Analysis of Integrated Photovoltaic Solar and Combined Cycle (IPVCC) Power Plants

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Executive Summary

Solar energy installed capacity in Thailand grew to 1.3GW in 2014 (1), a significant increase over the 111 MW in 2011(2). The estimated installed capacity for 2016 is 3.39 GW and the target for 2036 is 6 GW installed capacity for solar energy (1). In a case study utilizing detailed thermodynamic models, the integration of Photovoltaic (PV) solar with a natural gas combined cycle plant is analyzed and compared against a stand-alone combined cycle plant with duct burners. Parametric studies for different locations in Thailand and the Middle East using historical weather and solar radiation data are performed to quantify the fuel and emission savings that an Integrated Photovoltaic Combined Cycle (IPVCC) power plant can attain. Results include detailed heat balance results and a discussion of the effects of the photovoltaic integration on the hourly overall plant performance over an entire year of dispatch operations.

The paper studies and compares various commercially available configurations and designs of CCGT plants integrated with photovoltaic power generation. The study focuses on different configuration options to achieve fuel savings. It quantifies the fuel savings relative to a CCGT without a photovoltaic solar field. The study was performed using the EBSILON Professional heat and mass balance software (3) to construct detailed thermodynamic models for both, design and off-design conditions for two different locations, one in Thailand, and one in the Middle East. A typical 2-pressure level unfired HRSG is used in one case, and a typical 3-pressure fired HRSG is used in the other case. The study incorporates the extensive experience the authors have in power plant design, optimization, simulation and operations as well as available documentation, such as books, publications and government policies.

Introduction

This paper discusses the impact of adding a PV solar field to a combined cycle plant. For the Thailand location, the size was chosen to be similar to the current natural gas fired cogeneration SPPs. (90MW firm to EGAT, and remaining energy sold as steam or electricity to industrial customers, minimum 65% availability) (4). A study was run for an hourly evaluation of maximum IPVCC power production for an entire year. For the same configurations, a study was run to determine the fuel savings which could be achieved by adding a solar field to an existing co-generation power plant, assuming a standard dispatch profile and no energy storage.

Thailand

Thailand’s renewable energy plan targets 30% of total energy consumption from renewable resources. (5). The electricity sector will have 15-20% of the electricity production come from renewables (5). Of this, 6GW is projected to come from solar energy by 2036. At the end of October 2016, 2.761 GW installed capacity was available (6). About 3.39 GW of installed solar capacity was estimated at the end of 2016 (1). The majority of the solar power stations still come from two types of power plants: VSPPs (Very Small Power Plants <10MWe) and SPPs (Small Power Plants, 10-90 MWe). In 2014, 973 MWe (1) of the total installed capacity of 1.3 GW came from the VSPPs and the remainder from SPPs (7).

SPPs and IPPs (Independent Power Plants >100 MWe) have existed since 1994 (8). But solar plants were not common until about 2011, and even then there was only 111 MWe installed capacity. (2)

Some of the issues related to rapid growth of renewables are:

- unstable operation
- power management system reliability
- power distribution continuity.

To address these issues the Energy Policy and Planning Office of Thailand (EPPO) decided to grant licenses for hybrid systems, allowing more stable operation with the “firm” contracts. (9). The power plants described in this paper (IPVCC) can also offer solutions to such problems, but they would of course not count as fully renewable.

Very recently EPPO has decided to request bids for hybrid solar and renewable SPP projects with firm contracts. But, unlike the plants discussed in this paper, this new type of SPP cannot use the natural gas, and must use either biomass or other renewable energy to provide at least 65% of capacity off-peak (10pm-9am). In addition such new type SPP must be able to deliver 100% output during all peak hours, 9am to 10pm (possibly aided by storage) (10). Up to 300 MW in hybrid licenses are expected to be granted for 3.66 Thai Baht/kWh, partially adjustable for inflation) for the hybrid power plants ranging in capacity from 10 to 50 MW.

850-1000 MW in licenses are expected to be awarded this year for renewable projects, of which 300 MWe are the firm hybrid SPPs, nearly 300 MWe semi-firm hybrid VSPP and 200 MW of waste-to-energy projects (11). Rooftop solar is also expected to become a significant factor in the coming years (12)

Middle East

An additional location was chosen to see the impact of adding a solar field to a power plant more likely to have duct firing. Thailand’s power plants typically do not have duct burners. So, for this purpose a location in the Middle East was chosen using Abu Dhabi weather conditions. Due to the seemingly wider dispatch range and more variable weather such power plants are more likely to have duct burners.

Base Models

The two locations studied in this paper have distinctly different plant configurations. But, the layout of the combined cycle power plant was chosen to be 2 x 2 x 1 (2 gas turbines and HRSGs, 1 steam turbine) in both cases.

For the Thailand location, two configurations are considered. One uses a Siemens SGT800 gas turbine type, and the other configuration uses a GE LM6000PF+. Both were modelled with VTU’s Gas Turbine Library software, developed for the EBSILON Professional power plant simulation program (3). Figure 1 below shows the overall simulation model for one of the variants analyzed in this study.

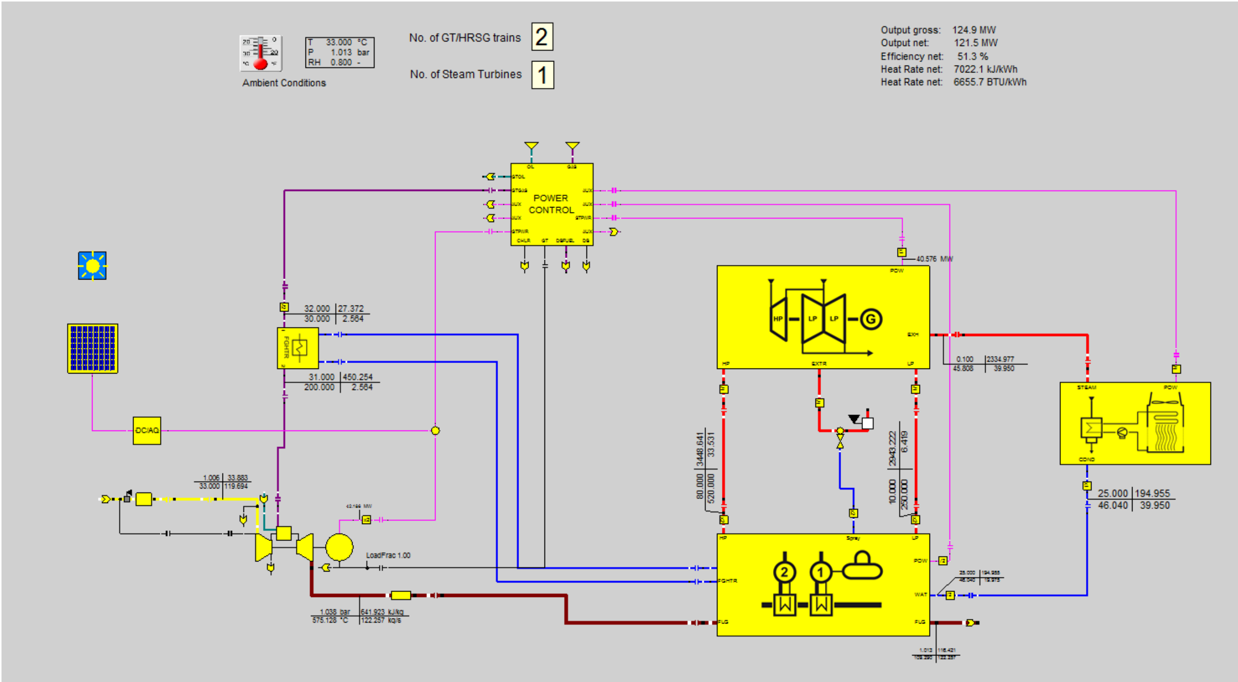

Figure 1: Overall plant simulation model for Thailand location

The HRSG configuration is horizontal with natural recirculation in the evaporators. The condenser uses a mechanical draft wet cooling tower to remove the heat of condensation. Since it was assumed that the two trains of the plant are always operated at the same load level if both are running, the model was simplified by using stream multipliers/dividers on the connecting streams between the GT/HRSG trains and the steam turbine and cooling system. There is no turbine inlet conditioning (chillers or evaporative coolers) foreseen for this power plant.

All EBSILON models used a base model that was derived from design information of a real plant, and for the analysis the operating conditions were modified for the cases that were studied. Tables further below summarize the key design parameters of the combined cycle power plants, and Figure 2 shows the details of the HRSG sub-model included in the overall plant model. The configuration of the HRSG is a 2-pressure level non-reheat HRSG with a separate deaerator.

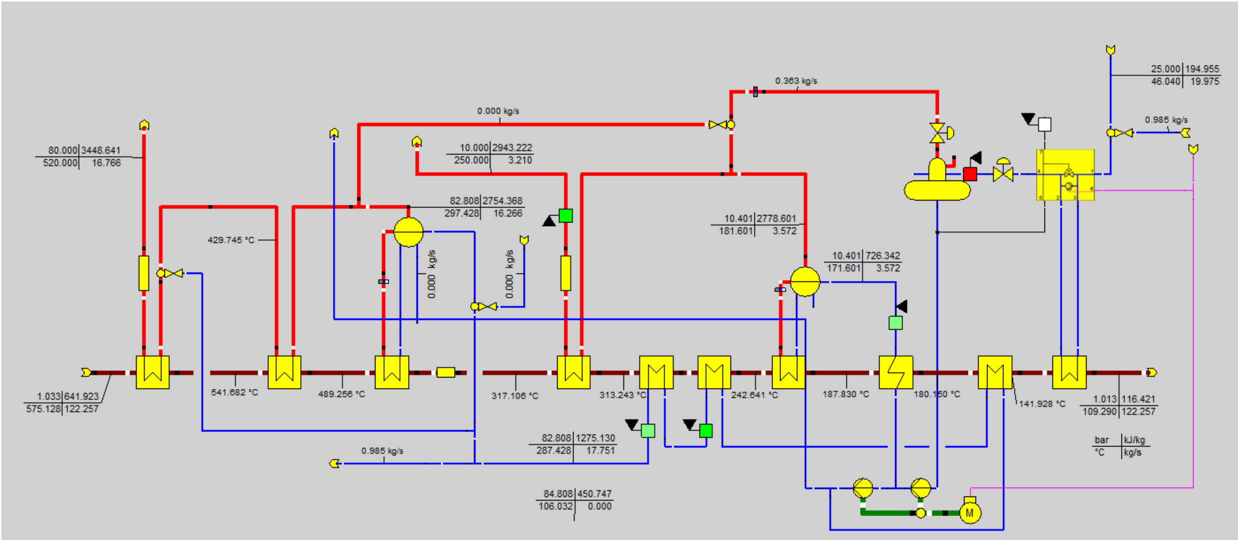

Figure 2: Heat balance model of the HRSG, a 2 pressure section HRSG with a separate deaerator

For the operating scenario, the firm power commitment was chosen at 90MW, as well as a maximum export of 40 tonm/hr of steam at 25 bara. For the SGT800-based plant this left 23.9 MWe for non-firm sales at reference conditions. The LM6000PF+ based plant has 16.4 MWe for non-firm electricity sales at reference conditions. These conditions are similar to typical SPPs (Small Power Plants with cogeneration PPAs) in Thailand

For the fuel gas a typical Thai EAST gas was chosen (94.1 vol% CH_4, LHV 46232 kJ/kg), as measured on the 20th of April 2017 at Navanakorn Rangsit. (13)

The assumed load profile was based upon a daily load profile (14), super-imposed on a monthly profile (15). The 90MW firm capacity was assumed to follow the dispatch profile equal to the variation in electricity sales to the grid. And the 23 MW non-firm power sales and the steam export were both assumed to follow the profile equal to the variation of EGAT's direct sales figures. A minimum dispatch of 65% was assumed. The end result was an average dispatch of 81% of the firm capacity plus 70% of the non-firm "capacity". EGAT is assumed to be obligated to buy 80% of the minimum yearly capacity (16).

An hourly weather profile was based upon historical data for Bangkok, Thailand. (17)

The maximum capacity of the solar generation was chosen at 30 MWe at 1000 W/m2.

For the Middle East Location, a yearly temperature profile for Abu Dhabi was chosen (18). The dispatch profile was chosen as per running hours specified in a typical PPA in the Middle East, which uses about 15 operating points representing different amounts of running hours. The dispatch profile for the Middle East location as well as the weather have more variations in load and ambient conditions than those for the Thailand location.

Two configurations are considered for this location as well. One uses a Mitsubishi M701JAC gas turbine type, and the other configuration uses an Ansaldo AE36-S5. Figure 3 below shows the overall simulation model for one of the variants analyzed in this study.

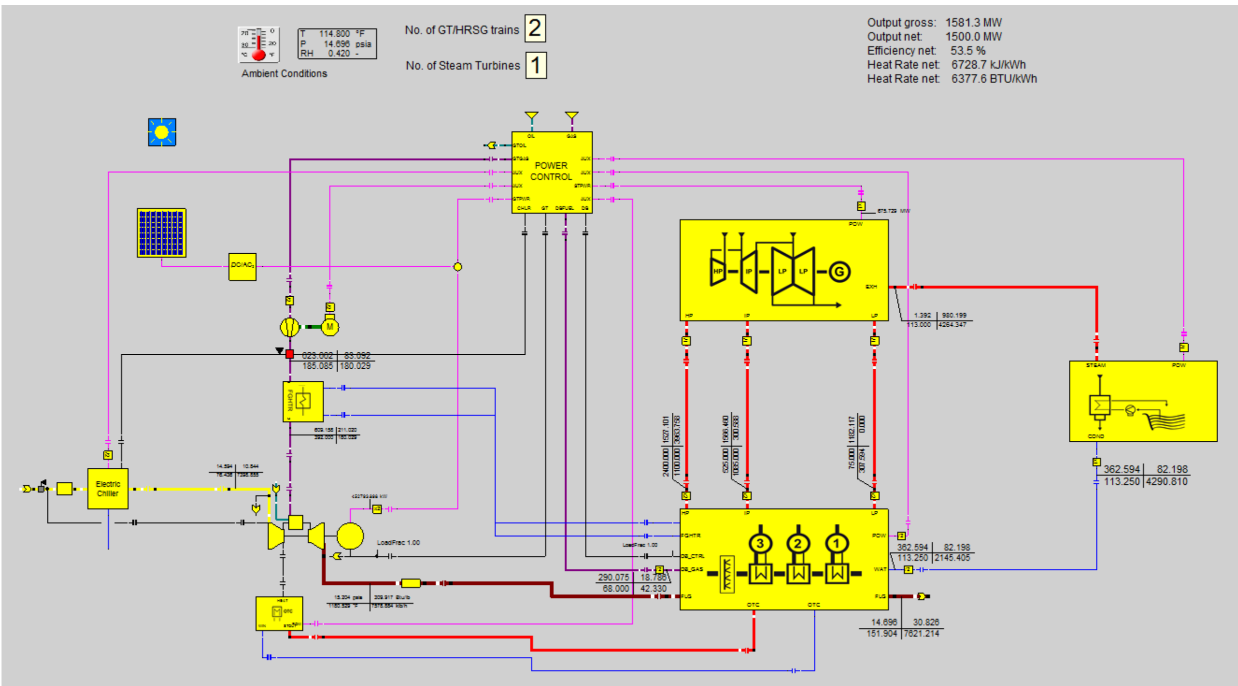

Figure 3: Overall plant simulation model for Middle East Location

The HRSG configuration is horizontal with natural recirculation in the evaporators. The condenser uses sea water to remove the heat of condensation. Since it was assumed that the two trains of the plant are always operated at the same load level if both are running, the model was simplified by using stream multipliers/dividers on the connecting streams between the GT/HRSG trains and the steam turbine and cooling system. The plants are equipped with duct burners and inlet air chillers.

The duct burners were assumed to go up to 850C, and the size of the chillers was chosen to achieve 1500 MWe for the plant based upon the larger Ansaldo engine and 1400 MW for the Mitsubishi based plant at Reference site conditions.

The plants are also assumed to produce potable water using Reverse Osmosis technology, resulting in an additional fixed power consumption of 35 MWe. Figure 4 shows the details of the HRSG sub-model included in the overall plant model. The configuration of the HRSG is a 3-pressure level reheat HRSG with an integral deaerator, equipped with a duct burner.

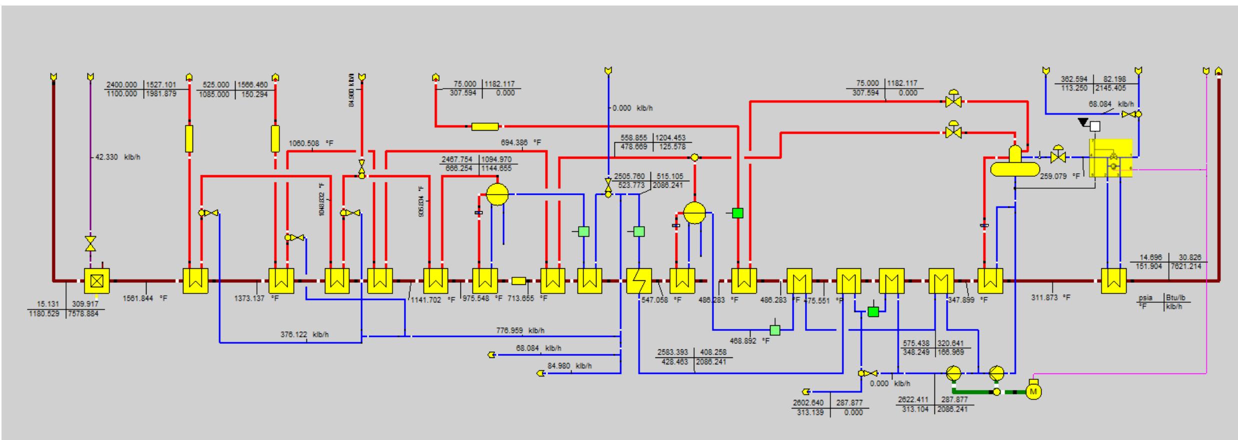

Figure 4: Heat balance model of the HRSG, a 3 pressure section reheat HRSG with a duct burner and an integral deaerator

Study Approach

To ensure this study properly compares the different configurations, care was taken to apply the same design conditions and limits, such as HRSG configuration, minimum HRSG water inlet temperature, condenser pressure, solar field size, etc. in all configurations, whenever possible. Obviously, due to the different gas turbine exhaust conditions, the steam temperatures and pressures of the HP section are limited. So some differences will exist.

Two configurations were compared which both have no duct burners and no turbine inlet air conditioning for a location in Thailand. A further two configurations were compared which do have duct burners as well as turbine inlet air conditioning for a location in the Middle East.

For each configuration, 8760 individual simulation runs were performed, representing an entire year of forecasted dispatch and weather conditions. Using VTU Energy's distributed calculations these 8760 runs can be processed in about 15 minutes (on 91 processors).

Various Configurations

Below is a description of the four different configurations:

1. **General Electric LM6000 PF+**

This configuration uses a 2 pressure level HRSG without duct firing. The gas turbine has no inlet air conditioning. Table 1 below summarizes the key design parameters.

HP Steam Pressure	57.5 bar	834 psia
HP Steam Temperature	480 C	896 F
Extraction Pressure	25 bar	362.6 psia
LP Steam Pressure	10 bar	145 psia
LP Steam Temperature	250 C	482 C
Condenser Pressure	0.1 bar	2.95 inHg
HP Evaporator Pinch Point	19.5 C	35.1 F
LP Evaporator Pinch Point	6.1 C	11.0 F
HRSG Inlet Temperature	60 C	140 F
Design Ambient Conditions	(1.013 bar, 33C, 80% RH)	(14.696 psia, 91.4F, 80% RH)

Table 1: Key design parameters of the LM6000 PF+ base model

Under these chosen circumstances the plant can have an output of 115.27 MW, with no export steam. It can produce 106.44 MW in case of the maximum assumed steam export of 40 ton/h. The heat rates for those two cases are: 6931 and 7506 kJ/kWh respectively.

A solar field rated at 30 MWe for a DNI of 1000 W/m2 was assumed for this plant.

2. **Siemens SGT800**

This configuration uses a 2 pressure level HRSG without duct firing. The gas turbine has no inlet air conditioning. Table 2 below summarizes the key design parameters.

HP Steam Pressure	80 bar	1160 psia
HP Steam Temperature	520 C	968 F
LP Steam Pressure	10 bar	145 psia
LP Steam Temperature	250 C	482 C
Condenser Pressure	0.1 bar	2.95 inHg
HP Evaporator Pinch Point	19.7 C	35.5 F
LP Evaporator Pinch Point	6.2 C	11.1 F
HRSG Inlet Temperature	60 C	140 F
Design Ambient Conditions	(1.013 bar, 33C, 80% RH)	(14.696 psia, 91.4F, 80% RH)

Table 2: Key design parameters of the SGT800 base model

Under these chosen circumstances the plant can have an output of 121.53 MW with a heat rate of 7022 kJ/kWh, in case of no export steam, and 113.98 MW with a heat rate of 7488 kJ/kWh in case of the maximum assumed steam export of 40 ton/h.

As with the other configuration, a solar field rated at 30 MWe for a DNI of 1000 W/m2 was assumed for this plant.

3. Mitsubishi M701JAC

This configuration uses a 3 pressure level reheat HRSG with a duct burner. The gas turbine has an inlet air chiller. Table 3 below summarizes the key design parameters.

Duct Burner Exit Temperature	850 C	1562 F
HP Steam Pressure	165.5 bar	2400 psia
HP Steam Temperature	593 C	1100 F
IP Steam Pressure	36.2 bar	525 psia
IP Steam Temperature	585 C	1085 F
LP Steam Pressure	5.2 bar	75 psia
LP Steam Temperature	153 C	307.6 F
Condenser Pressure	0.096 bar	2.83 inHg
HP Evaporator Pinch Point	26.3 C	47.4 F
IP Evaporator Pinch Point	4.3 C	7.7 F
LP Evaporator Pinch Point	2.1 C	3.8 F
HRSG Inlet Temperature	60 C	140 F
Design Ambient Conditions	(1.013 bar, 46C, 42% RH)	(14.696 psia, 114.8F, 42% RH)

Table 3: Key design parameters of the M701JAC base model

Under these chosen circumstances the plant can have an output of 1433.3. MW with a heat rate of 6497 kJ/kWh with no export power to the RO facility. The plant can produce 1398.3 MW with a heat rate of 6660 kJ/kWh in case of the maximum 35 MW export to the RO facility.

A solar field rated at 220 MWe for a DNI of 1000 W/m2 was assumed for this plant.

The maximum power added (at reference conditions) due to the operation of the duct burner is 205 MWe. So, in theory the solar field could replace the entire duct burner operation when operated at the best weather conditions. Similarly, the inlet air chillers of the two gas turbines add another 110 MW at full load and reference site conditions.

4. Ansaldo AE36-S5

This configuration also uses a 3 pressure level reheat HRSG with a duct burner. The gas turbine has an inlet air chiller. Table 4 below summarizes the key design parameters.

Duct Burner Exit Temperature	850 C	1562 F
HP Steam Pressure	165.5 bar	2400 psia
HP Steam Temperature	593 C	1100 F
IP Steam Pressure	36.2 bar	525 psia
IP Steam Temperature	585 C	1085 F
LP Steam Pressure	5.2 bar	75 psia
LP Steam Temperature	153 C	307.6 F
Condenser Pressure	0.096 bar	2.83 inHg
HP Evaporator Pinch Point	26.3 C	47.4 F
IP Evaporator Pinch Point	4.2 C	7.6 F
LP Evaporator Pinch Point	2.4 C	4.3 F
HRSG Inlet Temperature	60 C	140 F
Design Ambient Conditions	(1.013 bar, 46C, 42% RH)	(14.696 psia, 114.8F, 42% RH)

Table 4: Key design parameters of the AE36-S5 base model

Under these chosen circumstances the plant can have an output of 1535.1. MW with a heat rate of 6575 kJ/kWh with no export power to the RO facility. The plant can produce 1500.0 MW with a heat rate of 6729 kJ/kWh in case of the maximum 35 MW export to the RO facility.

A solar field rated at 220 MWe for a DNI of 1000 W/m2 was assumed for this plant. The maximum power added (at reference conditions) due to the operation of the duct burners is 227 MWe at reference conditions. The inlet air chillers of the two GT units add another 193 MW at full load and reference site conditions.

Results

1. **General Electric LM6000 PF+**

The LM6000PF+ configuration can produce 115.3 MWe, at a net LHV efficiency of 51.9% (6931 kJ/kWh, 6569 BTU/kWh), assuming no PV solar electrical output, at standard day conditions.

This configuration (LM6000 PF+) shows a maximum possible increase in power generation of 48947 MWh per year due to the solar field. This equates to about 134 MWh per day out of a total maximum plant electrical output of 2820.5 MWh per day (including PV solar output).

This is for a solar field rated at 30 MWe for a DNI of 1000 W/m2. Practically it was found that for the peak hour the maximum extra output attributable to the solar field was 27.23 MWe, and that an average hourly output 5.59 MW can be achieved (including hours that have no sunshine).

At the worst combination of expected weather conditions, the maximum output of the plant is 103.8MWe, compared to 140 MWe at the best expected weather conditions and an average value of 117.5 MWe (including PV solar output) over the entire year.

This compares favorably to the maximum output of the same plant without solar PV: minimum of 98.4 MWe, highest capacity of 123.45 MWe and an average capacity of 111.93 MWe.

An alternative way of looking at the benefit of having/adding a solar fields, is that you could meet the same dispatch instructions, at a reduced fuel cost.

For the chosen dispatch profile discussed earlier, totaling the hourly fuel savings from 8,760 hourly simulation runs show that a fuel savings per year of 2.59e11 kJ (or about 1.7 million US$ at a gas price of 7 US$/MMBTU) could be achieved. Notice that this is much less than 5.59 * 365 * 24 * 1000 * 6931 = 3.394e11 kJ, which you would achieve, if you assume base-load heat rate. The fuel savings will be lower because the addition of the PV output for the same target net output lowers the load factor of the combined cycle plant, and in this case the lower load results in reduced fuel efficiency. However, the value of 2.59e11 kJ represents 4.47% in fuel savings.

2. Siemens SGT800

The SGT800 configuration can produce 121.5 MWe, at a net LHV efficiency of 51.3% (7022 kJ/kWh, 6656 BTU/kWh), assuming no PV solar electrical output, at standard day conditions and no steam extraction.

This configuration (SGT800) shows a maximum possible increase in power output of 48947 MWh per year due to the solar field. This equates to about 134 MWh per day out of a total maximum plant electrical output of 2975 MWh per day.

Since the PV plant is identical to case 1, the maximum achievable additional output from the solar field (rated 30 MWe at DNI 1000 W/m^2) is 27.23 MWe, with an average hourly output (including hours that have no sunshine) of 5.59 MWe.

At the worst combination of expected weather conditions, the maximum output of the plant is 111.0MWe, compared to a value of 145.9 MWe at the best expected weather conditions, and an average value of 124.0 MWe (including PV solar output) over the entire year.

This compares favorably to the maximum output of the same plant without solar PV: minimum of 102.1 MWe, highest capacity of 126.95 MWe and an average capacity of 118.4 MWe.

Meeting the same dispatch instructions as in the case of the reference plant, fuel savings per year of 2.73e11 kJ (or about 1.8 million US$ at a gas price of 7 US$/MMBTU) could be achieved. Again, due to lower average load of the combined cycle plant due to the production from PV, this is much less than 5.59 * 365 * 24 * 1000 * 7022 = 3.439e11 kJ, which you would achieve if you assume base-load heat rate. The 2.73e11 kJ represent fuel savings of 4.51%.

While the achievable net electrical output is approximately the same in both configurations, and the heat rate for those configurations is similar too, the SGT800 based GT has the higher fuel savings, in part because part loading that engine does not hurt plant heat rate as much. After all, the SGT800 plant is slightly larger. In other words, the drop of power of the combined cycle (due to the same size of the PV solar field), would represent a smaller fraction of the plant load for the SGT800 plant. Also, the LM6000PF+ plant has a better heat rate at higher load factors than the SGT800, whereas the SGT800 has a better heat rate at lower load factors, which further explains the additional fuel savings.

3. Mitsubishi M701JAC

The M701JAC base configuration can achieve maximum design output of 1400 in all but 29 hours of the year, for the chosen dispatch profile, and none by more than 1 percent. But, given the structure of typical PPAs in the region, the plant would probably not be able to sell its output above the design value of 1400 MW for most ambient conditions, unless there are power shortages.

Adding a solar field would drop the number of hours where the 1400 MW could not be reached down to 15, all of them high humidity cases which would limit the chiller performance, and all after sundown.

This configuration (M701JAC) shows a maximum possible increase in power output of 553940 MWh per year due to the solar field. This equates to about 1517 MWh per day out of a total maximum electrical output of 38788.5 MWh per day (including solar PV field).

It was found that the maximum extra output due to the solar field was 213.2 MWh, with an average hourly output of 63.2 MWe (including hours that have no sunshine).

At the worst combination of expected weather conditions, the maximum output of the plant is 1391 MWe, at the best expected weather conditions a maximum value of 1711 MWe can be achieved, and on average the plant produces an output of 1543.0 MWe including PV solar generation.

For comparison, the respective performance numbers for the plant without solar PV are the following: minimum output of 1390 MWe, highest capacity of 1517 MWe and an average capacity of 1480 MWe.

But, given the nature of the PPAs in the region, such extra power output would be hard to sell under most circumstances.

Given the dispatch profile discussed earlier, totaling the hourly fuel savings from 8,760 hourly simulation runs shows that fuel savings per year of 3.24e12 kJ (or about 21.5 million US$ at a gas price of 7 US$/MMBTU) or a reduction by 6.62% in fuel consumption could be achieved by using the solar field mentioned. Notice that this is less than 63.2 * 365 * 24 * 1000 * 6660 = 3.678e12 kJ, which you would achieve if you assume base-load heat rate. Simulating every hour of operation during the year provides a much more accurate assessment of the impact of adding the solar field.

4. Ansaldo AE36-S5

The AE36S5 configuration can achieve maximum design output of 1500 in all but 15 hours of the year. Given the structure of typical PPAs in the region, the plant would probably not be able to sell its output above the contracted value of 1500 MW for most ambient conditions, unless there are power shortages.

Adding a solar field would drop the number of hours where the 1500 MW could not be reached down to 5. As these 5 hours are after sundown and at high humidity cases which would limit the chiller performance.

This configuration (AE36S5) shows a maximum possible increased output of 553940 MWh per year due to the solar field, about 1517 MWh per day out of a total electrical output of 39376.4 MWh per day (including solar PV field).

Since the PV plant is identical to case 1, the maximum achievable additional output from the solar field (rated at 220 ME for a DNI of 1000 W/m2) was 213.2 MWh, and the average hourly output resulted to 63.2 MWe (including hours that have no sunshine).

The maximum output of the plant is 1494.0MWe at worst combination of weather conditions, and 1808.4 MWe at the best expected weather conditions, with a value of 1640.7 MWe including PV solar output on average.

The results for maximum output of the same plant without solar PV are much lower (minimum of 1493 MW, highest capacity of 1616.9 MWe and an average capacity of 1577.4 MWe), but, given the nature of the PPAs in the region, this extra power output would be hard to sell under most circumstances.

For the chosen dispatch profile as per the PPA, fuel savings per year of 3.37e12 kJ (or about 22.4 million US$ at a gas price of 7 US$/MMBTU) could be achieved by using the solar PV field. Notice that this is less than 63.2 * 365 * 24 * 1000 * 6729 = 3.725e12 kJ, which you would achieve if you assume base-load heat rate. In reality, fuel savings will be lower since the addition of the PV output at constant net output, lowers the load factor of the combined cycle plant and in this case the lower load results in a worse efficiency. The value 3.37e12 kJ represents 6.37% in fuel savings.

Table 5 shows the summary of the heat balance study, comparing configurations for the Thailand location.

		LM6000PF+	SGT800
Plant Heat Rate at RSC	kJ/kWh	6931	7022
Plant Output at RSC	MWe	115.27	121.53
Average Hourly Solar Field Output	MWe	5.59	5.59
Maximum Solar Field Output	MWe	27.23	27.23
Max Power Increase	MWh/day	134	134
Fuel Savings / yr	kJ	2.59E+11	2.73E+11
Percent Fuel Savings / Total Fuel	%	4.47	4.51

Table 5: Summary of heat balance results for plant configurations 1 to 2

Table 6 shows the summary of the heat balance study, comparing configurations for the Middle East location

		M701JAC	AES36S5
Plant Heat Rate at RSC	kJ/kWh	6660	6729
Plant Output at RSC	MWe	1398.3	1500
Average Hourly Solar Field Output	MWe	63.2	63.2
Maximum Solar Field Output	MWe	213.2	213.2
Max Power Increase	MWh/day	1517	1517
Fuel Savings / yr	kJ	3.24E+12	3.73E+12
Percent Fuel Savings / Total Fuel	%	6.62	6.37

Table 6: Summary of heat balance results for plant configurations 3 to 4

Biomass Solar Hybrid Power Plants

A few words on the new IPPs proposed in Thailand. If the solar plant for configurations 1 or 2 were used for a biomass fired power plants, and the biomass plant in question would be able to produce 100% capacity, then the solar plant would result in fuel savings.

The fuel savings would be higher since the heat rate of a biomass fired power plant is worse than the heat rate of a natural gas fired power plant. But the fuel savings would in that case of course be renewable fuel savings.

In the other extreme case where the biomass plant can only produce the minimum of 65% of the total plant capacity, then one would need to install storage capabilities to the plant to ensure the missing 35% to peak-load could be provided by the solar plant. In this case the day with the worst weather conditions would need to be considered: only 2MW of solar power could be achieved (for the 13 peak hours specified in the PPA, assuming a solar filed rated at 30 MWe for a DNI of 1000 W/m2), using just enough storage to handle the production of that day, assuming a return trip efficiency (RTE) of 90%. The best day of solar production would be able to achieve 16.6 MW per hour during all 13 peak hours (for a PV solar field rate at 30 MWe for a DNI of

1000 W/m2). But, in order to use all available solar energy for that day as added capacity, the storage capacity would have to be 59.8 MW, again assuming a RTE of 90%.

Given the high variability of the daily solar PV electrical output, it's likely that the optimal solution is somewhere in between the two extremes. So, the biomass plant would probably have to cover more than 65% of the capacity but not quite 100%. The optimization of the ideal size of the solar plant vs. biomass plant vs. storage is outside of the scope of this paper, but such a study could be performed using EBSILON Professional and the VTU high throughput heat balance calculation grid for EBSILON.

Conclusions

When comparing the different configurations, the fuel savings for configurations 3 and 4 which include duct burners and electric chillers were expected to be much higher, when compared to configurations 1 and 2 without such equipment, and this was confirmed in this study.

When comparing configurations 1 and 2 for the Thailand location, it appears that the larger, but slightly less efficient SGT800 benefits more from the solar field in terms of fuel savings per year. Similarly, when comparing configurations 3 and 4 for the Middle East location, it again it appears that the larger, less efficient power plant (AES36-S5) would benefit more from the addition of the solar field, in terms of fuel savings per year.

Identifying the optimal configuration for a specific set of operating points requires flexible modeling software which can handle all configurations and off-design scenarios the plant is likely to encounter. EBSILON Professional's PV Module model and its extensive VTU OEM GT Library made studying this unique PV + CCGT configuration possible and fairly straight forward.

Accurate weather projections and dispatch profiles will have to be known, to estimate the fuel savings which can be achieved.

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