BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems.	Filed Public Utilities Commission December 16, 2010 San Francisco, California Rulemaking 10-12-007

Comments of The Nevada Hydro Company

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Pursuant to the request of the California Public Utilities Commission ("Commission") in the above referenced Order Instituting Rulemaking ("OIR"), The Nevada Hydro Company ("NHC") provides herein its comments to identify the facts and issues of laws that NHC believes to be relevant to this proceeding's scope. These comments relate to the directions and remarks provided in this OIR and to the Commission's staff's white paper.[1]

1. The Party and Interest of the Party in This Proceeding

NHC is co-applicant with The Elsinore Valley Municipal Water District to the Federal Energy Regulatory Commission ("FERC") for a license under the Federal Power Act to construct and operate the Lake Elsinore Advanced Pumped Storage ("LEAPS") facility at Lake Elsinore (FERC Project Number P-11858).

Because NHC's ability to construct and operate LEAPS may be dependent on the findings, policies and conclusions of this proceeding, NHC has a particular interest in assuring that the Commission properly understand the costs, value and benefits of advanced pumped hydro facilities like LEAPS. NHC filed to be an active party in this proceeding shortly after the OIR was issued.

2. Description of the LEAPS facility

LEAPS is an environmentally friendly facility that will help meet regional generation needs while providing the full range of electrical and mechanical products and services to help manage grid operations, shift off–peak energy closer to the demand center during peak periods, enhancing the reliability of the Southern California transmission grid while helping the State achieve its renewable resource use goals. LEAPS complements the existing area generation by storing

[1]/ On July 9, 2010, the Commission's Policy and Planning Division issued a white paper entitled," Electric Energy Storage: An Assessment of Potential Barriers and Opportunities", referred to herein as "the Commission's white paper."

energy during low demand periods and releasing the stored energy during peak load periods over a separate project known as the Talega–Escondido/Valley–Serrano 500kv Interconnect Project ("TE/VS Interconnect")[2], connecting SDG&E's 230 kV main grid with the State's 500 kV backbone transmission system for the first time. The 500 MW of new LEAPS generation has the advantage of being an air quality friendly source of energy and an immediate source of both real and reactive power available instantly in the event of system disturbance.

The Project is located in unincorporated Riverside County, California, approximately midway between Los Angeles and San Diego at Lake Elsinore, California. Lake Elsinore, which is the largest natural lake in southern California, will serve as the lower reservoir for the LEAPS facility. A new 100 acre upper reservoir will be constructed above the crest of the Elsinore Mountains. The upper reservoir will connect with the power plant through a penstock bored into and through the Elsinore Mountains.

Lake Elsinore is an "impaired water body", and studies have shown that the operations of LEAPS will contribute greatly to improving water quality in the lake. In addition, the region has been rapidly growing, and due to grid congestion, is an area of primary concern to the California Independent System Operator ("CAISO") and to Southern California Edison ("SCE"). As such, the project includes a number of 115 kV connections to the local grid.

LEAPS will have an installed generating capacity of 500 MW and pumping capacity of 600 MW provided by two single-stage reversible Francis–type pump-turbine units operating under an average net head of approximately 1,600 feet. This high head will make the plant one of the most efficient pumped storage facilities in the world. The total energy storage available will be approximately 6,000 MWh per day, potentially allowing 12 hours of generation at full plant production capacity. The corresponding pumping requirement will be 12 hours at full plant pumping capacity with additional required pumping occurring on Saturday and/or Sunday if a weekly cycle is used.

The pump-turbine and motor-generating units and associated mechanical and electrical equipment will be located below ground, immediately adjacent to Lake Elsinore, at the foot of the Elsinore Mountains. The equipment will be manufactured and installed by Voith Hydro of York Pennsylvania ("Voith"). Voith is the premier manufacturer of these large, highly efficient, reversible pump turbines, and has an extensive portfolio of installed equipment around the world.

Power generated in the underground power plant will be transformed to 500 kV and transmitted to the surface to a ground level compact gas insulated substation. The plant will be interconnected to the high voltage grid over the new 500 kV TE/VS Interconnection that will

2/ The TE/VS Interconnect is the subject of a separate Commission proceeding in A.10–07–001.

connect the existing lines of SCE and SDG&E. In addition to connecting LEAPS into the grid, the TE/VS Interconnection will also serve to provide a vital link between these two southern California utilities, thereby contributing to the creation of a transmission backbone system in southern California.

As a result of this advanced planning and design, LEAPS is a state of the art, fully integrated energy and capacity delivery system able to provide:

- 500 MW of black start, and up to 8,000 MWh of emergency generation.
- All forms of ancillary services ("AS"); and some can be provided simultaneously.
- Additional capacity at a ramp rate of 500 MW in less than 15 seconds.
- 600 MW of off-peak load for grid baseload generation and stability.

In addition, the Project will firm up and store renewable energy and will be one of the most efficient storage facilities in the country, rated at 82% net at the 500 kV primary levels.

The engineering, design, and construction services for the entire electrical portion of the Project, including the entire TE/VS Interconnection and associated substations and switchyards will be provided by Siemens Energy, Inc. ("Siemens"). Siemens is a global leader in the manufacture, construction and installation of electric generation and transmission systems, including high voltage, direct current transmission lines.

2.1. Licensing and Permitting

The LEAPS Project is being licensed as a major unconstructed hydroelectric facility by FERC under the provisions of the Federal Power Act of June 10, 1920 (FPA), Chapter 285. This Project is identified as FERC Project Number 11858, under Licensing Regulations found at 18 CFR, Subchapter B, Part 4. The license application was filed on February 2, 2004, and was accepted by FERC on January 25, 2005. FERC is an independent agency within the United States Department of Energy (DOE). Pursuant to Part 1 of the FPA, FERC is authorized to grant permits for the construction, operation and maintenance of certain projects involving federal waterways and or federal lands.

The TE/VS Interconnect is a high-voltage regional interconnection linking SCE's Valley-Serrano 500-kV line in western Riverside County with SDG&E's 230-kV Talega-Escondido transmission line in northern San Diego County.

The Project involves two related license/permit processes:

Federal License from FERC for LEAPS. Under Project Number 11858, FERC is licensing the 500 MW advanced pumped storage facility and associated transmission lines. FERC is also the lead federal agency for National Environmental Policy Act ("NEPA") compliance.

The application for the LEAPS Project was accepted by FERC on January 25, 2005. On August 9, 2004, the Commission published a "Notice of Intent to Prepare an Environmental Impact Statement and Notice of Scoping Meetings and Site Visit and Soliciting Scoping Comments." That notice announced the commencement of a FERC-prepared environmental impact statement (EIS) pursuant to the provisions of NEPA.

On February 28, 2005, the Commission published a "Notice of Application Ready for Environmental Analysis". Final scoping documents were issued January 25, 2005, and in February, 2006, FERC issued its draft Environmental Impact Statement. In July, 2006 FERC gave notice that it expects to issue its Final EIS in October, 2006 and the Final EIS was issued in January 2007.

Approval process for the TE/VS Interconnection Project. The TE/VS Interconnection is a stand-alone high-voltage transmission project utilizing the same transmission alignment, towers, and many of the same facilities as associated with the LEAPS Project (without the corresponding hydroelectric facility). An application for the transmission line project was accepted by the Forest Service in 2003. As the alignment, transmission towers, substations, and, the power lines on both projects are identical to that being licensed for LEAPS by FERC, in June 2004, the Forest Service and FERC executed a Letter of Understanding ("LOU") under which the Forest Service is a cooperating agency with FERC for purpose of compliance with NEPA. The LOU allows for one federal environmental process, and one set of NEPA documents describing both LEAPS and the TE/VS Interconnection.

On July 6, 2010 the Commission accepted NHC's application for a Certificate of Public Convenience and Necessity ("CPCN") for the TE/VS Interconnect in proceeding number A.10–07–001. If approved by the Commission, this CPCN proceeding will allow for construction of the TE/VS Interconnect.

3. Grid Operations Benefits of LEAPS

As described in the Commission's white paper, storage, and particularly pumped storage as provided by LEAPS, provides a panoply of grid as well as environmental benefits while being uniquely situated to provide the "wires" and non–wires" solution to a range of critical regional problems. The Commission's white paper indirectly references a number of critical issues pertaining to the State's electricity generation and transmission infrastructure. These include ongoing concerns with congestion and local reliability, prospective operational issues associated with renewables integration, as well as corridor planning, permitting, and the associated lead times and issues pertaining to cost.

LEAPS is flexible enough to provide solutions for all of these issues and more.

3.1. LEAPS Operational Characteristics

Advanced pumped storage facilities like LEAPS are amazingly versatile machines. The flexibility of the facility is dependent on a number of factors, particularly the operational limits imposed by the amount of water available for storage and generating. For LEAPS, these operating limits are shown in the following table. In addition, Attachment 1 (LEAPS Operating Characteristics) provides detailed operating characteristics for LEAPS.

Water Operation Limitations

MWh of pumping per MWh of output capacity at 500 kV.*

Upper Reservoir Live Storage (ac.-ft.)	5500-7437
Upper Reservoir Dead Storage (ac.-ft.)	250-1305
Upper Reservoir Total Storage (ac.-ft.)	5750-8742
Upper Reservoir Storage Available for Emergency Generation at PMAX (h)	16-22
Upper Reservoir Storage Available for Normal Generation at PMAX (h)	12-20
Upper Reservoir Storage Available for Emergency Generation (MWh)	8000-11000
Upper Reservoir Storage Available for Normal Generation (MWh)	6000-10000
Lower Reservoir Storage Available for Pumping to Upper Reservoir (hours)	67
Lower Reservoir Space Available for Release from Upper Reservoir (hours)	69
Pumping Capacity (MW)	600
Turnaround Efficiency **	78.70%

* Assumed 250 MW at transformer

** Turnaround efficiency assumes emptying of the upper reservoir from 2790 to 2660 feet at 250 MW and refill in the pumping cycle

3.2. Comparing Pumped Storage and Conventional Generation

The LEAPS and the TE/VS Interconnect will together serve as uniquely valuable grid and system assets. LEAPS is a power facility that can provide all forms of ancillary services ("AS") to meet operating criteria. These transmission and grid services can be performed both with energy and capacity production, simultaneously.

LEAPS has some features unique to an advanced pumped storage facility that provides far more flexibility than can any other facility that may be offered to address these issues. Advanced pumped storage generation provides unique strategic, operational, and economic benefits, resulting in reduced operating risks, increased total efficiency, increased critical system control and reliability, all while providing value to ratepayers. Pumped storage can provide a rapid response to continuously changing conditions and thereby assist in maintenance of system–wide reliability.

LEAPS will offer the following features to assist in meeting system reliability objectives:

- Spinning reserve and the prompt availability of additional capacity dispatched at any time;
- System load following capability which can reduce unit commitment and cycling of thermal generating plants in the system;
- System frequency regulation; power factor and voltage regulation capability;
- Improved efficiency of the regional transmission system; and,
- Storage of low-priced off-peak energy from clean air attainment areas to non-attainment areas.

Pumped storage is the most efficient technology available for energy storage.

In addition to standard AS, LEAPS will provide opportunities specifically for the storage and dispatch of renewable energy. With the increase in renewable production in California and State-imposed renewable portfolio standards ("RPS"), system-wide problems must be overcome relative to dispatch and coordination. In real time, LEAPS can nominally dispatch 6,000 MWH of stored renewable energy (wind turbine and geothermal) from sources as diverse as the Palm Springs and the Tehachapi areas.

Based on the above information, presented below is a table that both outlines the benefits that LEAPS provides and presents a comparison to traditional generation assets.

COMPARISON OF LEAPS TO OTHER GENERATION TECHNOLOGIES
for Ancillary Services and RMR Value

Issue	Peaker	Combined Cycle	LEAPS and TE/VS
Air Quality Issues	NOx, CO, VOC, PM10 Offsets	NOx, CO, VOC, PM10 Offsets	None
Dispatchability	10 – 60 minutes	1 – 4 hours	Spinning <15 sec. / secured 15 min.
Black Start	10 – 30 minutes	No	Spinning <15 sec. / secured 15 min.
Dispatchable Capacity	Can produce either energy or capacity	Dispatchable capacity limited between 70-100% full load	0 - 500 MW / <15 sec.
Regulation	No	Yes; limited to 5 MW/min.	Yes; better than 500 MW/min.
Spinning Reserve	No	Yes; limited to 5 MW/min.	Yes; better than 500 MW/min.
Voltage Support	Yes; but typically not used for voltage support	Yes	Yes. When pumping and generating
Comparable Heat Rate	Appx. 10,000 – 12,000	7,000	Appx. 18% more efficient than lowest off–peak rate

Issue	Peaker	Combined Cycle	LEAPS and TE/VS
Alternative Fuels Or Renewables	No	No	Yes; can source 6,000 MWh nominally
Mitigation of Overgeneration Conditions	No	No	Yes; up to 600 MW of pumping load

As may be apparent, advanced pumped storage facilities have benefits that are significantly different than are available from conventional generating units. Besides the ability to generate power and consume energy when needed to balance the grid or shift load, a pumped storage hydro unit provides a multitude of AS of unparalleled quality. These services are of high value to the grid operator and, via the bilateral markets, to other market participants. By offering these services into unrestrained markets, market clearing prices for on-peak energy, and market clearing prices for AS capacity in all hours, can be reduced with corresponding reductions in consumer costs. Pumped storage hydro units can be called upon, as needed, to satisfy the CAISO operational demands. Proper valuation requires that all these benefits be considered as complements to the standard benefits of a conventional generator.

To add to and supplement the list of operational benefits in Section 5.2 of the Commission's white paper, the unique capabilities of LEAPS include:

1. Ultimate flexibility in dispatchability and scheduling into energy and AS markets. LEAPS can be dispatched on and off for any number of hours in both pumping and generation mode without any limitation or penalty.
2. The ability to provide regulation-up and regulation-down. Regulation-up and regulation-down can be provided in both the generation and pumping mode. Because regulation in the CAISO's markets is presently a 30-minute service, the LEAPS project—which can switch between generating and pumping modes in minutes —will be able to provide regulation-up or regulation-down for the full 1,100 MW range of the facility when in full pumping mode (500 MW generating capability and 600 MW of pumping load).
3. The ability to provide spinning reserves in both the generation and pumping modes.
4. The ability to provide 500 MW of non-spinning reserves in both the generation and pumping modes.
5. One of the unique capacities of LEAPS is to provide reactive support without generating a single megawatt of energy (similar to a synchronous condenser). In contrast, conventional generating units, in order to provide energy, regulation, and spinning reserves, need to be on-line at least at some minimum output level. In

addition, when LEAPS is in the pumping mode, it will not lean on the grid for reactive support.

6. LEAPS offers black-start capability.
7. The minimum sustainable output and consumption level of the unit is 0 MW.

The benefits and services advanced pumped storage and particularly LEAPS provides are described in more detail in the following subsections.

3.3. Improved Regional Grid Reliability

LEAPS can provide significant AS benefits including regulation and operating reserves, key tools to manage a very complex state grid, and a subject of concern of many official reports recently released.

Because of its nearly instantaneous response time, LEAPS will help grid operators adjust to constantly fluctuating load conditions. LEAPS is the ideal tool to help grid managers ensure grid reliability by providing the full range of AS and real time imbalance energy. LEAPS with the TE/VS Interconnect will help to relieve congestion by connecting SCE and SDG&E systems and managing power flows in both directions (north to south and south to north) over the connection.

3.3.1. Load Shifting Peak Storage

Large scale storage systems, such as LEAPS, provide the ability to utilize low cost, baseload power, generated during period of low demand, during peak load periods. Without storage, the electrical industry must develop and maintain a delivery network capable of meeting the highest demand of the year. With storage, however, the electricity delivery system can be designed to accommodate a normal load and the stored energy can be used to respond to peak demands.

Pumped storage plants may be utilized as peak generating facilities. During off peak periods, water is pumped from a lower reservoir to an upper one. The water is then released for power generation during periods of peak power demand. Although a net consumer of energy, pumped storage can be economically viable because it uses baseload capacity during off peak periods to create additional peak capacity. Pumped storage can also be used to provide emergency reserve generating capacity. LEAPS can respond to a CAISO dispatch signal in and can provide up to 500 MW in less than 15 seconds.

Because LEAPS is located inside of the Southern California load area, it offers economic and operational advantages that make it a unique opportunity to improve the precarious conditions that the Southern California grid may face in the next few years. With its location near load centers west of the Devers substation, energy can be delivered closer to load and is less likely to limit on peak imports of energy coming into the Devers and Valley substations. Further, LEAPS will generally pump during off peak periods, at night or on the weekends, thus increasing use of transmission lines, which are lightly loaded during these off peak periods. Finally, increasing generation near the load center increases the import transfer capabilities, thereby allowing more energy to be imported to Southern California particularly during peak times.

This load shifting function is also closely linked with the more efficient use of certain renewable resources, discussed next.

3.3.2. Managing Renewables

As pointed out in the Commission's white paper, adding significant quantities of wind capacity to the grid will create integration challenges for the CAISO that, if not properly planned for, may lead to unnecessarily high integration costs. Without the additional regulation and quick responding spin capacity that LEAPS provides, grid operators face the unpleasant task of having to:

- Curtail wind resources because it was the most economic choice, given all considerations, such as unit start-up costs, etc.
- Adjust up or down the output of slow responding, fossil fuel thermal generation to integrate the additional wind capacity. This increased reliance on fossil fuel thermal generation for purposes of integrating wind resources would be contrary to California's RPS and GHG emission reduction objectives.
- Black–out certain sections of the grid because of insufficient regulation capacity and fast responding spin required to level out any sudden, unexpected decrease in wind output.

As is now clear, the task of managing renewables presents operational challenges for both the CAISO and individual utilities charged with increasing their use of energy from renewable sources. LEAPS and other storage will help to manage renewables and will strengthen the State's energy infrastructure (while LEAPS will also provide other services described herein and improve the water quality of Lake Elsinore, enhance regional recreation opportunities and improve the area's fisheries).

As well described in the Commission's white paper, LEAPS will help accommodate "intermittency" in generation from renewables, and its storage will also help to transmit more remote renewable energy to the load center. Further, minimum load and over generation issues may be exacerbated by the intermittent nature of some renewable resources. LEAPS is ideally located nearer to the load center to better complement intermittent renewable generation.

Most now agree as to the value of combining wind generation with pumped and other storage to create load during early morning high wind periods. As wind and geothermal resources increase in the region, LEAPS will allow the grid manager to accommodate and perhaps enhance the value of these important resources. Although minimum load issues may be exacerbated by the intermittent nature of some renewable resources, LEAPS will help to complement intermittent renewable generation, scheduling, and dispatch challenges.

3.3.3. Facilitate the development of workable competitive wholesale markets

LEAPS will also facilitate the implementation of California's MRTU energy and AS market design by providing significant energy storage, regulation up and down, load following, and spin services. For example, LEAPS will be a "shock absorber" in the physical and economic systems by easily accommodating frequency deviations, large energy ramps, and significant mismatches between day-ahead schedules and real time supply and demand. To the extent grid operators have the necessary tools to meet real time deviations from schedules, LEAPS will minimize their need for out–of–market calls that end up harming workable wholesale competition.

3.3.4. Black start capability

Referred to in the Commission's white paper as "back–up power", from the grid scale perspective of pumped storage, this function is referred to as "black start." Because there is always the possibility of natural disasters, malfunctions, and other events that could cause all or a portion of the southern California grid to go down, it is particularly vital to provide for the restoration of network interconnections to the CAISO and the southern California transmission system in the event of such grid-wide emergencies, especially contingencies involving SONGS or other generation units. Having this capability is a critical feature to grid management.

LEAPS is able to provide 500 MW of black start capability and can routinely produce 6,000 megawatt hours (MWh), and, in an emergency, 8,000 MWh, of stored energy. In addition, LEAPS can synchronize to and bring up a segment of the 500 kV interstate loop between Valley, Talega, and Case Springs substations. LEAPS can, independently of all other power facilities, fuel sources and transmission, from a cold start, be on line and ready to supply energy into the grid in 10 minutes. It can then, through its control room and associated substations, isolate the local segments of the 500 kV transmission system and resynchronize at 500 kV. Once these critical transmission segments are re-powered, the facility can expand outward to other grid segments and synchronize them as well. This will allow other power facilities to come on line and provide additional power supplies as the grid becomes re-established and re-interconnected.

All facility control rooms and substations have state of the art emergency power facilities and will provide long term power supply to all critical equipment, communications, and telemetry systems. The LEAPS control room will be equipped to function as an emergency command center, and will be able to communicate, not only with the CAISO, but with federal, State, and military facilities.

3.3.5. Voltage support

All high voltage AC transmission lines provide positive voltage support (that is, provide VARs to the grid) when they are loaded below the "surge impedance loading" level (normally about 1,600 MWs for a 500 kV line) through line charging effect.

All generators with excitation systems, which provide a range of lead and lag power factor (CAISO required +0.95 - 0.9 power factor capability for all generators), can help regulate transmission voltage. When in leading power factor, a generator supplies VARs to the system (increase voltage). When in lagging power factor, a generator consumes VARs from the system, thus reducing the transmission line voltage (when system is lightly loaded, transmission voltage tend to be too high, or above operating voltage limit). Further, VARs do not travel far. Local voltage support is, therefore, important to local areas. Because the location of the Project is central to SCE and SDG&E systems, LEAPS can provide voltage support to both the SCE and SDG&E systems.

In addition, SONGS has a voltage requirement imposed by the Nuclear Regulatory Commission (NRC) to maintain voltage and ensure off site power to the station for safe shutdown. LEAPS can provide this voltage and off site power requirement to the SONGS as well.

The Project can provide voltage support not only by supplying VARs directly but also indirectly by unloading the existing South of SONGS transmission line.

In terms of renewable resources, most forms of solar and wind energy conversion devices provide limited reactive voltage support to the grid. In fact, these devices are likely to have a negative voltage support. With the increase of renewable energy requirements in California, voltage support will become a critical element (this will continue to become a more critical issue as the State moves toward the required 33 percent RPS level).

By their nature, modern advanced pumped storage facilities provide large amounts of reactive support and can provide this support in all modes of operation. For example, pumped storage facilities can run dry, synchronized to the 500 kV system. In this mode of operation, the units produce no real power, but provide reactive power support services to the grid as synchronous condensers. In the wet mode of operation, the units provide energy simultaneously with all AS, particularly voltage support.

Most importantly, LEAPS can provide, as required, large amounts of voltage support for the CAISO controlled grid. This additional capacity will offset the local amounts of reactive support consumed by the wind and solar resources as they come on line.

3.3.6.Environmental Benefits

In addition to its electrical and grid–related benefits, LEAPS provides a range of environmental benefits to the region. These are described briefly in the following sections.

Air Quality – Hydropower is a non–combustion fuel source. By the nature of its fuel source (water) and the way in which it captures and converts the energy of falling water into electrical energy via the water turbine and generator set, lowers the amount of carbon dioxide emitted during the production of electricity.

With the exception of the southerly portion of the project, the proposed project is primarily located in the South Coast Air Basin (SCAB). The SCAB does not presently attain National Ambient Air Quality Standards (NAAQS) for a number of criteria air pollutants, including ambient CO, ozone (O3), and particulate levels (PM2.5 and PM10). The US Environmental Protection Agency ("USEPA") considers the SCAB to be in extreme non-attainment for ozone, serious non-attainment for CO, and non-attainment for PM2.5 and PM10.

Most of the State's energy is produced through the combustion of fossil fuels with. As they burn, fossil fuels emit carbon dioxide (CO2) due to oxidation of the carbon contained in the fuel (greenhouse emissions are released when fossil fuel is oxidized). In pumped storage, the energy to pump at night is the lowest cost, most efficient (and therefore, lowest emitting) resources. In addition, if LEAPS is used in conjunction with the Tehachapi wind basin, LEAPS may use resources that produce no emissions. In such case, the Project's potential contribution to total greenhouse gasses would be de minimus.

Most importantly, new pumped hydro diminishes the need to construct new fossil-fuel burning generation peaking facilities in non-attainment air basins. The reliability of California's fossil-fuel units over the next few years is uncertain since many will be taken out-of-service to install required oxides of nitrogen (NOX) emission controls and accommodate the limitation imposed on once–through cooling systems.

Water Quality – Due to natural features of its shallow depth, high nutrient input from its very large drainage basin, erratic water inflow and warm climate, Lake Elsinore is eutrophic. It exhibits the classic eutrophication symptoms of low dissolved oxygen, occasional fish kills, abundant nuisance blue-green algae, and poor water clarity. The lake has a very variable water level that exacerbates the eutrophication and reduces recreational potential.

LEAPS will result in the stabilization of lake levels through an operating agreement that stipulates allowable ranges in water elevation. That action alone will greatly enhance the lake's aquatic resources and allow for the development of facultative plant species around the lake's perimeter. This vegetation can provide shoreline protection for aquatic ecology that can help balance the food chain of the lake. In addition to the stabilization of lake levels, the daily operation of the turbines will oxygenate water returned to the lake during the power generation cycle which provides the basic ingredient, oxygen, to prevent fish kills. Thus, the Project will have beneficial effects for the water quality, fisheries, and recreational use of the lake. In particular the movement of such a large volume of water on an almost daily basis will add needed oxygen and destroy nuisance blue-green algae in the lake by collapsing internal gas vacuoles.

Recreation – Without lake stabilization or water level control of Lake Elsinore, primary beneficial uses of the lake will only be available part time without certainty. The primary beneficial uses of the lake are for body contact, recreation, boating, fishing and water skiing activities. Lake hydrologic records show that in the past 73 years there were natural flows into the lake large enough to match annual evaporation for only 13 years. Evaporation amounts to a loss of approximately 14,000 acre feet per year. During the same period there were 5 years when no flows were recorded entering the lake and 47 years, or 65% of the time, when flows were less than 800 acre feet per year. These highly seasonal fluctuating flows define the ephemeral nature of the lake.

By stabilizing lake levels and by improving the lake's water quality through the injection of oxygen into returning waters, the project has the potential to improve both recreational and sports fishing opportunities in Lake Elsinore. Currently, the major drawbacks to recreational uses are unpredictable fish kills in the lake and high turbidity due to the algae growth. These conditions define the eutrophic nature of the lake. Without lake stabilization, these conditions will continue unabated.

LEAPS will provide financial resources to supplement nature's lack of natural runoff to provide adequate water levels. With a stable lake elevation investment, improved lake water quality can be reasonably expected to succeed.

Socioeconomics – In total, the proposed hydropower project is projected to generate about 2,460 person–years of construction employment, of which roughly 55 percent will be skilled trades, 30 percent will be general labor, and 15 percent will be supervisory and support staff. Peak employment at site will reach about 600 workers.

LEAPS will contribute substantially to the revenues of local government directly through the payment of permit fees and increased real and personal property tax and indirectly through increased State taxes and local sales tax revenues, which are partially allocated to the various county and municipal governments. Over the construction period, total estimated construction payroll cost is estimated to exceed $140 million.

Input-output models provide multiplier effects for several measures of construction activity, including gross output, labor income, and employment. Gross output multipliers range from 2.1 to 2.5 times direct output. That is, for every $1.00 spent on construction activities, the value of total regional activity, including direct construction, increases by $2.10 to $2.50. Labor income multipliers range from 1.8 to 2.2 times direct labor income, while employment multipliers range from 2.1 to 2.6 times direct jobs.

Project-related expenditures, including indirect and induced impacts, will generate a total output of $1.05 to $1.25 billion, of which $227.05 to 277.51 million will be labor income and will generate between 5,166 to 6,396 man-years of employment. This increase in output value and labor income will flow largely to proprietors and workers. A part will accrue to governments in the form of personal and corporate income taxes, sales taxes on household and other purchases, and real property tax. The share of these impact captured within the socio-economic impact region is likely to be substantial.

3.3.7.Summary of Benefits

Presented below is a summary of ways the Project will contribute to solving the issues identified by the Commission in this OIR.

- Because of its nearly instantaneous response time (500 MW in less than 15 seconds), LEAPS will help grid operators adjust to constantly fluctuating load conditions.
- LEAPS will provide 500 MW of black start, 6,000 MWh of emergency generation and provide all forms of AS, some simultaneously.
- LEAPS will be one of the most efficient storage facilities in the world, at roughly 82% net, at the primary level.
- LEAPS will help to manage renewables and will strengthen the State's energy infrastructure (while improving the water quality of Lake Elsinore, enhancing regional recreation opportunities and improving the area's fisheries).
- LEAPS will help accommodate "intermittency" in generation from renewables, and its storage will also help to transmit more remote renewable energy to the load center.

- LEAPS is the ideal tool to help grid managers ensure grid reliability by providing the full range of AS and real time imbalance energy.
- LEAPS (with the TE/VS Interconnect) will help to relieve congestion by connecting SCE and SDG&E systems and helping to control the power flows over the connection.

Because the provision and availability of AS can be complex, LEAPS AS provision limits are presented in a separate table, in Attachment 2 (LEAPS Provision of Ancillary Services).

4. Valuation of LEAPS

The question the Commission is addressing in this OIR is how to value and provide storage and AS mechanisms and how to pay for these services. Not a simple set of tasks! As a starting point, the Commission may wish to take note of a CAISO planning process known as "CSRTP" ("California South Regional Transmission Plan"). In 2007, NHC was invited by the CAISO to join CSRTP. While this process was focused on valuing and approving the three southern California transmission projects (Sunrise, Tehachapi and the TE/VS Interconnect), the CAISO also decided to attempt to value LEAPS and TE/VS Interconnect together.

In CSRTP, the CAISO attempted to value some of the unit's AS capabilities (see table below for summary). NHC is continuing to work to refine these numbers. NHC believes that while an impressive first attempt, some of the CAISO's assumptions tended to under-valued the AS available from LEAPS by using a very conservative estimates for the quantity and prices of AS needed in 2010. NHC's own valuation estimate is also included in the following table. NHC believes that LEAPS has significantly greater value than the CAISO identified.

Valuation of LEAPS

Product	CAISO Conservative Estimated Values in 2015 with Limited Quantities[1]	TNHC Maximum Estimated Values[2]
Ancillary Services: Regulation up, Regulation down Spinning Reserves Non-spinning Reserves Wind integration Over Generation Mitigation	$ 36.77 Million[3] Q Reg up < 90 MW AVG Q Reg dn < 90 MW AVG Q Spin < 175 MW AVG Q N-spin <175 MW AVG $10.22 million $17.46 million	$ 113.45 Million[4] Q Reg up = 500 MW Q Reg dn = 600 MW Q Spin = 500 MW Q N-spin = 500 MW The value has not been quantified The value has not been quantified
Capacity	$31.45 million	The value has not been quantified
Reactive Support	The value has not been quantified by the CAISO	555.6 MVAR; the value has not been quantified[5]
Production Cost Savings	$42.99 million	The value has not been quantified
Black Start Capability	The value has not been quantified by the CAISO	$259.5 million[6]
RMR	$35.78 million	$200 million

ERC	The value has not been quantified by the CAISO	$100 million[7]
Regional Benefits	The value has not been quantified by the CAISO	>$1.25 billion[8]

Table Notes:

1. Note that the CAISO proposed to limit the quantity of AS that can be provided by the LEAPS project to 25% of the CAISO's need as established during the year 2005. It is not clear to TNHC that same limitation would apply if the AS from the LEAPS project were self-provided. It is also not clear if the CAISO's "need" for AS capacity is defined to include (a) only the amount acquired through the CAISO's 2005 AS capacity market, or (b) the sum of the self-provided and acquired AS capacity during the year 2005.
2. TNHC has assumed the Preferred Operating Point (POP) to be at zero. The CAISO 2005 average prices were used without any escalation and 97% capacity factor was assumed for the unit to calculate the AS values.
3. In 2006 dollars.
4. In 2006 dollars. Capacity value only (the energy generated revenue and energy consumed for providing the regulation up capacity are assumed equal and ignored for this calculation).
5. –
6. Equipment cost assumed at $280.00 per kW (for large diesel prime mover), facility cost $239.00 per kW comes to $519.00 per kW for the facility. The total shown is for 500 MW of new generation, assuming equipment is available.
7. Emission Reduction Credit ("ERC") value is calculated based on offset costs from 2005 SCAQMD Annual Report for a Simple Cycle alternative to LEAPS. The following table shows these calculations, thereby identifying the cost for 500 MW of ERCs in the SCAQMD.

	Tons/yr.	$/Ton/yr.	Total
NOx	561	126,486	$70,933,349
PM10	91	268,588	$24,414,649
SOx	16	78,123	$1,218,719
CO	114	30,961	$3,520,266
			$100,086,983

8. See Section 3.3.6.

5. Issues raised in the Commission's White Paper

The OIR and Commission's white paper raises a number of issues on which NHC would like to comment.

First, Section 5.1 of the Commission's white paper discusses economic benefits of EES primarily focused on retail and industrial customers. However, these same benefits may apply to utility scale EES systems like LEAPS. As such, the benefits accrue to all grid users and not to an individual owner of a retail EES system. These grid–scale benefits have been discussed in the previous sections of this filing. NHC suggests that the differences between individual EES system and grid–scale EES systems need to be addressed explicitly in this OIR. The cost and benefits of the two scaled systems need to be addressed separately. While fewer grid–scale facilities are likely to be constructed, those that are will be much more efficient at providing benefits the grid requires.

In addition, the Commission's white paper identifies only frequency regulation and operating reserves as AS, as these are "sold in California"[3]. However, NHC urges the Commission not to overlook other AS that are needed for grid operation, but are currently not

[3]/ Commission's white paper at page 7.

openly "sold" in California. EES generally, and pumped storage in particular, can supply the full range of AS. Because these services *could* be sold, and because the provision of revenue from these additional services would make the provision of other needed grid services less expensive, NHC urges the Commission to assess market potential as well as products now currently sold.

NHC would also like to point out that the KEMA report referenced on page 7–8 of the Commission's white paper does not address the entire EES picture. The report claims the total source of emissions was based on inefficiency of the operation, with the pumped storage unit turnaround efficiency of 70%. Modern units would have this higher efficiency- say 80% reducing the calculated emissions by one third. Further, the study does also not credit the pumped storage plant for helping keep fossil plants from running inefficiently to help system regulation. This would likely further reduce emissions credited to the existence of the pumped storage plants. NHC has included a technical paper produced by E.ON addressing pumped storage in Germany describing this effect of keeping fossil plants closer to best efficiency (See Attachment 3, E.ON Report on Pumped Storage). Note also that this KEMA report was funded by Beacon Power who makes flywheels. While pumped storage may have less efficient operation than a flywheel, it can firm a far greater amount of wind energy and allow the existing fleet of generators to operate more efficiently, thereby producing ness GHG and other emissions.

It is important to understand this vastly different scale of operation: From a mechanical perspective, there are practical limits to flywheels when used in grid-scale applications, so comparing a grid–scale pumped storage facility to a much smaller flywheel system is sort of like comparing a watermelon to a grape! The system KEMA was looking at is the Beacon Power 20 MW facility in Stephentown, NY. This facility will consist of 200 flywheel arrays or matrices, each of which is comprised of 10 flywheels for a total of 2,000 individual flywheels. Each of the individual flywheels has a storage capacity of 25 kWh for a total plant storage capacity of 50 MWh or 20 MW for 2.5 hours.

If we were to compare this to a typical 500 MW pumped storage plant facility like LEAPS with 16 hours of reservoir storage, this facility would have a total storage capacity of 8,000 MWh. If this storage capacity were required for a flywheel site, it would require 320,000 individual flywheels or 32,000 arrays. These machines do not drive synchronous generators like a pumped storage plant as the flywheel speed is changing constantly. Thus, the quality of the electricity and the stability of the machines are not is the same league as a hydro generator.

Scaling of the flywheel to larger size is limited as the 25 kWh Beacon Smart Energy 25 currently has a rim speed of twice the speed of sound at full storage. Since the Stephentown plant is not functioning, there is no data with regards to reliability or maintainability. NHC has no idea of Beacon's operating and maintenance budget would have to be to maintain 320,000 flywheels and their associated electrical hardware, controls, vacuum systems, etc. These flywheels are not simple machines. Beacon Power indicates the units will have a 20 year life. If this is the case, simple math reveals that one would need to replace/install roughly 5 arrays per day continuously at a plant with the capability of a single 500 MW pumped storage plant!

Also, note that the KEMA (commissioned by Beacon in 2007 and the battery storage providers in 2010) focused on the regulation market primarily and on short term storage. Hence the conclusions that rapid grid response of up to 40 mode changes an hour (charge and discharge) and a shorter, 4 hour duration for storage overall, is what the California Energy Commission thinks they need. Although it is such a completely different product and service as compared to pumped storage, it is still important to note that variable speed pump storage units (like LEAPS) can offer services similar to what a flywheel system provides at a <u>much</u> greater energy concentration.

6. Conclusion

NHC is very aware that assessing the value of storage to the grid is not an easy task. Determining which parties benefit from any value provided, and who should pay for the value provided is doubly difficult. Advocates of free and open markets may not see the task as that onerous: simply let the market work. Of course, California does not really have a truly functioning market.

Perhaps the Commission can value storage project's ability to mitigate many of the conditions discussed in the Commission's white paper by translating the resource integration and over-generation challenges into higher required quantities of, and market clearing prices for, regulation-up and regulation-down services. But perhaps this is too simplistic.

As NHC has been active in this area for a number of years, included in this filing are a number of additional attachments that the Commission staff may find useful. Included are:

Attachment Number	Title	Subject
Attachment 4	Dominion Pumped Storage Experience	Copy of a 2006 presentation made to the CAISO by Dominion, operator of the 2,500 MW Bath County Pumped Storage facility.

Attachment Number	Title	Subject
Attachment 5	Research Evaluation of Wind Generation, Solar Generation, and Storage Impact on the California Grid	KEMA's 2010 report prepared for the California Energy Commission
Attachment 6	Voith Pumped Storage Forum PowerPoint	PowerPoint prepared for a 2010 San Francisco meeting addressing Understand Grid System Dynamics and Pumped Storage Solutions

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Dated this 20th day of January , 2011

Attachment 1

LEAPS Operating Characteristics

The following tables present detail on operating characteristics of LEAPS:

Expected Generating Capacity and Expected Pumping Capacity of each Generating Unit		
Generating Unit Number	1*	2*
Expected Generating Capacity, MW, at Minimum Normal Upper Reservoir Level	250.00	250.00
Aggregate of Expected Generating Capacity, MW, at Minimum Normal Upper Reservoir Level	500.00	
Expected Generating Capacity, MW, at Maximum Normal Upper Reservoir Level	275.00	275.00
Expected Generating Capacity, MW, at Maximum Normal Upper Reservoir Level	550.00	
Expected Pumping Capacity, MW, at Minimum Normal Upper Reservoir Level	300.00	300.00
Aggregate of Expected Pumping Capacity, MW, at Minimum Normal Upper Reservoir Level	600.00	
Expected Pumping Capacity, MW, at Maximum Normal Upper Reservoir Level	300.00	300.00
Aggregate of Expected Pumping Capacity, MW, at Maximum Normal Upper Reservoir Level	600.00	
* Values above on a unit basis are at the high voltage side of the transformer with both units operating, excluding station usage, with 1245 ft level at Lake Elsinore		

Expected operating limits of each Generating Unit			
Generating Unit Number	1	2	Total
Generating Capacity			
PMAX (MW) (Section 1.02.01)	250-275	250-275	500-550
PMIN (MW)	150.00	150.00	300.00
Minimum Run Time (hours)*	20.00	20.00	20.00
Minimum Down Time (MDT) (hours)**	0.00	0.00	0.00
Pumping Capacity			
PMAX (MW) (Section 1.02.01)	300.00	300.00	600.00
PMIN (MW)	240.00	240.00	480.00
Minimum Run Time (hours)*	21.50	21.50	21.50
Minimum Down Time (MDT) (hours)**	0.00	0.00	0.00
* Minimum Run Time (hours) is the amount of time to drain the reservoir (at maximum upper reservoir volume) with both units operating at 250 MW of output at the transformer. For single unit operation, these times are doubled.			

Expected startup limits of each Generating Unit		
Generating Unit Number	1	2
Generating Capacity		
Maximum Number of Dail y Start-Ups	Unrestricte d	Unrestricted
MaximumNumberof WeeklyStart-Ups	Unrestricted	Unrestricted
Pumping Capacity		
Maximum Number of Monthly Start-Ups	Unrestricted	Unrestricted
MaximumNumberof AnnualStart-Ups	Unrestricted	Unrestricted

Maximum Operating Hours Allowed of each Generating Unit*		
Generating Unit Number	1	2
Generating Capacity		
Maximum Dail y On Time @PMAX	20	20
Maximum Weekly On Time @PMAX	82	82
Pumping Capacity		
Maximum Dail y On Time @PMAX	21	21
Maximum Weekly On Time @PMAX	86	86

* Assumestwo unitoperation at 250 MW each in the generatingcycle starting with a full reservoir (at maximumupper reservoir volume) and pumpingcycle startingwith a reservoir at normal maximumoperatinglevel. Note: spreadsheet does not allow 1/2

Maximum and Minimum Ramp Rates of each Generating Unit		
Generating Unit Number	1	2
Generating Capacity		
Minimum Ramp Rate (MW/min)	0	0
Maximum Ramp Rate (MW/min)	600	600
Pumping Capacity		
Minimum Ramp Rate (MW/min)	0	0
Maximum Ramp Rate (MW/min)	120	120

Start-Up Ramp Profiles of each Generating Unit*		
Generating Unit Number	1	2
At End of __ Hour	**1st**	**1st**
Generating Capacity		
Start (zero to PMIN)		
MW Outputat End of Hour	250-275	250-275
Pumping Capacity		
Start (zero to PMIN)		
MW PumpingLoad at End of Hour	300.00	300.00

* Standstillto fullload generatingin 120 secondsassumingvalve is open. Standstillto fullload generatingin 240 secondsif valve is closed. Standstillto fullload pumpingin 460 seconds

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Shut Down Ramp Profiles of each Generating Unit*		
Generating Unit Number	1	2
Generating Capacity		
PMIN to Shut down		
MW Output at End of Hour	0.00	0.00
Pumping Capacity		
PMIN to Shut down		
MW Pumping Load at End of Hour	0.00	0.00

* Full load generating to standstill in 240 seconds, Full load pumping to standstill in 240 seconds

Attachment 2

LEAPS Provision of Ancillary Services

The following tables present detail on the capabilities of LEAPS to provide ancillary services:

Ancillary Service Limits of each Generating Unit

Unit 1 Generation Mode

	Ancillary Service Regional Limits		lower of the delta between the A/S CapacityRegions and Reg (Op) Ramp Rate times 10		
A/S Name	Minimum A/S Capacity Region 1 (MW)	Maximum A/S Capacity Region 1 (MW)	Regulating or Operating Reserve Ramp Rate (MW/minute)	A/S Maximum Capacity (MW)	A/S Minimum Capacity (MW)
Regulation Up - Depending on Upper Reservoir Elevation	150	250-275	600	250-275	150
Regulation Down - Depending on Upper Reservoir Elevation	150	250-275	600	250-275	150
Spinning Reserve - Synchronous Condense to Full Load	0	250-275	600	250-275	170
Non-Spinning Reserve	0	250-275	600	250-275	170

Unit 2 Generation Mode

	Ancillary Service Regional Limits				
A/S Name	Minimum A/S Capacity Region 1 (MW)	Maximum A/S Capacity Region 1 (MW)	Regulating or Operating Reserve Ramp Rate (MW/minute)	A/S Maximum Capacity (MW)	A/S Minimum Capacity (MW)
Regulation Up - Depending on Upper Reservoir Elevation	150	250-275	600	250-275	150
Regulation Down - Depending on Upper Reservoir Elevation	150	250-275	600	250-275	150
Spinning Reserve - Synchronous Condense to Full Load	0	250-275	600	250-275	0
Non-Spinning Reserve	0	250-275	600	250-275	0

Unit 1 Pumping Mode**

	Ancillary Service Regional Limits				
A/S Name	Minimum A/S Capacity Region 1 (MW)	Maximum A/S Capacity Region 1 (MW)	Regulating or Operating Reserve Ramp Rate (MW/minute)	A/S Maximum Capacity (MW)	A/S Minimum Capacity (MW)
Regulation Up	240	300	120	300	240
Regulation Down	240	300	120	300	240
Spinning Reserve*	0	0	0	0	0
Non-Spinning Reserve*	0	0	0	0	0

* *Assumes reserve only applies to generation, not pumping*

Unit 2 Pumping Mode

	Ancillary Service Regional Limits				
A/S Name	Minimum A/S Capacity Region 1 (MW)	Maximum A/S Capacity Region 1 (MW)	Regulating or Operating Reserve Ramp Rate (MW/minute)	A/S Maximum Capacity (MW)	A/S Minimum Capacity (MW)
Regulation Up	240	300	120	300	240
Regulation Down	240	300	120	300	240
Spinning Reserve*	0	0	0	0	0
Non-Spinning Reserve*	0	0	0	0	0

* *Assumes reserve only applies to generation, not pumping*

Attachment 3

EON Report on Pumped Storage

Energy-Economic Evaluation of Pumped-Storage Plants

Dr. Klaus Engels, Michael Brucker, Michaela Harasta und Dr. Tobias Mirbach

Summary

Pumped-storage plants participate in two structurally different markets: the market for scheduled energy (also known as the spot market) and the reserve market. The marketing of the available capacity from pumped-storage plants needs to be optimized in both of these markets to achieve the best possible plant scheduling in terms of revenues. Moreover, due to their ability to provide reserve market products, pumped-storage capacities within an existing power plant portfolio can create synergies for the whole portfolio. The optimized combined participation of a power plant in both spot and reserve markets as well as the coherent portfolio effect are considered particular challenges in energy-economic evaluations, e.g. in the light of investment decisions. Based on the Waldeck 2+ expansion project, and in cooperation with RWTH Aachen University, E.ON simulated for the first time an optimized combined participation of a power plant in both markets by applying an integrated optimization algorithm. The same but enhanced evaluation methodology was applied to assess the market potential of pumped-storage plants in Germany. This article presents the complex but comprehensive methodological approach used in this simulation to evaluate the energy-economic viability of pumped-storage plants.

1 Technical and economic importance of pumped-storage plants

1.1 Future structure of electricity generation

Electricity generation structures are in a state of flux. Whereas in the past electricity used to be generated primarily by large-scale power stations that tended to be located at sites of high consumption, we can expect to see an increasingly decentralized load coverage in the future. In particular the volatile and unpredictable input from wind power will expand as climate protection endeavours gather pace. In such an environment the importance of highly controllable power plants ensuring grid stability will continue to grow. Pumped-storage power plants are technically highly flexible, and it is this quality coupled with their exceptional control capabilities that makes them ideal for the role of a 'grid stabilizer'.

1.2 Market opportunities of pumped-storage power plants

The development of the reserve markets will be of major significance for the commercial success of pumped-storage plants. We can already anticipate a rising demand for system reserve that will create a growing market demand for pumped-storage capacities. Besides a rising demand there may appear entirely new reserve products on the reserve market, e.g. a wind balancing product or hourly reserve.

At the same time we can expect an increase in volatility of prices on the spot markets that could be commercially exploited by fully flexible facilities such as pumped-storage plants, creating additional revenue potential in the generation sector.

It follows that pumped-storage projects represent attractive investment opportunities for electricity generators, as witnessed by the large number of projects ongoing in Europe (examples: Atdorf, Waldeck 2+, Jochenstein-Riedl).

Because of their wide diversity of possible applications and resulting high degree of complexity, pumped-storage plants require highly sophisticated calculation tools for the purpose of energy-economic simulation and subsequent commercial evaluation.

2 Marketing of pumped-storage capacities

2.1 Combined participation on the spot and reserve markets

The complexity of a pumped-storage plant arises from its combined participation in two different markets, the market for scheduled energy (spot and futures market) and the reserve market.

For most pumped-storage plants, the bulk of revenues come from participating in the scheduled energy market. The earned contribution margin is not determined by the prevailing price level but by the spread (price differential) between peak and off-peak hours. Water is usually pumped up into the reservoir during the cheaper off-peak hours and then turbinated during the expensive peak hours (also known as process of “refinement”).

Beside the market for scheduled energy there is a market for system reserve. This is based on the need to maintain a permanent balance between generation and demand. Based on the rules of UCTE there are three different reserve products in Germany: primary control power, secondary control power and minute reserve, each with a positive and negative direction. In Germany, it is the job of the transmission system operators (TSOs) to tender and procure the control reserve demand.

To maximize revenues, the capacity of a pumped-storage power plant must be optimally split between the two markets depending on prevailing market prices. From a mathematical perspective this poses a complex optimization problem when it comes to evaluating pumped-storage plants.

Another problem involves long-term price forecasting for the different products that are relevant for pumped-storage plants. Although established tools for long-term price simulation on the scheduled energy market already exist, there has so far been a lack of similar fundamental models for the reserve products, as their market mechanisms are extremely complex and difficult to model. This will pose a future challenge as reserve markets grow in importance.

2.2 Origin of the portfolio effect

Due to its ability to provide reserve energy in a most efficient way, (additional) pumped-storage capacity in an investor’s power plant portfolio can create synergies for the whole portfolio.

This synergy potential is derived from the various technical restrictions of the different power plant technologies, especially in combination with the marketing of structurally different products in the spot and reserve market. Pumped-storage power plants can be operated fully flexible and thereby increase the degree of freedom in an existing portfolio. This greater degree of freedom can be used for a *portfolio-optimized* provision of reserve capacity and reserve energy. By integrating an additional pumped-storage plant into the portfolio, generation capacity – especially thermal power plants – that was previously tied up for providing the marketed reserve capacity can now be freed up for spot market participation. This allows to operate the thermal capacities in a better load point which results in an increase in efficiency. There are therefore two elements to the resulting portfolio effect: the higher spot market earnings of thermal power plants, and the lower specific fuel costs in the thermal sector.

However, this is subject to the assumption that there is a fully liquid spot market in which the capacities that become available can be marketed without impacting the electricity price. Another constraint is an illiquid reserve market, i.e. tradable reserve capacities are restricted and do not increase if additional hydrothermal generation units participate in the portfolio/market. But due to the limited request every reserve market is indeed illiquid.

We should also note that the potential of the portfolio effect is largely dependent on the structure of the existing portfolio. It will be particularly strong in thermally dominated portfolios, while in portfolios with a high hydro component, the portfolio effect will be weak or even nonexistent.

Nevertheless any evaluation of power plants in general – and pumped-storage plants in particular – must take an existing power plant pool into consideration, since the portfolio effect can make a substantial contribution to operating income.

2.3 Impact on Market Prices

As well as the value of an individual pumped-storage plant in the portfolio, the overall market potential of this technology may also be of interest to an investor wishing to assess how much commercially meaningful pumped-storage capacity he can put on the market.

Such an assessment cannot ignore anymore the impact that additional capacity has on electricity prices, as it was acceptable for the evaluation of a single additional facility in the portfolio and market (assuming a perfectly liquid electricity market, see above).

Therefore, for this purpose, energy-economic portfolio simulations (power generation and trading) must be combined with market simulation methods. One approach to an evaluation of this type is presented in Chapter 5.

3 Energy-Economic Simulations

The contribution margin is determined by applying an approved optimization method for power generation and trading planning that has been developed by the Institute of Power Systems and Power Economics; this method considers markets for scheduled energy (spot market) as well as markets for system reserve [01], [02].

3.1 Method for Power Generation and Trading Planning

Power generation and trading planning is a highly complex, multi-dimensional, mixed-integer, non-linear optimization problem for which constraints that apply to all systems and times have to be taken into account. Standard procedures based on mixed-integer linear programming (MILP) might be used to solve the problem if the problem can be linearized. However, given the complexity of this particular problem (large power plant portfolios and simulation period of one year in an hourly granularity), the long computing times and a high demand on hardware preclude such an option as the complexity of the problem rises exponentially with the amount of integer variables, rendering the current optimization problem unfeasible for closed-loop approaches.

Decomposition procedures are practical approaches that break the optimization problem down into smaller sub problems that can be solved iteratively by coordinating their individual solutions. The relevant nonlinear and integer characteristics of each component and market can be taken into account using this approach. The entire procedure consists of several individual optimization stages, each applying the best fitting optimization algorithm – such as dynamic programming (DP), successive linear programming (SLP) and quadratic programming (QP) – to the sub problem of the entire generation and trading planning. At the same time all constraints in the system domain are satisfied due to their coordination by Lagrange relaxation. Lagrange relaxation is a decomposition approach based on the concept of reducing the main problem to less-dimensional sub problems. An overview of the structure of the HERMES optimization method is shown below [03].

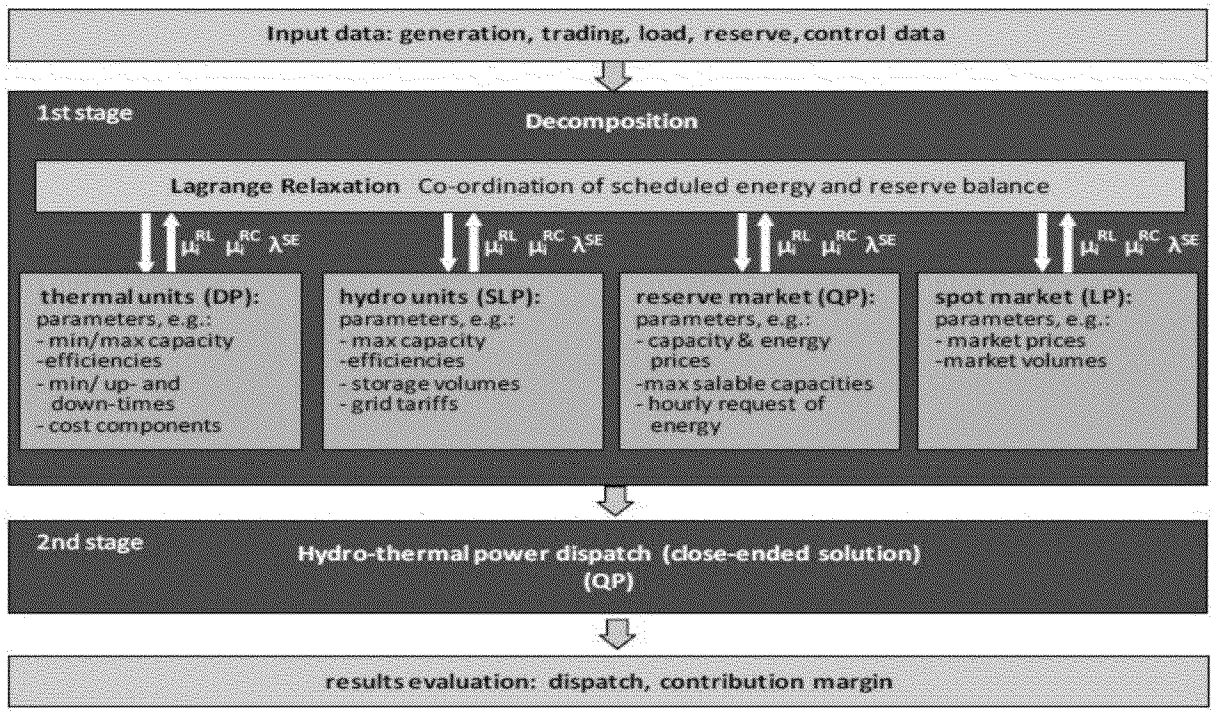

Fig. 1 Method overview

The result of the power generation and trading tool is the optimal energetic dispatch of all considered power plants on markets for scheduled energy and system reserve taking into account all technical restrictions of the power plants such as minimum and maximum output levels, minimum up and down times as well as organizational constraints of markets (minimum bids). Additionally, the tool determines hourly power plant schedules for each generator divided into scheduled energy, reserve capacity and reserve energy. Consequently the contribution margin of the entire portfolio can be computed. A high solution quality can be demonstrated for short-term problems by comparing simulations which have been conducted for the iterative decomposition approach and closed-loop optimization (MILP) which attains the guaranteed optimum. A detailed quantification of a new power plant's technical and economic impact on an existing power generation portfolio can be determined in this way.

3.2 Input Data

The input data for the generation and trading planning comprises the different parameters of the system components. On the supply side of electricity, these specifically include the technical parameters of the power plants and their different generation cost components, whereas prices and quantities are relevant for market modelling. The spot market is modelled by a chronological spot price curve on an hourly basis. Owing to the high observed liquidity of the EEX spot market, no price gradient or limit on the quantity tradable on the spot market are applied to our simulation calculations. The reserve markets are modelled as a function of the reserve quality (primary, second control and minutes reserve) and allowing for the differentiated consideration of the supply of reserve capacity and the provision of reserve energy. Input data include both the prices for reserve capacity and reserve energy and the maximum marketable reserve capacity of the various reserve products due to the limited tender quantities on the reserve markets of German transmission system operators. Because of the low calling signal for reserve energy – especially for minutes reserve – the markets for primary control and minute reserve are modelled as pure capacity markets. An hourly calling signal of reserve energy is taken into consideration for secondary control reserve.

3.3 Result – Derivation of the various contribution margin components

The power generation and trading planning tool performs an optimization of the entire power plant portfolio. Because of the interactions within the portfolio, the value of a single plant cannot be determined by simply evaluating the scheduled energy and reserve sold by that single plant on a stand-alone basis. Instead there has to be a comparative analysis of the power plant portfolio that both includes and excludes the power plant that is to be evaluated. The value of a particular plant can then be quantified by a differential consideration of the performed simulation calculations.

In order to be able to analyze the different components of the earned contribution margin of the power plant, various simulation calculations are performed. The total contribution margin consists essentially of three components: contribution market from spot market, reserve market and portfolio effect. Figure 2 illustrates the methodology and the simulations required to determine the different contribution margin components

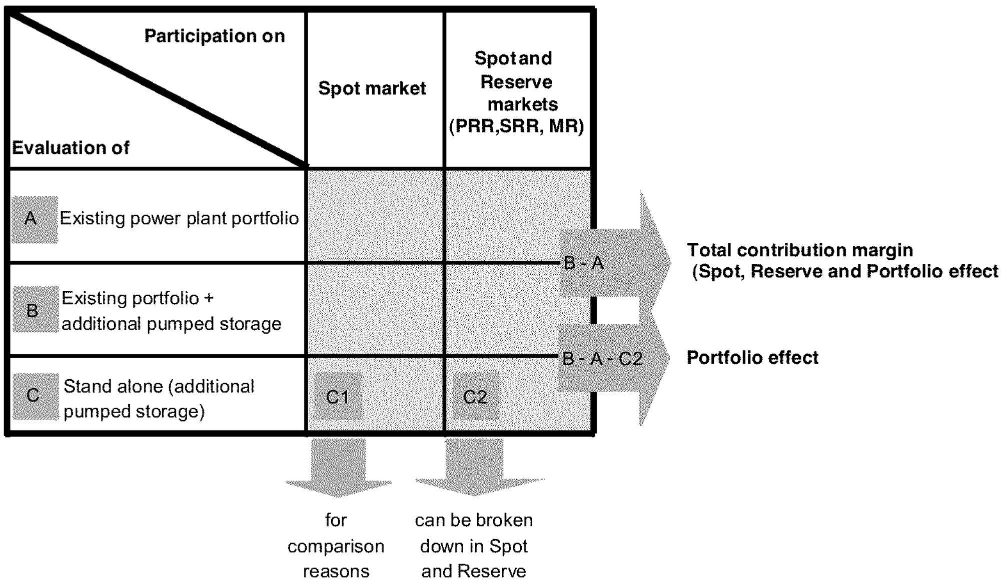

Fig. 2 Determination of the different contribution margin components

4 Investigation based on Waldeck 2+

Taking the Waldeck 2+ expansion project as a concrete example, E.ON has applied the energy-economic evaluation method described in Section 3 for the first time in an end-to-end investigation concept.

4.1 Derivation of the optimum level of expansion

The additional pumped-storage power plant Waldeck 2+ was incorporated into E.ON's existing power plant fleet by incrementally increasing turbine and pumping capacity and the various achievable contribution margins (spot, reserve and portfolio effect) were simulated in separate optimization calculations. Because of the size constraint for the existing upper reservoir (limiting factor in the system) the contribution margin curve is not linear but levels out as capacity increases. A profitability analysis compared the anticipated investment costs of each expansion stage with the attainable contribution margins. In this way it was possible to define an economically optimum capacity range which was then investigated further using smaller simulation steps both upwards and downwards but applying the same methodology.

4.2 Derivation of the optimum engine concept

A further step in the investigation involved simulations for determining the optimum engine concept. Three basic concepts are available, differing mainly in their controllability during pumping mode and the possible minimum load of the turbines:

- Pumping turbine with synchronous generator – cannot be controlled in pumping mode, turbine has a high minimum load
- Pumping turbine with asynchronous generator – can be controlled in pumping mode in the upper capacity band, turbine has medium minimum load
- Three-engine set with separate turbine and pump plus converter – fully controllable in pumping mode by running the hydraulic short circuit, turbine has low minimum load

The technical ability to participate in the different reserve markets was defined for each engine concept and operating mode (pumping or turbining mode). Owing to the extreme complexity of the mathematical problem however, this optimization calculation could 'only' be performed in the interconnected Waldeck group and not in the portfolio as a whole. However, comparing achievable contribution margins of the different engine types with related investment expenditure, the commercially optimum engine concept could be derived.

4.3 Sensitivity Calculations

The engine concepts that were investigated differ mainly in their ability to participate in the markets for different reserve products. A decision for or against a particular engine concept therefore depends largely on the assumptions about the underlying reserve market prices. Therefore sensitivity calculations were carried out with incremental upward and downward price variations for the individual reserve products while spot prices at the same time remained unchanged.

5 Assessment of the Market Potential for Pumped-Storage Plants

Additionally, E.ON has launched a study to assess the overall market potential for pumped-storage power plants in Germany.

The valuation method employed a three-stage investigation process to address the impact on spot market prices, if additional generation capacities are brought into the system.

Stage 1: Market simulation to determine the electricity price in defined market scenarios

The market scenarios were defined by their relevant influencing variables, mainly the hydrothermal power plant fleet for each market area, the installed capacity of wind power plants, primary energy and CO_2 prices, load, reserve demand and transmission capacities between the market areas. The market simulation calculated the economically optimum, i.e. least-cost power plant utilization needed to cover the demand while allowing for power plant-specific restrictions. On the basis of the hourly power plant utilization determined in this way, generation cost based market prices for scheduled energy could then be estimated.

Stage 2: Market simulation considering new build capacity

Since additional power plant capacities affect electricity market prices, market simulations for different new build scenarios had to be performed. These new build scenarios differ from the basic market scenarios only in the *additional* (pumped-storage) capacity introduced into the system. Various new build scenarios representing different expansion stages of the system were defined.

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Stage 3: Contribution margin calculation from portfolio simulation

To evaluate the market potential of pumped-storage new build units, this third stage simulated their spot and reserve market participation in incremental expansion stages. For this purpose the method described in Chapter 3 was used. To ensure the reliability of the results, the use of the related and hence consistent electricity price is essential when simulating an expansion stage. Result of these simulations was the contribution margins that can be generated with each expansion stage in the portfolio. While additional pumped-storage capacity earns extra revenue on the spot market, the contribution margin of the remaining portfolio decreases. This is because of the negative impact of that additional capacity on the electricity price. By comparing the contribution margins of the various expansion stages, it was possible to identify the expansion level that generates the maximum profit from an overall portfolio perspective.

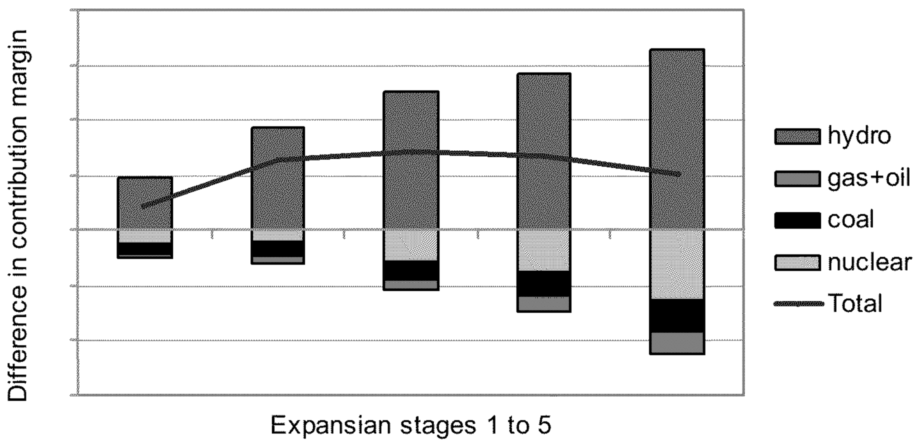

Fig. 3 Effect of pumped-storage expansion on the contribution margin of the portfolio

6 Experience and conclusion for industry

Both reserve revenues and portfolio effect move in orders of magnitude (+92% compared with pure spot marketing in the example of Waldeck 2+) that not only justify the use of complex calculation tools for the solid evaluation of pumped-storage plants but also show it to be indispensable.

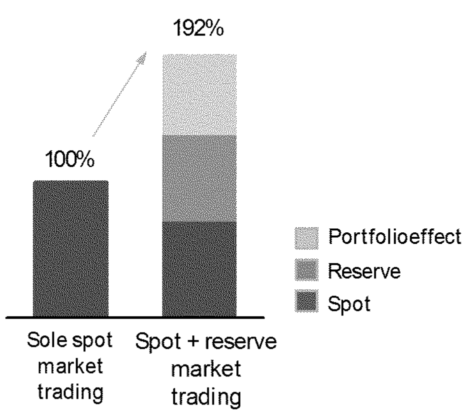

Fig. 4 Rise in contribution margin when using the evaluation approach described

Assumptions for the development of the reserve markets are of major significance for the evaluation. While established tools are available for long-term predictions on the scheduled energy market, there is a lack of such fundamental models for the reserve markets. Subsequently there is a need for action.

The high degree of detail used by RWTH Aachen in the Waldeck example when modelling systems and markets, and the underlying mathematical methods, involve long computation times. More pragmatic approaches that favour faster computation speeds while still producing reliable results must now be found for an industrially viable use of such tools.

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Attachment 4

Dominion Pumped Storage Experience

Twenty One Years of Pumped Storage Experience

Michael Wood

Director of Operations - F&H

Presentation to CAISO - 11/28/2006

Agenda

- Introduction
- Pumped Storage Benefits / Capabilities
- Comparison to other Generation Types
- Pumped Storage Challenges
- Dominion's Experience
- BC Actual Capabilities
- Pumped Storage in PJM RTO
- Summary

Dominion

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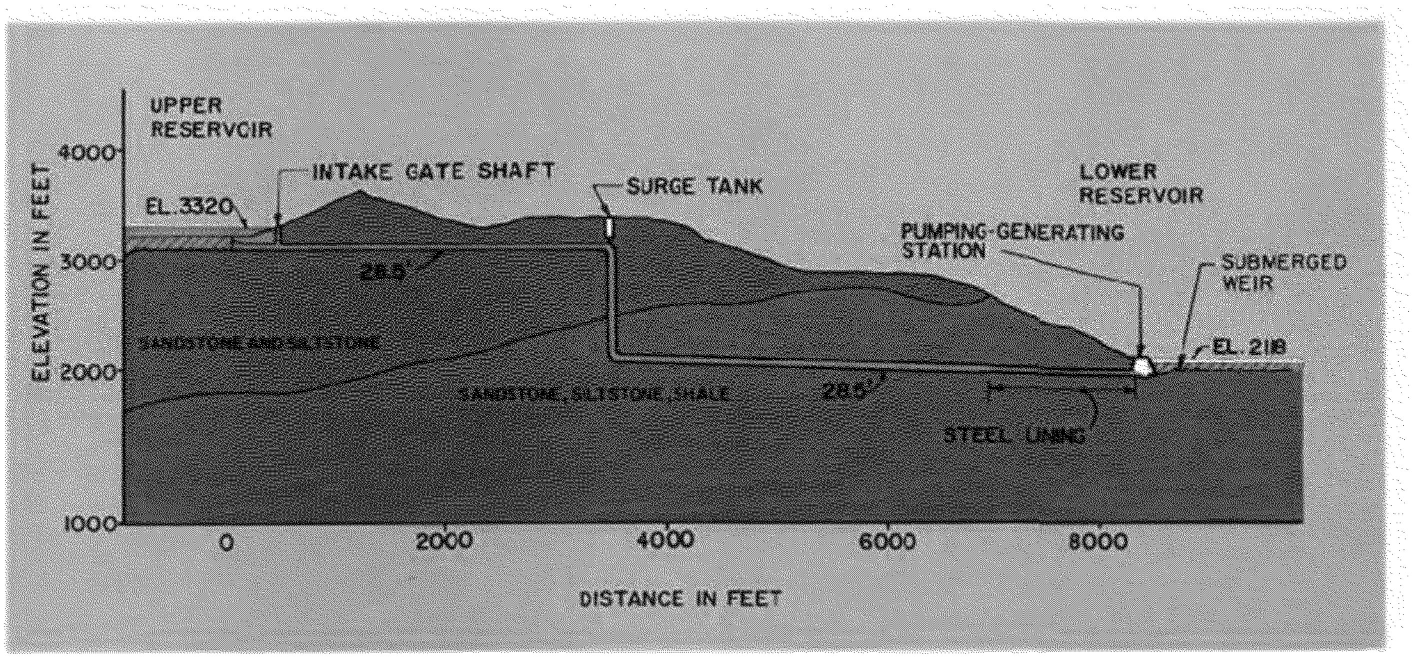
Pumped Storage

- Off Peak Energy pumps water to Upper Reservoir
- Reversible pump / turbines
- Store as Potential Energy in Upper Reservoir
- Water drops 1300 ft to Lower Reservoir
- Flexible on peak generation
- Efficiency 80%



Dominion

Pumped Storage Benefits

- Fast Start
- Fast ramp rate
- Superior Spinning Reserve
- Reliable Capacity Resource (Hydro)
- Intermediate Resource with peaking Capabilities
  - Cycle Time / Starting Cost
- Voltage Support - multi mode
- Significant Regulation Capability
- Black Start
- Thermal Generation Optimization
- Very reliable / timely starting
- Efficiency 80+%
- Fuel diversity
- Storage Volume/ Weekly / Daily Cycles
- Flexibility !!

Dominion

Comparison to other Generation Types

- High Capital Expense (compared to CT)
- Low O&M (compared to any thermal generation)
- Extended Asset Longevity - (compared to thermal)
- Non GHG emitting (pumping energy source remote)
- Potential for remote operation
- Very reliable (High equivalent availability - 93+%)
- Predictable and short start time, avoids uneconomic startup time typical of cycling intermediate resources (CC)
- No minimum run time

Dominion

Challenges

- On / Off Peak
  - Relies upon delta between on / off peak prices
    - Transmission capability
    - Commodity sensitive
- Pumping -
  - Fixed Pump Input Power (head dependent)
  - No Regulation Capability in pump mode
  - Both these issues have solutions
    - Variable speed pumps
    - Goldistahl

Dominion

Dominion's Experience

- Bath County PSS - December 1985
- World's Largest Pumped Storage Plant
- Plant co-owned
  - 60% Dominion (operator)
  - 40% Allegheny Energy
- Initially operated as plant in two Vertically Integrated Systems
  - Dominion 17,000MW
  - Allegheny 8,000 MW
- Now operates in the PJM RTO (163,000MW)

Dominion

Dominion VP System

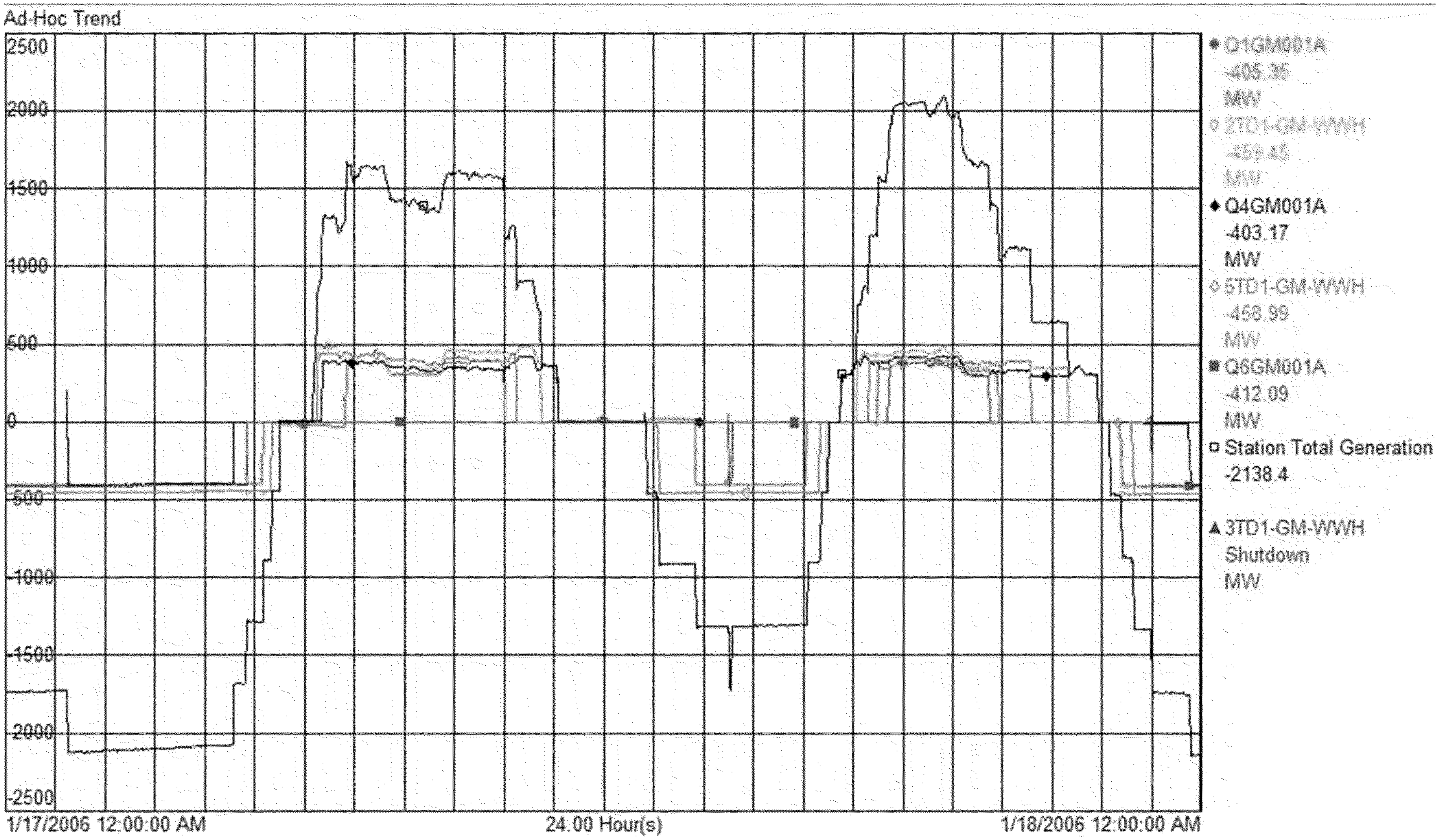
- Diverse
  - Nuclear 3,654MW
  - Coal 5,454MW
  - Gas 336MW
  - Oil 1,713MW
  - Wood 88MW
  - Hydro 326MW
  - CC 1,586MW
  - CT 2,201MW
  - NON Pumped Storage 15,358MW
  - Pumped Storage 1,552MW

Bath County Statistics

- Six units -
  - Peak output 2775MW
    - MDC 2586MW
  - Peak Input Power 2760MW
    - Typical Input 2520MW
- Cycle efficiency 80.5% >
- Generation 2002
  - 4,500,000 MWH
  - 5,500,000 MWH (pumping)
  - Utilization Factor - 50%
- Unit Operations
  - 4800 per year (800 per unit)
  - Summer + 1 pump / 1 gen
  - Winter - 2 pump / 2 gen cycles

Dominion

Winter Cycle - 1/17/2006



Dominion

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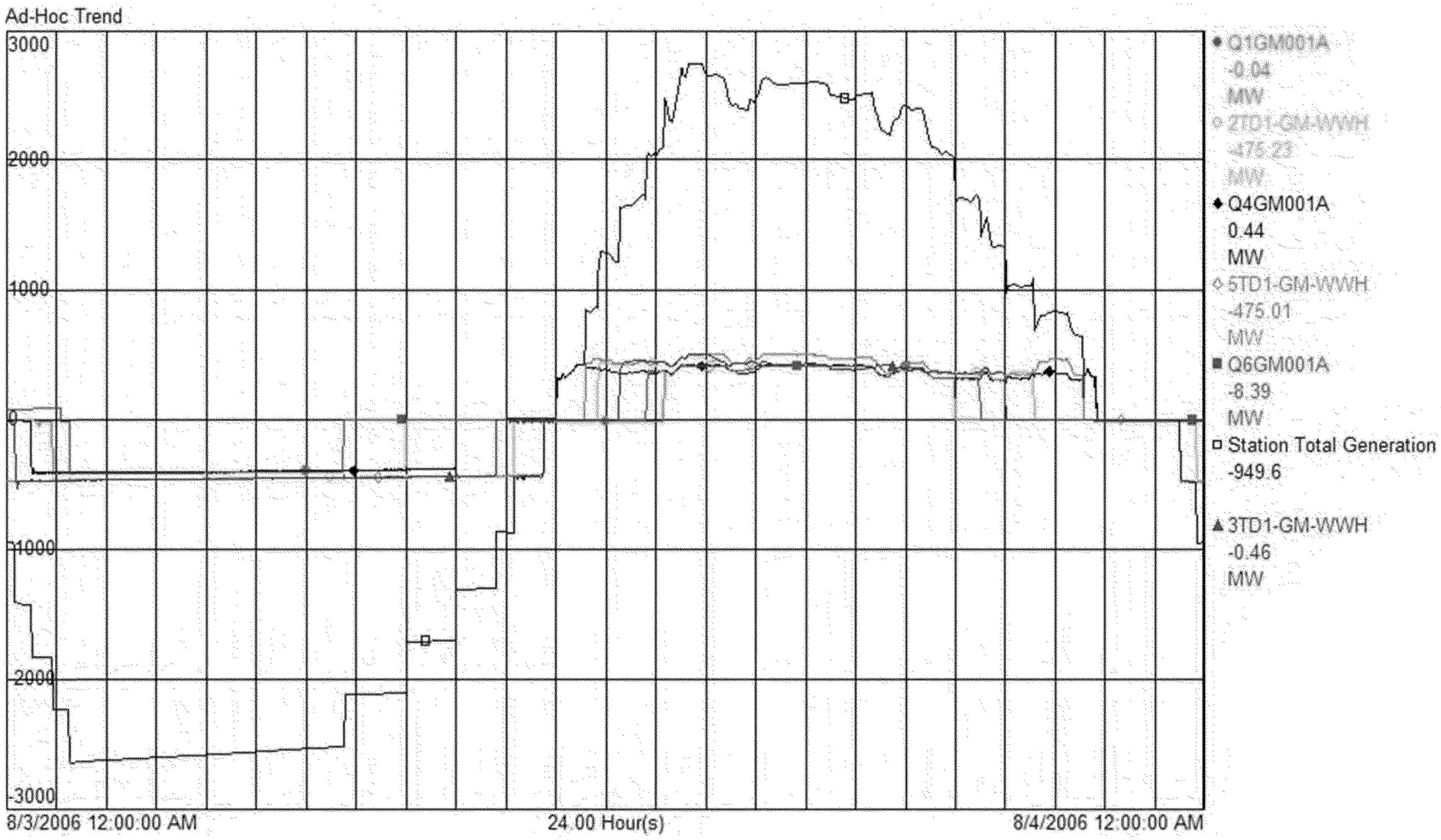
Summer Cycle - August 3, 2006



Dominion

BC Starting Capabilities (Typical)

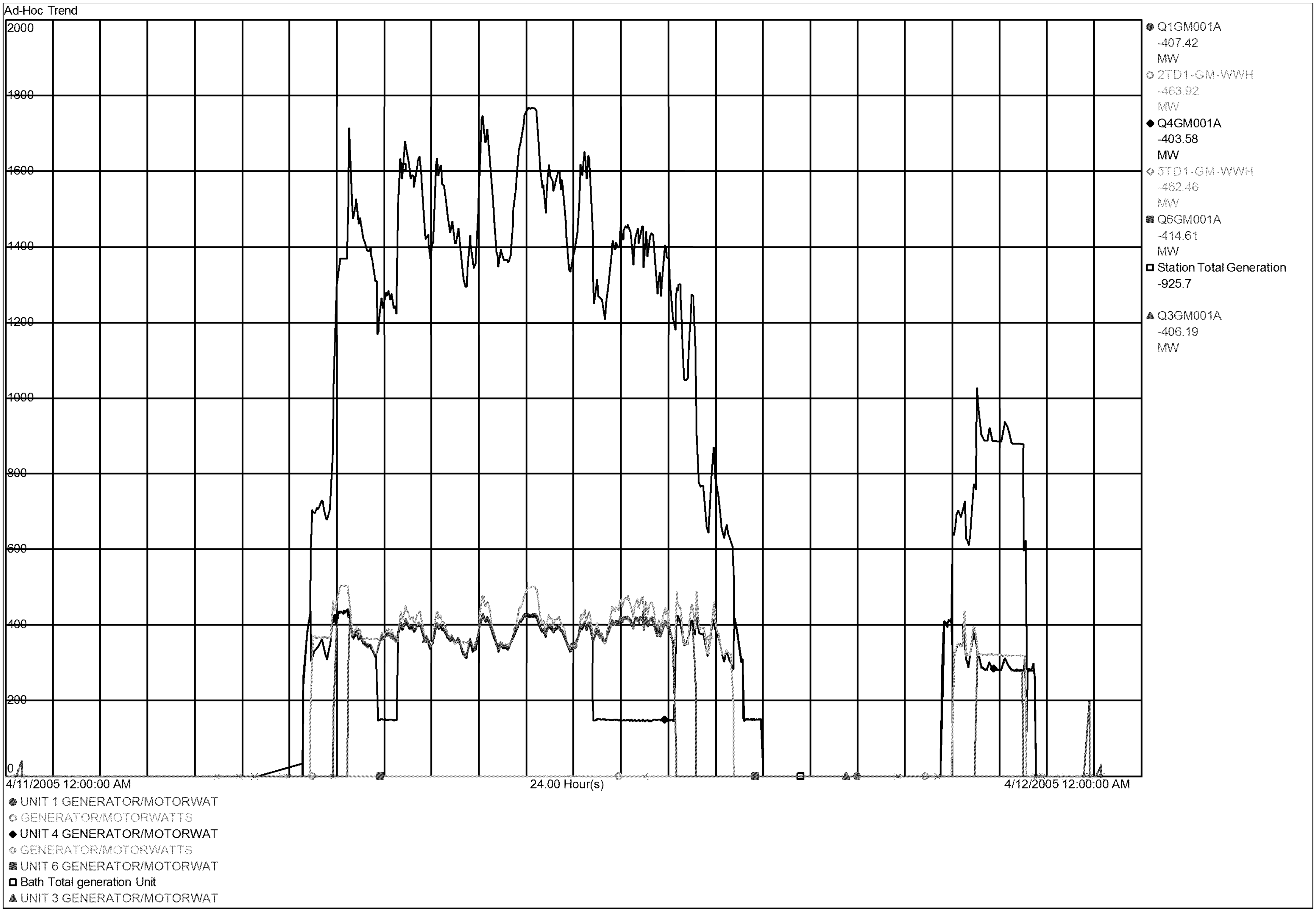
- Fast Start / Shutdown
  - Generate
    - Synchronized 4.5 minutes - 350 MW 6 minutes
    - Pick up loss of 900MW nuclear unit in 5 minutes
  - Pump
    - Synchronized 9.5 minutes - loaded 11.25 minutes
  - Start Times are Predictable within 1min+/-
- Multiple units can start simultaneously (generate mode)
- Starting Cost - very low - both modes
  - 4800 Unit Starts per year (800 per unit)
- Cycle Time / Run time / Mode Reversal
  - Unit Shutdown - < 3minutes (Synch speed to 0 rpm)
  - No minimum run time
  - Pump/Gen Mode reversal in < 10 minutes

Dominion

Ancillary Services

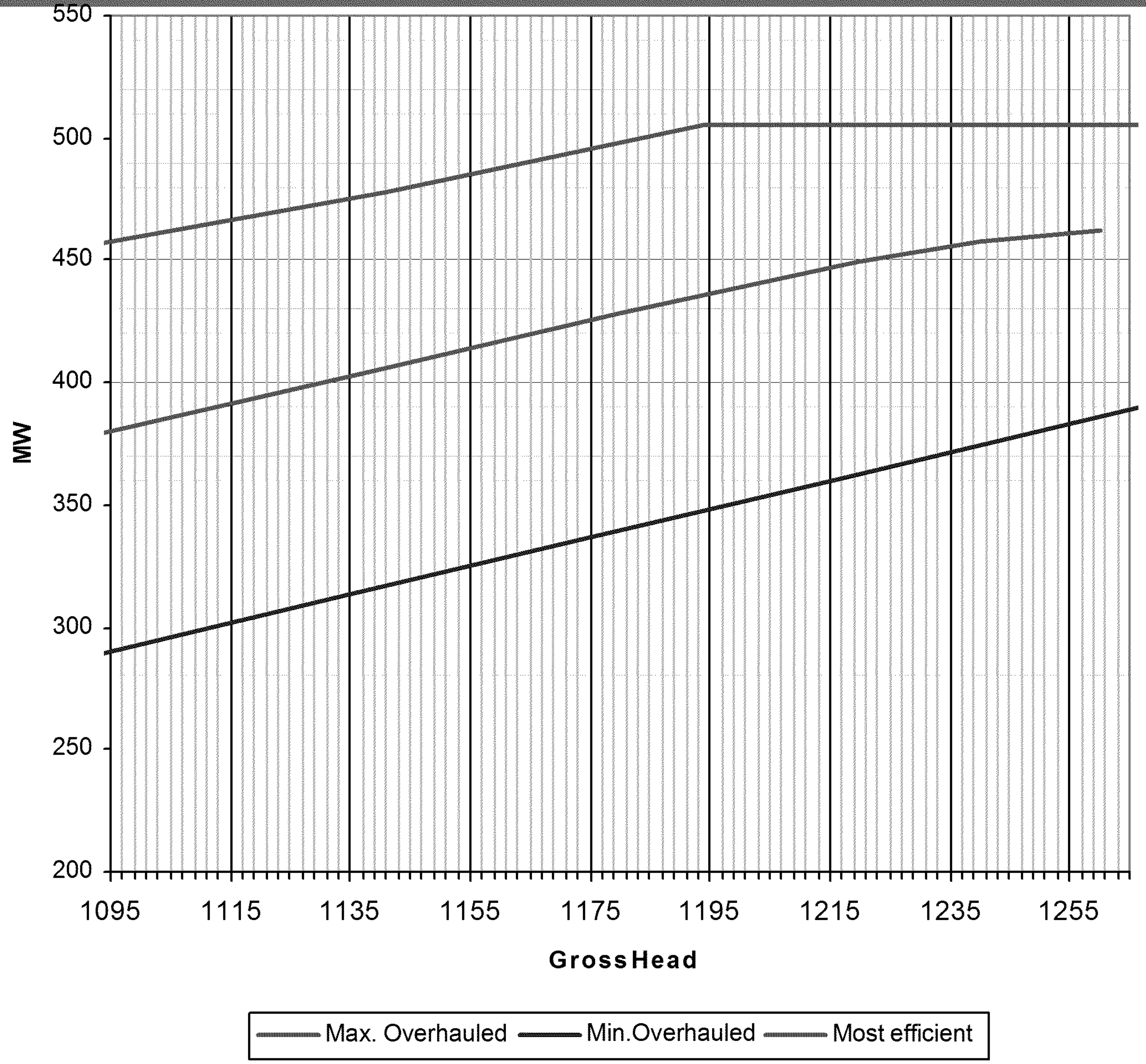
- Regulation
  - Unit Bandwidth 100-170MW
- Ramp rate
  - 100MW/min per unit (x6)
    - 33MW min per unit - in use (AGC)
- Pre-PJM
  - Two units on would regulate Dominion System
- ACE control -
  - CPS violations
- Black Start
  - Locational

Dominion


Ad-Hoc Trend
2000
1800
1600
1400
1200
1000
800
600
400
200
0
4/11/2005 12:00:00 AM
24.00 Hour(s)
4/12/2005 12:00:00 AM
Q1GM001A -407.42 MW
2TD1-GM-WWH -463.92 MW
Q4GM001A -403.58 MW
5TD1-GM-WWH -462.46 MW
Q6GM001A -414.61 MW
Station Total Generation -925.7
Q3GM001A -406.19 MW
UNIT 1 GENERATOR/MOTORWAT
GENERATOR/MOTORWATTS
UNIT 4 GENERATOR/MOTORWAT
GENERATOR/MOTORWATTS
UNIT 6 GENERATOR/MOTORWAT
Bath Total generation Unit
UNIT 3 GENERATOR/MOTORWAT

Dominion

Unit Bandwidth (U2, U3 & U5) - 2006



Dominion

Spinning Reserve

- VACAR - 10 min spinning reserve
  - Non synchronized - full load in 7 minutes (500MWx ?)
  - Synchronized - no requirement
- PJM Synchronized Spinning Reserve (10 min)
  - Tier 1 - Bandwidth ramp -
  - Tier 2 - Spin Gen (air) - 400MW in 90 seconds
- Demand Response
  - Pump Shut Down
    - -400MW in 1 minute (1 unit)
    - Two units off in 1 minute to compensate for nuclear loss
    - One unit off to compensate for 500MW coal unit

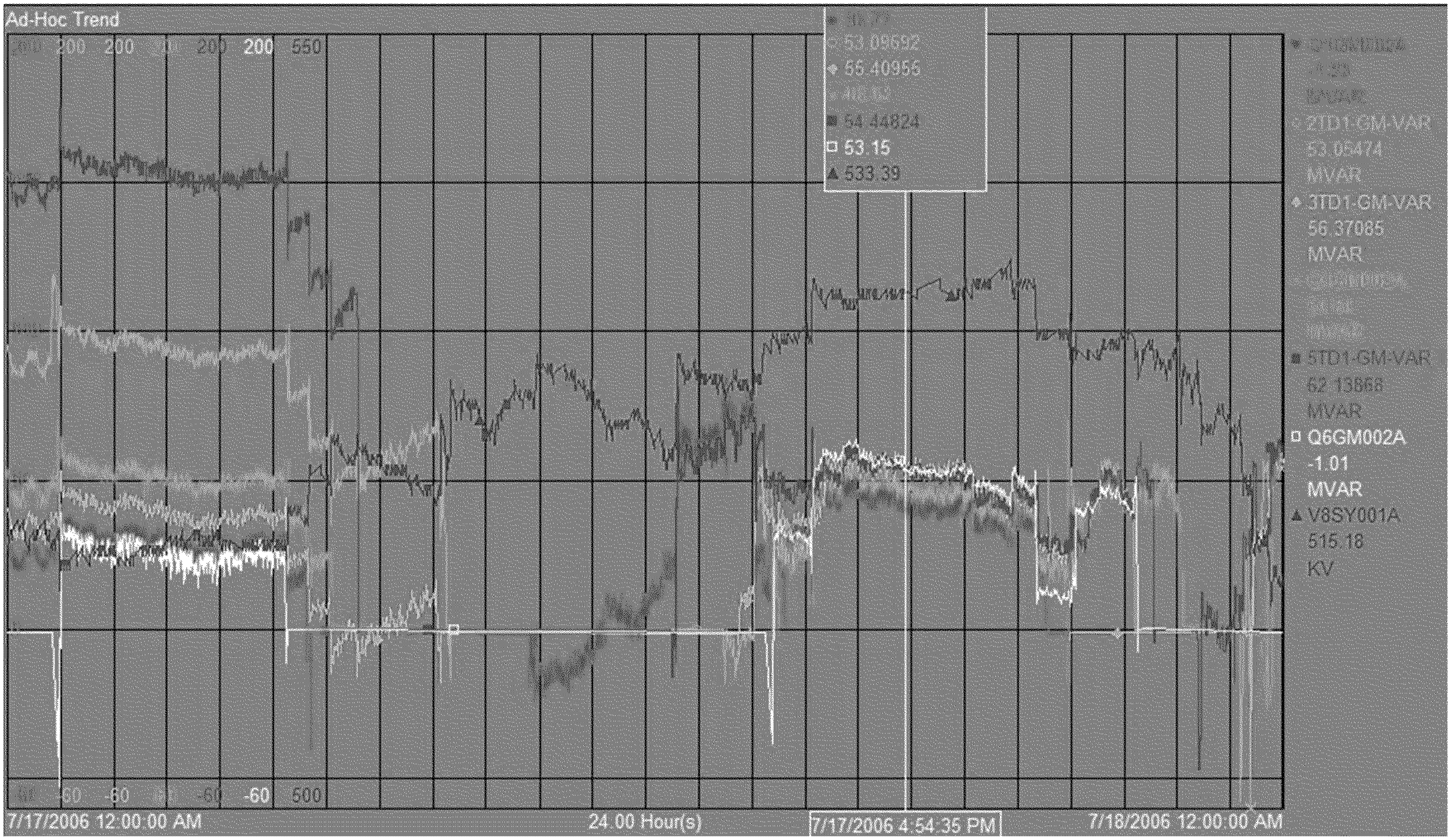
Voltage Control

- Support in pump and gen mode
- Synchronous condensing
  - Currently only available in spin pump mode
    - Can be converted to a pump in 90 seconds
  - Spin Gen mode
- Low speed , more massive units than thermal counterpart

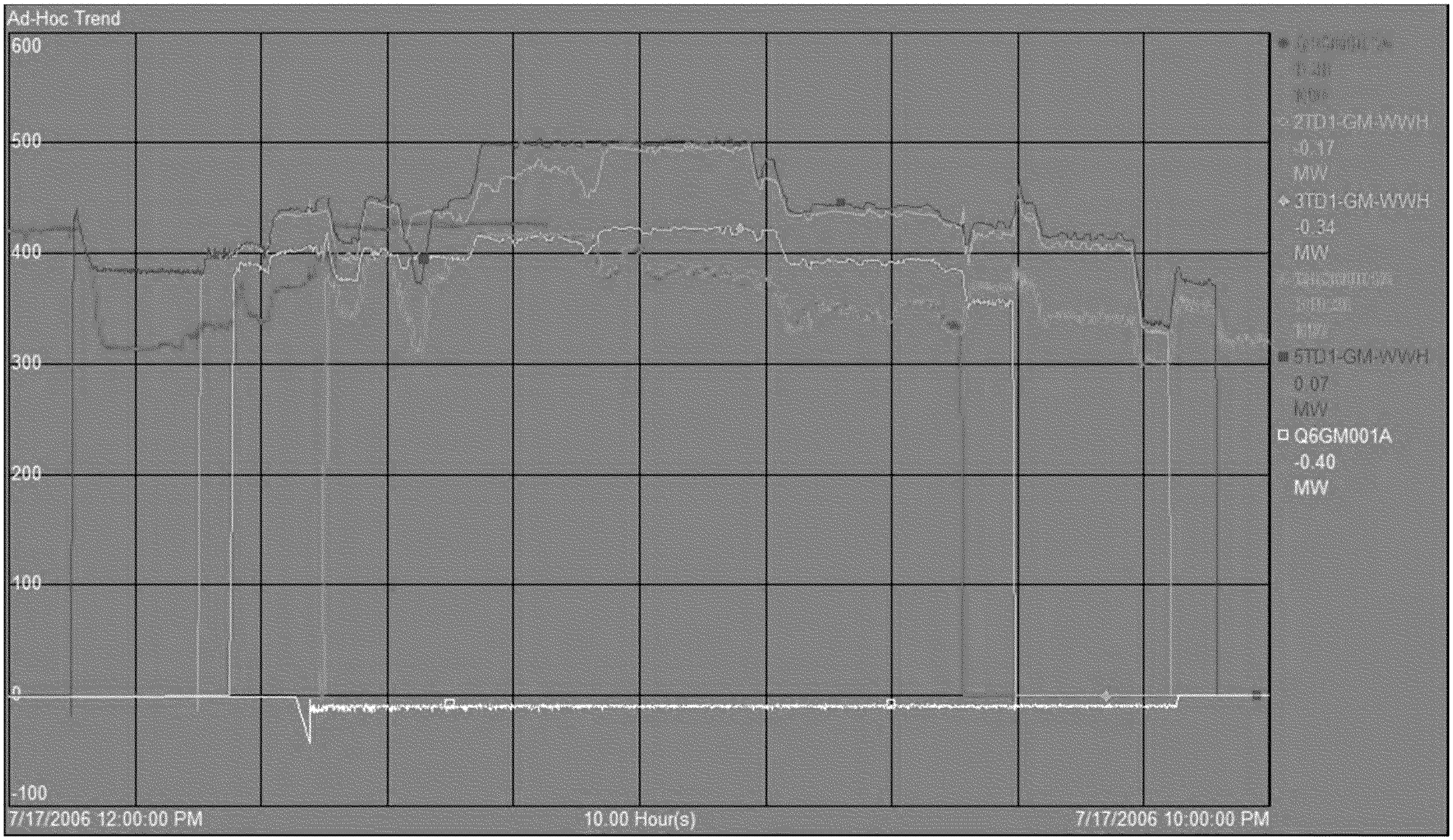
- Plant un-availability for voltage support (Off line time)
  - 1/26/2006 - 228 minutes (2 pump cycles/ 2 gen cycles)
  - 8/1/2006 - 141 minutes (1 pump cycle / 1 gen cycle)
  - 11/18/2006 - 214 minutes (2 pump cycles / 2 gen cycles)
  - Typical daily availability 80+%

Dominion

Voltage Support - 7/17/2006

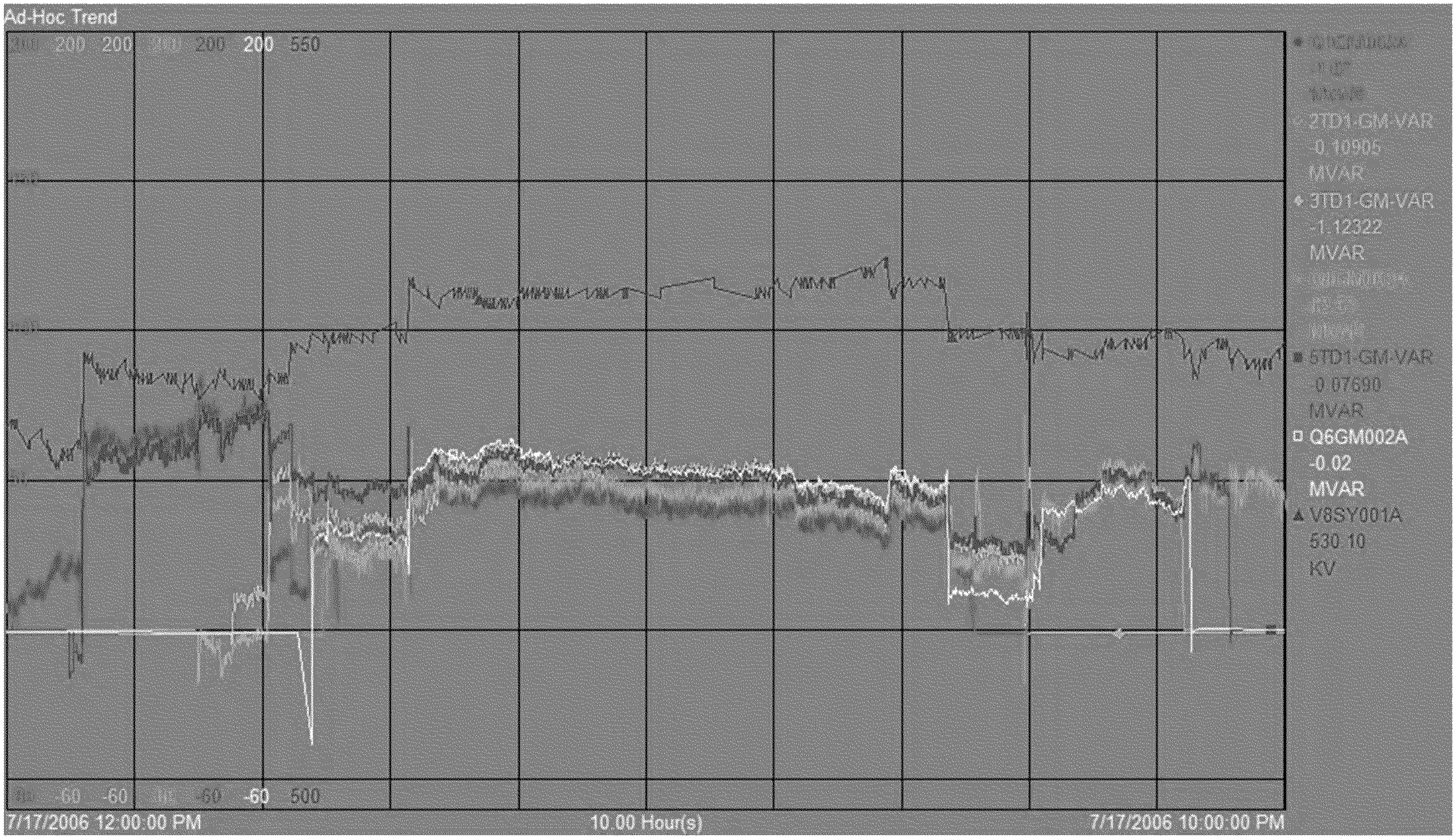


Synchronous Condensing - 7/17/2006



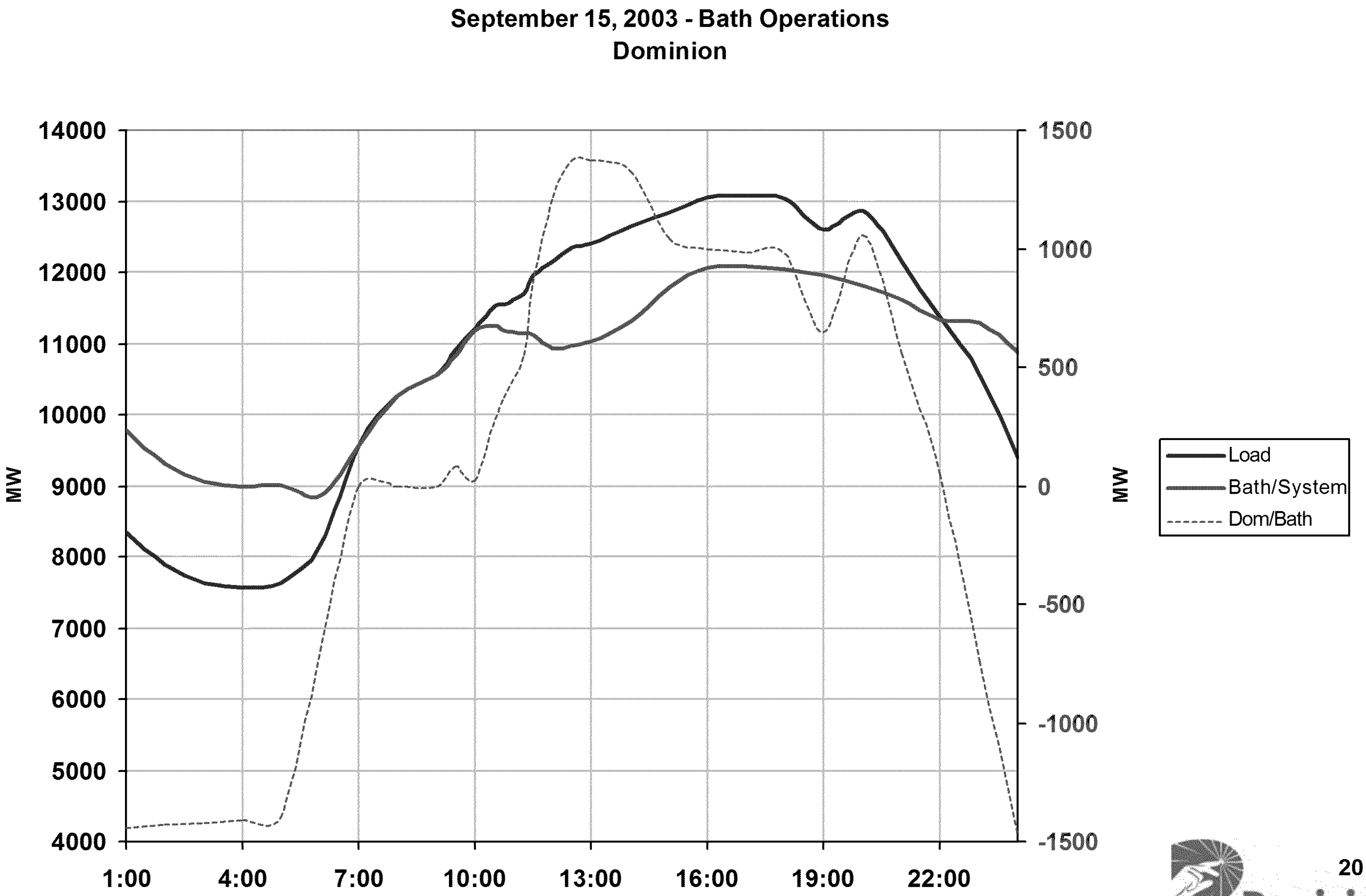
Dominion

Voltage Support - 7/17/2006



Dominion

Dominion System - Bath Load Leveling



Dominion

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Flexibility

- Reliable Capacity Resource
  - Drought impacts
    - Typically minimal to none
    - 21 years of operation - no impact from droughts
- Reliable Responsive Energy Resource
  - Intermediate resource - with peaking capabilities
- Flexibility Examples - Hurricane
  - Loss of Transmission Systems
    - Difficult to predict load
    - 500kv very robust
    - Generators islanded
  - Put Bath at mid pond and used to balance load against highly variable generation availability / load requirements
    - Analogous to renewables

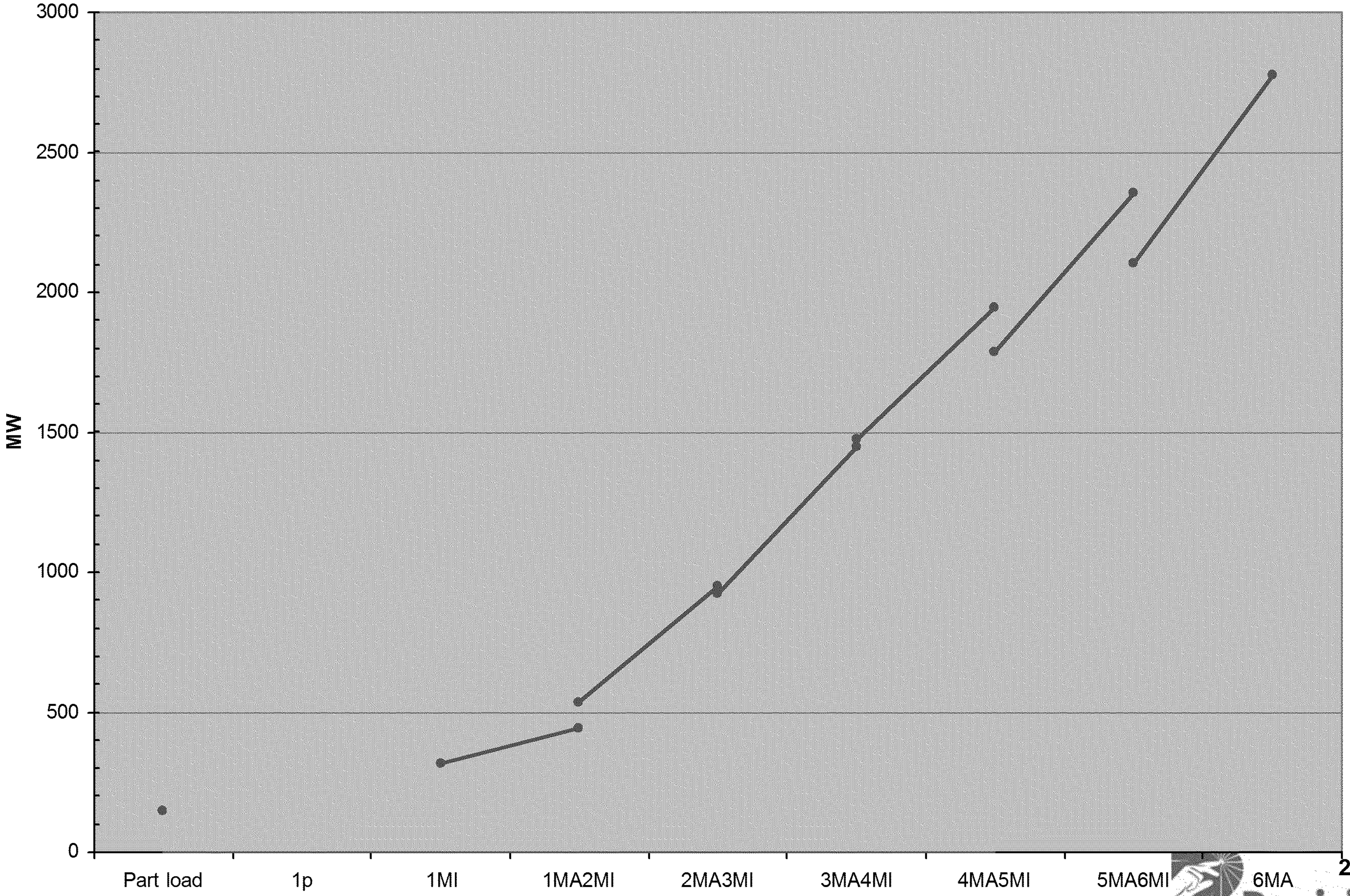
Dominion

Pumped Storage in PJM: LMP based RTO

- Energy can be:
  - Self scheduled
  - Bid into market
  - PJM Pumped Storage optimized schedule
- Optimize power pool usage over daily / weekly cycles
- Operates every day in both modes
  - Typically dispatches ahead of Combined Cycle Resources
- Regulation bid into market on an hourly basis
- Moving towards PJM Spinning Reserve Market
- Moving towards PJM Forward Capacity Market (RPM)
- Bath is a creator and solver of ACE issues
  - Working with RTO to help them utilize full capabilities of resource

Dominion

Station Bandwidth-Full Pool- 2006 (3/3)



Dominion

Summary

- Efficient, flexible resource
- Can be tailored to meet all stakeholder needs
- Potential to be used as a technology to integrate less predictable energy resources into the grid
- Enhances grid reliability
- Optimizes thermal generation - improves performance

Dominion

Attachment 5

KEMA's Storage Report for the CEC

Arnold Schwarzenegger
Governor

RESEARCH EVALUATION OF WIND GENERATION, SOLAR GENERATION, AND STORAGE IMPACT ON THE CALIFORNIA GRID

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
KEMA, Inc.

June 2010
CEC-500-2010-010

Prepared By:
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David Hawkins and Yagnik, Kunjal, California Independent System Operator Corporation,
Commission Contract No. 500-06-014
Commission Work Authorization No: KEMA-06-024-P-S

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Melissa Jones
Executive Director

PUBLIC INTEREST ENERGY RESEARCH
"Research Powers the Future"

Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

- PIER funding efforts are focused on the following RD&D program areas:
- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Research Evaluation of Wind and Solar Generation, Storage Impact, and Demand Response on the California Grid is the final report for the *Facilitation of the Results Gained from the Research Evaluation of Wind Generation, Storage Impact, and Demand Response on the CA Grid* project (Contract Number 500-06-014, Work Authorization Number KEMA-06-024-P-S) conducted by KEMA, Inc. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

Please use the following citation for this report:

KEMA, Inc. 2010. *Research Evaluation of Wind and Solar Generation, Storage Impact, and Demand Response on the California Grid*. Prepared for the California Energy Commission. CEC-500-2010-010.

Table of Contents

List of Figures

List of Tables

Abstract

This report analyzes the effect of increasing renewable energy generation on California's electricity system and assesses and quantifies the system's ability to keep generation and energy consumption (load) in balance under different renewable generation scenarios. In particular, researchers assessed four key elements necessary for integrating large amounts of renewable generation on California's power system. Researchers concluded that accommodating 33 percent renewables generation by 2020 will require major alterations to system operations. They also noted that California may need between 3,000 to 5,000 or more megawatts (MW) of conventional (fossil-fuel-powered or hydroelectric) generation to meet load and planning reserve margin requirements.

The study examines the relative benefit of deploying electricity storage versus utilizing conventional generation to regulate and balance load requirements. To reach storage's full potential, researchers developed new control schemes to take advantage of higher response speeds of fast storage, examined storage performance requirements, and noted maximum useful amounts to meet both regulation and balancing requirements. Researchers also noted the effectiveness of storage technologies, in comparison to conventional generation, to meet energy systems' need to accommodate large output changes of energy resources in a relatively short period.

The report provides policy and research options to ensure optimum use of electricity storage with the associated increase in renewable generation connected to the system.

Keywords: Renewable energy, solar, wind, energy storage, integration, AGC, ACE, ancillary services, frequency regulation, balancing, ramping, RPS, grid, independent system operator

Executive Summary

Introduction

The integration of renewable energy resources into the electricity grid has been intensively studied for its effects on energy costs, energy markets, and grid stability. These studies all conclude that the variability and high-ramping characteristics of renewable generation create operational issues. However, there have been few efforts to precisely quantify these effects with a highly dynamic model that simulates system performance on a time scale of one second or less, compared to a one-hour basis that is typical in production cost simulations. This study constitutes such an effort.

Project Purpose

This research identifies key issues and assesses the effects of high renewable penetrations on intra-hour system operations of the California Independent System Operator (California ISO) control area. It also looks at how grid-connected electricity storage might be used to accommodate the effects of renewables on the system. To do this, researchers used high-fidelity modeling to analyze the effects of planned additions of renewable generation on electric system performance. The research focuses on required changes to current systems to balance generation and load second-by-second and minute-by-minute, and to do so in the most cost-effective manner.[1] The study also assessed potential benefits of deploying grid-connected electricity storage to provide some of the required components—including regulation, spinning reserves,[2] automatic governor control response[3], and balancing energy—necessary for integrating large amounts renewable generation.

Project Objectives

The objective was to measure the effects of the variability associated with large amounts of renewable resources (20 percent and 33 percent renewable energy) on system operation and to ascertain how energy storage and changes in energy dispatch strategies could accommodate those effects and improve grid performance. This project used a new modeling tool—KEMA's proprietary KERMIT model, which employs a dynamic model of the power system and

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[1] Automatic generation control operates the generators that supply regulation services (up and down) every 4 seconds to keep system frequency and net interchange error as scheduled. The *real-time dispatch* buys and sells energy from generators participating in the real-time or balancing market every five minutes to adjust generator schedules to track a system's load changes.

[2] Regulation in MW is the amount of second-by-second *bandwidth* or controllability used in balancing generation and load. Spinning reserve is the excess amount of on-line generation capacity over the amount required to supply load and available to respond to sudden load changes or loss of a generator.

[3] Governor response is the near-instantaneous adjustment of each generator's output in response to system frequency changes, caused by the generator speed-governing device.

generators—to assess the electricity system's performance in one-second to one-day time frames using techniques that captured the full range of system dynamic effects.

Specific objectives of the research were as follows:

1. Calibrate the dynamic model—using existing electricity-generation-fleet capacities, actual daily schedules, loads, interchange, area control error,[4] and frequency data provided by the California ISO on four-second and one-minute bases as described below—and extend that model to 2012 and 2020 time frames with 20 percent and 33 percent renewables portfolio standard levels. Assume planned changes to the generation fleet (retirements, upgrades) and renewable capacities per current California Public Utilities Commission-developed forecasted portfolios and state forecasts for load growth.
2. Assess droop, ancillary services, and balancing needs[5] with current system controls.
3. Assess the effect of increased storage and regulation and balancing on system performance.
4. Examine automatic generation control[6] algorithms for storage.
5. Determine the relative benefits of different amounts of storage.
6. Determine storage characteristic requirements.
7. Determine the storage-equivalent of a 100-megawatt (MW) gas turbine.
8. Identify issues with incorporating large-scale storage in California.

Outcomes

Project outcomes, in the order of project objectives, are as follows:

1. The model was successfully calibrated to match historical data.
2. System performance degraded, in terms of maximum area control error excursions and North American Electric Reliability Corporation control performance standards, significantly for 20 percent renewables penetration and became extreme at 33 percent

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[4] Area control error is the deviation from scheduled interchange power flows (in MW) plus the system bias (a constant) times the deviation in system frequency, as defined by the North American Electric Reliability Coordinator.

[5] Droop is the gain on the generator's local speed-governing device, that is, how sensitive the generator's output is to changes in system frequency. Ancillary services are those services that generators *sell* to the California ISO to enable system reliability and to follow load. Balancing energy is the energy the California ISO buys and sells every five minutes via real-time dispatch to follow load.

[6] Automatic generation control is the computer system at the California ISO that controls the generators in real time to balance load and generation second-by-second

renewables penetration, using the same automatic generation control strategies and amounts of regulation services as today. Without adjustment to the automatic generation control and the amount of regulation procured maximum area control error excursions went from a typical band today of the order of ±100 MW to several times that in the 20 percent renewables scenario and to as much as 3,000 MW of error in the 33 percent scenarios. Such an excursion is not tolerable and would possibly cause other system protective devices to operate such as interrupting transmission flows to adjacent power systems.

3. The amount of regulation, without storage and using existing control algorithms, required to maintain system performance within acceptable limits for a 20 percent renewable case in 2012 was ±800 MW in the up and down direction, roughly double today's amount.[7]
4. The amount of regulation and imbalance energy dispatched in real time, without storage and using existing control systems to maintain system performance, within acceptable limits during morning and evening ramp hours for 33 percent renewable cases in 2020 was 4,800 MW. The amount of regulation and imbalance energy dispatched in real time, without storage and using existing control algorithms, to maintain system performance within acceptable limits during non-ramp hours to address system volatility for the 33 percent renewable cases in 2020 was approximately an additional 600 MW. By comparison, 1,200 MW of storage added to the baseline 400 MW of regulation provided superior results by comparison. (See Table 1).
5. Generally, the largest deviations in system performance occurred twice per day, once during the morning and once during the evening, corresponding to the interaction of diurnal production of wind and solar resources and fluctuation of demand. Accordingly, degradation of system performance appears to be predominantly caused by renewable ramping in the morning and evening along with traditional morning and evening load ramps.
6. Increasing regulation amounts, without the use of storage and improved control algorithms, can improve system performance. However, roughly 2-to-10 times the amount of today's regulation and balancing capacity would be required to maintain system performance absent other operating protocols, such as limiting ramp rates and new services that could be developed as alternatives to address renewable ramping as well as scheduling and forecasting errors.
7. Adjustments to the droop settings of generators from the current 5-10 percent had little effect on system performance.
8. Design changes to the automatic generation control mathematics and calculations allowed the automatic generation control to make better use of the higher response

[7] Regulation in MW is the amount of second-by-second *bandwidth* or controllability, California ISO-procured from participating generators, used in balancing generation and load.

speed of the storage devices and resulted in better system performance with less overall regulation procured.

9. Large-scale storage can improve system performance by providing regulation and imbalance energy for ramping or load following capability. The 3,000 to 4,000 MW range of fast-acting storage with a two-hour duration achieved solid system performance across all renewable penetration scenarios examined. (The range 3,000-4,000 MW reflects the different days studied and the levels of incremental storage simulated, for example, 3,200 MW, 3,600 MW, and so on.)
10. Existing battery technologies appear to have the capabilities required to manage renewable integration, including two-hour durations and ramping capabilities of 10 MW/second or greater.
11. On an incremental basis, storage can be up to two to three times as effective as adding a combustion turbine to the system for regulation purposes. The relative effect of each depends on how much storage or regulation and balancing is already in the system. For example, when the system has sufficient resources for stabilizing system performance, the incremental benefit of either technology approaches zero. This is an incremental ratio of the effect a combustion turbine or a storage device each have on system performance, and not an indicator of how much total capacity of each technology may be needed to manage the large ramping phenomena.
12. Without the use of storage, ramping of combustion turbine generators and hydro-electric generation is likely to increase. This may likely have detrimental effects on equipment maintenance costs and life of the equipment, and greenhouse gas emissions because the resources will be asked to generate more often at less than optimal production ranges as well as to remain *committed*—that is, on-line—in anticipation of ramping needs.

Conclusions

Governors' executive order S-14-08 established a goal of 33 percent energy from renewable resources to serve California customer load by 2020. This will require significant increases in ancillary services (regulation) and real-time dispatch energy, with attendant changes in the day ahead schedules of generation production by hour to ensure that such services are available—that is, that enough generators will be on-line with excess capacity available during each hour. Such a change in scheduling practice will incur additional economic costs in the production of power. The use of storage in conjunction with new control and generation ramping strategies offers innovative solutions that are consistent with the need to continue to comply with current North American Electric Reliability Corporation system performance standards. Electricity storage promises to be a useful tool to provide environmentally benign additional ancillary service and ramping capability to make renewable integration easier. However, while this report concludes that the system flexibility provided by storage is more efficient than equivalent conventional generation capacity, it has not performed a comparative cost-benefit analysis either in terms of fixed capital or variable costs.