HELCO Operational Issues
Bulk Energy Storage


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1.0 Purpose of Analysis

The purpose of this project is to evaluate the ability of energy storage to alleviate electricity transmission and reliability issues on the Big Island of Hawaii, which are expected to increase due to the projected growth in the use of distributed energy resources (DER) and renewable energy. It is postulated that bulk energy storage located at strategically placed nodes on the transmission network could result in a more robust electrical system that is inherently more flexible, especially for non-dispatchable renewable generation. This project will assess available bulk energy storage technologies, and determine their explicit value on the Hawaii Electric Light Company's (HELCO's) electric system.

Project objectives include the following:

- Examine existing impacts on the transmission system from DER and renewable energy.
- Forecast electricity demand on the Island of Hawaii through 2014.
- Project electricity supply resources, including fossil central station generation, transmission lines, renewable energy, and DER required to satisfy the forecasted demand.
- Assess potential transmission, power quality and reliability problems.
- Assess commercially available bulk (MWh) energy storage technologies that could ameliorate transmission reliability and power quality issues.
- Conduct an electric system evaluation to determine the optimum location and capacity of energy storage that could be added to the HELCO electric system.
- Estimate the costs of bulk energy storage and the resulting benefits to the electric network.
- Project the additional renewable and DER resources that could be accommodated if energy storage is installed on the transmission system.

2.0 Background

The Big Island's electric system faces a complex series of reliability, environmental and economic issues. These include:

- Rapid load growth on the west side of the island, inconsistent with primary power plants' locations on the Hilo side of the island, which creates transmission bottlenecks during certain line contingency situations;
- Addition of wind, solar, geothermal, and other DER resources are planned that have the potential to add significant stress to the existing electric system;

- Addition of dual train combined cycle units on the HELCO system, which are more efficient and provides the necessary cycling capability. However, this affects HELCO's system reliability with lower on-line inertia compared to a system prior to the commercial operation of Hamakua Energy Partners (HEP) because HEP with its two combustion turbines and one steam turbine replaced a larger number of smaller units and decreased the amount of spinning inertia on the system.

- The relative low night-time loads on the system sometimes results in a need to curtail as available renewable energy.

3.0 Transmission Constraints

3.1 <u>General Transmission Problem Description</u>

This analysis will quantify several transmission problems, which fall into two categories:

1) Line overloads

2) Low voltage conditions

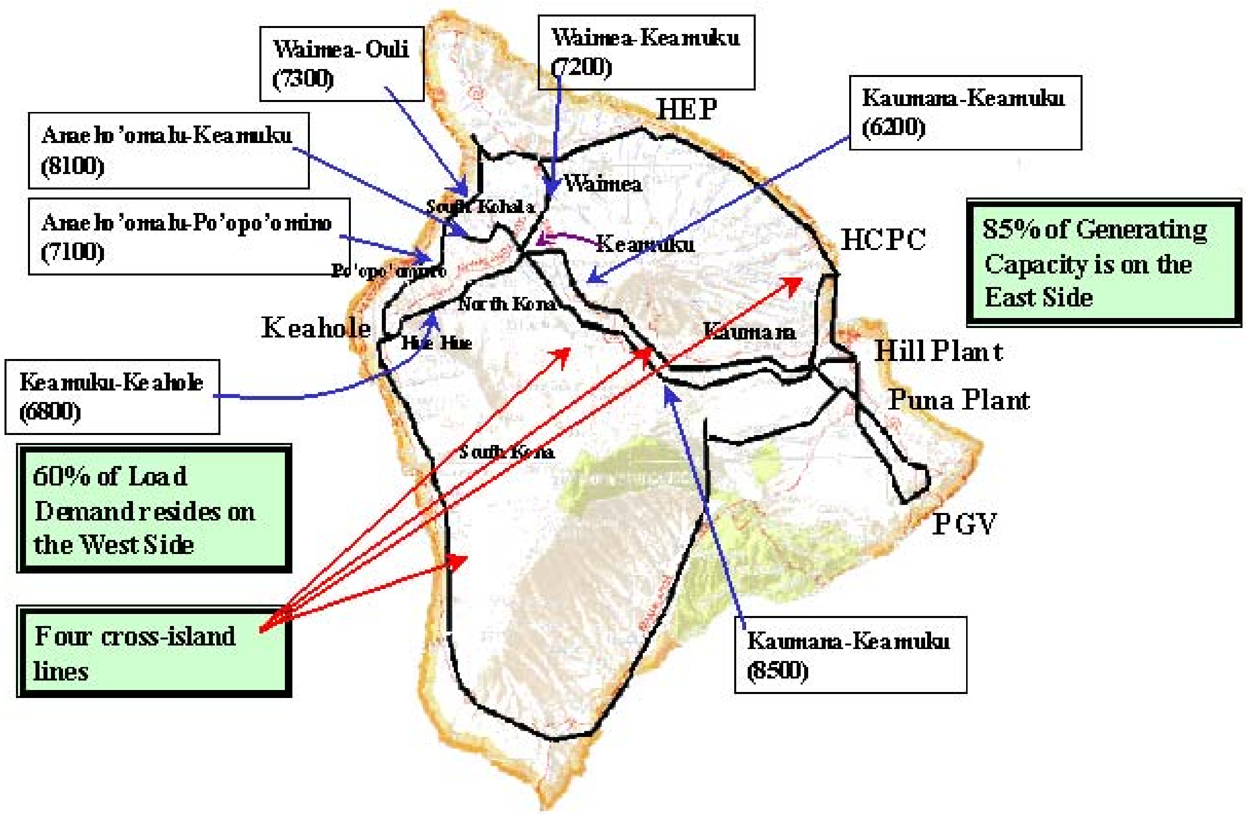
Transmission lines are designed to carry up to a rated level of current at a specified transmission voltage level and under certain environmental conditions (i.e., wind speed, outside air temperature). Lines are given a specified emergency current capacity rating, which is the amount of current the line is able to carry safely for a short time without overheating. Exceeding the emergency current capacity of a transmission line will cause the temperature of the conductor to rise. As the temperature rises, the line will begin to sag, a weak line splice may fail, or a termination point on a pole may fail. A sagging line may come into contact with trees, obstacles or the ground and produce a fault on the line. The fault or line failure could lead to a prolonged outage of the line as repairs are made. The length of the outage will depend on the severity of the line failure.

Low voltage conditions usually occur when there is a great distance between the generating source and the load being served. The voltage drop between two points is dependent on the characteristic of the lines carrying the power from point A to point B. If the transmission line has a large impedance characteristic, there will be a larger amount of losses and a larger amount of voltage drop compared to a transmission line with lower impedance. The utility has an obligation to provide power at certain voltage levels within a +/- 10% or +/- 5% tolerance. HELCO's operating voltage standard at the 69 kV level is to regulate the bus voltages to within +/- 5% of 69 kV.

3.2 *Existing HELCO Transmission System*

Figure 3.2-1 shows the entire HELCO transmission system. The major load centers on the Island of Hawaii are Hilo and Puna in the east and South Kona, North Kona and South Kohala in the west. About 60 miles separate the two load centers. Connecting the two load centers are four cross-island transmission lines. Approximately 60% of the load demand comes from the South Kona, North Kona and South Kohala areas in the west.

Figure 3.2-1 HELCO 69 kV Transmission System



As of November 2002, 85% of HELCO's generating capacity resided on the east side of the island. Based on normal economic commitment order with all of HELCO's transmission lines operating normally, HELCO, on a daily basis, transports the energy generated on the east side over to the load center on the west side. Only during some portions of the on-peak period and priority-peak period is west side generation (via Keahole or Waimea) on-line to serve the load demand in west Hawaii.

The preferred location for future generation has been documented by HELCO over the last decade including Docket 94-0079 (Purchase Power Contract Negotiations with Enserch Development), Docket 97-0102 (HCPC Complaint Docket), and HELCO's filed IRP-2 (Docket 97-0349), which explained the system need for additional generation and the advantages of installing generation on the west side.

The need for transmission system upgrades has also been documented in the Enserch, HCPC and IRP Dockets. In some cases, the transmission system upgrades were deferred because of HELCO's plan to install an efficient combined cycle unit at Keahole.

3.3 HELCO Transmission Planning Criteria

HELCO's Transmission Planning Criteria state that HELCO's transmission system shall be planned on the basis of serving the predicted peak kVA on any part of the system each year. Additions to the transmission system will be planned for the year in which it is predicted that:

1) Emergency current carrying capacity of any transmission circuit will be exceeded during any condition for which the transmission system is planned or;

2) Voltage levels cannot be kept within required limits.

The transmission planning criteria call for no exceedences of the emergency current carrying capacity on any transmission line. HELCO's operating standard of +/- 5% under certain contingencies applies to voltages on the HELCO system at 69 kV. Contingencies include:

- Outage of any overhead transmission circuit;
- Outage of any transmission wood structure;
- Outage of any underground transmission circuit;
- Outage of any transmission transformer;
- Outage of any overhead, transmission circuit, any transmission wood structure, any underground transmission circuit, or any transmission transformer, when a single generating station is exporting power equal to the sum of the individual generating unit Normal Top Load Ratings in kW at rated power factor.

3.4 *Analysis*

3.4.1 *HELCO System Under Normal Conditions*

With no transmission line outages, the worst case situation occurs at a load level of 164 MW, which is just before a Keahole combustion turbine (CT) is committed under normal economic commitment order. Voltage levels at Keahole and Huehue are just above the lower limit standard of 0.95 per unit (p.u.). For reference, The HELCO operating voltage standard is to maintain the voltage on the bus at +/- 5% (within 0.95 and 1.05 p.u.) on the 69 kV system.

Current flow in this worst case situation will be under the emergency current capacity of the lines with the highest loading at 85% on the Waimea-Ouli (7300) line. The emergency current capacity of the Keamuku-Keahole (6800), Waimea-Keamuku (7200) and Waimea-Ouli (7300) lines is 300 amps. Although the system voltages and currents are within maximum and minimum limits, as the system load level is increased, line overloads and/or low voltage conditions may begin to occur depending on which unit is committed to serve the additional increase in load.

In general, if the load increases from 164 MW, the next generating unit to be committed would be a CT unit (i.e., Puna CT3 at present conditions or Keahole CT4 once the unit is in commercial operation). If an east-side unit is committed, such as CT3, the voltage level at the Keahole would fall below the standard 0.95 p.u. lower limit. If a west-side generating unit is committed instead, the voltage level will increase, creating a cushion between actual voltage levels and the lower limit of 0.95 p.u.

3.4.2 *HELCO System Under Line Outage Condition*

The HELCO Transmission Planning Criteria provides guidelines for adding transmission facilities when current flowing through a transmission line exceeds the line's emergency current capacity rating under single contingencies. Contingencies include loss of an overhead or underground transmission line, outage of a transmission wood structure, or outage of a transmission system transformer.

Figure 3.4-1 identifies a worst-case overload for the year 2004 under HELCO's current operating system with one transmission line unavailable.[1] The loss of the Anaeho'omalu-Po'opo'omino (7100), line causes the Keamuku-Keahole (6800) line to exceed its emergency current capacity limit of 300 amps, and voltages on west side busses are significantly low. It should be noted that outages on the Anaeho'omalu-Keamuku (8100) and Po'opo'omino-Keahole (9100) transmission lines would yield similar results.

Exceeding the emergency current capacity of a transmission line will cause the temperature of the conductor to rise. As described above, when the temperature rises, the line may begin to sag,

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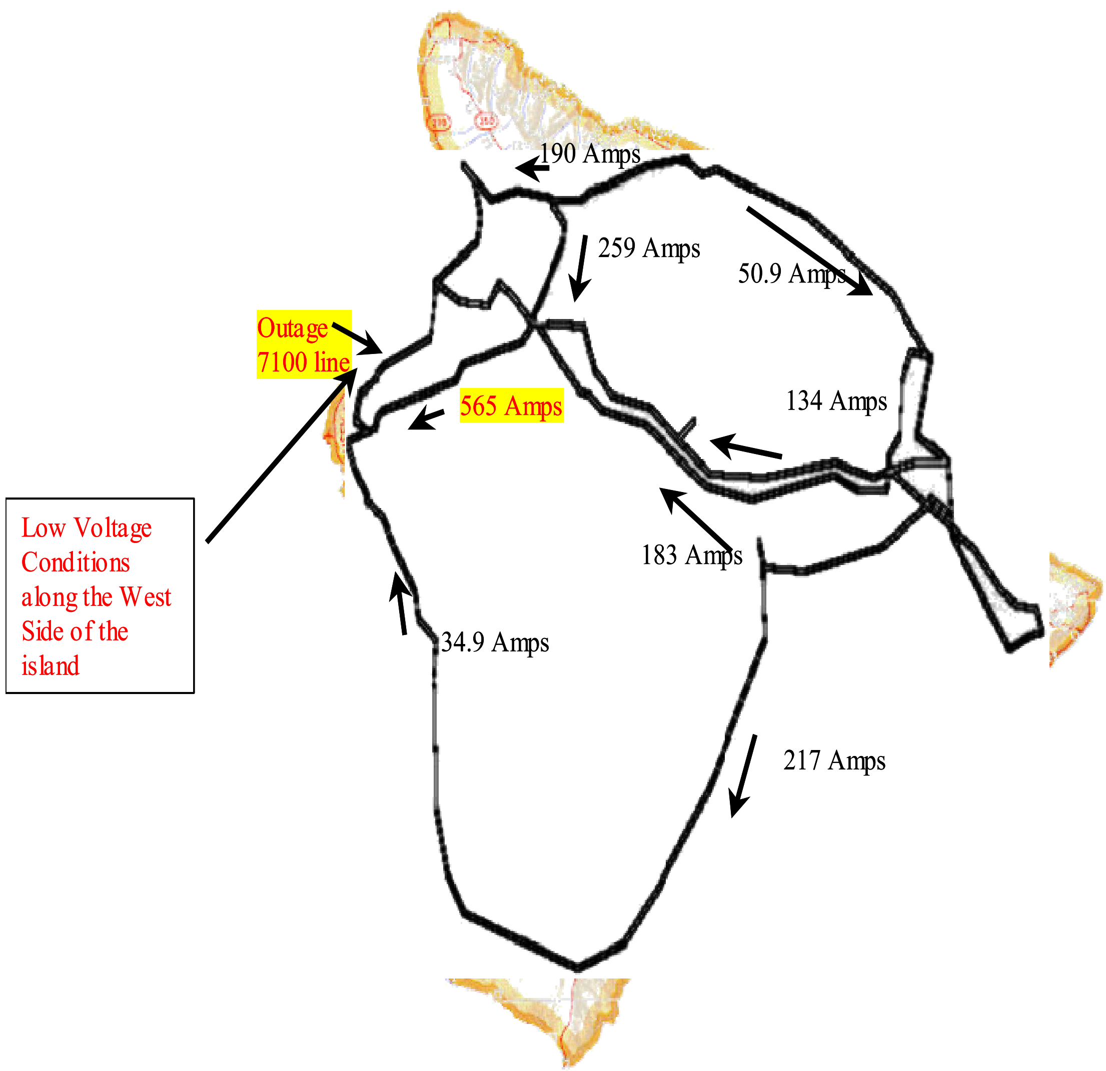
[1] Worst-case condition occurs when all east-side generators are serving the load with no Keahole generation committed. The load flow in Figure 3.4-1, assumes that this occurs at 164 MW (no generating units on overhaul). This is based on normal economic commitment order. As load increases, the next generating unit committed (not considering overhauls) will be a Keahole unit (Keahole CT4 or CT5), therefore the overload condition decreases.

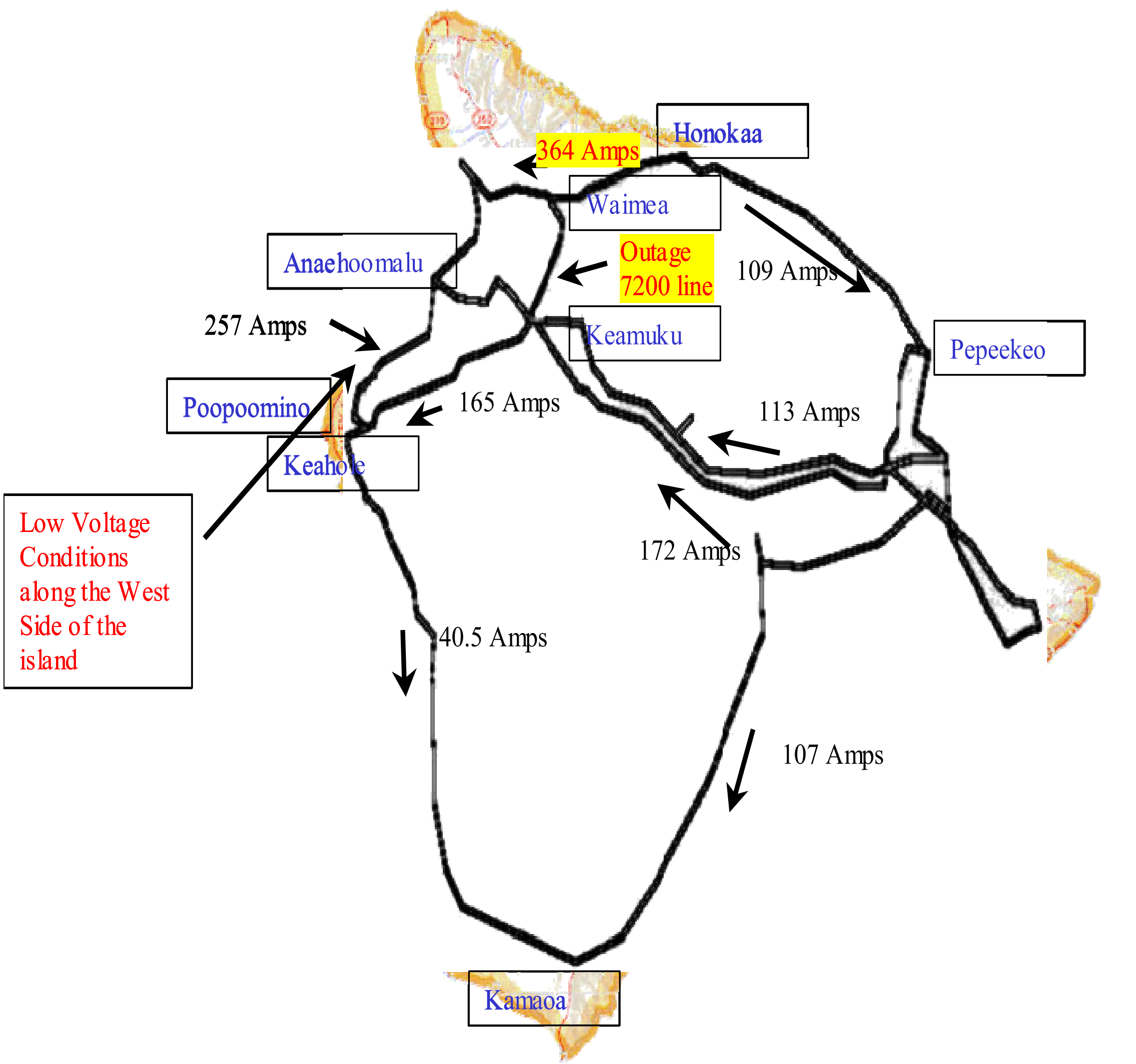
a weak line splice may fail, or a termination point on a pole may fail. A sagging line may come into contact with trees, obstacles or the ground and produce a fault on the line. The fault or line failure could lead to a prolonged outage of the line as repairs are made. The length of the outage will depend on the severity of the line failure.

Figure 3.4-1 HELCO Transmission System at Worst-Case Conditions and Outage of the Anaeho'omalu-Po'opo'omino (7100) line



Another worst-case overload condition exists on the Waimea-Ouli (7300) line if the Waimea-Keamuku (7200) line is not available.[2] The emergency current carrying capacity is 300 amps and Figure 3.4-2 shows the current flowing through the 7300 line at 364 amps at a system load level of 164.4 MW. The same overload exists on the 7200 line if the 7300 line is not available.

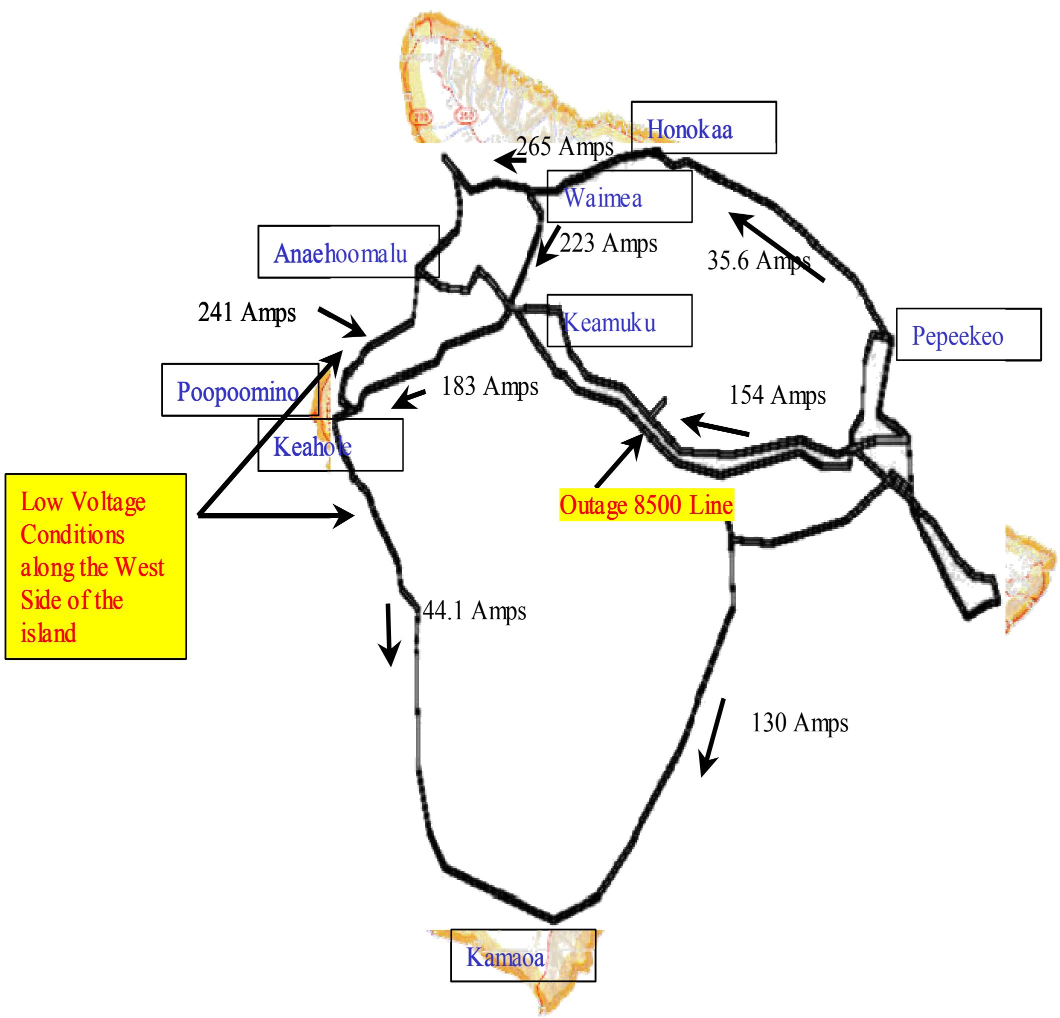
Figure 3.4-2 HELCO Transmission System Load Flow at Worst-Case Conditions and Outage of the Waimea-Keamuku (7200) Line



[2] Worst case condition is the same as explained in footnote 1. The load level that this occurs at is 164 MW.

Under the current HELCO system, the loss of any one of the cross-island lines (as shown in Figure 3.4-3) results in low voltage conditions on the west side. Low voltages occur along the Kona coast with the lowest at Huehue substation.

Figure 3.4-3 HELCO Transmission System Load Flow at Worst-Case Conditions and Outage of the Kaumana-Keamuku (8500) Line



3.5 Reducing the Potential for Line Overloads and Low Voltage Conditions

3.5.1 Near Term Operations and Maintenance Actions

Since the installation of Hamakua Energy Partners (HEP), the continuation of the Hilo Coast Power Company (HCPC) Power Purchase Agreement (PPA) and continuing load growth, HELCO has experienced conditions on the transmission system where mitigation measures were taken to reduce overload conditions.

The combined generating capacity at Keahole is 28 MW and includes CT2 at its normal top load (NTL) rating of 13 MW and the six Keahole diesels with a combined NTL rating of 15 MW. The next few sections explain some of the options HELCO operators now have available to mitigate line overloads and low voltage conditions on the system. These mitigation measures serve as near-term actions that operators have available today; longer-term solutions will also be discussed in this section of the report.

3.5.1.1 Line Maintenance Restrictions

Section 3.4.1 and 3.4.2 explained the potential line overload conditions and potential low voltage conditions with all transmission lines available and during a single-line outage. Generation at Keahole reduces the overload conditions and provides voltage support. In order to manage the overload situations, restrictions are placed on planned transmission line maintenance if Keahole CT2 or the Keahole diesels are unavailable and vice versa. The following is a list of lines, which is not all inclusive, that are affected if an adequate amount of generating capacity is not available at Keahole:

- Anaeho'omalu-Po'opo'omino (7100)
- Waimea-Keamuku (7200) — Location shown in Figure 3.2-1
- Waimea-Ouli (7300)
- Anaeho'omalu-Keamuku (8100)
- Mauna Lani-Anaeho'omalu (8200)
- Ouli-Mauna Lani (8300) — Location of the line is shown in Appendix A
- Po'opo'omino-Keahole (9100)
- Any of the cross-island lines (Location shown in Figure 3.2-1)

In general, planned maintenance outages on transmission lines occur during the day and the lines are usually returned to service before the evening peak. Therefore Keahole CT2 and the Keahole diesels must be available for commitment from about 6 am in the morning until the line on maintenance is placed back in service, which usually occurs before the end of the on-peak period.

3.5.1.2 Planned Line Maintenance and Generation Coordination

An estimated 25-28 MW of Keahole generation is required during peak periods to prevent line overload situations. If Keahole CT2 is on an overhaul and one of the west side transmission lines mentioned above is unavailable, HELCO may not have the ability to meet the load demand, depending on how high the peak load is and how quickly the generating unit or transmission line is placed back in service.

HEP's output is another factor that is affected by line outages. HEP may be curtailed in order to mitigate an overload condition during a transmission line outage. If other generating units (east side or west side) are not available and HEP's output is limited, the amount of generation available to serve the load demand will decrease and there could be situations where HELCO will not meet its generation planning criteria. Therefore coordination between planned line maintenance and generating unit outages must be coordinated to insure there is enough generating capacity on the system to mitigate line overloads, provide voltage support and meet HELCO's generation planning criteria.

3.5.1.3 Operator Actions

Forced outages on a transmission line are different from planned maintenance on a line. Forced outages occur suddenly without any notice. The operators have two options to mitigate line overloads due to forced line outages. One option is to deal with a line outage during a post-contingency situation and the second is to commit a west-side unit out of economic commitment order, in order to prevent the line overload situations.

Under the post-contingency mitigation measure, if a line such as the Waimea-Keamuku (7200) line is suddenly unavailable, an overload condition will occur in that instance and quick-start generation must be available at Keahole to reduce the overload and allow enough time for a CT at Keahole to come on-line to completely resolve the overload conditions. The output from any generator (i.e., HEP or HRD-II scheduled for 2003-2004 commercial operation), which results in power flowing through the 7200 line, will be curtailed to mitigate the overload condition. Using uneconomic unit commitment of Keahole generation (before the unit is needed to serve load) will increase system fuel costs compared to operating the system based on economic unit commitment. However, the transmission system will have increased reliability because Keahole generation would already be on-line to mitigate the overload conditions.

Both the post-contingency and uneconomic commitment will require about 21-23 MW of Keahole generation to mitigate line overloads at average load levels and during certain line outages. 25-28 MW of Keahole generating capacity is required at peak conditions in the 2002-2004 timeframe.

If Keahole CT2 is on overhaul, the Keahole diesels do not provide the adequate amount of Keahole capacity needed to mitigate the line overloads. If three or more Keahole diesels are on an outage simultaneously, then Keahole CT2 and the remaining three diesels at Keahole do not provide the adequate amount of Keahole capacity needed to mitigate the line overloads. Installing Keahole CT4 and CT5 will insure that there is enough Keahole capacity to mitigate line overloads in the near-term and to account for situations where one CT may be on overhaul or when several diesels need maintenance work and are unavailable. The decision to operate the Keahole units out of economic order in order to prevent line overload situations needs to be examined balancing the increase in transmission system reliability, lower system line losses and the added fuel costs versus using the diesels and CT units in post-contingency situations and the reliability (although less than if Keahole generation were already on-line) that this plan provides.

3.5.1.4 Recent Operational Experience

Several instances where required generating capacity at Keahole was needed to mitigate line overloads during line outages have already occurred since the commercial operation of HEP on December 31, 2000, including:

- On August 23, 2002, HELCO required an outage on one of the two lines along the saddle road. Load flows were performed to inform operators of possible line overloads and low voltage conditions, which required the operation of Keahole CT-2 and three Keahole diesels. HEP's output was lowered to insure a line overload did not occur.
- On August 1, 2002 the Anaeho'omalu-Keamuku (8100) line was out of service for line maintenance. HELCO operators committed Keahole CT2 and the Keahole diesels out of normal economic commitment order at about 9 am. As load continued to increase, HEP's output was lowered to insure the Waimea-Ouli (7300) line did not exceed its emergency current capacity.
- HELCO Operations requested an outage on the Pepe'ekeo-Puueo (8400) and Pepe'ekeo-Wailuku (7400) lines. These two lines close the northern cross-island line. Load flows showed that opening the northern cross-island path with generation from HEP and HCPC would cause line overloads. Keahole generation was dispatched to mitigate the line overloads.

3.5.1.5 Generation from Waimea Diesels

Capacity from the Waimea diesels will not resolve the line overloads and low voltage conditions described in Section 3.4.2. The location of the Waimea diesels will increase the line overloads because the power generated by theses diesel units must still flow through the Waimea-Keamuku (7200), Waimea-Ouli (7300) or Keamuku-Keahole (6800) lines in order to serve the load in Keahole.

3.5.1.6 Generation from Dispersed Diesels

Use of the four 1 MW dispersed generators does not resolve the line overloads or low voltage conditions. The locations of the dispersed units are not at Keahole, which is the ideal location. Depending on which line is outaged, output from the dispersed generator at Ouli may cause higher overload conditions. As with the Keahole diesels, if the dispersed units are on-line to mitigate transmission overloads, then the amount of quick-start capability for other system disturbances will decrease.

3.5.2 Long Term Options

Identified in the previous section are three transmission lines, which are subject to overload conditions during line contingency situations. One of the long-term options to relieve the overload conditions is to reconductor the three transmission lines with 556.6-kcmil all-aluminum conductor (AAC). This conductor will meet the continuous and emergency requirements determined in the studies and is a standard conductor for HELCO. The costs to reconductor the 7200 line, 7300 line and the 6800 line with 556.6-kcmil AAC conductors are estimated to be $2,527,700, $2,268,700 and $7,400,000 respectively. The total reconductoring cost for the three lines is $12,196,000. Based on the preliminary estimates for 2004, loss savings due to reconductoring all 3 lines are about $825,000 (13.2 MWh).

Other long-term options have been studied. These options include:

- a fifth cross-island transmission line,
- energizing a portion of the 69 kV system to 138 kV,
- installing capacitor banks for voltage support,
- dynamic line rating techniques, and
- bulk energy storage.

Various options such as those mentioned above will be reviewed in order to improve the reliability of the HELCO transmission system.

4.0 Power Quality Impacts

4.1 Overview

HELCO's 2002 system peak of 177.9 MW (net) occurred on December 30, at approximately 6.30 PM. Estimated HELCO Annual Net System Peaks for future years are provided in Appendix B.

HELCO has sufficient generating reserves to serve its peak load during planned maintenance of any generating unit (generating resources are tabulated in Appendix C). However, in practice, the type and location of HELCO's generation and loads are cause for concern:

- Load growth is primarily on the west side of the island, while generation is on the east side. As described in Sections 3.4 and 3.5, serving HELCO's new load will require greater reliance on transmission lines that are already loaded to the point where they are at capacity or are unable to serve load if any cross-Island line is out of service for scheduled or unplanned maintenance.
- HELCO must maintain a regulating reserve using its operating generators to compensate for fluctuations in load. Non-dispatchable generation cannot be used for regulating reserve. Also, intermittent wind- or solar-powered generation increases the variation between generation and load, requiring more dispatchable regulating reserves. (HELCO dispatchers typically require 4 MW of regulating reserve at minimum load, 5 MW during shoulder periods – morning and evening – and 3 MW during "steady state" high load periods.)

Managing the power system on the Big Island has for some time been a challenging task for HELCO system operators. Non-Utility Generators ("NUGs") own a significant amount of the firm and non-firm generation capacity on the island. HELCO's own generators are connected to growing load centers by long and exposed transmission lines, some of which are highly loaded under certain system conditions. Until the mid 1990's, there was no Automatic Generation Control (AGC) system, which necessitated a defensive strategy for generating unit commitment and dispatch.

Adding to the challenge is a commercial wind farm on the southern tip of the island. The Kamaoa Windfarm has a nameplate capacity of 9.25 MW, and has been in operation since 1985. They are contractually committed to provide a maximum of 7.0 MW to the HELCO grid. While small by mainland standards, data from the HELCO Energy Management System (installed in 1996) show that it has a measurable impact on system frequency deviations. Apollo Energy Corporation, the developer that owns the Kamaoa Wind farm, has submitted a proposal to HELCO for re-powering the plant and increasing the maximum capacity to 20.0 MW.

Additional wind generation is expected to be installed on the HELCO system including the following:

- 10 MW proposed wind farm in Hawi proposed by Hawi Renewable Development; and
- The possibility of re-powering the Lalamilo wind farm from 2.3 MW to 10 MW.

During the majority of the day, HELCO's generators provide the 3 to 5 MW of regulating reserve needed for the system. However, during low load conditions (approximately midnight to 6 AM), HELCO must back down its dispatchable generation to be able to accept as much renewable energy (wind, geothermal, hydro) as possible. At such times, HELCO's generators may be operating at very inefficient levels on their performance curve and/or there may be insufficient HELCO capacity online to regulate fluctuations in load *and* wind output. Under such circumstance, HELCO's production costs are high, and the system is at risk from generation/transmission outages or instability from load and wind dynamics.

At HELCO's minimum system load of roughly 80 MW, the "penetration" (ratio of wind farms rated capacity to system load) could exceed ten percent, a figure many times higher than what has been experienced on any electrical grid in the world running a traditional EMS with AGC (note that very small island power systems, or stand-alone hybrid systems are not considered to be true electric grids for purposes of the issues to be considered here).

In short, because of the unique characteristics of the HELCO power system, a relatively modest amount of intermittent generation from the Kamaoa Wind Farm has created a situation where many of the power quality issues long associated with wind power have become reality. These issues in power quality center around the following:

- Second to second variation for individual units responding to frequency perturbations, which includes inertial response and governor action;
- Units on Automatic Generation Control (AGC) to control frequency deviations and economically dispatch units;
- Fault ride through capability of wind generators;

- Effects of diurnal patterns of wind farm output or other intermittent generation on system operation; and
- Curtailment of as-available producers during minimum load periods.

4.2 System Inertia

System frequency stabilized at 60 Hz is a primary indicator of a balance between electric load and generation serving the load. When electric load on a synchronous generator exceeds mechanical input, the generator will begin to slow down as kinetic energy is extracted from the machine's rotational inertia and is converted to electric power. The decrease in shaft speed corresponds to a decrease in frequency in a synchronous generator. Power must be taken from the remaining on-line units to meet the increase in electrical load. If there is no spinning reserve, the only available source is the kinetic energy in the spinning turbine-rotor masses. The ratio of kinetic energy stored at synchronous speed (60 Hz) to the power rating of the generator (MVA) is defined as the generator's inertia constant. Power system inertia is based on the total kinetic energy of all the spinning turbines and rotors on the system.

HELCO's ability to maintain frequency has decreased over the last several years because of the change in the mix of on-line generation. These changes in HELCO generation dispatch which are contributing to the reduction in HELCO's ability to maintain frequency are:

- Fewer units on the HELCO grid. Prior to Hamakua Energy Partners' (HEP) coming on-line, with three units totaling 60 MW, HELCO met the energy demands of the electric grid with a larger number of smaller units.

- Different generator characteristics. In January 2001, HEP was operated in place of the HELCO-owned units CT-2, CT3, Shipman 3 and 4, and a number of diesel units that had been operated as peaking units during the year 2000.

The net effect of this change in on-line generation mix is that there is less spinning inertia on the grid today compared to year 2000. Less inertia on the HELCO grid results in a greater change in frequency for a given MW change in load or generation.

4.3 Frequency Bias

Frequency Bias is dependent upon the system's rotational inertia as well as the governor response characteristics. It is a measure of the power system's ability to respond to frequency disturbances. Currently HELCO utilizes the following equation to calculate the frequency bias.

Frequency Bias (MW/0.1 Hz) = 0.0195 x Load (MW)

The equation shows how the power system's frequency will react with a sudden loss of generation and HELCO's AGC program uses this number to determine the MW change required in order to return the system to the target frequency. The Frequency Bias formula is updated as the system is changed over time. The constant in the above formula was determined by using disturbance system monitors to measure the system frequency excursion as a result of load loss or generation loss. The table below illustrates the change in frequency bias over HELCO's range of net load.

System Load	Frequency Bias	Frequency Deviation for 1 MW changes.
85 MW	1.66 MW/0.1Hz	0.061 Hz
100 MW	1.95 MW/0.1Hz	0.051 Hz
135 MW	2.63 MW/0.1Hz	0.038 Hz
160 MW	3.12 MW/0.1Hz	0.031 Hz

Table 1. Frequency bias over HELCO's range of net load

4.4 Units on AGC Control

Speed governors on individual generating units maintain constant generator speed by adjusting the mechanical input from the prime mover (steam turbine, diesel engine, etc) in response to a speed error signal. These systems provide the fastest response to speed deviations caused by mismatch between generator input and output. The function of the AGC is to coordinate the output of all generating units to match aggregate electrical demand. In a given system, generating units responsible for system regulation are raised or lowered by AGC to maintain system frequency at 60 Hz. AGC involves two interrelated functions: 1) Load/frequency controls; and 2) Economic dispatch.

Response of load/frequency control is on the order of seconds. Variations, which occur more quickly, are handled by the individual units' speed governors. The economic dispatch function in AGC minimizes the cost of meeting the load demand by adjusting individual generating units' participation in load/frequency control. Inputs to the AGC for economic dispatch include incremental generating costs for participating units and transmission penalty factors.

During minimum load periods, HELCO utilizes three units for frequency regulation, which include Hill 6, Hill 5 and Puna steam. The other 24-hour base loaded unit is Puna Geothermal Ventures (PGV), which is a 30 MW geothermal unit and is not designed to regulate frequency. There are situations during low load periods where more than 50% of the generation on-line is not able to regulate frequency because the generation mix includes electrical energy from as-available units such as wind and hydro units and firm generation from the geothermal plant, which does not have the ability to regulate frequency.

During on-peak periods, another non-regulating coal fired unit (HCPC) is committed based on contract requirements, which require HELCO to accept an average of 18 MW for 14 hours per day, five days per week. Looking toward the future, HELCO is expecting an increase in wind power generation over the next several years, which could lead to a decrease in the amount of units regulating frequency. HELCO could experience further complications in its ability to maintain system frequency as the generation mix controlled by AGC is changed.

4.5 Fault Ride Through Capability

Three-phase dynamic simulations performed on the HELCO system indicate that multiphase faults on the transmission system could result in low voltage conditions throughout the HELCO system. Faults will result in voltage dips to between 0.75 pu and zero until the faulted line is cleared from the system. Pilot relaying requires about 167 milliseconds of fault clearing times. Backup relaying requires as much as 2 seconds for high impedance fault clearing. Wind farms of substantial size should be equipped with under voltage ride through capability for their entire outputs in order to account for the total wind farm generation levels expected on the system. Without fault ride through, the wind farm could trip on low voltage conditions, which could lead to customer load shedding each time a fault occurs on the HELCO system.

4.6 Intermittent Renewable Generation

Intermittent generation such as wind energy impacts the HELCO system. Through its experience with the Kamaoa Wind Farm, HELCO has seen a direct correlation between larger frequency deviations with a larger amount of wind on the system. The frequency deviations are smaller when less wind is on the system and the deviations increase as more wind is placed on the system.

HELCO units responsible for regulating frequency are called upon to adjust their output as wind fluctuations upset the balance between system load and generation supply. HELCO is expecting additional wind farms on the system. These wind farms may add to the difficulties HELCO is currently experiencing in trying to maintain the system frequency.

Wind and other renewable resources such as hydro and solar rely on the environment to provide the energy. HELCO obtains power from two wind farms (Kamaoa and Lalamilo) and several run of the river hydro plants (Wailuku River Hydro, Waiau Hydro and Puueo Hydro) on an as-available basis. When energy is available from these facilities, HELCO will reduce generation from or switch off fossil-fueled units to accommodate wind and hydro generation. A sudden decrease in wind resource or decrease in river flow will decrease energy output from these generating units and HELCO must rely on its fossil-fueled generation to make up for the lost output.

In general, HELCO maintains about 3-5 MW of regulating reserves. A sudden decrease or increase of renewable generation beyond this 3-5 MW will cause frequency deviations and could result in customer load shedding depending on the severity of generation loss. Beyond the 3-5 MW of regulating reserves, HELCO relies on quick-start diesels at Waimea, Keahole, Kanoelehua and its four 1 MW dispersed diesel generators to come on-line within 30-90 seconds to make up for a sudden loss in generation. The fast starting combustion turbine units require approximately 15 minutes to come on-line and ramp up to full output.

As intermittent renewable generation is increased on the system, HELCO will be at risk for situations where a sudden decrease in the intermittent generation can lead to customer load shedding. HELCO's current operating practices, on-line regulating reserves, quick-start diesels, and fast starting combustion turbine operation will change in order to provide the back-up energy to prevent load shedding. Other technologies could be incorporated onto the HELCO system to increase the system's ability to accept higher penetration of intermittent renewable energy without degrading service reliability to the customer.

4.7 Minimum Load Conditions

HELCO's minimum load level hovers around 70-80 MW. Although HELCO's peak has seen significant growth in 2001 and 2002, the minimum load has not seen comparable growth rates. HELCO's operating practice is to have at least three units with frequency regulation capability on-line at all times. In general, HELCO operates Hill 6, Hill 5 and Puna steam as the regulating units during low load periods. HELCO is also required to accept at least 27 MW of capacity from PGV during the off-peak period. The combined minimum from the four units equals 56.4 MW out of the 70 MW minimum.

It is HELCO's practice to accept as much energy from as-available wind and hydro units as operationally possible. At times some of the as-available units are curtailed because there is more on-line generation than what is needed to meet the system load. Future contracts may be subject to curtailment during the off-peak periods.

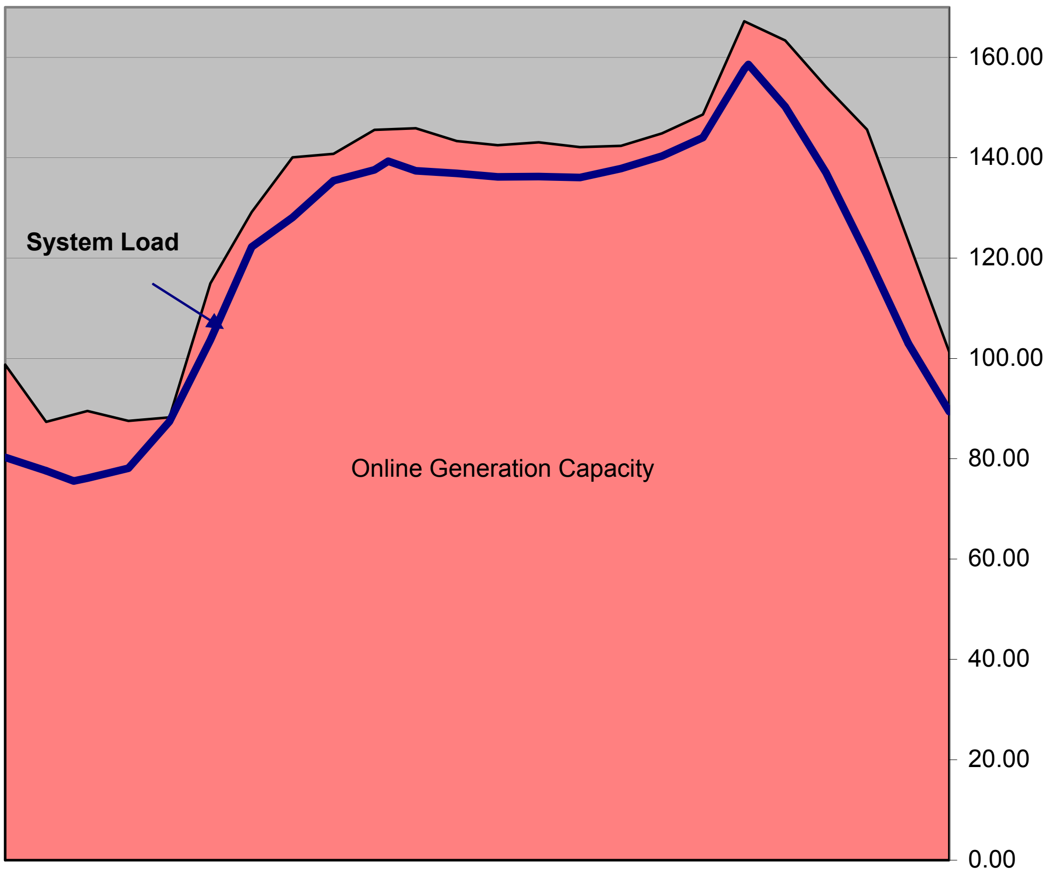
4.8 Further Discussion of Non-firm and Non-regulating Impacts

As described in Section 4.1 "Overview", the system operator matches generation production to the system load. As load increases, the system operator starts additional generating units as needed. As load decreases, the system operator stops generating units when they are not needed. This keeps the generators running near their peak output, which is more fuel-efficient.

The electric utility grid produces AC power. When the system load and generation production are equal, the system frequency is 60 Hz, the desired frequency. If the system load exceeds the generation production, frequency will drop below 60 Hz. If the generation production exceeds the system load, the frequency will increase above 60 Hz.

A typical day is used as an example to further explain the impacts to the HELCO system. Figure 4.8-1 shows the system load measured on March 21, 2002 (shown as the blue line), which includes the total customer energy usage plus transmission/distribution losses. Note that the load varies throughout the day, being lowest at early morning and highest at dusk. The peach area is the actual total generating capacity on the grid at that time of day. Note that the total online capacity is always slightly higher than the system load. This provides some reserve to increase generation production if load increases. The system frequency is 60 Hz when the generation production matches system load. There is usually not enough reserve to cover a large loss of generation, so these events usually result in low frequency.

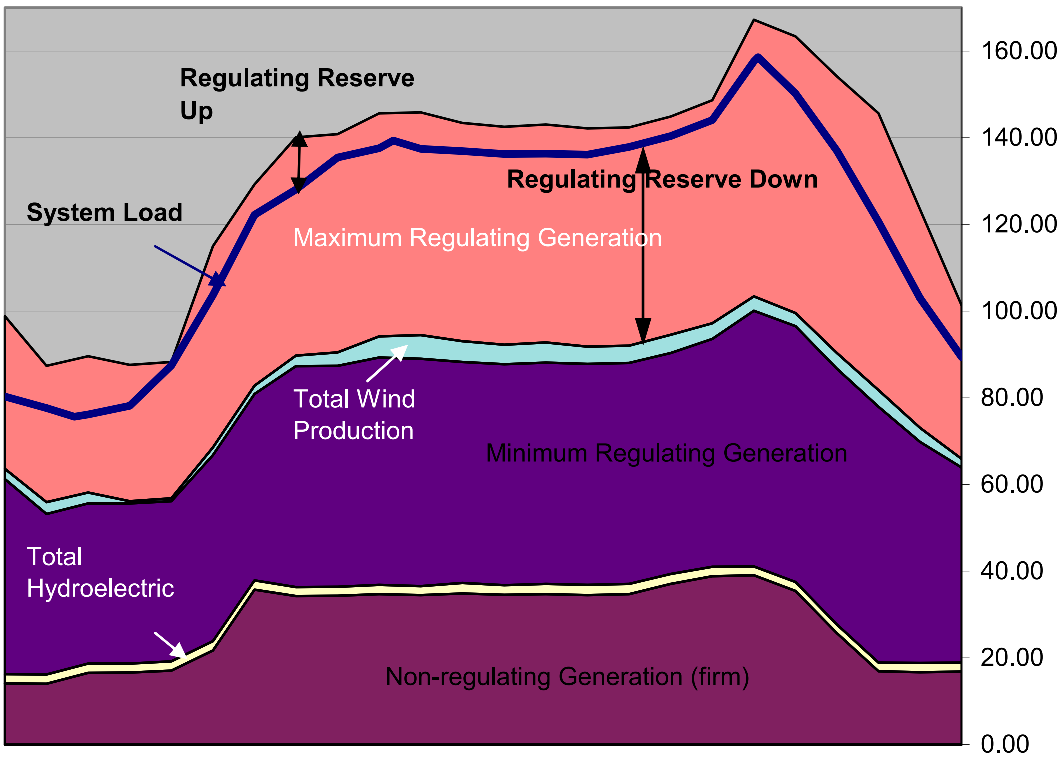
Figure 4.8-1 HELCO Load Curve for 3/21/02
Generation Capacity (MW) from Actual Measured Data



The low frequency results in automatic load shedding of selected loads to bring the generation and load into balance.

Figure 4.8-2 shows the present mix of generation based on actual dispatch from March 21, 2002. This figure has the same system load line and total system capability as in Figure 4.8-1 but has the breakdown of generation mix. The bottom burgundy layer is the fixed generation that is not under AGC control, but firm power. It has HCPC at contract levels and PGV at a derated level. The yellow and blue areas are the hourly and peak instantaneous measured production for hydroelectric and wind power, respectively. Note that the hydro power is more stable. On this day, one of the small HELCO units was put online.

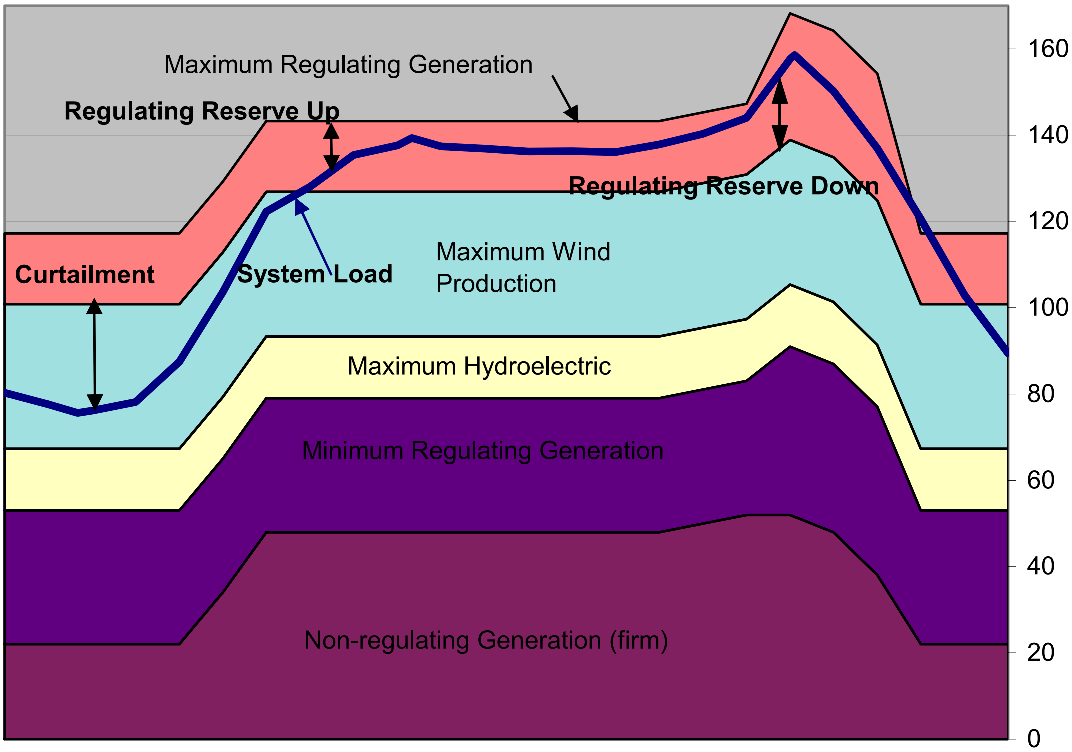
Figure 4.8-2 HELCO Load Curve for 3/21/02
Generation Characteristics (MW) from Actual Measured Data



The peach area shows the amount of regulation that is the difference between the regulating units' maximum output and actual output. The amount above system load line is available to increase output (regulate up) should another source of generation drop out. The amount below the system load line is the regulating reserve down, available to back off production should customer load be lost – such as when a tree falls on a transmission line that has customer loads tapped from it.

Figure 4.8-3 illustrates a scenario that HELCO will be encountering in the future. This figure assumes that three steam units – Hill 5, Hill 6, and Puna – can regulate the system frequency. As we get more experience we may find we need to have more regulating generation.

Figure 4.8-3 HELCO Load Curve for 3/21/02
Generation Characteristics (MW) for Future Wind Production
(Assumes Three Steam Units can Maintain Frequency)



The figure includes PGV and HCPC at contract levels for the fixed generation. Hydro is at 14.4 MW that consists of Wailuku River Hydro at 11 MW and HELCO's hydro at 3.5 MW. The expected maximum wind production, based upon planned expansion of Kamaoa, Lalamilo and Hawi, is expected to be approximately 40 MW in the near future. This example is based on wind loading at 83% and has Kamaoa at 16 MW, Lalamilo at 8.5 MW, and Hawi at 9 MW.

The peach area represents the total range of regulating power available to match production and load. Two items of particular interest are:

- There is no regulating reserve down during the early morning hours (left hand of chart), which will require curtailing some of the non-firm generation.
- The amount of regulating generation is significantly less than that presently available in Figure 4.8-2.

These two items may lead to problems controlling frequency since wind causes higher MW fluctuations on the system and this case is presented with only three regulating units. The addition of greater quantities of as-available units like wind will force HELCO to carry larger amounts of regulating reserve.

5.0 Candidate Bulk Storage Technologies

5.1 Overview

To summarize elements of the previous discussion, HELCO is experiencing operating constraints at both peak and light load conditions. Most of HELCO's generation is on the east side of the island, while loads are growing rapidly on the west side. There are a limited number of cross-island transmission lines, and at peak load they are close to fully loaded. This can lead to voltage or stability problems, and a single contingency (one line's outage) will overload the remaining lines. Much of the load growth is at resorts, and this may soon require investment to reinforce the transmission system.

HELCO purchases a large amount of non-dispatchable renewable energy from PGV geothermal plant and from numerous wind farms. Independent power producers are planning developments that may soon more than triple the Big Island's wind turbine capacity. However, wind turbines are non-dispatchable, and variations in wind result in significant fluctuations in power input to the HELCO grid. At light load (from midnight to 6 am HELCO's load is about 70 to 80 MW), HELCO's load is almost totally served by PGV and three regulating units. Because of the intermittent nature of wind-powered generation, HELCO requires more regulating reserves during this off-peak time (about 4 MW off-peak versus 3 MW on-peak). The renewable sources' and regulating units' capacities can exceed HELCO's load, requiring curtailment of the wind and/or geothermal. As more wind is added to the system, this problem will get worse.

During nighttime, HELCO uses 3 generators for system regulation:

- Hill 5 – 13.5 MW capacity, 7.4 MW minimum load
- Hill 6 – 20.2 MW capacity, 14.9 MW minimum load
- Puna Steam – 14.1 MW capacity, 7.1 MW minimum load

PGV is also on-line – 30 MW capacity, of which HELCO is obligated to take 27 MW. In addition, there are run-of-river hydro units – 3.5 MW of HELCO hydro and 11 MW of Wailuku hydro. Regulation, PGV and run-of-river hydro have a total 70.9 MW minimum generation.

With its present generation and transmission resources, the HELCO system would be unable to absorb even 10 to 15 MW additional wind generation without risking instability and power quality or frequency problems during low loads and transmission overloads (requiring rotating blackouts) during planned or scheduled transmission outages causing overloads of lines 6800, 7200 or 7300.

This section will evaluate possible use of energy storage to assist HELCO in accommodating the additional renewable energy.

5.2 *Bulk Energy Storage Location Consideration*

Two considerations for determining the location of the Bulk Storage are penalty factors and system constraints. Penalty factors are calculated by the real time generation control from loss sensitivities that are calculated from the real time network analysis program. The penalty factors are accumulated over time to provide an average. Penalty factors are a measure of the amount of power needed to add 1 MW to the system load. If the number is less than one, then the injection of power at that location will decrease system loss. If the number is greater than one, the injection of power at that location will increase losses. Partial lists of average penalty factors at various locations for 2002 in ascending order are:

Keahole	0.8347
Kapua	0.8651
Lalamilo WF	0.8873
Punaluu	0.9066
Ouli	0.9107
Waimea	0.9833
Wailuku Hydro	0.9881
Kanoelehua	0.9921
Puna	0.9930
HCPC	1.0000
PGV	1.0060
HEP	1.0163

From the above list it is clear to see that the low point of the system is in the area of Keahole, which is on the west side of the island. The results are intuitive since 85% of the generation capacity is on the east side of the island with 60% of the load on the west side of the island.

System constraints as described in Section 3.4 “Analysis” show for single line contingencies that overloads occur on the Keamuku-Keahole (6800), Waimea-Ouli (7300) and Waimea-Keamuku (7200) lines. The very worst contingency is with the loss of the Anaeho’omalu-Po’opo’omino (7100) line; the Keamuku-Keahole line exceeds the emergency current capacity of 300 amps and voltages on the west side are significantly low. This constraint forces the location of the bulk energy storage to be beyond the Keamuku-Keahole (6800) line termination at Keahole.

There are the only two west side locations currently owned by HELCO where there is enough land to put in such a facility (with exception of a pumped storage hydro system which is site specific). The two locations are Keahole Power plant and Kailua Base yard.

5.3 *Bulk Energy Storage Sizing*

Candidates for bulk energy storage were evaluated in 10 MW increments include various battery systems: lead acid, nickel cadmium, sodium sulfur, vanadium redox, zinc bromide and

Regenesys. These battery systems vary in terms of commercial availability, cost, and expected lifetime. Estimated costs are $1500/kW and higher, depending on the technology and the expected usage (cycling strategy, etc.). Technical and cost characteristics of each type of system are summarized in the "Bulk Energy Storage Fact Sheets" report, which is shown in Appendix D.

Additional storage technologies could be incorporated at the wind farms, on the developer's side of the connection to HELCO. A wind developer's power output must meet a constraint negotiated with HELCO (e.g., variation of output less than 1.5 MW per minute). This is accomplished through a combination of developer-owned storage (e.g., batteries, flywheel, compressed air), dumping wind, and adding resistance load to the turbines' outputs to reduce feed into the HELCO system. The possibility of using additional or advanced storage technologies, or generating hydrogen instead of expending excess output in resistance load, is a design option for the developer. The economics of such storage options will depend upon the contract terms with HELCO, including purchase price of power and maximum output variation allowed. Such options are outside the scope of this study, as they are the responsibility of the wind farm developers.

5.4 Project Cases

In this project, we examine the results of implementing two bulk energy technologies: 30 MW pumped hydro, one 20 MW or one 10 MW battery systems. Bulk Energy Storage scenarios being considered include:

- Pumped storage hydro – Case 1 will be 30 MW, 150 MWh storage, 75% pumping efficiency sited near Puuanauhulu Substation. There are two candidate sites: one, Puu Anahulu; two, Puu Waawaa. They are located on either side of the Puuanauhulu Substation. Both sites have estimated costs of approximately $2,880/kW or $576/kWh. The plant will cost $86,400,000. Both of these cases will require that a portion of the Keamuku to Keahole transmission line will be reconductored ($3,700,000). Total cost is $90,100,000.
- Battery (lead acid) at Kailua or Keahole switching stations, 75% charging efficiency. Case 2 will be 20 MW, 30 MWh of storage. Total plant will cost $25,000,000. Case 3 will be 10 MW, 15 MWh of storage. Total plant will cost $12,500,000.

5.4.1 General Operational Issues

Bulk energy storage has the potential to resolve some of the previously described problems. Energy storage can increase nighttime loads, enabling HELCO to keep dispatchable generators on-line to more efficiently provide regulating reserve and to avoid having to back down geothermal and wind sources. Discharging storage can lower peak loads, possibly reducing use of high cost (or higher polluting) peaking generation, reducing transmission loading, and/or providing load shedding to prevent equipment overloads in a contingency situation. Some energy storage technologies can provide regulating reserve. This will enable HELCO to accept more non-dispatchable renewable generation (i.e., wind) on its system. Table 2 lists the operational problems each technology could address. Each of these operational problems will be discussed in more detail in later sections of the report.

Bulk Energy Storage Technology	Provide regulating reserve	Accept more renewable generation (by increasing minimum load)	Accept more renewable generation (by reducing generation fluctuations)	Improve generation production efficiency	Reduce equipment overloads	Improve stability and power quality	Provide voltage regulation	Maintain system during transmission outages
Energy storage – pumped hydro		X		X	X		X	X
Energy storage – batteries	X	X	X	X	X	X	X	X

Table 2 – Bulk Energy Storage Technologies and HELCO Operational Issues

5.4.2 Cases Load Profiles

The pumped hydro (Case 1) would increase HELCO's minimum load and decrease peak load, but pumped hydro would not provide regulating reserve. Battery storage (Cases 2 and 3) would be able to provide some regulation.

Table 3 shows the load changes to HELCO's system load for each of these three scenarios if the storage is dispatched to provide daily load leveling – reduced peak load and increased minimum load.

MONTH	30 MW PUMPED HYDRO – CASE 1			
	Load Decrease		Load Increase	
	MW	Hours	MW	Hours
January	-30	1800–1859	+30	0000–0359
	-20	1600–1759	+20	2300–2359
	-20	1900–1959	+20	0400–0459
	-10	0900–1259	+13	2200–2259
	-10	1500–1559	+13	0500–0559
February	-30	1800–1859	+30	0200–0259
	-20	1700–1759	+20	0000–0159
	-20	1900–1959	+20	0300–0359
	-10	1600–1659	+10	2300–2359
			+10	0400–0459
March	-30	1800–1859	+20	0000–0359
	-20	1700–1759	+10	2300–2359
	-20	1900–1959		
April	-20	1700–1959	+20	0000–0359
	-5	1000–1259	+10	2300–2359
			+10	0400–0459
May	-10	1700–1959	+20	0000–0359
	-5	0900–1659	+10	2300–2359
	-5	2000–2059	+10	0400–0459
June	-10	1800–1959	+20	0200–0359
	-5	0900–1459	+10	0000–0159
			+10	0400–0459
July	-5	1800–1959	+5	0100–0359
August	-10	1800–1959	+10	0100–0359
September	-10	1800–1859	+10	0100–0359
	-5	1700–1759		
	-5	1900–1959		
October	-20	1700–1859	+20	0100–0359
	-5	0900–1259	+10	0000–0059
			+10	0400–0459
November	-30	1800–1859	+20	0100–0359
	-15	1700–1759	+10	0000–0059
	-15	1900–1959	+10	0400–0459
December	-30	1800–1859	+20	0100–0359
	-15	1700–1759	+10	0000–0059
	-15	1900–1959	+10	0400–0459

Table 3 – Load Changes from Pump Hydro Energy Storage – Case 1

During a contingency situation, if a transmission line is lost, then the storage unit(s) could be discharged, to reduce loading on the trans-Island lines. (Potential benefits are limited, as the 20 or 30 MW storage capacity available might not appreciably off-load the remaining trans-Island lines if one of the lines is out of service.) However, this is possible only if the storage unit has available capacity and energy. Tables 3 and 4 portray a storage dispatch schedule that maximizes HELCO load factor. This means that during the peak hours (1700 – 1900, approximately), the storage is being almost fully discharged and is not available as an additional resource during a contingency. After the peak period (1900 – 0200, approximately), the storage energy is depleted and recharge has not yet begun. Therefore, storage may not offer significant reliability support during a contingency from 1700 to 0200 unless its dispatch schedule is specifically designed to do so. The likely strategy is to use the schedule from Tables 3 and 4 (i.e., to reduce peak line and generator loading and increase minimum load) except during planned outages (e.g., line maintenance). For those days with planned transmission line maintenance the storage would be scheduled for reliability and system support. However, the overall production costs would not change much with this few days' schedule variance, so the Table 3 and 4 numbers should be used for P-Plus simulations of production costs.

MONTH	10 MW BATTERY – CASE 3				20 MW BATTERY – CASE 2			
	Load Decrease		Load Increase		Load Decrease		Load Increase	
	MW	Hours	MW	Hours	MW	Hours	MW	Hours
January	-10 -2 -3	1800–1859 1700–1759 1900–1959	+5	0000– 0359	-20 -5 -5	1800–1859 1700–1759 1900–1959	+10	0000– 0359
February	-10 -2 -3	1800–1859 1700–1759 1900–1959	+5	0000– 0359	-20 -5 -5	1800–1859 1700–1759 1900–1959	+10	0000– 0359
March	-10 -2 -3	1800–1859 1700–1759 1900–1959	+5	0000– 0359	-20 -5 -5	1800–1859 1700–1759 1900–1959	+10	0000– 0359
April	-5	1700–1959	+5	0000– 0359	-10	1700–1959	+10	0000– 0359
May	-10 -2 -3	1800–1859 1700–1759 1900–1959	+5	0000– 0359	-10 -5 -5	1800–1859 1700–1759 1900–1959	+9	0100– 0359
June	-5	1700–1959	+5	0000– 0359	-10	1700–1959	+13	0100– 0359
July	None		None		None		None	
August	-5	1700–1959	+5	0000– 0359	-10	1700–1959	+13	0100– 0359
September	-10 -2 -3	1800–1859 1700–1759 1900–1959	+5	0000– 0359	-20 -5 -5	1800–1859 1700–1759 1900–1959	+10	0000– 0359
October	-10 -2 -3	1800–1859 1700–1759 1900–1959	+5	0000– 0359	-20 -5 -5	1800–1859 1700–1759 1900–1959	+10	0000– 0359
November	-5	1700–1959	+5	0000– 0359	-10	1700–1959	+10	0000– 0359
December	-10 -2 -3	1800–1859 1700–1759 1900–1959	+5	0000– 0359	-20 -5 -5	1800–1859 1700–1759 1900–1959	+13	0100– 0359

Table 4 – Load Changes from Battery Energy Storage – Cases 2 and 3

5.4.3 Cases Production Simulations

Production simulations were made for one year only using 2004 as the generation model year. The cost analysis assumes an historical average of as-available energy usage. Five production simulations were made:

- **Base Case –** Economic dispatch of units
- **Case 1 –** 30 MW Pump Hydro with load changes as shown in Table 3. Cost is \$76,576 less than the Base Case.
- **Case 2 –** 20 MW Battery Storage with load changes as show in Table 4. The cost is \$243,515 less than the Base Case.
- **Case 3 –** 10 MW Battery Storage with load changes as show in Table 4. The cost is \$172,157 less than the Base Case.
- **Case 4 –** Non-economic dispatch of units. This dispatch requires generation to be on at Keahole so that post contingency operator response as described in 3.5.1.3 is possible. The cost is \$1,863,903 more than the Base Case.

An interesting trend is shown which shows that Case 3, 10 MW storage, saves money as expected. Case 2, 20 MW storage, has additional savings over Case 3. Case 1, 30 MW storage, is the larger storage and the savings are reduced to less than both Case 2 and 3. Case 1 appears to indicate that the size of the storage has more than hit diminishing returns; routinely utilizing 30 MW of storage is not needed on the HELCO system.

The cost savings for the above Cases 1 (30 MW), Case 2 (20 MW) and Case 3 (10 MW) were divided by the MWhs used in the production simulations to charge the storage and resulted in 0.259, 1.89 and 2.57 cents/kWh. These are the average savings per kWh and it shows that the savings are diminished as the storage size is increased.

5.4.4 Regulation

Battery storage can be used to some extent as regulating reserve, but again this will depend on available capacity. If the storage is depleted, then it cannot provide capacity, but it can commence charging, to provide load. If fully charged, the unit can provide capacity but not load. During charge or discharge operation, the unit's operation can be curtailed, to provide regulation the opposite of the scheduled operation. Table 5 gives approximate times of day and whether battery storage can provide positive or negative regulation. The available regulating capacities are very approximate, since the batteries cannot immediately switch to full (20 MW) charge or discharge mode. The maximum discharge rate is twice the maximum charge rate.

It has been estimated that 1 MW of available battery storage located *at a wind farm* and *integrated with the wind farm control and dispatch system* could provide about –1.5 MW (charge) or +3 MW (discharge) of short term (under 2 minutes) regulating reserve[3]. The HELCO-owned battery systems:

- will be located outside of the wind farms,
- will have to be dispatched according to conditions sensed on the HELCO system (i.e., not direct wind generator output),
- and may have to sustain their response for longer than 2 minutes (i.e., may have to respond until conventional generators can take over).

Therefore, it is estimated that only 1/3 the theoretical short-term regulating capability is available (–0.5 and +1.0 per 1 MW available storage capacity). Table 5 reflects these assumptions, based on the storage dispatch schedule of Table 4.

Approximate Time of Day	Availability for Positive Generation (Increase Generation or Decrease Load)	Availability for Negative Generation (Decrease Generation or Increase Load)	Normal Operating Status
0000 – 0059	+ 5 MW	- 5 MW	Discharged/Charging
0100 – 0359	+ 10 MW	- 5 MW	Charging
0400 – 1759	+ 20 MW	0	Fully Charged
1800 – 1859	0	- 10 MW	Discharging at full capacity
1900 – 1959	+ 5 MW	- 15 MW	Discharging/Mostly discharged
2000 – 2359	0	- 10 MW	Discharged

Table 5 – Availability of 20 MW Battery Storage for System Regulation

On-peak, HELCO has sufficient regulating generating capacity on-line. Even during shoulder periods, sufficient regulation is available. During off-peak times, 0000 to 0400, battery storage can provide additional regulating capability at times when it is most needed.

As discussed in 4.1, HELCO's generators provide 3 to 5 MW of regulating reserve on the system and rely on under frequency load shedding for protection of the system due to loss of generation. There is no value placed on this ancillary service because of HELCO's policy on minimal regulating reserve.

5.4.5 Capacity

The storage projects were not figured for capacity since they were not rated for enough duration. The 30 MW Pump Hydro has the storage (150 MWh) for a long enough duration to be considered for capacity but in practicality, the storage size was too large for HELCO's current system. The simulation was based on a yearly average of 81 MWh or 54%. The storage reached a maximum of 93% during only one month of the year.

[3] Norris, Parry and Hudson. "An Evaluation of Wind Farm Stabilization and Load Shifting Using the Zinc-Bromide Battery."

5.4.6 Additional Renewable Support

Currently, HELCO supports 11.9 MW of wind. This is planned to increase to 20.2 MW in 2005 and 30.9 MW in 2006. The performance requirements for the new wind farms (approximately 10 MW per new installation) will be less than 1 MW instantaneous fluctuation per 2 seconds and less than 0.3 MW per 60-second period. *Looking only at regulating reserve requirements for HELCO system power quality*, the 20 MW battery storage systems should be able to accommodate up to approximately an additional 50 MW of wind – 20 MW planned for 2004 - 2005 and up to an additional 30 MW in the future.

The 20 MW battery or 30 MW pumped hydro systems will also increase HELCO's minimum load by about 10 MW and 20 MW respectively. This will allow HELCO to take the full PGV output, even at minimum load (i.e., not have to back down the 30 MW PGV to 27 MW). Regulation units, PGV and run-of-river hydro now total 70.9 MW minimum generation. HELCO's minimum load will increase from 80 MW to 90 MW with battery storage (or 100 MW with pumped hydro). Thus, battery storage will allow HELCO to accept an additional 10 MW of wind output at light load, and pumped hydro will allow an additional 20 MW. Since the wind farms' actual power is expected to almost always be less than nameplate capacity, an increase in 1 MW of minimum HELCO load will support about 3 MW of wind turbine nameplate capacity. (While historical Kamaoa and Lalamilo capacity factors for 1998 - 2002 were about 0.15, planned Hawi and Apollo capacity factors are 0.35 - 0.37.) Thus, battery storage will allow HELCO to accept the output of approximately an additional 30 MW of wind turbine nameplate capacity during light load times.

Looking at HELCO's current regulating reserve requirements and operations/power quality concerns, any additional wind capacity beyond the present 12 MW will likely cause additional reliability or power quality problems during light load conditions. HELCO will be forced to bring additional regulating units on-line and, as a consequence, will be less able to accept wind turbine output during light load conditions. Storage will increase HELCO's minimum load, and battery storage will provide some regulating reserve. The 20 MW battery storage scenario will allow HELCO to support an additional 30 MW nameplate of wind, including the 20 MW now planned for 2004 - 2005. The 30 MW pumped hydro scenario will increase HELCO's minimum load by 20 MW. This should also allow HELCO to accept an additional 30 MW, approximately, of wind, but to do so HELCO will have to bring on-line at least 10 MW of additional dispatchable regulating generation to provide about 3 MW of regulating reserves. (Thus half the pumped hydro's 20 MW load increase will support wind farm output and half will be served by regulating units.)

Additional storage may be justified within the wind farms, as the storage can reduce the wind farms' output fluctuations and supply needed station power during periods of extremely light winds. However, this is outside of HELCO's jurisdiction, and is properly evaluated by the wind farms' developers.

6.0 Conclusions

The addition of significant non-dispatchable renewable power generation on the HELCO system since 2000 has markedly changed the nature of the regulating reserves available to keep the Big Island's power grid reliable and stable. Coupled with heavy economic development and construction – and resulting load growth – on the Kona side of the Island, while most generation is on the Hilo side, HELCO must immediately take steps to ensure the quality and integrity of electricity supplied to Hawaii's residents, services and businesses. This report has examined several power generation, energy storage and transmission reinforcement options to determine what is needed to continue to serve the Island's electricity needs while accommodating anticipated private sector investments in clean, renewable electricity sources.

The geographical disparity between HELCO's existing generation and its growing electrical load, and the fact that HELCO's cross-Island transmission facilities are already close to fully loaded, make it imperative for reliability, service quality (voltage level), and stability reasons (as well as the economic benefits of reducing losses and being able to more economically dispatch generators) to reconductor the three transmission lines and to install economical generation on the west side. The cost to reconductor all three lines is $12,196,000. Based on the preliminary estimates for 2004, loss savings due to reconductoring all 3 lines are about $825,000 (13.2 MWh) for the year.

At present, any scheduled maintenance or forced outage in a cross-Island transmission corridor puts the HELCO system at risk, as the remaining in-service lines will be close to or at overload conditions and areas on the west side will experience low voltage. The present HELCO system resources and transmission configuration cannot handle more than a few years of additional growth in electricity demand at current growth rates. Given the high rate of construction and load growth on the west side of the Island, delays in reconductoring these lines will make it more difficult to schedule the reconductoring and will markedly increase the chances of load curtailment incidents. Neither energy storage nor increased wind-powered electric generation will mitigate this problem.

Electricity produced by Hawaii's renewable energy sources is non-dispatchable (i.e., cannot be scheduled), and the fluctuations in wind farm output already strain HELCO's available regulating reserves, especially at light load conditions (nighttime). To maintain system stability, the output of geothermal- and wind-powered facilities must routinely be curtailed. There are plans to triple the amount of wind-powered electric generation on the HELCO system; the current HELCO grid cannot tolerate this. The result will be:

- Significantly greater probability of frequency excursions, necessitating load curtailments or blackouts.
- Higher generation operating (production) costs from bringing more regulating reserves on-line and operating generators at levels that are less fuel efficient and result in higher emissions.

- More frequent – probably routine – nighttime curtailment of the PGV geothermal generators' output.
- Minimal output variation accepted from new wind installations, necessitating more frequent need for the wind farms to shed wind or direct excess power to local resistors. This will markedly increase the cost of wind-powered electricity.

The line reconductoring projects and the Keahole CTs described previously will help mitigate this problem. The installation of 10 to 20 MW of electric battery storage at Kailua and/or Keahole will also mitigate this problem and should enable HELCO to accept up to an additional 30 MW nameplate of wind turbines on its system (with appropriate constraints on the allowable output fluctuations from these new wind turbines).

The 10 MW bulk energy storage has an approximate cost of $12,500,000. The facility will provide a yearly savings of $172,157. Because of the size, HELCO would still have to run in an uneconomic dispatch that will cost $1,863,903 for 2004 more than economic dispatch. The 20 MW bulk energy storage has an approximate cost of $25,000,000. The facility will provide an annual savings due to energy of $243,515 and HELCO would not have to incur the additional $1,863,903 cost of uneconomic dispatch of its fossil units for reliability and stability purposes. The size of the storage might allow HELCO to operate nearly economically for a few years but special provisions would have to be made to the controls for contingency response.
The Big Island has technically feasible sites for a 30 MW pumped hydro installation. Such a pumped hydro facility is larger than HELCO's needs, cannot deliver all the regulation benefits of battery storage systems, and costs significantly more than battery storage. Therefore, even without considering the environmental and land use implications of pumped hydro, such a facility is not an economically desirable option.

The yearly savings from any of the energy storage devices is not large enough by itself to justify the large capital expenditure of the facility. However, bulk storage does give HELCO some system reliability and stability benefits that will be essential for HELCO to tolerate the anticipated increases in as-available electric generators on its system. Plainly speaking, without bulk energy storage, HELCO will have to undertake mitigation measures such as adding spinning reserve, increasing its present regulating reserve, and/or curtailing as-available energy resources. Building spinning reserve or increasing regulating reserves will increase operating and maintenance expenses significantly. This will increase the costs of fossil-fueled generation. Because more dispatchable fossil units will have to be on-line during light load periods, HELCO will have to curtail as-available resources on its system, especially at night. This will add uncertainty to the projected sales from the wind farms and will likely affect the developers' ability to obtain financing for the projects, effectively limiting further development of as-available renewable energy projects. With external financial support and lower energy costs, Energy Storage *might* be a cost-effective means for HELCO to operate reliably with anticipated saturation of renewable energy sources.

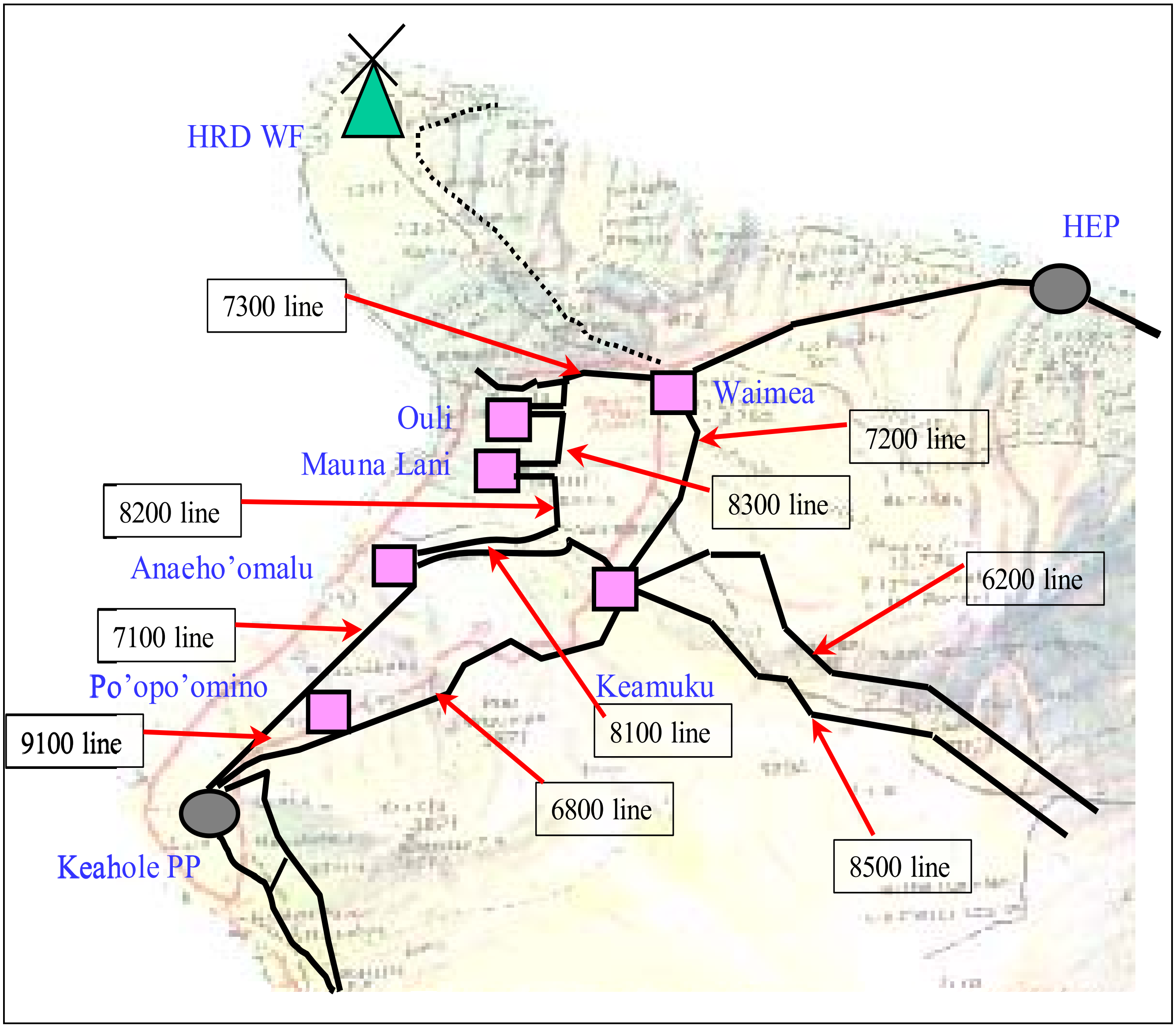
The conclusions of this scoping study are:

- Key HELCO cross-island transmission lines (6800, 7200, 7300) are operating at close to capacity and should be reconductored. Bulk energy storage is not a technically or economically viable alternative to reconductoring these lines.

- HELCO’s system cannot operate reliably with the anticipated 30 MW of wind-powered electric generation scheduled to go on-line in the near future. Some form of curtailment will be necessary under certain operating conditions. Even with that curtailment, the resulting uneconomic dispatch of HELCO’s fossil-fueled generators will increase production costs.
- 20 MW of energy storage, located at Keahole or Kailua, will enable HELCO to accept the anticipated windfarm additions.
- 10 MW of energy storage at Keahole or Kailua will enable more wind capacity to be added, but not the entire 30MW projected. 10 MW of storage would not prevent uneconomic dispatch of HELCO generators.
- More than 20 MW of storage (e.g., 30 MW of storage) is more than the HELCO system can utilize and is not economically justified.
- Battery storage provides necessary system regulating capability. Pumped hydro does not. Flywheels could provide power quality support but not the long-term (i.e., hours) storage capability needed for economic dispatch of HELCO’s fossil-fueled generators. Therefore, battery technology or ***a combined battery-flywheel installation are*** the best commercially-available storage choices for HELCO.
- A combination pumped storage with a flywheel could provide the short term regulating capability and power quality support. Further studies will be required to determine a suitable site and to optimize the unit sizes.
- Splitting the 20 MW of storage between the Keahole and Kailua sites would improve the projected reliability/availability of the storage resource but increase its per-MW capital costs. Choosing between the two options requires a detailed site engineering and system reliability study.

The addition of approximately 20 MW of bulk energy storage at Keahole and/or Kailua substations appears necessary for HELCO to continue to operate its system reliably and economically with the load growth and renewable energy development anticipated on the island. *To verify this, the* next step *would* be to perform more detailed site-specific cost analyses, load flows, production cost and unit commitment studies, system reliability analyses, and wind speed simulation studies to determine the optimum size and location, the effects on revenue requirements, and the resulting degree of dependence on fossil fuels of this nominal 20 MW of storage.

APPENDIX A: HELCO Transmission System – West Side



APPENDIX B: HELCO Estimated System Peaks

Year	Estimated Net System Peak (MW)
2004	187.3
2005	191.3
2006	195.6
2007	200.0
2008	205.5
2009	210.3
2010	215.3
2011	220.4
2012	225.5
2013	230.9
2014	236.3

Notes:

1. Estimates for 2004 through 2008 are based on HELCO's Forecast Planning Committee's Forecast of Annual Net System Peak, dated May 13, 2003.

2. Estimates for 2009 through 2014 are based on an extrapolated growth assumption.

APPENDIX C: HELCO Firm Generation Capacity (2004)

Unit	Reserve Rating (Net MW)	NTL Rating (Net MW)
Shipman 1	0.00	0.00
Shipman 3	7.10 (1)	7.10 (1)
Shipman 4	7.30 (1)	7.30 (1)
Hill 5	13.50	13.50
Hill 6	20.20	20.20
Puna	14.10	14.10
Waimea D8	0.00	0.00
Waimea D9	0.00	0.00
Waimea D10	0.00	0.00
Kanoelehua D11	2.00	2.00
Waimea D12	2.75	2.50
Waimea D13	2.75	2.50
Waimea D14	2.75	2.50
Kanoelehua D15	2.75	2.50
Kanoelehua D16	2.75	2.50
Kanoelehua D17	2.75	2.50
Keahole D18	0.00 (2)	0.00 (2)
Keahole D19	0.00 (2)	0.00 (2)
Keahole D20	0.00 (2)	0.00 (2)
Keahole D21	2.75	2.50
Keahole D22	2.75	2.50
Keahole D23	2.75	2.50
Kanoelehua CT1	11.50	11.50
Keahole CT2	13.00	13.00
Puna CT3	20.40	20.40
Keahole CT-4	19.90 (2)	19.90 (2)
Keahole CT-5	19.90 (2)	19.90 (2)
Panaewa D24	1.00	1.00
Ouli D25	1.00	1.00
Punaluu D26	1.00	1.00
Kapua D27	1.00	1.00
HELCO Total	**177.65**	**175.40**
HCPC	0.00 (3)	0.00 (3)
PGV	30.00	30.00
HEP	60.00	60.00
IPP Total	**90.00**	**90.00**
System Total	**267.65**	**265.40**

Notes:

(1) HELCO is temporarily restricting the outputs of Shipman 3 and 4 to 6.7 MW and 6.8 MW, respectively.

(2) Keahole CT-4 and CT-5 are assumed to be installed in mid-2004. D18-20 are to be retired with the installation of CT-4 and CT-5. Since CT-4 and CT-5 are in litigation, the service dates are subject to change.

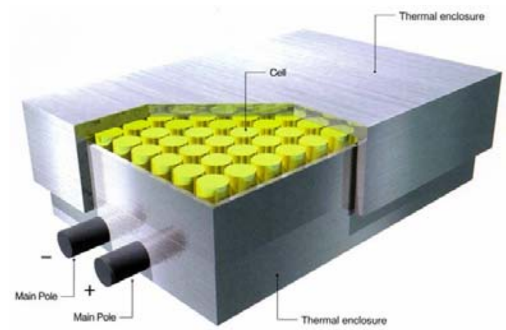
(3) HCPC to be terminated on December 31, 2004 (with early shutdown on November 30, 2004) for purposes of this analysis. Any decision to terminate HCPC would depend on the facts and circumstances at the time.

APPENDIX D: Bulk Energy Storage Fact Sheet

SODIUM SULFUR (NAS)

BASIS: an aggregate power level of 10 MW with 3 hours equivalent energy storage

Characteristics:



- Large capacity
- Compactness
- High efficiency
- Long-term durability
- Preservation of the environment
- High cost
- Limited commercial availability

Supplier: NGK / Technology Insight
http://www.ngk.co.jp/DEN/english/index.html
http://www.TechnologyInsights.com

Specifications:

Commercially Available?	Yes (limited)
Individual system	1.2 MW (NAS 20-Module Building Block). System can be scaled using module blocks
Maximum load	1.2 MW per NAS Building Block
Efficiency	76.7% average 100% DOD peak shaving cycle efficiency, including power conversion losses
Maximum energy available	7.2 MWh per day
Cycle frequency/cycle life	2500, 100% DOD cycles 15 years
Emission info	None
Forced outage rate	Probability of NAS cell failure over its design life is less than 10^{-4}
Fixed O&M	Average: \$6/kW for PCS, plus ~\$150 per battery module each year
Variable O&M	Depends on specific duty cycle
Cost	\$2.27 million for each NAS 20-Module Building
Lead time for delivery	6 months

SODIUM SULFUR (NAS)

Projects:

Companies	Site	kW/kWh	Purpose	Start of Operation
TEPCO/Pacifico	Media Center	2,000/14,400	LL + UPS	Apr-02
TEPCO	Chichibu Substation	1,000/7,200	Load Level	Jun-02
TEPCO/Fujitsu	Akiruno Technology Ctr	3,000/7,200	LL + UPS (PW=3)	Jun-02
AEP	Gahanna, OH, USA	500/720	LL + UPS (PQ=5)	Sep-02

Other Info:

The price of a NAS 20-Module Building Block (assuming Alternate Peak Shaving Profile) (1.2 MW for 3 hours and 0.5 MW for 7.2 hours), scheduled for delivery in 2003 or 2004, is $2.27 million, or $20.4 million for nine 20-Module NAS Building Blocks capable of 10.8 MW and 64.8 MWh. The scope of supply associated with this price consist of:

- Grid connection equipment, breaker protection and transformers
- Power conversion equipment and controller(s) to synchronize one or more NAS system trains with the grid
- NAS battery modules and battery management system
- DC circuit breakers for battery system protection and isolation
- Exterior enclosures
- Shipment from Japan, including import duties and fees
- System installation, startup and commissioning

The average annual cost for battery maintenance is about $150 per module. Thus, the expected annual maintenance costs for a NAS 20-Module Building Block is about $10,500 annually, or $91,800 per year for 9 NAS Building Blocks.

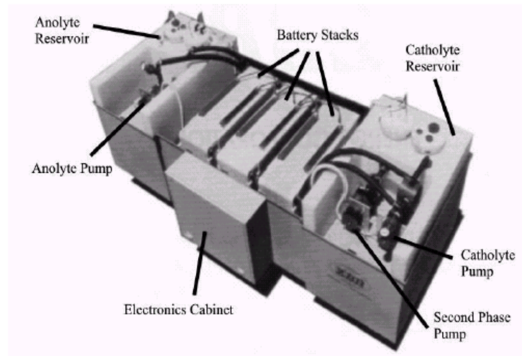
Variable operating costs includes the cost of energy to charge the batteries, plus the cost of energy consumed to maintain the PCS in a state of readiness and NAS batteries within the operating temperature regime. These costs depend on local electricity rates and the specific duty cycle of the facility.

ZINC BROMINE

BASIS: an aggregate power level of 10 MW with 3 hours equivalent energy storage

Characteristic:

- Store energy in external reservoirs
- Provide for greater volumetric energy density - storing up to three times the energy of conventional batteries
- Offer 2 to 3 times the energy density (75 to 85 watt-hours per kilogram) with associated size and weight savings over present lead/acid batteries
- Can be modified for selected applications



Supplier: ZBB Energy Corporation
http://www.zbbenergy.com/index.html

Specifications:

Commercially Available?	Yes (limited)
Individual system	50 kWh module that can be arranged in series and parallel configuration into 500 kWh system blocks
Maximum load	Depends upon system configuration
Efficiency	~ 75%
Maximum energy available	Data not available
Cycle frequency/cycle life	2000+ “deep discharge” cycles
Emission info	None
Forced outage rate	2000+ “deep discharge” cycles
Fixed O&M	To be determined
Variable O&M	$3,000 to $4,000/MWh/year
Cost	$400/kWh and $200,000/500 kWh system exclusive of PCS equipment and transformer. All battery protective devices, accessories, relay, etc. are included.
Lead time for delivery	18 months

Projects:

A 400 kWh system was installed on United Energy site in Melbourne, Victoria, Australia. This system is designed to test the functionality of all aspects of the energy storage system.

A 400 kWh system was installed on a Detroit Edison site in Lum, Michigan. The system was operated over a three-month period until October 2001, functioning as a load management asset to alleviate system stress at an "in field" transmission substation. By June 2002 the system underwent another round of testing until October 2002. This was then followed by the first winter testing of a ZBB battery system through winter 2002/2003.

Other Info:

The module for renewable energy applications consists of three battery stacks, with each cell stack in the module containing sixty cells in series, arranged in bi polar configuration and giving an open cell stack voltage of 108 Volts.

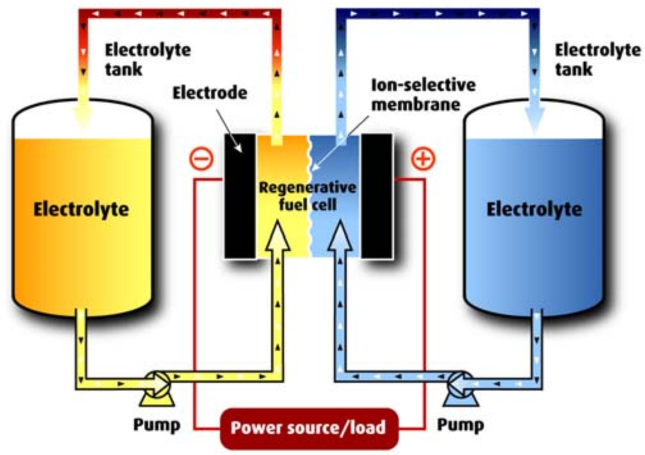
The discharge capacity of the module is 50 kWh. The module can be charged at different charge rates up to 225 amps. The ZBB battery can be charged from fully discharged to fully charged within 3 hours. Discharge can be sustained at continuous rates up to 300 amps.

Inspection and maintenance will be required on annual basis, and the specific procedures and parts replacement schedule are currently under refinement during the ongoing field projects in the USA and Australia. Annual maintenance contracts are to be negotiated.

REGENESYS

BASIS: an aggregate power level of 10 MW with 3 hours equivalent energy storage

Characteristics:



- Suitable for energy storage applications in the range of 5-500 MW or more and for storage times from a few seconds to 12 hours or more.
- Can be completely discharged without damage to the electrolytes or electrodes.
- Can be operated fully connected to the grid, capable of turning from charging to discharging or any state in between in the order of less than 1 cycle.
- Can be set to either a standby mode or a full shutdown mode with modules drained and pumps turned off.

Supplier: Regenesys Technologies Limited
http://www.regenesys.com

Specifications:

Commercially Available?	No
Individual system	Minimum size of the system is 15 MW, with scalability upward in increments of 400 kW, up to 500 MW or more and for storage times from a few seconds to 12 hours or more.
Maximum load	150% of nominal capacity
Efficiency	60-65% roundtrip, busbar to busbar
Maximum energy available	Full charge/discharge cycle anticipated daily
Cycle frequency/cycle life	Capable of rapid cycling with no effect on performance or life; the design life for the Regenesys system is about 15 years.
Emission info	Small quantity of sodium sulfate (solid form) is produced. The system is designed for continues electrolyte management, with chemical removal/replenishment occurring in operating mode. During operation, sodium sulfate is produced in an approximate rate of 500 kg/week (assuming a 15 MW system).
Forced outage rate	95% availability
Fixed O&M	$10/kW per year

Variable O&M	$10/MWh discharged
Cost	To be negotiated Current published plant costs are for an integrated system, including installation.
Lead time for delivery	To be negotiated

Projects:

A TVA pilot plant project (12 MW, 120 MWh plant) built in Columbus, Mississippi is using the Regenesys technology to store electricity during off-peak periods and retrieve it for use when the need for power increases.

Construction is on schedule for mechanical completion by April 2003. At that point, the delivery of Electrolytes and the Regenerative Cells or Modules is possible.

Little Barford energy storage plant (15 MW, 120 MWh) is currently under construction and will be completed by spring 2003. The target turnaround efficiency for this plant is approximately 60%.

VANADIUM REDOX BATTERY

BASIS: an aggregate power level of 10 MW with 3 hours equivalent energy storage

Characteristics:

- Cost per kWh decreases as the energy storage capacity increases.
- Cell and electrolyte sections can be separated to customize the system's layout and shape to fit installation locations.
- Expansion of storage capacity can be achieved by increasing the volume of electrolytes.
- The system operates at normal temperatures.
- The system can be fully discharged with no adverse effects to the battery.

Supplier: Reliable Power / Sumitomo
http://www.reliablepowerinc.com
http://www.sumitomocorp.co.jp/english/

Specifications:

Commercially Available?	Yes (limited)
Individual system	1 MW
Maximum load	10 MW
Efficiency	~ 70%
Maximum energy available	30 MWh per day (900 MWh in 30 days; assuming sufficient charging at night)
Cycle frequency/cycle life	12,000 cycles
Emission info	None
Forced outage rate	Lifetime of the equipment is approximately 10 years. Maintenance can be performed on one module at a time, so the remaining modules will be available for operation.
Fixed O&M	$20/kW/year
Variable O&M	Depends on configuration
Cost	The estimated cost of the VPS system (10 MW, 3 hour) will be in the range of $24-$26 million. The cost is negotiable and depends upon the actual performance specification.
Lead time for delivery	6 months – 12 months

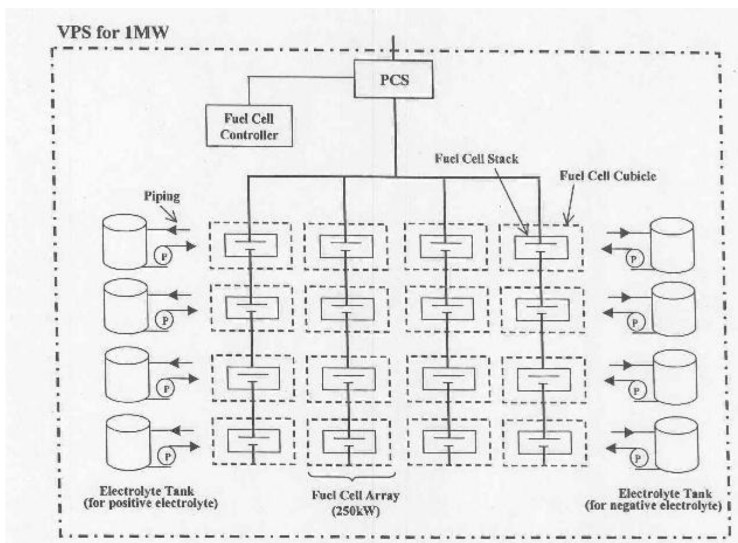
Projects:

Currently there are eight VPS projects operating around the world. Project capacities range from 30 kW to 3 MW, with discharge durations from 1.5 seconds to 10 hours.

Customer	Application	Capacity	Installed
Sumitomo Densetsu	Peak Shaving	100 kW / 8 hours	Feb. 2000
Kansai Electric Power	Peak Shaving	200 kW / 8 hours	Sep. 2000
New Energy and Industrial Technology Development Organization (NEDO)	Wind Output Stabilization	170 kW / 6 hours	Dec. 2000
Tottori SANYO Electric	Power Quality, Peak Shaving	3 MW / 1.5 seconds; 1.5 MW / 1 hour	Feb. 2001
ESKOM	Power Quality; Peak Shaving	250 kW / 2 hours	Mar. 2001
Kwansei Gakkuin University	Peak Shaving	500 kW / 10 hours	Jun. 2001
Obayashi Corporation	Renewable (PV) Energy Storage	30 kW / 8 hours	Apr. 2001
CESI	Peak Shaving	42 kW / 2 hours	Nov. 2001

Other Info:

The Vanadium Power System (VPS) as detailed here is a 1 MW bulk energy storage system. The VPS consists of a Power Conversion System (PCS) and 4 x 250 kW strings of rechargeable fuel cells.



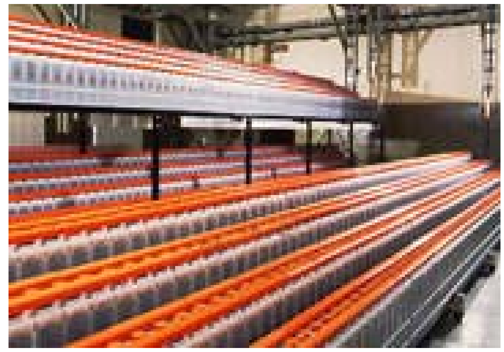
The standard cell stack is at 62.5 kW. Four cell stacks are arranged in parallel to from a 250 kW array. Four arrays are combined to form a 1MW Module. Each module has its own dedicated PCS, fuel cell controller, electrolyte tanks and piping and pumps.

The VPS system can provide up to two times overload emergency capacity for short durations. This function can be added as needed (cost will increase accordingly).

NICKEL CADMIUM BATTERY

BASIS: an aggregate power level of 10 MW with 3 hours equivalent energy storage

Characteristics:



- Provides 40 MW for up to 15 minutes (GVEA BESS battery)
- System voltages range from 1.2 V to over 4 kV
- Can be tailored to system needs
- High initial cost
- High self-discharge rate

Supplier: Saft (http://www.saftbatteries.com/)

Specifications:

Commercially Available?	Yes
Individual system	40 MW for up to 15 minutes
Maximum load	40 MW
Efficiency	65% for a round-trip full 5-hour discharge and recharge
Maximum energy available	Depends on usage
Cycle frequency/cycle life	Depends on plate design and DoD
Emission info	Hydrogen and oxygen during overcharge
Forced outage rate	20-25 years
Fixed O&M	Depends on operating conditions
Variable O&M	Depends on operating conditions
Cost	Cost varies by plate design and size of purchase commitment. It is around \$500-\$1,000 / kWh (based on a 5-hour discharge). The cost levels are for the battery only.
Lead time for delivery	To be negotiated

NICKEL CADMIUM BATTERY

Projects:

- Numerous projects.
- Golden Valley project, Fairbanks, Alaska
  - The world's most powerful storage battery, capable of supplying 40 MW of power
  - The battery, comprising 13,760 high performance nickel-cadmium cells in four strings, will form the heart of a Battery Energy Storage System (BESS) to provide continuous voltage support during normal operation as well as providing energy backup
  - In operation, it will produce of 40 MW of power for sufficient time from when a system disturbance occurs to allow the utility to bring backup generation on line.

Other Info:

A Ni-Cd system can be tailored to system needs. The GVEA BESS battery will provide 40 MW for up to 15 minutes, depending on the number of strings deployed. The GVEA BESS battery will be rated at 14.5 MWh in its initial implementation.

Hydrogen and oxygen will be released during overcharge. Highest rate (during last stage of recharge) is approximately 2.7 ft^3/hour of hydrogen per kWh of rated capacity. Evolution on float condition is approximately 0.01 ft^3/hour.

Maximum initial charge rate is approximately 1.2 kW per rated kWh. Maximum sustained charging power is approximately 300W per rated kWh. Discharge power depends on cell design.

Standard Ni-Cd life expectancy is 20-25 years under controlled conditions with minimal cycling. This figure may be reduced by operation at high temperatures and with frequency/deep cycling. Special warranties can be negotiated for large systems. Maintenance, in the form of water additions, can be performed with the battery online. The typical frequency is every 3-4 years on float in controlled conditions, varying down to every 60-90 days for heavy overcharging at high temperature.

LEAD ACID BATTERY

Characteristics:

- Low cost
- Short cycle life
- Used for power quality, and UPS
- Amount of energy (kWh) that a lead-acid battery can deliver is not fixed and depends on its rate of discharge

Suppliers: GNB, Delco, East Penn, Trojan, and others.

Specifications: GNB (www.gnb.com)

Commercially Available?	Yes
Individual system	Numerous models
Maximum load	Depends on system configuration
Efficiency	70-80%
Maximum energy available	Depends on system configuration
Cycle frequency/cycle life	Depends on system configuration
Emission info	None
Forced outage rate	20 years
Fixed O&M	$1.55/kW-yr (2001 data)
Variable O&M	$0.01/kWh (2002 data)
Cost	The cost for a 10 MW, 15 MWh system is $1,250/kW or $850/kWh or $12,500,000.
Lead time for delivery	2 – 3 months (battery only)

LEAD ACID BATTERY

Projects:

Plant Name and Location	Year of Installation	Rated Energy (MWh)	Rated Power (MW)
Chino, California	1988	40	10
PREPA, Puerto Rico	1994	14	20
BEWAG, Berlin	1986	8.5	8.5
Vernon, California	1995	4.5	3