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Combined-Cycle Power Tower

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ABSTRACT

This paper evaluates a new power tower concept that offers significant benefits for commercialization of power tower technology. The concept uses a molten nitrate salt central-receiver plant to supply heat, in the form of combustion air preheat, to a conventional combined-cycle power plant. The evaluation focused on first commercial plants, examined three plant capacities (31, 100, and 300 MWe), and compared these plants with a solar-only 100-MWe plant and with gas-only combined-cycle plants in the same three capacities. Results of the analysis point to several benefits relative to the solar-only plant including low energy cost for first plants, low capital cost for first plants, reduced risk with respect to business uncertainties, and the potential for new markets. In addition, the concept appears to have minimal technology development requirements. Significantly, the results show that it is possible to build a first plant with this concept that can compete with existing gas-only combined-cycle plants.

INTRODUCTION

Power tower technology has been actively pursued in the United States since the fossil-fuel price shocks of the early 1970s. Activities have included technology evaluations, component development, and system demonstrations (Sandia National Laboratories, 1986). A major accomplishment for the U. S. program was the construction and operation of the 10-MWe Solar 1 pilot plant at Barstow, California, in the 1980s. Research and development (R&D) in the United States has converged to a power tower system configuration with glass/metal heliostats, a tubular external receiver with molten nitrate salt as the heat transfer/storage fluid, a surround heliostat field, and a steam/Rankine power cycle (APS, 1988). The Solar Two project (De Laquil et al., 1993), which will demonstrate this configuration beginning in 1995, represents the culmination of the past 20 years of power tower R&D. Solar Two is a 50/50 cost-shared program between a consortium of utilities and industry and the U.S. Department of Energy and is aimed primarily at reducing to acceptable levels the economic risks in building the first commercial power tower projects.

Although commercial applications of power towers following the Solar Two project look promising, there are many risks (e.g., low fossil-fuel prices, changes in regulatory environment, uncertain business climates) that are beyond the control of the solar thermal industry and power tower end-users. These risks make it prudent to investigate alternative commercialization pathways for power tower technology as a hedge against an uncertain future. An important factor in the work described in this paper was a desire to select technology options that would minimize development effort and time. Consistent with this, we chose to focus on power tower options that would ensure that ongoing power tower technology and commercialization activities could be used to the greatest extent possible.

Low fossil-fuel costs and the need to compete with power generated from these fuels leads one to alternatives to present-day thinking. In particular, hybridized systems, in which solar heat is used to supplement or replace fossil-fuel combustion heat, have sparked a great deal of attention from industry and utilities in the past several years. In a companion paper (Williams et al., 1995), we discuss reasons for hybridizing solar thermal power technologies, hybridization options, and expected results from hybridization. From the perspective of power tower technology, hybridization offers opportunities to take advantage not only of low fossil-fuel costs, but also of the high-efficiency conversion equipment that is used in current practice with fossil fuels.

One of the first technology issues to consider is the high conversion efficiency of combustion turbines and a comparison of these efficiencies with the efficiency of state-of-the-art power tower steam/Rankine systems. The reason is that the heat provided by a power tower plant is costly and must be used as efficiently as possible. For the combined-cycle plants, net lower heating valve (LHV) cycle efficiency[1] exceeding 50% can be achieved by today's technology (Gas Turbine World 1993-94 Handbook), whereas the net, full-load conversion efficiency of the steam turbine in the first solar-only power tower plant is estimated at 41% (APS, 1988). More recent data on steam turbines show similar efficiencies. Ongoing R&D in gas turbines seeks to improve the intrinsic efficiency of the gas turbine itself. As an example, the Collaborative Advanced Turbine Program (CAGT) (Cohn and Hollenbacher, 1994) involves development of intercooled aeroderivative gas turbine combined cycles with 58% LHV efficiency by 2002. A hybrid power tower using solar heat at nearly 60% conversion efficiency is an exciting prospect. Combustion turbines offer benefits beyond high efficiency such as lower energy cost, low capital cost, and rapid cycling capability.

This paper discusses a new approach to power tower technology in which state-of-the-art molten salt power tower technology is coupled to and hybridized with contemporary, high-efficiency, combined-cycle power plant technology. Although several methods for hybridizing power towers have been proposed over the past several years, we feel that the concept described in this paper has some very important benefits, especially with respect to ongoing power tower commercialization efforts.

THE COMBINED-CYCLE POWER TOWER (CC/PT) CONCEPT

The basic concept behind the CC/PT is to use the solar heat to preheat the turbine combustion air. Figure 1 shows the schematic flow sheet. The solar heat is generated by a conventional molten salt central-receiver plant and delivered to an air/salt heat exchanger. Compressor outlet air is directed to the heat exchanger and is heated by the hot salt. This preheated air is returned to the combustor where it is heated to the desired turbine inlet temperature by combustion of the fossil fuel. The amount of fossil fuel required in the combustor is reduced by the amount of thermal energy added to the combustion air stream by the hot salt. The role of the thermal storage system shown in Figure 1 is to maximize the solar fraction by ensuring that regardless of plant dispatch, the required solar thermal energy is available for preheating the combustion air. A secondary function of storage is to buffer the air/salt heat exchanger and piping from solar transients.

The main benefit of the arrangement in Figure 1 is that by using the solar heat at the front end of the combustion turbine, heat is converted at the full efficiency of the cycle, i.e., about 50% for today's combined-cycle plants and 60% for the advanced gas turbine cycles discussed previously. There are a number of other advantages.

In keeping with the constraint that development cost and time be minimized, note that all solar components will be demonstrated by the Solar Two project. With the exception of the air/salt heat exchanger and the gas turbine air flow path, to be discussed later, the rest of the plant is essentially off-the-shelf technology.

A significant difference between a CC/PT plant and a solar-only plant is that the solar plant in the CC/PT concept can be designed and operated independently of the rest of the plant. This has several implications. First, plant capacity factor is independent of the solar plant design. A plant could be designed for a given capacity factor and operated at a larger capacity factor at some point in the future if desired. The absolute contribution of the solar plant to the plant heat input, i.e., the annual fuel saved, would be the same even though the relative solar contribution would be reduced. Second, plant dispatchability is independent of the solar plant design. If the plant dispatch strategy is changed, all the solar heat can still be used. Again, the relative solar contribution may decrease depending on how the dispatch strategy is changed. Third, the plant can operate at full capacity and at full efficiency regardless of the status of the solar plant. This is because the solar plant is simply replacing fossil-fuel heat at the front end of the combined-cycle plant; should this solar heat become unavailable at some time, the plant can continue to operate without interruption by increasing the fuel consumption. The design shown in Figure 1 has not imposed the necessity of solar heat to operate the plant or to maintain high conversion efficiency, as is the case in some other hybrid power tower concepts.

A further advantage is that an efficient and cost-effective plant can be built with a solar plant significantly smaller than that in a solar-only plant. A primary driver in the size of solar-only plants is the steam turbine. To a great extent, this constraint is removed by going to a plant based on combustion turbine technology because the solar plant in the CC/PT does not provide all the heat input to the turbine and because the solar plant shares the costly electric power generating system with the fossil-fired part of the plant.

State-of-the-art combustion turbine plants are able to meet existing emission regulations, so air emission benefits provided by solar-only or hybrid plants are a consideration for the future. Carbon emission reductions are one such benefit provided by CC/PT, as for any solar plant. The reduction in carbon monoxide and carbon dioxide should be directly proportional to the reduced fuel consumption that results from the contribution of the solar thermal heat in a CC/PT plant. Nitrogen oxide (NO_x) emission is probably not significantly affected because the high temperature in the gas combustor and nitrogen content of the air stream remains the same. At the same time, the concept should not preclude the use of state-of-the-art NO_x reduction technologies such as water injection or dry low NO_x.

Because the solar heat is used to preheat the turbine combustor air, and the temperature of that heat source is limited to about 550°C, the contribution to the total plant heat input, called the solar fraction, is limited to about 0.30. Relatively simple process modifications can increase the solar fraction to about 0.5, although a small loss of efficiency will result. For these reasons, the concept will always involve the combustion of fossil fuel.

[1]Lower heating value efficiency is the appropriate measure when replacing fossil-fuel combustion heat with solar heat. When solar heat is used to preheat the compressor outlet air stream, it does not introduce a burden of water vapor as does combustion. A detailed first-law analysis of the preheater and combustor can be used to demonstrate this concept quantitatively.

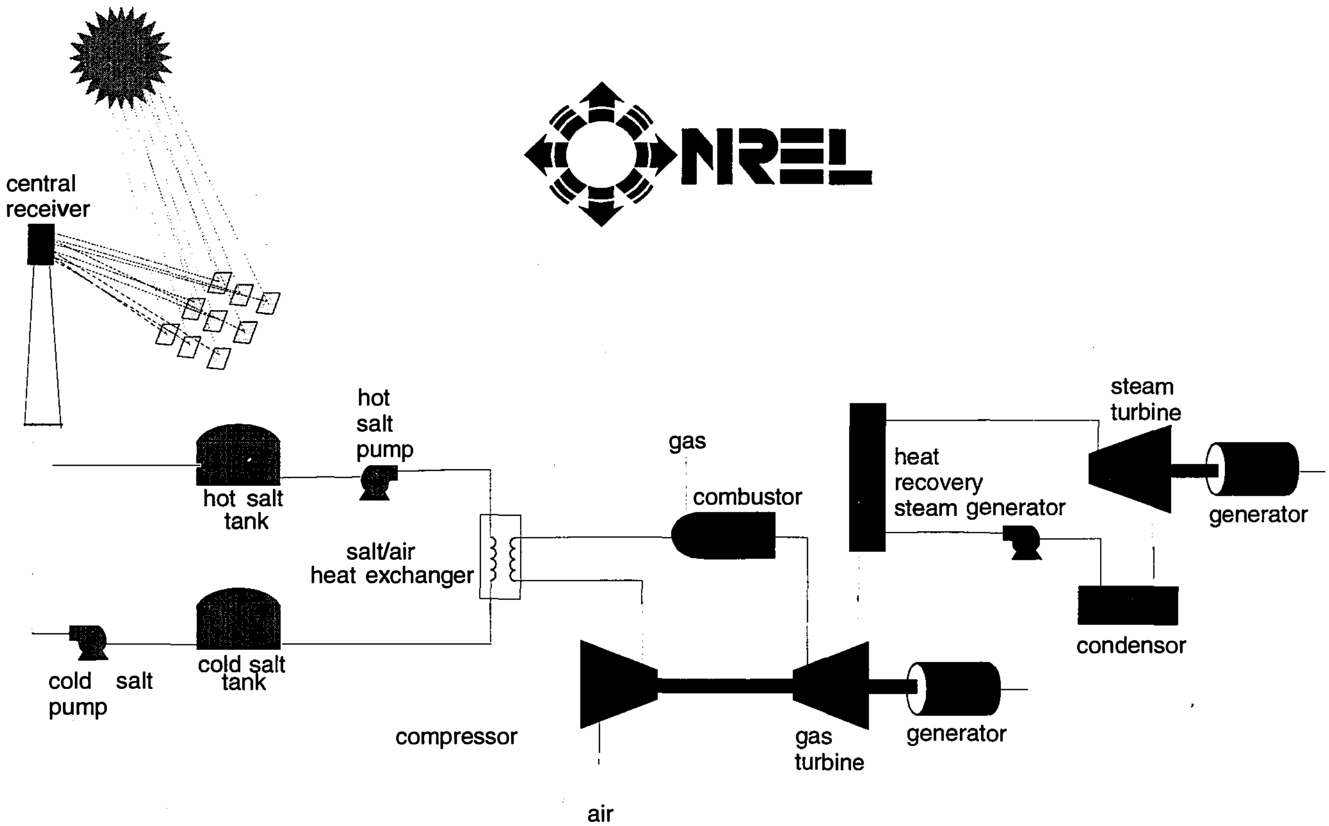

FIG. 1. SCHEMATIC FLOW DIAGRAM OF THE COMBINED-CYCLE POWER TOWER CONCEPT

We pointed out previously that the air/salt heat exchanger was one possible technical issue. This issue appears to have been resolved by a preliminary design completed by ABB Lummus Heat Transfer. This design uses the ABB APEX (Advanced Plate EXchanger) in a TEMA CXW configuration. A fully welded stainless steel plate-type heat exchanger core is installed inside a conventional carbon steel heat exchanger shell. A proprietary expansion/sealing mechanism provides a totally welded salt flow-path. The shell is oriented vertically to allow for salt drainage for shutdown. Capital cost estimates provided by ABB have been incorporated in economic calculations discussed later in this paper and appear to be a small fraction of the total-plant capital cost. The ABB design was based on a low pressure drop, which should have a small impact on turbine power.

The second technical issue is the turbine selection. Compatibility of the turbine with the CC/PT concept can be divided into several subissues. For the CC/PT concept, the compressor outlet air stream must be ducted to the air/salt heat exchanger and back to the combustor with minimal pressure losses. High compressor outlet temperatures are detrimental because they reduce the relative contribution that solar can make to the plant. High-efficiency machines are desirable because the CC/PT plant will need to compete with gas-only plants using the best available machines at any given time. Finally, preheating the combustion air to 540°C may impact the combustor design.

In keeping with the constraint that significant development is not appropriate for CC/PT, existing turbines or those currently under development in which these issues have been addressed are desirable. Two likely options identified to date are (1) the Westinghouse WR-21, an intercooled, recuperated machine developed for the Navy (Fulton, 1994), and (2) turbines under development in the CAGT (Cohn and Hollenbacher, 1994).

Because of intercooling and a relatively low high-pressure-compressor compression ratio, the WR-21 has a low compressor outlet temperature of 280°C. This will allow a relatively high solar fraction for a CC/PT plant—just under 30%. In addition, the machine is recuperated, which means that the air has been ducted off the compressor to the recuperator and returned to the combustor. For CC/PT, the recuperator will be replaced with the air/salt heat exchanger, and the turbine waste heat will be used in the bottoming steam turbine. Although this machine is small, it may fit in demonstration projects or in early commercial plants. Larger advanced intercooled aeroderivatives are likely to have overall compression ratios of up to 50 and high-pressure-compressor compression ratios of about 11. This will give a compressor outlet temperature of 350°C (Cohn and Hollenbacher, 1994), yielding a solar fraction of about 0.18.

For CC/PT, these advanced turbines will be needed within about 2 years. At that time, the Solar Two plant operation period will have been completed and molten salt power tower technology proven. It appears that the WR-21 will be commercially available within that time period, with the larger machines following within 2 years. It is reasonable to assume that these machines will be developed because they will be based on technology developed for an aircraft engine market valued at more than $60 billion over the next 20 years (Cohn and Hollenbacher, 1994). This results in an exceptionally competitive marketplace where very high value is placed on developing higher-efficiency, higher-performance turbines for both aircraft and power generation applications.

EVALUATION METHOD

This section briefly describes the method used in our quantitative evaluation of the performance and cost of the CC/PT concept. We focused this evaluation on conditions appropriate for the first commercial plants, which is the most relevant case for judging commercialization prospects.

We selected three CC/PT plant sizes for evaluation in different applications/scenarios and based on the gas turbines discussed in the previous section. A 31-MWe plant using the WR-21 gas turbine was selected as an "entry-market" size. This case provides insights into whether the concept could open up new markets and provides a "lowest financial risk" case that would minimize the total funds required for investing in the first power tower plant. The solar field for that plant is approximately the size of the Solar Two field. A 100-MWe CC/PT plant using an 83-MW advanced aeroderivative gas turbine case was selected as a size for allowing a comparison based on plant capacity to the baseline 100-MWe solar-only commercial plant. Finally, a 300-MWe case, using two 125-MW advanced aeroderivative gas turbines, was evaluated to investigate the effects of economies of scale. The 300-MWe plant has a solar field size about 80% of that of the Solar 100 plant. The 31-MWe and 100-MWe CC/PT plants were evaluated at capacity factors of 0.4 and 0.85, and the 300-MWe CC/PT plant was evaluated at a capacity factor of 0.85. Table 1 gives details of the turbines selected for the analyses.

The solar-only plant used for comparison purposes is the Solar 100 plant. This plant was sized and costed in significant detail by two utilities (APS, 1988; PGE, 1988) for the U. S. Department of Energy. In addition to providing a comparison baseline for total plant capital cost and levelized energy cost, these data supported the sizing of the solar plant for the CC/PT concept as described below.

Performance and cost evaluation of the CC/PT was carried out in three steps. First, a solar plant was sized to provide the maximum possible thermal energy (operation at the maximum possible solar fraction) to a selected combined-cycle plant. This was done with empirical calculations based on published results for power tower plant sizing (Sandia National Laboratories, 1986; APS, 1988). Second, the capital and operating costs for the resulting solar plant were estimated based on scaling data for a 100-MWe solar-only plant (APS, 1988) and for the combined-cycle plant from Electric Power Research Institute data (EPRI, 1988). An implicit assumption here is that capital costs for combined-cycle plants based on the advanced aeroderivative turbines will not be significantly greater than that for today's combined-cycle plants as reported by EPRI. Third, a calculation of the resulting levelized energy cost (LEC) was performed using the TEAM model (Brown et al., 1987). The TEAM model uses the following economic assumptions: general inflation rate = 3%, plant life = 30 years, construction period = 3 years, discount rate = 11%, depreciable life = 15 years, investment tax credit = 0%, combined tax rate = 38%, and other taxes and insurance = 2%. No special tax incentives or other externalities were used in the LEC calculations.

All costs were escalated from the year basis given in the data to early-1994 dollars. We used the Marshall and Swift equipment index for capital costs and the Implicit GNP Deflator for operating and maintenance costs.

Cost escalation estimates for natural gas were taken from the National Energy Strategy (U. S. DOE, 1991/1992). This gives a projection of natural gas cost, in 1990 dollars, per million BTU for years from 1985 to 2030. The value for 2000 is $3.41 and in 2030 is $8.82 and is roughly linear in between. A second gas-cost projection was used to investigate the effect of lower gas-cost escalation. A description of that projection will be given in the Results section.

Plant design calculations used in the evaluation were design-point calculations. Any reduction in efficiency or availability of the solar plant would necessitate an increased consumption of natural gas. We estimated this effect on the 100-MW CC/PT plant by assuming that the actual-plant annual thermal energy production would be reduced by the ratio of the annual efficiency to the design-point efficiency of the first 100-MWe solar-only plant (APS, 1988). This is a conservative estimate because it assumes all the solar plant outages occur during plant dispatch periods. The results show that the LEC would be increased by about $0.002/kWh (for the higher gas-cost escalation scenario) because of increased gas consumption. This increase is quite small and should not affect the conclusions drawn from those results.

RESULTS

Detailed plant-sizing data, capital cost, operating and maintenance cost, and the levelized energy cost for each plant type investigated are presented in Table 1.

A comparison of the levelized energy costs for the three CC/PT cases and the solar-only plant (Solar 100) are shown in Figure 2. The three CC/PT cases exhibit expected economies of scale, with the energy cost decreasing significantly as size increases. The 31-MWe CC/PT case has a slightly higher LEC than the 100-MWe solar-only plant (Solar 100). The most direct comparison is 0.4 capacity factor, 100-MWe CC/PT plant, and Solar 100. The former has an LEC about one-third less than the latter. The energy cost for the 300-MWe CC/PT, $0.059/kWh, is nearly two-thirds less than that of the Solar 100 case. Although the capacity factor for this large CC/PT plant is 0.85, versus 0.4 for the Solar 100 plant, this case demonstrates the potential for low-cost energy from the CC/PT concept. Even the 100-MWe CC/PT plant at 0.85 capacity factor produces energy at less than $0.07/kWh.

TABLE 1. SIZING, CAPITAL COST, OPERATING AND MAINTENANCE COST, AND ECONOMIC VALUATION FOR EACH PLANT TYPE INVESTIGATED

		PLANT TYPE										
		31-MW hybrid plant	31-MW hybrid plant	31-MW gas-only plant	31-MW gas-only plant	100-MW hybrid plant	100-MW hybrid plant	100-MW gas-only plant	100-MW gas-only plant	300-MW hybrid plant	300-MW gas-only plant	100-MW solar plant
SIZING AND ASSUMPTIONS	**UNITS**											
plant capacity	MWe	31	31	31	31	100	100	100	100	300	300	100
heat rate, net LHV rating	Btu/kWh	6767	6767	6767	6767	6093	6093	6093	6093	6093	6093	8055
capacity factor		0.4	0.85	0.4	0.85	0.4	0.85	0.4	0.85	0.85	0.85	0.4
solar fraction		0.3	0.3	0	0	0.18	0.18	0	0	0.18	0	1
receiver rating	MWth	32	67	0	0	56	119	0	0	356	0	468
storage capacity	MWh	59	215	0	0	104	382	0	0	1145	0	1560
collector area	10^3 m^2	62	132	0	0	110	234	0	0	701	0	883
heat exchangers required		1	1	0	0	2	2	0	0	4	0	0
heliostat unit cost	$/m^2	266	266	-	-	133	133	-	-	133	-	133
heat rate, net LHV effective	Btu/kWh	4737	4737	6767	6767	4996	4996	6093	6093	4996	6093	-
gas consumption	10^12 Btu/yr	0.524	1.114	0.745	1.582	1.745	3.707	2.135	4.537	11.12	13.61	0
CAPITAL COST												
receiver	million $	5	9	0	0	8	14	0	0	32	0	40
storage	million $	3	9	0	0	5	14	0	0	33	0	26
collector	million $	17	35	0	0	15	31	0	0	93	0	113
land	million $	0	0	0	0	0	0	0	0	1	0	4
solar indirects	million $	4	8	0	0	5	9	0	0	23	0	44
heat exchanger	million $	1	1	0	0	1	1	0	0	2	0	0
combined-cycle plant	million $	44	44	44	44	88	88	88	88	195	195	0
SGS/EPGS/BOP	million $	0	0	0	0	0	0	0	0	0	0	85
TOTAL CAPITAL COST	million $	74	106	44	44	122	158	88	88	381	195	312
O&M COST												
solar plant	million $/yr	0.4	0.4	0.0	0.0	0.4	0.4	0.0	0.0	0.5	0.0	5.2
combined cycle plant	million $/yr	4.0	4.0	4.0	4.0	4.9	4.9	4.9	4.9	6.9	6.9	0.0
TOTAL O&M COST	million $/yr	4.4	4.4	4.0	4.0	5.3	5.3	4.9	4.9	7.4	6.9	5.2
ECONOMIC EVALUATION												
levelized energy cost	$/kWh	0.170	0.118	0.140	0.088	0.095	0.069	0.087	0.061	0.059	0.053	0.160
note: all $ are early-1994 dollars												
SGS=steam generator system												
EPGS=electric power generation system												
BOP=balance of plant												

A breakdown of the energy cost into capital, fuel, and operating and maintenance costs is provided in Figure 3 for 100-MWe plants, i.e., a CC/PT plant, a gas-only plant, and Solar 100. Comparing the CC/PT plant to the gas-only plant, the tradeoff between lifetime fuel expense and capital costs of the solar equipment is apparent. In the CC/PT, the additional capital cost from the solar plant has a greater impact on the LEC than the gas-cost reductions. (For a larger CC/PT plant, this tradeoff becomes closer. At 300 MWe, the LEC for the CC/PT plant is only about 6 mil/kWh greater than a gas-only plant; see Figure 6.) The higher energy cost of the Solar 100 case compared to the other two plants is primarily due to the high capital investment costs.

The significant differences in the LEC between the CC/PT and the Solar 100 case are due primarily to the following factors: (1) higher efficiency for converting solar heat into electricity via the combined cycle, (2) lower capital cost per unit capacity for the combined-cycle relative to the Rankine-cycle conversion equipment, and (3) the use of low-cost natural gas for a significant fraction of the energy production. The first factor is the equivalent of reducing the heliostat field size or heliostat unit cost by approximately 25%.

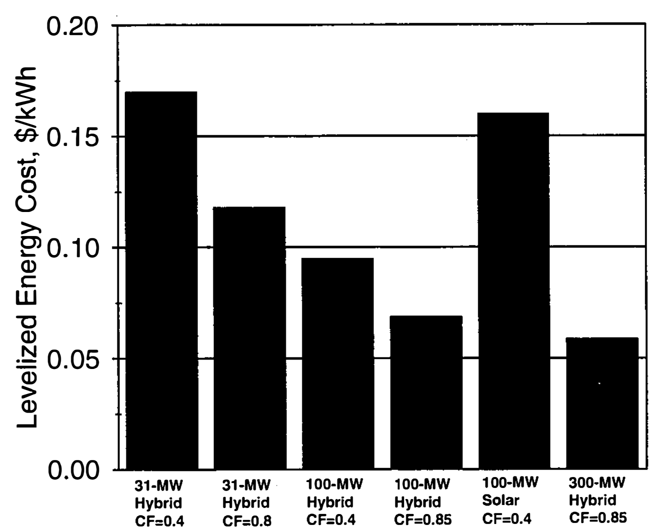

FIG. 2. LEVELIZED ENERGY COST COMPARISONS FOR CC/PT PLANTS AND SOLAR 100

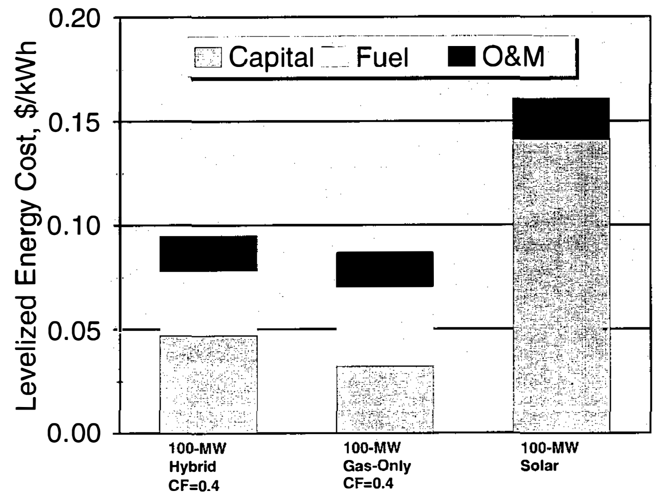

FIG. 3. LEVELIZED ENERGY COST BREAKDOWN FOR 100-MW PLANTS

One may question the relative benefit that derives from the use of natural gas to produce energy. The concern is that the solar technology used in the hybrid plant could be inferior to solar-only plants, but still result in a low LEC through the use of inexpensive natural gas. Although this issue is probably irrelevant from the standpoint of commercial deployment of power tower technology, we propose the following approach for developing first-order technical insights on hybrid versus solar-only plants. For a hybrid plant, the LEC can be broken into solar and fossil components by

$$LEC_{hybrid} = LEC_{solar} \times SF + LEC_{fossil} \times (1\text{-}SF) \quad (1)$$

where:

LEC_{hybrid} levelized cost of electrical energy produced by a hybrid plant

LEC_{solar} = levelized cost of electrical energy produced by the solar energy in a hybrid plant

SF = solar fraction

LEC_{fossil} = levelized cost of electrical energy produced by the fossil energy in a hybrid plant

The LEC of electrical energy produced by the fossil energy, LEC_{fossil}, can be determined by calculating the LEC for an equivalent capacity and capacity factor gas-only plant. We can then solve for the LEC of the solar plant by

$$LEC_{solar} = [LEC_{hybrid} - LEC_{fossil} \times (1 - SF)] \div SF \quad (2)$$

The values for the levelized energy cost from the solar plant, LEC_{solar}, for the CC/PT plants and Solar 100 are shown in Figure 4. The most relevant comparison is the 300-MWe CC/PT case, because the solar plant for that case is nearly as large as that of Solar 100 (356 versus 468 MWth receiver thermal rating). Although the solar plant is smaller for the CC/PT than Solar 100, the LEC_{solar} for the CC/PT in roughly half that of the solar-only case. The 100-MWe CC/PT has a LEC_{solar} just less than that of Solar 100, whereas the small CC/PT is about 50% more expensive than Solar 100. As a point of comparison, the receiver and solar field for the small CC/PT are roughly equivalent in scale to the Solar Two project.

From evaluating the LEC_{solar} results, the solar electricity produced by the CC/PT has the potential to cost much less than that of the Solar 100 plant, even if the solar plant is somewhat smaller. A second conclusion is that the need for large solar fields (~10^6 m^2) to achieve reasonable solar-electric energy costs is much less for the CC/PT than for the Solar 100 design. The 100-MWe CC/PT has potential to achieve a lower LEC_{solar} than Solar 100, although it needs to be scaled up only a factor of two from the Solar Two plant, rather than a factor of 10. Perhaps the most significant result shown in Figure 4 is the solar LEC for the large CC/PT plant, which is $0.086 per kWh. Recall that this is the cost of electricity produced by the solar plant and is for the first commercial plant.

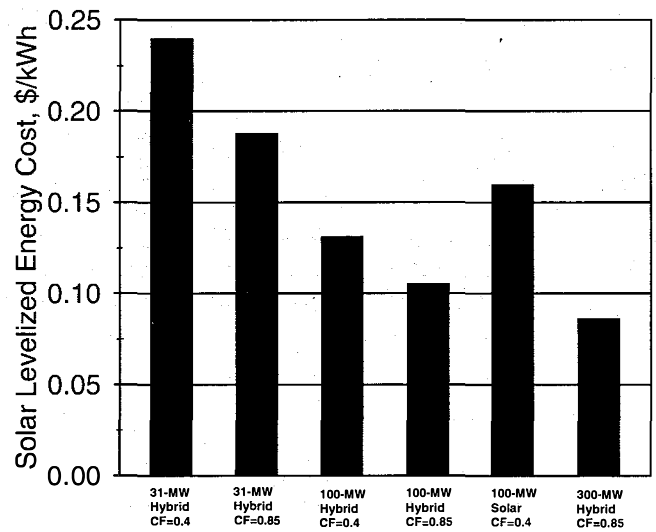

FIG. 4. SOLAR LEVELIZED ENERGY COST FOR CC/PT PLANTS AND SOLAR 100

A comparison of the four hybrid plants with equivalent gas-only combined-cycle plants is shown in Figure 5. This figure shows the cost premium associated with hybridizing a gas-only plant. The gas-only combined-cycle plants are less expensive than the solar plants at any size range. This is expected because these solar plants represent first commercial plants. The 31-MWe CC/PT case (at either capacity factor) has an LEC premium of $0.03/kWh compared to the gas-only case. For the 100-MWe plants, the premium for the CC/PT is $0.008/kWh, whereas the Solar 100 case is about $0.07/kWh more expensive than the 100-MW gas-only (capacity 0.4) plant. For the 300-MWe plants, the CC/PT plant is within a few mil/kWh of the cost of the gas-only plant. For a person considering a gas-only combined-cycle plant, these results show that solar hybridizing via CC/PT is a real option with small cost penalties and low technical risk.

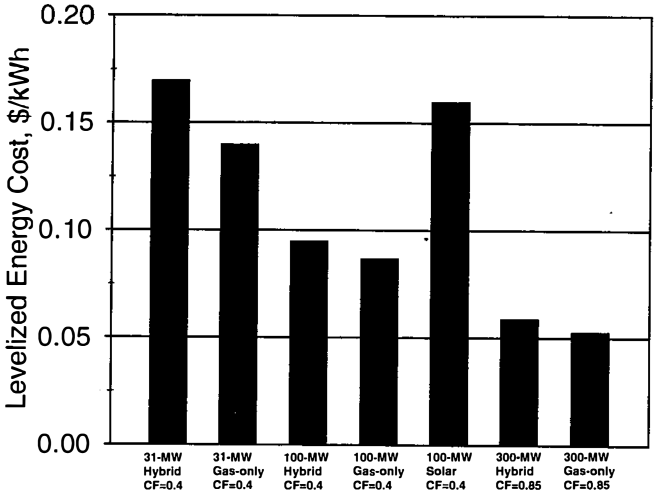

FIG. 5. LEVELIZED ENERGY COST FOR CC/PT PLANTS AND CORRESPONDING GAS-ONLY COMBINED-CYCLE PLANTS

Figure 6 compares the required capital investment against the resulting levelized energy cost for the three CC/PT plants and the first solar-only plant, Solar 100. This figure addresses two important issues regarding commercialization of a new technology. These are the capital investment that must be raised for the first commercial plant under conditions of technical uncertainty, and the resulting product (energy) cost from that investment. Clearly, one would like to reduce financial exposure and at the same time reduce the resulting product cost. CC/PT appears to provide good opportunity to do this.

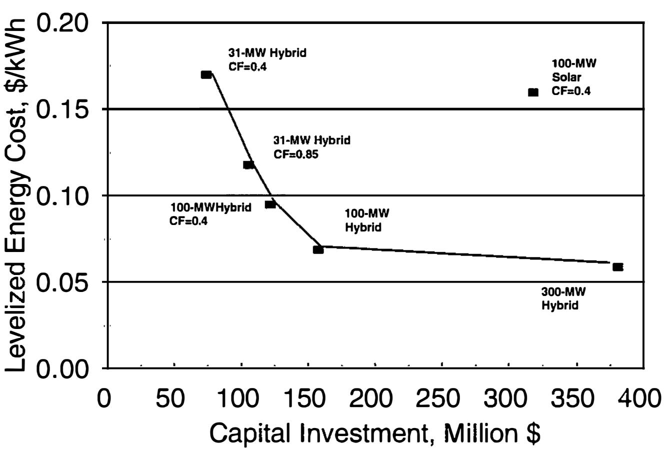

FIG. 6. PLANT INVESTMENT VERSUS RESULTING LEVELIZED ENERGY COST FOR CC/PT PLANTS AND SOLAR 100

The results presented so far have been based on gas-cost projections from the National Energy Strategy. The assumed price of natural gas has a large impact on the cost differential between the solar plants and the gas-only case. To examine this impact, we conducted a sensitivity analysis using a gas-cost curve based on a lower natural gas cost escalation. This escalation curve was based on the current price of delivered gas purchased via a fixed-price 15-year contract—$5 per million BTU. For the second 15 years of a 30-year plant life, we assumed a fixed-price contract would be available at $10 per million BTU. The effect on the 300-MW gas-only plant is a substantial reduction in levelized energy cost, from $0.053 per kWh to $0.039. For the equivalent (300-MW) CC/PT plant, the levelized energy cost is reduced from $0.059 per kWh to $0.048. Because there would be no effect on the solar-only plant, the comparison between the solar-only plant and either the gas-only or the CC/PT plant worsens. The lower gas price reduces the energy cost for the CC/PT plant, although to a lesser degree than for the gas-only case. This could be interpreted to mean that the CC/PT concept has significantly less economic risk relative to a solar-only plant from a downturn in gas prices and relative to the gas-only plant from an upturn in gas prices.

A final sensitivity that was investigated was the impact of heliostat costs on the LEC of the solar plants. The motivation for this evaluation is that heliostat prices are currently uncertain and are a key driver of the overall plant costs. The base value of $125/m^2$ (1990 $) is believed to be a reasonable estimate for early heliostat sales if committed orders for several years production are obtained. This cost was varied parametrically as high as $500/m^2$, which is felt to be a high cost even for prototype heliostats if produced at the volume required for even a single plant. Results of the analysis are shown in Figure 7. Solar 100 exhibits the strong influence of heliostat prices on the economics of the power plant that has been well known for power tower systems. The CC/PT plant is relatively unaffected by changes in heliostat prices, because the life-cycle cost is driven much less by the solar plant.

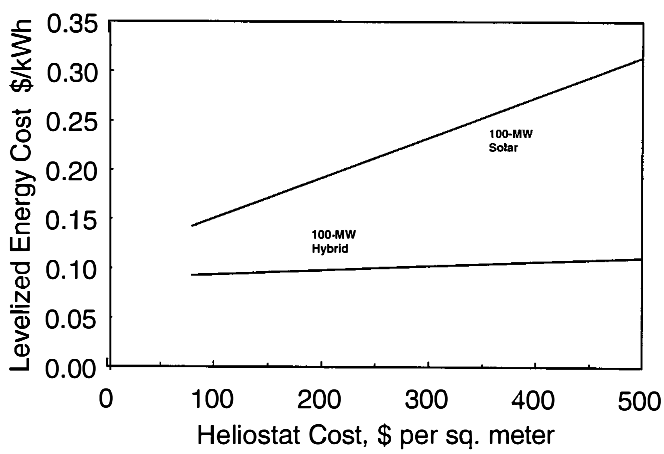

FIG. 7. SENSITIVITY OF LEVELIZED ENERGY COST TO HELIOSTAT COST

Even at the $500/m^2 limits of the analysis, the CC/PT energy cost is substantially below the energy cost of Solar 100 with $125/m^2 heliostats. This could have a significant impact on the commercialization of power tower technology because it could remove the need for low-cost heliostats for first plants.

CONCLUSIONS

The objective of this effort was to investigate a new power tower concept that could offer beneficial commercialization options relative to a solar-only plant. To evaluate whether the CC/PT concept met this objective, we considered the following factors:

Technology Response

In technology commercialization, increased risk translates into increased cost. The primary business uncertainties for power towers are fuel-price risk and future sales risk. Fuel-price risk accounts for the fact that if fossil energy prices decrease, the value of the solar plant also decreases. Future sales risks lump together many concerns to address risks about whether the future market will occur as the industry projects. This is especially important for heliostat costs, where costs are projected to be low if they could be amortized over several years of a stable production volume. Results for the CC/PT concept show that it should be much less affected by a downturn in gas prices than would solar-only plants. Initial plants can be built without stable heliostat markets that are required to ensure low prices. Less sensitivity to solar equipment costs should allow more flexible profit margins and less need to subsidize early plants and recover costs in later sales.

Limited Technical Risk

Overcoming technical risks requires time and money, both of which are scarce resources. Given that molten salt power towers are on a pathway to commercial applications by the end of the century, the value of an alternative commercialization option is reduced if it could not be achieved by nearly the same timeframe. The CC/PT concept is based on solar hardware to be demonstrated at Solar Two. Air/salt heat exchanger preliminary designs have been completed and revealed no significant technical issues. Commercial turbines have been identified that can be used with minimal modifications and that will be available within the Solar Two project-completion timeframe. A development pathway for large turbines is in place that should deliver these machines early in the next century. A large measure of risk reduction results because a CC/PT plant can operate regardless of the condition of the solar plant.

New Markets

The solar-only molten salt power tower concept is best suited for grid-connected applications between 100-200 MWe, with the most economic systems at the larger sizes. Opening potential new markets for deploying the technology should be viewed as a desirable attribute. The CC/PT concept can be applied to smaller applications more economically than solar-only technology, and this should provide more flexibility in placing the first plants. More flexible dispatch than a solar-only plant also opens new market opportunities. CC/PT may appeal to users whose baseline expansion plans are based on gas-only plants, because the extension to CC/PT is relatively simple and risk-free.

Low Energy Costs for First Commercial Plant

Most analyses comparing alternative power tower concepts have been performed with a long-term perspective, assuming mature and stable markets for solar components such as heliostats. In our study, we decided that the most relevant comparison point was for the first commercial plant. Our objective was not deciding the best option for capturing a large long-term market, but rather, identifying configurations that could help initiate commercial sales. The energy cost for a large CC/PT plant is only several mil/kWh higher than for a gas-only plant, even though it is does not use mature solar technology. Large and medium CC/PT plants produce energy at much lower cost than the solar-only plants.

Low Capital Investment in New Technology

Much of the uncertainty with new technology is resolved during the first several commercial plants. Investors generally prefer to resolve this uncertainty with the least amount of money at risk as possible, which is why the first commercial application of new technology is often deployed at smaller scales than would ordinarily be considered economic. Concepts that could be commercially deployed with less total capital investment in new technology were judged to be preferable to those that required higher capital investments. Commercial CC/PT plants are possible with solar plant investments of less than $40 million, compared to more than $300 million for solar-only plants.

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