

# System Justification And Vendor Selection For The Golden Valley BESS

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## **ABOUT GVEA**

Golden Valley Electric Association, Inc (GVEA) is an Rural Utility (RUS) Co-op that was founded in 1946. GVEA owns and maintains 2200 miles of distribution line, 336 miles of transmission line, a 25 MW coal fired generation facility and 200 MW of diesel and oil fired gas turbine generation. GVEA has a system peak of 182 MW during the winter months while serving 38,000 meters (90,000 residents) spread across 2,000 square miles. GVEA's total MWh sales were over 1,000,000 the last three years.

## **GVEA SYSTEM HISTORY**

Alaska is really a third world country in a number of ways. There is only one road into and out of Alaska. The capital of Alaska cannot be driven to, you can only fly or get there by boat. Alaska is also an electrical island. We are not connected to Canada or to the Lower 48. Small loads, small population, long distances, few roads and challenging conditions make for an interesting life. Outages are a fact of life and in Fairbanks, total system blackouts are not unknown.

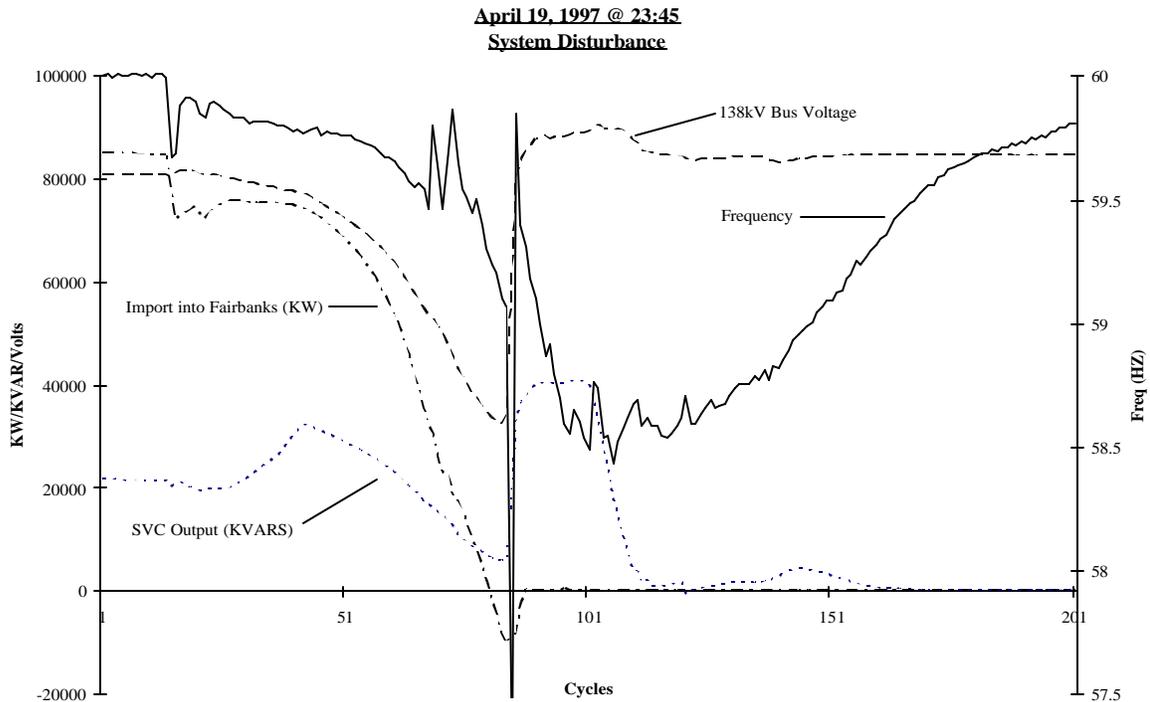
Before the mid 80's, GVEA was electrically isolated from the Anchorage area. GVEA used coal fired and oil fired generation to supply electricity to its members. In order to contain costs (keep rates low) GVEA implemented an under-frequency relay load shedding scheme and ran our generation with minimal or no spinning reserves. The under-frequency load shedding scheme required that each distribution substation be shed (the feeders) at different under-frequency shed points (59.4 Hz, 59.3 Hz, etc). Generation was dispatched to run as close to max output as possible and to minimize spinning reserves. The decision as to how much generation spinning reserves to have available were made daily and changed depending on the time of year, weather and system configuration. During a system disturbance (loss of a generator or transmission line) the generators on line supplied what ever reserves they have. If these reserves were not adequate, system frequency would decay and feeders would start to trip until enough load had been shed to turn the system frequency around and the system stabilized. As new generation is brought on line, the tripped feeders are restored until the system is put back together. The under-frequency relay load shedding scheme was the best tool available as an alternative to the operation of costly combustion based spinning reserves on an isolated system and to supply stability enhancements to reduce system blackouts. We were able to operate a very economical utility by not providing real spin and we avoided not only the fuel costs but the wear and tear on combustion turbines.

Radial transmission lines connect what is called the Railbelt portion of Alaska. three quarters of the population of Alaska lives in this narrow corridor. The Railbelt, which contains three quarters of Alaska's population, consists of an area from Homer to Fairbanks which is connected by railroad, electrical and road systems. The Railbelt power system is comprised of three load centers, the southern, central and northern. The southern area includes the Kenai Peninsula communities of Kenai, Soldotna, and Homer. The central area contains the largest generation capacity (natural gas fired) and loads in Alaska and includes the city of Anchorage, Palmer and Wasilla. The northern area is the GVEA system and has the communities of North Pole, Healy and Delta Junction as well as the city of Fairbanks. In the mid 80's GVEA was connected electrically to the central load center by a 186 mile 138kV transmission line known as the Intertie (how original!). Both the southern and the northern load centers are connected to the central load center through radial transmission lines (115 or 138kV) that have constrained transfer capacities. For example the Intertie is constrained to a 77MW import into GVEA's Healy substation. While the Intertie allowed us to gain access to cheaper power from hydro and natural gas fired generation it also increased GVEA's exposure to generation outages and transmission line disturbances in the central and southern load centers. The entire combined Railbelt power system has incredibly low inertia and is susceptible to large changes in frequency for relatively minor losses in generation. For example, the loss of a 110 MW unit in Anchorage will cause system frequency to decay to 59.0 Hz at a rate

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of 0.8 Hz/second. System disturbances have caused the central and northern load centers to go “out of step” with each other resulting in breaker trips and the islanding of the northern load center.



This chart shows a GVEA system disturbance that occurred following the loss of our 25 MW coal fired power plant in Healy (100 miles from Fairbanks). The chart was developed from a monitor at our Goldhill substation located in Fairbanks. At the time of this system disturbance there was local generation running with no reserves and the Intertie was loaded to 60 MW. Following the loss of Healy plant the generation in Anchorage responded and overloaded the Intertie. This resulted in a 138kV voltage decay to which our SVS's at Goldhill and Healy responded until their ceilings were hit (33 MVAR @ Goldhill). Because the system still needed additional VAR support, and there was none to be found, the voltage continued to collapse until reaching a 0.43 PU level at which time one of the Schweitzer 121-10 relays operated under a Zone 1 impedance and opened the transmission line breaker at Goldhill substation. After the breaker opened, Fairbanks was under an islanded condition with insufficient generation. Frequency continued to decay until under-frequency rate of change relays shed enough load to turned the system frequency around and stabilize the system.

All Railbelt utilities provide a share of the spinning reserves required due to loss of the largest operating generator on the Railbelt system. The shares are proportioned to each utility based on the largest unit each utility has operating and the largest unit which is on line. No distinction is made as to the type of spin that a utility provides or its response time to accepting the load obligation. As a backup to the spinning reserve obligation all Railbelt utilities installed three under-frequency load blocks. Each block represents 10% of each utilities load and are set to operate at 59.0 Hz, 58.7 Hz and 58.5 Hz. As GVEA had already been using under-frequency load shedding for spinning reserves, we had no problem integrating this into our existing scheme. But, the connection to the central load center, coupled with new system stability issues caused by the loss of the Intertie under heavy import conditions and the fact that GVEA could not provide real spinning reserves cheaply required GVEA to engineer more solutions that were economical, practical and easy to implement. A Shed-In-Lieu-Of-Spin (SILOS) application was developed that used a SCADA controlled load-shedding scheme. This SCADA application monitors the Railbelt spin requirement for GVEA, determines the requirement for each second and provides SCADA tripping of the feeders necessary to meet this requirement. System studies determined that a three step load shedding schedule would be needed. SILOS load blocks of 25%, 25% and 50% of the spin requirement are shed at 59.7 Hz, 59.4 Hz and 59.1 Hz respectively. The application allowed

for a ribbon rotation of feeders, logical conditioning for tripping, arming, and disarming of individual loads based on the historical number of feeder trips. This way you could insure that every member shared the pain equally. This system has been historically proven to be able to respond in less than two seconds to power supply system disturbances caused by generator trips as the rate of frequency decay (0.8 Hz/sec) was slow enough for the SCADA based SILOS system to react.

For faults on the Intertie a different under-frequency relay scheme had to be developed because of the speed at which frequency decays. Under heavy import conditions (>50MW<75MW) the loss of the Intertie requires GVEA to shed 50% to 70% of our load quickly to allow the transmission system and the remaining generation and load to stabilize. The SCADA based SILOS system could not react quickly enough to this type of disturbance as system studies showed the rate of frequency decay to be between 2.0 and 7.0 Hz/second. Under-frequency rate-of-change (ROC) relays were installed in some GVEA distribution substations and set to arm if the rate of frequency decay was greater than 1.5 Hz/second. The ROC relays are set to shed 13%, 12%, 10% and 10% of GVEA system load at 59.3 Hz, 59.2 Hz, 59.1 Hz, and 58.9 Hz respectively. These relays allow for quick reaction to an Intertie trip and when coupled with the standard under-frequency load shedding scheme provide for a simple and dependable protection scheme that has proven itself over and over again.

Small but consistent load growth, coupled with fuel price declines due to competition from access to the natural gas fired generation and hydro generation over the Intertie, has allowed GVEA to maintain electric rates at the same level for the last 20 years. The Intertie has increased our system reliability but we are still shedding our customers in an effort to minimize the cost of our spinning reserve obligations. As the number of outages has decreased, our customers have become less enthused about having their lights turned off, even though they are extremely interested in low rates. Obviously with a radial transmission system throughout the Railbelt there is a need to loop those systems if possible. But as with any decision in the Railbelt, can you make a project pay for itself with small populations, small loads (small revenue), long distances and the associated high construction costs. Typically, without State assistance, the answer is no.

### **BESS JUSTIFICATION**

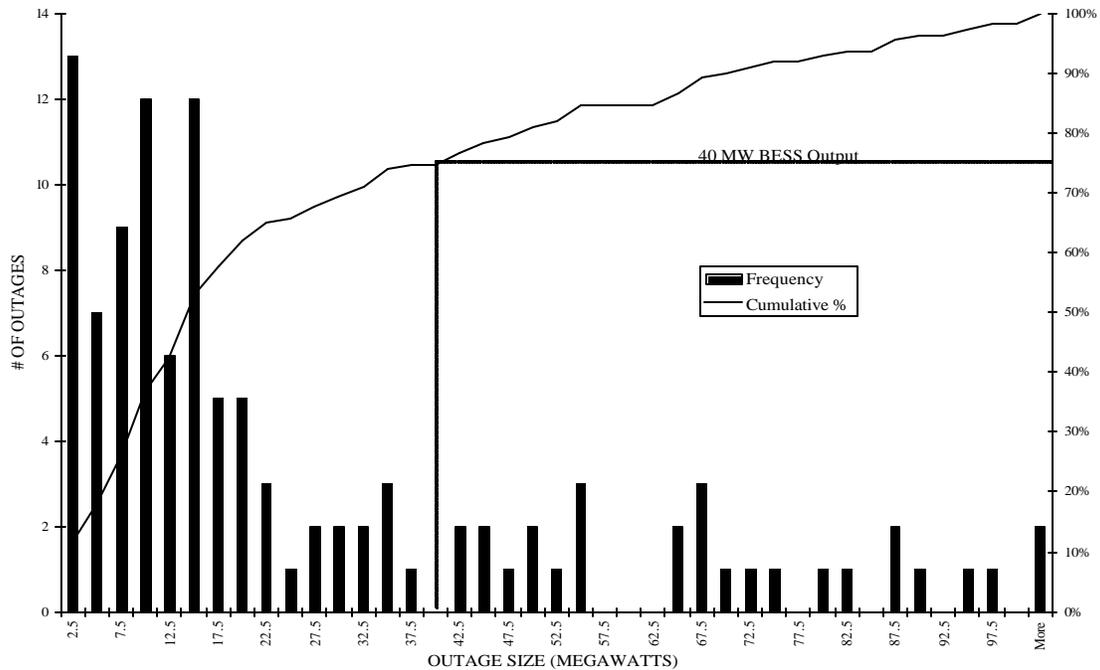
The State of Alaska recognized that it needed to help the utilities with electrical infrastructure and in 1993 Alaska State Legislature approved grants for the Southern and Northern Intertie Projects. These grants would be used to cover a portion of the costs to build each project. The Southern Intertie would build a second line between Anchorage and the Kenai Peninsula. The Northern Intertie would build a second transmission line between Healy and Fairbanks. The existing 105 mile 138kV transmission line between Healy and Fairbanks was built in the mid 60's and consists of aluminum lattice towers that are starting to show their age. For the Northern Intertie, an Intertie Participants Group (IPG) was formed that included Homer Electric Association (HEA), Matanuska Electric Association (MEA), Anchorage Municipal Light and Power (AML&P), Fairbanks Municipal Utilities Services, Chugach Electric Association (CEA), the City of Seward and GVEA. Various studies were initiated for this project and assigned to subcommittees. One of subcommittees looked at the best way to provide voltage compensation for the Northern Intertie. This subcommittee investigated more than a dozen options using life cycle cost analysis and determined that a Battery Energy Storage System (BESS) was the best option and provided the greatest benefit potential. The incremental costs of choosing a BESS over traditional SVC voltage support solutions were mitigated by additional project benefits in three primary areas; T&D, Generation and Strategic.

- T&D benefits include: Voltage regulation, First swing stability, Loss reduction
- Generation benefits include: Spinning reserves, Ramp -rate constraint relief, Load following, Black start, Load leveling, Reduced or deferred turbine starts
- Strategic benefits include: Improved power quality, Reduced demand peaks, Enhanced reliability through the reduction of power supply generated outages.

The primary benefit to the participants of the IPG was the ability of the BESS to provide system stability following the loss of a major transmission line or generator. Obviously with the high cost of providing spinning reserves the BESS also had the potential to lower Railbelt operating costs by allowing generation units to be run at lower levels or shut down entirely, resulting in significant savings (fuel costs and wear and tear on turbines).

For GVEA the ability to reduce the number of power supply (generation or transmission line) outages was also important. The chart below depicts outage frequency and size over the period from 1994 through 1997. For each outage a MW size was determined and the outages of similar MW size were added with the number of outages being shown on the left Y-axis. The X-axis shows the outage size. For example, there were six outages that measured 12.5 MW in size during 1994-1997. With the total number of outages known, the cumulative number of outages is charted starting with the smallest sized outages and working towards the largest size outages. The chart below shows that a 40 MW BESS would have reduced the number of power supply outages our members experience in 1994-1997 by 75%.

**1994 - 1997 POWER SUPPLY OUTAGE FREQUENCY BY MEGAWATT DEMAND**



### **BESS SPECIFICATION**

After the BESS was selected as the preferred option, the IPG selected Power Engineers to write a technical specification for the BESS. Stan Sostrom with Power Engineers started with a EPRI specification and modified it based on the experience of the BESS owned by Puerto Rico Electric Power Authority (PREPA) in San Juan, Puerto Rico, input from Abbas Akhil with Sandia National Laboratories, Phil Symons with Symons/EECI, Black & Veatch and GVEA.

The specification evolved into a functional specification that required each vendor to justify their offering while providing GVEA with a turnkey BESS. The vendor would be responsible for finding the right partners for the various subsystems, finding a battery manufacturer, coordinating building demolition and construction, and guaranteeing that the installation would work. The BESS is required to operate in all four quadrants (ie full power circle) and to provide continuous, infinitely adjustable, control of real and reactive power over the entire operating range. The specification required that the vendor guarantee that the BESS could supply 40MW for 15 minutes, with a 4MW/min ramp down after the 15 minute mark, for twenty years.

GVEA also required the BESS be able to operate in seven distinct modes; VAR support, spinning reserve, power system stabilizer, automatic scheduling, scheduled load increases, automatic generator control (AGC), and charging. These operating modes are described below.

1. VAR Support: This mode requires that the BESS provide voltage support for the power system under steady state and emergency operating conditions. The VAR support controls are not be affected by changes in system frequency and include selectable setpoints and droop characteristic that are settable from GVEA's SCADA system. The VAR support mode has the lowest priority of all operating modes, but is used more than any other operating mode.
2. Spinning Reserve: This mode requires that the BESS respond to remote generation trips in the Railbelt system. Spinning reserve mode will initiate at a system frequency of 59.8 Hz with the BESS loading to full output if the system frequency continues to drop to 59.4 Hz. The BESS will remain in this mode until system generation brings the frequency back to 60 Hz or the batteries reach their discharge limit. Once the spinning reserve mode is initiated, the BESS droop control shall control the BESS output as the system recovers to 60 Hz. After a spinning reserve discharge, the BESS returns to the mode in which it was operating at the start of the spinning reserve discharge, as allowed by the battery's state of charge at that time. Spinning reserve has the highest priority of all modes and will interrupt any other mode the BESS is operating.
3. Power System Stabilizer: The control for the BESS will include a power system stabilizer to effectively damp power system oscillations.
4. Automatic Scheduling: This mode is used to provide instantaneous system support in the event of a breaker trip on either a transmission line or a local generator. The BESS has fifteen independently triggered inputs which will be tied remotely to the trip circuits of the important breakers. The SCADA system will monitor the load on these breakers and continually update a table in the BESS control system. The BESS will use this table to determine what to ramp to in the event a triggered input is received.
5. Scheduled Load Increases: This mode will be initiated and terminated by SCADA and puts the BESS in a frequency and voltage regulation mode to allow it to respond to the addition of large motor loads. Since the Golden Valley system is relatively weak, sudden addition of large loads will cause frequency and/or voltage variations on the system. It is not expected that this mode will be used very often.
6. Automatic Generation Control: The BESS shall be capable of Automatic Generation Control (AGC) similar to that of rotating machinery. The BESS output will be controlled by a remote signal from the SCADA AGC and allow the SCADA dispatchers to schedule power or vars into or out of the BESS as needed. The BESS voltage and frequency controls regulate the output based on appropriate Owner selectable droop settings.
7. Charging: This mode allows the SCADA dispatcher to control how fast (selectable rate) the BESS will be charged at and when the charging will start after a BESS discharge event. This will provide the dispatcher with the flexibility to schedule the most economic units to recharge the BESS. The maximum allowable normal recharge period shall be 12 hours. The charging system is designed to ramp up from zero to the maximum demand at an Owner selectable ramp rate to avoid shocking the system and allow generation to easily follow the recharging load.

## **EVALUATION PROCESS**

We knew from the start that the evaluation process was going to be complex and difficult. Different power converter systems (PCS), different battery technology, different configurations, guarantees, warranties and modularity issues would make an apple to apple comparison impossible. Our primary focus would be to verify that each proposal could meet the technical aspects of the specification and then evaluate the total cost of ownership over a twenty year period. Personnel from purchasing, operations, power supply, dispatch, engineering, accounting as well as our consultant helped with the evaluation. The major areas that were evaluated were (10 total):

**LIFE CYCLE COST CALCULATION.** The life cycle cost calculation used a net present value method to bring identified 20 year costs and benefits back to the year 2000. Sensitivity analysis using different loan rates, inflation rates, cell replacement costs and discount rates. To evaluate the life cycle cost of the proposal each vendor was asked to supply the following information.

- Battery Replacement: This identified the number of cells that would be permanently retired from service and need replacement for the twenty-year period. The vendors were asked to supply this in the form, number of cells/year.

- **Maintenance Hours:** This identified the manhours needed to maintain the facility including, but not limited to, battery and auxiliary systems, AC and DC station service, HVAC, building, PCS and auxiliary systems, cooling system, controls, protection and monitoring equipment calibration, and transformers. The vendors were asked to supply this in the form of manhours/year.
- **Total Energy In:** This identified all net electric energy input into the system required by GVEA. It would include all charging energy, transformer load losses, PCS losses, battery losses and station service and auxiliary systems loads. The information was to take into account the effects of battery aging and replacement, maintenance procedures and testing requirements. The vendors were asked to provide this in the form of MWh/year.
- **Self-discharge Losses:** This identified the sum of battery system losses in MWh that occur due to battery self-discharge, and included the replacement batteries in storage as well as spare modules on float charge. The vendors were asked to provide this in the form of MWh/year.
- **Charging Efficiency:** Charging efficiency was defined as the net difference between the MWh/MVARh delivered to the GVEA 138kV system and the MWh required from the GVEA system to recharge the batteries. This included the transformer load losses, PCS and battery losses, but excluded the station service and auxiliary systems. The information supplied was to take into account the effects of battery aging and replacement for the specified 20-year life of the BESS. The vendors were asked to provide this in the form of percent/year.
- **Reduced Capacity Time:** For the purposes of the life-cycle evaluation, a day is defined as a calendar day or any portion thereof that the BESS is at reduced capacity due to the battery, portion of the battery, or any other system device being out of service for maintenance or replacement. The vendors were asked to identify the number of days for each of the following categories.  
 Days of full capacity, 100% (Days/year)  
 Days of reduced capacity, 75-99% (Days/year)  
 Days of reduced capacity, 50-74% (Days/year)  
 Days of reduced capacity, 0-49% (Days/year)
- **Efficient use of Building Space:** The BESS is being built in an existing 120' X 500' building. A credit for the purposes of the Life-Cycle Evaluation will be applied to useable space designated solely for GVEA use. For example, if the BESS was small enough to be built in 120' x 300' the vendor would get credit for the 120' 200' space remaining. The square footage for the evaluation was determined by GVEA based on the layout drawings provided with each proposal. This credit did not apply to space required by the specification for storage of spare parts, the substation control room, or aisles designated for maintenance access.

To assist the vendors in sizing the battery and to help GVEA in evaluating each proposal, the following anticipated cycling loads were included in the specification for use in all Life-Cycle evaluation calculations

- Three (3) full duty discharges per year. Each event will consist of a ramp up from 0 to 40 MW within a few cycles, a continuous output of 40MW for 15 minutes and a ramp down of 4MW per minute to zero. Each event will have a total net energy discharge of 13.3 MWh.
- Fifteen (15) partial discharges per year. Each event will consist of a ramp up from 0 to 25 MW within a few cycles, a continuous output of 25MW for 5 minutes and a ramp down of 4MW per minute to zero. Each event will have a total net energy discharge of 3.4 MWh
- Five (5) partial discharges per year from a reduced state of charge. This event will consist of a ramp up from 0 to 25 MW within a few cycles, a continuous output of 25MW for 5 minutes and a ramp down of 4MW per minute to zero. This event will have a total net energy discharge of 3.4 MWh. The battery charge prior to the start of the event will be at 85% of total charge.

#### WARRANTIES AND GUARANTEES.

- **Construction Warranty:** A standard 12 month construction warranty that covers quality of workmanship issues.
- **Availability Guarantee:** Since the BESS is critical to the stable and economic operation of the system, it must be available for use to the maximum extent possible. An 18 month availability guarantee period was implemented where the ownership & operation transfer to Golden Valley, but the maintenance

responsibility stays with the vendor. If the BESS fails to meet the required availability, the 18 month period is extended until 18 consecutive months at the required availability is achieved.

- Capacity Guarantee: The BESS was evaluated over a 20 year life span. To accomplish this is was necessary to determine how many, if any, complete change-outs of the battery would be required. The vendors were required to provide battery life information based on the operating descriptions and outage data contained in the specification.

**OPERATIONAL CONSIDERATIONS.** This area had a number of subcategories that included the vendors implementation of the operating modes (spinning reserves, VAR support, etc), the short term ratings of the equipment, ease of maintenance with regard to the PCS, batteries and other equipment, and if there was any initial capacity increase (above 40 MW) built into the BESS. This area also evaluated the flexibility of the recharging mode, how user friendly the operator interface is, the availability of spare parts and the ease with which drawings are interpreted.

**OVERALL DESIGN.** This area evaluated how efficient the building was being used, the flexibility of the station service configuration, standardization of equipment (PLC's, equipment and protocols), how completely the vendor complied with the requirement for system modeling, the detail of the PTI PSS/E BESS model that was to be provided, software issues and the design of the buss, battery connection and overall configuration.

**RISK.** Risk looked at the likelihood of battery failure, the type of battery failure and the likelihood of a total battery failure vs a partial failure. This area also looked at the likelihood of a transformer or PCS failure, the availability of spare parts and the ability to use GVEA's mobile substation in the event of a transformer failure.

**COMMERCIAL AND CONTRACTUAL.** This area evaluated the commercial terms and conditions, arbitration, the choice of subcontractors, the milestone payment schedule and the project schedule.

**FLEXIBILITY OF THE PROPOSED DESIGN.** The ability to convert to a different battery technology, mixing battery types and converting the BESS to an SVC were evaluated in this area.

**CORPORATE PROACTIVENESS.** We evaluated the vendors ability to develop a win-win relationship, how difficult it was to communicate ideas across with the project people and we looked at the location of the support personnel (how fast can they get to Alaska) and the long term stability of the support team.

**OTHER.** This area was a grab bag of items that evaluated what training was available, site security, completeness of testing plans, and another catch all category called green stuff which evaluated battery disposal, how preexisting building conditions were handled, noise and other hazards.

**EXIT STRATEGY.** If the BESS ultimately failed, what were our options? Could the equipment be redeployed throughout our system, could it be resold? We also looked at how the building could be reused.

Even though we had received proposals in February of 2000 it became clear that the Northern Intertie would be delayed over environmental permitting issues. GVEA decided to complete the evaluation process but delay the BESS selection process until it became clear that the permitting issues on the Northern Intertie would be resolved. When the environmental hurdles were cleared in March 2001, ABB, with their partners ABB Industrie (Switzerland) and Saft (France), was notified that they were the vendor of choice. After four months of contract negotiation the contract was signed in October, 2001.

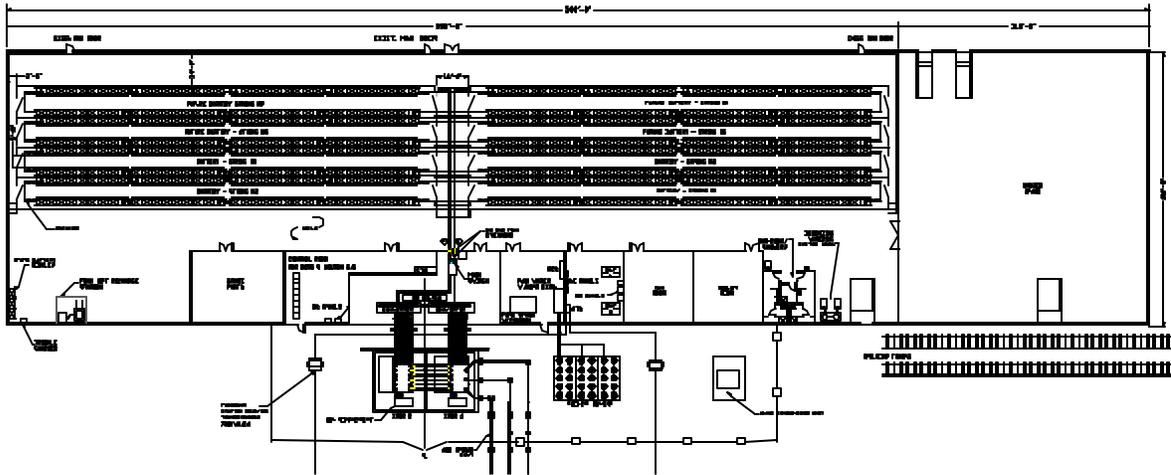
### **BESS DETAILS**

The BESS is comprised of the power converter system, battery, converter transformers and supporting subsystems. The BESS is being installed in an existing 500' x 120' building. The PCS interfaces the battery to the AC system using standard ABB medium voltage three level 2-phase modules utilizing Integrated Gate-Commutated Thyristors (IGCT). Maximum sustained output out of the PCS is 46 MVA. The PCS is water cooled utilizing a SwedeWater fine water/raw water system. The fine water system can flow over 400 gallons a minute of 100% demineralized water and uses a heat exchanger in the raw water (glycol) side to dissipate heat.

The raw water side has external cooling towers for heat dissipation. The primary control of the PCS will be handled by ABB's programmable high-speed controller (PHSC) with local system control and interface to GVEA's SCADA system handled by redundant ABB micro SCADA systems.

The battery consists of four strings (expandable to eight) connected in parallel with each string containing 3,440 cells arranged in 10 cell modules. Each cell is a Saft type SBH920 liquid filled Ni-Cad. This is a high performance, 920 ampour, pocket plate Ni-Cad that can with stand repeated deep discharges with little effect on battery life. Each cell is 16" high x 21" long x 8" wide and weighs 159 #'s. There will be a total of 13,760 cells installed and 10 spare modules (100 cells) on site for maintenance purposes. The strings are connected to a +/- 2500 volt bus. This bus is sized to handle the 12,000 amps output from the battery as the cell voltage approaches 1.0 Volts at the end of a 40 MW discharge. Nominal float voltage for the battery is 1.4 V/cell or 4,816 Volts at the buss. The recharging voltage is limited to 1.45V/cell or 4,988 Volts at the buss.

Each module will be tied to the battery monitoring system (BMS). At each module a Philadelphia Scientific Sentry Unit will monitor the module voltage, electrolyte level in one cell, temperature in one cell and the presence of any liquids in the bottom of the module. Each Sentry Unit will relay its information to a single Sergeant Module dedicated to each string. The Sergeant module will collect data from each Sentry Unit and then send the information to BMS supervisory computer. The Sergeant module will also monitor string current and ambient temperature.



GVEA BESS LAYOUT (30% Design)

**Project Schedule**

The demolition of the building started in January with existing electrical, plumbing and mechanical systems being removed. The walls, floor and ceiling are being cleaned, prepped and painted. A new HVAC system is being installed, the existing fire system upgraded and new lighting will be installed. The exterior of the building will be patched and painted. Interior walls for the PCS, SwedeWater system, control room, air handling and boiler will start in May 2002. PCS equipment will start arriving in October 2002 with battery modules arriving in late in 2002.

Project Start	10/30/01
30% Design Review Complete	12/15/01
90% Design Review Complete	3/22/02
Construction and Installation Complete	4/25/03
BESS Start Up with two battery strings	7/11/03
Begin 18 month Availability test	7/30/03
Final Documentation & Training complete	7/31/03
All four battery Strings installed	12/19/03
Provisional Acceptance Certificate	1/30/04