Solar-Generated Steam for Oil Recovery: Reservoir Simulation, Economic Analysis, and Life Cycle Assessment
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Abstract
Integrated solar thermal steam generation and heavy-oil recovery projects have garnered interest because of their ability to decrease the variability of steam generation costs arising from fluctuations in natural gas prices as well as life-cycle carbon dioxide emissions. The viability of a solar thermal steam generation system (with and without natural gas back-up) for thermal enhanced oil recovery (TEOR) in heavy-oil sands was evaluated in this study. Using the San Joaquin Valley as a case study, the effectiveness of solar TEOR was quantified through reservoir simulation, economic analysis, and life-cycle assessment of oil-recovery operations. Reservoir simulation runs with continuous but variable rate steam injection were compared with a base-case Tulare Sand steamflood project. Reservoir properties and well geometries were drawn from the literature. For equivalent average injection rates, comparable breakthrough times and recovery factors of 65% of the original oil in place were predicted, in agreement with simulations in the literature. Daily cyclic fluctuations in steam injection rate do not greatly impact recovery for this reservoir setting. Oil production rates for a system without natural gas back-up to moderate injection rates do, however, show seasonal variation. Economic viability was established using a discounted cash flow model incorporating historical prices and injection/production volumes from the Kern River oil field. This model assumes that present day steam generation technologies could be implemented fully at TEOR startup for Kern River in 1980, for the sake of comparison against conventional steam generators and cogenerators. All natural gas cogeneration and 100% solar fraction scenarios had the largest and nearly equal net present values (NPV) of $12.54 B and $12.55 B, respectively, with production data from 1984 to 2011. Solar fraction refers to the steam provided by solar steam generation. Given its large capital cost, the 100% solar case shows the greatest sensitivity to discount rate and no sensitivity to natural gas price because it is independent of natural gas. Because there are very little emissions associated with day-to-day operations from the solar thermal system, life-cycle emissions for the solar thermal system are significantly lower than conventional systems even when the embodied energy of the structure is considered. Here, we estimate that less than 1 g of CO2/MJ of refined gasoline results from the TEOR stage of production if solar energy provides all steam. By this assessment, solar thermal based or supplemented steam generation systems for TEOR appear to be a preferred alternative, or supplement, to fully conventional systems using natural gas (or higher carbon content fuels), especially in areas with large solar insolation.

Introduction
The objective of this paper is to investigate the impacts of using solar energy rather than natural gas to generate steam for Thermal Enhanced Oil Recovery (TEOR). Multiple metrics are used to evaluate solar TEOR: reservoir performance, economics, and environmental impact. Unlike previous studies (van Heel et al., 2010) this paper considers feasibility more broadly than at the reservoir level and roots this discussion on actual projects in the San Joaquin Valley (USA) rather than an idealized, analytical model. From a reservoir engineering perspective, the major challenge in implementing a solar thermal based system is to determine the interplay of oil production and the daily cycles in heat production caused by the rising and setting of the sun as well as the yearly cycle caused by the changing of the seasons. From an economics standpoint, it is important to show that a solar TEOR project has profits at least equal if not in excess of conventional systems, such as natural gas cogeneration, by which most steam is generated for TEOR (Molchanov, 2011). And lastly, from an environmental perspective, it is important that sources of “green” energy provide actual benefits in their life-cycle impacts (relative to conventional sources), whether from an energy or emissions perspective. By benchmarking the performance of current solar thermal technologies against conventional fossil fuel systems in this way, we hope to highlight the strengths and weaknesses
of solar TEOR. We also seek to highlight the potential for future utilization that we see as great given the current and increasing importance of TEOR methods worldwide (Alvarado, 2010).

The San Joaquin Valley was selected as an ideal site for our work because well-documented studies and historical injection/production data are available. Also, solar-steam generation demonstration projects are already underway. Specifically, the BrightSource tower at Chevron’s Coalinga field (BrightSource, 2011) and the GlassPoint single-transit trough system at Berry Petroleum’s 21Z Lease in Midway Sunset (GlassPoint, 2011). Here, we use the single-transit trough, shown in Fig. 1, as a prototype solar steam generator. It features light-weight trough-shaped mirrors that focus solar insolation onto carbon-steel pipe that serves as a receiver. The mirrors and receivers are housed inside of a “glasshouse” that is visible in Fig. 1. The glasshouse is, essentially, a repurposed greenhouse to protect the mirrors from weather, dirt, humidity, and other elements. Maximum steam conditions are stated as 2500 psi and 950 °F.

Solar steam technology is being introduced in the San Joaquin valley for a number of reasons. First, there are numerous mature, heavy-oil fields, many of which are under TEOR. The area has excellent direct solar insolation, making it a good candidate site for solar collectors. The area is also quite accessible enabling simpler transportation of solar boiler components to project sites. Additionally, many of these fields have shallow, thick, laterally extensive sands. Steam injection pressures are relatively low on account of reservoir depth and reservoirs are more easily modeled due to geological structure.

Unfortunately, we were unable to study a single reservoir/development in the San Joaquin Valley when quantifying the field performance, economics, and life-cycle assessment (LCA). We found it necessary to perform interrelated studies based on the data available. For this reason, the simulation study employs data from prior study of steam injection into Tulare Sands (Spivak, 1987), the economics study uses data from the Kern River oil field (Sigworth, 1983), and the LCA makes use of data from single-transit trough pilot project at 21Z.

Following the discussion of our methodology, we present results from reservoir, economic, and life-cycle modeling. Our results from reservoir simulation are comparable to those of van Heel et al. (2010) in that for equivalent amounts of total heat injection continuous variable-rate solar thermal and conventional based projects have equivalent long-term recoveries of oil. The solar thermal case does show some local-variations in production caused by the variable-rate injection; however, these do not reduce the overall recovery. Economic viability, through discounted cash flow analysis, was also established for the solar thermal case relative to several other conventional means of generating steam. By our measure, solar thermal generation even out-performed an all cogeneration solution that is a preferred alternative for generating steam at present. Lastly, LCA indicates that the single-transit trough solar thermal technology modeled in this study is extremely net positive in terms of total energy produced relative to energy input. When compared with conventional technologies that burn natural gas, significant emissions are predicted. It is worth noting that even though we have established the feasibility of such a system on several levels for the San Joaquin Valley, it does not mean that such a system is necessarily a good solution for all locations, as there are a number of other important factors that are relevant to siting a project (such as land use), that we have not considered in our analysis.

Methodology

The components of our evaluation include: (i) reservoir engineering using simulation, (ii) economic analysis, and (iii) engineering life-cycle analysis of capital equipment, construction, and operating procedures. The solar boiler and steam generator is modeled as a single-transit trough.

Reservoir Engineering

The reservoir model was developed by choosing a geological environment and a consistent set of fluid and flow properties. Model input parameters and simulation grid are based primarily on literature values for Tulare Sands (Spivak, 1987). The simulation grid utilizes a quarter of a five-spot element of symmetry with 5-acre spacing (Fig. 2). The model has been refined (with regard to the original study) in the horizontal direction, but not in the vertical. The distributions of permeability and porosity are given in Table 1. The reservoir rock in this model is assumed to be water-wet with temperature independent relative permeability. The PVT data for the oil, typical for a heavy oil, was obtained from the Tulare Sands (Spivak, 1987). Simulations were performed using CMG’s STARS simulator that has a range of functions for thermal simulation. Three-phase relative permeabilities were defined using the Stone II model, as shown in Fig. 3, that does not require one to assume residual saturations (Stone, 1973). The 9-Point Method was chosen to minimize grid orientation effects. The initial conditions were selected in line with the Tulare Sands model (Table 3). Boundary conditions are given in Table 4. It is worth noting that variations in these parameters have a pronounced effect on the results as Spivak (1987) showed, but these sensitivities are not the focus of our work. Please refer to Spivak (1987) for the sensitivity analysis and applicable discussion.

The effect of solar variability on injection rate is modeled using a variable-rate injection schedule. Achievement of an equivalent daily/annual average steam rate for the conventional and variable-rate cases with and without heat backup relative to the base case is assumed achievable through appropriate scaling of the size of the solar thermal collector system. MATLAB (a high-level computing environment) was used to create a schedule that varied daily. Over 24 hours, a high injection rate of 159 BBL cold-water equivalent (CWE)/d for 8 hours simulated daytime solar steam and a low rate of 5 BBL CWE/d for 16 hours simulated conventional steam overnight (Fig. 4). Using this schedule, steam injection is continuous keeping valves open and the injectors warm. In order to represent annual variability, hourly solar data from NREL (2005) for
the Bakersfield, CA area (Fig. 5) was adapted to steam injection rates. In this case, the length of usable daylight is assumed to be constant but the peak rate is varied in order to reflect historical annual variability.

**Economic Analysis**

The economic viability and attractiveness are analyzed for six steam generation scenarios:
- direct steam generation using natural gas,
- all cogeneration using natural gas,
- “real” cogeneration using natural gas that approximates actual oil-field steam-generation conditions,
- 100% solar steam where overnight storage of solar heat must be incorporated,
- 50% solar fraction steam with the balance from natural gas fired direct steam generation, and
- 25% solar fraction steam with the balance from natural gas fired direct steam generation.

Clearly, the first 3 scenarios have 0% solar input. The so-called real cogeneration case models the scenario where only the minimum monthly steam demand is supplied by cogeneration, and the remaining requirement, in months with demand above the minimum, is supplied by direct steam generation. The various solar cases assume performance that approximates a single-transit trough steam generator. The portion of direct natural-gas fired steam generation can be thought of as the fraction of additional capacity required to cover for times of low solar activity, such as night, inclement weather, and so on. Alternately, solar fractions less than 100% can be thought of as a hybrid approach for reducing the land area required for solar collection, for example.

For each scenario, the economics of the specific installation were assessed on a Net Income Before Tax basis using the historical production of the Kern River Field (Fig. 6). In each case, it was assumed the generation facility was constructed prior to any other steam generators, and every scenario was run with a 30-year lifespan. This varies from the actual, staged development at Kern River (Sigworth et al., 1983), but serves as a good representation for a new TEOR project. Monthly energy prices were taken from the Energy Information Administration’s database (EIA.gov, 2011). When a monthly price was not available, an annual average was used. Electricity prices are the average retail price of electricity to the industrial sector. The U.S. Crude Oil Domestic Acquisition Cost by Refiners was used for the monthly oil price, while the U.S. Natural Gas Wellhead Price was used for monthly natural gas prices (EIA.gov, 2011). All prices used in the analysis are shown in Fig. 7.

Capital expenditures for each scenario were required in order to evaluate better full life-cycle profitability of each project versus only considering operating costs. The capital cost of steam output and capital was determined for each generation plant as millions of dollars per million BTU output (Fig. 8). For direct steam generation and cogeneration, values were derived from Sigworth et al. (1983). The simplifying assumption was made that capital expenditure and steam output scale linearly, thus the costs determined from Sigworth et al. could be scaled easily for larger generation facilities (Fig. 9). More recent studies confirm that this trend is reasonable (Martin, 2002). This analysis does not include the capital costs for electricity transmission, which could be significant for the cases with a high percentage of cogeneration. Capital costs of the single-transit trough solar facility were derived from industrial literature (GlassPoint, 2011). A summary of the assumptions for each scenario is represented in Table 6. This chart includes an additional 2 MMS of capital expenditure in the 100% solar case to account for a small amount of thermal storage or about 680 MMBTU assuming the literature value of $10/kWh, (Price, 1999) or natural gas steam generation (70 MMBTU/hr) (using the correlation from Fig. 8). The required capacity of the steam generators was determined by the maximum monthly steam injection, 1.2 x10^7 MMBTU or 34x10^6 BBL cold water equivalent (CWE), for the field between 1980 and 2010. It is important to note, that capital expenditure, as calculated here, does not include the cost of injector drills, steam pipelines, royalties, etc. that are relevant to actual projects but are equivalent for each scenario. Thus the results presented for each case are better utilized for comparison rather than appraisal purposes.

Two methods of depreciation were used: straight-line and sum of years digits (SOYD). Both depreciation methods were used to show the impact of the different accounting on present value calculations. In practice, operators would choose an accelerated schedule depreciation method (such as SOYD) in order to recover their capital most quickly.

In all scenarios besides 100% solar, the most significant monthly expenditure is natural gas. Efficiencies of cogeneration and direct steam generators presented by Brandt and Unnatsch (2010), and the relationship between steam output and electricity output extrapolated from the data in Sigworth et al. (1983) yielded a correlation between barrels of water equivalent steam and natural gas input for both direct steam generation and cogeneration. The values assumed in this conversion are given in Table 7. Monthly natural gas demand was derived from this relationship.

All monetary values presented are in 2010 dollars. Monetary values were adjusted using the Consumer Price Index (CPI). Monthly CPI data is available from the Bureau of Labor Statistics (BLS.gov, 2011). Present Value calculations were done with an industry standard interest rate of 10%. Those more aggressive about market returns may assume higher interest rates.

**Life-Cycle Analysis**

A variety of methods were used in the life-cycle energy analysis of the plant. The LCA approach was modeled after a workflow developed by Brandt (2011). Following this approach, we defined our system as the plant site and tracked the mass and energy flows from the factory into the system and from the system to the end user over the life of the project. In this analysis, we quantified the energy to manufacture and transport the materials used in the plant, the operational energy, the energy required for any replacement of materials (especially glass), and the energy produced by the plant. For simplicity,
some energy flows were excluded from the analysis. The most important exclusion is likely the energy used during construction/repairs and the energy used for employee commutes to the facility. These factors, although non-negligible in some cases, are often excluded in LCA calculations (Brandt, 2011) thereby making our analysis comparable to others in the literature, namely Brandt and Unnatsch (2011). After calculating the relevant mass and energy flows into the system, these were then converted back to equivalent CO₂ emissions based on the type of energy utilized.

A per-unit LCA of materials was referenced from various sources including most notably the GaBi life-cycle database (PEInternational, 2011). Because LCA values vary significantly, a low-medium-high approach was used to capture the full range of life-cycle estimates. Transportation was calculated using standard mileages, engine power, tonnage capacity, and distances for the respective mode of transportation. In the high emissions case, a distinction is made between transport in the United States and China.

The solar thermal plant used for the LCA analysis was a 4-acre module single transit trough including the glasshouse. Embodied energy was separated into three categories: materials, transportation, and operation. As Fig. 1 illustrates materials include window glass, aluminum, steel, concrete for footings of the glasshouse, polyethylene tarp to cover the bare earth within the glasshouse, and so on. The embodied energy of materials was calculated on a per-unit basis, and operation data was provided by the manufacturer (on a per-MMBTU produced basis) (O’Donnell, 2011). The location of the steam generator was assumed to be Bakersfield, CA, and materials were assumed sourced from Shenzhen, China.

**Results**

Results from each area of study are now presented.

**Reservoir Engineering**

Simulation of the base and continuous injection variable-rate cases, as summarized in Fig. 10, gives nearly equivalent results in terms of cumulative recovery, breakthrough timing, and peak oil production rates. The role of heat losses is shown shortly. In this study, the maximum injection pressure of 500 psi slightly reduces the performance of the variable rate injection case relative to the continuous or “base” case. This occurs because the model is unable to achieve the high rates during the day that are necessary for equivalent total amounts of injection. Figure 11 shows the injector and producer bottom-hole pressure (BHP) response. The injector BHP in the variable rate case, plotted here as a moving average to highlight the trend, fluctuates on the order of 50 psi per injection cycle, quickly climbing to the 500 psi constraint during peak rates and then falling at night. The maximum fluctuations occur at the time of steam breakthrough to the producer. Following breakthrough, the producer BHP rises towards the 500 psi constraint on the injector as the injector and producer approach equilibrium. We conclude that despite the hourly differences in injected heat, over the 2,000 days considered, the total heat injected is the dominant factor. This result is shown in Figure 15, where the maximum bottom hole pressure on the injector is doubled, allowing for equivalent amounts of steam injection and even better parity with the base case.

Heat losses are considered in the other cases in order to provide a more realistic description of how this reservoir might actually perform. Heat loss parameters were obtained from Prats (2007) for a sandstone reservoir and are detailed in Table 5. Simulations were performed using the heat loss model built into STARS. The model is based on an analytical solution for over and under burden heat losses (Vinsome and Westerveld, 1980). Although the addition of heat losses reduces the expected ultimate recovery and increases the time to steam breakthrough time, results in Figure 12 show that the recovery remains substantial. Heat losses to the overburden and underburden are considered as are wellbore heat losses. It was observed that, the rate of heat loss decreases with time after steam breakthrough. Therefore, the reservoir becomes more effective at retaining thermal energy as the surrounding rock heats up.

Sensitivity cases were performed in order to quantify the impact of changes in the assumed parameters. As Figure 12 shows, changes to the heat-loss parameters affect the timing of the oil production but have little impact on the overall recovery. Oil recovery is not sensitive to the thermal diffusivity and volumetric heat capacity of the over- and under-burden because the change in heat loss as we vary parameters is minor during the period of oil recovery (Fig. 13). Results are similar for different values of thermal conductivity. This conclusion, however, is valid only when the volumetric heat capacity and thermal conductivity of the over- and under-burden vary within their common range. The model is more sensitive to the injected steam quality because for a given steam rate in CWE and pressure, the steam enthalpy increases significantly with quality.

Solar insolation, and equivalently solar steam output, varies seasonally and this effect was considered as a sensitivity using the data in Fig. 5. Figure 14 compares the continuous steam injection base case with a solar steam case incorporating daily and seasonal fluctuations in steam injection rate. All runs include reservoir heat losses. The timing of peak production is somewhat later in the continuous variable rate case, but comparable in magnitude. The decline in oil rate post breakthrough is quite similar for both cases.

There are some important differences in the results, however. First, the issue of maximum injection pressure is most limiting in the annual variability case as the summer injection rates are choked back to the extent that cumulative steam injection is lower than the base case (Fig. 13). We associate this difference in the rate of heat delivery with the systematic delay in the oil production peak rate. Doubling the pressure constraint to 1000 psi, offsets this effect. As expected for continuous injection, increasing the maximum BHP in variable rate cases accelerates recovery. Also unlike the base case, the oil production rate in the annual variability case mirrors the oscillations in the injection rate. The delayed response of the
variable rate case is also evident in the producer BHP history post breakthrough in Fig. 14. Additional sensitivity runs are presented in Fig. 15. Upon close inspection, peaks in production occur in the winter after periods of high injection in the summer and troughs in the summer for the same reason.

Comparison of the variable rate and annual variability cases provides further evidence that oil recovery, peak production rates, and breakthrough time are insensitive to short-term fluctuations in injection as shown in Fig. 12. Although the effects of cyclicity in injection rate are apparent in all plots of oil rate, the overall differences seem to be relatively minor. Thus, for fluctuations in injection on the scale of even a year, net injection, which is equivalent on a yearly basis, is the crucial factor.

**Economic Analysis**

The steam demand for Kern River peaked in the late 1980’s (Fig. 7) with a corresponding peak in the SOR (Fig. 16). From that time forward, oil production diminished only slightly, thus the drop in SOR was due primarily to efficiency gains. These gains in SOR efficiency are especially important in assessing the competitiveness of solar thermal steam generation because of the comparatively high capital costs for equivalent capacity (Fig. 9). If the Kern River SOR had been lower during the time of maximum steam demand, the modeled size of the solar thermal installation could be much smaller, leading to significant gains in NPV. Nevertheless, we have modeled the actual historical trends.

Given the historical SOR and associated maximum steam demand, the solar thermal scenarios still yield NPVs that are comparable if not better than the traditional scenarios (Fig. 17). Solar thermal scenarios perform strongly even with their greater associated capital cost and the additional revenue from electricity sales for the co-generation cases. As one would expect, the solar thermal cases have lower discounted profitability indices (DPI), reflecting this high capital cost. Nevertheless, this model predicts a DPI of 1.6 for even the 100% solar case (using a 10% discount rate) that is still very attractive by industry standards. This DPI is relevant to projects, where the steam injectors and handling facilities already exist but new generation capacity is needed. The large capital costs for the solar thermal cases also account for the variation in profitability due to depreciation schedule (Figs. 17 and 18). In the SOYD schedule, the operator is able to depreciate a greater percentage of the solar thermal plant in early years and this has a significant benefit on the NPV given the relative size of the capital expenditure.

The sensitivity of the economics to various parameters is explained by the initial capital costs as well. Figure 18 shows that the 100% solar case is the least sensitive to oil price fluctuations on a percentage basis. This is due to the high initial capital cost that reduces the percentage impact of any change. On an absolute basis, the change in oil prices has equal effects on all scenarios. Fluctuations in the electricity price shown in Fig. 19 have a similar impact to the cases that use cogeneration. This variation in prices is enough to shift the optimal development scenario from 100% solar to all cogeneration. The results, predictably, are most dependent on the choice of discount rate. For greater discount rates, we see an erosion in value from the 100% solar case given its larger capital investment (Fig. 20). The inverse is true for smaller discount rates.

**Life-Cycle Analysis**

Results show that operations and maintenance (O&M) make up the significant fraction of embodied energy with transportation proving to be negligible (Fig. 21). The O&M calculation was performed using an estimated input of 4kWh per MMBTU steam delivered (for running the servos and pumps) and a generation efficiency of 40% (O’Donnell, 2011). Of the materials, glass makes up more than 57% of the total material embodied energy mix (Fig. 21). In the high case, replacement of 50% of the glass accounts for most of the incremental increase in energy consumption over the medium case. Steel and aluminum are the only other significant sources of embodied energy. The CO\textsubscript{2} emissions results closely track embodied energy.

Compared to the lifetime quantity of energy produced via steam, energy inputs from materials, operation and maintenance, and transportation have proven to be largely negligible indicating large net positive energy output from the single-transit trough system. Three estimates are obtained for the projection of lifetime energy consumption of the plant, with the middle value (264,000 GJ) having the highest probability (Fig. 22). Fig. 22 teaches that construction of a 4 acre plant in Bakersfield is projected to produce 6,650,000 GJ over its lifetime, yielding a net energy ratio (net output / net input) of 25.2. Overall CO\textsubscript{2} emissions are estimated to be 17.1 metric tons over the lifetime of the plant for the medium case. This averages out to much less than 1 gram of CO\textsubscript{2}/MJ of refined gasoline (RBOB) from the TEOR stage of production. This calculation was made using a 90% conversion of crude oil to RBOB (in terms of energy content) and an average SOR of 4.0. In contrast, the California average emissions for TEOR production using natural gas are estimated as 23.8 g/MJ of gasoline on a lower heating value (RBOB) after taking emissions credits for cogeneration (Brandt and Unnasch, 2011). The range of emissions is 13.0 to 25.5 g/MJ RBOB. The actual environmental improvement offered by solar TEOR could be even more drastic, in comparison to cogeneration, because the embodied energy of conventional steam generators is not considered fully.

**Discussion**

Our approach has evaluated the reservoir engineering, economic, and environmental feasibility of solar TEOR using a single transit trough system. While many factors have been considered, a number of assumptions and simplifications were made. Importantly, no reservoir geomechanics were included. It is assumed that the cycling of injection rate does not lead to significant pore pressure variation in the reservoir that might lead to compaction or steam fracturing. This assumption is reasonable for the permeable sand modeled, but needs to be examined more carefully in light of the observation of greater
Another assumption is that the steam generator performance does not change over the 30-year lifetime. The mirrored surfaces of the parabolic troughs modeled here and the receiver tube are sealed from dirt and humidity. They are likely to function well over the entire project period. The exterior of the glass house, however, might suffer abrasions, scratches, and weather damage over time. Wear and tear on the glasshouse surfaces could lead to increased reflection and refraction of some portion of the solar insolation thereby reducing the amount of insolation that is concentrated and collected. We have no information to gauge if degradation might be significant and no data to model decreases, if any, in solar steam output. We suggest that this is an area for further study.

In the life-cycle assessment, we have not included any impacts from land-use changes. For some renewables, such as biofuels, consideration of changes to land use has significant impact on imputed CO₂ emissions (e.g. Searchinger et al., 2008). It is impractical to move steam over long distances and we assume that solar steam generators are sited within oilfields near to injection wells without significant land-use changes. In fact, at the 21Z site in the Midway Sunset Field described above, the steam generator is located near the site of an abandoned separator and storage facility. At scale, many acres of collector are needed because an acre of collector produces about 90 bbl CWE steam per day (GlassPoint, 2011). This assumption of no changes in land use may need to be revisited.

The investment scenario is clearly not optimized. The early history of Kern River does not reflect industry learnings regarding reservoir heat management and steam injection policy. If developed again from the start, the field might be operated differently and this might make solar steam appear to be even more attractive under the input economics. We should also reiterate that the capital costs for solar steam generators are yet to be proven beyond the pilot scale. Additionally, we assumed constant capital costs for solar steam per unit of collector developed. As solar steam generation and storage technology matures, we expect some decline in cost as the solar thermal technology and manufacturing process progresses and economies of scale are realized. We also reiterate that all economic calculations were on a before tax basis and accounting for different capital and operating expenses among the various scenarios is likely to change revenues. In short, there appear to be considerable alternate economic scenarios to consider.

What this paper has made more clear, we believe, is that switching to a high solar fraction case, as, compared to natural gas, offers economic and environmental benefits. Successful solar TEOR clearly reduces life-cycle CO₂ emissions for the oil produced. Brandt and Unnasch (2011) analyze greenhouse gas emissions from TEOR using natural gas and some alternate fossil fuel sources. Their numbers are useful for comparison. They find that with current recovery techniques 121 g CO₂ / MJ RBOB is the gross average life-cycle emissions for TEOR production in California. This figure includes production, refining, transportation, and combustion of the resulting gasoline. Of these gross CO₂ emissions, 24.4%, or 29.5 g CO₂ / MJ RBOB, are associated with the combustion of natural gas for steam generation before any emission credits for cogeneration. Cogeneration systems generally consume more gas per unit of steam produced in comparison to direct-fired steam generation, but they produce electricity as well that must be credited in some fashion. In a similar sense, solar steam generation might be credited.

A modest solar fraction of one-third of the total steam generated results in a reduction in emissions of 10.0 g CO₂ / MJ. This fraction of solar steam corresponds to daytime solar steam generation and nighttime natural gas generation with no reduction in steam injection rates. In the accounting of Brandt and Unnasch (2011), cogeneration of steam and electricity results in an average credit of 6.1 g CO₂ / MJ. That is, a fraction of solar steam of 20% is equivalent to the emissions reduction associated with cogeneration.

Switching to a high solar fraction of steam, as compared to natural gas, reduces significantly CO₂ emissions from heavy-oil production. Although much work and reduction in the number of assumptions is needed, substituting solar generated steam for natural gas is a step toward meeting low carbon fuel standards, where solar steam generation is applicable.

**Conclusions**

The continuous variable-rate injection scenario resulting from a solar thermal system meets the oil production benchmarks set by conventional steam flood and is thereby potentially viable in terms of reservoir performance. Reservoir simulation predicts that oil recovery is insensitive to daily and annual cycles on multiyear time scales thereby confirming the van Heel et al. (2010) result. Steam breakthrough times are also comparable for variable-rate versus constant-rate cases. Annual variability does affect the seasonal oil rate slightly, the produced steam rates, and quality post breakthrough. The trends and expected ultimate recovery, however, are consistent. Overall, the oil recovery performance of a solar thermal system is on par with conventional steam floods given consistent average amounts of injected heat. If we exclude any well injectivity concerns, such as sanding, we conclude that natural gas generation is not required to maintain constant injection rates overnight. Sufficient steam generation for injection is only needed to prevent back flow into the well at night and to minimize thermal fluctuations along the wellbore. If it is desired to reduce significantly natural gas input, thermal storage of solar energy could be substituted for overnight steam generation.
The economic analysis also points to the viability of a high solar fraction TEOR project. Solar thermal steam generation appears highly attractive in this initial study, especially the 100% solar case that has the greatest NPV of all scenarios. This case benefits from the lowest operational costs and least natural gas price sensitivity. The economics of the high solar fraction cases are driven by capital costs that are moderately large per unit of steam output.

The LCA also paints solar thermal generation using a single-transit trough in a favorable light. Given a thorough analysis of the embodied energy of the structure including raw materials used in the solar thermal plant as well as the energy and carbon intensity of their manufacture/transport/construction versus the O&M including the energy inputs to the project needed to keep it running, it was found that the embodied energy forms a relatively small fraction of the energy inputs to the facility over its life. It was also found that the plant modeled in this exercise has a very good ratio of energy output to input, which is not the case for many alternative energy sources such as the bio-fuel corn ethanol (Patzek and Pimental, 2005; Pimental et al. 2007). This large ratio of energy returned upon embodied energy when coupled with the fact that the plant does not have a fossil fuel source of energy input, gives solar TEOR a significant reduction in terms of the mass of CO₂ emitted from the production of the crude oil.

In sum, this work indicates that solar thermal steam generation systems are a value added approach to TEOR given the presence of good solar insolation, as is the case in the San Joaquin Valley. While our results indicate that solar thermal steam generation is feasible for use as the primary steam generation mechanism for well-sited projects, it is perhaps best utilized in combination with conventional generation schemes in a fashion much like direct-fired steam generators and co-generation plants are used at present. Blending solar and conventional natural gas based generation allows operators to better address the multi-dimensional challenges they face in balancing environmental impact, risk from fuel prices, capital expenditure, and so on. Although solar TEOR is clearly in need of further detailed study, we see strong technical, economic, environmental feasibility for broader utilization in the future.

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References
Bazargan, Mohammad. Personal communications. 1 Apr. – 25 May 2010.


**Table 1. Distribution of permeability and porosity for the Upper Tulare Reservoir (Spivak, 1987).**

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<td>34.8</td>
</tr>
<tr>
<td>6</td>
<td>MT 3</td>
<td>10</td>
<td>1,030</td>
<td>38.0</td>
</tr>
</tbody>
</table>

**Table 2. PVT data for a heavy-oil sample from the Upper Tulare Reservoir (Spivak, 1987).**

<table>
<thead>
<tr>
<th>Basic PVT Data</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature (deg. F)</td>
<td>Viscosity (cp)</td>
</tr>
<tr>
<td>100</td>
<td>1952</td>
</tr>
<tr>
<td>122</td>
<td>552</td>
</tr>
<tr>
<td>180</td>
<td>71</td>
</tr>
<tr>
<td>210</td>
<td>30</td>
</tr>
<tr>
<td>500</td>
<td>0.2</td>
</tr>
<tr>
<td>Gravity, degr. API</td>
<td>13</td>
</tr>
<tr>
<td>Oil Molecular weight, kg/kmol</td>
<td>425</td>
</tr>
<tr>
<td>Oil isothermal compressibility, psi⁻¹</td>
<td>8.00E-05</td>
</tr>
<tr>
<td>Oil thermal expansion coefficient, degr. F⁻¹</td>
<td>3.80E-04</td>
</tr>
<tr>
<td>Oil heat capacity, BTU/lbm - degr. F</td>
<td>0.45</td>
</tr>
</tbody>
</table>
Table 3. Initial conditions selected for reservoir simulations (Spivak, 1987).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{\text{init}}$ @ top of structure</td>
<td>90</td>
<td>psia</td>
</tr>
<tr>
<td>$T_{\text{init}}$</td>
<td>100</td>
<td>°F</td>
</tr>
<tr>
<td>$S_{\text{g init}}$</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>$S_{\text{w init}}$</td>
<td>0.4</td>
<td></td>
</tr>
</tbody>
</table>

Table 4. Boundary conditions selected for reservoir simulations (Spivak, 1987).

<table>
<thead>
<tr>
<th>Boundary Conditions</th>
<th>Well</th>
<th>Producer</th>
<th>Injector</th>
</tr>
</thead>
<tbody>
<tr>
<td>Perforations</td>
<td>All layers</td>
<td>All layers</td>
<td></td>
</tr>
<tr>
<td>$\text{Min BHP}$</td>
<td>20 psi</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>$\text{Max BHP}$</td>
<td>-</td>
<td>500 psi</td>
<td></td>
</tr>
<tr>
<td>$\text{Max Total Fluid Rate}$</td>
<td>2000 STB/d</td>
<td>1000 BBL CWE/d</td>
<td></td>
</tr>
<tr>
<td>$\text{Max Steam Cut}$</td>
<td>0.1</td>
<td>0.7</td>
<td></td>
</tr>
</tbody>
</table>

Table 5. Assumed over-/under-burden heat transfer parameters used in STARS heat loss model (Prats, 2007).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volumetric Heat Capacity</td>
<td>2.35E+06</td>
<td>J/m³-K</td>
</tr>
<tr>
<td>Thermal Conductivity</td>
<td>1.87E+05</td>
<td>J/m-d-K</td>
</tr>
</tbody>
</table>

Table 6. Assumed values for calculating capital and operating costs of solar thermal plant.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost</td>
<td>500,000</td>
<td>$/acre</td>
</tr>
<tr>
<td>Available Energy</td>
<td>10,000</td>
<td>MMBTU/acre/year</td>
</tr>
<tr>
<td>Operating Costs</td>
<td>0.5</td>
<td>$/MMBTU</td>
</tr>
</tbody>
</table>

Table 7. Assumptions used to calculate natural gas required for direct and cogeneration steam plants based on Brandt and Unnasch (2011) and Sigworth et al. (1983).

<table>
<thead>
<tr>
<th>Value</th>
<th>Unit</th>
<th>Equivalent Value</th>
<th>New Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>cubic ft nat. gas</td>
<td>1026</td>
<td>BTU</td>
</tr>
<tr>
<td>1</td>
<td>lb steam</td>
<td>1000</td>
<td>BTU</td>
</tr>
<tr>
<td>1</td>
<td>BTU nat. gas (LHV)</td>
<td>0.825</td>
<td>BTU steam</td>
</tr>
<tr>
<td>1</td>
<td>BTU nat. gas (LHV)</td>
<td>0.661</td>
<td>BTU elec. + steam</td>
</tr>
<tr>
<td>1</td>
<td>BTU steam output</td>
<td>0.11</td>
<td>BTU elec. out</td>
</tr>
</tbody>
</table>
Figure 1: Image of a single-transit trough system at the 21Z Lease in Midway Sunset.

Figure 2: Grid horizontal permeability and dimensions for quarter 5-Spot (5-acre spacing) element of symmetry. Injector is represented by a downward pointing arrow and vice versa for the producer.
Figure 3: Water-oil and oil-gas relative permeability curves (Stone, 1973).

Figure 4: Injection rates vs. time for base and continuous injection variable-rate cases over a simulated day.
Figure 5: Historical solar insolation for a year in the Bakersfield, CA area (NREL, 2005).

Figure 6: Monthly Kern River oil production and steam injection rates in BBL CWE (EIA.gov, 2011).
Figure 7: Historical natural gas, oil, and electricity prices (EIA.gov, 2011; BLS.gov, 2011).

Figure 8: Comparison of calculated capital expenditure by scenario.
Figure 9: Correlations used to scale capital cost as a function of installed capacity (O’Donnell, 2011; Sigworth, 1983).

Figure 10: Oil production rate and cumulative recovery for base and variable (daily) rate injection cases.
Figure 11: Producer and injector bottom hole pressures for base and variable (daily) rate injection cases.

Figure 12: Oil and water production rate for base case with and without reservoir and wellbore heat losses.
Figure 13: Cumulative heat loss and oil production for variable rate injection cases with different volumetric heat capacity values (J/m$^3$·K) (Prats, 2007).

Figure 14: Oil production rate and producer bottom hole pressure for base and variable (both daily and seasonally) rate injection cases.
Figure 15: Sensitivity of variable (both daily and seasonally) injection rate case to injector bottom hole pressure constraint.

Figure 16: Historical Steam Oil Ratio (SOR) for Kern River field.
Figure 17: Comparison of net present value calculations for the six scenarios.

Figure 18: Sensitivity to 10% increase in oil prices for six scenarios.
Figure 19: Sensitivity to 10% increase in nominal electricity prices for six scenarios.

Figure 20: Sensitivity to discount rate for all six scenarios (assumes SOYD depreciation).
Figure 21: Fraction of embodied energy by material for modeled solar thermal plant.

Figure 22: Comparison of lifetime energy consumption vs production for modeled solar thermal plant.