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An Integrated Techno-economic Modeling Tool for sCO_2 Brayton Cycles

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ABSTRACT

The supercritical CO_2 (sCO_2) Brayton Economics Tool (sBET) was developed to evaluate and perform sensitivity studies on recompression closed Brayton cycles (RCBCs). This integrated techno-economic tool calculates key system performance and levelized cost of energy (LCOE) based on user-defined input on key variables such as system size, recuperator effectiveness, turbine inlet temperature, etc. The goal of this integrated tool is to allow system designers to understand the tradeoffs associated with various key design decisions, such as recuperator effectiveness and overall system cost. This work includes a description of LCOE calculation methodology, component system cost models for turbomachinery and heat exchangers based on vendor quotes and published literature, and the results of several parameter studies to identify desirable system parameters.

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EXECUTIVE SUMMARY

The supercritical CO_2 (sCO_2) Brayton Economics Tool (sBET) was developed to evaluate and perform sensitivity studies on recompression closed Brayton cycles (RCBCs). This integrated techno-economic tool calculates key system performance and levelized cost of energy (LCOE) based on user-defined input on key variables such as system size, recuperator effectiveness, turbine inlet temperature, etc. The goal for this integrated tool is to allow system designers to understand the tradeoffs associated with various key design decisions, such as recuperator effectiveness and overall system cost.

The sBET integrates a basic LCOE methodology with an existing Brayton cycle evaluation tool developed at Sandia by Jim Pasch: the RCBC Evaluation and Trade Studies Tool (RETS) (Pasch 2015, 2016). RETS is a sCO_2 RCBC modeling tool that calculates system and component performance characteristics based on user-defined inputs. Figure 1 shows an example output from RETS for a 20 MWe system with a turbine inlet temperature of 550°C, a recuperator effectiveness of 95%, and an overall system efficiency of 40.2%.

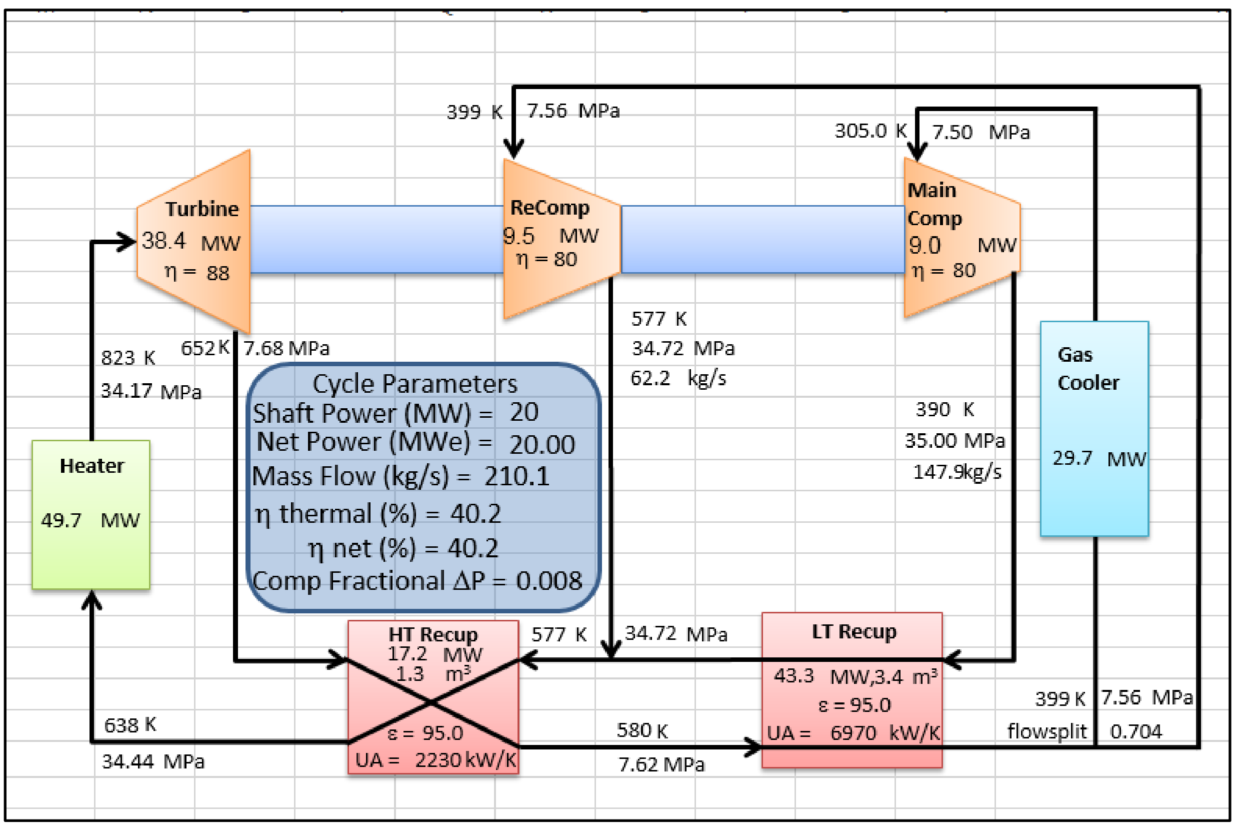

Figure 1. Illustrative RETS output: 20 MWe system, turbine inlet temp = 550°C, recuperator effectiveness = 95%, system efficiency 40.2%.

In addition to technical input from RETS, the integrated tool requires assumptions about:

- fuel costs
- fixed and variable operations and maintenance costs

- scaling and costing relationships for plant components; and
- detailed financial assumptions (financing costs, depreciation, taxes, economic plant life, debt/equity split)

Costing information from various components for Brayton cycles were derived from a variety of sources and other costing estimates, as will be discussed in this report. In addition to component costs, the costs include estimates for:

- Site preparation, including facility construction
- Project indirect costs (engineering, labor, management fees, and contingency fees)
- Development costs (engineering studies, permitting, legal fees, insurance fees, property taxes during construction)
- Electrical interconnection costs.

For a 100 MWe RCBC operating with natural gas-fired heating with a turbine inlet temperature of 700°C with dry cooling operating in St. Louis in the summer, the estimated LCOE is 0.092 \$/kWh and 0.083 \$/kWh for a first-of-a-kind and n^{th}-of-a-kind plant, respectively. Figure 2 and Figure 3 show the relative importance of each major expense category to the total estimated cost. For the 100 MWe facility, system components account for 38.2% of the total costs for the first-of-a-kind plant and 33.3% for the n^{th}-of-a-kind plant. The various heat exchangers account for 18.3% and 16.4%, for these two plants. Assuming \$3.00/MMBtu natural gas, the fuel costs account for 23% and 26%, respectively.

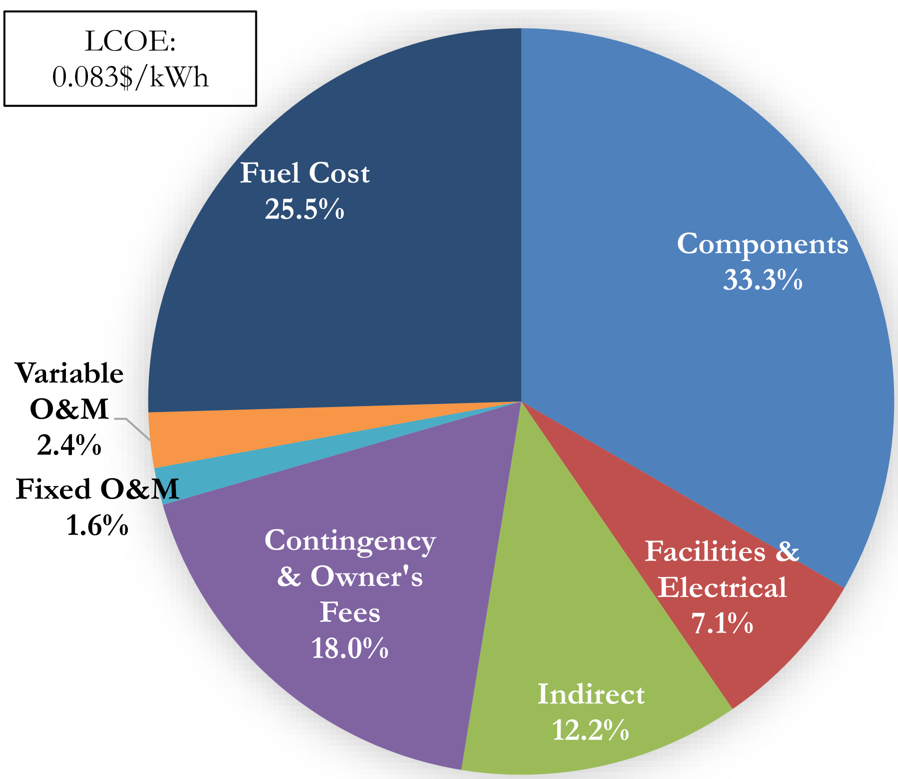

Figure 2. Estimated LCOE for an n^{th}-of-a-kind, 100 MWe RCBC with dry cooling by major category.

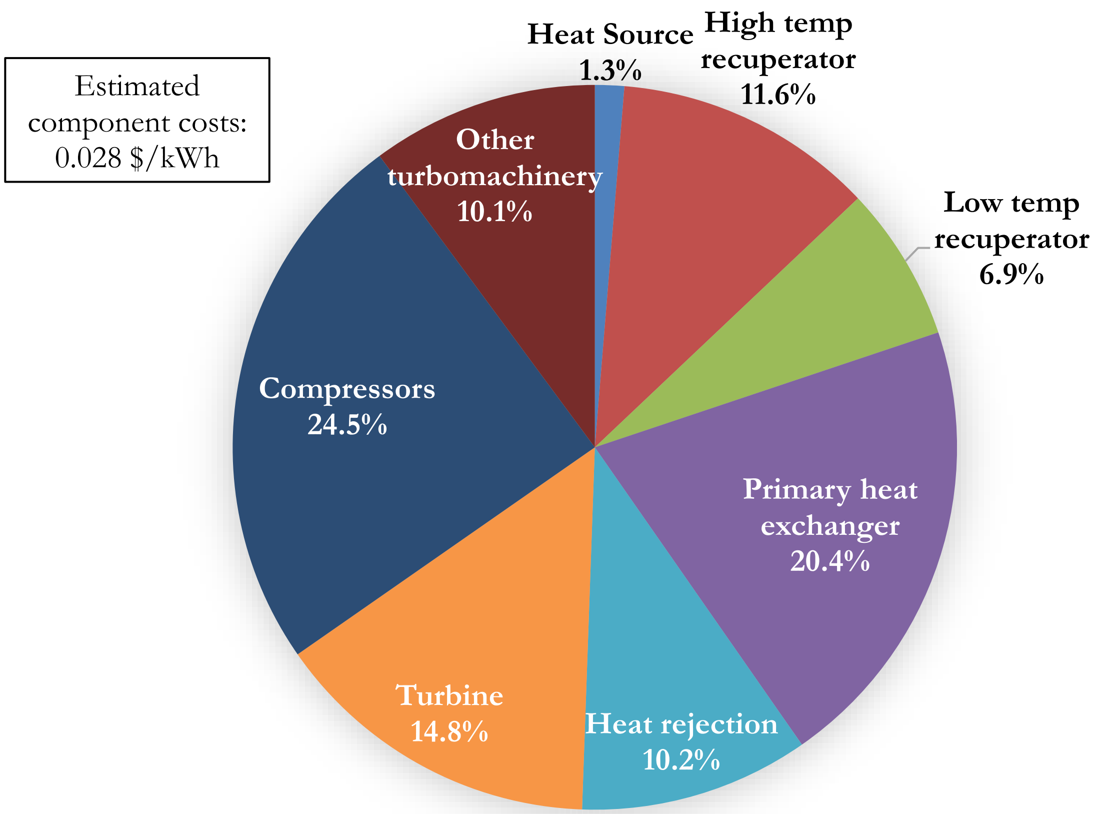

Figure 3. Breakdown of component costs for the estimated LCOE for an n^{th}-of-a-kind, 100 MWe RCBC with dry cooling.

This report documents several key sensitivities, including:

- LCOE estimates decline rapidly as size increases from 10 to 50 MWe, before slowly leveling off for larger sizes. While the estimated LCOE for plants under 50 MWe, typically used for distributed or remote generation, are higher, these applications may place greater value on the flexibility that this scale provides.
- LCOE costs are generally lower for higher turbine inlet temperatures (0.018 $/kWh for the 100 MWe system going from 550 to 750°C). A similar cost reduction is realized when lowering the assumed minimum system temperature from 42 to 33°C (0.018 $/kWh). This similar cost reduction shows a benefit of these parameter studies as it shows that a relatively small decrease in cycle minimum temperature of 9°C has as much benefit as increasing the turbine inlet temperature by 200°C.
- As recuperator effectiveness increases, system efficiency increases. However, increasing recuperator effectiveness increases system costs and beyond a certain point, the increased costs begin to outweigh the benefit of increased system efficiency. This analysis shows that for lower natural gas prices, the optimal recuperator effectiveness is 88%. At higher natural gas prices, the optimal effectiveness increases to 90%. LCOE begins increasing sharply for recuperator effectiveness above 92%.
- While Brayton cycles can maintain high system efficiencies using dry cooling technologies, there is a cost penalty associated with more arid locations, such as Yuma, Arizona, due to the need for larger cooling systems. Specifically, the results show that all else constant, a

100 MWe system operating in Yuma, Arizona would cost approximately 0.46 cents/kWh more than a comparable system in Bismarck, ND.

- Each one percent increase is assumed turbine efficiency from the base (90%) translates into a 1.0% decrease in LCOE. Each one percent improvement in compressor efficiency over the base (85.5%) leads to a 0.8% decrease in LCOE.

ACRONYMS AND DEFINITIONS

Abbreviation	Definition
CFR	capital recovery factor
CSP	concentrated solar power
CT	combustion turbine
EPC	engineering procurement cost
FCR	fixed charge rate
FOAK	first-of-a-kind
HTR	high temperature recuperator
kWe	kilowatt electric
LCOE	levelized cost of energy
LMTD	log mean temperature difference
LTR	low temperature recuperator
MACRS	Modified Accelerated Cost Recovery System
MWe	megawatt electric
MWth	megawatt thermal
NGCC	natural gas combined cycle
NOAK	n^{th}-of-a-kind
sBET	sCO_2 Brayton Economics Tool
sCO_2	supercritical CO_2
O&M	operations and maintenance
RCBC	recompression closed Brayton cycle
RETS	RCBC Evaluation and Trade Studies Tool
S&T	shell and tube
SFR	sodium fast reactor
STP	standard temperature and pressure
UA	conductance area variable
WACC	weighted average cost of capital

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1. INTRODUCTION

Sandia National Laboratories, with funding from the U.S. Department of Energy (DOE), is developing supercritical CO_2 (sCO_2) Brayton cycles for use in a wide-range of power systems. The mission statement of Sandia's Brayton Energy Conversion team is:

> *"By April 2020, Sandia National Laboratories, in collaboration with government and industry partners, shall investigate the science, develop the test capabilities, and experimentally validate a grid compatible sCO_2 Brayton Power System that transitions laboratory technologies to domestic energy commercial applications."*

As summarized in the June 2018 Roadmap for development of sCO_2 systems (Mendez and Rochau, 2018):

> "Supercritical carbon dioxide is a fluid state of carbon dioxide (CO_2) where CO_2 is held at or above its critical temperature and critical pressure. Carbon dioxide usually behaves as a gas in air at standard temperature and pressure (STP), or as a solid called dry ice when frozen. If the temperature and pressure are both increased from STP to be at or above the CO_2 critical point, it can adopt properties midway between a gas and a liquid. At this state, sCO_2 can be used efficiently throughout the entire Brayton cycle.
>
> A closed Brayton cycle recirculates the working fluid. The turbine exhaust is used in a recuperating heat exchanger to heat the turbine feed. A "supercritical cycle" is a closed Brayton cycle in which the working fluid (sCO_2) is maintained near the critical point during the compression phase of the cycle. This cycle is a thermal-to-shaft power cycle consists of five basic components; compressors, turbines, heat input, heat rejection, and recuperation. Each component offers unique challenges to improvements, and consequent cycle thermal-to-shaft power conversion efficiency. Optimization of each of these components contributes to the overall optimization of the cycle efficiency. As with any engineered system, performance and economic considerations present an engineering optimization problem.
>
> Cycle efficiency increases with temperature monotonically and rapidly. Current goals seek to achieve temperatures of approximately 450 °C for waste heat applications at the low end, up to 700 – 750 °C for high temperature primary cycles. Cycle efficiency also improves with pressure ratio, but only to a point. In general, the lower the maximum temperature of the cycle, the lower the optimum pressure ratio."

A key property of sCO_2 systems operating near the critical point is the higher gas density. In this scenario the working fluid is closer to a liquid than a gas and volumetric flow is reduced. This significantly reduces the footprint of key components, including the turbines and heat rejection heat exchangers, as well as reducing pumping requirements for the compressors. These properties of sCO_2 systems suggest several potential benefits compared with traditional steam plants including: higher plant efficiency, reduced fuel use, lowered greenhouse gas emissions, and suitability for dry cooling in arid climates.

In addition to developing and testing technical components for sCO_2 power cycles, Sandia is developing a techno-economic tool—the sCO_2 Brayton Economics Tool (sBET)—to evaluate and optimize Brayton system configurations. This report summarizes efforts to develop an integrated tool that calculates system performance based on user-defined variables such as system size, recuperator effectiveness, and turbine inlet temperatures. The goal for this integrated tool is to allow the Sandia Brayton team to understand the tradeoffs associated with various key design decisions, such as recuperator effectiveness and overall system cost.

This report summarizes the design and key assumptions of this integrated tool, initial results, and detailed sensitivity analysis. It concludes with a detailed analysis of the applicability of Brayton systems in arid regions where access to water is limited as well as a discussion of next steps.

2. OVERVIEW

The integrated techno-economic sBET calculates key system performance and levelized cost of energy (LCOE) based on user-defined input on key variables such as system size, recuperator effectiveness, and turbine inlet temperature. The goal for this integrated tool is to allow system designers to understand the tradeoffs associated with various key design decisions, such as recuperator effectiveness and overall system cost.

Recognizing that any new technology must be able to compete economically with existing options or must deliver a superior product, early efforts focused on the development of a LCOE tool that allows users to compare the economics of various Brayton configurations to other technologies (Drennen, 2016). Data for non-Brayton cycle technologies comes from the Energy Information Administration's (EIA) *Annual Energy Outlook 2016 (DOE, 2016).* The LCOE tool includes three scenarios for entering basic operating and technical assumptions about various Brayton cycle configurations. The main purpose for this tool is to allow users to compare the costs of various Brayton configurations with other existing technology options on a consistent basis.

Figure 2-1 provides an illustrative example of the output from this earlier model (Drennen, 2016). The three examples on the right, labelled Custom 1, 2, and 3, are illustrative Brayton cycle configurations. For the base case assumptions, the lowest cost option for a new utility-scale facility is the natural gas combined cycle (NGCC) plant, estimated at 0.042 $/kWh[1]. New technologies that want to compete in this market need to meet this target or provide additional value, such as the ability to use dry cooling.

[1] All results in this model are 2015 $.

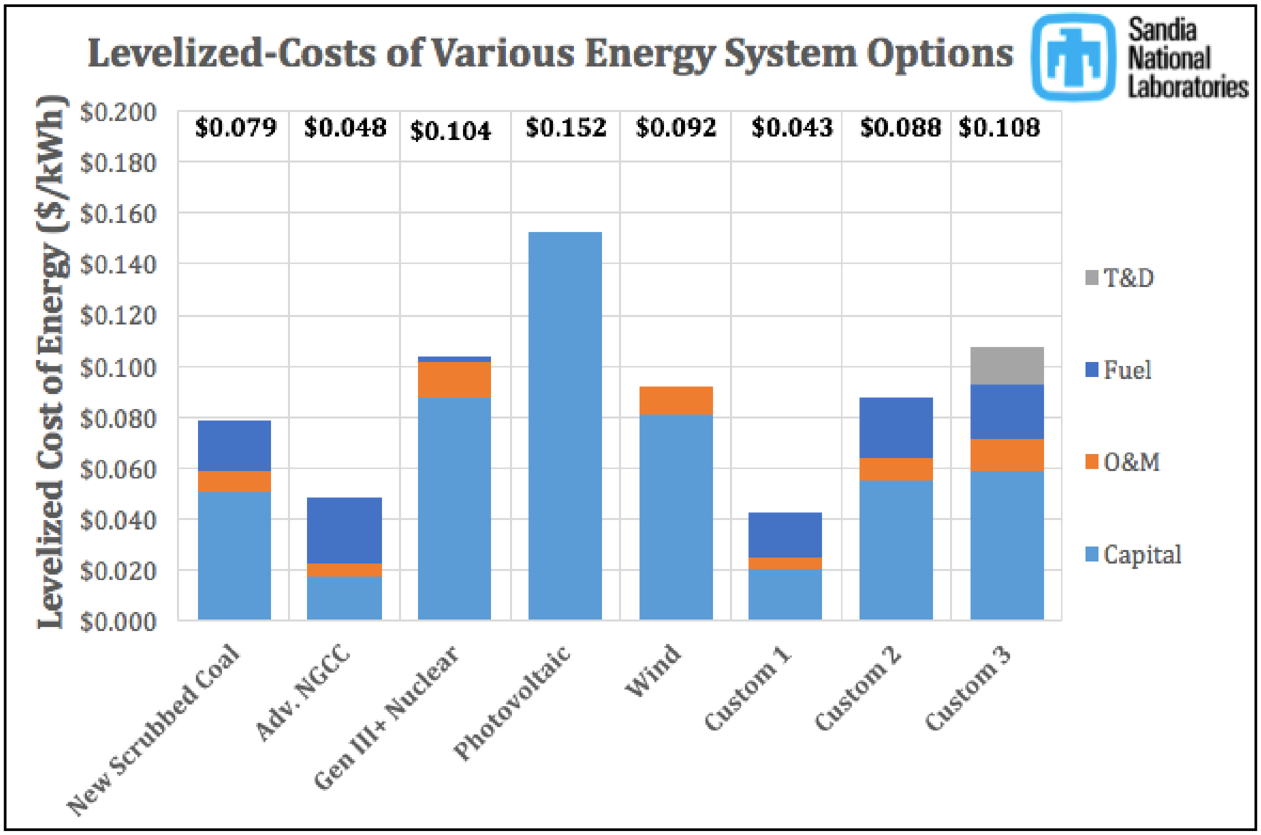

Figure 2-1. LCOE comparisons between three sCO_2 Brayton cycle estimates and existing technology.

The sBET tool integrates the basic LCOE methodology with an existing Brayton cycle evaluation tool developed at Sandia – the RCBC Evaluation and Trade Studies Tool (RETS), developed by Jim Pasch (Pasch 2015, 2016). RETS is a sCO_2 recompression closed Brayton cycle (RCBC) modeling tool that calculates key system performance characteristics based on user-defined input on key variables such as: system size, recuperator effectiveness, and turbine inlet temperature. Figure 2-2 shows an example output from RETS for a 20 MWe system with a turbine inlet temperature of 550°C, a recuperator effectiveness of 95%, and an overall system efficiency of 40.2%.

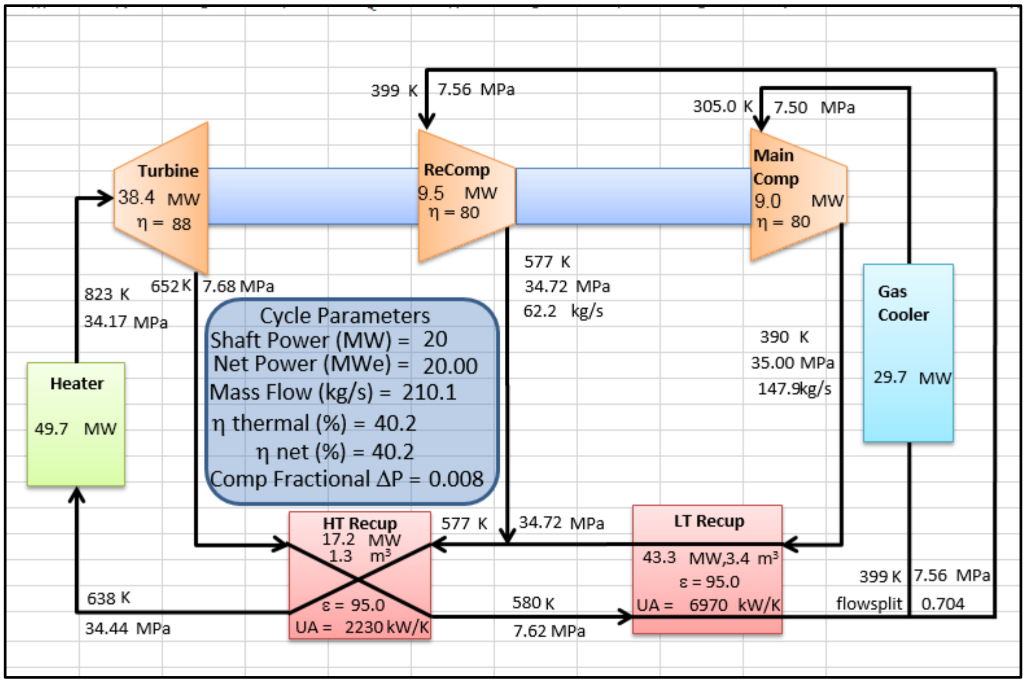

Figure 2-2. Illustrative RETS output: 20 MWe system, turbine inlet temp = 550°C, recuperator effectiveness = 95%, system efficiency 40.2%.

In addition to technical input from RETS, the integrated tool requires assumptions about:

- fuel costs
- fixed and variable operations and maintenance (O&M) costs
- scaling and costing relationships for plant components; and
- detailed financial assumptions (financing costs, depreciation, taxes, economic plant life, debt/equity split)

Costing information from various components for the Brayton systems were derived from a variety of sources and other costing estimates, as will be discussed in this report. In addition to component costs, the costs include estimates for:

- Site preparation, including facility construction
- Project indirect costs (engineering, labor, management fees, and contingency fees)
- Development costs (engineering studies, permitting, legal fees, insurance fees, property taxes during construction)
- Electrical interconnection costs.

The integrated techno-economic model requires access to both RETS and sBET. Users can change technical assumptions such as turbine inlet temperature, pressure, compressor efficiencies, and recuperator effectiveness in the RETS input file prior to executing a model run. Results from the run are sent to an Excel output file which is linked to sBET. Instructions for using this tool are included in the Appendix.

Figure 2-3 provides an overview of the layout of the costing assumptions. Costs are broken down into categories: heat exchangers (recuperators, primary, and heat rejection), turbomachinery (turbine, compressors, and related subcomponents), electrical and control, facilities, project indirect, contingency, and owner's costs. Each of these categories is explained in additional detail in this document. For each scenario, the main goal is to estimate the total financed costs ($/kWe) for both the first-of-a-kind (FOAK) and n[th]-of-a-kind (NOAK) plant. For the illustrative example shown in Figure 2-3, the total FOAK and NOAK costs are highlighted.

Levelized Cost of Energy Calculator					
	Subsystem Cost ($1000)	**$/kWe Net (FOAK)**	**% Total Cost**	**R-Value**	**$/kWe Net (NOAK)**
Heat Source	**2537**	25.37	1%	0.06	19
Heat Exchangers					
High temp recuperator	11,430	114.30	4%	0.06	87
Low temp recuperator	7,775	77.75	2%	0.06	60
Primary Heat Exchanger	35356	353.56	11%	0.04	296.38
Heat rejection (Air Coolers/Condensers)	19,879	198.79	6%	0.04	167
Turbomachinery					
Turbine	27,772	277.72	9%	0.06	213
Compressors	43,051	430.51	14%	0.06	329
Turbine stop valve	4,600	46.00	1%	0.06	35
Turbine governor valve	4,700	47	1%	0.06	36
Gear box	585	6	0%	0.06	4
Turbomachinery control	396	4	0%	0.06	3
Other instrumentation	396	4	0%	0.06	3
Inventory control	1,186	12	0%	0.06	9
Generator	7,865	79	2%	0.06	60
Total Mechanical	**164,990**	**1,675**			**1,322**
Electrical, Instrumentation, Control	7,569	75.69	2%	0.02	69
Facilities (includes major infrastructure)	20,930	209	7%	0.01	200
Project indirects	49697	497	16%	0.01	476
Total EPS	243,187	2,457			2,068
Contingency	24,319	243	8%	0.01	233
Owner's Costs	48,637	486.37	15%	0.01	466
Total Project Costs ($1000s)	**316,144**	**3,187**	100%		**2,767**

Figure 2-3. Layout of the costing tool in the integrated model.

3. COSTING METHODOLOGY

3.1. Levelized Cost of Energy Methodology

Production costs are estimated using a LCOE approach[2]. LCOE calculations estimate the per unit ($/kWh) cost of production over the economic lifetime of the technology. Specifically, this calculation outputs a per unit production cost from capital costs, associated financing costs, O&M, and fuel costs. The LCOE is often used as an economic measure of energy costs as it allows for comparison of technologies with different capital and operating costs, construction times, and plant load factors.

The LCOE calculation is given by:

$$LCOE = \frac{I * FCR}{E} + \frac{O\&M}{E} + \frac{F}{E} \tag{1}$$

where:
- I = total financed capital costs
- FCR = fixed charge rate
- E = annual plant output (i.e. kWh)
- $O\&M$ = fixed and variable operating and maintenance costs
- F = feedstock costs (i.e. natural gas, biomass)

We assume that capital expenditures are uniformly distributed over the construction period.[3] The financed capital cost (I) is multiplied by a fixed charge rate (FCR), which includes assumptions about state and federal taxes, the depreciation period (as defined by the Modified Accelerated Cost Recovery System (MACRS) methodology), and other exogenous costs.

The FCR is calculated using:

$$FCR = \frac{CRF[1 - bT\ \sum_{n=1}^{M} V_n \,/\, (1 + r_{wacc})^n - t_c\,]}{(1 - T)} + p_1 + p_2 \tag{2}$$

where:
- CRF = capital recovery factor
- b = fraction of investment that can be depreciated (initially is 100%)
- T = effective tax rate (default 37.6% (federal, 34%; state, 6%))
- M = depreciation period (3 to 20 years; default depends on technology)
- V_n = fraction of depreciable base in year *n* (initially 100%)
- r_{wacc} = real weighted average cost of capital
- t_c = tax credit (initially zero)
- p_1 = annual insurance cost (initially zero)
- p_2 = other taxes (initially zero)

---

[2]Rhodes (2016) provides a good overview of the LCOE methodology.

[3]Capital expenditures are often not uniform over the construction period. For example, a more detailed LCOE calculator developed at Sandia assumes that for a five-year construction period, the percent breakdown of financed capital is 10%, 30%, 25%, 20% and 15% respectively over the five-year period (Drennen and Andruski, 2012). Future versions of sBET may use this modified methodology.

MACRS is an accelerated depreciation method used in the U.S. and allows for faster depreciation of capital investments than allowed by straight-line methodologies. Accelerated depreciation methods allow firms to take tax-deductible depreciation expenses earlier in the life of a capital expenditure, giving them an upfront tax advantage for new investments. In the U.S., most utility type investments use either a 15 or 20-year depreciation schedule. Certain investments, such as renewables, are allowed to use a five-year depreciation schedule. Quicker depreciation schedules effectively lower the annual capital requirements for these investments (the CRF in equation 2 is lowered as number of years allowed for depreciation decreases).

The fixed charge rate (FCR) typically ranges from 0.11 and 0.17 and represents the percentage of capital costs that must be recovered each year to cover all investment costs, including return on debt and equity. For example, for a $1 million capital investment and a FCR of 0.15, the annual capital requirement for that investment is $150,000.

An important part of LCOE calculations is the percentage of the capital investment that is either debt or equity financed. The real weighted average cost of capital (r_{wacc}) takes into account the debt-to-equity ratio and their specific financing rates. Debt financing refers to the part of the investment that is financed through traditional financing options, such as those from banks or bonds, while equity financing can include owner or investor financing.

The r_{wacc} is calculated by:

$$r_{wacc} = \frac{E}{V} * r_e + \frac{D}{V} * r_d * (1 - T) \tag{3}$$

where:

	E/V	= percent of total project equity financed
	r_e	= equity financing rate
	D/V	= percent of total project debt financed
	r_d	= debt financing rate (pre-tax)
	V	= capital cost
	T	= effective tax rate

Assumptions about the debt/equity financing split are technology specific. For example, for a plant that assumes a 50%/50% debt/equity financing, with a debt financing rate of 4.5% and equity financing rate of 12.0%, the r_{wacc} is 7.4%.

The CRF is calculated using:

$$CRF = r_{WACC} * \frac{(1 + r_{WACC})^n}{(1 + r_{WACC})^n - 1} \tag{4}$$

where:

r_{wacc} = real weighted average cost of capital

n = economic plant life (initially 20 years).

Table 3-1 summarizes the default economic assumptions in sBET.

Table 3-1. Default financial assumptions used in sBET.

Parameter	Assumption
Debt/equity financing ratio	50%/50%
Debt financing rate	8%
Equity financing rate	12%
Economic plant life	20 years
Depreciation period	20 years
Federal tax rate	34%
State tax rate	6%
Fixed O&M	9.94 $/kWe
Variable O&M	1.99 $/MWh
Fuel costs	3.00 $/MMBtu

In addition to the component costs discussed in the following section (3.2 Component Costs), plants have both fixed and variable O&M costs. For this analysis, we assumed that the RCBC will have O&M costs comparable to an advanced natural gas combined cycle plant and used the assumptions from the *Annual Energy Outlook 2016* (DOE, 2016).

3.2. Component Costs

Brayton power cycles are compatible with a variety of heat sources. In the near term, Brayton cycles will likely use natural gas as the primary fuel source, but future market opportunities exist for use of waste heat (bottoming cycles), concentrated solar power (CSP), and eventually for advanced nuclear reactors such as the sodium fast reactor (SFR). Components typically fall into two categories: 1) turbomachinery and 2) heat exchangers. The turbomachinery includes both the main compressor and recompressor for the recompression cycle as well as at least one turbine, depending on the specific design. Several smaller cost items required to support the turbomachinery include a turbine control valve, turbine stop valve, gearboxes, generator, etc. The heat exchangers include the primary, high and low temperature recuperators, and cooling. Recuperated Brayton cycles are closed cycles and can achieve high thermal efficiency, partly from the high levels of recuperation or 'recycling' of heat within the cycle. Even though the industry has considerable expertise in designing and costing traditional heat exchangers, there are some key differences that make costing more difficult and hence, introduce greater uncertainty in the estimates used for this tool. Specifically, the heat exchangers used in sCO_2 Brayton cycles are much different from the common shell and tube (S&T) design. Generally, diffusion bonded microchannel heat exchangers are used instead of S&T designs for their lower cost and smaller size for the high operating pressures of these cycles.

3.2.1. Heat Source

The sBET includes three options for the heat source: natural gas (default), CSP, and SFR. A summary table of results is shown in Table 3-2. Many sources of component cost information cite numbers in a \$/kWe, meaning the capital cost of the component divided by the electric output of the plant. This measure is not ideal for component costing because the electrical output of the entire plant depends on a lot of factors that are typically independent of the component in question. Nevertheless, this scaling was used out of necessity and consistency between the cost information from all three heat sources. In this work, the natural gas heat source cost was scaled from \$/kWth ("th" meaning thermal) to \$/kWe, as described below.

The cost estimate for the default case, natural gas, is based on a review of vendor estimates for a commercial blower and burner. Based on this review, we assume a base case cost of 13.2 \$/kWth for a 53 MWth size system. To be consistent with the CSP and SFR heat source costs, this can be scaled to a \$/kWe value as the equipment estimate is about 700k\$ for a 20 MWe plant. Cost estimates for systems of different sizes are calculated using a simple exponential scaling relationship:

$$Cost_{\,new} = Cost_{base} * \left(\frac{Size_{\mathrm{new}}}{Size_{\mathrm{base}}}\right)^{n} \tag{5}$$

where n is a scaling factor. The National Renewable Energy Laboratory (NREL, 2014) notes that typical scaling factors for power systems typically range from 0.5 to 0.8. A scaling factor of 0.8 is used for the natural gas burner and blower.

As scalability costing factors for both CSP and SFR are less certain, this tool only considers these options for 100 MWe systems. Ho *et al.* (2015) evaluated several closed-loop Brayton cycles, including simple (SCBC), recompression (RCBC), cascaded (CCBC), and combined bifurcation with intercooling (CBI) (partial cooling) closed-loop Brayton cycles. For each option, they summarize the total solar and power block costs. For the RCBC configuration, they estimate solar costs of 2800 \$/kWe for a 100 MWe system located in Albuquerque, NM. That estimate is used here as the base scale capital cost for a 100 MWe system. As no scaling factors are currently included in this model for the CSP heat source option, users should be aware that using other system sizes may be less accurate. This high capital cost is mainly due to the heliostat field and tower costs, but these are targets for cost reduction that are aggressively being reduced by the DOE office of Energy Efficiency and Renewable Energy to realize a LCOE of 0.06 \$/kWh (Mehos, 2017).

For the SFR option, we relied on estimates by Pidaparti *et al.* (2016). Their reference plant–a 100 MWe, sodium cooled fast reactor with sCO_2 Brayton cycle and wet cooling–has an estimated capital cost of 4780 \$/kWe. As with the CSP option, heat source cost scaling has a constant normalized cost.

The heat source capital costs vary greatly with heat source. For the natural gas combustor, results will be more sensitive to fuel costs than will be the case for the CSP and SFR options. Concentrated solar has no fuel cost and the SFR has very low fuel costs when normalized to energy output.

Table 3-2. Heat source cost summary

Heat Source	Cost [$/kWe]	Cost for $100\ \mathrm{MWe}$ [$/kWe]
Natural Gas Combustor ($Size_{new}$ is in MWe)	$\frac{700\mathrm{k\$}}{Size_{\mathrm{new}}}\left(\frac{Size_{\mathrm{new}}}{20\mathrm{MWe}}\right)^{0.8}$	25.4
Concentrated Solar	2800	2800
Sodium Fast Reactor	4780	4780

3.2.2. Heat Exchangers

The Brayton cycle includes a primary heat exchanger, high and low temperature recuperators, and a cooling heat exchanger.

The primary heat exchanger transfers heat from the source (whether natural gas, concentrating solar power (CSP), nuclear, or waste heat) to the working fluid (sCO_2). The cost is a function of the required heat transfer surface area (A), the overall conductance of the heat exchanger (U), and the temperature differential between the two interacting flows (ΔT_{lm}). The UA of the system (the conductance area variable) is calculated based on output from RETS for the thermal duty Q and the temperature difference between the two fluids:

$$UA = \frac{Q}{\Delta T_{lm}} \tag{6}$$

For the temperature differential between the two flows, (ΔT_{lm}), we use the log mean temperature difference (LMTD). The LMTD for the primary exchanger in this work was 22°C as calculated from literature (Carlson, 2017).

Note that the UA equation above assumes constant fluid properties inside the primary heat exchanger. The potential for error with this method is small for high temperature gases, even sCO_2, as it behaves like an ideal gas at these conditions. A parameter study was conducted to determine where this assumption results in a large error. The error in predicted UA in the high temperature recuperator (HTR) was less than 2%, but the errors in the low temperature recuperator (LTR) and the cooling heat exchanger were 60-100%. Consequently, a discretized heat exchanger model was developed for the LTR and the cooling heat exchanger using 10 and 20 nodes, respectively, using variable fluid properties for a more accurate calculation of UA. The error for using these number of nodes compared with 1000 was less than 1%.

Carlson *et al.* (2017) developed the following generic costing equation for heat exchangers suitable for Brayton cycles based on quotes from a broad range of equipment vendors and from the database of the Engineering Sciences Data Unit (ESDU). The ESDU dataset contains estimates for high pressure fluid systems like sCO_2 Brayton cycles that were useful for creating scaling factors for the costing equation:

(7)

$$Cost = C_{scaled} * C^* * UA$$

where C_{scaled} are cost scaling factors based on estimates from equipment vendors; C^* are normalized cost scaling factors for different levels of UA in (W/K); and UA is the conductance-area product.

Carlson *et al.* (2017) estimated baselined cost scaling factors of 1.1 - 4.0 for recuperators and 2.3 for air coolers/condensers. For the primary heat exchanger, Carlson *et al.* relied solely on the ESDU database to estimate a cost scaling factor of 3.5. These numbers, along with the default values used in sBET, are shown in Table 3-3. Discussion of the default values will be given herein.

Table 3-3. Heat exchanger costs from Carlson 2017 and the accepted values in sBET

Heat Exchanger	C_{scaled} [$/(W/K)]	
	Carlson 2017	sBET Model
Primary	3.5	3.0 for natural gas, 3.5 for CSP and SFR
Recuperators	1.1-4.0	1.6
Dry Cooling	2.3	2.75
Wet Cooling	-	0.750

Carlson *et al.* recognized that smaller heat exchangers will have a larger portion of their cost in non-recurring engineering and higher margins. To compensate for this, they suggest cost scaling factors (C^*) as shown in Table 3-4. The factors increase for smaller UA and asymptote to 1.0 for values above 1x10^6 W/K. As the UA for systems above 10 MWe will generally be above this, we assume $C^* = 1.0$ in this model.

Table 3-4. Cost scaling factors (C^*) for various heat exchangers in Brayton system (adapted from Carlson *et al.*, 2017)

UA (W/K)	5x10^3	3x10^4	1x10^5	3x10^5	1x10^6
Primary Heat Exchanger	1.9	1.3	1.1	1.0	1.0
Recuperators	6.3	1.4	1.3	1.1	1.0
Cooling Heat Exchanger	7.6	2.4	1.3	1.1	1.0

For primary heat exchangers subjected to higher operating temperatures (above 600°C), an additional scaling factor of 1.25 is applied to account for the need to transition from traditional 316 stainless steels to nickel-based alloys. This factor assumes that 25% of the primary heat exchanger material is nickel-based at double the cost and the remainder is stainless.

To narrow the range on cost scaling factors for recuperators of 1.1-4.0 given by Carlson *et al.* (2017), an additional eight vendor estimates were obtained for this modeling effort that support RCBC plants with a turbine inlet temperature of 550°C and with outputs of 2.5, 5, and 10 MWe (Fleming *et al.*, 2016). Of the eight compact heat exchanger estimates, four allowed their estimates to be used in an averaged model that is publicly available. A cost scaling factor was derived from these estimates, while also considering that costs have likely decreased 10-20% in recent years. We estimate a cost scaling factor of $C_{scaled} = 1.6$ \$/(W/K) for recuperators. The value of C^* converges to 1.0 for UA values greater than approximately $1\text{x}10^6$W/K as shown in Table 3-4. As with primary heat exchangers, the UA for systems above 10 MWe will generally be greater than this value, allowing for the default value of $C^* = 1.0$ in this model. For turbine inlet temperatures above 600°C, a cost factor of 2.0 is applied to the HTR to account for the need of nickel alloys.

As mentioned previously, a discretized heat exchanger model was developed that accounts for variable fluid properties in the LTR and the cooling heat exchanger. RETS provides a UA value for both recuperators but assumes constant properties that were found to have an approximately 60% error in the LTR. As UA is an important factor in heat exchanger cost, correcting for this assumption was an important addition to sBET.

The discretized heat exchanger model uses 10 nodes for the LTR and 20 nodes for the cooling heat exchanger as sCO_2 properties vary more rapidly in the cooling unit, requiring more nodes for solution grid convergence. CO_2 temperature was calculated in NIST's REFPROP (Lemmon *et al.*, 2002) software as a function of pressure and enthalpy, tabulated in a 100x100 matrix, and copied into sBET. The heat exchanger inlet and outlet conditions are set with known temperature and pressure. Enthalpy is therefore known at these locations. The model discretizes the heat exchanger domain into equal segments of enthalpy change. It assumes that the pressure changes linearly inside this domain, which is reasonable as pressure will change linearly with physical length. With known enthalpy and pressure, the matrix is used for temperature lookup in a two-dimensional interpolation scheme.

All end conditions of the LTR are determined from RETS, but the external cooling fluid inlet and outlet conditions are not set in the cooling heat exchanger. This fluid may be water or air. The user defines the temperature of the fluid inlet and the model assumes that the temperature rise is half of that of the sCO_2 temperature drop. This is an arbitrary assumption that sets the cooling fluid mass flow rate; future work should include use of industry accepted practices. The temperature input to the model should be the dry bulb temperature for dry cooling, the wet bulb temperature for recirculating wet cooling, or the bulk water temperature for once-through cooling.

There are major cost differences associated with wet and dry cooling. For example, dry cooling requires significant fan power to circulate large quantities of air through the heat exchangers to compensate for poor heat transfer to air. Wet cooling requires pumping power to circulate water through the system. There are also considerable operating costs associated with water consumption and water chemistry maintenance. In a comparison of wet and dry cooling technologies for a 10 MWe Brayton cycle plant, Held (2016) finds that while the dry cooling has a significantly larger footprint (240 m^2 vs. 97 m^2), the total capital costs are comparable. This result may be specific to sCO_2 systems as other, more thorough studies have shown that the capital costs for dry cooling for the steam Rankine cycle are approximately four times as expensive than for wet cooling (EPRI, 2012)[4]. sBET assumes that the dry cooling system costs are 3.6 times more expensive than the wet cooling system costs. This version of sBET does not adequately capture the total operating costs of dry vs. wet cooling. In this version, costs are calculated based solely on the differing UA

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[4] The EPRI (2012) report estimates total system and annualized operating costs for various cooling systems for 500 MWe coal-fired plant in various locations. For a plant located in Yuma, AZ, EPRI estimates total capital costs for a wet cooling system of \$22.3 million and annualized operating costs of \$3.5 million. The dry cooling system has estimated capital costs of \$97.2 million and annualized operating costs of \$18 million.

requirements. As this ability to use dry cooling technologies is one of the key considerations for use of Brayton cycles, additional work is necessary to capture the differences in operating costs (power requirements for pumps vs. air flow, water chemistry, etc.) and the potential value of the water savings and the siting flexibility that dry cooling can provide.

3.2.3. Turbomachinery

Carlson *et al.* (2017) estimated power law costing functions for both the turbomachinery and the compressors using estimates from the literature, supplemented with vendor estimates. For turbines, the relationship is:

$$C_{\mathrm{turbine}} = 7790 \left(\frac{\dot{W}}{\mathrm{kW}} \right)^{0.6842} \tag{8}$$

where $\dot{W}$ is the shaft power, calculated within RETS, which is a function of the plant size, configuration, and turbine efficiency. This work uses a default efficiency of 90% for turbines. This costing equation assumes the use of nickel alloys; for operating temperatures below 600°C, a scaling factor of 0.67 is used as the lower temperatures allow for the use of stainless steel components.

For the compressors, the estimated cost model is:

$$C_{\mathrm{compressor}} = 6898 \left(\frac{\dot{W}}{\mathrm{kW}} \right)^{0.7865} \tag{9}$$

where $\dot{W}$ is the shaft power, calculated within RETS with similar dependencies as the turbine. The default efficiency for the compressors is 88.5%. As compressors are not expected to operate at elevated temperatures, no temperature scaling factor is used.

Turbomachinery support equipment has lower cost than heat exchangers or turbomachinery but can account for about 5% of the total LCOE. These include the turbine control and stop valves, generator, inventory control, etc. These costs are generally 10% of the other component costs.

3.2.4. Additional Costs

In addition to the component costs, several additional costs are included, ranging from site preparation to contingency fees. Many of these costs are often ignored in costing estimates of new technologies but can add significantly to the estimated LCOE. The EIA (2013) provides a methodology for estimating total costs for utility scale electricity generating plants. This methodology includes the following categories:

- Mechanical equipment supply (major equipment)
- Electrical, instrumentation and control (transformers, switch gear, etc.)
- Civil and structural costs (site preparation, underground utilities, structural steel supply, and on-site building construction)
- Project indirect costs (engineering, labor, construction management)
- Fees and contingency
- Owners costs (development costs, feasibility and engineering studies, legal fees, insurance, electrical interconnection

The sum of the first four categories is referred to as the engineering procurement cost (EPC). The EIA (2013) uses this methodology to estimate total project costs, excluding financing, for a wide-range of technologies. For example, the EIA estimates a conventional combustion turbine (CT) with a rated nominal capacity of 85 MWe is $973/kWe. The equipment cost is just $394/kWe, highlighting the importance of capturing these additional cost categories.

While the specific costs vary for different types of facilities, the EIA (2013) assumes that fees and contingency costs and owner's costs are 10% and 20% of the EPC costs, respectively. For the conventional CT plant mentioned above, the civil and structural costs are an additional 13.1% of the sum of the first two items above (mechanical and electrical); and the project indirect costs are 28.8% of the sum of those two items. For an advanced CT, the civil and structural and indirect costs are 15.7% and 21.9% of the sum of the first two categories, respectively.

For sBET, we used the proportions estimated for the conventional combustion turbine plant. Using estimates for other technologies would result in slightly different results. Summarizing the methodology, we assume:

- Civil and construction costs: 13.1% of mechanical + electrical
- Project indirect: 28.8% of mechanical + electrical
- Fees and contingencies: 10% of EPC costs
- Owner's costs: 20% of EPC costs

3.2.5. First- and Nth-of-a-kind Methodology

Costs are estimated for both the first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) plants using a methodology developed by NETL (2013). Figure 3-1 illustrates the basic theory. Prior to actual construction of a new type of facility, costs usually increase as cost estimates become more robust. Costs can increase further as the second or third plant is built as alternative configurations and/or materials are tested. As additional plants are built and economies of scale are recognized, costs begin to fall. Accurately incorporating this methodology into a costing model requires consideration at the subcomponent level; experimental or newer technologies will experience higher rates of technology learning than will be the case for off-the-shelf technologies.

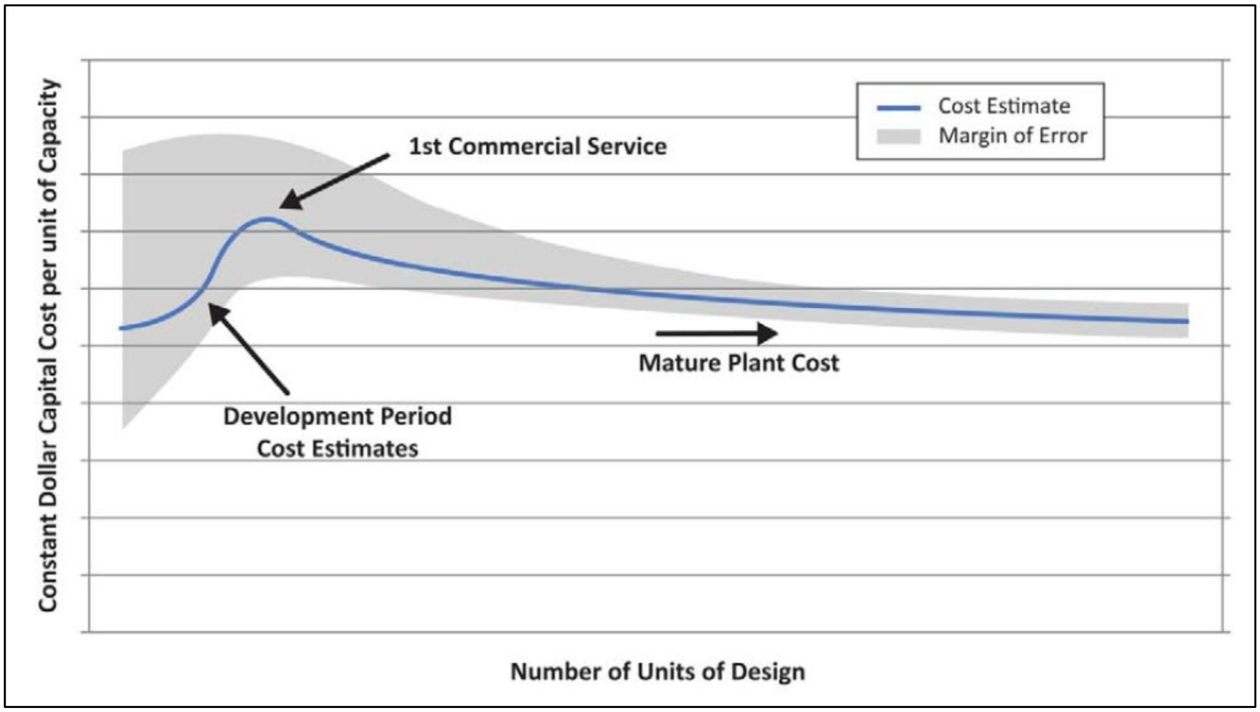

Figure 3-1. Theoretical Learning Curve (NETL, 2013).

NETL (2013) defines NOAK costs as:

$$Cost_{NOAK} = Cost_{FOAK} * X^{-b} \quad \textbf{(10)}$$

Where X is the cumulative number of units and b is the learning rate exponent, which is further defined as:

$$b = \frac{\log(1 - R)}{\log(2)} \quad \textbf{(11)}$$

where R is a technology-specific learning rate. The NETL methodology suggests R values as high as 0.06 for experimental technologies (e.g., fuel cells) and in the range of 0.01 for mature technologies (e.g., buildings, steam turbines, instrumentation). Figure 3-2 illustrates the relationship between costs and the number of units constructed (n) and the learning rate (R). sBET uses a default value for n of 20 plants. Components with an R value of 0.6 show an approximate 25% decrease in costs for $n = 20$; more mature components ($R = 0.01$), see much smaller cost reductions (a couple percent).

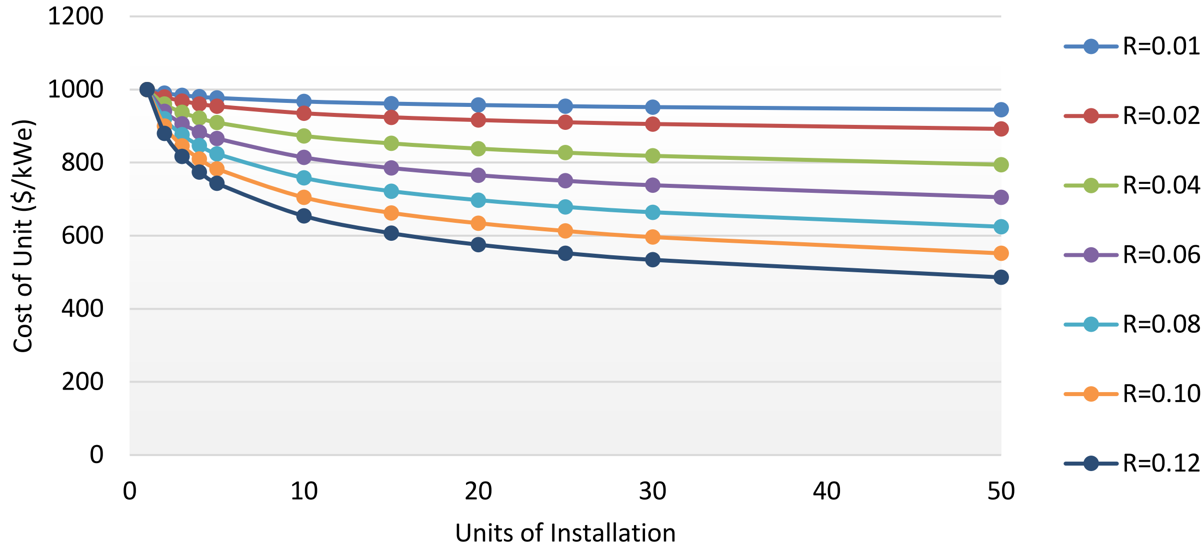

Figure 3-2. NOAK costs as a function of number of units n and learning rate *R*.

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4. RESULTS

This section summarizes the estimated LCOE for a nominal 100 MWe RCBC as well as detailed parameter studies to understand key sensitivities and local optima for cycle parameters. All studies use a RCBC that is natural gas-fired as the costs are lower and the heat source is more mature than the other two heat sources. The nominal case has a turbine inlet temperature of 700°C and dry cooling operating in St. Louis in the summer[5]. Table 4-1 summarizes the key input assumptions used for the nominal case in this analysis.

Table 4-1. Technical assumptions for the base analysis.

Parameter	Assumption
Turbine inlet temperature (°C)	700
Compressor inlet temperature (°C)	33
Compressor inlet pressure (MPa)	7.5
Compressor outlet pressure (MPa)	35.0
Recuperator effectiveness (%)	93
Turbine efficiency (%)	90
Compressor efficiencies (%)	85.5
Power output (MWe)	100

The estimated LCOE for the nominal case is 0.092 \$/kWh and 0.083 \$/kWh for a first-of-a-kind and n^{th}-of-a-kind plant, respectively. Figure 4-1 and Figure 4-2 show the relative importance of each major expense category compared to the total estimated cost. For the 100 MWe plant, system components account for 38.2% of the total costs for the first-of-a-kind plant and 33.3% for the n^{th}-of-a-kind plant. The various heat exchangers account for 18.3% and 16.4%, respectively. Consider the component costs, the two main categories of turbomachinery and heat exchangers account for very near 50% each. Assuming \$3.00/MMBtu natural gas[6], the fuel costs account for 23% and 26%, respectively.

This work is a comprehensive accounting of costs that feed into the LCOE, with considerably more depth than component cost studies that have been performed previously for sCO_2 power cycles. In fact, component costs are estimated to be only about 35% of the total for the nominal case. Apparent increases in LCOE from previous versions of the economics tool are largely attributed to including all expected non-component costs so that predictions are as accurate as possible.

[5] Average dry bulb temperature in St. Louis in summer is 21°C (EPRI, 2012).
[6] The September 11, 2018 *Short Term Energy Outlook* from the Energy Information Administration (DOE, 2018a), estimates an average spot price for natural gas \$2.99 /MMBtu) in 2018, increasing to \$3.12/MMBtu in 2019. Average delivered prices to utilities in 2017 were \$3.52/MMBtu. The EIA projects delivered natural gas prices to utilities of \$4.48/MMBtu in 2025 (DOE, 2018b).

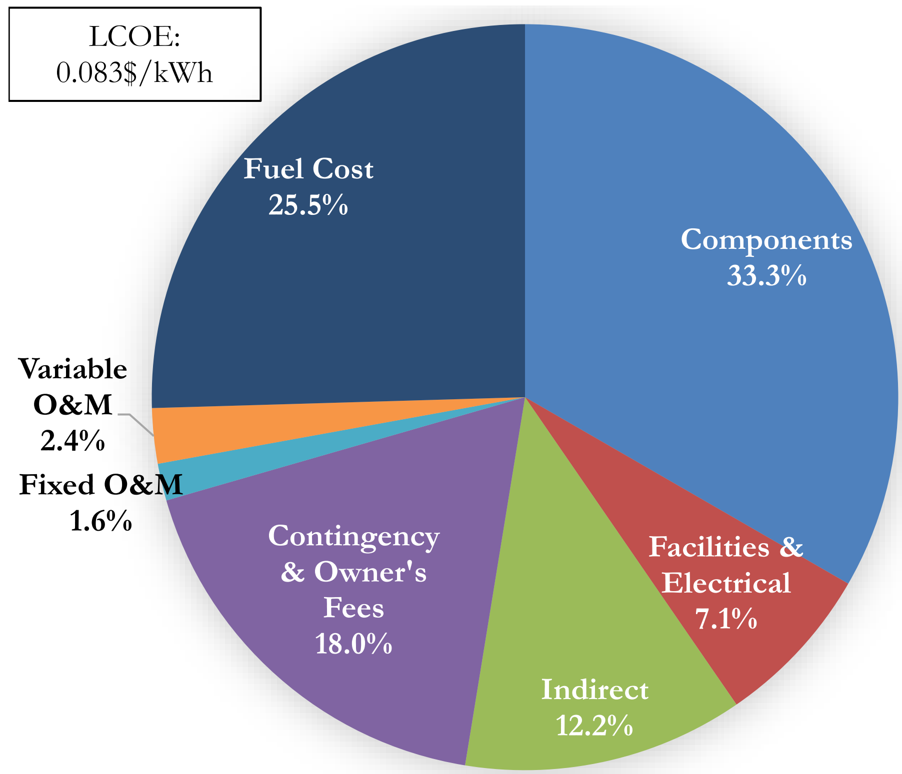

Figure 4-1. Estimated LCOE for an n^{th}-of-a-kind, 100 MWe RCBC with dry cooling by major category.

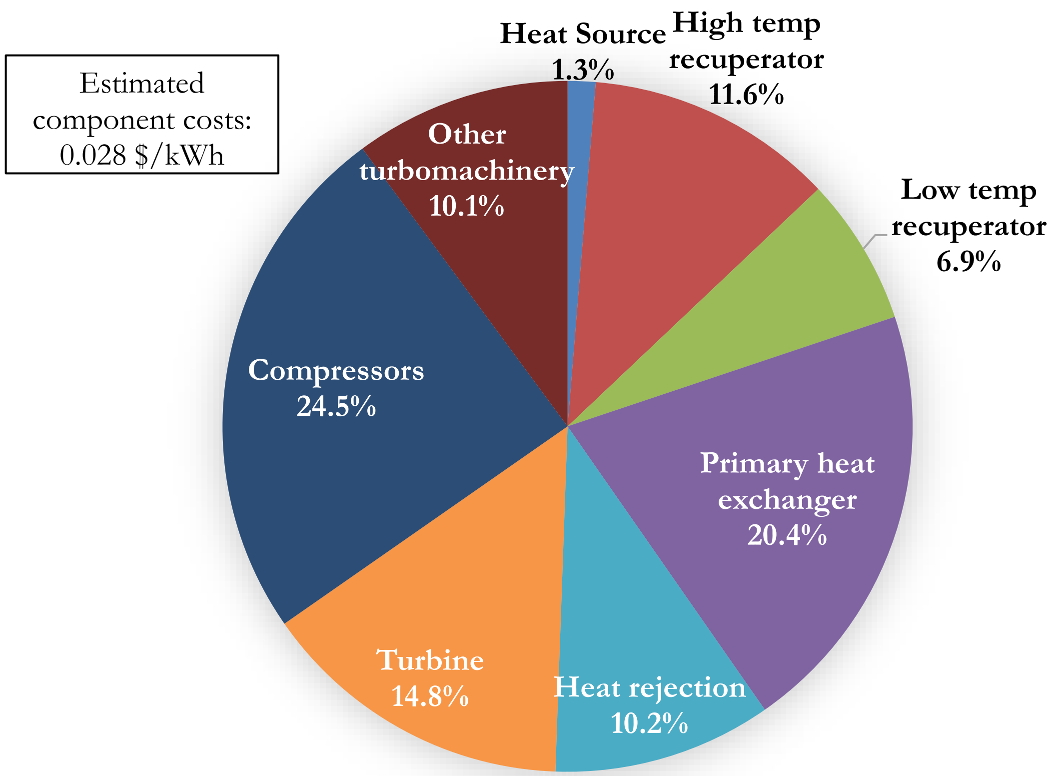

Figure 4-2. Breakdown of component costs for the estimated LCOE for an n^{th}-of-a-kind, 100 MWe RCBC with dry cooling.

This integrated tool allows for the testing of key sensitivities related to plant size, turbine inlet temperatures, recuperator effectiveness, etc. Each of the examples that follow required multiple runs of the RETS model, varying the parameter under consideration.

Figure 4-3 shows the projected LCOE for systems from 10 to 300 MWe for several cases, varying turbine and minimum system temperatures. The results show that costs decline rapidly as size increases from 10 to 50 MWe before slowly leveling off. While the costs for plants under 50 MWe—typically used for distributed or remote generation—are higher, these applications may place greater value on the flexibility that this scale provides. The trends also show that costs are lower for higher turbine inlet temperatures (0.018 $/kWh for the 100 MWe system going from 550 to 750°C). A similar cost reduction is realized when lowering the assumed minimum system temperature from 42 to 33 °C (0.018 $/kWh). This similar cost reduction shows a benefit of these parameter studies as it reveals that a relatively small decrease in cycle minimum temperature of 9°C has as much benefit as increasing the turbine inlet temperature by 200°C. It may be more cost-effective to increase the cooling system rather than increasing the turbine inlet tempratures due to the larger capital and O&M costs required for a much higher temperature engineered system. This is motivated further when considering that cooling technology is mature but high temperature materials in this regime are currently a topic of research. It also shows that LCOE parameter studies can help guide cycle condition design and research activities for effective use of funding.

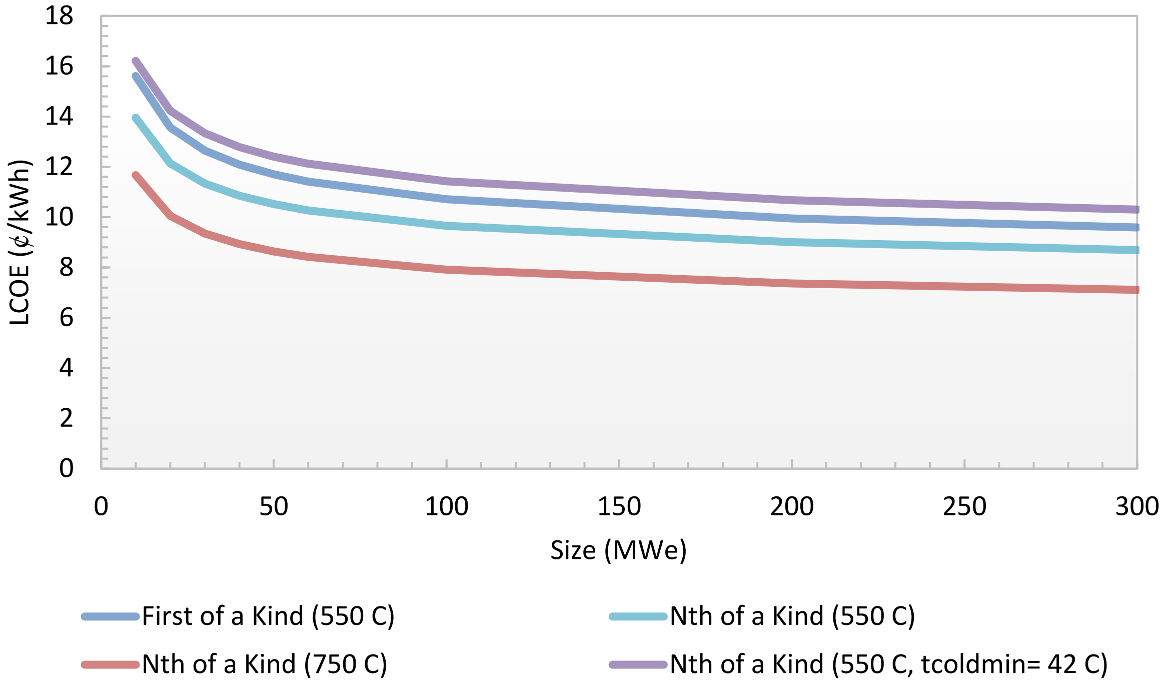

Figure 4-3. LCOE as a function of plant size, turbine inlet temperature, and minimum system temperature.

Figure 4-4 is a more detailed analysis of the impact of varying turbine inlet temperatures on LCOE for a 100 MWe system with dry cooling. As discussed in the methodology, as turbine inlet temperature increases above at 600°C, certain individual system components (primary heat exchanger, turbine, and HTR) will require higher-quality alloys. The higher component costs are quickly offset by the increased overall system efficiency. This figure also demonstrates the impact of fuel costs on the LCOE. For a system operating at 700°C, a $4/MMBTU difference in natural gas costs translates into a 0.028 $/kWh difference in LCOE. Increased fuel costs are more impactful at lower temperatures.

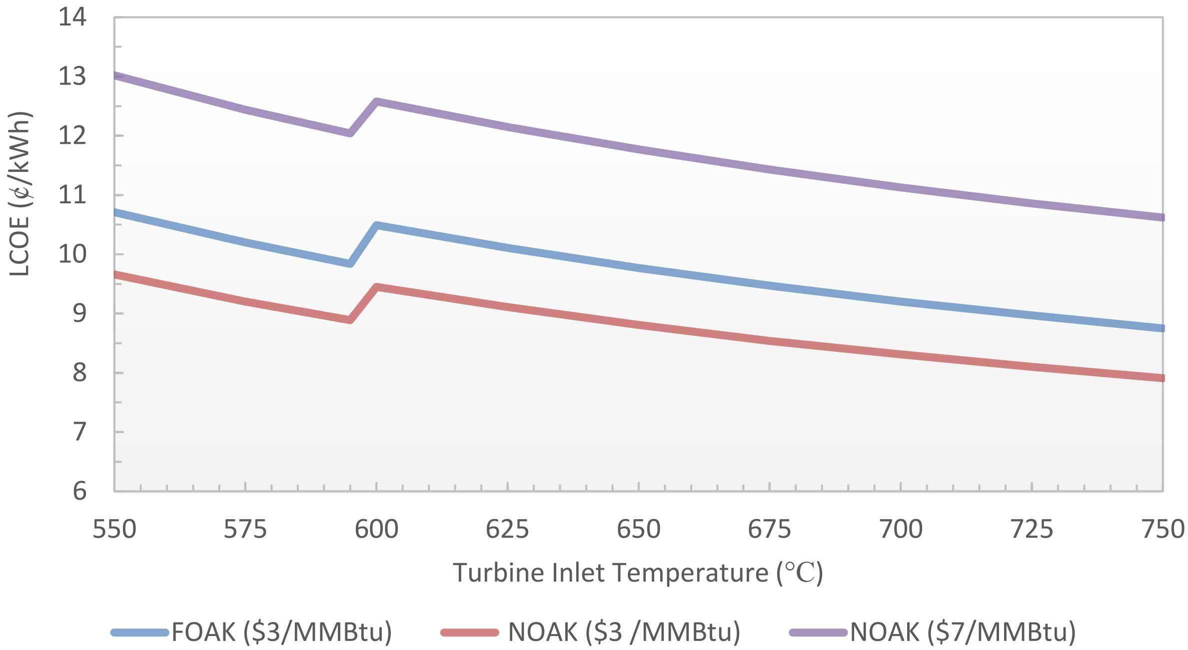

Figure 4-4. LCOE as a function of turbine inlet temperature and fuel costs.

Figure 4-5 demonstrates the impact of recuperator effectiveness on system efficiency and LCOE. As recuperator effectiveness increases, system efficiency increases. However, increasing recuperator effectiveness increases system costs and beyond a certain point, the increased costs begin to outweigh the benefit of increased system efficiency. The increase in recuperator cost with increasing effectiveness has been discussed by Shiferaw *et al.* (2016) and becomes drastic above 95%. This analysis shows that for lower natural gas prices, the optimal recuperator effectiveness is 88%. At higher natural gas prices, the optimal effectiveness increases to 90%. LCOE begins increasing sharply for recuperator effectiveness above 92%. These results suggest that research towards high effectiveness heat exchangers (>92%) is not likely to be adopted when the system designers consider cost.

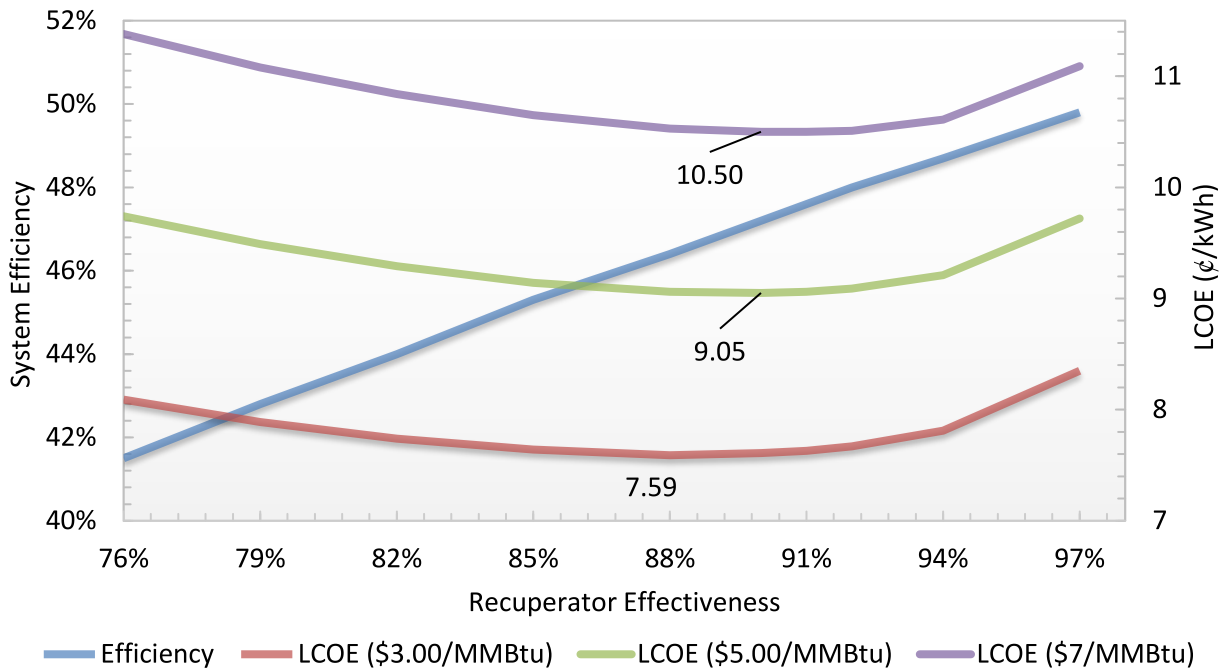

Figure 4-5. System efficiency and LCOE as a function of recuperator effectiveness.

Figure 4-6 and Figure 4-7 illustrate the sensitivity of the results to the technical assumptions regarding the approach temperatures for dry cooling in a hot, dry climate (Yuma, AZ) and a cold, wetter location (Bismarck, ND). According to EPRI (2012), the average dry bulb temperatures (required for calculating dry cooling requirements) in these two locations in summer are 80.2°F for Yuma and 65.4°F for Bismarck. Average wet bulb temperatures, used for calculating wet cooling requirements, are 59.3°F and 55.3°F. The results show that overall system efficiency drops sharply with increases in compressor inlet temperature (CIT). In Yuma, system efficiency drops as much as 1% for every 2°C increase in CIT. This is due to the savings of compressor work as the sCO_2 density increases sharply near the critical temperature of 31.1°C. This same relationship holds for Bismarck, ND, although the overall LCOE is lower as the lower ambient temperatures translate into smaller cooling systems.

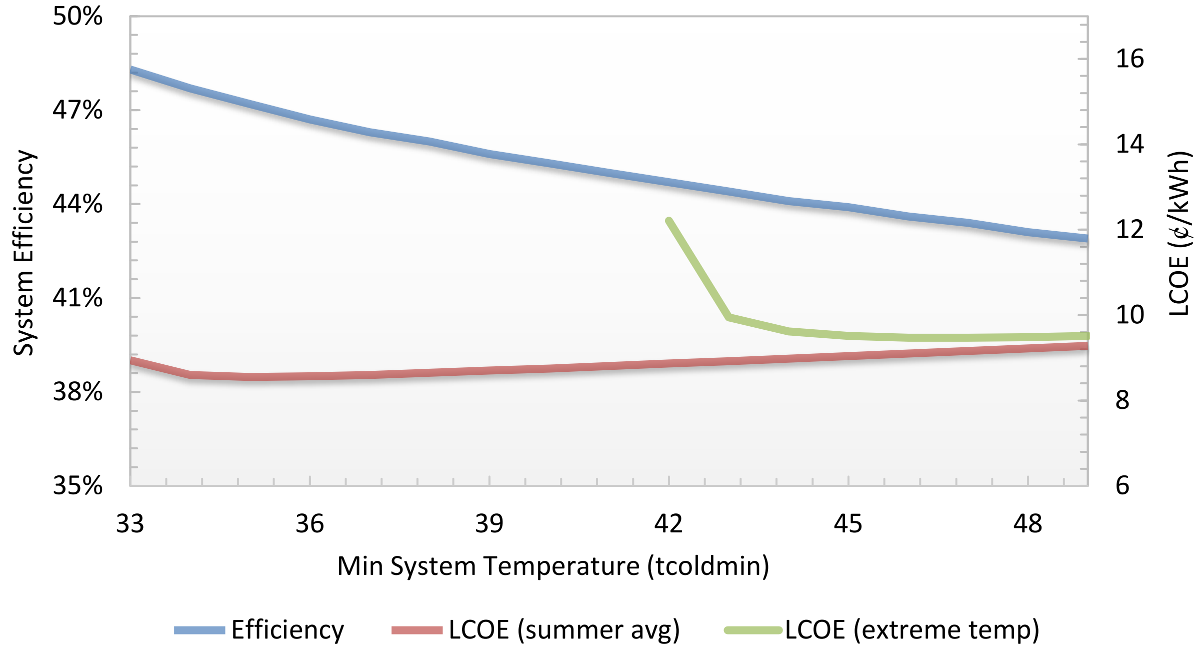

Figure 4-6. System efficiency and LCOE as a function of CIT for 100 MWe RCBC with dry cooling in Yuma, AZ in the summer (average dry bulb temperature and extreme).

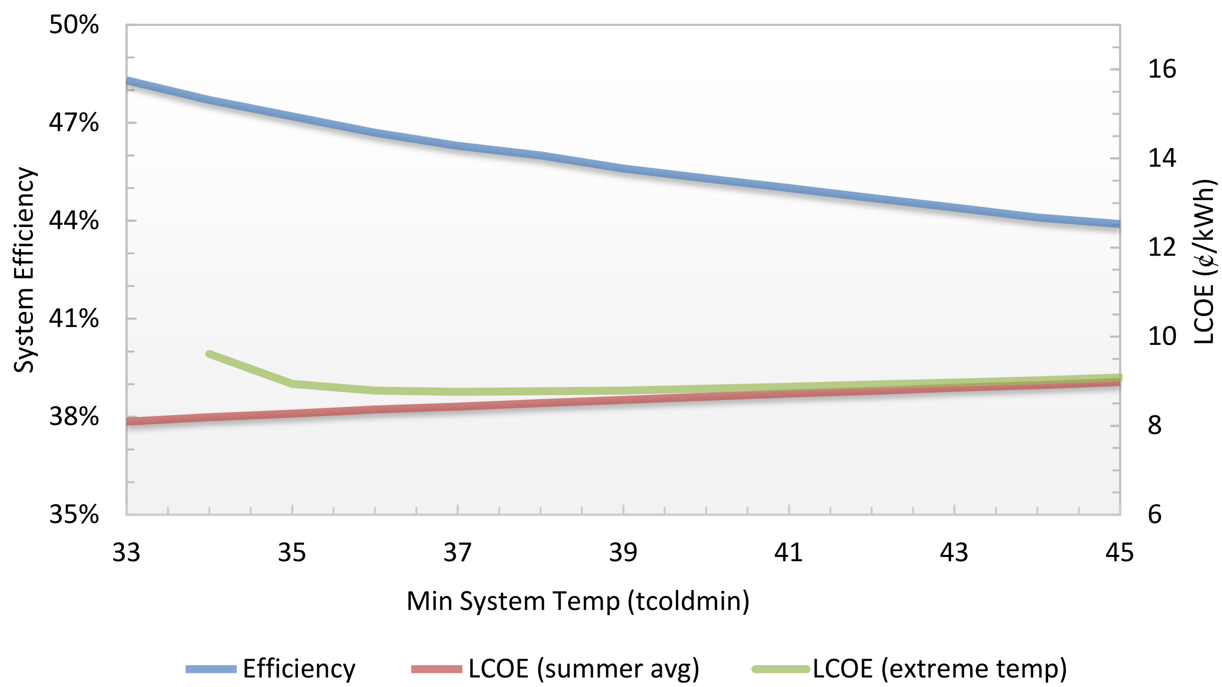

Figure 4-7. System efficiency and LCOE as a function of CIT for 100 MWe RCBC with dry cooling in Bismarck in the summer (average dry bulb temperature and extreme).

The figures also show the estimated LCOE for what EPRI (2012) defines as the extreme summer cases in each location. The extreme case is defined as the dry bulb temperature relating to observations for the hottest 2% of the year on an hourly basis. For Yuma, the extreme case is 107°F (41.67 °C); for Bismarck, the extreme case is 86 °F (30 °C). For the case of Yuma, this means significantly higher minimum CIT. The closer the CIT is to the assumed dry bulb temperature, the larger the required cooling system. This case highlights another key design decision, namely whether to design the system based on average or extreme summer temperatures. Designing for extreme summer temperatures requires a larger cooling system that is underutilized most of the year. For the 100 MWe system with dry cooling located in Yuma, a system designed for the average summer dry bulb conditions would have a UA of 7,610 kW/K. However, if the system was designed based on the summer extreme conditions that happen 2% of the time, the cooling system would be sized at 9,077 kW/K which would increase the LCOE by 0.0012 $/kWh.

Figure 4-8 shows the increased cooling system size (in terms of UA) for average summer temperatures in the two locations. These results suggest that, all else constant, the Yuma system results in higher LCOE due to need for a larger cooling system. For the summer average assumptions, the Yuma LCOE is 0.46 cents/kWh higher than for Bismarck. For the extreme case, Yuma is approximately 0.7 cents/kWh more expensive. These results suggest that location is important for cooling considerations and that the optimal CIT is higher when the dry bulb temperatures are higher. The optimal CIT for Bismarck is likely to be near the critical temperature of 31.1°C, but the current discretized cooling heat exchanger model does not allow solution at that level.

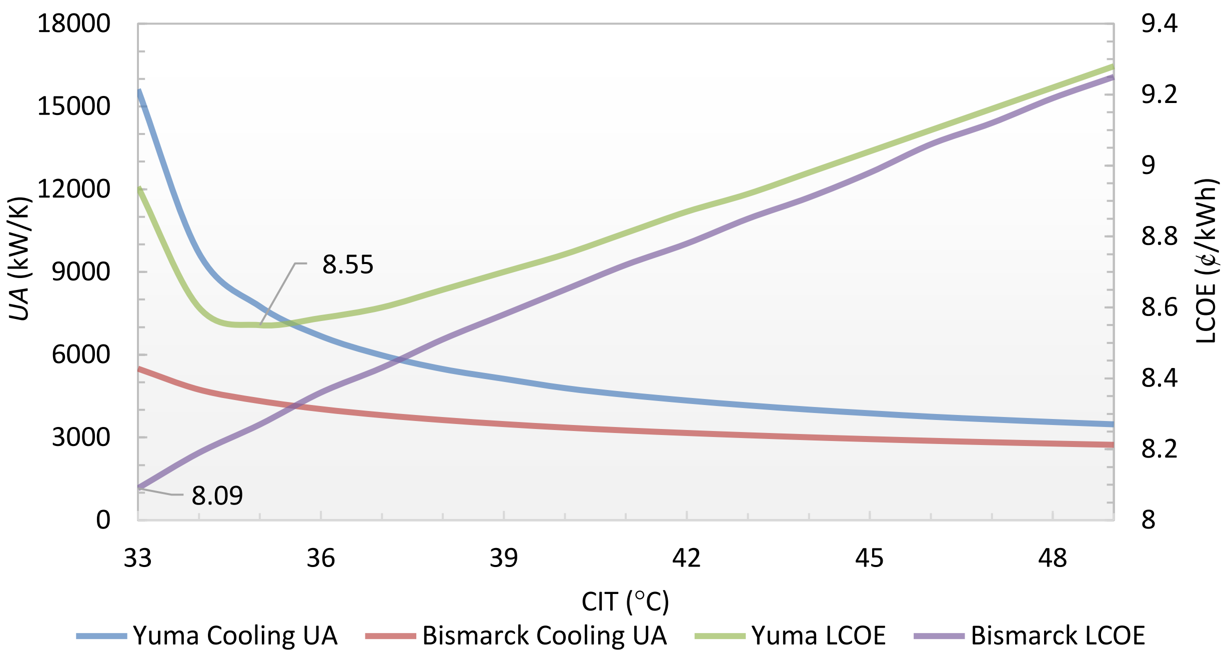

Figure 4-8. Calculated UA and LCOE as a function of CIT for a 100 MWe RCBC with dry cooling in Yuma, AZ and Bismarck, ND.

Figure 4-9 shows the linear relationship between turbine efficiency, overall system efficiency, and LCOE. Each one percent increase in assumed turbine efficiency from the base (90%) translates into a one percent decrease in LCOE. As the cost models do not consider efficiency as an input, the optimal efficiency is the highest possible. In reality, it is likely that increased engineering or advanced turbine designs could increase efficiency for a higher capital cost. These considerations should be included in future studies.

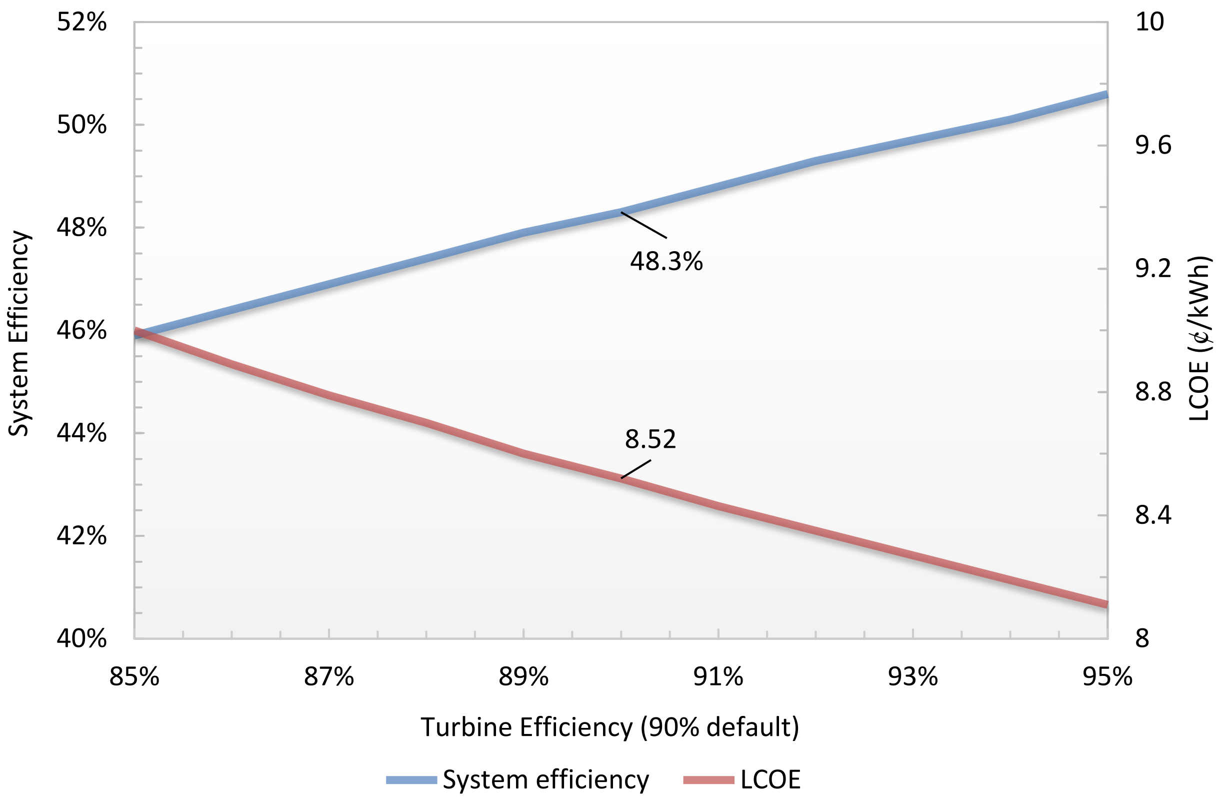

Figure 4-9. Effect of increased turbine efficiency on overall system efficiency and LCOE for a 100 MWe RCBC with dry cooling.

Figure 4-10 shows the relationship between compressor efficiency, overall system efficiency, and LCOE. Each one percent improvement in compressor efficiency over the base (85.5%) leads to a 0.8% decrease in LCOE. Therefore, improvements in turbine efficiency will have a larger impact on LCOE than that of compressors by a small margin.

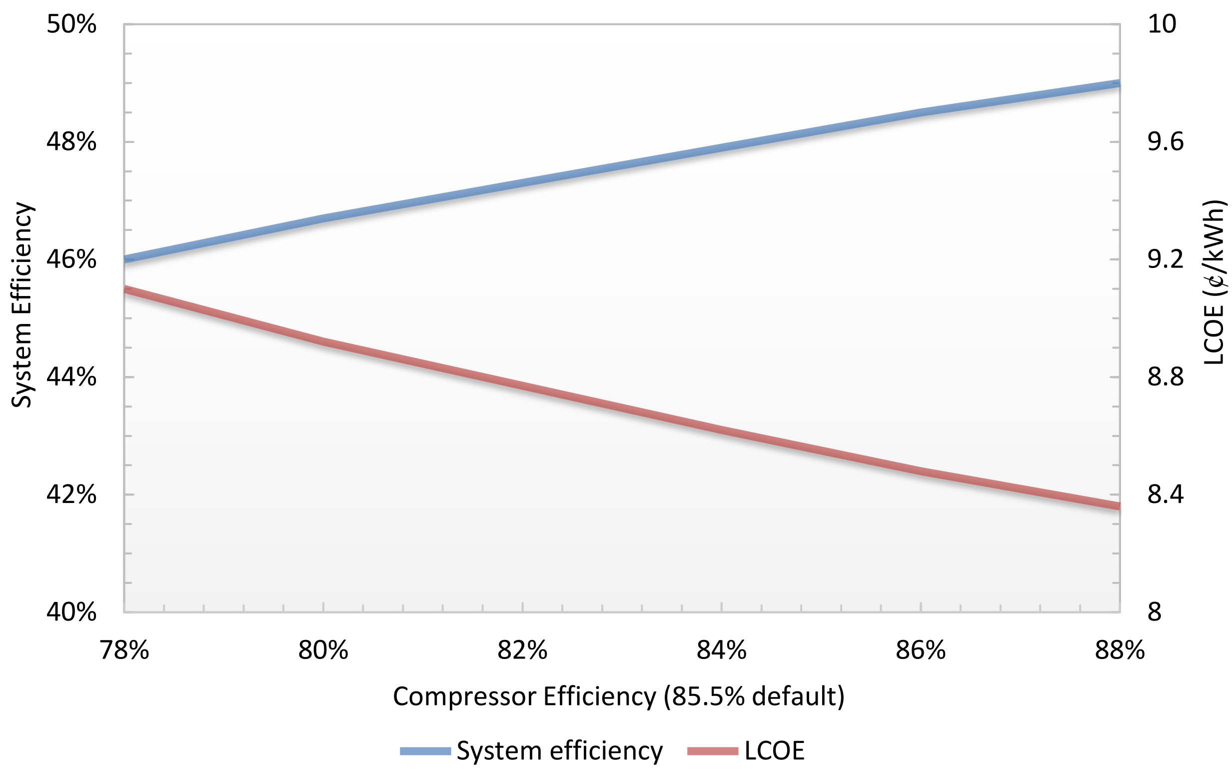

Figure 4-10. Effect of increased compressor efficiency on overall system efficiency and LCOE for a 100 MWe RCBC with dry cooling.

5. NEXT STEPS

The results presented here are the latest that have been implemented into the techno-economic coupling of RETS and sBET. As of the report completion, a conference paper is expected to be published in the proceedings of the 2019 ASME Turbo Expo that has updated component cost models from a more comprehensive source of vendor data (including many used in this work). These can easily be implemented in sBET and the analyses performed again for an updated and more accurate estimate of LCOE. Nevertheless, there are still areas where improved component cost models should be developed, especially for turbomachinery that has a sizeable cost that is very uncertain.

There would also be great value in moving beyond single operating point LCOE estimation or the cumbersome single value parameter studies presented in this work. Multi-parameter optimization to minimize LCOE can readily be achieved by wrapping RETS and sBET in optimization software. There is a current work that is pursuing this avenue that can be a significant contributor to sCO_2 Brayton cycle design from an economics perspective. This perspective is among the ultimate ones on which sCO_2 cycles will be evaluated.

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APPENDIX. RUNNING THE INTEGRATED MODEL

RETS is a Fortran-based model available from Sandia National Laboratories. The latest version of sBET has been shown to work with the RETS version dated 2016-10-04. In addition to the executable file (“Split flow recup prediction.exe”), RETS includes three folders with various input and output files. Fluids, Input, Out.

To run the integrated model:

1. Open the input file (Input > DCBCSFRin.txt) and make any changes. Save the file. You may leave this file open.

2. Run the model (double click on “Split Flow Recup Prediction.exe”).

3. Open the output file (Output > DCBCSFRout.csv). This file shows the basic output from the RETS model, including temperatures and pressures throughout the cycle.

4. Open the sBET (Output > sBET.xlsx). The LCOE output is displayed in the tab labeled “LCOE Calculator”.

To run a different scenario, you must exit out of DCBCSFRout.csv for it to be updated. You may leave sBET.xlsx open and the results will automatically update when DCBCSFRout.csv is updated.

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