Case Study of a Californian Brewery to Potentially Use Concentrating Solar Power for Renewable Heat Generation

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Abstract

A case study for a proposed concentrating solar power (CSP) integration into an existing Californian brewery is highlighted. Using the System Advisor Model (SAM), the modelled annual thermal yield from the 1 MW_{th} solar field (SF) was approximately 2,636 MWh_{th}. The economics considered the viability of the project where different variables such as the installed SF cost were changed to determine the effect on the Net Present Value (NPV) and payback period. With a 15-year project life, changing the tax rate from 35% to 21% (which occurred in 2018), flips the Base Case from economically viable with an NPV > 0 (i.e. +$9k), to economically unattractive, i.e. with an NPV = -$7k. For the Base Case, without the Investment Tax Credit (ITC), and with a Federal tax rate of 21%, the project's NPV reached $0 (i.e., the project becomes viable), when the installed SF cost reached $146/m^2. The biggest influences on project viability measured by NPV were the project life, Federal tax rate, and the SF cost. For viability, solar industrial process heat (SIPH) projects, need SF costs of $150 to $200/m^2 in California.

CSP, solar IPH, SIPH, NPV, food processing, case study, System Advisor Model (SAM), thermal yield, LCOH

1. Growing Demand for Solar Heat for Industrial Processes

It has been found that 32% of total global energy is consumed by Industry. From that, 74% of the total energy used by Industry is for industrial process heat (IPH) applications, and 90% of that energy provided comes from fuels such as coal and natural gas (Philibert, 2017). For any significant impact to decrease fuel use and emissions, renewably generated heat, for example through solar thermal, is paramount for industry. Globally the examples of solar thermal to provide a heated fluid e.g. water, synthetic oil or even steam for industry are increasing rapidly (Business Wire, 2017; Solar Payback, 2017). CSP and non-concentrating systems are proven solutions to provide the temperatures and quantity of heat needed in SIPH (Kurup and Turchi, 2015a). As an example of the benefit of SIHP, in December 2018 Artic Solar installed a non-concentrating SF and boiler integration into the Four Father's distillery in Jacksonville, Florida (Digital Journal, 2018), where it is expected the integration will save thousands of dollars annually from the avoided costs of burning natural gas (Dixon, 2019). Key sectors deploying SIPH solutions today are the food processing and brewery sectors (Muang, 2018). This paper aims to showcase defined conditions where NPV > 0 (i.e. economic viability), challenges and the key aspects to consider.

2. Introduction

A detailed case study using the liquid-heat transfer fluid (HTF), process-heat trough module in the SAM has been undertaken for a brewery exploring the potential of a 1 MW_{th} SF. SAM 2017.9.5 was utilized (NREL, 2017a), and concentrating parabolic troughs were modelled. Note, SAM 2018.11.11 was not used, as the process-heat module code relative to 2017.9.5 has not changed. This SAM process-heat module has been validated against operational data for SFs providing heat, both for liquid-HTF and direct steam generation (DSG) systems (Kurup et al., 2018).

The potential project (near Los Angeles, CA) was being pursued by the developer Heat2Hydro Inc. (New York, NY), who shared confidential project sensitive information e.g. SF layout. The SF of approximately 1,800 m^2 in aperture area, was expected to use unpressurized water as the HTF. Project finance sensitivities to SF cost, natural gas price, project life, Federal corporate tax rate, debt interest rate, and project incentives were explored. The Base Case (i.e. Case 1) set the expected project life at 15-years and was undertaken without incentives. Case 2 and Case 3 included incentives. The analysis that follows is based on the hypothetical integration using the Rackam S20 parabolic troughs (Rackam, 2016) as proposed by Heat2Hydro, and incorporating a hot water tank of ~189k liters.

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The operational 100 kW_{th} S20 demonstration loop setup by Heat2Hydro in 2017 in Surprise, Arizona provides heat for sludge drying, a byproduct of municipal wastewater treatment (Rackam, 2017). This is shown in Figure 1a (left). The modelled SF and the ideal thermal storage (TS) water tank, then couples with the brewery process heat exchanger (HE), and can be seen in Figure 1b (right). The heated water from the HE is sent to the brewery for further heating if needed by the existing natural gas burner. The simplified modelling scenario allows the generated heat to be directed to the HE or the TS to store and to deliver ~80°C water to the HE at all-times.

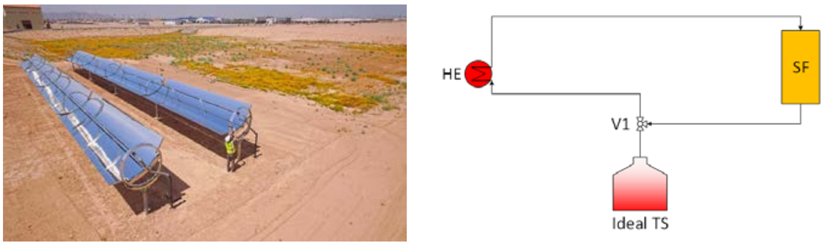

Figure 1. Heat2Hydro/Rackam test loop in Surprise, AZ (a). Credit Heat2Hydro; Modelled solar field and water tank (b).

Incentives were considered after the Base Case (Case 1). The ITC (Case 2) and the California solar-thermal production-based incentive (PBI) of approximately \$800k (Case 3) were applied separately. Despite these incentives and, the favorable economics they suggest (e.g. receiving \$800k in Case 3 within 2-years due to the potential natural gas displaced), deployment of SIPH in California has been weak, and time is running out on these incentives. The 30% ITC is expected to decrease in 2021, and the PBI to be closed from 2019.

3. Base Case Assumptions

A key parameter in the analysis is the current and future price of California Industrial Natural Gas, since gas consumption costs will be displaced by the solar heat and system integration. The 2017 annual California Industrial gas price used for the analysis was \$7.12 per thousand cubic feet (Mcf), as set by the Energy Information Administration (EIA), based on monthly data to produce an average (EIA, 2019a). As of July 2019, the California 2017 annual Industrial Natural Gas price has been back adjusted by the EIA to \$7.05/Mcf (EIA, 2019a). This is approximately a 1% natural gas price change relative to that used in this analysis, as such the Base Case and analysis have used the earlier gas price of \$7.12/Mcf. The exact gas pricing for the brewery was not disclosed, and the California average has been used. Conversion from Mcf to million British Thermal Units (MMBTU) yields \$6.87/MMBTU (EIA, 2019b). From 2017 the gas price is assumed to increase with inflation at 2.5%/year.

The assumptions used for the Base Case are highlighted in Table 1, which includes several parameters for the Solar Field, Project and System, Tax, Integration into the existing site, and the Financial variables. It is worth noting that from 2018, the Federal corporate tax rate changed from 35% to 21% (Murray, 2018; WSJ, 2017). As seen in Table 1, conservative estimates and assumptions have been used, which are representative and valid for multiple sites in California that could utilize a similar solar integration. The weather file for the site outside of Los Angeles has been created using the National Solar Radiation Data Base within SAM, and the brewery site has a daily average direct normal irradiance (DNI) of 6.5 kWh/m^2/day (NREL, 2019). For different sites, the SAM simulation would need to be run again to consider the DNI variation. As seen in Table 1, in 2017 \$150/m^2 for the installed SF cost was representative of commercial parabolic trough collector fields for CSP electricity generation (NREL, 2017a). The Base Case assumes that a CSP SIPH project developer and technology provider can meet \$150/m^2 for the installed solar field cost, which is an aggressive aspirational target for a small process-heat project. To note, the \$150/m^2 of installed solar field cost does not include the subsidiary system integration costs.

Consistent with the Department of Energy (DOE) SunShot goals for economic solar without incentives, the Base Case has assumed that the ITC and the California gas displacement incentive are set to zero. Any project in California today would likely benefit from the ITC and the incentive. These two situations will be highlighted as separate Cases, i.e. Case 2 and Case 3, respectively. The project life for the Base Case has been set to 15 years.

Discussions with Heat2Hydro have confirmed key details such as the hourly thermal load of the brewery (annual load is 2,201 MWh_{th}/yr) and a 15-yr proposed project life. For a 1 MW_{th} solar field, a 1-yr build and integration is expected. The fixed operation and maintenance (FOM) of \$8/kW-yr is from SAM (NREL, 2017a), based on SF maintenance for items such as mirror replacement. Heat2Hydro agreed with this for a well-installed system.

Table 1. Main assumptions for the Base Case (Case 1) of the brewery case study.

Area/Section	Assumption
Solar Field	The SF design is 1 MW_{th}
	The Base Case assumes a $150/m^2 for the installed SF cost and is not the real project cost. This is taken from SAM 2017.9.15 (NREL, 2017a)
	Rackam S20 trough with 1,800 m^2 of net aperture area (Rackam, 2016)
	FOM per year is $8/kW-yr, i.e. $8k/yr e.g. for mirror replacement (NREL, 2017a)
	SAM was used to determine the hourly thermal yield, which when summed over 365 days provides the annual yield of 2,636 MWh_{th}. The DNI was ~6.5 kWh/m^2/day (NREL, 2019)
Project and System	1-year construction period. Generation starts in 2019
	15-yr project life
	0% Salvage value at end of life
	10% Contingency on Direct Cost (DC)
	25% Project Indirect cost
Tax Rates	Federal Income Tax Rate: 35% and 21% for 2017 and 2018 (Murray, 2018; WSJ, 2017)
	California Income tax rate: 8.84% (DePersio, 2015)
Integration into existing site	Gas price increases with inflation at 2.5%/yr
	CA Industrial Gas price for 2017 of $0.0234/$kWh_{th}$ ($6.87/MMBTU). The 2017 average was derived from monthly data in 2017 (EIA, 2017a)
	With an 85% efficiency, the existing natural gas burner provides 2,590 MWh_{th}/yr of thermal energy to meet the 2,201 MWh_{th}/yr thermal load of the site.
	The process HE from the SF to the site is assumed to have a 50% heat exchanger effectiveness i.e. 50% of the maximum possible heat is transferred to the process water.
Financial Parameters	Inflation set to 2.5% (NREL, 2017b). $2017-dollar year, using USD
	Real discount rate of 5.5%
	The debt borrowed is 100% of the Total Installed Cost
	10-yr loan for the new solar field and project, with a 7% annual interest on the loan
	Investment Tax Credit (ITC) = 0%
	California Incentives = 0, i.e. no use of the California Solar Thermal-Incentive for natural gas displacement in the Base Case (CPUC, 2017)
	5-yr Modified Accelerated Cost Recovery System (MACRS) applied
	100% of the Total Installed Cost is subject to Property Tax.

4. Results

4.1: Case 1 - Base Case with Sensitivities

It was found that with the interaction of the thermal yield from the solar field (e.g. 2,636 MWh_{th}/yr), the heat exchanger effectiveness and the natural gas burner to make up the remainder of the site load, the natural gas energy consumed at the site is reduced from 2,590 MWh_{th}/yr to 1,047 MWh_{th}/yr. This is effectively a decrease in gas consumption from the site by 60%/yr. The Base Case, nor the other cases, assume no degradation of the SF. The Base Case (as well as the sensitivities in Case 1, Case 2 and Case 3), have used the SAM financial model within SAM 2017.9.5, and the SAM parametric capability to run the sensitivities. The Excel financial model was exported from SAM's 'Physical Parabolic Trough Commercial model' and modified to suit this case study (NREL, 2017a). Table 2 shows the estimated direct cost and total installed cost of the Base Case for the system.

Based on a target $150/$m^2$ SF cost (not real SF cost), the estimated total installed project cost is ~$514k or $285/$m^2$ for the system cost. A Project Indirect percentage of 25% has been used as this is one of the first projects for SIPH in California. It is likely for early projects, there would be a lack of knowledge in the construction of such a site.

It is important to highlight that in all the cases; the SF is a key variable to determine NPV equal to zero conditions.

Table 2. Overall solar field, integrated system capital expenditure (CAPEX) and installed project costs.

Integrated System	Size/Count	Unit Cost	Unit	Total ($)
Solar field	1,800	150	$/m^2	$270k
Tank	189,271 litres (50,000 gallons)	0.23	$/litre	$44k
Pumps	3	3,000	$/pump	$9k
Piping	200	49.48	$/m	$10k
Heat exchanger	1	1,000	-	$1k
Installation	-	-	-	$40k
Direct Cost (DC)				$374k
Contingency (on DC)	10%			$37k
Project Indirect (on DC and Contingency)	25%			$103k
Total Potential Installed Cost				$514k

The sensitivities varied around the Base Case are shown in Table 3. It is worth highlighting that the sensitives are variables that in most cases have some level of influence from the project developer, the site-user benefiting from the solar integration, or areas where research can help to address, such as the development of very low-cost CSP collectors specifically designed for solar IPH. Case 2 adds the ITC at varying levels to the Base Case (and the SF sensitivity), and Case 3 adds the California natural gas displacement incentive (PBI) for two natural gas scenarios. In Case 3, the natural gas price increases with inflation as in the Base Case, or the price of natural gas halves from the Base Case. All sensitives, and Case 2 and Case 3 include the 35% and 21% tax rates. The sensitivity analyses vary one main parameter, while keeping other inputs and parameters as the Base Case constant.

Table 3. Sensitivities varied from the Base Case, and details for Case 2 and Case 3.

Case	Sensitivity	Further Details
Case 1: Base Case with Sensitivities	Solar Field Installed Cost varied from 100 – 300 $/m^2	The installed solar field costs is varied from $100/m^2 to $300/m^2, as in previous NREL work (Kurup and Turchi, 2015b).
	CA Natural Gas Price Projections	CA industrial gas price changes using Henry Hub spot prices projections (EIA, 2017b), as the basis from 2018 to 2040, in 3 scenarios: (1) High, (2) Mid (which is very similar to Base, but with slightly higher natural prices), and (3) Low
	Salvage value as a percentage of the Total Installed Cost	The end of life Salvage Value (as a percentage of the Total Installed Cost) varied from 0 – 30% in 10% increments (e.g. 0% as in Base, 10%, 20%, and 30%).
	Project life	Project Life varied from 10-30 years in 5-yr increments
	Interest rate of loan	Interest rate set at 5%, 7% (Base), 10% and 12%.
	Total system installed without debt	Debt for the project set to 0% of the Total Installed Cost.
Case 2: Base + ITC	ITC added to base case and varied. California incentive = 0	ITC varied from 0 – 30%, in 10% increments based on schedule (DOE, 2017): 30% as the current level , 20% as the transition (rather than 22% at the end of 12/31/2021 (DOE, 2017), and 10% as permanent low
Case 3: Base + CA incentive	California natural gas displacement incentive added for two scenarios. ITC = 0	CA Incentives added using the current gas prices with inflation as in Base. CA Incentives added, and the gas price drops to half the Base and continues with inflation.

Effect of Solar Field Costs. A key area that research and industry can both help to decrease the Total Installed Cost, is through the installed SF cost. Prior detailed analysis has found that SIPH collectors have installed solar field costs of at least $200/m^2, which is more expensive than heat produced via natural gas (Turchi et al., 2016). Figure 2 shows the resulting impact on the levelized cost of heat (LCOH) of the Base Case project, where the installed solar field cost varies from $100 to $300/m^2 at both tax rates of 35% and 21%.

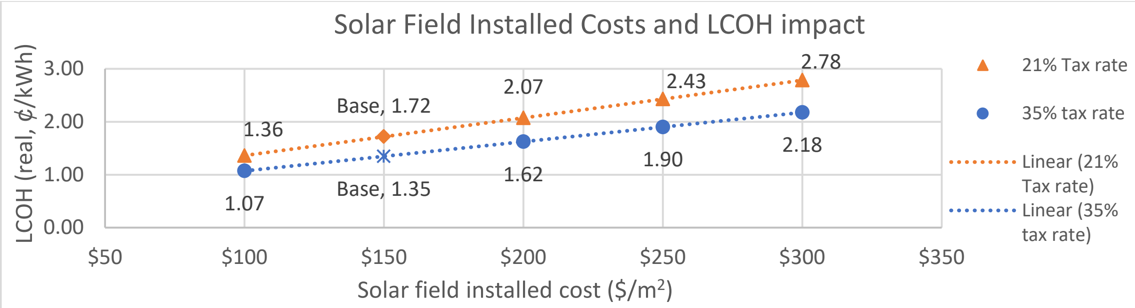

Figure 2. Impact on LCOH by varying the solar field installed cost for the project, 35% (blue) and 21% (orange) tax rates.

The impacts of varying the solar field cost are shown in Table 4. As shown, at the 21% tax, the real LCOH varies from 1.36 to 2.78 ¢/kWh$_{th}$, ($3.99 to $8.12/MMBTU). This is only less than the cost of industrial natural gas in CA (i.e. $6.87/MMBTU), at the lowest SF cost of $100/m^2. Due to the low cost of the displaced natural gas and slow payback, few projects recoup the total installed cost sufficiently in 15 years to have an NPV > 0. It is important to note that the 21% Federal tax creates higher LCOHs as less of the capital cost can be amortized.

Table 4. Impact on the Total Installed Cost and NPV of a project as the installed solar field cost varies, with 35% and 21% Federal income tax rates.

Solar field installed Cost ($/m^2)	Total Installed Cost ($)	NPV with 35% tax	LCOH real, ¢/kWhth	Payback Period (yrs)	NPV with 21% tax	Payback Period (yrs)	LCOH real, ¢/kWhth
100	$390k	$74k	1.07	8	$76k	8	1.36
150 (Base)	$514k	$9k	1.35	10	-$7k	10	1.71
200	$638k	-$55k	1.62	12	-$90k	12	2.07
250	$762k	-$120k	1.90	15	-$174k	15	2.42
300	$885k	-$184k	2.18	> 15	-$257k	> 15	2.78

Effect of Natural Gas Price. Here the sensitivity is the price of California industrial natural gas, from 2018 going out to at least 2034 (i.e., 15-yr project life), with operation starting in 2019. Using the 2017 Annual Energy Outlook (EIA, 2017b), the Henry Hub spot price in $/MMBTU to 2040 is used as a basis for the three gas price projections created for California industrial gas prices. The 10-yr average ratio of Henry Hub prices to California industrial gas prices was 1.93. That is, average California industrial gas prices have been approximately 1.93 times greater than Henry Hub spot prices for 2008 – 2017. The three California industrial natural gas price projections (High, Mid and Low) use the three Henry Hub projections to 2040, all with the 1.93 multiplier to get a rough estimate of what California industrial natural gas prices could be going into the future. This does not include possibilities related to California's increasing efforts to de-carbonize and tax fossil fuels. This analysis also has no carbon tax.

As can be expected, the natural gas price plays a significant role in the viability and potential of a solar IPH project, where the value of the heat is derived from the displaced natural gas. The four scenarios (i.e. Low gas price, Mid, Base, and High gas price), and the effect on the minimum solar field installed costs, where NPV = 0 are seen in Figure 3. When the Low gas price projection is used, at 35% Federal income tax, the solar field would need to cost $115/m^2 for NPV=0, and similarly, with 21% tax, the solar field would need to be approximately $105/m^2 for NPV=0. These are challenging installed solar field costs for solar IPH, albeit within the scope of the DOE's recent Solar Desalination and COLLECTS programs, and the respective goals (DOE EERE, 2018; DOE SETO, 2016). For example in the Solar Desalination funding, through research, low-cost CSP collectors are targeting $100/m^2 as the installed SF cost for producing heat for a large desalination system (DOE EERE, 2017).

In contrast, in the High gas price scenario, with 21% Federal income tax rates, a project could withstand installed solar field costs of approximately $289/m^2 and still achieve NPV = 0. With 35% Federal income tax applied, in the High gas price scenario, the project could install SFs of $309/m^2 and be viable.

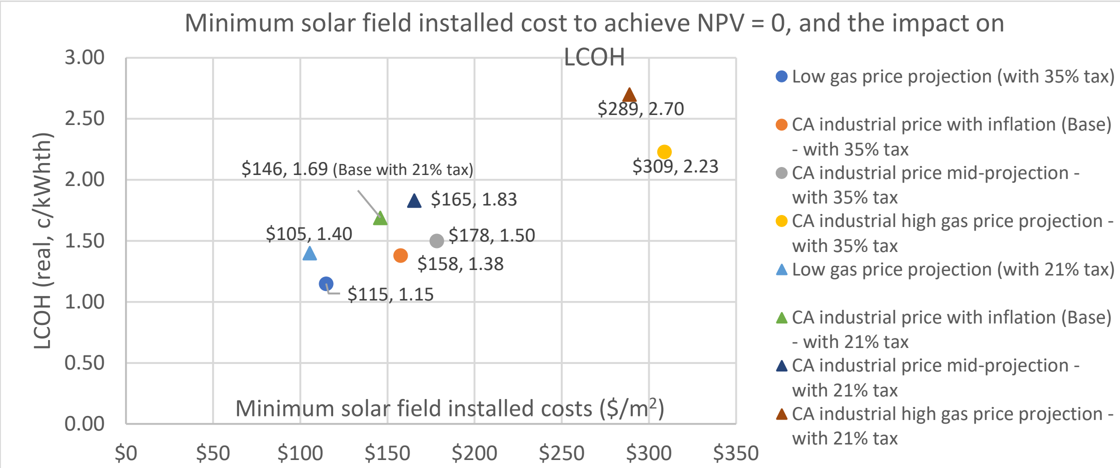

Figure 3. Minimum solar field installed costs to get NPV = 0, and the impact on LCOH, for 35% and 21% tax rates.

Current and future gas prices will heavily influence the viability and profitability of solar IPH projects. California industrial gas prices are heavily location dependent (e.g., proximity to the natural gas networks), and natural gas prices are a variable over which solar developers have little control. Figure 4 shows the impact on the NPV, when the variables of installed solar field costs and the natural gas price projections are varied simultaneously, creating a 3D contour plot for the 21% federal tax rate. The green areas in the figure highlight conditions where NPV is positive and improves (i.e. darker green) with decreasing installed solar field costs. The orange band is where NPV is transitioning to > 0. As seen in Figure 4, all gas price scenarios allow for some cases where NPV is > 0, even in the Low industrial gas price scenario, but only with sufficiently low-cost solar fields. In contrast, when the 35% federal tax rate is applied, only solar fields with installed costs of $100 to $115/m^2 have NPV > 0.

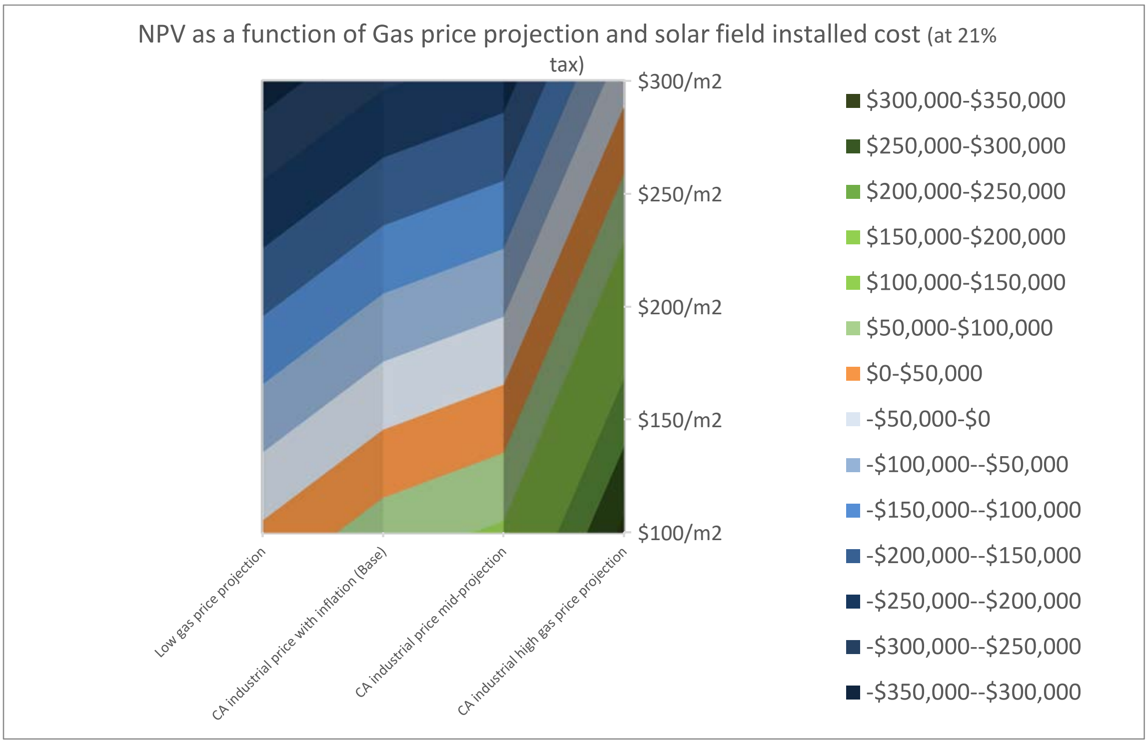

Figure 4. 3D contour plot of resulting NPV, by varying the solar field costs and gas projection, with 21% tax applied.

Effect of Salvage Value. The salvage value is a residual end-of-life value, e.g. recycling steel parts in the solar field, which is recovered at the end of the project life. Figure 5 shows the impact on the Base Case of varying the salvage value from 0 – 35% of the Total cost, at 35% and 21% tax rates. Salvage value has a relatively minor impact on NPV due to the time-value of money. That is, the recovered system value after 15 years of operation has a relatively minor influence on overall economics.

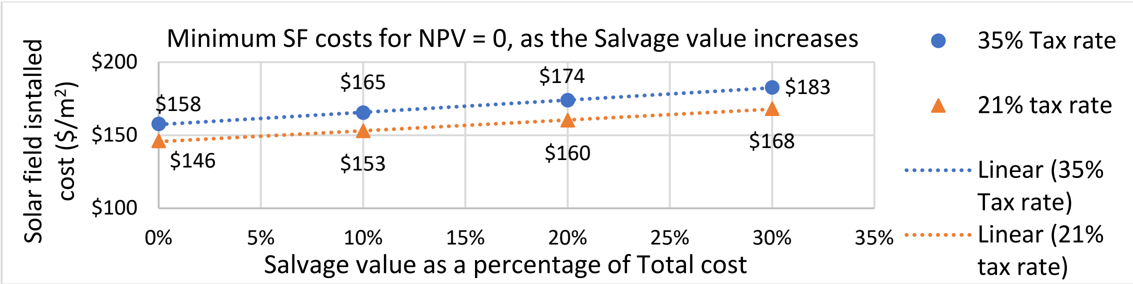

Figure 5. Minimum solar field cost as the Salvage Value is increased from 0-30%, with 35% (blue dots) and 21% (orange triangles) tax rates.

Effect of Project Life. Out of the variables analyzed, the project life had the most significant impact on the resulting NPV, i.e. simple project viability. After payoff of the project loan, project net savings of natural gas can be substantial. Figure 6 shows a contour plot of NPV when the installed solar field cost and project life are varied for the Base Case. The orange band highlights conditions where NPV transitions to positive values; thereby defining the border of economic viability for the assumptions. As seen, the increase in life of the project significantly increases project NPV. Conversely, a project with a 10-yr financial life would require a much cheaper solar field cost of less than $100/m^2 for it to determined viable (i.e. positive NPV).

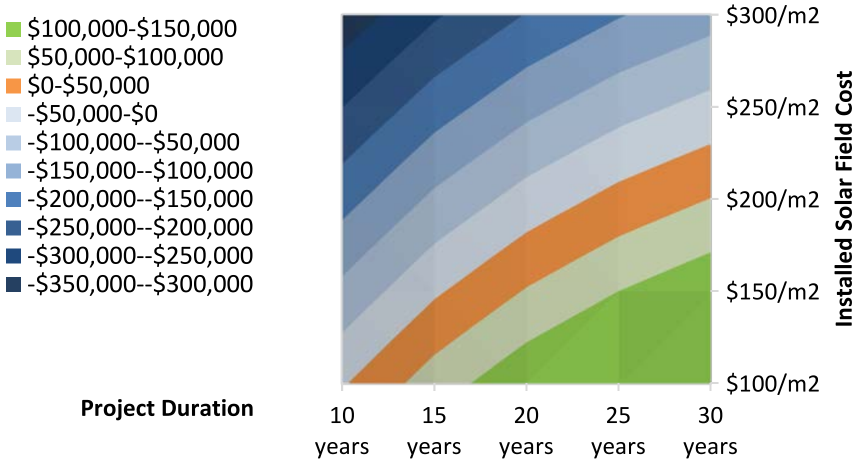

Figure 6. 3D Contour plot of NPV for varying the installed solar field cost and project duration in years.

Effect of Varying Interest Rates. In this sensitivity, the interest rate on the loan for the project is varied from 5%, 7% (Base Case), 10% and 12%. Figure 7 shows the impact of changing the annual interest rate (for the 10-yr loan, with a project life of 15 years), on the resulting minimum solar field costs that produce NPV=0. As seen in Figure 7, as the interest rate of a project increases, the likelihood of profitability decreases, and the viability decreases, as cheaper solar fields are needed that can reduce the Total Installed Cost.

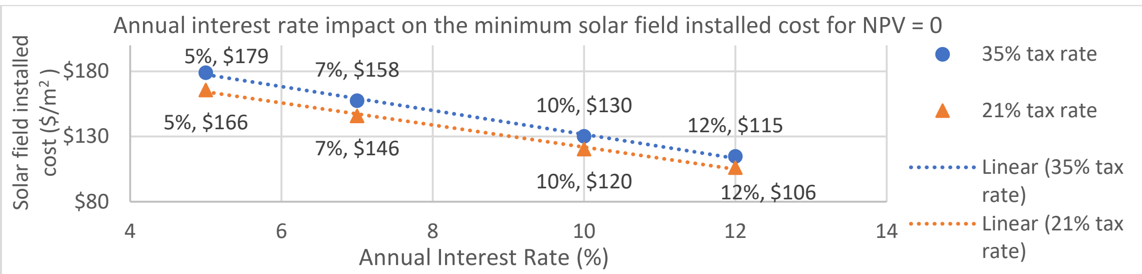

Figure 7. Varying interest rates from 5 - 12%, and the impact on minimum solar field costs for NPV = 0.

Effect of Debt Fraction. This sensitivity is the removal of debt from the project, for example, where the end-user has a 100% equity available and can finance the project immediately. Most commercial and industrial projects (either photovoltaics or CSP), utilize a mix of debt and equity. The 0% debt sensitivity has been used as a way of showing the maximum effect of equity, where in the Base Case 100% of the project cost was borrowed.

When the project is without debt (for both the 35% and 21% Federal tax rates), project viability decreases with 0% debt when compared to the Base Case of 100% debt. For example, at the 35% tax rate, the Base Case NPV goes from $9k to -$82k, with and without debt respectively. That is, it is economically more difficult to deploy solar IPH projects when fully equity financed. This impact is mainly due to the time value of money and the tax benefits received by companies in having project debt, i.e. the CAPEX and debt interest can be written off.

Effect of Federal Tax rate. When the main goal of the case study is considered, i.e. defined conditions where NPV > 0, it is found that the NPV is highly dependent on the federal tax rate. As highlighted in Table 1, federal tax law changes effective in 2018 dropped the 35% corporate income rate to 21% (Murray, 2018; WSJ, 2017). The federal tax rate applied is based on the income generated (DePersio, 2015), but for conservative estimates, 35% has been used for the various cases in the case study. For example in SAM 2017.9.5, a 28% Federal Income tax is applied as the default (NREL, 2017a). The federal income tax rate makes a significant difference to the NPV. The Base Case uses a 15-yr project life and a 10-yr loan at 7% interest. As seen in Table 5, with a 35% Federal Corporate Income tax rate, the same project is effectively economic, with a NPV of $9k, while under the 21% tax situation, the project is uneconomic and has a negative NPV at the end of 15 years of -$7k.

Table 5. NPV for the Base Case, and solar field conditions to reach NPV = 0, for 35% and 21% Federal Tax rates.

	35% Federal Tax		**21% Federal Tax**	
NPV for Base Case	$9k (10-yr Payback)		-$7k	
	Minimum SF cost ($/m^2)	Total Installed Cost ($)	Minimum SF cost ($/m^2)	Total Installed Cost ($)
For NPV to = $0	$158/m^2	$533k	$146/m^2	$504k

The minimum solar field costs to drive NPV to zero is calculated in Table 5, with the other Base Case assumptions unchanged. Required Total Installed Costs were $533k and $504k, with the 35% and 21% Federal tax rates respectively, and Payback is approximately 10-yrs with the 35% Federal tax for the minimum solar field conditions. As mentioned, the NPV was a key metric used for project viability. For the Base Case, without the 30% ITC and using a 2017 Federal corporate income tax rate of 35%, the project's NPV reached $0 (i.e., the project becomes viable), when the installed solar field cost reached $158/m^2. With the 30% ITC and 35% tax rate, the solar field installed cost is estimated at $324/m^2 to get NPV = $0. In 2018, the Federal corporate income tax was decreased to 21%. With a 15-year project life, the change in the tax rate from 35% to 21%, flips the Base Case from NPV > 0 i.e. economically viable at +$9k, to unattractive where the NPV is < 0 at NPV = -$7k. Similarly, instead of the $158/m^2 for the solar field costs in the 35% tax scenario, in the 21% tax scenario, the minimum installed solar field cost of $146/m^2 is needed for the NPV = 0.

The influence of tax rate and project life touches on the metric that is often most important to industrial users, namely payback period. Industrial users may require relatively short payback periods (e.g., less than 3-5 years), regardless of overall project NPV due to uncertainties in future costs and market projections. Sensitivities to the loan interest rate, salvage value, and 100% equity (i.e. no debt for the project) had lesser effect on the NPV.

4.2: Case 2 - Base and Investment Tax Credit (ITC) added

The ITC is an important Federal tax credit for CSP for Commercial and Industrial applications, and allows an end-user that installs a new solar IPH field to benefit from up to a 30% tax credit (DOE, 2017). The credit amount applied for solar IPH projects is dependent on the construction start date. With the current 30% ITC valid till 12/31/2019, solar IPH projects that begin construction before the end of 2019 can receive the maximum credit. The ITC in the present schedule, transitions to 26% by the end of 2020, to 22% by the end of 2021, and finally tails off to 10% from 2022 (DOE, 2017). Case 2 has utilized the Base Case with the solar field sensitivity, and then added three ITC percentages of: 30% (current level); 20% (for the transition); and 10% for the tail off. The Base Case used a 0% ITC to remove the beneficial effects of the tax credit, consistent with other DOE SunShot goals. Figure 8 shows the impact of the ITC on the resulting minimum solar field costs to get NPV = 0.

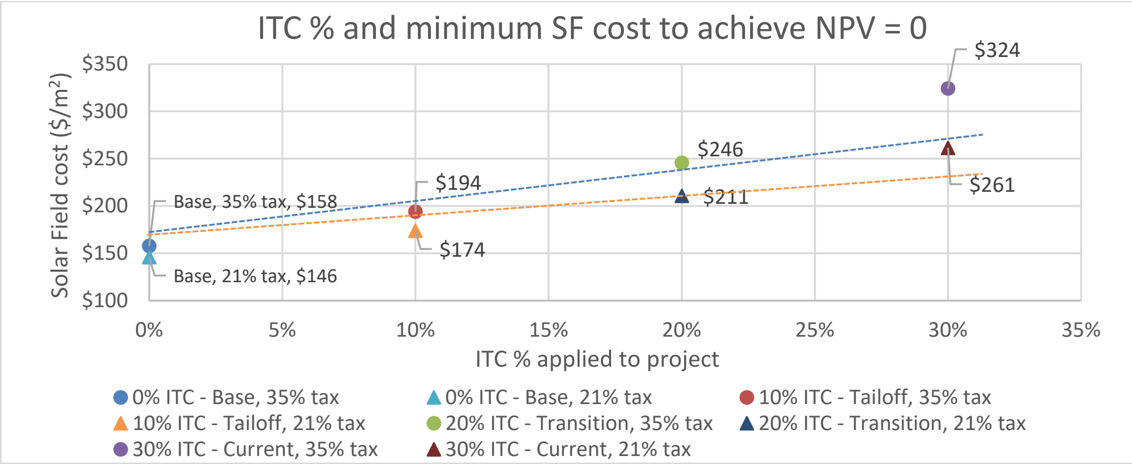

Figure 8. SF costs required to achieve NPV=0 as a function of ITC % applied, for 35% (blue line) and 21% (orange line) tax rates.

As expected, the most benefit for projects occurs with the 30% ITC. For example, with the 35% Federal tax, a solar IPH project can sustain installed solar field costs of up to $\$324/m^2$ ($945k for the Total Installed Cost) and still achieve NPV = 0. With the 21% tax rate, this drops to $\$261/m^2$ of installed solar cost ($789k for the Total Installed Cost). In the transition period (e.g. at 20%) and the tail off (10%), the decreasing ITC requires that solar field costs come down for solar IPH projects to be viable.

4.3: Case 3 – Base and Production Based Incentive (PBI) for California added

The California PBI for solar process heat has been extended by two years (California Legislative Information, 2017), and has potential to be very valuable, if projects can be identified and built in time. As of June 2017, the incentive for industrial customers using solar thermal to displace natural gas, was $\$0.3443/kWh_{th}$ (CPUC 2017). The maximum benefit available to a newly installed solar IPH integration is $800k (CPUC, 2017), after performance is proven. Discussions with Heat2Hydro also confirm that they expect the brewery to gain the $800k incentive with the solar integration, up to two years after the initial build of the solar field, though their current expectations are that year one would bring in ~$550k of the incentive value, and year two with the remainder of ~$250k. The estimates from SAM and the financial modelling, indicate that the incentive earned in years one and two is about $750k and $50k, respectively. Nonetheless, it can be expected, based on estimated gas displacement per annum due to the solar integration (i.e. a 60% gas decrease/year), the full PBI could be earned in two years.

The two incentive scenarios used for Case 3 are: (1) the current California industrial natural gas price increasing with inflation; and (2) a low-gas price case of California industrial natural gas prices halving from the current 2017 price (from 2.34 $¢/kWh_{th}$ to 1.17 $¢/kWh_{th}$) but also increasing with inflation over time. Table 6 shows the impact of the incentive scenarios, compared to the Base Case with the solar field installed cost sensitivity. With the PBI applied to projects where the installed solar field cost ranges from $\$100\text{-}300/m^2$, for both tax conditions, the entire range of projects was found to have NPV > 0.

As in Table 6, even with a 50% decrease in gas prices, projects that benefit from the PBI have a positive NPV even with installed SF costs in excess of $\$300/m^2$. Payback periods without the incentive are much longer than industry-preferred levels (< 3-5 years), though this fast payback is achieved in most scenarios with the incentive.

Table 6. PBI scenario, and impacts on NPV and Payback Period, for 35% and 21% tax rates.

Incentive Scenario	Solar field installed Cost ($\$/m^2$)	Total Installed Cost ($)	NPV with 35% tax	Payback Period (yrs)	NPV with 21% tax	Payback Period (yrs)
Without Incentive	100	$390k	$74k	8	$76k	8
	150 (Base)	$514k	$9k	10	-$7k	10
	200	$638k	-$55k	12	-$90k	12
	250	$762k	-$120k	15	-$174k	15
	300	$885k	-$184k	> 15	-$257k	> 15

(1) Incentive applied for 2 yrs (at current gas prices and inflation)	100	\$390k	\$510k	1	\$606k	1
	150 (Base)	\$514k	\$446k	1	\$523k	1
	200	\$638k	\$381k	2	\$440k	1
	250	\$762k	\$316k	3	\$357k	2
	300	\$885k	\$252k	4	\$274k	4
(2) Incentive applied for 2 yrs and 50% decrease in gas price	100	\$390k	\$348k	1	\$409k	1
	150 (Base)	\$514k	\$283k	1	\$326k	1
	200	\$638k	\$219k	2	\$243k	1
	250	\$762k	\$154k	4	\$159k	3
	300	\$885k	\$90k	6	\$76k	6

5. Discussion

The importance of project life points to the need for research and demonstration of durable technologies for SIPH applications that reduce CAPEX. Under the constraint of fast payback for industrial users (e.g. 3-5 years), reducing materials and concentration ratios of the collector for lower upfront cost may be suitable. For example, Sunvapor Inc., SkyFuel and Hyperlight Energy have been funded through the DOE to develop new low-cost SIPH collectors as an important lever to reduce the overall LCOH in SIPH applications (DOE EERE, 2018; DOE SETO, 2016).

The potential to receive the \$800k California PBI credit for a SIPH installation within two years of operation, yielding a positive NPV even with relatively high solar field costs of \$300/m^2, seems to provide a strong incentive to end-users wanting to install SIPH. Yet, currently no new solar IPH projects have been built in California, even with the very lucrative California incentive in place, and potentially the use of the incentive in conjunction with the 30% ITC. There are likely several reasons for this, including that the majority of solar IPH projects in California present risk due to the relative newness of the technology and the technology providers. The incumbency of low-cost natural gas remains a hurdle. Research from the Climate Policy Institute (CPI) indicates that large heat users like cement manufacturers, require a payback period of less than three years before they will invest in carbon abatement options, even if the project can be profitable in the longer term (Zuckerman et al., 2014). This confirms what solar IPH developers are highlighting about the demand for quick (< 3 year) payback periods. Solar IPH developers like Heat2Hydro and Sunvapor, have found it is still very difficult to get projects closed and constructed, especially when gas prices the end-users are paying can be as low as \$3.30/MMBTU (about half the average California industrial gas price), dependent on the site location.

Part of this lack of new projects, is also related to the extension of Bill AB-797, which has extended the natural gas incentive for only two years, and was signed in late 2017 (California Legislative Information, 2017). Solar developers working in 2017 with end-users would have faced a situation where the original incentive could have been withdrawn by the end of 2017, and as such would have dissuaded the end-users from committing to go ahead with the project. The extension of Bill AB-797 will make 2019 the last year where this specific California natural gas incentive is available. But for end-users to fully benefit from the incentive the project must be built by the end of 2018, to have the requisite year of operations data to show metered decreases in natural gas consumption.

In discussions with Heat2Hydro, it is clear the Engineering, Procurement and Construction (EPC) costs in California can be a significant issue that can derail a project due to high costs and risk adders, in many cases EPC costs significantly more than in other solar IPH markets. While the installed solar field cost assumed for the Base Case has been achieved for large CSP power projects, smaller IPH projects do not benefit from those economies of scale, and newer technical and business models will be needed to allow solar IPH to proliferate. Another reason for the high installed cost estimated by the EPC contractors could be the lack of experience with small IPH projects. Both the EPC contractors and the end-users are unfamiliar with solar IPH integrations. End-users also perceive solar IPH integrations as potentially risky as the operation of the site could be affected. This perception will be difficult to shake until there are multiple operating solar IPH plants in the region and U.S.

As of July 2017, the current CO_2 Cap-and-Trade scheme for California was extended from 2020 to 2030, via Bill AB-398 (Nemec, 2017a). In March 2019, the average price of CO_2 emissions/ton was approximately \$15.10/ton (CPI, 2019), but currently the ‘pain’ of an emissions penalty is still quite low for most industrial natural gas users.

The carbon price/ton in California is not included in the analysis, to remove the potential beneficial effects and showcase the situation without additional penalties or incentives. There is potential that by 2030, the cost per ton of CO_2 could reach \$55/ton (Nemec, 2017b). This could force large industrial end-users to not only consider alternatives like solar thermal, but rapidly increase their uptake to reduce the additional costs associated with CO_2 penalties. The impact would need to be understood for small industrial sites like food processors and brewers. It is likely that California going forward will continue to penalize CO_2 emissions, which would raise the future costs of natural gas usage and thereby promote conservation. CO_2 penalties, along with technology cost decreases, business model and market improvements, could rapidly increase the deployment of SIPH systems.

6. Conclusions

A case study of a potential 1 MW_{th} CSP solar field integration into an existing brewery in California was completed, where the annual solar field thermal yield was approximately 2,636 MWh_{th}. It is expected that the solar field integration would last a minimum of 15-years. With the base case 15-year project life, changing the tax rate from 35% to 21% (which occurred in 2018), flips the Base Case from economically viable with an NPV > 0 (i.e. +\$9k), to economically unattractive, with an NPV = -\$7k. The pronounced influence of the federal tax is due to the large upfront costs of solar IPH projects that lead to tax-deductible losses in the early years of the project period. A higher tax rate produces larger deductions, and lower LCOHs. There are likely several reasons for a lack of SIPH projects in California. SIPH projects present risks due to the relative infancy of the SIPH technologies, EPC contractors and the technology providers. The incumbency of low-cost natural gas remains a key hurdle. For instance, industrial gas prices can be as low as \$3.30/MMBTU in some locations, even though the 2017 California Industrial Gas price average was \$7.12/MMBTU (EIA, 2017a). The biggest influences on project viability (measured by NPV) were the project life, federal tax rate, and the solar field installed cost.

It is important to highlight that from this study, the target for SIPH developers must continue to reduce the installed solar field and total system costs within the U.S. through various mechanisms such as learning through doing and low-cost collectors. These mechanisms are also very important for SIPH projects globally. Even for small scale SIPH projects, solar field installed costs need to reach at least \$150 to \$200/m^2 within the U.S, which this case study highlighted is currently not the case. The total installed cost of the system integration can be nearly double the solar field installed cost e.g. due to EPC costs. Lower overall system costs are needed to compete with the low incumbent natural gas prices in California at least. For other U.S. with higher natural gas prices, e.g. in Hawaii where in 2017 the annual industrial natural gas price was \$19.92/Mcf (EIA, 2019a), higher installed solar field and system integration costs are acceptable for SIPH projects to still be viable i.e. via NPV and payback.

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