Development of a reference concept for a solar-assisted hybrid cycle for the fossil fuel-fired power plant : A Case Study for Syrdaria Thermal Power Plant, Uzbekistan

Ravshanjon Khujanov[1], Jürgen Dersch[2], Uwe Gampe[3], Shavkat Nurmatov[4]

[1]Research Associate, Chair Thermal Power Machinery and Plants, TU Dresden, Dresden – Germany,
[2]Team Leader, Dr., Institute for Solar Research, German Aerospace Center (DLR), Cologne – Germany,
[3]Professor, Chair Thermal Power Machinery and Plants, TU Dresden, Dresden – Germany,
[4]Assistant Professor, Institute of Material Science, SPA "Physics-Sun", Tashkent –Uzbekistan.

Abstract - *In this study, two options of solar heat integration into an existing gas fired thermal power plant are investigated, namely integration into the last high pressure preheater and into the last low pressure preheater. Simulations of both options are done by using models set up in Ebsilon®Professional and performing annual simulations with hourly time steps. Two operational schemes are considered for both options: utilization of solar heat to boost the electricity output or to save fossil fuel and keep the output constant. Comparison of the results from the models with solar heat integration with the results from the model of the fossil reference plant running under the same conditions provides the solar electricity as well as the fuel saving. These results show that integration of solar heat into the high pressure preheater will lead to higher conversion efficiency and higher annual solar output. The net conversion efficiency of solar heat is in the range of 33 – 34% and the economic evaluation based on cost assumptions from literature delivers LCOE values between 9 and 14.5 US ¢/kWh which is comparable to the values for large standalone CSP plants worldwide.*

Key Words: heat, high pressure preheater, low pressure preheater, parabolic trough collector, solar field.

1. INTRODUCTION

The Republic of Uzbekistan today operates 42 thermal power units for electricity production with nominal electrical output between 160 MW to 800MW. 25 of them are older than 50 years. They urgently require greater maintenance investments and need to be adapted to changing operating conditions in order to improve their economic efficiency and reduce CO_2 emissions. Because some plants cannot operate at full load due to defects in the steam generators modernization and improvements are indispensable. This is an option to introduce solar hybrid concepts. Since the direct irradiation levels in Uzbekistan with up to 1900 kWh/m^2 per year are very interesting for solar thermal systems, a national program for the use of solar energy in Uzbekistan until 2018 was adopted by the government. Utilization of solar feed water preheating has been investigated before and published in several papers [1, 2]. These papers are concluding that the solar heat may be converted in these cases with even higher efficiency than in a standalone solar thermal power plant. A lot of work has been done also for the calculation and evaluation of solar aided power generation [3-7]. Nevertheless each case is very specific because of the available data such as existing plant equipment, available land and local weather conditions.

In general the following advantages for such integration schemes are prevailing:

- Implementation costs are lower compared to standalone solar power plants since the turbine/generator set and balance of plant are already available.
- Operating a solar field and introducing solar heat when it is available makes the erection of storage obsolete. When the solar heat is not sufficient bled steam is used instead.
- Operation of a solar field in parallel offers a minimal risk for the existing plant
- Solar heat can be implemented in a modular manner, thus the total investment might be reduced compared to a standalone solar power plant.

There is one existing power plant in Australia with 2*9 MW$_{th}$ solar feed water preheating made by linear Fresnel collectors. Another plant in Florida is using parabolic troughs to produce solar heat which is fed into a gas fired combined cycle power plant [8].

2. MATERIALS AND DATA COLLECTION METHODS

With a complete thermodynamic plant model set up in Ebsilon®Professional, possible integration options can be investigated. In this investigation it was decided to look detailed into 2 options: integration of solar heat into the last high pressure preheater (PH7) and into the last low pressure preheater (PH4), both locations are indicated in Figure 1. Although almost all existing parabolic trough solar plants are operated with thermal oil as heat transfer fluid, here a direct steam generating solar field is considered. The advantage is that such a direct steam generating solar field would not need a separate handling system for the thermal oil and also no oil/steam heat exchangers. Instead the feed water can be drawn directly from the existing plant and the solar steam can be introduced directly into the preheaters. Such direct steam generating parabolic trough fields are investigated by DLR since many years [9] and a first 5 MW_e solar power plant is in operation in Thailand [10].

Three different Ebsilon®Professional models were set up in our investigation: one model for the fossil reference plant, one model with a solar field to replace bled steam for PH 7, and one model with a solar field to replace bled steam for PH 4. For all 3 models the Ebsilon®Professional time series calculation has been used to simulate a typical operation year in hourly time steps. A meteorological dataset of Dagbid with 1997 kWh/m^2a of DNI is used as input for all three models. This dataset was generated from quality controlled ground measurements. Similar data for the Syrdaria site was not available. The fossil operation of the plant is considered as reference in order to calculate the surplus electricity production and the fuel saving of the two options for solar heat integration. The operation strategies used for the annual simulation are:

1. The fossil reference plant is operated in manner that the net electricity output is fixed to 280 MW all the time. From this simulation the reference annual net electricity production and the reference annual natural gas consumption are generated as main results.

2. The models with solar heat integration are operated as fuel saver which means that the net electricity output is also fixed to 280 MW all the time. Whenever solar heat is provided by the parabolic trough field, the gas input is reduced in order to keep the net output constant.

In a second operation mode the models with solar heat integration were operated as booster which means that the fuel input was kept almost constant and the solar heat was used to increase the net electricity output. The bled steam is reduced and instead this additional steam mass flow could be expanded in the turbine down to the condenser pressure which increases the electricity output.

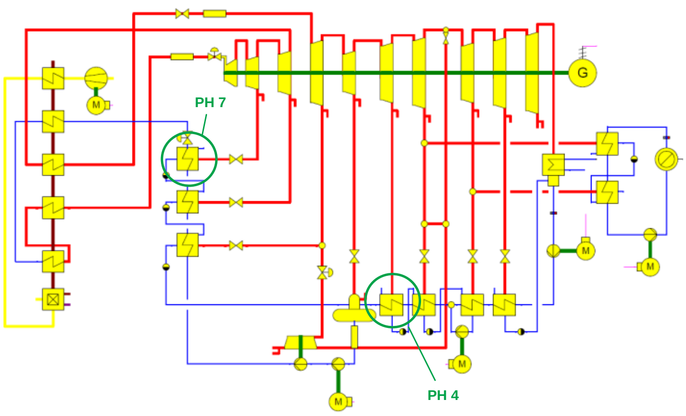

Fig -1: Simplified Ebsilon®Professional model of Syrdaria thermal power plant

The next step is to design a solar field suitable for the specific site requirements. During the site visit an area of about 300m × 250m close to the power plant has been identified which is currently not used and may eventually be used for the installation of a parabolic trough field.

This area would be sufficient to install 7 loops in parallel where each loop is made of 4 Euro trough parabolic trough collectors (150m length and 5.77m width) connected in series. The parabolic troughs are arranged in the standard configuration used for power plants with a row-to-row distance of 17.3m. The total effective aperture area fitting into the available area is 22888m^2. In order to calculate the design output of this solar field, annual DNI datasets for typical years have been analyzed.

Fig -2: Aerial view of Syrdaria power plant with conceptual solar field layout (Source Google Earth)

Two dataset have been generated by the German company CSP Services during a project conducted for Asian Development Bank. They have combined satellite data with high quality ground measurements taken at Dagbid, about 200 km away from Syrdaria power plant and at Parkent about 130 km from Syrdaria. These datesets are so called P50 datasets, representing a long term average year with 50% probability that the actual year will show a higher DNI sum. The annual sum of DNI from this datasets is 1997 kWh/m^2 for Dagbid and 1858 kWh/m^2 for Parkent. Since both meteorological stations are not exactly at the power plant site, a third dataset was generated by METEONORM 7.1.3 [11], a software tool capable to generate such datasets for arbitrary sites using satellite maps and ground measurements from adjacent stations together with interpolation routines. Chart 1 shows the plot of sorted hourly DNI values for all 3 datasets. The artificial dataset generated from METEONORM shows a considerable lower annual DNI sum of 1627 kWh/m^2 as well as a different distribution. The reason might be that for the Syrdaria site METEONORM is interpolating data from Tashkent und Karshi (117 km and 594 km from Syrdaria). Therefore the METEONORM dataset was not considered as suitable for this study. Instead the other 2 datasets may be used to estimate the output of a solar field at Syrdaria. Since there is no dataset for the actual site the available datasets of Dagbid was used to consider a realistic range of DNI resources. This approach is considered being adequate for such a study wheras for an actual project development suitable metorological datesets for the specific site should be used instead. Based on the plot in chart 3, the design DNI for the Syrdaria site of 800 W/m^2 is chosen. There is no strict rule to fix the design DNI but typically one would like to have a considerable number of hours with DNI values above the design value during a typically year. Otherwise the solar field will not be able to deliver design output most of the time. Taking into account this rule, the design DNI may be chosen in the range of 750 to 850 W/m^2, thus 800 W/m^2 was fixed. It is obvious that the DNI distribution from the METEONORM dataset would require a lower design DNI of about 650 W/m^2. Without having further data nor resources the decision was to use the DNI data measured for Dagbid city for this study. Due to the fact that the city is situated on the flat land, as Syrdaria power plant, while the city of Parkent is located close to the southern part of Kazakhstan, in the highlands.

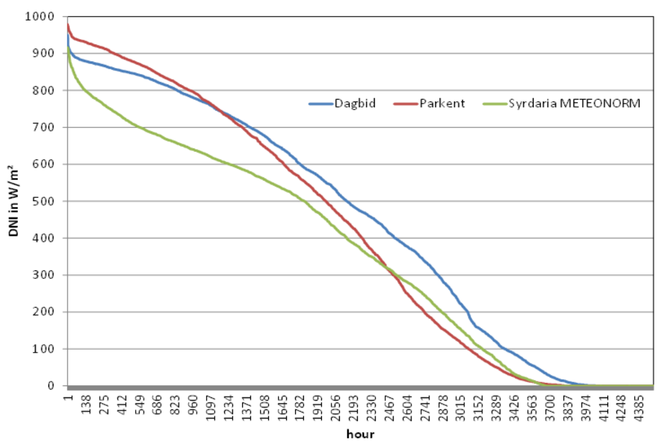

Chart -1: Sorted DNI values of the P50 dataset for 3 sites Using this design DNI together with the performance data of an Euro through 150 collector equipped with Schott PTR 70 receiver tubes the solar field design output and efficiency shown in table 1 were calculated.

Table -1: Design data of the solar field for option 1

Parameter	Value	Unit
Number of loops	7	-
Number of collectors	28	-
Total effective aperture area	22888	m^2
Design time	Solar noon @ 21. Jun	
Design DNI	800	W/m^2
Design incidence angle	16.8	°
Design inlet pressure	6.3	bar
Design inlet temperature	160	°C
Design outlet pressure	62.7	bar
Design outlet temperature	358	°C
Design output	12102	kW$_{th}$
Design solar field efficiency	66.1	%

Table 1 indicates that the nominal power of the parabolic trough field which might be installed in the area shown in figure 2 would be only 12.1 MW$_{th}$. The steam drawn from the HP turbine for preheater 7 is equivalent 41 MW$_{th}$. Therefore option 1 is not further analyzed in this study. Instead it is assumed that sufficient area on the other side of the river will be available for installation of a larger solar field.

For option 2 it was assumed that the solar field will be installed totally at the other side of the river, northeast of the power plant (at the upper right corner of figure 1). The space is not limited and the solar field size is chosen according to the heat demand of HP preheater 7.

Table -2: Design data of the solar field for option 2

Parameter	Value	Unit
Number of loops	24	-
Number of collectors	96	-
Total effective aperture area	78472	m^2
Design time	Solar noon @ 21. Jun	
Design DNI	800	W/m^2
Design incidence angle	16.8	°
Design inlet pressure	6.3	bar
Design inlet temperature	160	°C
Design outlet pressure	62.7	bar
Design outlet temperature	358	°C
Design output	41493	kW$_{th}$
Design solar field efficiency	66.1	%

The area needed for such a solar field is approximately 430 m (east-west) x 630 m (south-north) or alternatively 840 m (east-west) x 325 m (north-south).

Using again the meteorological dataset of Dagbidthe seasonal dependency of solar field output shown in chart 2 is calculated. During summer the solar field will be able to deliver more than the required 41 MW$_{th}$ for several hours but in winter, early spring and late autumn times the output is always lower than the design value of 41 MW$_{th}$.
For option 3 it is also assumed that space on the other side of the river may be used to install the solar field to provide solar heat for LP preheater 4.

This option is investigated in order to check the integration of solar heat into the last low pressure preheater and compare the results to those of option 2. Solar field outlet pressure and outlet temperature are lower compared to option 2, which may lead to lower cost and higher solar field efficiency. On the other hand, the design power of PH 4 is lower than that of PH 7 and the replacement of the bled steam used for PH 4 by solar heat will lead to lower conversion efficiency of this solar steam to electricity.

Table -3: Design data of the solar field for option 3

Parameter	Value	Unit
Number of loops	15	-
Number of collectors	60	-

Total effective aperture area	49046	m^2
Design time	Solar noon @ 21. Jun	
Design DNI	800	W/m^2
Design incidence angle	16.8	°
Design inlet pressure	6.3	bar
Design inlet temperature	147	°C
Design outlet pressure	6.1	bar
Design outlet temperature	284	°C
Design output	26039	kW_{th}
Design solar field efficiency	66.4	%

3. RESULTS AND DISCUSSION

As mentioned above, two different operation modes have been investigated for integration options 2 and 3.

1. Booster operation, in order to increase the plants output with almost constant fuel input
2. Fuelsaver operation mode, in order to reduce fossil fuel consumption and provide almost the same net electrical output as the fossil reference plant

Chart 2 and 3 show the surplus electricity production for option 2 and 3 in booster operation mode. Due to the limited number of hours with direct solar irradiance, the total number of hours with boosted output is limited too.

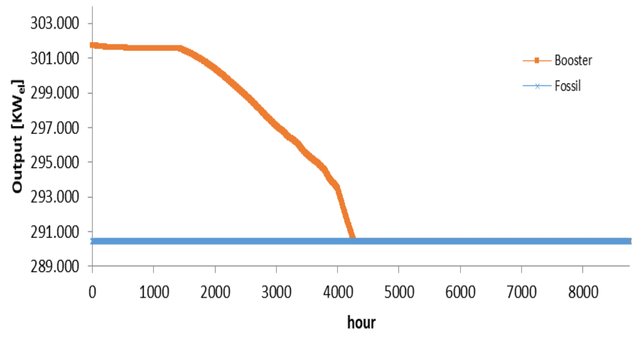

Chart -2: Sorted gross electrical power output with solar field integration option 2 (PH 7)

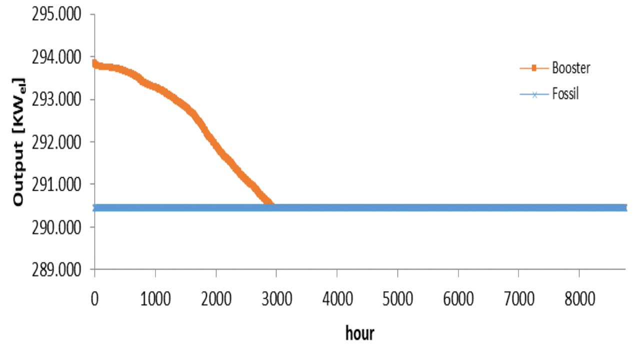

Chart -3: Sorted gross Electrical power output with solar filed integration 3(PH 4)

Chart 4 shows electrical output and fuel consumption for option 2 (solar heat integration into HP 7) for one single day with high DNI. The net electricity output for the fossil reference plant and in saver operation mode is always constant whereas for the booster operation it increases up to 11 MW when the solar field is providing heat. The fuel consumption of the fossil reference operation and the booster operation is almost the same without solar heat but it decreases by up to 25 MW_{th} when solar heat is available.

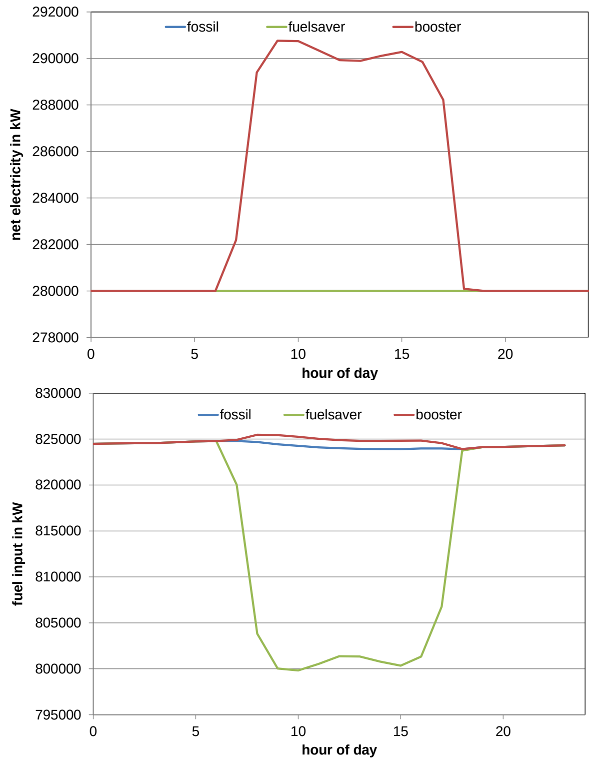

Chart -4: Electricity output and fuel consumption for option 2 for the 25th March

Of course the solar heat input is varying depending on DNI and sun position and there are single days throughout the year without any heat delivered from the solar field due to cloudy conditions. The same applies for night time operation hours. This is the reason why the performance of solar power plants must be evaluated using annual yield simulation tools and typical meteorological year datasets.

Tables 4 and 5 show summaries of the annual yield calculations for both integration options. The annual solar fraction is only in the range of 1% or even lower, due to the small solar fields and the fluctuating nature of solar input.

Table -4: Results of the annual performance calculations for integration of solar heat into PH7

		Operation mode		
	unit	fossil	fuelsaver	booster
Gross electricity output	MWh	2545463	2542434	2568350
Net electricity output	MWh	2452800	2452800	2475625
Utilized solar heat	MWh_{th}	0	85729	85257
Utilized fossil energy	MWh_{th}	7252952	7196957	7254912

Fossil input related to fossil mode	-	1,0000	0,9923	1,0003
Net efficiency	-	0,3382	0,3408	0,3412
Solar heat fraction	-	0,0000	0,0118	0,0116
Additional net electricity	MWh	0	0	22825
Fuel savings	MWh_{th}	0	55995	-1960
Conversion of fuel savings to electricity	MWh	0	18936	-663
Total solar electricity	**MWh**	**0**	**18936**	**22162**

In both solar operation modes almost the same annual amount of solar heat is utilized. In fuel saver mode the gas consumption is reduced by about 56 GWh_{th}, whereas in booster mode the annual electricity production is 22.8 GWh higher. During the simulation the fuel consumption for the booster mode could not be kept exactly the same as in fossil operation mode but was slightly increased by 1.96 GWh_{th}. This additional fuel consumption (or negative fuel saving) is considered in the calculation of the additional net electricity as reduction using the nominal net efficiency of the power plant. Thus the corrected surplus annual net electricity production in booster mode is only 22.2 GWh.
The annual efficiency of 34.12 % in booster operation mode is slightly higher than in fuel saver (34.08 %) and in fossil (33.8 %) operation mode. It is calculated using the following (equation):

$$\eta_{an} = \frac{E_{el.an}}{Q_{fuel.an} + Q_{sol.an}}$$

The booster operating mode offers higher annual solar electricity output for the integration of solar heat into PH 7 while the fuel saver operation is more favorable for solar heat integration into PH 4. Any fuel savings (or additional fuel consumption) have been converted into electricity by using the mean efficiency of the fossil operation mode. The highest solar electricity production of the options investigated here reached by the integration of solar heat into PH 7 in booster operation mode.

Table -5: Results of the annual performance calculations for integration of solar heat into PH4

		Operation mode		
	unit	fossil	fuelsaver	booster
Gross electricity output	MWh	2544715	2543195	2552529
Net electricity output	MWh	2453080	2453080	2460816
Utilized solar heat	MWh_{th}	0	52631	52829
Utilized fossil energy	MWh_{th}	7267199	7234810	7267204
Fossil input related to fossil mode	-	1,0000	0,9955	1,0000
Net efficiency	-	0,3376	0,3391	0,3386
Solar heat fraction	-	0,0000	0,0072	0,0072
Additional net electricity	MWh	0	0	7736
Fuel savings	MWh_{th}	0	32389	-5
Conversion of fuel savings to electricity	MWh	0	10933	-2
Total solar electricity	**MWh**	**0**	**10933**	**7734**

3.1. Economic model

It is common practice to use levelized cost of electricity (LCOE) for the evaluation of renewable energy projects in feasibility studies like this one. The LCOE may be calculated from the following formula. It is an approximation for the price at which electricity would need to be sold to break even. It is an approximation because it is a simple economic calculation not considering specific details like taxes, individual depreciation rates, and other details of a full economic calculation.

LCOE might be calculated from [12]:

LCOE= (INV·CRF+O&M+F)/E

CRF= (i (1+i)^n)/((1+i)^n-1)

With

INV total investment for the plant in $

CRF capital recovery factor

I interest rate

n life time of the investment

O&M total annual operating and maintenance costs in $

F total annual fuel costs in $ (may be negative if there is fuel saving)

E total annual electricity production in kWh

3.2. Cost assumptions

In the IRENA 2016 study [13] costs of 231 US$/m² of aperture area are mentioned for the solar field cost for 2015 and a large parabolic trough plant having 1.5 million m² of aperture area, 160 MW gross electric output with 7.5 h thermal storage. These costs are been used as basis for the cost assumptions in the current study. The costs mentioned above are valid for a plant operated with thermal oil as heat transfer fluid (HTF) and they include the HTF as well as the HTF-system. They don't include EPC services and profit (15%) and owners costs (land, infrastructure, development cost, 20%).

In our case we have a solar field with direct steam generation and do not need HTF nor a HTF system which makes about 58 US $/m of the above mentioned costs. Thus the solar field might be at 173 $/m². This are the costs for the solar field used for the LP 4 preheater (pressure at SF inlet is about 22 bar, thus not higher than for a thermal oil system).

For the HP 7 preheater the DSG field will be slightly more expensive because the pressure will be about 90 bar at SF inlet, thus the absorber tubes must have thicker walls and the same applies to all equipment carrying fluid. Thus the cost of that solar field is estimated to be 15% higher: 200 $/m². Additionally the solar fields considered in our study are much smaller (only 49000 and 78000 m² instead of 1.5

million m^2) which means that an EPC company cannot benefit from economy of scale effects. The impact of this effect is difficult to determine but is estimated as a surplus of 40% to the cost mentioned above. Annual operating and maintenance costs are assumed as 2% of total CAPEX for the solar field. This assumption is applied for both solar fields options considered here.

The interest rate is assumed to be 1.5%, a value mentioned by ADB in Uzbekistan. The lifetime was assumed to be 25 years. In order to calculate any savings of natural gas, the gas price must be known. The actual price for Syrdaria power plant is not disclosed, therefore the world market gas price of 8.6 US$/MWh (2.5 $/MMBtu) is used. All these cost figures are just reasonable assumptions and are not backed up by offers. Any invitations for offers were out of scope for this investigation.

Table ~~6~~ shows the economic input data as well as the LCOE results for both integration options and both operating modes. The final LCOE values are in the range between 9 and 14.5 US ¢/kWh which is comparable to the values for large standalone CSP plants worldwide. The integration of solar heat into preheater 7 in booster operation mode offers the lowest LCOE of the different options investigated in this study. Although the specific investment costs for this solar field are almost 16% higher than for the integration of solar heat into PH 4, it offers lower LCOE.

Table -6: Input and results of the economic calculations

		HP Preheate7	**HP Preheater7**	**LP Preheater4**	**LP Preheater 4**
	Unit	Booster operation	Fuelsaver Operation	Booster operation	Fuelsaver Operation
Solar field cost	$/m^2	200	200	173	173
Surplus for small system	%	40	40	40	40
Indirect EPC	%	15	15	15	15
Additional owners costs	%	20	20	20	20
Total cost	**$/m^2**	**386**	**386**	**334**	**334**
Operating & maintenance	%	2	2	2	2
Solar field aperture	m^2	78.473	78.473	49.046	49.046
Total CAPEX	$	30.321.967	30.321.967	16.392.939	16.392.939
Annual OPEX	$	606.439	606.439	327.859	327.859
Annual net solar electricity	MWh	22.825	18.963	7.736	10.933
Additional annual fuel consumption	MWh_{th}	1.960		5	
Additional annual fuel costs	$	16.856	0	43	0
LCOE	**$/kWh**	**0,091**	**0,109**	**0,145**	**0,102**

The main reason for this is the higher "value" of bled steam at PH 7 compared to the bled steam at PH4. The bled steam replaced at PH 7 can be used throughout all remaining stages of the turbine to produce electricity. The bled steam replaced at PH 4 instead has a lower enthalpy and therefore the benefit is lower. The slightly higher solar field efficiency and lower specific costs of the solar field used to replace steam at PH 4 cannot compensate the higher value of steam at PH 7.

4. CONCLUSION

The final LCOE values for integration options investigated here are in a range between 9 and 14.5 US¢/kWh and thus comparable to the values for large standalone CSP plants worldwide. Considering the small solar field and the DNI resource which is not as high as in South Africa or Morocco, the results are encouraging. Therefore the integration of solar heat to replace bled steam in existing power plants might be a scenario to gain first experience with this solar technology in Uzbekistan. Nevertheless it should be mentioned that the net conversion efficiency of solar heat is in the range of 33 to 34%, which is slightly lower than the typical value reached by modern standalone parabolic trough plants with wet cooling (~ 36%). Solar heat utilization should only be considered for quite new fossil power plants or power plants which have been retrofitted because the solar heat is often more expensive than fossil heat particularly when depreciated power plants and current world market gas prices are considered.

5. ACKNOWLEDGEMENT

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BIOGRAPHIES

Mr. Ravshanjon Khujanov, his research is focused solar heat, heat storage and upgrading of thermal energy. Chair Thermal Power Machinery and Plants, TU Dresden Dresden, Germany

Mr. Jürgen Dersch
Lead of the team "System Integration" at the Institute of Solar Research. Main focus on CSP plants and concentrating solar collectors for process heat application. German Aerospace Center (DLR), Cologne, Germany

Uwe Gampe has been full professor for Thermal Power Machinery and Plants in the Institute of Power Engineering of the TU Dresden since 2001. He is director of the “Centre for Energy Technology”

Mr. Shavkat Nurmatov his research is focused solar energy, thermal energy storage. Institute of Material Sciences, SPA “Physics-Sun”, Academy of Sciences of Uzbekistan