CONF-920916--5

PNL-SA--20600

DE93 007868

BENEFIT/COST COMPARISONS OF SMES IN SYSTEM-SPECIFIC APPLICATION SCENARIOS

J. G. De Steese
D. K. Kreid
W. E. Myers
J. E. Dagle
J. M. Haner

September 1992

Presented at the
3rd International Conference
and Exhibition
September 14-18, 1992
Munich, Germany

Prepared for
the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

Pacific Northwest Laboratory
Richland, Washington 99352

BENEFIT/COST COMPARISONS OF SMES IN SYSTEM-SPECIFIC APPLICATION SCENARIOS

John G. De Steese, Jeffery E. Dagle and Dennis K. Kreid

Pacific Northwest Laboratory
Richland, Washington 99352(a)
USA

John M. Haner and Walter E. Myers

Bonneville Power Administration
Portland, Oregon, 97208
USA

ABSTRACT

The inherently high storage efficiency, instantaneous dispatch capability and multi-function uses of superconducting magnetic energy storage (SMES) are attributes that give it the potential for widespread application in the electric utility industry. Opportunities appear to exist where SMES at a given location could provide multiple benefits either simultaneously or sequentially as system conditions dictate. These benefits, including diurnal storage and system stability and dynamic control enhancement, increase the application potential of SMES to a larger number of opportunities than might be justified by the value of its diurnal storage capability alone. However, the benefits an individual utility may realize from SMES applications are strongly influenced by the characteristics of the utility system, the location of the SMES unit and the timing of its installation in the system. Such benefits are typically not evaluated adequately in generic studies. This paper summarizes results of case studies performed by Pacific Northwest Laboratory (PNL) with funding provided by the Bonneville Power Administration (BPA) and the Electric Power Research Institute (EPRI). The derivation of SMES benefits and costs are described and benefit/cost (B/C) ratios are compared in system-specific scenarios of interest to BPA. Results of using the DYNASTORE production cost model show the sensitivity of B/C ratios to SMES capacity and power and to the forecast system load. Intermediate-size SMES applications which primarily provide system stability and dynamic control enhancement are reviewed. The potential for SMES to levelize the output of a wind energy complex is also assessed. Most of the cases show SMES to provide a positive net benefit with the additional, sometimes surprising indication, that B/C ratios and net present worth of intermediate-size units can exceed those of larger systems.

BACKGROUND

The future structure of the utility industry in the United States is being shaped by many influences already at work. For example, combustion turbines (CT's) are being installed in large numbers to meet increasing daytime peak loads, while efficient base-load generation is under-utilized at night. Environmental restrictions and the cost of new generation and transmission

---

(a) Operated by Battelle Memorial Institute for the U.S. Department of Energy under Contract DE-AC06-76RLO-1830.

construction are among factors that motivate utilities to improve the functional efficiency of existing systems. If utilities approach this goal by operating with lower reserve margins and nearer to the absolute power transfer limits of the system, new stability, reliability, and peak load management problems are expected to result. These difficulties would be magnified by anticipated escalation in the price of natural gas, which is being used for peak power production in increasing quantities.

SMES is an efficient and instantly dispatchable electric energy storage technology. At present, small-scale, transportable SMES units, with capacities of a few hundred watt-hours, are entering commercial use as devices that improve end-use power quality (1). The development of much larger site-built units, with capacities ranging from tens to thousands of megawatt-hours (MWh), could find widespread utility application as an economical solution to many of the above operational problems.

While SMES principles and generic designs together with generic costs and benefits are well-documented (2-8), information on system-specific benefits is scarce. Achieving an industry-wide awareness of SMES potential is a necessary step in building a "critical mass" of utility support for the development of large-scale SMES technology. However, the actual SMES benefits that might be realized by an individual utility are expected to be highly dependent on system characteristics and operations and also on the location of SMES in the system. Such system-specific benefits cannot be fully evaluated on the basis of available generic information. The need for additional system-specific analysis to promote the industry's awareness of these benefits is an incentive for the work summarized below.

METHODOLOGY

SMES benefit values are estimated from the annual worth of avoided capital and energy costs hypothetically provided by SMES in each application scenario. The principal benefit provided in the large unit scenarios is the ability to reduce electricity production costs by displacing more expensive thermal peaking plants. All SMES units evaluated are considered capable of providing system stability and dynamic control enhancement. Other benefits, including reliability and operational enhancement of transmission lines, enhancement of automatic generator control (AGC) systems and system R&D values are credited in each case, as appropriate. The total of all benefits in a given case are combined and accrue at a constant annual rate for the 30-year equipment life period.

In each scenario, costs of the energy storage components and power conditioning system (PCS) are estimated separately. Figure 1 shows the energy-related capital cost versus stored energy relationships used in this analysis. These curves are adapted from those published by Luongo and Loyd (12) for storage capacity in the range 100 MWh to 10,000 MWh, constructed in hard rock and soil. Below 100 MWh, the referenced curves are extrapolated using a 0.5 exponent to account for increasing SMES cost per kilowatt-hour as unit size decreases. Information from electrical equipment vendors established the economy-of-scale in the power-related capital cost shown in Figure 2. This downward trend in PCS cost per kilowatt is incorporated into the capital cost model.

The total annual cost of the SMES unit is the levelized capital and annual operation and maintenance (O&M) cost combined. The levelized annual capital cost of the SMES plant is assumed equal to the fixed annual payment that would repay the installed cost over 30 years with the 4.6% real discount rate recommended for cost analysis of Federal projects (13). Fixed O&M costs of SMES are assumed to be $10/kW-yr (14). A variable SMES operating cost of $1/MWh (14) and refrigeration energy consumption (12) are included as production costs. These are subtracted from estimated electricity production benefits giving the net production benefit. All benefit values and costs are converted to 1992 dollars using the GNP implicit price deflator (15). The levelized annual cost includes allowance for funds used during construction (AFUDC), assuming a linear funding rate during the construction period and construction time scaled on the basis of stored energy capacity, as reported by Schoenung, et al (8).

CASE STUDIES

Case studies were performed to estimate and compare annual benefits and costs of SMES applications in the BPA service area and on utilities that connect or exchange power with the BPA system. A primary objective of these studies is to refine and expand analyses of SMES scenarios reported previously (9-11). Table 1 summarizes the benefit and cost analyses of the five case studies reviewed below.

SCENARIO 1

In Scenario 1, a large SMES unit is located west of the Cascade Mountains and provides a number of generation benefits in the Puget Sound area including daily dispatch of energy to supply a portion of the area's peak load, emergency peak load management and spinning reserve. If built with capacity and power in excess of these requirements, the unit could also be used for voltage support, transient damping and stability enhancement.

The diurnal storage benefits were estimated using DYNASTORE, a computer-based production cost model developed by EPRI. The model computes the annual system production cost both with and without SMES. This is achieved with heuristically-applied rules to compute the least-cost, hourly dispatch of generation resources to supply a given load. The benefit due to SMES is the difference in the total production cost of the two cases. The system-descriptive input, forecasted loads and load shapes required to run DYNASTORE was taken from the database BPA uses to run its Power Market Decision Model (PMDAM). DYNASTORE also includes the variable O&M cost, refrigerator load and the round-trip efficiency associated with the SMES unit. However, DYNASTORE does not include other diurnal storage benefits such as the avoided capacity cost or annual fixed O&M of alternative generation capacity. These benefits are estimated separately using input consistent with PMDAM data and added to the total.

Many combinations of SMES capacity, power and commissioning year were simulated using the DYNASTORE code, to determine the optimum size for a SMES unit providing diurnal storage functions in the Puget Sound area. A net annual benefit was calculated for each case as the total of the annual net production cost difference reported by DYNASTORE and the other benefits associated with SMES that are not included in the DYNASTORE simulation, as described above. The displaced thermal capacity credit is calculated based on the observed difference in annual unit commitment between the SMES dispatch case and the case without SMES. The capital cost of the SMES unit and corresponding fixed O&M cost are calculated on the basis of the maximum observed stored energy and power indicated by output of the DYNASTORE simulation.

Based on available load and load shape forecasts, the first time SMES can make a significant contribution in the Puget Sound area is in the year 2015. Figure 3 shows the net annual levelized benefit and net present worth of 22 DYNASTORE-derived cases that span the SMES capacity and power range from 200 MWh to 5000 MWh and from 500 MW to 1500 MW, respectively. The quasi-optimum SMES capacity and power that provide the least-cost dispatch of diurnal storage and spinning reserve are 1040 MWh and 1000 MW, as shown in Figure 3. Figure 4 shows the DYNASTORE-derived hourly dispatch schedule for the diurnal storage function of this unit during a typical week in January 2015. The maximum power shown is about 500 MW and is required during the charging process. The power capability to provide the spinning reserve benefits accounts for the remainder of the 1000 MW rating of this unit.

As shown in Table 1, total annual benefits amount to $75 million which exceed the estimated annual cost either rock or soil construction by a large margin. The corresponding benefit/cost ratios are 1.67 and 1.44, respectively. The benefits and costs shown are for a 1200 MWh/1500 MW SMES unit to accommodate the additional capacity and power needed to provide benefits not estimated by DYNASTORE, including stability enhancement and dynamic control capabilities. An increase in capacity and power of 160 MWh and 500 MW, respectively, over the 1040 MWh/1000 MW case is required to provide these additional benefits.

This analysis uses the year 2015 as a proxy for estimating total annual benefits for the life of the equipment, which is also the year in which the unit first demonstrates cost-effective operation. However, since area load would probably continue to grow after this commissioning date, an increase in SMES benefit potential would also occur in future years. Therefore, a unit of still larger capacity and power, commissioned in 2015, would be needed to maximize the net present worth of the project over its projected 30-year life.

SCENARIO 2

This scenario considers a second large SMES unit (7000 MWh, 1400 MW) that might be justified in the Pacific Northwest as an energy depot to manage Canadian Entitlement Power (CEP). This need could arise with the expiration of agreements between the United States and Canada regarding hydropower generated at U.S. dams on the Columbia River system (9). Beginning in 1998, Canada might require the return of 700 MW, rising to 1400 MW by the year 2010. A SMES unit could be beneficial in storing off-peak energy so that CEP could be returned to Canada or wheeled on a schedule beneficial to the parties involved. The unit could be dispatched to avoid conflict with peak conditions and transmission limitations of the Pacific Northwest system.

In a search for additional benefits, this SMES scenario was evaluated as a adjunct to the wind energy system concepts studied by the Pacific Northwest Utilities Conference Committee (PNUCC). The PNUCC considered two wind farm scenarios (a 500-MW and a 3000-MW case) located near Browning, Montana (16).

The SMES unit would store energy during times of peak production and discharge during wind-still periods. A major objective of levelizing the wind energy output would be to gain (in the case of the 3000-MW case) a $300 million reduction in the cost of the transmission system needed to deliver wind-derived power to load centers in the Northwest. With SMES, the necessary transmission system additions could be sized for the average output of the wind farm rather than for its peak output. A computer model was developed to follow the hour-by-hour charge and discharge history of a SMES system located near the wind energy complex. When exercised with the hourly plant output derived from wind speed data from the site, the model indicated that little value was achieved with SMES capacity in the 2000 MWh to 8000 MWh capacity range. The character of the wind resource in this region would require SMES capacity as large as 200,000 MWh to fully levelize the output of a 3000-MW wind farm. Such capacity would be prohibitively expensive and not capable of justification by any combination of anticipated benefits.

While the above application of SMES is not economically viable, two alternative SMES benefits were suggested by the results of this analysis. First, variations in the output of the wind farm might be compensated by CT's fueled by cheap, local natural gas. A small SMES with a 20-MWh to 40-MWh capacity might be sited near the wind farm to maintain power output during each ramp-up period of the CT's. The second alternative is to site the SMES unit of Scenario 2 at Garrison, Montana, where the line from Browning would join the grid. At this location, a large SMES could provide the multiple benefits of diurnal energy storage both from the wind farm and the Colstrip plants. There also appears to be seasonal synergism between these resources, since the wind farm produces excess power in the winter and Colstrip typically is set-back during off-peak periods in the summer.

Developing this second alternative, a 7000 MWh/1400 MW SMES unit located at Garrison, Montana could provide CEP storage, wind-farm integration and Colstrip night-setback reduction benefits, as well as the diurnal storage and stability enhancement benefits common to all of the large SMES cases reported previously (11). Table 1 shows that annual benefits totalling $99 million are not quite large enough to justify the $104 million annual cost for the rock construction case or the $118 million annual cost for the soil construction case. However, DYNASTORE simulation has yet to be performed with this scenario. It is likely that the chosen case is far from optimum and that optimizing the unit's capacity would show a more favorable benefit/cost ratio from improved utilization.

SCENARIOS 3 AND 4

The BPA transmission system could benefit from a unit located near Hanford, Washington, with about 20-MWh storage capacity to enhance system stability and manage short-duration, large-magnitude swings in the system's power demand. Credit is also taken for VAR control and savings of O&M cost contributed by the extra wear and tear on hydropower generators that are otherwise ramped rapidly to achieve the same purpose.

Scenario 3 is a unit with 20 MWh storage capacity and 400 MW power handling capability. In Table 1, the 10.5-million annual value of benefits compare with annual costs of $7.7 million to provide a 1.36 benefit/cost ratio for the rock construction case. The soil construction case, with annual costs of $8.4 million, has a benefit/cost ratio of 1.25.

Scenario 4 is for a unit of similar storage capacity (20 MWh) but with 1200 MW charge/discharge capability to handle larger swings and transients. The corresponding benefit/cost ratios are 2.37 and 2.23 for the rock and soil construction cases, respectively.

SCENARIO 5

The final scenario is a large SMES unit attached to the Pacific DC Intertie at Sylmar, California. The 15,000 MWh system would be rated at the 3,100 MW transmission capacity of the intertie for contingency load pickup. The unit would provide operational flexibility and system stability in conjunction with the Los Angeles Department of Water and Power system. About 10,000 MWh of its diurnal energy storage capacity would supply 2,000 MW of Southern California's peak load and provide contingency spinning reserve. SMES is credited with a 15-mills/kWh production cost difference on the basis of an average 10,000 MWh weekday operation.

Using similar analysis as before, the estimated $214 million value of annual benefits is larger than the $177 million annual cost for the rock construction case. The benefit to cost ratio for this scenario is 1.21. A benefit to cost ratio of 0.95 for this scenario constructed in soil is less than unity, indicating that the potential unavailability of a hard rock site has more influence on the viability of this scenario than other considerations.

CONCLUSIONS

The quasi-optimum, 1200-MW unit in Scenario 1, has less than a sixth of the capacity originally considered applicable in this case. While the actual optimum capacity would tend to be larger than this to accommodate later load growth, the smaller unit provides a larger net annual benefit and net present worth than all the larger cases considered in this scenario. This advantage was identified by simulation using the DYNASTORE model and probably would not have been discovered by the simple analysis used in earlier work. The higher benefit/cost ratios of the smaller units simulated in Scenario 1, together with the refined results of Scenarios 3 and 4, show that benefit/cost ratios of intermediate-size units can exceed those of larger systems. This modifies conventional wisdom that the economy-of-scale in the cost of SMES capacity generally favors application of the largest units.

The cases studied provide a general indication that SMES may be viable on other utility systems. Because of the region's large hydropower base and low-cost energy, SMES probably meets its most stringent viability test in the Pacific Northwest. Some of the benefits indicated in these case studies should increase in value on systems with little or no hydropower and higher energy costs.

The results of this study reinforce PNL's previous work in showing considerable variation in the indicated cost-effectiveness of SMES depending on the functions performed and system-specific conditions. System characteristics, location and the timing of SMES introduction control the viability of any SMES application scenario. Generic analysis would be blind to most of these influences. Utilities will need to conduct detailed, system-specific analysis to determine the value of SMES on their individual systems.

REFERENCES

1. Wall Street Journal. 1992. "Power Glitches Become Critical as World Computerizes." Article in May 18 Issue. Dow Jones and Company, Inc., Publisher.

2. Boom, R. W., J. J. Skiles, R. F. Bischke and D. J. Helfrecht. 1984. "Superconductive Energy Storage for Electric Utility Load-Leveling." Proc. 1984 American Power Conference.

3. Loyd, R. J., S. M. Schoenung, and T. Nakamura. 1986. "Structural Design of a Utility Scale Superconducting Magnetic Energy Storage Plant." Paper 869200, Proc. 21st Intersociety Energy Conversion Engineering Conference, American Chemical Society Publication.

4. Loyd, R. J., et al. 1986. Design Improvements and Cost Reductions for a 5000 MWh Superconducting Magnetic Energy Storage Plant. LA-10668-MS Part 2, Los Alamos National Laboratory, Los Alamos, New Mexico.

5. Loyd, R. J., S. M. Schoenung, T. Nakamura, W. V. Hassenzahl, J. D. Rogers, J. R. Purcell, D. W. Lieurance and M. A. Hilal. 1987. "Design Advances in Superconducting Magnetic Energy Storage for Electric Utility Load Leveling." IEEE Transactions on Magnetics, MAG-23 (2): 1323-1330.

6. Schoenung, S. M., R. C. Ender, and T. E. Walsh. 1989. "Utility Benefits of Superconducting Magnetic Energy Storage." Proc. 1989 American Power Conference.

7. Hassenzahl, W. 1989. "Superconducting Magnetic Energy Storage." IEEE Transactions on Magnetics, 25 (2): 750-758.

8. Schoenung, S. M., W. R. Meier, R. L. Fagaly, M. Heiberger, R. B. Stephens, J. A. Leuer and R.A. Guzman. 1992. "Capital and Operating Estimates for High Temperature Superconducting Magnetic Energy Storage. Proc. 1992 American Power Conference.

9. De Steese, J. G., and J. E. Dagle. 1990. Electric Utility Benefits of Superconducting Magnetic Energy Storage. PNL-SA-18353, Pacific Northwest Laboratory, Richland, Washington.

10. De Steese, J. G., D. K. Kreid, J. M. Haner and W. E. Myers. 1991. "Assessment of SMES Benefits in Electric Utility Applications." Proc. 1991 American Power Conference.

11. De Steese, J. G. and J. E. Dagle. 1991. "Benefit/Cost Comparisons for Utility SMES Applications." Proc. 26th Intersociety Energy Conversion Engineering Conference, American Nuclear Society Publication.

12. Luongo, C. A. and R. J. Loyd. 1987. "Superconducting Magnetic Energy Storage for Electric Utility Load Leveling: A Study of Cost vs. Stored Energy." _Proc. 1987 American Power Conference_.

13. Lippiatt, B. C. 1991. _Energy Prices and Discount Factors for Life-cycle Cost Analysis 1992_. NISTIR 85-3272-6, Revised October 1991.

14. Schainker, R. B. 1987. "A Comparison of Electric Utility Energy Storage Technologies." _Proc. ASCE Energy '87 Conference_, Atlantic City, New Jersey.

15. _Wholesale Power Rate Projections 1990-2011 and Historical Wholesale Power Rates 1940-1989_. Bonneville Power Administration, November 1990.

16. Watkins, K. M. et al. 1991 "Blackfeet Area Wind Integration Study." Pacific Northwest Utilities Conference Committee, Portland Oregon, August 1991.

TABLE 1. Case Study Benefit and Cost Summary

	Scenario Number				
	1	2	3	4	5
Benefits					
Displaced alternative thermal plant capacity (MW)	800	1000	-	-	2000
Capital construction credit	485	607	-	-	1214
Annual fixed O&M	22	27	-	-	54
Annual levelized cost of deferred thermal plant capacity	52	65	-	-	129
Net production cost savings (energy savings less variable cost)	11	18	-	-	39
System stability and power transfer enhancement	10	8	7.9	23.7	22
Operational enhancement (Colstrip setback, line protection)	-	6	-	-	20
Automatic generator control	1	1	1.0	1.0	2
Voltage support and equipment substitution	1	1	1.2	1.2	2
System R&D and testing	-	-	0.4	0.4	-
Total levelized annual benefits	75	99	10.5	26.3	214
Rock Construction Cost					
Energy storage capital cost	328	1143	39.2	39.2	1834
Power handling equipment	88	85	37.2	79.9	117
Total capital cost	416	1228	76.4	119.1	1951
Construction time (years)	5	6	3	3	7
Annual fixed O&M cost	15	14	2.5	3	31
Total levelized annual cost	45	104	7.7	11.1	177
Soil Construction Cost					
Energy storage capital cost	437	1333	49.8	49.8	2471
Power handling equipment	88	85	37.2	79.9	117
Total capital cost	525	1418	87	129.7	2588
Construction time (years)	5	6	3	3	7
Annual fixed O&M cost	15	14	2.5	3	31
Total levelized annual cost	52	118	8.4	11.8	225

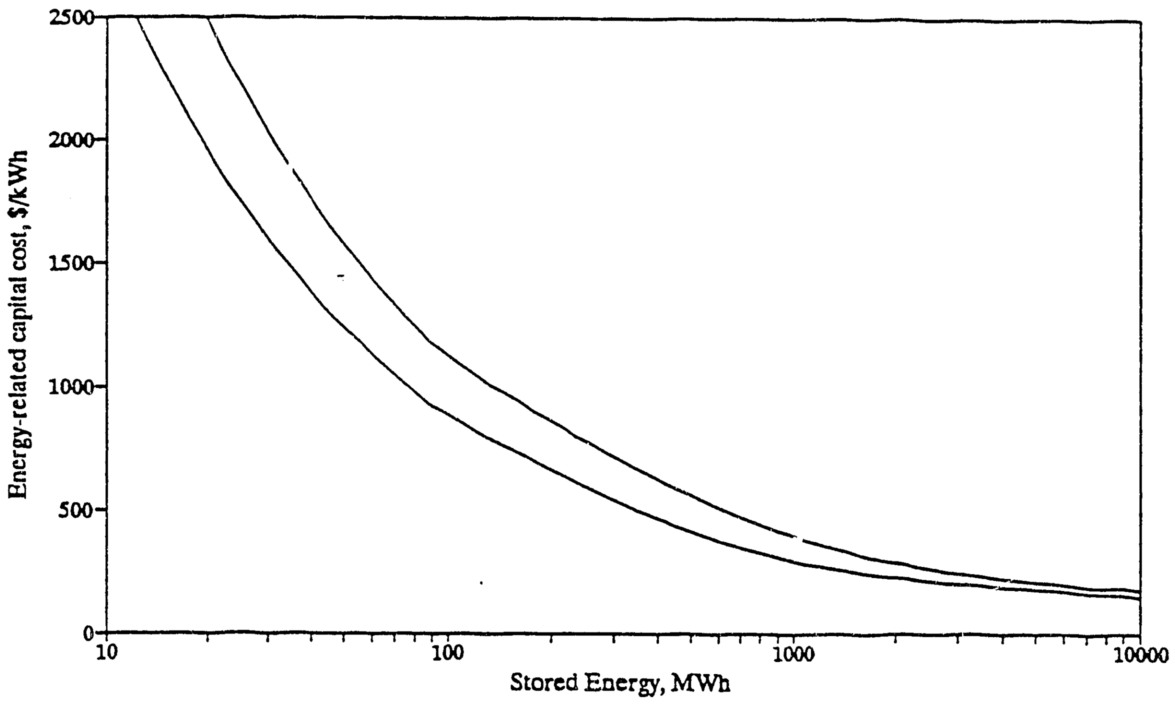

FIGURE 1. Energy-Related Capital Cost

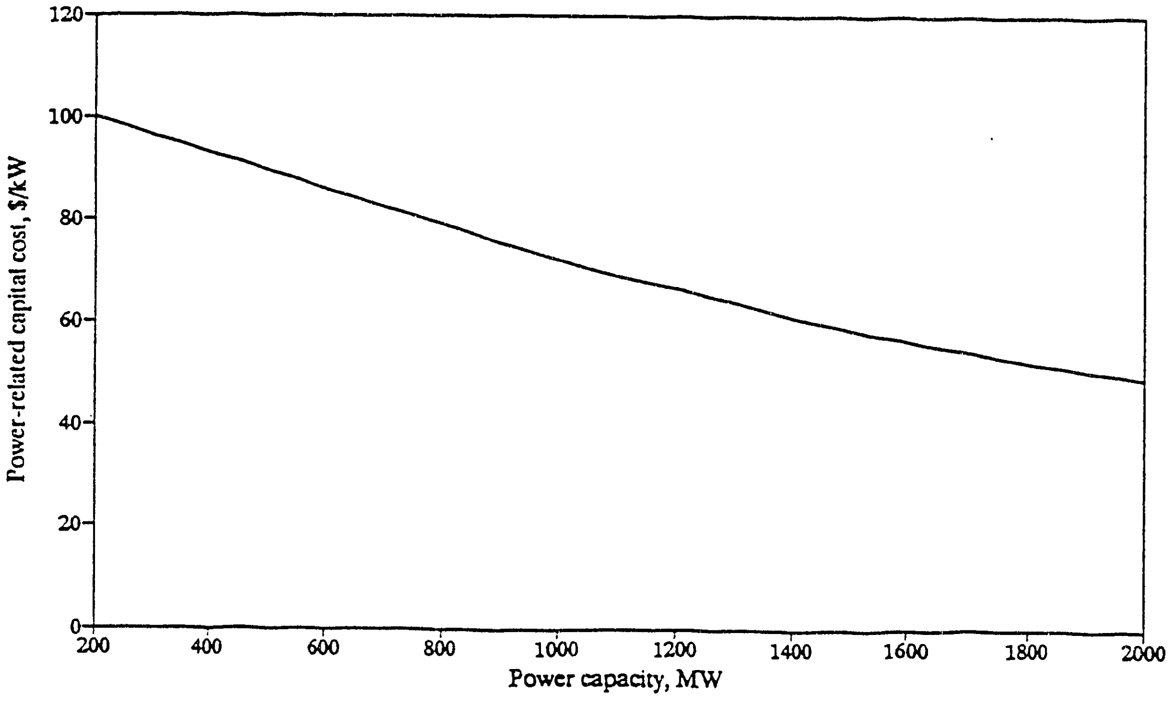

FIGURE 2. Power-Related Capital Cost

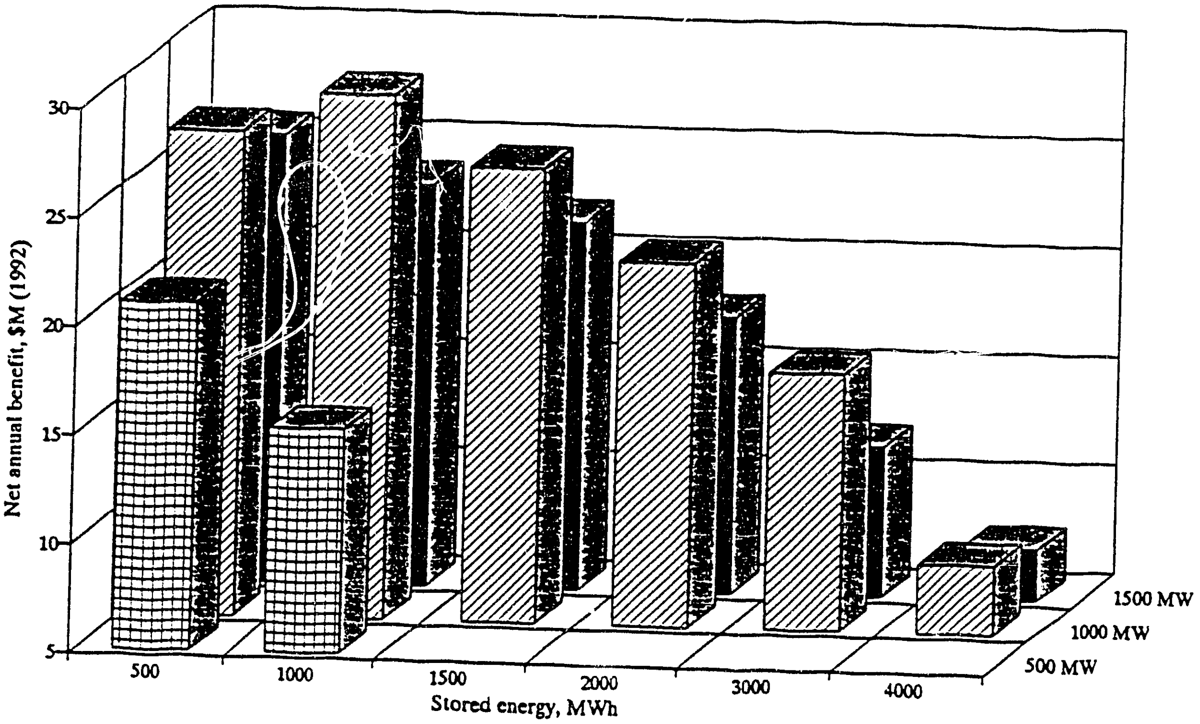

FIGURE 3. Net Annual Benefit of Scenario 1 Cases

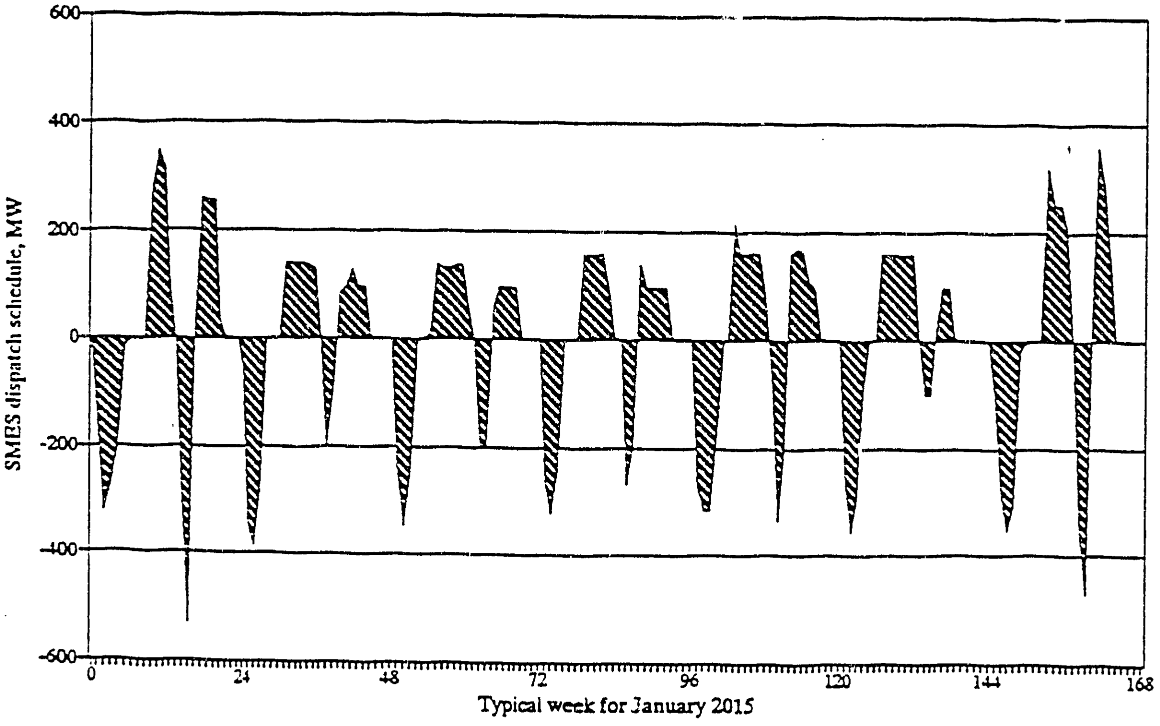

FIGURE 4. SMES Dispatch Schedule for Week in January 2015

END

DATE FILMED

5/6/93