PEAKING POWER GENERATION

Peaking Power Generation

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FOREWORD

Power plants for meeting peaking and mid-range demand economically have always been of interest to the utilities, much more so recently because of the scarcity of gas turbine fuels. Utility load factors, an indication of peaking generation requirements, after showing some improvement in the 1950s and 1960s, have declined again in the 1970s. Conservation measures such as rate restructuring and peak load pricing will tend to improve load factor while new technologies such as wind power and solar heating will exacerbate daily and seasonal electric demand peaks. The net effect on the load factor of conservation measures and new technologies is not clear, but projections for the nine National Electricity Reliability Council members for the 1980-1990 period show generation capacity growing at an annual rate of 4.5% and peak load at 5.2% annual rate. The summer of 1980, with prolonged hot weather for most of the country, has again underscored the vital importance of electric power availability. The scaled down national projections for peak load growth, the result of economic downturn, conservation, and mild weather, are now being drastically revised upwards. The peaking power symposium was intended to bring together papers on peaking power requirements for the eighties and the power generation facilities to meet these needs.

On the demand side, the influence of conservation, cogeneration, district heating, rate restructuring, as well as the introduction of solar, wind and other technologies, will have a pronounced effect on electric demand peaks. Unfortunately papers have not been submitted covering these topics, although a number of related studies have been completed and others are in progress. We suspect that the absence of such papers is due less to reserve on the part of forecasters and probably more to the fact that most such studies are carried out by mathematicians and economists, unaccustomed to attending ASME meetings. An opportunity for communication between the varied disciplines working in this very important area has been missed.

Power generation facilities to meet peaking demand were expected to be covered by papers on compressed air storage, pumped hydro, thermal storage, coal-fired plants with built-in peaking capability, district heating plants and innovative storage technologies. Compressed air storage plants are certainly well represented in the symposium and there are also papers on thermal storage and other storage technologies. Two papers on peaking generation built into baseload plants have not been made available in time to be included in the symposium, but there is one paper on the peaking generation capability of a district heating plant. It is interesting to note that at the "Conference on Peak-Load Coverage" in Budapest (November 1969), twenty-one papers were presented on peak power production from condensing power stations and district heating plants. Let us hope that the attractive peaking generation features of district heating plants will not be overlooked in this country, now that district heating is finally receiving some attention.

The symposium is intended to stimulate further discussion of future peaking power requirements and generation technologies to meet such needs. It was sponsored by the Power Division of the ASME.

E. S. Miliaras, Chairman
Energotechnology Corp.
Cambridge, Massachusetts

Brett C. Krippene, Co-Chairman
Stone & Webster Engineering Corp.
Denver, Colorado

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AIR STORAGE STSTEM ENERGY TRANSFER (ASSET) PLANTS FOR PEAKING

Z. S. Styś, Vice President
Brown Boveri Corporation
North Brunswick, New Jersey

ABSTRACT

Energy storage is becoming increasingly important, especially in energy management schemes, because it provides the capability of using off-peak power generated by highly efficient base-load units to supply peak period demands. Peaking power is usually generated by those units on a utility system that are least efficient and more costly to operate.

So far, only pumped-hydro energy storage has been able to satisfy the high-capacity requirements of the electric utilities. But sites for such plants are becoming increasingly scarce or are being ruled out by environmental considerations, so other energy storage methods are being actively considered, particularly in government-funded research projects.

Air storage plants have been discussed for almost three decades, but they have not been used because no suitable machine has been available for this unique application. The advent of high pressure machines made the Air Storage System Energy Transfer (ASSET) plants a commercial feasibility. So the world's first ASSET Plant was designed, constructed and commissioned in Huntorf near Bremen (F. R. Germany). This plant of the 300 MW class operates commercially since 1978. Future plants can be derived easily and adjusted for specific needs.

1. INTRODUCTION

The power generation patterns will probably change only comparatively slightly in the not too distant future. Nuclear and/ or large sophisticated fossil plants will constitute the bulk of base load electric power supply. Since these plants are very costly, although very efficient on the other hand, the goal to keep them loaded to the highest possible level at all times is undisputable. The low demand for energy at night makes this goal difficult, unless a suitable energy storage system is devised to allow shifting energy from the valleys to the peaks. ASSET plants can fulfill this goal without environmental impact as the pumped hydro plants. As mentioned, the first plant of this type, the 290 MW plant at Huntorf (near Bremen, F.R. Germany) has been in successful operation for over two years. Operational experience gives excellent results in terms of availability and flexibility. A second generation of such plant is being developed, with improved efficiency and larger energy transfer capability than the original Huntorf unit. Both 50 and 60 cycle modules of this improved unit are being designed.

2. ASSET CYCLE DIAGRAM

The Air Storage System Energy Transfer (ASSET) plant diagram is presented in Figure 1.

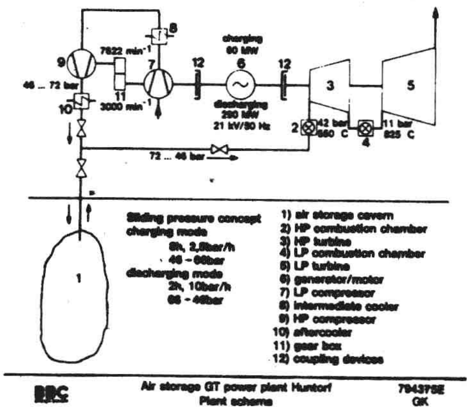


Figure 1

The ambient air is compressed by an axial-flow compressor, intercooled and boosted up in a high-speed centrifugal blower, to 72 bar. Aftercooling follows air discharge, before leading to the air storage facility. The generator is used as a motor during the compression cycle.

During the peaking cycle, air is led from the underground storage through a control valve, where the pressure is throttled down to 43 bar at full load before reaching the HP combustion chamber, where it is heated to 550°C. After passing through a portion of the expander, the gases are reheated in an LP combustion chamber to 825°C, and upon passing through the end of the expander, the gases are then exhausted to the atmosphere.

2.1 Basic Philosophy

The economic foundation of the ASSET plant was the applicability of the high pressure ratio gas turbine. The standard open cycle gas turbine operating with a pressure ratio of 1:10 was too low to make the air storage facility economical. A storage pressure of about 70 bar greatly reduced the necessary volume of such facility.

To avoid an excessively high pressure drop between the storage cavity and the first expansion stage, a high pressure turbine stage was added in front of the normal gas turbine, based on experience with a standard steam turbine design. The parameters of the gas entering the first stage of this expander are 42 bar and 550°C, i.e., parameters of a conservative steam turbine.

3. HUNTORF 290 MW ASSET PLANT

3.1 Concept

The Nordwestdeutsche Kraftwerke (NWK) of Hamburg, West Germany, ordered the world's first ASSET plant in June, 1974.

NWK power system supplies electric power in the coastal area of the Federal Republic of Germany (Figure 2). The company serves a population of some 4.5 million over an area of 34,000 square kilometers, i.e., about 1/7th of the entire Republic, and has an electricity demand growth rate of about 13% over the last 20 years. This value represents almost double of the average growth rate in Germany.

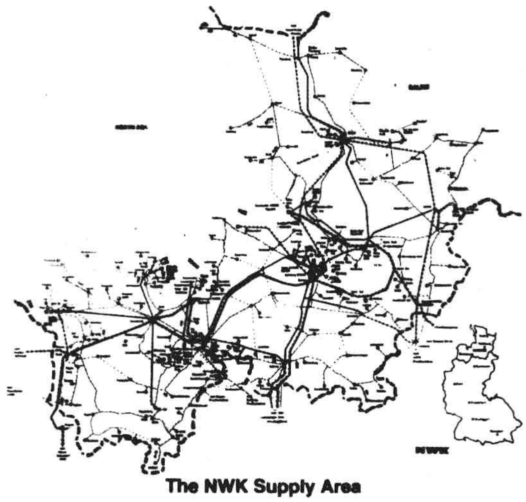


Figure 2

Some 5000 MW installed capacity can be divided into:

Nuclear	26%
Coal Plants	62%
Gas Turbines	6%
Huntorf ASSET Plant	6%

The NWK supply area is virtually flat and does not permit the installation of a conventional pumped hydro plant. The subsoil of North West Germany, however, contains about 200 salt domes. Most of these are very well suited and have partly been utilized for underground storage of mineral oil and natural gas.

Two caverns were leached in one of the salt domes to provide for 150,000 m^3 volume each, sufficient to cover 2 hours full load peak of the NWK system.

3.2 Construction & Commissioning

3.2.1 Cavern. The air storage facility in Huntorf was created by a well-known solution mining or leaching process, presented schematically in Figure 3.

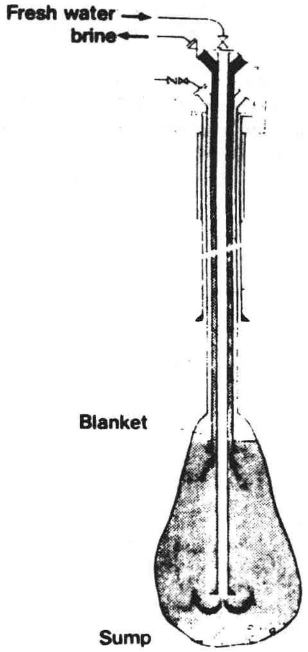


Figure 3

Two concentric pipes are introduced in a borehole. Fresh water pumped through the inner pipe dissolves the salt and becomes saturated with it. The resulting brine is pumped up the other pipe and then is taken directly to the sea or is disposed of in a salt water aquifer.

3.2.2 Plant Layout. The installation is a very simple one (Figure 4). The building has a crane which can service the heaviest piece with the exception of the generator stator. The machine house is 70 x 15 x 25 m and has a stack 35 m high. The installation is totally remotely controlled over a 100 km distance. There are no personnel in the plant.

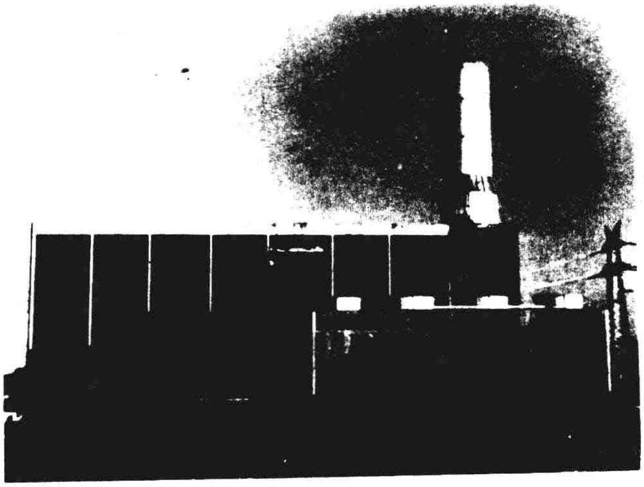


Figure 4

Figure 5 shows the site plan at Huntorf.

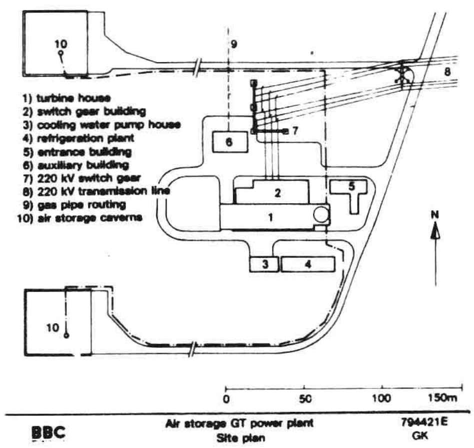


Figure 5

3.2.3 <u>Mode of Operation</u>. Figure 6 depicts start-up of the Huntorf plant. The plant is started remotely several times a day.

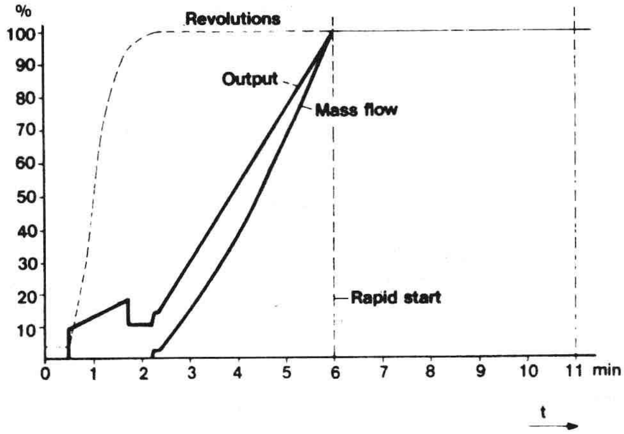


Figure 6

No electric start-up machine is necessary to start the unit. This is achieved by using the compressed air to start rotating the gas turbine shaft. At a certain speed the HP combustion chamber is ignited, the air heated to 1000°F and exhausted to the gas turbine. The gas turbine shaft accelerates and is, at a certain speed, automatically engaged, through a synchro-self-shifting (SSS) clutch, to the generator. The generator is then synchronized.

The start-up time (in minutes) can be subdivided as follows:

	Normal	Emergency
Preparation for start	.5	.5
Synchronize	3.0	3.0
To full load	7.5	2.5
TOTAL START-UP TIME	11.0	6.0

Slight shortening of total start-up time is possible.

The unit is started in the same manner in both the compression and generation cycles.

In the compression cycle, after coming up to speed, the motor-generator is synchronized, then the expander is disconnected and, finally, compression commences as energy is taken from the grid.

3.2.4 <u>Performance; Partial Load Heat Rate</u>. As shown in Figure 7, the heat rate at partial load of ASSET is much better than the partial load heat rate of a conventional combustion turbine, because with ASSET, mass flow control is possible whereas the combustion turbine circulates the same amount of air at all times.

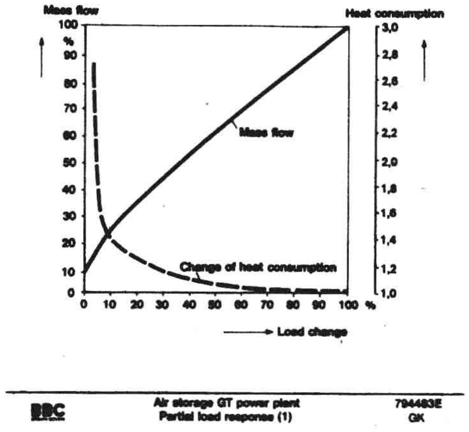


Figure 7

3.2.5 <u>Possibility and Frequency of Utilization of the Plant</u>. The best possibility of utilizing the Huntorf plant presents itself in Winter, since there are great differences in demand at night as compared to the daytime in Northern Germany.

Figure 8 depicts the operation of Huntorf on January 22, 1979. This chart itself shows three different possibilities of utilization of this plant:

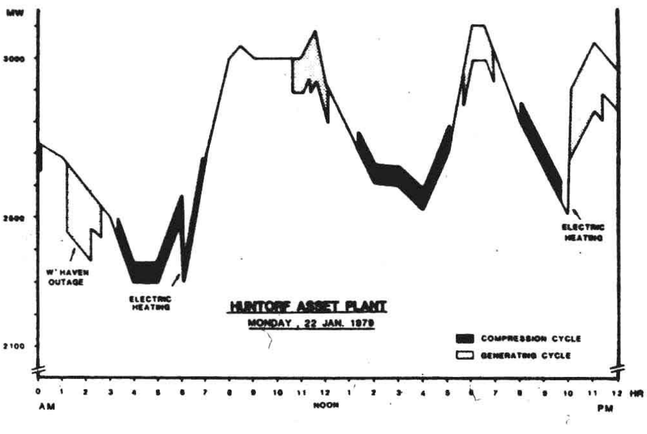


Figure 8

The daily load diagram of January 22, 1979 therefore pictures very distinctly how flexibly such plant can serve the system with a maximum load following gradient of about 90 MW/min. This value represents the load following gradient of a 1300 MW nuclear power plant.

4. OPERATIONAL RECORD HUNTORF

Originally designed for: 2 hrs. generating daily
8 hrs. charging daily

Actual Operation:

	To 12/7/78 (Start of commercial operation)	To 12/31/79
Starts for compressor operation	132	474
Starts for generation	277	772
Fast starts for generation	24	35
Running hours compressor set	546	1958
Charging hours	510	1902
Running hours electricity generation	247	854
Produced MWH	20527	89304

Overhauled: 5/19/79 - 8/2/79
found: excellent condition, no sign of any corrosion or erosion

Back in operation: 8/3/79

4.1 <u>Availability & Reliability</u>

As an example of availability and reliability of Huntorf, the following data can be quoted:

Operation during	April 79	Nov. 79	Sept. 79
Starts for pumping:	33	28	47
Starts for generation:	45	37	68
Operating Hours:			
In pumping mode:	129	98	226
In generation mode:	54	37	87
Availability:	97.64	94.58	94.31
Start availability:	98%	93.8%	100%
Start reliability:	99.5%		

Availability includes also the automatic remote control system.

These figures are very good for a normal plant, and extremely good for a first-of-a-kind!

4.2 <u>Economical Aspects</u>

Investment -- The total cost of the plant was about 125 Million DM (approx. 70 Million U.S. Dollars), which corresponds to about 430 DM/kW, or app. 230 U.S.$/kW. The cost of the two caverns is included in this price. In other terms the value is split down into 345 DM/kW for the power plant installation and 45 DM/kWh for the storage part.

Energy Costs -- The energy costs for the produced kWh are composed of 80% as compressor energy and about 20% of energy from natural gas.

4.3 Acceptability of the Huntorf Plant

In spite of the teething problems of such first-of-a-kind installation, it can be stated without any doubt that the Huntorf plant complements the NWK grid requirement to the fullest.

The present high availability and reliability, as well as the flexibility of the whole installation and also its rapid load following capability, make Huntorf a real asset to the NWK system.

5. SECOND GENERATION ASSET PLANTS

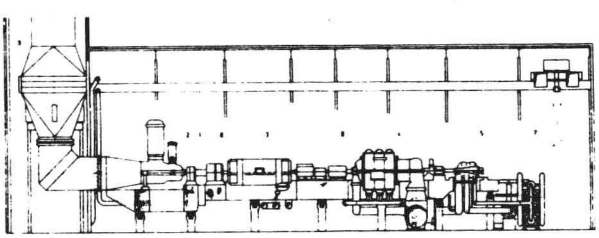
The U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) of Palo Alto, California, sponsored two studies to develop the second generation of the ASSET plant.

BBC was a member of two study teams with Middle South Services and Potomac Electric Co. These teams designed and cost-appraised the whole ASSET plant, including the cavern. The plants were designed to cycle daily, where the cavern is rock-mined and water-compensated, or weekly, where the air storage facility is solution-mined cavern in salt.

These examples can be completed by others in various countries of the world.

Inasmuch as many parameters of Huntorf are adopted in the second generation units, the heat rate can be improved by 25-30% by installation of the regenerative air preheater, taking advantage of the off-gas heat. Also, the compressor train was designed to take advantage of large valleys in the power demand at night and thus provide energy for storage - to cover much larger peaks during the high demand time. These principles can be adopted for sets of 50 as well as 60 cycle operation. The 50 cycle set will reach an output of 300 MW and the 60 cycle unit 220 MW.

An example of the second generation unit is presented in Figure 9.



1 Turbine
2 Combustion chambers
3 Generator/Motor
4 LP-Compressor
5 HP-Compressor
6 Intercoolers
7 Aftercoolers
8 Clutches
9 Recuperator

Figure 9

6. GENERAL APPLICATION OF ASSET PLANTS TO THE UTILITY'S SYSTEM

Before adopting energy storage, an electric utility must be assured that favorable economics exist. The obvious economic benefits are: the replacement of high cost fuel with low cost fuel and the better utilization of large base load units.

In addition to gaining favorable economics and reducing scarce fuel consumption, the utility must also be assured that the storage system will mesh properly with the utility's other capacity on a daily, seasonal and annual basis.

6.1 Growth of Nuclear- and Coal-fired Plants

The main prerequisite of ASSET plants is the availability of off-peak power from nuclear- and coal-fired plants. Since the generation patterns in the future will promote these type of plants, ASSET plants will find also a consideration in the planning of the future generation mix.

6.2 Load Management

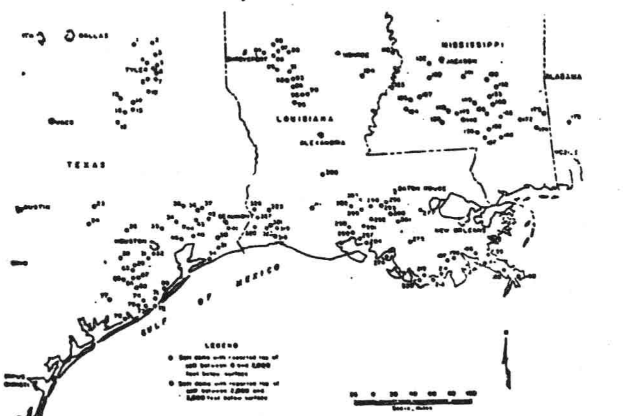
The basic idea of load management, besides the colloquial description of "flattening of the load curve", is to improve system efficiency, shift fuel dependency from limited to more abundant energy resources, reduce reserve requirements for generation and transmission capacities and improve reliability of service to essential loads.

The ups and downs in the daily electric power demand can be smoothed by installing an energy storage system which could accomplish the above-mentioned goals.

7. AIR STORAGE POSSIBILITIES

7.1 Salt Domes and Salt Deposits

The availability of salt domes in the Gulf Coast area of the United States is shown in Figure 10. Salt mining companies have defunct mines in many areas. These can be easily adapted to create a convenient air storage facility. Similar salt domes can be found in many places of the world.



Onshore Salt Domes That Offer Good Possibilities for Salt Extraction or Underground Storage Sites.

Figure 10

7.2 Aquifers

The porous rock trapped between layers of impermeable strata can also be used for a potential air storage facility. The technique of storing natural gas in aquifers has been known for decades.

7.3 Rock-Mined Caverns

A hydraulically compensated cavern is probably the most suitable solution for these cases. Figure 11 shows the basic idea of such a constant pressure facility.

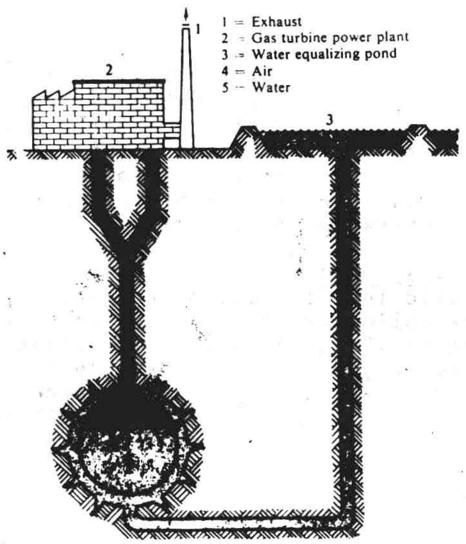


Figure 11

7.4 Depleted Oil and Gas Wells, Mines, etc.

Since the earth has for millions of years held gas under pressure, there is no reason air could not be stored in this same facility. The same goes for empty oil wells.

8. CONCLUSION

It took a lot of courage by NWK to decide to implement a first-of-a-kind installation such as the Air Storage System Energy Transfer plant at Huntorf. The teething problems have been eliminated and the plant is performing better than expected, since it is used in more functions than originally anticipated.

The fact that there is a Huntorf plant in successful operation has resurrected a great interest among utilities and architect-engineers all over the U.S. and the world. With the availability of salt domes, aquifers, depleted oil and gas wells, defunct salt, potash, iron and other mines, there is a natural potential to build such plants in numerous places. Even a man-made cavern, specially excavated for air storage, is not too exhorbitantly high in cost, compared with today's extra additions to fossil and nuclear plants, to comply with environmental and safety requirements only.

With the inevitable growth of nuclear generation, future base load will be generated more and more by these type of plants. Since the peaks will grow, there will be a requirement for finding adequate energy storage, to use energy generated by more efficient and economical base load plants rather than cover them with the inefficient gas turbines, which use up more precious gas and oil. Through Air Storage System Energy Transfer (ASSET) plants, this can be accomplished.

With coming solar and wind energy in the future, such facilities will be almost indispensible due to the intermittent character of these energy sources.

The basic idea to be able to transfer off-peak power to the peaking period, to have a better load factor on the machines, or even defer new capacity investments, is appealing more and more to many utilities.

Building an energy storage facility, similar to pumped-hydro storage in a flat country, presents a definite advantage from an environmental point of view.

Several American utilities show a genuine interest in ASSET plants. The need for better utilization of the present base load capacity and with staggering prices of oil, it should be natural that this type of energy storage plant should become popular in the United States.

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ENERGY STORAGE FOR PEPCO – THE ECONOMIC FEASIBILITY OF COMPRESSED AIR AND UNDERGROUND PUMPED HYDROELECTRIC ENERGY STORAGE ON THE PEPCO SYSTEM

C. L. Driggs, Project Coordinating Engineer
Acres American Incorporated
Columbia, Maryland

P. W. Robb, Manager of Energy System Planning
Potomac Electric Power Company
Washington, District of Columbia

ABSTRACT

Potomac Electric Power Company and Acres American Incorporated have been performing a three year DOE/EPRI/PEPCO sponsored program for preliminary design of water compensated Compressed Air Energy Storage (CAES) and Underground Pumped Hydroelectric (UPH) power plants. This paper, one of a series covering the results of that effort, presents both the costs of the CAES and UPH plant design which were developed and the results of economic evaluations performed for the PEPCO system.

The PEPCO system planning analyses was performed in parallel stages with plant design development. Analyses performed early in the project indicated a requirement for 1000 MW/10,000 MWH of energy storage on a daily operating schedule, with the most economic project being installed in two segments of 500 MW in 1990 and 1997. The analysis was updated eighteen months later near the end of the program to reflect the impact of new growth projections and revised plant costs. The revised results indicated that installations for either UPH or CAES of approximately 675 MW/6750 MWH on a daily cycle, installed in blocks of approximately 225 MW in 1990, 1993 and 1995 to be most economic. Significant savings in revenue requirements and oil fuel demand over the combustion turbine alternative were identified for both CAES and UPH.

The plant cost and design inputs are presented with a discussion provided to assist in applying the input data to other utilities.

INTRODUCTION

Potomac Electric Power Company (PEPCO) has been studying the addition of centralized energy storage in future system expansions for over ten years. In the latest and most in-depth study, PEPCO, with Acres American Incorporated as engineering subcontractor, has been evaluating both the technical and economic feasibility of Compressed Air Energy Storage (CAES) and Underground Pumped Hydro (UPH) to meet peak power and system regulation requirements. This study has been jointly funded by the Department of Energy (DOE), the Electric Power Research Institute (EPRI) and PEPCO.

PEPCO is a medium size investor owned utility operating in a 643 square mile (1665 km^2) service area, wholly including the District of Columbia. System installed capacity is presently 5001 MW, with a summer peak load of approximately 4000 MW expected in 1980. Peak demand is expected to grow at less than 2 percent per year through 2010. Customer makeup is dominated by office buildings and residences.

The terrain in the PEPCO region does not favor conventional hydroelectric or pumped storage development. The PEPCO area does, however, include several massive bodies of hard rock suitable for the large underground excavations required for UPH and the hard rock CAES design.

The latest study was initiated to provide a) estimates of cost based upon preliminary engineering designs, b) project schedules, and c) estimates of risk upon which a decision to construct either a CAES or UPH station at one of these sites can be made.

UPH and CAES plant designs have been developed based upon both a single site and design criteria applicable to the PEPCO system. These criteria included black start, load regulation and synchronous condenser operating capability. Transmission connection would be made directly to a 500 kV power pool intertie. The overall plant designs are considered to be typical of those required for installation by a United States utility.

COMPARISON OF THE UPH AND CAES DESIGNS

The PEPCO study addressed the possible application of two potential large scale energy storage concepts to meet PEPCO's system peak power and regulation needs.

Underground Pumped Hydro (UPH), as presented on Figure 1, is basically similar to conventional pumped hydro. In both cases, energy is stored by pumping water from a lower reservoir to an upper reservoir.

Energy is then returned to the utility's grid when the water is allowed to flow back through a hydroelectric turbine-generator. Utilization of an underground cavern for the lower reservoir offers the advantages of operating at considerably higher heads and enhanced siting opportunities. A variation in the basic concept used in the preliminary design effort involves hydraulic operation of two pump-turbines in series.

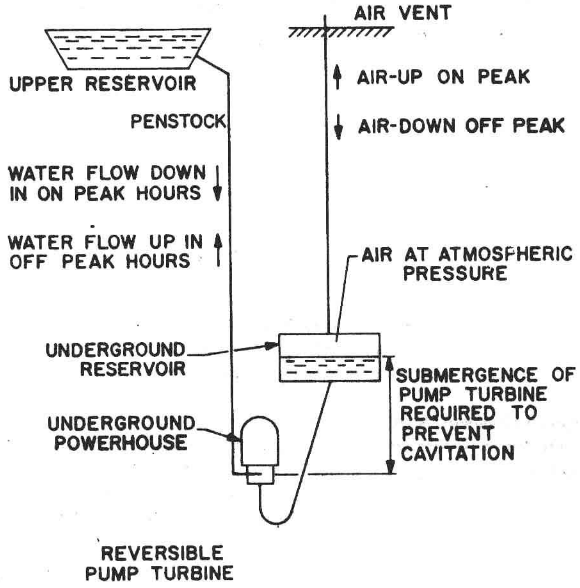

FIG. 1 UNDERGROUND PUMPED HYDRO STORAGE

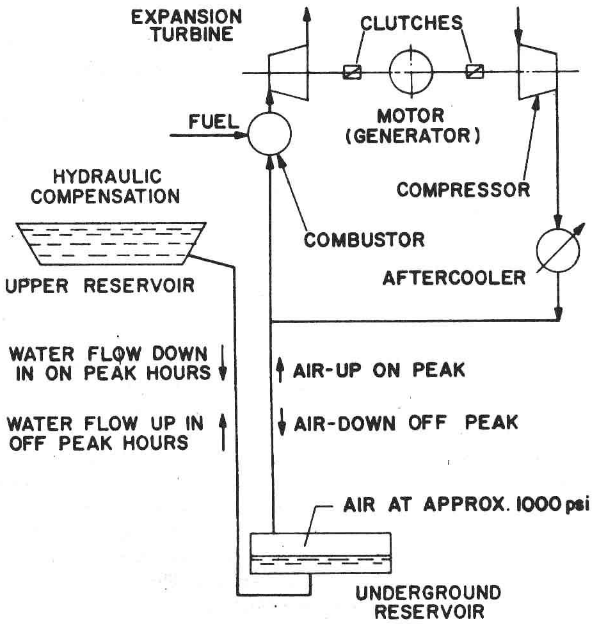

FIG. 2 COMPRESSED AIR ENERGY STORAGE

Compressed Air Energy Storage (CAES) as presented on Figure 2 is a time delayed Brayton cycle with storage of compressor discharge air in an underground cavern reservoir. Air storage occurs during the off-peak demand periods, with discharge through the combustion turbine section occurring during peak load periods. The plant design incorporates a water compensated cavern system to maintain a constant air storage pressure. Although other designs have been proposed or are in use for both the storage system and the turbomachinery, they were neither used in the study nor are they covered in this paper.

IMPLEMENTATION OF ENERGY STORAGE

Energy storage, like any conventional form of electric power generation, will be implemented when four criteria are met:

(1) There must be a need for more generating capability on a utility's system.

(2) This need must be for an energy output which can be met by storage, (i.e., peaking or cycling as storage cannot be run continuously) and it must also complement off-peak availability of low cost energy. Pumping or compressing with other cycling units in order to meet daily demands is generally uneconomic.

(3) The technology must be cost competitive with conventional forms of generation.

(4) The technology must be sufficiently developed to present an acceptably low level of risk to the utility.

The first three criteria are the basis for system planning analyses and economic evaluations. These analyses have been performed as part of the study and are the subject of this paper. The technical portion of the PEPCO study has addressed the last of the above criteria. For the requirements of this paper, it is sufficient to state that no major technical barrier appears to exist to the implementation of either UPH or hard rock CAES.

SYSTEM PLANNING STUDY

Preliminary system planning with UPH and CAES on the PEPCO system was initially performed within this latest study during the first half of 1978. The results indicated an economic plant capacity of about 1000 MW/10 hr storage operating on a daily cycle. The installation of four 250 MW units was selected as the basis for design of both plant types. Subsequent design work, along with the changing future outlook, altered much of the input data to these early studies, as had been anticipated.

Development of the CAES plant equipment initially indicated a unit capacity reduction to an estimated 225 MW, whereas the UPH unit size

TABLE 1

PLANT INPUT DATA

	CAES	UPH	CT
Variable O&M Costs	0.25 mill/kWh (1980$)	0.16 mill/kWh (1980$)	$100/hr (1980$)
Fixed O&M Costs	$3.75/kW-yr (1980$)	$39.25/kW-yr (1980$)	$7,200/yr (1980$)
Turnaround efficiency, kWh output / kWh input	1.33(1)	0.72	NA
Fuel Heat Rate	4250 Btu/kWh(1) (4484 kJ/kWh)	---	12,800 Btu/kWh (13,504 kJ/kWh)
Storage Energy	10-hour x Inst. Cap.	10-hours x Inst. Cap.	NA
Generation Output, MW/unit	225	333/666*(2)	50
Planned Outage Rate	2 wk/yr	4 wk/yr	2 wk/yr
Forced Outage Rate	10%	4%(3)	16%

(1) Fuel fired CAES is a hybrid storage system; efficiency is measured by combining electrical energy stored and fuel consumed to produce each kilowatt of output. Round Trip Heat Rate (RTHR) is typically 11,500 to 12,500 Btu/kWh with coal plant charging power. UPH RTHR with the same coal plant efficiency range would vary from 13,000 to 14,000 Btu/kWh. A CAES cycle requiring no fuel input is under development, with RTHR in the range of 13,000 to 15,000 Btu/kWh.

(2) Two-step system, two 333 MW units operating in series.

(3) Combined outage rate for two units in series operation.

increased to 333 MW per machine (or 666 MW per machine pair, as a two step design had been selected). The UPH plant was also increased in capacity to 2000 MW to achieve economy of scale, on the assumption that the plant would be jointly owned with another utility. Revision of the PEPCO load growth forecast in October 1978 substantially reduced the load projection used in the preliminary study. Accordingly, plant installation schedules were modified by delaying the need for baseload unit additions.

The most recent system planning study was performed using the PROMOD system production cost program, in combination with the PEPCO revenue requirements program. PROMOD includes a recently developed subroutine to handle both charging energy and fuel inputs, as required for CAES plant simulation.

The analysis was based upon modeling of the existing PEPCO system and planned unit additions in conjunction with a total of 22 different installation plans using CAES, UPH or combustion turbines. Cash flows and energy storage plant operating characteristics were developed by Acres, and combined with inputs developed by PEPCO for other plant types in the evaluation. A partial summary of the energy storage plant data is presented in Tables 1, 2 and 3.

RESULTS

The updated analyses continue to show that both CAES and UPH are economic for provision of mid range, peaking and reserve capacity in the PEPCO system. These results are based upon load growth and cost projections available in late 1979 and early 1980. The alternative of conventional combustion turbine installation requires greater annual system revenues, and is projected to increase system oil based fuel usage over the period of the analysis.

The planning studies have shown a need for approximately 670 MW of energy storage on the PEPCO system beginning in 1990. The plans which best satisfied the system needs and produced minimum costs were:

(1) CAES - three units totaling 675 MW with 10 hours of daily storage capacity installed in 1990, 1993 and 1995.

(2) UPH - one-third ownership of a total of three 666 MW unit pairs operating with 10 hours of daily storage capacity installed in 1990, 1993 and 1995.

TABLE 2

CAES
3 UNITS - 10 HOUR STORAGE
DIRECT COST CONSTRUCTION CASH FLOW

Year	Compensated Hard Rock Storage at 70 atm (7.0 MPa)
1986	36.7
1987	27.8
1988	37.7
1989	67.6
1990*	2.2
1991	3.7
1992	51.9
1993*	2.5
1994	50.3
1995*	-
TOTAL	280.4 (415 $/kW)

Notes:

* Commercial operation dates.

All costs are in millions of July 1979 dollars.

Escalation and "interest during construction" are not included.

Engineering, Administration and Contingencies are not included

TABLE 3

UPH
2000 MW - 10 HOUR STORAGE
DIRECT COST CONSTRUCTION CASH FLOW

Year	4600 Feet (1400 M) Nominal Head
1983	18.6
1984	27.4
1985	35.0
1986	56.2
1987	104.3
1988	133.6
1989	75.8
1990*	29.5
1991	46.2
1992	97.2
1993*	82.6
1994	60.0
1995*	17.3
TOTAL	783.6 (392 $/kW)

Notes:

* Commercial operation dates.

All costs are in millions of July 1979 dollars.

Escalation and "interest during construction" are not included.

Engineering, Administration and Contingencies are not included.

Feasibility of Plans

CAES. The highest ranked CAES plan indicated a cumulative present worth of minimum revenue requirements (CPWMRR) savings of $1.36 billion (or 8.3 percent) over the life of the plant when compared with the least cost combustion turbine alternative plan. This result is based upon contracted 1989 prices for distillate of $11.80 to $11.93 per million Btu, with escalation at 9 percent thereafter, and $2.67 to $3.28 per million Btu (depending on sulfur content) for coal with escalation at 7 percent per year. The results are affected by coal and distillate fuel price escalation, but increases in escalation rates to 9 percent for coal and 11 percent for oil per year only serve to make CAES more economic than the combustion turbine alternative. Installation of a CAES plant for operation in 1990 will require that licensing begin in 1981 and construction of the plant facilities begin in 1986.

UPH. The economic evaluations for the highest ranked UPH plan indicated a CPWMRR savings of some $1.25 billion (or 7.6 percent of revenue requirements) when compared with the combustion turbine alternative. The evaluation was based upon the same fuel costs as used for the CAES analysis. The results are also affected by coal and distillate oil fuel price escalation, but escalation rate increases equal to those mentioned above also serve to make UPH more economic. Generally eleven years would be required from filing of license applications to first operation. Therefore, the 1990 operating date could only be achieved through expeditious licensing and/or an accelerated construction schedule.

Fuel Savings

The installation of energy storage indicated significant fuel oil savings could be realized during the study period of 1990 through 2007, in comparison to the combustion turbine alternative.

CAES plant results indicated system-wide fuel savings of 11 million barrels of No. 6 oil and 8 million barrels of No. 2 oil for the 1990 - 2007 period.

UPH plant results indicated system-wide fuel savings of 8 million barrels of No. 6 oil and 8 million barrels of No. 2 oil for the 1990 - 2007 period.

Annual oil savings over the operating lives of the CAES and UPH plants are estimated to be approximately 1 million barrels of No. 2 oil per year and about 1 million barrels of No. 6 oil for either plant.

Alternative Plans

The most economic plan for both energy storage plant types involved units installed in 1990, 1993 and 1995. In total, seven plans for CAES, ten plans for UPH, and five plans for combustion turbines were studied.

CAES plans included three, four and five unit installations, with various completion dates based upon approximate needs shown by the load forecast. The lowest cost four unit plan increased the present worth of revenue requirements (in comparison with the most economic three unit plan) by 9.2 percent, while average plant capacity factor dropped from 20.7 to 19.7 percent. The lowest cost five unit plan increased the revenue requirements by 20.8 percent, accompanied by a drop in average capacity factor to 18.3 percent.

UPH plans included one third, one half and two thirds ownership. Fifty percent ownership, at best, resulted in a present worth of required revenues increase of 7.5 percent, while the average equivalent capacity factor of the PEPCO share dropped from 15.9 to 14.4 percent. Two thirds ownership increased revenue requirements by 55.9 percent, while average equivalent capacity factor dropped to 11.4 percent.

The least cost combustion turbine plan produced a cumulative present worth of revenue requirements of $16,361 million, versus $15,003 and $15,115 million with CAES and UPH respectively.

Sensitivity Analyses

The results of the system planning study were tested for sensitivity to the following factors, since unit sizes and operating pressure for CAES and operating head for UPH were established using separate economic optimization studies:

(1) Storage capacity
(2) Capital cost increases
(3) Fuel cost escalation
(4) Forced outage rate

Table 4 summarizes the sensitivity of the results to these factors.

Capital cost escalation does not affect plant usage, as it has no relation to production (incremental) cost. The percentage increase in cost is therefore directly reflected as a percentage increase in revenue requirements to recover the added investment.

Fuel escalation affects the production cost of both energy storage plant types and combustion turbines. The impact of distillate price escalation on combustion turbines, although not shown, is much greater than for CAES (or UPH). This reflects the total dependency of combustion turbines on distillate fuel, as compared to the storage plants which obtain their charging energy from coal (or nuclear) units.

TABLE 4

SENSITIVITY RESULTS

	CPWMRR*		Average Capacity Factor, %	
	CAES	UPH	CAES	UPH
Storage Capacity				
5 hour, daily cycle	15,027	15,311	14.1	12.4
8 hour, daily cycle	15,004	15,138	19.5	15.1
10 hour, daily cycle	15,003**	15,115**	20.7	15.9
13 hour, weekly cycle	15,011	15,136	21.4	16.7
Capital Cost				
+5%	15,025	15,138	20.7	15.9
+10%	15,048	15,160	20.7	15.9
Fuel Cost Escalation				
Coal, 9 vs. 7% base rate	16,569	16,747	20.6	16.0
No. 2 Oil, 11 vs. 9% base rate	15,579	15,529	15.4	16.0
Forced Outage Rate				
8 vs. 4% base rate (combined unit value)	--	15,126	--	15.6
20 vs. 10% base rate	15,019	--	19.3	--

* Cumulative Present Worth of Minimum Revenue Requirements in millions of 1980 dollars.

** Reference case.

Since neither of the energy storage technologies have yet been installed to a degree necessary to provide credible data on equipment reliability, forced outage rates must be estimated. For the study, these were estimated based upon experience with similar yet significantly different technologies. The impacts of errors in these forecasts were tested by doubling the estimated forced outage rates. This reduced plant usage slightly as shown, but did not produce substantial economic penalty. Actual forced outage rates can only be determined once sufficient numbers of units are in commercial operation.

DISCUSSION - CAES RESULTS

The CAES plant design study has been based upon construction of a four unit plant using the hydraulically compensated ("constant pressure") hard rock storage system design. Final output per unit is slightly higher than the 225 MW used in the system planning analysis, at a net 231 MW at the switchyard bus.

The study results indicated that CAES plant charging power would be largely supplied by coal-fired plant. Consequently the oil savings of nearly 2 million barrels per year attributable to CAES are the result of both increased use of coal-fired plant and low generation mode oil consumption. Fuel requirements of the CAES generation cycle are substantially reduced at 4250 Btu (4484 kJ) per kWh of generated output, compared to typical combustion turbine heat rates of 12,000 Btu/kWh (12,660 kJ/kWh).

The sensitivity of CAES to escalation of No. 2 fuel oil price has been a point of major concern. The effect of increased price escalation over the base rate of 9 percent only serves to increase savings over the combustion turbine alternative, because of the higher combustion turbine oil consumption per kWh of output for this type of plant.

The sensitivity of the CAES plant to charging power incremental cost escalation was tested by increasing coal price at 9 rather than 7 percent per year. This resulted in a slight reduction in plant usage, and an increase in revenue requirements over the base CAES case of some 10 percent.

The capital cost of the CAES plant (when completed in 1995) used in the CPWMRR evaluation was 1,285 $/kW. This cost is for the three unit, 10 hour storage plant and includes escalation (average 7.5 percent per year) and utility indirects, but excludes interest during construction. In comparison, 1200 MW nuclear or 800 MW coal units are projected to have an equivalent cost of 1,800 and 1,465 $/kW respectively for a 1995 operating date. The cost of interest during construction for the CAES plant is estimated to be 13.3 percent, yielding a total capital cost at completion in 1995 of approximately 1,450 $/kW, based upon 225 MW per unit. Tables 1 and 2 show operating characteristics and the construction cash flow for the three unit plant used in the system planning analysis.

DISCUSSION - UPH RESULTS

The UPH plant design study was based upon the construction of a six unit/three unit pair plant using a two-step arrangement of machinery. Per unit output is 333.3 MW, or 666.6 MW per unit pair, with a total plant capacity of 2000 MW.

The proportion of plant ownership appears to be the most sensitive influence on revenue requirements. One third ownership produced minimum cost of the alternatives studied. Fifty percent ownership increased revenue requirements by 7.5 percent, while 2/3 ownership increased revenue requirements by 56 percent. A decision by PEPCO to construct a UPH plant of this size would by necessity be preceeded by a firm committment to joint ownership with a utility partner.

Most of the UPH production cost is for pumping power supplied by coal plants. The effect of increasing coal price escalation from 7 percent to 9 percent per year is to increase revenue requirements by some 11 percent over the UPH base case.

As with CAES, the capital cost of 1,177 $/kW used for the CPWMRR evaluation (10 hour plant) does not include interest during construction (AFUDC). Addition of this cost is estimated to increase the overall capital cost by some 19.8 percent to a total cost at completion in 1995 of 1,410 $/kW.

During the detail design phases of the study, the UPH plant design has been revised to a two-step design operating at 2500 feet (760 meters) and 5000 feet (1520 meters). This design change decreased capital cost slightly compared to the figures used in the system planning analysis.

APPLICATION TO OTHER UTILITY SYSTEMS

Investigation of energy storage application to other utility systems must involve a system expansion/planning analysis as each utility has different needs. The data of Table 3 provides part of the information required to evaluate CAES and UPH on other systems. However, the storage and/or plant capacity required for some other installation is likely to differ from that needed by PEPCO, and thus capital costs per unit output will differ. The following figures are generally applicable to a UPH plant of two step design with 666 MW unit pairs at 2500 (760 M) and 5000 feet, and to 231 MW CAES units operating at 70 atmospheres (7.0 MPa) storage pressure with compensated hard rock storage:

	UPH	CAES*
Power related costs, $/kW direct (1980)	285	340
Storage related costs, $/kWh direct (1980)	13.3	3.7
Total Cost, $/kW 1980 - 10-hr storage	416	373

It should be borne in mind that major changes in plant storage capacity, the number of units or in geological conditions from the design base of this study can alter the "split" of capacity related and storage related costs provided above.

Figure 3 provides a screening curve, based upon 1995 costs, for energy storage, combustion turbines and 800 MW coal baseload within the PEPCO system. This indicates the general applicability of CAES and UPH to peaking and midrange load duty.