approximately 28 MW) is taken out of service for planned maintenance during separate times of the month. In October, a LSC margin shortfall of 2.2 MW could occur when Maalaea Unit 10 (approximately 12 MW) is taken out of service for planned maintenance. In November, a LSC margin shortfall of 1.0 MW could occur when Maalaea Unit 10 (approximately 12 MW) is taken out of service for planned maintenance.

In 2011, with a 20 MW simple cycle combustion turbine installed on the system, there will be no LSC margin shortfalls.

In 2012 and beyond, without mitigation measures or additional generation, LSC margin shortfalls are expected to exceed the shortfall levels estimated for 2011. The extent of the LSC margin shortfalls in 2012 and beyond will be a function of three primary factors. These factors are (a) the rate of load growth, (b) whether or not the HC&S contract is extended or renegotiated, and (c) if the HC&S contract is renegotiated, the amount of capacity that HC&S will be obligated to deliver under the contract. Historically, the annual load growth on the island of Maui has been between 3 to 6 MW. HC&S accounts for 16 MW towards Maui's system capacity. For planning purposes, the HC&S contract is assumed to terminate on December 31, 2011. (See Section 1.5, HC&S PPA). Therefore, if HC&S does not provide capacity to the system, then coupled with the annual load growth, the LSC margin shortfall in 2012 and beyond could be substantial. Installation of a large block of generating capacity may be needed to accommodate load growth and replace the possible loss of HC&S capacity. Therefore, MECO is continuing to take action to provide additional firm capacity in 2011 that could prevent LSC margin shortfalls in 2011 and 2012. (See Section 1.10, Waena Unit 1 Status). Any plan to install additional firm capacity is required to proceed under the guidance of the Competitive Bidding Framework issued by the Commission on December 8, 2006 in Decision & Order No. 23121. With the possibility of the termination of the HC&S contract at the end of 2011, the installation of Waena 1 may not cover the capacity deficit resulting from both the loss of HC&S and the load growth in 2012 and in future years. Therefore, MECO plans to begin discussions with HC&S to extend the contract beyond December 31, 2011 to avoid possible LSC margin shortfalls.[8]

[8] In accordance with the Competitive Bidding Decision & Order No. 23121, dated December 8, 2006, in Docket No. 03-0372, the Commission adopted "exemptions applicable to qualifying facilities and non-fossil fuel producers" as proposed by the HECO Utilities. These included: (3) power purchase agreement extension for three years or less on substantially the same terms and conditions as the existing power purchase agreements and/or on more favorable terms and conditions; (4) Power purchase agreement modifications to acquire additional firm capacity or firm capacity from an existing facility, or from a facility that is modified without a major air permit; (5) Renegotiations of power purchase agreements in anticipation of their expiration, approved by the Commission.

1.16 Generation Shortfall

Generation shortfall is defined as not having sufficient capacity on the system to meet the expected load. Rolling blackouts may occur with generation shortfalls, but other factors need to be considered before any assessment of rolling blackouts can be made. Factors that affect whether or not there is adequate generation to meet the load are more complex than those that affect reserve margin shortfalls. These factors include the following:

- Actual vs. Forecasted Peak and Actual DSM Penetration – Actual or expected daily peaks are affected by factors such as time of year and weather variables such as rainfall, cloud cover, humidity and temperature. Actual DSM penetration is affected by many other factors; for example, whether or not a compact fluorescent light bulb in a home is actually on during the actual MECO system day peak. These factors are very difficult to quantify, let alone forecast.

- Condition and Reliability of Existing Units – Even with timely and prudent maintenance practices, all generating units are subject to forced outages. There is also a risk of multiple forced outages on a given day. Statistical or stochastic analysis may be appropriate for longer-term analyses; however, on a day-to-day basis, forecasting whether or not forced outages are likely to occur is very difficult to quantify.

- Availability of Non-Dispatchable As-Available Resources – Resources in this category include run-of-river hydro units and wind turbines. A key characteristic of non-dispatchable as-available resources is their unpredictable variability. Because each of these resources depends either directly or indirectly on the weather, the amount of capacity they will provide at a given time cannot be quantified. As-available resources do provide a system benefit (fuel savings) when they are able to provide energy; however, the amount they can provide at a given moment cannot be quantified.

- Uncertainties with Future Load Growth – The Maui system consists of large customers that affect the future load growth of Maui. Some entities have the capability to generate their own power to facilitate their energy requirements without support from MECO. However, some of these entities have inquired to MECO that they would prefer to be supported by the MECO system and discontinue their generation facilities. Maui Land & Pine ("ML&P") has approached MECO and requested to be connected to the MECO system. ML&P has the capability to generate approximately 6 MW of capacity. If MECO were to provide power to ML&P, this would result in an increase in load anywhere between 1 MW and 3 MW. ML&P plans have changed since their initial request, which demonstrates the uncertainties MECO must account for when planning for load growth.

1.17 Reliability Issues

Based on the above discussion, quantifying the risk of rolling blackouts is difficult. Many factors cannot be quantified. A qualitative analysis can be performed, but in the end, only assessments can be made of what can and cannot be done.

MECO has sufficient capacity on its system to meet the forecasted load. MECO may not, at times, have sufficient capacity to cover for the loss of the largest unit in 2007 until M13 is returned to service. Several mitigation measures have been identified to mitigate the effects.

The implementation of mitigation measures does not provide the same level of reliability as a large increment of firm capacity. It is, however, a necessary alternative.

1.18 Mitigation Measures

MECO plans to mitigate the potential LSC margin shortfall in 2007 and the RM shortfall in 2010, through one or more of the mitigation measures identified below, depending on the particular circumstances. These mitigation measures are as follows:

1.18.1 Optimize Unit Overhaul Schedule

MECO will optimize its unit overhaul schedule to minimize any LSC margin shortfall by matching a unit's outage with the available reserve capacity at that time.

1.18.2 Deviation from Standard Maintenance Practices

Combined-Cycle Unit Overhaul - MECO will modify its combined-cycle unit overhaul procedure to minimize the outage capacity for that unit. The exhaust bypass option of MECO's Maalaea DTCC No. 1 (Maalaea Units 14, 15, and 16) and Maalaea DTCC No. 2 (Maalaea Units 17, 18, and 19) will be used to allow for the possible operation of the combustion turbine ("CT") (if needed) in simple-cycle mode while certain planned maintenance is being performed on the heat recovery steam generators and steam turbine generator (Maalaea Units 15 and 18). While not the ideal outage method, this modified maintenance procedure will allow, if the situation warrants, the possible use of an additional 20 MW from the CT.

1.18.3 Coordination with HC&S

MECO will coordinate closely with HC&S for the delivery of supplemental power, if needed, as described in the Purchase Power Agreement under Section II D.

1.18.4 Public Communications Campaign

MECO may request voluntary customer curtailment of demand during LSC margin shortfall conditions.

2.0 Lanai Division

2.1 Peak Demand and System Capability in 2006 - 2009

Lanai's 2006 system peak occurred on December 27, 2006 and was 5,550 kW (gross). Lanai had a 2006 reserve margin of approximately 87 %. Attachment 1, Table 2, also shows the expected reserve margins over the next three years, based on the MECO 2006-2011 Sales and Peak Forecast dated June 2006.

2.2 Lanai Division Capacity Planning Criteria

The following criterion is used to determine the timing of an additional generating unit for the Lanai Division and the Molokai Division:

New generation will be added to prevent the violation of any one of the rules listed below where "units" mean all units and firm capacity suppliers physically connected to the system, and "available unit" means an operable unit not on scheduled maintenance.

1. *The sum of the normal top load ratings of all units must be equal to or greater than the system peak load to be supplied.*

2. *With no unit on maintenance, the sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the system peak to be supplied.*

3. *With a unit on maintenance:*

   a) *The sum of the reserve ratings of all units minus the reserve rating of the largest available unit must be equal to or greater than the daytime peak load to be supplied.*

   b) *The sum of the reserve ratings of all units must be equal to or greater than the evening peak load to be supplied.*

2.3 Lanai Combined Heat and Power Project

On June 16, 2006, MECO executed a CHP agreement with Castle & Cooke Resorts for the installation of an 884 kW (net including electric chiller offset and auxiliary loads) CHP system at the Four Seasons Resort Lanai at Manele Bay. The CHP agreement was filed for approval by the Commission on July 14, 2006, in Docket No. 2006-0186. On September 11, 2006, the Commission issued a Schedule of Proceedings for its consideration of this CHP project. MECO has provided additional information in support of its application to the Consumer Advocate and the Consumer Advocate filed its final statement of position on January 18, 2007. MECO filed its response to the Consumer Advocate's statement of position on February 15, 2007, reiterating its position that the proposed MECO CHP System presents a reasonable and justifiable proposal to meet Lanai's need for additional generating capacity in 2008. Should the Commission approve the CHP agreement, MECO projects the CHP system to be placed in service in the first quarter of 2008.

MECO's CHP development efforts with Castle & Cooke Resorts were initiated within the context of MECO's existing service contract ("Service Contract") with Castle & Cooke Resorts, filed with the Commission in Docket No. 03-0261. MECO has reviewed D&O 22248 in Docket No. 03-0371, as clarified by Order No. 22375, and is continuing to pursue this CHP project based on its interpretation of the D&O and the justifications to pursue CHP that were presented in Docket No. 03-0261.

The Service Contract contemplated the addition of a CHP system at the Manele Bay Hotel, whether installed by MECO or a non-utility vendor, at a date closer to the projected need date for additional firm capacity on Lanai. The need date for additional firm capacity is projected to be September 2008, under the base planning scenario for Lanai. In this base planning scenario, the aggregate capacity of Miki Basin EMD units 1-6 was reduced from 6,000 kW to 5,000 kW on December 31, 2006, because a condition assessment performed by an outside consultant indicated that it would be appropriate, for capacity planning purposes, to rely on less than their full rated capacity based on the ages and condition of the units. (See Attachment 1, Table 2, Note VI.) With the addition of the CHP system at Manele Bay in early 2008, MECO will be able to meet electric load requirements on Lanai, satisfy the energy cost savings objectives of its Service Contract with Castle & Cooke Resorts, and be able to meet a need for additional capacity in September 2008.

3.0 Molokai Division

3.1 Peak Demand and System Capability in 2006 - 2009

Molokai's 2006 system peak occurred on March 13, 2006 and was 6,300 kW (gross). Molokai had a 2006 reserve margin of approximately 91%. Attachment 1, Table 2, also shows the

expected reserve margins over the next three years, based on the MECO 2006-2011 Sales and Peak Forecast dated June 2006.

3.2 Molokai Division Capacity Planning Criteria

Molokai Division's capacity planning criteria are identical to those of the Lanai Division. See Section 2.2 above, Lanai Division Capacity Planning Criteria.

4.0 Conclusion

In consideration of the above, MECO has sufficient capacity to meet the forecasted loads on the islands of Maui, Lanai and Molokai for the next three years. Although, MECO may not, at times, have sufficient capacity on the Maui system to cover for the loss of the largest unit, MECO will implement appropriate mitigation measures to overcome the insufficient reserve capacity situation.

The Maui Division needs additional firm generating capacity in the 2011 timeframe. This is consistent with the determination made to date in its currently on-going IRP-3 process. MECO will comply with the requirements of the Commission's Competitive Bidding Framework in order to acquire that additional firm capacity.

Very truly yours,

Edward L. Reinhardt

Attachments

cc: Division of Consumer Advocacy

Table 1
Maui Adequacy of Supply

ADEQUACY OF SUPPLY
Maui Electric Company, Limited

	With Small CHP[I]				
		Without Future DSM (Includes Acquired DSM)[II]		With Future DSM (Includes Acquired DSM)[III]	
Year	System Capability at Annual Peak Load[IV] (kW) [A]	System Peak[V] (kW) [B]	Reserve Margin (%) [[A-B] / B]	System Peak[V] (kW) [C]	Reserve Margin (%) [[A-C] / C]
Maui Division (Net Generation)					
Recorded					
2006	232,800 [VI]	206,400 [VII]	13%	N/A	N/A
Future					
2007	262,300 [VIII]	210,300	25%	209,300	25%
2008	262,300	217,200	21%	212,000 [IX]	24%
2009	262,300	224,200	17%	215,900	21%
2010	262,300	232,300	13%	221,300	19%
2011	262,300	238,500	10%	225,200	16%
Maui Division (Gross Generation)[X]					
Recorded					
2006	237,600	210,800 [VII]	13%	N/A	N/A
Future					
2007	267,700	215,300	24%	213,800	25%
2008	267,700	222,400	20%	217,000 [IX]	23%
2009	267,700	229,500	17%	221,000	21%
2010	267,700	237,800	13%	226,600	18%
2011	267,700	244,200	10%	230,500	16%

Notes – Table 1:

(I) With Small CHP Market: Forecasted system peaks include reductions for CHP impacts. [9]

[9] CHP impacts are from a CHP forecast dated January 9, 2007. These impacts are at system level based on a T&D loss factor of 5.96%. For capacity planning analysis, an availability factor is also included to account for periods when the utility CHP is unavailable due to forced outage and maintenance.

(II) System Peaks (Without Future Peak Reduction Benefits of DSM Programs):
Implementation of full-scale energy efficiency DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peak values for the years 2007-2011 include the actual peak reduction benefits acquired in 1996-2005 and also include the estimated peak reduction benefits acquired in 2006, as well as peak reduction benefits of Rider M and T customer contracts, and CHP impacts.

(III) System Peaks (With Future Peak Reduction Benefits of DSM Programs).
The forecasted System Peaks for 2007-2011 include the peak reduction benefits of energy efficiency DSM programs (acquired and future) and peak reduction benefits of Rider M and T customer contracts, and CHP impacts.

(IV) The net reserve ratings of the units are used in the determination of the Maui system capability. In addition, the Maui Division system capability includes 16,000 kW (which includes 4,000 kW of system protection capacity) from HC&S. When the system capability at the time of the system peak differs from the year-end system capability, an applicable note will indicate the year-end system capability.

(V) The 2007 - 2011 annual forecasted system peaks are based on MECO's June 2006, 2006-2011 Sales and Peaks Forecast and includes reductions for CHP impacts. The Maui annual forecasted system peak is expected to occur in the month of August.

(VI) Maalaea Unit 13, a Mitsubishi 12.34 MW (net) diesel engine generator, suffered equipment failure on December 9, 2005. MECO projects Maalaea Unit 13 will be unavailable for service to the system until approximately July 2007, while corrective maintenance measures are being performed to repair the unit. The year-end system capability was 232,800 kW.

A 30 MW independent power producer (IPP) wind farm resource was added to the Maui system on June 9, 2006. MECO and Kaheawa Wind Power (KWP) executed a new purchase power agreement (PPA) on December 3, 2004. MECO submitted an Application on December 16, 2004 for approval of the PPA. On March 18, 2005, the Commission issued D&O No. 21701 approving the PPA. The installation of this wind resource will not affect the system capability, because the wind resource is an as available resource, which is not dispatchable and cannot provide given amounts of power at scheduled times.

On September 22, 2006, Makila Hydro, LCC, an independent power producer ("IPP"), completed construction of a 500 kW hydro-electric facility and commenced with providing energy to the Maui system. MECO and Makila executed a PPA on May 10, 2005. MECO submitted an application to the Commission on June 28, 2005, which among other things, requested approval of the PPA. On May 10, 2006, the Commission issued Decision & Order No. 22460, approving the PPA. The installation of this hydro resource will not affect the system capability, because the hydro resource is an as

available resource, which is not dispatchable and cannot provide given amounts of power at scheduled times.

(VII) The actual 2006 recorded system peak was 210,800 MW (gross) which is equivalent to 206,400 MW (net).

(VIII) Maalaea Unit 13, a 12.34 MW (net) diesel engine generator, is projected to be available for service in approximately July 2007 and should be available during the 2007 annual system peak which is forecasted to occur in August.

Maalaea Unit 18, steam turbine generator (Phase III of a nominal 56,780 kW (net) dual train combined-cycle unit), was placed in service on October 27, 2006 and will be available during the 2007 annual system peak, which is forecasted to occur in August.

MECO filed a letter with the Commission in Docket No. 6616 (HC&S), on July 27, 2005, which informed the Commission that MECO and HC&S agreed on June 28, 2005 not to issue a notice of termination of the PPA resulting in termination of the PPA prior to the end of the day on December 31, 2011.[10]

(IX) Includes a reduction in system peak load due to the implementation of planned Commercial and Industrial Direct Load Control (CIDLC) and Residential Direct Load Control (RDLC) Load Management DSM Programs developed in MECO's IRP-2 Report. Full-scale Load Management DSM Program benefits are forecasted to start in 2008.

(X) The Maui Division Gross Generation data is provided here for comparative purposes.

[10] Previously, in a letter dated June 11, 2002, MECO and HC&S had agreed that neither company would give written notice of termination resulting in a termination of the PPA prior to the end of the day on December 31, 2007. MECO filed the June 11, 2002 letter with the Commission on June 27, 2002 in Docket No. 6616.

Table 2
Lanai and Molokai Adequacy of Supply

Year	System Capability at Annual Peak Load[III] (kW) [A]	Without Future DSM (Includes Acquired DSM)[I] System Peak[IV] (kW) [B]	Without Future DSM (Includes Acquired DSM)[I] Reserve Margin (%) [[A-B] / B]	With Future DSM (Includes Acquired DSM)[II] System Peak[IV] (kW) [C]	With Future DSM (Includes Acquired DSM)[II] Reserve Margin (%) [[A-C] / C]
Lanai Division (Gross Generation)					
Recorded					
2006	10,400	5,550	87%	N/A	N/A
Future					
2007	9,400 [V]	5,926	59%	N/A	N/A
2008	10,284 [VI]	6,039	70%	N/A	N/A
2009	10,284	6,142	67%	N/A	N/A
Molokai Division (Gross Generation)					
Recorded					
2006	12,010 [VII]	6,300	91%	N/A	N/A
Future					
2007	12,010	6,635	81%	N/A	N/A
2008	12,010	6,660	80%	N/A	N/A
2009	12,010	6,685	80%	N/A	N/A

Notes – Table 2:

(I) System Peaks (Without Future Peak Reduction Benefits of DSM Programs): Implementation of full-scale DSM programs began in the second half 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 also include the estimated peak reduction benefits acquired in 2006.

(II) System Peaks (With Future Peak Reduction Benefits of DSM Programs): Currently no future DSM impacts are forecasted for Lanai or Molokai.

(III) The gross reserve ratings of the units are used in the determination of the Lanai and Molokai system capabilities. All unit projected retirement dates are planned for December 31 of the designated year unless otherwise specified. When the system

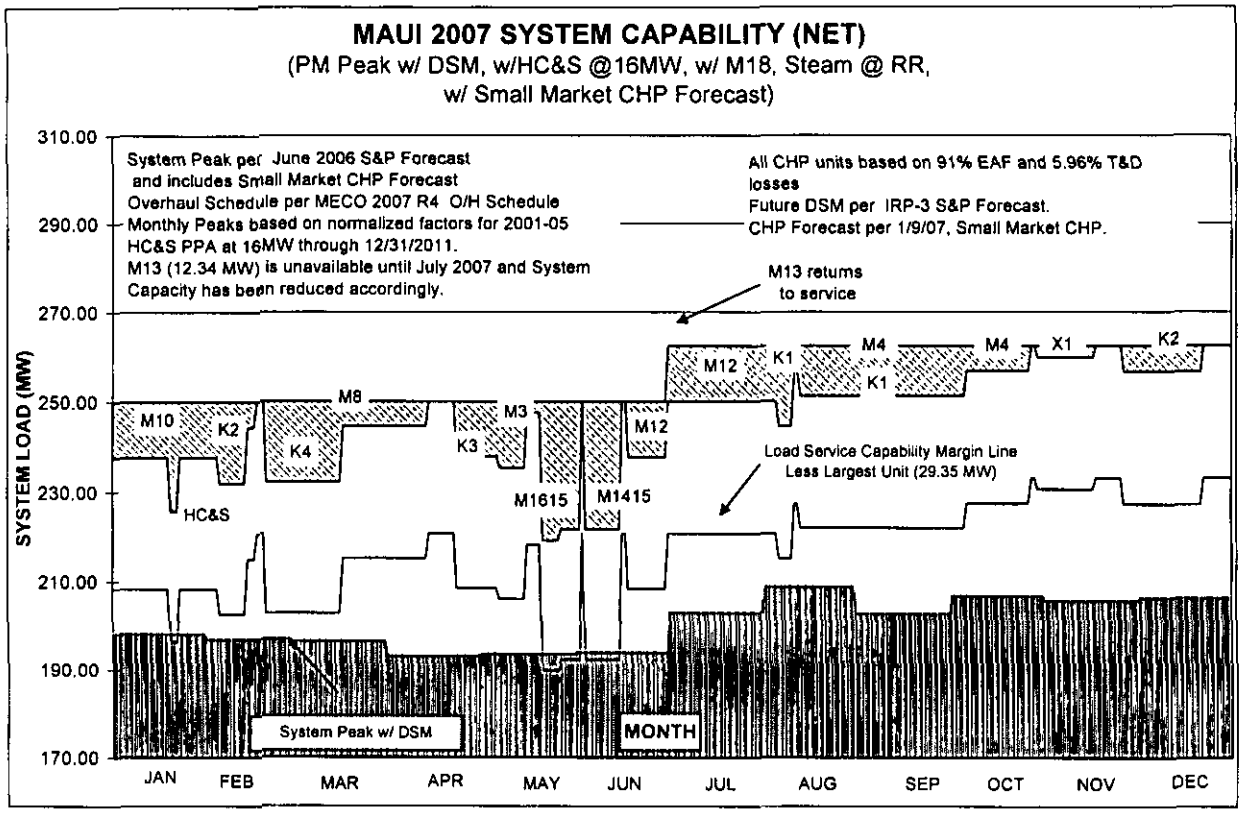
capability at the time of the system peak differs from the year-end system capability, an applicable note will indicate the year-end system capability.

(IV) The 2007 - 2009 annual forecasted system peaks are based on MECO's 2006-2011 Sales and Peaks Forecast dated June 2006. The Lanai and Molokai annual forecasted system peaks are expected to occur in the months of December and January, respectively.

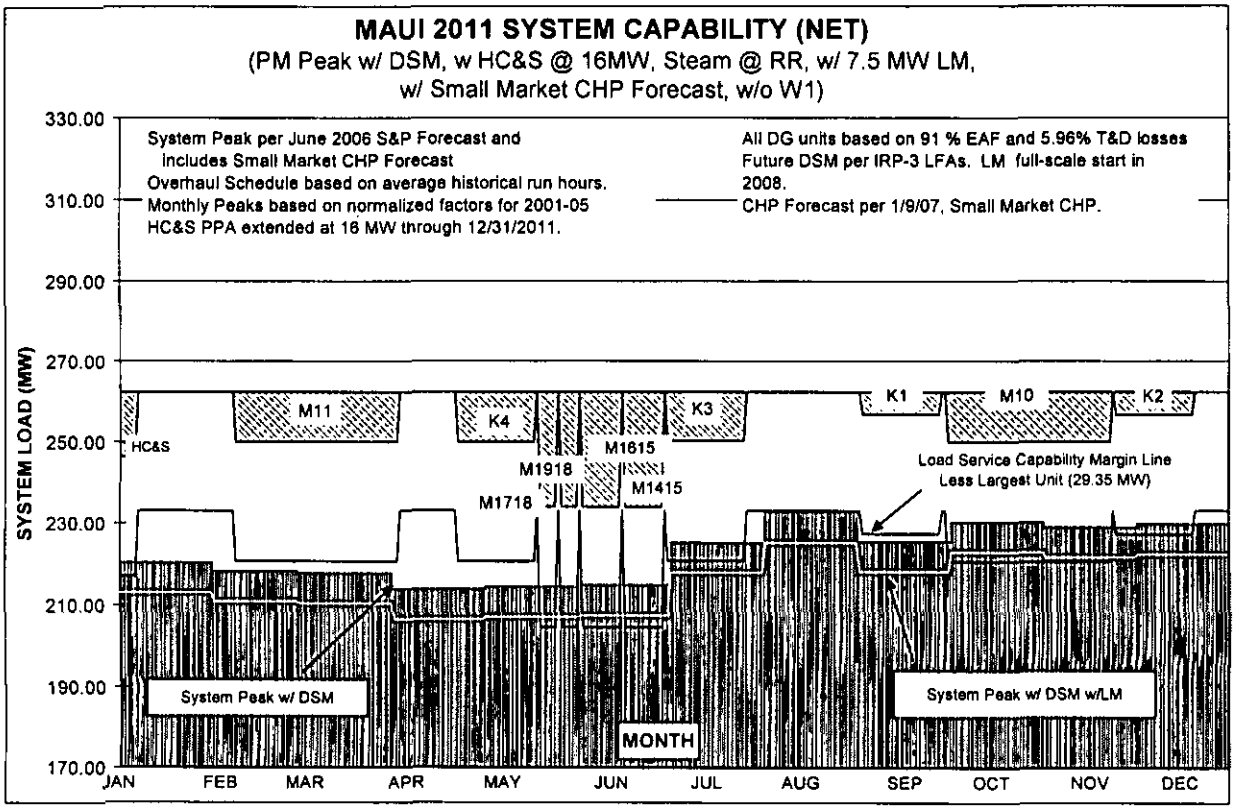
(V) Miki Basin Units LL-1 to LL-6 (six,1,000 kW diesel engine-generator units totaling 6,000 kW) were converted to peaking status at the end of 2006, and as such, can be relied on for 5,000 kW of capacity to the Lanai system.

(VI) MECO has signed an agreement with Castle & Cooke Resorts for the installation of an 844 kW (net including electric chiller offset and auxiliary loads) CHP system at the Manele Bay Hotel in the first quarter of 2008. Refer to Section 2.3 for further details

(VII) Palaau Units 1 and 2 (two 1,250 kW Caterpillar units), and Palaau Units 3, 4, 5 and 6 (four 970 kW Cummins units) operate in peaking service. Because of the age and operating history of these units, MECO includes one Caterpillar unit and two Cummins units (1,250 + 970 + 970 = 3,190 kW) towards firm capacity for the Molokai system.



Month (1)	System Peak w/ DSM w/ Riders w/ Small Mkt CHP (MW) (2)	System Cap (MW) (3)	Maint (MW) (4)	Reserve (MW) (5)=(3)-(4)-(2)	% Reserve (Less Maint) (5) / (2)	Lrgst Avail (MW) (7)	LSC Diff (MW) (8) = (5) - (7)	LSC Diff + LM (impact) (MW) (8) + 0 MW
JAN	198.6	250.0	24.3	27.1	14%	29.35	-2.3	-2.3
FEB	197.4	250.0	18.1	34.5	17%	29.35	5.1	5.1
MAR	197.0	250.0	17.9	35.1	18%	29.35	5.8	5.8
APR	193.5	250.0	12.2	44.3	23%	29.35	15.0	15.0
MAY	194.0	250.0	30.9	25.1	13%	29.35	-4.3	-4.3
JUN	194.3	250.0	28.4	27.3	14%	29.35	-2.1	-2.1
JUL	203.4	262.3	12.3	46.6	23%	29.35	17.3	17.3
AUG	209.3	262.3	18.0	35.1	17%	29.35	5.7	5.7
SEP	203.1	262.3	11.1	48.1	24%	29.35	18.7	18.7
OCT	207.2	262.3	11.1	44.0	21%	29.35	14.6	14.6
NOV	206.2	262.3	5.8	50.4	24%	29.35	21.1	21.1
DEC	206.8	262.3	5.8	49.7	24%	29.35	20.4	20.4



Month (1)	System Peak w/ DSM w/ Riders w/ Small Mkt CHP (MW) (2)	System Cap (MW) (3)	Maint (MW) (4)	Reserve (MW) (5)=(3)-(4)-(2)	% Reserve (Less Maint) (5) / (2)	Lrgst Avail (MW) (7)	LSC Diff (MW) (8) = (5) - (7)	LSC Diff + LM (impact) (MW) (8) + 7.5 MW
JAN	220.5	262.34	16.0	25.9	12%	29.35	-3.5	4.0
FEB	218.3	262.34	12.3	31.7	15%	29.35	2.3	9.8
MAR	217.9	262.34	12.3	32.1	15%	29.35	2.8	10.3
APR	214.0	262.34	12.4	36.0	17%	29.35	6.6	14.3
MAY	214.6	262.34	28.4	19.4	9%	29.35	-10.0	-2.5
JUN	215.0	262.34	28.4	19.0	9%	29.35	-10.4	-2.9
JUL	225.3	262.34	12.2	24.9	11%	29.35	-4.5	3.0
AUG	232.7	262.34	0.0	29.7	13%	29.35	0.3	7.8
SEP	225.6	262.34	12.3	24.4	11%	29.35	-5.0	2.5
OCT	230.3	262.34	12.3	19.7	9%	29.35	-9.7	-2.2
NOV	229.1	262.34	12.3	20.9	9%	29.35	-8.5	-1.0
DEC	229.9	262.34	5.8	26.6	12%	29.35	-2.7	4.8

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 MECO'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 Commission 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. To help ensure that only cost-effective DG is installed by customers, the Commission determined that other customers should not be required to subsidize those who install DG. Thus, D&O 22248 requires that costs incurred by the electric utilities to accommodate DG, including costs of interconnection and of providing standby and backup services, should be borne by the DG customer.

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, MECO (along with HECO and HELCO, 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. This CHP tariff application, considered in 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.

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 is conducting 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 will be difficult to determine.

Maui Unit Ratings

As of January 31, 2007

Units	Gross (MW)		Net (MW)	
	Reserve	NTL[I]	Reserve	NTL[I]
M1	2.50	2.50	2.50	2.50
M2	2.50	2.50	2.50	2.50
M3	2.50	2.50	2.50	2.50
X1	2.50	2.50	2.50	2.50
X2	2.50	2.50	2.50	2.50
M4	5.60	5.60	5.51	5.51
M5	5.60	5.60	5.51	5.51
M6	5.60	5.60	5.51	5.51
M7	5.60	5.60	5.51	5.51
M8	5.60	5.60	5.48	5.48
M9	5.60	5.60	5.48	5.48
M10	12.50	12.50	12.34	12.34
M11	12.50	12.50	12.34	12.34
M12	12.50	12.50	12.34	12.34
M13[II]	0.00	0.00	0.00	0.00
M14/15/16	58.00	58.00	56.78	56.78
M17/18/19[III]	58.00	58.00	56.78	56.78
Maalaea GS	199.60	199.60	196.08	196.08
K1	5.90	5.00	5.62	4.71
K2	6.00	5.00	5.77	4.76
K3	12.70	11.50	12.15	10.98
K4	13.00	12.50	12.38	11.88
Kahului GS	37.60	34.00	35.92	32.33
HC&S[IV]	16.00	12.00	16.00	12.00
Hana 1[V]	1.00	1.00	1.00	1.00
Hana 2[V]	1.00	1.00	1.00	1.00
Maui System	255.20	247.60	250.00	242.41

Notes:

(I) NTL = Normal Top Load

(II) Maalaea Unit 13, a Mitsubishi 12.34 MW (net) diesel engine generator, suffered a catastrophic equipment failure on December 9, 2005. MECO projects that Maalaea Unit 13 will be unavailable for service to the system until approximately July 2007, while corrective measures are being accomplished to restore the unit.

(III) The NTL rating for Maalaea Unit 17/18/19 of 56.78 MW (net) reflects the expected output of the dual train combined cycle based on the output of Maalaea Unit 14/15/16

(existing dual train at the Maalaea Power Plant). Testing of Maalaea Unit 17/18/19 to establish an NTL rating for the unit is currently in progress and is expected to be completed in the second quarter of 2007. The amount of the LSC or RM shortfalls estimated in the system capability charts may change depending upon the final NTL rating established for Maalaea Unit 17/18/19.

(IV) All values for HC&S are net to the system. The reserve ratings include an additional 4.0 MWs of system protection capacity.

(V) Unit located at Hana Substation No. 41. MECO plans to complete a communication and controls project in early 2007, which will allow the Hana units to be operated as dispatchable distributed generation units. As a result, the Hana units are included in the total reserve rating of the system capability.

Lanai Unit Ratings

As of January 31, 2007

Units	Gross (kW)	
	Reserve	NTL(I)
LL-1(VI)	1,000	1,000
LL-2(VI)	1,000	1,000
LL-3(VI)	1,000	1,000
LL-4(VI)	1,000	1,000
LL-5(VI)	1,000	1,000
LL-6(VI)	1,000	1,000
LL-7	2,200	2,200
LL-8	2,200	2,200
Miki Basin GS	9,400	9,400

(VI) Miki Basin Units LL-1 to LL-6 (six,1,000 kW diesel engine-generator units totaling 6,000 kW) were converted to peaking status at the end of 2006, and as such, can be relied on for 5,000 kW of capacity to the Lanai system.

Molokai Unit Ratings

As of January 31, 2007

Units	Gross (kW)	
	Reserve	NTL[(I)]
P-1[(VII)]	1,250	1,250
P-2[(VII)]	1,250	1,250
P-3[(VII)]	970	970
P-4[(VII)]	970	970
P-5[(VII)]	970	970
P-6[(VII)]	970	970
Solar CT	2,220	2,220
P-7	2,200	2,200
P-8	2,200	2,200
P-9	2,200	2,200
Palaau GS	12,010	12,010

(VII) Palaau Units 1 and 2 (two 1,250 kW Caterpillar units), and Palaau Units 3, 4, 5 and 6 (four 970 kW Cummins units) operate in peaking service. Because of the age and operating history of these units, MECO includes one Caterpillar unit and two Cummins units (1,250 + 970 + 970 = 3,190 kW) towards firm capacity for the Molokai system.