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Nexant Parabolic Trough Solar Power Plant Systems Analysis

Task 3: Multiple Plants at a Common Location
January 20, 2005 — December 31, 2005

B. Kelly
Nexant, Inc.
San Francisco, California

Subcontract Report
NREL/SR-550-40164
July 2006

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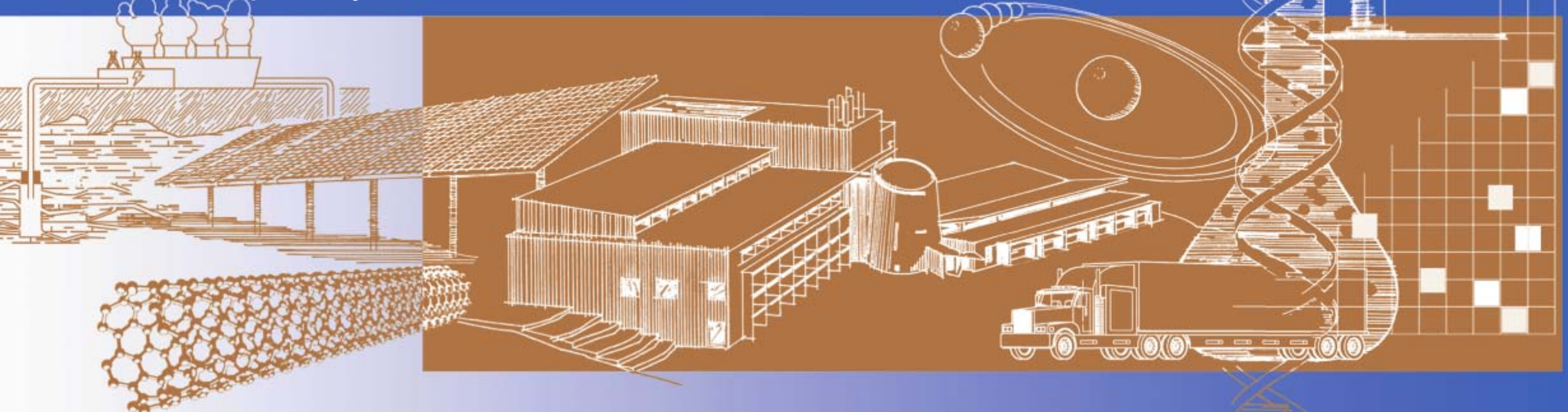

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Task 3
Multiple Plants at a Common Location

1. Introduction

Nine Solar Electric Generating Station (SEGS) parabolic trough solar power plants, ranging in capacity from 13.5 MWe to 89 MWe, are located in the southern California desert. Each of the plants is located adjacent to at least one other plant: SEGS I and II at Daggett; SEGS III through VII at Kramer Junction; and SEGS VIII and IX at Harper Lake. The plants are co-located to take advantage of common site permits, evaporation ponds, access to utility transmission lines, and sharing of the operation and maintenance staff. However, each of the projects was privately financed and constructed separately from the adjoining projects.

In principle, additional benefits could have accrued if the individual plants were owned, financed, installed, and operated under one organization. An analysis was conducted to determine the economic benefits to locating multiple plants at a common site with a common owner. The potential economic advantages included the following:

- Capturing the discounts available from the purchase of larger numbers of mirrors, heat collection elements, drives, structural steel elements, and sensors
- Capturing the discounts available from the multiple purchase of the large Rankine cycle components, including the turbine-generator, condenser, steam generator, and main transformer
- Using the final design engineering, the equipment specifications, and the procurement packages from the first plant on the subsequent plants
- Reducing the permit schedule and expense by applying for, and submitting the environmental impact statement for, all of the plants with the first
- Sharing the operation and maintenance staff and facilities
- Securing a learning curve benefit on the construction labor schedule and hours by retaining one constructor for the series of plants
- Reducing interest during construction expenses due to a reduction in the construction schedule
- Simultaneously financing multiple plants to reduce the debt origination and lenders' fees.

Task 3 is the final task in an overall study, which includes the following tasks: 1) Preferred Plant Size and Capital Cost Estimate; 2) Dry Heat Rejection; and 3) Multiple Plants at a Common Location.

The results from Task 1 are briefly discussed in Section 2 below.

The analyses for Task 3 were conducted as follows:

1) Using the preferred plant identified in Task 1 (Ref. 1), conceptual plant arrangements were developed for the following multiple plant options: a) four collector fields, each delivering thermal energy to a Rankine cycle located at the center of each collector field; and b) four collector fields, each delivering thermal energy to a central site where the four Rankine cycles are co-located.

   The plant arrangements were based on the equipment designs developed during Task 1, and on additional field piping calculations to determine the relative capital costs and parasitic energy demands for the two multiple plant options.

2) Using the capital cost estimate from Task 1 as the baseline, differential capital costs for the two multiple plant options were estimated for each of the elements above. The estimates were based on Bechtel experience with the construction of multiple plants at a common site, historical cost information from the Federal Power Commission, and the experience of Solar Millennium and RW Beck with the design, financing, and construction of multiple plants at a common site.

2. Task 1 Results

As described in the Task 1 report, Preferred Plant Size, the optimum size for a parabolic trough project with thermal storage was determined to be in the range of 200 to 250 MWe. For the purposes of Task 1, a detailed capital cost estimate was developed for a nominal 250 MWe plant with 3 hours of thermal storage. The basic characteristics of the plant were as follows:

Table 1
Nominal 250 MWe Plant Characteristics

Gross plant rating, MWe	265
Net plant capacity, MWe	232
Thermal storage capacity, hours	3
Collector area, m^2	1,960,097
Annual plant output, MWhe	740,980
Capital cost [1], $ 1000	878,600
Operation and maintenance cost, $ 1000	11,780
Levelized cost of energy [2], $/kWhe	0.137

Notes:
1) Overnight construction cost
2) 2008 dollars; first year of plant operation

3. Plant Configurations and Collector Field Arrangements

3.1 One 250 MWe Plant

Using the field piping arrangement of the SEGS VIII / IX plants as a reference, a potential collector field arrangement for a single 250 MWe plant was developed, as illustrated in Figure 1. The power block was located at the center of the collector field, with the heat transport fluid distribution headers arranged in an 'H' pattern. Four East-West headers supplied cold fluid to, and collected hot fluid from, 8 collector field segments. Each segment consisted of 87 loops, each of which contains 6 solar collector assemblies.

The header pipe diameters were selected using an optimization program developed in an earlier study for NREL (Ref. 2). The largest pipe sizes required were the 54 in. cold and hot headers running North and South to and from the power block. One of the four cold headers is labeled as (A) in Figure 1; there was also a similar arrangement of hot return headers (not shown). The East-West headers, labeled as (B) in the figure, were 36 inches in diameter at the center of the field, decreasing to 6 inches in diameter at the edge of the field.

At the design point, the pressure loss through the collector field was 17.4 bar, and the heat transport fluid pump power requirement was 17,400 kWe.

3.2 Four 250 MWe Plants with Separated Power Blocks

Potential arrangements for four 250 MWe with separated power blocks are shown in Figures 2A (East-West configuration) and 2B (North-South). Each of the four plants essentially replicated the 250 MWe plant above. Thus, the header sizes and the collector field pressure loss are also the same. However, the heat transport fluid pump power requirement was four times as high, at 69,700 kWe.

The North-South arrangement may offer some modest economic advantages over the East-West layout; i.e., the perimeter fence should be shorter, and travel times between collector fields may be slightly less. However, for the purposes of the study, the differences were believed to small enough that both configurations offered the same performance and economics.

3.3 Four 250 MWe Plants with Adjacent Power Blocks

An East-West arrangement for four 250 MWe plants with adjacent power blocks is illustrated in Figure 3A, and a North-South arrangement is shown in Figure 3B. The heat transport fluid header lengths and pressure losses for the North-South layout were much lower than the East-West arrangement, and the former was selected for the analysis.

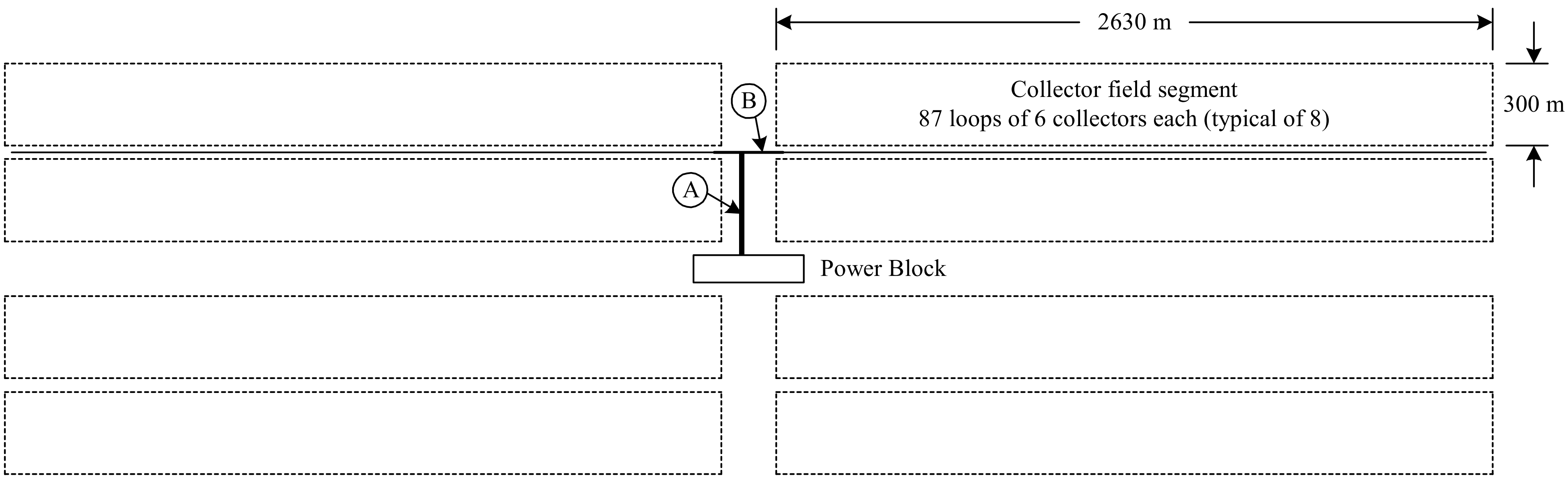

Figure 1 250 MWe Plant Arrangement
Partial Field Piping Shown

Legend:

A) 54 in. cold header to semi-field (typical of 2)
B) 36 in. cold header to quadrant (typical of 4)

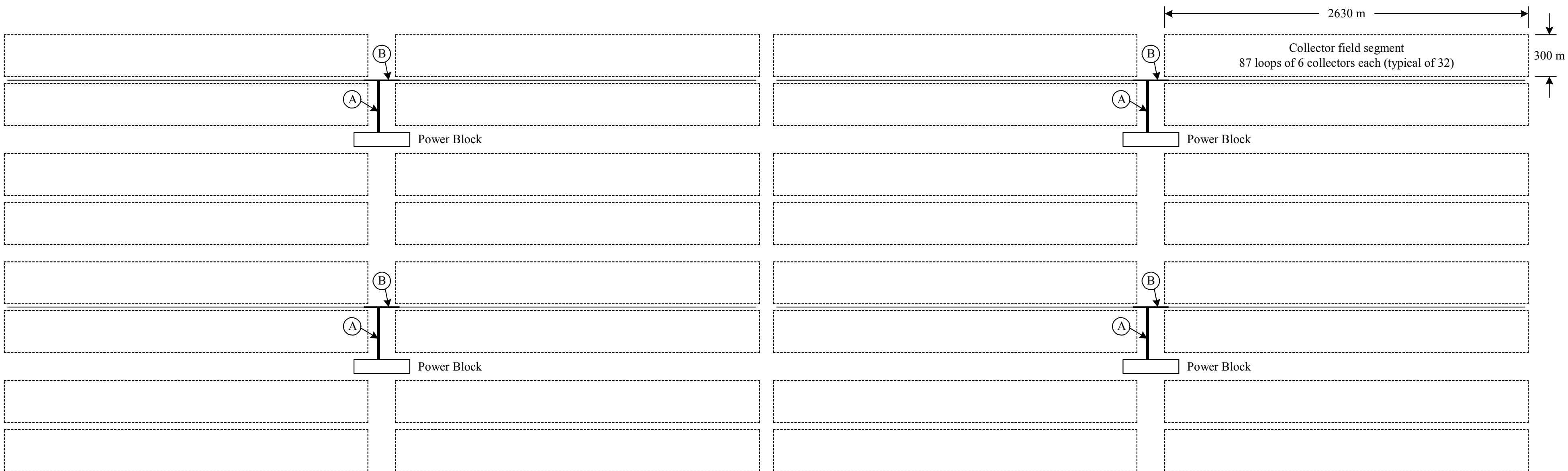

Figure 2A 4 x 250 MWe Plant East-West Arrangement
Separate Power Blocks
Partial Field Piping Shown

Legend:

A) 54 in. cold header to semi-field (typical of 2)
B) 36 in. cold header to quadrant (typical of 4)

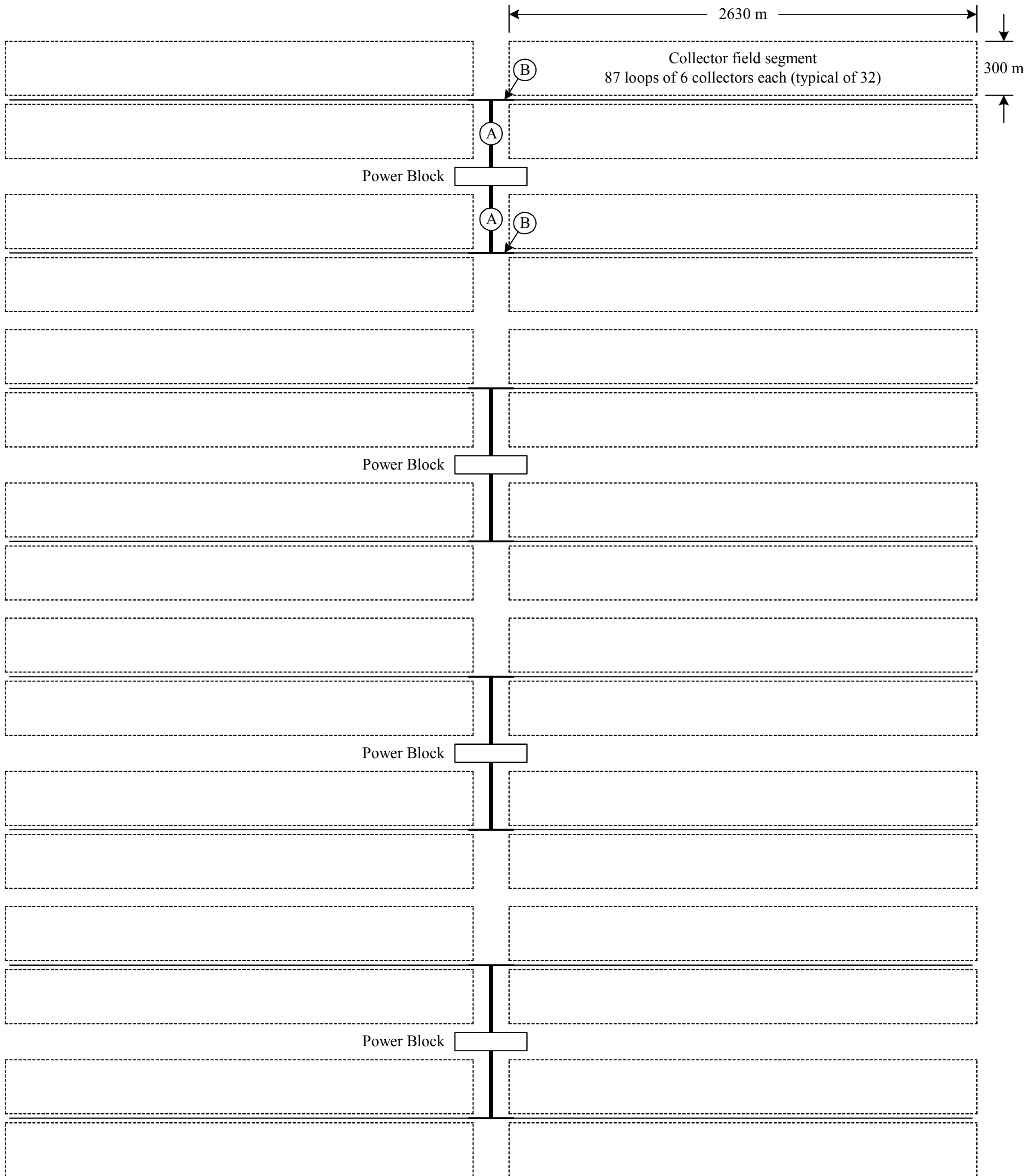

Figure 2B 4 x 250 MWe Plant North-South Arrangement
Separate Power Blocks
Partial Field Piping Shown

Legend:

A) 54 in. cold header to semi-field (typical of 2)
B) 36 in. cold header to quadrant (typical of 4)

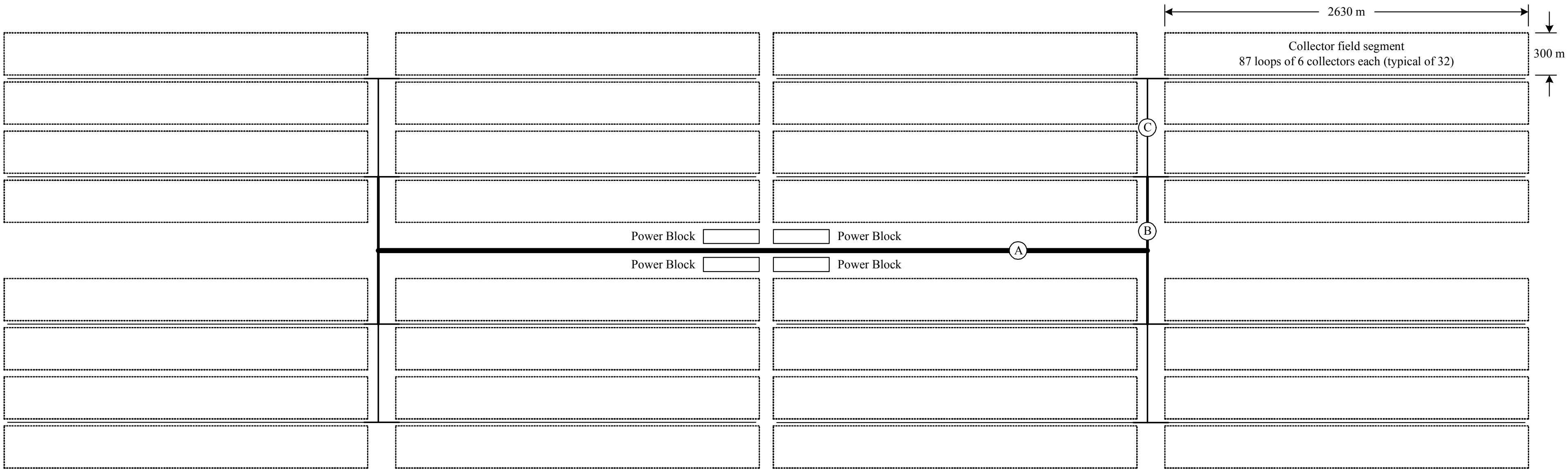

Figure 3A 4 x 250 MWe East-West Plant Arrangement
Adjacent Power Blocks
Partial Field Piping Shown

Legend:

A) 72 in. cold header to 16 segments; 3 required per semi-field
B) 72 in. cold header to 8 segments
C) 60 in. cold header to 4 segments

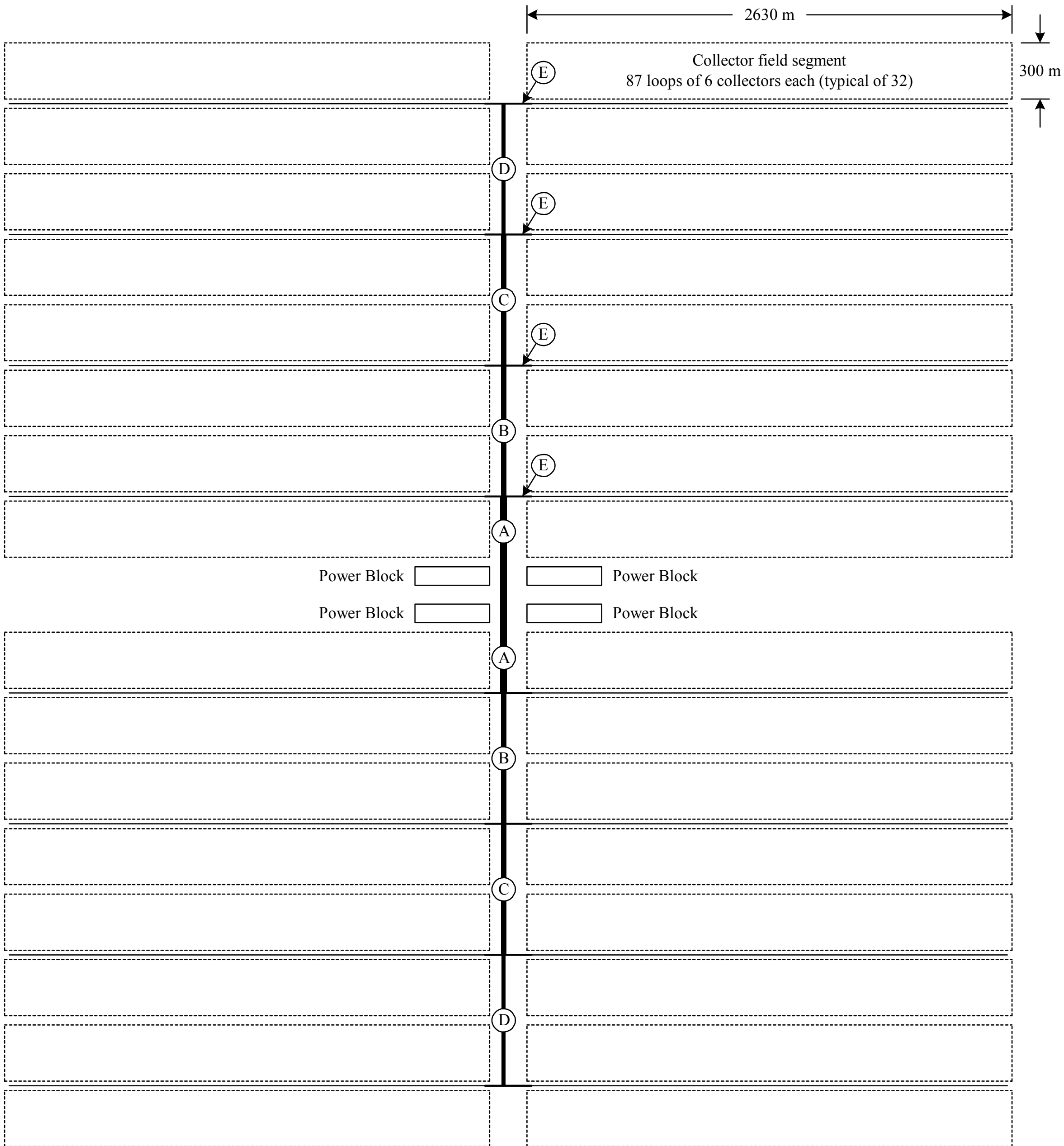

Figure 3B 4 x 250 MWe North-South Plant Arrangement
Adjacent Power Blocks
Partial Field Piping Shown

Legend:
A) 60 in. cold header to 16 segments; 3 required per semi-field
B) 72 in. cold header to 12 segments; 2 required per semi-field
C) 72 in. cold header to 8 segments
D) 60 in. cold header to 4 segments
E) 36 in. cold header to 2 segments

Locating the four Rankine cycles at one location offered the following benefits:

- Plant Availability The default plant availability within Excelergy is 94.0 percent, based on the following: a 10-day scheduled outage every year; an extended 5-week scheduled outage every 10 years (3.5 days per year); and an unscheduled forced outage rate of 2.3 percent (8.4 days per year). For the adjacent plant option, the 4 steam generators can, during the winter months, supply steam to 1, 2, 3, or all of the Rankine cycles. As such, each Rankine cycle can, in series, be removed from service during the winter months for scheduled maintenance without reducing the plant electric output. In principle, it should be possible to eliminate both the 10 day scheduled outage and the 3.5 day extended scheduled outage from the availability calculations. The flexibility in Rankine cycle operation should also allow a reduction in the unscheduled forced outage rate of perhaps 10 percent. With these changes, the plant availability increased by 3.7 percentage points to a new value of 97.9 percent.

- Annual Solar-to-Electric Efficiency The Rankine cycle efficiency, as a function of load, is modeled in Excelergy as follows:

  N_{th} = .Qtpb / Qdesign
  N_{el} = T2EPLF0 + T2EPLF1 * N_{th} + T2EPLF2 * N_{th}^2 + T2EPLF3 * N_{th}^3 + T2EPLF4 * N_{th}^4

  The default values for the coefficients are -0.0377, 1.0062, 0.0763, -0.0448, and 0.0000.

  For the adjacent plant option, it should be possible to isolate one or more Rankine cycles during the winter months. The Rankine cycles which remain in operation then operate at higher loads and at higher thermal-to-electric efficiencies. In the limit, the improved efficiencies can be modeled in Excelergy by selecting coefficients of 0, 1, 0, 0, and 0 for the equation above. Running Excelergy with the latter coefficients increased the net plant output by about 0.36 percent. The modest improvement can be traced to a comparison of N_{el} for the two sets of coefficients. For loads above 40 percent, the two efficiency values were almost identical; only when the load fell below 25 percent was there a marked advantage to isolating a Rankine cycle. Since the annual winter energy delivered with the Rankine cycle operating at loads below 25 percent was rather limited, the annual improvement in energy output was also modest.

- Operation and Maintenance Costs A modest improvement in the efficiency of the operation and maintenance staff should accrue if all of the thermal storage and the Rankine cycle equipment are in one location. An analysis of the potential savings is described in Section 7, Operation and Maintenance Costs.

Compared to the separated power block option, the adjacent plant option required additional field piping headers to distribute the heat transport fluid to the collector loops. The incremental piping, and the associated design point pressure losses, are presented in Table 2. In principle, the primary North-South headers to and from the power blocks could use a 102 inch diameter line for both the cold fluid and the hot fluid. However, the required wall thicknesses would be about 1.5 inches for the cold line, and 1.1 inches for the hot. For pipe sizes of 42 inches and above, the heaviest commercial wall thickness is 1.00 inch. For the purposes of the study, three 60 inch diameter lines for the cold fluid, and two 84 inch diameter lines for the hot fluid, were selected to retain the use of commercial pipe sizes and wall thicknesses.

Table 2
Incremental Field Piping for
Four 250 MWe Plants with Adjacent Power Blocks

Header	Diameter, in.	Total length[1], m	Pressure loss, bar
A) To/From 16 segments[2]			
Cold: 3 required[3]	60	4,500	0.73
Hot: 2 required[3]	84	3,000	0.20
B) To/From 12 segments			
Cold	72	3,000	0.43
Hot	72	3,000	0.48
C) To/From 8 segments			
Cold[4]	54	1,500	0.74
Hot[4]	54	1,500	0.74
D) To/From 4 segments			
Cold[4]	54	1,500	0.21
Hot[4]	54	1,500	0.22

Total			3.45

Notes:
1) Includes an allowance for an expansion loop every 70 m
2) Segments are shown in Figure 3
3) Multiple lines required to limit wall thickness to maximum commercial value of 1.00 in.
4) Incremental pressure loss relative to separated power block option

The design point power requirement for the heat transport fluid pumps was 80,200 kWe, which was about 15 percent higher than the separated power block option.

4. Capital Costs

4.1 One 250 MWe Plant

The estimate developed in Task 1 for the 250 MWe project was an overnight construction cost. The estimate included all of the costs associated with land, vendor equipment, bulk materials, field labor, field supervision, engineering, procurement, construction management, startup, checkout, and contractor fees.

To assemble a complete capital cost, several expenses associated with conducting the project must be added to the overnight cost. The additional expenses included project development costs, working capital, interest during construction, and debt origination fees (Ref. 3, 4, 5, 6, and 7). The major components of the overnight construction cost, together with the development of the project related expenses for the 250 MWe project, are summarized in Table 3.

Table 3
250 MWe Plant Capital Cost Estimate
2005 $1,000

Overnight construction cost	
Total installed material and labor	831,423
Engineering, procurement, and home office	14,662
Construction management and field procurement	5,756
Startup and checkout	2,640
Contractor fee	24,110

Total overnight construction cost	878,590
Project related expenses	
Development costs (5.0 percent)	43,929
Development fees (2.0 percent)	17,572
Owner's general and administrative (2.5 percent)	21,965
Constructor mobilization (1.0 percent)	8,786
Initial spare parts (0.6 percent)	5,272
Owner's contingency (1.5 percent)	13,179
Initial working capital (2.5 percent)	21,965
Interest during construction (2/3 year; 8 percent)	46,858
Lender initiation fee (1.5 percent)	13,179
Lender closing fee (0.5 percent)	4,393
Funded debt reserves (6 month debt service)	12,081

Total project related expenses	209,178
Total capital cost	1,087,768

The project related expenses added approximately 24 percent to the overnight construction costs.

4.2 Multiple Plants at a Common Site

The Federal Power Commission, now the Department of Energy, maintains a database of performance and cost information on power plants constructed in the United States. Data on 175 conventional gas fired, combustion turbine, and combined cycle plants, were reviewed for the study. The plants, constructed between 1950 and 1980, included both single and multiple units at a total of 55 sites in the South and the Southwest.

Of the 55 sites, at least 46 had more than on unit at the same site. After adjusting the costs to a common price level, the unit costs, in $/kWe, for subsequent units were compared with the unit costs for the initial units. The results for 80 plants, in which the subsequent unit was the same capacity as the initial unit, are summarized in Table 4. As shown, the average unit cost for the subsequent units was about 13 percent less than the cost of the initial unit.

The statistics indicate there is a meaningful cost savings to locating multiple plants at a common site. The factors which might contribute to the reduction of costs include the following:

- Procurement of multiple quantities, capturing the discounts available from the purchase of two or more identical components, such as the turbine-generator, condenser, steam generator, and main transformer. Unfortunately, traditional procurement processes of bidding or negotiating a lump sum price for equipment make it impossible to accurately measure the effect of volume purchasing. Nonetheless, an examination of purchase orders for large components indicates that 5 to 10 percent of the order is tied to delivery of certified vendor prints. As such, it would be reasonable to assume that some fraction of this cost could be avoided in the purchase of multiple quantities.

- Reusing the final design engineering, the equipment specifications, and the procurement packages from the first plant on each of the subsequent plants.

Two important qualifications should be placed on the estimated savings of 13 percent for subsequent units. First, details of the capital costs for each plant in the DOE database are not maintained. As such, it is not possible to determine what, if any, pre-investments in the subsequent plant were included with the initial plant. Such pre-investments might include the land for the second plant, soils analyses, geologic studies, site preparation, fences, raw water supplies, operator control room, warehouse facilities, evaporation pond, and grid connections. An intuitive estimate from a Bechtel cost engineer suggests that one-third of the savings in the subsequent plants are due to the pre-investment in the first plant.

Second, the projects listed in Table 3 go back several years. As such, the plants are likely owned and financed by the local utility. This arrangement is somewhat different than today, in which many projects are owned and financed privately, and in which the only source of revenue is energy sales to the local utility. In general, the financial resources of a utility are greater than a private source. Further, a utility may be willing

Table 4
Historical Cost Data on Multiple Plants

Station - Unit	State	Utility	Capacity, MWe	Unit cost, $/kWe	Commercial Operation	Adjusted to 1970 price, $/kWe	Change
Agua Fria 1	AZ	SRP	106	108	57	166	
Agua Fria 2	AZ	SRP	106	88	57	135	-19%
Bertron 1	TX	HLP	165	89	56	146	
Bertron 2	TX	HLP	165	80	58	119	-19%
Bertron 3	TX	HLP	220	80	59	116	
Bertron 4	TX	HLP	220	65	60	93	-20%
Braunig 1	TX	SAPS	225	89	66	111	
Braunig 2	TX	SAPS	255	63	68	71	-36%
Clark 1	TX	HLP	42	61	47	138	
Clark 2	TX	HLP	42	61	47	138	0%
Clark 3	TX	HLP	86	63	50	143	
Clark 4	TX	HLP	86	71	51	147	3%
Coughlin 1	LA	CLE	9	138	48	312	
Coughlin 2	LA	CLE	9	112	48	254	-19%
Greens Bayou 1	TX	HLP	73	77	49	174	
Greens Bayou 2	TX	HLP	73	63	49	143	-18%
Greens Bayou 3	TX	HLP	111	68	53	130	
Greens Bayou 4	TX	HLP	111	68	53	130	0%
Hill 1	TX	CPL	75	96	54	177	
Hill 2	TX	CPL	75	79	56	130	-27%
Jones 1	TX	SPS	244	102	71	96	
Jones 2	TX	SPS	244	111	74	82	-14%
Kyrene CT 1	AZ	SRP	53	103	71	97	
Kyrene CT-2	AZ	SRP	53	103	72	92	-5%
Kyrene CT 3 & 4	AZ	SRP	2x60	93	73	79	
Laredo 1	TX	CPL	35	114	51	236	
Laredo 2	TX	CPL	39	114	55	198	-16%
Lee 1	TX	SWEP	34	91	50	206	
Lee 2	TX	SWEP	34	91	50	206	
Lee 3	TX	SWEP	34	91	52	182	-12%
Leon Creek 1	TX	SAPS	31	103	50	233	
Leon Creek 2	TX	SAPS	32	144	52	288	23%
Lieberman 1	LA	SWEP	26	128	47	290	
Lieberman 2	LA	SWEP	26	89	49	202	-30%
Nichols 1	TX	SWPS	106	133	60	190	
Nichols 2	TX	SWPS	106	117	63	160	-16%
Nine Mile Point 4	LA	LPL	748	76	71	71	
Nine Mile Point 5	LA	LPL	763	63	73	53	-25%
North Texas 1	TX	BEP	20	106	58	157	
North Texas 2	TX	BEP	20	106	58	157	0%
Ocatillo 1	AZ	APS	115	122	60	174	
Ocatillo 2	AZ	APS	115	96	61	136	-22%

Table 4 (Continued)
Historical Cost Data on Multiple Plants

Station - Unit	State	Utility	Capacity, MWe	Unit cost, $/kWe	Commercial Operation	Adjusted to 1970 price, $/kWe	Change
Paint Creek 1	TX	WTU	36	114	53	217	
Paint Creek 2	TX	WTU	36	94	54	174	-20%
Patterson 1	LA	NOPS	40	125	48	283	
Patterson 2	LA	NOPS	40	102	48	231	-18%
Plant x 2	TX	SWPS	103	98	53	187	
Plant x 3	TX	SWPS	106	105	55	183	-2%
Reeves 1	NM	PSNM	50	150	59	217	
Reeves 2	NM	PSNM	51	125	60	179	-18%
Riverside 1	LA	GSU	40	108	49	245	
Riverside 2	LA	GSU	46	108	50	245	0%
Riverside 1	OK	PSO	463	116	74	86	
Riverside 2	OK	PSO	463	114	76	70	-19%
Sabine 1	TX	GSU	230	111	62	153	
Sabine 2	TX	GSU	230	91	62	126	-18%
Saguaro 1	AZ	APS	99	125	54	231	
Saguaro 2	AZ	APS	99	99	55	172	-25%
Saguaro CT1	AZ	APS	53	98	72	87	
Saguaro CT2	AZ	APS	53	106	73	90	3%
Seminole 3	OK	OGE	522	98	75	64	
Seminole 4	OK	OGE	522	98	75	64	0%
Southwestern 1	OK	PSO	80	106	52	212	
Southwestern 2	OK	PSO	80	80	54	148	-30%
Sweatt 1	MS	MPC	46	125	51	259	
Sweatt 2	MS	MPC	46	103	53	196	-24%
Tuttle 2	TX	SAPS	100	87	56	143	
Tuttle 3	TX	SAPS	105	98	61	138	-3%
Watson 1	MS	MPC	81	145	57	223	
Watson 2	MS	MPC	79	120	60	171	-23%
Webster 1	TX	HLP	110	87	54	161	
Webster 2	TX	HLP	110	71	54	131	-18%
Wharton 3	TX	HLP	102	53	74	39	
Wharton 4	TX	HLP	102	53	74	39	0%
Wharton CC3	TX	HLP	317	189	74	140	
Wharton CC4	TX	HLP	329	173	75	113	-19%
Wharton CT2-4	TX	HLP	3x51	129	71	121	
Wharton CT5-7	TX	HLP	3x51	129	72	115	-5%
Wilkes 2	TX	SWEP	360	61	70	61	
Wilkes 3	TX	SWEP	342	61	71	57	-6%
Average							-13%

to commit future funds if the utility believes both the first and the subsequent projects will eventually be incorporated in the utility's rate base. As a result, a utility may be more willing than a private source to commit to the necessary resources in the first project which will yield cost reductions on the subsequent plants. These resources could include the pre-investments noted above, and may also involve vendor purchase orders for two turbine-generators, two cooling towers, and so on.

For the purposes of the study, a net reduction in the capital cost for the second plant was estimated to be two-thirds of the 13 percent savings cited above, or 9 percent. A savings of 9 percent was also consistent with the cost projections developed for the two 50 MWe AndaSol projects, in which the second plant was estimated to be 10 percent less expensive than the first. The savings were derived from the following: vendor purchase orders which included an option for the purchase of identical components on the second project; construction of a switchyard with sufficient capacity for up to 5 projects; incorporating an intentional lag between the two construction schedules which allowed the craft labor to finish the activities on the first project, and then move to the second; and reusing the engineering and procurement documents from the first project on the second.

4.3 Capital Cost of Four 250 MWe Plants with Separated Power Blocks

As shown in Table 1, the overnight construction cost for a 250 MWe plant was estimated to be $878.6 million. Of this total, $831.4 million was the total field cost for installed material and labor, and $47.2 million were the indirect costs for engineering, procurement, construction management, startup, checkout, and contractor fee.

For the purposes of the study, the total field cost for installed material and labor on the second plant was estimated to be 9 percent less than the first, or $756.6 million. However, no further reductions in the total field cost were credited for the third and the fourth projects, based on the following:

- No data were identified for three or more identical plants at a common site to substantiate further cost reductions.

- Most, if not all, of the potential cost reductions due to pre-investment or multiple purchase orders were likely have been achieved with the second project.

- The third and fourth plants in a series will start construction at least 2, and perhaps as much as 4 years, after the first. As such, the benefits to be achieved in 2 to 4 years from an investment today may be more than offset by potential changes in regulatory requirements, transmission line access, interest charges on committed funds, and changes in equipment designs and pricing. The last item is of particular relevance for solar facilities, as design improvements and cost reductions are likely to take place in the trough structure, the heat collection elements, the mirrors, and the heat transport fluid. For example, committing a future project to an indirect thermal storage system when the industry may, in the long run, be switching to an inorganic heat transport fluid could be counterproductive.

The indirect costs for the second, third, and fourth plants were estimated to be 8 percent less than of the costs for the first, based on the following:

- Much of the engineering and procurement documentation from the first plant could be used on the subsequent projects, reducing the costs by 25 percent.

- The remaining indirect costs for construction management, field procurement, startup, checkout, and contractor fee involved primarily field labor, with a minimum of documentation. As such, discounts on the second and subsequent plants were believed to be, at most, minor.

The anticipated progression in the overall plant expenditure is shown in Table 5.

As with the direct and the indirect costs, some of the project related expenses were also expected to decrease for the second, third, and fourth plants. For example, the project development costs could decrease by as much as 75 percent if the land, the power purchase agreement, and the land use permits for the first plant were applicable to the subsequent plants. Similarly, mobilization costs could decline by 50 percent if the same constructor was used for all of the projects. However, discounts on the lenders fees were not anticipated for the subsequent projects, as discussed below in Section 6.

For the single 250 MWe plant, the project related expenses added approximately 24 percent to the overnight construction costs. For the four 250 MWe plants, the average of the related expenses decreased to 20 percent of the overnight costs.

4.4 Four 250 MWe Plants with Adjacent Power Blocks

With adjacent power blocks, the additional collector field piping listed in Table 2 was required. Based on the unit costs in the piping optimization model, the total field cost for the incremental piping was estimated to be $75 million. To this was added an incremental cost of $7 million for the additional heat transport fluid pump capacity of 10,600 kWe. The economic effect of the additional piping and the heat transport pump capacity was fairly significant, representing an increase in the collector field piping cost of about 35 percent, and an increase in the unit plant cost of $88/kWe.

As shown in Figure 3, the incremental field piping was sufficiently segregated that only those headers associated with each 250 MWe collector field needed to be installed with each collector field. Thus, the incremental costs were distributed over the four plants. The anticipated progression in the overall plant expenditure is shown in Table 6.

As with the four plant option above, the average of the related expenses decreased to 20 percent of the overnight costs.

Table 5
Progression of Overnight Construction Costs
4 x 250 MWe Plants with Separated Power Blocks; 2005 $1,000

Overnight construction cost	Plant 1	Plant 2	Plant 3	Plant 4
Total installed material and labor	831,423	756,595	756,595	756,595
Engineering, procurement, and home office	14,662	13,562	13,562	13,562
Construction management and field procurement	5,756	5,324	5,324	5,324
Startup and checkout	2,640	2,442	2,442	2,442
Contractor fee	24,110	21,950	21,950	21,950
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Total overnight construction cost	878,590	799,872	799,872	799,872
Project related expenses				
Development costs (5.0 / 1.25 / 1.25 / 1.25 percent)	43,929	9,998	9,998	9,998
Development fees (2.0 percent)	17,572	15,997	15,997	15,997
Owner's general and administrative (2.5 / 2.0 / 2.0 / 2.0 percent)	21,965	15,997	15,997	15,997
Constructor mobilization (1.0 / 0.5 / 0.5 / 0.5 percent)	8,786	3,999	3,999	3,999
Initial spare parts (0.6 percent)	5,272	4,799	4,799	4,799
Owner's contingency (1.5 percent)	13,179	11,998	11,998	11,998
Initial working capital (2.5 percent)	21,965	19,997	19,997	19,997
Interest during construction (2/3 year; 8 percent)	46,858	42,660	42,660	42,660
Lender initiation fee (1.5 percent)	13,179	11,998	11,998	11,998
Lender closing fee (0.5 percent)	4,393	3,999	3,999	3,999
Funded debt reserves (6 month debt service)	12,081	10,998	10,998	10,998
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Total project related expenses	209,178	152,442	152,442	152,442
Total capital cost	1,087,768	952,315	952,315	952,315

Table 6
Progression of Overnight Construction Costs
4 x 250 MWe Plants with Adjacent Power Blocks; 2005 $1,000

Overnight construction cost	Plant 1	Plant 2	Plant 3	Plant 4
Total installed material and labor	875,812	800,984	800,984	800,984
Engineering, procurement, and home office	14,662	13,562	13,562	13,562
Construction management and field procurement	5,756	5,324	5,324	5,324
Startup and checkout	2,640	2,442	2,442	2,442
Contractor fee	25,362	23,202	23,202	23,202
	----------	----------	----------	----------
Total overnight construction cost	924,232	845,515	845,515	845,515
Project related expenses				
Development costs (5.0 / 1.25 / 1.25 / 1.25 percent)	46,212	10,569	10,569	10,569
Development fees (2.0 percent)	18,485	16,910	16,910	16,910
Owner's general and administrative (2.5 / 2.0 / 2.0 / 2.0 percent)	23,106	16,910	16,910	16,910
Constructor mobilization (1.0 / 0.5 / 0.5 / 0.5 percent)	9,242	4,228	4,228	4,228
Initial spare parts (0.6 percent)	5,545	5,073	5,073	5,073
Owner's contingency (1.5 percent)	13,863	12,683	12,683	12,683
Initial working capital (2.5 percent)	23,106	21,138	21,138	21,138
Interest during construction (2/3 year; 8 percent)	49,292	45,094	45,094	45,094
Lender initiation fee (1.5 percent)	13,863	12,683	12,683	12,683
Lender closing fee (0.5 percent)	4,621	4,228	4,228	4,228
Funded debt reserves (6 month debt service)	12,708	11,626	11,626	11,626
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Total project related expenses	220,044	161,141	161,141	161,141
Total capital cost	1,144,276	1,006,656	1,006,656	1,006,656

5. Construction Schedule

In principle, a learning curve benefit on the construction labor schedule and craft hours can be achieved if one constructor is used on a series of two or more plants. In practice, not all of the theoretical benefits are often realized. If the subsequent unit is constructed at the same time as, or shortly after, the first, some of the learning curve benefits are offset by efficiency losses arising out of the execution of a larger project. The efficiency losses include the need for additional coordination and supervision, and an increased requirement for skilled labor. The timing of the project in relation to other work in the area is important. If there are other projects under construction at the same time, the increase in demand for craft labor will raise the prevailing wage rates, and eliminate some of the potential savings. Similarly, if the additional unit is completed some period of time after the initial project, there are likely no learning curve benefits, as perhaps a different constructor, and certainly a different labor pool, would be used.

For the purposes of the study, the construction schedule on the second, third, and fourth plants should be somewhat shorter than the first plant. However, the shorter schedules were not believed to provide a measurable reduction in the construction cost.

6. Project Financing

In principle, simultaneously financing multiple plants should allow a reduction in the debt origination and closing costs. Some of the savings can be derived by distributing the bank costs over a larger debt quantity, and by avoiding the due diligence activities on replicated plants. However, in practice, each plant is likely to be financed separately, and a reduction in fees probably will not occur. The reasons are as follows:

- It is anticipated that a different group of banks will provide the debt financing for each project. Each bank defines its limit to exposure in any particular area, including solar projects, and the limits are likely to be low enough that an individual bank will not be in a position to provide funds to more than one or two projects.

- Parabolic trough technology is not yet fully mature, and the number of banks interested in financing a developing industry is limited. As such, it is not necessary for the interested banks to discount their fees to attract those in search of solar project financing.

For the purposes of the study, the baseline bank fee structure used in the New Mexico Concentrating Solar Plant Feasibility Study (Ref. 6) was adopted for each of the four plants in the series.

7. Operation and Maintenance Costs

Operation and maintenance cost estimates were developed using a spreadsheet model prepared by NREL, with minor modification developed by Nexant for the larger plant sizes in Task 3. The NREL model was based on detailed assessments of the operating expenses at the SEGS III through VII plants at Kramer Junction. The NREL costs were extrapolated to the larger plant sizes based on the following approach:

- Administration costs were largely independent of the capacity of the plant, and were weakly dependent on the number of plants at a site.

- Solar field operating and maintenance costs were essentially proportional to the size of the collector field.

- Rankine cycle operating costs were essentially proportional to the number of the number of cycles, and varied with the power rating based on exponents ranging from 0.5 to 0.7.

For the study, operation and maintenance estimates were developed for 4 cases, as follows:

1) SEGS III through VII, as a point of reference

2) The baseline 250 MWe plant

3) A 940 MWe (net) plant, with four separated 250 MWe power blocks

4) A 940 MWe (net) plant, with four adjacent 250 MWe power blocks.

The results are summarized in Table 7.

As might be expected, Case 1 had the highest unit costs, in both $/kWe-year and $/m^2-year. The results can be traced to the operating complexities associated with 5 Rankine cycles, and the corresponding high staffing requirement of 0.78 personnel per MWe.

The operating costs for Case 2 were about one-third lower than Case 1. Most of the benefit was derived from the smaller staff needed to operate and maintain one, as opposed to five, Rankine cycles. A review of the remaining data showed most of the balance in the operating costs were essentially proportional to the collector field area.

The unit operating costs for Case 3 were about 20 percent lower than for Case 2. Although Case 3 had four Rankine cycles, as opposed to one for Case 2, the ability to distribute the Administration and the Power Plant Maintenance costs over 940 MWe, rather than 235 MWe, was the principal source of the savings.

Table 7
Operation and Maintenance Cost Estimates

Case	1	2	3	4
Capacity at site, MWe	150	235	940	940
Capacity per plant, MWe	30	235	235	235
Plants at site	5	1	4	4
Total solar field size, m^2	1,094,000	1,962,000	7,849,000	7,849,000
Staff				
Administration	18	12	16	16
Solar Field Maintenance	19	32	120	108
Solar Field Operations	12	22	86	77
Power Plant Operations	48	11	39	32
Power Plant Maintenance	20	14	26	23
	------	------	------	------
Total	117	90	287	257
Staff / MWe	0.78	0.38	0.31	0.27
Annual Costs, $ 1,000				
Administration	1,430	1,030	1,350	1,350
Solar Field Maintenance	1,470	2,400	8,900	8,060
Solar Field Operations	790	1,420	5,690	5,120
Power Plant Operations	3,590	850	2,920	2,390
Power Plant Maintenance	1,570	1,130	2,050	1,820
Service Contracts	280	330	580	550
Water Treatment	170	310	1,230	1,210
Power Block Spare Parts	1,040	720	2,870	2,870
Solar Field Spare Parts	1,410	2,540	10,140	10,140
Miscellaneous	550	750	1,970	1,870
Capital Equipment	220	300	600	570
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Total	12,520	11,780	38,300	35,950
Unit Costs				
$ / kWe-yr	83	50	41	38
$ / m^2-yr	11,400	6,000	4,900	4,600

The unit operating costs for Case 4 were about 6 percent lower than for Case 3. The savings were derived in the following areas:

1) The labor efficiency for the solar field maintenance staff, excluding the manager and the foreman, and the solar field operations staff were both estimated to improve by 10 percent. The improvements were derived by sharing warehouse and maintenance facilities, and by using a smaller contingency in the number of maintenance workers required to handle the peak, as opposed to the average, work load in the collector fields.

2) The power plants operations staff was reduced by 8 percent by sharing the senior operators, the control room operators, and the plant equipment operators among the plants, and by locating the control operations for the four plants in one location. The number of staff for operations manager, assistant operations manager, and chemical technician remained unchanged.

3) The power plants maintenance staff was reduced by 8 percent by sharing the mechanics, the HTF mechanics, and the mechanics helpers among the plants, and by locating the warehouse and the maintenance facilities in one location. The number of staff for maintenance manager, plant maintenance foreman, electricians, instrumentation and control technicians, HTF mechanics helpers, machinist/welder, warehouse clerk, and vehicle mechanic remained unchanged.

4) The annual expenses for plant service contracts, capital equipment for solar field maintenance, and miscellaneous expenses were each estimated to decrease by 5 percent due to the improvements in labor productivities noted above. The water treatment costs were also estimated to decrease by 5 percent due the higher annual thermal-to-electric conversion efficiencies for the Rankine cycles. However, as discussed in Section 3.3, the increase in the plant availability of 3.7 percent raised the annual output by a like amount, which resulted in a net reduction in the water treatment cost of about 1 percent.

8. Levelized Energy Costs

Levelized energy costs were calculated to determine the economic benefits to multiples plants at a common site. The calculations were based on the following:

- For a Barstow location, the 4 x 250 MWe plant with the separated power blocks had a net annual electric energy production of 2,963,900 MWhe. The plant arrangement with adjacent power blocks incurred a penalty of about 15 percent in the annual energy required for the heat transport fluid pumps, which increased the overall parasitic energy demand by 4 percent. However, the improvements in the plant availability and the winter thermal-to-electric conversion efficiencies resulted in net energy production increase of about 4.5 percent, to a new value of 3,098,500 MWhe.
- From the Excelergy analyses in Task 1, a nominal fixed charge rate of 10.25 percent was calculated, based the default financial parameters, and on an optimum debt fraction and equity fraction of 0.60 and 0.40, respectively.
- For the purposes of Task 3, levelized energy costs were calculated based on the following simplified approach:

$$\textit{Levelized energy cost, \$/kWhe} = \frac{\textit{(Fixed charge rate)(Capital cost)} + \textit{(Operation and maintenance cost)}}{\textit{Annual energy production, kWhe}}$$

The results of the calculations are presented in Table 8.

Table 8
Levelized Energy Costs

	1 x 250 MWe	4 x 250 MWe plant Separated power blocks	4 x 250 MWe plant Adjacent power blocks
Equivalent annual capital cost, $1,000	111,496	404,333	413,900
Annual operation and maintenance cost, $1,000	11,780	38,300	35,950
Annual energy production, MWhe	740,980	2,963,920	3,098,532
Levelized energy cost, $/kWhe	0.166	0.149	0.145
Savings due to multiple plants, percent	Base	-10.2%	-12.7%

Replicating the 250 MWe plant, and keeping the power block at the center of each respective collector field, yielded a nominal 10 percent reduction in the levelized energy cost. Locating the power blocks at a common location offered an additional 2.5 percent reduction in the energy cost.

9. Summary

In principle, installing multiple plants at a common site should offer a reduction in the levelized energy cost of 10 to 12 percent. In this study, the savings were allocated approximately as follows:

- 55 percent to the purchase of greater quantities of equipment and bulk materials
- 1 percent to the reuse of the final design and procurement documents
- 25 percent to the reuse of one organization for project development, and one organization for project construction
- 20 percent to the sharing of the operation and maintenance staff among the plants.

It should be noted the potential for savings is not automatic. If the full benefits are to be realized, one organization must assume the responsibility for maintaining the same equipment vendors and the same contractors throughout the projects. Further, the equipment designs must be sufficiently mature that the benefits to replicating the design are at least as great as switching to an improved approach.

10. References

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