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# TRNSYS MODELING OF A 100 MWE HYBRID COMBINED CYCLE CONCENTRATING SOLAR POWER PLANT


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## Abstract

This paper presents results of thermodynamic and cost modelling of a 100MWE Hybrid Concentrating Solar Power Plant with thermal storage, situated in the Upington area of South Africa. Several control strategies are explored and their effect on the levelized cost of electricity noted. The availability of storage allows us to fine tune our output power to match demand patterns, and to optimize economy. A levelized cost of electricity in the region of 0.09 € /kWh was calculated for the hybrid plant, at an annual solar fraction of 46%.



*Keywords: Concentrating Solar Power; Thermal Storage; combined cycle; hybrid generation.*


## 1. Introduction

South Africa (especially the Northern Cape and North West provinces) has some of the finest solar resources in the world. For example around Upington the annual DNI is estimated to be in excess of 2800 kWh /m$^2$ [1] and some regions even exceed 3000 kWh /m$^2$. By comparison the solar sites in Spain are in the region of 2000-2200 kWh /m$^2$, and most of the solar plant in the USA is around 2700 kWh /m$^2$. This coupled with a growing need for electricity and concern about greenhouse gas emissions make solar plants an attractive possibility. As with the automotive industry, where hybrid cars lead the way to a renewable future, hybrid CSP stations offer many advantages in the initial phases of solar power build out. The reasons for this are many: improved economy, flexibility of operation, dispatchable power and reduced engineering risk.

## 2. Summary of plant

This plant model is based on the SUNSPOT concept proposed by Prof D Kröger [2]. It is modelled in TRNSYS [3], a component based modelling software originally developed for thermal modelling of buildings, but now also widely used in the CSP industry [4]. In particular Jones et. al. [5] used TRNSYS to model the SEGS IV parabolic trough system, and compared it to actual plant data for different days - full sun and cloudy days with transients. The model matched the real data quite well; tracking the real plant output and gave results for total generated power and parasitic power within 10% of the measured figures.

The initial model shown in Figure 1 consists of fields of 4000 heliostats of size 100 m$^2$ each. Solar DNI and azimuth and zenith angles are given by a weather file for Upington, South Africa, which contains weather data for a whole year, in hourly increments. The heliostat field is modelled by a simple efficiency matrix which gives a global figure for the whole field efficiency, which is only dependant on azimuth and zenith solar angles.

These heliostats focus onto an air receiver with a secondary and tertiary concentrator. Such air receivers have been built and tested [6], and air exit temperatures of greater than 1000 °C have been achieved. Air is compressed by an axial flow compressor to 15 bar and fed through the receiver at 1500 tons/hr. After the receiver (where peak temperatures in this simulation reached 930 °C) there is a combustion chamber that raises the air temperature to 1100 °C. This hot air is then fed through a gas turbine and exhausts from the turbine at roughly 500 °C.

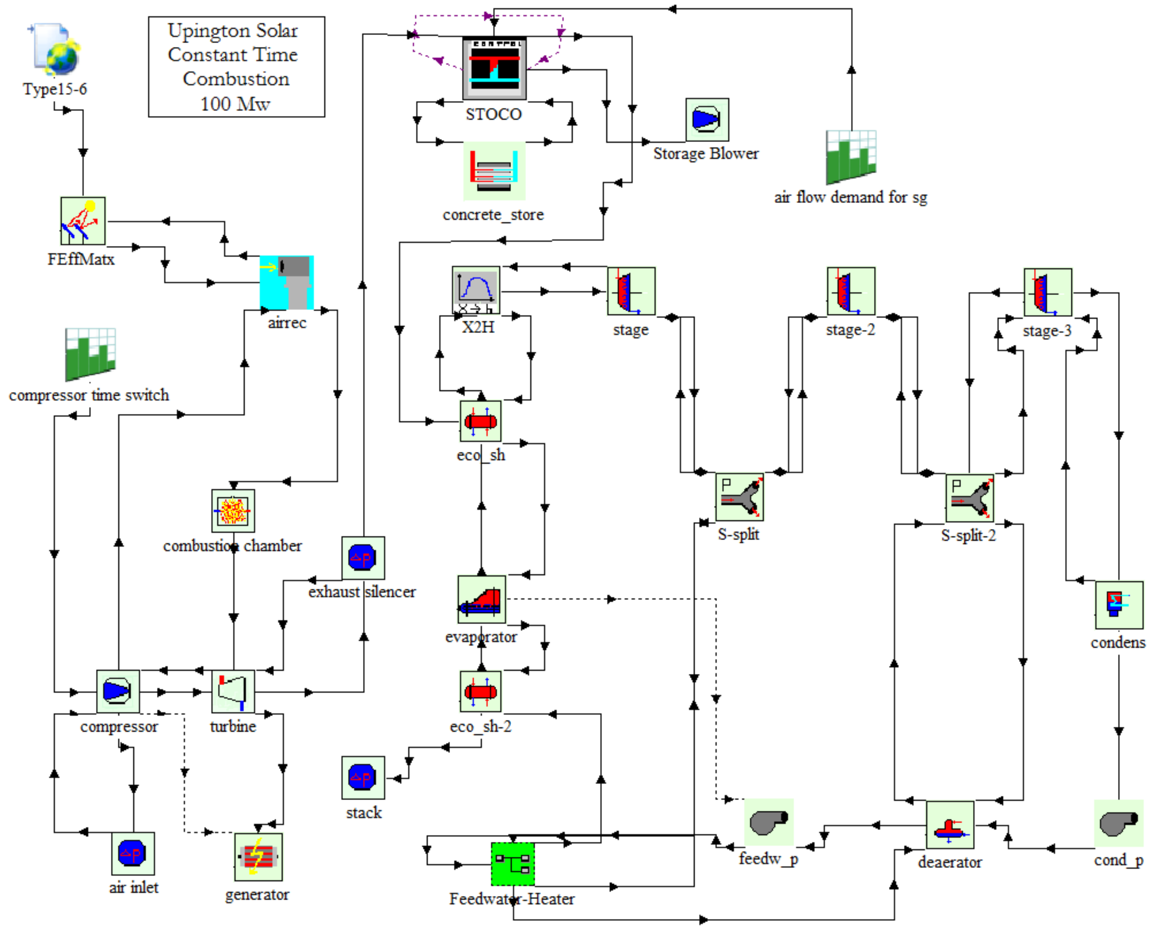


**Figure 1 TRNSYS Plant Layout**

The gas turbine ramped up every day between 5h45 and 6h00 and ramped down again at 18h45 to 19h00. During the day (when we have the gas turbine running) it produces roughly 110 MWe.

This gas turbine exhaust is then split (depending on steam demand) between a Heat Recovery Steam Generator (HRSG) and a thermal storage consisting of 20,000 tons of thermal concrete with pipes running down its length. We initially tried to use the rock bed thermal storage component in TRNSYS, but problems with this component and controller led us to use the concrete heat storage component. Substantial work has been done at Stellenbosch on modelling rock bed storage [7] and it would be a useful piece of future work to incorporate rock bed storage into the model.

The HRSG and thermal store is controlled by a steam demand pattern which we set empirically. We requested 600 tons/hr of hot air into the HRSG throughout the day, with a ramp up to 1500 tons/hr during Eskom's peak load period [8] (see Figure 2). The ramp up from 600 to 1500 tons/hr occurred over the hour from 15h00 to 16h00, and the ramp down back to 600 ton/hr occurred between 20h00 and 21h00. This pattern is easily configurable for any demand pattern or pricing model that a grid operator might demand. When there is hot gas flowing from the turbine exhaust, the thermal control decides whether to charge the thermal store or provide gas directly to the HRSG based on the steam demand. The thermal store can either be in charge mode or discharge mode, it cannot do both simultaneously.

The steam generation system consists of standard STEC (Solar Thermal Electric Components) parts of feed water heater, economizer or preheater, evaporator and superheater. The superheated steam is then passed through three turbine stages with steam extraction between each stage. The steam extracted between the second and third stages was sent to the preheater, and the steam extracted between the second and third stages was used in the deaerator.

This model includes a water condenser, mainly because there was not an air condenser component in the STEC libraries. This might be a useful addition to the libraries to write such a component. Based on South African conditions, we would probably want to move to an air-cooled condenser [9], which would save water, but at a slight decrease in efficiency.

## 3. Startup Sequence

When the system is initially started with the thermal store at ambient temperature, it takes several days (see Figure 3) for the thermal store to reach steady state. With the current sizing of the thermal store, only on the first night (see **Figure 4**) do we run out of steam. From then on through the rest of the year there is adequate thermal energy in the store to keep the steam system running all night, albeit at reduced capacity.

**Figure 2 Eskom Demand curve**

When we initially constructed the model, we used a solar power threshold to start the gas turbine in the morning, and to shut it down in the evening. This led to a large mismatch between summer and winter operation, either there was waste heat in the summer or insufficient thermal energy in the winter to run the steam system all through the night. It was found much easier to model, and correctly size the thermal store and steam components, if we ran the combustion chamber for a constant time period summer and winter. This would probably also happen in a real plant, as South African electricity demand is greatest in winter.

If we examine the power output during startup as seen in **Figure 4**, we see the daily gas turbine output, which is nearly constant, with slight variations as solar intensity changes and the combustion chamber makes up for it, then the steam output which runs steadily at around 20 MW during the day. At this time the controller diverts some of the hot turbine exhaust straight to the HRSG, and the rest to charge the thermal storage. Then at around 4 pm we increase the steam demand and steam output power rises to roughly 40MW. At 19h00 the compressor and combustion chamber are ramped down, and the steam system starts running just from the thermal storage. At 20h00 the steam demand is ramped down, and the turbine continues running from the thermal storage all night, although with declining power production as the temperature of the hot end of the storage is decreased. We set a minimum of 300 °C for the steam controller, if the hot end of the storage dropped below this, the steam system shut down.

## 4. Results for a year run

The summary of the plant parameters is given in Table 1, Table 2 and Table 3, and a summary of output in Table 4

| | |
|---|---|
| Number heliostats | 4000 |
| Heliostat area each | 100 $m^2$ |
| Peak thermal power onto receiver | 285 MW |
| Combustion chamber exit temp | 1100 °C |
| Combustion chamber air flow | 1500 ton/hr |
| Compressor pressure | 15 bar |
| Peak power electric | 117 MW |
| Peak turbine shaft power | 280 MW |

**Table 1 Solar Field and gas turbine Plant Parameters for 100 MW Plant**

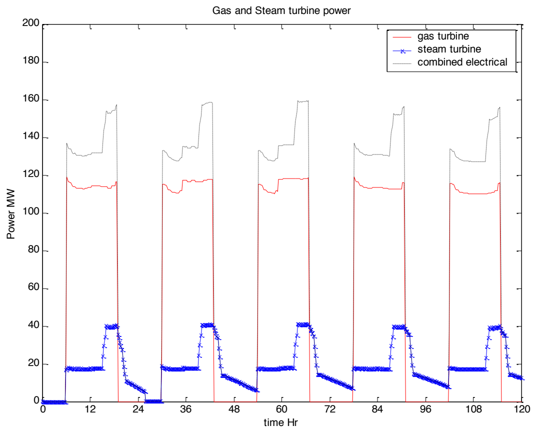


**Figure 3 Storage Charging**

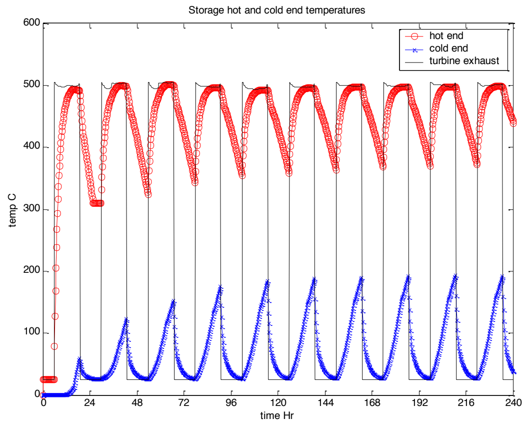


**Figure 4 Gas and Steam turbine output**

| | |
|---|---|
| Mass thermal concrete | 20,000 ton |
| Length | 100 m |
| Total cross section area pipes | 20 $m^2$ |
| Temp cold | 300 °C |
| Temp hot | 500 °C |
| Thermal Storage capacity | 1260 MW Thermal |

**Table 2 Thermal Storage Plant Parameters for 100 MW Plant**

| | |
|---|---|
| Hot side flow rate | 1500 ton/hr (peak 16h to 20h) 600 ton/hr (other) |
| Steam/water flow rate (peak) | 180 ton/hr |
| HTC | Heat Transfer Coefficient |
| Preheater (heated with steam) HTC | 1860 MJ/hr.K |
| Economizer HTC | 4000 MJ/hr.K |
| Evaporator HTC | 5000 MJ/hr.K |
| Super heater HTC | 1860 MJ/hr.K |
| Steam turbine 1 Pressure drop | 100 bar-20 bar peak Elect 15.4 MW |
| Steam turbine 2 Pressure drop | 20 bar-5 bar peak Elect 9.5 MW |
| Steam turbine 3 Pressure drop | 5 bar-0.05 bar peak Elect 15.8 MW |
| Condenser cool water inlet | 20 ton/hr |

**Table 3 Heat recovery steam generator and steam turbines for 100 MW Plant**

| | |
|---|---|
| Total Gas Turbine Energy Yield | 532 GWh |
| Total Steam Turbine Energy Yield | 174 GWh |
| Total Electic output | 700 GWh |
| Total Fuel input | 869 GWh |
| Total Solar Input to receiver | 737 GWh |
| Overall Efficiency | 43% |
| Solar fraction | 46% |
| Fraction of power from Steam cycle | 25% |

**Table 4 Annual Output and performance summary**

## 5. Costing

### *5.1 Assumptions*

We obtained cost data from several previous publications, and usually tried to get more than one cost estimate for each component. We also checked how many towers we would need for a 100 MW plant. It seems from a Japanese study [10] that optical spillage losses get too large when the radial distance of the heliostats exceeds 4x the tower height. If we assume a 100m tower height, then the maximal field size (assuming a semicircle on the South side of the tower) is 2.5 x$10^5$ $m^2$. Our total heliostat area is 4 x$10^5$ $m^2$, so we will need at least 4 towers (assuming a heliostat mirror area of 0.5 to land area). As further corroboration of this, we note that the Spanish power tower PS20 with a height of 165m has 1255 heliostats of 120$m^2$ each; this gives 1.5 x $10^5$ $m^2$ per tower, which means we could get by with three towers of 165m high each. It might be advantageous to build a single very tall tower (200m or greater) to avoid the complexity of multiple turbines and the piping between them.

The costs of various components in the plant are shown in Table 5, together with the references for each component. Since some costs were calculated as long as 10 years ago, we have applied inflation and conversion factors as indicated in Table 6.

| Component | Cost | | Units | Ref | |
|---|---|---|---|---|---|
| | Min | Max | | Min | Max |
| Heliostat field | 114 | 150 | €/m$^2$ | [11] | [12] |
| Receiver(s) | 150 | 165 | €/kW Th | [12] | [11] |
| Tower(s) | | 2 m | €/tower | | [12] |
| Power Block Gas Turbine | | 286 | €/kW El | | [13] |
| Power Block Steam (incl. turbine, pumps, condenser)) | | 714 | €/kW El | | [14] |
| Heat storage (thermal concrete) | 18 | 30 | €/kWh Th | [15] | [12] |
| HRSG | 163 | 232 | €/kWh Th | [11] | [13] |
| Power Electronics | | 303 | €/kW El | | [11] |

**Table 5 Cost parameters of 100 MW Solar plant**

| | |
|---|---|
| Conversion factor DM to € | 2 |
| Conversion factor $ to € | 1.4 |
| Conversion € to ZAR | 10.5 |
| Inflation over 10 years | 30% |

**Table 6 Conversion factors and inflation**

| SunSPOT | M € | Percentage |
|---|---|---|
| Heliostat field | 60 | 17% |
| Receiver(s) | 42 | 11% |
| Tower(s) | 12 | 3% |
| Power Block (gas turbine) | 33 | 9% |
| Power Block steam, (incl. turbine, pumps, condenser) | 29 | 8% |
| Heat storage (Thermal concrete) | 38 | 10% |
| HRSG | 28 | 8% |
| Power Electronics | 48 | 13% |
| Total Capital Equipment | 289 | 80% |
| Land and Construction | 72 | 20% |
| Total Overall Capital Cost | 364 | |
| Specific Investment | €/W | 4.55 |

**Table 7 Actual cost of plant**

| Component | Cost | Units | Reference |
|---|---|---|---|
| cost natural gas | 0.35 | € /kg | [13] |
| Plant lifetime | 25 | years | [11] |
| Interest rate | 9 | % | |
| Annual O & M | 10 | % of capital cost | [12] |

**Table 8 Annual Operating cost assumptions**

| Item | Cost M € |
|---|---|
| Fuel cost/year | 23.23 |
| O & M per year | 3.6 |
| Total running costs/year | 26.87 |
| Interest rate | 9 |
| Plant lifetime years | 25 |
| Total capital repayment/year | 37.04 |
| Total cost/year | 63.9 |
| Total levelized cost electricity | 0.091 € /kWh |

**Table 9 Actual Operating Cost and Levelized Electricity cost**

### *5.2 Levelized cost*

Using the parameters mentioned above the capital costs worked out as shown in Table 7. Next we calculated operating costs using current prices of natural gas as a fuel, and estimating Operations and Maintenance as 10% of capital cost. We assumed an interest rate of 9% and a plant life of 25 years, as shown in Table 8. With these assumptions, we arrived at an annual operating cost of 64 M€ as shown Table 9. Here we calculated the levelized electricity cost as just the total running cost of the plant per year divided by the total number of kWh produced per year. This result compares favorably with estimates of similar power plants, and when converted to South African Rands is 0.96 ZAR/kWh. For example the Ecostar Roadmap [12] estimated roughly € .08 /kWh in 2005 for a 50 MW hybrid solar/gas turbine.

## 6 Optimizing for Lower cost of electricity

We tried two approaches, firstly adjusting the size and costs associated with the heliostat field, then adjusting the control strategy. Here we tried two approaches, firstly adjusting the gas burn time in the combustion chamber, and then also adjusting the steam demand.

### *6.1 Adjusting Heliostat field size*

We adjusted heliostat field size by just altering the size of each heliostat mirror from 90m$^2$ to 120 m$^2$. We found that as the heliostat field size increased, the plant produced slightly less power per year, but this was offset by a lower fuel requirement. The net result of this was that the levelized cost of electricity dropped slightly (about 1%) as the heliostat field size rose as shown in Table 10. This is a first rough study on the effect of increasing the heliostat size. To investigate this effect properly, one would have to employ a detailed optical model of the heliostat field, which was beyond the scope of this study.

| mirror size m$^2$ | Cost heliostats M€ | Cost receivers M€ | GWh per Year | kTons fuel | Solar Fraction | Levelized Elec cents € |
|---|---|---|---|---|---|---|
| 90 | 54 | 38 | 703 | 71.1 | 41 | 9.15 |
| 100 | 60 | 43 | 700 | 65.7 | 46 | 9.13 |
| 110 | 66 | 47 | 697 | 60.3 | 50 | 9.09 |
| 120 | 72 | 51 | 694 | 54.8 | 55 | 9.06 |

**Table 10 Effect of altering Heliostat field size**

### *6.2 Adjusting Combustion chamber burn time*

A summary of this is shown in Table 11. Longer burn times mean more fuel burnt, lower solar fraction and slightly lower cost of electricity.

| combustion burn time | ramp up | ramp down | GWh per Year | kTons fuel | Solar Fraction | Levelized Elec cents € |
|---|---|---|---|---|---|---|
| normal | 05h45-06h00 | 18:75-19:00 | 700 | 65.7 | 46 | 9.13 |
| extra hour | 04h45-05h00 | 18:75-19:00 | 754 | 75.0 | 43 | 8.90 |
| extra hour + off peak steam up to 700 ton/hr | 04h45-05h00 | 18:75-19:00 | 759 | 75.0 | 43 | 8.85 |

**Table 11 Changing combustion chamber burn time**

### Summary and conclusions

We have built a thermodynamic and cost model for a hybrid combined cycle CSP plant, based in Upington, South Africa. The resulting costs per kWh (0.96 ZAR) of electricity seem reasonable compared to other similar plants. Apparently one of the main factors driving take up of solar electricity is a reliable, stable, bankable tariff structure. To this end we would recommend that the South African government set a feed in tariff and guarantee it (at least for the first few plants built) for 25 years. We also recommend that the feed in tariff allow for hybrid plants, and plants with storage, as well as giving the CSP plants an incentive to match the demand curve. To put costs in perspective, the new Medupi power plant has cost 125 billion Rand [16] for a 4.8 GW power plant. This works out to a capital cost of 26 Rand/W or 2.5 €/W. The capital cost of the solar CSP plant is estimated to be 4.5 €/W, and then the CO2 burden and fuel costs of the hybrid plant will only be 54 % of those of the coal plant, as it has a 46% solar fraction.

### Acknowledgements

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