Competitive Solar Electricity

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Abstract

Australia's primary environmental issues are atmospheric greenhouse emissions (the highest in the world), water shortage and soil degradation. Competitive dispatchable solar electricity would radically improve all three areas. In energy markets, it would replace coal-fired generation. As a desalination energy source, new sources of fresh water, and it would allow relatively sustainable drip irrigation of otherwise dry land. While much attention has been placed upon small remote or rooftop systems, governments are increasingly interested in large Greenhouse benefits. Large grid-based solar electricity has the capability to achieve such massive environmental gains.

In this paper, a new general design philosophy for a large pure solar storage plants is discussed, with application to central electricity generation and desalination. This involves the mating of a low cost solar array technology to very large low temperature Rankine cycle turbines and cavern based steam accumulators. The advantage gained by low temperature operation derives from an unusual combination of large low cost low temperature turbines developed for the nuclear industry, and an inexpensive storage concept that suits that particular temperature range. Should both options be applicable, then this may be the most cost-effective solar thermal electricity development path.

The proposed stand alone plant design will use the same low cost Compact Linear Fresnel Reflector (CLFR) array system previously reported (Mills et al, 2003) and currently being trialled for a coal fired plant preheating project. Based upon early production costing, costs using large turbines appear to be comparable to conventional coal fired generation, even in the first plants.

1. INTRODUCTION

There has been much emphasis placed in the past on the adaptation of high temperature fossil fuel turbines to solar energy, with an attendant ability to utilise fossil fuel for backup energy. However, there has been a recent shift of interest to high solar fraction or even 100% solar plants because of the strict incentives that have been set up in countries like Spain, and Germany. Fully renewable operation is also advantageous in tradeable renewables certificates programmes like that of Australia, because the investment in the power block can be repaid at a higher rate if the renewable energy is available around the clock.

In the past, it has been usually presumed that primary fossil fuel in large quantities is cheaper than solar heat. However, the handling of fossil fuel is also expensive.

Hybridisation with fossil fuel was used in early parabolic trough plants to give solar more reliability in the absence of storage. However, the price paid by a solar system for hybridisation is high, because the solar system must be made compatible in a higher output temperature with the fossil fuel turbine, increasing array thermal losses, and because the actual cost of equipment to handle, combust and dispose of fossil fuel waste is also surprisingly high. Recent results of a tender in Cyprus for a 120 MW oil fired fossil fuel plant were Turbines: 42.7%; Boilers: 31.6%; Flue Gas Desulphurisation: 14.1%; Transformers: 11.6%. Boilers and fossil fuel treatment are about 45% of the cost. The cost of 20 years of oil is very similar to the avoided fossil fuel equipment. Thus, perhaps 2/3 of the lifecycle cost of this oil-fired plant can be directly related to either fossil fuel handling or fossil fuel price. Removal of the fossil fuel input saves a great deal of money. Is fossil fuel hybridisation really necessary?

A turbine system and storage unit optimally designed for a pure solar plant may be very different from that which is designed for a solar/fossil hybrid. Such a unit would operate at lower temperature to minimise array thermal loss, involve very low cost collector technology in order to be cost effective with a lower temperature turbine of limited efficiency, and would need inexpensive storage to allow full turbine utilisation over day and night.

2. LOW COST SOLAR ARRAY DESIGN

In this paper, the stand alone plant design proposed will use the same low cost Compact Linear Fresnel Reflector (CLFR) array system previously reported (Mills et al, 2003; Hu et al, 2003) as being constructed for a coal fired plant preheating project; this project has now been re-estimated to be approximately 40 MWe. The project, reported in this conference (Mills et al 2004) as being built for Macquarie Generation in NSW, has been recently reformulated into three stages; a proving array of 1350 m2, a stage 2 array of 67500 m2 incorporating stage 1, and a stage 3 array of another 67,500 m2. After stage 3 is built, this will be the largest solar electricity plant built since the last LS3 parabolic trough field built in California in 1990, and will provide a solar electricity capacity roughly the same as current installed PV capacity of Australia (Watt, 2003). However, it is employed in this application as a transitional system that proves the array components prior to production for much larger pure solar power plants. Stage 1 performance has been proven in initial testing at Liddell as reported in a technical paper at this conference (Mills, 2004).

The array technology was originally developed at the University of Sydney in 1993 (Mills and Morrison, 1999). It is called the Compact Linear Fresnel Reflector (CLFR) technology. In this approach, ground level reflector rows aim solar beam radiation at downward facing linear receivers mounted on multiple elevated parallel tower lines. The technology is innovative in that it allows reflectors to have choice of two receivers so that a configuration can be chosen which offers minimal mutual blocking of adjacent reflectors and minimum ground usage.

Fig. 1. The 1350 m^2 Stage 1 array and tower line produced by SHP at the Liddell power plant site. This plant will be 100 times larger by stage 3.

However, there are also many supporting engineering innovations in the commercial product developed by SHP, including highly rigid space frame mirror supports with 360° rotation capability, hoop-like driver rings allowing high mechanical advantage for tracking motors, long horizontal direct steam generation cavity receivers, and array fine tracking control electronics. The design of the CLFR array design also incorporates high volume production elements used in other industries to reduce engineering cost. The array system is linear like a parabolic trough collector, but it has a number of advantages over troughs that allow significant cost reductions, such as a long focal length allowing elastically bent flat standard 3 mm glass reflector to be used instead of expensive heat-sagged glass.

In a recent paper (Mills et al, 2004), the costs of the CLFR array were estimated in larger production to be approximately US$102 per m^2 installed, but this paper was written conservatively and before recent aggressive cost reductions involving some redesign and the use of highly competitive international quotations. A recent cost determination has determined an underlying installed array cost (not including profit or land cost) in near term plants of A$88 per m^2 with a possible future potential as low as $80 in Australia.

3. POWER BLOCK + BOP COSTS

The traditional approach to the design of a line focus solar plant is to use a parabolic trough system for the supply of heat at between 320°C and 400°C to the main boiler and superheater of a conventional turbogenerator (NREL, 2003). However, in trough and CLFR systems, thermal losses can rise rapidly with array operating temperature, partially cancelling out improvements in thermal conversion efficiency. In addition, the traditional path of using a superheated turbine requires more highly efficient and durable selective coatings, thicker-walled tubing for steam pressure containment, and the use of oil instead of water as a heat transfer fluid if operating above the water triple point.

An alternative case can be made for a design that minimises array thermal losses using low temperature (200°C – 300°C) saturated steam Rankine cycle turbines. Although some effort has been made to look at low temperature trough systems using small organic Rankine cycle turbines (NREL, 2002), in this temperature range, higher efficiency demands a large turbine. In addition, the array cost of the CLFR is low enough that the added cost of fossil hybridisation is relatively high. For low cost and reliability, one needs a proven system stripped of expensive fossil fuel equipment.

Interestingly, the nuclear power industry has spent many years and huge sums developing non-fossil fuel turbines that meet these requirements. These, at about 31-33%, are more efficient than smaller organic Rankine cycle turbines or high temperature micro-turbines. They operate from saturated steam, using steam separators to dry out the steam before entering the turbine, and they use special turbine blade design. No superheating stage is required, so the solar array needs only meet the main boiler operating temperature, which in the case of the Russian VVET is only 250°C. If one were to design a turbine type to suit a large solar direct steam generation array like the CLFR, it would be something close to the VVER design, although there might be a case for operating in the range 300°C – 350°C to increase thermodynamic efficiency. However, operation at 250°C allows significantly lower array losses than operation at 450-500°C as proposed for advanced trough systems (NREL, 2003) and allows the use of a wider variety of air stable selective coatings on the receiver. Steam pipes are also substantially cheaper in the lower temperature range.

The smallest nuclear turbines one can obtain are of about 240 MWe peak capacity, which would lead to a solar plant larger than any yet built. The low temperature turbine costs used in the paper are based upon approximate estimates (VVER, 2003) supplied by JSC “Atomstroyexport” (Russia). The supply of a 240 MWe VVER steam turbine and steam separator and control equipment of about US$18 million for a single turbine, well below high temperature turbine cost. It is conservatively assumed in this paper that an additional 1/3 will be added to the turbogenerator price to cover delivery and installation. Several sites have been found in Australia with excellent solar radiation and grid access. The most attractive of these has enough spare grid capacity for a 240 MWe installation.

Estimates from are used for the high temperature power block costs. The low temperature turbine costs are based upon approximate estimates (VVER, 2003) directly supplied by JSC “Atomstroyexport” (Russia) for the supply of a 240 MWe VVER steam turbine and steam separator and control equipment of about US$18 million (A$26 million) for a single turbine. It is assumed in this paper that an additional A$11 million will be added to the turbogenerator price to cover delivery and installation. The power block costs include the steam turbine and generator, steam turbine and generator auxiliaries, feed water and condensate systems. Balance of Plant (BOP) costs are taken from (NREL, 2003). BOP costs 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. Table 1 gives the combined power block and BOP costs:

Table 1. Total Power Block and BOP Costs in US$/kWe for a 240 MWe Solar Power Station

HT Power Block Cost, 500°C	226
LT VVER Power Block Cost	100
NREL BOP Estimated Cost	163

4. A LOW TEMPERATURE LOW COST STORAGE SYSTEM

Storage in two tank systems using hot oil and molten salt has been demonstrated, and single tank thermocline systems may be substantially cheaper (NREL, 2003). The year 2010 projection for a direct thermocline storage uses Hitec XL (ternary) salt HTF in both the solar field and the thermal storage system, removing the need for a heat exchanger between the solar field and storage system. Use of the Hitec allows higher outlet temperatures (450°C), increasing the power cycle efficiency and further reducing the cost of the thermal storage. SunLab (NREL, 2003) estimates the storage system cost at US$7.9/kWht for 500°C operation, but demonstration of this salt circulation at 500°C has not yet been reported in a solar concentrator, although it is known that work is going on in Italy along these lines. This can be taken as a long term cost target for other storage possibilities.

The concept of underground thermal energy storage (UTES), which we will refer to in this paper as 'cavern storage', appears to have been first advanced by R&D Associates in 1977, as quoted in 1983 report from SERI (Copeland and Ullman, 1983; Dubberly et al, 1983). It involves storage of water under pressure in deep metal lined caverns where the pressure is contained by the surrounding rock and the overburden weight. Fourteen organizations were involved in deriving the comparative rankings, which indicated quite definitively that cavern storage was the cheapest storage method at the time. More recently, Tanner (2003), produced, at the suggestion of one of the authors, a thesis report on cavern storage applied to the case of the CLFR. This study investigated the current costs of a steel lined cavern at depths of 200m and 400m and indicated that cavern storage is much cheaper than other currently proposed storage methods at an installed cost of US$16.4 million for a plant providing 54% capacity factor. In this paper we have conservatively assumed this cost to be 1.5 times the indicated Tanner value, to reflect cost uncertainty.

Table 2. Storage Options Considered for Solar Thermal Plants

Medium	US$/kWe	Reference
VP-1/Solar Salt	958	(NREL, 2003)
HitecXL at 450°C	425	(NREL, 2003)
Cavern at 300°C	90	SHP estimate
Caloria Two-Tank	674	(NREL, 2002)

Oil storage is well proven, having been used for many years on the first LS2 trough plant in California, and can be used instead of cavern storage for operation below 304°C. Oil storage was examined in a recent NREL report (NREL, 2002) on organic Rankine cycle trough systems. In this report, thermal storage using mineral oil (Caloria) in a two-tank system approaches an asymptotic cost of US$14/kWht. In Mills et al (2004), this cost is estimated to be US$674 per kWhe. The resulting options are given in Table 2; these include heat exchange cost where applicable.

5. TOTAL PLANT COSTS FOR 240MWE 12 HOUR STORAGE SYSTEMS USING CLFR AND TROUGH TECHNOLOGY

In this section US dollar costs are used because of the number of USD sources.

In (NREL, 2003), the receiver thermal loss factor is 0.81 for the 500°C 2010 case and a 40% turbine efficiency is used. For the 500°C case the temperature across the field is assumed to rise by approximately 200°C, so that the average fluid temperature will be 400°C. The loss factor will be reduced by operating at 300°C, which corresponds to an average field fluid temperature of 275°C; the new emissivity loss factor (ELF) - neglecting the change of emissivity with temperature – will vary as the 4th power of the absolute temperature difference, so that making a simplifying mathematical assumption that the fields have these average temperatures throughout and that the emissivity is constant with temperature,

ELF = 1-[(547-300)**4 /(673-300)**4 x 0.19] = 0.963

The header pipe loss factor HLF is 967 at 500°C outlet temperature and at 300°C outlet temperature will be

HLF = 1-[(275-30)/(400-30) x 0.033] = 0.978

These thermal losses may be summed, so that (1- ELF) + (1- HLF) = 0.059 and the total thermal loss factor at 300°C is consequently 0.94. Thermal efficiency of the power block at 300°C is lower, increasing the array size by the factor of 0.4/0.315 = 1.27, but lowered heat loss decreases the array size by .81/.94 = 0.861 for a net size increase of 1.27 x 0.861= 1.09. In practice, the collector may be able to be constructed more cheaply at the lower temperature, but the extent of this reduction is unknown and is not included.

Table 3. Total system costs for trough systems in US$ per kWe in 2010, for a capacity factor of 56%.

Trough System	400°C Trough (current)	500°C Trough Hitec	300°C Trough Caloria	300°C Trough Cavern
Array	3531	2644	2882	2882
PowerBlock+BOP	499	389	207	207
Storage	958	383	674	90
Total	4856	3416	3763	3179

It is clear in Table 3 that trough systems can obtain the most positive cost/benefit using VVER + Cavern storage, but the VVER + Caloria option is less favourable than the 500°C Hitec salt option. While it may seem that Caloria should be ignored, it is an option which contains very little risk and could be installed at a premium of only 10% compared to a year 2010, 500°C molten salt system. Operation at 500°C with salt in long absorber tubes has not yet been demonstrated.

Table 4 shows similar results for the CLFR; much reduced collector costs attained in the CLFR system are the predominant factor in cost reduction. In this case, the use of Caloria now incurs an approximate 50% penalty over the Cavern storage option, but the result is still far lower in absolute cost than any trough option. The cost of a Caloria CLFR system is approximately half the cost than a 500°C Trough, and the Cavern storage option is cheapest, at about one third the cost of a 500°C Trough system.

Table 4. Total system costs for CLFR systems in US$ per kWe in 2008 for a capacity factor of 56%

CLFR System	300°C CLFR Caloria	300°C CLFR Cavern
Array	898	898
Power Block + BOP	207	207
Storage	674	90
Total	1779	1195

Cavern storage has not been proven but can be costed due to the commonality with modern mining technology, and it is an open question whether the technical risk is higher than that of 500°C molten salt trough system operation. Certainly, the environmental impact of a Cavern storage accident will be minimal, as water is the storage medium and any release of water HTF will not pollute the environment.

The CLFR/cavern 2008 proposal of 56% CF at US$1185 per kWe also offers costs well below 2020 estimates for both troughs at 56% CF (2225 – 3220 $/kWe) contained in a NREL report (NREL, 2003) which use Hitec salt storage at up to 500°C. It should be mentioned that the CLFR/cavern 2008 proposal is far from optimised; Tanner (2003) suggests cavern storage to be lower in cost than we have assumed, and this may decrease project cost further. The array costs are for the first large CLFR plant, and further array costs reductions may occur in high volume production.

6. AN EXAMPLE PLANT IN AUSTRALIA

Table 5 show the projected costs of the first large plant which might be built in NSW at high solar radiation sites on grid. The project costing is without manufacturer profit included in order to emphasise underlying cost; such a project could be mounted by the company without profit in order to acquire rights to the plant IRR, which is in essence the model used by conventional utilities, who own the generating plant and obtain profit throughout the plant lifetime. It is also possible to onsell the future plant income to an investor at the future life cycle value.

Table 5. Financial analysis of a 240 MWe CLFR stand alone plant in NSW that in Phase 1 has only a buffer storage, but in phase 2 acquires a cavern storage system. The total project cost is a societal cost similar before company profit and subsidies. If the manufacturer installs the plant without profit, a substantial IRR can be generated which can be pre-sold to investors. All costs are in Australian dollars.

240MW Segment	Phase 1 (low CF)	Phase 2(CF expansion)	Phase 1 + Phase 2
$M Capital Cost (No Margin)	$155.66	$292.38	$448.04
Mirror Area m2	1,054,000	2,450,000	3,504,000
Daily Average Thermal Output MJ	11.00	11.00	11.00
Peak Output MW(th)	800	1,860	2,660
Peak Output MW(e)	240	240	240
Annual Output MWh	1,176,308	2,734,302	3,910,610
Annual Plant Capacity Factor	17%	39%	56%
Thermal to Electrical Efficiency	30%	30%	30%
Annualised MWH(e) output	352,892	820,291	1,173,183
Cost of capital	8.5%	7.8%	7.8%
CPI	1.5%	1.5%	1.5%
Levelised Cost per KWh	$0.0525	$0.0384	$0.0427

It should be understood that under MRET the selling price of the solar electricity would be always about A$0.08 per kWhe, and this allows a high IRR. However, of greater long term interest is the levelised cost shown, which under an unsubsidised regime with carbon credits, should also be competitive against fossil fuel. Herzog and Golomb (2003) suggest that the basic generation cost of pulverised coal plants in the USA is US$0.045 (A$0.064 at the time of writing), much higher than a CLFR plant in a high solar radiation location. Furthermore, Herzog and Golomb suggest that pulverised coal plants could incur an additional cost of US$0.025 to 0.05 per kWh$_e$ for long term cost carbon sequestration.

In Australia in 2002, the long-term average electricity pool price ranged from 3.25 to 3.85 c/kWhe in NSW, Victoria, Queensland and SA but this operates already amortised plant. A new coal plant in Western Australia would cost 4 – 4.5 cents per kWh according to WA government statements (Farrant, 2000), and with recent rises in gas price, gas fired plants are likely to be higher then the solar cost. Because of different costs at different sites, the best one can say is that the solar cost seems similar to low cost fossil fuel before consideration of the evironmetnal costs of the latter.

7. DESALINATION

Energy for desalination can be supplied by CLFR arrays without pollution either as thermal energy or as Reverse Osmosis (RO) membrane plants using electricity. In NSW, high solar radiation regions are inland but not near the seacoast, so an inland RO solar electricity supply is probably more cost effective than a thermal plant on the coast. In Western Australia, good solar conditions persist to the coast, so a CHP solar electricity plant supplying electricity to the grid and thermal energy (using a higher than usual condensation temperature) to a thermal MSF or MED desalination plant may be optimal.

Pure solar thermal desalination is unlikely to be cost effective in NSW as MRET does not allow solar heat to attract Renewable Energy Certificates (REC's). Preliminary estimates of the cost for RO desalinated water in RO plants eligible for MRET are below A$0.10 per kL, compared to about $0.25 per kL for thermal plants. These are highly competitive prices, comparable to desalination from cheap fossil fuel or baseload electricity.

8. IMPACTS

Provided an initial array can be proven in storage form, it would be possible to devise a strategy in which growth of new fossil capacity is capped while retirement of old fossil capacity is replaced by solar capacity. It would still take decades to fully replace coal because of the expected lifetime of current coal fired plants, but large scale implementation of solar technology should be possible after 2010, well in advance of many forecasts. There would be regional impacts, with coal based economies slowly declining and high unemployment inland regions with high solar potential benefiting substantially.

Although intended to replace fossil fuel, the new CLFR technology may have other impacts. Australia's support for the commercialization of renewable energy is through a competitive framework in which renewable sources of energy compete against one another. A 54% CF 240 MW plant will generate 21% of MRET targets, and the maximum likely plant construction by 2010 (530 MW) would generate about 46%, but it is probable the current MRET target would be exhausted before much of the solar plant capacity could be installed. This means most of the MRET target is likely to be met by wind and solar water heating. However, about the time of full subscription of MRET, the low cost of CLFR technology may begin to seriously affect other renewable energy technology in the marketplace. This will be compounded by other advantages of the CLFR, such as dispatchability, small land usage, and small visual impact relative to end use solar and wind approaches. Drivers for energy efficiency and such end use technologies such as solar water heating may become purely economic rather than environmental.

In environmental terms, the technology provides relatively low cost electricity and would allow Australia to approach IPCC-based climate targets (around 9 times less than Australia's current per capita emissions) which are much stricter than the Kyoto targets.

CONCLUSIONS

The potential cost advantage gained by low temperature operation derives from a unique combination of a low cost array technology, large low cost low temperature turbines developed for the nuclear industry, and an inexpensive storage concept which suits that particular temperature range. This proposed concept is likely to be the most cost-effective and low risk solar thermal electricity development path, as it uses simple solar collector technology already being installed, and a proven turbine from the nuclear industry. Levelised societal costs of around 4 Australian cents per kWh seem achievable with the first plants, with possible further drops in later.

Cavern storage cannot be taken higher than about 360°C and still has some developmental uncertainty ahead of it, but two reports have now identified it as potentially the lowest cost storage concept. Recent discussions that the authors have had with geologists and mining companies suggest the concept is in the realm of current mining technology and can be widely applied; suitable rock structures are common. The CLFR/cavern approach is unoptimised and costs should trend lower, in particular with the adoption of large turbines in the 600-1000 MW class and identification of the true costs of cavern storage after initial prototyping. However, the uncertainty in total project future costs is relatively small since the collector array is the largest portion at 75% of a large project cost, and these costs are now well known.

If suitable geological structures are not available, Caloria oil storage with a CLFR array is a low risk option available for a cost which is still below the cost of trough collector systems, but the LEC of the solar system would rise from 4.1 to 5.9 Australian cents per kWh. Environmentally, however, cavern storage would be safer than either molten salt or oil solutions.

The conclusions of this paper are that

1) Dispatchable solar thermal electricity will become competitive with fossil fuel in Australia during the next 5 years. SHP is already looking to acquire investment funding for the first CLFR stand alone plant.

2) CLFR systems should be much cheaper than new fossil plant incorporating any form of carbon sequestration, should the latter technology be able to be demonstrated together with coal technology, and earlier in implementation.

3) Solar desalination will become a low impact, cost effective option in the same time frame.

4) Other renewable technology may face some difficulties in the marketplace in the face of low cost solar electricity, and may need to reassess R&D goals and markets.

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