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CONCEPT BACKGROUND

8 Rivers is pursuing this Pre-FEED study for a 714 MWt (HHV) near zero emissions coal fired power plant located adjacent to Peabody's North Antelope Rochelle Mine (NARM) in Wyoming. The power plant will receive coal directly from the mine and use that coal to generate syngas which will then be utilized in a syngas fueled Allam-Fetvedt Cycle power plant. The power plant will export about 285.6 MWe of power to the local network, yielding an efficiency of 40.02% (HHV). This will be via a dedicated switchyard for export of power from the site.

Because of the inherent low emissions nature of the Allam-Fetvedt Cycle (Allam Cycle) the overall plant will have over 93% carbon capture. The various gases produced in the process will either be re-used within the process or will be sold for commercial use. Water will be cleaned and re-used within the process, with the facility operated on a zero liquid discharge basis.

Allam Cycle Coal is a syngas fired power generation cycle invented by 8 Rivers Capital, LLC. Simply stated, Allam Cycle Coal is an integration of commercially available coal gasification technology and the Allam Cycle natural gas (NG), as shown in Figure 1 below. The natural gas version of the cycle is being commercialized by NET Power, beginning with a 50 MWth plant currently operational in La Porte Texas. The Allam Cycle is essentially fuel agnostic. Based on "desk top" studies, engineering design and analysis the Allam Cycle can run on a wide range of fuels including but not limited to NG, coal syngas, tail gas, industrial off-gas, to name a few, by using the syngas combustor in development by 8 Rivers[i].

Work on the coal syngas-fueled Allam Cycle has advanced in a parallel program to the NG cycle. This program is focused on the coal-specific aspects of the Allam Cycle, building off of the advancement of the core Allam Cycle at the La Porte 50 MWth facility. The Allam Cycle coal program has been supported by several consortiums over the past 5 years. Activities have been centered on addressing key potential challenges specific to the coal syngas Allam Cycle, including corrosion testing, gasifier selection, impurity removal and syngas combustor development. This study contributes to advancing the technology towards a commercial 286 MW_e net output Allam Cycle plant. This study will be used by 8 Rivers, the technology and project developer, to support the development of a near zero emissions project with a goal to commission the commercial facility by 2026.

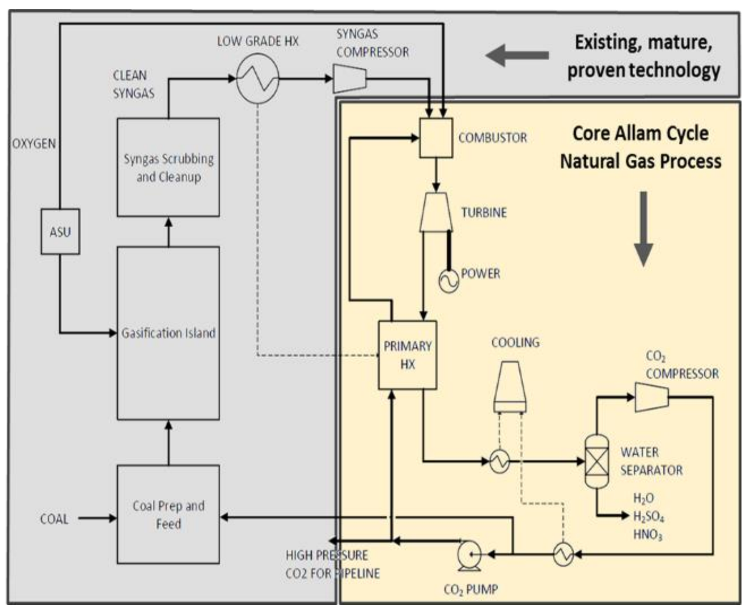

Figure 1 - Allam Cycle Coal Process Integration

The technology has the potential to enable new coal generation globally and domestically, using American technology and American coal. An Allam Cycle coal power system has the potential to produce electricity at a lower cost than new natural gas combined cycle (CCGT), supercritical pulverized coal (CCGT) and integrated gasification combined cycle (IGCC) facilities. The system includes full carbon capture and eliminates nearly all other air emissions. The inherent emissions capture of the Allam Cycle provides an additional revenue stream, CO_2 for various uses including enhanced oil recovery and likely "proofs" it against future environmental regulations. Including revenue from CO_2, Argon, and tax credits, a first of a kind plant power price of $38 / MWH is expected, with capital cost declines to come on subsequent plants.

An Allam Cycle coal plant will be the cleanest fossil fuel plant ever built with regards to Environmental Health and Safety since there is no combustion exhaust stack in the system, all the combustion derived species will be captured in the system. The system removes nearly all NOx, SOx, and particulate emissions, while >93% of the CO_2 can be captured and stored permanently. Thus, there would be no airborne hazards or toxicological impacts from the Allam Cycle section of this plant, and to the degree that it displaces generation from neighboring fossil plants, it will actually reduce local air pollution. The "zero carbon" argon generated will be transported by truck or rail to existing industrial gas users, displacing argon that is generated with carbon-emitting power. Conventional black water treatment system and zero liquid discharge system are included in the system design in this study.

Plant production/facility capacity

The proposed Allam Cycle coal plant is designed to have 550MWt in LHV cleaned syngas fed into the Allam Cycle power island. Table 1 shows the plant's net and gross capacity with the Wyoming subbituminous coal chosen for the Pre-FEED study. The system efficiency and auxiliary load with selected site and Wyoming coal was updated with vendors' input in the Pre-FEED study.

Coal thermal input (MW in LHV)	676
Gross generator output (MW)	468.15
ASU load (MW)	-74.19
Total compression/pumping load in the Allam Cycle (MW)	-92.51
Gasification Island utility (MW)	-5.23
Cooling tower (MW)	-4.35
CO_2 Purification Unit (MW)	-1.57
Miscellaneous BOP (MW)	-1.83
Transformer Losses (MW)	-2.88
Net power output (MW)	285.6
Net efficiency (% LHV)	42.25%
Net efficiency (% HHV)	40.02%

Table 1 - Allam Cycle Efficiency With Wyoming subbituminous coal

In addition, the Allam Cycle coal plant produces CO_2 and Argon for sale. At the 85% Capacity Factor modeled in the Conceptual design, the plant will produce 1.61 million tons of CO_2 per year, and 53,000 tonnes of Argon.

Plant location consistent with the NETL QGESS

For the Pre-FEED study, 8 Rivers has selected to site the plant at Peabody's North Antelope Rochelle Mine (NARM), and to use Peabody's coal from that mine. Peabody submitted a Letter of Support to the original Coal FIRST application, and has agreed to provide all the necessary site and coal information for the Pre-FEED. Due to the large native power demand and the proximity to multiple CO_2 offtakes, this is a favorable location for siting an actual power plant.

When available, we have used NARM specific parameters. Otherwise, we have used NETL QGESS design parameters.

Parameter	**Value**
Location	Greenfield, Teckla, WY
Topography	Rolling
Transportation	Rail or highway
Ash/Slag Disposal	Off Site
Water	Ground water
Elevation, (ft)	4830
Barometric Pressure, MPa	0.101
Average Ambient Dry Bulb Temperature, °C	9
Average Ambient Wet Bulb Temperature, °C	5.2
Design Ambient Relative Humidity, %	61%
Cooling Water Temperature, °C	10

Air composition based on NETL QGESS, mass %	
N_2	72.429
O_2	25.352
Ar	1.761
H_2O	0.382
CO_2	0.076
Total	100.00

Table 2 - NARM Site Parameters

Business Case

Allam Cycle Coal can create a business case for coal to thrive in the most difficult economic and regulatory conditions. The technology can enable new coal generation both globally and domestically, using American technology and American coal. This is because the Allam Cycle coal power system has the potential to produce electricity at the same or lower cost than conventional coal and natural gas plants, with natural gas seen as the key competitor for new-build dispatchable power. And, the system includes full carbon capture (>93%) and eliminates nearly all other air emissions. This inherent emissions capture provides an additional revenue stream to the Allam Cycle coal plant, and future-proofs it against environmental regulations.

Coal Type

For this scenario, we assume the use of Powder River Basin (PRB) Coal from the NARM mine. Given the abundance of natural gas, and a desire to be conservative, we based the analysis off of the High Oil and Gas Resource case from EIA, which projects a market average of $2.90 / MMBTU gas in 2025, and $1.62 /MMBTU coal at mine mouth and $2.64 coal delivered cost.[ii] To adjust this projection for PRB coal we assume that the mine mouth price remains at $.72 / MMBTU for PRB coal, given that EIA has mine mouth coal prices changing by <2%,while keeping 2025 delivery costs the same. This led to a net $1.72/ MMBTU delivered coal cost, and a $0.83/MMBTU mine mouth cost once the price is levelized.

Renewables Penetration

Using the EIA base case, renewables penetration is expected to grow from 18% to 31% of domestic power generation by 2050, with 73% of that power coming from intermittent solar and wind. The direct impact of renewables on Allam Cycle coal will be felt in terms of fluctuations in power prices and resulting dispatch of the plant. Our analysis doesn't attempt to predict future power prices and power market structure, and instead compares the price competitiveness of the facility to other dispatchable power plants. If Allam Cycle coal is the lowest marginal cost option for dispatchable power, it will be competitive.

The second related impact is capacity factor. Modeling of system economics shows that a high capacity factor is required for initial Allam Cycle Coal plant to remain economic, given its high relative CAPEX and reliance on byproduct revenues that themselves would be decreased at lower capacity factors. However, given the lower marginal cost of production of the Allam Cycle due to additional byproduct revenues, we expect this plant to dispatch ahead of all other fossil plants, and to maintain a high capacity factor even with the 31% renewables projected by EIA, and above. As shown in the Levelized Cost Comparison, with current value of CO_2, Allam Cycle coal can bid into the dispatch order at $0 / MWH, ensuring it runs at a high capacity factor necessary to remain economic. With future plants that have lower byproduct revenues and only $15 / MT from CO_2 (from EOR or a future carbon price), the marginal bid would be <$10 / MWH, which would still be low enough to be the first fossil source in the dispatch stack.

CO_2 Constraint

We assume a base case CO_2 value of $30.7 / MT, which can be currently realized in the US market through the 45Q tax credit ($35 post-tax value for 12 years) combined with $13.6 / MT CO_2 sales for enhanced oil recovery (EOR). Similar values can be realized in the US or the Middle East with EOR, or through energy policy, like the industrial carbon price in Alberta ($21-

36 / MT)[iii], the cap and trade system in Europe ($29 / MT)[iv], or the Korean emission trading system ($20 / MT).[v] The same CO_2 value could be achieved through policy schemes like clean energy standards or cap and trade, and have the same functional impact on the competitiveness of the Allam Cycle. This model includes the cost of CO_2 transport at $2.45 / MT for a 60 mile pipeline.

Note on Cost Modeling Methodology and NETL QGESS

The cost methodology is explained in detail in the Cost Results Section. When available, we have used NARM site specific parameters. Otherwise, we have used NETL QGESS design parameters.

Domestic Market Applicability

As shown in Figure 2, Allam Cycle Coal's (AC Coal's) levelized cost of electricity in the US is economically competitive with new emitting combined cycle plants, which is the main competition for new dispatchable generation, while having near zero emissions. The first-of-a-kind plant (FOAK) base case is projected to cost $38 / MWH after coproduct sales. This is possible because of industrial gas sales, which amount to revenue of $39 / MWH: $30.7 of that revenue from CO_2 sales, a third of which comes from sale of CO_2 for Enhanced Oil Recovery (EOR) and two thirds of which comes from the 45Q. The remaining comes from Argon from the air separation process, which is a valuable industrial feedstock for uses like arc welding. The 48A tax credit, which is already claimable given AC Coal's high efficiency, makes AC Coal significantly cheaper than a combined cycle (CCGT), and this 48A mine-mouth case is what's expected to allow the first plant to be built. A permanent 45Q that lasts 30 years, which would require further legislation, would have a similar positive impact on the economics.

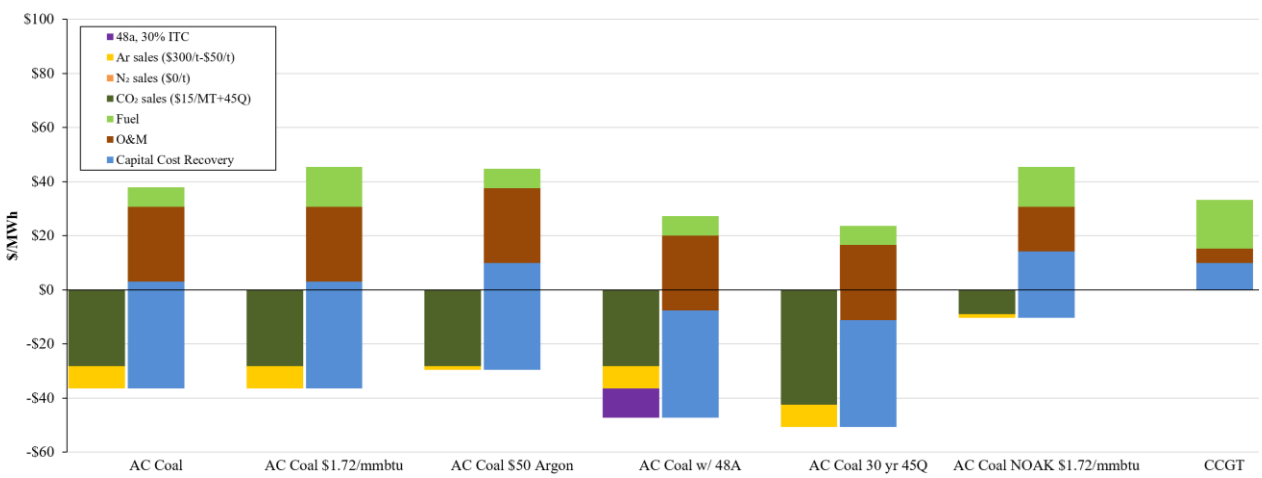

Figure 2 - Levelized Cost Comparison In The US Market

AC Coal here has a $3,647 / KW overnight capital cost, compared to $952 / KW for the CCGT. Total first of a kind capital cost is $4,209 / KW. It has $18 / MWH fixed O&M cost, and $9.7/ MWH variable O&M cost. Natural gas is priced at $2.9 / MMBTU and PRB coal at $.83/MMBTU at the minemouth and then at $1.72 / MMBTU for the cases on delivered coal and Next-of-a-Kind (NOAK).[vi] The assumptions across cases are detailed in the Cost Results section.

Allam Cycle Coal outcompetes Supercritical Pulverized Coal and Combined Cycle Gas Turbines (CCGT) because of a mixture of its high inherent efficiency, manageable capital costs, and its multiple revenue streams. As more plants are built, it is assumed that the revenues from Argon sales will decline, as shown. But the levelized cost of power remains competitive for AC Coal to be the superior option due as capital costs decline. Additionally AC Coal offers fuel security and diversification benefits of retaining some coal generation, as well as the near-zero emission attribute, which future proofs AC Coal against environmental regulation that could add risk and cost to CCGTs.

Capital costs to NOAK will decline as learnings from early plants improve the overall design and constructability. Without 45Q, a Nth of a kind plant (NOAK) will produce electricity at $45 / MWH, cheaper than SC-PC, but more expensive than CCGT with $2.90 / MMBTU gas. It would reach cost parity when natural gas prices are above $5 / MMBTU as is common globally, and in any domestic scenarios when the total CO_2 value is greater than $30 / MT between EOR and carbon policies.

The 48a tax credit is expected to allow the very first AC Coal plant to be financed. 48a is a 30% Investment Tax Credit (ITC) available to power plants that use 75% coal feedstock and achieve 70% carbon capture with 40% HHV efficiency for bituminous coal, and ≈37% HHV for Wyoming Powder River Basin coal, a benchmark that Allam Cycle coal meets in all scenarios. It requires 400 MW total nameplate capacity. This Allam Cycle Coal design exports about 286 MW of electricity, but its nameplate capacity will be above 468 MW, and thus qualifies for 48a. For the purposes of 48a, IRS has defined nameplate capacity as "aggregate of the numbers (in megawatts) stamped on the nameplate of each generator to be used in the project."[vii] It can be claimed alongside 45Q, is already in statute, and has over $1 billion in credits currently claimable.[viii] This 48a credit and the higher CO_2 revenue per MWH of coal makes the Coal Allam Cycle competitive against gas power plants even with low gas prices.

Additionally, the US has over 5,000 miles in CO_2 pipelines connecting over 100 CO_2 offtakes, expanding the map of locations to build a CCS plant with minimal infrastructure required. The market for CO_2 for EOR is massive, with total potential demand enough to purchase 25 billion tons of CO_2 as the industry advances.[ix] In 2014, 3.5 billion cubic feet of CO_2 were injected for EOR. The natural supply of CO_2 is limited geographically and in total size, with only 2.2 billion metric tons of total natural reserves. This necessitates a supply of CO_2 for the EOR industry to grow, and guarantees a large and growing market for Allam Cycle coal CO_2.

The subsurface geology in the US is attractive for sequestration as well, with a number of pilot projects and one commercial scale injection well operating in Decatur, Illinois. Sequestration will be particularly important on the coasts and the Midwest where EOR is not an option. The DOE has estimated the total storage capacity in the United States ranges between 2.6 trillion and 22 trillion tons of CO2, enough for thousands of CCS plants running for thousands of years.[x]

International Market Applicability

The Coal Allam Cycle's biggest international market is in fast growing economies where power demand is quickly increasing, and cheap natural gas is in short supply. This encompasses parts of India and China as well as much of eastern Asia. This region also has the most experience in constructing the coal gasifiers needed for this system. We have modeled further sensitivities for the global market: the nth-of-a-kind Allam Cycle with $0-$15 value per MT of CO_2, compared against conventional coal (SC-PC) and a CCGT with $6 / mmbtu imported liquefied natural gas, as shown.[xi] Argon is shown at $50 / ton. Capital costs are not adjusted internationally, nor are they adjusted for additional coal handling that may be necessary for non-minemouth projects. We expect capital cost decreases to be roughly proportional across technologies, and thus not greatly impact relative competitiveness.

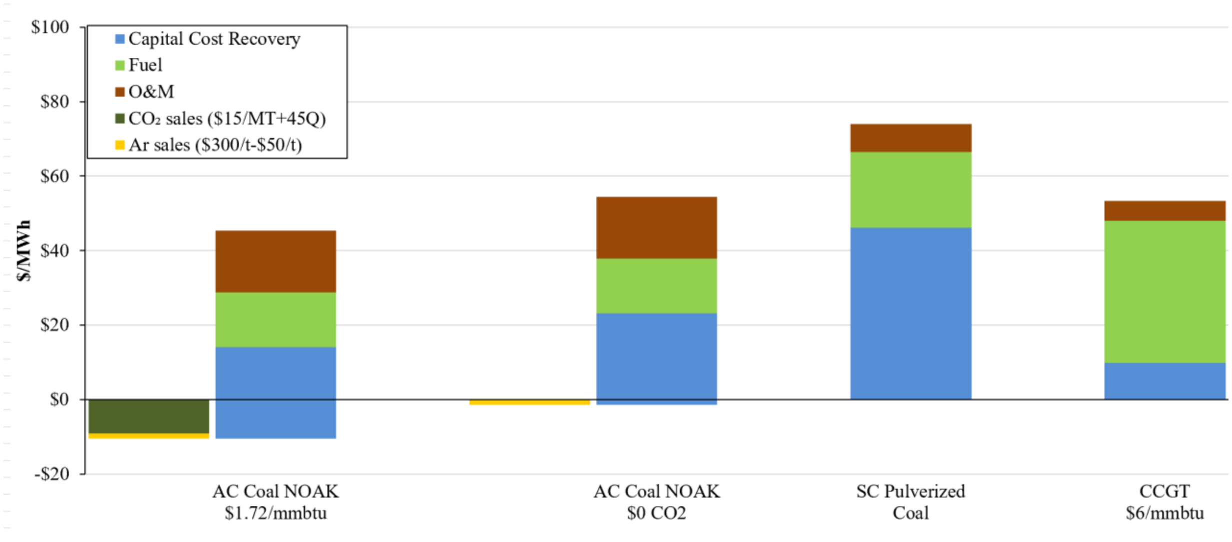

Figure 3 - Allam Cycle Coal Cost Comparison in Global Market Conditions

We expect the initial FOAK Allam Cycle plants to be built in the US, as with 45Q it is the most attractive place for CCS in the world for initial deployment. The deployment of both coal- and gas-based Allam Cycle plants will bring down the cost for the core cycle agnostic of fuel source. This is key: deployment of the natural gas Allam Cycle will have a direct impact on lowering the cost of the Coal Allam Cycle, since the core Allam Cycle is common and nearly identical in each system. Thus we expect to deploy the Allam Cycle at scale globally with nth-of-a-kind costs. As shown above with conservative industrial gas prices, this system will be cheaper than conventional coal with $15 CO_2 and at cost parity with $0 CO_2. After economics, the zero air pollution profile of this cycle may drive deployments globally, particularly in countries like Korea and China and India where air pollution is a top domestic issue. Allam Cycle may even be deployed without carbon capture initially, venting the CO_2 until an offtake is fully developed, and in the meantime delivering power at the same price with zero other air emissions.

Canada and the EU are also attractive international markets given their CO_2 policies, as are Middle Eastern countries like Saudi Arabia and UAE that have large demand for CO_2 for their oilfields, though the potential for Allam Cycle plants may be limited by power demand not CO_2 demand, and Middle Eastern coal power is still being built despite massive gas supplies. In UAE, for example, 2.4 GW of coal are currently under construction and

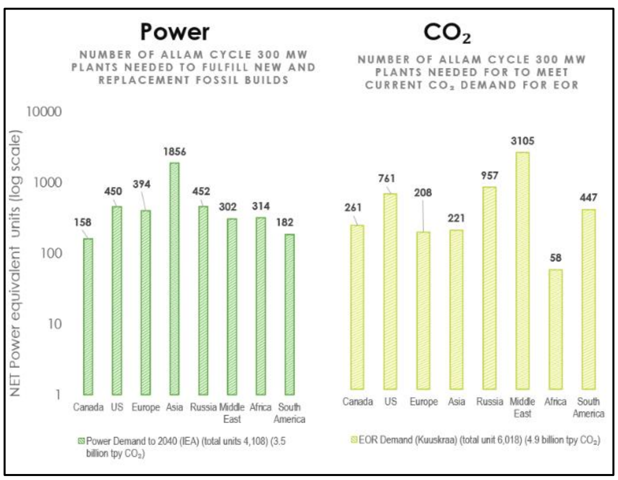

Figure 4 - Global Power and CO_2 Demand

UAE is targeting 11.5 GW of new coal by 2050.[xii]

The basic economic proposition for these countries is similar to the 45Q and EOR LCOE's previously shown, and so have not been broken down specifically here.

The scale of the global region is broken down above by power demand and CO_2-EOR demand. CO_2 sequestration and utilization are not included, which greatly increases the CO_2 offtake potential and opens up regions without EOR for CCS.

Estimated cost of electricity (and ancillary products)

As shown above, the cost of electricity is estimated at \$24-\$45 per MWh with 45Q, across the cases shown above. Without CO_2 incentives, the price rises to \$45-\$54 per MWh. Byproduct revenues are modeled as inputs to this power price output. Internal research and industry quotes led to our conservative estimate of \$15 / MT CO_2 for EOR, and our range of estimates for Argon at \$50-\$300 per ton. Byproduct values are uncertain and site specific. For the FOAK each year, 2,126,429 MWH of power, 1,610,224 tons of CO_2, and 53,164 tons of Argon will be produced. The Pre-FEED's base case economics are shown broken down below.

Component	Value, \$/MWh	Percentage
Capital	39.98	53.3%
Fixed	18.23	24.3%
Variable	9.69	12.9%
Fuel	7.12	9.5%
Total (Excluding T&S)	**75.02**	**-**
CO_2 Transport	2.45	
CO_2 EOR Revenue - Sales	-11.36	-
CO_2 EOR Revenue - Pre Tax 45Q for 12 years	-19.34	-
Total (Including T&S)	**46.76**	
Argon Revenue	-8.27	
Total (Including T&S and Revenue from Byproducts)	**38.49**	-

Table 3: Levelized Cost of Energy Table

Market advantage of the concept

By producing power that is cheaper and has nearly zero emissions, the Allam Cycle applied to coal as well as gas can become the new standard for power generation worldwide. Never have clean and cheap and dispatchable all coincided. Additionally, the power island has a much smaller footprint compared to conventional fossil fuel power plants given that the supercritical CO_2 working fluid has a very high density heat capacity, hence reduce the size of the power plant equipment, including gas turbine, heat exchanger, compressor and pumps. The compact design heat exchangers currently tested in the NET Power demo plant has much smaller footprint compared to the commercial heat recuperator. The smaller material needs of this equipment reduces construction costs, and most of the equipment in the power cycle can be built as modular, factory assembled skids. As an oxy-fuel cycle, the core cycle equipment, gas turbine, is not dependent on ambient conditions and is nearly identical from plant to plant. This will help to enable an assembly line, modular approach for construction, and also make sure the gas turbine can have a constant power output with site conditions. In general, only the cooling water system and the first stage of the main air compressor in Air Separation Unit experience ambient conditions. Design of the transition points between compressors and pumps will also minimize the impact of the cooling water temperature change. Therefore, the impact of ambient conditions on the Allam cycle efficiency is much smaller than its impact on CCGT system. Finally, CO_2 is generated at high purity and pressure, reducing the cost of getting the CO_2 pipeline ready, and virtually eliminating the penalty of capturing CO_2 instead of venting it.

PROCESS DESCRIPTION

Proposed Plant Concept Based on Conceptual Design

The Allam Cycle Coal is a syngas fired power generation cycle invented by 8 Rivers Capital, LLC. Simply stated, Allam Cycle Coal is an integration of standard thermal power plant equipment, commercially available coal gasification technology and the Allam Cycle natural gas system, as shown in Figure 5 below. The natural gas version of the cycle is being commercialized by NET Power, beginning with a 50 MWth plant currently operational in La Porte Texas. The Allam Cycle is essentially fuel agnostic. Based on “desk top” studies, engineering design and analysis the Allam Cycle can run on a wide range of fuels including but not limited to NG, coal syngas, tail gas, industrial off-gas, to name a few, by using the syngas combustor being developed by 8 Rivers.

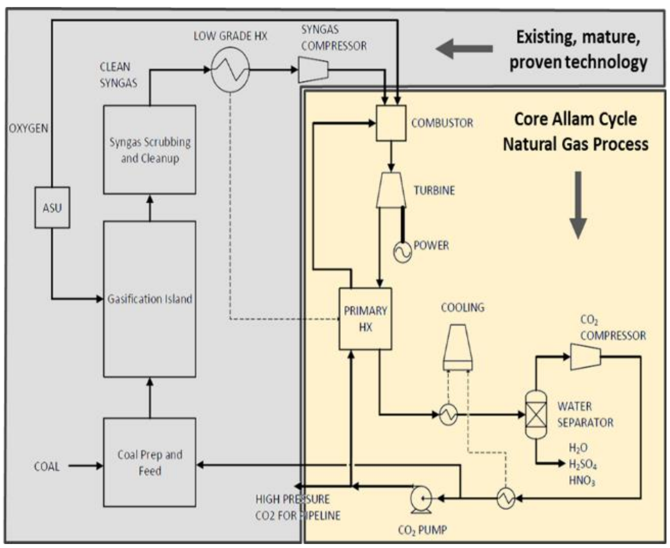

Figure 5 - Allam Cycle Coal Process Integration with Gasification

Work on the coal syngas-fueled Allam Cycle has advanced in a parallel program to the NG cycle. This program is focused on the coal-specific aspects of the Allam Cycle, building off of the advancement of the core Allam Cycle at the La Porte 50 MWth facility. The Allam Cycle coal program has been supported by several consortiums over the past 5 years. Activities have been centered on addressing key potential challenges specific to the coal syngas Allam Cycle, including corrosion testing, gasifier selection, impurity removal and syngas combustor development.

This study contributes to advancing the technology towards a commercial Allam Cycle plant. This study will be used by 8 Rivers, the technology and project developer, to support the development of a near zero emissions project with a goal to commission the commercial facility within 5 years.

The technology's power cycle is unique and innovative. It is a direct-fired, meaning the combustion turbine is directly integrated into the supercritical CO_2 power cycle. Since CO_2 is used as the primary process fluid in the cycle, combustion-generated CO_2 within the semi-closed cycle is simply cleaned, dried and pressurized along with this primary process CO_2, and exported as high-pressure CO_2 export product, typically at 2175.57psia (150 bar), for sequestration or utilization.

RFP Design Criteria

Allam Cycle coal is able to meet or exceed all of the 10 design criteria for the coal plant of the future outlined by the RFP, while fulfilling the other objectives laid out through DOE's evaluation points.

Modularity

The proposed Allam Cycle coal plant is designed to have 550MWt clean syngas fed into the power island and produce 286 MWe power. The power island has a much smaller footprint compared to conventional fossil fuel power plants given that the supercritical CO_2 working fluid has a very high density heat capacity. The smaller material needs of this equipment reduces construction costs, and most of the equipment in the power cycle can be built in a modular basis. High pressure sCO_2 cycles have a high power density which leads to small equipment and therefore increased modularity.

The syngas processing / purification system in the Allam Cycle is much simpler and smaller size compared with conventional coal to chemical plants and IGCC systems, given that water gas shift reactor, pre-combustion CO_2 removal units are eliminated in the Allam Cycle.

Near Zero Emissions

Allam Cycle coal inherently captures over 93% of CO_2 at pipeline pressure, without any additional equipment. This is expected at 150 bar, but can go as high as 300 bar, the highest operating pressure in the cycle without additional CapEx. The oxy-combustion cycle generates near-pure CO_2 that does not require expensive separation from other flue gases. Coal derived nitrogen is the only nitrogen source entering the cycle, so NOx formation is expected to be very low. In this study, a conventional acid gas removal system is included to remove sulfur from syngas down to single digit ppm level, any residual SO_X and NO_X in the flue gas can be removed in the CO_2-water separator without additional equipment to prevent contaminant buildup effect. In addition, mercury and heavy metals are removed from syngas in the gasifier island and zero liquid discharge is included in the plant design to ensure zero emissions.

Ramp Rates

Ramping speeds of the Allam Cycle power island are projected to at least be in-line with NGCC, with the potential to exceed that performance. The plant is operated to maintain the turbine outlet temperature and pressure as constant as possible throughout the operational load curve. This is accomplished by allowing the turbine inlet temperature and pressure to change. In this manner, the temperature profiles of the heat exchangers remains nearly constant. This constant profile virtually eliminates the impact of thermal inertia in the system by maintaining nearly constant metal temperatures. This will be validated through operation of the La Porte plant. Greater turndown capabilities than NGCC are expected, all the way down to zero net load (or negative) to the grid, enabling rapid dispatch and low-load operation. The ability to generate extra power for sale beyond the plant's 286-MWe rating is also possible for duration up to 4 hours. This is done by lowering ASU power usage by using locally stored oxygen, which was generated during times of low power demand and stored in tanks, and the oxygen storage tank is included in the standard Air Separation Unit (ASU) design package. For the coal based Allam Cycle, because the syngas combustor can co-fire natural gas and coal syngas without changing the turbine inlet condition, natural gas will be used to meet the required ramping and turndown capacity without interfering with the gasifier operation. The natural gas addition is used to decouple the operation of the gasifier from the requirements of fuel in the power cycle. Gas is used to cover the deficit from the gasifier since the gasifier ramp rate is slower than the power cycle and not a constant addition to the cycle. In addition, a syngas storage system is considered in the plant design to facilitate the plant ramping process and mitigate the impact of any unexpected instability of the syngas supply on the turbine operation.

Minimum turndown capability of gasification island is expected to be around 60% of rated flow for a single train. SE gasifier is fed by two separate coal lines, and the low turndown ratio can be achieved by operating the train on only one of these lines. All key components in gasification island like coal drying, coal feed delivery, gasifier, syngas clean up, COS hydrolysis, Hg removal, AGR and sulfur removal unit can be operated at turndown capacity of at least 60% of rated flow. Overall Gasifier Island is expected to be able to operate reliably from 60% to 110% of rated capacity.

Water Consumption

Allam Cycle coal would provide water savings as compared to conventional thermal technologies. With the dry cooling, there is no requirement for raw water withdrawal, since all process waste water is of suitable quality to be recycled in the syngas scrubber or it is suitably treated within the RO or ZLD to be reused elsewhere within the plant. In the dry cooling design, the plant is actually a net water producer with raw water production being approximately 1.16 gpm/MWe. For the wet cooling design, the raw water consumption is 4.3 gpm/MWe, which is less than the typical water consumption in the IGCC/CCS systems in DOE reference reports. The major reductions for water usage are the result of two primary factors. 1: The elimination of the steam cycle reduces water needed for steam. 2: The semi-closed Allam cycle captures and condenses combustion derived water. Inclusion of RO and ZLD process waste water treatment means that there is no process water discharge at the plant battery limits.

Based on the DOE NETL report (Cost and Performance Baseline for Fossil Energy Plant Volume 1: Revision 3, 2015), the raw water withdrawal for NGCC without carbon capture is 4.2 gpm/MW_{net}, and the raw water consumption is 3.3 gpm/MW_{net}, and carbon capture coal systems have 5.5-7.4 gpm/MW_{net} water consumption.

Reduced Design, Construction and Commissioning Schedules

The smaller footprint of Allam Cycle equipment will reduce material costs and enhance efforts for modular fabrication. The module core power cycle shared by NET Power and Allam Cycle coal will allow learnings from the design and construction of the initial NET Power Plants, to be constructed in the early 2020s, to be utilized by Allam Cycle coal.

Enhanced Maintenance

Maintenance costs for the Allam Cycle will be low compared to an IGCC due to the simplicity of the cycle. It requires only one turbine and its oxy-syngas combustor eliminates a portion of the upstream and downstream cleanup required by IGCC, such as a water gas shift reactor, and a downstream NOx removal system. The heat exchangers have excess surface area to allow for a given level of fouling before system performance is impacted. In addition, maintenance access is planned and available for inspection and cleaning as needed when the cycle is not operating.

Sparing Philosophy

The sparing philosophy is as follows. The plant is currently being planned as 1x100% for simplicity of operation, increased modularity, decreased piping complexity, and other factors, with exceptions where equipment capacity requires an additional train.

The plant design consists of the following major subsystems:

- One ASU (1 x 100%).
- Two trains of coal milling and pulverizer systems (2 x 50%).
- One fluidized bed coal dryer system (1 x 100%).
- One train of gasification, including gasifier, cyclone and syngas scrubber (1 x 100%).
- One black water system and ZLD(1 x 100%).
- One COS Hydrolysis Reactor (1 x 100%).
- One Hg removal unit (1 x 100%).
- One AGR unit (1 x 100%).
- One tail gas clean up for sulfur recovery unit (1 x 100%).
- One syngas combustor (1 x 100%)
- One syngas compressor (1 x 100%)
- One CO_2 compressor (1 x 100%)
- One turbine (1 x 100%)
- One CO_2 pump – 110bar (1 x 100%)
- Three CO_2 pumps – 393bar (3 x 33%)
- Two oxidant pumps (2 x 50%)
- One CO_2 purification stream (1 x 100%).

Coal Upgrading and Other Value Streams

One of the most important traits of the coal Allam cycle is that it can be integrated with coal to chemical processes efficiently and cost effectively, to co-produce hydrogen, methanol, ammonia and other coal derived chemical products. Syngas produced from gasifier system goes to a water gas shift reactor and then hydrogen is removed from syngas by a PSA unit, high CO rich syngas is fed to the Allam Cycle for power generation, CO_2 captured from the cycle can combine with H_2 for chemical productions. In addition, being primarily fuel gas agnostic, the Allam cycle could be integrated with a wide range of coal derived syngas including; gasification, tail gas, pyrolysis gas, etc. Entrained flow dry feed gasification technology gives added benefits by using a wide variety of coal feedstocks without the need of any major upgrading. The Allam Cycle itself generates significant secondary value streams. In addition to oxygen, the ASU can be configured to produces Nitrogen as well as Argon, two valuable industrial gases used for fertilizer and welding that can be sold. Sulfur removal and recovery unit in the gasifier island can turn sulfur in the coal into either elementary sulfur or sulfuric acid, as the by-products that can be sold.

Natural Gas Co-Firing

The Allam Cycle syngas combustor has the ability to co-fire natural gas. Recycled CO_2 is the tuning parameter for the combustor operation with different fuel gas input. Since over 90% of mass in the combustor is recycled CO_2, with different fuel input, the turbine can maintain the same operating conditions in terms of temperature, pressure, flow rate and flue gas composition.

Target level of Performance

In this pre-FEED project, detailed Aspen modeling was conducted to estimate the Allam Cycle coal plant performance using Sinopec-ECUST (SE) entrained flow gasifier system with full water quench design. Wyoming subbituminous coal is used for the process modeling. North Antelope Rochelle Mine (NARM) site in Wyoming was selected for the pre-FEED design. The net efficiency of the Coal Allam Cycle was shown previously in Table 1 with the gross output and incurred parasitic load displayed. The efficiency for the Coal Allam Cycle system Montana PRB Coal was 43.3% on a LHV basis in the DOE Coal First Phase 1 feasibility study. The parasitic loads of the entire Allam Cycle coal plant was accounted for in the system efficiency calculation, including ASU, coal preparation, coal drying, coal feeding, gasifier, syngas cleanup, acid gas removal, zero liquid discharge, slag and ash handling, cooling tower, Allam Cycle power island and CO_2 purification unit (CPU). Since the coal used in the pre-FEED study has a similar quality compared with Montana PRB coal used in the concept design, and the same entrained flow gasifier system was selected in pre-FEED study, the system performance in the pre-FEED is similar to the estimate in the concept design, the detailed plant efficiency was generated from the Aspen modeling with vendors' data inputs.

It should be noted that the Allam Cycle plant has an ability to handle partial load which is unique. Compared to the conventional power cycles, the Allam Cycle turbine exhaust temperature can be maintained constant during the ramping process, due to the independent controls of oxidant stream flow rate/temperature and recycled CO_2 flow rate/temperature. Since turbine exhaust gas will be captured and purified in CPU, oxy-combustion does not produce NOx at any conditions. The emission profile at partial load should be very similar to full load, and since there is not an emissions profile associated with the plant, there is no increase in NOx, CO, or particulate emissions with turning down the plant. The power island is capable of operating anywhere from peak efficiency (full load) to a negative efficiency (plant is not exporting electricity and powering auxiliary loads from the grid). This level of operation would have to be supported by the lowest point of operation of the gasifier and will have to be determined in the FEED. During periods of partial load, liquid oxygen and syngas can be stored for use later during periods of high electrical demand as a form of chemical energy storage. In addition, there are other potential revenue streams coming from the plant. All of this changes decisions around operating at partial loads since it moves from a generating efficiency decision to one of maximizing the economics of the entire plant as a whole.

Emissions control summary

In the gasifier system, conventional water quench, cyclone and water scrubber are applied in the Sinopec-ECUST (SE) gasifier system for slag, fine particulates and soluble acid gas removal, such as Chlorine and ammonia. An activated carbon bed unit is applied for mercury and heavy metal removal. A conventional acid gas removal system is included to remove sulfur from syngas down to less than 2ppm level. Coal derived nitrogen is the only nitrogen source entering the cycle, so NOx formation is expected to be very low. Any residual SOx and NOx in the flue gas can be removed in the CO_2-water separator without additional equipment to prevent contaminant buildup effect. 8 Rivers has successfully tested trace SOx/NOx removal in the CO_2-water separator at the Energy & Environmental Research Center (EERC).[xiii]

The Allam Cycle is an "Inherent CO_2 Capture" technology, due to its use of Oxy-combustion. It is designed to capture all of the produced CO_2, with expected capture rates above 93% after accounting for potential turbo-machinery leakage and the loss from the CO_2 purification Unit. CO_2 in the design is captured at 150 bar with pipeline quality.

System Description

The Allam Cycle utilizes a recirculating, trans-critical CO_2 working fluid in a high-pressure, low-pressure-ratio, highly-recuperated, semi-closed Brayton cycle. The cycle operates with a single turbine that has an inlet pressure of approximately 4,350 psia (300 bar) and a pressure ratio of 10. The ratio of recycled CO_2 mass flow to the combined fuel and O_2 mass flow is in the range of 25:1 to 35:1. To maintain a mass balance within the semi-closed cycle, a portion of the high-purity CO_2 process gas is exported at a point within recompression to a high-pressure CO_2 pipeline (typically at 2175.57psia [150 bar]) for sequestration or utilization. This net export is approximately 7% of the total recycle flow.

The coal-based Allam Cycle, as shown in Figure 6, comprises two primary processes: the gasifier island and the core Allam Cycle power generation process. The gasifier island utilizes proven technologies supplied by several commercial vendors from small (50 tons/day) to large (>2000 tons/day) scale systems that are in operation throughout the world (272 operating gasification plants worldwide, utilizing 686 gasifiers) (Higman, 2016). Thus, this portion of the overall process is commercially available, and for this effort, the team has selected SE gasifier system in the pre-FEED study.

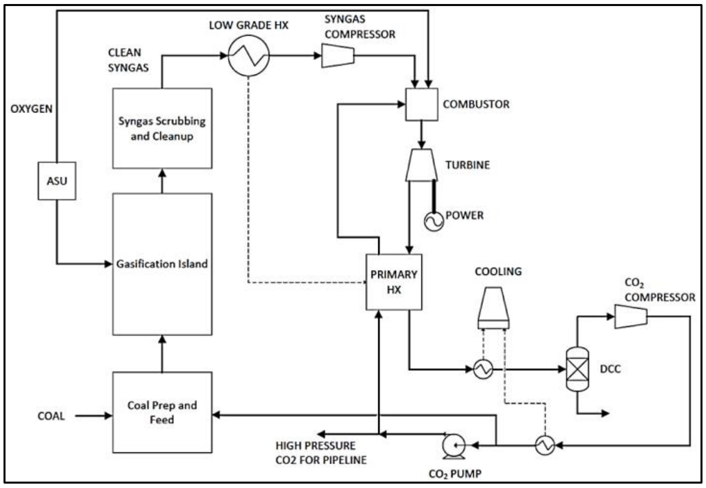

Figure 6 - Process Schematic of the Coal Syngas Fueled Allam Cycle

Advanced technology aspects

As a new power cycle, the Allam Cycle itself can be considered an "advanced technology aspect," as has been described above in the system description. In particular the combustor is advanced, as oxy-combustion is done in the presence of a large mass of pre-heated CO_2, to reach the pressures and temperatures require to drive the turbine. The combustor utilized in the demonstration turbine is a single 50MWt combustor. The La Porte plant demonstrated the first such combustor. The commercial design proposed by one turbine vendor would utilize 10-12 combustors at this scale, aligned radially around the commercial scale turbine.

The sCO_2 turbine is the other advanced aspect. It is driven by CO_2 rather than steam or air, and experiences pressures similar to a steam turbine simultaneously with the temperature profile of a gas turbine. Toshiba's turbine in La Porte was a partially arced 50MWt turbine. Because of this partial admission, the casing of the turbine is closer to a 200MWt size. Therefore the combustor in a can-annular arrangement will have a 1x scale up, and others will have a 2.5x-3x (the casing).

In this pre-FEED study, Siemens is selected as the syngas combustor and turbine provider. All the technical information related to the Allam Cycle was provided to Siemens for the turbine design.

Further information on the advanced aspects of the Allam Cycle and validation already performed are in the Tables in the next section.

The remainder of the components, from an air separation unit to CO_2 pumps and compressors to heat exchangers are available and should not be considered advanced technology aspects.

Development of the coal-based Allam Cycle will build off of the knowledge gained from lab-, pilot-, and large-scale testing programs already completed or currently under way since the coal-based variant is nearly identical to the natural gas-based Allam Cycle in terms of facility design, process conditions, required equipment, controls, etc. However, switching to a coal-based fuel and integrating with a gasifier island requires several additional developments prior to being ready for commercial demonstration. These additional developments were identified via a detailed feasibility and scoping study completed on the coal-based Allam Cycle by a consortium consisting of 8 Rivers, the Electric Power Research Institute, ALLETE Clean Energy (ALLETE), and Basin Electric Power Cooperative (BEPC) (Forrest et al., 2014). Significant work was conducted to address technical challenges via lab- or pilot-scale testing in preparation for a large-scale program. Each key issue and the associated severity and mitigation are summarized in Tables 4 and 5.

Based on work to date, the coal-based Allam Cycle is ready for full scale demonstration. The technology readiness level (TRL) of the gasifier island is at TRL9, with over 20 years of operating experience and multiple installations, and the core Allam Cycle will soon be at TRL 8 using natural gas as fuel, once the La Porte plant exports power in the coming months. Key technological risks specific to the coal Allam Cycle have been addressed to the degree indicated in Table 4, which puts the overall coal-based system at a TRL5–6, indicating it is ready for a large pilot. The proposed program will mitigate remaining risks to ready the technology for commercial demonstration.

We believe that after this Pre-FEED, and with the potential for syngas combustor development under the Critical Components FOA, Allam Cycle Coal will be immediately ready for a FEED study followed by financing and construction of a first of a kind full scale plant. As such, we are planning to apply for the Coal FIRST FEED announced in the recent NOI for release on May 2020, so long as Allam Cycle Coal is not specifically prohibiting from submitting an application.

List of components that are not commercially available

A 300 MWe scale Allam Cycle plant has not yet been built, but the 50 MWth facility has undergone adequate testing that makes the 300 MWe plant the next development step.

All components for Allam Cycle Coal are commercially available today except for the turbine, which will soon be available due to the commercialization of the natural gas Allam Cycle, and the syngas combustor, which will require further funding to develop.

- >500 MWth sCO_2 turbine
    - Though one has not been built yet today, this sCO_2 turbine will be commercially available in time for Allam Cycle Coal deployment. NET Power has announced plans to deploy multiple plants at this scale, with the first targeted for 2022, indicating that this turbine will soon be available. [xiv] In full commercial deployment, it is expected that multiple turbine OEMs will provide turbines to Allam Cycle Coal facilities. While 8 Rivers does maintain, and will continue to develop, IP around the cycle, including in the combustor and turbine, each turbine vendor will bring their own strengths and IP base to their offering. Having provided the demonstration facility turbine, Toshiba will be able to apply gained knowledge to the larger, commercial scale turbine, taking into account the differences due to fuel changes. In this pre-FEED study, Siemens will provide the turbine design based on the Allam Cycle coal system conditions.
- 50 MWt syngas combustor.
    - Pilot-scale testing of the 5-MWth natural gas-fired combustor was completed in 2015. Data from this program were used to design the 50-MWth-scale unit at NET Power's pilot facility in La Porte, Texas. In July of 2018, NET Power successfully completed the combustion testing phase of the test program. At that time, major equipment had been operated between 500 and 900 hours, and over 170 hours of testing with fuel in the system was completed, with individual test runs lasting over 24 hours. Findings from this program will be applied to the syngas combustor.
    - Demonstration of the syngas combustor is the only key piece of equipment that needs further demonstration beyond the NET Power effort. Siemens has extensive syngas combustion experience including co-fired syngas/natural gas.
    - Successful testing of a commercial scale syngas combustor will allow rapid commercial deployment of the ca. 50 MWth "can-type" combustor scale or larger silo type combustor required by the commercial-scale Allam Cycle combustion turbine. Controllability of this system, including start-up, shutdown, and transient operation, also needs to be demonstrated. 8 Rivers is pursuing funding to run a syngas combustor test. If this is funded as part of the Critical Components FOA, we anticipate a 2 year test duration finishing.

Table 4 - Summary of Allam Cycle Coal key issues and suggested mitigations

Development Pathway for the Coal-Based Allam Cycle	Lab- or Small Pilot-Scale Validation
Materials selection. The materials utilized in the core Allam Cycle power island must be able to withstand the additional corrosion risks presented by the introduction of coal-derived impurities that are able to bypass the gasification island and enter the process stream with the syngas fuel.	Three sets of static corrosion tests (1000–2000 hr each) were completed in 2016. Six different materials which can be potentially used in the coal Allam Cycle were tested at 30 bar, 50°– 90°C in the gas mixture, mimicking the chemistry of the flue gas in the coal Allam Cycle (Lu et al., 2016). These tests showed that standard stainless steel materials could survive the expected conditions of the Allam Cycle. A 1500-hr dynamic corrosion test was completed in mid-2017. Six alloy coupons were tested at 30 bar, 50°–750°C, in the gas mixture mimicking the chemistry of the flue gas in the coal Allam Cycle. Analysis of those materials indicated adequate lifetimes for materials in the recuperator. A 1500-hr, 300-bar corrosion test was completed at the end of 2017. The test mimicked the corrosion of the oxidant stream in the coal Allam Cycle at 300 bar, from 50° to 750°. None of the alloys were rejected for use in a sCO_2 system under these conditions. It is expected that the alloys will have typical lifetimes for use in these environments and under these conditions.
Impurity management. As a semi-closed supercritical CO_2 Brayton Cycle, impurities introduced into the system must be actively controlled in order to prevent their concentration in the process stream which would impact material corrosion rates. For the coal Allam Cycle, impurity management will consist of bulk, pre-combustion removal (prior to introduction into the core Allam Cycle) and post-combustion, maintenance removal to prevent elevated concentrations in the recycled gas stream.	Pre-combustion removal of coal-derived impurities is a well-proven process with commercially available technologies able to achieve the required performance (e.g. Selexol, Sulfinol [monodiethanolamine], Rectisol, etc.) A parametric laboratory-scale study was conducted in 2017 of the post-combustion DeSNOx process, which consists of a simple water wash column to treat the combusted syngas and recirculated CO_2. Under coal Allam Cycle conditions typical of precombustion impurity removal, approximately 99% SO_2 removal and 50% NOx removal is expected with the DeSNOx process. Additional process strategies could be considered to increase the NOx removal. However, the combination of Sulfinol pre-combustion removal and DeSNOx post-combustion cleanup were identified as adequate to maintain the required process conditions.

Syngas combustion. A combustor is required to utilize coal-derived syngas produced by the gasification island. The design of this component represents a modification of the natural gas-fired combustor able to utilize the lower Btu content of coal-derived syngas.	The natural gas development program has informed the design of the syngas-fired unit. Computational fluid dynamics (CFD) modeling of this design was performed as part of a U.S. Department of Energy (DOE)-funded program in 2016, which showed that only slight modifications to combustor geometry were required to match the combustor outlet conditions of the natural gas unit. Pilot-scale testing of the 5-MWth natural gas-fired combustor was completed in 2015. Data from this program were used to design the 50-MWth-scale unit at NET Power's pilot facility in La Porte, Texas. In July of 2018, NET Power successfully completed the combustion testing phase of the test program. At that time, major equipment had been operated between 500 and 900 hours, and over 170 hours of testing with fuel in the system was completed, with individual test runs lasting over 24 hours. Findings from this program will be applied to the syngas combustor. Shock tube testing of syngas combustion at the conditions required in the Allam Cycle was conducted in 2017 and was used to further validate modeling parameters, especially for the calibration of the supercritical CO_2 oxy-syngas combustion reaction kinetics.

Table 5 – Remaining AC Coal Key Risks Required to Be Mitigated

Remaining Challenges	Risk Mitigation
Materials selection. Selected materials must be shown to provide necessary lifetimes of both piping and equipment.	Materials have been shown to demonstrate sufficient survival at simulated conditions in the lab to mimic the coal Allam Cycle conditions. However, operation in actual conditions is necessary to inform estimates of lifetime to achieve the necessary assurances and maintenance cost estimates for a full-scale commercial demonstration. Furthermore, estimates of lifetimes of equipment utilizing these materials is required in the actual environment.
Syngas combustion. Combustor must be shown to operate with syngas, which has a lower heating value and higher flame speed relative to natural gas. Controllability must also be demonstrated.	Successful testing of a 20 MWth syngas combustor will allow rapid scale-up to the ca. 50 MWth "can-type" combustor, or larger scale silo combustors required by the commercial-scale Allam Cycle combustion turbine. Controllability of this system, including start-up, shutdown, and transient operation, also needs to be demonstrated. 8 Rivers is pursuing funding to run a syngas combustor test. If this is funded as part of the Critical Components FOA, we anticipate a 2-year test duration finishing in 2022.
Combustor/turbine. Issues specific to the combustion turbine process.	Areas of technical risk initially identified include seal buffering and leakage, high Reynolds Number gas path and cooling flow behaviour, combustion testing and development plus corrosion behaviour. This list is not all-inclusive but indicative of developing trends. Should the design go forward a full Systematic Integrity Risk Analysis assessment would be performed at the start of the project. This assessment would be used to plan design tasks intended to retire or mitigate identified risks.

Brief description of each process block

Syngas Compressor: The syngas fed from the syngas conditioning, metering and filtering skid is compressed to above 330 bar in the gas compressor before entering the combustor. A single motor driven reciprocating compressor shall be provided. The discharge pressure accounts for the all relevant pressure drop between the compressor and the inlet connection to the combustor. The syngas entering the compressor (supplied from syngas skid) is assumed to be of adequate cleanliness such that there is no damage to the compressor.

O_2-CO_2 Pump: The O_2 required for combustion is delivered from ASU at 110 bar and diluted with recycled CO_2 leaving the CO_2 compressor. The composition will be around 20% mass O_2 and 80% mass CO_2. The oxidant is compressed to over 330 bar in the pump before entering the combustor. The discharge pressure accounts for the all relevant pressure drop between the pump and the inlet connection to the combustor.

Combustor System: The design philosophy of the syngas combustor is its being capable of using a range of fuels without any hardware changes. By adjusting the fuel mix to dilution CO_2 ratios for each fuel, adiabatic flame temperatures were maintained at the desired 1980°C (3600°F) and combustor exit temperatures remained close to 1150°C (2100°F).

The design allows for the use of a very stable diffusion flame injector. The swirl-stabilized diffusion flame permits a wide range of stable operating conditions from ambient start-up to 300 bar at design point pressures and temperatures. Additionally, the inlet temperature of the oxidizer and diluent is above fuel auto-ignition levels, which contributes to flame stabilization. The flame zone is near the fuel injector and combustion occurs as oxidizer and fuel mix near the front of burner.

Carbon dioxide has a high heat capacity, which means it is a suitable fluid medium for heat transfer. This thermos-physical property makes it ideal to cool the combustor liner walls. However, there are limitations on the amount of heat that the CO_2 can remove from the liner. To satisfy liner material limitations, a ceramic thermal barrier coating will be plasma sprayed to the hot side walls (inside) of the combustion liner.

Turbine-Expander: Conceptual geometry of the turbine expander was developed. The current preliminary concept is a single-flow design and has 10 stages of which the first three are cooled. Inlet annulus diameter is estimated to be 700 mm with a blade radial height of approximately 140 mm based on a preliminary analysis. The design is expected to be a hybrid of state of the art steam turbine pressures combined with D or E-Class gas turbine inlet temperatures. Initial analysis indicates the cooled rows would incorporate convectively cooled internal cavities. The high Reynolds numbers that are a consequence of the high molecular weight gas composition would require development of new cooling correlations. Siemens would make use of the Siemens Energy Center facility located on the campus of the University of Central Florida to perform these experiments. Rig hardware procured under a previous DOE contract and donated to the university by DOE would be used to maximize cost-effectiveness.

Main CO_2 Compressor: One 100% centrifugal compressor shall be provided to elevate the re-circulating stream of CO_2 to a pressure of about 60-70 bar. This allows CO_2 to achieve a dense phase after being cooled in a stainless-steel plate-fin cooler to a temperature of about 13°C (achievable as a result of the ambient conditions used in this study) before entering the CO_2 pump.

At this discharge pressure and temperature, the CO_2 density approaches a value of 50 lb/ft^3 which is adequate for CO_2 pump suction. There will be no danger of cavitation when the discharge pressure is combined with cooling conditions prevailing during peak ambient temperatures. The discharge pressure accounts for the all relevant pressure drop between the main CO_2 compressor and the inlet connection of the CO_2 pump.

The main CO_2 compressor shall be designed in accordance with the appropriate vendor standards. The compressor set will be provided with inter-coolers (as required)

CO_2 Pump: A centrifugal pump shall be provided to increase the pressure of the CO_2 to higher than 330 bar before entering the combustor after being heated to close to turbine exhaust temperature in the main heat exchanger. The discharge pressure accounts for the all relevant pressure drop between the compressor and the inlet connection to the combustor.

Heat Exchanger: One high pressure, counter flow heat exchanger train with two sub-sections is provided to cool the turbine exhaust stream while heating the high-pressure CO_2 recycle stream that flows into the combustor, and O_2-CO_2 stream.

Materials for lower temperature section of the heat exchanger and associated piping will withstand slightly acidic and corrosive environments. Appropriate instrumentation for all interconnecting piping indicating inlet and outlet conditions, with respect to temperature and pressure will be provided, with vendor providing appropriate interfaces for the required instrumentation.

All required interconnection between the two heat exchanger sub sections will be included as part of vendor's scope of supply. End connections shall be suitable for welding to adjacent pipes and equipment.

Water Separator: The turbine exhaust stream leaving the heat exchanger is directed to a water separator, which cools process fluid to the ambient temperature and remove any residual combustion-derived water in the process fluid. In the water separator, CO_2 process gas at approximately 30 bar and low temperature (60–90°C) comes in direct contact with sub-cooled combustion derived water. The liquid combustion derived water as well as any soluble trace species, such as SOx and NOx, are removed from the gaseous CO_2 stream, the CO_2 process stream leaving the water separator, which is free of liquid water and at ambient temperature, is directed to the main CO_2 compressor.

ASU: The ASU is required to supply 1,506 tpd of oxygen to the gasifier, 27 tpd of oxygen to the oxy-Claus unit and 2,879 tpd of oxygen to the Allam Cycle power block. Cryogenic air separation technology is a well-established process, offered by several technology providers with strong expertise in the cryogenic sector, with plants configured to provide pure oxygen, nitrogen or oxygen plus nitrogen in operation in multiple locations across a range of industries. The total oxygen requirement of 4,412 tpd represents a world-scale facility but is within the capacity range of existing facilities; a plant with five (5), 5,250 tpd oxygen, ASU trains was brought on-line in 2017 at Jamnagar, India.

In the ASU, air is filtered, compressed, cooled and dried before being separated through cryogenic distillation in a cold box to produce the oxygen and nitrogen product streams. A fraction of the nitrogen product stream is used for regeneration of the molecular sieve units which dry and remove carbon dioxide from the air before it enters the cold boxes, and also to produce chilled water used to pre-cool the air. Since the ASU is sized on oxygen production, the use of nitrogen for ancillary duties does not result in an increase in the size of the ASU. As well as producing gaseous oxygen, the ASU has been designed to liquefy oxygen, so that a back-up store of liquid oxygen (LOX) can be provided. This LOX storage provides redundancy in the oxygen supply to the plant in the event of an ASU outage, but also allows the operation of the ASU to flex in order to vary the electrical power available for export, thereby taking advantage of variations in power price or to provide grid support functionality. The ASU has also been designed to separate the Argon from the incoming air stream, producing 171 tpd of liquid Argon for selling to the industrial gas market.

Coal Delivery, Storage And Handling: Coal will be delivered to the plant by trucks or conveyor. Raw coal with particle size up to 3 inch will be delivered from the mine to the site. The coal will be stored in Coal Silo to get sufficient operating capacity.

Coal Feed System: Raw coal ~3,111 tpd (with 27% moisture) is delivered to the Coal Silo. The raw coal will be dried to 8-10% moisture using fluidized bed dryer system. This dried coal gets transferred to the coal pulverizer by the weight belt conveyor. The raw coal enters the pulverizer where it is pulverized. The feed is ground to the desired particle size distribution and dried to about 8% for Sub bituminous PRB coal.

The dried coal is drawn from the coal feedstock bins and fed through a pressurization lock hopper system to high pressure discharge feeder using coal lock hoppers which operate in cycles to pressurize the solids in a batch process. There are four main steps in each Coal Lock Hopper cycle: Draining, Depressurization, Filling, and Pressurization. The coal is fed from high pressure feeder in a dense phase mode, with carbon dioxide as transport gas. Total of ~2,500 tpd of dry pulverized coal (8% moisture) is fed to SE gasifier.

Gasifier Island: For this study, a SE entrained flow gasifier was chosen, producing syngas at high pressures and temperatures. SE entrained-flow gasification technology of pulverized coal consists of the units of coal grinding and drying, pulverized coal pressurization and conveying, gasification, scrubbing, slag removal, gray water treatment and gasification utilities, etc. The process flow diagram is as follows:

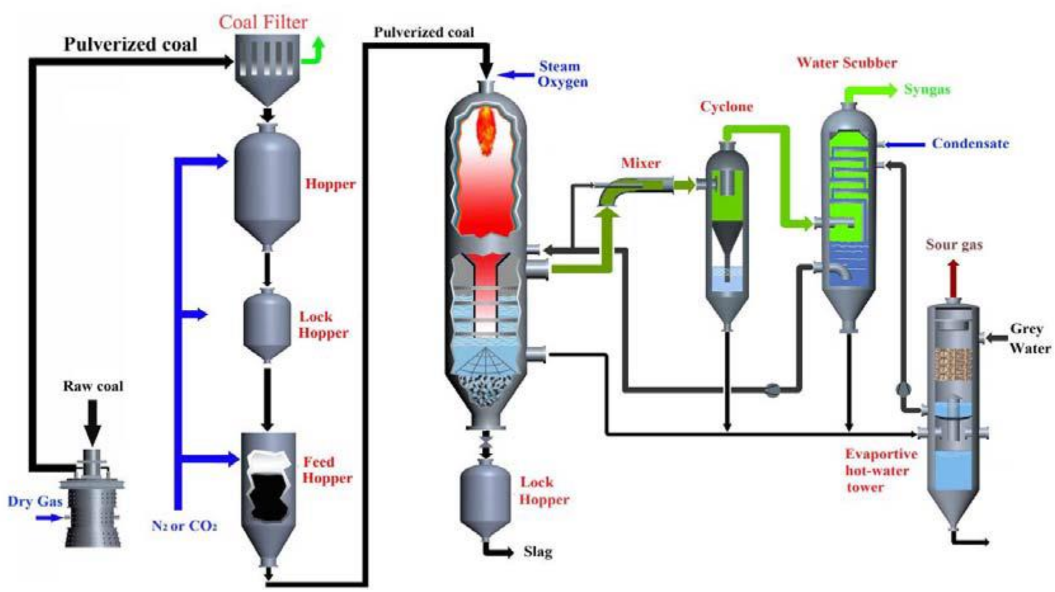

Figure 7 - Gasifier Island Process Flow Diagram

The pulverized coal in the lock hopper is pressurized to feed hopper pressure by carbon dioxide, and is then discharged to the feed hopper. After that, the pulverized coal is pneumatically conveyed to the gasifier to the coal burner positioned at the top of gasifier. The pure oxygen from the ASU and Medium Pressure (MP) steam from the gasification battery limit are also introduced to the coal burner. Gasification reaction takes place at pressure of 40bar, generating crude syngas with main compositions of H_2, CO, and CO_2. The syngas at high temperature (1400 ~ 1600 ºC) after reaction with molten slag, descends downward into the quenching chamber. A large portion of slag after being cooled, will fall into the bottom of quenching chamber. The crude syngas, after quenching and scrubbing by the multi-layer bubble breaking plate in the quenching chamber, leaves the gasifier and enters the mixer, where it is mixed with black water from the bottom of scrubber. The mixture of water/crude syngas leaves the mixer and goes into the cyclone separator to separate liquid and solid. A majority of the fine ash in the crude syngas enters the liquid and is continuously discharged from the bottom of cyclone separator to the evaporative hot-water tower in the black water treatment unit.

Slag Collection and Handling: The solids are removed as both slag and ash. Liquid slag is solidified in a water bath and removed via a lock hopper system. The slag from the lock hopper is transferred to the slag conveyor belt, where it separates from the water and the slag gets carried away to storage for selling (slag is an inert, non-leaching glass-like material, that can potentially be utilized as a construction material) or disposed in waste land fill. Fine ash carried over with the syngas is captured in a venturi and syngas scrubber.

Syngas Scrubber/Black Water Treatment: The crude syngas after separating liquid phase and fine slag goes into a water scrubber, where it is further scrubbed by gray water to remove fine solid particles. The scrubbed crude syngas with ash content less than 1mg/Nm3, leaves the scrubber and enter into a heat exchanger for low grade heat recuperation.

The reaction chamber of the gasifier is lined with a membrane water wall, with saturated hot water at an operating temperature of 271 ºC and operating pressure of 55 barg. The steam/water mixture leaving the water-wall structure will generate saturated steam of 55 barg after steam drum separation. The steam drum saturated water, after being pressurized by the membrane circulating hot water pump, returns to the water wall circulation.
In the slag water treatment unit, the black water generated in the quenching and scrubbing/dedusting units, experiences flash evaporation in the lower part of the evaporative hot-water tower, while the heat contained in the flash gas is recovered by the cycled grey water in the upper part of evaporative hot-water tower.

Mercury Removal: Mercury removal from the syngas stream is achieved using down flow packed beds of solid sorbent. Typically, activated carbon is used for this application, but proprietary adsorbents consisting of a mixture of metal sulphides are also available from some suppliers. The sorbents are not regenerated; spent sorbent is replaced and sent for disposal when the bed becomes saturated, typically on a 2-3 yearly interval.

COS Hydrolysis: Many acid gas removal processes have a low selectivity in the removal of carbonyl sulfide (COS). The use of COS hydrolysis pretreatment in the feed to the acid gas removal (AGR) process converts the COS to more easily capturable H_2S. The COS hydrolysis reaction is equal molar with a slightly exothermic heat of reaction, as shown in the following reaction:

$$COS + H_2O \leftrightarrow CO_2 + H_2S$$

COS hydrolysis is achieved in a fixed-bed catalytic reactor, with activated alumina catalysts typically being employed. Since the reaction is exothermic, higher conversion is achieved at lower temperatures. However, at lower temperatures the reaction kinetics are slower. Although the reaction is exothermic, since the concentration of COS in the syngas is low, the heat of reaction is dissipated among the large amount of non-reacting components and the reaction is essentially isothermal. The product gas typically contains less than 4 ppmv of COS

Acid Gas Removal: Acid gas removal (i.e. H_2S removal) is achieved using a chemical or physical solvent. The syngas is contacted counter-currently in an absorber column against lean solvent, where near-complete H_2S removal (typically together with partial CO_2 removal) is achieved, with 'sweetened' syngas discharged from the top of the column and routed to the Allam Cycle power block. The rich solvent from the bottom of the absorber is transferred to the stripper column, where heat and depressurization are utilized to regenerate the solvent and produce a stream of sour gas that is routed to the LO-CAT sulfur recovery unit.

A range of solvents may be employed in the AGR unit. These include a range of amine-based formulations (for example, based on methyl diethanolamine (MDEA)), along with proprietary solvent processes such as Selexol, Rectisol and Sulfinol. For the purpose of this study it has been assumed that the Sulfinol process is employed. For the Allam Cycle, CO_2 removal from syngas is not required, a simple and low cost amine based sulfur removal can be applied.

Tail Gas Treatment for Sulfur Recovery:

Liquid Redox process can be implemented to treat off gas from AGR unit to recover sulfur. It is based on a reduction-oxidation reaction- that converts H_2S present in sour gas to elemental sulfur through reaction with aqueous ferric ions. Process forms solid sulfur particles that can be easily filtered from the solution. Liquid Redox is commonly used when gas stream has a high content of H_2S, so solid bed technology is not feasible, and in addition low flow rate results in a non-economic application of direct oxidation process (Claus).

The LO-CAT® process by Merichem selected here, is a liquid redox technology that converts H_2S to elemental sulfur in an inherently safe aqueous solution. The elemental sulfur when filtered from the solution is a 60 wt% sulfur "cake", which is safe for transport and can be used as a fertilizer or disposed of in a landfill.

The combined sour gas streams pass through a coalescing filter first to remove any entrained liquids prior to entering the unit. The feed gas is then routed to a liquid full absorber (LFA) where it contacts with a proprietary aqueous solution of chelated iron. H_2S is absorbed into the water and then reacted with the iron to form solid elemental sulfur as follows:

$$H_2S + (H_2O) \rightarrow S^{=} + 2H^{+} + Fe^{+++} \rightarrow S^{o} + Fe^{++} + 2H^{+}$$

The sweet gas exits the LFA and passes through a knock-out pot with water wash to recover any entrained solution prior to entering the fuel gas system. The solution leaving the bottom of the LFA is pumped to the Oxidizer for regeneration. In the Oxidizer, oxygen produced from the ASU is sparged through the solution and the ferrous iron (Fe++) is oxidized to the active ferric state (Fe+++) as follows:

$$\frac{1}{2} O_2 + H_2O + Fe^{++} \rightarrow 2Fe^{+++} + 2OH$$

The air exiting the Oxidizer is routed to a knock-out pot to recover any entrained solution. This stream contains no H_2S so it is routed directly to the atmosphere. Most of the regenerated solution is circulated back to the LFA.

By adding the reactions shown for the LFA and Oxidizer, the overall reaction becomes the direct oxidation of H_2S to elemental sulfur as follows:
$H_2S + ½\ O_2 \rightarrow S^o + H_2O$

This reaction takes place at near ambient conditions in the aqueous phase. This makes the chemistry inherently safer than a fired process such as a modified Claus unit.

Extent and manner of use of other fuels in conjunction with coal

The Allam Cycle is basically gaseous fuel agnostic and can run on a wide range of fuel gas. The combustor is designed to use the most readily available fuel source. As the fuel differs from this, through use of a different coal feedstock, or just simply from variations in the coal, the fuel entering the cycle can be modified through the use of diluent CO_2 or NG. In this manner, key combustion control parameters, such as the Wobbe Index, can be controlled. This allows for variability in the fuel without impact on the operation of the cycle.

Zero Liquid Discharge (ZLD) Unit

The focus of ZLD is to economically process wastewater and produce clean water that is suitable for reuse. Various vendors offers thermal and non-thermal ZLD solutions to manage tough-to-treat wastewaters stream generated from gasification island and other process streams. The waste water and ZLD unit chosen for this project is a two stage reverse osmosis (RO) and evaporator / crystallizer system that can help to recover more than 95% of plant's wastewater while producing the remaining brine as a slurry or solid.

Typical stages involved in ZLD depending on water chemistry are as follows:-

Stage 1 - Caustic Softening – for removing heavy metals and silica from initial feed. Concentrate /softening waste will be discharge as a sludge for disposal, permeate will be sent on to stage 2.

Stage 2 - Membrane Filtration – An RO system will recover 95% of the water as permeate, permeate will be sent to blend tank, and the concentrate will be sent to stage 3;

Stage 3 - Pre-Concentration – A Falling Film MVR Evaporator will concentrate the brine stream just below its saturation point. The distillate will be sent to the blend tank, and the concentrate will be sent to stage 4.

Stage 4 - Salt Crystallization – A forced circulation MVR Crystallizer will super-saturate the brine to a slurry. The salt will be separated from the slurry for disposal, and the liquor will be returned to the crystallizer.

Description of any thermal or energy storage

The Allam Cycle has unique ability to actually provide energy storage services by storing electricity as chemicals, through the Air Separating Unit (ASU) and the gasifier. During low power demand, the plant can be turned down to zero net load while running the ASU and gasifier at full capacity, storing liquid oxygen and syngas for later use. At times of high power demand, the Allam Cycle uses this stored oxygen and syngas or pipeline natural gas to lower the parasitic load a few hours at a time, extra power for sale beyond the 286-MW rating. Potential syngas storage capacity can be included which will enable flexibility for the gasifier during load following. In this Pre-FEED there are O_2 tanks sufficient to store 4 hours of oxygen, giving the plant a 294 MWH storage system, solely for the cost of the tanks. The final sizing of this storage system will be dependent on the specific site and power grid node and pricing and will be determined in the next phase of the study. Additional tanks could extend the hours of storage to >10 hours and > 1,000 MWH total capacity.

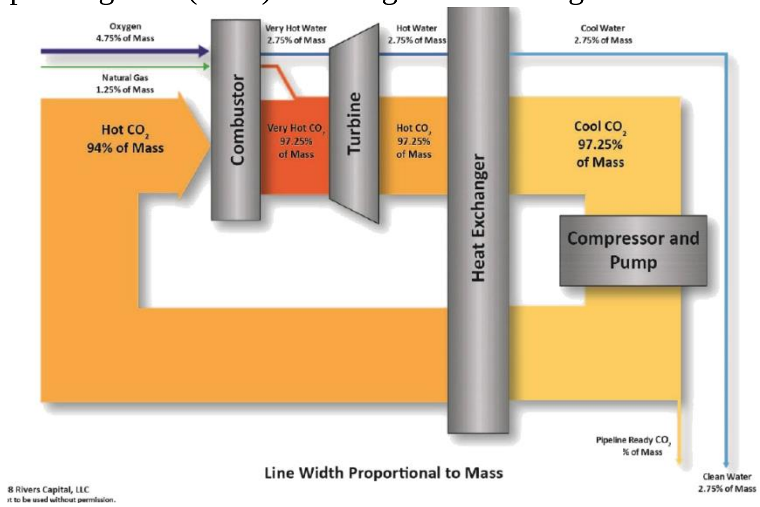

Figure 8 - Simplified Allam Cycle Process

Power system working fluid and process conditions

The Allam Cycle utilizes a recirculating, trans-critical CO_2 working fluid in a high-pressure, low-pressure-ratio, highly-recuperated, semi-closed Brayton cycle. The cycle integrates with the exhaust from a single turbine that has an inlet pressure of approximately 4,350 psia (300 bar) and a pressure ratio of 10. All heat from combustion is recuperated in the cycle, eliminating the need for a bottoming cycle such as a steam Rankine cycle use in conventional combined cycle (CCGT) systems. The cycle is also direct-fired, meaning the combustion turbine is directly integrated into the supercritical CO_2 power cycle. Since CO_2 is used as the primary process fluid in the cycle, combustion-generated CO_2 within the semi-closed cycle is simply cleaned, dried and pressurized along with this primary process CO_2, and exported as high-pressure CO_2 export product, typically at 2175.57psia (150 bar), for sequestration or utilization. This net export CO_2 is approximately 3.25% of the total CO_2 process flow for the natural gas cycle, and 7% of the CO_2 for the coal cycle.

Features that minimize water consumption

As discussed above, Allam Cycle coal can eliminate water consumption with a dry cooling design, and has a reduced water consumption compared to other CCS technologies with a wet cooling design. These major reductions are the result of two primary factors. 1: The elimination of the steam cycle reduces water needed for steam. 2: The semi-closed Allam cycle captures and condenses combustion derived water.

Techniques to reduce design, construction, and commissioning schedules

A range of approaches may be adopted to accelerate project implementation and bring forward entry into service. These include:

Completing as much detailed engineering as possible ahead of the Final Investment Decision

The authorization of some detailed engineering scope ahead of FID allows an acceleration of the EPC program by facilitating earlier placement of orders for long-lead equipment items and special material procurement as soon as the design parameters have been fixed. While the detailed engineering is performed ‘at risk’, the fee associated with the early engineering is modest in the context of the overall project. As opposed to conventional NGCC, there is very little impact from the environment on the design and operation of the AC coal facility. This will provide for modularization which will decrease the engineering, construction, and commissioning schedules for further plants.

Early order placement for long lead items

From the above early engineering, it is possible to bring forward the placement of equipment orders. However, it is likely that the delivery of long-lead items will still lie on the critical path of the project. To further accelerate the program, it is possible to place orders for the longest lead items at risk ahead of FID, such as the syngas valve, based on Siemens’ experience in the previous IGCC project. A significantly greater value will be committed at risk ahead of FID through this approach, so it should only be adopted when entry into service is extremely time critical.

Standardization of design / procurement of ‘off the shelf’ where possible

Adopting standard design can reduce the timescale for engineering design and potentially reduce the delivery timescale and equipment costs from suppliers. While the plant design may not be fully optimized, reduced performance may be accepted if this is outweighed by schedule and EPC cost benefits. For the 2nd and subsequent plants, adopting a ‘cookie cutter’ design, replicating the first plant, can significantly reduce engineering and procurement time and costs, with lessons learnt in the commissioning of the first plant also reducing commissioning schedules for subsequent facilities.

Multiple parallel units rather than one large unit

Adopting multiple parallel trains does add to overall complexity, piping runs, number of instruments, valves, etc. However, it does reduce the size of individual equipment items and packages. This has the benefits of potentially widening the number of potential suppliers, accelerating construction/fabrication, making transportation from fabricator to site easier and quicker and facilitating more modularization/off-site construction (see below). A cost benefit analysis would need to be completed based on site specific operating conditions for design optimization. The benefits of multiple stream operation, particularly implementation of an N+1 redundancy philosophy, also carries through to the operational phase in terms of increased overall plant availability.

Modularization/Off-site Construction

Minimizing site work can accelerate construction programs by reducing the potential for scheduling conflicts and weather-related delay, especially where the site is in a challenging location. Modular packages and sub-assemblies can be fabricated off-site, in parallel in multiple fabrication yards in potentially more benign environmental conditions and closer to suppliers and skilled labor. They are then delivered to site and installed directly to prepared civil foundations with consequent time savings.

Use of a dynamic simulator for operator training

Conventionally, operator training will commence on the plant during the commissioning phase. However, by developing a dynamic plant simulator, this can be used as a training package for the plant operations team at an earlier stage, ahead of the plant being commissioned. This facilitates an earlier entry into service and reduces the potential for plant trips during early operation since the operators will already be fully up to speed. Provided the Plant Model is sufficiently accurate it can also be used to verify changes to the Integrated Plant Control System (IPCS) prior to the systems coming on-line.

Smart scheduling of construction activities to minimize the potential for weather disruption

Where a plant is located at a site with a challenging climate (e.g. severe winters or tropical storm risk in summer) then key construction activities can be scheduled for those periods of the year when the weather is most benign. For example, major crane operations should be scheduled for those seasons when high winds are least likely to cause disruption and delay.

Gain-share contracting strategies

With a conventional EPC or EPCm contract, there may be no advantage for the contractor to complete the EPC program and hand over the plant ahead of the agreed contractual date. However, by adopting a gain-share approach, there is a financial incentive to encourage early completion and the contractor is more likely to focus on schedule acceleration. It should be noted that acceleration must not be detrimental to safety and/or quality.

Global procurement strategy

By broadening the range of potential suppliers, shorter delivery times may be achievable for critical long-lead equipment items. Also, splitting orders between suppliers facilitates in parallel rather than sequential fabrication, again reduces delivery schedules.

Rigorous Factory Acceptance Tests

Devoting adequate time and effort to the completion of Factory Acceptance Tests increases surety that equipment will be fit for purpose, with any problems identified and rectified prior to the equipment being delivered to site. This will minimize on-site commissioning problems and reduce the commissioning schedule

DESIGN BASIS

Site Characteristics and Ambient Conditions:

The design will be tailored to the North Antelope Rochelle Mine (NARM) site. The NARM site characteristics were shown previously in Table 2, and the Make-Up water quality assumptions are shown below.

Table 6 - NETL QGESS Make-Up Water Quality[xvi]

Parameter	Ground Water (Range)	POTW Water (Range)	Makeup Water (Design Basis)
pH	6.6–7.9	7.1–8.0	7.4
Specific Conductance, µS/cm	1,096–1,484	1,150–1,629	1312
Turbidity, NTU		<50	<50
Total Dissolved Solids, ppm			906
M-Alkalinity as $CaCO_3$, ppm[a]	200–325	184–596	278
Sodium as Na, ppm	102–150	172–336	168
Chloride as Cl, ppm	73–100	205–275	157
Sulfate as SO	100–292	73–122	153
Calcium as Ca, ppm	106–160	71–117	106
Magnesium as Mg, ppm	39–75	19–33	40
Potassium as K, ppm	15–41	11–21	18
Silica as SiO	5–12	21–26	16
Nitrate as N, ppm	0.1–0.8	18–34	12
Total Phosphate as PO	0.1–0.2	1.3–6.1	1.6
Strontium as Sr, ppm	2.48–2.97	0.319–0.415	1.5
Fluoride as F, ppm	0.5–1.21	0.5–0.9	0.8
Boron as B, ppm	0.7–0.77		0.37
Iron as Fe, ppm	0.099–0.629	0.1	0.249
Barium as Ba, ppm	0.011–0.52	0.092–0.248	0.169
Aluminum as Al, ppm	0.068–0.1	0.1–0.107	0.098
Selenium as Se, ppm	0.02–0.15	0.0008	0.043
Lead as Pb, ppm	0.002–0.1		0.026
Arsenic as As, ppm	0.005–0.08		0.023
Copper as Cu, ppm	0.004–0.03	0.012–0.055	0.018
Nickel as Ni, ppm	0.02–0.05		0.018
Manganese as Mn, ppm	0.007–0.015	0.005–0.016	0.009
Zinc as Zn, ppm	0.005–0.024		0.009
Chromium as Cr, ppm	0.01–0.02		0.008
Cadmium as Cd, ppm	0.002–0.02		0.006
Silver as Ag, ppm	0.002–0.02		0.006
Mercury as Hg, ppm	0.0002–0.001		3E-04

Fuel type and composition:

The system will be designed on the PRB Coal from the NARM. The composition of the fuel has been removed from the public report.

Flexible plant performance targets

The flexibility of Allam Cycle Coal is projected to at least be in-line with NGCC, with the potential to exceed that performance. Flexible performance targets to match and exceed are:

- The current ramp rate assumes that we are targeting an ability to provide 30 MW - 45 MW of load increase or decrease each minute during warm operation.
- Cold Start Up to reach full load in less than 4 hours assuming that pre-heating systems have been adequately sized to operate during the ramping period. This is subject to confirmation in detailed design.

- Turn Down: Zero net load to the grid, enabling low-load operation and rapid dispatch.
- Energy Storage: 294 MWH of energy storage capacity were built into this design via oxygen buffering, with the ability to increase to >1200 MWH of storage capacity in detailed design stage if desirable. This increase can be achieved with additional capacity from syngas storage or from additional O_2 tanks to add storage duration.
- Peaking: Peak from 286MW up to approximately 325 MW using stored oxygen and assuming an ASU turndown of 50%.

AC Coal is still expected in its initial deployments to run at >80% capacity factors, due to the higher capital costs of initial plants, and the byproduct revenues which allow for marginal bids close to $0 / MWH, allowing for the plant to run like baseload even with low power prices.

Water requirements

Allam Cycle coal would provide water savings as compared to conventional thermal technologies. With the dry cooling, there is no requirement for raw water withdrawal, since all process waste water is of suitable quality to be recycled in the syngas scrubber or it is suitably treated within the RO or ZLD to be reused elsewhere within the plant. In the dry cooling design, the plant is actually a net water producer with raw water production being approximately 1.16 gpm/MWe. For the wet cooling design, the raw water consumption is 4.3 gpm/MWe, which is less than the typical water consumption in the IGCC/CCS systems in DOE reference reports. The major reductions for water usage are the result of two primary factors. 1: The elimination of the steam cycle reduces water needed for steam. 2: The semi-closed Allam cycle captures and condenses combustion derived water. Inclusion of RO and ZLD process waste water treatment means that there is no process water discharge at the plant battery limits.

Based on the DOE NETL report (Cost and Performance Baseline for Fossil Energy Plant Volume 1: Revision 3, 2015), the raw water withdrawal for NGCC without carbon capture is 4.2 gpm/MW_{net}, and the raw water consumption is 3.3 gpm/MW_{net}, and carbon capture coal systems have 5.5-7.4 gpm/MW_{net} water consumption.

System size basis

The proposed Allam Cycle coal plant is designed to have cleaned syngas fed into the Allam Cycle power island. The table below shows the plant's net and gross capacity with the Wyoming subbituminous coal chosen for the Pre-FEED study. The system efficiency and auxiliary load with selected site and Wyoming coal was updated with vendors' input in the Pre-FEED study.

Coal thermal input (MW in LHV)	676
Gross generator output (MW)	468.15
ASU load (MW)	-74.19
Total compression/pumping load in the Allam Cycle (MW)	-92.51
Gasification Island utility (MW)	-5.23
Cooling tower (MW)	-4.35
CO_2 Purification Unit (MW)	-1.57
Miscellaneous BOP (MW)	-1.83
Transformer Losses (MW)	-2.88

Net power output (MW)	285.6
Net efficiency (% LHV)	42.25%
Net efficiency (% HHV)	40.02%

Table 7 - Allam Cycle Efficiency With PRB Coal updated during Pre-FEED

Environmental targets

Allam Cycle Coal is a near zero emissions coal facility, with the associated environmental targets from the system shown below:

- >93% CO_2 capture at 150 bar
- Zero liquid discharge: Recovery of >95% of plant's wastewater and production of the remaining brine as a product or a solid.
- Since there is no combustion exhaust stack, we have nothing to emit to the air. All the combustion derived species are captured either in gas phase or liquid phase.
- >99% SOx removal
- >99% NOx removal. Coal derived nitrogen is the only nitrogen source entering the cycle, so NOx formation in the first place is low
- Mercury and heavy metal are removed from syngas in the gasifier island

Projected plant capacity factor

Due to the by-product revenues from CO_2 and Argon, this Allam Cycle Coal plant is expected to be dispatched right after solar and wind, given its near zero marginal cost of production given those revenues. Its projected capacity factor in Wyoming is thus expected to be limited solely by its availability, rather than by market conditions. We conservatively project a capacity factor of 85%, with the potential for higher availability and capacity factors to further boost the economics of the facility.

PERFORMANCE RESULTS

Aspen Plus was used for the process modeling of the coal based Allam Cycle system. The model is a combination of proprietary models and know-how developed by 8 Rivers during the invention, optimization, and demonstration of the NET Power demonstration plant. When available, vendor provided information was incorporated into the model. In some cases, vendors provided detailed information. In other cases, the vendor supplied equipment has to be "black-boxed" inside of Aspen Plus. A process block flow diagram is presented below. The data for the numbered streams is provided in the below tables.

Aspen 11.0 was used for the process modeling of the coal based Allam Cycle. RK-SOAVE and Peng-Robinson were used as the Equation of State. Peng-Robinson was used to simulate the process at the conditions close to the critical point of CO_2. Vendor data were used for the simulation of each sub-process in the system, which includes ASU, coal milling, coal drying, coal gasification process with quench and scrubbing system, Acid Gas Removal, Sulfur recovery, and the entire Allam Cycle power island. The vendor data includes heat and mass balance of the entire coal gasification system, inlet/outlet conditions as well as utility consumption for each process, turbomachinery efficiency, heat exchanger minimum temperature approach and detailed combustor/turbine design conditions and efficiency. 3% motor driven mechanical loss were considered.

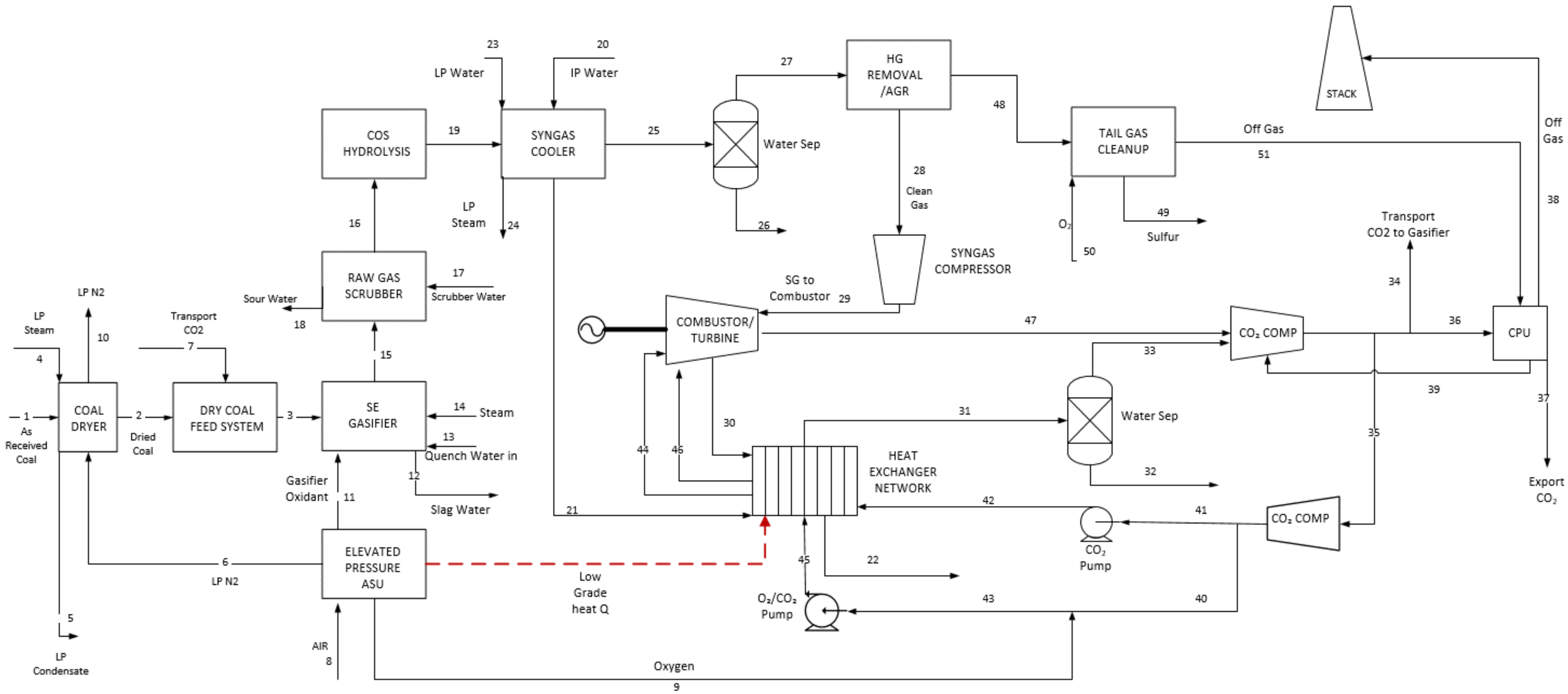

Figure 9 – Process Block Flow Diagram

Plant performance results

The overall performance of the plant is summarized in

Table 8, which includes auxiliary power requirements. The ASU accounts for approximately 41% of the auxiliary load, with a further 52% of the auxiliary load being consumed by the motor driven pumps and compressors specific to the power island and the Allam Cycle process. Motor efficiencies are included in efficiency calculations for the rotating machinery. Some gasifier auxiliaries are separated out and listed individually, as are the transformer losses.

Coal Thermal Input (MW in HHV)	**713.6**
Coal Thermal Input (MW in LHV)	**676**
Gross Turbine Shaft Power Output (MWe)	**472.88**
Gross Generator Power output (MWe)	**468.15**
Auxiliary Load (MWe)	
Coal Handling and Crushing	1.27
Coal Drying	0.41
Air Separation Unit	74.19
Grey Water Pump	0.99
Waste Water Pump	0.51
Quench Water Pump	0.19
Filter Vacuum Pump	0.26
Gasifier Auxiliaries	0.59
Acid Gas Removal	0.37
Sulfur Recovery	0.34
Zero Liquid Discharge	0.30
Cooling Tower Pump	1.13
Cooling Tower Fan	3.22
Syngas Compressor	18.45
CO_2 Compressor	38.13
CO_2 Pump	28.14
Oxidant Pump	7.79
CO_2 Purification Unit	1.57
Miscellaneous Power Island	0.83
Miscellaneous Balance of Plant	1.00
Total Auxiliary Load (MWe)	**179.68**
Transformer loss (1% of power output)	2.88
Net Power Output (MWe)	**285.6**
Net Plant Efficiency, % (HHV)	**40.02%**
Net Plant Efficiency, % (LHV)	**42.25%**

Table 8 - Plant Performance Summary

Carbon balance

The carbon balance for the plant is shown in Table 9. The carbon input to the plant consists only of carbon from the coal. The ASU rejects the CO_2 in the air as part of the input stream treatment, since this is immediately returned to the environment, it is not accounted for in the carbon balance. Carbon in the plant leaves as unburned carbon in the slag, in the CO_2 outlet stream from the plant, acid gas vented from black water/ZLD system, and the off gas from the CO_2 purification unit.

Carbon In (kg/hr)		Carbon Out (kg/hr)	
Coal	63,852	Stack (stream 38)	3819.0
		CO_2 Product (stream 37)	58,999.8
		Slag	1033
		Acid Gas	0.8
Total	**63,852**		**63,852**

Table 9 - Plant carbon balance

Sulfur Balance

Table 10 shows the sulfur balance for the plant. The sulfur input comes solely from the sulfur in the coal feedstock. The main output is elemental sulfur from the sulfur recovery unit. There is also sulfur leaving the system as sulfuric acid from turbine exhaust condensate and being neutralized in the ZLD.

Sulfur In (kg/hr)		Sulfur Out (kg/hr)	
Coal	236	Sulfur to ZLD	0.77
	0	Solid S	235.23
Total	**236**		**236**

Table 10 - Plant sulfur balance

Water Balance

In this pre-FEED study, a mechanical draft hybrid cooling tower is used to provide the cooling and a reverse osmosis (RO) unit and zero liquid discharge (ZLD) system is used for process water treatment to allow water to be reused within the plant. The water balance calculation is performed for both wet cooling design and dry cooling design. A wet cooling design water balance schematic has been included in Figure 10 and an overall plant water balance has been shown in Table 11. A dry cooling design water balance schematic has been included in Figure 11 and an overall plant water balance has been shown in Table 12.

With the dry cooling, there is no requirement for raw water withdrawal, since all process waste water is of suitable quality to be recycled in the syngas scrubber or it is suitably treated within the RO or ZLD to be reused elsewhere within the plant. In the dry cooling design, the plant is actually a net water production, with raw water production being approximately 1.16 gpm/MWe.

For the wet cooling design, the raw water consumption is 4.3 gpm/MWe, which is less than the typical water consumption in the IGCC/CCS systems in DOE reference reports. The major reductions for water usage are the result of two primary factors. 1: The elimination of the steam cycle reduces water needed for steam. 2: The semi-closed Allam cycle captures and condenses combustion derived water.

Inclusion of RO and ZLD process waste water treatment means that there is no process water discharge at the plant battery limits.

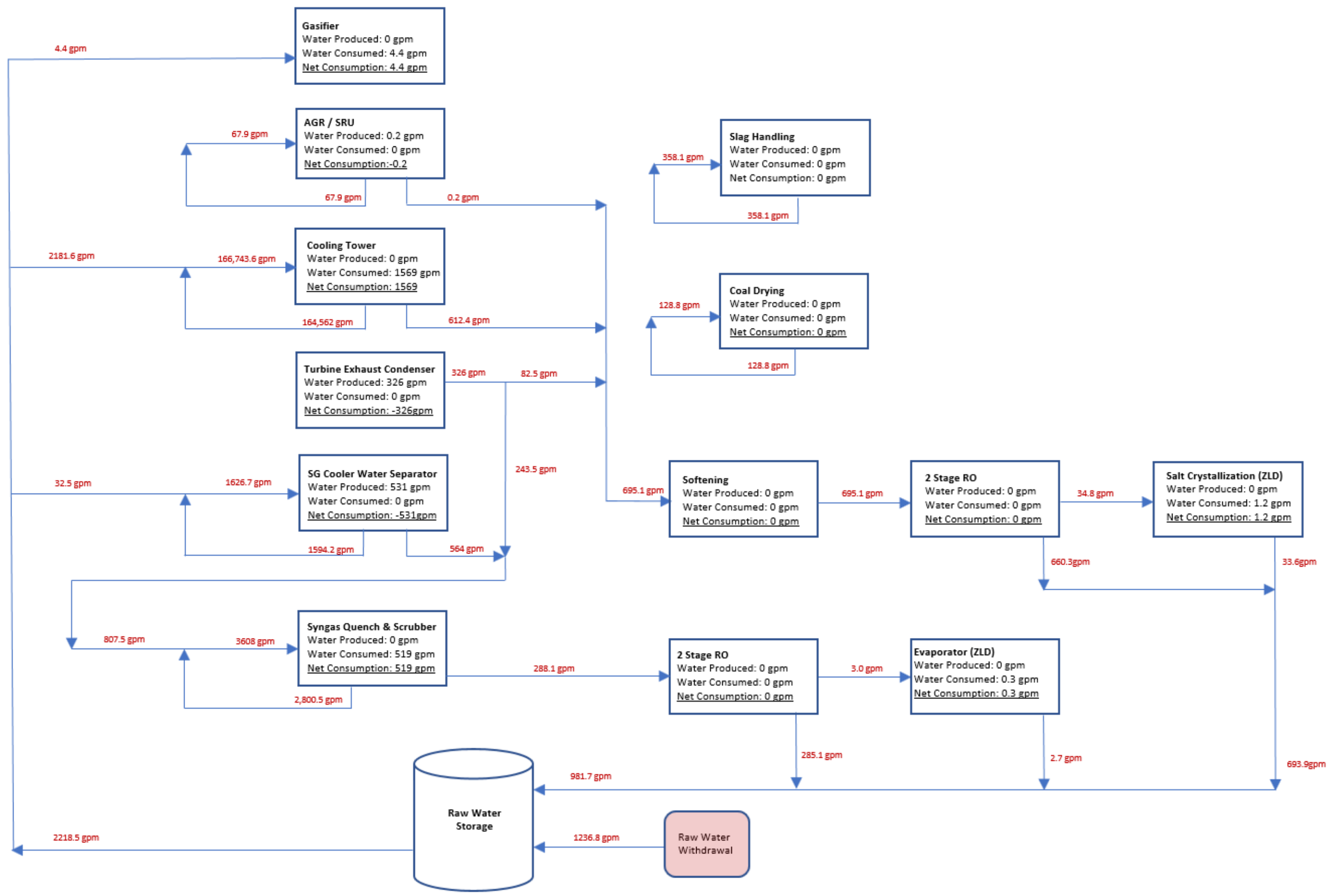

Figure 10- Wet Cooling Water Balance Schematic

Wet Cooling Water Use	Water Demand	Internal Recycle [1]	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Overall Balance	172537.5	171300.7	1236.8	0	1236.8

[1] *Internal Recycle is plant internal recycle and includes internal recycle within components, recycle of process waste water into the syngas scrubber and discharge from the 2 stage RO and ZLD.*

Table 11 – Overall Plant Water balance - Wet cooling operation

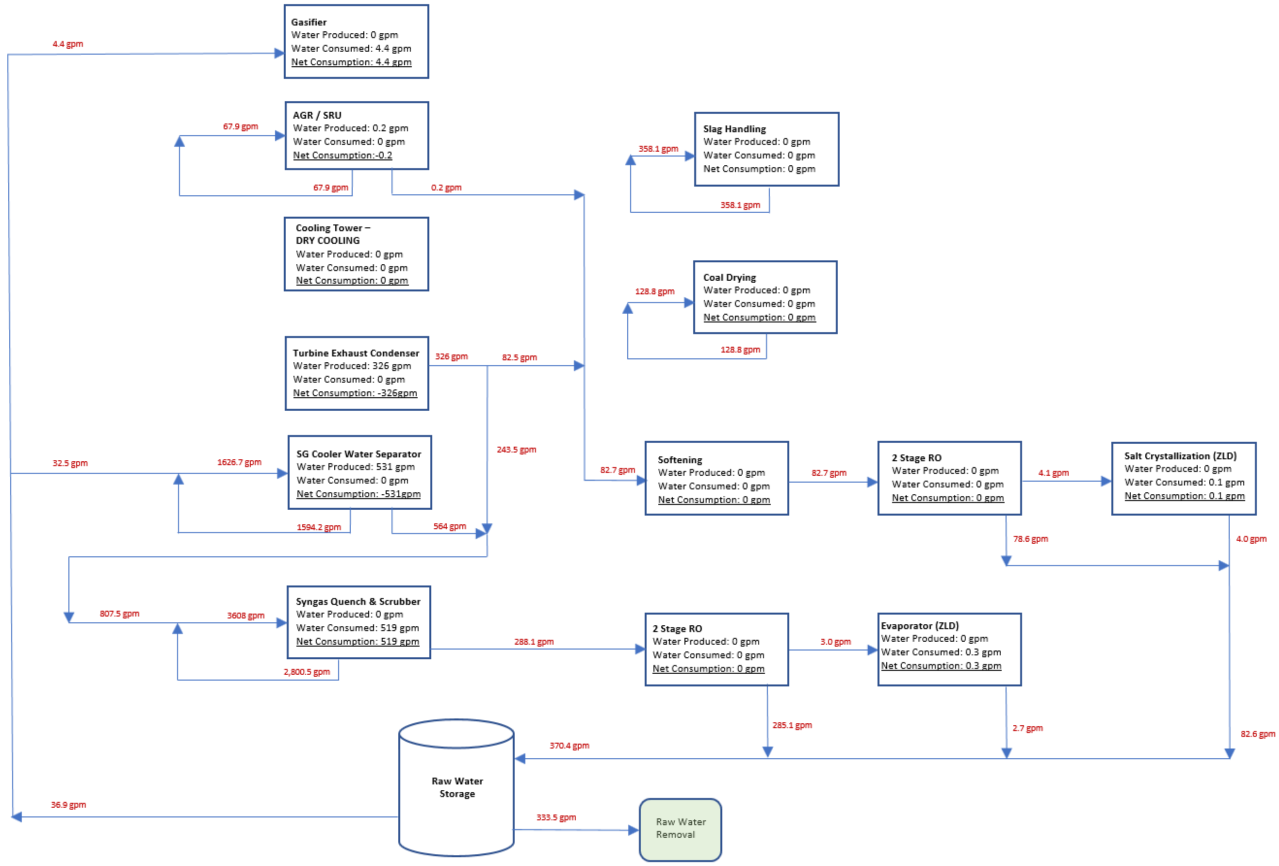

Figure 11- Dry Cooling Water Balance Schematic

Dry Cooling Water Use	Water Demand	Internal Recycle [1]	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Overall Balance	5793.9	6127.4	-333.5	0	-333.5

[1] *Internal Recycle is plant internal recycle and includes internal recycle within components, recycle of process waste water into the syngas scrubber and discharge from the 2 stage RO and ZLD.*

Table 12 – Overall Plant Water balance - Dry cooling operation

Plant Emissions

The low level of SO_2 emissions is achieved by capturing the sulfur in the gas by the AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 2 ppmv. The tail gas from AGR goes to tail gas treatment unit where using liquid redox, all of the sulfur gets converted into elemental form. The other source of SO_2 will be from sour acid gas vented from black water treatment on continuous basis.

NOx emissions are negligible as we are using 99.5% pure oxygen going to gasifier, combustor and tail gas treatment unit. N_2 from the fuel which makes it into the system is converted to NOx in the combustor and removed as HNO_3 in the water separator.

Particulate discharge to the atmosphere is extremely low values by the use of a total quench gasifier, cyclone separator with in addition to the syngas scrubber with venturi and the gas washing effect of the AGR absorber. The particulate emissions are negligible from gasifier. The other particulates emitted will be from coal handling and dry coal feed preparation and delivery systems

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds. CO_2 emissions represent the uncontrolled discharge from the process.

Steady State Emissions

The steady state emissions are shown below.

	kg/GJ[C]	lb/MMBtu[C]	Tonne/year	ton/year	kg/MWh [B]	lb/MWh [B]
SO_2	0.00316	0.00736	57.670	63.552	0.0165	0.0365
NOx	n/a	n/a	n/a	n/a	n/a	n/a
Particulate[D]	0.0005	0.0012	9.515	-10.48	0.0027	0.006
Hg	9.22E-11	2.14E-10	0.002	0.002	4.82E-10	1.06E-09
HCl	n/a	n/a	n/a	n/a	n/a	n/a
CO_2	5.72	13.31	104,310	114,949	29.92	65.95

A – Calculations based on 85% capacity factor
B – Emissions based on gross generator output power, except where noted
C – Heating value based on LHV
D- particulates not captured by bag filters

Table 13- Steady-state plant emissions

Start-Up Emissions

According to the gasifier vendor, 2 start-ups per year are considered while utilizing a lower coal feed rate. The start-up will last for 2 hrs, during which all the syngas generated will be flared downstream of syngas scrubber. Alternate locations for the vent, including the possibility of taking the gas into the power cycle, will be determined and investigated during the FEED stage. Table 14 provides emissions expected during these two gasifier starts.

	tonne/year	ton/year
SOx	0.371	0.408
NOx	n/a	n/a
Particulate	n/a	n/a

Hg	1.80749E-05	1.99E-05
HCl	n/a	n/a
CO_2	254	280

Table 14 - Start-Up Emissions

Open Loop Fluidized Bed Dryer With No Water Recovery

Wet coal is conveyed to feed distribution screw conveyor that discharges the feed material to feed rotary air locks. The introduced feed is allowed simply to fall by gravity into the area of the feed zone where it can back-mix with dry material before migrating in the main drying area. Inert gas nitrogen is used as a fluidizing and drying media for this dryer.

LP Nitrogen from ASU unit is directed to supply fan which is intended to increases static pressure of nitrogen to use in the system. This nitrogen is heated to 146°C by LP steam. This LP steam (~5 bar) is generated by syngas cooler block, which is used to heat the LP N_2.

Fluidization and direct contact drying of the coal is accomplished via inert fluidizing heated nitrogen gas stream. The fluidic behavior of the material itself, volumetric displacement of the fluidized material within the unit due to additional material feed and the inclusion of a special, directional-flow gas distribution plate create conditions within the fluid bed wherein material is conveyed through several drying “zones.” The heated fluidizing gas entering the fluid bed unit passes through specially-designed gas distribution plate to ensure proper distribution of the fluidizing gas across the fluidized surface. The gas passes through the fluidized layer and provides a portion of the necessary drying energy to coal during fluidization.

The dried material is discharged from the fluid bed unit via a “discharge boxes” / chutes located at the end of the fluid bed dryer unit. Material discharge from each of these discharge boxes is accomplished via two means - a fixed-height overflow weir and an integrally-constructed underflow discharge screw. The main portion of the material discharged from the unit is via the fixed-height overflow weir. A small portion of the material is discharged via the integrally-constructed underflow screw. The moisture- and fines-laden exhaust gas is then carried via ducting to the inlet of the dust-recovery cyclone unit or bag house filter system. The recovered fines can then either be mingled with the material exiting the dryer or handled separately. After flowing through the dust-recovery cyclone or bag filters, the exhaust gas is vented to safe location. If there is limitation of fluidization LP N_2 gas, then provision can be made for vented gas to be recycled

Closed Loop Fluidized Bed Dryer

Wet coal is conveyed to feed distribution screw conveyor that discharges the feed material to feed rotary air locks. The introduced feed is allowed simply to fall by gravity into the area of the feed zone where it can back-mix with dry material before migrating in the main drying area. Inert gas nitrogen from ASU is used as a fluidizing media. LP steam (~5 bar) generated by syngas cooler block is used as heating media. The necessary thermal energy for accomplishing drying of the material is imparted through convective and conductive heat transfer means. Convective heat transfer is accomplished via heating of the fluidizing gas entering the dryer, which then comes into direct contact with the fluidized material within the dryer - imparting a portion of the required heating / drying energy. Conductive heat transfer is accomplished via the use of steam passing through the tubes of the dryer's in-bed heat exchangers. As the material comes in contact with the outer surfaces of the in-bed heat exchanger tubes, heating / drying energy is transferred from the in-bed heat exchanger units to the fluidized material via tube-side condensation of the steam. Heating will be controlled precisely to deliver only the necessary energy required to reach the target moisture specification for the product exiting the fluid bed. The fluidic behavior of the material itself, volumetric displacement of the fluidized material within the unit due to additional material feed and the inclusion of a special, directional-flow gas distribution plate create conditions within the fluid bed wherein material is conveyed through several drying "zones." The heated fluidizing gas entering the fluid bed unit passes through specially-designed gas distribution plate to ensure proper distribution of the fluidizing gas across the fluidized surface. The gas passes through the fluidized layer and provides a portion of the necessary drying energy to coal during fluidization.

The dried material is discharged from the fluid bed unit via a "discharge boxes" / chutes located at the end of the fluid bed dryer unit. Material discharge from each of these discharge boxes is accomplished via two means - a fixed-height overflow weir and an integrally-constructed underflow discharge screw. The main portion of the material discharged from the unit is via the fixed-height overflow weir. A small portion of the material is discharged via the integrally-constructed underflow screw. The moisture- and fines-laden exhaust gas is then carried via ducting to the inlet of the dust-recovery cyclone unit or bag house filter system. The recovered fines can then either be mingled with the material exiting the dryer or handled separately. After flowing through the dust-recovery cyclone or bag filters, the exhaust gas is then carried scrubber-condenser unit. Prior to its entry into the scrubber-condenser unit, a small portion of the exhaust gas is "purged" from the exhaust air stream, carrying with it a small portion of the water vapor that was evaporated from the material in the dryer unit. This purge gas stream is removed from the closed-loop gas stream to provide pressure control for the dryer unit's exhaust gas and is approximately the equivalent volume of air entering the drying system with the feed material. In this manner, the overall water-condensing requirement for the scrubber-condenser unit is slightly lowered, relative to its duty without purging the excess gas volume prior to the unit. The remaining exhaust gas then enters the scrubber-condenser unit via an integral venturi scrubbing section for further particulate removal. After passing through the scrubbing section of the unit, the gas then enters the integrally-constructed condensing section of the unit where it comes in contact with recirculated cooling water and further cooled. As the exhaust cools, moisture is removed from the gas stream (i.e. the gas stream is dehumidified). The condensed moisture is continually discharged from the scrubber-condenser unit as a "recover" water stream.

Equipment list

The following tables show the major equipment in the facility, broken into sections by operation.

No	Description	Type	Operating	Spares

			Quantity	
1	Feeder	Vibratory	1	0
2	Conveyor	Belt	1	0
3	Roller Mill Feed Hopper	Dual Outlet	1	0
4	Roller Mill & Pulverizer	Rotary	2	0
5	Weigh Feeder	Belt	1	0
6	Coal Dryer	Fluidized Bed	1	0
7	Coal Dryer Feed Hopper	Vertical Hopper	1	0
8	Scrubber Condenser	Packed Tower	1	0
9	Vent Filter	Hot Baghouse	1	0
10	Low pressure Coal Feed stock Bin	Vertical Hopper	1	0
11	Coal Lock Hoppers	Vertical Hopper	2	0
12	High Pressure Feeder	Vertical Hopper	1	0

Table 15 - Coal Preparation and Feed

No	Description	Type	Operating Quantity	Spares
1	Gasifier	Pressurized Entrained Flow Dry Feed	1	0
2	HCL Scrubber with Venturi	Tray Column	1	0
3	Synthesis Gas Cyclone	High Efficiency	1	0
4	Steam Drum	NA	1	0
5	Coolant Drums	NA	1	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	1	0
7	Pumps	Centrifugal	2	2

Table 16 - Gasifier and Accessories

No	Description	Type	Operating Quantity	Spares
1	COS Hydrolysis Reactor	Fixed Bed, Catalytic	1	0
2	Hg Removal Unit	Carbon Bed	1	0

3	Acid Gas Removal Plant	Sulfinol-M	1	0
4	Auto circulation Oxidizer Vessel Sulfur Recovery	N/A	1	0
5	Vacuum Belt Filter Sulfur Cake separator	N/A	1	0
6	Syngas Cooler	Shell and tube	1	0
7	K.O.Drums	Vertical with mist eliminator	1	0

Table 17 - Syngas Cleanup:

No	Description	Type	Operating Quantity	Spares
1	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	1	0
2	Primary Sour Water Stripper	Counter-flow with external reboiler	1	0
3	De-aerator	N/A	1	0
4	Low Temperature Heat Recovery Coolers	Shell and tube	4	0
5	Black Water Filter	Pressurized Filter	1	0
6	K.O.Drums	Vertical with mist eliminator	2	0
7	High and LP Flash	Vertical	2	0
8	Milling Water Tank	Tank with motor rotator	1	0
9	Gray Water Tank	Storage Tank	1	0
10	Pumps	Centrifugal	5	5

No	Description	Type	Operating Quantity	Spares
Scrubber Waste Water Treatment				

1	Reverse osmosis System	2 Stage, membrane filtration	1	0
2	Evaporator	Flash tank	1	0
3	Tanks	-	2	0
4	Pumps	Centrifugal	5	0
Other Process Waste Water Treatment				
1	Softening System	-	1	0
2	Reverse osmosis System	2 Stage, membrane filtration	1	0
3	Preheater	Shell and tube	1	0
4	Heat Exchanger	Force Circulation	1	0
5	Crystallizer	Force Circulation	1	0
6	Tanks	-	2	0
7	Pumps	Centrifugal	5	0

Table 18 - Water Treatment and ZLD

No	Description	Type	Operating Quantity	Spares
1	Slag Crusher	Roll	1	0
2	Slag Quench Tank	Water Bath	1	0
3	Slag Depressurizer	Lock Hopper	1	0
4	Slag Receiving Tank	Horizontal, weir	1	0
5	Slag Conveyor	Drag Chain	1	0
6	Slag Separation Screen	Vibrating	1	0
7	Pumps	Centrifugal	2	2

Table 19 - Slag Recovery and Handling System

No	Description	Type	Operating Quantity	Spares
1	Circulating Water Pumps	Vertical, wet pit	2	2
2	Cooling Tower	Hybrid, mechanical draft, multi-cell	1	0

Table 20 - Cooling Water System

No	Description	Type	Operating Quantity	Spares
1	Syngas compressor	Centrifugal	1	0
2	Combustor(s) and turbine	Proprietary	1	0
3	Recuperative Heat Exchanger	Printed Circuit	1	0
4	Water Separator	Venturi Mixer Type	1	0
5	Main CO_2 Compressor	Centrifugal	1	0
6	Compressor After-cooler	Printed Circuit	1	0
7	CO_2 Pump – 110 bar	Centrifugal	1	0
7	CO_2 Pump – 393 bar	Centrifugal	3	0
8	Oxidant Pump	Centrifugal	2	0

Table 21 - Allam Cycle Power Island

Additional Equipment Information

Some additional equipment information is provided below to add further context to these performance results.

Heat Exchangers: The heat exchanger network includes multiple heat exchangers to deal with multiple hot and cold fluids, not a single unit. The minimum temperature approach of the heat exchanger network is 3°C, and it is at the low end of the heat exchanger which is made by stainless steel. Additionally, low grade heat taken from the main air compressor is used to preheat the recycle CO_2 stream to close to 200C. The total amount of the low grade heat from ASU is around 34 MWt.

CPU: The CPU is an auto-refrigeration cryogenic process with one flash and a distillation column for liquid CO_2 and contaminants (N_2, Ar, O_2) separation. Water is removed from a conventional molecular sieve desiccant to prevent ice formation in downstream equipment. Given that the feed pressure is 65bar with 98% CO_2 purity, there is no need for compression to provide any additional cold energy, and the oxygen concentration can be reduce down to less than 0.5ppmv based on the Aspen modeling. However, there is some CO_2 loss in the CPU to ensure the low oxygen concentration, which leads to about 94% CO_2 capture rate of the overall system. CO_2 capture rate can be higher by relaxing the oxygen concentration requirement. If export CO_2 is for sequestration or other chemical use which does not require oxygen removal, then CPU can be fully eliminated to reduce the cost and increase the CO_2 capture to almost 100%.

The major equipment within the CPU are listed below:

- Molecular sieve desiccant
- Plate and fin heat exchanger
- Pressure reducing valve

- Flash column;
- Distillation column with reboiler
- Liquid CO_2 pump
- Off gas compressor

Combustor: Siemens has calculated combustor exit gas composition using in-house tools previously verified for other mixtures. Additionally, 8 Rivers has reduced reaction kinetic modeling validated by the shocking tube testing data done by University of Central Florida, which shows complete combustion of syngas under the Allam Cycle condition (Samuel Barak, 2020).[xv]

Oxygen in the recycled CO_2 is injected back to the combustor with recycled CO_2, to ensure a complete combustion in an oxygen rich combustion mode. CPU is included in the system design to remove the excess oxygen from the export CO_2. The oxygen in the recycled CO_2 stream is close to 1% in volume at the steady state.

Turbine: The front of the turbine need be cooled, and the cooling information is provided by Siemens. The cooling flow is pulled from the middle of the heat exchanger network. However, given that it's vendor confidential information, it is not shown in the PFD.

Turbomachinery: Turbomachinery efficiency of CO_2 compressors and pump in the Allam Cycle is taken from vendor data. Low to mid 80 percent efficiency were assumed for the compressors without getting vendor data, and 3% motor driven mechanical loss were considered.

COST RESULTS REPORT

General Cost Estimation Methodology

The cost analysis has been compiled to the level of accuracy for a nominal AACE 18R-97[xvi] Class 4 Estimate. A Cost Confidence Assessment has been provided later on in the report to demonstrate the cost is within the expected accuracy range for a AACE 18R-97 Class 4 Estimate.

The cost analysis has been built up with reference to the NETL Cost Estimation Methodology Report[xvii] and the NETL Baseline for Fossil Energy Plants - Volume 1 Report (NETL Baseline Report)[xviii]. Using the definitions outlined in the NETL Cost Estimation Methodology Report, the following levels of capital cost have been included:

- Bare Erected Cost (BEC) - Comprises the cost of process equipment, on-site facilities and infrastructure that support the plant, delivery of all equipment and material and the direct labor required for construction and / or installation.
- Engineering, Procurement and Construction Cost (EPCC) - An EPC contracting strategy will be used, as given the newness of this technology we believe this approach compared to an EPCM is more likely to yield a bankable project. The cost comprises the BEC plus the cost of services provided by the EPC contractor. These include engineering and

design costs, contractor permitting and project / construction (direct and indirect) management costs. If an Engineering, Procurement and Construction Management (EPCM) contracting strategy is assumed, the NETL Cost Estimation Methodology Report indicates the EPCC add-on should be 15 – 20% of the BEC, depending on the technology considered. For this cost analysis, 15% of the BEC has been assumed for all cost lines.

- Total Plant Cost (TPC) - Comprises the EPCC cost plus project and process contingencies. To determine project contingency, a percentage of the Total Process Capital, EPC Contractor Services and Process Contingency has been used. The percentages range from 10% to 30%, with a percentage assigned based on the certainty of bare erected cost for that line item, as per the recommendation in AACE 16R-90[xix]. Process contingency has only been included for process items where there are uncertainties associated with the development status of the technology. These include the Heat Exchanger Network and the CO_2 Purification unit (off-the shelve technology but when combined, original design). A percentage (factor) of the BEC for the specific line item has been assumed based on the guidelines outlined in AACE 16R-90 and EPRI[xx]. The below provides a summary the allowances outlined in AACE 16R-90 and EPRI:

State of Technology Development	Process Contingency Allowances as Percentages of Total Process Capital Cost
New concept with limited data	40+
Concept with bench-scale data	30% to 70%
Small pilot plant data	20% to 35%
Full-size modules have been operated	5% to 20%
Process is used commercially	0% to 10%

Table 22: Guidelines to aid in assigning process contingency allowances to various sections of the plant.

- Total Overnight Cost (TOC) - Comprises the TPC plus 'overnight' costs, including owner's cost. The methodology used to determine the owner's cost is provided later within this section.

The TOC is an overnight cost, expressed in base-year dollars and as such does not include escalation during construction or construction financing costs. To determine a cost expressed in mixed, current-year dollars over the capital expenditure period, the Total As-Spent Cost needs to be calculated.

- Total As-Spent Cost (TASC) - Comprises the sum of all capital expenditures as they are incurred during the capital expenditure period for construction, including their escalation. TASC also includes interest during construction, comprised of interest on debt and a return on equity (ROE).

  The TASC can be calculated from the TOC using specific factors as outlined in Exhibit 3-7 within the NETL Cost Estimation Methodology Report. The specific factor used for this cost analysis has been chosen based on the assumption of real dollars and a duration of construction for 5 years. The factor has been verified by ensuring the economic assumptions (Exhibit 3-1) and the financial structures for investor-owned utilities (Exhibit 3-2) outlined within the NETL Cost Estimation Methodology Report align with the specific economics for the project. Amongst others, these include:

- Income Tax Rates of 21% and 6% at federal and state level, respectively;
- An effective tax rate of 25.74%;
- A financing structure of 55% debt and 45% equity

Owners Costs

Owner's Costs were established from the guidance within the NETL Cost Estimation Methodology Report.

Pre-production costs to include a proportion of operating labor, maintenance materials, non-fuel consumables, waste disposal and fuel consumables. An additional 2% of TPC added to cover all other pre-production costs.

Inventory capital costs includes 60-day supply of fuel and 60-day supply of non-fuel consumables assuming 100% capacity factor and an additional 0.5% of TPC for spare parts.

Other owner's costs include for initial purchase of catalyst and chemicals, cost for land ($3,000/acre, with estimated 27.073 acres as per Indicative Site Layout produced), financing cost of 2.7% of TPC and 10% of TPC added to cover all other owner's costs.

The NETL Performance and Cost Assessment of a natural Gas-Fueled Direct sCO_2 Power Plant report[xxi] (NETL Direct sCO_2 report) utilized a 15% of TPC unit for this "other owner's costs" category, stating that: "Significant deviation from this value is possible, because it is very site and owner specific. AACE 18R-97 indicates the "other owner's cost" of 15% of TPC is only an estimate based on rule of thumb and so flexibility to adjust based on site and owner specifics. The lumped 'Other Owner's Costs' includes: Preliminary feasibility studies, including a front-end engineering design study; Economic development (costs for incentivizing local collaboration and support; Construction and/or improvement of roads and/or railroad spurs outside of site boundary; Legal fees; Permitting costs; Owner's engineering; Owner's contingency." Given the chosen siting on an existing coal mine, the lower permitting burden due to the near-zero air emissions and zero-liquid-discharge nature of the Allam-Fetvedt Cycle, and the higher overall Total Plant Cost of the coal cycle, the project team has deemed that 15% of TPC is an inaccurate representation and agreed that taking 10% of TPC provides a more realistic cost.

Initial and Annual Operating and Maintenance Costs.

The O&M costs have been split by fixed operating costs, variable operating costs and fuel costs.

Fixed Operating Costs

The fixed operating cost includes a cost for the annual operating labor for the Allam-Fetvedt Cycle, ASU and gasification plants. An average base labor of $38.50/hr was assumed cross all operating staff, with a 30% labor burden and 25% of labor plus burden to cover overheads.

The maintenance labor was calculated as a percentage of the maintenance material in line with the NETL Baseline Report.

For administrative and support labor, 25% of the annual operating and maintenance labor was assumed.

For property taxes and insurance, 2% of the TPC was assumed.

Variable Operating Costs

For Maintenance materials, 1.95% of the TPC was assumed, in line with the NETL Baseline Report.

Non-fuel consumables and waste disposal specific to the Coal Allam Cycle Plantwas determined from per unit rates and assuming the plant capacity factor when calculating annual cost.

Fuel Cost

The 2018 unit cost of fuel of $12.68/ton was taken from EIA Table 31, Annual Coal Report 2018 [xxii] for the Wyoming average coal price at the mine mouth. Because of the chosen location at the North Antelope Rochelle Mine, a mine mouth coal price was determined to be more representative than the delivered coal price used in the Conceptual Design.

Adjusting the 2018 cost of fuel to 2023 cost of fuel ($13.11) and levelizing over 30 year operational period (Year over year escalation for Wyoming, taken from Exhibit 2-2, Fuel Prices for NETL Quality Guidelines for Fuel Prices for Selected Feedstocks in NETL Studies[xxiii]), results in a levelized fuel price of $14.69/ton or $7.12/MWh. Based on the net plant HHV efficiency, this corresponds to a levelized fuel cost of $0.83/mmbtu.

This is a significantly lower fuel cost compared to $1.72/mmbtu for delivered PRB coal as stated in the Conceptual Design, and so a sensitivity case is also run for non-mine mouth PRB coal.

Byproduct Revenues

For CO_2 transport and storage, it was assumed that 60 total miles pipeline would be built and that CO_2 would be utilized for Enhanced Oil Recovery (EOR). The FE/NETL CO_2 Transport Cost Model from 2018 was utilized with a 10% return on debt and equity, leading to a $3.23/MT cost of CO_2 transport, which was then converted into dollars per MWh.[xxiv]

The Wyoming Enhanced Oil Recovery Institute provided a list of nearby oil fields that are CO_2 miscible and potentially suitable for CO_2-EOR. This provides 141.6 million tonnes of total CO_2 demand, shown in the below Table 23. The value of CO_2 for EOR is assumed to be $15 / MT, which is both a standard and a conservative value in the industry.

Distance	Field	Reservoir	Cumulative Oil	CO2	Incremental Oil
Miles	Name	Name	mmbo	Demand Bcf	mmbo
25	Porcupine	Turner	4.9	26.22	3.2
25	Highlight	Muddy	81.7	261.37	32.2
25	Steinle Ranch	Muddy	4.3	23.60	2.9
50	Big Hand	Minnelusa	8.1	25.35	3.2
50	Bone Pile	Minnelusa	9.4	29.72	3.7
50	Clareton	Turner	7.4	23.60	2.9
50	Donky Creek	Minnelusa	17.3	46.33	5.7
50	Dry Gulch	Minnelusa	5.5	17.48	2.2
50	Halverson	Minnelusa	17.5	55.95	6.9
50	Hartzog Draw	Shannon	120.2	382.88	47.2
50	Hawk Point	Minnelusa	4.7	25.35	3.2
50	Heldt Draw	Shannon	7.9	20.98	2.6
50	Hornbuckle	Sussex	14.1	76.05	9.4
50	House Creek	Sussex	65.7	208.92	25.8
50	Jepson Draw	Shannon	1.9	6.99	0.77
50	Kaye	Teapot	10.1	32.34	3.9
50	Lance Creek	Leo	121.2	393.37	48.4
50	Meadow Creek	Minnelusa	35.7	96.16	11.9
50	Meadow Creek North	Frontier	9.5	51.57	6.4
50	Mush Creek	Muddy	14.8	48.08	5.9
50	Mush Creek West	Muddy	4.2	22.73	2.8
50	Pine Tree	Frontier	11.4	60.32	7.4
50	Powell	Frontier	29.4	156.47	19.3
50	Raven Creek	Minnelusa	47.7	154.72	19
50	Reel	Minnelusa	10.6	34.09	4.2
50	Salt Creek East	Tensleeep	13.6	43.71	5.4
50	Sand Dunes	Frontier	27	142.49	17.5
50	Scott	Parkman	22.7	72.55	8.9
50	Slattery	Minnelusa	14.8	47.20	5.8
50	Spearhead Ranch	Sussex	9.4	49.83	6.1
50	Table Mountain	Shannon	6.3	20.98	2.5
50	Timber Creek	Minnelusa	22.9	73.43	9
			Totals	2,730.84	336.27

Table 23: Adjacent Wyoming CO_2-EOR Opportunities[xxv]

On top of CO_2-EOR sales, an additional $35 / MT of CO_2 is added due to the value of the 45Q tax credit (in the year 2026). This credit is then grossed up to its Pre-Tax value for the levelized cost analysis using the 21% federal corporate income tax rate. To claim the 45Q tax credit, construction for the project must start before January 2024. The Project Execution Plan developed as part of this Pre-FEED indicates construction is scheduled to commence Q1 2023 and so the project will be entitled to claim the 45Q tax credit. Once qualified, the tax credit is available for 12 years. The revenue has therefore been adjusted to reflect claiming the 45Q tax credit for only 12 years but levelized over the 30 years of operation. To do this, the net present value of the total CO_2-EOR sales over 30 years and net present value of toal income from 45Q tax credit over the first 12 years was determined (using a discount rate of 5%). The NPV ratio and the levelized CO_2-EOR sales was used to determine the levelized 45Q over the 30 years of operation.

The prices for sales of Argon and Nitrogen, both byproducts of Air Separation, were calculated from 8 Rivers in-house data, estimates, and conversations with industrial gas distributors. Prices in the industrial gas market are very localized and kept quite confidential. Given the remote location of this facility and its low value, nitrogen is assumed to be too expensive to transport and thus have no value. Argon is in high demand in Salt Lake City, Denver, and California, all of which are reachable by rail from the NARM site. Argon routinely sells for over $400/ton, but to allow for this project to break into the market, a $300/ton argon pick-up price is assumed to undercut the existing supply. Different sensitivity analyses were run with different Argon prices to show the impact on the cost of electricity. To include the additional revenue from producing and selling excess Argon, a cost add-on has been included on top of the equipment cost for the ASU, along with an efficiency hit. This cost add-on has been provided from the ASU vendor based on the additional cost to produce the gases at required flowrate.

Levelized Cost of Energy (LCOE)

The Levelized Cost of Energy (LCOE) is determined from summation of the levelized capital cost, levelized annual O&M cost and levelized annual fuel cost. Alternate LCOE figures have also been determined, which include and/or exclude CO_2 transport & storage (T&S) and revenue from other byproducts.

The levelized capital cost has been determined as a function of the after-tax weight average cost of capital, tax depreciation and effective tax rate in line with the equations included within the NETL Cost Estimation Methodology Report. The following economic assumptions and finance structure has been assumed:

- Number of operating years: 30
- Number of years of depreciation: 21
- Effective tax rate: 25.74%
- Finance Structure:
  - Debt: 55%
  - Equity: 45%
- Capital Recovery Factor: 6.305%

The levelized O&M cost assumes the same financial structure as the levelized capital cost but also considers annual escalation rate over the number of operating years (30 years assumed). For the purpose of this cost assessment, a 0% annual escalation rate has been assumed, which is consistent with the NETL Baseline Report.

The levelized fuel cost assumes the same financial structure as the levelized capital cost, with details outlined of the build-up of the levelized fuel cost detailed previously within this report.

Specific Equipment Cost Estimation Methodology

The capital cost estimate for entire plant was developed based on the equipment sizes defined by the process HMB. Cost for each piece of major equipment was estimated based on either vendor quotes, WSP and Gas Technology Institute’s (GTI) in house estimating software, scaled from historical project data or were developed based on the NETL Baseline Report. The costs were adjusted for differences in unit or plant capacity according to NETL’s guidelines as described in the NETL Cost Estimation Methodology Report.

Bulk material, packing & delivery and installation costs are added to complete the major equipment direct installation costs. Bulk material costs, which include instrumentation, piping, structure steel, insulation, electrical, painting, concrete & platform preparation works that are needed to complete the major equipment installations, were factored from major equipment cost (MEC) based on WSP and GTI's in house historical data for similar services where available.

Packing and delivery costs have been assumed as a percentage of combined equipment and material costs. With the exception of the gasifier, US supply has been assumed (to be confirmed at the next project stage). It is understood that a sales tax would apply for any goods delivered to Wyoming from US but it has been assumed that this would be waivered or if not, the tax would be reclaimed back on any goods purchased. For US supply, a band system has been used to determine packing and delivery. For low equipment cost (<$1million), 9% of that cost has been assumed, for medium equipment cost (<$5million), 6% of that cost has been assumed and for high equipment costs (>$5million), 3% of that cost has been assumed. Further details on the packing, delivery and import duty cost for the gasifier has been provided later on in this report.

Labor costs were obtained from real project data and factored to align with the equipment size and Wyoming labor rates (Again, obtained from real project data). When this information was not available, labor rates were scaled from the NETL Baseline Report.

Coal Handling

WSP were responsible to generate the cost estimate for coal handling from the mine up to the coal dryer. A coal vibrating feeder is required at the coal mine to distribute coal onto a conveyor. A 1km coal ground mounted conveyor has been assumed which supplies a short-term coal storage silo (1 day).

Previous project data was used and scaled to obtain the cost for the coal vibrating feeder and storage silo and the cost for the conveyor was obtained by a vendor quote.

Gasifier and Syngas Cleanup

GTI were responsible to generate the cost estimate for gasification island and syngas clean up. Gasifier Island consist of sections like coal drying, coal milling and pulverization system, dry coal pressurize feed system; gasifier, syngas scrubber, quench and grey water system along with slag and ash handling system (conveyed and disposed within hooklift type trailers for easy removal from site). While the syngas cleanup consists of COS hydrolysis reactor, mercury removal, SG cooler, AGR and tail gas treatment for sulfur recovery unit.

Gasification technology selected for this project is SE entrained flow gasifier developed by SINOPEC and East China University of Science and Technology (ECUST). Costs for equipment in the SE gasification system that are proprietary to ECUST, such as SE gasifier and sub system were provided by ECUST.

The level of detail provided in these cost estimates was determined by ECUST itself. WSP and GTI used and reported these costs on an as-provided basis. It is assumed that all the equipment in the gasification island will be manufactured in China and shipped to the site in the US. For delivery, import duty (tariffs) from China has been assumed to be 25% of equipment / material cost and 0.21% of equipment / material cost for insurance. This is on top of shipping and haulage cost for delivery of the equipment to site. The import duty, insurance and shipping and haulage costs have been obtained from a logistics company which has calculated from cost and volume of equipment / material. Direct Labor Cost was scaled from similar reference gasification project in comparable location. As SE entrained flow gasification technology is matured and commercially available with over ten thousand hours of operation experience from multiple projects, no process contingency was included for gasification island

In syngas cleanup section, cost for equipment and material were obtained from vendors for given sizes. Direct labor costs were estimated based on NETL Baseline Report. Like gasification technology all syngas clean technologies are commercially available, hence no process contingency was included for the systems.

Air Separation Unit (ASU)

The ASU includes the plant to obtain the required oxygen for the Allam-Fetvedt Cycle and gasifier and the required nitrogen for coal drying.

The equipment cost for the ASU plant has been obtained through a vendor quote and assumes a single stream, with storage for oxygen and nitrogen. US supply has been assumed and 3% of equipment cost has been included for packing and delivery. An assumption of 38% of the equipment cost is used for direct labor for erection and installation, which aligns with the NETL Baseline Report.

The ASU vendor have provided an additional add-on cost for when an ASU is supplied which produces excess Argon and Nitrogen for sale off site. Given the additional cost, energy usage, and low project specific value, Nitrogen is not projected to be sold for this Wyoming project. Cases with Argon sales, and the associated cost, will be shown.

The ASU vendor has confirmed that the system is designed to produce additional N_2 (45,000Nm^3/h / 56.22 MT/hr) with no impact on cost or electrical load. This will be more than sufficient for internal use for adsorbent regeneration

Allam-Fetvedt Cycle Power Island

Syngas and CO_2 Compressors

Two stage compressors with aftercoolers are required to compress the syngas and CO_2 as part of the process. The equipment cost for the compressors has been obtained from vendor quotes. US supply has been assumed and so 3% of equipment cost has been assumed for packing and delivery. 5% of the equipment cost has been assumed for direct labor for interconnection of pipes, instruments and ancillaries. The syngas compressor cost used for this project is from vendor quote with ancillaries included. Connecting pipework, fitting and valves for the Allam Cycle Plant is included as a separate line item. Assumed equipment will be delivered as skid unit, so minimal labor required for installation and connections hence the assumption of 5% of equipment cost for direct labor.

Although the same vendor has provided a cost for both compressors, a combined supply discount has not been explored at this stage.

Syngas Combustor and Turbine

Siemens provided a quote for the syngas combustor and turbine set for this project. US supply has been assumed and so 3% of equipment cost has been included for packing and delivery. Further, 5% of the equipment cost has been assumed for direct labor for interconnection works with the other plant.

Recuperative Heat Exchanger

The recuperative heat exchanger is a multiple high pressure and temperature stream network, with the arrangement still under discussion with vendors. At this stage, a vendor quote has not been obtained and so the cost of the heat exchanger unit has been estimated from scaling the equipment cost from the NET Power Demonstration Plant. At this stage, this is deemed a sufficient estimate due to the process conditions being comparable for the two projects.

US supply has been assumed and so 3% of equipment cost has been included for packing and delivery, with 5% of the equipment cost assumed for direct labor for interconnection works.

CO_2 Pumps and Oxidant Pump

The equipment cost for the pumps has been obtained from vendor quotes. US supply has been assumed and so 3% of equipment cost has been included for packing and delivery. An additional 5% of the equipment cost has been assumed for direct labor for installation and interconnection of pipes, instruments and ancillaries.

Although the same vendor has provided a cost for both pumps, a combined supply discount has not been explored at this stage.

Additional Equipment

The additional equipment included in the Power Island are the following: Syngas Turbine Generator, Direct Contact Cooler, Civils / Foundations, and Allam Cycle Connection Pipework, Fittings, and Valves. Each of these has no process contingency, and a 15% project contingency, with the exceptions of the Civils / Foundations category which has a 20% project contingency.

Cooling Water System

A hybrid (wet / dry) mechanical draft cooling tower with circulating cooling water pumps is required to provide the plant cooling.

During the winter months, the system uses indirect dry cooling. Circulating water heated through the plant process is cooled through finned tubes, by passing air over the exterior surface of the tubes. The wet system is not in use and so water lost through evaporation, drift or blowdown is minimized.

During the summer months, the system uses dry cooling in series with wet cooling. Similar to operation in winter months, the circulating water heated through the plant process is cooled through the finned tubes. It then undergoes further cooling by evaporation of a proportion of the water through direct contact with the air in a wet fill section. Although the dry cooling section reduces the amount of evaporation, the system is open and water is still lost and so make-up water is required.

Based on the extreme winter conditions seen in Wyoming, a no-plume design point of -4°C (dry bulb temp, with relative humidity of 70%) has been chosen to size the dry part of the cooling tower. This has been discussed and agreed with vendors to allow the best compromise between performance and costs.

Three similar vendor quotes have been obtained and the cost used is an average of the three quotes. 35% of the equipment cost has been assumed for direct labor for erection and installation which aligns with the NETL Baseline Report. Thermoflow PEACE cost estimating software has been used to estimate the cost of the circulating water pump based on required flow.

Waste-Water Treatment and ZLD

The exact quality and analysis of the different process waste-water streams is not yet known but through discussion with a waste water treatment vendor, indicative zero liquid discharge (ZLD) waste water treatment systems have been formulated.

For the black water from the gasification water scrubber, it is understood the waste is mostly contaminated with COD (Assumed COD contents have molecular weight > 100). To treat this, a two stage reverse osmosis (RO), with a final evaporator stage, to allow the distillate from the RO stages and the evaporator to be recycled within the plant.

The other waste water streams is predominantly made up of the cooling tower blowdown. To treat this, a softening plant for removal of heavy metals and silica is required, followed by a two stage RO and a salt crystallization plant to saturate the brine to a slurry. The slurry will be collected and disposed of off-site and the distillate is recycled back to the plant process.

A vendor quote has been obtained for these waste water treatment systems. The vendor has indicated 25% cost for direct labor for erection and installation of the water treatment plants.

Miscellaneous / BOP

Cost for miscellaneous plant and BOP have been obtained from a mixture of vendor quotes, from Thermoflow PEACE cost estimating software or scaled from historical projects. Once the definition of this plant is more refined at the next stage, vendor quotes can be obtained.

Electrical Plant

For the electrical plant, all electrical and distribution equipment has been assumed up to the busbars within the electrical switchyard i.e. no electrical transmission from the switchyard have been assumed at this stage.

All electrical plant equipment costs have been obtained from vendor quotes, with the cost for the electrical switchyard being estimated by WSP electrical team.

Instrumentation and Control

The cost for the site wide DCS has been determined from historical project data and scaled to align with the control and instrumentation requirements for this project. A quote from a vendor is being awaited and will feed into the cost estimate when available.

Buildings / Structures and Civil Works

The cost for buildings has been obtained by laying out the equipment within buildings on a site layout, with consideration given to operation and maintenance requirements. The equipment footprints and heights have been taken from information provided by vendors.

The site layout produced has also been used to determine the costs for site finishing to include road network, drainage and landscaping and cost for pipe supports and.

POTENTIAL COST SAVING AREAS

GTI contacted different vendors for quotation of sub-systems in gasification and gas clean up island. While reviewing the quotations and discussion with vendors, GTI have identified a few potential cost saving areas. These can be evaluated in detail during FEED stage.

1) Tail Gas Treatment for Sulfur Removal:-

In this study we compared 5 technologies for sulfur removal:- 3 stage Claus SRU, LO-CAT® process, AECOM’s Crystasulf , FLEXSORB and GPUR. The technology selected and cost quoted currently is for the Merichem’s LO-CAT® process which is a liquid redox technology that converts H_2S to elemental sulfur in an inherently safe aqueous solution. The elemental sulfur if filtered from the solution as a 60 wt% sulfur “cake” that is safe for transport and can be used as a fertilizer or disposed of in a landfill. The equipment cost quoted for LO-CAT® process is USD $12,500,000 with low annual operating cost (under $650,000).

There is another gas/liquid contactor technology called GPUR for sulfur removal; which is suitable for the proposed system. The equipment cost quoted from the vendor is about USD $6,000,000 (almost $6,500,000 cheaper than the LO-CAT® process), but the annual operating cost is in the range of USD $3,000,000. Trade study can be done in FEED stage for potential capital cost saving compared to annual operating cost, if this technology is chosen.

2) Zero Liquid Discharge: As stated above a quote has been obtained for a waste water ZLD system based on the assumed quality and preliminary flows for the different streams. The total installed cost comes in at approximately $29 million. USD s range. ZLD requirement is site/project specific, so if the site chosen does not have requirement of ZLD, it could be eliminated and replaced with a simple waste-water treatment plant and be a potential cost saving.

Cost Confidence Assessment

A Cost Confidence Assessment has been carried out to demonstrate the cost is within the expected accuracy range for an AACE 18R-97 Class 4 Estimate. The assessment has looked at the main plant areas as split in the Cost Analysis Results and assigned a cost confidence category (Refer to the Cost Confidence Matrix). An accuracy is then estimated for each line depending on the maturity level of the design and the quality of cost obtained. This methodology of the accuracies for each of the main plant areas calculates a total plant cost accuracy of -17.1% to +28.3%.

CONFIDENCE LIMITS	
Increase on Most Likely Price	50%
Decrease on Most Likely Price	30%

Accuracy range taken from Class 4 Estimate within AACE 18R-97

DECREASE ON ESTIMATED PRICE

Quality of Design		Quality of Price			
		Factored	Estimated / Databank	Budget Price	Fixed Price
		D	C	B	A
No Design. Development Unknown	4	30%	25%	20%	15%
Design Incomplete. Major Development	3	25%	20%	15%	10%
Design Incomplete. Minor Development	2	20%	15%	10%	5%
Design Complete. No Development	1	15%	10%	5%	0%

INCREASE ON ESTIMATED PRICE

Quality of Design		Quality of Price			
		Fixed Price	Budget Price	Estimated / Databank	Factored
		A	B	C	D
Design Complete. No Development	1	2%	8%	17%	25%
Design Incomplete. Minor Development	2	8%	17%	25%	33%
Design Incomplete. Major Development	3	17%	25%	33%	42%
No Design. Development Unknown	4	25%	33%	42%	50%

Table 24: Cost Confidence Category Matrix

Reference Plant Owner’s Costs

Description	$1,000s	$/kW
Pre-Production Costs (Assume 100% Capacity Factor)		
6 months - all labor	10,488	36.7
1 month maintenance materials	1,700	6.0
1 month Non-Fuel Consumables	312	1.1
1 month Waste Disposal	8	0.0
25% of 1 Months Fuel Cost (at 100% CF)	320	1.1
2% of TPC	17,782	62.3
Inventory Capital (Assume 100% Capacity Factor)		
60 day supply of fuel	2,526	8.8
60 day supply of non-fuel consumables	616	2.2
0.5% of TPC (Spare Parts)	4,399	15.4
Other Owner's Costs		
Initial Cost for Catalyst and Chemicals	1,283	4.5
Land	81	0.3
Finance Cost: 2.7% of TPC	24,006	84.1
Other Owner's Costs	88,912	311.3

TOTAL Owner's Cost	152,482	534

Table 25: Owner's Costs Table

Reference Plant Operating Costs

Table 26: Operating Costs and Output Table

Coal Mass Flow	125520	kg/hr	
Thermal Input (HHV)	714	MW	
Plant Output (Net)	286	MW	
Plant Capacity Factor	85	%	
CO_2 Output	216	MT/hr	
Argon Output	7.14	MT/hr	
Nitrogen Output	0	MT/hr	

O&M Labor - Allam Cycle

	Rate ($/hr)	No. Required / Shift	Annual Cost $
Skilled Operator	62.56	1	465,822
Operator	62.56	3	1,397,465
ASU Operator	62.56	2	931,644
Foreman	62.56	1	465,822
Lab Technician	62.56	1	465,822
			3,726,574

O&M Labor - Gasification Plant

	Rate ($/hr)	No. Required / Shift	Annual Cost $
Shift Supervisor	62.56	1	465,822
Board Operators	62.56	3	1,397,465
Field Operators	62.56	3	1,397,465
Lab Technician	62.56	1	465,822
			3,726,574

Fixed Operating Costs						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**	**Annual Cost**	
					($)	**($/MWh-net)**
Annual Operating Labor:					7,453,148	$3.505
Maintenance Labor:					9,327,744	$4.387
Administrative & Support Labor:					4,195,223	$1.973

Property Taxes and Insurance:					17,782,373	$8.363
Fixed Operating Costs Total:					**38,758,488**	**$18.227**

Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$17,337,814	$8.153
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (gal/1000):	172.5	1,684	$1.90	$328	$992,676	$0.47
Makeup and Waste Water Treatment Chemicals (gal):	0	1000.0	$2.20	$0	$682,550	$0.32
Sulfur-Impregnated Activated Carbon (ton):	13	0.04	$13,380	$173,940	$147,849	$0.07
COS Hydrolysis Catalyst (ft^3):	2389.74	6.55	$338.00	$807,732	$686,572	$0.32
Sulfinol Solution (gal):	18814	12.89	$16.00	$301,024	$63,968	$0.03
Chemicals cost of Merichem (gal)	0	230	$8.59	$0	$612,747	
Subtotal:				**$1,283,024**	**$3,186,362**	$1.50
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):		0.035616438	$80.00	$0.00	$884.00	$0.00
COS Hydrolysis Catalyst (ft^3):		6.547232877	$2.50	$0.00	$5,078.20	$0.00
Sulfinol Solution (gal):		12.88630137	$0.35	$0.00	$1,399.29	$0.00
Crystallizer Solids (ton):		6.7	$38.00	$0.00	$78,989.65	$0.04
Slag (ton):		236.4	$0.00	$0.00	$0.00	$0.00
Subtotal:				**$0.00**	**$86,351.14**	$0.04
Variable Operating Costs Total:				**$1,283,024**	**$20,610,526**	**$9.69**

Fuel Costs						
Wyoming subbituminous Coal (US ton):	0	3,321	12.68	$0.00	$13,063,353	$6.14
Fuel Cost Total:				**$0.00**	**$13,063,353**	**$6.14**

Cost of Energy and Sensitivity Analysis

Component	**Value, $/MWh**	**Percentage**
Capital	39.98	53.3%
Fixed	18.23	24.3%
Variable	9.69	12.9%
Fuel	7.12	9.5%
Total (Excluding T&S)	**75.02**	-

CO_2 Transport	2.45	
CO_2 EOR Revenue - Sales	-11.36	-
CO_2 EOR Revenue - Pre Tax 45Q for 12 years	-19.34	-
Total (Including T&S)	**46.76**	
Argon Revenue	-8.27	
Total (Including T&S and Revenue from Byproducts)	**38.49**	-

Table 27: Levelized Cost of Energy Table

The Levelized Cost of Energy (LCOE) is broken down in the above table, based on the assumptions described earlier methodology section. The LCOE is shown first solely based on power sales, then including the cost of CO_2 transport and the revenue from 45Q and EOR, and then finally with byproduct revenues from Argon.

This LCOE is depicted in Figure 12 below, with a couple key sensitivity cases applied. There is the baseline case for the First of a Kind (FOAK). Next is a case which assumes $1.72/MMBtu for delivered Wyoming PRB coal, rather than the $0.83/MMBtu mine-mouth coal price. Third is a case using mine mouth coal but including Argon sales at a lower $50/ton price. The fourth sensitivity case applies the 48a tax credit, a 30% Investment Tax Credit for which AC Coal could qualify under the current requirements. Fifth is a case which assumes that the 45Q tax credit is available for the life of the project, rather than just the first 12 years. And finally, for reference, the LCOE of a combined cycle gas plant is included, pulled from the NETL performance baselines case B31A, except with a natural gas cost of $2.85/MMBtu rather than $4.42/MMBtu.[xxvi]

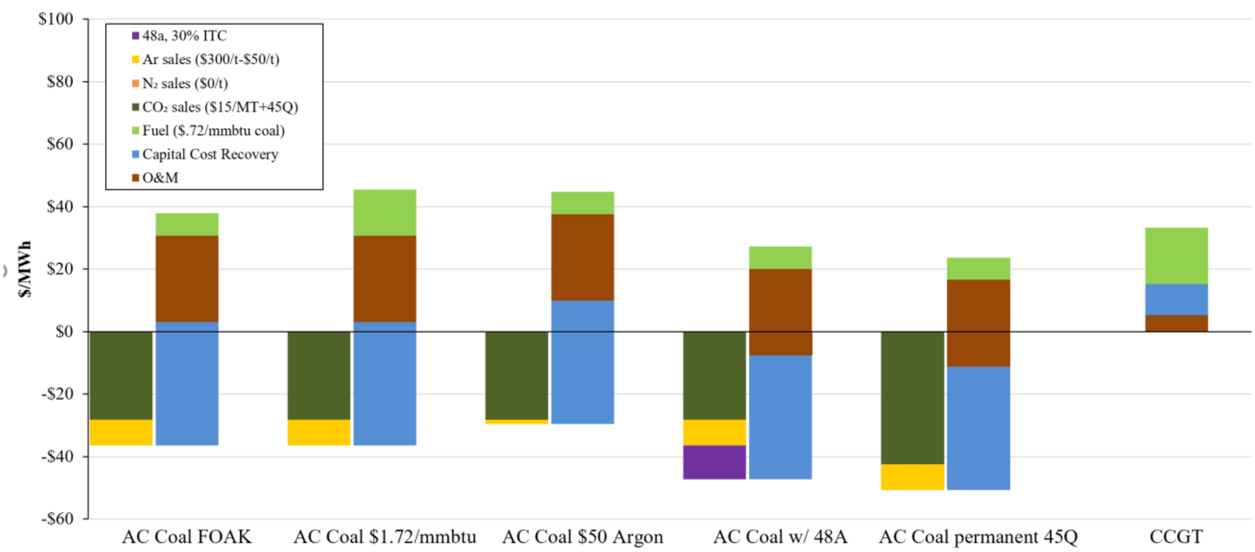

Figure 12: LCOE Sensitivity Analysis

The Coal Allam Cycle's biggest international market is in fast growing economies where power demand is quickly increasing, and cheap natural gas is in short supply. This encompasses parts of

India and China as well as much of eastern Asia. This region also has the most experience in constructing the coal gasifiers needed for this system. We have modeled further sensitivities for the global market: the Next-of-a-kind (NOAK) with \$0-\$15 value per MT of CO_2, compared against conventional coal (SC-PC) and a CCGT with \$6 mmbtu imported liquefied natural gas, as shown.[xxvii] The deployment of both coal- and gas-based Allam Cycle plants will bring down the cost for the core cycle agnostic of fuel source, accelerating the path to NOAK costs.

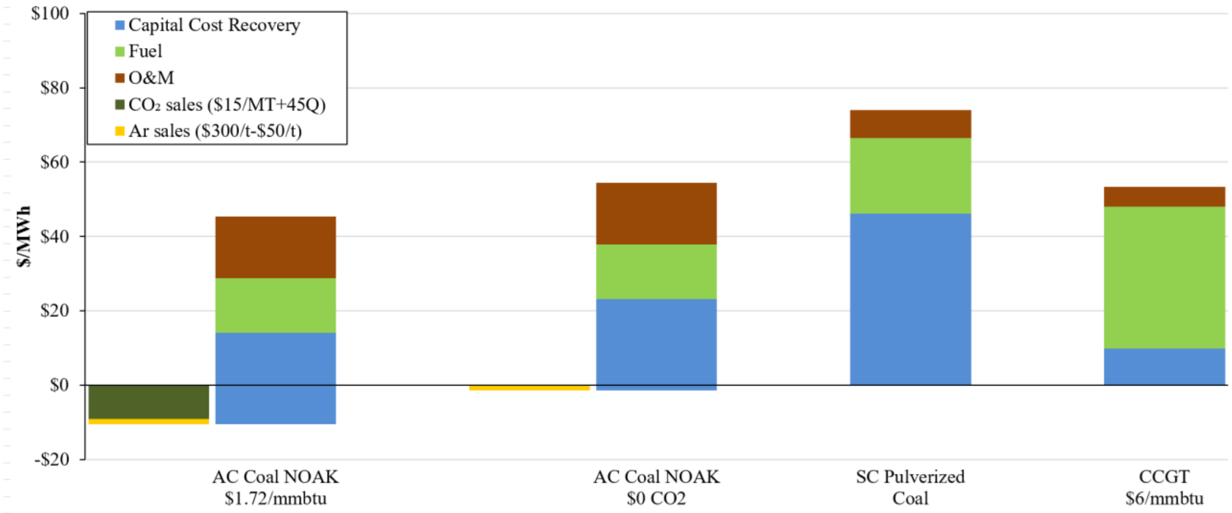

Figure 13 - Allam Cycle Coal Cost Comparison in Global Market Conditions

TECHNOLOGY GAP ANALYSIS

Current State Of The Art

As a new power cycle, the Allam Cycle is itself a state-of-the-art technology system that largely relies on fully proven components. With two key exceptions. First, the sCO_2 combustor, which is an oxy-combustion system, done in the presence of a large mass of pre-heated CO_2, to reach the pressures and temperatures require to drive the turbine. The La Porte plant demonstrated the first such combustor. The test was on a 50 MWt combustor, which Toshiba considers their commercial size, as they plan to use 10-12 combustors aligned radially around a larger turbine. Siemens plans to use one or two silo combustors. In July of 2018, NET Power successfully completed the combustion testing phase of the test program. At that time, major equipment had been operated between 500 and 900 hours, and over 170 hours of testing with fuel in the system was completed, with individual test runs lasting over 24 hours. Findings from this program will be applied to the syngas combustor.

The sCO_2 turbine is the other exception. It is driven by CO_2 rather than steam or air, and experience pressures similar to a steam turbine simultaneously with the temperature profile of a gas turbine. Toshiba's turbine in La Porte was in a 200 MWt pressure shell, leading to 2.5x-3x scale up to full scale. Due to size limitations on the blades, the demonstration turbine had partial arc admission of approximately 90°. This resulted in parts of the turbine being closer to a 200 MWt design with the corresponding difference in scale-up to a full design.

Development of the coal-based Allam Cycle will build off of the knowledge gained from lab-, pilot-, and large-scale testing programs already completed or currently under way since the coal-based variant is nearly identical to the natural gas-based Allam Cycle in terms of facility design, process conditions, required equipment, controls, etc. However, switching to a coal-based fuel and integrating with a gasifier island requires several additional developments prior to being ready for commercial demonstration. These additional developments were identified via a detailed feasibility and scoping study completed on the coal-based Allam Cycle by a consortium consisting of 8 Rivers, the Electric Power Research Institute, ALLETE Clean Energy (ALLETE), and Basin Electric Power Cooperative (BEPC) (Forrest et al., 2014). Significant work was conducted to address technical challenges via lab- or pilot-scale testing in preparation for a large-scale program. Each key issue and the associated severity and mitigation are summarized in the below tables.

Based on work to date, the coal-based Allam Cycle is ready for full scale demonstration. The technology readiness level (TRL) of the gasifier island is at TRL9, with over 20 years of operating experience and multiple installations. Dry-feed entrained flow gasifiers (SE/Siemens/Shell and others) can handle bituminous coal, subbituminous coal and lignite. The core Allam Cycle is at TRL 7. Commercial scale projects are being actively pursued. Key technological risks specific to the coal Allam Cycle have been addressed to the degree indicated in Table 3, which puts the overall coal-based system at a TRL5–6, indicating it is ready for a large pilot. The proposed program will mitigate remaining risks to ready the technology for commercial demonstration.

We believe that after this Pre-FEED, and with the potential for syngas combustor development under the Critical Components FOA, Allam Cycle Coal will be immediately ready for a FEED study followed by financing and construction of a first of a kind full scale plant. As such, we are planning to apply for the Coal FIRST FEED announced in the recent NOI for release on May 2020, so long as Allam Cycle Coal is not specifically prohibiting from submitting an application.

Overcoming shortcomings, limitations, and challenges

Our approach to overcoming the remaining challenges were shown in Tables 4 and 5. Thes tables focused on the challenges facing the Coal Allam Cycle. The other main challenges to the Allam Cycle, particularly the scale up to the first 300 MWe unit with a >500 MWt sCO_2 turbine, will be overcome by the first deployments of the Gas Allam Cycle by NET Power, with the first plant targeting commissioning in 2022, and so are listed in a separate table. The Allam Cycle risks and mitigations will benefit from being retired commercially before the implementation of the syngas fired version. There risks and potential mitigation have been presented in Tables 4 and 5, along with their potential impact on the Coal Allam cycle.

Perceived technology gaps and R&D needed for commercialization by 2030

The key remaining technology gap after the Coal FIRST Pre-FEED and given the in-progress commercialization of the natural gas Allam Cycle is the syngas combustor. The sCO_2 turbine is also a gap, but this gap is planned to be closed through the commercial deployment of the natural gas Allam Cycle, rather than through a dedicated coal program. The coal turbine can be the same turbine that will be used in the natural gas version of the cycle. The turbine inlet temperature, pressure, and volumetric flow is that same between the two different fuels. Due to the highly recycled nature of the process, the majority of the fluid entering the turbine is CO_2. There is a slight difference in water content due to the C:H ratio differences between natural gas and coal derived syngas. Siemens has extensive experience in thermal barrier coatings development for syngas environments with elevated water contents. This C:H ratio difference manifests itself as a difference in average molecular weight of the process stream. This difference has a negligible impact on the operation of the turbine[xxviii].

Fuel Selection	NG	Slurry-Feed	Dry-Feed
Average Process Fluid MW	41.8	42.5	43.0
Condition/Design MW	–	1.017	1.029

Table 28- Comparison of Turbine Inlet Streams[xxix]

Successful testing of a 50 MWth combustor run at a 20 MWth syngas load will allow rapid scale-up to the 50 MWth "can-type" combustor scale required by the commercial-scale Allam Cycle combustion turbine, or scale-up to a 250 MWth silo style combustor. Controllability of this system, including start-up, shutdown, and transient operation, also needs to be demonstrated. Confidence is high based on the successful completion of the natural gas combustion testing. 8 Rivers is pursuing funding to run a syngas combustor test. If this is funded as part of the Critical Components FOA, we anticipate a 2-year test duration. At the end of this syngas combustor test, the syngas combustor/turbine system will be at a TRL level 6.

Development pathway description for the plant concept, including need for pilot plant.

The commercialization timeline for Allam Cycle coal is shown below. A pilot of the syngas combustor is required, but no further pilot plant is needed, because of the learning from the 50 MWt Allam Cycle plant in La Porte and the impending commercial scale gas Allam Cycle plants. Currently, initial plants are expected to be located in the US, where the 45Q tax credit ($50 / MT of capture) and the 48a tax credit (30% investment tax credit for coal with CO_2 capture) can offset the costs of initial deployments, as shown in the Business Case. To qualify for 45Q, a plant must commence construction before January 1st of 2024. To meet this deadline, the syngas combustor test must be completed, as is currently scheduled for Q4 2021, and a FEED must be completed, as is scheduled for 2022 through the Coal FIRST FEED FOA in May of 2020. Before the first coal Allam Cycle plant, a 300 MW Allam Cycle natural gas plant is expected to be commissioned, the learnings from which will be applied to future coal plants, including the de-risking of the full scale sCO_2 turbine. This natural gas deployment will have proven out all of the technology elements, in particular the turbine, except for the coal gasifier which is already commercial, and the syngas combustor which is planned to be fully de-risked at the La Porte site through the Coal FIRST Critical Components program.

KEY TECHNOLOGY EQUIPMENT MANUFACTURERS

Coal Delivery, Handling and Reclaim

Bruks Siwertell

Bruks Siwertell design, produce and deliver systems for loading, unloading, conveying, storing, and stacking and reclaiming dry bulk materials. With a main office in Alpharetta, GA, they specialise in high capacity, enclosed screw-type coal unloaders with discharge rates in excess of 3,000 t/hr, and have delivered thousands of projects worldwide.

Doosan Heavy Industries & Construction

Doosan delivers integrated EPC solutions for the power plants and water treatment plants. They have a number of US offices and they provide bulk handling systems to domestic and overseas coal-fired thermal power plants, steel mills, cement plants and other industrial plants. Doosan have a number of EPC contracts in the Asian power markets, including power stations in Vietnam, India and Korea.

Heilig B.V.

Heilig B.V. is based in the Netherlands and design, develop, and deliver machinery for handling bulk goods and conveying and processing recyclable waste streams. They have a number of demonstrated coal handling projects in screening/crushing, conveying, washing and drying and many demonstrated projects for the handling and treatment of ash. They offer bulk handling installations with capacities of up to 6,000 t/hr.

Metso

Metso offers equipment and services for the sustainable processing and flow of natural resources in the mining, aggregates, recycling and process industries. They have a strong presence in the United States. They offer solutions from the mining of raw materials to the production of feedstock, and their range of bulk handling equipment includes stockyard equipment, conveyors and railcar unloading. Their coal stack and reclaim rates are up to 6,000 t/hr.

Coal Drying and Pulverizing

Williams Patent Crusher

Williams Patent Crusher is a manufacturer of size reduction equipment to meet the unique needs of a variety of specialized industries. Their products feature customized systems heavy-duty size reduction products, including shredders, crushers, grinders and pulverizers. Williams Fluid Bed Roller Mill design can have infinite turn down while maintaining product size. They offer roller mill system capable of handling ~1500 TPD each. They have wide range clients and also have experience with coal driven power plants.

Carrier Vibrating Equipment, Inc

Carrier Vibrating Equipment offers more than 60 years experience developing customized solutions for material processing. They offer full range of drying and cooling equipment for foundry and processing applications. From fluid bed dryers and coolers to sand coolers to tornesh dryers, they can customize a solution for virtually any material. They have a number of demonstrated coal handling projects in conveying, washing and drying. Carrier has developed a number of thermal coal dryer systems for several types of coal and process applications. Some of these include:-Anthracite coal for additives in the steel making industry; metallurgical grade bituminous coals used in making coke; bituminous coals used in direct steel making processes such as the "Corex" process; beneficiation of PRB coals, beneficiation of lignite coals and lignite coals prior to gasification or liquefaction. They offer fluidized coal dryers with capacities up to 250 TPH in a single unit, depending on the thermal load.

Schwing Bioset

Schwing Bioset have been helping wastewater treatment plants, mines and power generation customers by engineering material handling solutions. They offer coal drying technologies for a variety of coals.

Air Separation Unit

Air Liquide

Air Liquide is a global provider of gases, technologies and services for Industry and Health with extensive experience in the supply of ASUs. They have a range of standard and large cryogenic air separation units with capacities up to 6,000 tons/day.

Air Products

Air Products is based in the United States and provide gases, chemicals and services for Industry. They offer an air separation solution which can be integrated with the customer's gasification process. Air Products has produced over 1200 air separation plants and currently owns and operates over 300 air separation plants.

Linde Engineering

Linde is an EPC provider of customised industrial plants from design and construction through to operation and support. In 2018, Linde merged with Praxair, a provider of industrial gases, plant systems and services. They have produced over 3,000 ASUs, with capacities up to 5,500 tons/day.

Hangyang

Hangyang is a China based global provider of gases, technologies and services for Industry with extensive experience in the supply of ASUs. They have a range of standard and large cryogenic air separation units with capacities up to 140,000Nm^3/hr oxygen production capacity.

Mercury Removal

Calgon Carbon

Calgon is a producer of activated carbon and manufacture it in granular, powdered, pelletized, catalytic, and impregnated forms for vapour and liquid purification solutions. They offer activated carbon solutions for mercury removal, primarily focussed around their Fluepac powdered products.

Honeywell UOP

Honeywell offers a broad platform of regenerable and non-regenerable adsorbents capable of removing mercury. UOP offer GB copper-based adsorbents and HgSIV™ molecular sieve regenerative adsorbents for fixed-bed solutions for mercury removal.

Johnson Matthey

Johnson Matthey produces mercury removal adsorbents for the gas processing industry. Their PURASPEC fixed bed absorbents are suited for a range of applications within the Gas Processing, Refineries and Petrochemical markets, including mercury removal.

COS Hydrolysis

Axens Solutions

Axens Solutions provides their COSWEET™ technology, a combined absorption catalytic conversion process for COS removal, which allows gas sweetening with either total or selective COS removal. Their gas processing business has over 2,500 industrial units under licence.

Haldor Topsoe

Haldor Topsoe provides a range of high-performance catalysts and proprietary technology for the chemical and refining industries. Haldor Topsoe delivered the plant methanation section design for the Huineng SNG plant in inner Mongolia, and for the Qinghua SNG plant in China. They offer CKA-3, a COS hydrolysis catalyst, and can provide project development services.

Johnson Matthey

Johnson Matthey has more than 25 years' experience in purification solutions for the gas processing industry. Their PURASPEC™ adsorbents and processes are suitable for COS hydrolysis and a range of gas processing requirements. PURASPEC performance is proven within the industry with hundreds of installations worldwide.

Acid Gas Removal

Air Liquide

Air Liquide has designed numerous acid gas removal plants around the world across a range of industry sectors, and can provide systems with capacities up to 1.5 million Nm^3/h.

Axens Solutions

Axens Solutions provides solutions for the production and purification of major petrochemical intermediates as well as for gas treatment and conversion options. They offer their SPREX® process for the removal of bulk acid gas from highly sour gas. SPREX® is a joint development between IFP Energies nouvelles, TOTAL and Axens Solutions.

BASF

BASF is a provider of chemicals to industry, and also provide a range of chemical process plant / services. They have contributed to around 400 gas treatment plants across the world.

Dow Chemical Company

Dow supplies speciality solvents to gas processing plants across the world, and provide acid gas removal products, services and technologies to the gas industry.

UOP

UOP provides process solution, equipment, product and service in refining and chemical industries. For acid gas removal products, they supply both MDEA solvent process and Selexol process.

Tail Gas Treatment for Sulfur Recovery

Merichem Company

They have lhe LO-CAT® process which is wet scrubbing, liquid redox system that uses a chelated iron solution to convert H_2S to innocuous, elemental sulfur. The LO-CAT technology's sulfur removal capacity niche ranges between 0.5 to 25 TPD. When the ratio of CO_2 to H_2S is greater than 3 and/or the volumetric sour gas flowrate varies on a frequent basis, LO-CAT technology can be a valid option to remove up to 40 tons/day of sulfur from sour gas streams.With over 200 licenses globally, the LO-CAT technology is in use within several markets and industrial segments. LO-CAT systems are extremely versatile and the plants can process any type of gas stream. The process provides licensees the flexibility of maintaining very high H_2S removal efficiencies (in excess of 99.9%) at 100% turndown, regardless of the H_2S concentration, flowrate and sulfur loading.

Pietro Fiorentini

Pietro Florentini is a service provider in the field of oil and gas clean up. They license H_2S removal technology based on reduction-oxidation reaction that converts H_2S present in sour gas to elemental sulphur through reaction with aqueous ferric ions. Process forms solid sulphur particles that are easily filtered from the solution.

GTUIT

GTUIT's GPUR H_2S treatment equipment is operating in over 60 countries providing treatment of H_2S or sour gas. GPUR is a self-regenerative system with operating costs of 1/8 of other traditional sweetening technologies. The resulting product of the GPUR equipment is moist elemental sulfur cake that can be landfilled or used as a soil amendment.

AECOM CrystaSulf

CrystaSulf® can remove sulfur economically without the operating issues of aqueous-iron systems and with significantly lower pumping costs for most applications. Using SO_2 as an oxidant, CrystaSulf® converts inlet H_2S to elemental sulfur through a modified liquid-phase Claus reaction. Elemental sulfur is soluble in CrystaSulf® solution, which eliminates circulating solids in high-pressure equipment. The sulfur is crystallized and separated in equipment designed to handle solids, while the rest of the process remains solids-free.The CrystaSulf® process can achieve pipeline H_2S specifications of less than 4 parts per million by volume (ppmv) at pressures above 150 psig. CO_2 has been shown to have no effect on the process. Inlet hydrocarbons also have little or no effect.

Gasification Island

Air Products

Air Products is a provider of turn-key sale-of-gas gasification facilities for solids (coal and biomass) and liquids (refinery residues). In 2018, they acquired Shell's Coal Gasification Technology / Patents, a proven coal gasification technology in place at nearly 200 gasification systems delivering syngas around the world.

East China University of Science and Technology (ECUST)

ECUST provides a range of gasification systems, including the Opposed Multi-Burner (OMB) system, which operates with dry-feed and coal-water slurry feed, and the SE dry-feed gasification system (developed in collaboration with Sinopec). As of 2017, there were more than 60 gasifiers in industrial operation, with single gasifier capacity between 750 and 4,000 tpd.

Gas Technology Institute (GTI)

GTI is a research, development and training organisation addressing energy and environmental challenges. GTI is established as an Illinois not-for-profit corporation. GTI have been actively involved in gasification research and development (R&D) for over 60 years, and have extensive experience in the design, construction, and operation of gasification systems, including seven trademarked processes. The R-Gas coal gasification technology provided by GTI requires further research and development to bring it to commercial demonstration.

Zero Liquid Discharge (ZLD)

Aquatech

Aquatech is a provider of water purification technology for industrial and infrastructure markets with a focus on desalination, water recycle and reuse, and zero liquid discharge (ZLD). They have more than 160 ZLD installations, including stand-alone thermal / evaporative processes, membrane processes or hybrid systems.

Condorchem Envitech

Condorchem Envitech provides primary water, wastewater and air emissions treatment solutions for a wide range of industrial activities. They specialise in vacuum evaporators and crystallisers for the effective implementation of their zero discharge systems.

ROSENBLAD DESIGN GROUP (RDG)

RDG evaporators offers unique solutions for wastewater treatment. They have over 500 installations across the globe for evaporators, RO units and crystallizers.

SAMCO Technologies

SAMCO provides custom water, wastewater, process separation, and filtration solutions to a diverse range of industries. They provided a ZLD system with deionisation to a chlor-alkali company in Nekoosa, Wisconsin.

SUEZ

SUEZ offers complete thermal and non-thermal ZLD solutions to manage tough-to-treat wastewaters. Their evaporators, brine concentrators and crystallisers claim to recover more than 95% of a plant's wastewater. Their ZLD solutions are in operation at the Stanton Energy Centre, Florida.

Existing OEM Relationships

The members of the 8 Rivers consortium were primary contributors to the development of the commercial-scale natural gas NET Power project, which was developed in conjunction with key OEM providers including Toshiba, Heatric and other project development partners related to the Allam Cycle. The team therefore have a proven, effective working relationship which is demonstrated by the successful development and delivery of the NET Power project.
In the NET Power project, the key OEM providers provided development and supply of the following equipment packages:

- Toshiba
  - Allam Cycle CO_2 combustor & turbine
- Heatric

— Allam Cycle CO_2 heat exchanger

Both this concept study plant design and the NET Power project design use the same key Allam Cycle equipment packages, with exception of the turbine OEM, and therefore we will have the opportunity to engage the same OEM providers for these packages to ensure learnings from the demonstration plant are carried into this project.

In addition, WSP have experience working with Linde (through their BOC subsidiary in the UK) as the ASU technology provider to a proposed oxy-combustion coal-fired CCS power project in the UK.

Currently, 8 Rivers is working with Siemens on the development of the syngas turbine system for the coal based Allam Cycle application. Siemens has extensive experience in gas turbine design, development, testing and operation as well as corresponding expertise in high pressure steam turbines. These two skills can me merged together to create the necessary hybrid technology needed to develop the Allam Cycle turbomachinery and combustion system. Further details of Siemens turbomachinery work are later in this report.

List of commercial equipment

All the equipment in the coal gasifier island mentioned above are commercial available. In the Allam Cycle power island, except for the full scale combustor and turbine system, all other equipment are commercial available, including:

SYNGAS COMPRESSOR

The syngas fed from the syngas conditioning, metering and filtering skid is compressed to above 330 bar in the gas compressor before entering the combustor. One 100% motor driven reciprocating compressor shall be provided. The discharge pressure accounts for the all relevant pressure drop between the compressor and the inlet connection to the combustor. The syngas entering the compressor (supplied from syngas skid) is of adequate cleanliness to ensure that there is no damage to the compressor.

O_2-CO_2 PUMP

The O_2 required for combustion is delivered from the ASU at 110 bar and mixed with recycled CO_2 leaving the 100% motor driven CO_2. compressor. The target composition will be around 20% mass O_2 and 80% mass CO_2. The mixture is compressed to slightly over 300 bar in the 100% O_2/CO_2 pump before entering the combustor. The discharge pressure accounts for all relevant pressure drops between the pump and the inlet connection to the combustor.

CO_2 COMPRESSION

One 100% 1st stage centrifugal CO_2 compressor shall be provided to elevate the re-circulating stream of CO_2 to a pressure of circa 65 bar. This allows CO_2 to achieve a dense phase after being cooled in a stainless-steel plate-fin cooler to a temperature of about 101ºF. before entering the 2nd stage CO_2 centrifugal compressor.

At this point the flow splits with circa 10% of the flow going to the CO_2 Purification Unit and the balance of the flow to the second 100% centrifugal compressor which elevates the pressure to give 110 bar at the O_2/CO_2 pump inlet.

The discharge pressure accounts for the all relevant pressure drop between the inlet to the 1st stage CO_2 compressor and the inlet connection of the O_2/CO_2 pump inlet.

The CO_2 compressors shall be designed in accordance with the appropriate vendor standards. The compressor sets will be provided with inter-coolers (as required)

CO_2 PUMP

A single 100% centrifugal pump shall be provided to increase the pressure of CO_2 to higher than 330 bar before it enters the combustor after being heated to close to turbine exhaust temperature in the main heat exchanger. The discharge pressure accounts for the relevant pressure drop between the compressor and the inlet connection to the combustor.

HEAT EXCHANGER

One high pressure, counter flow heat exchanger train is provided to cool the turbine exhaust stream while heating the high-pressure CO_2 recycle and O_2-CO_2 streams that flow into the combustor.

Materials for the lower temperature section of the heat exchanger and associated piping are designed to withstand the slightly acidic and corrosive environments. Appropriate instrumentation for all interconnecting piping indicating inlet and outlet conditions, with respect to temperature and pressure will be provided, with vendor providing appropriate interfaces for the required instrumentation.

All required interconnection between the two heat exchanger sub sections will be included as part of vendor's scope of supply. End connections shall be suitable for welding to adjacent pipes and equipment.

Water separator

The turbine exhaust stream leaving the heat exchanger is directed to a water separator, which cools process fluid below the dew point to condense and remove any residual combustion-derived water in the process fluid. In the water separator, CO_2 process gas at approximately 30 bar and low temperature (60–90°C) comes in direct contact with sub-cooled combustion derived water. The liquid combustion derived water as well as any soluble trace species, such as SOx and NOx, are removed from the gaseous CO_2 stream, the CO_2 process stream leaving the water separator, which is free of liquid water and at ambient temperature, is directed to the main CO_2 compressor.

CO_2 Purification Unit (CPU)

A cryogenic process is applied to purify the export CO_2 to over 99.99% purity to meet the pipeline standard. Water and oxygen in the purified CO_2 stream are less than 10ppmv. CPU in the Allam Cycle is simpler and less energy intensive compared to the conventional CPU design because the CO_2 stream entering CPU unit is already at high pressure (60-70bar). CO_2 is liquefied through expansion by exploring the J-T effect, and separated from gaseous species in a distillation column. The purified liquid CO_2 is pumped to 152bar for pipeline transportation. The off gas which contains CO_2, O_2 and Argon is sent to the vent stack. The overall CO_2 capture rate in CPU is around 93-95% and can be tuned by the distillation column design.

List of equipment requiring R&D

A 300 MWe scale Allam Cycle plant has not yet been built, but the 50 MWth facility has undergone adequate testing that makes the 300 MWe plant the next development step.
All components for Allam Cycle Coal are commercially available today except for the turbine, which will soon be available via the natural gas Allam Cycle turbine which can be repurposed, and the syngas combustor, which could be fully demonstrated by the end of 2022 through the Critical Components program.

>500 MWth sCO_2 turbine

Though one has not been built yet today, this sCO_2 turbine will be commercially available in time for Allam Cycle Coal deployment. NET Power has announced plans to deploy multiple plants at this scale, with the first targeted as early as 2022, indicating that this turbine will soon be available[xxx]. Learnings from Toshiba's 200 MWt pressure shell turbine deployed in La Porte Texas will allow for this successful scale up. Multiple turbine OEMs are expected to supply this turbine. In this pre-FEED study, Siemens will provide the turbine design based on the Allam Cycle coal system conditions.

Syngas combustor

Pilot-scale testing of the 5-MWth natural gas-fired combustor was completed in 2015. Data from this program were used to design the 50-MWth-scale unit at NET Power's pilot facility in La Porte, Texas. In July of 2018, NET Power successfully completed the combustion testing phase of the test program. At that time, major equipment had been operated between 500 and 900 hours, and over 170 hours of testing with fuel in the system was completed, with individual test runs lasting over 24 hours. Findings from this program will be applied to the syngas combustor.

Demonstration of the syngas combustor is the only key piece of equipment that needs further demonstration beyond the NET Power effort.

Successful testing of a 50 MWt commercial scale syngas combustor will allow rapid commercial deployment of the 50 MWth "can-type" combustor scale or to the larger silo type combustors required by the commercial-scale Allam Cycle combustion turbine. Controllability of this system, including start-up, shutdown, and transient operation, also needs to be demonstrated. 8 Rivers is pursuing funding to run this syngas combustor test.

In the current Pre-FEED study, Siemens is responsible for the syngas combustor/turbine development. The Siemens design has proceeded on a multi-track approach which breaks down the study into several key topics, which are confidential and not in this Public Report.

A&E Firm Prior Work With OEMs

WSP already has experience of working with Siemens both as a turbine generator OEM and also in other areas such as control systems, large electric motors and power distribution equipment.

APPENDIX A: PROJECT EXECUTION PLAN

1 | Allam Cycle

ALLAM CYCLE ZERO EMISSION COAL POWER

US Department of Energy Coal FIRST Phase 2

Project Execution Plan Presentation

2 | Allam Cycle

Potential Project Schedule

Task	Timing
Wyoming Pre-FEED Completion	Q2 2020
Coal FIRST Syngas Combustor Test Start	Q4 2020
Coal FIRST Design and FEED Funding Start	Q1 2021
Negotiate Wyoming Project Offtake Contracts	2021-2022
Project Permitting	2021-2023
Commercial NET Power Plant Commissioned on Gas	2022/2023
Wyoming FEED Completion	H2 2022
Combustor Test Completion	Q4 2022
Project Financial Close & Commence Construction	Q1 2023
Wyoming Allam Cycle Project COD	2025-2026

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Syngas Combustor And Turbine

The Syngas Combustor Test Plan is still under development schedule is thus still open for modification.

The test is expected to take roughly two years and finish in 2022.

Multiple potential turbine vendors will be prepared to supply the commercial turbine for the coal system by well before the 2023 FID date.

This includes turbines specifically designed for coal syngas and repurposing turbines designed for natural gas but that can be repurposed due to the operational flexibility of the Allam-Fetvedt cycle

Commercial Gasifier Suppliers

All commercial gasifiers can be integrated with the Allam Cycle for power and chemical production

Entrained flow gasifier:

- Sinopec-ECUST (SE gasifier)
  - Vendor selected in current Pre-FEED
- ECUST OMB gasifier
- Air Product
- E-gas

Fluidized bed gasifier:

- KBR Transport
- SES
- U-gas

Moving bed gasifier:

- BGL
- Lurgi Dry-Ash

Advanced Gasifier Technology

- **R-GAS™ Advanced Gasification Technology 800TPD Demo unit is being commissioned in China**
- **90% smaller reactor volume allows for factory integration and enables modularization**
- **High CGE: 2-4% > than other dry feed, 7%-9% > than slurry**
- **Lower capex: ~15-25% plant cost reduction vs. lowest cost entrained flow technology**
- **15%-25% reduction in cost of product (power, chemicals, liquids)**

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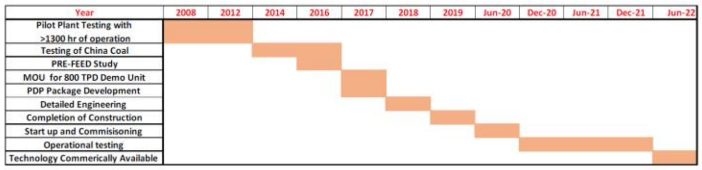
R-GAS^{TM} Timeline:-



Economics of China-base Plant

	TECHNOLOGY				
Parameter	R-GAS™	Dry Feed (Western)	Dry Feed (PRC Domestic)	Slurry	Units
Capex	377689	500058	347291	426377	10,000 RMB
Annual Revenue	517106	513031	511404	511404	10,000 RMB/yr
Annual Cost	270280	372212	370093	319734	10,000 RMB/yr
Annual Profit	151438	83245	84540	115795	10,000 RMB/yr
Syngas Cost	318.3	445.5	437.7	373.3	RMB/kNm^3
Payback	3.65	5.41	4.52	4.3	yr
FIRR	48.26	24.7	33.02	35.95	%

Study performed by East China Engineering Science and Technology Co.

15%-29% Cost Of Syngas Advantage

gti

NET Power To De-Risk The Core Allam Cycle

Commissioning of the first commercial scale plant is targeted for 2022

8RIVERS

POWER

News & Technology for the Global Energy Industry

News

300-MW Natural Gas Allam Cycle Power Plant Targeted for 2022

Testing continues at NET Power for a much-watched project that is demonstrating production of low-carbon natural gas power. The project is using a supercritical carbon dioxide (sCO_2) cycle, and its developer is confident that the technology will be commercially deployed in 2022.

Detailed Design: FEED Study

The next phase of engineering after Pre-FEED for this project would be a detailed site-specific FEED study.

An upcoming FOA could potentially provide the funding for this FEED.

U.S. DEPARTMENT OF ENERGY

NATIONAL ENERGY TECHNOLOGY LABORATORY
Albany, OR • Morgantown, WV • Pittsburgh, PA

Notice of Intent No.: DE-FOA-0002176

DISCLAIMER: The "Notice of Intent to Issue" is for informational purposes only; the Department of Energy is not seeking comments on the information in this notice and applications are not being accepted at this time. Any information contained in this notice is subject to change.

This is a Notice of Intent to issue

Funding Opportunity Announcement No. DE-FOA-0002180
"Design Development and FEED Studies for Coal FIRST Systems"

AND

Funding Opportunity Announcement No. DE-FOA-0002057
"Critical Components for Coal FIRST Power Plants of the Future"

8RIVERS

Site Selection

This Pre-FEED has been sited at Peabody's North Antelope Rochelle Mine (NARM) to enable access to mine mouth coal near transmission and CO_2 infrastructure.

Selection of the exact site would occur after completion of Pre-FEED.

Peabody's North Antelope Rochelle Mine

8RIVERS

COMMERCIAL DEVELOPMENT

Project Outputs

The project has 3 main revenue streams: power, CO2, and industrial gases.

CO2

- **1.6 MMT CO2 output per year at 150 BAR**

Industrial Gases

- **53,000 MT Argon output.**

Power:

- **286 MW net output**
- **364 MW peak output using stored oxygen**

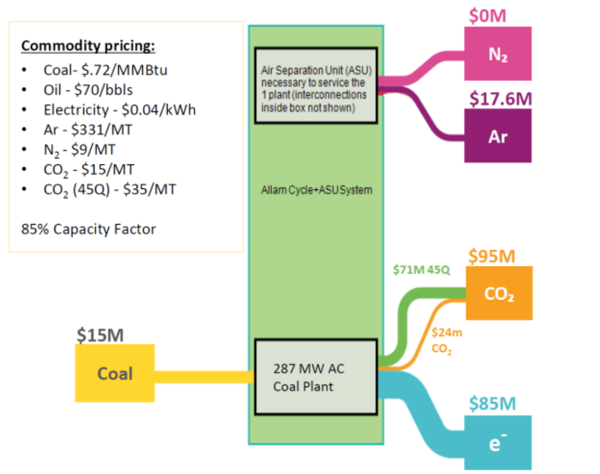
Coal thermal input (MW in LHV)	676
Gross generator output (MW)	468.15
ASU load (MW)	-74.19
Total compression/pumping load in the Allam Cycle (MW)	-92.51
Gasification Island utility (MW)	-5.23
Cooling tower (MW)	-4.35
CO_2 Purification Unit (MW)	-1.57
Miscellaneous BOP (MW)	-4.7
Net power output (MW)	285.6

8RIVERS

Project Revenue Streams

CO_2 and Electricity are the dominant revenue streams, and together will hedge the risk of the project, as oil and CO2 prices are not strongly correlated to power prices

Allam-Fetvedt Cycle Coal Revenue Flow Chart



Power Offtake

Finding customers for the power and suitable transmission to deliver it will be one of the key aspects of development to enable the raising of funds for the project.

Sending the power west will reach markets with higher power prices, higher power demand, and higher premiums for zero-emission power.

Review of Existing Transmission Infrastructure

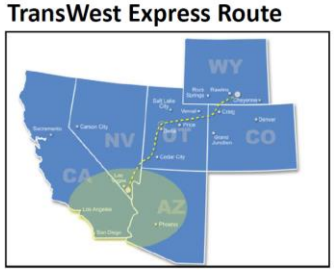
115 kV existing transmission line at NARM

230 kV transmission lines owned by Basin Electric / PacifiCorp connect to Dave Johnston Power Station in Glenrock and Dry Fork Station in Gillette, each of which has transmission infrastructure for regional distribution.

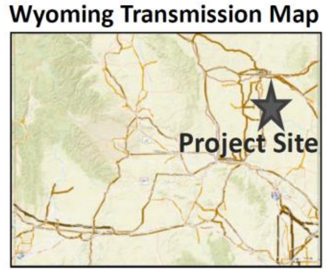
The TransWest Express wind transmission project can reach the California market. It has received its permits and is scheduled to be online in 2023. This project could utilize any spare transmission capacity as well as balanced out wind farms by utilizing the transmission when the wind isn't blowing.

California's SB 100 bill targets 100% zero emission power by 2045.

TransWest Express Route



Wyoming Transmission Map

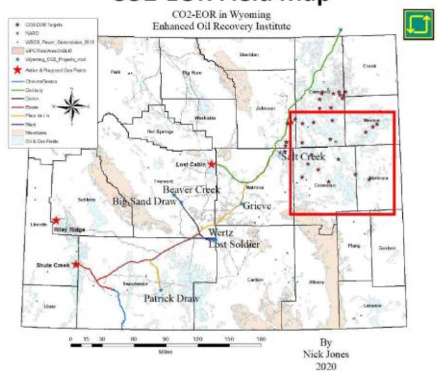


CO2 Offtake

20+ oil fields in <50 mile radius that can utilize and store the project's CO2.

Field selection and CO2 offtake contracts would be put together during the development period from 2021 up to FID.

CO2-EOR Field Map



Citation: Enhanced Oil Recovery Institute (EORI); 2020; www.eoriwyoming.org

CO2-EOR Field List

Distance Miles	Field Name	Reservoir Name	Cumulative Oil mmbo	CO2 Demand Bcf
25	Porcupine	Turner	4.9	26.22
25	Highlight	Muddy	81.7	261.37
25	Steinle Ranch	Muddy	4.3	23.60
50	Big Hand	Minnelusa	8.1	25.35
50	Bone Pile	Minnelusa	9.4	29.72
50	Clareton	Turner	7.4	23.60
50	Donky Creek	Minnelusa	17.3	46.33
50	Dry Gulch	Minnelusa	5.5	17.48
50	Halverson	Minnelusa	17.5	55.95
50	Hartzog Draw	Shannon	120.2	382.88
50	Hawk Point	Minnelusa	4.7	25.35
50	Heldt Draw	Shannon	7.9	20.98
50	Hornbuckle	Sussex	14.1	76.05
50	House Creek	Sussex	65.7	208.92
50	Jepson Draw	Shannon	1.9	6.99
50	Kaye	Teapot	10.1	32.34
50	Lance Creek	Leo	121.2	393.37
50	Meadow Creek	Minnelusa	35.7	96.16
50	Meadow Creek North	Frontier	9.5	51.57
50	Mush Creek	Muddy	14.8	48.08
50	Mush Creek West	Muddy	4.2	22.73
50	Pine Tree	Frontier	11.4	60.32
50	Powell	Frontier	29.4	156.47
50	Raven Creek	Minnelusa	47.7	154.72
50	Reel	Minnelusa	10.6	34.09
50	Salt Creek East	Tensleep	13.6	43.71
50	Sand Dunes	Frontier	27	142.49
50	Scott	Parkman	22.7	72.55
50	Slattery	Minnelusa	14.8	47.20
50	Spearhead Ranch	Sussex	9.4	49.83
50	Table Mountain	Shannon	6.3	20.98
50	Timber Creek	Minnelusa	22.9	73.43
			Totals	2,730.84

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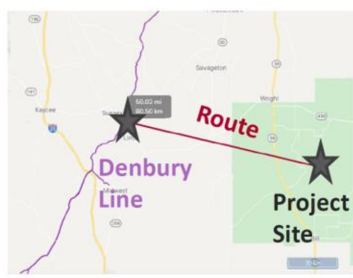
Sample CO2 Pipeline to Denbury CO2 Pipeline

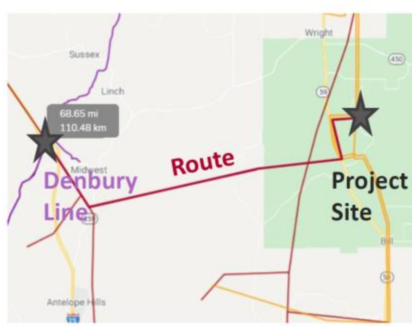
Denbury's Greencore 20 inch pipeline delivers CO2 to the Bell Creek EOR field in Montana, and it runs west of NARM.

A 50 mile straight line pipeline could connect to the existing Denbury line, or a longer 68 mile route that follow existing pipelines for 53 miles, with 15 miles of new route required.

50 mile straight line route



68 mile route to minimize permitting



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Industrial Gas Offtake

The NARM mine is already connected to a BNSF rail-line with a rail terminal that can hold >300 rail cars. This allows access to all key regional markets.

Nearest competitor Air Separation Units are located in Salt Lake City and Denver.

Trucking is also a potential mode of transport for nearby customers and distributors.

Rail Access For Industrial Gas Export

Cryogenic Argon Rail Car

8RIVERS

Project Permitting

Permitting will be a key workstream to enable the project to rapidly advance to both Final Investment Decision and then to start construction and reach COD.

Key Permitting Items

- Air Permits
- Water Permits
- Power Infrastructure
- Intrastate CO2 Pipeline Permit
- Class 2 CO2-EOR Permits

Permitting and Compliance Strategies

- Permitting considerations for startup, shutdown, and malfunctions emissions will be considered
- Includes Basic Available Control Technology (BACT), air dispersion modeling, and other permitting considerations
- EPA Approved Regulations in the Wyoming SIP
- All necessary permits shall be obtained prior to the initiation of construction
- A local, state, and federal permitting matrix shall be created, with timelines to track long lead permits.

8RIVERS

Accelerated Air Permitting

The Project is expected to have a reduced permitting burden due to the low emissions rate, potentially qualifying as a Minor Source of Emissions.

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds.

CO_2 emissions represent the uncontrolled discharge from the process

N_2 from the fuel which makes it into the system is converted to NOx in the combustor and removed as HNO_3 in the water separator

Plant Emissions

	kg/GJ	lb/MMBtu	Tonne/year	kg/MWh
SO2	n/a	n/a	n/a	n/a
NOx	n/a	n/a	n/a	n/a
Particulate	0.0005	0.0012	9.515	0.0027
Hg	9.22941E-11	2.14615E-10	0.002	4.82614E-10
HCl	n/a	n/a	n/a	n/a
CO2	5.72	13.31	104,310	29.92

Start-Up Emissions

	tonne/year
SOx	0.371
NOx	n/a
Particulate	n/a
Hg	1.80749E-05
HCl	n/a
CO2	254

- 2 start-ups per year are considered while utilizing a lower coal feed rate.
- The start-up will last for 2 hrs

8RIVERS

Water Permitting and Design Decisions

Water and Wastewater Permits required will depend on if Zero Liquid Discharge is selected, as well as if Wet Cooling or Dry Cooling is utilized.

With Zero Liquid Discharge and Dry Cooling, there would be both no process water discharge and no water withdrawal to permit.

Dry Cooling and Zero Liquid Discharge

Dry Cooling Water Use	Water Demand	Internal Recycle [1]	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Overall Balance	5793.9	6208.8	-414.9	0	-414.9

Wet Cooling and Zero Liquid Discharge

Wet Cooling Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Overall Balance	7975.5	6806.0	1169.5	0	1169.5

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Gasifier Impact on Permitting

Emissions from the gasification island will be a key part of the permitting analysis

Coal Drying and Feed System

- Particulate Emissions

Gasifier

- Emissions sources typically include gasifier startup vents (CO and NOX), gasifier feed system vents (CO, VOC, and HAPs), and equipment leak components (CO , VOC, and HAPs)
- Off-specification raw syngas may be vented to the flare during startup, shutdown, and malfunction events

Gas Clean Up

- Sour syngas may be vented to the flare during startup, shutdown, and malfunction

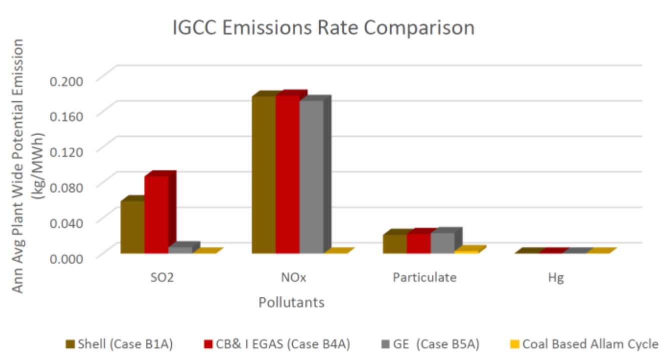
HAP- Hazardous Air Pollutants ; VOC-Volatile organic compounds

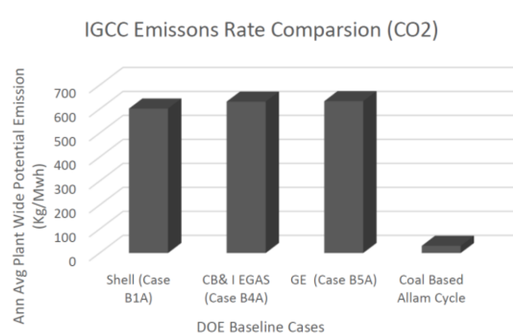
20

Emissions Comparison to IGCC

- **Comparison of Coal Based Allam cycle emissions with DOE baseline case studies.**
- **Emissions from DOE reports were compared to per MWh power generation**

Ref:- "COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY", NETL-PUB-22638 , Sept 24,2019





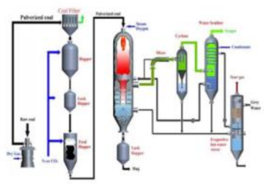
Partnering with Technology Providers

For key equipment items and packages, we are working in collaboration with selected, world-class technology providers during pre-FEED and FEED. This will ensure an optimum process configuration and minimize technology risk.

For standard equipment packages we will adopt a competitive tendering approach from a range of approved suppliers to ensure minimum cost and ensure that alternative technology options are considered.

Key Partners for this Project:

Gasifier Island



Syngas Burner & CO_2 Turbine

Printed Circuit Heat Exchangers

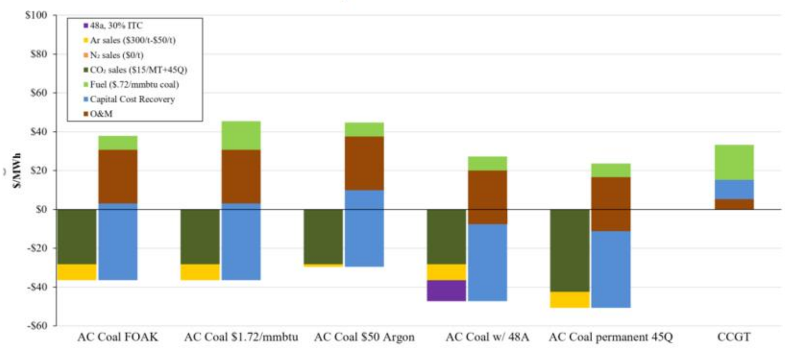
Does not exclude engaging with alternative suppliers at later stage

Financing

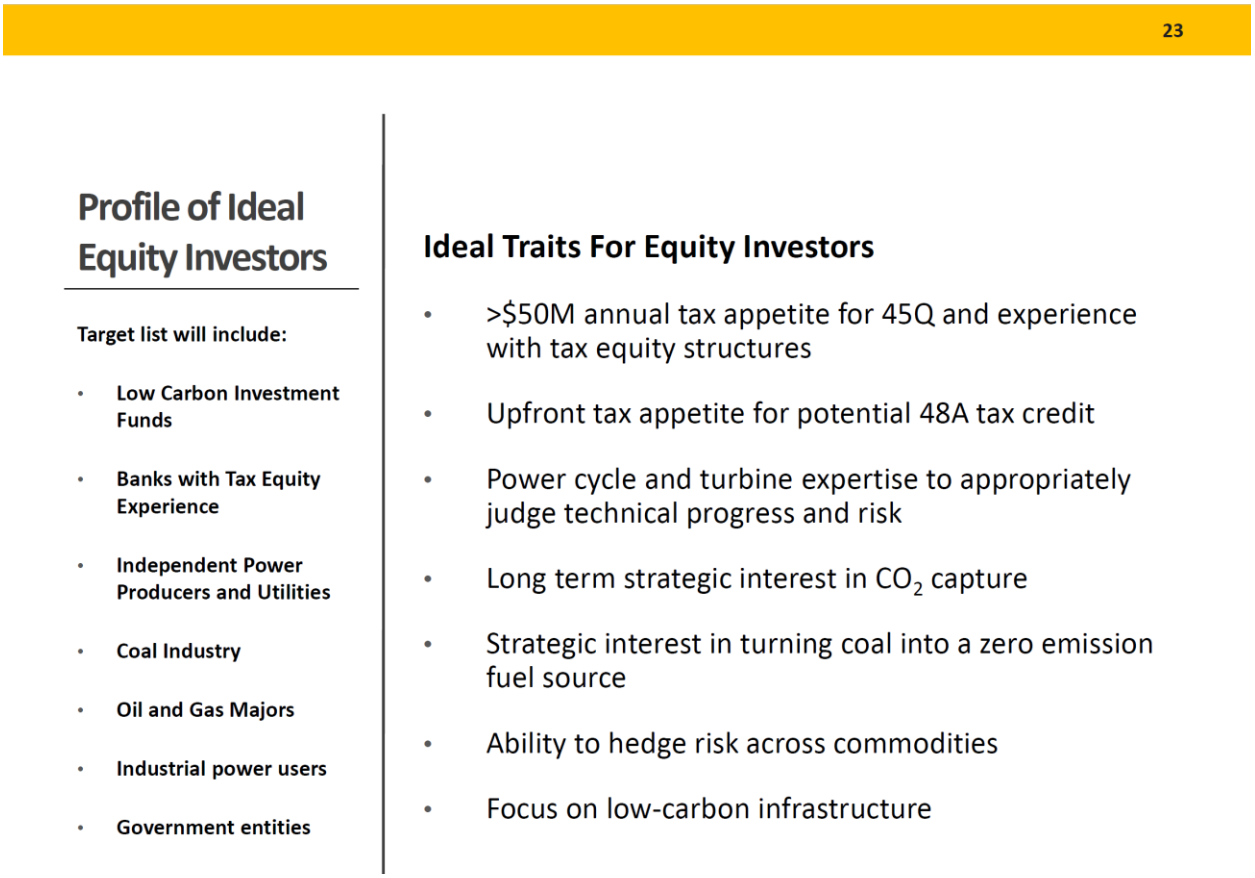
Keys to Successful Financing Include:

- **Project IRR**
- **Diversification of project risk**
- **Long term offtake contracts**
- **Lump Sum Turnkey EPC contract**
- **Low emissions profile**
- **Tax appetite**

Levelized Cost of Electricity Scenarios



- Wyoming Project can be competitive with a <$40 / MWH power price, both with and without industrial gas sales, and with <$30 / MWH with the 48A tax credit.
- To be financeable the project must commence construction before 45Q expiration at the end of 2023. 45Q
- Project may need to pay more for capital than the 5.15% Weighted Average Cost of Capital assumed In NETL Baselines



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