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A COST COMPARISON OF THE SATELLITE POWER
SYSTEM AND SIX ALTERNATIVE TECHNOLOGIES

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by

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DEFINITIONS OF UNIT SYMBOLS

Btu:	British thermal unit
°C:	degrees celsius
Ci:	curie (unit of radioactivity)
cm:	centimeter
d:	day
dB:	decibel
dBa:	decibel, adjusted
°F:	degrees Fahrenheit
g:	gram
GHz:	gigahertz (10^9 cycles per second)
GW:	gigawatt (10^9 watts)
h:	hour
J:	joule
kg:	kilogram (10^3 grams)
kJ:	kilojoule
km:	kilometer
kV:	kilovolt
kW:	kilowatt
kWh:	kilowatt-hour
L:	liter
lb:	pound
m:	meter
mL:	milliliter (10^{-3} liter)
mW:	milliwatt
MeV:	mega electron-volt (10^6 electron-volts)
MW:	megawatt
MWe:	megawatt (electric energy)
MWt:	megawatt (thermal energy)
MW-yr:	megawatt-year
μm:	micrometer (10^{-6} meter)
N:	newton (unit of force)
N/m ² :	newton per square meter
Pa:	pascal (unit of pressure: $1 \text{ Pa} = 1 \text{ N/m}^2$)
Q:	quad (10^{15} Btu)
s:	second
t:	metric ton (1000 kilograms)
T:	tesla (unit of magnetic force); also English ton
W:	watt
yr:	year

CONTENTS

EXECUTIVE SUMMARY	vii
REFERENCES FOR EXECUTIVE SUMMARY.	xx
1 INTRODUCTION	1
1.1 Background.	1
1.2 Objective and Approach.	1
2 ASSESSMENT FRAMEWORK	3
2.1 Overview.	3
2.2 Comparative Issues.	4
2.3 Selection of Energy Alternatives.	4
2.4 Characterization of Energy Systems.	5
2.5 Side-by-Side Analysis of Energy Systems	7
2.6 Alternative Futures Analysis.	7
2.7 Assessment Integration/Aggregation Techniques	8
3 CHARACTERIZATIONS OF THE SPS AND ALTERNATIVE TECHNOLOGIES.	9
3.1 Selection of Alternative Technologies	9
3.2 Brief Technical Description of Alternative Generation Systems	12
3.2.1 Satellite Power System	12
3.2.2 Central-Station Terrestrial Photovoltaic System.	19
3.2.3 Conventional Coal-Fired Power Plant.	20
3.2.4 Coal-Gasification/Combined-Cycle Power Plant	24
3.2.5 Light Water Reactor Power Plant.	28
3.2.6 Liquid-Metal, Fast-Breeder Reactor	30
3.2.7 Fusion	35
3.3 Cost Characterizations.	39
3.3.1 Satellite Power System	40
3.3.2 Conventional Coal-Fired Power Plant with Advanced Flue Gas Desulfurization	43
3.3.3 Combined-Cycle Power Plant with Low-Btu Gasifiers.	44
3.3.4 Light Water Reactor.	44
3.3.5 Liquid-Metal, Fast-Breeder Reactor	45
3.3.6 Fusion Reactor	45
3.3.7 Central-Station Terrestrial Photovoltaic	46
4 COMPARATIVE ANALYSIS	47
4.1 Assumptions and Alternative Futures Scenarios	47
4.1.1 Assumptions of the Comparative Analysis.	47
4.1.2 Alternative Futures Scenarios.	49
4.2 Cost and Performance.	66
4.2.1 Introduction	66
4.2.2 Uncertainty in Capital Cost Ranges for SPS and Alternatives	67
4.2.3 Fuel Price Projections	70

CONTENTS (Cont'd)

4.2.4	Cost Comparisons.	72
4.2.5	Cost Sensitivity Analysis	77
4.2.6	Comparative Cost Uncertainty.	85
REFERENCES.		92

TABLES

1	Developmental Status of the Technologies Selected for Comparison. .	ix
2	Major Characteristics of Alternative Central-Station Technologies .	xi
3	Capital Cost Ranges for Technical and Regulatory Uncertainty. . .	xiii
4	Levelized Energy Cost Ranges for Scenario CI.	xiv
5	Cost and Performance: Key Issues, Uncertainties, and Comparative Conclusions	xvi
6	Energy Supply Options	xvii
7	Evaluation of Energy Supply Options S1-S3 for Demand Scenario UH - Unconstrained, High Demand.	xviii
8	Evaluation of Energy Supply Options S4-S6 for Demand Scenario CI - Constrained, Intermediate Demand.	xix
2.1	Candidate Alternative Technologies.	6
3.1	Technologies Considered in Initial Screening.	10
3.2	Quantitative Screening of Energy Systems	11
3.3	Characterization Parameters for Plant Site and Fuel Cycle	13
3.4	SPS Cell and Planform Power Characteristics	17
3.5	Air Pollutants from a 1250-MW Coal Facility	24
3.6	Solid and Sludge Wastes from a 1250-MW Coal Facility, 70% Capacity Factor	24
3.7	Postulated Radionuclide Releases, 1250-MW LMFBR Power Plant at 70% Capacity Factor.	34
3.8	LMFBR Wastewater Effluents at Nominal Operation	35
3.9	Capital Requirements of the SPS, 1978 Dollars x 10 ⁶	42
3.10	Operations and Maintenance Costs of the SPS	43
4.1	RFF Model Assumptions about Population, Labor Force, Productivity and GNP, 1975-2025	52
4.2	Constrained Energy Supplies for Future Scenarios.	53
4.3	Assumed Long-Run Costs per Million Btu.	54
4.4	Nuclear Fuel Prices for Future Scenarios.	63

TABLES (Cont'd)

4.5	Electrical Generation in Comparative Scenarios and Two Other Projections	63
4.6	Total Installed and New-Construction Baseload Capacity for Six Comparative Assessment Scenarios.	64
4.7	Energy System Deployment for Scenario UH with and without SPS . . .	64
4.8	Energy System Deployment for Scenario UI with and without SPS . . .	65
4.9	Energy System Deployment for Scenario CI with and without SPS . . .	65
4.10	Capital Cost Uncertainty Factors for Alternative Technologies . . .	69
4.11	Capital Cost Ranges for Technical and Regulatory Uncertainty . . .	71
4.12	Fuel Cost Projections: Delivered Prices for Three Scenarios, 1980 to 2020	73
4.13	Base Capital Structure and Economic Assumptions	77
4.14	Levelized 2000-2030 Cost of Electricity from SPS and Alternative Technologies.	78
4.15	Effect of Reduced SPS Implementation Rate on Costs: Nominal Average Unit Costs.	83

FIGURES

1	Fuel Price Projections for Different Scenarios.	xiv
2	Development Costs of the SPS.	xv
2.1	Analysis Sequence for Comparative Assessment.	4
3.1	Satellite Power System Concept.	14
3.2	SPS Satellite Configurations.	15
3.3	SPS Efficiency Chain, GaAlAs and Si	16
3.4	Efficiency Chain of the Central-Station Photovoltaic System	19
3.5	Generation of 1250 MW, High-Sulfur Coal, Wellman-Lord Process . . .	21
3.6	Wellman-Lord Process.	23
3.7	1250-MW Coal-Gasification/Combined-Cycle System	25
3.8	Summary of Emissions from a 1250-MW, Low-Btu Gasifier, Combined-Cycle Plant.	27
3.9	Simplified LWR Flow Diagram	29
3.10	1250-MW Liquid-Metal, Fast-Breeder Reactor.	32
3.11	Configurations of Pool- and Loop-type Primary Coolant Systems . . .	33
3.12	Schematic of NUWMAK Fusion Power Plant.	36
3.13	Schematic of NUWMAK Load-Leveling System.	37

FIGURES (Cont'd)

3.14	Tritium Effluent System Design.	38
3.15	Development Costs of the SPS.	41
4.1	U.S. Energy Output Ratios, 1929-1974, and Base Projections to 2025.	50
4.2	Simplified Macroeconomic Model of the Interaction between Energy and the Economy.	51
4.3	Ratio of Gross Energy/GNP, in 10^3 Btu/1971 \$	55
4.4	Supply-Demand Patterns for Various Scenarios in the Year 2000	56
4.5	Supply-Demand Patterns for Various Scenarios in the Year 2025	57
4.6	Electrification as a Percentage of Net Energy Use: Three Scenarios	58
4.7	Delivered Oil Prices.	59
4.8	Delivered Natural Gas Prices, $\$/10^6$ Btu	60
4.9	Delivered Coal Prices, $\$/10^6$ Btu.	61
4.10	Electricity Prices, $\$/10^6$ Btu	62
4.11	Cost and Performance Evaluation Framework	67
4.12	Fuel Price Projections for Different Scenarios.	74
4.13	U ₃ O ₈ Prices for Constrained and Unconstrained Scenarios	75
4.14	Typical Patterns of Costs and Revenue Requirements.	76
4.15	Levelized Energy Cost Ranges for Scenario UH.	79
4.16	Levelized Energy Cost Ranges for Scenario UI.	80
4.17	Levelized Energy Cost Ranges for Scenario CI.	81
4.18	Total Energy Costs as a Function of Capacity.	82
4.19	Effect of Changes in Financial Assumptions on Relative Positions of Technologies	84
4.20	Comparison of Coal and SPS Energy Costs with Fixed Parameters and Inputs	85
4.21	Coal Prices	86
4.22	Real Coal Price Increases	88
4.23	Distributions of Levelized Fuel Cost and Levelized Capital Charge of a Coal Plant.	89
4.24	Typical Cost Distribution for Advanced Technologies	89
4.25	Distributions of the Sum of Cost Elements	90
4.26	Probability Curves of SPS Costs Equalling Coal Costs.	91

EXECUTIVE SUMMARY

The SPS Concept Development and Evaluation Program (CDEP)¹ was established by the Department of Energy (DOE) and the National Aeronautics and Space Administration (NASA) to generate information by which a rational decision could be made regarding the direction of the Satellite Power System (SPS) program after fiscal 1980. The four functional areas within the joint DOE/NASA CDEP are as follows:

- Systems Definition: development of the SPS reference system design.
- Environmental Assessment: evaluation of potential environmental effects of SPS.
- Societal Assessment: evaluation of potential societal effects of SPS.
- Comparative Assessment: development of a comparative data base on the SPS and six other energy technologies.

The results of the first three activities are inputs to the comparative assessment process as well as independent program assessments.

This report describes the comparative cost analysis portion of the comparative assessment. Other relevant issues are compared in another report,² and the integrated comparative assessment is comprehensively described in other reports.^{3,4} The objective of the comparative assessment was to develop an initial understanding of the SPS with respect to a limited set of energy alternatives. This is consistent with the overall CDEP objective, that is, to determine whether or not the SPS concept is sufficiently attractive (presenting no insurmountable barriers) to receive further research investment.

In all comparative assessments it is vital that the assumptions, uncertainties, and significant differences between the systems being compared are clearly and objectively presented. Otherwise, the comparison may prove useless for making meaningful decisions. The key assumptions and ground rules of this assessment are as follows:

1. The baseload electric generation technologies are projected to be on line in the year 2000, with an approximate availability date of 1990. Further, the R&D base and the infrastructure are assumed to be in place when required.
2. All data are traceable to publicly available information.
3. Each technology is treated as an independent variable. For example, if coal costs go up or down, the costs of the other technologies are assumed not to change for the same reasons.

4. Where no historical data or basic reports were available, the analysts specified the conditions they chose and presented their rationales for choosing them. In cases where the chosen conditions favor or disfavor a technology, the analysts stated the bias.

The SPS, fusion, and central-station terrestrial photovoltaics technologies have received less engineering design and R&D than the other technologies examined in this assessment. Therefore, they are subject to larger uncertainty as well as greater optimism. Furthermore, the life cycle costs of these three technologies are reduced, since the R&D and infrastructure costs are not addressed explicitly, in keeping with the second part of the first assumption.

The third assumption tends to exaggerate cost overlap, but taking correlated characteristics into account was not feasible in this study except in a theoretical way. The choices made under the fourth assumption tend to favor the two solar technologies and fusion.

The intent of the data derived under these assumptions is to compare SPS to each of the other six technologies, or to subsets of the six, or to all six technologies together. The limitations resulting from the assumptions preclude other comparisons. Within these assumptions and ground rules, the six limited but representative energy technologies were selected, characterized, and documented. These data were normalized to unit bases, such as dollars per megawatt, and alternative futures were compared (i.e., possible technology mixes, supply and demand cases, and cost uncertainties).

The technology alternatives selected for comparison with the SPS were limited to the following:

- Improved conventional coal technology
- Light water reactor (LWR)
- Coal gasification/combined cycle (CG/CC)
- Liquid-metal, fast-breeder reactor (LMFBR)
- Central station, terrestrial photovoltaic (TPV)
- Fusion (magnetically confined)

These selections were considered to be the most representative set of year-2000 energy technologies for comparison to the SPS reference system. It should be noted that the selections were not made by DOE, but by the Concept Development and Evaluation Program.

A six-step comparative methodology is described briefly in this report and more thoroughly in a companion report.⁵ This assessment included only five of the six steps (i.e., selection of alternatives, issue selection, system characterizations, side-by-side analysis, and alternative futures analysis).

The present report represents an update of the cost comparison reported in the preliminary comparative assessment³ and has added an alternative

futures analysis. The update includes changes in the technology descriptions as well as improvements in the analyses.

Included in this document are a brief description of the comparative methodology, brief characterizations of the alternative technologies, side-by-side comparisons, and alternative futures analysis for three different scenarios.

Comparisons were performed for technologies that are at different stages of development -- current, near-term, and advanced -- and for which, therefore, different degrees of information are available (e.g., actual vs. projected construction data). Table 1 lists experience and uncertainty levels for the technologies evaluated in this assessment. Capital cost uncertainty factors and cost uncertainty issues are also listed. These cost uncertainty factors were developed on the basis of existing relevant documentation and on the judgments of the assessment participants.

As stated earlier, the information presented and developed in these comparisons has been derived from published research and information found in the literature for the various technologies. However, in some instances, data have not been available from such sources, and it has been necessary to develop these data either through analysis or on the basis of engineering judgment. In these instances, the rationales are explained and the inherent uncertainties duly noted.

Table 1 Developmental Status of the Technologies
Selected for Comparison

Technology	Units in Operation	Capital Cost Uncertainty Rating	Cost Uncertainty Issues
Conventional			
Coal	100	2	Fuel, ECT ^a
LWR	50	2	Fuel, ECT
CG/CC	5	3	Fuel
LMFBR	5	3	Fuel, ECT
TPV	0	4	Materials, cell efficiency
SPS	0	4-5	Materials, ECT, Space Transport, and Construction O&M
Fusion	0	4-5	Materials, Con- tainment Design, ECT

^aECT - Environmental Control Technology.

Cost and performance characterization data for the alternative technologies are presented briefly in Sec. 3 and form the basis for the comparisons that are reported in Sec. 4. Cost data for the SPS were obtained from NASA-sponsored Boeing and Rockwell systems design efforts. Cost estimates for the alternative technologies were developed from reference design reports.

ALTERNATIVE TECHNOLOGY CHARACTERIZATIONS

Six alternative technologies were selected for comparison with the SPS; their major characteristics are displayed in Table 2. The general approach was to review a broad segment of the recent technical literature concerned with the characteristics of the individual technologies and their accompanying fuel cycles. This data base of information was then synthesized into the alternative technology reference characterizations by adapting the data into internally consistent energy and materials balances for each of the systems. Where appropriate, a nominal generating capacity of 1250 MWe was selected for the reference technologies. Only the terrestrial photovoltaic and fusion systems differ from this nominal capacity due to special considerations unique to each system.

Detailed lists of equipment, materials, and site labor requirements from the Energy Economic Data Base (EEDB) and other major references were used as the basis for estimating the direct and indirect capital construction costs and construction labor requirements for many of the systems. For technologies not included in the EEDB, similar data from other major references were used. All costs are presented in 1978 dollars.

Direct capital costs include the costs of all materials, components, structures, and direct labor necessary for construction of the reference facility at the plant site. Indirect costs include temporary site construction facilities, payroll insurance and taxes, and other construction services. Excluded are items sensitive to the particular policies of individual utilities, including owner's costs, fees and permits, interest on construction funds, contingency funds, and price escalation during construction.

Nonfuel O&M costs were derived on the basis of labor requirements, disposal and materials handling costs, and other factors applicable to the respective technologies. Decommissioning costs for each of the nuclear systems were also included. Fuel costs for each of the systems are scenario-dependent and will be estimated as part of the subsequent cost and performance analysis.

ALTERNATIVE FUTURES SCENARIOS

Since the objective of this comparative assessment is to compare technologies projected for the post-2000 era, a great number of assumptions are required. Most of these assumptions are highly uncertain and interdependent so that a single consistent set may not present the decision maker with an adequate comparative perspective of the future. The alternative futures analysis was chosen as a means of providing a broader perspective of key parameters that may describe the future. The assumptions underlying the

**Table 2 Major Characteristics of Alternative
Central Station Technologies***

Characteristic	Conventional Coal with Advanced FGD	LWR, Improved Fuel Use	CG/CC	LMFBR	TPV	Magnetic Confinement Fusion
Major Feature	Wellman-Lord SO ₂ Removal	Fuel Burn up 50 MWd/kg U	32 Fixed-Bed Gasifiers	Uranium/ Thorium Fuel Cycle	Cell Efficiency Like SPS	NUWMAK Concept
Nominal Capacity (MWe)	1,250	1,250	2 @ 625	1,250	200	2 @ 660
Heat Rate (Btu/kWh)	9,546	10,224	8,865	9,330	NA	10,835
Conversion Efficiency (%)	35.8	33.4	38.5	36.6	14.2	31.5
Air Emissions						
Plant Site						
SO ₂ (T/yr)	21,200	-	11,090	-	-	-
NO _x (T/yr)	22,000	-	2,320	-	-	-
Particulates	250	-	200	-	-	-
Radionuclides (Ci/yr)	-	4,100	-	155	NA	730
Fuel Cycle						
SO ₂ (T/yr)	290	6,040 ^a	270	6	NA	-
NO _x (T/yr)	220	1,600 ^a	205	23	NA	-
Particulates	1,300	1,550	1,200	1	NA	-
Radionuclides (Ci/yr)	-	95	-	409,500	NA	-
Solids and Sludges						
Plant Site						
Dry Sulfur (T/yr)	95,565	-	91,725	-	NA	-
Ash Sludge (T/yr)	426,490	-	317,060	-	NA	-
Other (T/yr)	18,400	b	18,600	b	c	b
Radionuclides (Ci/yr)	-	11,000	-	33,000	NA	9,000 ^d
Fuel Cycle Solids (T/yr)	113,600	215	105,650	1	NA	-
Liquid Effluents						
Plant Site						
Total Solids (T/yr)	16,000	1,330	16,000	1,330	-	c
Radionuclides (Ci/yr)	-	405	-	482	NA	c
Fuel Cycle						
Total Solids (T/yr)	5,220	-	4,850	-	NA	-
Radionuclides (Ci/yr)	-	1,500	-	c	NA	-
Water Use (10 ⁶ gal/day)	70	33	13	29	-	37
Land Use						
Plant Site (acres)	500	500	500	500	1,000	500
Fuel Cycle (acres/yr)	250	22	235	1	NA	-
Labor Requirements						
Plant Construction						
(10 ⁶ man-hours)	9.3	15.5	13.4	12.7	1.7	17.4
Plant Operation (persons)	259	215	336	225	26	c
Fuel Cycle (persons)	650	225	605	c	NA	-
Costs (1978 dollars)						
Direct (10 ⁶ \$)	452.1	486.0	537.4	702.9	117.5	1,533.2
Indirect (10 ⁶ \$)	90.7	197.1	132.7	262.6	20.0	628.6
Total (10 ⁶ \$)	542.8	683.1	670.1	965.5	137.5	2,161.8
Total (\$/kWe)	434.2	546.5	536.1	772.4	687.5	1,637.7
O & M Cost (mills/kWh)	3.1	2.2	2.7	2.9	3.4/4.6 ^e	7.3
Operating Factor (%)	70	70	70	70	25.8/19.1 ^e	70

NA: Not Applicable.

-: Small or Negligible

^a98% due to supporting power production

^bQuantified in terms of Ci/yr

^cNot estimated

^dAfter 10 yrs of on-site storage

^eValues for Phoenix/Cleveland

*Conversion factors: Btu x 1.06 = kJ; T x 0.907 = t; gal x 0.0038 = m³;
acres x 0.004 = km².

alternative futures analysis constitute a set of energy supply/demand futures or scenarios.

Six scenarios were created from a consistent economic model so that interdependencies between economic assumptions were preserved. Scenarios were selected as a means of exploring and analyzing, not predicting, the economic energy future. The scenarios were selected to represent a plausible future world, and no probabilities were assigned to any of them. Scenarios were selected to provide a comparative perspective on the negative and positive aspects of demand and mixes of supply technologies in the post-2000 era.

A model developed by Resources for the Future, Inc. (RFF)⁶ was selected for this assessment on the basis of several selection criteria -- sectoral detail, endogenous treatment of both capital investment and final demand, and transferable experience in the form of existing model runs covering the desired time frame, 2000-2030.

One GNP trajectory was selected for all scenarios. For simplicity, three alternative price elasticities of aggregate demand for energy were considered, viz.,

- H: High energy intensiveness, corresponding to low elasticity (-0.25);
- I: Intermediate energy intensiveness, corresponding to intermediate elasticity (-0.4 for residential and housing demand, -0.7 for industry, 0 for feedstocks);
- L: Low energy intensiveness, corresponding to high elasticity (-0.75).

Regarding constraints, two cases were selected:

- U: Unconstrained supply of coal and nuclear power;
- C: Constrained supply, due to health, safety, environmental, and other limitations on the rate of supply increase.

The three price elasticities and two different constraints resulted in the development of six scenarios. Each of these scenarios resulted in different supply-demand patterns and different fuel (i.e., coal and nuclear) price trajectories. Three of these six scenarios [i.e., unconstrained high energy (UH), unconstrained intermediate energy intensity (UI), and constrained intermediate energy intensity (CI)] were selected for the alternative futures comparisons.

COST AND PERFORMANCE

Table 3 shows the nominal capital costs and capital cost uncertainty factors that were developed for the SPS and the six alternative technologies. The following three factors were considered to include the major capital cost uncertainties and were used to derive the capital cost uncertainty ratios shown in Table 3.

Table 3 Capital Cost Ranges for Technical
and Regulatory Uncertainty (\$/kW)

Costs	Coal	LWR	CG/CC	LMFBR	TPV	Fusion	SPS
1978 Costs (Nominal)	549	712	690	1037	844	2378	3340/3079
2000 Costs							
Low	647	886	813	1291	731	2378	3139/2874
Nominal	762	1100	957	1603	1057	3677	3646/3362
High	1605	2566	2623	5048	4229	?	16,698/ 15,398
Cost Ratios:							
2000 Low/1978 Nominal	1.18	1.24	1.18	1.24	0.87	1.00	0.94/0.94
2000 Nominal/2000 Low	1.18	1.24	1.18	1.25	1.45	1.55	1.16/1.16
2000 High/2000 Nominal	2.11	2.33	2.74	3.14	4.00	?	4.58/4.58

1. Uncertainty about future costs of materials, supplies, and labor necessary to construct powerplant facilities;
2. Uncertainty about the future requirements and associated costs of environmental and safety equipment; and
3. Uncertainty about the capability of technologies to perform as conceptualized.

The analysis of the alternative energy supply/demand scenarios resulted in the range of fuel prices shown in Fig. 1. The range of coal prices seems to bracket forecasts made by others, and the light water reactor fuel price is similar to that in other projections.

The capital cost ranges and scenario-dependent fuel prices were used to calculate levelized energy cost ranges for each technology. Table 4 shows the levelized energy cost ranges for the SPS and the six alternatives for scenario CI (constrained coal and nuclear, intermediate energy demand). Similar energy cost ranges were calculated for other scenarios with similar cost ranges. These cost ranges were developed with independent reference costs so that the degree of overlap between coal and nuclear technologies and the SPS systems is not as large as shown in Table 4, because there is probably some correlation between the SPS cost base and coal/nuclear data bases that are not accounted for in these calculations.

DEVELOPMENT COSTS

Boeing⁷ estimated development costs on the basis of the reference system scenario, which predicates a 20-year development schedule and a 30-year deployment schedule (for 60 5-GW satellites). These costs amount to \$100-110 billion and are broken down as follows (Fig. 2):

- Research costs: mainly ground-based research to address environmental and social issues and alternative systems, resulting in a preferred system;

Table 4 Levelized Energy Cost Ranges for Scenario CI^a

Technology	Cost, (1978) mills/kWh		
	Low	Nominal	High
SPS			
Si	45.6	52.1	218.1
GaAlAs	42.3	48.5	201.7
Coal			
Conventional, High-S	-	41.1	54.8
CG/CC	-	42.0	69.0
Nuclear			
LWR	-	30.0	53.8
LMFBR	-	35.1	90.9
TPV	36.6	51.4	195.7
Fusion (NUWMAK) ^b	-	74.0	-

^aThis constrained scenario represents continuation and augmentation of current regulatory trends concerning emissions, health, and safety. The price elasticity of energy demand is assumed to be moderate (intermediate), which is considered the most likely situation if constraints are maintained.

^bNo range was established for the cost of energy from fusion.

Fig. 1 Fuel Price Projections for Different Scenarios

Fig. 2 Development Costs of the SPS
(Source: Ref. 8)

- Engineering: development and testing of prototype sub-systems, resulting in specifications for demonstration units and production facilities;
- Demonstration: flight tests of a 100-200 MW unit integrated with a commercial network;
- Investment: development of industrial infrastructure, e.g., transportation, photovoltaic, and klystron manufacturing facilities.
- Construction and implementation: the first 5-GW SPS unit put into place.

It is important to note that these cost estimates assume that all effort is specific to the SPS. The benefits from generic research or from cost sharing (e.g., industry or other federal program support for photovoltaics manufacturing facilities) have not been considered. Such cost modifications could amount to 50-70% of the \$102.5 billion.⁹

Since comparable cost data for the other six technologies were not available, side-by-side comparisons of costs or of the benefits or disadvantages of public expenditures were not attempted.

RESULTS

This comparative assessment analyzed each technology, given different post-2000 economic climates and the economic trajectories that would lead to those climates (alternative futures analysis). Conclusions were formed separately for these two types of analyses and are summarized in Table 5. Comparisons are described in terms of the key issue, uncertainty about the understanding of that issue, and a concluding comparative statement that cuts across all technologies.

Table 5 Cost and Performance: Key Issues, Uncertainties, and Comparative Conclusions

xviii

System	Key Issue	Uncertainties	Comparative Conclusions
Coal (Conventional, CG/CC)	Capital cost expected to escalate only slightly but coal price would raise energy price substantially.	Coal price uncertain but dependent on amount of demand and environmental regulations.	SPS is economically competitive with coal and nuclear if fuel prices rise sharply and environmental regulations raise the capital cost of these technologies. However, if the regulatory climate is severe for coal and nuclear it may also affect SPS. The probability that SPS will be cost competitive with coal is very small until well after 2000.
Nuclear (LWR, LMFBR)	Capital cost will probably escalate due to environmental and safety regulations. Uranium prices expected to increase.	Capital cost increases are uncertain.	
TPV	Costs depend strongly on cell production cost.	Large improvements required in cell cost.	SPS has approximately the same cost range as TPV and fusion, but the range is very large and no judgments can be made regarding any cost advantages. More detailed cost evaluations and design studies would be required to evaluate the relative economic viability of the advanced technologies.
SPS	Capital cost and system efficiency dominate energy cost.	Cell cost; transportation cost, and system performance are all uncertain.	
Fusion	Containment costs cannot be estimated very well.	Plasma containment cost is highly uncertain. System performance and reliability unknown.	

Table 6 describes the six mixes of technologies that were analyzed in terms of meeting the energy demand for two different scenarios (i.e., UH and CI). Tables 7 and 8 summarize results about mixes of technologies from an energy supply/demand perspective. In these tables, the comparative analyses are described briefly.

Table 6 Energy Supply Options

Supply Option	Description
S1 Conventional	Conventional coal combustion and combined-cycle plants and nuclear LWRs with advancement to LMFBRs make up this supply option. Coal and uranium would be continually used in conventional systems until they are replaced by improved systems, e.g., combined-cycle coal gasification and the LMFBR.
S2 Conventional fuel utilization plus SPS	This supply option includes the use of coal, with nuclear only in the form of the LWR, replaced by the SPS when fuel prices for uranium either rise too high or the resource is depleted.
S3 Conventional fuel sources plus fusion	This option utilizes coal, with nuclear in the form of both the LWR and LMFBR, and replaces these systems with fusion. If fusion is not available when the LWR fuels are running low, the LMFBR would be utilized until fusion technology is available.
S4 This is the same as Supply Option 1	
S5 Conventional systems plus SPS	Same as Supply Option 2.
S6 Conventional systems plus fusion	In this case since the energy demand is expected to be low, only nuclear LWRs would be used until fusion would be available. Since the energy demand is low, it is expected that the uranium fuel would last until fusion technology could be applied.

Table 7 Evaluation of Energy Supply Options S1-S3 for Demand
Scenario UH - Unconstrained, High Demand

Scenario Definition			
Energy Demand	Energy Supply	Issue	Comparative Analysis
Electrical energy demand is high because coal and nuclear energy remain relatively cheap. Regulation impositions will not get much larger. Conservation and substitution do not penetrate to a great degree.	<u>S1 - Conventional Coal</u> (Conv. and CG/CC)	<u>Energy Cost</u>	Low because costs of conventional sources remain relatively lowest of all scenarios).
	Nuclear (LWR, LMFBR) Continued use of conventional sources with improved systems. LMFBR could provide energy for many years.		
	<u>S2 - Conventional + SPS</u> (Coal, LWR, SPS)	<u>Energy Cost</u>	Higher energy cost than S1 because of depleting uranium stocks and the introduction of a new technology.
	Conventional systems will be used until the SPS is implemented.		
	<u>S3 - Conventional + Fusion</u> (Coal, LWR, LMBFR, and Fusion)	<u>Energy Cost</u>	Higher than S1; slightly lower than S2.
	Conventional systems including some form of breeder until fusion technology is available.		

Table 8 Evaluation of Energy Supply Options S4-S6 for Demand
Scenario CI - Constrained, Intermediate Demand

Scenario Definition		Issue	Comparative Analysis
Energy Demand	Energy Supply		
Electrical energy demand is low because regulations and fuel prices have driven up the cost of energy. Conservation and other supply substitutions are selected, thereby lessening the demand for electrical energy.	<u>S4 - Conventional</u> (Coal, LWR, LMFBR) Because of low electrical demand, conventional supply systems could be used for many years (i.e., fuel stretchout). Breeder could be implemented when fuels are depleted (e.g., 2030).	<u>Energy Cost</u>	High because of restrained conventional sources.
	<u>S5 - Conventional + SPS</u> (Coal, LWR, and SPS) Because of low demand for electricity, SPS would not be required until later (e.g., 2020).	<u>Energy Cost</u>	Lower than S4 because replacement technology will hold down fuel prices somewhat.
	<u>S6 - Conventional + Fusion</u> (Coal, LWR, LMFBR, and Fusion) Because of low demand for electricity, fusion would not be needed until later (e.g., 2020).	<u>Energy Cost</u>	Lower than S4, maybe less than S5.

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1 INTRODUCTION

1.1 BACKGROUND

The SPS Concept Development and Evaluation Program (CDEP)¹ was established by the Department of Energy and the National Aeronautics and Space Administration to generate information from which a rational decision could be made regarding the direction of the Satellite Power System (SPS) Program after fiscal 1980. The comparative assessment program is one of four functional areas within the joint DOE/NASA CDEP. The other CDEP functional areas are:

- Systems definition: reference system design, alternative and advanced concept design, and critical supporting studies.
- Environmental assessment: evaluation of human health and safety, ecological, atmospheric, and electromagnetic interference issues pertaining to microwave transmission, power-line transmission, transportation activities, construction, and operation of the SPS.
- Societal assessment: evaluation of international issues, institutional issues (e.g., utility interfacing), resource issues, and public outreach.

The results of these three activities are inputs to the comparative assessment process as well as to program assessments. These four areas form the basis for the CDEP assessment of the technical possibility, economic viability, and environmental and social acceptability of the SPS concept.

1.2 OBJECTIVE AND APPROACH

The objective of the assessment is to provide an initial, traceable and consistent comparison of the SPS and selected current, near-term, and advanced energy technologies. To achieve this objective, the comparative assessment was divided into four parts:

1. Energy alternatives characterization: terrestrial alternatives were selected, and their cost, performance, and environmental and societal attributes were specified for use in the comparison with the SPS in the post-2000 era.
2. Methods: the framework for comparisons was established.
3. Evaluation: the SPS was compared with alternative systems in terms of key issues such as life-cycle cost and environmental impacts.
4. Management and integration: the results of the assessments were assembled and integrated into a consistent comparative assessment.

Data on alternative technologies were sought from previous research and from other comparisons, and data on the SPS developed by other parts of the program were evaluated and used for the cost comparison. Traceable data were gathered on alternative technologies, evaluated, and normalized to some consistent power or energy level and then synthesized into a format convenient for comparison.

A cost comparison such as this cannot proceed without a large number of initial assumptions. Furthermore, a group of technologies that is representative, for which data exist, and of a size reasonable for study must be selected from a larger set. These assumptions and technologies were selected on the basis of an objective selection procedure and the subjective judgments of the assessors and their program staff. The documentation of this comparison was prepared to provide the reader who strongly objects to some assumptions or data with ample information for reanalysis of the comparison with other data or assumptions. However, the many assumptions and data selections supporting this report were made carefully and thoughtfully.

This cost comparison is a revision and expansion of the comparison found in the preliminary assessment.

The preliminary assessment² evaluated six centralized baseload technologies: conventional coal; light water reactor (LWR); coal gasification/combined cycle (CG/CC); liquid-metal, fast-breeder reactor (LMFBR); central-station, terrestrial photovoltaic (TPV); the satellite power system (SPS); and fusion. For the final comparative assessment, some minor modifications were introduced into this group of technologies; most notably, an improved emission control system for the conventional coal technology and an improved fuel utilization cycle for the LWR were assumed.

The technologies compared with the SPS in this assessment vary in their stages of development and, therefore, in their degree of definition. This variability was handled by qualifying the data wherever possible: for example, a technological uncertainty factor was applied to data used in the cost and performance comparisons.

The assessment framework or methodology for the complete comparative assessment is described briefly in this report and in more detail in another report.³ The sixth (integration/aggregation techniques) was not carried out in the comparative assessment. Instead of a formalized procedure for reducing the comparative information to a specific, condensed format for decision-making, the information is presented in its entirety; it was assumed that decision makers would use their own procedures for summarizing and evaluating the information.

The side-by-side comparison reported here is a normalized comparison (i.e., per unit of energy output) based on assumptions about the economic conditions in the beginning of the 21st century. This alternative-futures comparison defines plausible economic and energy futures and makes comparisons on the basis of the energy and economic climate pertinent to these futures.

Reported in this document are a brief description of the comparative methodology; brief characterizations of the alternative technologies; side-by-side and alternative futures cost comparisons.

2 ASSESSMENT FRAMEWORK

2.1 OVERVIEW

This section describes a framework for comparing the SPS with various projected alternative energy sources on the basis of technical possibility, economic viability, and social and environmental acceptability. This cost comparison followed the framework for cost issues only. Other issues were compared in the broader framework of the comparative assessment. A more detailed description of the approach and method used in the assessment is contained in the methodology report for the comparative assessment.³

The analysis in the comparative methodology is composed of the following steps (Fig. 2.1):

1. Comparative issues selection and organization. Key issues from the deployment of the SPS and the alternative systems are selected and organized into an appropriate taxonomy.
2. Energy alternatives selection. Alternatives similar in utility to SPS are selected. Many possible issues and alternatives are examined, and these selections provide an initial focus for the remaining steps in the comparative assessment.
3. Energy system characterization. The energy system characterization provides reference data on technology costs and performance, resource use, and environmental residuals.
4. Side-by-side analysis of energy systems. Side-by-side analysis normalizes the energy output from each system to allow comparison of alternative technology impacts.
5. Alternative futures analysis. The alternative futures analysis incorporates the results of the side-by-side impact analysis into future energy supply/demand and state-of-the world scenarios that are not forecasts but are designed to examine specific issues and potential problems over a range of possible futures.
6. Development and application of integration/aggregation techniques. The development of formal techniques for integrating and aggregating the large amounts of data and information provided by the analysis will aid the decision maker in formulating SPS program recommendations.

Only the first five steps have been carried out in this comparative assessment. The following sections describe each of these six steps of the comparative assessment framework in more detail.

Fig. 2.1. Analysis Sequence for Comparative Assessment

2.2 COMPARATIVE ISSUES

The selection of issues for the comparative assessment must be guided by the idea that not only should the issues structure be general enough to accommodate different impacts that result from the alternative technologies, but it should also be specific enough so that comparisons between technologies are feasible and commensurate.

In the cost and performance category, the life-cycle cost and system performance are compared. The R&D cost comparison between technologies was not considered because of the inability to develop an acceptable methodology or accurate data. Life-cycle cost includes development, construction, operation, maintenance, and decommissioning. Reliability is an example of an important system performance issue. The costs being compared are projected, and it is important to specify the uncertainty in these projections so that conclusions can be drawn in perspective.

2.3 SELECTION OF ENERGY ALTERNATIVES

The technologies initially considered for comparison with the SPS listed in Table 2.1 include six fossil options, ten nuclear technologies (including two fusion options), five solar technologies, and three geothermal technologies. The list was narrowed to six technologies according to the following criteria:

- Technical data must be available in sufficient detail to allow adequate technical characterization and comparison.
- The candidates must be central-station, baseload technologies.
- The technology should be available for commercial application by year 2000.
- Include improved current baseload technologies.
- Include representative advanced technologies currently being engineered.
- Include alternative (nonspace) applications of photovoltaic solar energy technology.
- Include alternatives that show potential as long-term energy sources after 2000.
- Fuel must be available for a long period (e.g., 2000-2050).

The energy alternatives selected were conventional coal with stack scrubber, coal gasification/combined cycle, the light water reactor, the liquid-metal breeder reactor, fusion, and the photovoltaic solar central station. Missing from this list are wind, biomass, decentralized solar (e.g., space heating and cooling, process heating and cooling, water heating; and photovoltaics for electrical energy production), and OTEC. These technologies were not included in the final list because they are not large central-station-baseload options or they have only regional application.

2.4 CHARACTERIZATION OF ENERGY SYSTEMS

Following the selection of energy alternatives and the preliminary selection of comparative issues, the reference energy systems were defined and described, and data on cost, performance, and environmental impact were collected from published sources for issue comparisons.

The ground rules for this data collection included the following:

- Characterizations should use readily available information.
- Characterizations should be performed and documented by persons who are knowledgeable about alternative technologies and DOE programs.
- Each technology characterization should be internally consistent.
- The set of characteristics should be consistent enough overall, to facilitate comparisons with the SPS concept.
- There should be enough information to allow adequate evaluation of issues (failing this criterion, a candidate technology may have to be dropped).

Table 2.1 Candidate Alternative Technologies

Fossil

Coal-Steam, Conventional
 with Improved Environmental Controls
 with Atmospheric Fluidized Bed
 Pressurized Fluidized Bed
 Gas Turbine, Closed-Cycle
 Open-Cycle, Low-Btu Gasifier
 Open-Cycle, Synthetic Liquid Fuel
 Metal Vapor Topping Cycle
 Molten Carbonate Fuel Cell
 Magnetohydrodynamic, Open-Cycle
 Closed-Cycle

Nuclear Fission

Light Water Reactor, Conventional
 with Improved Fuel Utilization
 with Mixed-Oxide Fuel
 High Temperature Gas-Cooled Reactor
 Advanced High Temperature Reactor
 Liquid-Metal, Fast-Breeder Reactor
 Gas-Cooled, Fast-Breeder Reactor
 Light Water Breeder Reactor
 Electronuclear Breeder
 Fusion-Fission System

Fusion

Magnetic Confinement
 Inertial Confinement

Solar

Terrestrial Thermal
 Terrestrial Photovoltaic
 Ocean Thermal Energy
 Wind Energy
 Biomass Fuels

Geothermal

Hydrothermal
 Geopressurized
 Hot Dry Rock

2.5 SIDE-BY-SIDE ANALYSIS OF ENERGY SYSTEMS

The objective of the side-by-side analysis is to compare the alternatives on the basis of single units normalized to the same power level, using a consistent set of ground rules for all units. This was the first analytical step of the comparative assessment, and it entailed listing information (some detailed, some summary) for each of the energy systems. Information categories cover the technical, economic, environmental, and societal issues mentioned earlier.

Two important functions of the side-by-side analysis are: (1) providing the decision maker and analyst with a normalized comparison,* and (2) functioning as an intermediate step between the technology characterizations and the alternative futures analysis.

2.6 ALTERNATIVE FUTURES ANALYSIS

The alternative futures analysis compared alternative energy-supply systems (i.e., alternative mixes of coal, nuclear, and SPS technologies) under different levels of energy demand (i.e., alternative supply-demand patterns). This analysis addressed synergistic impacts or those that result from aggregation of single-plant effects. An integral part of the analysis was the creation of scenarios (e.g., statements about future supply, demand, life-style, resources, and regulation) to serve as inputs to other analyses.

The primary objective of the alternative futures analyses was to provide a comparison of the impacts of alternative technologies under several different assumptions of future conditions.

The following criteria were considered in the choice of scenarios that drive the alternative futures:

- A limited number of scenarios should be used, and they should be credible and representative;
- They must illustrate a suitably large range of alternative policies, and economic and social conditions (or at least those of major concern or interest);
- They must not produce a flood of data that would tend to overwhelm analysts and the decision-making process;
- They should highlight or identify major categories of issues for further analysis; and

*The term "normalized comparison" simply means that quantifiable impacts are expressed in amount of impact per unit output of electrical energy, e.g., per/megawatt-year (MW-yr). Thus, a 5-MW system that provides energy continuously for one year and expels 1,000 tons of pollutants to the environment in the process will be characterized by the normalized amount of 200 ($= 1,000 \div 5$) tons of pollutant per MW-yr of electrical energy; similarly, a 1 MW plant that operates for half a year and produces 50 tons of pollutants is assigned the normalized amount of 100 ($= 50 \div 1/2$) tons of pollutants per MW-yr.

- Uncertainty should be included in a consistent and efficient manner, conveying useful information to the decision maker.

Although a scenario must be plausible, it does not necessarily have a probability of occurrence associated with it, but instead addresses key economic parameters and, perhaps, reveals other problems that result from specific future models.

2.7 ASSESSMENT INTEGRATION/AGGREGATION TECHNIQUES

The objective of integration/aggregation techniques is to analyze and focus the data assembled for the comparison of SPS with terrestrial technologies. A further objective is to begin reducing the complexity of the decision-making problem (which is aggravated by the large amounts of supporting data for each technology) by using techniques such as formal incorporation of preferences.

There are a number of criteria for deciding the appropriate level at which to carry out such integration/aggregation techniques. These include:

- The number of measurement categories desired;
- The number of alternatives desired;
- The manner in which views of priorities are determined, represented, and incorporated into the decision-making process;
- The use of uncertainty;
- The degree of inclusion of interactions between variables and priorities; and
- The suitability of the aggregated information for describing dynamic and time-varying conditions.

The degree of appropriateness of any of these criteria is determined by the degree of quantification of variables and effects that is achievable. Cost-risk-benefit analysis, total social cost, minimum energy cost with environmental constraints, and decision analysis are some of the techniques that may be considered. These approaches are formalized techniques that require value judgments. Since these value judgments would mainly be those of the analysts, it was decided to present the comparative information in its entirety and permit the reader to use his or her own values for arriving at any aggregate evaluation.

3 CHARACTERIZATIONS OF THE SPS AND ALTERNATIVE TECHNOLOGIES

This section contains brief descriptions of each of the technologies considered. More detailed characterizations are contained in the SPS CDEP Reference System Report¹ and in the alternative technology characterization reports.^{4,5} The objective of the technology characterizations was to collect and develop a consistent and traceable set of characterization parameters for the SPS and other possible post-2000 baseload systems. The characterizations represent "first-order" characteristics that define systems in sufficient detail for the cost and environmental analyses.

3.1 SELECTION OF ALTERNATIVE TECHNOLOGIES

The preliminary list of 29 technologies (Table 3.1) was initially screened according to two sets of criteria. The list was reduced to a subset of systems that were then further screened by more restrictive criteria to a final subset of alternatives. Decentralized technologies were excluded from the comparative assessment, since the focus was on baseload alternatives to SPS. A more detailed description of the technology screening and selection process is presented in another report.⁶

Initial screening was both qualitative and quantitative. The qualitative screening procedure included the following criteria for selection of an initial and representative subset of candidate electrical power generation systems:

- A. The initial set should include improved conventional systems (e.g., coal and LWR systems).
- B. It should represent the following classes of advanced systems:
 - 1. Advanced coal combustion and synfuels,
 - 2. Solar,
 - 3. Fission,
 - 4. Fusion, and
 - 5. Geothermal.
- C. It should include the principal energy systems most suitable for large, central-station baseload generation within each class of inexhaustible energy sources.
- D. It should reflect the consensus about which candidates are most likely to be viable in the year 2000.

A group of qualified energy technology researchers was asked to judge the candidate technologies according to the listed criteria, and their choices of the most viable candidate technologies for the year 2000 constituted the qualitative screening selections.

The quantitative screening technique explicitly considered five major technology factors and numerous subfactors (Table 3.2). The following criteria were used in the final alternative technology selection:

Table 3.1 Technologies Considered in Initial Screening

Energy Source	Conventional Systems	New Systems
<u>Exhaustible Resource Technologies</u>		
Coal	Coal-steam plants with flue-gas desulfurization	<ul style="list-style-type: none"> - Coal-steam plants with improved environmental controls - Atmospheric fluidized-bed combustion (AFBC) - Pressurized fluidized-bed combustion (PFBC) - Low-Btu gasifier/open cycle gas turbine, combined cycle - Closed cycle gas turbine - Metal vapor topping cycle - Open cycle magnetohydrodynamics (MHD) - Closed cycle magnetohydrodynamics - Molten carbonate fuel cell with gasifier (MCFC) - Synthetic fuels for advanced power cycles
Fission	Light water reactors with once-through fuel cycle	<ul style="list-style-type: none"> - Light water reactors (LWR) with improved fuel utilization efficiency - Light water reactors with mixed oxide fuels - High temperature gas-cooled reactors - Advanced high temperature reactors
Geothermal	Dry steam	<ul style="list-style-type: none"> - Liquid-dominated hydrothermal - Geopressure
<u>Renewable or Essentially Inexhaustible Resource Technologies</u>		
Solar	Hydroelectric Wood-fired steam	<ul style="list-style-type: none"> - Solar thermal electric with storage - Solar photovoltaic with storage - Ocean thermal energy conversion - Wind energy conversion with storage - Biomass fueled (other than wood-fired steam)
Fission		<ul style="list-style-type: none"> - Liquid-metal, fast-breeder reactor (LMFBR) - Gas-cooled, fast-breeder reactor - Light water breeder reactor - Electronuclear breeder - Fusion-fission systems
Fusion		<ul style="list-style-type: none"> - Magnetic confinement fusion - Inertial confinement fusion
Geothermal		<ul style="list-style-type: none"> - Hot dry rock (HDR)

1. Technical data must be available in sufficient detail to allow adequate technical characterization and comparison.
2. The candidates must be central-station, baseload technologies.
3. The technology should be available for commercial application by the year 2000.
4. Include improved current baseload technologies.
5. Include representative advanced technologies currently being engineered.
6. Include alternative (non-space) applications of photovoltaic solar energy technology.
7. Include alternatives that show potential as long-term energy sources after 2000.
8. Fuel must be available for a long period (e.g., 2000-2050).

The details of the qualitative and quantitative screening procedures are reported in a supporting document.⁶

Table 3.2 Quantitative Screening of Energy Systems

Factors	Subfactors
Technology Availability	Technology Feasibility Fuel or Energy Resource Availability Regional Limitations Status of Development
Economic Attractiveness	RD&D Costs Capital and O&M Costs Fuel Costs Plant Availability and Reliability Utility Compatibility
Environmental Impacts	Air and Water Pollutants Land Use or Disturbance Public Health and Safety Reversible vs. Irreversible Impacts
Critical Resource Requirements	Energy, Materials Land, Water Capital, Manpower
Socioeconomic Impacts	Economic Industrial Infrastructure Social International

The light water reactor (LWR) and coal technologies best satisfy the applicable criteria and thus were included in the final list of technologies to be compared with the SPS. Only one technology, terrestrial photovoltaics (TPV), meets the special criterion (No. 6) established to provide for a direct comparison of photovoltaics in space and terrestrial applications.

The combined-cycle system had the highest rating of the three advanced coal systems and thus was selected for the comparative assessment.

The liquid-metal, fast-breeder reactor (LMFBR), although controversial, has great potential, is close to demonstration, and has received worldwide backing; it was thus included in the comparative assessment.

Fusion is a technology of high scientific interest and potential. Therefore, it was selected to fill a position as a baseload alternative, even though DOE's Fusion Review Panel has stated that a date for a commercially competitive prototype reactor cannot now be established.

3.2 BRIEF TECHNICAL DESCRIPTION OF ALTERNATIVE GENERATION SYSTEMS

The characteristics of each of the alternative generation systems have been derived primarily through a synthesis of data and information obtained from available technical literature. The best self-contained system characterizations available in single documents were chosen as primary data sources. Where deficiencies were noted, available supplemental material was obtained or input from reviewers was solicited.

In most cases, the available data are for nominal systems that differ in some respects from the reference alternatives chosen for comparison. Usually, these differences are a result of varying assumptions about system generating capacity, cooling type, or, in some cases, even the site or fuel characteristics. Thus, in some cases, the reference characterizations required engineering judgment to adjust data to the system capacities and basic assumptions being used. The subsequent analyses are generally not sensitive to small variations in the system parameters derived in this fashion. However, the analysis is broad enough to allow reasonable conclusions to be drawn.

The parameters addressed in the system characterizations include those that relate to the physical system design and operating factors, capital and operating costs, reliability and availability, resource requirements, and environmental residuals. Table 3.3 briefly summarizes the characterization parameters for the technologies. Studies conducted by TRW⁴ and United Engineers and Constructors⁵ provide the basis for the non-SPS technical, environmental, and cost characterizations summarized in the following sections of this chapter.

3.2.1 Satellite Power System

The satellite power system characterization is based on data available in the SPS CDEP Reference System Report,¹ supplemented by additional studies

Table 3.3 Characterization Parameters for Plant Site and Fuel Cycle

Physical System Characteristics	Capital and Operating Costs
<ul style="list-style-type: none"> - Plant Configuration - Thermodynamic Cycle Characteristics - Capacity Factor - Environmental Controls - Mass & Energy Balances 	<ul style="list-style-type: none"> - Construction Schedule - Construction Cash Flow - Direct and Indirect Capital Cost - O&M Costs - Decommissioning Costs
Environmental Residuals	Natural and Human Resource Requirements
<ul style="list-style-type: none"> - Air-Borne Emissions - Liquid Effluents - Solid Wastes - Radionuclides - Waste Heat 	<ul style="list-style-type: none"> - Fuel Use - Water Use - Land Use - Construction Labor - Operating Labor

performed for NASA by Boeing⁷ and Rockwell.⁸ The satellite power system consists of three basic elements: the first two, in geosynchronous orbit at 36,000 km, are the solar collector, which receives energy from the sun and converts it to electrical energy, and a microwave antenna, which transmits that energy to the third element, an earth-based rectifying antenna (rectenna). The reference system is sized for 5 GW of DC power output to a conventional utility grid. The satellite has one end-mounted antenna, as illustrated in Fig. 3.1.

The satellite consists of a planar solar array structure of graphite composite material. Two conversion options (Fig. 3.2) are presently being considered: one is the use of single-crystal gallium aluminum arsenide (GaAlAs) solar cells with a concentration ratio of 2; the other is the use of single-crystal silicon (Si) solar cells with no concentration.

The size of the solar array is dictated primarily by the efficiency chain of the various elements in the system. Figure 3.3 shows the end-to-end efficiency chain for the GaAlAs and silicon cell options. The satellite is designed to provide 5 GW of DC power to the utility busbar, and with an overall efficiency of approximately 7%, it is necessary to size the solar arrays so that approximately 70 GW of solar energy will be intercepted. The efficiency assumed is the minimum efficiency, including the worst-case summer solstice factor (0.9675), the seasonal variation (0.91), and the end-of-life (30-year) solar cell efficiency (assuming annealing in the silicon case). For the GaAlAs case, the end-of-life (30-year) concentrator reflectivity is 0.83. Since only half of the intercepted solar energy is reflected by the concentrators, the equivalent lifetime average efficiency is 0.915.

The GaAlAs option is a five-trough configuration with a solar blanket area of 26.52 km², a reflector area of 53.04 km², and an overall planform area of 55.13 km². The silicon option has the solar blanket with no concentration, resulting in a blanket area of 52.34 km² and a planform area of 54.08 km². Table 3.4 lists the cell and planform power characteristics for each cell type.

Fig. 3.1 Satellite Power System Concept (Source: Ref. 1)

SILICON CR = 1
 BLANKET AREA = 52.34 km²
 PLANFORM AREA = 54.08 km²

GaAlAs CR=2
 BLANKET AREA = 26.52 km²
 PLANFORM AREA = 55.13 km²

Fig. 3.2 SPS Satellite Configurations (Source: Ref. 1)

Fig. 3.3 SPS Efficiency Chain,* GaAlAs (CR = 2) and Si (CR = 1)
(Source: Ref. 1)

*Individual efficiencies are approximate and may be expected to change with additional analysis.

Table 3.4 SPS Cell and Planform Power Characteristics

Cell Type	GaAlAs	Silicon
Concentration ratio	2	1
Solar power available	1,353 W/m ²	1,353 W/m ²
Solar power on cell at maximum off-sun pointing	2,414 W/m ²	1,190 W/m ²
Cell conversion efficiency at 28°C AMO (in vacuum)	20%	17.33%
Blanket power output		
Beginning of life	380 W/m ²	186 W/m ²
End of life	370 W/m ²	149 W/m ²
Planform power output		
Beginning of life	185 W/m ²	186 W/m ²
End of life	171 W/m ²	149 W/m ²

Source: Ref. 1.

The end-mounted microwave antenna is a phased-array transmitter of 1-km diameter. The phase control system utilizes an active, retrodirective array with a pilot beam reference for phase conjugation. Klystrons are used as the baseline power amplifier with slotted waveguides as the radiating element. The ground rectenna has subarray panels with an active element area of 78.5 km². At 35° latitude, the total rectenna area, including the buffer zone, would be 149 km².

The construction of the satellite in geosynchronous orbit (GEO) is estimated to require six months. The initial estimates of construction crew size are 555 for the silicon option [480 in GEO and 75 in low earth orbit (LEO)] and 715 for the GaAlAs option (680 in GEO and 35 in LEO).

The transportation system assumed for the NASA contractor reference system consists of four major components: the heavy-lift launch vehicle (HLLV), the cargo orbit-transfer vehicle (COTV), the personnel launch vehicle (PLV), and the personnel orbit-transfer vehicle (POTV). The HLLV is a two-stage, vertical launch, winged, horizontal landing, reusable vehicle with a 424-metric ton payload to low earth orbit. The Kennedy Space Center was chosen as the reference earth launch site. The COTV is an independent, reusable, electric engine-powered vehicle, which transports cargo from the HLLV delivery site in low earth orbit to the geosynchronous earth orbit. For the GaAlAs option, the COTV is powered by GaAlAs solar cells, whereas a silicon solar cell power supply is assumed for the silicon option.

Personnel for the orbital construction and support functions are transported to LEO by the PLV, which is a modified space shuttle orbiter with a passenger module. The POTV, a two-stage, reusable, chemical-fuel vehicle, is used to transfer personnel from LEO to GEO and vice versa. Additionally, a LEO operations base would be constructed and used for temporary storage of supplies and propellant.

Power conversion equipment converts the direct current (DC) power from the collectors into high density microwave (RF) power; the microwave antenna transmits it to the ground-based rectifying antenna, called the rectenna. The microwave antenna is a phased-array transmitter of 1-km diameter and contains 7,220 subarrays or power modules. The antenna transmits 6.85 GW of power at 2.45 GHz.

The subarrays are arranged to provide a 10-dB Gaussian power distribution across the array surface. The power density varies from 22.14 kW/m^2 at the center module to 2.45 kW/m^2 at the outer edge. At the earth's surface, the power is 23 mW/cm^2 at the rectenna center and 0.08 mW/cm^2 in the first sidelobe.

Each subarray covers 108 square meters and contains from 4 to 50 klystrons, depending on the power output of the subarray. Each klystron converts DC to 70 kW of RF. An alternative concept described in the SPS CDEP Reference System Report, would use a 50-kW klystron tube that would result in the use of 6 to 50 tubes per subarray (Ref. 1, p. 30). The subarray radiates power through slotted waveguides on the surface. Electronic phasing equipment in each subarray processes a beam-phasing signal from the ground and focuses the microwave beam. Waste heat is dissipated by radiation. The subarray also includes power distribution and conditioning equipment, waveguides, amplifiers, and frequency-control electronics.

The rectenna consists of a dipole network and diode rectifiers, which receive and rectify the microwave power; a power distribution and conditioning system, which collects and delivers the rectified DC power to the utility interface; and the structure that provides support to the dipole rectenna panels and components of the distribution system. The support structure also provides a ground plane for the microwave power.

At 35° latitude, the rectenna area of 10 km by 13 km contains 814 rows of rectenna panels tilted 40° from the horizontal, providing an active intercept area of 78.5 km^2 . A total of 436,805 panels will be assembled on site and erected. In order to minimize electrical wiring from the rectenna panel area, two electrical switchyards will be employed, each with its own converter and relay building. The rectenna site, including auxiliary buildings and the buffer zone, has been estimated to be an elliptical plot 12 km by 15.8 km, with a total area of 149 km^2 .

The configuration of the ground-based rectenna, which receives and rectifies the downlink power beam, has half-wave dipoles feeding Schottky barrier diodes. Two-stage, low-pass filters between the dipoles and diodes suppress harmonic generation and provide impedance matching. The rectenna is a series of serrated panels perpendicular to the incident beam, rather than a continuous structure. Each panel has a steel-mesh ground plane with 75-80% optical transparency. This mesh is mounted on a steel framing structure, supported by steel columns in concrete footings. Aluminum conductors are used for the electrical power collection system.

3.2.2 Central-Station Terrestrial Photovoltaic System

The reference terrestrial photovoltaic (TPV) alternative is a 200-MW system in which silicon cells are mounted in fixed-tilt, flat-plate arrays, in eight 25-MW modular components. The reference system, which does not include storage, is based primarily on designs published in a 1978 EPRI study.⁹ That study defined the cost and performance goals for utility photovoltaic conversion devices and assessed the effects of photovoltaic generation on electric utility systems.

The reference TPV system is assumed to have a silicon-cell efficiency equal to that of the SPS silicon cell, or 19%. (A cell efficiency of 12% was assumed in the EPRI study.) This modified assumption alters the EPRI design, in that it reduces by approximately 37% the number of solar cells required to generate 200 MW. Figure 3.4 shows the energy efficiency chain for this system.

Eight 25-MW modules of photovoltaic arrays are connected radially to a 34.5-kV switchyard, which, in turn, supplies the transmission grid through a step-up transformer. Each module contains 48.9×10^6 cells measuring 6 cm x 6 cm. Each module is composed of the solar array field and its connecting DC cables and main bus, the DC-to-AC converter station, and the AC medium-voltage connection to the 34.5-kV switchyard. Within each module, the photovoltaic cells are connected in series and parallel to provide as high a voltage as

Fig. 3.4 Efficiency Chain of the Central-Station Photovoltaic System

practical. This produces improved inverter efficiency and minimizes DC cable losses. The arrangement is such that $\pm 5,200$ V DC and 2,438 V AC are provided at the inverter input.

The plant capacity factor can be highly variable, since it is critically dependent on the plant's geographic location. Capacity factors have been estimated to range from nearly 25.8% in the Phoenix area to just under 18% in Boston. The Phoenix site was chosen for this analysis.

The reference system is designed to occupy a 4-km² (1000-acre) site, which houses the solar arrays, switch gear, transformer station, and personnel buildings. Excluding periodic maintenance crews, the staff requirement is about 26 persons.

Environmental residuals from the plant site should be minimal under normal operating conditions. No gaseous emissions should result from the normal operation of the system, and any waste heat should be removed from the arrays by natural convection. Small amounts of waste and garbage would be generated by personnel on site and small amounts of combustion products would be produced by on-site maintenance vehicles. An unquantified but small amount of runoff would result from cleaning of the solar arrays. Some environmental residuals would be generated as a result of the cell manufacturing process, but these effects have not yet been characterized.

3.2.3 Conventional Coal-Fired Power Plant

The reference, high-sulfur coal-combustion system is a single-unit facility. The steam plant uses a cross-compound turbine generator with two parallel shafts and has a net plant capacity of 1250 MW. The basic steam cycle is modeled after a 1232-MW concept designed by United Engineers and Constructors (UE&C), as described in their report "Commercial Electric Power Cost Studies."¹⁰ The UE&C design utilizes a conventional lime flue-gas desulfurization system for stack gas cleaning and a mechanical draft cooling tower for removing condensate heat.

The characterization represents high-sulfur coal-combustion technology and SO₂ removal as projected to be available in 2000. The plant capacity factor is assumed to be 70%. It is also assumed that all of the plant's stack gases are processed to remove 90% of the SO₂ (recent EPA regulations). Thus the reference high-sulfur coal facility for the year 2000 is assumed to use a Wellman-Lord SO₂ removal system. The Wellman-Lord process has recently been demonstrated by the EPA,¹¹ and it is expected that this or a similar technology will be the preferred option in the year 2000. The Wellman-Lord system reduces the area of land required, but the processing of all stack gases decreases the net plant efficiency. Therefore, the plant capital cost is higher than that for the UE&C design.¹⁰ These factors have been fully accounted for in the characterization.

Figure 3.5 is a simplified schematic of the functional plant components. The combustion boiler produces steam at 26.5×10^6 N/m² (3845 psi) and 543°C (1010°F). Turbine power is produced with throttle steam of 24.2×10^6 N/m² (3515 psi) at 540°C (1000°F) for the high pressure turbine and steam at 4.1 N/m² (600 psi) at 540°C for the intermediate pressure turbine.

Gross Generation	1365 MWe
Aux Use	<u>115 MWe</u>
Net Generation	1250 MWe

Fig. 3.5 Generation of 1250 MW, High-Sulfur Coal, Wellman-Lord Process

Figure 3.5 illustrates the generation of a net capacity of 1250 MW with an assumed capacity factor of 70%, from typical eastern high-sulfur bituminous coal. The amount of pulverized coal yielding 10.1×10^3 kJ is required to generate one kWh of net output; this corresponds to a net plant efficiency of 35.75%. The coal characteristics assume a higher heating value of 25.6×10^3 kJ/kg of coal on an as-received basis. At this rate, an average of 8245 metric tons (t) of coal would be needed at the site each day. Because coal storage requirements are estimated at full capacity factor, a 3-day live storage stock pile would contain 35.3×10^3 t of coal, and a 57-day reserve storage would contain 67.2×10^4 t of coal. A 9.1-m-high active storage and a 15.24-m-high reserve storage pile results in a site area of 56×10^3 m² devoted to coal storage.

Other fuel in the form of natural gas is also required for reducing sulfur dioxide (SO₂) from the Wellman-Lord scrubber system (Fig. 3.6) to elemental sulfur. This process requires about 148×10^6 kJ/h of natural gas at full plant capacity or, at 70% capacity and 34×10^3 kJ/m³ of gas, about 2.7×10^6 m³ of natural gas per year.

The design has hot electrostatic precipitators sized for the removal of 99.7% of the flyash particulates emitted from the combustion furnace boiler. Auxiliary electric power of 13.9 MW is required for effective operation of the electrostatic precipitators.^{12,13}

The combustion of 4.9×10^5 kg/h of coal with an ash content of 10.29% by weight produces 40×10^3 kg/h of flyash, assuming an 80% flyash/20% bottom ash proportion. (About 10^4 kg/h of bottom ash would be produced.) Removal of 99.7% of this flyash leaves 120 kg/h of flyash to be sent downstream for further processing in the Wellman-Lord SO₂ removal system.

The sludge wastes from the electrostatic precipitators and bottom ash total 63,120 kg/h for the 1250 MW reference coal facility at 100% capacity.

Downstream from the electrostatic precipitators is the Wellman-Lord flue-gas desulfurization system. This system uses a regenerable process in which SO₂ is removed from flue gases with a sodium sulfite scrubbing solution. The concentrated SO₂ stream that is produced can be processed into elemental sulfur or sulfuric acid, both of which are marketable industrial products.

The Wellman-Lord process consists of the four basic steps shown schematically in Fig. 3.6. These steps are (1) flue gas pretreatment, (2) SO₂ absorption, (3) purge treatment, and (4) sodium sulfite regeneration. A fifth step, the processing of SO₂ into marketable sulfur by-products, is not part of the Wellman-Lord process, but is generally associated with Wellman-Lord installations.

Tables 3.5 and 3.6 show the air pollutants and solid waste products emitted by this 1250 MW facility.

The normal construction period would take a total of seven years. Two years would be taken up for site selection, design, and preparation, and five years for on-site construction. Operation of the plant would require a staff of 259.

Fig. 3.6 Wellman-Lord Process (Adapted from Ref. 5)

Table 3.5 Air Pollutants from a 1250-MW Coal Facility

Pollutant	100% Capacity Factor		70% Capacity Factor		
	kg/h	t	kg/h	t	kg/10 ⁶ kJ
SO ₂	3136	27,605	2203	19,323	0.26
Particulates	36	318	25	223	0.003
NO _x	3254	28,537	2278	19,978	0.27

Table 3.6 Solid and Sludge Wastes from a 1250-MW Coal Facility, 70% Capacity Factor

Solid Waste	Accumulation Rates at 70% Capacity Factor			Land Area ^a
	kg/h	t/yr	10 ³ m ³ /yr	10 ³ m ²
Elemental Sulfur ^b	9,917	86,964	44	190
Ash Sludge ^c	44,260	388,105	269	1,145
Sodium Sulfite/ Sodium Sulfate	2,909	16,744	8.6	40.5
Total	-	-	-	1,375.5

^aAssumes 8-m disposal depth typical of current practices.

^bDisposal density = 1953 kg/m³.

^c80% ash, 20% water, density = 1440 kg/m³. Solids content is 40,100 kg/h from bottom ash, and 85 kg from Wellman-Lord pretreatment.

3.2.4 Coal-Gasification/Combined-Cycle Power Plant

The coal-gasification/combined-cycle plant is an integrated system whose primary components are a gasifier, an open-cycle gas turbine, and a Rankine bottoming cycle. The basic plant is modeled after a 579-MW plant described in the ECAS study;¹⁴ the design was augmented with information from the EPRI Preliminary Design study.¹⁵ The plant design was scaled to 1250 MW net plant output (2 units at 625 MW each).

The reference facility is fired with eastern high-sulfur bituminous coal with heat content of 25,646 kJ/kg (11,026 Btu/lb). The overall net plant efficiency, which accounts for in-plant auxiliary steam and electrical consumption, is 38.5%. Figure 3.7 displays the major pieces of plant equipment in a simplified cycle schematic and energy flow diagram of the reference design.

Fig. 3.7 1250 MW Coal-Gasification/Combined-Cycle System

The prime cycle consists of eight air-cooled gas turbine generator units, with a 12:1 compressor pressure ratio and 1315°C firing temperature (that is, the temperature at the inlet of the first-stage rotor). The prime cycle generates two-thirds of the total electrical power output. The gas turbine exhaust temperature is 640°C.

The bottoming cycle includes eight heat-recovery steam generators (HRSG) and two steam turbines. The HRSGs extract thermal energy from the gas turbine exhaust stream. The steam is supplied to steam-turbine generators, which contribute about one-third of the total power output. At full capacity, coal feed is required at a rate of 455 t/h or 2.8×10^6 t/yr at 70% capacity factor. At this rate, an average of 7650 t of coal would be required at the site each day; as coal storage requirements are estimated at full capacity factor, a 3-day live storage stock pile would contain 22,950 t of coal, and a 57-day reserve storage would contain 435,000 t of coal.

The average storage density of utility coal in live storage is 700 kg/m³ and reserve storage density averages 865 kg/m³. The assumption of 9.15-m-high active storage and 15.25-m-high reserve storage yields an area of about 36×10^3 m² devoted to coal storage and handling.

Figure 3.8 depicts the major environmental pollutants that arise from the impurities in the fuel and water used by the plant. The major impurities in the fuel are the sulfur and nitrogen compounds and incombustible ash. In the gasification step, almost all of the ash is separated from the coal, so it does not show up as a potential air pollutant. Similarly, about 93% of the sulfur is removed from the process stream by the combined Alkazid-Claus process. Another 1.3% is disposed of in the scrubber sludge from the wet limestone scrubber. The remaining sulfur appears as SO₂ in the stack gas from the various plant flues and exhausts. NO₂ control is effected by removing most of the NH₃ from the fuel gas streams before combustion.

Water used for plant cooling is also a source of environmental pollution. As the water is evaporated, concentrations of dissolved solids increase. This brackish "blowdown" water must be specially handled, to avoid pollution of local water systems.

The cleanup system must remove enough sulfur as elemental sulfur so that the sum of the SO₂ emitted from incinerator flues and the SO₂ emitted from the power plant flues will be no greater than allowed by EPA standards. The carbonyl sulfide (COS) formed in the gasifier and entering with the raw gas is almost completely hydrolyzed to hydrogen sulfide (H₂S) before entering the Alkazid plant. Five percent of the H₂S removed by the Alkazid plant will not be converted to elemental sulfur in the Claus plant. The tail gas is treated in the Wellman-Lord plant, which allows 90% of the sulfur to be recycled back to the Claus process. The Alkazid plant removes 95% of the H₂S entering with the raw gas. Only 5.6% of the total sulfur is emitted to the atmosphere as SO₂.

Nitrous oxides are formed by combustion of ammonia, and to a limited extent by oxidation of N₂ gas diluent. To meet the emission standards, 0.14 kg of NO₂ may be emitted to the atmosphere per million kJ of gaseous fuel.

In the cleanup system, foul water condenses from the gas during dewatering. A foul process water enters with oil and phenol from the gasifier washer-coolers. These foul waters contain dissolved H_2S , NH_3 , CO_2 , and phenols. The water separated from the oil and phenol is returned to the washer-coolers where some additional makeup water is located. This makeup water evaporates and enters the cleanup systems with the saturated gas.

The construction period for a large coal-fired electric generation facility of the type characterized here would take a total of seven years. This includes a two-year period of fairly low level of effort for site selection, design and preparation, and a five-year period of actual on-site construction. During the on-site construction period, an estimated 8.1 million person-hours of direct craft labor would be required. The operating personnel requirement (336 persons) for this plant were estimated from experience with conventional plants.

3.2.5 Light Water Reactor Power Plant

The reference light water reactor (LWR) power plant¹⁶⁻²⁰ is a 1250-MW single-unit facility consisting of a pressurized water reactor supplying superheated steam to a conventional turbine generator. Condenser cooling is accomplished with a cooling tower.

The reference reactor as shown schematically in Fig. 3.9 was scaled up to 3750 MWt from a basic Westinghouse 3450-MWt design. At the present time, nuclear fuel is being discharged from reactors after an average burnup of 25,000 to 30,000 megawatt days per metric ton of fuel (MW-d/t). LWR technology has a goal²¹ of achieving 50,000 MW-d/t, and therefore this value was assumed to be achieved by the year 2000 for the purpose of this characterization.

The nuclear steam supply system (NSSS) consists of a light-water-moderated nuclear reactor having a reactor core containing low-enriched uranium oxide fuel, approximately 4.15% U-235, in approximately 193 fuel assemblies. Loaded in the core are 98,000 kg of fuel. The core is refueled by replacing approximately one-third of the total set of fuel elements at roughly one-year intervals. The spent fuel is stored on site in a special fuel handling building. This building is also a repository for fresh fuel prior to its insertion in the core.

The NSSS produces approximately 3750 MWt at nominal full power. The power generation system consists of the reactor core and vessel, its associated pressurizer, and four primary reactor coolant loops and four steam generators. Primary coolant (water) is heated from 295°C to 330°C by the nuclear reaction taking place in the core. The nominal coolant pressure is 15.5×10^6 Pa (or N/m^2). The high pressure is maintained in the primary system by a pressurizer to prevent boiling in the core. This hot water is then passed through the steam generators (u-tube heat exchangers) where water on the secondary side of the heat exchanger is heated to produce steam. Water on the primary side of the steam generator is returned to the core to be reheated to 330°C. Steam produced on the secondary side of the steam generator passes through the turbine generator power-conversion system. The turbine generators, at nominal rated power, produce 1250 MW. The condensate from the

Fig. 3.9 Simplified LWR Flow Diagram

turbine is returned by the steam generator feedwater pumps. The reactor is equipped with residual-heat removal systems. The condensers are designed to condense the outlet steam from the low pressure turbine and the exhaust steam from the auxiliary turbine drive of the feedwater pump at 500 Pa, by dissipating the heat to three mechanical-draft wet cooling towers. The three main mechanical-draft wet cooling towers are each sized for one-third of the requirements. Each tower is designed to cool $13.6 \text{ m}^3/\text{s}$ of water from 48°C to 33°C when operating at a wet bulb temperature of 23°C . Each tower employs a reinforced concrete-filled structure combined with components for water distribution, fill splash service, support system, drift eliminators, louvers, and fan deck.

Radioactive contaminants can come from the fuel itself or from (1) impurities in the fuel cladding, (2) activated wear products, or (3) other sources. Because several systems are contaminated, normal maintenance, operations, and leaks will lead to release of some of these elements. The mechanisms of release of these radioactive elements are primarily leakage through the building ventilation systems and dissolution in liquid effluents. Areas that have the potential for contamination are ventilated through high efficiency particulate filters, which remove more than 99.9% of the particles larger than $0.3 \text{ }\mu\text{m}$. Potentially contaminated liquid effluents are monitored or processed to remove radioactive elements by filtration and ion exchange. In each case, not all of the radioactive elements can be prevented from entering the biosphere. Consequently, radioactive elements are emitted to the biosphere by the LWR,* within the limits prescribed by the EPA and enforced by the NRC.

Water consumption results primarily from cooling tower evaporative losses and cooling tower blowdown ($1.42 \text{ m}^3/\text{s}$ at full power). The largest consumers of water are the mechanical-draft cooling towers (about $1 \text{ m}^3/\text{s}$).

The primary sources of liquid effluents from a LWR facility include the cooling tower blowdown stream and process water effluent. No radioactive wastes are discharged in effluent streams. These waste streams, which are processed to remove radionuclides, are then discharged under controlled conditions.** Cooling tower blowdown does not contain any radionuclide contamination but does contain chemicals added for control of corrosion and biological growth.

3.2.6 Liquid-Metal, Fast-Breeder Reactor

The LMFBR plant reference design[†] is a 3400-MWt loop-type, sodium-cooled fast-breeder reactor plant with a nominal electrical rating of 1250 MW.

*Airborne radionuclides: total noble gases, $3 \times 10^3 \text{ Ci/yr}$; iodine, $13.1 \times 10^{-2} \text{ Ci/yr}$; Mn, Fe, Co, Sr, Cs, $4.1 \times 10^{-2} \text{ Ci/yr}$.

**Waste-water effluents at 70% capacity factor: total suspended solids, 0.94 t/d ; total dissolved solids, 2.35 t/d ; organics, 210 kg/d .

[†]The plant design was developed by United Engineers and Constructors for the Department of Energy in the Energy Economic Data Base (EEDB) program as described in Ref. 22. Additional input was derived from Ref. 23.

The plant area will be about 70 acres, including the reactor building, switchyard, parking lot, access roads, and wet cooling towers. As a minimum, a buffering area of 400 acres is needed. Thus with other physical facilities, a total area of 1000 to 1200 acres is needed. The 1000-MWe LMFBR design (about 2500 MWt) was scaled up to 1250 MWe because the cost estimate is also based on this plant and major equipment.

The LMFBR primary system consists of a liquid sodium-cooled nuclear reactor having a reactor core containing low-enriched (about 11-15%) uranium and plutonium oxides in approximately 400 fuel-and-blanket assemblies. The core is refueled by replacing approximately one-third of the assemblies after achieving a 53,000 MW-d/t average burnup. Both the new and spent reactor fuels are intensely radioactive and must be stored in heavily shielded areas.

The reactor produces approximately 3417 MWt at nominal full power. The LMFBR heat transport system removes the heat generated by the reactor core and converts it to the rotational mechanical energy required by the generator to produce electric power. The overall system consists of a radioactive primary coolant (liquid sodium) system, a nonradioactive secondary coolant (also liquid sodium) system, a steam generation system, and a steam plant system, the latter including the turbine that delivers the required mechanical energy to the electrical generator. A simplified system diagram is given in Fig. 3.10.

The primary coolant system consists of several redundant circulating loops that conduct sodium from the core exit plenum of the reactor vessel and circulate it through intermediate heat exchangers. Here, the heat is transferred to the sodium of the secondary coolant system. The primary sodium then returns to the reactor vessel. In the secondary system, secondary sodium is heated in the intermediate heat exchangers and is circulated to the steam generation system. There are four parallel primary loops and four secondary loops, one serving each primary loop.

Two basic arrangements for the primary coolant system have been proposed: the pool-type and the loop-type configurations. These are depicted schematically in Fig. 3.11. In the pool-type configuration, the reactor, intermediate heat exchangers, primary pumps, and interconnecting piping are all immersed in a large primary tank filled with sodium. During operation, sodium is drawn from the bulk content of the tank by the primary pumps and is forced through the reactor. Then, the sodium flows by gravity through the intermediate heat exchangers and discharges back to the bulk sodium in the primary tank. The driving force for the intermediate heat exchanger flow is the difference between the level of sodium over the reactor and that in the remainder of the primary tanks. With this configuration, the primary tank with its cover and the tubes and tube sheets of the intermediate heat exchangers constitute the primary coolant system boundary.

In the loop-type configuration, the primary pumps and the intermediate heat exchangers are located outside the reactor vessel. Either hot-leg or cold-leg pumps could be used in the primary system. The primary loop piping is elevated, and guard vessels are provided around the pump, intermediate heat exchanger, and reactor vessel so that leaks in the primary piping or these components cannot cause the sodium level in the reactor to drop below the minimum safe level. The loop nozzles would be covered, and continuous

Fig. 3.10 1250 MW Liquid-Metal, Fast-Breeder Reactor

Fig. 3.11 Configurations of Pool- and Loop-type Primary Coolant Systems

heat removal by sodium circulating through the loops could be permitted. The LMFBR characterized in this section is a loop-type plant.

The primary sodium system is designed to operate at a lower pressure than the secondary system. Thus, should a leak develop in an intermediate heat exchanger between these two systems, sodium would flow from the nonradioactive secondary system into the radioactive primary system. Finally, even though such leakage would not result in a radiological problem in the secondary system, the intermediate heat exchangers are designed to facilitate removal or replacement of faulty tubes.

The overall steam cycle is expected to be similar to that of modern fossil-fired, steam-electric power plants. The turbine design assumed in this study is a set of tandem compound turbines like those used in fossil-fuel plants.

Barriers to release of fission products are the fuel element cladding, the boundary of the primary coolant system, and the outer reactor containment.

The outer containment consists of a leak-tight cylindrical steel or steel-lined concrete building with a flat bottom and hemispherical or ellipsoidal dome. The containment building houses the reactor and entire primary coolant system, spent fuel handling and storage facilities, and sodium service systems related to the primary system.

The turbine configuration consists of two half-capacity tandem, compound, four-flow machines with 0.85-m last stages designed to operate at 3600 rpm. Inlet steam conditions at the high-pressure throttle valves are

15.4×10^6 Pa and 455°C . This reactor plant design provides the superheat so the inlet steam is not saturated; its condition resembles that in a fossil-fired power plant.

The condensers are designed to condense the low-pressure turbine outlet steam and exhaust steam from the auxiliary turbine drive of the feedwater pump by dissipating the heat to three mechanical-draft wet cooling towers. Each tower is designed to cool $12.3 \text{ m}^3/\text{s}$ of water from 48° to 33°C when operating at a wet bulb temperature of 23°C .

Radioactive contaminants come from the fuel itself, impurities in the fuel cladding, activated wear products, or other sources. Because several systems are contaminated, normal maintenance, operations, and leaks will lead to release of some of these elements. The building ventilation systems and processed liquid effluents are the transport mechanisms for release of these radioactive elements. Areas with the potential for contamination are ventilated through high-efficiency particulate filters, which remove more than 99.9% of the particles greater than $0.3 \mu\text{m}$. Potentially contaminated liquid effluents are monitored or processed to remove radioactive elements primarily by filtration and ion exchange. In each case, not all of the radioactive elements can be prevented from entering the biosphere. Table 3.7 shows the estimated airborne radionuclide releases from the reference 1250-MW LMFBR facility. These emissions are within the limits prescribed by the EPA for the LWR.

The aqueous chemical wastes from a nuclear power plant generally enter the environment via the blowdown stream from a closed-cycle cooling system or the circulating cooling water stream from an open-cycle system. The major sources of the waste streams from a nuclear power plant are those originating from the condenser cooling system and the process water system. All other waste streams are minor compared to those. Negligible radioactive effluents will be emitted from an LMFBR plant. A summary of effluents is provided in Table 3.8.

Solid wastes generated at the reactor will consist typically of filters from the heating and ventilation system, deactivated primary coolant sodium cold traps, analytical laboratory and liquid waste treatment residues, contaminated tools and parts, and waste such as plastic bags, footcovers, paper towels, and protective clothing. These wastes will be compacted and packaged in 55-gallon (0.21 m^3) sealed drums, then shipped to a low-level waste burial ground. About 0.26 m^3 of tritium waste per year, in the form of $\text{Ca}(\text{O}^3\text{H})_2$, will be included in these solid wastes.

About 3117 curies of beta-gamma waste and about 30,000 curies of tritium waste will be generated each year.

Table 3.7 Postulated Radionuclide Releases, 1250-MW LMFBR Power Plant at 70% Capacity Factor

Nuclide	Atmospheric Release, Ci/yr
H-3	65.63
Ar-39	87.50
Kr-85 m	0.33
Kr-85	0.44
Kr-87	0.44
Kr-88	0.54
Xe-133	0.03

The 1250-MW LMFBR would reject heat at about 7.5×10^6 kJ/h through the cooling towers. In addition, there will be miscellaneous thermal losses to air (called general plant losses) amounting to less than 1%, a value typical of present-day nuclear facilities. Approximately 2.8×10^5 m² of land will be required for facilities associated with the LMFBR power plant; namely, the reactor buildings, turbine building, switchyard, parking lot, access roads, and cooling towers. As a minimum, an exclusion area of at least 16×10^6 m² is needed, and presently most LWR stations are on even larger sites.

Water consumption results primarily from cooling tower evaporative losses, cooling tower blowdown, and general plant uses, totalling 1.28 m³/s. By far the largest consumers of water are the mechanical-draft cooling towers, which use approximately 0.88 m³/s.

3.2.7 Fusion

The reference fusion-power plant is based on the NUWMAK power plant design developed by the University of Wisconsin Fusion Engineering Program of the Nuclear Engineering Department.²⁴ The NUWMAK power plant produces electricity through a boiling-water reactor power cycle with heat supplied by a Tokamak fusion reactor. One plant produces 660 MW net, and the power facility characterized here consists of two NUWMAK reactors, producing 1320 MW net power.

The NUWMAK discussed here is a newer and more realistic design than the UWMMAK series developed by the University of Wisconsin. The objective of the new treatment was to simplify mechanical design and maintainability. The power density in NUWMAK is increased to about 10 W/cm³ as compared to 0.5 to 2 W/cm³ in earlier designs. Figure 3.12 is a schematic of this NUWMAK concept. The reference fusion plant uses deuterium-tritium fuel. During the reactor burn cycle the deuterium (D) and tritium (T) in the toroidal reactor chamber are in a plasma state. When a D-T fusion reaction occurs, a helium-4 nucleus (alpha particle) is formed and a 14-MeV neutron is given off. The high-energy neutrons are absorbed by a blanket that surrounds the fusion reaction chamber. The neutrons heat the blanket, and this heat is then removed from the blanket and used to produce electricity. NUWMAK uses boiling water as a coolant and a conventional boiling-water reactor power cycle to produce electricity.

Table 3.8 LMFBR Wastewater Effluents at Nominal (1250 MW) Operation

Effluent	Amount
<u>Chemical</u>	<u>t/h</u>
BOD	0.000
Chromates	0.000
Phosphates	0.007
Boron	0.051
Acids	0.013
Organics	0.011
Chlorine	0.004
<u>Radiological</u>	<u>Ci/yr</u>
Uranium	negl.
Ra-226	0
Th-230	0
Th-234	0
Co-60	0.774
Sr-90	0.257
I-131	0.01
Cs-134	9.38
Cs-137	7.97
Ce-144	0.030
Pu	0
Tritium	350
Ru-106	0.014
Other activation and fission products	70.32

Fig. 3.12 Schematic of NUWMAK Fusion Power Plant

The power flow for one NUWMAK reactor is shown in Fig. 3.12. The gross thermal efficiency is 34.5%. After accounting for auxiliary power requirements of 65 MW, of which 60 MW is needed to cool the magnets, the net power output is 660 MW with a net thermal efficiency of 31.5%. Two reactors would have a net output of 1320 MW.

The NUWMAK reactors differ from those of previous studies (such as UWMAK) in that no diverter is used. Impurity control (which is needed in order to keep the plasma from cooling) is accomplished instead by gas puffing, which, along with partial pellet fueling, permits operation for approximately 225 seconds with adequate plasma cleanliness. During a burn, neutral deuterium gas is puffed into the plasma approximately every 0.5 seconds. Tritium is introduced in solid pellets, which penetrate only the outer plasma mantle. A sharp temperature profile develops at the plasma edge, which is kept cold both by the gas puffing and by introduction of impurities. However, the step temperature profile prevents impurities from diffusing towards the plasma center. The impurities are neutralized and pumped out through vacuum-pump ports.

The plasma requires a magnetic field of 6.05 T (tesla) at a major radius of 5.13 m, which means a maximum field of 12 T at the magnet. To provide the needed access for maintenance and repair, NUWMAK is designed with only eight large superconducting "D"-shaped TF coils and the increased ripple is corrected with 16 saddle-shaped trimming coils. The primary design of the

TF coil uses NbTi superconductor with subcooled superfluid liquid helium at 1.8 K and atmospheric pressure. There are four cryogenic vertical field coils inside the TF coils and four superconducting coils at the outside of the TF coils to maintain the elongated plasma. The ohmic heating coils are located inside the central core of the reactor system. Since the magnets require a pulsed power supply, each reactor is supplied with a 2-MWh superconductive energy storage unit.

Since ohmic heating is effective only at relatively low plasma temperatures, auxiliary heating is necessary to raise plasma temperatures to ignition conditions (when fusion reactions will sustain themselves without further heat input). The NUWMAK design employs radio-frequency (RF) supplementary heating in the ion cyclotron range of frequencies in order to ignite the plasma. The design entails launching a fast magnetosonic wave into a 50-50 DT plasma and heating the ions at the second harmonic cyclotron frequency of deuterium.

The NUWMAK reactor operates with a cycle length of 245 seconds: 225 seconds of burn followed by 20 seconds of down time. The heat stored in the blanket material provides energy to the coolant during the down time, reducing the cyclic variation from 70% to 30% of the maximum energy to the turbines. Since a 30% variation is still unacceptable, a steam drum is used and the feedwater temperature is adjusted. Figure 3.13 is a schematic of this load-leveling system, with which constant electrical output can be achieved. Simultaneous operation of the two reactors is not necessary for constant electrical output. Two reactors produce 4566 MWt with a net electrical output of 1320 MW. Since the burn time is 92% of the cycle time, the net thermal efficiency is 31.5%.

Fig. 3.13 Schematic of NUWMAK Load-Leveling System

The total tritium inventory in NUWMAK may amount to more than 10^{10} Ci. In order to limit tritium releases from NUWMAK to less than 10 Ci per day, tritium losses must be limited to one part in one hundred million on a daily basis. Essentially perfect containment of tritium depends on clearly identifying possible routes of tritium release. During normal operation, potential sources of tritium loss include the plasma fueling and fuel purification components, energy-storage equipment (both normal and emergency), tritium breeding and extraction system components, and the first wall and blanket coolant. Tritium containment associated with each of these systems is examined in the analysis of a multi-layer containment system.

The three-level containment system (Fig. 3.14) is designed to deal with tritium release under both normal and abnormal conditions. Each level prevents the dilution of released tritium, so that it can be recovered before permeating to the next barrier. The primary containment system consists of those pipes and other structural elements that contain tritium or tritium-bearing materials.

The secondary containment system consists mainly of a second physical barrier around the primary system components: for example, primary system piping outside the plasma chamber is contained within larger-diameter piping. A slowly flowing inert gas is passed through the annulus and monitored for tritium leakage. Large pieces of equipment requiring maintenance or adjustment are enclosed in glove boxes.

LEGEND:

TERS = TRITIUM EFFLUENT REMOVAL SYSTEM

ETCS = EMERGENCY TRITIUM CONTAINMENT SYSTEM

Fig. 3.14 Tritium Effluent System Design

The tertiary containment system includes the reactor hall, rooms containing tritium processing equipment, the reactor building itself, the tritium effluent removal system (TERS), and the emergency tritium containment system (ETCS). The TERS is designed to operate on routine tritium losses while the ETCS is used only under abnormal conditions.

As with the primary and secondary systems, the reactor building is subdivided to reduce both the extent of loss and the extent of contamination in the event of a leak. Each reactor hall has a volume of $8.7 \times 10^4 \text{ m}^3$ and may be divided radially to provide the least impediment to maintenance operations. The reactor building is maintained at $8.4 \times 10^3 \text{ Pa}$ during operation, and the pressure can be reduced to $1.3 \times 10^3 \text{ Pa}$ under emergency conditions.

About 20% of the building volume atmosphere would be circulated each day, from areas of smallest to largest radioactive hazard before leaving through a stack of sufficient height to guarantee proper dispersal of the effluent. Under normal operation, this stack effluent would contain about 1 Ci per day.

The emergency tritium containment system (ETCS) consists of a heated catalyst to oxidize HT and T₂ to HTO and T₂O, alumina beds presaturated with water at 100% humidity, and the required air handling equipment. The ETCS is used in the event of a simultaneous breakdown of both the primary and secondary systems to rapidly detritiate air from contaminated areas of the reactor building. During cleanup, the inlet dampers of contaminated areas are closed and only a small fraction of fresh air is allowed to circulate to reduce tritium losses from the stack.

One further source of tritium leakage is the boiling water coolant. It has been calculated that the leak rate of tritium into the cooling water will be limited to a few curies per day. In the event that the leak rate increases, it is possible, without much increase in costs, to add equipment for removing tritium (in the range of 0.001 to 10 Ci/mL) by combined electrolysis-catalysis or by molecular photo-excitation.

The 14-MeV neutrons from the fusion reaction induce radioactivity in the structure surrounding the plasma. Most of the activity originates in the inner region of the blanket. The blanket should be replaced every two years, and the material processed and stored on the plant site.

3.3 COST CHARACTERIZATIONS

A comparative assessment of the electric generation costs for the SPS and alternative technologies requires that the cost components of each system be characterized on a consistent and normalized basis. Unfortunately, technology cost estimates from previous efforts were usually developed under assumptions that differed from study to study, and are inconsistent with the characteristics assumed for the nominal reference systems in this assessment. Thus the remainder of this section quantitatively documents the procedure used to derive a set of consistent capital and operation and maintenance (O&M) costs for the SPS and alternative technologies.

Costs from the original data source are displayed for each technology and it is shown how these costs are adjusted to be consistent with the nominal reference system characteristics such as plant capacity and overall efficiency. Where the original data present estimated costs in other than 1978 dollars, these are normalized to 1978 dollars by application of appropriate escalation factors.

The development presented in this section results in baseline point estimates based on the assumption that each technology is constructed to come on line in 1978 and is financed totally in 1978 dollars. This is the starting point for the analysis presented in the cost and performance comparison, where these 1978 point estimates are adjusted to reflect systems coming on line in the year 2000. These costs are analyzed in the cost and performance comparison in terms of their potential uncertainties in the 2000 time frame by assigning an upper range to the year-2000 base costs. Subsequent analysis is then based on these cost ranges.

As previously mentioned, construction costs for each of the nominal reference systems were developed on a consistent basis by adjusting published data to a common set of rules and assumptions. Thus, all costs make similar assumptions about the owner's costs, contingencies, and allowances for funds used during construction. The primary source of data for the coal and nuclear systems was the Energy Economic Data Base (EEDB)²² compiled and updated for DOE by United Engineers and Constructors. The General Electric study for EPRI⁸ and the SPS concept definition studies^{1,7,8} were used for cost data on the terrestrial photovoltaic system and the SPS, respectively.

In several cases the available cost estimates were for plant sizes and heat rates (efficiencies) different from those selected for the reference technologies. These were adjusted by power factors commonly used in electric utility cost estimation. A construction cost that excludes contingencies, owner's costs, and interest during construction was thus derived. Where costs were in a different year's dollars, they were adjusted to 1978 dollars by an appropriate escalation rate; SPS cost estimates^{7,8} given in 1977 dollars were escalated to 1978 dollars using an 8.0% escalation factor.

3.3.1 Satellite Power System

Development Costs. Boeing²⁵ estimated development costs on the basis of the reference system scenario, which predicates a 20-year development schedule and a 30-year deployment schedule (for 60 5-GW satellites). These costs amount to \$100-110 billion and are broken down as follows (Fig. 3.15):

- Research costs: mainly ground-based research to address environmental and social issues and alternative systems, resulting in a preferred system;
- Engineering: development and testing of prototype subsystems, resulting in specifications for demonstration units and production facilities;
- Demonstration: flight tests of a 100-200 MW unit integrated with a commercial network;

Fig. 3.15 Development Costs of the SPS
(Source: Ref. 26)

- Investment: development of industrial infrastructure, e.g., transportation, photovoltaic, and klystron manufacturing facilities.
- Construction and implementation: the first 5-GW SPS unit put into place.

It is important to note that these cost estimates assume that all effort is specific to the SPS. The benefits from generic research or from cost sharing (e.g., industry or other federal program support for photovoltaics manufacturing facilities) have not been considered. Such cost modifications could amount to 50-70% of the \$102.5 billion.²⁷

Since comparable cost data for the other six technologies were not available, side-by-side comparisons of costs or of the benefits or disadvantages of public expenditures were not attempted.

The SPS development program would consist of five phases and include basic research, engineering verification, prototype demonstration, investment requirements, and commercial production of the satellites. A cost estimate compilation based on 1977 dollars was presented on February 20, 1980, by R.J. Harron and R.C. Wadle of NASA.²⁸ The estimates were updated to 1978 dollars by a factor of 1.08 and are shown in Table 3.9. The required investment in facilities to produce satellites and related equipment is unique to this program and will enter into the commercial operation costs as an allocated expense, i.e., depreciation of investment for each satellite. In accordance with the reference accounting method, developing and establishing the space fleet for transport of materials, supplies, and personnel are not considered part of the depreciable satellite investment and, accordingly, have been excluded from capital recovery. The cost estimates of the work breakdown structure include provisions for price escalations and for project management and integration, which are included herein, in addition to the applied contingency and owner's costs added for this review.

Table 3.9 Capital Requirements of the SPS
(5000 MW), 1978 Dollars x 10⁶

Development Phase	Solar Array Satellite		Space Construction Bases	Space Transport		Earth-Based Facilities	Totals	
	Silicon	GaAlAs ^a		Silicon	GaAlAs		Silicon	GaAlAs ^b
Research								
Specific Systems Studies	152 3 8 2	-	27 0 1 5	199 8 10 8	-	-	379 1 20 5	-
Total	160 5		28 5	210 6			399 6	
Engineering								
Specific Project Management ^a	621 0 4 8	-	3,005 1 ^c 23 2	4,896 1 ^d 37 9	-	-	8,522 2 65 9	-
Total	625 8		3,028 3	4,934 0			8,588 1	
Demonstration								
Specific Operations ^e Project Management	6,119 3 852 5 46 6	-	6,580 4 916 7 50 1	6,977 9 972 1 53 1	-	1,897 6 264 3 14 4	21,575 2 3,005 6 164 2	-
Total	7,018 4		7,547 2	8,003 1		2,176 3	24,745 0	
Investment								
Specific Project Management	2,322 0 31 0	-	18,571 7 248 2	24,361 6 325 6	-	16,246 4 217 1	61,501 7 821 9	-
Total	2,353 0		18,819 9	24,687 2		16,463 5	62,323 6	
Satellite								
First								
Specific Proj Mgt	4,928 6 167 4	-	1,892 8 64 3	4,345 3 147 6	-	2,539 7 86 2	13,706 4 465 5	-
Total	5,096 0		1,957 1	4,492 9		2,625 9	14,171 9	
Avg								
Specific ^f Proj Mgt	5,432 2 212 8	5,552 2 212 8	945 0 37 0	3,062 8 119 9	1,900 6 119 9	2,421 3 94 7	11,861 3 464 4	10,819 1 464 4
Total	5,645 0	5,765 0	982 0	3,182 7	2,020 5	2,556 0	12,325 7	11,283 5
Project Contingency ^g							2,147 0	1,980 2
Owners Costs at 3% Interest During Construction (IDC), 4%, 3 yr							491 0	455 0
Investment Costs/SPS							816 3	755 3
Total Capital							1,092 0	1,092 0
							16,872 0	11,566 0

^aAllocated on dollar ratio

^bSPS Ref System Costs - GaAs Option - Memo 3/3/80, D Taylor to NASA Used only charges in avg SPS/space transport Assumed investment phase unchanged

^cFull cost of LEO Lab + 0.5 x cost of LEO shuttle flight

^d0.5 x cost of LEO shuttle flight

^eDemonstration period expenditure allocated on dollar ratio

^fVarious segments include "cost growth and escalation" omitted earlier

^g16% Total + \$1092 x 10⁶ Investment per SPS, net of space transport fleets

Table 3.10 Operation and Maintenance Costs
of the SPS (5000 MW)

Cost Component	10 ⁶ \$ (1978)	Mills per kWh
Maintenance		
Satellite		
Klystron	10.8	0.27
DC-RF Converter	15.7	0.40
Balance	15.9	0.40
Total	42.4	1.07
Transportation		
Materials Facility	41.3	1.04
Personnel Facility	87.5	2.22
Total	128.8	3.26
Ground Receiving Station	15.1	0.38
Space Construction Bases	4.2	0.10
Cumulative Total	190.5	4.81
Contingency at 13%	24.8	0.63
Management and Integration at 5%	9.5	0.24
Grand Total O&M Costs	224.8	5.68

Harron and Wadle also estimated annual operating and maintenance (O&M) expenses for the space transport, space construction, and repair of the satellites and the ground receiving station. These were not adjusted in any way except for conversion to 1978 dollars (with a multiplier of 1.08). Total annual expenses (shown in Table 3.10) of \$224.8 x 10⁶ 1978 dollars are equivalent to an annual charge of 5.7 mills per kWh of net electrical output.

3.3.2 Conventional Coal-Fired Power Plant with Advanced Flue Gas Desulfurization (H-S Coal)

The capital costs for the reference system were based on EEDB costs,²² adjusted to reflect a 5.9% increase in the steam system, insertion of the Wellman-Lord sulfur removal system (and removal of the conventional lime treater), an additional heat exchanger to increase stack gas temperatures, and a larger turbine generator to accommodate higher internal requirements.

Direct and indirect capital costs are estimated at \$452.1 million and \$90.7 million (1978 dollars), respectively. A contingency allowance of 7% is added to account for the conventional nature of the plant. It is anticipated that the owner will spend approximately 9.2% of the cumulative subtotal on expenses such as consultants, permits, and site selection, and an allowance for funds during construction over the seven-year construction period is

estimated to total approximately \$52 million (expressed at "real" rates in January 1978 dollars).

Annual operating and maintenance expenses are estimated to be \$23.5 million, representing \$5.7 million for the payroll, \$4.8 million for disposal of residues, and \$5.0 million for acid-gas removal supplies. Other components of O&M are materials, supplies, and interim replacements, which contribute \$7.1 million, and administrative and general expenses, estimated at \$0.9 million. Based on an annual plant capacity factor of 0.7, the annual cash expenditures amount to 3.06 mills per kilowatt hour.

3.3.3 Combined-Cycle Power Plant with Low-Btu Gasifiers (CG/CC)

Capital costs and annual expenses were based on a 1975 Energy Conversion Alternatives Study (ECAS)¹⁴ reference plant of 579-MW capacity. As a reference system, the unit was updated to 1978 dollars, general facilities were segregated, and processing segments were exponentially scaled to 625 MW with two units on one site making up the total facility. Appropriate adjustments were made to substitute the reference eastern bituminous coal and more rigorous emission standards. Direct capital costs are \$537.4 million.

Indirect capital costs, \$132.7 million or 24.7%, were derived from data presented on a 630-MW coal gasification facility found in the Energy Economic Data Base (EEDB).²² A comparison was made summarily to validate this match-up by comparing ECAS with EEDB indirect costs for plants with identical capacity (of a different type). The indirect construction costs for the two units total \$132.7 million, with a breakdown of 60% for construction service, 22% for home-office engineering, and 18% for field engineering.

A construction contingency at 9% of the cumulative expenditures was added, resulting in installed facilities amounting to \$730.4 million in 1978 dollars. Owners' costs of \$66.5 million and an Allowance for Equity Funds Used During Construction (AFUDC) over the seven-year construction period of \$65.1 million yield a capital requirement for the 1250-MW CG/CC of \$862 million, or \$689.60 per installed kilowatt.

Of the estimated operating and maintenance expenses of \$20.66 million, materials, supplies, expenses, and interim replacements contribute 47%. The 336-person staff accounts for \$7.4 million, and related administrative and general costs are \$1.2 million. Environmental control costs are estimated to be \$2.3 million/yr, principally for disposal of dry solid wastes. The total contribution of environmental control expenditures to energy cost, at the 70% plant capacity factor, is 2.70 mills per kilowatt hour.

3.3.4 Light Water Reactor (LWR)

A 1139-MW system was changed to the reference 1250-MW design by use of conventional capacity-ratio exponential factors used by the electric industry for various segments of the plant. This method yielded an estimate for installed plant cost, in 1978 dollars, of \$485.9 million. Indirect construction costs for the nuclear plant were estimated to be \$197.1 million, or some 40.6% of the installed equipment. These indirect construction costs

included construction services (\$75.0 million), home-office engineering (\$91.2 million), and field engineering (\$30.8 million). An allowance for contingent expenditures amounting to 8% of the cumulative subtotal yields a combined plant investment of \$737.7 million. Owners' costs of 9.3% and interest during construction (IDC) computed on a 12-year construction cycle result in overall capital requirements of \$890.2 million in 1978 dollars.

Annual expenditures for operation and maintenance total \$16.9 million, or 2.31 mills per kWh of net production. Materials, supplies, expenses, and interim replacements contribute 57% (1.32 mills) to these costs, with staff costs (including administration and general) at 0.83 mills and the balance accruing to inspection fees, special insurance, and amortized decommissioning expenses.

3.3.5 Liquid-Metal, Fast-Breeder Reactor (LMFBR)

The basic plant cost estimate, in 1978 dollars, for a 1390-MW LMFBR unit, which was prepared by United Engineers and Constructors for the EEDB,²² was downscaled by the appropriate capacity ratio exponents to the 1250-MW reference size for a total of \$702.9 million in direct construction costs. Because of safety and inspection requirements, indirect construction costs amount to \$262.6 million, for a total facility cost of \$965.5 million. A project contingency at 11% was deemed reasonable for this technology, resulting in a plant investment totalling \$1071.7 million in 1979 dollars. Owners' costs over the 12-year construction period are estimated at more than \$93 million, and during the lengthy period, IDC will accumulate to 11.3% of the cumulative subtotal, even at the reduced "real" cost of utility capital.

Annual non-fuel operating expenses amount to 2.96 mills per annual kWh of net production, and total \$22.7 million. Materials, supplies, expenses, and interim replacements account for 64%; staff, 22%; administrative and general, 9.2%; and the balance (insurance, inspection fees, and allocated decommissioning expenses), approximately 4.8%.

3.3.6 Fusion Reactor (NUWMAK)

The direct capital costs for the magnetically confined fusion facility presented in the NUWMAK report²⁴ were adjusted to a different average labor rate for consistency with the LWR and LMFBR data. Unlike the procedure in past assessments, in this assessment design allowances for unproven technology appropriate for this system were incorporated in the equipment accounts to eliminate the customary omissions in conceptual design. Direct capital costs for the entire two-unit facility are estimated at \$1.5332 billion (in 1978 dollars) over the staged construction period of 10 years, which includes eight years per unit with a two-year lag between construction starts. Indirect costs for the reference system have been adjusted upward from those contained in the NUWMAK report (41% vs. 35%) for consistency with the EEDB boiling water reactor plant, and thus amount to \$628.6 million. Reflecting the project uncertainties and status of technology development, a project contingency of 18% is applied to the subtotal for a total plant investment of \$2.551 billion. The combination of design allowance, increased indirect costs and higher contingency rate may seem to escalate the final cost more than for the other

technologies, but it is considered prudent for this concept. In any event, the incremental margin would amount to between 15% and 20% of the total plant investment, well within cost-estimating accuracy of a novel process. Owners' costs of 9% and IDC accruals over the 10-year construction period (\$389.2 million) result in a capital requirement of some \$3.1395 billion, roughly 2.5 times more expensive than the next most costly terrestrial energy investment, LMFBR.

Annual operating and maintenance expenses for the facility were adjusted, from the basic NUWMAK report, to be \$57.9 million/yr, which includes a 2% factor of direct and indirect costs for O&M plus scheduled replacements of other plant facilities. Total O&M costs applied to the energy output amount to 7.29 mills per kWh, adjusted from the reference report to include amortized decommissioning expenses.

3.3.7 Central-Station Terrestrial Photovoltaic (TPV)

Direct construction costs⁹ are estimated to be \$120.1 million (1978 dollars), and indirect construction amounts to \$22.4 million, for a cumulative total construction cost of \$142.5 million. Project contingency allowances (13.0%) of \$18.5 million yield an installed plant cost of \$161.0 million.

Owners' costs for permits, coordination, consultants, and site selection are estimated at 10.2% of the installed plant cost, or \$16.4 million in 1978 dollars. The IDC, calculated on a five-year construction period, is \$9.0 million in real terms, for a capital requirement of \$186.4 million in 1978 dollars, or \$863.8 per installed kW.

Operating expenses, in 1978 dollars, are \$1.66 million per year, including \$561,000 in payroll and \$762,000 for the sinking fund accrual of 30% of the basic facility costs for interim replacements. The total, at an assumed 25% plant capacity factor, is calculated at 3.5 mills per kWh.

4 COMPARATIVE ANALYSIS

4.1 ASSUMPTIONS AND ALTERNATIVE FUTURES SCENARIOS

4.1.1 Assumptions of the Comparative Analysis

Three levels of comparative analysis are described in the assessment framework (Sec. 2) and illustrated in Fig. 2.1. These levels are (1) comparison of characterizations, (2) side-by-side analysis, and (3) alternative futures analysis. In this section, comparisons are made, issue by issue, at each of these levels. Each level of analysis has associated assumptions, and are ordered in a hierarchy: therefore, the analysis and assumptions are cumulative as one proceeds from the lowest level (characterization comparison) to the highest level (alternative futures analysis). Before proceeding to the description of these comparative analyses, it is important to delineate the assumptions used here in order to place the comparisons in proper perspective. By assumptions we mean any important information, caveats, or baseline data that affect the analysis.

Many assumptions were made in the course of the comparative analyses, and to describe them all would obscure the comparisons. Therefore, the ones described here are those that most affect the perspective of the analysis. The description of these assumptions is handled sequentially (i.e., as part of the characterization, side-by-side analysis, and alternative futures analysis).

Comparison of Characterizations. These comparisons are made on the basis of the parameters that define a system (e.g., capital cost, O&M cost, resource consumption, and environmental residuals). Therefore, the characterization comparison is solely dependent on the technology description. For currently utilized technologies (i.e., coal and nuclear fission) most of these parameters are fairly well-defined because advanced technologies represent extrapolations of existing systems. In the case of the newer technologies (i.e., TPV, SPS, fusion), in which similar technology is not in operation, the parameters represent estimates based on design assumptions.

The technologies selected and characterized for these assessments are intended to represent electrical supply systems that could satisfy energy demand in the 2000-2030 era. Some of the advances in design are in limited operation or have been demonstrated, but for others, only design or conceptual information exists. The characterizations were carefully prepared so that the analysis of each technology is internally consistent. For example, the capital cost information presented for a technology includes the cost of environmental control systems, and the assessment of environmental performance is based on the same environmental control systems. The characterizations were developed according to an integrated procedure; therefore, characterization data reported in this assessment may be different from piecemeal information (e.g., capital cost, environmental performance) reported elsewhere.

Side-By-Side Analysis. The side-by-side analysis uses the characterization information with impact models to determine the impact of a technology, and then normalizes this impact to a unit of net energy output. The determination of impact in most cases requires assumptions about the state of the world (e.g., economic conditions, technology penetration, other environmental pollutants). These assumptions were made in a nonintegrated fashion from issue to issue. For example, in the health and safety analysis certain baseline environmental assumptions were necessary, from which incremental health impacts from the addition of another power plant could be determined. The results of this type of assessment are generic, not region-specific. The impact models are based on dose-response data derived from experience with existing technology, and the pollution levels they indicate do not necessarily represent projections of what the impact might be from pollution by new technologies. For example, occupational health and safety information was developed from the most representative current technology, in an attempt to predict the levels of occupational health and safety impact of the future technologies. The important assumptions (e.g., key economic parameters) that are made in each side-by-side comparative analysis are described in each section.

Alternative Futures Analysis. Since the objective of this comparative assessment is to compare technologies projected for the post-2000 era, a great number of assumptions are required. Most of these assumptions are highly uncertain and interdependent, so that a single consistent set may not present the decision maker with an adequate and consistent comparative perspective of the future. The alternative futures analysis was chosen as a means of providing a broader perspective of the most important parameters that describe the future. These alternative futures perspectives represent an integrated parametric analysis of plausible but unforecastable events, to provide a broader picture of the comparative issues. The assumptions underlying the alternative futures analysis constitute a set of energy supply/demand futures or scenarios.

The alternative futures scenarios describe the level of energy demand and the mix of energy technologies that are used to meet this demand, given a set of assumptions about the U.S. economy. The levels of technology deployment and economic assumptions in each scenario can be used to calculate a comparative assessment. The scope of this assessment is limited to electrical energy and does not describe mixes of nonelectrical energy supply.

These scenarios are created from a consistent economic model so that interdependencies between economic assumptions are preserved. Scenarios were selected as a means of exploring and analyzing, not predicting, the economic energy future. The scenarios were selected to represent a plausible future world, and no probabilities are assigned to any of them. We are not attempting to eliminate uncertainty in our choice of scenarios; in fact, by choosing a range of scenarios we hope to explore the dimensions of uncertainty more fully. Scenarios were selected to provide a comparative perspective on the negative and positive aspects of demand and mixes of supply technologies in the post-2000 era. The remaining part of this section will briefly describe the procedure and the energy supply-demand scenarios used in the alternative futures analysis. A more detailed technical description of these scenarios is found in a separate report.²⁹

4.1.2 Alternative Futures Scenarios

At a time when petroleum energy prices have increased nearly tenfold in a decade, and analysts have difficulty understanding events that have already occurred, the notion of making energy/economic forecasts well into the 21st century seems foolhardy.

Given the long-range perspective of the SPS (i.e., not available until year 2000), a 50-year horizon for evaluating alternative major energy technologies (such as the SPS) is necessary. The key problem is how to reduce the vast number of possible "alternative futures" to a few meaningful alternatives that encompass the range of significant policy variables and unknowns without simply creating confusion. The solution is to focus attention mainly on the factors that may cause energy prices and demands to vary under a given set of economic-demographic assumptions. The underlying economic analysis -- a major research effort in itself -- was borrowed from the work of Ridker and Watson.³⁰

Most energy/economic analyses begin with some model of the relationship between energy consumption and GNP. The simplest model, found mainly in pre-1973 studies, was based on the observation that GNP and energy demand, E, have tended to move closely in tandem in the U.S. for several decades. A simple E/GNP ratio was sometimes assumed. Deeper study of the data revealed a long-term declining trend in this ratio (see Fig. 4.1). This can be interpreted as a result of the economy's shift from energy-intensive primary agriculture and materials and manufacturing industries toward services, which add greatly to the GNP without consuming much energy.

Until 1973, energy prices were declining, on the average, so that demand for energy presumably would have increased if it were not for the structural changes in the economy mentioned above. After 1973, of course, energy prices rose very sharply. The expected response in a market economy is a further decrease in demand, together with increased supplies. The balancing mechanism is illustrated schematically in Fig. 4.2.

A number of medium- and long-term energy/economic models have an optimizing scheme (usually some mathematical programming algorithm) to project future energy costs for specified levels of demand. This procedure is classified as partial equilibrium insofar as the reverse feedback, i.e., the dependence of GNP on energy prices, is neglected. Examples include the ETA Model,³¹ the Nordhaus Model,³² the Brookhaven BESOM Model,³³ and a dynamic version known as DESOM.³⁴ All of these models assume that energy prices are bounded by the long-term marginal costs of supply. The independence of GNP and energy-influenced price changes can be a convenient, although rough, approximation if the energy sector is very small (4%) compared to the rest of the GNP.

The ETA-MACRO³⁵ model is another kind of general equilibrium model with a more detailed energy sector driven by an aggregated macroeconomic model, which includes a link between economic growth and investment. There are several dynamic, multisector, general equilibrium models in the literature, including Hudson-Jorgenson,³⁶ PIES,³⁷ and Gulf-SRI,³⁸ but they are all necessarily very complex and consequently difficult to use and to explicate.

Fig. 4.1 U.S. Energy Output Ratios, 1929-1974, and Base Projections to 2025

Fig. 4.2 Simplified Macroeconomic Model of the Interaction between Energy and the Economy

Probably the long-term model that is most sophisticated in its treatment of interindustry relationships and capital accumulation is the Resources for the Future (RFF) model, developed by Ridker and Watson,³⁰ based on a 185-sector dynamic interindustry model.³⁹ The RFF model was selected for this assessment on the basis of several selection criteria -- sectoral detail, endogenous treatment of both capital investment and final demand, and transferable experience in the form of existing model runs covering the desired time frame -- 2000-2030.

Table 4.1 provides our assumptions about population, labor force, labor productivity, and GNP in constant (Jan. 1978) dollars. The population figures incorporate a replacement fertility rate of 2.1 children per woman. Although the total fertility rate is currently around 1.9, there is no basis on which to assume it will remain at this unprecedented level. Moreover, immigration -- illegal as well as legal -- will probably remain above the 400,000 per year that is incorporated into these projections. The labor numbers, which take into account increased female participation in the labor force, somewhat earlier retirement age, and other trends, are consistent with the population figures. The GNP, derived from projections about the labor force, participation rates, employment rates, changes in working hours per year, and productivity growth rates, increases at an annual rate of 2.8% between 1980 and 2000 and 2.5% thereafter. This compares with a rate of 3.1% per year between 1970 and 1979 and 3.4% between 1950 and 1970. The decrease in GNP growth is due in part to declining productivity, attributable to the need to divert capital into the energy sector and energy conservation. Clearly, this economic scenario is only one of several self-consistent possibilities. It probably represents an upper limit to GNP growth.

Table 4.1. RFF Model Assumptions about Population, Labor Force, Productivity, and GNP, 1975-2025

Element	1975	1980	1985	2000	2025	2030
Population (millions)	214	225	236	264	304	312
Labor force (millions)	95	107	111	124	139	142
GNP (billions, 1978 \$)	1754	2108	2394	3691	6449	7000
Consumption	1131	1350	1451	2351	4226	-
Investment	219	304	435	426	1011	-
Government	383	403	482	742	1154	-
Exports	131	175	196	315	676	-
Imports ^a	-99	-152	-184	-312	-643	-
Inventory change	-14	11	14	17	27	-

^aImport requirements are computed explicitly in the RFF model, making due allowance for the cost of imported energy. Exports are then calculated on the basis of the long-run equilibrium assumption that international currency exchange rates automatically adjust to permit exports to balance imports.

But future energy demand and prices depend not only on GNP but also on other parameters of the economy. The key unknowns are as follows:

- The inherent energy-intensiveness of the economy, or (equivalently) the price elasticity of demand;
- The degree of effective constraint on production of coal and nuclear energy that will be imposed for health, safety, and environmental reasons;
- The cost of synthetic fuels from coal and energy from other medium- or long-term technological alternatives, including wind, biomass, passive solar collectors, terrestrial photovoltaic cells, SPS, and fusion.

For simplicity we have considered three alternative price elasticities of aggregate demand for energy, namely:

- H: High energy intensiveness, corresponding to low elasticity (-0.25).
- I: Intermediate energy intensiveness, corresponding to intermediate elasticity (-0.4 for residential and housing demand, -0.7 for industry, 0 for feedstocks).
- L: Low energy intensiveness, corresponding to high elasticity (-0.75).

Regarding constraints, we have selected two cases:

- U: Unconstrained supply of coal and nuclear power.
- C: Constrained supply, due to health, safety, environmental, and other limitations on the rate of increase of supply.

It is important to note that we have assumed domestic production of petroleum and natural gas, and imports of these fuels, to be strictly limited by geological factors in the first instance and by international political factors in the second. The combined effect of all constraints is shown in Table 4.2.

As regards long-run supply costs, our basic assumptions (Table 4.3) are taken from a recent comprehensive appraisal by Resources for the Future.⁴⁰

Table 4.2 Constrained Energy Supplies (10^{15} Btu)
for Future Scenarios

Energy Source	1980	1985	2000	2025	2030
Petroleum					
Domestic production	20.2	16.5	11.2	6.1	5.1
Net Imports	18.0	18.0	18.0	18.0	18.0
Total	38.2	34.5	29.2	24.1	23.1
Natural gas					
Domestic gas	19.4	17.6	12.0	5.6	4.3
Net Imports	2.3	3.0	3.0	3.0	3.0
Total	21.7	20.6	15.0	8.6	7.3
Coal					
Direct	14.9	19.2	21.1	22.0	28.2
Converted	0	0	8.5	20.8	23.0
Total	14.9	19.2	29.7 ^a	47.8 ^a	51.3 ^a
Nuclear	3.0	5.0	10.0	14.5	15.4
Hydro	3.2	3.2	3.3	3.5	3.5
Geothermal	0	0	1.0	3.0	3.5
Solar ^b	0	0	1.1	6.4	7.5
Shale	0	0	5.0	18.3	21.0
Total Consumption	81.0	82.5	94.3	126.2	136.6

^aOr other combinations with the same total.

^bPassive solar collectors or hot water and seasonal space heating in suitable applications.

Table 4.3. Assumed Long-Run Costs per
Million Btu (1978 \$)

Coal gasification

\$3.17 for conversion
+ \$0.97 for distribution

Shale oil

\$4.67 for extraction
+ \$1.90 for refining and distribution

"Alternatives" (e.g., passive solar, wind, etc.)

\$9.00 standard case, or
\$4.50 "decentralized" case, assuming a cost
breakthrough

Electricity

\$7.33 for conversion from coal
\$8.96 for conversion from nuclear fuel

Source: Ref. 40.

Note that two price cases for "alternative sources" were considered. The higher (\$9/10⁶ Btu) is consistent with continued dependence on centralized electric or gas utilities. However, the lower-price case (\$4.50/10⁶ Btu) would presumably lead to more decentralized energy production. Two scenarios of the latter type are considered.

The procedure for quantifying scenarios is outlined briefly as follows. First, from the assumed GNP growth rate and assumed price elasticities of demand, a set of projections of alternative energy (E) to GNP ratios can be derived, as shown in Fig. 4.3. Detailed demands by each of 185 sectors of the economy are computed from an input-output model for this economic scenario, assuming fixed prices.³⁰ Next, demands for specific fuel types are generated, and a supply-demand balance is computed for each of six scenarios, representing combinations of the levels of price elasticity and constraints, as follows: UH, UI, UL, CH, CI, CL. The supply-demand balances are displayed in Fig. 4.4 (2000) and Fig. 4.5 (2030).

The next step was to calculate the energy prices (for each primary fuel and for electricity) that would match supply and demand in each year. Adjustment lags of unknown length make this calculation approximate. The final steps involve recomputation of total demand, by sector, for the revised energy prices; recomputation of total E and E/GNP; and reiteration of the whole sequence until convergence is achieved.

Our baseline scenario is the constrained case with an intermediate value of price elasticity (designated CI). This choice reflects our belief that constraints on production growth are likely to continue, rather than abate; that the intermediate value of elasticity is more likely than either of the extremes; and that the higher cost level (\$9.00/10⁶ Btu) is more realistic for "alternative sources" than the lower cost (\$4.50/10⁶ Btu).

Fig. 4.3 Ratio of Gross Energy/GNP, in 10^3 Btu/1971 \$

Fig. 4.4 Supply-Demand Patterns for Various Scenarios in the Year 2000

Fig. 4.5 Supply-Demand Patterns for Various Scenarios in the Year 2030

In only one case -- the unconstrained, high-energy-intensiveness scenario (UH) -- does the economy of 2030 depend on electricity more than it does at present.

In all other cases, the use of electricity can be expected to decline in relative importance, at least after the year 2000. In Fig. 4.6 electrification is plotted as a percentage of net energy use in the economy, for three representative scenarios.

It is noteworthy that the foregoing results are qualitatively dependent on most of the detailed supply/demand price projections. The calculated supply-demand balances are shown graphically for all scenarios for the years 2000 and 2030 in Figs. 4.4 and 4.5. Price projections for all scenarios are displayed graphically in Figs. 4.7-4.10 for oil, gas, coal, and electricity, respectively. Nuclear fuel prices for light water reactors and LMFBRs are shown in Table 4.4. As expected, energy prices rise much faster and higher in the 'constrained' scenarios than in the unconstrained cases.

Table 4.5 shows a comparison of the six comparative assessment scenarios and projections updated by the Energy Information Administration.*⁴¹ The

Fig. 4.6. Electrification as a Percentage of Net Energy Use: Three Scenarios

*Supply assumptions and costs for uranium were developed separately but are consistent with the rest of the calculations.

Fig. 4.7 Delivered Oil Prices

Fig. 4.8 Delivered Natural Gas Prices, \$/10⁶ Btu

Fig. 4.9 Delivered Coal Prices, \$/10⁶ Btu

Fig. 4.10 Electricity Prices, $\$/10^6$ Btu

Table 4.4 Nuclear Fuel Prices (1978 \$/10⁶ Btu)
for Future Scenarios

Year	Light Water Reactor		LMFBR
	UH, UI, UL	CH, CI, CL	All Scenarios
1980	0.62	0.62	a
1985	0.67	0.76	a
1990	0.71	0.81	a
2000	0.72	0.86	0.64
2010	0.79	0.95	0.65
2025	0.89	1.12	0.67
2030	0.93	1.17	0.68

^aLMFBR introduction assumed between 1990 and 2000.

Table 4.5 Electrical Generation in Comparative Assessment
Scenarios and Two Other Projections (10⁹ kWh)

Energy Source	EIA ^a (1995)	EPRI ^b (2000)	Comparative Assessment (2000)					
	1978 Annual Report		UH	UI	UL	CH	CI	CL
Coal	2549-3163	3396	1922	1300	738	563	91	1010
Oil	130-85	390	126	126	126	126	126	126
Gas	42-17	0	126	126	126	126	126	126
Nuclear	978-1215	2795	3010	1621	1223	893	970	970
Hydro	327-323	395	320	320	320	320	320	320
New	96-76	164	106	106	106	106	106	106
Total	4122-4879	7140	5610	3600	2640	2134	2610	2660

^aSource: Ref. 41.

^bSource: Ref. 42.

comparative assessment scenarios fall within the range of those reported by EIA (with the exception of the nuclear/coal distribution) but lower than the EPRI projections. We do not feel that the comparative assessment scenarios are any better or worse than the EIA or EPRI scenarios, just different. However, we feel that the comparative assessment scenarios are plausible, representative, and useful for alternative future comparisons.

Table 4.6 shows the total installed capacity and new baseload construction for the six scenarios. Since the total capacity and additions were not substantially different for several of the scenarios, only the three most representative scenarios (UH, UI, and CI) were selected for comparative analysis. These cases represent the range of energy growth in the six scenarios. Tables 4.7-4.9 report the cumulative capacity for each technology for the three scenarios with and without SPS. These capacity levels will serve as the basis for the comparative analyses reported in subsequent sections of this report.

Table 4.6 Total Installed and New-Construction Baseload Capacity
(1000 MW) for Six Comparative Assessment Scenarios

Year	UH		UI		UL		CH		CI		CL	
	Total	New	Total	New	Total	New	Total	New	Total	New	Total	New
1980	202	63	202	63	202	63	202	63	202	63	202	63
2000	906	231	536	140	364	91	288	47	402	63	364	91
2015	1344	382	570	114	359	58	385	184	398	100	358	58
2030	1772	417	586	173	335	78	503	80	378	110	335	78

Table 4.7 Energy System Deployment (GW
of Capacity) for Scenario UH
with and without SPS

Technology	Year			
	1980	2000	2015	2030
<u>With SPS</u>				
Coal	155	354	395	460
LWR	47	508	546	534
LMFBR	0	44	175	312
TPV	0	0	36	72
SPS	0	0	150	300
Fusion	0	0	42	94
Total	202	906	1344	1772
<u>Without SPS</u>				
Coal	155	354	470	584
LWR	47	508	574	628
LMFBR	0	44	210	375
TPV	0	0	36	72
SPS	0	0	0	0
Fusion	0	0	54	113
Total	202	906	1344	1772

Table 4.8 Energy System Deployment (GW of Capacity) for Scenario UI with and without SPS

Technology	Year			
	1980	2000	2015	2030
<u>With SPS</u>				
Coal	155	238	166	70
LWR	47	263	208	169
LMFBR	0	34	81	125
TPV	0	0	24	48
SPS	0	0	75	150
Fusion	0	0	16	24
Total	202	535	570	586
<u>Without SPS</u>				
Coal	155	238	181	109
LWR	47	263	227	177
LMFBR	0	34	111	195
TPV	0	0	24	48
SPS	0	0	0	0
Fusion	0	0	27	57
Total	202	535	570	586

Table 4.9 Energy System Deployment (GW of Capacity) for Scenario CI with and without SPS

Technology	Year			
	1980	2000	2015	2030
<u>With SPS</u>				
Coal	155	224	121	24
LWR	47	157	116	75
LMFBR	0	22	79	124
TPV	0	0	18	36
SPS	0	0	50	100
Fusion	0	0	14	19
Total	202	403	398	378
<u>Without SPS</u>				
Coal	155	224	135	30
LWR	47	157	130	94
LMFBR	0	22	92	169
TPV	0	0	18	36
SPS	0	0	0	0
Fusion	0	0	23	49
Total	202	403	398	378

4.2 COST AND PERFORMANCE

4.2.1 Introduction

The comparison of projected energy costs for alternative technologies is a prime consideration in the selection of programs for further research and development. The basic energy costs of the SPS and other technologies are described in Sec. 3.3. The goal of these cost analyses is to produce an objective comparison using consistent data and assumptions. These comparisons were performed with an internally consistent and traceable data base that was developed for this assessment. In addition, many assumptions were made in performing the cost comparisons reported in this section. Therefore, the absolute numbers reported here are intended only for the present comparison, should not be compared to assessments or energy cost studies reported elsewhere.

Different costing methods, assumptions, or base data could affect the calculations substantially so that comparability to other studies is not possible without a detailed knowledge of technology costing and the differences in assumptions and data that exist between studies. However, the goal of this study was not to produce information that is directly comparable in detail to other studies, but rather to be internally consistent, so that this cost comparison would be useful in decision making concerning the relative economic viability of SPS.

The comparative cost analysis conducted in this assessment was a multistep process. These steps were assembled into an evaluation framework so that the numerous analytical steps could be performed in an orderly progression. Figure 4.11 shows the sequence of steps in the evaluation framework.

The results of four of these steps are discussed in other sections of this report: the SPS and the six alternative technologies are characterized in Sec. 3; the cost characterization, which includes capital and operation and maintenance data, is described in Sec. 3.3; and the alternative future energy supply-demand scenarios, which include SPS implementation rates, are described in detail in Sec. 4.1.

The next section of this report (Sec. 4.2.2) will begin with a description of the cost uncertainty that exists in the base data that is reported in Sec. 3.3 for all of the technologies. The uncertainty in fuel price projections that resulted from the alternative futures scenarios will be reported in Sec. 4.2.3. Section 4.2.4 contains comparative cost information standardized to levelized annual costs for all technologies. The comparative cost information described in Sec. 4.2.4 was subjected to sensitivity analyses, which are discussed in Sec. 4.2.5. Finally, an uncertainty analysis of the comparative costing approach was conducted, and this analysis and its implications for any future comparisons are discussed in Sec. 4.2.6. This cost comparison section ends with some summary statements regarding the status and conclusions of the analysis.

Fig. 4.11 Cost and Performance Evaluation Framework

4.2.2 Uncertainty in Capital Cost Ranges for SPS and Alternatives

Capital costs of technologies that have not yet been developed are highly uncertain and depend in part on the commitment made to, and the results of, future R&D efforts. At this time the estimated ranges of capital costs for the SPS and the other advanced technologies are large. Significant uncertainties also exist in the projected cost of energy from current or conventional technologies. Capital costs for electric generation technologies to commence operation in the year 2000 are highly uncertain. Accurate projections of costs in that era, even for technologies that are in commercial operation today, are still difficult. Consideration of factors that contribute to the range of estimated costs is necessary for a valid pairwise comparison of technologies, and these factors have been included in the following analysis and assessment.

There are many parameters that could be factored into the estimation of capital cost uncertainty, but we have chosen to aggregate the capital cost uncertainty into the following three factors that we feel represent the major uncertainties:

1. Uncertainty about future costs of materials, supplies, and labor necessary to construct power plant facilities;
2. Uncertainty about the future requirements and associated costs of environmental and safety equipment; and
3. Uncertainty about the capability of technologies to perform as conceptualized.

The uncertainty associated with factor 1 was generally accounted for through an analysis of the Handy-Whitman Index⁴³ of public utility construction costs, which is widely used as a "benchmark" index by the electric

utility industry. It is here referred to as a benchmark since it is derived not from actual project construction costs, but rather from a periodic sampling of a market basket of over 50 standard commodities and components used in conventional utility plant construction. The market basket contents have not been updated significantly in many years, so that the index more closely tracks a lower bound of cost increases. Thus, the Handy-Whitman Index does not appropriately account for technological or regulatory cost increases, as is typified by the added cost of sulfur-removal or nuclear-safety requirements imposed by legislation in recent years.⁴⁴

However, this index does measure the nominal real cost increases in power plant construction. The lack of revision in commodity mix is judged not to be a serious problem, since the mix of added environmental and safety equipment and personnel in post-1970 plants is the same as that of the plants overall.

Over the 30-year period 1948-1978, the Handy-Whitman Index has increased in real terms (relative to the GNP deflator) at an average compound rate of 1.5% per year. For the period 1948-1978, increases were about 1% per year, while for the period 1968-1978 increases averaged over 2% per year relative to the GNP deflator. The analysis of the Handy-Whitman Index indicates that the compound annual real cost increases exhibited over the past 10 years are 1.5% per year for coal and 2.0% per year for nuclear.

Information on factor 2 was derived from construction cost information assembled over the past decade. Although the available data contain the cost estimates of actual construction projects, these estimates are for a mix of plant sizes. However, the data indicate approximately a 10% per year real increase early in the period, with the rate of increase tapering off to about 7% per year more recently. These rates of real escalation are due primarily to added safety regulations and environmental controls that have been imposed over this period; no time-related factors are included. The easing of these rates in more recent years is a result of attempts to consolidate and simplify the existing regulations and of a decrease in the escalation rate due to new regulations. Although these rates may ease even more in the future, it is also possible that they may continue to be quite substantial. Thus, continuing rates of 5% and 6% per year have been assumed as a high range of escalation for the coal and nuclear technologies, respectively.

Factor 3 uncertainties are based on judgments about the technical uncertainty surrounding an advanced technology. Since this is a comparative assessment, these numbers were derived from a range of estimates reported for each technology or from uncertainty in the technology definition.

Low, nominal, and high capital costs were derived for each technology, using the three factors just described. The uncertainties for each technology, at the low, nominal and high cost levels, are summarized in Table 4.10.

A factor of 1.3 was applied to the combined-cycle system and one of 1.35 to the LMFBR system. For the combined-cycle alternative, the gasifier elements make up the major technological uncertainty and also compose 30% of the nominal plant costs. It has been assumed that this component might increase in cost by as much as 100%. For the LMFBR, two recent estimates provided by United Engineers and Constructors show plant costs to vary by 35%.

Table 4.10 Capital Cost Uncertainty Factors for Alternative Technologies
(Low, Nominal, and High Values)

Value	Conventional Coal	LWR	CG/CC	LMFBR	TPV	Fusion	SPS
Low	0.75% per year - 1/2 the historical Hardy-Whitman Index (HWI)	1.0% per year - 1/2 the historical HWI.	Same as conventional coal.	Same as LWR.	No real cost increases assumed in 1978 estimate, a 43% decrease in nominal solar cell costs to \$21.60/m ² (1978 \$) from \$37.80/m ² .	Assumed to be the same value as originally estimated in the NUWMAK report, which served as the basis for the characterization.	No cost increases assumed, a cost reduction in solar cells to \$21.60/m ² from \$37.80/m ² . This reduction in costs is an example of the magnitude of cost reduction believed achievable by Westinghouse as a result of a major production technology breakthrough beyond the projections currently being assumed in the reference design.
Nominal	1.5% per year - historical HWI.	2.0% per year - historical HWI.	Same as conventional coal.	Same as LWR.	Cost increases equivalent to 1.0% per year on the total plant cost. Derived from applying the nominal coal plant increase of 1.5% per year to the non-solar array portion of the plant (about 2/3 the total cost).	Cost increases equivalent to 2.0% per year (1978-2000), or the nominal nuclear rate.	Nominal rate of increase of 1.5%/yr, as for coal applied to the terrestrial, i.e., rectenna, portion of the system, or about 26.7% of the total costs.
High	5.0% per year - continuation of recent high rate of environmental regulatory imposition.	6.0% per year - continuation of recent high rate of safety requirements being imposed for next 22 years	Same as coal, multiplied by 1.30, which is attributed to a possible doubling of the gasifier vessel costs that make up about 30% of the base plant costs.	Same as LWR, multiplied by 1.35, which is based on the ratio at different cost estimates representing technology uncertainty.	Applies a factor of 4 to the year 2000 nominal cost (mainly cell cost uncertainty).	No estimate of the high endpoint was made because the scientific feasibility of plasma confinement has not been demonstrated.	Technical uncertainty factor of 5.0 applied to 1978-dollar cost estimate.

An uncertainty factor of 5.0 was applied to the 1978-dollar costs of the SPS system. This value is equivalent to a factor of 4.6 applied to the year-2000 base construction cost and was estimated from various cost ranges recently documented in the SPS literature.^{45,46} During 1976 and 1977, several independent study teams gave cost estimates that ranged from a low \$1400 per kilowatt to a high of \$6000 per kilowatt.

A recent ECON report⁴⁷ points out the sensitivity of the probability distribution of a cost to a change only in the solar cell assumptions of the Rockwell International design.⁸ By a change in assumptions, the spread of a total cost distribution for the first theoretical unit was increased from a high/low ratio of 2 to one of 4. In an article on SPS costs,⁴⁸ Glaser discusses the SPS price tag and cost distributions. He states that the cost of producing the second 5-GW SPS may range from \$8 to \$35 billion, with a median cost of \$14 billion.

Little information is available from which a possible range of costs for the terrestrial photovoltaic system can be derived. A reasonable assumption, however, is that this cost range should lie somewhere between the range of the combined cycle or LMFBR and that of the SPS. Since most of the uncertainty results from technical unknowns related to solar cell technology, and in light of ECON's results⁴⁷ concerning the possible impact of cell costs on SPS, a factor of 4.0 was assigned.

A combined factor, used to derive the high, year-2000 bounds of capital costs, was thus taken to be the product of the high multiplicative factor and the uncertainty factor for the appropriate technology option. The resultant combined factor was then multiplied by the 1978 base costs to arrive at the upper bound estimate.

An examination of the ratio of high to low year-2000 capital cost estimates resulting from these assumptions shows a reasonable consistency with the level of current knowledge and state of development apparent for each technology. This ratio varies from a value of 2.11 for conventional coal systems to come on line in the year 2000, to 4.58 for the SPS in the same period. Table 4.11 summarizes the year-2000 capital cost ranges used in the analysis.

4.2.3 Fuel Price Projections

Background and Methodology. Projections of any type extending far into the future involve many uncertainties that are amplified when that forecast attempts to define energy supply, demand, and costs. Energy sector uncertainties arise in three principal areas: (1) Future energy policy decisions, reflecting actions and reactions between producers and consumers, are not predictable. (2) The ultimately recoverable reserves of energy resources cannot be precisely defined and, similarly, the rate of improvement in production or efficiency for developing technologies such as photovoltaic cells cannot be rigorously determined. (3) The price elasticity of energy substitution in the total economy is not fully known, and therefore assumptions must be made about the adaptability of GNP to varying components of gross energy supply.

Table 4.11 Capital Cost Ranges for Technical
and Regulatory Uncertainty (\$/kW)

Costs	Coal	LWR	CG/CC	LMFBR	TPV	Fusion	SPS
1978 Costs (Nominal)	549	712	690	1037	844	2378	3340/3079
2000 Costs							
Low	647	886	813	1291	731	2378	3139/2874
Nominal	762	1100	957	1603	1057	3677	3646/3362
High	1605	2566	2623	5048	4229	?	16,698/ 15,398
Cost Ratios:							
2000 Low/1978 Nominal	1.18	1.24	1.18	1.24	0.87	1.00	0.94/0.94
2000 Nominal/2000 Low	1.18	1.24	1.18	1.25	1.45	1.55	1.16/1.16
2000 High/2000 Nominal	2.11	2.33	2.74	3.14	4.00	?	4.58/4.58

Possible future scenarios (described in Sec. 4.1) were defined by assuming certain values for key unknown parameters and by following an internally consistent computational pathway. Reasonable boundary assumptions were made concerning the key unknowns, which established the range of values within which most plausible futures will fall.

The long-run costs of fuel (primary energy) are, in part, predicated on OPEC maintaining petroleum prices just below the long-run costs of producing substitutes from oil shale or coal. The cost of synthetic natural gas from coal was projected from a non-fuel cost of \$3.17/10⁶ Btu plus 1.25 times the cost of coal per 10⁶ Btu (to allow for the 80% efficiency estimated for the gasification process) plus an assumed \$0.97/10⁶ Btu for transmission and distribution. Similarly, the long-run cost of natural gas was determined to be equivalent to its alternative -- high-Btu gas from coal. Finally, the long-run cost of electricity was based on non-fuel capital costs for the projected coal/nuclear ratios, assuming generation from oil and natural gas phased out and modest improvements in conversion efficiency between now and 2030.

Fuel Price Paths. The long-run costs dictate the price of electricity, but the cost of other energy forms can differ when there are supply constraints. Oil prices are estimated to increase at a rate that maintains OPEC production more or less at constant levels, and, at a relatively inelastic demand, OPEC could seek increased prices because of constraints on coal and oil shale. However, if the price should reach \$9.20 per 10⁶ Btu, it is estimated that large quantities of low-level solar thermal energy could become economically attractive,⁴⁰ free of the environmental constraints affecting the development of other resources. Natural gas prices essentially follow the pattern of oil prices and are set so that remaining resources are produced before higher-cost gas from coal or substitutes such as solar enter the market. In scenarios featuring low elasticities (energy-intensive GNP), the rate of price increases is high, and particularly so when supply constraints affect coal production.

The price of coal is expected to increase from \$1.15 to \$1.38/10⁶ Btu between 1980 and 1985 because of impacts from the Surface Mine Control and Reclamation Act of 1977 and the possible continuation of decline in

productivity. Beyond 1985, new federal leases of land with high-quality coal will keep prices constant until 2000, with modest increases thereafter to reflect increased long-run costs resulting from rapid production increases when the supply is not constrained. If the supplies are constrained and the price-demand elasticity is moderate or low, prices increase above the long-run costs until demand is dampened to the required level.

Uranium prices, for convenience, are assumed to differ only between the constrained and unconstrained scenarios. The rationale is that future supply-demand conditions of the world-wide market, not local markets, will determine prices.

Projections. Three scenarios were used to measure a range of possible fuel prices and supplies. They are:

- UH: An unconstrained scenario wherein energy price elasticities of demand are low (-0.25) and the energy/GNP ratio is therefore relatively constant. The unconstrained scenario is defined as possessing controls at about the level that existed in 1970.
- UI: An unconstrained scenario wherein the energy price elasticities of demand are moderate (-0.7 for industrial fuel use, -0.4 for all other fuel uses and 0 for feedstock use).
- CI: A constrained scenario wherein the energy price elasticities of demand are moderate, as in UI. The constraints imposed are based on environmental, health, and safety aspects of coal and nuclear fuels and serve to restrict rapid expansion of production. Petroleum and natural gas are constrained only by world market conditions.

The delivered costs of fuels as projected by the RFF model³⁰ are shown in Table 4.12 and graphically displayed in Fig. 4.12 for the period 1980 to 2030. For comparison, the EPRI Technical Assessment Guide⁴⁹ gives coal price estimates of between \$2.00 and \$2.40/10⁶ Btu, depending on the consuming and supply regions. Our unconstrained price trajectory for LWR fuel agrees very closely with the EPRI projection until 2000, after which EPRI does not project LWR fuel costs. The corresponding U₃O₈ prices for the unconstrained and constrained scenarios are shown in Fig. 4.13.

4.2.4 Cost Comparisons

The comparative costs reported in this section were calculated by the revenue-requirements (RR) method used by utilities and prescribed by regulatory agencies. Levelized life-cycle costs were calculated by a constant-dollar revenue-requirements method similar to the approach recommended by the Electric Power Research Institute (EPRI) for the analysis of generating costs of alternative technologies.⁵⁰ The important assumptions of this method will be briefly described here; a detailed description of the methodology is provided in the EPRI report.⁵⁰

Table 4.12 Fuel Cost Projections (1978 \$/10⁶ Btu): Delivered Prices for Three Scenarios, 1980 to 2020

Scenario and Energy System	Study Period						
	1980	1985	1990	2000	2010	2025	2030
<u>UH</u>							
Oil	5.75	6.49	6.49	6.79	7.13	7.65	7.82
Natural Gas	2.45	3.11	4.60	5.87	6.10	6.29	6.36
Coal	1.15	1.38	1.38	1.38	1.55	1.73	1.78
LWR Nuclear	0.62	0.67	0.71	0.72	0.79	0.89	0.93
LMFBR	-	-	-	0.64	0.65	0.67	0.68
<u>UI</u>							
Oil	5.75	6.49	6.49	6.49	6.49	7.65	8.04
Natural Gas	2.45	3.53	4.60	4.60	4.60	5.98	6.44
Coal	1.15	1.38	1.38	1.38	1.48	1.66	1.72
LWR Nuclear	0.62	0.67	0.71	0.72	0.79	0.89	0.93
LMFBR	-	-	-	0.64	0.65	0.67	0.68
<u>CI</u>							
Oil	5.75	6.49	6.49	7.33	8.21	9.55	10.00
Natural Gas	2.45	3.53	4.60	6.59	7.10	7.87	8.13
Coal	1.15	1.38	1.66	2.17	2.68	3.45	3.71
LWR Nuclear	0.62	0.76	0.81	0.86	0.95	1.12	1.17
LMFBR	-	-	-	0.64	0.65	0.67	0.68

Annual revenue requirements for an investment will normally vary from year to year over the life of the investment, but as a means of developing a single overall cost metric, the varying annual revenue requirements are converted to an equivalent stream of constant (levelized) annual revenue requirements. Equivalency is established by equating the present worth of the varying annual revenue-requirements stream with the present worth of the constant annual revenue-requirements stream. The revenue requirements are made up of the capital (i.e., return on equity, interest on debt, and depreciation) and operating costs (i.e., income and property taxes, fuel, operation and maintenance, and insurance).

Capital and operating costs usually proceed over the plant life as described in Fig. 4.14. The levelized annual revenue requirement (LARR) is arrived at by the following equation:

$$LARR = \frac{\sum_{n=1}^B R_n \left(\frac{1}{1+D} \right)^n}{\sum_{n=1}^B \left(\frac{1}{1+D} \right)^n}$$

Fig. 4.12 Fuel Price Projections for Different Scenarios

U_3O_8 Price
1978 \$/lb
200

Fig. 4.13 U_3O_8 Prices for Constrained and Unconstrained Scenarios

Fig. 4.14 Typical Patterns of Costs and Revenue Requirements

where:

R_n = revenue requirements in year n ,

D = discount rate (weighted average cost of capital), and

B = book life.

A discount rate consistent with financial assumptions is needed for the present worth and levelizing calculations. Most electric utilities use their own weighted average cost of capital as the discount rate for making these calculations. The weighted average cost of capital is composed of the appropriate fractions of preferred stock, common stock, and bonds multiplied by the corresponding rates of return required in the marketplace.

In general, observed market rates of return reflect the investor's expectation of future general inflation plus some premium known as a "real" rate of return. The GNP deflator was used to estimate the historic inflation and to adjust the current-dollar rates of return to obtain real rates of return. In the comparative analyses, annual and levelized revenue requirements were calculated in inflation-free or "constant" dollars. A 1978 dollar value was used as the constant-dollar basis. Hence, only the "real" part of the discount rate should be used. Future prices of goods were expressed in the 1978 values, and increases higher than general inflation were added to these prices.

Base capital structure and economic assumptions typical of privately-owned utilities are used in the analysis and are summarized in Table 4.13.

Table 4.13 Base Capital Structure and Economic Assumptions

Capital Structure			
Debt	50%	Interest	2.0%
Common Stock	35%	Return	7.5%
Preferred Stock	15%	Return	2.5%
Discount Rate	4%		
Fed. Income Tax Rate	46%		
State Income Tax Rate	4%		
Ad Valorem Taxes	2.5%		
Plant Book Life	30 yr		

Variations in base capital structure and interest rates were examined as part of the analysis. Reasonable variations did not significantly affect the relative ranking or cost differential of technologies.* No investment tax credits were applied in this analysis because these politically determined incentives have had a history of frequent change. Current regulations are considered to be applicable only to the analysis of near-term projects.

Table 4.14 reports the levelized energy cost for the two SPS reference designs and the six alternative central station systems. These energy costs were calculated by using the capital cost ranges reported in Sec. 4.2.2, the fuel prices generated by the alternative futures scenarios, and the cost characterization information reported in Sec. 3.3. Figures 4.15-4.17 display the cost ranges for each of the scenarios for the six technologies and two SPS reference designs. Some sensitivity calculations using these numbers as a basis are described in the next section.

4.2.5 Cost Sensitivity Analysis

Several cost assumptions were made in the comparisons presented in the previous section, and a few of these assumptions were tested to determine their effect on the cost comparisons. The first sensitivity analysis was made on the plant capacity factors. Baseline capacity factors for the technologies were: SPS, 90%; LWR, LMFBR, and coal, 70%; fusion, 70%; and TPV, 25%. The relationship between capacity factor and energy costs is shown in Fig. 4.18, in which energy costs are plotted for the constrained scenario and nominal cost values. Generally speaking, the more capital-intensive the technology, the more sensitive it is to the capacity factor. The TPV curve is steeper than the others, mainly due to the fact that the scaling for this technology is much smaller and therefore the incremental change in capacity factor is much larger.

*These variations included higher real interest and return rates of 5%, 5.5% and 10.2% for bonds, preferred stock and common stock, respectively. Debt to equity ratio variation was also examined at 70% bonds, 20% common stock, and 10% preferred stock to bracket most utility financial configurations considered reasonable.

Table 4.14 Levelized 2000-2030 Cost of Electricity from SPS and Alternative Technologies (1978 mills/kWh)

Scenario and Cost Level	SPS		HS Coal	LWR	CG/CC	LMFBR	NUWMAK	TPV
	Silicon	GaAlAs						
<u>Unconstrained Scenarios</u>								
Nonfuel O&M	5.7	5.7	3.1	2.3	2.7	3.0	7.3	3.6
Capital Related								
Low	39.9	36.6	10.5	14.4	13.2	20.9	38.5	33.0
Nominal	46.4	42.8	12.3	17.8	15.5	26.0	59.6	47.8
High	212.4	196.0	13.8	20.0	20.1	35.1	--	192.1
UH: Fuel Cost	--	--	14.8	8.2	13.7	6.1	7.1	--
Electricity Cost								
Low	45.6	42.3	28.4	24.9	29.6	30.0	52.9	36.6
Nominal	52.1	48.5	30.2	28.3	31.9	35.1	74.0	51.4
High	218.1	201.7	31.7	30.5	36.5	44.2	--	195.7
UI: Fuel Cost	--	--	14.4	8.2	13.3	6.1	7.1	--
Electricity Cost								
Low	45.6	42.3	28.0	24.9	29.2	30.0	52.9	36.6
Nominal	52.1	48.5	29.8	28.3	31.5	35.1	74.0	51.4
High	218.1	201.7	31.3	30.5	36.1	44.2	--	195.7
<u>Constrained Scenarios</u>								
Nonfuel O&M	5.7	5.7	3.1	2.3	2.7	3.0	7.3	3.6
Capital Related								
Low	39.9	36.6	--	--	--	--	--	33.0
Nominal	46.4	42.8	12.3	17.8	15.5	26.0	59.6	47.8
High	212.4	196.0	26.0	41.6	42.5	81.8	--	192.1
CI: Fuel Cost	--	--	25.7	9.9	23.8	6.1	7.1	--
Electricity Cost								
Low	45.6	42.3	--	--	--	--	--	36.6
Nominal	52.1	48.5	41.1	30.0	42.0	35.1	74.0	51.4
High	218.1	201.7	54.8	53.8	69.0	90.9	--	195.7

Fig. 4.15 Levelized Energy Cost Ranges for Scenario UH^b

^aNo upper limit of the range for fusion could be determined.

^bUnconstrained scenario, no significant restrictions on coal or nuclear power. There are relatively low prices and high energy demand. The price elasticity of demand is -0.25.

Fig. 4.16 Levelized Energy Cost Ranges for Scenario UI^b

^aNo upper limit of the range for fusion could be determined.

^bUnconstrained scenario, no significant restrictions on coal or nuclear power. This is considered the most likely unconstrained scenario, with moderate price elasticity of demand. Industrial fuels are -0.7, all other fuel uses are -0.4, and chemical feedstock elasticity is 0.0.

Fig. 4.17 Levelized Energy Cost Ranges for Scenario CI^a

^aThis constrained scenario represents a continuation and augmentation of current regulatory trends affecting emissions, health, and safety. The energy price elasticities of demand are moderate, and this is considered the most likely situation if constraints are maintained.

Fig. 4.18 Total Energy Costs as a Function of Capacity

The second parameter that was investigated in the sensitivity analysis was the implementation rate for the satellite power system. The reference design scenario for the implementation of the SPS is to build 60 5,000 MW satellites over a 30-year period. As was pointed out in the scenario description of this report, this number of satellites may not be feasible if the demand for energy is not adequate (e.g., in the unconstrained intermediate or the constrained intermediate supply/demand scenarios). Table 4.15 shows the change in cost with different building schedules for both the silicon and the gallium aluminum arsenide reference systems. The table shows the total capital cost per unit as a function of three different schedules. The first schedule entails building 60 units over a 30-year period, and the other schedules are 30 and 20 units, respectively, over a 30-year period, a substantial reduction in the commitment to SPS. The increase in unit cost is less than 4% as the implementation rate decreases. However, this may be a result of the accounting system, rather than a real estimate, because the SPS base costs were derived under the assumption of a mature industry.

The third cost parameter that was examined for sensitivity to comparative costs was the set of economic or financial assumptions that were made in order to calculate energy costs. The baseline economic assumptions were reported in Table 4.13. Figure 4.19 shows the relative technology cost ranges and percentages for bonds, stock, and preferred stock returns on investment for the baseline assumptions and two other sets of assumptions. As shown in the figure, the cost range of each of the technologies varies slightly with different assumptions, but the overall comparative cost position does not change at all.

Table 4.15 Effect of Reduced SPS Implementation Rate on Costs:
Nominal Average Unit Costs (10^6 1978 \$)

Unit Cost Component	No. of SPS Units, Silicon Reference System			No. of SPS Units, GaAlAs Reference System		
	60	30	20	60	30	20
Direct	11,073	11,073	11,073	10,035	10,035	10,035
Indirect	464	464	464	464	464	464
Investment	1,093	1,324	1,555	1,093	1,324	1,555
Subtotal	12,630	12,861	13,097	11,592	1,823	12,024
Contingency	2,020	2,058	2,095	1,855	1,892	1,929
Owner's Cost	439	448	455	404	411	420
Interest During Construction	684	745	758	670	685	697
Total	15,773	16,112	16,400	14,521	14,811	15,100
% Increase	Base	2.1	3.8	Base	2.0	4.0

Fig. 4.19 Effect of Changes in Financial Assumptions on Relative Positions of Technologies

4.2.6 Comparative Cost Uncertainty

Previous sections of this report have compared the costs of the SPS and alternative technologies through an analysis of possible capital and fuel cost ranges. These ranges of capital and fuel cost uncertainty have resulted in substantial overlap in total generating costs for all of the energy technologies. The degree of overlap in these cost comparisons is large because the comparisons were made from independent data bases and have not taken into account the correlation between state-of-the-world variables (e.g., the cost of labor) and these independent estimates. In addition, the cost estimates for capital and fuel cost were developed deterministically, by including upper and lower bounds as a means of dealing with uncertainty.

In this section of the report, the question of uncertainty in technology cost comparisons is discussed in a probabilistic framework. This approach to cost comparison is primarily a method using historical data, and information used in other sections of the report was prepared to indicate the results of such an approach to uncertainty. The methodology was applied to a comparison between coal and the SPS but is equally relevant to comparisons between any technologies.

To illustrate the focus of the probabilistic cost comparison between coal and nuclear, consider the relationship between the cost of energy from coal technology vs. that of the SPS. Figure 4.20 illustrates the relationships for a fixed set of cost parameters and input assumptions. The typical levelized cost of electricity from coal is generally shown to increase in real terms because of increased coal costs. On the other hand, the cost of electricity from the SPS would not be expected to increase so rapidly, because it does not stem from a depleting resource base. Conceptually, the levelized cost of these two technologies should intersect somewhere in the future. There is no way of telling in what year the intersection will occur. Much

Fig. 4.20 Comparison of Coal and SPS Energy Costs with Fixed Parameters and Inputs

depends on the supply and use of coal. Figure 4.20 is only a hypothetical and simplistic illustration of a complex relationship, and it is not expected that the levelized cost of energy from these technologies would follow such straight line projections.

The uncertainties in the cost of energy from coal are dominated by uncertain fuel costs, whereas the uncertainties in the cost of energy from the SPS are dominated by technologically uncertain fixed costs. The approach in this probabilistic analysis was to focus only on these two dominant variables (other uncertainties were ignored in this analysis) and to treat the costs as random variables; to determine a cost probability distribution for each of the technologies for any particular year; and to combine them to develop a probability distribution for the differences in energy cost between the technologies. First, the coal probability function will be described, along with its ties to historical data, and then the foundation for SPS cost uncertainty will be discussed. The resultant combined probability function will then be shown for a few parameters.

Coal Price Relationships. Figure 4.21 shows a plot of constant-dollar coal prices from 1950 through 1977. From 1950 to 1968, the real cost of coal declined by 1.2% per year, mainly due to decreased use because of substitution by oil and gas. After 1968, the real cost of coal rose sharply (11% per year), and this could be attributed to the passage of mine safety regulations

Fig. 4.21 Coal Prices (Constant Dollars)

in 1969 and the increased use of coal. Coal prices fluctuated around these mean increases and decreases, with the average fluctuation between 1950 and 1968 being 3.5% and that between 1968 and 1977 being 14%. The trend and fluctuation in coal prices in the future is uncertain. However, it is unlikely that the trend will be similar to either of the two shown in Fig. 4.21. More probable are some moderate real increases in coal prices (less than in the volatile period from 1968-1977) with fluctuation similar to that in the period from 1950 to 1968 (i.e., 3.5%). The range of average price increases for coal, as described in the supply/demand futures analysis, is shown in Fig. 4.22. The figure shows that the average real increases in coal price ranged from 2.4%/yr to 0.87%/yr for the constrained intermediate case and unconstrained high case, respectively. In approximately the same period of time (i.e., 1964-1977), electrical equipment prices declined 1.5%/yr, with a 1.7% fluctuation. Similarly, construction costs increased 1.9%/yr with 2.6% fluctuation, and transportation and utility labor rose 1.6%/yr with a 3.0% fluctuation.

The price of coal in any particular year (Y_t) can be related to that of another year (Y_0) through a series of factors.

Let:

$$Y_t = Y_0 (1 + \mu + \eta_1) (1 + \mu + \eta_2) \dots (1 + \mu + \eta_t)$$

where:

Y_0 = constant dollar amount, year 0,

Y_t = constant dollar amount, year t,

μ = mean rate of increase,

η = independent random variable with mean 0 and standard deviation σ .

Examples of and

	$\mu(\%)$	$\sigma(\%)$
Coal prices, 1950-1958	-1.2	3.5
Coal prices, 1968-1977	11	14
Electrical equip. prices 1964-1977	-1.5	1.7
Construction cost 1964-1977	1.9	2.6
Transportation and utility labor 1964-1977	1.6	3.0

This expression gives the price of coal in, say, the year 2000, but in reality, that figure is the levelized cost of coal. Thus the cost of coal for every year over the whole period of operation of the coal plant must be weighted by a discount factor so that the random variable is not just the price of coal in the year 2000 but the levelized cost of coal for the whole period. The equation for the levelized cost of coal, regarded as a random

Fig. 4.22 Real Coal Price Increases

variable, for a plant that operates between the year t' and the year t , is as follows:

$$\hat{Y}_{t-t'} = Y_0 \sum_{k=t'+1}^t (1-\alpha)^k \prod_{i=1}^k (1 + \mu + \eta_t) / \sum_{k=t'+1}^t (1-\alpha)^k$$

where:

$\hat{Y}$ = the levelized cost of coal over the period $t - t'$,

k = no. of years in the period, and

$1 - \alpha$ = discount factor.

Figure 4.23 shows the distribution for levelized fuel cost and levelized capital charge for a 2% average growth with 4% fluctuation per year and a real discount rate of 4%. A normal distribution is plotted in dotted lines to show the slight skew of this distribution. The skewed distribution has a long tail on the high side, which is important because the high side of the coal distribution will be important in the comparison to SPS.

SPS Price Relationships. In the case of the SPS, the dominant uncertainty factor is technical uncertainty, since there is no economic experience. The SPS is made up of a number of subsystems that were broken up into six categories: energy conversion, space construction and support, power transmission, transportation, rectenna, and other. A typical probability distribution for the cost that one might expect for each of these subsystems is shown

by the triangular distribution in Fig. 4.24. A skewed distribution was considered representative, because more factors seem to be left out than extra ones included at the early developmental stages of an advanced technology, since a design can never be complete 20 years in advance or before the technical problems have been solved.

What is needed, in reality, is a cost distribution for the SPS. However, to assemble a subsystem cost distribution like that illustrated in Fig. 4.24 requires the consideration of correlation* in the cost components, which means that several subsystems would fall into the high cost range because of the same factors. SPS subsystems are probably highly correlated in some areas and highly uncorrelated in others. For example, energy conversion is heavily dependent on the manufacturing cost for solar cells, which is very dependent on fuel cost. That would

Fig. 4.23 Distributions of Levelized Fuel Cost and Levelized Capital Charge of a Coal Plant

Fig. 4.24 Typical Cost Distribution for Advanced Technologies

*A more detailed discussion of the correlation effects can be found in Ref. 2, pp. 70-72.

correlate with transportation. On the other hand, solar cell production depends on the manufacturing sector (not strongly fuel dependent), and this would be uncorrelated with transportation. If the subsystem cost components were completely correlated, the resulting distribution would look like the triangular figure in Fig. 4.25. If the components were completely uncorrelated the resulting distribution would look like the normal distribution in that figure. Since the SPS components are partially correlated, the distribution for the entire system starts out as a triangle and probably ends up something like the smooth distribution shown in Fig. 4.24 (dotted line). A distribution like this was obtained for the SPS, with 20% of the area to the left of the modal value and 80% to the right. This assumption was based on the earlier discussion that component projections for advanced technologies err more on the high side than on the low side. The resulting analysis could be performed using other distributions. This assumption is consistent with the capital cost range developed in Sec. 4.2.2.

Probabilistic Cost Comparisons Between Coal and the SPS. The main problem in comparing the coal and SPS cost distributions is to establish the size of the overlap between the two technologies. Again, developing a cost distribution for the difference between these technologies is dependent on the degree of correlation of cost elements between coal and the SPS. The correlation was tested and found to be unimportant, because the two technologies stem from such radically different bases.

The goal of this probabilistic analysis is to determine the probability that the cost of electricity from the SPS will equal that from coal, and the time at which this might occur. Figure 4.26 shows 1%, 10%, and 20% probability curves for the difference in generating cost between coal and the SPS. For example, the slope of the 20% curve indicates that there is a 20% probability that the SPS will cost the same as coal in the year 2018. Similarly,

Fig. 4.25 Distributions of the Sum of Cost Elements

there is a 20% probability that the cost differential will be around 16 mills/kWh in the year 1990. This curve was plotted for the constrained intermediate coal price increases (2.4% real per year) and a 3% fluctuation. A real 4% discount rate was used. Curves similar to those in Fig. 4.26 were calculated for other coal price increases and fluctuations, but the results are no more representative than those shown in the figure. It should be pointed out that the probabilistic results were obtained using nominal values for coal and the SPS and only show the conceptual probabilistic differences. The exact numbers plotted in Fig. 4.26 are illustrative and should not be used as hard conclusions, because changing some of the assumptions (e.g., SPS cost distribution, coal price rise and fluctuations) could change the results substantially.

^aA $P(\Delta)$ value of 20% is the highest curve that can be calculated from the SPS cost-uncertainty curve assumed in this study, i.e., with 20% of the probability distribution to the left of the modal cost.

Fig. 4.26 Probability Curves of SPS Costs Equalling Coal Costs

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