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An Assessment of High Temperature Nuclear Energy Storage Systems for the Production of Intermediate and Peak-Load Electric Power

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AN ASSESSMENT OF HIGH TEMPERATURE NUCLEAR ENERGY STORAGE
SYSTEMS FOR THE PRODUCTION OF INTERMEDIATE
AND PEAK-LOAD ELECTRIC POWER

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ABSTRACT

Increased cost of energy, depletion of domestic supplies of oil and natural gas, and dependence on foreign suppliers, have led to an investigation of energy storage as a means to displace the use of oil and gas presently being used to generate intermediate and peak-load electricity. Dedicated nuclear thermal energy storage is investigated as a possible alternative. An evaluation of thermal storage systems is made for several reactor concepts and economic comparisons are presented with conventional storage and peak power producing systems. It is concluded that dedicated nuclear storage has a small but possibly useful role in providing intermediate and peak-load electric power.

INTRODUCTION

Increased cost of energy, which has been caused by the depletion of the U.S. oil and gas reserves and accentuated by the 1973 oil embargo, has led the U.S. to seek a means to increase our domestic supply of oil and decrease our overall usage and dependence on foreign suppliers. One important technique for decreasing our oil usage is to substitute another fuel source such as coal or nuclear power. It is in this role that energy storage has a direct application.

The role of an electric utility is to provide reliable electricity. Although the load varies seasonally, weekly, and daily, the utility must install enough capacity to meet its peak demand with some predetermined reliability. Therefore, much of its installed capacity is unused. This can be seen directly by examining a typical utility load duration curve such as that shown in Fig. 1.

The electric utilities provide for this varying demand by installing a variety of equipment which has a reasonable balance between high capital cost equipment using inexpensive fuels and low capital cost equipment using expensive fuels. The typical utility is made up of a mixture of plant types which are relegated to their role in the system based on their operating costs and the system demand. The base load is usually made up

Fig. 1. Typical load duration curve.

of hydroelectric, nuclear and newer coal plants. These plants have a high capital cost but use inexpensive fuels relative to oil, so they are operated as much as possible. Older coal plants which have less efficient steam cycles and oil-fired plants which have high fuel costs are operated to provide intermediate load. The peak load is usually provided by inexpensive internal combustion engines (gas turbines) which are less efficient than the steam-power plants and use a premium fuel (gas or oil).

There are two incentives for the introduction of energy storage into the utilities generation mix. First, it is possible to store energy during off-peak periods, when less expensive fuels (e.g., coal, nuclear) are being used and discharging during the peak demand periods rather than burning petroleum derived fuels. The actual incentive in this case would be the cost savings derived from burning less oil. The second incentive is to utilize stored energy instead of installing added capacity. This would result in load leveling and would provide some savings in capital expenditures.

Energy storage can be divided into two distinct categories: (1) general storage systems, and (2) dedicated storage systems. Figure 2 shows both types of systems. The general storage system stores electrical energy directly from the utilities power grid and returns it to the grid during peak periods. This type of system is distinctly different from a dedicated one because the storage facility does not have to be located in close proximity to the power generation units. The dedicated system stores thermal energy before it is converted to electricity. During the peak demand periods the energy is extracted from storage and converted to electrical power. In either system the same result is accomplished: base loaded power sources are utilized to produce peak and intermediate load power.

High temperature nuclear energy storage systems are dedicated systems which allow the reactor to operate base loaded while some or all of the turbine generator equipment may be operated intermittently. These high temperature systems have the unique capability of not only converting a traditionally base loaded system to one which can produce peak and intermediate load power, but because they store thermal energy directly they are generally highly efficient storage systems. The reactor

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GENERAL STORAGE SYSTEM

DEDICATED STORAGE SYSTEM

- 1 ENERGY GENERATOR
- 2 POWER CONVERSION AND TRANSMISSION
- 3 STORAGE
- 4 USER

Fig. 2. Energy storage systems.

concepts which are covered in this report include Light Water Reactors (LWR), High Temperature Gas-Cooled Reactors (HTGR), and Liquid Metal Fast Breeder Reactors (LMFBR). This report highlights the technology required for these systems and makes an economic evaluation.

THERMAL STORAGE MEDIA STATE OF THE ART

Since all the dedicated storage systems discussed in this study involve liquid heat transfer fluids, a discussion of the state of the art is appropriate. Liquid heat transfer media has been employed by industry to a myriad of applications. These have varied from steam and water to liquid metals at elevated temperatures. Various materials including Dowtherms,[®] Aroclors, mercury, lead, and molten salts have been used within these extremes. Selecting a particular storage medium is based on many of the same physical properties that are important in choosing a heat transfer fluid. These are a high heat capacity, heat of fusion or vaporization in the case of phase-change material, a high density, high thermal conductivity and low viscosity. These important properties are discussed by Rottenburg,¹ Vosnick and Ulh,² and in detail by Checketkin.³

High pressure water and steam was brought into use in Germany during the 1930s. Temperatures as high as 500°C (932°F) have been recorded but the associated high pressure precluded its wide use. Further, the development of organic heat transfer media has gradually displaced water as a transport fluid above 200°C (392°F). Because water has such a high heat capacity and low cost, it is an excellent choice at temperatures below 200°C (392°F).

Considerable effort has been expended developing organic heat transfer fluids. These include materials such as Aroclors, Dowtherms,[®] Therminols,[®] Caloria HT-43,[®] and many others. Although these vary in structure, all are limited in temperature to below 350°C (662°F). High temperatures often cause thermal decomposition that results in fouling of heat transfer surfaces. These compounds do not have heat transfer properties as good as water, but they exert much lower vapor pressures at high temperatures and subsequently are more usable in the 200–350°C

(392–662°F) temperature range. It should be noted that some of these fluids have inherent safety-related problems such as toxicity and flammability. Organic fluids vary in cost and availability. For instance, Dowtherm-A and ethylene glycol are both used in large quantities but cost \$0.22/kg (\$.10/lb) and \$0.57/kg (\$.26/lb),⁴ respectively.

Liquid metals have found some use as heat transfer fluids. Mercury can be used as a heat transfer agent in both the vapor and liquid phases. The use of boiling mercury as a coolant in multitube reactors dates back to the 1920s, where it was used for phthalic anhydride oxidation processes. However, because of its relatively high cost (9/kg) and toxicity, it becomes unattractive as a storage medium. Lead baths have been used for many years in metallurgical processes. Major disadvantages of using lead for energy storage include its high melting point, low specific heat, and expense. While some lead alloys have been developed which have lower melting temperatures, they are nearly all more expensive than pure lead.

Liquid metals and alloys, such as the sodium potassium (NaK) mixture, offer a wide temperature range for heat transfer application. Low melting points and excellent thermal stability make these materials attractive for use at elevated temperatures. Their high thermal conductivity and low specific heat give very low Prandtl numbers. However, their heat transfer coefficients are very high. Equipment for handling liquid metals is quite specialized (e.g., electromagnetic pumps, etc.) and sealed systems are required. Their corrosion properties are unusual in that even though the term "corrosion" is employed, the phenomenon of mass transfer is observed (i.e., metal is dissolved and transferred from the hot section of the system and deposited in the cooler section). Considerable development work of liquid metal systems on the Liquid Metal Fast Breeder Reactor (LMFBR) project has resulted in numerous technological advances, improvements and satisfactory equipment for containing and handling these liquids. Major disadvantages of the liquid metals include violent reactions with water (steam generator area) and other oxidizing materials and the cost of the special equipment required for handling and containing these metals. Sodium and potassium are available in large quantities, the former at ~\$0.57/kg (\$.26/lb) and the latter at

2.2/kg (\$1/lb). The alloy NaK is quoted at a cost of \$3.50/kg (\$1.59/lb).⁴

Nitrate-nitrite salt mixtures have been used for many years in metallurgical heat treatment operations. The petroleum process industry also used these mixtures to control their catalytic cracking reactions. A particular mixture known and patented as heat transfer salt (HTS),⁵ containing 40% sodium nitrite (NaNO_2), 7% sodium nitrate (NaNO_3) and 53% potassium nitrate (KNO_3) by weight, was developed by the DuPont Co. It has a low melting point, 142°C (288°F) and modifications in composition do not affect the freezing point greatly. A binary mixture containing 45% sodium nitrite and 55% potassium nitrate was adopted for use in the Houdry catalytic cracking process for all plants built after 1941. The practical temperature range for HTS is about $200\text{--}550^\circ\text{C}$ ($392\text{--}1022^\circ\text{F}$); the lower limit is based on handling impurities such as NaOH and Na_2CO_3 in the molten mixture (formed by decomposition of nitrite) while the upper limit is usually based on the cost of replacing the nitrite decomposed thermally. The effect of variations in composition on the physical and chemical properties of HTS are well documented.⁶

Heat transfer salt (HTS) has negligible vapor pressure, which simplifies its use in low pressure or atmospheric systems. Unlike the organics, it does not foul and has superior thermal properties. In contrast to the heat transfer metals, it is safe and relatively nontoxic. Its cost is reasonable [$.33\text{--}.45$ \$/kg ($.15\text{--}.20$ \$/lb)] and it is available in sufficient quantity to make it a prime candidate for sensible heat energy storage in the $200\text{--}550^\circ\text{C}$ ($392\text{--}1022^\circ\text{F}$) range. Proven equipment for handling this molten salt has been developed by industry over the past several decades. It can be contained in mild steel at temperatures up to 480°C (896°F), but above this temperature low alloy or stainless steels are recommended.

The hot salt reacts with solid inflammable materials, but by itself presents no fire danger. Properly designed closed circulating systems have operated for years without incident.^{7,8}

A 54-46 weight percent mixture of potassium nitrate and sodium nitrate has received use in the metallurgical industry. Although it has the same physical characteristics as the HTS mixture, its melting point is 218°C (425°F). It is, however, cheaper [$\sim.22\text{--}.33$ \$/kg

(.1-.15 \$/lb)] than HTS and is considered to be more stable at high temperatures. Because of these two considerations, this mixture is an excellent candidate as a storage medium. Additionally, many fused salt mixtures have been discussed for use as energy storage medium by means of their high heats of fusion. However, the technological difficulties involved with the heat transport within a liquid solid phase change system seem to preclude it from near term development for an energy storage system.

LIGHT WATER REACTOR STORAGE SYSTEMS

Two methods for adapting thermal energy storage to light water reactors have been investigated. The first system, which is receiving some development effort from the Exxon Co.,⁹ is basically a feedwater heating system. It uses the sensible heat of a high boiling heat transfer oil such as a Dowtherm[®] or Caloria-HT-43[®] for storing the thermal energy. As in other feedwater storage systems, this one uses large amounts of extraction steam to heat excess feedwater (Fig. 3) during off-peak periods reducing the output power from the turbine generator. This extra feedwater is cooled, rather than stored as it is in other concepts, by heating the oil in a series of heat exchangers. The oil is then sent to storage tanks where it awaits use during the peak demand periods. During these periods, the extraction steam is reduced causing an increase in power output. To maintain the feedwater at the same boiler inlet temperature, the hot oil is removed from storage and used to heat the feedwater by heat recovery through the same series of heat exchangers. In order to heat the oil to a temperature above the boiler feed temperature, some live steam must be extracted for auxiliary heating.

To utilize this concept with conventional light-water reactors (LWR), the turbine generator and condensing system must be sized larger than the conventional system and designed to allow for the large amounts of extraction steam. It would be possible to retrofit this system to an existing power plant if the boiler portion of the plant has been derated relative to the turbine generator section. This concept is applicable to

Fig. 3. LWR/hot oil energy storage system.

either a pressurized-water reactor (PWR) or a boiling-water reactor (BWR). However, the cost of storage is directly proportional to the temperature difference between the hot and cold oil, which would favor a PWR over a BWR because of the lower feedwater temperature limitation of a BWR.

This storage concept has many advantages which include: (1) use of a reactor system which is in broad use, technologically developed, and has great potential for fulfilling a large portion of the U.S. electrical demand; (2) the relatively low temperature allows the use of conventional materials throughout this system; (3) the storage technology can draw directly from the extensive experience of conventional oil storage; and (4) very little research and development is needed to commercialize this system. Some of the drawbacks are: (1) If a flammable oil is chosen as the storage medium, unique safety problems involving oil handling and problems with plant licensing may arise. (2) Because of the storage technique and lower temperatures, the storage system will have a relatively low storage efficiency (73.4%).⁹ Typical system parameters for this storage system are listed in Table 1.

Table 1. LWR/hot oil storage system parameters^a

Item	Parameter
Base load capacity, MW(e)	1066
Peak capacity, MW(e)	1325
Off-peak capacity, MW(e)	713
Steam temperature, °C	285
Steam pressure, kPa	6804
Hot storage temperature, °C	260
Cold storage temperature, °C	93
Storage efficiency, %	73.4

^aObtained from Ref. 9.

Another potentially attractive application for this storage system is with conventional coal-fired steam plants. Increased emission standards, which have required many plants to shift to a low sulfur coal,

and an overall decrease in coal quality has contributed to the decrease in efficiency in coal plant boiler components. The result is that many coal plants have boilers which are derated 10-20% with respect to their turbine generators.¹⁰ Then these plants have the turbine generator and condenser capacity needed to retrofit an oil storage system without many of the technical and licensing problems inherent with a nuclear reactor system.

The second system which was investigated involves an organic heat transfer fluid used to store energy directly from a nuclear reactor for the production of off-peak electricity. Dowtherm-A[®] was chosen as this storage agent because of its high heat capacity, excellent heat transport properties, relatively low cost, and stability at temperatures approaching 600°F. This organic heat transfer fluid is heated in a light water reactor by cooling the primary heat loop (Fig. 4). During periods of low electric demand the hot Dowtherm[®] is sent to storage tanks. When the demand for power is greater, the Dowtherm[®] is removed from the tanks and pumped through a heat exchanger/boiler combination which produces steam for use in the intermediate load power cycle. The cold Dowtherm[®] is then returned to storage. This system requires a separate turbine generator dedicated to producing intermediate load power. Table 2 lists pertinent storage system parameters. It should be noted that the efficiency reported here was based on a conventional style turbine and may be less if a peaking style turbine is used.

The advantages to this system are basically the same as those for hot oil storage with the exception that this system has a higher storage efficiency. The disadvantages are primarily economic which will be discussed later.

The interaction of the storage medium and the reactor coolant and core is a very important consideration. Oil ingress into the reactor in the case of the hot oil system is quite remote. The oil storage in this instance is isolated from the reactor by the steam cycle. Ingress into the steam cycle would be deleterious, but it is considered to be unlikely due to the pressure difference between the oil and steam sides of the heat exchangers. The Dowtherm[®] system is not isolated from the primary coolant,

Fig. 4. LWR/Dowtherm[®] energy storage system.

Table 2. LWR/Dowtherm[®] storage system parameters

Item	Parameter
Base load capacity, MW(e)	900
Peaking capacity, MW(e)	1096
Steam temperature, °C	280
Steam pressure, kPa	3400
Hot storage temperature, °C	304
Cold storage temperature, °C	240
Thermal energy to storage, MW(t)	1000
Thermal losses from storage, MW(t) (12 hr storage)	-35
Net thermal power, MW(t)	965
Net power generation (31%), MW(e)	299
Auxiliary power (6%), MW(e)	18
Pumping power, MW(e)	7
Station net power, MW(e)	274
Cycle efficiency, %	27.4
Conventional LWR cycle efficiency, %	32.2 ^a
Storage efficiency (27.4/32.2), %	85

^aRef. 11.

however, the pressure differential between the water side and oil side should preclude reactor ingress.

In the event there is oil ingress into either the reactor coolant or the steam cycle, fouling of the heat transfer surface would occur with a lowering of heat transfer coefficients. If the oil contacted the fuel rods, the reaction between the fuel cladding (zirconium) and the oil would be minimal as long as water was present. If there is no water present, the reaction between zirconium and oil would probably yield zirconium carbide or zirconium hydride, but this possibility is very remote.

HIGH TEMPERATURE GAS-COOLED REACTOR STORAGE SYSTEMS

The high temperature gas-cooled reactor (HTGR) is a reactor concept which has received considerable development both in the U.S. and overseas. The HTGR uses helium as the reactor coolant and graphite as the moderator and core structural material. The fuel is a mixture of enriched uranium carbide and thorium oxide used in the form of particles individually clad with ceramic coatings. Because of this unique core design, helium exhaust temperatures of 760°C (1400°F) are possible with current technology. These high temperatures lead to the possibility of efficient thermal storage cycles. There are several configurations possible in which the HTGR can be coupled to a thermal storage system to provide intermediate load power. In the systems considered for this analysis, the thermal energy was transferred from the hot helium stream in a counter current heat exchanger where a molten salt is heated from 260°C – 540°C . The hot salt is pumped during off peak hours to insulated tanks. During periods of peak demand, the salt is removed from storage and pumped through a series of heat exchangers to produce steam in an intermediate load power cycle.

Two proposed storage systems are presented in Figs. 5 and 6. The first configuration uses the standard General Atomic 3000-MW(t) HTGR core design¹² with the exception that one of the steam generator pods has been replaced with a helium-to-helium heat exchanger. This intermediate helium loop is then used to transmit the heat into the storage salt via a counter current heat exchanger. The steam cycle proposed for this design has the conditions listed in Table 3. The pressure and temperature were selected by trading off steam cycle conditions for a gain in the temperature difference between the hot and cold storage.

The second system is one proposed by General Atomic Company. In this configuration, all the reactor heat is transferred to an intermediate helium loop (Fig. 6). The standard HTGR core is used with the exception that all the steam generator pods have been replaced with helium-to-helium heat exchangers. This design is unique in that the intermediate helium loop can distribute its thermal energy in a limitless variation between the base load steam cycle and the salt heater because they are placed in

Fig. 5. HTGR/salt energy storage system.

Table 3. HTGR/salt storage system parameters

Item	Parameter
Base load capacity, MW(e)	955
Peaking capacity, MW(e) (6 hr/day)	714
Peaking cycle steam temperature, °C	440
Peaking cycle steam pressure, kPa	12,250
Hot storage temperature, °C	538
Cold storage temperature, °C	260
Thermal energy dedicated to storage, MW(t)	500
Circulator power, MW(t)	22
Total thermal power, MW(t)	522
Thermal losses from storage, MW(t) (12 hours storage)	7.8
Total gross thermal power, MW(t)	514.2
Net power (40% efficiency)	205.6
Circulator power, MW(e)	22
Auxiliary power, MW(e)	4
Pumping power, MW(e)	1
Total station power, MW(e)	178.6
Cycle efficiency, %	35.7
Cycle efficiency conventional HTGR, %	38.2 ^a
Storage efficiency (35.7/38.2), %	93

^aRef. 11.

parallel. The second system has several technological advantages over the first. The first system requires the placing of different types of components in the primary helium loop. While this is considered to be feasible, the pressure differential between the loops may cause some control problems. Further, the second configuration has the advantage of isolating the base load steam cycle from the reactor core which would preclude steam ingress. The advantages of the first system are primarily economic. The smaller IHX is cheaper and requires considerably less consumptive compressor power. The actual choice of steam cycle condition and

turbine generator will be dependent in part on the specific application or duty cycle chosen. For instance, a high pressure steam cycle with close tolerance turbines could be used in systems operating for relatively long periods of time with higher efficiencies at the cost of higher capital charges and longer response time. Lower pressures can be adapted to peaking style turbines with a gain in response time and a loss of efficiency.

The candidate heat storage fluids include several salt mixtures and some liquid metals. From a standpoint of economics, operating experience and efficiency, only two molten salt mixtures were considered for this analysis. These were the eutectic mixture of 53 wt % NaNO_2 , 40 wt % KNO_3 , and 7 wt % NaNO_3 , and the eutectic mixture of 54.3 wt % KNO_3 and 45.7 wt % NaNO_3 . Both of these fluids have had considerable operating experience as outlined in Ref. 13. Although both of these salts have basically the same physical properties, i.e., thermal conductivity, viscosity, heat capacity, they have different melting points, 142°C (288°F) and 218°C (425°F), respectively. Because this thermal storage concept uses the sensible heat of the salt, the lower melting mixture would be favored because of a larger temperature variation between the hot and cold storage. However, another important economic consideration is the cost of salt replacement. At high temperatures, $>480^\circ\text{C}$ ($>900^\circ\text{F}$), the decomposition of NaNO_2 by the following reaction becomes significant.¹⁴

Because the ternary mixture contains NaNO_2 , this decomposition could require the replacement of ~20% of the salt inventory per year. The binary mixture, on the other hand, initially contains no NaNO_3 , but contains NaNO_2 which might decompose to NaNO_3 by the following reaction:

with subsequent decomposition of the NaNO_2 . Potassium nitrate may decompose in a similar reaction but thermodynamic equilibrium indicates it would be insignificant. In any event, the binary mixture will have much slower decomposition rates and the decomposition of the NaNO_3 to NaNO_2

may actually tend to lower the melting point. Additionally, the formation of Na_2O in the case of the ternary mixture may have the result of hydroxide formation if there is any water vapor present. This would have a significant deleterious effect from the standpoint of corrosion. In addition to being more stable, the binary mixture is cheaper [approximately \$0.24/kg (\$.11/lb) vs \$.37/kg (\$.17/lb)] than the ternary system.

The storage of these high temperature salts can be accomplished with conventional storage tanks. However, because of the high temperature, carbon steel does not have the strength required and a material such as a stainless steel will probably be used. The high thermal stresses encountered while filling and emptying these tanks will limit the bottom course thickness and require the tanks to be somewhat smaller than traditional oil storage tanks. Another option would be to line an excavated cavity to reduce the tankage costs.

The possibility of ingress of salt into the reactor core should be eliminated because the reaction of the hot molten salts with the graphite would be significant and rapid. Although the primary helium coolant is at a much higher pressure than the salt [4000 kPa vs 100 kPa (40 atm vs 1 atm)], an intermediate loop would be desirable both from a safety standpoint and to minimize the thermal decomposition of the salt, which would be accentuated by radiation.

The storage cycle parameters have been estimated and outlined in Table 3. The high efficiency of this storage concept is a result of the temperature level but can be significantly affected by the steam cycle chosen for the intermediate load or peaking section.

LIQUID METAL FAST BREEDER REACTOR STORAGE SYSTEM

The successful development of a breeder reactor and commercial introduction into the electrical power market will have a solid impact on the strategy of future energy sources and the price of electricity. A scenario can be envisioned in which liquid metal fast breeder reactors (LMFBRs) capture a major share of the electrical market as fossil fuels become more scarce. In the event that this scenario does come to

fruition, then a dedicated storage system coupled to an LMFBR could be an important technique to lower utility capital costs.

Because there is no commercial LMFBR, the Clinch River Breeder Reactor¹⁵ was used as the basis for this storage design. Prospective heat storage media are assumed to be the same as those discussed in the HTGR peaking analysis. The proposed storage system is shown schematically in Fig. 7. The generated nuclear heat is extracted from the primary sodium loop through the secondary loop by heating the molten salt in a countercurrent heat exchanger. During off-peak periods, the hot molten salt is sent to a storage area which could be a series of insulated conventional tanks or an underground storage cavity. When the electrical demand increases, the salt can be removed from storage and used to generate steam in a series of heat exchangers. The steam cycle and heat exchanger configuration used for this analysis was able to produce 8500 kPa (1250 psi) steam with the closest point of approach in the heat exchanger larger than 5.5°C (10°F). This cycle has one stage of reheat after the high pressure turbine and a low pressure section. The technical problems presented in such a system are no greater than those discussed in the HTGR concept with the exception of the coolant-salt interaction. Because this system operates at lower temperatures, the material problems could in fact be less severe.

A salt storage loop coupled to an LMFBR presents several unique problems with respect to coolant salt interaction. Because sodium is a very strong reducing agent and the nitrate salts are very strong oxidizing agents, there is the possibility of rapid reaction if the salt should ingress into the sodium coolant. Thermodynamic data indicate that the reaction between these two species generates more energy than the water-sodium reaction. In addition, exposure of the nitrate salts to radiation will increase its decomposition at higher temperatures which must be avoided from an economic standpoint. An intermediate sodium loop as shown in Fig. 8 will decrease the possibility of radioactive contamination but will still possess the potential hazard of a violent sodium-salt reaction. An alternate possibility would be to use helium for the intermediate loop rather than sodium. This would decrease many of the safety problems but would also decrease the overall efficiency

Fig. 7. LMFB/HTS storage system.

Fig. 8. Typical utility load fuel mix and effect of storage.

of the storage system because of the increased pumping power requirements of an intermediate helium loop. As with the HTGR system, the interaction of the storage salt and the steam cycle is considered to be minimal.

An alternative to using HTS as the storage medium is to use sodium. Sodium would eliminate the hazardous interaction between the reactor coolant and the storage material. However, the reaction between sodium and steam in the steam generators would also be hazardous. To estimate the cost differential between HTS and Na, a simple comparison of inventory and tankage costs can be made. Assuming the maximum temperature difference between hot and cold storage is that of the high operating temperature of the system and the melting point of the fluid, then the ratio of inventories required would be:

$$\frac{Na_{INV}}{HTS_{INV}} = \frac{\left[T_H - T_{BP(HTS)} \right] C_{P_{HTS}}}{\left[T_H - T_{BP(Na)} \right] C_{P_{Na}}} = \frac{(482-142^{\circ}\text{C}) \cdot 0.37 \frac{\text{cal}}{\text{gm}^{\circ}\text{C}}}{(482-98^{\circ}\text{C}) \cdot 0.31 \frac{\text{cal}}{\text{gm}^{\circ}\text{C}}} = 1.06 \quad (1)$$

And the ratio of inventory costs:

$$\frac{\text{Inventory cost (Na)}}{\text{Inventory cost (HTS)}} = 1.06 \left(\frac{\text{Na Cost}}{\text{HTS Cost}} \right) = 1.06 \left(\frac{.57 \text{ \$/kg}}{.44 \text{ \$/kg}} \right) = 1.37 \quad (2)$$

Since either system will require stainless steel tanks, the tankage cost ratio will be proportional to the respective storage volumes or

$$\frac{\text{Tank cost (Na)}}{\text{Tank cost (HTS)}} = 1.06 \frac{\text{Density (HTS)}}{\text{Density (Na)}} = 1.06 \left(\frac{1857 \frac{\text{kg}}{\text{m}^3}}{874 \frac{\text{kg}}{\text{m}^3}} \right) = 2.25 \quad (3)$$

Therefore the cost of inventory for a Na system would be about 37% higher than HTS and tankage more than twice as expensive. For this reason sodium is precluded as a candidate storage fluid in this assessment but could be reconsidered if HTS proves to be unacceptable from a safety standpoint. In any event, if sodium is chosen as the storage material, the economic competitiveness of an LMFBR system would be reduced from the

results derived in this report. The storage cycle parameters are listed in Table 4.

Table 4. LMFBR/salt storage system parameters

Item	Parameter
Base load capacity, MW(e)	177
Peaking capacity, MW(e)	675
Peak cycle steam temperature, °C	427
Peak cycle steam pressure, kPa	8500
Hot storage temperature, °C	482
Cold storage temperature, °C	260
Thermal energy dedicated to storage, MW(t)	487
Thermal losses (12 hr storage), MW(t)	8
Net thermal power, MW(t)	<u>479</u>
Gross power (38%), MW(e)	182
HTS pumping power, MW(e)	2
Total gross power, MW(e)	<u>180</u>
Gross efficiency (180/487), %	36.9
Estimated gross cycle efficiency for standard LMFBR cycle, %	38.7 ^a
Storage efficiency (36.9/38.7), %	95

^aRef. 15.

ECONOMIC ANALYSIS

The rationale for developing energy storage is twofold. By installing an energy storage system, it is possible to save fuel by displacing oil with nuclear and coal, and capital, by being able to provide added capacity at a cost lower than that for installing new base load plants. It should be emphasized that when a storage system is installed in a utility it will interact with the other plants in the same way regardless of whether the storage system is a dedicated or general storage

system. An energy storage system takes advantage of present energy generating capacity to produce electrical power during peak demands. By displacing in time the energy producing capacity, it is possible to also displace the expensive petroleum-derived fuels with less expensive fuels. To determine what fuels will be affected depends entirely on the utility generation mix or the type and capacity of each power plant and its integration into the utility system as a whole. This interaction can be demonstrated by the following example. There is a hypothetical utility system which is composed of nuclear, coal, steam, oil-steam, and gas turbines. A typical load which is experienced by this utility is shown in Fig. 8a. To meet this demand the utility turns its plants on and off as is necessary and chooses which plant is to be operated primarily based on the operating cost of that plant, or more simply the cost of fuel that is to be used. Since nuclear plants will have the cheapest fuel costs and this utility has only 10% of its capacity composed of nuclear plants, it will choose to operate these as much as possible. The coal plants will also be operated with the next priority because they have lower fuel costs than the next option, oil-steam, which in turn is more efficient than gas turbines, which would be operated sparingly due to their inefficient usage of oil and gas. This distribution of power production by fuel source can be seen as described in Fig. 8a. As the load increases, power plants are turned on in order of their operating costs (low cost fuels first, high cost fuels last). This hypothetical utility now installs a general energy storage system. Some of the off-peak power can now be utilized to meet some of the peak demand which is represented by the shaded areas in Fig. 8b. This represents the system operating the coal plants longer during the off-peak period to provide the stored energy and the stored energy used to supply power rather than burning oil. For the purpose of this example, we can now assume that this utility system could have installed a dedicated energy storage system retrofitted to one of its nuclear plants. The effect of using the nuclear energy for storage is seen in Fig. 8c. This dedicated storage system has exactly the same effect on the total utility system as the general one did. That is, the nuclear plant was used to charge the storage system during the off-peak period, decreasing its output and forcing the coal plants

to operate more. This energy was then used to produce power during the peak demand rather than burning oil. The net result again was coal being used to displace oil (Fig. 8d). Further, the cost of operating any of these storage systems is the cost related to the power plants which are left on the line to generate the energy. The cost of energy use for storage is the operating cost of the plant providing the incremental energy divided by the efficiency of storage.

$$\begin{aligned} \text{Operating cost of energy storage} &= \frac{\text{incremental fuel cost}}{\eta} & (4) \\ &+ \text{storage operating cost} \end{aligned}$$

To evaluate the benefit of energy storage, it must be done in context to its interaction with the total utility system and the cost of storage only determined by a detailed evaluation of the fuel level that a particular utility would operate with the energy storage system installed.

To simplify the calculation, it is assumed that the hypothetical utility system is able to charge the storage system at some incremental operating cost (IOC), which can be viewed as a system average. Then the total annual cost of storage would be:

$$CS = (SCAP)*FCR + AOM_s + IOC*8760*PCF \quad (5)$$

$$CP = \frac{CS}{8760*PCF} \quad (6)$$

where

- CS = Annual cost of storage (\$/kW)
- SCAP = Storage capital costs (\$/kW)
- AOM_s = Annual storage operating cost (\$/kW)
- IOC = Incremental operating cost (\$/kW-hr)
- FCR = Fixed charge rate
- PCF = Plant capacity factor (design)
- CP = Cost of peaking power (\$/kW-hr)

The cost of capital will vary for each storage system depending on how much storage capacity is needed or how long the energy must be stored. On a daily cycle which charges and discharges once a day, this is simply:

$$SCAP = PWR CST + STCST * 24 * PCF \quad (7)$$

where

PWR CST = the power related cost (\$/kW)

STCST = the storage related cost (\$/kW-hr)

For an idealized weekly cycle detailed in the Appendix, the cost becomes

$$SCAP = PWR CST + STCST \left[\left(\frac{72 - 43 PCF}{1 - PCF} \right) - 11.7 \right] PCF \quad (8)$$

This weekly cycle takes advantage of the weekend off-peak periods, while the daily cycle is not able to.

To calculate potential energy storage costs, the capital investment for the storage systems was estimated and is presented in Tables 5-7. The disparate cost differential between the two LWR storage systems is because the Dowtherm[®] system operates at a much lower temperature difference between the hot and cold storage and requires a separate turbine generator where the hot oil system does not. The LMFBR capital costs were adjusted from those developed in the HTGR system to reflect a lower differential between hot and cold storage.

Table 5. LWR storage systems costs, 1976 dollars

Item	LWR/Dowtherm [®]	LWR/hot oil
Storage-related costs, \$/kWhr(e)	23	13 ^a
Power-related costs, \$/kW(e)	327 ^b	257 ^a
Operating costs, \$/kW(e)	3 ^c	3 ^d

^a Estimated from Ref. 9 and adjusted to include interest during construction and adjusted to 1976 dollars.

^b Estimated with aid of Ref. 16.

^c Estimated with the aid of Ref. 17.

^d Estimated from Ref. 18.

Table 6. HTGR/salt peaking costs, 1976 dollars
[714 MW(e) 6 hr storage]

Item	Cost	
Power-related costs (10^6 \$)		
Structures and improvements	13	
Steam generator	10	
Turbine generator	71	
Electrical	<u>21</u>	
Subtotal	115	
Contingency (10%)	<u>11</u>	
Total direct costs	126	
Indirect costs (10^6 \$)	32	
Interest during construction (8%)	<u>47</u>	
Total power related costs	205	[287\$/kW(e)]
Storage costs (10^6 \$)	27	
Inventory	27	
Piping and pumps	5	
Tankage	<u>11</u>	
Subtotal	43	
Contingency (20%)	<u>8.6</u>	
Total direct costs	51.6	
Indirect costs (10^6 \$)	3.6	
Interest during construction	<u>10</u>	
Total storage costs	65	[15\$/kWhr(e)]
Storage-related costs	15\$/kWhr(e)	
Power-related costs	287\$/kW(e)	
Operating costs	4\$/kW(e)	

Table 7. LMFBR salt storage system
costs, 1976 dollars

Item	Cost
Storage-related costs, \$/kWhr(e)	19
Power costs, \$/kW(e)	319
Operating costs, \$/kW(e)	3.6

Figures 9, 10, and 11 are plots of projected cost for energy storage as a function of the incremental operating cost of the power system for each of the subject storage techniques. These are estimated for three storage cycles: (1) a daily cycle with 6 hr of storage; (2) a daily cycle with 12 hr of storage; (3) a weekly cycle with 21 hr of storage. Pumped storage is taken as a basis for comparison. The assumed economic parameters used to estimate the cost of the pumped storage system are listed in Table 8. These results show that at low incremental operating costs, representative of a utility system composed of a nuclear base load, pumped storage is the lowest cost. In the event that pumped storage is not available either through siting or environmental constraints, the HTGR/salt storage system is the next best choice for a 12 hr daily cycle, hot oil storage for a 21 hr weekly cycle and both are approximately equal for a 6 hr daily cycle. For incremental operating costs representative of a coal base loaded system, pumped storage is the best choice for the 6 hr-daily and 21 hr-weekly cycles, but the HTGR/salt system is cheapest for the 12 hr daily cycle. For systems that have oil fired plants in their base load, the HTGR/salt system has the cheapest power costs. Because of the high capital costs associated with the PWR-Dowtherm[®] system, it is not considered to be a viable option. Additionally, the LMFBR system could be competitive at very high fuel costs. The relative economic competitiveness of these systems is a strong function of three factors (1) their storage energy efficiency, (2) their storage related costs and (3) their power related costs. For instance, the HTGR/salt system has a higher storage efficiency than either pumped storage or the hot oil system so it becomes more competitive at higher incremental operating costs. Further, for a daily cycle the HTGR/salt power related costs are dominant compared to the storage costs, so a longer storage cycle (12 hr vs 6 hr) is more competitive because it has a larger capacity factor.

While evaluating the operating costs of the various storage systems gives an indication as to the relative economic value of each, it does not weigh the merit of a storage system against producing intermediate or peaking power directly with a power plant. To assess this we can equate

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Fig. 9. Power costs for storage systems (6 hr of storage, daily cycle).

Fig. 10. Power costs for storage systems (12 hr of storage, daily cycle).

Fig. 11. Power costs for storage systems (21 hr of storage, weekly cycle).

Table 8. Pump storage costs,
1976 dollars

Item	Cost
Storage-related costs, \$/kWhr	13 ^a
Power-related costs, \$/kW	192 ^a
Operating costs, \$/kW	2 ^a

^aEstimated from Ref. 18 and
adjusted to 1976 dollars.

the annual cost of storage and the annual cost of an intermediate or peaking power plant:

$$AC_s = ACAP_s + AOM_s + AF_s = ACAP_{ip} + AOM_{ip} + AF_{ip} = AC_{ip} \quad (9)$$

where

AC = Annual cost

ACAP = Annual capital cost

AOM = Annual operating and maintenance cost

AF = Annual fuel cost

Solving for CAP_s we have the equation for the breakeven cost of storage. That is the amount of money which can be expended to purchase energy which would breakeven with the cost of a fossil fuel plant:

$$ACAP_s = ACAP_{ip} + AOM_{ip} - AOM_s + AF_{ip} - AF_s \quad (10)$$

$$CAP_s = CAP_{ip} + \frac{AOM_{ip} - AOM_s + AF_{ip} - AF_s}{FCR} \quad (11)$$

$$AF_{ip} - AF_s = \text{cost fuel} \left(\frac{\eta - 1}{\eta} \right) * 8760 * PCF \quad (12)$$

$$CAP_s = CAP_{ip} + \frac{AFOM_{ip} - AFOM_s}{FCR} + INC \left(\frac{\eta - 1}{\eta} \right) \frac{* 8760 * PCF}{FCR} \quad (13)$$

where

AFOM = Annual fixed operating cost (\$/kW)

FCR = Fixed charge rate

CAP = Capital cost (\$/kW)

INC = Incremental operating cost (fuel + variable operating) (\$/kWhr)

PCF = Plant capacity factor

s = Storage

ip = Intermediate steam plant

η = Storage efficiency

To estimate the fuel costs, the utility system is assumed to charge the storage at approximately the incremental cost of a coal plant. This is a reasonable assumption because there are no utility systems that have a base load composed solely with nuclear, and those using oil and gas in their base load cannot use the storage to displace oil and gas, because storage would have the effect of using even more of these premium fuels. The economic parameters assumed for this comparison are listed in Table 9. The breakeven costs are plotted for both the HTGR/salt and pumped storage systems in Figs. 12 and 13 for fuel costs of 7, 10 and 15 mills, and are plotted as a function of plant capacity factor. The actual projected costs for the storage is also presented as a function of the design plant capacity factor for both daily and weekly storage cycles. From this it could be inferred that pump storage is competitive with fossil fuel plants at a plant capacity factor less than 0.3 for a weekly cycle and a plant capacity factor less than 0.6 for a daily cycle. The HTGR/salt storage system is competitive with the intermediate load fossil plants at a plant capacity factor less than 0.27 for a weekly cycle and less than 0.7 for a daily cycle.

For peaking use at low plant capacity factors, a gas turbine is an option trading its low capital cost for the high consumption of petroleum distillates. To estimate the breakeven cost of storage, the same equating procedure is used with the economic parameters listed in Table 10.

Table 9. Cost basis for coal electric steam plant comparison, 1976 dollars

Item	Cost
Capital cost of coal steam plant, \$/kW	533 ^a
Operating cost of coal steam plant	
Fixed, \$/kW	9 ^b
Variable, mills/kWhr	1.3 ^b
Fixed charge rate assuming no escalation, %	11

^a Estimated with the aid of Ref. 16.^b Estimated with the aid of Ref. 17.

Table 10. Cost basis for oil gas turbine comparison, 1976 dollars

Item	Cost
Capital cost of gas turbine generator, \$/kW(e)	125 ^a
Operating cost of gas turbine	
Fixed, \$/kW(e)	.70 ^a
Variable, mills/kWhr(e)	3.6 ^a
Fixed charge rate assuming no escalation, %	11

^a Ref. 19.

$$CAP_s = CAP_{gt} + \frac{AF_{gt} - AF_s}{FCR} + \frac{AOM_{gt} - AOM_s}{FCR} \quad (14)$$

$$CAP_s = CAP_{gt} + \frac{(INC)*8760*PCF}{FCR} + \frac{AFOM_{gt} - AFOM_s}{FCR} \quad (15)$$

where

s = Storage

gt = Gas turbine

CAP = Capital cost (\$/kW)

INC = Incremental operating cost (\$/kWhr) = $AF_{gt} - AF_s - VOM_{gt} - VOM_s$

Fig. 12. Cost comparison between HTGR/salt storage and coal-fired steam plants.

Fig. 13. Cost comparison between pumped storage and coal-fired steam plants.

VOM = Variable operating and maintenance cost (\$/kWhr)

AFOM = Annual fixed operating cost (\$/kW)

AOM = Annual operating and maintenance cost (\$/kW)

AF = Annual fuel cost (\$/kWhr)

The breakeven costs for the two storage systems with conventional gas turbines are shown in Figs. 14 and 15 as a function of plant capacity factor and the incremental differences in operating costs. It is clear that pumped storage is competitive with gas turbines on a daily storage cycle if the PCF is greater than 0.05 and greater than 0.08 on a weekly cycle. Because of the higher capital costs associated with the salt storage system, it would not be competitive for plant capacity factors below 0.13 on a daily cycle and 0.23 on a weekly cycle.

These results bring about the conclusion that at today's coal cost, energy storage is viable compared to producing intermediate load power within a certain range of operation. From the preceding we have determined that pumped storage is competitive with the coal-steam and gas turbine options within a 0.05–0.6 plant capacity range if the storage is done on a daily cycle and within a range of 0.13–0.3 if on a weekly cycle. With the HTGR/salt storage system the ranges are about 0.13–0.6 and 0.23–0.27 on daily and weekly bases, respectively.

To obtain an estimate of the market potential for a nuclear-dedicated storage system, a typical electric utility load duration curve can be used (Fig. 16). Given an approximate economic range of application such as that previously arrived at for the HTGR/salt system, the total energy market potential can be approximated by the areas under the curve in Fig. 16. It is clear that on a daily or weekly cycle it is impossible to physically make all of the off peak power available for peak power production because much of the variation is seasonal. In their recent report, Public Service Electric and Gas of New Jersey¹⁸ determined after an extensive analysis of many utility systems, that about 70% of the off-peak power is available on a weekly cycle and 40% on a daily cycle. Therefore, if the HTGR/salt system is constrained to plant capacity factors between .15–.6 on a daily cycle, this represents a total energy potential of about 3.8%. That is about 3.8% of the utility's energy can

Fig. 14. Cost comparison between HTGR/salt storage and gas turbines.

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Fig. 15. Cost comparison between pumped storage and gas turbines.

Fig. 16. Load duration curve.

economically be used for this storage system. If this were projected to a national level, it would represent about 7.2×10^7 MWhr, or equivalent to nine 3000 MW(t) HTGR's. However, this would in actuality be much smaller since some utilities are still using gas and oil to produce base load power and existing plants could be available to produce intermediate load and peaking power if additional nuclear base load was added. A more important point is the adaption of a dedicated nuclear storage system to a particular utility. Assuming a large utility generates about 5×10^7 MWhr annually and it has the same potential for energy storage (3.8%), then this would represent 1.9×10^6 MWhr(e) or equivalent to about 750 MW(t) of reactor power. This is probably rather optimistic and real potential would be somewhat less. The electricity produced by oil and gas in 1974 was estimated to be 6.19×10^8 MWhr(e).²⁰ On this basis 11.6% of the oil and gas could potentially be saved by thermal storage systems or 176,000 bbl/day of oil and 9.8×10^8 ft³/day of natural gas. While these storage systems have a moderate market if they are constrained to a daily cycle, a weekly cycle is much less attractive at today's fuel prices and could capture a much smaller market (Fig. 16).

In the distant future, nuclear power could encompass the entire base load. In such a scenario, it is envisioned that these dedicated nuclear storage systems could capture more of the intermediate and peak load market. In the extreme case where all available off-peak power is available for storage use to produce peak power, it is estimated in Ref. 18 that the energy portion needed to do this is 4% on a daily cycle and 7% on a weekly cycle, assuming the typical utility loads follow the present trend.

Another important factor to consider with any power system is its availability; that is the percentage of time that a plant is able to produce power irrespective of the demand. Since all storage systems addressed in this report are inherently coupled to a nuclear power plant, their availability can be no greater than that of the reactor and will in fact be somewhat less. However, a general storage system such as pumped hydro, batteries etc., would have an advantage because they draw their power directly from the utilities grid and are not dependent on a particular power plant. The past history of light water nuclear plant

availability can be seen in Fig. 17²¹ and was reported to be an average of 72.2% in 1975.²² Because most of the storage systems in this report have separate steam cycles, heat exchanger, pumps and piping, then their availability would probably be somewhat less than the reactors (65-70%). Pump storage is estimated to have an availability of 87%.¹⁸

The energy storage techniques considered here will have varying effects on their local environments, depending on the particular system. However, this effect will probably be small compared to the power plant it is coupled to. The areas of concern are the handling of massive quantities of storage media either the fused salts or oils and the possibility of their escape into the environment during operation or processing. However, it should be noted that these problems are well within current technological capabilities and should not pose any significant problems. Another consideration which is applicable to all storage techniques is the effect it has on the entire power system. Because all storage systems are less than 100% efficient, the system requires more energy production with storage than without, and a corresponding increase in effluents being released from the charging plants. Additionally, since storage systems will be charged primarily at night, the amount of effluents will increase at a time when the air is generally still and not conducive to dispersion.

CONCLUSIONS AND RECOMMENDATIONS

Thermal storage systems coupled to a variety of reactor concepts are both technologically feasible and economically competitive with fossil fuel power cycles for producing intermediate load and peaking power. The technology required to develop any of these storage systems is no more severe than that needed to develop the reactor concepts. In the event that pump storage is unobtainable either through site or ecological restrictions, then the LWR/hot oil storage system appears to be the best choice at nuclear level fuel prices and weekly storage cycles. However, the HTGR/salt system appears to be the best choice at present incremental operating cost (10-15 mills/kWhr) and better than pump storage at elevated costs because of its higher efficiency.

Fig. 17. U.S. LWR plant availability and forced outage rate.

The immediate market impact for these storage systems is considered to be small. Optimistically, 3-4% of the utilities energy generation could be used economically for storage, which represents only a portion of the thermal power of a commercial size reactor even for a very large utility system. In the future, if nuclear power or an alternate low fuel cost energy source captures a significant portion of the base load market, the importance of dedicated thermal energy storage will be somewhat greater, possibly capturing 5-7% of the total electricity demand. This would indicate a small but significant market for these storage systems depending on the size of the total power market, at a substantial savings of oil and natural gas. In addition to the potential market, another important factor is the system reliability. The nuclear dedicated storage facilities will have a lower availability than a system which is uncoupled from a power plant and can draw from multiple sources.

Although the results obtained in this study are based on simplifying assumptions and generalizations of utility systems, they are believed to be applicable to the nation as a whole. However, there are specific utility systems which do not fit this model and subsequently may have more or less potential for storage depending on their generation mix, size, and load variation. A more rigorous analysis should include not only allowances for capital based or operating costs but effects that these storage systems will have on future growth as well.

It is recommended that future studies include a case basis evaluation using actual utility systems as the models and utilizing a dispatching type computer code to determine the value that a high temperature nuclear storage system would have within operating systems. Further, an expansion planning code can be used to determine the value of these storage systems in providing reliability in future utility expansion. The results from this type of analysis should compliment the present work and provide reliable estimates for the potential impact of these systems.

APPENDIX

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WS	WEEKEND TIME (hr)	S	WEEKDAY CHARGE TIME (hr)
WD	WEEKEND DISCHARGE TIME (hr)	X	CHARGING CAPACITY (kW)
D	WEEKDAY DISCHARGE TIME (hr)	Z	DISCHARGING CAPACITY (kW)

Fig. A1. Weekly storage cycle.

Assumptions:

1. The storage charges and discharges only once per day or

$$D + S = 24 \quad (1)$$

2. The storage is totally discharged once per week or

$$X (WS - 2WD) = 2WD * Z + 4S * X = 5D * Z \quad (2)$$

3. The plant capacity factor (PCF) is defined as the energy output divided by the maximum energy output or

$$PCF = \frac{5D*Z + 2WD*Z}{168 Z} = \frac{5D + 2WD}{168} \quad (3)$$

4. The total hours in a week is 168 or

$$WS + 5D + 4S = 168 \quad (4)$$

If the charge discharge ratio is

$$C/D = X/Z$$

and by combining Eqs. (1) through (4) and rearranging

$$C/D = \frac{PCF}{1 - PCF}$$

Assuming the maximum storage will be that at the end of the weekend, then the energy stored will be:

$$\text{ENERGY STORED WEEKEND} = X(WS - 2WD) - 2WD*Z$$

Since $X = (C/D) Z$ then

$$\text{ENERGY STORED WEEKEND (kWhr)} = C/D*Z (WS - 2WD) - 2WD*Z$$

$$\frac{\text{Energy stored weekend}}{Z} = C/D (WS - 2WD) - 2WD = \text{hours stored}$$

From Eqs. (1), (3) and (4):

$$WS = 72 - 33.6 PCF + 2/5 WD$$

then

$$\text{Hours stored} = \left(\frac{PCF}{1 - PCF} \right) (72 - 33.6 PCF - 8/5 WD) - 2WD$$

and from Ref. 18 the ratio of the weekday peak demand/weekend peak energy demand is ≈ 13.3 then from Eq (3):

$$\frac{2WD + 26.6 WD}{168} = PCF$$

$$WD = 5.87 PCF$$

and

$$\text{Hours stored} = PCF \left(\frac{72 - 43 PCF}{1 - PCF} - 11.7 \right)$$

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