Appendix D

Evaluation of Technology Improvements and Capital Cost Projections for Parabolic Trough Solar Plants

D. EVALUATION OF TECHNOLOGY IMPROVEMENTS AND CAPITAL COST PROJECTIONS FOR PARABOLIC TROUGH SOLAR PLANTS

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D.1 COST DRIVERS

The direct costs of a parabolic solar plant can be summarized into the following five major categories:

- Siteworks and Infrastructure
- Solar Field
  - Heat Collection Element (HCE)
  - Mirror
  - Support Structure
  - Drive
  - Piping
  - Civil Work
- Power Block
  - Steam Turbine and Generator
  - Electric Auxiliaries
  - Thermal Storage/Heat Transfer Fluid System
  - Balance of Plant (BOP)
- Cooling System
- Water treatment
- Electrical
- Instrumentation & control
- Miscellaneous Civil Work

The Solar Field, Thermal Storage and Power Block costs encompass approximately 95% of the total direct costs, as illustrated in Figure D-1. Of these three highest cost categories, the Solar Field cost comprises 58% of the total direct cost. Figure D-2 shows the solar field component cost breakdown. The component cost breakdown of the Solar Field reveals the Support Structures are 29%, the Heat Collection Elements (HCE) 19%, and the Mirrors 18% of the Solar Field direct costs, for a total of 68% of the Solar Field direct costs.

Figure D-1 — Major Cost Categories for Parabolic Trough Plant 2004 Near-Term Case: 100 MWe, 12 hrs TES, 2.5 Solar Multiple

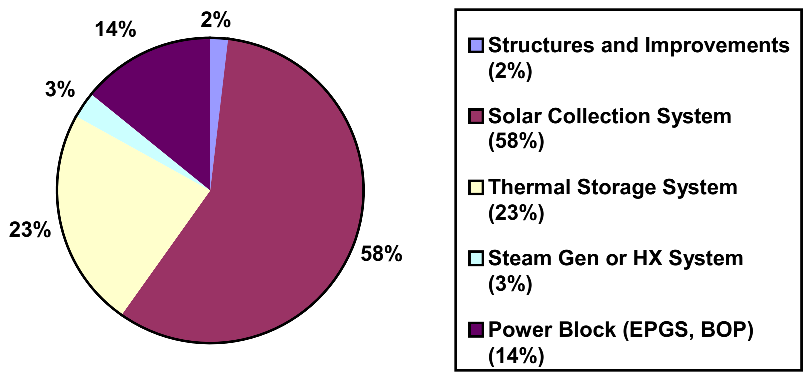
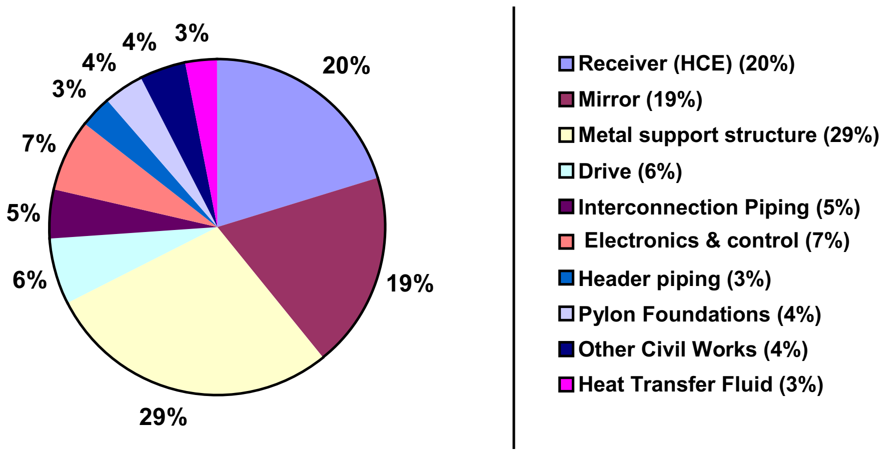


Figure D-2 — Solar Field Component Cost Breakdown for Parabolic Trough Plant 2004 Near-Term Case: 100 MWe, 12 hrs TES, 2.5 Solar Multiple



The evaluation of cost reductions for a parabolic trough plant focuses on the solar field, power block, and thermal storage since these three areas account for approximately 90% of the total direct costs (based on 12 hours of thermal storage). As pointed out previously and illustrated in Figure D-2, the support structures are 29%, the HCE 19%, and the mirrors 18% of the solar field direct costs; 68% of the total solar field direct cost. As such, the following main items were focused on for evaluation of cost reductions:

- Net annual solar-to-electric efficiency
- Solar field
  - — Support structure

   - HCE
   - Mirrors
- Power block
- Thermal storage

The following major potential cost reductions were considered:

- Technology improvements
- Scale-up (economy of scale)
- Production volume

Table D-1 provides a summary of SunLab's design, deployment, and cost projections for trough plants with the SEGS VI plant as the base case.

Table D-1 — SunLab Cost Projections

	SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
	1999	**2004**	**2007**	**2010**	**2015**	**2020**
Plant size, net electric, MWe	30	100	100	150	200	400
Plant size, gross thermal input, MWt	88	294	279	408	544	1,087
Thermal Storage, hr	0	12	12	12	12	12
Annual Plant Capacity Factor	22.2%	53.5%	56.2%	56.2%	56.2%	56.5%
Annual Solar-to-Electric Efficiency	10.6%	14.2%	16.1%	17.0%	17.1%	17.2%
Solar Field Design:						
Number of Collectors	800	4,768	1,269	1,808	2,392	4,783
Receivers per SCA	12	12	36	36	36	36
Number HCE	9,600	57,216	45,700	65,072	86,101	172,201
Number HCE Accumulative	9,600	66,816	112,516	177,588	263,688	435,889
Collector Size, m^2	235	235	817.5	817.5	817.5	817.5
Field Aperture Area, m^2	188,000	1,120,480	1,037,760	1,477,680	1,955,200	3,910,400

	SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
	1999	**2004**	**2007**	**2010**	**2015**	**2020**
Heat Transfer Fluid System						
HTF Type	VP-1	VP-1	Hitec XL	Hitec XL	Hitec XL	Hitec XL
Fluid Volume, gallons	115,500	688,380	637,560	907,830	1,201,200	2,402,400
Direct Capital Cost:						
Structures & Improvements	2,526	7,279	6,538	8,097	9,596	16,284
Collector System	44,793	249,654	181,533	226,753	259,852	452,825
Thermal Storage System	0	95,807	42,475	57,426	76,567	153,135
Steam Gen or HX System	4,304	9,964	9,227	11,161	12,772	19,394
EPGS	15,805	36,713	34,877	44,008	51,134	78,915
Balance of Plant	9,190	21,346	20,279	25,588	29,732	45,884
Total Direct Costs	76,619	420,763	294,929	373,033	439,654	766,438
Solar Collection System, $/m^2 field	250	234	184	161	140	122
Receivers, $/m^2 field $/unit	43 847	43 847	34 762	28 635	22 508	18 400
Mirrors, $/m^2 field	40	40	36	28	20	16
Concentrator Structure, $/m^2 field	50	47	44	42	39	36
Concentrator Erection, $/m^2 field	17	14	13	12	11	10
Drive, $/m^2 field	14	13	6	6	6	5
Interconnection Piping, $/m^2 field	11	10	3	3	3	2
Electronics & control, $/m^2 field	16	14	4	4	4	3
Header piping, $/m^2 field	8	7	7	6	6	5
Foundations/Other Civil, $/m^2 field	21	18	17	15	14	12

	SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
	1999	2004	2007	2010	2015	2020
Other (Spares, HTF, freight), $/m^2 field	17	17	11	10	9	8
Contingency, $/m^2 field	12	11	9	8	7	6
Direct Capital Cost, $/kWe						
Structures and Improvements, $/kWe	84	73	65	54	48	41
Solar Collection System, $/kWe	1,493	2,497	1,815	1,512	1,299	1,132
Thermal Storage System, $/kWe	0	958	425	383	383	383
Steam Generator or HX System, $/kWe	143	100	92	74	64	48
EPGS, $/kWe	527	367	349	293	256	197
Balance of Plant, $/kWe	306	213	203	171	149	115
Total Direct Cost, $/kWe	2,554	4,208	2,949	2,487	2,198	1,916

In a series of evolutionary design improvements, the following major advancements formed the basis of the SunLab estimates:

- Collector
  - A comprehensive series of wind tunnel tests on parabolic trough collector models was carried out in 2001–2002, establishing design pressure force coefficients for various wind approach angles and collector orientations, with and without a wind fence.
  - Using these coefficients, finite element methods stress analyses were used to optimize the collector structure for wind survival conditions, minimizing collector weight and defining design parameters for mirror strength, pylons, and foundations. With more tightly known design parameters, collector weight, and thus costs, can be lowered.
  - High efficiency and durable receivers are assumed to be developed, with selective surfaces (consisting of special selective coatings on the metal tube receivers) to maximize the absorption of incident solar radiation and minimize radiation losses from the receiver. High efficiencies result in smaller solar fields for a given thermal energy delivery, and longer lifetimes to reduce operation and maintenance costs.
  - Advanced receivers are assumed utilizing selective surfaces that can operate efficiently at temperatures of 500°C or higher, paving the way for major advancements in thermal storage and power block operation for trough plants.

  - Alternative mirror design development using thin-glass with non-metallic structural elements, or using thin silverized films is assumed. Both approaches reduce weight and offer less expensive reflector options.

- Heat transfer fluid (HTF)
  - Alternate HTFs, such as inorganic molten salts and ionic fluids, are being investigated that will permit operation at higher temperatures (at or above 500°C), leading to lower thermal storage costs and higher power block efficiencies.

- Thermal Storage System
  - The Solar Two two-tank molten salt storage system is designed for commercial operation in a trough plant for the case of the conventional synthetic oil HTF. Termed an indirect storage system, this also requires an oil-to-salt heat exchanger in the system.
  - This same two-tank molten salt storage system is designed for direct operation with a molten salt HTF.
  - A single-tank direct molten salt thermocline system is designed to reduce thermal storage costs.

- Electric Power Block
  - The efficiency of a SEGS-type plant is improved by refining the integration of the solar field with the power block.
  - Turbine efficiencies are improved through use of the higher temperature heat transfer fluids in the solar field.

D.2 DEPLOYMENT

The inherent capital-intensive nature of the technology and the current high costs and early mass-production hurdles are disadvantages for the trough technology. While the trough technology was commercialized for a brief period, no trough plants have been built in nearly a decade. Trough solar plants are a proven technology and 354 MW of trough technology generation at the SEGS plants have and are still being operated commercially.

Deployment is a key element in the cost reductions as it impacts the component production volume. Table D-2 below shows a case of two scenarios set forth by SunLab that could be realistically representative of how systems would be deployed commercially if a market existed considering the potential trough deployment presented in Table D-3. The first assumes one plant built per year. The second assumes a doubling of cumulative installed capacity with each new technology case introduced. This second case is an aggressive development scenario; however, if the projects were financially competitive, this represents a plausible development scenario. The second case is the type of scale-up that Luz envisioned and actually achieved with the SEGS plants to some degree, building multiple plants in the same year. The SunLab projections are based on the Case 2 deployment scenario. S&L estimates are based on the Case 1 deployment scenario.

Table D-2 — Trough Deployment Scenarios

	Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Installed (MWe)	Cumulative (MWe)
Technology Cases		X			X			X					X					X		
Case 1 Deployment Scenario: One Plant per Year Deployment																				
2004 Technology	100 MW	1	1	1															300	650
2007 Technology	100 MW				1	1	1												300	950
2010 Technology	150 MW							1	1	1	1	1							750	1,700
2015 Technology	200 MW												1	1	1	1	1		1,000	2,700
2020 Technology	400 MW																	1	400	3,100
Total																			**2,750**	
Case 2 Deployment Scenario: Cumulative Capacity Doubled with Each New Technology Case																				
2004 Technology	100 MW	1	1	1															300	650
2007 Technology	100 MW				1	2	2	1											600	1,250
2010 Technology	150 MW							1	1	2	2	2							1,200	2,450
2015 Technology	200 MW												1	2	2	3	3	1	2,400	4,850
2020 Technology	400 MW																	1	400	5,250
Total																			**4,900**	

Approximate estimates of CSP deployment have been identified in several reports (Morse 2000). Based on the projections presented in those reports, a potential trough deployment is presented in Table D-3. The potential trough deployment estimates are significantly greater than the two deployment scenarios investigated; thus, cost reductions would be greater if the potential deployment estimate proves to be accurate.

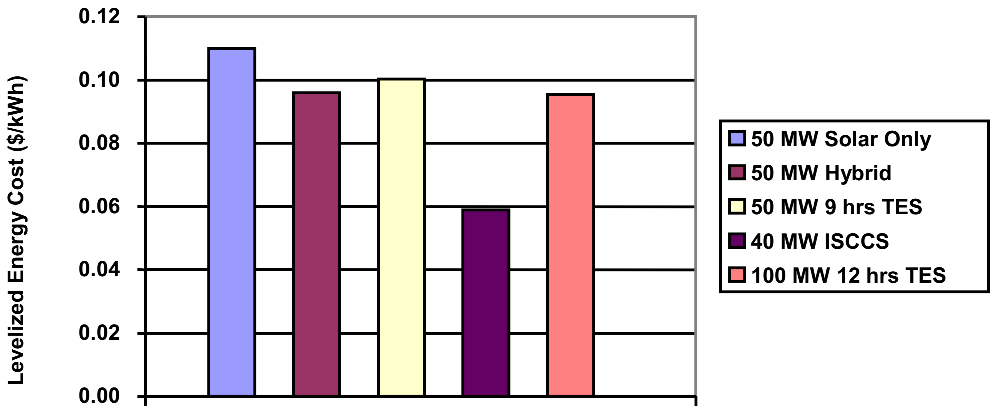
Table D-3 — Potential Trough Deployment

	2010		2020	
	International	U.S.	International	U.S.
Total Deployment	8,300 MW	1,800 MW	30,000 MW (min.)	2,900 MW (min.)
Estimated Trough Deployment	4,980 MW	1,080 MW	18,000 MW (min.)	1,740 MW (min.)
Total Estimated Trough Deployment	6,060 MW		19,740 MW (min.)	

The actual strategy employed by the plant suppliers can be significantly diverse, with more emphasis on near-term cost reduction with a minimum of risk. The suppliers may opt to provide multiple plants in the 50-MWe to 100-MWe size range with no thermal storage but with a supplemental steam generator, replicating the proven technology of the existing SEGS plants. The suppliers can rely more on initial production volume to reduce costs as opposed to efficiency and technology improvements and scale-up factors. Minimizing or eliminating thermal storage, with its current elevated cost, appreciably reduces the total direct cost of the plant as discussed later in this section of the report. The suppliers' strategy will depend on the deployment of trough plants.

Figure D-3 below illustrates the SunLab projected range in cost of power from various near-term trough plant configurations. The first three plants are all 50 MWe in size. The first is a solar-only plant with no hybrid backup or thermal energy storage. This plant has the lowest capital cost but the highest levelized energy cost (LEC) expressed as $/kWhe. The next plant is the 50-MWe hybrid plant that is assumed to produce 25% of its electricity from natural gas, similar to the existing SEGS plants. This plant has the lowest LEC of the 50-MWe plants. This is the type of plant that Duke Solar is proposing for development in the U.S. Southwest, where lowest cost and on-peak capacity is required. The third configuration is a 50-MWe plant with 9 hours of thermal storage and an oversized solar field. Note that the LEC is lower than the solar-only plant without thermal storage. This is the configuration of the proposed 40-MWe trough project in Spain. Note that this plant is preferred in Spain because of the requirements of the solar tariff. The fourth plant configuration is a trough hybrid that is integrated with a combined-cycle plant. This configuration, referred to as an integrated solar combined-cycle system (ISCCS), is what is proposed for several of the GEF projects in India, Mexico, Egypt, and Morocco. This configuration has the lowest LEC, but it must be integrated into a much larger combined-cycle plant. Depending on the specific market, different configurations of plants are typically proposed. The fifth plant is the near-term SunLab 100-MW configuration with 12 hours of thermal storage. With the exception of the ISCCS, this plant provides the lowest cost of power. This plant represents a low-cost technically feasible design, but is not necessarily the configuration that will be built.

Figure D-3 — Cost of Near-Term Trough Technology Configurations



D.3 EFFICIENCY

The Solar Field is defined by the collector area in square meters (m^2), which can be estimated by the following simplified equation:

$$C = \frac{(kW_d \times CF \times h)}{\eta \times I}$$

Where:

C = Collector area square meters (m^2)

kW_d = electric generation design capacity, kilowatts

CF = Capacity Factor = kWh actual / (kW_d x 8,760)

h = hours per year (8,760)

η = net annual solar-to-electric efficiency

I = annual insolation (kWh_t/m^2)

kWe = kilowatts electric

kWh_t =kilowatts thermal

For a given plant size and capacity factor the net annual efficiency is the determining factor in the collector area; as the efficiency increases the collector area decreases on the same percentage basis.

The annual net solar-to-electric efficiency determination and the current efficiency of the 1989 era 33-MW SEGS parabolic trough plant are shown in Table D-4.

Table D-4 — Annual Solar-to-Electric Efficiency

Solar Field	
Incidence Angle	87.3%
Solar Field Availability	99.0%
Solar Field Optical Efficiency	61.7%
Receiver Thermal Efficiency	72.9%
Piping Thermal Losses	96.1%
No Op Low Insolation	99.6%
Solar Field Thermal Delivered Efficiency (SFE)	37.2%
Thermal to Power Plant Efficiency (TPPE) (Start-up/shutdown losses)	93.4%
Gross Steam Cycle Efficiency (ST)	37.5%
Parasitics (P) (1 - % auxiliary power consumed by plant)	82.7%
Plant-Wide Availability (A)	98.0%
Annual Solar-to-Electric Efficiency (E_{net}) E_{net} = SFE x TPPE x ST x P x A	10.6%

The net annual solar-to-electric efficiency has a significant impact on the cost of a trough plant. An example of the difference in solar field cost for a 100-MWe plant is illustrated in Table D-5.

Table D-5 — Annual Solar-to-Electric Impact on Cost

Plant Size net electric, MWe		100	100	100	100	100	100
Annual Plant Capacity Factor		25%	25%	25%	25%	25%	25%
Annual Solar-to-Electric Efficiency		**10.6%**	**14.2%**	**16.1%**	**17.0%**	**17.1%**	**17.2%**
Field Aperture Area, m^2		709,248	527,138	464,854	440,880	437,692	435,079
Solar Collection System	**$/m^{2} ***	**Thousands $**					
Receivers	43	30,680	22,802	20,108	19,071	18,933	18,820
Mirrors	40	28,507	21,187	18,684	17,720	17,592	17,487

Solar Collection System	$/m^2	Thousands $					
Concentrator Structure	47	32,981	24,513	21,616	20,501	20,353	20,232
Concentrator Erection	14	9,777	7,267	6,408	6,077	6,033	5,997
Drive	13	9,484	7,049	6,216	5,895	5,852	5,817
Interconnection Piping	10	7,172	5,331	4,701	4,458	4,426	4,400
Electronics & control	14	10,276	7,638	6,735	6,388	6,341	6,304
Header piping	7	4,875	3,623	3,195	3,030	3,008	2,990
Foundations/Other Civil	18	12,429	9,237	8,146	7,726	7,670	7,624
Other (Spares, HTF, freight)	17	11,841	8,801	7,761	7,360	7,307	7,264
Contingency	11	7,901	5,872	5,178	4,911	4,876	4,846
Total, $/m^2	**234**	165,928	123,323	108,752	103,143	102,397	101,786
Total, $/kWe		1,659	1,233	1,088	1,031	1,024	1,018
Relative Cost		1.00	0.74	0.66	0.62	0.62	0.61

$/m^2 costs based on SunLab values for 2004 case.

Table D-5 shows that the solar field cost for a 100-MWe plant can be reduced by approximately 40% by improving the net annual solar-to-electric efficiency from the current 10.6% to 17.2%.

The collector area is directly proportional to the plant megawatt size and the capacity factor, as evident in the preceding equation. There are economies of scale associated with increasing the plant megawatt size.

Without thermal storage, the annual capacity factor of the solar plant is limited to approximately 20% to 25%. To provide generation during non-solar periods and thereby increase the plant capacity factor, thermal storage is required. Thermal storage can reduce plant thermal losses by reducing the number of steam turbine start-stop cycles and decreasing the heat transfer fluid heating during no-load periods. The plant megawatt size and thermal storage will be discussed in further detail later in the report.

The major efficiency improvements projected by SunLab and the approximate corresponding contribution to the annual net solar-to-electric efficiency improvement are indicated in Table D-6.

Table D-6 — Projected Efficiency Improvements

Annual Values (not Design Point) referenced to 1999 SEGS VI	Current	SunLab Short-Term 2007	SunLab Long-Term 2020
Solar Field Optical Efficiency	61.7%	70.4%	73.0%
Percentage Point Improvement**	—	+1.5	+2.0
Receiver Thermal Efficiency	72.9%	86.2%	85.3%
Percentage Point Improvement**	—	+2.0	+1.8
Steam Cycle Efficiency	37.5%	39.3%	40.3%
Percentage Point Improvement**	—	+1.0	+1.4
Thermal to Power Plant Efficiency * (Start-up/shutdown losses)	93.4%	99.2%	99.2%
Percentage Point Improvement**	—	+0.7	+0.7
Parasitics *	82.7%	88.3%	92.8%
Percentage Point Improvement**	—	+0.4	+0.8%
Total Percentage Point Improvement**	—	+5.6	+6.7

* Improvements based on 12 hours thermal storage

** Relative to net annual efficiency

The technological advances and research, upon which the SunLab efficiency improvement estimates are based, include the following:

- The development of the new Solel UVAC receiver. The UVAC has improved thermal and optic properties. Field tests of the new receiver at SEGS VI shows a 20% increase in thermal performance compared to original receiver tubes.
- The development of ball joint assembly replacements for flexhoses. A demonstration of new ball joint assemblies has shown that they can reduce the hydraulic pressure drop in the solar field by approximately 50%. This results in lower solar field heat transfer fluid pumping electric parasitics.
- Improvements in mirror washing techniques have resulted in increased solar field average mirror reflectance.
- Investigation of higher temperature heat transfer fluids.
- Research of direct thermal energy storage.
- Research of higher temperature receiver selective coatings.

D.3.1 Solar Optical Efficiency

The near-term projected optical efficiency improvement from 61.7% to 70.4% optical efficiency is based on the following considerations:

- Increase in mirror cleanliness from 93.1% in 1999 to 95% in 2005. The standard mirror cleanliness assumption is 95%, and this is considered achievable with a normal, reasonably aggressive mirror wash program.
- Increase in receiver envelope glass transmissivity from 92.5% to 97%. Solel has developed improved anti-reflective coatings for the glass envelope.
- Increase in receiver absorption from 92% to 96%. The new Solel cermet coating has demonstrated solar absorption of 96%. Additional optimization of the coating is needed to maintain this level and achieve the desired low emittance.
- The concentrator is increased in length from 50 meters to 150 meters. This longer length reduces end losses, light that reflects off the end of the collector, by 2.2%.

The projected near-term efficiency improvement is summarized in the following equation:

$$\eta_{Opt,\ near\text{-}term} = \eta p * (Cn/Cp) * (Tn/Tp) * (An/Ap) * (1 + EL)$$

where:

η = efficiency

C = mirror cleanliness

T = transmissivity

A = absorption

EL = end loss reduction

n = new

p = present

$$\eta_{Opt,\ near\text{-}term} = 0.617 * (0.95/0.931) * (0.97/0.925) * (0.96/0.92) * 1.022 = 0.704$$

The long-term projected optical efficiency improvement from 70.4% to 73% optical efficiency is based on the following considerations:

- The Solar weighted mirror reflectivity is assumed to increase from 93.5% for current back silvered 4 mm thick glass to 95% for next generation reflectors that are front surface reflectors with a hard coat for protection.
- Mirror cleanliness of new reflectors is projected to be maintained at higher levels of cleanliness due to new glass anti-soiling coatings that are now being sold on building window glass. Mirror cleanliness is projected to increase from 95% to 96% in future plants.

- Anti-soiling coatings will also be added to the receiver glazing. The coatings are expected to have a bigger impact due to the receiver glazing orientation. The important side of the receiver to keep clean is normally facing in a downward direction, where as the mirror normally face up. Receiver soiling factor improves from 0.98 to 0.99.

The projected long-term efficiency improvement is summarized in the following equation:

$\eta_{\text{Opt, long-term}} = 0.704 * (0.95/0.935) * (0.96/0.95) * (0.99/0.98) = 0.730$

D.3.2 Receiver Thermal Efficiency

The projected receiver thermal efficiency improvement from 72.9% to 86.2% receiver thermal efficiency is based on the following considerations:

- The primary factor in reducing solar field thermal losses is through reduction in the emittance of the receiver selective coating. The selective coating on the receivers in the SEGS VI solar field is half cermet and half black chrome. These receivers had fairly high emittance in comparison to the latest Solel UVAC selective coating. Solel testing at SPF showed an emittance of 0.091. Solel believes that with further optimization, an emittance of 0.07 at 400°C is possible while maintaining high solar absorptance 98%. Some R&D and testing are required to achieve the near-term receiver assumptions. SunLab believes these projections are aggressive and have set the receiver absorptance and emittance goals at 0.96 and 0.07 (at 400°C), respectively.
- A secondary factor in reducing solar field thermal losses is through increasing receiver reliability, which results in fewer receiver tubes in the solar field with lost vacuum, broken glass, or coating defects. Field test results on the Solel UVAC receiver indicate failure rates below historic levels. In addition, the new UVAC selective coating will not fail even when exposed to air at temperature. Thus no coating failures are assumed in future plants.
- The near-term plant is assumed to operate at 450°C outlet temperature. This results in a slight decrease in solar field thermal efficiency. Piping heat losses are actually reduced because the plant is assumed to use HitecXL, and a three component inorganic molten salt, that has a higher heat capacity/density product than Therminol VP-1 that allows substantially smaller piping to be used in the solar field. This results in lower solar field piping heat losses overall.

There is some uncertainty in the current properties of the Solel UVAC receiver. The tubes tested at Kramer Junction had their properties measured by Sandia. These had a solar absorptance of 96% and a thermal emittance of 13.5% at 400°C. These tubes showed a 20% thermal performance increase on the test loop at SEGS VI. Solel had the properties measured from a later batch of tubes that indicated an absorptance of 94.4% and an emittance of 9.1% at 400°C. There is significant uncertainty in the property measurements but better properties are expected by SunLab. The following table lists the receiver tube property assumptions used in the SunLab cases.

Table D-7 — Receiver Tube Property Assumptions

	Luz (original)	Current (SEGS 1999)	SunLab Near-Term	SunLab Long-Term
	SEGS VI	UVAC 1/2	Assumption	Assumption
Absorptance	0.92	0.96/0.944	0.96	0.96
Envelope Glass Transmissivity	0.92	0.965/0.965	0.97	0.97
Emittance at 400°C	>0.18	0.135/0.091	0.07	0.07
Operating Temperature	392°C	>450°C	450°C	500°C

D.3.3 Steam Cycle Efficiency

The steam cycle foundation is the Rankine cycle. As the inlet steam conditions (pressure and temperature) increase, the Rankine cycle efficiency increases. The near-term steam cycle gross efficiency from 37.5% to 39.3% is predicated on increasing the inlet steam temperature from 390°C to 450°C. The long-term increase to 40.3% is based on 500°C steam inlet temperature. The net steam turbine efficiency (gross efficiency minus the percentage of parasitic power consumption required for plant operation) is accounted for by calculation of the parasitic consumption separately, as shown on Table D-6, "Projected Efficiency Improvements," and discussed in the following section.

The near-term turbine efficiency is verified based on the ABB-Brown Boveri heat balances (HTGD 582395, Sheets 1-7) for SEGS IX, which show an efficiency of 37.7% (in LUZ International Limited 1990). The Rankine cycle efficiency gains for increasing the inlet steam temperature from 390°C to 500°C were verified by S&L by using General Electric STGPER software program (Version 4.08.00, January 2002). The turbine efficiencies are summarized in Table D-8.

Table D-8 — Steam Turbine Efficiencies

Turbine Inlet Temperature	ABB-Brown Boveri (SEGS IX)	SunLab Projection	S&L Estimate (GE STGPER basis)
390°C	37.7%	37.5%	37.5%
450°C	—	39.3%	39.5%
500°C	—	40.3%	40.6%

There are no steam turbine technological risks in achieving the SunLab projected efficiencies. There are currently numerous steam turbines operating with steam inlet conditions over 250 bar pressure and 590°C temperature, with gross efficiencies over 44%.*

However, the type of heat transfer fluid (HTF) used determines the operational temperature range of the solar field and thus the maximum power cycle efficiency that can be obtained. Currently, synthetic oil (Therminol VP-1) is used in the trough technology as the HTF with an operating temperature of approximately 390°C.

To achieve the near-term increased Rankine cycle efficiency the HTF will have to be changed to obtain the 450°C inlet steam temperature. The SunLab projections assume a nitrate salt HTF with an upper operating range of 500°C, such as HitecXL, similar to the HTF used for the power tower technology. Use of nitrate salt has not been demonstrated for the trough technology.

For the near-term, additional development and field testing is required on alternate HTFs for higher temperature applications. For the long-term, not only is alternate HTF development required but the current HCE absorber coating upper temperature limit is approximately 450°C, which will necessitate an advanced HCE coating for the projected 500°C operating temperature.

D.3.4 Thermal to Power Plant Efficiency — Parasitics

The parasitic electric consumption is reduced from 17.3% at SEGS VI to 8.4% in the near-term case and to 7.2% in the long-term case. The major reasons for the reductions are the following:

- SEGS VI uses flex hoses for interconnection of collectors. Future plants will use ball joint assemblies. Ball joints reduce pressure drop in the collector loop by about 50%. Increasing from a 50-meter to a 150-meter collector length reduces the number of collector interconnections by 3, thereby reducing the pressure drop. The HTF pumping parasitics is reduced from 5.9% of gross generation to 3.8%.
- Changing the HTF from VP-1 to HitecXL reduces HTF pumping parasitics from 3.8% to 1.7%. This is based on a new solar field piping model developed by Nexant.
- Additional plant parasitic reduction is assumed through further optimization of power plant motors and other electrical equipment through the use of more energy efficient components and control systems. Current parasitic models are based on the parasitics at the SEGS plants. Significant improvement in motors and other parasitic equipment have occurred in the last 15 years.

* Plant (commercial operation date): Nanaoota 1 (1995), Noshiro 2 (1995), Haramachi 1 (1997), Haramachi 2 (1998), Millmerran (2002), Matauura 2 (1997), Misumi 1 (1998), Tachibana Bay (2000), Bexback (2002), Lubeck (1995), Aledore 1 (2000), Nordjylland (1998). From *Power* (Swanekamp 2002).

The efficiency improvements are based on 12 hours of thermal storage. The storage allows the plant to operate during non-insolation periods, thereby reducing thermal losses by minimizing the energy loss during plant start/stop cycles (thermal to plant power efficiency) and HTF heating during off-line periods. Even though efficiency improvements can be gained by thermal storage, additional direct costs will be incurred. First, the cost of the storage system is estimated to be between \$20/kWh$_t$ and \$31/kWh$_t$ (Price et al. 2002), and second, the collector area required will be approximately doubled for 12 hours storage capability. For a 33-MWe plant, approximately 1,060-MWh$_t$ storage will be required for 12 hours storage at an estimated cost between \$21,000,000 and \$33,000,000 (\$640/kWe and \$1,000/kWe) and an increased collector cost of approximately \$37,000,000 (\$1,100/kWe). Offsetting the additional capital expenditures is the additional revenues for the extra electrical generation (approximately double for 12 hours of storage).

D.3.5 Efficiency Improvements Summary

The S&L evaluation is based on a less aggressive technology development approach, basing the maximum optical efficiency on the tested receiver tubes weighted absorptance of 94.4%, receiver coatings solar transmittances of 96.5%, mirror reflectivity of 93.5%, and mirror cleanliness factor of 95%. A comparison of SunLab and S&L efficiencies is illustrated in Table D-9.

Table D-9 — Comparison of SunLab and S&L Efficiencies

		SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
		1999	**2004**	**2007**	**2010**	**2015**	**2020**
Solar Field Efficiency	SunLab	0.533	0.567	0.582	0.598	0.602	0.602
	S&L	0.533	0.567	0.570	0.570	0.570	0.570
Incidence Angle		0.873	0.873	0.873	0.873	0.873	0.873
Solar Field Availability		0.990	0.990	0.990	0.990	0.990	0.990
Other (IAM, row to row shadowing, end loss)		0.899	0.910	0.918	0.918	0.918	0.918
Tracking Error and Twist		0.994	0.994	0.994	0.994	0.994	0.994
Geometric Accuracy		0.980	0.980	0.980	0.980	0.980	0.980
Mirror Reflectivity	SunLab	0.935	0.935	0.935	0.950	0.950	0.950
	S&L	0.935	0.935	0.935	0.935	0.935	0.935

		SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
		1999	2004	2007	2010	2015	2020
Mirror Cleanliness Factor	SunLab	0.931	0.950	0.950	0.960	0.960	0.960
	S&L	0.931	0.950	0.950	0.950	0.950	0.950
Concentrator Factor		1.000	1.000	1.000	1.000	1.000	1.000
Bellows Shadowing		0.971	0.971	0.971	0.971	0.971	0.971
Dust on Envelope		0.980	0.985	0.985	0.985	0.985	0.985
Envelope Transmissivity	SunLab	0.925	0.965	0.970	0.970	0.970	0.970
	S&L	0.925	0.965	0.965	0.965	0.965	0.965
Receiver Solar Absorption	SunLab	0.920	0.944	0.960	0.960	0.960	0.960
	S&L	0.920	0.944	0.944	0.944	0.944	0.944
Receiver Thermal Efficiency	SunLab	0.729	0.859	0.862	0.852	0.853	0.853
	S&L	0.729	0.843	0.823	0.810	0.810	0.810
Piping Thermal Losses		0.961	0.965	0.967	0.967	0.968	0.968
Storage Thermal Losses		1.000	0.991	0.997	0.996	0.996	0.996
EPGS Efficiency		0.351	0.370	0.390	0.400	0.400	0.400
Electric Parasitics		0.827	0.883	0.916	0.922	0.922	0.928
Power Plant Availability		0.980	0.940	0.940	0.940	0.940	0.940
Annual Solar-to-Electric Efficiency	SunLab	0.106	0.143	0.162	0.170	0.171	0.172
	S&L	0.106	0.140	0.151	0.154	0.155	0.155

While the SunLab efficiency improvements are theoretically reasonable, the 12 hours of thermal storage is problematic since it has not been commercially demonstrated for the higher solar field operating temperatures (approximately 390°C) of the later SEGS plants. Thermal storage is discussed in greater detail later in this report.

The near-term (2007) efficiency improvement from 10.6% to 16.2%, based on available information, appears to be optimistic. A more conservative efficiency improvement, based on maximum optical efficiency on the tested receiver tubes weighted absorptance of 94.4%, receiver coatings solar transmittances of 96.5%, mirror reflectivity of 93.5%, and mirror cleanliness factor of 95%, is 15.1%. If an HCE performance improvements, higher temperature HTF, and compatible thermal storage system can be developed and implemented in the near-term, a 16.2% annual net solar-to-electric efficiency is feasible. Additional investigation and development of HCE, storage systems, including the optimum HTF for steam cycle efficiency and storage compatibility, is required to achieve the near-term efficiency projection.

D.4 SOLAR FIELD — SUPPORT STRUCTURE

D.4.1 Direct Capital Cost

The SunLab projections for the structure material and erection are shown in the Table D-10.

Table D-10 — SunLab Cost Projections

		Reduction from	
		SEGS VI	$/kWe
SEGS VI	$67/m^2	—	420
2004	$61/m^2	9%	683
2007	$57/m^2	15%	591
2010	$54/m^2	19%	531
2015	$50/m^2	25%	489
2020	$46/m^2	31%	450

The baseline cost of $67/m^2 is consistent with estimates prepared by Pilkington International (1999) indicating $63/m^2. Using $1,500 per ton for erected structural steel (National Construction Estimator 49th edition) results in a total direct cost of $12,400,000 for the SEGS VI 188,000-m^2 collector area, which is also consistent with the Pilkington estimate of $13,252,000 for a 209,280-m^2 collector area (209,280 m^2/188,000 m^2 x $12,400,000 = $13,785,000).

Cost comparisons based on weight, as discussed in the following section, for the various structures are illustrated in Table D-11.

Table D-11 — Costs of Various Structures

LS-2	$58/m^2
LS-3	$66/m^2
EuroTrough	$58/m^2
Duke Solar	$48/m^2
IST	$48/m^2

Additional cost reductions will be realized by minimization of the number of required parts, simplification of fabrication and field erection reducing labor costs for on-site assembly and erection. This cost reduction potential has not been quantified since there has not been an actual erection of a new collector structure. While the trough technology was commercialized for a brief period, no trough plants have been built in nearly a decade. There are active solar field suppliers, which will reduce costs through competition; however, structure cost reductions due to commercialization was not considered in this evaluation.

D.4.2 Technology Improvements

The Luz LS-3 collector was the final concentrator design used at the newest SEGS plants (SEGS VII–IX). The thermal performance and alignment maintainability of the LS-3 collector has not proved to be equal to the earlier LS-2 design used on the SEGS II–IX plants. There are at least three new parabolic trough collector structure designs under various stages of development:

- EuroTrough (ASME 2001)
- Duke Solar (Duke Solar 2000)
- Industrial Solar Technology (IST 2001))

The new collectors concentrate on weight reduction and emphasize simplicity of fabrication and a minimum number of required parts. A weight comparison of the LS-2, LS-3, and the aforementioned new design structures is provided in Table D-12.

Table D-12 — Structure Weight Comparison

Structure	Weight (kg/m^2)	Reduction
LS-2	29	12%
LS-3	33	Base
IST	24	27%
Eurotrough	29	12%
Duke Solar	24	27%

D.4.3 Scale-Up

Structure cost reductions due to scale-up were not considered since the collector area for the same net annual solar-to-electric efficiency, and thus the structure, is directly proportional to the plant size. The collector area is inversely proportional to the efficiency and will influence the structure cost by reducing the collector area with the improvement of the efficiency.

D.4.4 Production Volume

The experience curve (Neij 1997) is related to the commercialization of the solar plants. The experience curve describes how unit costs decline with cumulative production, with a specific characteristic that cost declines by a constant percentage with each doubling of the total number of units produced.

The formula is as follows:

$$C_{CUM} = C_0 \times CUM^b$$

Where:

C_{CUM} = the cost per unit as a function of output

C_0 = the cost of the first unit produced

CUM = the cumulative production over time

b = the experience index

The cost reduction is ($1-2^b$) for each doubling of cumulative production, where the value (2^b) is called the progress ratio (PR). PR is used to express the progress of cost reductions for different technologies. The lower the PR value the higher the cost reduction realized. The cost reductions refer to the total costs (labor, capital, administration, research, etc.). Experience curves is not an established method, but a correlation that has been observed for several different technologies. Cost reductions were projected based on evaluation of technology improvements and experience curves.

The SEGS solar field areas are shown below. The cumulative area indicates approximately five doublings were experienced for the SEGS plants. One of the criteria for the applicability of experience curves, according to the Neij literature (1997), is at least three doublings of production volume.

Table D-13 — SEGS Solar Field Area

SEGS Plant Number	MW	Solar Field Area, m^2	Solar Field Area, m^2 - Cumulative
I	13.8	82,960	82,960
II	30	190,338	273,298
III	37	230,300	503,598
IV	37	230,300	733,898
V	39	250,500	984,398
VI	35.5	188,000	1,172,398
VII	35.5	194,280	1,366,678
VIII	80	464,340	1,831,018
IX	80	483,960	2,314,978

There are recognized scale-up cost reductions for increasing the plant size:

$$\$B = \$A \times (B_{MW}/A_{MW})^{Sf}$$

Where:

Plant B is larger than Plant A

$B = cost of Plant B

$A = cost of Plant A

B_{MW} = MW size of Plant B

A_{MW} = MW size of Plant A

Sf = scale-up factor

Based on the cost data provided by the SEGS Plant (SEGS Data Package obtained during plant visit), an average scale-up factor of 0.7 was attained: SEGS I to SEGS II had a 0.6 scale-up factor; SEGS II to SEGS III, a 0.8 scale-up factor; and SEGS V to SEGS VII, a 0.7 scale-up factor. The SEGS Cost Data in 2001 dollars from "Advances in Parabolic Trough Technology" (Price et al. 2002) show a savings of $1,643/kWe from SEGS VI to SEGS IX. Three doublings of the solar field area had occurred before SEGS VI. Using the average scale-up factor of 0.7, $1,447/kWe cost reduction was realized by plant scale-up. The majority of the remaining $196/kWe savings ($1,643/kWe – $1,447/ kWe = $196/ kWe) was assumed to be attributable to production volume cost reduction since there were no significant technological advances from SEGS VI to SEGS IX. Applying the SEGS VI solar field cost ($/m^2) to the SEGS IX plant and then reducing that cost by the $196/ kWe savings yielded a progress ratio (PR) value of 0.92. The Enermodal Study (undated) shows a PR range between 0.85 and 0.92 for the installed capital cost of a trough power plant. Arguably, for the highly automated manufactured components, such as the support structure, receiver tubes, and mirrors, a PR of 0.80, as used in the Neij literature (1997), may be more representative based on manufacturing experience. The S&L cost estimates for comparison to the SunLab model are based on a progress ratio (PR) value of 0.92 based on the estimated PR value from the SEGS cost data and since establishing an experience curve for a given component is somewhat speculative. A PR value of 0.92 will be more conservative, and if the actual PR value is less than 0.92 used in this evaluation, then the cost reductions will be greater than the estimated values.

The initial starting point for estimating the cumulative production is the 2004 Technology Trough Plant. The cumulative production does not include the nine original SEGS plants because 10 years have elapsed since commercial production occurred for these plants.

D.4.5 Cost Comparison

A comparison of the SunLab projected costs are compared to the estimated cost based on a progress ratio of 0.92 in Table D-14.

Table D-14 — Support Structure Cost Comparison ($/m^2)

Year	SunLab	S&L
SEGS VI	67	67
2004	61	61
2007	57	58
2010	54	56

Year	SunLab	S&L
2015	50	54
2020	46	52

The baseline cost of $67/m^2 (SEGS VI) is consistent with estimates prepared by Pilkington International (1999) indicating $63/m^2. Cost comparisons based on weight for the various structures are illustrated below. Recent wind tunnel testing has provided improved data for use in optimizing the structural design, and reducing the weight, necessary for long-term reliability. Future designs may include more efficient integration of the reflectors into the overall structure, thus sharing the loads and reducing material requirements. Non-metallic materials are being considered, but may not be cost-effective. Additional cost reductions can be realized by minimization of the number of required parts and simplification of fabrication and field erection reducing labor costs for on-site assembly and erection. This cost reduction potential has not been quantified in this evaluation since there has not been an actual erection of a new collector structure. The individual metal parts of the structure can readily be manufactured by suppliers worldwide, leading to potential cost reductions through competition. However, structure cost reductions due to commercialization were not specifically considered in this evaluation.

The estimated cost reductions are a result of the experience curve and indicate that the SunLab projected costs are reasonable. Even lower costs can be expected if lower structure weights, such as shown in Table D-12, are employed. Other potential cost reductions are simplification of fabrication and decreasing the number of required parts.

D.5 SOLAR FIELD – HEAT COLLECTION ELEMENT (HCE)

D.5.1 Direct Capital Cost

The SunLab projected HCE deployment and costs are shown in Table D-15.

Table D-15 — SunLab Projected HCE Deployment and Costs

	SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
	1999	**2004**	**2007**	**2010**	**2015**	**2020**
Number HCE	9,600	57,216	45,700	65,072	86,101	172,201
Number HCE Accumulative	9,600	66,816	112,516	177,588	263,688	435,889
Cost, $/m^2 field	43	43	34	28	22	18
Cost, $/unit	847	847	762	635	508	400

D.5.2 Technology Improvements

The Solel UVAC HCE is considered the current state-of-the-art receiver and will be used in the new near-term trough plants.

Sandia National Laboratories (SNL) is investigating new concepts in receiver design that could result in substantially lower-cost receivers with nearly the same high performance as the Solel receivers (Price and Kearney 1999). One of the SNL designs uses a high-temperature gasketing approach for connecting the glass envelope to the metal absorber, in place of the glass-to-metal seal. To reduce convective heat losses, the receiver annulus between the glass and metal tube would be pressurized with an inert gas. Although preliminary testing shows potential, extensive long-term field-testing is required on any new receiver design to evaluate and validate the reliability and also to assess whether the receiver's life-cycle costs have been lowered. In the last couple of years, the focus of the research has returned to evacuated receiver designs. The focus now is on developing a more robust and lower-cost glass-to-metal seal design and on identifying higher temperature selective coatings with better thermo/optic properties. Sandia has identified new materials that could be used in the glass-to-metal seal to reduce the potential stress in the seal. In general, however, the current Housekeeper seal used in the HCE is very expensive and a significant part of the total receiver cost. Sandia has also identified some new glass-to-metal seal options that have the potential to be much lower in cost to manufacture and be more robust at the same time. NREL has been evaluating new selective coatings. Several new cermet coatings have been identified that may be easier to manufacture and have better thermo/optic properties. These are multi-layer cermets as opposed to the graded cermet used by Solel. The graded cermets require a sputtered manufacturing process, whereas the multilayer coating can probably be deposited with simpler coating processes that facilitate better quality control of the final properties. NREL is also investigating changing the materials used in the cermet to give better high temperature performance and stability. Both the design work and the coating development are being funded in the current DOE budget and will be continued next year.

Alternate HCE designs (Zhang et al. 1998; Morales and Ajona 1998; San Vicent, Morales, and Gutiérrez 2001) are under various stages of development that indicate lower cost than the Solel UVAC HCE, although at reduced efficiency levels. Reduced HCE efficiency will result in a lower net annual solar-to-electric efficiency and require a larger collector area. Schott Glass, a large international supplier of specialty glass and related products, has recently announced its entry into the HCE supply market. However, start-up of HCE production is a significant cost, and a viable market growth is imperative to justify market entry for a new supplier.

D.5.3 Scale-Up

Cost reductions due to scale-up is not considered applicable since the collector area for the same net annual solar-to-electric efficiency, and thus the number of HCE, is directly proportional to the plant size. The collector area is inversely proportional to the efficiency and will influence the HCE cost by reducing the collector area with the improvement of the efficiency.

D.5.4 Production Volume

Cost reductions were projected based on evaluation of technology improvements and a progress ratio of 0.92. The Case 1 deployment values are used in the S&L evaluation. The Case 2 deployment values, used in the SunLab projections, are provided for comparison of the production volume between the two cases in Table D-16.

Table D-16 — Number of HCE

Number HCE, Cumulative	2004	2007	2010	2015	2020
Case 1 Deployment	57,545	219,535	380,117	735,606	1,265,782
Case 2 Deployment	57,545	219,535	520,817	1,076,652	2,225,366

D.5.5 Cost Comparison

A comparison of the SunLab projected costs to the SunLab estimated costs are shown in Table D-17.

Table D-17 — HCE Cost Comparison ($/unit)

Year	SunLab	S&L
2004	847	847
2007	762	762
2010	635	675
2015	508	625
2020	400	525

D.6 SOLAR FIELD – MIRRORS

D.6.1 Direct Capital Cost

The SunLab projected mirror costs are shown in Table D-18.

Table D-18 — SunLab Projected Mirrors Costs

	SEGS VI	Trough 100	Trough 100	Trough 150	Trough 200	Trough 400
	1999	2004	2007	2010	2015	2020
Mirrors, $\$/m^2$ field	40	40	36	28	20	16

D.6.2 Technology Improvements

Alternatives to glass mirror reflectors have been in service and under development for more than 15 years. It is noted that all the identified alternatives are in various stages of initial development or testing. The major current developments are listed below.

- Thin glass mirrors are as durable as a glass reflector and relatively lightweight in comparison to thick glass. However, the mirrors are more fragile, which increases handling costs and breakage losses. To address corrosion problems, new thin glass experimental samples were recently developed and are being tested under controlled conditions.
- 3M is developing a nonmetallic, thin-film reflector that uses a multi-layer *Radiant Film* technology. The technology employs alternating co-extruded polymer layers of differing refractive indices to create a reflector without the need for a metal reflective layer. 3M plans to

develop an improved solar reflector with improved UV screening layers and a top layer hardcoat to improve outdoor durability.

- ReflecTech and NREL are jointly developing a laminate reflector material that uses a commercial silvered-polymer reflector base material with a UV-screening film laminated to it to result in outdoor durability. Initial prototype accelerated-exposure test results have been promising, although additional work on material production is needed. The material would also benefit from a hardcoat for improved washability.
- Luz Industries Israel created a front surface mirror that consists of a polymeric substrate with a metal or dielectric adhesion layer; a silver reflective layer; and a proprietary, dense, protective top hardcoat.
- SAIC of McLean, Virginia, and NREL have been developing a material called *Super Thin Glas*s. This is also a front-surface mirror concept with a hard coat protective layer.
- Alanod of Germany has developed a front-surface aluminized reflector that uses a polished aluminum substrate, an enhanced aluminum reflective layer, and a protective oxidized alumina topcoat. These reflectors have inadequate durability in industrial environments. A product with a polymeric overcoat to protect the alumina layer has improved durability.

Table D-19 summarizes the characteristics of the reflector technology alternatives. At this point, thick glass will likely remain the preferred approach for large-scale parabolic trough plants, although alternative reflector technologies may be more important in the future as more advanced trough concentrator designs are developed.

Table D-19 — Alternate Mirror Technologies

	Weighted Reflectivity (%)	Cost ($/m^2)	Issues
Flabeg Thick Glass	94	40	Cost, breakage
Thin Glass	93 – 96	15 – 40	Handling, breakage
All-Polymeric	99	10	UV protective coating needed with hard coat
ReflecTech Laminate	>93	10 – 15	Hard coat and improved production
Solel FSM	>95	—	Solel product durability currently unknown
SAIC Super Thin Glass	>95	10	Manufacturing scale-up
Alanod	~90	<20	Reflectivity

There are active mirror suppliers, which will reduce costs through competition, however mirror cost reductions due to commercialization was not considered in this evaluation.

D.6.3 Scale-Up

Similar to the collectors, cost reductions due to scale-up are not considered applicable since the mirror area for the same net annual solar-to-electric efficiency, and thus the mirror area, is directly proportional to the plant size. The mirror area is inversely proportional to the efficiency and will influence the mirror cost by reducing the collector area with the improvement of the efficiency.

D.6.4 Production Volume

Cost reductions were projected based on evaluation of technology improvements and a progress ratio of 0.92. The Case 1 deployment values are used in the S&L evaluation. The Case 2 deployment values, used in the SunLab projections, are provided for comparison of the production volume between the two cases. These are shown in Table D-20.

Table D-20 —Mirror Volume
(Square Meters, Cumulative, Thousands)

	2004	2007	2010	2015	2020
Case 1 Deployment	1,120	4,399	7,952	15,818	27,550
Case 2 Deployment	1,120	4,399	11,066	23,365	48,782

D.6.5 Cost Comparison

A comparison of the SunLab projected costs are compared to the SunLab estimated costs in Table D-21.

Table D-21 — Mirror Cost Comparison ($/m^2)

Year	SunLab	S&L
2004	40	40
2007	36	36
2010	28	32
2015	20	29
2020	16	26

D.7 POWER BLOCK

D.7.1 Direct Capital Cost

The SunLab projected power block costs are shown in Table D-22.

Table D-22 — SunLab Projected Power Block and Balance of Plant Costs

	SEGS VI	2004	2007	2010	2015	2020
Plant size, gross electric, MWe	**33**	**110**	**110**	**165**	**220**	**440**
Power Block, $/kWe	410	349	349	293	256	197
Balance of Plant, $/kWe	248	203	203	171	149	115
Total, $/kWe	658	552	552	464	405	312

There are multiple suppliers for the power block equipment, and costs will be market-driven. While a trough plant will benefit from competitive prices, power block cost reductions due to commercialization were not considered in this evaluation.

D.7.2 Technology Improvements

The power block is a conventional Rankine-cycle steam turbine. The Rankine-cycle steam turbine is an established technology with future major improvements focusing on increased inlet steam pressure and temperature conditions to increase the cycle efficiency.

D.7.3 Scale-Up

There are recognized scale-up cost reductions for the power block. Using the SOAPP software program, S&L estimated the scale-up factor for increasing the plant size from 100 MW to 400 MW, as depicted on Figure D-4. The projected SunLab values are included for comparative purposes. Power block costs (Figure D-4A) include the steam turbine and generator, steam turbine and generator auxiliaries, feedwater and condensate systems. Balance-of-plant costs (Figure D-4B) include general balance-of-plant equipment, condenser and cooling tower system, water treatment system, fire protection, piping, compressed air systems, closed cooling water system, plant control system, electrical equipment, and cranes and hoists.

Figure D-4A — Estimated Scale-Up Costs: Power Block ($/kW)

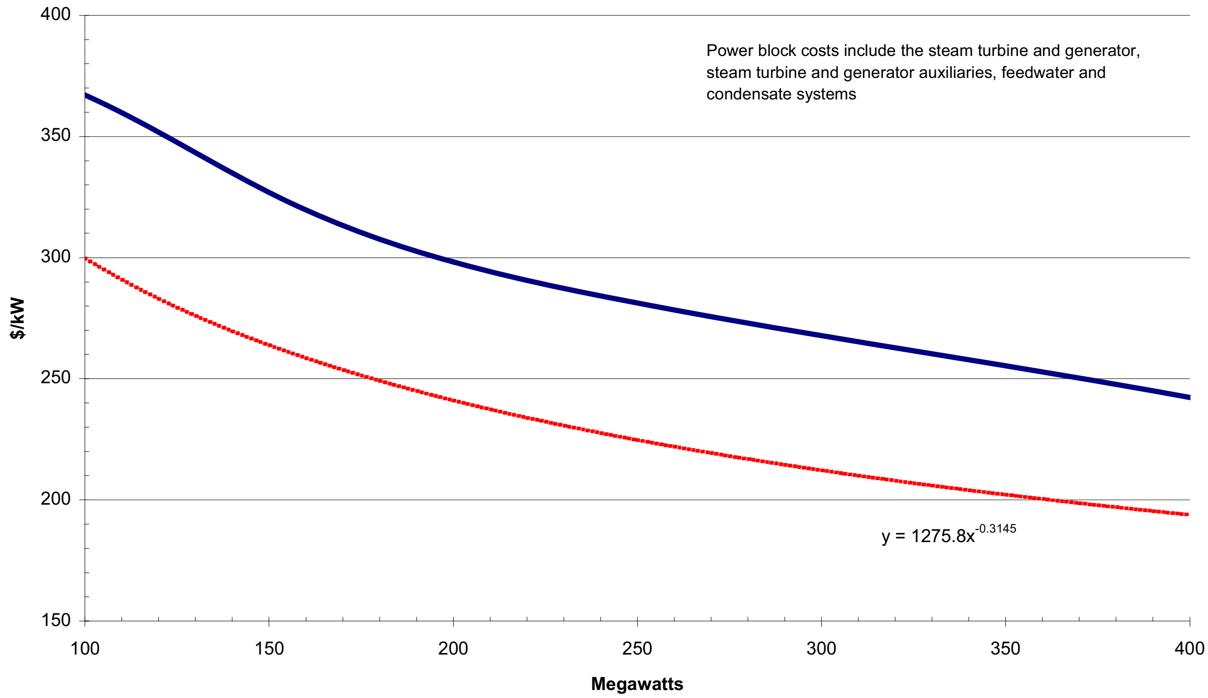
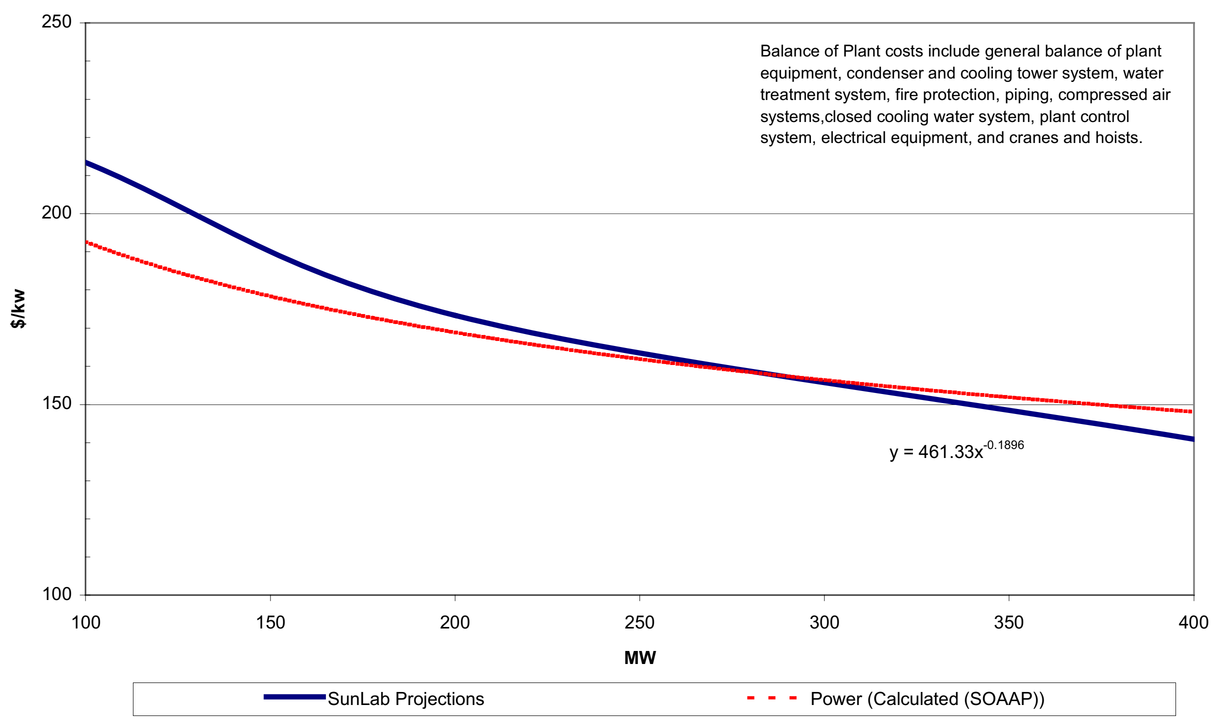


Figure D-4B — Estimated Scale-Up Costs: Balance-of-Plant ($/kW)



The estimated costs based on the SOAPP program indicate that the SunLab projected costs for the power block are conservative (on the high side), approximately $50/kW higher than estimated by the SOAPP program. The SunLab power block cost estimates are based on a 1990 ABB quotation for a 100-MW steam turbine. The ABB quotation was escalated and scaled-up for the larger sizes. The SunLab power block cost estimates are based on dated information and the escalation and scale-up factors add to the uncertainty of the data with respect to current pricing. Equipment prices in the SOAPP program reflect 2001 actual costs. Since the SOAPP pricing is current, the SOAPP-generated costs were used in this evaluation.

D.7.4 Production Volume

Since a single steam turbine is supplied with each trough plant, production volume is not a consideration for cost reduction.

D.7.5 Cost Comparison

A comparison of the SunLab projected cost versus the SOAPP predicted $/kW for the power block plus the balance of plant is shown in Table D-23.

Table D-23 — Power Block & BOP Cost Comparison

Total Power Block + BOP	2004 – 2007	2010	2015	2020
Plant size, MWe	100	150	200	400
SunLab Projected, $/kWe	581	525	472	383
SOAPP Estimate, $/kWe	499	450	399	346

D.8 THERMAL STORAGE

D.8.1 Direct Capital Cost

The SunLab projected thermal storage costs are shown in Table D-24. Note that the SunLab projections are based on 12 hours of thermal storage for each case.

Table D-24 — SunLab Projected Thermal Storage Cost

	2004	2007	2010	2015	2020
Plant size, gross electric, MWe	110	110	165	220	440
Storage, MWh_t	3,525	3,349	4,894	6,525	13,050
Type	Indirect Two-Tank	Direct Two-Tank	Direct Thermo-cline	Direct Thermo-cline	Direct Thermo-cline
Heat Transfer Fluid	VP-1/ Solar Salt	HitecXL	HitecXL	HitecXL	HitecXL
HTF Temperature, °C	400	450	500	500	500
SunLab Projected, $/$kWh_t$	27.18	12.68	11.73	11.73	11.73
$/kWe	958	425	383	383	383

Binary solar salt (sodium and potassium nitrate) is the same HTF as used for the power tower Solar Two project, whereas HitecXL is a ternary salt (sodium, potassium, and calcium nitrate). The main advantage of ternary salt is a lower freezing temperature (120°C) compared to 225°C for binary salt and a high HTF operating temperature of 500°C. Ternary salt costs approximately 2 times more than binary salt.

The number of hours of storage impact on the total capital cost is illustrated below in Table D-25 for the year 2004 case (100 MWe) with a two-tank indirect storage system.

Table D-25 — Thermal Storage Impact on Cost

	Hours of Thermal Energy Storage						
	0	2	4	6	8	12	16
Annual Capacity Factor	32.0%	33.6%	37.8%	41.7%	46.7%	53.5%	54.1%
Net Annual Generation, GWh	280.1	294.6	331.1	365.2	408.9	468.6	473.9
Installed Capital Cost, $/kWe	2,816	3,074	3,471	3,867	4,280	4,859	5,190

The impact of the type of storage system on the total capital cost is shown in Table D-26 for the year 2004 case (100 MWe) for 12 hours of storage.

Table D-26 —Type of Thermal Storage Impact on Cost

Type of Thermal Storage System – 12 Hours	Plant Capital Cost ($/kWe)
Two-Tank Indirect, VP-1 HTF, Solar Salt Storage	4,859
Thermocline Indirect, VP-1 HTF, Solar Salt Storage	4,668
Two-Tank Direct, Solar Salt (450°C)	4,427
Direct Thermocline, Solar Salt (450°C)	4,115
Direct Thermocline, HitecXL (500°C)	4,027

As exemplified in Tables D-25 and D-26, the amount of storage and the type of storage have significant impacts on the total cost of the plant and are key considerations for cost reductions.

D.8.2 Technology Improvements

Thermal storage allows solar electricity to be dispatched to the times when it is needed most and allows solar plants to achieve higher annual capacity factors. Although the first commercial 14-MWe trough plant included thermal storage, a simple two-tank storage system that used the plant HTF for a storage media, later plants operated at higher temperatures that precluded the same method due to the higher vapor pressure and high cost of the HTF. No thermal storage technology has been commercially demonstrated for the higher solar field operating temperatures (approximately 400°C) required for more efficient steam cycles in the later SEGS plants.

Various studies point to an indirect thermal storage system for near-term application where the heat from the collector field is transferred from the synthetic oil (VP-1) HTF to another thermal storage media, such as molten salt, which can be stored at atmospheric pressure (Kearney 2001a, 2001b; Sandia National Laboratories 2001; Nextant Inc. 2001). For the two-tank indirect system, heat from the collector field is transferred from the synthetic oil HTF to another thermal storage media, such as molten salt, which can be stored at atmospheric pressure. However, the molten salt storage temperature is limited by the synthetic oil HTF operating temperature of 390°C. The technological risk using the two-tank molten-salt storage system is low based on the successful utilization at the Solar Two plant but the cost of this system is high ($958/kWe for 2004 SunLab case). The thermocline system will also reduce the storage system costs with synthetic oil HTF and binary molten salt storage fluid by the elimination of one storage tank and the reduction in the fluid volume requirement compared to the indirect two-tank system. Estimates show a 35% reduction in the storage system cost ($31/kWh$_t$ to

$20/kWh$_t$) using a thermocline system as opposed to a two-tank system (Sandia National Laboratories 2001; Kearney 2001a; Nextant Inc. 2001).

The year 2007 projection for a direct two-tank storage will use HitecXL (ternary) HTF in both the solar field and the thermal storage system, eliminating the need for the heat exchangers between the solar field and storage system. In addition, the solar field can be operated to higher outlet temperatures (450°C), increasing the power cycle efficiency and further reducing the cost of thermal storage. The primary disadvantages are the high freezing temperature of the salt (120°C), higher heat losses from the solar field, concerns about the durability of the selective coating on the trough receivers, and the need for more expensive piping and materials to withstand the increased operating temperatures.

Subsequent projections after the year 2007 use a direct thermocline system with HitecXL (ternary) solar salt as the storage media and HTF. The solar field can be operated to higher outlet temperatures (500°C), increasing the power cycle efficiency. The thermocline uses a single tank that is slightly larger than one of the tanks in the two-tank system. A low-cost filler material, which is used to pack the single storage tank, acts as the primary thermal storage medium. The filler displaces the majority of the salt in the two-tank system. With the hot and cold fluid in a single tank, the thermocline storage system relies on thermal buoyancy to maintain thermal stratification. To date, a preliminary assessment was made on the potential impact that a thermocline storage system might have on the annual performance of the plant, and a more detailed analysis is in progress this year. However, this system will have similar concerns as the binary solar salt direct storage system. In addition to the development of a thermocline system, an advanced HCE will be required to obtain the 500°C HTF operating temperature.

The use of HitecXL solar salt is a major factor in lowering costs for future trough plants in the SunLab projections. The benefits and risks of the use of HitecXL are summarized below.

- Benefits:
  - Higher temperature – increases the power cycle efficiency
  - Single fluid in solar field and storage eliminates expensive heat exchanger required of earlier storage technology
  - Larger temperature difference across the solar field reduces the size of storage.
  - Molten-salt has better density and thermal capacity product reducing the amount of storage, shrinking flow rates and piping sizes, and heat losses.

- Risks:
  - Freeze protection in the solar field. The solar field must be maintained at temperatures higher than the freeze point. Impedance heating is envisioned for the HCEs. Nexant is currently working on a design for this.
  - Special O&M procedures are required to drain and refill loops for maintenance.
  - Solar salt corrodes graph-oil seals, and as such the current ball joints will not work with HitecXL. Sandia is working on flexhose and balljoint sealing options to resolve this issue.
  - The receiver selective coating needs to withstand higher temperatures. The Solel cermet coating will hold up to 500°C in vacuum. It is only when vacuum is lost that this is a problem.

The SunLab technology forecasts assume future storage will be based on the using HitecXL directly in the solar field and thermal energy storage. A number of alternative storage technologies are currently under development. The Europeans have a thermal energy storage research and development focusing on the development of two thermal storage systems for troughs. The first is a system that uses concrete for the storage media. The second uses phase-change materials and could be applicable for use with direct steam in the solar field. SunLab has also been working on the development of a new class of organic salt HTFs. The organic fluids offer the potential advantage of a molten-salt that is liquid at room temperature, eliminating the major drawback of inorganic molten-salts like HitecXL. Cost and temperature stability appear to be the main hurdles for organic salt HTF. Although all of these storage options are in the early stages of development, they provide alternative paths to achieving cost targets in a range similar to HitecXL.

D.8.3 Scale-Up

Cost reductions due to scale-up are not considered applicable since the storage system size, for the same number of hours’ storage, is directly proportional to the plant size. The SunLab projections also change the type of storage system in the years 2004, 2007, and 2010, which will tend to negate near-term potential scale-up cost reduction.

D.8.4 Production Volume

The storage system is not a manufactured module but consists of individual single components combined to create a system. The SunLab projections show a constant $/kWh$_t$ and $/kWhe for the direct thermocline system from the year 2010 and forward.

D.8.5 Cost Comparison

Definitive cost estimates for an indirect two-tank storage system based on detailed design drawings and material takeoffs were developed by Nextant (2001). The unit costs were \$36.40/kWh_t for 470 kWh_t system and \$31/kWh_t for a 688-kWh_t system. The SunLab projection appears to be conservative (on the high side) based on the previous estimates.

The direct two-tank storage value of \$12.68/kWh_t in the SunLab projection also appears to be conservative (on the high side) based on the power tower estimated values of \$8.65/kWh_t (Solar 50) and \$8.25/kWh_t (Solar 100).

The direct thermocline system value of \$11.73/kWh_t also appears to be conservative (on the high side) based on the Nextant estimates, which indicate a 35% cost reduction (\$8.37 kWh_t) going from a two-tank system to a thermocline system.

Since the values used in the SunLab projections appear to be at least 25% higher than expected based on other thermal storage estimates, the SunLab values were used in the cost analysis.

D.9 CAPITAL COST COMPARISON

The SunLab model projects parabolic trough plant capital and O&M costs based on various technology advances and commercial deployment predictions. The SunLab projections are considered the best case analysis where the technology is optimized and a high deployment rate is achieved. S&L developed capital and O&M costs based on a more conservative approach whereby the technology improvements are limited to current demonstrated or tested improvements and with a lower rate of deployment than used in the SunLab model. The two sets of estimates, SunLab's and S&L's, provides a band in which the costs can be expected to be, assuming the parabolic trough technology reaches the projected levels of deployment. A comparison of key parameters used for the estimates is summarized on Table D-27.

Table D-27 — Key Parameters Comparison

	2004		2007		2010		2015		2020	
	SunLab	S&L	SunLab	S&L	SunLab	S&L	SunLab	S&L	SunLab	S&L
Deployment, MW	300	300	600	300	1,200	750	2,400	1,000	400	400
Cumulative Deployment, MW	650	300	1,250	600	2,450	1,350	4,850	2,350	5,250	2,750

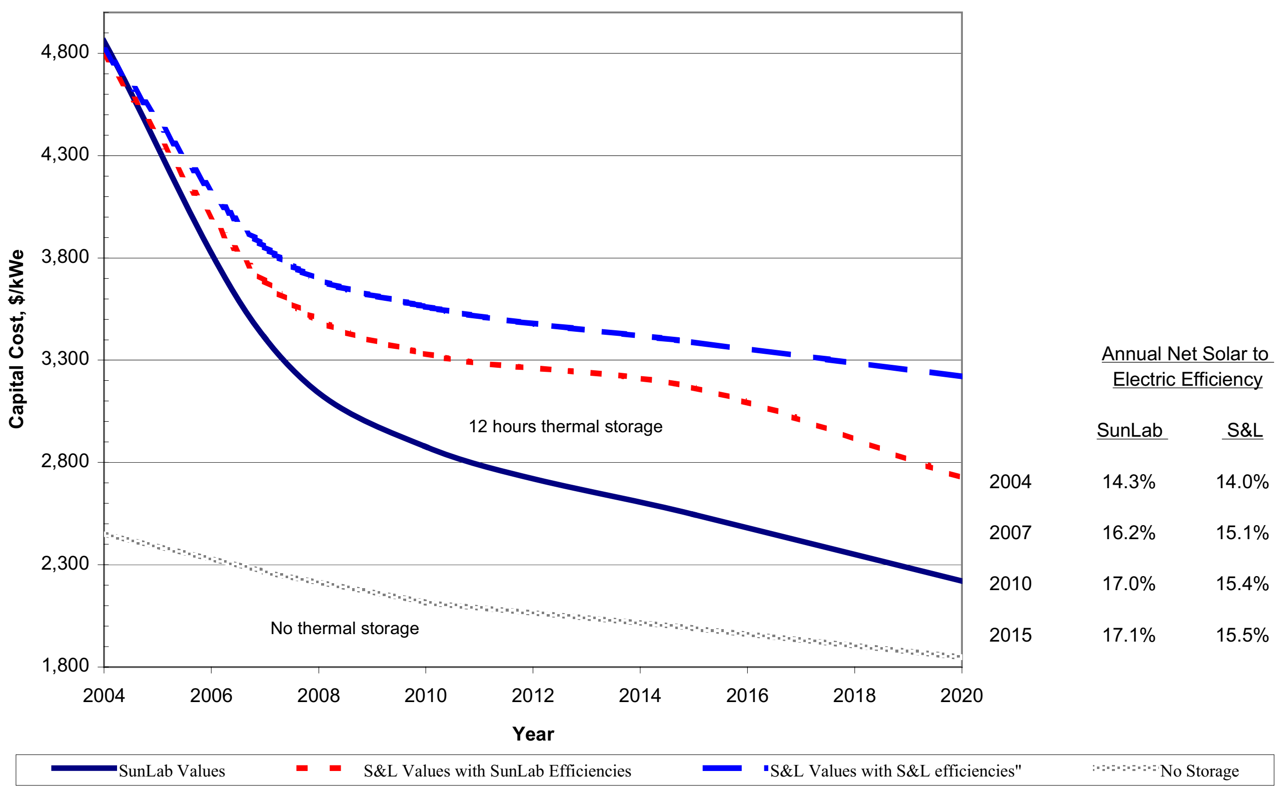
	2004		2007		2010		2015		2020	
	SunLab	S&L	SunLab	S&L	SunLab	S&L	SunLab	S&L	SunLab	S&L
Net Annual Solar Efficiency	14.2%	14.0%	16.1%	15.1%	17.0%	15.4%	17.1%	15.5%	17.2%	15.5%
HCE Cost, \$/unit	847	847	762	762	635	675	508	625	400	525
Mirror Cost, \$/m^2	40	40	36	36	28	32	20	29	16	26

Table D-28 and Figure D-5 illustrates the SunLab projected total installed capital cost (\$/kWe) compared to the more conservative S&L values. Figure D-5 also shows the total installed capital cost based on achieving the annual net efficiencies projected by SunLab, but not the projected cost reductions. The curves highlight the impact of the annual net efficiencies on the capital cost. The curves also indicate that additional cost reductions above and beyond the more conservative S&L values, due to technology improvements and increased deployment rates, will result in convergence of the capital costs toward the SunLab values.

Table D-28 — Comparison of Total Investment Cost Estimates (\$/kWe): SunLab vs. S&L

	2004	2007	2010	2015	2020
SunLab	\$ 4,859	\$ 3,408	\$ 2,876	\$ 2,546	\$ 2,221
S&L – S&L Efficiencies	4,816	3,854	3,562	3,389	3,220
S&L – SunLab Efficiencies	4,791	3,687	3,331	3,165	2,725
S&L – No Storage	2,453	2,265	2,115	1,990	1,846

Figure D-5 — Capital Cost Comparison



D.10 OPERATIONS AND MAINTENANCE

Sargent & Lundy has reviewed the SunLab O&M cost model based on our experience with fossil and other power plant technologies and in the course of a site visit to KJC Operating Company, the operator of the five 30-MWe trough projects located at Kramer Junction. KJC Operating Company provided proprietary information on the last five years of operation. The SunLab O&M estimate is based largely on the experience at the KJC Operating Company SEGS plants. The model assumes a stand-alone trough power plant (as opposed to the five co-located plants at Kramer Junction) and adjusts cost depending on the size of the solar field and total electric generation per year. It breaks out the specific staffing requirements for operations and maintenance crews for both the conventional power plant and for the solar field. Administrative staffing is also included. In addition to labor breakdown, the model breaks out service contracts, water treatment costs, spares and equipment costs, miscellaneous costs, and periodic capital equipment requirements. S&L conducted a detailed review of the SunLab model and compared it to general power industry experience.

The S&L O&M costs for comparison to the SunLab projections are based on the following:

- Solar Field
  - The initial unit costs are based on the SunLab values, and cost reductions for years beyond 2004 are based on a PR = 0.92
  - Replacement rate for the mirrors and HCE are based on the average actual replacement rates for SEGS III – VII for the period 1997–2001
  - The replacement rates for the balance of the solar field are based on the SunLab values
- Power Block and Balance of Plant
  - Costs are based on S&L data for the respective MW size plant for the steam turbine systems and balance of plant
- Water and Process
  - Costs are based on are based on the average actual costs for SEGS III – VII for the period 1997–2001
- Staffing, Services Contracts, Miscellaneous, and Capital Equipment
  - The costs are based on the SunLab values since the SunLab values were determined to be reasonable
- Thermal Storage
  - The costs are based on 0.4% of the capital cost per annum

Analyzing the two estimates revealed that the major component to account for the cost difference is the HCE replacement rate. Table D-29 shows a comparison of the SunLab and S&L projected replacement rates.

Table D-29 — Projected Trough Receiver Replacement Rates

Annual Failures (Percent of Field)	Current	2004	2007	2010	2015	2020
SunLab	3.5%	2.0%	1%	0.5%	0.5%	0.5%
S&L	5.5%	5.5%	2.5%	1.5%	1.0%	0.5%

The SunLab near-term values are not consistent with the average actual HCE replacement rate of 5.5% reported for SEGS III – VII for the period 1997–2001.

Sargent & Lundy reviewed the actual receiver (HCE) replacement rate reported by KJC Operating Company over the last five years. The S&L evaluation is based on total HCE replacement reported for the SEGS III – VII for the period 1997–2001. S&L's evaluation is based on the current replacement rate experienced at all the SEGS plants, with step reductions in the replacement rate based on the following considerations:

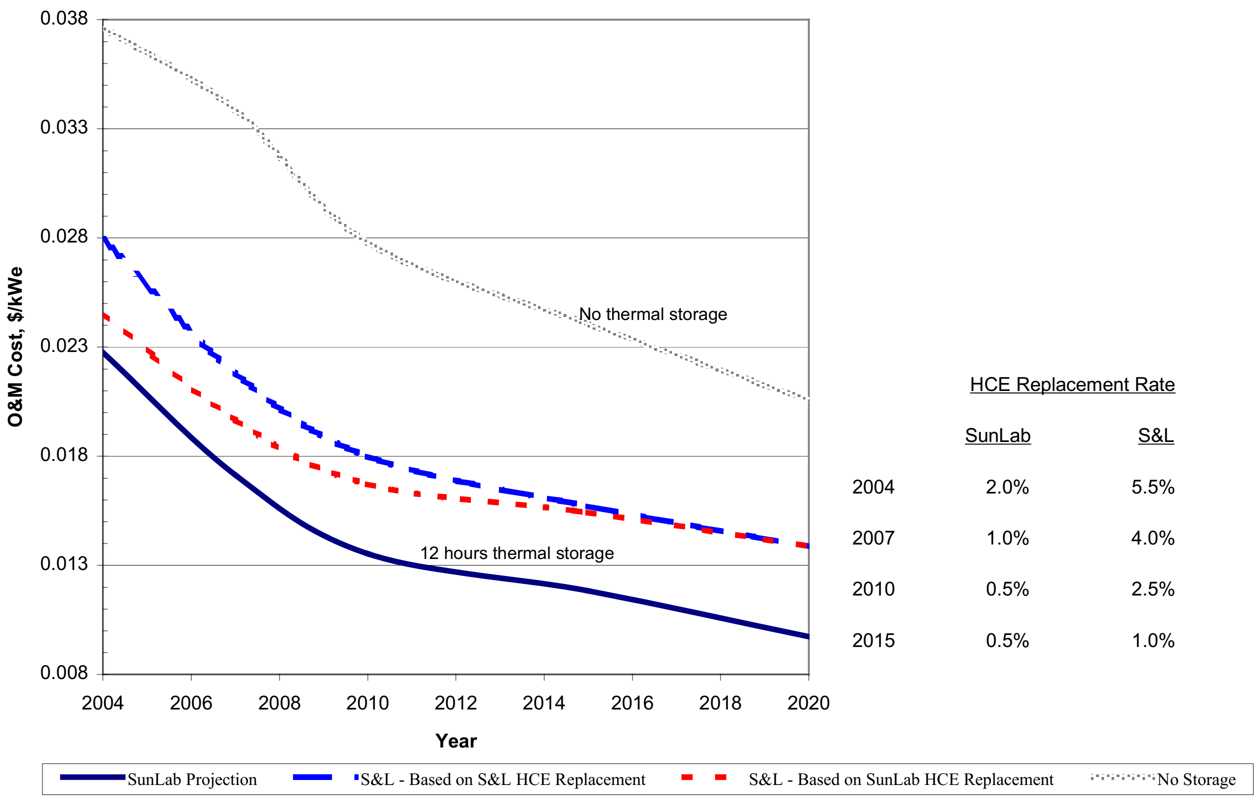
- The average actual HCE replacement rate of 5.5% was reported for SEGS III – VII for the period 1997–2001. The total HCE replacement includes breakage and fluorescence. Fluorescence is due to cermet coating failures. This failure is due to the existence of molybdenum in the original Luz cermet coating. Solel no longer uses molybdenum in the UVAC cermet coating, so this type of failure will presumably no longer occur. Eliminating replacements due to these failures reduces the site failure/replacement rate.
- SunLab has used the SEGS VI plant as the baseline reference plant. The SEGS III – V plants had problems during initial startup and the early years of operation that caused bowing of the HCEs, which increased breakage at those plants. SEGS VII has had higher breakage on the LS-3 half of the field, although the LS-2 failures are similar to SEGS VI. SEGS VI was the last full plant constructed with LS-2 collectors and represents the most mature version of this generation of collector technology. The HCE total replacement rate at SEGS VI during the 5 years is in the 5.5% range. Discounting the fluorescence failures, the replacement rate was 4.2% over the 5-year period.
- The high HCE failure rate at the existing plants is in part due to issues that would not be found at a future plant. A significant portion of the failures has been due to the hydrogen remover (HR) device installed in the HCEs at SEGS VI – X, operational problems that caused bowing, and HCE installation procedures. The HR is no longer part of the HCEs provided by Solel.

Based on these factors, it is very possible that future plants will have substantially lower HCE failure rates than currently found at the SEGS plants. The SunLab assumption of a 2% failure rate assumes that current approaches for reducing failures are successful. S&L believes this is an aggressive assumption that cannot be assured for future plants without the field data to verify the failure rate reduction. Using the current replacement rate at all the SEGS plants, with step reductions in the replacement rate, reflects the current conditions and allows for the aforementioned improvements to reduce the replacement rate.

Additional development of the HCE will likely be necessary to achieve the future receiver reliability goals. The current glass-to-metal seal is one of the more expensive elements and the key failure point of the current receiver design. The current design, known as a Housekeeper seal, relies on a sharp metal point being inserted into a glass bead. Failures occur when concentrated light focuses on the seal and the differential expansion between the glass and metal causes the failure of the seal. New designs are currently under investigation that attempt to improve the match between the coefficient of thermal expansion of the metal and glass. Kramer Junction is currently testing a new design UVAC2 with a revised internal shield.

To achieve the SunLab projected replacement rates the reliability of the HCE will have to significantly improve. Figure D-6 compares the O&M costs and illustrates the impact of the HCE replacement rate. The O&M costs without thermal storage is included for informational purposes.

Figure D-6 — Levelized O&M Cost Comparison



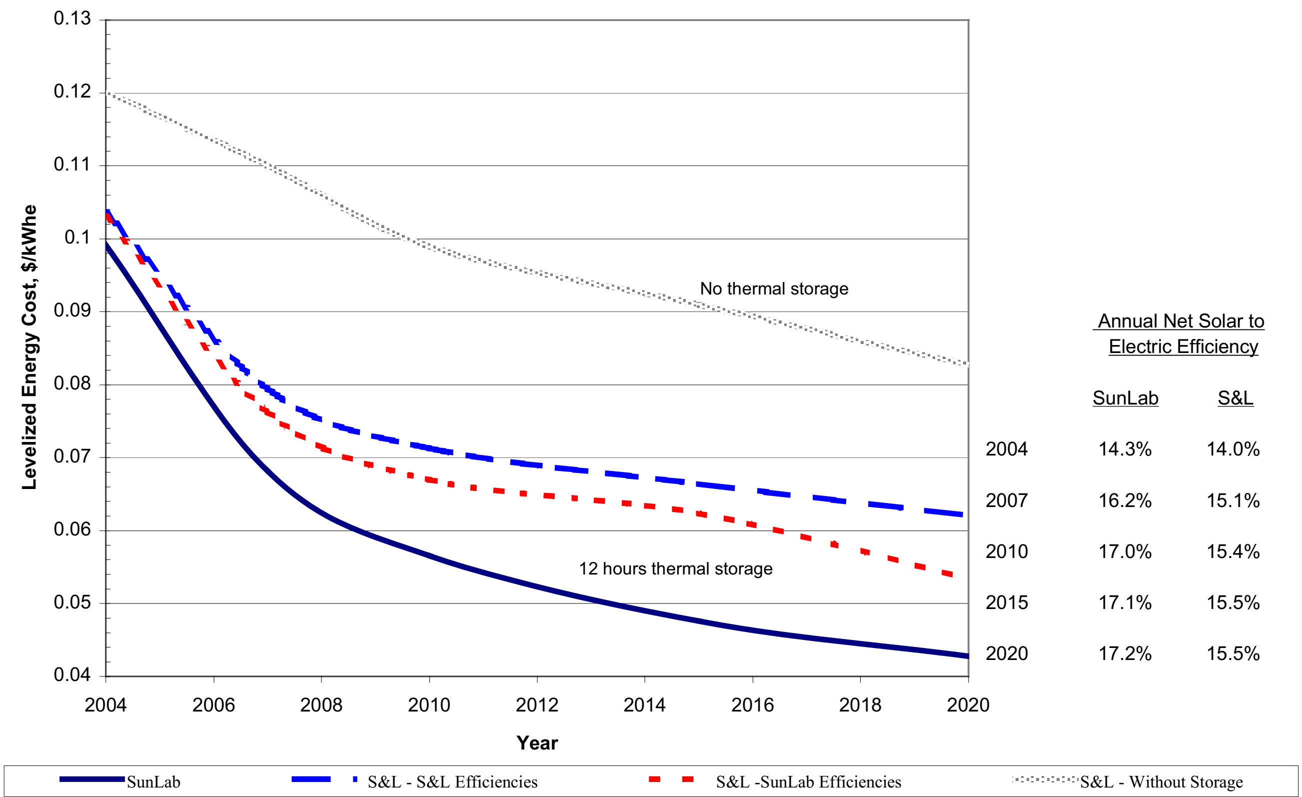
The reduction in O&M cost is primarily a result of the increase in plant size and the increase in annual plant capacity factor. The plant capacity increases directly as a result of the increases in thermal storage. Increasing the size (MWe) and capacity factor of the power plant incurs minimal increase in the fixed O&M expenses ($/year).

D.11 LEVELIZED ENERGY COSTS

Figure D-7 illustrates the SunLab projected levelized energy cost ($/kWhe) compared to the S&L values. The figure also shows the levelized energy cost based on achieving the annual net efficiencies projected by SunLab.

For comparison, the estimated levelized energy cost for the trough plants without thermal storage is included to underscore the importance of thermal storage in the reduction of the levelized energy cost.

Figure D-7 — Levelized Energy Costs



The curves highlight the impact of the annual net efficiencies on the levelized energy costs. The curves also indicate that additional cost reductions above and beyond the more conservative S&L values, due to technology improvements, reduced HCE replacement rates, and increased deployment rates, will result in further convergence of the levelized energy costs toward the projected SunLab values.

Figure D-8 shows the levelized energy cost for the SunLab technology forecasts with a breakdown that shows the source of the cost reduction from plant scale-up, technology R&D, and cost reduction through learning. Of the projected cost reduction in 2020, plant scale-up is projected to provide 20% of the total cost reduction, technology development will provide over half of the cost reduction at 54%, and production volume and competition will provide approximately 26% of the cost reduction.

Figure D-8 — Breakdown of LEC Cost Reduction (Scale-Up, R&D, Volume Production)

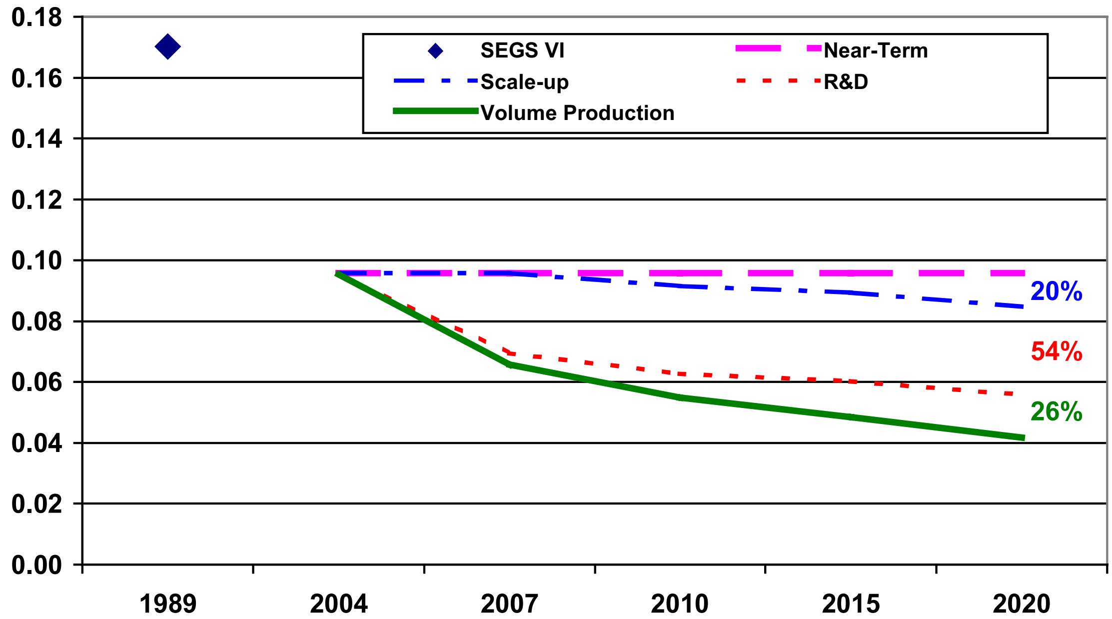


Figure D-9 below shows the importance of the five major cost components in reducing the LEC.

Figure D-9 — Breakdown of LEC Cost Reduction (by Major Cost Component)