Appendix A

Cost and Performance Tables

Appendix A
Cost and Performance Tables

Table A-l.—Cost and Performance of Central Station Photovoltaics

May 1985 technology status	Flat-plate	Concentrator
Level of technology development	Commercial	Commercial
Installed capacity	9.5 MWe	9.5MWe
Reference system: general characteristics	general characteristics	
Reference year	1995	
1995 deployment level scenario	20-4,730 MWe[2]	
Plant size[3]	10 MWe[4]	
Lead-time	2years[5]	
Land required:		
Fixed	40-90 acres[6]	
Tracking	70-370 acres[7]	60-320 acres[8]
Water required	very little[9]	
Reference system: performance parameters	performance parameters	
Operating availability	90-100%[10]	
Capacity factor[11]:		
Fixed:		
Boston	20-25%	
Miami	20-25%	
Albuquerque	25-30%	
Tracking:		
Boston	30-35%	20-25%
Miami	30-35%	20-25%
Albuquerque	35-40%	30-35%
Duty cycle		intermittent
Lifetime[12]		10-30 years[13]
Efficiency:		
Module:		
Boston	10-17%[14]	15-24%[15]
Miami	10-16%[14]	15-23%[15]
Albuquerque	10-16%[14]	15-23%[15]
BOS	80-85%[16]	80-85%[17]
Plant[18]	8-14%	12-20%
Reference system: costs		
Capital costs[19]:		
Modules	$100-500/sq m[20]	$100-400/sq m[21]
BOS (area dependent):		
Fixed	$50/sq m[22,23]	n/a
Tracking	$100/sq m[24,25]	$100/sq m[26,27]
BOS (power dependent)	$100-200/kWe[28]	$100-200/kWe[29]
Total[30]:		
Boston	$2,000-11,000/kWe	$2,000-8,000/kWe
Miami	$1,000-9,000/kWe	$1,000-5,000/kWe
O&M costs[31]:		
Fixed	5-26 mills/kWh[32]	
Tracking	4-28 mills/kWh[33]	4-23 mills/kWh[34]

[1] While modules of both types are at present commercially available, these differ substantially in cost and performance from those which will be on the market in 1995.

[2] The lower end of the range is the total capacity of grid-connected photovoltaic capacity which will be installed by the end of 1985. The upper end of the range coincides with the high estimate made by Pieter Bos, Polydyne, Inc., in a submission at the OTA Workshop on Solar Photovoltaic Power (Washington, DC, June 12, 1984) and discussed in Paul D. Maycock and Vic S. Sherlekar, *Photovoltaic Technology, Performance, Cost and Market Forecast to 1995: A Strategic Technology & Market Analysis* (Alexandria, VA: Photovoltaic Energy Systems, Inc., 1984), pp. 130-136.

[3] The plant rating system used here follows that used by EPRI in Roger W. Taylor, *Photovoltaic Systems Assessment: An Integrated Perspective* (Palo Alto, CA: Electric Power Research Institute, September 1983), EPRI AP-3176-SR. The plant is rated by its peak output under nominal peak operating conditions at a particular site. See footnote 30 below.

[4] The Electric Power Research Institute; see Bechtel Group, *Photovoltaic Balance of System Assessment* (Palo Alto, CA: EPRI, 1982), EPRI AP-2474. This report indicates that 5 MW subfields in central PV plants are optimum. A utility may consider a 50 to 100 MW plant; see Dan Utroska, "SMUD Forges a New Path in Photovoltaics Generation," *Electric Light and Power*, vol. 62, No. 8, August 1984, p. 21. As PV technologies other than single-crystal-silicon begin to be used, it is likely that initial plants would be in the 1 to 5 MW size range. Non-utility sponsors may undertake new capacity additions in the 5 to 10 MW range.

The plant auxiliary load other than tracking (i.e., lighting, HVAC, I&C, computer) is expected to consume less than 0.1 percent of the annual energy generated. The energy for array tracking is also insignificant because the drives use little power and operate only intermittently; see Bechtel Group, op. cit., 1982. For example, each drive in the Sacramento Municipal Utility District PV 1 plant is rated at 1/20 HP; from M. Wool, Acurex Solar Corp., personal correspondence with O. Chukumerije, Gibbs & Hill, Inc., May 1984. Consequently, the difference between gross and net plant capacity is neglected.

[5] Includes 12 to 18 months for licensing and permits. Installation at the site could be achieved at a rate of 5 to 10 MW per month. This is based on information provided in the following sources: 1) Bechtel Group, op. cit., 1982; 2) Dan Utroska, op. cit., 1984.

[6] OTA calculation. The low estimate is for Albuquerque, using a plant efficiency of 14 percent, insolation of 0.998 kWe/square meter, and a ratio of array surface/total land surface of ½. The high estimate is for Boston, using a plant efficiency of 8 percent, insolation of 0.676 kWe/square meter, and a ratio of array surface/total land surface of ½.

[7] OTA calculation. The high estimate is for Boston, assuming 5 arrays/acre, 100 square meters (net) per array, 0.676 kWe/square meter insolation, 8 percent plant efficiency. The low estimate is for Albuquerque, assuming 10 arrays/acre, 100 square meters (net) per array, 0.998 kWe/square meter insolation, 14 percent plant efficiency.

[8] OTA calculation. The high estimate is for Boston, assuming 5 arrays/acre, 100 square meters (net) per array, 0.521 kWe/square meter insolation, 12 percent plant efficiency. The low estimate is for Albuquerque, assuming 10 arrays/acre, 100 square meters of array area (net), 0.881 kWe/square meter insolation, 20 percent plant efficiency.

[9] Small amounts of water may be needed to periodically clean the module surfaces.

[10] OTA estimate. Refers to availability of the entire 10 MWe field. For information on operating availabilities, see: 1) Boeing Computer Services Co., *Photovoltaic Field Test Performance Assessment: Technology Status Report Number 3* (Palo Alto, CA: Electric Power Research Institute, November 1984), EPRI AP-3792; 2) Alexander B. Maish and Clement J. Chiang, "Photovoltaic Concentrator

Array Reliability *A Compilation of Sandia Contributed Papers to the 17th IEEE Photovoltaic Specialists Conference Orlando FL May 1-4 1984* Edward L Burgess (ed) (Albuquerque NM Sandia National Laboratories 1984) SAND84-1167c pp94-100

"Capacity factor is defined as the ratio of actual energy produced by the plant in a year to the energy the plant could have generated If It operated continuously al its rated power The capacity factor is a function of location The three figures represent Boston Miami and Albuquerque The high values for the fixed flat-plate arrays are taken from Taylor op cit 1983 pp 4-6, the high values for tracking-arrays were found by enhancing the fixed array data by 40 percent as suggested by R E L Tolbert and J C Arnett ARCO Solar Design Installation and Performance of ARCO Solar Photovoltaic Power Plants *Proceedings of 17th IEEE Photovoltaics Specialists Conference* Kissimmee, FL May 1984 p 1149 and the high concentrator values were compiled from tables from the following 1) J W Deane and J B Gresham Science Applications Inc *Photovoltaic Requirements Estimation—A Simplified Method* (Palo Alto, CA Electric Power Research Institute February 1983 ,EPRI AP-2475 2) Gary J Jones Supervisor, PV Systems Development Division Sandia National Laboratories A Comparison of Concentrating Collectors to Tracking Flat Panels *A Compilation of Sandia Contributed Papers to the 17th IEEE Photovoltaic Specialists Conference Orlando FL May 1-4 1984* Edward L Burgess (ed) (Albuquerque, NM and Livermore CA Sandia National Laboratories June 1984) SAN D84-1 167c pp 8-13

In all cases the low capacity factors arbitrarily are set 5 percentage points below the high value 10 reflect the effects of low operating availability dirt and other factors of her than long-term cell degradation on capacity factors

[12]Lifetime is defined as the period in which the energy output of a plant drops by 20 percent Ronald G Ross Jr Manager Reliability and Engineering Sciences Flat-plate Solar Array Project Jet Propulsion Laboratory interview with OTA staff, Aug 22 1984

[13]The low value is an extrapolation of the performance of equipment which has already been in the field for several years Ronald G Ross Jr op cit 1984 The high value represents DOE goals U S Department of Energy (DOE), *Five Year Research Plan* 1984-1988 (Washington DC DOE May 1983)

[14]These figures are based on *adjusted* estimates that modules would have efficiencies of 11 to 18 percent The 11 percent value is from a currently commercial module Dan Arvizu and Michael Edenburn Sandia National Laboratories *An Overview o! Concentrator Technology* paper presented at the Annual Meeting of the American Society of Mechanical Engineers New Orleans LA December 1984 The 18 percent value represents a module efficiency based on the best laboratory silicon cell Taylor op cit 1983 The module efficiencies shown in the table result from adjusting the 1 1 to 18 percent range to reflect *nominal* peak operating *conditions* at each site The methodology used is described in app B of an Electric Power Research Institute report Taylor op cit 1983

[15]These figures are based on *adjusted* estimates that modules would have efficiencies of 16 to 25 percent The 16 percent value is from a currently commercial module Arvizu and Edenburn, op cit 1984 The 25 percent figure is Sandia's estimate for the best commercial GaAs module in the 1990s The module efficiencies shown in the table result from adjusting the f 6 to 25 percent range to reflect nominal peak operating conditions at each site The methodology used is described in app B of Electric Power Research Institute Taylor op cit 1983

[16]The low end is a Bechtel prediction Bechtel Group *Photovoltaic Balance-of-System* Assess. *ment* op cit 1982 and the high end is a Sandia estimate from Gary J Jones, Supervisor PV Systems Development Division Sandia National Laboratories Albuquerque NM interview with OTA Staff August 8 1984

[17]The low end is a Bechtel prediction Bechtel Group *Photovoltaic Balance-of-System Assessment* op cit 1982 and the high end is a Sandia estimate Gary J Jones, op cit 1984

[18]Plant efficiency is the product of the module and the BOS efficiencies

[19]These cost figures do not include overhead Contingency or owner's costs

[20]The low figure represents industry Charles F Gay Vice President, Research & Development ARCO Solar Inc interview with OTA staff August 10 1984 Electric Power Research Institute Roger Taylor *Photovoltaic Systems Assessment An Integrated Perspective* OP cit 1983 and the Department of Energy, U S DOE *Five Year Research Plan 1984-1988* OP cit *1983* goals The high figure represents OTA estimates of costs of current commerial lines if they were run at larger volumes of production and used less labor

"The low end represents Department of Energy U S OOE *Five Year Research Plan. 1984-1988* op cit 1983, and Sandia Dan Arvizu and Michael Edenburn, *An Overview of Concentrator Technology* op cit 1984 goals The high figure is the cost of the best currently commercial module if it were produced at 10.20 MW/yr This is based on Information from 1) Juris Berzins Intersol Power Corp interview with OTA staff August 10 1984 and 2) Dan Arvizu and Michael Edenburn, *An Overview o! Concentrator Technology*, op cit 1984

[22]Bechtel Group *Photovoltaic Balance-of-System Assessment* op cit 1982

[23]Photovoltaic Sytems *EPRI Journal* vol 9 No 6 July/August 1984 PP 43 4 5

[24]Bechtel Group *Photovoltaic Balance-of-System Assessment* op cit 1982

[25]Photovoltaic Sytems *EPRI Journal* op cit 1984

[26]Bechtel Group, *Photovoltaic Balance-of-System Assessment* op cit 1982

[27]Photovoltaic Sytems *EPRI Journal* op cit 1984

[28]Bechtel Group *Photovoltaic Balance-of-System Assessment* op cit 1982

[29]Ibid

[30]The total capital cost is given by

cost - module cost . BOS area cost module effic e n .) . BOS e t ficiency . insolation . BOS power i costs

Nominal peak Insolation and efficiency vary in different locations so that the capital costs of a given system will vary depending on where it is shed The values gwen represent Capital costs at *ideal sites* In general these costs will be higher From Roger W Taylor *Photovoltaic Systems Assessment An Integrated Perspective*, op cit 1984 the nominal peak insolation in several cities is

	tota k* sq -i , xed plate)	d rect kW sq m) co ent ato
Albuquerque	- 998	c 881
Miam	0 821	0 634
Boston	0 676	C 521

Note The total cost figures are rounded to the nearest integral multiple of a thousand

[31]The O&M cost range used here is $2 00 to $2 50/square meter per year This is based on estimates made in the following 1) Jet Propulsion Laboratory ' 'Summary of Session VI on Array Maintenance Issue, " *Proceedings of the F/at-P/xc Solar Array Project Research Forum on the Design of F/at-Plate Photovoltaic Arrays for Central Stations* (Pasadena CA Jet Propulsion Laboratory 1984) Dec 5-8, 1983, Sacramento, CA DOE/JPL-1012-98 pp 301-304 2) P K Henry 'Economic Implications of Operation and Maintenance '' *Proceedings of the Flat-Plate Solar Array Pro/eel Research Forum on the Design of Flat-Plate Photovoltaic Arrays for Central Stations* op cit pp 315-316

[32]OTA Calculation The high estimate is based on a system efficiency Of O 138 *insolation* of 0676 kWe/square meter, capacity factor of O 2 and annual O&M costs of $2 50/square meter The low estimate is based on a system efficiency of O 14, insolation of O 998 kWe/square reeler capacify factor of O 3 and annual O&M costs of $2 00/square meter

[33]OTA calculation The high estimate is based on a system efficiency of O 08, Insolation of 0676 kWe/square meter, capacity factor of O 3. and annual O&M costs of $2 50/square meter The low estimate is based on a system efficiency of O 14 insolation of O 998 kWe/square meter capacity factor of O 4, and annual O&M costs of $2 00/square meter

[34]OTA Calculation The high estimate is based on a system efficiency of O 12 Insolation of 0 521 kWe/square meter capacity factor of O 2 and annual O&M costs of $2 50/square meter The low estimate is based on a system efficiency of O 20, Insolation of O 881 kWe/square meter capacity factor of O 35 and annual O&M costs of $2 00/square meter

Table A-2a.—Cost and Performance of Solar Thermal-Electric Plants Parabolic Dishes (Mounted-Engine)

May 1985 technology status

Level of technology development: demonstration units in operation
Installed capacity: 0.075 MWe[1]
Reference system: general characteristics
Reference year: 1995
Deployment level scenario:[2]
High . . . . 200 MWe
Medium . . . . 100 MWe
Low . . . . 0.4 MWe
Plant size: 10.8 MWe (gross) (400 units @ 27.1 kWe (gross))[3]
10.2 MWe (net) (400 units @ 25.6 (kWe net))
Lead-time: 2 years[4]
Land required: 67 acres[5]
Water required: negligible[6]
Reference system: performance parameters
Operating availability: 95 percent[7]
Duty cycle: intermittent
Capacity factor: 20-35 percent[8]
Plant lifetime: 30 years[9]
Plant efficiency: 20-25 percent[10]
Reference system: costs
Capital costs: $2,000-3,000/kWe (net)[11]
O&M costs: 15-53 mills/kWh[12]

[1]This includes three 25 kWe parabolic dish units

[2]Deployment scenarios depend heavily on whether or not the currently provided Renewable Energy Tax Credit is extended beyond the end of 1985, and whether the federal government subsidizes installations m any other way The low scenario assumes that the only additions to currently installed capacity will be 1) two 25 kWe parabolic dish installations now being constructed under the McDonnell Douglas Astronautics Co s Dish/SIWmg Program 2) four additional parabolic dish installations expected under the McDonnell Douglas Astronautics Co 's Dish/Stwhng Program 3) 100 kWe at the federally sponsored Osage City, KS, Small Community Experiment #1, and 4) 100 kWe at the federally sponsored Molokai, HI, demonstration project Under favorable conditions (e g with an extension of the RTC), however hundreds of MWe may be installed by 1995 see Nina Markov, "Exclhng Developments Reflect Bright Future, *Renewable Energy News,* vol7, No 2 May 1984, pp 8-12 An upper limit of 200 MWe will be used here, the medium deployment scenario will is half that figure or 100 MWe

[3]Based on Advanco Corp 's Vanguard I module, at direct insolation levels of 1,000 watts/square meter, ambient air temperatures of 28 C, wind speed of 22 m/s (5mph) see Byron J Washom et al *Vanguard/ Solar Parabolic Dish-Stirling Engine Module* (Palm Springs CA Advanco Corp 1984), final report summary of work performed under Department of Energy cooperative agreement DE-FC04-82AL16333, May 28, 1982 -Sept 30, 1984, DOE. AL-16333-2 (84. ADV-5) p 142

[4]And design and 1 year of construction

[5]Ibid Based on six modules per acre

[6]Ibid

[7]Figure for individual module availability Based on information provided by 1) OTA contractor N Hinsey Gibbs & Hill Inc interviews with James E Rogan, Manager Market Development McDonnell Douglas Astronautics Corp July 16 and Aug 13, f984 2) Byron J Washom, President, Advanco Corp personal correspondence with OTA staff, Nov 9 1984 3) Advanco Corp *Proposal to the U S DOE Relating to the Small Community Solar Experiment at Molokai Hawaii* (Palm Springs, CA Advance, 1984)

[8]The range provided here is identical to that used for the photovoltaic concentrator modules See Footnote 11 of the photovoltaics cost and performance table (table A-t) for an explanation of the capacity factor used there Within this range fall estimates from the following sources 1) James H Nourse Branch Manager McDonnell Douglas Corp personal correspondence with OTA staff, Nov 1 t 984, 2) Byron J Washom, President, Advanco Corp personal correspondence with OTA staff, Nov 9 1984 Washom indicated that a facility located at Barstow CA, would have an annual capacity factor of 257 percent, 3) Byron J Washom, et al *Vanguard / Solar Parabolic Dish-Stirling Engine Module* op cit , 1984, 4) Tony K Fung, Senior Research Engineer Southern California Edison comments on OTA draft report, April 1985

[9]OTA contractor N Hinsey, Gibbs & Hill, Inc interviews with James E Rogan op cit 1984

[10]Washom op cit Nov 9 1984 Annual average efficiency at Barstow CA, would be about 23 percent

[11]Based on Information provided by 1) OTA contractor N Hinsey, Gibbs & Hill, Inc interviews with Don H Ross, Director, Energy Systems Center, Sanders Associates, Inc July 1 t and 16, 1984 2) OTA contractor N Hinsey, Gibbs & Hill, Inc Interviews with James E Rogan, op cit 1984 3) James H Nourse, Branch Manager, McDonnell Douglas Corp personal correspondence with OTA staff, Nov 1, 1984 4) Byron J Washom, President, Advanco Corp personal correspondence with OTA staff, Nov 9, t984

Advanco reportedly estimates that mass produced Stlrhng/dish units would cost approximately $2,300/kWe see 'SCE's 'A/R' Program Rediscovers a Solar Thermal Power Technology –'The Parabolic Dish '," *SCE R&D* Newsletter vol 13 No 1, 1st Quarter 1984, pp 1-2

[12]OTA figure, based on Information obtained from McDonnell Douglas and Advanco Corp. see Byron J Washom et al *Vanguard / Solar Parabolic fish-.stwhrrg Engine Module* op cit 1984 and Advanco Corp *Proposal to the U S DOE Relating to the Small Community Solar Experiment at Molokai Hawaii* op cit 1984 The O&M cost for a commercial module would be $1 ,600/year and average annual module net output would be 56234 kWh This amounts to 28 mills kWh a figure within the lower end of the OTA range

[a]The capital cost for this plant varies most Importantly with the cost of the heliostats which here are assumed to 42 percent of total plant costs This coincides roughly with estimates made by the California Energy Commission, the Electric Power Research Institute, and Teknekron Research, Inc California Energy Commission, *Appendices, Technical Assessment Manual,* op cit 1984

Heliostat costs are especially sensitive to the number of heliostats produced Using extremely optimistic assumptions about heliostat production levels a Sandia study suggested that heliostat costs would vary between $100 and $150 per square meter of heliostat (1980$) if 520000 heliostats were produced over an 11 year period see H F Norris Jr and S S White, Manufacturing and Cost Analyses of Heliostats Based on the Second-Generation Heliostat Development Study (Livermore CA Sandia National Laboratories n d) DE83006664 If a single 100 MWe plant requires about 15400 heliostats that is enough heliostats for nearly 34 Installations of 100 Mwe each The report suggests that if production were scaled down to half that number (about 17 installahens over an 11 year period) the costs per square meter of heliostat could Increase 4 to 14 percent If the larger increase (14 percent) m heliostat cost is applied to the original costs per square meter one obtains a range of $114 to $171 per square meter of heliostats (1980$) If a 100 MWe installation requires 663000 square meters of heliostats this amounts to $756 to $1 134 per kWe (1980$) this averages out to $945 per kWe (1980$) if enough heliostats for 17 100-MWe plants are sold

For this to occur the construction of a heliostat plant would have to be initiated no later than 1992, as an initial production facility would take 3 years 10 build a fully automated factory would have to be initiated even earlier than that The manufacturer would have to have assurance that high rates of production could continue beyond the end of the century from McDonnell Douglas Response by McDonnell Douglas, General Workshop Discussion Questions submitted to OTA in response to written questions submitted in connection with OTA workshop on Solar Thermal Electric Technologies 1984 It is highly unlikely that this quantity of orders would be expected to support production over the decade beginning m 1995

Heliostat costs probably therefore might be considerably higher for the few commercial units which are completed m the latter half of the 1990s However, while low production levels might drive costs higher technical improvements alone may drive heliostat costs downward as much as 25 percent see California Energy Commission *Technical Assessment Manual* op cit 1984 As a rough approximation, it is assumed here that the two opposite effects on heliostat costs roughly cancel each other out

If the heliostat cost represents 42 percent of total plant costs then total plant costs would be $2 250/kWe (1980$) Using the producer price index this yields about $2531 m 1983 dollars or $2 500 rounded-off This figure is based mostly on optimistic assumptions for 1995 and therefore will be used as the low end of the OTA cost range for 1995

The high end of the range assumes that heliostats will cost $250 per square meter (1983$) the present estimated cost for heliostats This is based on information from the following sources 1) Personal correspondence between A Skinrood Sandia National Laboratories Livermore CA and N Hinsey Gibbs & Hill Inc May 11 1984 2) Nma Markov Exciting Developments Reflect Bright Future Renewable Energy News, vol 7, No 2 May 1984 pp 8-12

If 663000 square meters are required for a 100 MWe plant the price of the heliostats is approximately $1 658/kWe If this represents about 53 percent of plant costs then total capital costs would be $3, 108/kWe This table will use the rounded figure of $3, 100/kWe as the high end of the cost range This is somewhat lower than the $3,616/kWe (1983$) used in a 1984 analysis by the Solar Energy Industries Association to represent the costs of building three central receiver plants (30 MWe 60 MWe and 100 MWe) between 1985 and 1992 And it is considerably lower than the $4 000/kWe figure cited m one source, Markov, op cit 1984 as being the present cost of central receivers, as estimated by 'industry analysts

Several published estimates for commercial units fall within the lower bounds of OTA range The California Energy Commission uses a construction cost estimate in f982 dollars of $2580 (about $2606 m 1983 dollars) for a 1990 central receiver system with the capacity 10 store 3 hours-worth of power and 10 operate with a capacity factor of 40 percent see California Energy Commission op cit 1984 EPRI estimates a similar figure for a 1992 central receiver see EPRI *Technology Assessment Guide*, op cit 1982

It should be noted these earner estimates assume mass production of heliostats m numbers sufficient to allow heliostat costs to drop to relatively low levels It is here assumed that mass production of heliostats will not Immediately follow the startup of the first 100 MWe commercial demonstration unit, and that the heliostats utilized by any commercial units which begin operation in the 1990s will utilize heliostats manufactured in relatively small batches al costs as high as $250/square meter yielding plant costs of about $3, 100/kWe Fortifying this estimate is the fact that Solar One cost about $16,060/kWe (1983$) and the projected installed cost for Socal Ed's proposed (and cancelled) 100 Mwe unit was about $6,000/kWe (1983$) see California Energy Commission, *Technical Assessment Manual* op cit 1984

[14]Based on information from the following sources 1) Battleson op cit 1981 2) OTA Work shop on Solar Thermal- Electric Generating Technologies op cit 1984

Based on 42 percent capacity factor (escalated to 1983$) O&M costs could be reduced with the installation of central control facilities and roving operators from OTA contractor N Hinsey Gibbs & Hill Inc Interview with J Bigger Electric Power Research Institute May 10, 1984 However a pool of several plants is necessary fo operate on such a basis This will most likely not be the case in 1995 Therefore, O&M costs are not expected to drop significantly until many plants are on-line

E Weber indicates a 124 mill/kWh O&M cost for a 60. MW plant with a 23 percent capacity factor, see E Weber, ''Financial Requirements for Solar Central Receiver Plants' (Phoenix, AZ Arizona Public Service Co 1983)

This is considerably higher than the estimate provided by Teknekron Research Inc Energy and Environmental Systems Division, *Draft Cost Estimates and Cost-Forecasting Methodologies for Selected Nonconventional Electrical-Generation Technologies*, submitted to Technology Assessments Project Off Ice, California Energy Commission, May 1982 This report estimated that annual O&M for a 100 MWe plant would be $1,166000 (1978$) Assuming a 42 percent capacity factor [his amounts to 46 mills/kWh (1983$) The figure however is lower than would be obtained If another source's estimate of annual O&M of $56 million/year (1981$) for a 100 MWe plant is used see J R Roland and K M Ross Solar Central Receiver Technology Development and Economics–100 MW Utility Plant Conceptual Engineering Study, ' op cit 1983 That figure with a 42 percent capacity factor would yield about 16 mills/kWh in 1983$

Table A-2 b.—Cost and Performance of Solar Thermal. Electric Plants Central Receivers'

May 1985 technology status

Level of technology development: concept supported by small pilot facility[2]
Installed capacity: 10.8 MWe[3]
Reference system: general characteristics
Reference year: 1995
Deployment level scenario:[4]
- High . . . . 110 MW
- Medium . . . . 60 MWe
- Low . . . . 10 Mwe

Plant size:[5]
- Gross: 110 MWe
- Net: 100 MWe

Lead-time, years: 5[6]
Land required: 700 acres[7]
Water required: 0.7 million gallons/day[8]
Reference system: performance parameters
Operating availability: 90-95 percent[9]
Capacity factor: 42 percent[10]
Duty cycle: intermediate
Plant lifetime: 30 years[11]
Plant efficiency: 20-25 percent[12]
Reference system: costs
Capital costs for commercial unit: $2,500-3,100/kWe (net)[13]
O&M costs: 10-12 mills/kWh[14]

[1]The system referred to here is a molten-salt central receiver This presently is the preferred variety of central *receiver among major proponents*

[2]The pilot facility referred to here is Solar One, a receiver which uses water to absorb the Sun's heat: no such electricity-producing pilot-facility exists for the molten salt variety of central receiver However Sandia National Laboratories in New Mexico operate a Molten Salt Electric Experiment (MSEE) which began operating in 1984. It can produce 750 kWe

[3]This figure represents the 10 8 MWe Solar One central receiver While it is not a molten salt receiver, it is included here because it is in many ways very similar to a molten salt central receiver

[4]The low scenario assumes that no central receivers other than Solar One (10 MWe) will be operating by 1995. The medium scenario assumes that a 50 MWe molten salt pilot plant begins operating by that time The high scenario assumes in addition that a 100 MWe commercial demonstration is unit is operating by the end of 1995

[5]". .commercial receivers are expected to be as large as 200 to 500 MWth. . ." T Tracey, *Development of a Solar Thermal Central Heat Receiver Using Molten Salt* (Denver, CO: Martin Marietta, 1982) (At a nominal efficiency of 25 percent, the electric generation range is 50 to 125 MWe.) Receiver development and investigation has been performed by Babcock & Wilcox and Martin Marietta in the 100 MWe plant size range; this also was selected as the reference size used by the Electric Power Research Institute in its Technical Assessment Guide. *See the following sources* 1) Electric Power Research Institute. *Technical Assessment Guide* (Palo Alto, CA: EPRI, 1982), EPRI P-2410-SR; 2) O. Durrant, *The Development and Design of Steam/Water Solar Receivers for Commercial Application*(New York: Babcock & Wilcox Co., 1982); 3) S Wu et al., *Conceptual Design of an Advanced Water Steam Receiver for a Solar Thermal Central Power System* (Livingston NJ Foster Wheeler Development Corp 1982)

In the OTA s Solar Thermal Electric Power Workshop June 12 1984 Charles Finch of McDonnell Douglas Indicated that lhe gross capacity of a plant should be 110 MW if it is to yield 100 MW ret

It should be noted [hat industry observers foresee an initial development of 30 to 50 MW modular *demonstration units Subsequent* commercial *units* could possibly be multiples of 50 MW plants This is based on information from 1) E Weber Arizona Public Service personal correspondence with N Hinsey Gibbs & Hill Inc May 10 1984 2) A Skinrood Sandia National Laboratories personal correspondence with N Hinsey Gibbs & Hill Inc May 1 11984

'Two years of preconstruction licensing and design and 3 years of construction see Electric Power Research Institute *Technical Assessment Guide* op cit ' 982 and K Battleson *Solar Power Tower Design Guide Solar Thermal Central Reciever Power Systems 4 Source of Electricity and/or Process Heat* (Albuquerque NM Sandia National Labs April 1981 SAN081 8005 The latter report estimates 4 years but does not include permitting and licensing

California Energy Commission (CEC) Technology Assessments Project Off Ice *Appendices Technical Assessment Manual (Sacramento* CA CEC 1984 vol I 3rd ed This source estimates a lead time of 8 years it Includes time for advance planning 'year) regulatory (2 years, purchase orders (1 year) and construction and start up (4 years)

Based on approximately O 53 acres/million Btu hr for a plant with a capacity factor of 42 percent and 2850 kWh/ sq m-yr insolation see Battleson op cit 1981

In one source Arizona Public Service Co Responses to Questions Pertaining 10 Solar Thermal Electric Power Plants for the Off Ice of Technology Assessment s New Generating Technology Cost and Performance Workshop June 1984 it was estimated that about 84 acres per MWe would be required for a central receiver system this would amount 10840 acres for a 100 MWe plant

[8] The water requirements for a solar plant would be essentially the same as those for a water cooled fossil powered utility plant There would be a small Incremental water requirement for washing heliostats 15000 gal /yr per MWth peak) Battleson op cit 1981 Water requirements for a conventional power plant are 675 gal ' hr MW see K Yeagar *Fluidized Bed Combustion An Evolutionary Improvement in Electric Power Generation* VOl 1 August 1980 USDOE CONF 80048 This corresponds to 680400 gal 'day for a plant with 42 percent capacity factor This figure added to 5000 gal/day for washing heliostats (380 MWth + 100 MWe) yields 685400 gal day

'Based on Information from the following sources 1) N Hinsey Gibbs & Hill Inc OTA contractor interview with E Weber Arizona Public Service May 10 1984 2) N Hinsey of Gibbs & Hill Inc OTA contractor interview with A Skinrood Sandia National Laboratories Livermore CA May 11 1984 3) U S Congress Off Ice of Technology Assessment Workshop on Solar Thermal Electric Generating Technologies Washington DC June 12 1984

Availability must be 90 percent or greater especially for an intermediate duty unit to be seriously considered by utilities O Van Alla Israeli Solar Plant Blooms *Engineering News Record* vol 211 No 2 ? Nov 24 1983 This figure is supported by J R Roland and K M Ross Solar Central Receiver Technology Development and Economics– 100 MW Utility Plant Conceptual Engineering Study *Energy Technology X A Decade of Progress* Richard F Hill ed (Rockville MO Government Institutes Inc 19831 pp 1421-1444

[10]From Gibbs & Hill Inc *Overview and Evaluation of New and Conventional Electrical Generating Technologies for the 1990s* OTA contractor report 1984 Actual capacity factors will vary considerably depending on system design location and operating practices

The California Energy Commission in a 1984 report assumes a 40 percent capacity factor for a unit with 3 hours' worth of storage For the same amount of storage EPRI assumes a capacity factor of 30 percent and Teknekron Research Inc assumes a capacity factor of 50 percent see Electric Power Research Institute *Technology* Assessment *Guide* op cit 1982 and Teknekron Research Inc *Cost Estimates and Cost Forecasting Methodologies for Selected Nonconventional Electrical Generation Technologies* (Sacramento CA CEC 1982) CEC Report No P300 300-82-006

[1]'Based on information in the following sources 1) Battleson op cit 1981 2) N Hinsey Gibbs & Hill Inc OTA contractor Interview with J Bigger Electric Power Research Institute May 10 1984 3) E Weber *Financial Requirements for Solar Central Receiver Plants* (Phoenix AZ Arizona Public Service Co 1983)

' 'From Gibbs & Hill Inc *Overview and Evaluation of New and Conventional Electrical Generating Technologies for the 1990s* op cit 1984

Table A.3.—Cost and Performance of Medium-Sized Wind Turbines

May 1985 technology status

Level of technology development[1]: commercial
Installed capacity: 650+ MWe[2]
Reference system: general characteristics
Reference year[3]: 1995
Deployment level scenario[4]:
High . . . . 2,900 MWe
Medium . . . . . 2,200 MWe
Low . . . . 1,500 MWe
Plant size (no. of units x unit nameplate capacity):
50 turbines @ 400 kWe[5]
Lead-time: 1-2 years[6]
Land required: 300-2000 acres[7]
Water required: negligible
Reference system: performance parameters
Availability: 95-98[8]
Duty cycle: intermittent
Plant lifetime: 20-30 years[9]
Capacity factor:[10]
High . . . . 85 percent
Medium . . . . . 30 percent
Low . . . . 20 percent
Reference system: costs
Capital costs: $900-1,200/kWe (net)[11].
O&M costs: 6-14 mills/kWh[12]

[1]Almost all of the commercially operating units in 1984 were small wind turbines, rather than the medium-sized units expected to dominate in the 1990s.

[2]Thomas A. Gray, Executive Director, American Wind Energy Association, personal correspondence with OTA staff, Jan. 29 and May 6, 1985. Gray estimated that 550 MWe were in place in California and that approximately 100 MWe were in place elsewhere in the United States at the end of 1984. It is not known how much additional capacity was installed during the first 4 months of 1985.

[3]The reference year 1995 is selected as being the year for which wind turbine cost and performance will best typify the cost and performance of turbines during the 1990s.

[4]In estimating the low range, it is assumed that: a) an additional 400 MWe will be installed in California in 1985, and b) the sum of the capacities installed from 1985-95 in California and from 1983-95 in the rest of the country is equal to 400 MWe. This low estimate essentially assumes a boom and bust situation where high levels of tax-subsidized investment through the end of 1985 is followed by a period of very low—though continued—growth over the following decade. The high range assumes: a) that the 1,450 MWe projected by the California Energy Commission to be on-line in California by 1996, and b) an equivalent amount of wind power will be installed elsewhere in the country by that time; see Thomas Tanton, California Energy Commission (CEC), "Memo to Interested Parties: Background Material for Nov. 2, 1984, CEC workshop on Resource Estimates of Small Power Technologies in California" (Sacramento, CA: CEC, Oct. 26, 1984). The medium deployment level is roughly halfway between the high and the low.

[5]Units in sizes ranging from 200 to 600 MWe are being actively developed and may be deployed before the end of 1985. See: 1) Tanton, op. cit., 1984; 2) Robert Lynette, R. Lynette & Associates, Inc., personal correspondence with OTA staff, Dec. 5, 1984; 3) "Westinghouse Nearing Final Agreement on Selling 15 600-kWe Windmills to HEI," *Solar Intelligence Report*, Dec. 24, 1984, p. 406; 4) Tom Gray, Executive Director, American Wind Energy Association, personal correspondence with OTA staff, November 1984.

[6]This assumes that the pre-construction period is 6 months to 1 year, and that the construction period is 6 months to 1 year as well. Based on information provided by: 1) OTA workshop on Wind Power, June 12, 1984, Washington, DC; 2) Lynette, op. cit., 1984.

[7]Based on information provided by Donald A. Bain, Wind Energy Specialist, Oregon Department of Energy, personal correspondence with OTA staff, June 11, 1985. The low estimate assumes a power density of 15 acres/MWe based on a turbine spacing of 3 rotor diameters on each side and 6 rotor diameters in front and behind each turbine. The high estimate assumes a power density of 80 acres/MWe based on a turbine spacing of 10 rotor diameters on each side as well as in front and behind.

[8]Based on information provided by: 1) Lynette, op. cit., 1984; he stated that current reliable units are averaged 95 percent reliability in 1984; he suggests a range of 92 to 97 for intermediate sizes in the 1990s. 2) "Wind Turbine Operating Experience and Trends," *EPRI Journal*, vol. 9, No. 9, November 1984, pp. 44-46. This source indicates that an availability of 70 to 96 percent has been achieved with small turbines and that availabilities could reach 95 to 96. It cautions, however, that it is not clear what capital costs would be associated with that range of availabilities. 3) Bain, op. cit., 1985. He expects availability to be 98 percent.

[9]Based on information from the following: 1) Lynette, op. cit., 1984. He estimated that the lifetime will be 20 to 30 years. 2) "Wind Turbine Operating Experience and Trends," *EPRI Journal*, op. cit.; this article assumes a lifetime of key wind turbine components is 20 to 30 years. EPRI does, however, acknowledge that this is a key assumption that has "not yet been adequately tested in operational systems because of insufficient field experience." 3) Bain, op. cit., 1985. He indicated that the lifetime of windfarms would be 20 to 30 years.

[10]This range generally corresponds with average wind speeds of 14 to 18 mph. Higher average wind speeds will yield higher capacity factors, all other things being equal. This is in rough accordance with the following estimates: 1) The California Energy Commission's 22 to 35 percent range used in an analysis of wind-generated electricity cost; see Tanton, op. cit., 1984. 2) A figure of 30 percent estimated by The Southern California Edison Co. for the projected mature technology; from I.R. Straughan, Southern California Edison Co., "R&D Input to the Fall 1984 Generation Resource Plan," unpublished memorandum, Aug. 30, 1984. 3) A figure of 30 percent provided by Lynette, op. cit., 1984 is used as the medium-range figure. 4) The 35 percent figure was considered reasonable by participants in OTA's Workshop on the Cost and Performance of Wind Turbines, June 7, 1984, Washington, DC.

[11]Based on information provided by: 1) Panelists attending OTA's Workshop on the Cost and Performance of Wind Turbines, June 7, 1984, Washington, DC, who felt that the cost could go below $1,000 by 1990. 2) Lynette, op. cit., 1984. He suggested it could go below $1,000 in 2 to 3 years. By 1995, costs presumably could drop still further. 3) Charles R. Imbrecht, chairman of the CEC, stated in mid-1984 that turbine costs should drop to $950/kWe by the year 2000; see *Solar Energy Intelligence Report*, June 18, 1984, p. 199. 4) Straughan, op. cit., 1984; this memo indicates that the projected mature technology would be characterized by total direct costs of $1,175/kWe (1985$).

Donald A. Bain, Oregon Department of Energy, personal correspondence with OTA staff, June 11, 1985; he indicated that wind farms could be installed today at a cost of $1,330/kWe, and that the OTA estimate may be too high.

[12]This is based on information from the following: 1) Lynette, op. cit., 1984. 2) "Wind Turbine Operating Experience and Trends," *EPRI Journal*, November 1984, pp. 44-46; this article indicates that O&M costs of 7 to 10 mills/kWh (1984$) are possible with small machines. 3) Straughan, op. cit., 1984; he suggests that the "projected mature technology" would be characterized by first year O&M costs of $22/kWe (1985$) for a wind farm of 10 MWe operating with a 30 percent capacity factor. This amounts to 8.4 mills/kWh (1983$).

Table A-4.—Cost and Performance of Geothermal Technologies

May 1985 technology status	Dual flash	Binary[1] Large/small
Level of technology development	Commercial experience overseas; first commercial unit in U.S. to operate in 1985[2]	Large: demo plant under construction/Small: commercial units operating[3]
Installed capacity (gross)	none[4]	none/22.3 MWe
Reference system: general characteristics		
Reference year	1995	1995/1995
1995 deployment-level scenario (dual-flash and binary only)[5]:		
High	1,166-1,830 MWe[6]	
Medium	406-1,165 MWe[7]	
Low	122-405 MWe[8]	
Plant size (number of units x unit size):		
Gross, MWe	1 x 53[9]	1 x 70[10]/2 x 5[11]
Net, MWe	1 x 50	1 x 50/2 x 3.5
Lead-time, years	3-5[12]	3-5/1[13]
Land required, acres	8-20[14]	8-20/1-3[15]
Water required, gals/day	3 million[16]	4.1 million[17] /0.6 million[18]
Reference system: performance parameters		
Operating availability, percent	85-90[19]	85-90/85-90[20]
Duty	Base[21]	Base/Base[22]
Unit lifetime, years	30[23]	30/30[24]
Plant efficiency (watt-hours/lb of steam)[25]:	7.0-8.0[26]	9.5-12.0/7.0-9.0[27]
Reference system: costs		
Capital costs, $/kWe (net)	1,300-1,600[28]	1,500-1,800[29]/ 1,500-2,000[30]
O&M costs, mills/kWh:	10-15[31]	10-15[32]
Fuel (brine) costs, mills/kWh[33]:	20-70	20-70

[1]Two scales of binary technology are included Although large binary geothermal plants will benefit from economies of scale smaller modular wellhead units will also be deployed Smaller 5 to 10 MWe modular units will allow the progressive development of a geothermal resource This approach lessens the initial upfront dedication of capital and allows for demonstration of the resource Module sizes of 10 MWe for flash units are most likely the smallest to be developed due fo limitations in turbine design from R Walter and N Hinsey Gibbs & Hill Inc personal correspondence with OTA staff May 7 and June 26, 1984

[2]Geothermal dual flash technology is considered commercial today see W Collins *Proceedings of the* Geothermal *Program Review II* (Washington DC U S Department of Energy December 1983) CONF-8310177 Nearly 400 MWe of dual flash generated electricity was installed worldwide by the end of 1983 see R DiPippo Worldwide Geothermal Power Development *Geothermal Resources Council Bulletin* vol 13 No 1 January 1984 The first U S unit is expected to operate commercially in 1985

[3]The larger binary cycle plants will have their first demonstration when a 45 MWe plant operates in 1985 at Heber CA Small units are already operating at several locations in the U S

[4]Although no dual flash units are presently operating m the U S a 30 MWe unit has been operating since 1981 at Cerro Prieto Mexico 50 km south of California An additional 440 MWe (four 110 MWe units) of dual flash capacity is expected to be on-line this year in the same vicinity The first U S dual flash unit (47 MWe) is under construction at Heber see DiPippo op cit 1984

[5]Since the most recent and comprehensive estimates referenced make no distinction between binary and dual flash plants a single set of deployment values are projected

[6]From the Electric Power Research Institute s Utility Geothermal Survey s possible estimate of U S geothermal electricity power capacity in 1995 see P Kruger and V Roberts " Utility Industry Estimates of Geothermal Energy *Geothermal Resources Council Transactions* vol 7 October 1983 pp 25-29 Eshmate has been corrected to exclude 2680 MWe expected at The Geysers in 1995 see T Cassel et al *National Forecast for Geothermal Resources Exploration and Development* (Washington DC U S Oeparfmenf of Energy March 1982) DOE/ET/27/242-T2

[7]Kruger and Roberts op cit 1983 Estimate has been corrected to exclude 2680 MWe expected at The Geysers in 1995 see Cassel et al op cit 1982

[8]The low end of the range represents the total generating capacity (dual-flash and binary only) now Installed or under construction The high end of the range is derived from Kruger and Roberts op cit 1983 This figure has been corrected to exclude 1,753 MWe of capacity at The Geysers either operating under construction planned or a speculate addition see DiPippo op cit 1984

[9]An EPRI Utility Geothermal Survey indicated that nearly 60 percent of respondents consider 50 MWe to be the minimum size for a commercial plant With regard 10 optimum Size commercial plants two. thirds indicated a preference for 100 MWe and one-third for 50 MWe see V Roberts Utility Industry Estimates of Geothermal Electricity " *Geothermal* Resources *Council Bulletin* vol 11 No 5 May 1982 pp 7-10 California regulations require that electric generating facilities greater than 50 MWe (net) file for certification and also perform a documentation of the resource and technology To date all geothermal plants planned or under construction (excluding The Geysers) in California do no! **exceed** 49 MWe (net) in order to avoid the delay and cost of complying with regulations for units larger than 50 MWe (net) Since most geothermal development is expected to occur in California in the next 5 to 10 years 50 MWe appears to be a reasonable size for the reference plant discussed here This is based on information provided by 1) Walter and Hinsey op cit 1984 2) R DiPippo. Southeastern Massachusetts University. personal correspondence with N Hinsey Gibbs & Hill, Inc May 7, 1984 3) Collins op cit 1983

Gross plant size shown (53 MWe) represents that of a dual flash system

[10]Same rationale as in footnote 9 Binary cycles require much more auxiliary power to pump brine and would need a 70 MWe turbine (size reduction would occur as efficiency of the cycle is Improved) see DiPippo. op cit 1984

[11]Several observers have projected that modular, wellhead units will comprise a large portion of binary development at lower temperature, less understood resources 1) Jack S Wood Wood & Associates personal correspondence with OTA staff Oct 6 1984 2) Evan Hughes Electric Power Research Institute. personal communication with OTA staff Oct 4 1984 3) Janos Laszlo Senior Mechanical Engineer, Pacific Gas & Electric personal communication with OTA staff Oct 10, 1984

The 5 MWe unit corresponds to a *powerplant* geared to the output of one *well* from Ben Holt Ben Holt Co personal communication with OTA staff Sept 10 1984

[12]Great variations may result from licensing requirements about which there is considerable uncertainty The first unit at a given site will take longer possibly 5 years due to initial permitting and licensing Subsequent units could require as little as 3 years Based on Information provided by 1) OTA, Workshop on Geothermal Power Washington DC June 5 1984 2) Cassel et al op cit 1982

[13]For large Units see footnote 13 Smaller units can be factory fabricated and shipped to the site much quicker than larger units Modular units depending on the site could be brought on-line in as few as 6 months (not including permitting and licensing) Jack S Wood, Wood & Associates. personal communication with OTA staff Oct 6, 1984 indicated that it takes only 100 days to full operation after a modular unit arrives onsite Inclusion of licensing and permitting should extend lead-time to 1 year Great variations may result from licensing requirements about which there is considerable uncertainty

[14]OTA Workshop on Geothermal Power op cit 1984 This value does not include the entire area of the field because much of the land above the field can stall be utilized and only part of the surface is occupied by the facilities (Modular units would be at the low end of this range)

[15]The larger units should require up to 20 acres—similar to dual flash units from Walter and Hinsey. op cit 1984 A smaller unit can vary from less than 1 acre for a modular container-mounted unit 103 acres for a unit similar to an East Mesa CA unit see Gibbs & Hill Inc *Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s* OTA contractor report Sept 13 1984

[16]Based on an estimate made by J A Bickerstaffe. Gibbs & Hill, Inc personal correspondence with OTA staff, May 1 1985 he estimated that the 47 MWe (net) Heber dual flash unit will require approximately 2800 gallons/minute of make-up waler This figure was adjusted for the slightly larger 50 MWe (net) reference plant operating with a capacity factor of 70 percent The figure

assumes that all steam condensate IS reinjected with the spent brine If any of the condensate IS used for cooling purposes, make-up water requirements will be smaller

[17]Based on estimate that the 45 MWe (net) Heber Binary plant will consume water at a rate of 3,700 gallons per minute The water requirement was estimated by Southern California Edison Co in comments made on OTA draft cost and performance tables, Apr 10, 1985 This was adjusted for the slightly larger 50 MWe (net) reference plant, operating with a capacity factor of 70 percent

[18]Based on estimate made by Zri Krieger of Ormat Turbines Mr Krieger stated that a 20 MWe (net) Installation consisting of 26 modules planned for East Mesa, CA, would have make-up waler requirements of about 1,500 to t ,800 gallons/minute This was adjusted for the considerably smaller 7 MWe (net) reference plant, operating with a capacity factor of 70 percent

[19]OTA Workshop on Geothermal Power op cit 1984

[20]Ibid

[21]Ibid

[22]Ibid

[23]Design life of current plants IS 30 years This IS nof expected to change in the next 10 years; from Walter and Hinsey, op cit 1984

[24]OTA Workshop on Geothermal Power Op cit 1984

[25]Evaluated at a 400 ° F resource

[26]Figures shown represent " net brine effectiveness'' (defined as watts of net electric power output per pound per hour geothermal flow) m w-hr/lb For current state-of-the-art power systems the net brine effectiveness ranges from 70 to 80 for dual flash cycles, respectively, given a resource temperature of 200= C (400 ° F), see T Cassel, C Amundsen, and P Blair, *Geothermal Power Plant R&D, An Analysis of Cost-Performance Trade-offs and the Heber Binary Cycle Demonstration Project* (Washington, DC U S Department of Energy, June 30, 1983), DOE/CS/30674-2 Dual flash IS a mature technology and basic cycle efficiency improvements are not expected as with conventional cycles, gains in efficiency can be achieved through greater capital and operating expenditures Economic considerations, as opposed to technical breakthroughs, drive these decisions; see Gibbs & Hill, Inc op cit 1984

[27]Figures shown fo high, medium, and low represent "net brine effectiveness'' (defined as watts of net electric power output per pound per hour geothermal flow) m w-hr/lb For current state-of -the-art power systems the net brine effectiveness is about 95 for binary cycles, respectively given a resource temperature of 200 C (400" F), see Cassel, Amundsen, and Blair, op cit 1983 Reference 10 reveals that an advanced binary system (utilizing a countercurrent condensor and a recuperator) brine effectiveness could reach 11 9 for a 2000 C resources with 2,000 to 100000 ppm total dissolved solids, with additional penetration Binary cycle research Indicates that there will be Improvements in brine effectiveness as more work IS performed on direct contact heat exchangers, staged heat rejection, recuperation and counter-current condensing Twelve w-hr/lb represents the estimated maximum probable net effectiveness; see J Whitbeck, Idaho National Engineering Lab, "Heat Cycle Research Program, *Proceedings of the Geothermal Program Review //* (Washington, OC U S Department of Energy, December 1983), CONF-831O77 The smaller binary plants are not as efficient as their larger counterparts With significant penetration net effectiveness could increase to 9 w-hr/lb; from H Ram, Ormat, Inc , personal communication with OTA staff, Oct 6, 1984

[28]Based on Information from 1) Walter and Hinsey, Op cit , 1984 2) OTA Workshop on Gee" thermal Power, op cit , 1964 3) Cassel, Amundsen, and Blair, op cit., 1983

Capital costs are not expected to decrease as a function of on-line capacity Small, modular, flash units (approximately 10MWe) cost $1 ,500 to 1,600/kWe for single units (based on data from Gibbs & Hill, San Jose Off Ice) When several units are purchased together the cost could be as low as $1 ,000/kWe; from Walter and Hinsey, op cit 1984 Installations at highly saline resources will be more costly, however

?? Based on Information from the following sources 1) Walter and Hinsey, op cit 1984 2) OTA Workshop on Geothermal Power, op cit , 1984 3) Gibbs & Hill, Inc op cit, 1984

Capital costs are not expected to increase as more units are deployed Large binary plants will have larger capital costs because of the greater complexly revolved

[30]The smaller binary plants will have higher Capital costs than large binary cycle plants Costs of $2,000/kWe have been reported for a 7 MWe (net) plant, from Holf, op cit , 1984 Very small 5 MWe, containerized, binary umts have been advertized for $1 ,500/kWe, installed, from Ram, op cit 1984

[31]OTA Workshop on Geothermal Power, op cit , 1984 O&M costs of Plants now in operation vary widely due to the qualities of the resouces being utilized The Heber flash plant has an O&M cost of 103 mills/kWh and could be considered average Advances in operation, including computerized controls and roving operators, could reduce the operating component of O&M costs somewhat in the next 10 years But this Improvement would not be significant when compared to the possible range of total O&M costs, see Walter and Hinsey, op cit , 1984

[32]O&M costs are expected to be the same as those of the dual flash technology Based on information provided by 1) Walter and Hinsey,' op cit 1984 2) OTA Workshop on Geothermal Power, op cit 1984

[33]OTA Workshop on Geothermal Power, op cit 1984 Brine costs result from negotiation with the brine supplier The brine cost will tend towards a price which causes the total cost of the geothermal plant to be competitive with the least expensive alternate form of base load generation Depending on location, this could vary between 20 to 70 mills/kWh; see P Blair, T Cassel and R Edelstein, *Geothermal Energy Investment Decisions and Commercial Development* (New York Wiley Interscience, 1982)

Table A-5.—Cost and Performance of Large Atmospheric Fluidized-Bed Combustion Systems'

May 1985 technology status

Level of technology development: commercial demonstration unit under construction
Installed capacity (large units only): none
Reference. system: general characteristics
Reference year: 1990
U.S. deployment level scenario, 1990 (large units only, including retrofit units):[3]
High. . ...735 MWe
Medium . ...610 MWe
Low . ...510 MWe
Plant size (no. of units x unit size):
Gross . . . . .1 x 163 MWe
Net . . . . . . .1 x 150 MWe
Lead-time: 5-10 years[4]
Land required: 90-218 acres[5]
Water required: 1.5 million gallons/day[6]
Reference system: performance parameters
Availability: 85-87 percent[7]
Duty cycle: base/intermediate
Plant lifetime: 30 years
Plant efficiency: 35 percent[8]
Reference system: costs
Capital costs: $1,260-1 ,580/kWe[9]
O&M costs: 7.66 mills/kWh[10]
Fuel costs: 17.4 mills/kWh [11]

'Unless otherwise specified the figures relate to entirely new "grass roots" electric power-plants not to the retrofits of fluidized bed combustors to existing power plants Also unless otherwise stated the figures apply only to plants designed and operated to produce electric power only, cogenerators are excluded

'Note that three large retrofit units are under construction Two of these are utility demonstration units; one IS a commercial nonutility unit

'The deployment figures include both entirely new plants and retrofits All deployment levels assume that the following plants will have been completed and will be operating by 1990
—Tennesee Valley Authority Shawnee Unit 160 MWe, to be completed 1989
—Colorodo Ute, Nucla unit, 100 MWe, to be completed 1987 (retrofit)
—Northern States Power Co Black Dog Unit 2, 125 MWe, to be completed t986 (retrofit)
—Florida Crushed Stone Co Brookesville FL 125 MWe to be completed 1987 (retrofit cogeneration)

The low scenario assumes that no plants other than those listed above will be operating in 1990 The high scenario assumes that two additional retrofit unit will be operating with a total additional capacity of 225 MWe and the medium scenario assumes that one additional 100 MWe units will be operating Neither the medium nor the high scenarios are expected only the low one IS

[4]It IS assumed that the AFBC will have roughly the same lead.time as the IGCC This assumes 3 to 5 year preconstruction period and a 2 to 5 year construction period Exceptionally favorable circumstances could lead to lead-times below this range unusually poor conditions to result in a higher lead-time

[5]Using a figure of O 6 to 1 45 acres/MWe The land estimate includes the land required for solid waste disposal and coal storage This figure IS based on two sources 1) Battelle Columbus Division, *Final Report orr Alternative Generation Technologies,* VOIS I and II (Columbus OH Battelle, 1983) This source Indicated that a 1 000 MWe plant would require 1 450 acres this averages out to 1 45 acres/MWe 2) Kurt E Yeager, Electric Power Research Institute `Coal Utilization in the U S –Progress and Pitfalls "' *Proceedings of the Sixth In ternational Conference on Coal Research,* London UK, Oct 4, 1982 (London, UK National Coal Board, 1982) pp 639-664 This source suggests that 1,200 acres would be required for a 1,000 MWe plant this averages out to 1 2 acres/MWe 3) James W Bass, Ill Project Engineer, AFBC Technical Services TVA personal correspondence with OTA staff Apr 30, 1985 He estimated that the TVA 160 MWe demonstration plant will occupy approximately 93 acres This amounts to about O 6 acres/MWe

[6]Based on an estimate that an AFBC would consume approximately O 6 gallons per kWh and a capacity factor of O 7; see Yeager, op cit 1982 These figures are consistent with estimates made by Bass, op cit 1985

[7]Based on Information provided by 1) Workshop on Fluidized-Bed Combustors OTA, Washington OC, June 6, 1984 2) Electric Power Research Institute *Technical Assessment Guide* (Palo Alto, CA EPRI, May 1982), P-241O-SR 3) Stratos Tavoulareas, Project Manager Fluidized Combustion, Coal Combustion Systems Division EPRI, personal correspondence with OTA staff Feb 19, 1985

[8]Based on information provided in the following sources 1)K E Yeager 'Fluidized Bed Combustion–An Evolutionary Improvement in Electric Power Generation, *The Proceedings of the Sixth International Conference on Fluidized-Bed Combustion* Apr 9-11, vol 1.1980, CONF-800428 2) "EPRl, B & W Score Major Advance with Atmospheric Fluidized Bed Boiler *The Energy Daily* Oct 10, 1979 3) Burns and Roe *Conceptual Design of a Gulf Coast Lignite-Fired Atmospheric Fluidized-Bed Power Plant* (Palo Alto CA Electric Power Research Institute 1979) EPRI EP-1 173 *4)* R Smock, " Utilities Look to Fluid Bed Design as Next Step in Boiler Design, *Electric Light and Power,* vol 62 No 7, July 1984, PP 27-29 5) Yeager, OP cit 1982 This source suggests that a 1,000 MWe unit would have an efficiency of 353 percent

'The high end of the range IS based on an estimate made by Tavoulareas, op cit May 15 1985 He estimated that the costs, in 1984 dollars, might be approximately $1 ,640/kWe for a plant with a net capacity of 1933 MWe (209 6 MWe gross) Converted to 1983 dollars using the Handy Whitman Bulletin Cost Index (see Definitions section of this apppendix), this yields $1 ,580/kWe This IS considered the high range of the OTA estimate The low end of the range IS set 20 percent lower than that figure, or $1,260

[10]This is based on an estimate made by Tavoulareas op cit 1985 He estimated that the O&M costs, in 1984 dollars, might be approximately 796 mills/kWh for a plant with a net capacity of 1933 MWe (209 6 MWe gross) Converted to 1983 dollars using the Handy Whitman Bulletin Cost Index (see Definitions section), this yields an O&M cost of 766 mills/kWh

[11]Based on a 1990 coal cost of $1 78/million Btu (see details in the Definitions section of this appendix for an explanation for fuel costs) and an average annual heat rate of 9751 Btu/kWh

Table A.6.—Cost and Performance of Integrated Gasification/Combined-Cycle Powerplants[1]

May 1985 technology status
Level of technology development: demonstration plant
Installed capacity: 100 MWe
Reference system: general characteristics
Reference year: 1990
Deployment level scenario: 200 MWe[2]
Plant size: 500 MWe (net)[3]
Lead-time: 5-10 years[4]
Land required : 300-600 acres[5]
Water required : 3-5 million gallons/day[6]
Reference system: performance parameters
Operating availability: 85 percent[7]
Duty cycle: base
Plant lifetime: 30 years[8]
Plant efficiency: 35-40 percent[9]
Reference system: costs
Estimated capital cost, 1990: $1,200-1,350/kWe[10]
O&M costs, 1990: 6-12 mills/kWh[11]
Fuel costs, 1990: 15-17 mills/kWh[12]

[1]The performance and cost data presented in this table are expected to bracket the various gasification technologies used in IGCC plants; Workshop on IGCC, OTA, Washington, DC, June 6, 1984.

[2]It is assumed that by 1990, two IGCCs will have operated in the United States: the 100 MWe Cool Water plant and the Dow Chemical Co. plant in Plaquemine, LA, the capacity of which will be 100 MWe or more.

[3]The plant auxiliary power requirements will vary between 10 and 16 percent of net output depending on the design; see Fluor Engineers, Inc., *Cost and Performance for Commercial Applications of Texaco-Based Gasification-Combined-Cycle Plants*, vols. 1 and 2 (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3486; and Argonne National Laboratory (ANL) and Bechtel Group, Inc., *Design of Advanced Fossil Fuel Systems (DAFFS): A Study of Three Developing Technologies for Coal-Fired, Base-Load Electric Power Generation*, summary report (Chicago, IL: ANL, 1983), ANL/FE-83-9. By far the greatest portion of the power (roughly 3/4 of parasitic power requirements) is required to run the oxygen plant.

[4]This assumes a preconstruction, licensing and design period of 2 to 5 years and a construction lead-time of 3 to 5 years.

The lower end of the estimate is the design potential of the IGCC. In general, if great care is taken during construction and early operation, and close cooperation with regulatory authorities is pursued, the 5-year lead-time could be achieved. If these steps are not taken, however, for the first few plants, the complexity and uncertainty inherent in any new technology will cause the lead-times to extend to as much as 10 years.

Overall lead-time estimates have been made by: 1) Peter Schaub, Manager, New Technology Program, Potomac Electric Power Co. (PEPCO), personal correspondence with OTA staff, Feb. 1, 1985. He suggested that 10 years was a reasonable estimate. This view was supported by Steven M. Scherer, Senior Project Engineer, PEPCO, personal correspondence with OTA staff, May 23, 1985. PEPCO is likely to be one of the first utilities to commit to building an IGCC. Feasibility studies for an IGCC had been initiated by April 1985; the entire installation is not expected to be on-line until 1997. 2) The California Energy Commission estimates that the lead-time would be 9.5 years and the L.A. Department of Water and Power which estimates that the lead-time would be 10 years; see California Energy Commission, *Technical Assessment Manual*, vol. I, Edition II, Appendices (Sacramento, CA: CEC, June 1984), p. B-3. 3) The participants at the OTA Workshop on the IGCC, op. cit., 1984, who endorsed an 8 to 10 year estimate.

Preconstruction, licensing, and design period estimates have made by: 1) Electric Power Research Institute, *Technical Assessment Guide* (Palo Alto, CA: EPRI, 1982), EPRI P-2410-SR. This source estimates that preconstruction, licensing and design for an IGCC would take 4 years. The analogous period for the Cool Water was nearly 4 years: February 1978 to December 1981. 2) S. Sessions, U.S. Environmental Protection Agency, Acting Director, Regulatory Policy Division, Office of Policy Analysis, personal correspondence with OTA staff, Feb. 1, 1985. Mr. Sessions suggested that 4 to 5 years was not an unreasonable estimate for a typical IGCC being licensed over the next 10 years, particularly in view of the relative inexperience with the technology which will characterize the applicants and the regulators.

Thomas L. Reed of Southern California Edison, stated in personal correspondence with OTA staff, May 24, 1985, that the California site-selection process for the Cool Water facility took 18 months and that the licensing period also took 18 months, for a total of 3 years. Mr. Reed also stated that the site-selection process is an ongoing process that does not have to await a plant commitment before it is initiated. He therefore thought that 6 months would be a typical period for the site-selection process and that as a result the total preconstruction period would be only 2 years.

Construction period estimates have been made by: 1) EPRI, op. cit., 1982. This source estimates that construction lead-times for an IGCC would be approximately 3 years. 2) Schaub, op. cit., 1985. Mr. Schaub suggested that 3 to 5 years was a reasonable estimate. This estimate was confirmed by Scherer, op. cit., 1985. 3) Reed, op. cit., 1985. Mr. Reed estimated that construction would take 3 years. However, he saw no reason why the period would be longer than 3 years. 4) Michael Gluckman, EPRI, personal correspondence with OTA staff, June 12, 1985; he estimated 2 to 3 years. However, like Tom Reed, he does not believe a plant could take longer than 3 years to build unless extraordinary problems arise.

Note that the selected range is lower than the estimated 68 month lead-time typical of U.S. coal plants which began operating in 1976; see Applied Decision Analysis, Inc., *An Analysis of Power Plant Construction Lead Times*, Vol. 1: Analysis and Results (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-2880.

The Cool Water plant was characterized by a construction lead-time (from initial construction to beginning of the demonstration period) of less than 3 years. The plant however was characterized by circumstances which are unlike those expected of a commercial plant. Some of these characteristics tended to lengthen the lead-time; others to shorten it. The evidence used in making the OTA estimate suggests that early commercial plants will take longer to build. An important reason for this is the fact that commercial plants are currently projected to be much larger than the Cool Water plant.

[5]See ANL and Bechtel, op. cit., 1983; this report indicates that about 400 acres are required for plant, access and interim onsite disposal with 110 to 140 additional acres for off-site permanent disposal. Also see Fluor Engineers, op. cit., 1984; this study shows that about 260 acres are required for the plant including storage for 30 years worth of ash. The differences probably result from differences in coal quality, plant rating, and layout criteria for the buffer zone. Hence a range of 300 to 500 acres is shown in the table.

[6]See Fluor Engineers, op. cit., 1984; this report indicates 6 to 7 gpm/MWe water would be required depending on the method by which the gas is cooled. See also ANL and Bechtel, op. cit., 1983; this report indicates 8 to 10 gpm/MWe. Based on 6 to 10 gpm/MWe, a plant size of 500 MWe and a 0.7 capacity factor, 3 to 5 million gallons/day would be required.

[7]EPRI, op. cit., 1982, indicates that an operating availability of 89 percent and equivalent availability of 81 percent is likely. See also Fluor Engineers, op. cit., 1984; this report indicates that IGCC plants can be designed for equivalent availabilities in the 80 to 85 percent range.

[8]EPRI, op. cit., 1982.

[9]Fluor Engineers, op. cit., 1984; this report suggests efficiencies of 34.4, 36.2, and 37.9 percent for total quench, radiant only and radiant plus convective Texaco designs. The ANL/Bechtel study, op. cit., 1983, indicates 36.9, 37.5, and 39.5 percent efficiencies for Texaco, BGC Lurgi, and Westinghouse designs. Hence a range of 35 to 40 percent is used here. This range is in rough accordance with the 35 to 39 percent estimate made by B.M. Banda et al., 'Comparison of Integrated Coal Gasification Combined Cycle Power Plants with Current and Advanced Gas Turbines,' *Advanced Energy Systems—Their Role in our Future*, Proceedings of 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984, San Francisco, CA. (U.S.: American Nuclear Society, 1984), paper 849507, pp. 2404-2407.

[10]Fluor Engineers, Inc., op. cit., 1983; this report gives $/kWe costs of 957, 998, and 1061 for total quench, radiant only and radiant plus convective Texaco designs. These costs do not include contingency costs. Based on a 20 percent contingency allowance (versus 17 to 19 percent used in the Fluor study) and Handy Whittman Index Ratio of 242/233, a 1,200 to 1,350 $/kWe range is shown in the table. The ANL/Bechtel report, op. cit., 1983, mentions comparable (January 1980) costs of $1,030/kWe (BGC/Lurgi) and $1,252/kWe (Texaco).

[11]The following estimates fall within this range: 1) ANL and Bechtel, op. cit., 1983. The study indicates that O&M costs would be in the 10.8 to 11.5 mills/kWh range (January 1980 dollars and 67 percent capacity factor). 2) Synthetic Fuels Associates, Inc., *Coal Gasification Systems: A Guide to Status, Applications, and Economics* (Palo Alto, CA: Electric Power Research Institute, June, 1983), EPRI AP-3109; the study shows O&M costs (for 1,000 MWe plant) to be 5 to 6 mills/kWh (mid-1982$). 3) D. F. Spencer, Vice President, Advanced Power Systems Division, Electric Power Research Institute, personal correspondence with OTA staff, May 17, 1985; Mr. Spencer estimated that O&M costs would be 6 to 8 mills/kwh.

[12]Based on 8,533 to 9,751 Btu/kWh heat rate (equivalent to 35 to 40 percent efficiency) and 1990 coal costs of $1.78/MM Btu (see Definitions section of this appendix for an explanation of fuel costs).

Table A-7.—Cost and Performance of Fuel Cell Powerplants[1]

May 1985 technology status	Large	Small
Level of technology development[2]:	Demonstration units planned	Demonstration units operating[3]
Installed capacity:	none	1.5 MWe[4]
Reference system: general characteristics		
Reference year: 1995		
Deployment level scenario:[5]		
High . . . . 800-1,200 MWe		
Medium . . . . 400-600 MWe		
Low . . . . 40 MWe		
Plant size (number of units x unit size):[6]		
Gross	1 x 11.5 MWe	2 x 200 kWe
Net	1 x 11.0 MWe	2 x 200 kWe
Lead-time[7]	3-5 years	2 years
Land required	0.5 acres[8]	480-600 sq. ft[9]
Water required[10] [11]	negligible	
Reference system: performance parameters		
Operating availability[12]	80-90 percent	
Duty cycle	Variable	Variable
Plant lifetime[13]	30 years	20 years
Plant efficiency[14]	40-44 percent[15]	36-40 percent[16]
Reference system: costs		
Capital costs:	$700-$3,000/ kWe[17]	$950-$3,000[18]
O&M costs (mills/kWh):[19]		
Base/Cogen (75 percent c.f.)	4.2-11.5	42-11.5
Intermediate (40 percent c.f.)	4.2-11.3	42-11.3
Peaking (10 percent c.f.)	4.3-10.7	43-107
Fuel costs (mills/kWh)[20]	27-30	30-33

[1]Only phosphoric-acid fuel cells are considered

[2] In 1983 no commercial-scale demonstration units were operating in the United States In 1984 the first of a series of about fifty 40 kWe units were operating In the United States and a 4 5 MWe facility was operating in Japan Further demonstration units are planned for the next five years in a variety of sizes both in Japan and in the United States

[3]These units are 40 kWe and are substantially different in design trom the larger units (with capacities of several hundred kWe) expected 10 be commercially deployed in the 1990s

[4]This consists of 38 units rated at 40 kWe each

[5]The low estimate assumes that approximately fifty 40-kWe (net) units two 11-MWe units and two 7 5-MWe powerplants will have been installed by 1995 All would be demonstration units some of which will cease operation betore 1995 The low scenario assumes that no commercial units will be operating in 1995

The medium scenario assumes the following 1) The bulk of initial orders will be for large fuel cell powerplants rather than small ones 2) Investors will not initiate commercial fuel-cell projects until they have seen demonstration units operating tor a year 3) Large commercial demonstration units will go into service in 198889 and Investors will initiate projects no sooner than 1989-90 4) Demonstration and commercial projects will have lead-times of 3 years the commercial projects therefore would not yield operating generating capacity until 1992-93 5) Beginning in 1992-93 an average of 200 MWe of fuel cell powerplants will be placed in operation each year through 1995 This deployment level is considered by industry sources to be the minimum level which allows the economic production of fuel cells in one manufacturing facility This is equivalent 10 the startup of about eighteen 11 MWe plants each year

This results in a deployment scenario of 400 to 600 MWe (absorbing all of the fuel cells produced in 2103 years from a single manufacturing facility) This is equivalent to between thirty-six and fifty-five 11 MW units though in actuality the installations would vary in size

The high scenario is based on assumptions (1) through (4) above Assumption (5) however is changed to an average deployment level of 400 MWe annually from 1992-93 through 1995–double the deployment levels assumed in the medium scenario This results in a deployment level in 1995 of 800 to 1200 MWe This deployment level could be met by expanding the fuel-cell output of a single manufacturing plant or by operating more than one manufacturing plant Under this scenario the equivalent of thirty-six 11 MWe plants would be started up each year, starting in 1992 or 1993 a total of 73 to 109 such plants would be operating by mid-1995 under this Scenario

[6]The small fuel cell installations deployed m the 1990s likely will be budt around two or more stacks each capable of delivering 200 kWe (net) AC It is assumed that two stacks would be used in the reference plant but several more might be deployed at any one site It is assumed that the large fuel cell installations in the 1990s will be bud! around stacks each capable of generating 250 to 700 kWe (DC) Installation capacity probably would range from several megawatts and up The installation assumed here would consist of approximately 18 stacks, each capable of generating 675 kWe (DC) While larger or somewhat smaller installations are likely to be budt and operated their cost and performance should roughly coincide with that of the 11 MWe plants

[7]The lower estimate for the large fuel cell installation is based on discussions at OTA Workshop on Fuel Cells Washington DC June 6, 1984 The upper estimate for the large plant is based on estimates made by California Energy Commission *Technical Assessment Manual* vol 1 Edition III (Sacramento CA CEC 1984) P300-84-013 and by OTA staff The greatest uncertainty m the range results primarily from uncertainty regarding regulatory delays Many of the fuel cell installations are likely to be deployed in areas where little previous powerplant development has occurred and where population densities increase the possibilities for regulatory conflicts The potential for regulatory problems was exemplified by a 45 MWe demonstration umt which was built (but never operated) m New York City Numerous unanticipated regulatory delays were encountered, and prevented the expeditious completion of the plant approval of the project by New York City's fire department fook 3 years

The estimate for the small fuel cell installation is based on discussions at OTA Workshop on Fuel Cells op cit 1984 The extremely small size of the plant suggests thaf regulatory delays would be considerably less problematic than would be the case with larger plants Some within the industry believe that lead-times could be as short as several months see R A Thompson Manager Business Planning, United Technologies Corp Fuel Cell Operations personal correspondence with OTA staff Feb 15, 1985

[8]Burns & McDonnell Engineering Co *System Planner's Guide for Evaluating Phosphoric Acid Fuel Cell Power Plants* (Palo Alto CA Electric Power Research Institute, 1984) EPRI EM-3512 See also comments of Thompson op cd 1984

[9]OTA estimate based on two modules, each measuring 30 x 8 feef This is the size of module suggested by Richard R Woods Jr Manager Fuel Cells Gas Research Institute in personal correspondence with OTA staff Feb 4 1985

[10]United Technologies Corp *Specification for Dispersed Fuel Cell Generator* Interim Report (Palo Alto CA Electric Power Research Institute 1981) EPRI EM-2123 Project 1777-1

[11] United Technologies Corp Power Systems Division *Onsite 40-kilowatt Fuel Cell Power Plant Model Specification* prepared for U S Department of Energy and the Gas Research Institute (South Windsor CT United Technologies September 1979), FCS-1460

[12]This is based on Fuel Cell Users Group. System Planning Subcommittee Ad Hoc Reliability Task Force *Report on Fuel Cell Reliability Assessment* (Washington DC Fuel Cell Users Group March 1983) The report recommended use of an 85 percent availability factor in system planning studies for large fuel cell powerplant Installations It however stated that availability could range between 80 and 88 percent, depending on assumptions made about component redundancy and about the availability of spare parts It is assumed that the operating availabilities of small fuel cell powerplants will fall within the same range as that of the larger fuel cells as no comparable studies are available on the operating availabilities of the small plants

[13]This refers to the plan! lifetime Cell stacks themselves are assumed to have lifetimes of 40000 hours when running at full capacity

[14]This is the operating efficiency at which electricity is produced when the plant is operated at its full rated capacity In cogeneration applications where useful heat will be produced along with electric power the total energy efficiency [which includes all useful energy outputs thermal and electric) would be much higher The cogeneration efficiency could be as high as 85 percent

[15]Based on higher heating value of fuel This range is consistent with estimates made in numerous sources including 1) United Technologies Corp *Specification for Dispersed Fuel Cell Generator* Interim Report (Palo Alto CA Electric Power Research Institute 1981) EPRI EM-2123 Project 1777-1 2) Mike Ringer California Energy Commission *Relative Cost of Electricity Production* (Sacramento CA CEC, Oecember 1983) 3) Utilities Show Interest in Large Fuel Cell Installations for Late 80s *Electric Light and Power* vol 62 No 6 June 84 p 53 4) Irwin Stambler Fuel Cell Outlook Brightens as Technical Obstacles Fall *Research & Development* December 84 pp 50-53 5) Battelle Columbus Division *Final Report on Alternative Generation Technologies* vols I and II (Columbus OH Battelle 1983) 6] Thompson, op cit 1985

[16]Based on higher heating value of fuel From 1) J W Staniunas and G P Merten and R M Smith United Technologies Corp *Follow-On 40-kWe Field Test Support* Annual Report prepared for Gas Research Institute (Chicago IL Gas Research Institute 1984) FCR-6494 GRI-84/0131 2) Woods, op cit Feb 4, 1985

[17]Estimates do not include cell replacement costs The lower end of the range assumes a mature technology and mass production the high end of the range represents the estimated cost of the commercial demonstration units expected to be installed and operated in the late 1980s Within this range fall the estimates cited in the following 1) The participants in an OTA Workshop on Fuel Cells op cit 1984 2) Ringer op cit 1983 3) California Energy Commission, op cit 1984 4) I R Straughn Southern California Edison Co R & D Input to the Fall 1984 Generation Resource Plan unpublished memorandum August 1984 5) Lee Catalano Can Fuel Cells Survive the Free Market m the 1990's?' *Power,* vol 128 No 2, February 1984 pp 61.63 6) Burns & McDonnell Engineering Co *System Planner's Guide for Evaluating Phosphoric Acid Fuel Cell Power Plants* (Palo Alto, CA Electric Power Research Institute 1984) EPRI EM-3512 7) Battelle op cit 1983 8) J R Lance et al Westinghouse Electric Corp Economics and Performance of Utility Fuel Cell Power Plants "*Advanced Energy Systems—Their Role in Our Future* Proceedings of 19th Intersociety Energy Conversion Engineering Conference Aug 19-24 1984 San Francisco CA (U S American Nuclear Society 1984) paper 849133 pp 821-826

Where a single expected' value is used m this report a value of $1 430/kWe is used

[18]The estimates do not include cell replacement costs The lower end of the range assumes a mature technology and mass production the high end of the range represents the estimated cost of the first commercial cogeneration units Within this range fall the estimates cited in the following 1) Richard Woods Gas Research Institute as quoted m Ernest Raia, Fuel Cells Spark Utilities Interest " *High Technology* vol 4 No 12 December 1984 pp 52-57 2) Catalano op cit 1984 3) OTA Workshop on Fuel Cells op cit 1984 4) Thompson op cit 1985

As an *expected* value for capital costs OTA uses in its analysis a value of $2240 (1983 $) This is based on an estimate made by the Gas Research Institute (G RI) of the cost of a 200 kWe cogeneration module see Stephen D Ban GRI Gas-Fueled *Cogeneration—GRI's Current R&O Program* unpublished mimeograph (Washington DC GRI n d) The GRI estimate referred 10 the expected costs during the period of early market entry with low-quantity fuel-cell production levels

[19]Total O&M costs include fixed O&M costs, variable O&M costs and stack replacement costs This study assumes fixed O&M costs of $200 to $5 00/kWe-year and variable O&M costs of 2 to 5 mills/kWh These estimates of fixed and variable O&M costs appear to be in accord with information provided in the following documents 1) Ringer, op cit , 1983 2) Straughn, op cit 1984 3) Burns & McDonnell Engineering Co , op cit , 1984 4) Battelle, op cit , 1983

Estimates made in the above sources do not appear 10 include stack replacement costs, these are rarely estimated in the literature Evidence available to OTA suggests that these will range between $100 and $300/kWe, depending especially on fuel-cell production levels at the hme the replacements are made It is assumed that fuel cells are replaced after 40,000 hours of operation at full capacity The replacement cost estimates are levelized values over 30 years, using a 5 percent discount rate

Total O&M costs estimates consequently are as follows (mills/kWh)

Duty Cycle	*Fixed*	*Variable*	*Replacement*	*Total*
Base/Cogen	03-08	2-5	19-57	42-11 5
Intermediate	06-14	2-5	16-49	42-11 3
Peaking	23-57	2-5	-0-	43-107

Under the assumption that fuel cells would have to be replaced every 40,000 hours at full capacity operating levels, no replacement stacks would be required for a peaking powerplant

[20]Based on 1995 natural gas price of $4 40/mm Btu (see Definitions section of this appendix for an explanation of assumed fuel costs), and a heat rate of 8,533 to 9,481 Btu/kWh (36 1040 percent efficiency) for small fuel cell plants and 7,757 to 8,533 Btu/kWh (40 to 44 percent efficiency) for large fuel cell plants

Table A-8.—Cost and Performance of Compressed Air Energy Storage Plants

May 1985 technology status	Maxi -CAES	Mini -CAES
Level of technology development[1]:	No U.S. demos./ 2 demo. plants overseas	
Installed capacity[2]	-0-	-0-
Reference system: general characteristics		
Reference year: 1990		
Plant size[3]	220 MWe	50 MWe
1990 deployment level scenario	-0-	0-100 MWe[4]
Lead-time[5]	5-8 years	4.5-6.5 years
Land required	15 acres[6]	3 acres[7]
Water required	360,000 gals/ day[8]	100,000 gals/ day[9]
Reference system: performance parameters		
Operating availability:	90-98	percent[10]
Duty cycle: peaking to intermediate[11]		
Plant lifetime: 30 years[12]		
Plant efficiency:		
Fuel (Btu/kWh)	4000[13]	4000[14]
Electricity (kWh-in/kWh-out)	0.78[15]	0.78[16]
Electricity out/ (Fuel + Electricity in)[17]	0.51	0.51
Discharge/charge[18]	4-10 hours	16-8 hours[19]
Reference system: costs		
Capital costs:		
Above-ground equipment	$515/kWe[20]	$392/kWe
Below-ground equipment:		
Aquifer	$50/kWe[21]	$48/kWe
Salt	$55/kWe[22]	$95/kWe
Rock	$85/kWe[23]	$441/kWe
Total	$565-600/ kWe	$487-833/kWe[24]
O&M costs: 3.6 mills/kWh[25]		
Fuel costs:		
Fuel:		28 mills/kWh
Electricity:		16-35 mills/kWh
Total:		42-63 mills/kWh[26]

[1]A 290 MWe salt dome based CAES plant is operating in Huntorf West Germany Another smaller 25 MWe plant just has been completed in Italy Neither however has ever been demonstrated in the United States

[2]No capacity in the United States has been Installed One project sponsored by Soyland Power cooperative was scheduled for commercial operation in 1986 However it was canceled in 1983

[3]Brown Boveri currently offers plant equipment for 50 100 220 and 300 MWe applications from Z Stanley Stys Vice President BBC Brown Boveri Inc personal correspondence with Fred Clements Gibbs & Hill Inc May 9 1984 The following two references selected 200 MWe as a typical size 1) Electric Power Research Institute *Compressed Air Energy Storage Commercialization Potential* (Palo Alto CA EPRI 1982) EM-7750 2) Electric Power Research Institute *Technical Assessment Guide* (Palo Alto CA EPRI 1982) EPRI P-241O-SR

However since then EPRI commissioned a study on mini CAES plants see Gibbs & Hill Inc *Mini Compressed Air Energy Storage Systems (25 MWe 50 MWe modules)* draft report submitted to EPRI (New York Gibbs & Hill Inc April 1984) the report indicates that mini CAES plants in the 25 to 100 MWe range are also economically viable and can compete with the larger 220 and 300 MWe plants The mini CAES plants use proven equipment in modular configurations and require shorter lead-time

[4]The low end of the estimate assumes no plants are completed by 1990 The high end assumes two mint-CAES plants are completed by that time

[5]Based on Information from the following 1) Construction time of 3 to 4 years for maxi-CAES and 2 5 years for mini-CAES from Robert B Schainker Electric Power Research Institute and Michael Nakhamkin Gibbs & Hill Inc Compressed-Air Energy Storage (CAES) Overview Performance and Cost Data for 25 MWe-220MWe Plants " *IEEE Power Engineering Review* April 1985 pp 32-33 2) Licensing time of 2 to 4 years The low estimate is provided by Schainker and Nakhamkin op cit 1985 The high estimate was obtained from Peter Schaub Manager New Technology Program Potomac Electric Power Co personal correspondence with OTA staff November 1984

[6]Gibbs & Hill Inc *Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s* OTA contractor report 1984, calculated for a plant using a salt cavern

[7]Gibbs & Hill Inc op cit April, 1984 Calculated for a plant using a salt cavern

[8]Hans Christoph Herbst NWK and Z Stanley Stys Vice President BBC Brown Boveri Inc *Huntorf 290-MWe the World's First Air Storage System Energy Transfer (Asset) Plant Construction and Commissioning* Presented to American Power Conference Chicago, IL Apr 24-26 1978 Downsized for typical 220 MWe plant calculated for a plant using a salt cavern Note that CAES plants can be designed to use no water at all from Robert B Schainker EPRI personal correspondence with OTA staff May 28 1985

[9]Gibbs & Hill Inc op cit April 1984 calculated for a plant using a salt cavern

[10]With respect to maxi.CAES see Robert B Schainker EPRI and M Nakhamkin Gibbs & Hill Inc *Compressed-Air Energy Storage Overview Performance and Cost Data for 25MWe to 220Mwe Plants* paper prepared for the Joint Power Generation Conference October 1984 Toronto Canada That paper states that the Huntorf West Germany plant has 90 percent availability the availability for the last reporting period was 98 percent—Stys op cit May 1984 For mini.CAES operating availability is expected to be at the high end of the range this is supported by information provided by 1) Gibbs & Hill Inc op cit 1984 2) Schainker and Nakhamkin op cit October 1984

[11]Gibbs & Hill Inc op cit 1984

[12]The estimate for maxi-CAES is based on Information provided by EPRI *Compressed Air Energy Storage Commercialization Potential* op cit 1982 The estimate for maxi-CAES is based on Information provided by Gibbs & Hill Inc op cit April 1984

[13]Schainker and Nakhamkin op cit October 1984

[14]Robert B Schainker EPRI in a personal correspondence with OTA staff May 28 1985 indicated that mini-CAES would have the same fuel efficiency as maxi-CAES

[15]Schainker and Nakhamkin op cit October 1984

[16]Schainker op cit May 28 1985 indicated that mini-CAES would have the same electricity efficiency as maxi-CAES

[17]This calculation assumes that for every kWh (3 413 Btu) generated 4 000 Btu of fuel and 2662 Btu of electricity are required Thus the efficiency is 3 413/6,662 or 51 percent This calculation does not consider the efficiency losses associated with the electric power supplied to the CAES plant

[18]A CAES plant does not need to charge and discharge at the same power Thus a plant which discharges 220 MWe for 4 hours can charge with 43 MWe for 16 hours In general the power needed to charge a CAES plant which will discharge at full power for TO hours is

Power-in = (aMWe x T0)/(T1 x O 78)

where T1 is the charge time O 78 is the kWh-in/kWh-out efficiency, and a is the capacity rating of the CAES plant

[19]The Huntorf plant has a 4 hour/16 hour discharge/charge cycle see Peter Maass and Z Stanley Stys *Operation Experience With Huntorf 290 MW World's First Air Storage System Energy Transfer (ASSET) Plant* paper presented to American Power Conference Chicago IL Apr 21-23 1980 However plants can be made with discharge times over 10 hours see BBC Brown Boveri, 220 *MW Sixty-Cycle Asset Plant* Promotional Brochure (USA BBC Brown Boveri n d) Publication No CH-T 113390 E

[20]Gibbs & Hill Inc op cit 1984 $570/kWe total comprises $515/ kWe for above ground components (e g , turbomachinery structures) and $55/kWe for underground salt dome cavern Cost is based on average U S conditions and is not expected to be sensitive to location

[21]Schainker and Nakhamkin op cit October 1984

[22]Ibid

[23]Ibid

[24]Gibbs & Hill Inc op cit April, 1984 This report provides costs in January 1984 dollars for 266, 50, and 100 MWe plants with 10 hour storage Based on The Handy Whitman Index (see Definitions to this appendix) these costs were reduced by 17 percent to reflect mid-1983 dollars The costs depend on the type of cavern $487/kWe is for a 50 MWe module with salt dome cavern The breakdown of $487/kWe is as follows $392/kWe above-ground items and $95/kWe for salt dome cavern For rock and aquifer storage the total costs would be $833/kWe and $440/kWe respectively Cost is based on average U S conditions and is not expected to be sensitive to location

[25]The estimate is based on an estimate by EPRI *Compressed Air Energy Storage Commercialization Potential* op cit 1982 Mini-CAES costs would of roughly the same magnitude

[26]Based on 1990 distillate costs of $7 O/MM Btu, and based on a 4,000 Btu/kWh discharging heat rate fuel cost is 28 mills/kWh Charging-energy fuel-cost is estimated at 16 to 35 mills/kWh based on an energy-ratio of O 78 kWh-in/kWh-out and an Incoming-electricity cost of 20 to 35 mills/kWh The total fuel cost for CAES plant thus lies between 54 and 72 mills/kWh (between (28 + 26) mills/kwh and (28 + 45) mills/kwh) (see Definitions section of this appendix for an explanation of fuel and incoming-electricity costs)

Table A-9.—Cost and Performance of Battery Plants

May 1985 technology status	Lead-acid	Zinc-chloride
Level of technology development	Small-scale test[1]	Small scale tests[2]
Installed capacity	0.5 MWe[3]	None[4]
Reference system: general characteristics		
Reference year	1995	
Plant size[5]	20 MWe[6]	
Deployment level scenario	0-600 MWe[7]	0-2,800 MWe[8]
Lead-time[9]	2 years	
Land required[10]	0.2-0.3 acres	
Water required (gallons/day)	200-300[11]	11,000[12]
Reference system: performance parameters		
Availability	90 percent[13]	
Duty cycle[14]	peaking [15]	
Lifetime[16]		
Stacks	2,000-4,000 cycles[17]	2,000-5,000 cycles[18]
Balance of plant	30 years	30 years
Plant efficiency[19]	70-75 percent[20]	60-70 percent[21]
Discharge/charge[22]	5 hours/6.7-7.0 hours	5 hours/7.0-8.3 hours
Reference system costs:		
Capital costs[23]	$600-800/kWe[24 25 26]	$500-$3,000/kWe[27]
O&M costs		
Annual	1-4 mills/kWh	1-4 mills/kWh
Replacement	5-16 mills/kWh[28 29]	2-7 mills/kWh[30 31]
Total	6-20 mills/kWh	3-11 mills/kWh
Fuel costs	27-50 mills/kWh[32]	29-58 mills/kWh[33]

[1]This refers to the testing of a single module at the Baffery Energy Storage Test (BEST) facility In New Jersey The baffery hasnot been demonstrated In a commercial-scale facility in the United States

[2]Ibid

[3]This figure refers toa demonstration unit which was in operation by the end of 1983 at the BEST facility The battery is expected to be capable of producing 500 kWe, with a 1 hour discharge rate, at theend of its life; seeGNB Batteries. Inc *500-kWe Lead-Acid Battery for Peak. Shaving Energy StorageTesting and Evaluation* (Palo Alto, CA Electric Power Research Institute, 1S84), EPRI EM-3707

[4]Note however that an advanced-design zinc-chloride baffery operated from the end of 1983 to early t985 at the BEST facrhfy The unit was capable of producing 100 kWe over 5-hour discharge periods

[5]The zinc-chlorlde battery comes in 2 MWe modules, see Electric Power Research Institute, *ZnCl Batteries for Utility Applications* (Palo Alto. CA EPRI, 1984) The lead-acid battery comes in 440 kWe strings see Exide Management & Technology Co *Research Development and Demonstration of Advanced Lead-Acid Batteries for Utility* Load *Leveling* Argonne IL Argonne National Laboratory, August 1983] ANL/OEPM-83-6

[6]Assumes 5-hour discharge periods, or 100 MWh storage capacity; see Albert R Landgrebe, "Operational Characteristics of High-Performance Batteries for Stationary Applications," *Advanced Energy Systems—Their Role in Our Future* Proceedings of 19th Intersociety Energy Conversion Engineering Conference, Aug 19-24 1984 San Francisco CA(U S American Nuclear Society 1984), paper 849122, pp 1091-1096

[7]Assumes 5-hour discharge periods ora storage capacity under the high scenario of 30,000 MWh The highestimate assumes that 200 MWe worth of batteries are produced during each of the following years 1991 1992, 1993, and 1994 This Is the level of production on which the capital cost estimates are based These batteries would begin producing electrical power in 1992, 1993, 1994, and 1995, respectively Gwen 2-year lead-times for batteryinstallations, this productionscenario assumes that ten 20-MWebaffery Installations are intiated each year, beginmng m 1990

[8]Assumes 5-hour discharge periods, or a storage capacity under the high scenario of 8,400 MWh The high estimate assumes that 700 MWe worth of batteries are produced during each of the following years 1991, 1992, 1993, and f994 This is the level of production on which the capital cost estimates are based These batteries would begin productionin 1992 1993, 1994, and 1995, respectively Gwen2-yearlead-times for battery installationsthis production scenario assumes that thirty-five 20-MWe battery installations are initiated each year, beginning in f990

[9]Consensus from OTA Workshop on Energy Storage, Washington OC, June 6, 1984, based on 2 MWe installation short permitting time (negligible pollution) factory assembly and simple siting requirements

[10]Theland used depends on theenergy densityfootprint (measuredly units of kWh/sq meter) of the battery It is assumed that lead-acid and zinc-chloride batteries have similar footprints of 80-125 kWh/sq meter This footprint esimate Is consistent with estimates made in the following three documents l] Philip C Symons Electrochemical Engineering consultants, Inc "Advanced Technology Zinc/Chlorine Batteries for Electric Utility Load-Leveling " *Advanced Energy Systems—Their Role in Our Future*, op cit pp 857-862 2)Landgrebe et al op cit 1984 3) James Quinn, U S Oeparfment of Energy "OOE Multiyear Planing," *Extended Abstracts Sixth DOE Electrochemical Contractor's Review* June 25-29 1984 (Washington, DC US DOE, June 1984), CONF-840677 pp 64-67

[11]Based on a rough estimate that the system would use 1,000 to1,500 gallons per week This figure assumes a full discharge/chargecycle five times each week Estimate provided by John L Del Monaco, Principal Staff Engineer, Research, Public Service Electric&Gas Co Newark, NJ personal correspondent with OTA staff May 1, 1985

[12]Based on a rough estimate that the system would use 11,000 gallons each day This figure assumes a full discharge/charge cycle, and includes only the water requirement of the battery system itself Mosf of the wafer is used In evaporative cooling Estimate provided by Monaco, op cit 1985

[13]From EPRI *Technical Assessment* Guide (Palo Alto, CA EPRI, 1982). EPRIP-2410-SR; modified (rounded off) in accordance with discussion at OTA Workshop on Energy Storage, op cit., 1984

[14]Batteries can also provide spinning reserve and system regulation functions see EPRI *Utility Battery Operations and Applications* (Palo Alto, CA EPRI, March 1983), EPRIEM-2946-SR

[15]Gibbs & Hill Inc *Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s* OTA contractor report, Sept 13 1984

[16]The number of cycles peryear depends on how the battery was used but a figure of 250 cycles/year is offen used asa reasonable average In general the stacks (and sumps where appropriate) would be replaced several times over the life of the system The remainder of the battery plant should last 30 years

[17]Arnold Fickett EPRI personal correspondence with OTA staff Aug 30 1984

[18]Fickett op cit 1984

[19]AC to AC efficiency, includes the 85 percent efficiency of the power-conditioning equipment

[20]Exide Management & Technology Co op cit, 1983

[21]Round trip efficiency kWh AC out divided by kWh in including auxiliaries Efficiency is constant with deployment because multiple units are used to achieve various plant sizes Based on Information provided by the following sources 1) B.D Brummet, et al Energy Development Associates, *Zinc Chloride Battery Systems for Electric Utility Energy Storage* paper prepared for the 19th Annual Intersociety Energy Conversion Engineering Conference, SAE San Francisco CA August 1984, these estimates apply to the 2 MWe commercial battery 2) OTA Workshop on Energy Storage op cit 1984 3) Energy Development Associates *Development of the Zinc-Chloride Battery for Utility Applications* (Palo Alto, CA EPRI, June 1983) EPRI EM-3136

[22]Consistent with plant size and plant efficiency, assuming plant charges and discharges al 20 MWe

[23]Battery costs are measured in units of $/kWh To convert the given $/kWe figures to $/kWh, divide by five

[24]The range corresponds to the price of lead varying from $0 25/l b to $0 58/lb The price as of August f984was $030/lb see JJ Kelley, Director of Research, EXIOECorp personal correspondence with OTA staff Aug 28, 1984 The cost figures assume a production of about 200 MWe/yr, see Exide Management &Technology Co, op cit 1983 However lead acid battery prices should not be strongly dependent on the volume of production

[25]Fickett, op cit 1984

[26]Exide Management & Technology Co, op cit 1983

[27]The low cosf figure assumes a production volume of about 700 MWe/yr; see Energy Development Associates op cit 1983 The price of zinc-chlorlde batteries should be strongly dependent on the level of production Based also on Information provided by Fickett, op cit 1984 The high figure is based on an estimate provided by P Sioshansi, Southern California Edison Co personal correspondence with OTA staff Apr 10, 1985 The high estimate reflects the price penalties which might be associated with early commercial units

[28]This is a levelized value over 32 years, using a discount rate of 5 Percent The low value assumes a lifetime of 4,000 cycles so that after 16 years parts totaling $300/kWe must be replaced The high value assumes a lifetime of 2000 cycles so that these $300/kWe parts must be replaced after 8, 16, and 24 years

[29]Fickett, op cit 1984

[30]This is a levelized value over 32 years, using a discount rate of 5 percent The low value assumes a lifetime of 4,003 cycles, so that after 16 years parts totaling $130/kWe must be replaced The high value assumes a lifetime of 2,000 cycles, so that these $130/kWe parts must be replaced after 8, 16 and 24 years

[31]Fickett, op cit, 1984

[32]The charging-energy fuel-cost is eshmated to be 27 to 50/mills kWh, based on an energy ratio of O 7 to O 75 kWe-out/kWe-in and incomjnn-electricity cost in 1995 of 201035 mills/kWh (See Definitions section of this appendix for an explanation of Incom-mg-electricity costs)

[33]The charging-energy fuel-cost is estimated to be 29 to 58/malls kWh based on an energy ratio of O 6 to O 7 kWe-out/kWe-in and incoming-electricity cost in 1995 of 20 to 35 mills/kWh (See Definitions section of this appendix for an explanation of Incommg-electricity costs)

Table A-l O.—Summaries: Cost and Performance for Reference Installations (based on tables A-1 through A-9 in this appendix)

	Technologies						
	Solar photovoltaic		Solar	Wind	Geothermal		
May 1985 technology status	Flat plate	Concen.	Parabolic dish (mounted-engine)		Dual-flash	Large binary	Small binary
Level of technology development	Commercial	Commercial	Demo,	Commercial	Commercial unit	Commercial unit	Commercial
Installed capacity	9.5 MWe	9.5 MWe	O 075 MWe	650 + MWe	none	none	223 MWe
Reference system: general							
Reference year	1995	1995	1995	1995	1995	1995	1995
Reference-plant size	10 MWe	10MWe	10 MWe	20 MWe	50 MWe	50 MWe	7 MWe
Reference-year installed capacity (est.)	355-4,730 MWe		5-200 MWe	1,500-2,900 MWe	12-1,830 MWe		
Lead-time	2 years	2 years	2 years	1-2 years	3 years	3 years	1 year
Land required	40-370 acres	60-320 acres	67 acres	300-2,000 acres	8-20 acres	8-20 acres	1 acre
Water required	very little	very little	very little	none	3 milllon gal/day	41 million gal/day	0.6 million gal/day
Reference-system performance parameters							
Operating availability	90-100%	90-100%	95Y0	95-98%	85-90%	85-90%	85-90%
Duty cycle	intermittent	intermittent	intermittent	intermittent	base	base	base
Capacity factor	20-40%	20-35%	20-35%	20-35%	70%	70%	700/0
Plant lifetime	10-30 years	10-30 years	30 years	20-30 years	30 years	30 years	30 years
Plant efficiency	8-14%	12-20%	20-25%	—	7.0-8.0%	9.5-12.0%	7 0-90/0
Reference-system: costs							
Capital costs	$1,000-$11,000/kWe	$1,000-$8,000/kWe	$2,000 - $3,000/kWe	$900-$1 ,200/kWe	$1,300-$1 ,600/kWe	$1,500-$1,800/kWe	$1,500-$2,000/kWe
O&M costs	4-28 mills/kWh	4-23 mills/kWh	15-23 mills/kWh	6-14 mills/kWh	10-15 mills/kWh	10-15 mills/kWh	10-15 mills/kWh
Fuel costs	None	None	None	None	20-70 mills/kWh	20-70 mills/kWh	20-70 mills/ kWh

Only individuals modules are being demonstrated. No large multi-module installation yet exists

Table A.10.—Summaries: Cost and Performance for Reference Installations
(based on tables A-l through A-9 in this appendix) —Continued

	Technologies							
			Fuel cells		CAES		Batteries	
May 1985 technology status	AFBC	IGCC	Large	Small	Maxi	Mini	Lead-acid	Zinc-chlor
Level of commercial development	Demo. under	Demo.	Demos. planned	Demos. operating under const., & planne	No Demo.[2]	No demo.	Demo.	Demo
Installed U.S. capacity	none	100 MWe	None	1.5 MWe	none	none	0.5 MWe	0.1 MWe
Reference-system: general								
Reference year ., ...	**1990**	**1990**	1995	1995	1990	1990	1995	1995
Reference-plant size .,	**150** MWe	500 MWe	11 MWe	0.4 MWe	220 MWe	50 MWe	20 MWe, 100 MWh	20 MWe, 100 MWh
Reference year U.S. installed capacity (est.)	510-735 MWe	200 MWe	40-1,200 MWe		O MWe	0-100 MWe	0-600 MWe	0-2,800 MWe
Lead-time	5-10 years	5-10 years	3-5 years	2 years	5-8 years	4,5-6,5 years	2 years	2 years
Land required ., ., ~ .,	90-218 acres	300-600 acres	0,5 acres	0.009-0.014 acre	15 acres	3 acres	0.2-0.3 acres	0.2-0,3
Water required .,	1.5 million gal/day	3-5 million gal/day	very small	very small	360,000 gals/day	100,000 gals/day	11,000 gals/day	200-300 gals/day
Reference-system: performance parameters								
Operating availability	85-87%	85%	80-90%	80-90%	90-98%	90-98%	90%	90%
Duty cycle	base/interm.	base	variable	variable	peaking/inter,	peaking/inter.	peaking	peaking
Capacity factor	20-70%	***70%***	40-75%	40-75%	10-20%	1O-2O%	10%	10%
Plant lifetime	30 years	***30*** years	30 years	20 years	30 years	30 years	30 years	30 years
Plant efficiency	35%	***35-40%***	40-44%	36-40%	51%[3]	51%[3]	70-75%[3]	60-70%
Reference-system: costs								
Capital costs	$1,260-1,580/kWe	$1,200-$1 ,350/kWe	$700-$3,000/kWe	$950" $3,000/kWe	$565-$600/kWe	$487-$833/kWe	$600-800 kWe	$500-3,000/kWe
O & M costs	7.66 mills/kWh	6-12 mills/kWh	4,2-11.5 mills/kWh	4.2-11.5 mills/kWh	3.6 mills/kWh	3.6 mills/kWh	6-20 mills/kWh	3-11 mills/kWh
Fuel costs ., ., .,	17 mills/kWh	15-17 mills/kWh	27-30 mills/kWh	30-33 mills/kWh	42-63 mills/kWh	42-63 mills/kWh	27-50 mills/kWh	29-58 mills/kWh

[2]While no demonstration plant is operating in the U.S., one has operated in Huntorf, West Germany, and a smaller one has just been completed in Italy

[3]This efficiency is computed by dividing as follows:

$$\text{Efficiency} = \frac{\text{Electricity out}}{(\text{Electricity in}) + (\text{Fuel in})}$$

The value for the ''electricity in'' is based on a conversion factor of 3,413 Btu/kWh in. The computation does not consider the efficiency of the plant which generates the power provided to the compressors

Definitions

These tables provide basic information on each technology. The data constitutes the basis for important portions of the analysis. The cost and performance characteristics listed in the tables are not definitive predictions. Rather they are reasonable approximations of the status of the technology during the 1990s, and are used to typify the technology during the last decade of the century. Great uncertainty surrounds these numbers and they should be treated for what they are: educated guesses.

Where important subcategories of any particular technology exist, and where their characteristics differ significantly from one subcategory to the next, the subcategories are listed separately. For example, photovoltaics are divided between flat-plate and concentrator modules.

May 1985 Technology Status

This section provides information on the current status of the technology.

Level of Technology Development.–The technology already may be commercially deployed, or it may be operating as a demonstration unit or pilot plant; or plans may be underway to deploy such units.

Installed Capacity .–This section of the table describes the status of the technology as of May 1, 1985. Only capacity installed and operating at that time is included in the capacity totals.

Reference System: General Characteristics

Reference Year.— For each technology a reference year is established. For technologies with lead-times of 5 years or less, the reference year is 1995. For those with lead-times longer than 5 years, the reference year is 1990. All cost and performance figures refer to the technology as it might appear in the reference year. The cost and performance figures for that year are expected to typify the cost and performance of most of the units which are deployed and operating by the end of the century.

Plant Size.–The technologies examined in this report in many instances will be deployed in a variety of sizes. The size listed in the tables is considered typical of plants installed in the 1990s. Considerable variation may occur from plant to plant, but most capacity installed during the 1990s is expected to be similar in cost and performance to the reference plant.

1995 Deployment **Level Scenario.–This** is the total capacity expected to be operating by January 1 of the reference year. The estimates are important because they provide an idea of the level of nationwide experience with the technology by the reference year. This in turn is an indicator of the extent of risk associated with the technology. Generally speaking, the greater the amount of capacity deployed by the reference year, the lower will be the uncertainty associated with the technology.

Lead-Time.—The lead-time is the time required to deploy a plant once a decision has been made to do so. Included is the time required for various activities prior to construction (including licensing and permitting) and construction itself.

Land Required.—This is the amount of land needed for the plant and all necessary facilities, including fuel storage areas and waste storage areas.

Water Required.—This includes any water drawn from some external source and required for the routine operation of the plant.

Reference System: Performance Parameters

Operating Availability.—Operating availability applies to the entire plant and is defined as:[1]

$$(1\text{-POR}) \times (1\text{-UOR}) \times 100$$

where: POR = Planned Outage Rate
= (Planned Outage Hours)/(Period Hours)
and UOR = Unplanned Outage Rate

$$= \frac{\text{Unplanned Outage Hours}}{\text{(Period Hours)—(Planned Outage Hours)}}$$

Several of the technologies use multiple nonconventional components in parallel, for example, multiple turbines in a wind farm or several gasifiers in an IGCC plant. In such cases also, the availability refers to the operating availability to generate rated output (and not to the individual nonconventiaonal component reliability). In all cases the figures are estimates, since no commercial units have operated over the full course of their lifetimes.

Duty Cycle and Capacity Factor.—Duty cycles are either intermittent, base, intermediate, or peaking. An installation is termed intermittent if its output cannot be controlled; this is the case with solar or wind technologies which are not coupled with any kind of energy storage system. Capacity factors for intermittent technologies will vary according to technology, time, and location. A base load system is one which runs most of the day; in the analysis such systems are assigned a capacity factor of 70 percent. A peaking system is assumed to have a capacity factor of about 10 percent, and operates during the relatively short part of the day when electricity demand is greatest.

[1] The definition is that provided in the Electric Power Research Institute's Technical Assessment Guide

Capacity factors for intermediate systems are assumed to fall between the two systems, at around 20 percent. Where technologies are expected to operate under more than one duty cycle, both are stated. Actual capacity factors may be quite different form the nominal values shown.

Lifetime.—This is the time over which the entire plant would be operated commercially.

Efficiency .-This is the annual average plant efficiency, defined as the ratio of total net energy produced to total available energy contained in the fuel or resource.

Reference System: Costs

All capital and O&M costs are reported in mid-1 983 dollars. Escalation of published costs, where required, was performed as per the Handy Whitman Bulletin Cost Index for electric utility construction:

Date	Index
1/1 /78	159
7/'1 i78	166
1/1 ,'79	175
7/1 /'79	183
1/1 1'80	193
7/I /'80	I 99
1/1)81	210
7/1/81	219
1/1/82	225
7/1/82	230
1/1/83	233
7/1/83	238
1/1/84	242

Capital Costs.—Capital costs (tota plant cost or TPC) generally represent approximate budgetary overnight constructed costs for the indicated location including an average allowance of 5 to 10 percent for engineering and home office overhead and fee and a 20 to 25 percent allowance for overall contingence.

Thus:

TPC = Bare Erected Cost (BEC) X (1 .05 to 1,1) X (1 2 to 1.25)

Capital costs do not include interest and escalation during construction, land costs, and other costs such as royalties, preproduction, startup, initial catalyst/chemical charges, and working capital.

O&M Costs.–These are "first year" costs, the average O&M costs expected during the reference year. In the case of both battery and fuel cell installation, a portion of cost of periodically replacing batteries or fuel-cell stacks during the installation's lifetime is included in the O&M costs.

Fuel Costs.— Electricity and fuel costs are first year annual average costs based on a typical plant in the reference year. Electricity for CAES and batteries is assumed to be generated by a base load plant, at prices expected to range from 20 to 35 mills/kWh.[2] Fuel prices are based on 1983 fuel prices, with assumed real escalation rate of 1 percent per annum for coal, and 2 percent per annum for oil and gas. The 1983 fuel prices used **in making the reference year estimates are:**

Fuel) (in **dollars per million British thermal units (Btu))**

	Oil		
Gas	*Residual*	*Distillate*	*Coal*
3.47	4.58	6.09	1.66

[2] This is **based on an** esti **mate provided by** William Birk, Electric Power Research Institute, personal correspondence with OTA staff, May 7, 1985 Mr Birk indicated that EPRI uses a figure of 25 mills/kWh; for a range, he suggested 20 to 30 mills/kwh **This analysis uses a range with a higher upper** limit: **20 to 25** mills/kWh.

[3] **From U .S,, Department** of **Energy, Energy I** nformation Admi n istration, **Nov. 27, 1984 Average cost of** fossil fuel **receipts** for **steam electric** plants **of 50 MWe capacity or larger, 1983**