U.S. Department of Energy
National Energy Technology Laboratory
Assistance Agreement DE-FE0024085

"Development of a Field Demonstration for Cost-Effective Low-Grade Heat Recovery and Use Technology Designed to Improve Efficiency and Reduce Water Usage Rates for a Coal-Fired Power Plant"

DUNS Number: 137519547

Final Report
Heat Recovery –Use Technology Assessments

Submitted by:
Russell Noble – Power Generation R&D Manager
Southern Company Services, Inc.
600 North 18th Street
Birmingham, AL 35203
Phone: 205-257-7232
Fax: 205-257-5367
Email: rtnoble@southernco.com

Signature of Submitting Official:

RTNOBLE

Digitally signed by RTNOBLE
DN: DC=com, DC=southernco, OU=Accounts, OU=Users, OU=Employee, CN=RTNOBLE
Reason: I am approving this document
Location:
Date: 2016/09/28 10:09:14 -06'00'

Russell Noble, Power Generation R&D Manager and Principle Investigator

September 26, 2016

DISCLAIMER

NOTE

This document presents the results of Cooperative Agreement DE-FE0024085, “Development of a Field Demonstration for Cost-Effective Low-Grade Heat Recovery and Use Technology Designed to Improve Efficiency and Reduce Water Usage Rates for a Coal-Fired Power Plant.” This project was funded by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL). Southern Company Services, Inc. (SCS) was the prime contractor and co-funder of the project. The Electric Power Research Institute, Inc. (EPRI) and AECOM were project team members.

ACKNOWLEDGMENTS

The following organizations, under contract to SCS, prepared this report:

AECOM Technical Services
9400 Amberglen Boulevard
Austin, TX 78729
Principal Investigators:
K. Dombrowski
M. Bernau
D. Morett

EPRI
3420 Hillview Avenue
Palo Alto, CA 94304-1338
Principal Investigators:
A. Maxson
S. Hume

This report describes research sponsored by U.S. DOE-NETL and SCS.

Executive Summary

Coal-based power generation systems provide reliable, low-cost power to the domestic energy sector. These systems consume large amounts of fuel and water to produce electricity and are the target of pending regulations that may require reductions in water use and improvements in thermal efficiency. While efficiency of coal-based generation has improved over time, coal power plants often do not utilize the low-grade heat contained in the flue gas and require large volumes of water for the steam cycle make-up, environmental controls, and for process cooling and heating. Low-grade heat recovery is particularly challenging for coal-fired applications, due in large part to the condensation of acid as the flue gas cools and the resulting potential corrosion of the heat recovery materials. Such systems have also not been of significant interest as recent investments on coal power plants have primarily been for environmental controls due to more stringent regulations. Also, in many regions, fuel cost is still a pass-through to the consumer, reducing the motivation for efficiency improvements. Therefore, a commercial system combining low-grade heat-recovery technologies and associated end uses to cost effectively improve efficiency and/or reduce water consumption has not yet been widely applied. However, pressures from potential new regulations and from water shortages may drive new interest, particularly in the U.S. In an effort to address this issue, the U.S. Department of Energy (DOE) has sought to identify and promote technologies to achieve this goal.

DOE contracted with Southern Company Services (SCS), who in turn partnered with the Electric Power Research Institute, Inc. (EPRI) and AECOM Technical Services (AECOM) to investigate this issue under the project entitled “Development of a Field Demonstration for Cost-Effective Low-Grade Heat Recovery and Use Technology Designed to Improve Efficiency and Reduce Water Usage Rates for a Coal-Fired Power Plant.” The project team conducted an engineering study with two primary objectives. The first was to survey available heat recovery and use technologies (HRUT) and evaluate their potential to cost-effectively recover low-quality heat and use it to improve system efficiency and/or reduce water consumption. The second was to develop the conceptual design and cost estimate for a potential pilot demonstration of the selected technology that would be conducted within the next few years as well as an estimate for the cost of a potential future full-scale installation.

As a prelude to the technology survey work, EPRI solicited feedback from a number of U.S. coal power generators to assess the industry’s interest in the recovery and use of low-grade heat. The response was tepid for several reasons: the potential for the resulting efficiency improvement to trigger a costly New Source Review (NSR); concern about retrofitting plants due to lack of space, required downtime, and potential for operation and maintenance (O&M) issues/outages; limited opportunity for several potential heat uses (e.g., there is no opportunity for cogeneration and/or water management is not considered a limiting factor for most cases); and lack of interest to invest in existing coal power plants. However, if a clear, attractive payback can be established for these technologies, one that overcomes any perceived risks, most thought they at least would be considered. This feedback was used to shape parts of the technology survey process, which was divided into three subtasks: 1) the establishment of the design basis; 2) identification of candidate technologies; and 3) collection of information for use in the evaluation.

The goal of the first subtask was to establish a design basis that would allow the technologies to be compared on a consistent basis. Input was provided by DOE to assist in developing the process parameters for a 550-MWe net unit burning an Illinois #6 bituminous coal, equipped with an SCR for NO_X control, a fabric filter baghouse for particulate control and wet flue gas desulfurization (wFGD) for SO_2 control. The project team added a lime injection system for SO_3 control upstream of the baghouse to the DOE Baseline Study Case 9 550-MW subcritical pulverized-coal plant [1]. SCS supplied information for a ~1-MWe pilot demonstration host site, elements of which were then incorporated into the overall design basis.

The second subtask was to identify candidate HRUTs. This was accomplished by a literature review and interviews with selected experts. The team identified 38 technologies for consideration that ranged from commercial to conceptual and represented a variety of heat recovery and/or use solutions. These included bottoming cycles, heat exchangers, heat pipes, thermoelectrics, and water treatment systems, along with several other approaches.

In the third subtask, information was gathered for the identified technologies and then evaluated using a scoring methodology to determine the best candidate(s). The approach was to establish a two-phase request for information. In the first phase, a set of high-level screening questions was prepared and used to conduct interviews with the technology providers for each candidate technology. The responses were reviewed to eliminate upfront those that were either not feasible for this application or uninterested in participating. This step reduced the number down to 24 candidates. A more detailed set of questions was then submitted to the remaining technology providers, 16 of which ultimately responded, the information from which was used to score candidates relative to one another to guide making final recommendations.

At the conclusion of the second-round evaluation process, the highest-scoring technologies were Gas Technology Institute's (GTI) transport membrane condenser (TMC) and LJUNGSTRÖM's technology for enhanced air-heater (AH) operation. Primary reasons these technologies scored well in the second-round assessment were the relatively low cost and significant benefits as provided by the organizations, few perceived negative impacts on power plant operation, and strong organizations backing them.

GTI's TMC simultaneously recovers water and its latent heat as well as sensible heat from the flue gas, producing benefits for both power plant efficiency and water consumption rate. The technology has previously been applied to gas-fired industrial boilers and piloted on a small scale at a coal plant. It would be installed downstream of the wFGD in a coal-fired boiler application. In the approach from LJUNGSTRÖM (a division of ARVOS Group), the flue gas is treated upstream of the AH to remove acid gases and the surface area of the AH is increased to facilitate the removal of more heat from the flue gas. The energy is transferred from the flue gas to the combustion air, which improves boiler efficiency and reduces the amount of water needed for evaporative cooling of the flue gas entering the wFGD. GTI and LJUNGSTRÖM's technologies were then reviewed in more detail in a final evaluation round to better assess their costs and benefits. AECOM conducted an engineering analysis to develop a conceptual design and indicative costs for the installation and operation of the technologies for the specified baseline commercial-scale coal power plant. Costs are shown as ± 30% due to the lack of project definition; each system was costed for a hypothetical plant. The cost-benefit analyses accounted for the capital and O&M costs and both efficiency and generation improvements. High-level results from these analyses include:

- **GTI –** The benefits analysis showed that for the commercial-scale TMC system, the increase in electrical generation as a result of the recovered heat from the flue gas was 1 MWe; additionally, the estimated water recovery of 104 gallons per minute constituted 140% of the boiler makeup water needed for the steam-condensate system. Upon detailed evaluation, the cost for constructing and installing the system at a typical 550-MW plant was found to be more expensive than GTI's original estimate. The best way to significantly decrease the cost of the system, determined by AECOM to be $63M ± 30%, is to advance the technology such that significantly fewer modules are needed, to the point that it can be installed in and supported by the overhead space above the scrubber (i.e., not requiring a separate structure). Under this scenario, AECOM estimated the cost could be reduced to approximately $26M for the entire system, resulting in a capital cost of $250,000/gpm of high quality water recovered, or $26,000/kW of additional electrical generation.

- **LJUNGSTRÖM –** An increase in plant efficiency of up to one percentage point can be obtained by upgrading the regenerative AH to recover more heat from the flue gas. For plants firing medium- and high-sulfur coals, the AH upgrade will need to be acc ompanied by alkaline solution injection upstream of the AH to reduce flue-gas SO_3 concentrations to avoid AH corrosion. The combined systems provide several environmental benefits including: reduction in scrubber blowdown volume, reduced water usage in the wet FGD due to lower evaporative losses, and air emissions reductions for several pollutants. AECOM estimated the cost for the combined system at $18.1M ± 30%. For a 1 percentage point increase in net plant efficiency, this capital cost translates to $73,000/Btu/kWh for the improvement in net heat rate.

Findings from the project indicated that incorporating low-grade heat into the steam cycle as boiler feedwater preheating increases the heat input and overall plant efficiency, but actually lowers steam cycle efficiency. For example, raising the water temperature prior to the low-pressure (LP) heater train will divert steam away from extraction and continue through the LP turbine (more output), however, more steam reaches the condenser to be rejected by the cooling tower. If a wet tower is used, the increased heat load will result in more evaporation losses in the tower. Furthermore, the boiler feedwater handling system is typically on the opposite end of the plant from the flue-gas clean-up system, potentially resulting in significant capital costs for the pipe to convey the feedwater to the heat source. Overall, if low-grade heat is to be used, in many instances applications should be outside the steam cycle such as preheating combustion air, drying coal, water treatment, or any variety of non-steam cycle enhancements – if the economics are justified.

Table of Contents

Executive Summary v

Coal Power Industry Survey 11

Technology Evaluation Overview 16

Second Round of Evaluations 18

Heat Exchangers 21

Water Treatment 36

Bottoming Cycles 45

Other 53

Detailed Cost Estimate and Design 59

Conclusions 80

Appendix A: Detailed Questionnaire for HRUT Selection 82

Appendix B: Reference Data 87

Appendix C: Complete List of Technologies Reviewed 93

Appendix D: Check on Efficiency Improvement for LJUNGSTRÖM's Commercial-Scale System 97

Appendix E: Cost Information for LJUNGSTRÖM's Pilot-Scale System 100

Appendix F: Design and Cost Evaluation for GTI's Pilot-Scale TMC System 101

Appendix G: Exergy Analysis 105

Works Cited 109

List of Figures

Figure 1. Planned Capacity Factors for Coal Power Plants 13

Figure 2. LJUNGSTRÖM® AH [4] 25

Figure 3. AH Upgrade by Filling Empty Voids in AH Rotor with Additional Basket Layers [5] 26

Figure 4. GTI's TMC Module [6] 27

Figure 5. Schematic of the TMC Concept [6] 29

Figure 6. Porifera Treated Water (left) and Pilot System (right) [7] 38

Figure 7. SSI System High-Level Diagram [8] 39

Figure 8. Vacom System Process Flow Diagram [9] 40

Figure 9. T-s Diagram for a Dry (left) and Wet (right) Rankine Cycle; 1-2: Compression, 2-3: Heat Input, 3-4: Expansion and Work Output, 4-1: Condensation [12] ... 46

Figure 10. Organic Rankine Cycle Process Flow Diagram [13] ... 46

Figure 11. Cross-flow Heat Exchange Temperature Profile [14] ... 47

Figure 12. Left Shows the System in an M1/A2 Abrams Tank Exhaust; Right Shows the Heat Exchanger Coupled with the TEGs [18] ... 55

Figure 13. TMC Integration Diagram [6] ... 68

Figure 14. (Left) Three Planes of Modules; (Right) Arrangement Showing One Module from Each Plane Acting as a Cross-flow Heat Exchanger ... 69

Figure 15. Simplified General Arrangement of TMC System ... 70

Figure 16. Simple Piping and Instrumentation Diagram (P&ID) of TMC Train ... 73

List of Tables

Table 1. Survey Questions for Utilities with Coal Power Generation ... 11

Table 2. Operational Data on Coal Power Plants ... 12

Table 3. Scoring Criteria and Associated Weighting Factors ... 18

Table 4. Final Rankings ... 20

Table 5. Detailed Second-round Evaluation of the Heat Exchangers ... 31

Table 6. Detailed Evaluation of the Water Treatment Technologies ... 41

Table 7. Detailed Second-round Evaluation Results for Bottoming Cycles ... 51

Table 8. Detailed Second-round Evaluation of GRE, Novus, and SSI technologies ... 57

Table 9. Information for Cost Analysis on AH ... 64

Table 10. TMC Train Dimensions and Gas Velocity ... 69

Table 11. TMC Train Equipment List ... 72

Table 12. Mass Balance Assumptions ... 74

Table 13. Flue Gas and Steam Condensate Conditions at Each TMC Train ... 75

Table 14. Extraction Flow Rate for Feedwater Heater 1 ... 75

Table 15. Benefit Analysis Commercial-Scale TMC System (2015 dollars) ... 76

Table 16. Cost Summary ... 76

Table 17. Materials and Construction Costs ... 77

Table 18. Construction Direct Labor Costs Breakdown ... 77

Coal Power Industry Survey

As a prelude to the study on heat recovery and use technologies (HRUT), EPRI sought feedback from utilities with coal-fired power generation on their experience with and interest in HRUT, particularly those technologies that obtain low-grade heat from the flue gas after the air heater (AH). The goal of this feedback was to use it to help shape the project. Ultimately, seven major U.S. utilities, representing over 50 GW of coal power, were interviewed both verbally and using a survey of questions given in Table 3. Responses were kept anonymous to protect the confidentiality of each utility respondent.

Table 1. Survey Questions for Utilities with Coal Power Generation

1. How many coal-fired plants do you have in your portfolio and what are their MW capacities? Can you provide information on their average efficiencies / capacity factors (CF), coal quality, environmental controls, and operating conditions (e.g., steam conditions) on these plants?
2. Do these plants have variation in operating conditions (load and coal quality in particular)?
3. Is there available space around your plants for installing new equipment if desired, especially downstream of the boiler?
4. Do any of these plants have water-related issues—either lack of extant water for makeup (now or in the future) or water cleanup issues or concerns, especially around SO_2 scrubbing? Is there a need/potential use for improved water cleanup at any of your plants or additional water (either at the plant or in the surrounding community)?
5. What are your short- and long-term plans for operating these plants—will CFs be changed? Do you anticipate any plants being decommissioned? If so, why? Do you foresee any coal-fired new builds in the future?
6. How important is efficiency as a metric/operating goal for your coal-fired power plants? What is driving its importance or lack thereof? Have the proposed EPA 111(b) & (d) regulations driven any review of efficiencies and new goals for improving them at your coal plants?
7. How have you tried to improve efficiency at any of your operating coal-fired plants by updating processes or existing technology? If so, what have you done and what lessons were learned? Are you planning on implementing any future process changes designed to improve efficiency?
8. Have you made any capital investments on new technology designed to improve efficiency? If so, what technologies have you used and what has been the outcome? What was your selection methodology for these technologies? How important was the maturity of the technology in your buying decision?
9. Have you looked at/are you interested in low-temperature heat recovery as a potential option for improving efficiency and/or obtaining low-grade heat for on- or off-site use? If you have investigated this option, which technologies/concepts have you looked at? If you have installed any, what have been your operational experiences?
10. If you have looked at low-temperature heat recovery and rejected it (at least for now), why did you do so? What were your biggest concerns?
11. If you have not thought about low-temperature heat recovery as an option previously, what additional information would help to drive your interest in low-temperature heat recovery?
12. If you could obtain low-grade heat what options for its use would make the most sense for your coal plants? Would you consider using the heat for coal drying, converting it into usable shaft

	power to replace electric motors, low-cost refrigeration or heating, ventilation, and air conditioning, pre-heating of boiler feedwater (potentially replacing feedwater heaters), or something other?
13.	Are there low-grade heat cogeneration opportunities near any of your plants (e.g., district heating)?
14.	Do you have interest in improving/updating any water cleanup around your plant especially related to SO_2 scrubbing (e.g., by heating of applicable water-treatment processes or generating water on-site (e.g., by desalination)?

A summary of the information collected for each question given in Table 1 is shown below.

- Data collected for Question 1 are given in Table 2.

Table 2. Operational Data on Coal Power Plants

Total Installed Capacity, MW	47,645
Average Unit Size, MW	497
Efficiency, % Net (HHV)	
Min	24
Max	38
Average	32
CF, %	
Min	2
Max	99
Average	66
Coal Type, % of Fleet	
Bituminous	71.4%
Lignite	0.6%
Sub-Bituminous	27.9%
Environmental Controls, # of Installations	
Low-NOx Burners	86
Selective Catalytic Reduction (SCR)	37
Selective Non-Catalytic Reduction	18
Baghouse	14
Electro-static Precipitator (ESP)	84
Mercury Abatement	2
Dry FGD	1
wFGD	58
Steam Conditions, % of Fleet	
Subcritical	51.6%
Supercritical	46.6%
Ultra-Supercritical	1.8%

- For Question 2, 41% of the coal plants were currently operating at baseload, 57% were operating on daily shift cycles, and only 2% were used for peaking duties. Some had a wide range in ash and moisture as many plants were taking advantage of the opportunity to use cheaper coals, but many used a fixed coal quality with PRB being the most prevalent.

- For Question 3, nearly 75% of coal power plants had significant spatial constraints, making new equipment difficult to accommodate, while only 7% had no restrictions.
- For Question 4, the vast majority of coal-fired plants were stated to have adequate water supply within the next 5 to 10 years, while less than 2% had a limited supply of water. Similarly, over 75% of the coal-fired plants were perceived to have adequate water treatment capabilities for SO_2 scrubbing, while less than 15% were considering water treatment upgrades. Hence, new and improved technology for water treatment was not considered a priority for most coal power plants at this point in time save for select regions.
- The results from Question 5 are shown in Figure 2. None of the utilities interviewed had any current plans for construction of new systems or significant updates of existing systems and most expressed it was unlikely their utility would build any new coal plants after 2035 and highly unlikely before 2035. All believed some plants would be decommissioned in the future. Many saw CFs dropping on existing plants especially in the long term, although a plurality of the plants expected to maintain current CF in both the short and long term. Lowered CFs will reduce the desire to invest in a plant, and make any benefits from technologies that improve efficiency smaller.

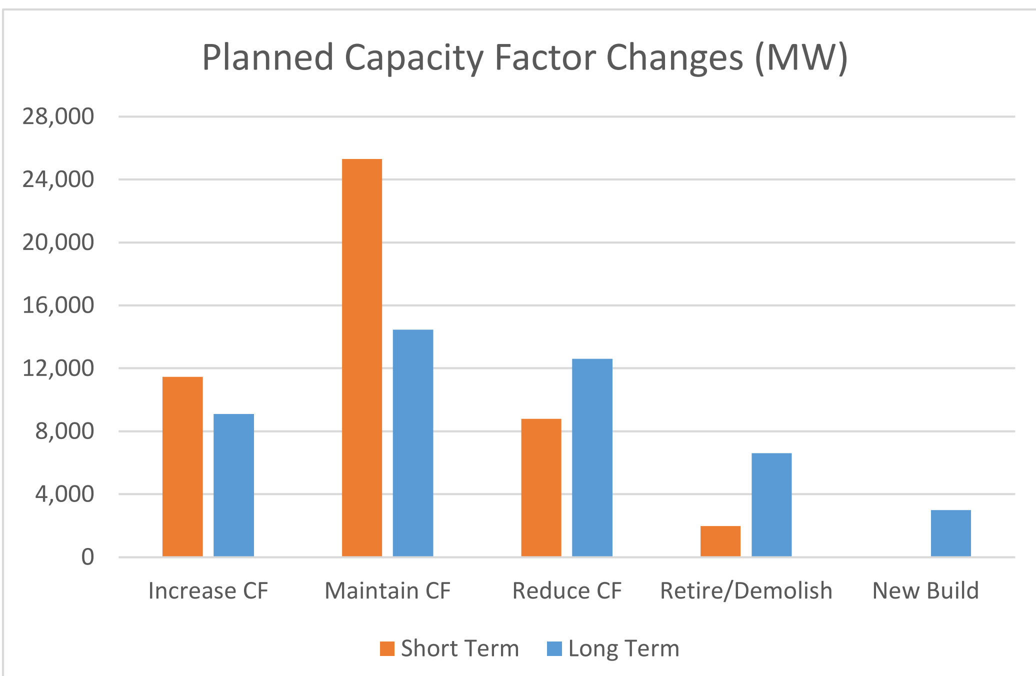

Figure 1. Planned Capacity Factors for Coal Power Plants

- For Question 6, while all said efficiency was important, impacts from 111 (b) and/or 111 (d) were given as the most compelling reason to review plant efficiency, retire plans, and to change operating missions. As these regulations were uncertain, utilities were unlikely to invest in HRUT or other efficiency improvements until the regulations became clearer, although they were likely to research potential ways to improve efficiency.

- For Question 7, all respondents had implemented steam-turbine upgrades on coal power plants. Most have carried out feed water heater upgrades and cooling system upgrades (condenser or tower). Only one example of a low-temperature HRUT (used to feed coal drying process for lignite fuel) was given as operational at any plant in any of the seven utilities interviewed. Most thought that capital expenditures on efficiency improvements were unlikely to be a priority, which negatively impacts the potential for HRUT installations.
- For Question 8, all had implemented some form of efficiency improvements on coal-fired power plants, with steam turbine upgrades being the principal type. In general, a cost-benefit analysis was used to assess the value of installing new technology, with the maturity level being important, but not essential (although some type of demonstration or reference was typically required).
- For Question 9, only two of the seven utilities interviewed had investigated HRUT options and only one had installed one. Most stated it was not a priority in comparison to the tasks associated with keeping the plants operating.
- For Question 10, the most important concerns with HRUT were cost, future plans for the plant not warranting investment, potential fan limitations, and lack of space.
- For Question 11, the most important factors when looking at HRUT were given in this order of priority:
  - Cost
  - Efficiency improvement
  - Impact on performance
  - Potential for reduction in hazardous air pollutants
  - Reliability
  - Method of heat utilization.

  Things that were not considered as important included:
  - Decreased water consumption
  - Improved ESP performance
  - Reduced SO_3 emissions.
- For Question 12, the most important uses for heat were for additional power and coal drying (all thought these would be useful applications); other uses such as feed water heating or refrigeration were seen as less appealing. However, in all cases, respondents expressed that if a business case could be made for an HRUT, they would potentially look at it, regardless how the heat was used.
- For Question 13, there was little opportunity for cogeneration at most plants and no opportunity for district heating as most plants were either remote or not situated close enough to industries that could use heat.

- For Question 14, the most important applications when looking at water treatment were given in this order of priority:
    - FGD waste water treatment
    - wFGD makeup reduction
    - Cooling tower makeup reduction
    - Generation use.

Based on discussions had with the respondents along with an analysis of the responses to the survey questions, these high-level conclusions were drawn related to HRUT:

- The potential for NSR was seen as a major obstacle, as there were legal implications for the owner and the costs could be significant
- Planned reductions in CF will make investments harder to justify for coal power plants until or unless regulations drive it
- Most plants did not have space to accommodate new processes easily
- Required downtime for installation and the potential risk of increased O&M cost and outages were seen as a detriment, although this is true for the retrofit of any new equipment
- Reducing the final temperature of the flue gas was perceived as a potential risk for impacting plume dispersion, which in turn could impact ambient air quality standards
- There were limited opportunities seen for heat use and, in particular, there were little cogeneration and no district heating opportunities identified. However, using recovered heat within the fence, particularly to generate more power or to dry coal, was seen as a potential benefit.
- Respondents were generally not water constrained; however, reducing FGD or makeup could be of interest.

Many of the responses from the survey were negative in tone due to the current decline in coal power generation in the U.S. However, all respondents said that if a clear, attractive payback could be established for HRUT technologies, one that overcomes any perceived risks, the technologies would be considered. All thought if regulations drove the need for improved efficiency that HRUTs would be given more priority to be investigated.

Technology Evaluation Overview

The project team investigated potential technologies – both commercial and developmental – that can recover low-grade heat from a coal flue gas and then use it elsewhere. In some cases, the technology is capable of performing both functions, while some were either heat recovery or heat use and hence needed another technology to be coupled with it. The selection of potential candidate technologies investigation was conducted by a literature review and was based on the project team's knowledge on this topic.

The selected potential technologies that could recover and/or use heat from the flue gas were broken down into several technology types:

- **Bottoming Cycles –** Convert low-grade heat into additional electrical power generation using a thermodynamic cycle with a working fluid.
- **Heat Exchangers –** Transfer heat between the flue gas and another fluid (e.g., boiler feedwater), sometimes through an indirect medium. A special case is heat exchangers that employ condensation heat recovery to capture the latent heat of the water in the flue gas.
- **Heat Pipes –** Transition between phases of a fluid to transfer heat between two solid interfaces along a pipe.
- **Thermoelectrics –** Create voltage and hence power generation when there is a temperature difference maintained on each side of two semiconductors.
- **Water Treatment –** Uses low-grade heat in the cleanup treatment of waste water (generally wFGD waste water).
- **Coal Drying –** Apply low-grade heat to evaporate water and remove pollutants from the incoming coal.

38 technologies were reviewed in these categories. Each organization associated with the technology was contacted to obtain high-level information for a first-round evaluation, which acted as a screening to winnow down the technologies. A set of criteria was established that was required for the technology and its organization, namely:

- Organization must be willing to share information publicly and participate in the project
- Can be used with flue gas from a coal power plant
- Must be able to work with flue-gas temperatures of 350°F or less
- Must be able to be used or scaled up to a gas flowrate ≥1000 scfm within the next 2 years.

Those technologies that passed these criteria (24 in total) then progressed to a second round of evaluations. In this round, a more detailed questionnaire (given in Appendix A) was provided to the organizations adding to the previous information that had been collected along with any interviews and meetings that had been held. The design basis (given in Appendix B) was included in the survey packet so that the organizations could develop responses according to a consistent set of parameters. Note that several organizations that were selected for this round then decided to not participate, leaving 16 total (as one organization submitted two uses of its technology, 17 total technologies were ultimately assessed).

Second Round of Evaluations

A scoring matrix was developed so that the detailed information collected could be compared on a relative basis, and each technology could then be assessed based on its application to the design basis. The matrix was divided into five major categories:

- Organization experience
- Design and operation
- Technology (benefits, O&M, availability, and safety)
- Potential for future improvements
- Costs

The team established a weighting system for every item in the scoring matrix, since some parameters have a greater impact on the suitability of a particular technology. The weighting for each criterion was given based on the team's assessment of its relative importance. A relative score of "High", "Medium", or "Low" was given for each item for each technology with High scores given a 9, Medium a 3, and Low scores a 1. The final score for each technology was then non-dimensionalized into a percentage. In this way, each technology was given a quantitative score between 0 and 100%. The list of criteria and their relative weights is given in Table 3.

Table 3. Scoring Criteria and Associated Weighting Factors

Criteria	Weight %	Total %
I. Organization Experience	**10.0%**	**---**
A. Tech Experience	*50.0%*	5.0%
B. Organizational Experience	*20.0%*	2.0%
C. Size	*30.0%*	3.0%
II. Design and Operation	**25.0%**	**---**
A. Design	30.0%	---
1. Soundness of Design	*50.0%*	3.8%
2. Integration Complexity	*50.0%*	3.8%
B. Operation	70.0%	---
1. Response to Load Changes	*35.0%*	6.1%
2. Impact on Startup Times	*35.0%*	6.1%
3. Acceptable Flue Gas Composition	*15.0%*	2.6%
4. Pressure Drop	*15.0%*	2.6%
III. Technology	**30.0%**	**---**
A. Benefits	70.0%	---

Criteria	Weight %	Total %
1. Efficiency	*40.0%*	8.4%
2. Water Treatment	*15.0%*	3.2%
3. Water Use/Generation	*15.0%*	3.2%
4. Environmental	*30.0%*	6.3%
B. Operations, Maintenance, Availability, and Safety	30.0%	---
1. Operations	*25.0%*	2.3%
2. Maintenance	*25.0%*	2.3%
3. Availability	*25.0%*	2.3%
4. Safety	*25.0%*	2.3%
IV. Potential for Future Improvements	**2.5%**	**---**
A. Future Technology Improvements	50.0%	1.3%
B. Future Integration Improvements	50.0%	1.3%
V. Costs	**32.5%**	**---**
A. Commercial-Scale Plant Capital Cost	40.0%	13.0%
B. Cost-Benefit Analysis	40.0%	13.0%
C. Pilot Plant Capital Cost	20.0%	6.5%
Total Score (Out of 100)	**100.0%**	**100%**

The responses from each of the 16 providers were reviewed and the two highest-ranked technologies were selected for a detailed design and level four cost estimate performed by AECOM for both a pilot- and commercial-scale system. The rankings based on the scoring for each technology, along with its type and technology readiness level (TRL),[1] are given in Table 4.

It is important to keep in mind the rankings shown are only pertaining to how a technology applies to a 550-MW power plant burning bituminous coal under the specified constraints of this project and may not reflect the quality of the technology in the market for which it was designed or its fit into another type of plant (e.g., one using a different coal type). Additionally, the project team believes there was likely variation in the fidelity of both the performance metrics and system costs provided from organization to organization, especially for low-TRL technologies. For this reason, more detailed technical and cost analyses were performed for the top two technologies, GTI and LJUNGSTRÖM, with results from this final evaluation presented later in this document.

The efficiency increase each system could provide to the plant was the second-highest weighted parameter after cost as shown in Table 3. The team received these values several different ways from

[1] The formal concept of TRLs was originally developed for use by NASA as a way of comprehensively assessing the development of specific technologies for launch deployment. TRLs have been adopted by other organizations as a way of categorizing a technology's maturity and its closeness to commercial readiness, including the DOE.

the developers surveyed. Where possible, these numbers were converted to a common basis. For the purposes of this report, a 1 percentage point increase in efficiency refers to an increase in the reference plant's net thermal efficiency from 36.8% to 37.8%. This equates to an approximate 2.7% reduction in fuel use and heat rate.

Table 4. Final Rankings

Rank	Organization	Type	TRL
1	GTI	Heat Exchanger (Condensing Heat Recovery)	6
2	LJUNGSTRÖM	Heat Exchanger	9
3	ConDex	Heat Exchanger (Condensing Heat Recovery)	9
4	Sylvan Source, Inc. (SSI)	Heat Pipe	4
5	SSI	Water Treatment	5
6	Wallstein Group	Heat Exchanger	9
7	PAX Pure	Water Treatment	5
8	Flucorrex	Heat Exchanger	9
9	Mitsubishi Hitachi Power Systems (MHPS)	Heat Exchanger	9
10	Recurrent Engineering	Bottoming Cycle	8
11	Porifera	Water Treatment	4
12	Novus Energy Technologies (Novus)	Thermoelectric	5
13	Great River Energy (GRE)	Coal Drying	8
14	Turboden	Bottoming Cycle	8
15	Ormat	Bottoming Cycle	8
16	Vacom Systems (Vacom)	Water Treatment	8
17	e-Tech	Heat Exchanger (Condensing Heat Recovery)	7

Details on each technology (broken down by type), along with the second-round responses for each category, are given in the following sections. Overall, the responses represent those provided by each organization. However, there are many instances where the project team either paraphrased responses or rephrased them. For instance, many technologies do not provide a co-benefit of removing pollutants; in these cases the responses for "Benefits – Environmental" were altered to "No pollutant removal."

Heat Exchangers

The heat exchanger category represents a group of technologies that transfer heat from the flue gas to one or more other fluids. In the context of their application after AHs, these devices act more or less like low-temperature economizers. Typically, the heat recovered from flue gas is used to heat feedwater within the power cycle or to reheat flue gas, but could be used for other purposes including water treatment.

Multiple organizations were reviewed in the heat exchanger technology category. A complete list of the heat exchanger technologies that were considered for this study is presented in Appendix C. Those that progressed past the initial evaluation round of evaluation were the following:

- ConDex
- e-Tech
- Flucorrex
- GTI
- LJUNGSTRÖM
- MHPS
- Wallstein Group.

Background on the conventional flue-gas heat exchanger technologies and results from the assessment of their detailed questionnaire responses are summarized below. Since LJUNGSTRÖM's and GTI's technologies were chosen for more detailed review, the descriptions of these technologies were provided in separate write-ups following the discussion of the other flue-gas heat exchangers.

Technical Background

Heat exchangers recover heat from the flue gas by indirect contact of water or another heat transfer medium with the flue gas. Typically, large heat exchangers are required to recover an appreciable amount of thermal energy in the temperature ranges and locations included in this study. The heat recovered can then be used to pre-heat boiler feedwater, combustion air, re-heat flue gas, or to supply heat to other systems, thereby increasing plant efficiency. The primary benefit of pre-heating the boiler feedwater to the power cycle is a reduction in the steam extracted from the turbines to heat the boiler feedwater, thereby increasing the turbines' gross power production. Increasing heat transfer from the flue gas to the combustion air improves boiler (and overall plant) efficiency. The recovered heat can also be used to re-heat the plant flue gas downstream of the wFGD unit to reduce plume visibility and condensation occurring in the stack; this configuration does not improve plant efficiency but will reduce evaporative water consumption in the wFGD due to the decreased flue-gas temperature at the inlet to the wFGD. The design and operational features of these heat exchangers can vary as described in the following sections.

Condensing vs Non-condensing

Condensing heat exchangers are designed to cool the flue gas below the dew point of the gas moisture, thereby recovering the latent heat of condensation and achieving greater thermal energy recovery than non-condensing systems. Condensing systems may require more expensive, corrosion-resistant materials, and many of the condensing systems are only in the development phase for coal flue gas applications. Organizations with condensing heat exchangers that responded to the detailed questionnaire included ConDex, e-Tech, GTI, and Wallstein Group. Non-condensing heat exchangers only exchange sensible heat between the flue gas and the cooling medium. Organizations with non-condensing heat exchangers that responded to the detailed questionnaire included LJUNGSTRÖM, Flucorrex, and MHPS.

Heat Exchanger Surface Materials and Design

Materials of construction can include carbon steel and stainless steel, as well as corrosion-resistant coatings such as phenolic materials, enameled liners, fluoropolymer materials, and other plastic materials. The use of these corrosion-resistant coatings will increase the surface area required in heat exchangers due to the lower thermal conductivity of polymer coatings when compared to carbon steel [2]. For example, it has been estimated that a heat exchanger using 2-inch polytetrafluoroethylene (PTFE) tubes (without a carbon-steel enclosure) will require twice the surface area for heat exchanger tubing when compared to a 2-inch carbon steel pipe coated with only 0.0015-inch thick PTFE.

ConDex

The ConDex heat exchanger recovers heat from the flue gas after the particulate control device (baghouse or ESP) at temperatures around 300°F. Typically this heat is then used to heat feedwater from approximately 100°F to 180°F. The ConDex system is constructed of stainless steel; all surfaces exposed to flue gas are coated with Heresite, a baked phenolic corrosion- protection material.

e-Tech

e-Tech's heat recovery system is an application of new corrosion-resistant metallurgy to conventional tubular heat exchangers. The new metallurgy is known as S-Ten Tube and is made by Nippon Steel & Sumitomo Metal Corporation. It is a modification of Corten Steel with a small amount of antimony added to the alloy.

Flucorrex

The Flucorrex heat exchanger uses two water-gas heat exchanger modules with a combination of plastic and enamel-lined steel tubes to recover heat from flue gas after the ESP or baghouse at temperatures around 300°F. The recovered heat is transferred to the boiler feedwater, increasing the temperature from 120°F to approximately 200°F. The coating for the tubes and tubesheet is designed for a maximum temperature of 338°F, but can be upgraded for a maximum temperature of 464°F.

MHPS

MHPS' technology is composed of finned-tube heat exchangers made of carbon steel and requires a certain ash load in the flue gas to protect the carbon steel from SO_3 corrosion. If there is not enough ash or solids in the flue gas upstream, additives such as limestone or lime need to be injected. The system can be integrated downstream of the AH to recover heat from the flue gas at temperatures around 300°F. The recovered heat can be used in the boiler/steam turbine Rankine cycle to improve the efficiency of the unit; actual integration has been demonstrated in a DOE-funded pilot demonstration at Alabama Power's Plant Barry. Alternately, the recovered heat can be used to reheat the wet-FGD exhaust to reduce plume visibility and condensation occurring in the stack, as currently employed at commercial coal-fired power plants in Japan [3].

Wallstein Group

Wallstein Group's heat-recovery system uses a closed water circuit to either preheat feedwater, combustion air, or water for district heating and consists of:

- Flue-gas cooler with fluoropolymer tube bundles to extract the heat (casing lined with fluoropolymer foil)
- Heat exchanger to heat up either water or air
- Water circulation system using a redundant pump group with a pressure maintaining system
- Conditioning system with pH measurement and NaOH-dosing for the water circuit to neutralize acids partially diffused through fluoropolymer tubes
- Emergency quenching system installed in the duct before the flue-gas cooler to protect the tube bundles from excessive flue-gas temperatures.

Location of the Heat Exchanger

While placement of the heat exchanger may be dictated by site-specific space constraints, it is generally placed downstream of the particulate control device, and located after the induced draft fans to take advantage of the temperature increase across the fans. If placed upstream of the particulate control device (such as with MHPS' technology), the heat exchanger can aid in the removal of particulate matter (PM) and trace metals by enhancing the ESP performance due to reduced flue-gas temperature. An issue that can arise when placing the heat exchanger upstream of the particulate control device is that the alkaline ash and sulfuric acid can form a concrete-like substance that is difficult to remove if not maintained properly; buildup of particulates on the heat exchanger surface can eventually lead to reduction of the overall heat-transfer coefficient. MHPS solves this issue with sootblowers that periodically clear ash off the heat exchanger tubes.

Temperature and Pressure

Typical inlet temperatures for heat exchangers used in these applications are approximately 250–350^{o}F. System pressure drop will increase due to placement of the heat exchanger in the flue-gas stream, which can require operating modification of the forced/induced draft fans. Reduction in bulk flue-gas velocity due to the decrease in temperature across the heat extractor can help mitigate this effect to some degree but may be minor.

Benefits

In the configurations in which recovered flue-gas heat is used to pre-heat boiler feedwater or combustion air, typically net plant efficiency gains of 0.1–1% points can be achieved. Other benefits include reduction in fuel consumption, generated CO_2, and wet FGD water consumption via lower evaporative losses from reduced flue-gas temperatures. Heat exchangers placed upstream of the particulate control device will increase mercury and PM removal via reduced gas temperature and velocity across the device.

Evaluation Summary

The detailed second-round evaluation of the flue-gas heat exchangers for the different organizations is presented in Table 5.The technologies from LJUNGSTRÖM and GTI were selected for more detailed design and cost analysis; they are discussed in the following sections.

Heat-exchanger technologies are generally mature, commercially-available technologies with advantages in design and operation, maintenance requirements, availability, and safety. These technologies are mostly supplied by well-established, large companies. The technology is relatively simple and generally well understood by power plant operators, as coal power plants already utilize multiple types of heat exchangers. Significant environmental benefits are associated with cooling the flue gas upstream of the particulate control device, including potential reductions in mercury and selenium from the flue gas and reduction of water evaporation from a wFGD unit.

These technologies all have relatively high capital costs compared to some of the other technology types surveyed; however, they were generally the most mature technologies in the survey. If regulations, e.g., the proposed Clean Power Plan, increase the need for improving efficiency, heat-exchanger technologies will likely be the first employed to achieve low-grade heat recovery from flue gases.

LJUNGSTRÖM

One option for recovering energy from coal flue gas is to improve the efficiency of the AH. The efficiency of existing AHs is often limited by the available heat transfer surface area and by the potential for AH corrosion from decreasing the flue-gas temperature below the sulfuric acid dew point. LJUNGSTRÖM offers technology to upgrade the AH heat transfer surfaces and other necessary components to increase the amount of heat recovered. To prevent acid gas corrosion from the resulting decrease in flue-gas temperature, LJUNGSTRÖM's retrofitted AH is coupled with an alkaline solution injection system to reduce flue-gas SO_3 concentrations to less than 5 ppm at the AH inlet.

Technical Background

AHs are standard equipment in electric utility coal-fired power plants. The function of the AH is to recover low-quality heat from the flue gas and transfer it to the combustion air to improve overall plant efficiency. The AH is typically located downstream of the boiler and NO_X control system and upstream of the particulate control device.

The most commonly installed AHs at electric generating utility coal-fired units are rotary regenerative AHs (Figure 2), which recover heat from the flue gas by means of a heat exchanger consisting of a rotating rotor filled with heat transfer plates. In a counter-flow regenerative AH, the air flow is typically upwards and the flue-gas flow is downwards.

The thermal energy recovered from the flue gas heats the part of the rotor located in its path; as the rotor moves, the heated plates move into the path of the combustion air and pre-heat it. The rotor contains a number of sections with seals that prevent the flue gases from mixing with the combustion air.

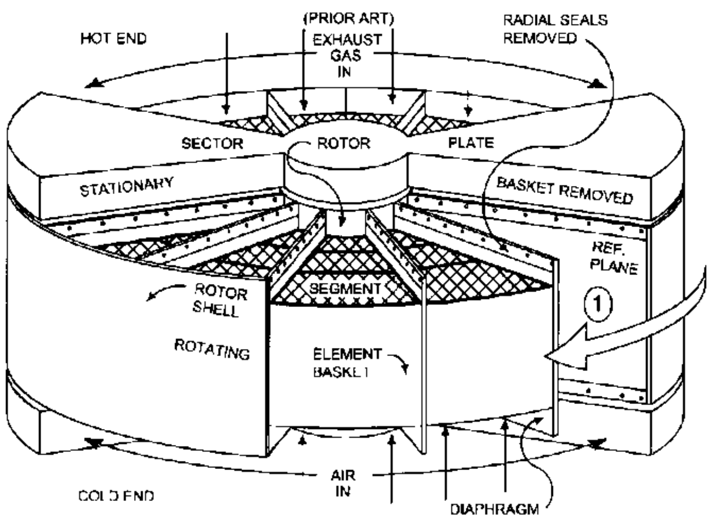

Figure 2. LJUNGSTRÖM® AH [4]

Rotary regenerative AHs are comprised of several layers of heat transfer surface; each layer consists of baskets of heat-transfer elements. The baskets closest to the flue-gas entrance of the AH are referred to as the hot-end baskets; conversely, the baskets closest to the exit of the flue gas from the AH are referred to as the cold-end baskets. The cold-end of the AH is the location most likely to experience corrosion due to acid gas condensation. Different sections of the AH use materials such as mild steel and low-alloy steel with porcelain (enameled) coating. Enameled coatings may be used for cold-end baskets to provide some protection against acid gas corrosion. The heat-transfer surfaces are designed to be replaced in intervals ranging from 4 to 10 years depending on the materials and location of the surfaces within the AH.

LJUNGSTRÖM offers significant improvement in AH heat transfer efficiency by one or more of the following upgrade options for the AH: increasing basket depth to fill void space in the rotor (Figure 3), using alternate basket designs to increase element depth, consolidating basket layers, switching to a more efficient heat-transfer surface, and/or modifying the rotor to increase available space.

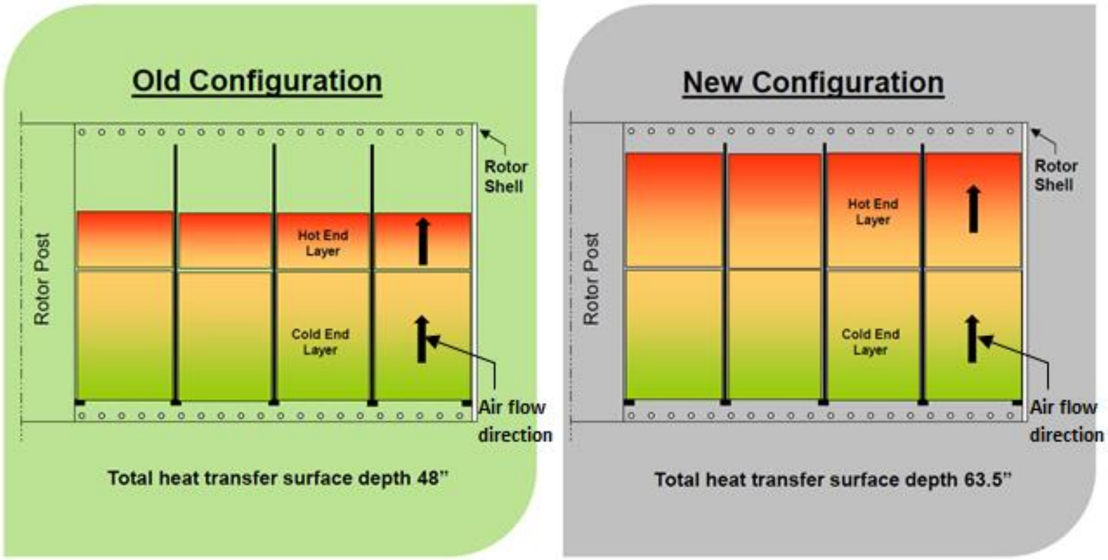

Figure 3. AH Upgrade by Filling Empty Voids in AH Rotor with Additional Basket Layers [5]

Combustion air inlet temperatures into the AH are variable and depend on the plant load, time of year, and whether the plant pre-heats the air prior to the AH. The temperature of the flue gas entering the AH is typically in the range of 500–800°F and flue-gas temperatures at the AH outlet can typically range between 260–425°F, depending on the configuration of the plant and the operating load. The lower limit for the flue-gas exit temperature is typically defined to avoid sulfuric acid dew point corrosion. By combining alkaline solution injection and AH upgrades, it is possible to lower the exit flue-gas temperature to 240°F. The alkaline solution is injected and spray dried in the flue gas upstream of the AH via an array of injection lances with atomizing nozzles. The solution neutralizes a significant portion of the gaseous SO_3, thereby lowering the acid dew point. The dried solids are then removed through the plant's particulate control device downstream of the AH. The alkaline solution injection lances require regular maintenance to ensure proper reagent atomization into the duct; obstructions of the spray pattern can lead to deposits buildup on the lance and within the duct. The proposed approach results in a potential 1–3 percentage point boiler efficiency improvement, or 0.5–1 percentage point plant efficiency improvement. An upgraded LJUNGSTRÖM AH with an alkaline solution injection system is currently operating at a 500-MWe Midwestern power plant.

Evaluation Summary

The detailed second-round evaluation of the LJUNGSTRÖM technology is presented in Table 5 with the other heat-exchanger technologies. In summary, LJUNGSTRÖM scored particularly well on design and operation and had good experience, references, and a solid cost-benefit analysis on top of environmental improvements that could be significant – potentially reducing water treatment and air pollution control costs and reducing outages and forced emission-related de-rates. The AH upgrade does not require any additional space at the power plant, a constraint expressed by utilities, since the new AH components can fit within the existing AH; the required space for the alkaline solution injection system is minimal since it only requires a storage tank for the reagent and an injection skid. LJUNGSTRÖM chose AECOM's SBS Injection™ to provide the SO_3 control required to achieve the requisite low (< 5ppm) SO_3

concentrations at the air heater inlet; LJUNGSTRÖM and AECOM have an exclusive co-marketing agreement for the installation of the technologies for air heater efficiency improvements. The cost of the AH upgrade can be significantly reduced for plants that do not require alkaline solution injection. These factors combined for the LJUNGSTRÖM technology to score within the top two of the technologies reviewed, leading to its being selected for the final round of evaluation. The information presented in this section only includes that provided by LJUNGSTRÖM in response to the detailed questionnaire; the final performance evaluation and engineering analysis performed by the team-members can be found later in Design and Cost Evaluation for LJUNGSTRÖM's Commercial-Scale System.

GTI

The TMC is a waste-heat and water recovery technology based on a nanoporous ceramic-membrane water vapor separation mechanism developed by GTI. A photo of a TMC module is shown in Figure 4. The technology extracts the water vapor and its latent heat from low-temperature, high-moisture content flue-gas streams. Water vapor condenses inside the membrane pores and passes through to the permeate side, which is in direct contact with a low-temperature water stream. Contaminants such as CO_2, O_2, NO_X, and SO_2 are inhibited from passing through the membrane by its high selectivity. The recovered water is of high quality and mineral-free, and therefore can be used as supplemental makeup water for almost all industrial processes.

Figure 4. GTI's TMC Module [6]

Technical Background

Membrane separation technology has been in commercial practice for many years for gas separation and liquid filtration and features low energy cost and high separation ratio compared with competing separation methods. There are two kinds of membranes: porous and non-porous. For porous membranes, the pore size is normally in the nanometer range. To achieve a good separation ratio with a porous membrane for gaseous species, including the separation of water vapor from flue gas, the typical pore size must be less than 50 nm.

When one of the gas components is a condensable vapor and the pores are small, capillary condensation can occur. In this mode of operation, vapor can condense below the saturation vapor pressure. Additionally, the condensate can block gas phase diffusion through the pores, allowing only the condensed phase to pass through. Thus, a very high separation ratio can be achieved for water vapor.

GTI has investigated water vapor transport from flue gas and found that a nanoporous ceramic membrane can achieve both high water vapor transport rate and high separation ratio when it works at favorable capillary condensation conditions. For high-moisture content coals and plants equipped with wet FGDs, the flue-gas humidity is typically 15% by volume downstream of the FGD. This provides a favorable condition for extracting water vapor from flue gas [6].

In the TMC, water vapor from flue gas passes through a permselective, nanoporous membrane (4 nm pore size) as shown in Figure 5 and is condensed by direct contact with low-temperature water. In this way, the transported water is recovered along with virtually all of its latent heat. The conditioned flue gas leaves the TMC at a reduced temperature and relative humidity below saturation.

GTI has experience with implementing the TMC system on natural gas fired boilers. As of 2012, there were four TMC systems in long-term operation. There was no detectable performance degradation after nearly three years of use. GTI performed slipstream testing at 500 scfm on coal flue gas under DOE funding in 2007 and is currently conducting a DOE project to design and build a lab-scale device (500 scfm) to test an improved design, which should provide higher efficiency gains, handle higher-sulfur coals, and reduce capital costs.

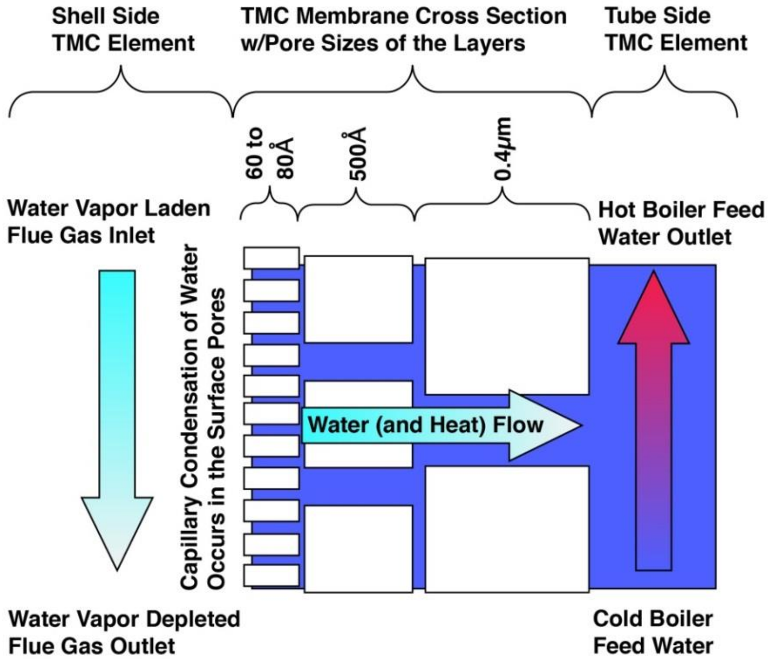

Figure 5. Schematic of the TMC Concept [6]

Key details of the technology:

- The technology can work on coal flue gases and can operate in the 150-400°F range, but for this application, GTI located the system downstream of the wFGD (135°F) and before the stack.
- Ancillary equipment includes pumps that are external.
- The system requires a separate control system.
- The system captures water and heat from the flue gas. Around 50 to 70% of the flue-gas moisture is recovered.
- The TMC system can provide all of the required high quality makeup water for boilers that require up to 5% makeup. The boiler feedwater makeup water (74 gpm) accounts for approximately 0.1% of the total makeup water (6,212 gpm) for the Reference Plant. G
- The device is modular so it can more easily increase scale by piecing several units together
- The technology is all ceramic; GTI claims that corrosion will not occur at pH as low as 2 and at SO_2 concentrations in the flue gas up to 300 ppm
- Flue-gas pressure drop across the modules is stated to be less than 1–2 inches water column
- Membranes will need to be cleaned every 6–12 months and will last more than 5 to 10 years (per GTI); however, there is not yet sufficiently long operating data to confirm these claims.

Evaluation Summary

The detailed second-round evaluation of the GTI technology is presented in Table 5 with the other heat-exchanger technologies. In summary, GTI scored particularly well on its cost-benefit analysis and reasonably well on most other categories, such as heat and water recovery, with no major penalties. These factors combined for the GTI TMC technology to score within the top two of the technologies reviewed leading to its being selected for the final round of evaluation. The information presented in this section only includes that provided by GTI in response to the detailed questionnaire; the final performance evaluation and engineering analysis performed by the team-members can be found later in Design and Cost Evaluation for GTI's Commercial-Scale System.

Table 5. Detailed Second-round Evaluation of the Heat Exchangers

Organization	MHPS	LJUNGSTRÖM	Wallstein Group	e-Tech	GTI	ConDex	Flucorrex
Technology Type	**Heat Exchanger**	**Heat Exchanger**	**Heat Exchanger**	**Condensing Heat Recovery**	**Condensing Heat Recovery**	**Condensing Heat Recovery**	**Heat Exchanger**
I. Organization Experience							
A. Tech Experience	Full scale, used coal flue gas	Full scale, used coal flue gas	Full scale, used coal flue gas	Beyond lab-scale, no coal flue gas with new material	Partial scale, used coal flue gas	Full scale, used coal flue gas	Full scale, used coal flue gas
B. Organizational Experience	HRUT: 1981, 20 full-time employees (FTE)	HRUT: 2006, 1 FTE	HRUT: 2006, 25 FTE	Company: 1976, has flue gas experience	HRUT: 2001, 5 FTE	HRUT: 2006, <50 FTE	HRUT: 1992, >100 FTE
C. Size	21,000+ employees	1000+ employees	210 employees	30 employees	272 employees	<50 employees	>100 employees
II. Design and Operation							
A. Design							
1. Soundness of Design	Boiler feedwater heated in a heat exchanger, simple and proven	Simple and proven	Heat extracted via a heat exchanger, proven	Overall design is simple but the new metallurgy is untested	Published references showed a simple design	Boiler feedwater heated in a heat exchanger, simple and proven	Boiler feedwater heated in a heat exchanger, simple and proven
2. Integration Complexity	Includes all the complexities of adding a heat exchanger to the flue-gas path	AH is likely already present. SBS injection system must be added.	Heat exchanger in gas path. Needs NaOH system and emergency cooling spray.	Includes all the complexities of adding a heat exchanger to the flue-gas path	Includes all the complexities of adding a heat exchanger to the flue-gas path	Includes all the complexities of adding a heat exchanger to the flue-gas path	Includes all the complexities of adding a heat exchanger to the flue-gas path
B. Operation							

Organization	MHPS	LJUNGSTRÖM	Wallstein Group	e-Tech	GTI	ConDex	Flucorrex
1. Response to Load Changes	Responds automatically to changing process conditions	SBS can vary with plant load. AH is unaffected by load.	Responds automatically to changing process conditions	Components are controllable to fluctuations in process variables	Responds automatically to changing process conditions	Responds automatically to changing process conditions	Responds automatically to changing process conditions
2. Impact on Startup Times	Comparable to other heat exchangers	Cold: 5–15 min for SBS. No extra time for air heater.	Cold: 1 day Hot: 5 min	Described start-up time as typical to similar technologies	Connected with the boiler control, so it can be started in seconds after the boiler starts	Not specified, but thought to be similar to other heat exchangers	Not specified, but thought to be similar to other heat exchangers
3. Acceptable Flue Gas Composition	Dust/SO_3 ratio is crucial. Has not been proven in high-sulfur coal.	Able to handle a wide range of SO_3 due to SBS injection	Inlet flue-gas temperature must be under 392°F. Requires cooling spray in case flue-gas temperature gets too high.	Not sure of practical sulfur limit with the untested metallurgy	Typically located after the ESP or baghouse, and preferably after the FGD, so PM level is low and moisture content is high. Current membrane can handle SO_2 level at 300 ppm without long-term damage, and development is ongoing to raise this level higher.	Claims flue-gas composition is acceptable, but does specify a range on particulates and SO_2	Well proven, corrosion-resistant heat exchangers
4. Pressure Drop	4–6" H_2O	<2” H_2O	2" H_2O	Can be customizable to any realistic pressure constraints	2" H_2O	5" H_2O	5" H_2O
III. Technology							
A. Benefits							

Organization	MHPS	LJUNGSTRÖM	Wallstein Group	e-Tech	GTI	ConDex	Flucorrex
1. Efficiency	0.5-1 percentage point net thermal efficiency increase	0.5–1 percentage point efficiency gain	6 MW 0.43 percentage point efficiency gain	Claimed 5%. Evidence should be provided.	0.7–1.3% percentage point efficiency increase	1 percentage point efficiency gain	1 percentage point efficiency gain
2. Water Treatment		SBS removes HCl thereby decreasing scrubber blowdown frequency					
3. Water Use / Generation	50% reduction in scrubber water consumption	Reduces scrubber consumption by decreasing gas temperature and decreasing blowdown frequency	10–15% reduction in scrubber water consumption	No estimate provided. Will reduce water consumption.	About 500 kg/min high purity water can be generated for boiler water makeup and about 3500 kg/min regular quality water can be generated for other plant uses	Will reduce scrubber consumption by some unknown amount	Will reduce scrubber consumption by some unknown amount
4. Environmental	Enhances removal of several pollutants	Enhances removal of several pollutants	No pollutant removal	No pollutant removal	Reduces water vapor emissions by more than 60%	No pollutant removal	No pollutant removal
B. Operations, Maintenance, Availability, and Safety							

Organization	MHPS	LJUNGSTRÖM	Wallstein Group	e-Tech	GTI	ConDex	Flucorrex
1. Operations	No additional labor or consumables required. Sootblower required.	Additional labor and consumables required for SBS system	Consumables (NaOH) but no additional labor required	No additional labor or consumables required. Fan power to be increased.	System is fully automatically controlled and can be operated without any staff labor	No additional labor or consumables required	No additional labor or consumables required
2. Maintenance	No maintenance required	Maintenance required for SBS. High risk if maintenance not performed.	No maintenance required	Possible replacement of portions of heat exchanger. Unknown is survivability of metallurgy in flue gas.	Suggested 6 to 12 month maintenance schedule with membrane module removal for cleaning.	Routine maintenance is required	Routine maintenance is required
3. Availability	99%	>99%	>98%	Response not given	Should be available whenever it is needed and no redundant equipment is needed, but no data were given	99%	99%
4. Safety	No added risk	Added risk of lance inspection	No added risk	No added risk	Low pressure and temperature device with no chemicals involved	No added risk	No added risk

Organization	MHPS	LJUNGSTRÖM	Wallstein Group	e-Tech	GTI	ConDex	Flucorrex
IV. Potential for Future Improvements							
A. Future Technology Improvements	No indication of significant design enhancements	No indication of significant design enhancements	New heat exchanger tube materials currently being tested	New metallurgy to be tested	Working on improving the overall system design, developing new membranes to tolerate higher SO_2, and reduce fabrication costs	No indication of significant design enhancements	No indication of significant design enhancements
B. Future Integration Improvements	No indication of significant integration enhancements	Addition of ambient air could aid in heat recovery	No indication of significant integration enhancements	Metallurgy could also be used in AH applications	There is opportunity to improve integration, but response was vague on how	No indication of significant integration enhancements	No indication of significant integration enhancements
V. Costs							
A. Commercial-Scale Plant Capital Cost	$22 million	$14.5 million	$6.7 million	No information provided	$2.6 million	$9.4 million	$18.4 million
B. Cost-Benefit Analysis	7–22 years	3 years	7–8 years	No information provided	<2 years	1.2 years	< 3 years
C. Pilot Plant Capital Cost	$1 million	$150k	$30–50k	No information provided	$190k	No information provided	No information provided

Water Treatment

The goal of water treatment processes is to clean water that has been used by the host plant so that it can be re-used or delivered back to where it was obtained without violating environmental regulations. Low-grade heat from flue gas can be used in a variety of water treatment processes that are generally aimed at FGD waste water treatment or cooling water treatment. Typically this heat can be used within an evaporative, membrane, biological, or osmosis-based process, reducing the energy that would otherwise be supplied by some other means such as a natural-gas heater.

Multiple organizations were reviewed in this technology category. A complete list of the water treatment technologies that were considered for this study is presented in Appendix C. The following organizations responded to the detailed questionnaire:

- PAX Pure
- Porifera
- Sylvan Source Inc. (SSI)
- Vacom Systems.

Background on these technologies and results from the assessment of their detailed questionnaire responses are summarized below.

Technical Background

As many of the water treatment processes require low-quality heat, they may be a good fit for this application. The technologies assessed in this study were focused on treating FGD waste water (primarily) and cooling water blowdown. Water emissions from these streams at coal power plants are heavily regulated. In each case, while several classes of substances must be removed, the most difficult and costly one is total dissolvable solids (TDS). Several methodologies have been proposed for removing TDS including boiling (evaporative) techniques, membranes (driven by pressure or osmosis), and biological techniques. Each of these requires heat and power to run and therefore could benefit from offsetting these requirements by recovering low-grade heat from the power plant.

PAX Pure

PAX Pure has created a device that simulates high-altitude boiling by reducing the pressure on the liquid, causing it to boil at a much lower temperature. The technology achieves low-temperature boiling with a multi-stage vacuum condenser that pulls the vapor into a condensation loop, where an automated batch process flushes out concentrates contained in the vapor. PAX Pure claims the technology uses heat more effectively in the multi-stage system, reducing costs and improving the quality of the water treatment. The technology condenses water with no moving parts, membranes, or chemicals, therein removing TDS from either FGD waste or cooling water with over 99% efficiency.

In the currently planned design for an oil-and-gas application, the technology includes a kettle reboiler with a shell-and-tube bundle heat exchanger. For a coal flue gas application, a thin-film evaporator is proposed instead of the kettle reboiler. The thin-film evaporator purported benefits include a lower gas-side pressure, better gas-side heat transfer, and less fouling due to having the FGD water flow through the tubes rather than being held up in the large kettle.

In general, PAX Pure's technology is a heat-use technology only and would require flue gas heat to be provided to it by other means such as a heat exchanger (without heat it typically uses a gas-fired heater). This technology is still in the pilot-scale testing phase.

All laboratory and bench-scale developments have been completed in California at the PAX Pure laboratory facilities. During the past three years, PAX Pure has built over 10 generations of demonstration units in its high-bay R&D space.

Currently, PAX Pure is working on a pilot project that will be installed at an oil and gas production site located in the U.S. in late 2016. The initial pilot will treat approximately 10,000 gallons of water per day and there are engineering plans in-place to move to a 5-phase system with a capacity of 42,000 gallons per day. The pilot will be delivered in two 24-ft storage containers. The pilot will be automated, able to treat water with an estimated level of total dissolved solids over 50,000 ppm, and will run continuously for several weeks with a target of less than 10% down time.

Porifera

Porifera is developing and optimizing a water treatment system, which uses forward osmosis (FO), a process driven by a concentration differential, to first remove foulants, such as scaling cations, metal oxides, and biologicals, among others. This allows reverse osmosis (RO) to occur more effectively, which removes salts without clogging and fouling and is driven by hydraulic pressure. Porifera's technology has the potential to provide cost savings over conventional thermal evaporators. A large portion of these savings is due to significantly lower energy use achieved by Porifera's FO process. In this patented FO method, the concentration of salts occurs without elevated temperatures and phase changes. This "cold concentration" process can operate at low temperatures, with low shear and low fouling, reducing costs.

Porifera's technology utilizes FO and modified RO to achieve greater concentrations of TDS for removal than conventional RO technologies can achieve alone. Several key innovations allow the technology to achieve high concentrations. Principal amongst these is the system utilizes FO to first remove foulants that rapidly clog RO membranes, allowing RO to then process only clean salts (e.g. NaCl), so clogging and fouling are reduced.

Porifera's current technology is a heat-use technology only and in its typical installation would require electrical power supplied from the plant. Porifera is developing a next-generation FO system that uses low-grade heat to recover the draw solution.

Porifera has tested on salt water at pilot scale under U.S. Department of Defense funding. The project performed desalination using a low-pressure forward osmosis pre-treatment stage that eliminated foulants from the feedwater followed by a high-pressure, high-permeability reverse osmosis stage. The pilot desalinated salt water with 32,000 ppm of TDS at a rate of 75 gph using an average of 10 W/gph of power. Figure 6 shows the water (left) run through the Porifera pilot system (right).

Figure 6. Porifera Treated Water (left) and Pilot System (right) [7]

Porifera is currently in the process of piloting two systems for the state of California in six different industrial customer sites for energy-efficient water treatment. These pilot tests are expected to be completed in 2018.

SSI

The SSI Heat Core process incorporates a patented technique that uses a principle similar to heat-pipe technology to capture heat at an advantage. Heat pipes facilitate removal of heat from a variety of sources including flue gas. This is done using a working-transfer fluid that evaporates and condenses while moving by capillary action along a pipe, transferring heat by conduction and phase change. SSI claims to transfer heat at a much higher rate (80x) than traditional heat exchangers, reducing size and cost. The SSI technology transfers heat over distances without requiring external pressure or mechanical means (no moving parts and no auxiliary power).

The heat is transferred from the heat pipe for use in treating water via a vertical, multi-stage boiler/evaporator/condenser process that separates out TDS. The upward flow of energy allows for heat capture and reuse, thus treating contaminated feedwater with low operational cost. SSI's technology has demonstrated in early-stage testing to be more efficient than traditional water-treatment evaporator systems (e.g., falling-film evaporators, brine concentrators, and crystallizers).

A schematic of the SSI technology is shown in Figure 7. For the coal-fired power plant case, the heat capture insert would be located in a short section of the flue-gas ducting after the particulate control device. Captured heat would be transferred below and away from the duct via the SSI HRUT heat transfer device. The heat could then be used directly by the SSI Core system to treat wFGD blowdown. The SSI Core would produce water of near-distillate quality that could be used for boiler feedwater, closed cycle cooling water makeup, lime or limestone preparation, cooling tower makeup, scrubber makeup water, ash system sluice water, and/or plant service water.

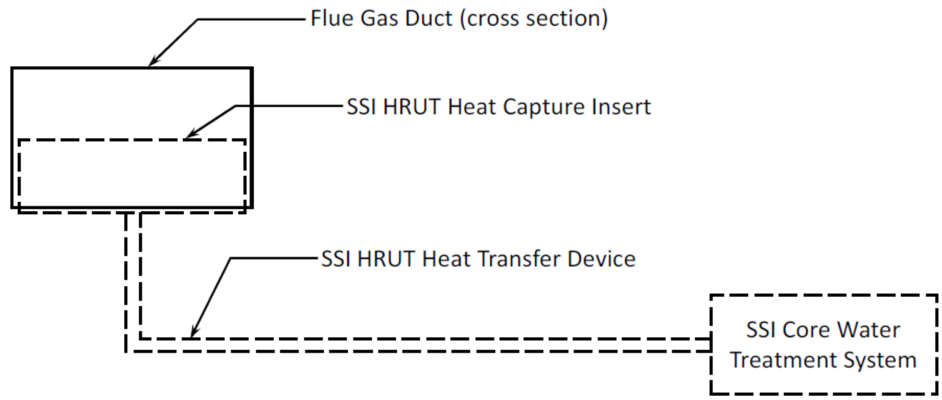

Figure 7. SSI System High-Level Diagram [8]

SSI's bench-scale water treatment pilot plant has been operating from 2010 to the present at SSI's facility in San Carlos, California. Over a thousand hours of tests have been conducted treating a range of contaminated feedwaters.

SSI is currently deploying a field pilot plant to treat contaminated waters at a U.S. power plant. It is anticipated that the pilot plant will be deployed in late 2016. First among several potential tests will be the treatment of cooling tower blowdown waste streams. This pilot plant will utilize steam energy to drive the SSI Core Water Treatment System, but all parts of the full system will be in place including the heat-transfer device.

Vacom

Vacom's system combines an evaporator and crystallizer to perform water treatment whereby solid TDS cakes are created. The technology also integrates a heat transfer system that currently utilizes steam typically provided by compression of the evaporated wastewater, but could be reshaped to use low-quality heat from flue gas. A high-level process flow diagram for the technology is shown in Figure 8 with the option where heat from coal flue gas is provided by a heat exchanger into the circulation loop where evaporation occurs.

The Vacom system has been tested at pilot scale in several places including the Water Research Center located at Georgia Power's Plant Bowen. The focus of this pilot study was on concentration of wFGD blowdown consisting of approximately 25,000 mg/L TDS to over 500,000 mg/L TDS. Testing was performed between September 2014 and March 2015.

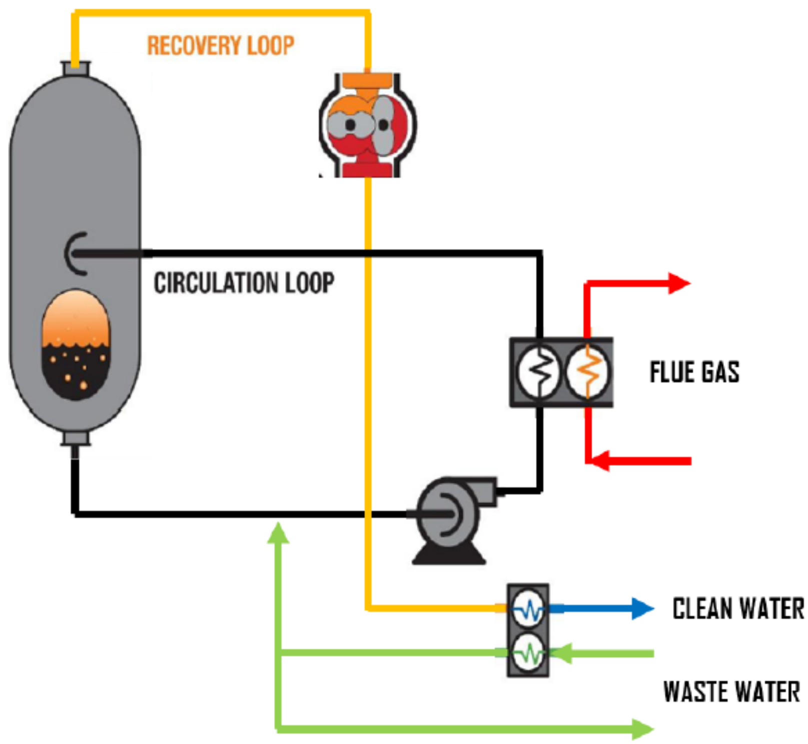

Figure 8. Vacom System Process Flow Diagram [9]

The Vacom system was also tested in 2015 in Bakersfield, California on an oil and gas application. Testing was performed to concentrate untreated water produced from an oil and gas reservoir, generating a salt filter cake for discharge and thus providing a potential zero liquid discharge solution.

Evaluation Summary

The detailed evaluation of the water treatment technologies is presented in Table 6. In summary, the water treatment technologies scored less well on the organization and experience aspects of the survey because the technologies were relatively immature with organizations that were relatively small. PAX Pure and Porifera were marked down in some design and operation categories, largely due to these technologies being at the lowest TRLs of any technology reviewed and hence work is still ongoing to optimize the technology for a coal-fired application. All of these organizations were protective of their intellectual property at this critical stage in their development, and were hence unwilling to release publicly some information requested for the survey, leading to a reduction of scores in certain categories. Vacom, in particular, was severely penalized in the scoring for not providing any cost information. SSI, on the other hand, provided an attractive cost-benefit analysis, causing it to be one of the highest scoring technologies surveyed, despite the technology still being relatively untested. The potential for improvement and cost reductions is high for these technologies and the need for water treatment and generation is growing significantly in the power generation market in some regions, which will work to increase the future benefits when using for these technologies.

Table 6. Detailed Evaluation of the Water Treatment Technologies

Organization	PAX Pure	Porifera	SSI	Vacom
Technology Type	**Water Treatment**	**Water Treatment**	**Water Treatment**	**Water Treatment**
I. Organization Experience				
A. Tech Experience	No pilot in place; first one will be on-line in 2016 on oil and gas application	Several pilots in place through DARPA at scale	Over 1000 hours of operating time and 1 pilot-scale unit in operation with another starting this year	Testing has occurred at two pilot-scale sites including the Water Research Center
B. Organizational Experience	HRUT: 2012, 5 FTE	HRUT: 2010, 15 FTE	HRUT: 2010, 5 FTE	HRUT: 2015, 2 FTE
C. Size	5 employees	15 employees	5 employees	55 employees
II. Design and Operation				
A. Design				
1. Soundness of Design	Overall design is complicated and only a process flow diagram was provided; while the cycle makes sense, the effectiveness of the vacuum condenser is questionable	Complicated, multi-stage design that is not well described, but has been proven in the field	Very simple design. Limited detail provided due to IP concerns.	Fairly well thought out system, but complicated by many potential loops
2. Integration Complexity	Response was not detailed and the type of system that would be used is unknown at this point, along with where they would locate the unit	Integration with the FGD wastewater treatment should not be an issue, but no discussion about how to get or use low-quality heat	Integration between heat exchanger and water treatment is well defined as the systems are being developed by the same organization	Significant work is required to integrate this system with heat recovery from coal flue gas
B. Operation				
1. Response to Load Changes	Should be able to respond to changing conditions, although operation is different if temps are higher	Responds automatically to changing process conditions	Responds automatically to changing process conditions	Does not respond dynamically

Organization	PAX Pure	Porifera	SSI	Vacom
2. Impact on Startup Times	5–10 minutes with automatic control	1–3 days	8–10 hours for water treatment plant	2 hours
3. Acceptable Flue Gas Composition	Flue gas is interacted by a coupled heat exchanger	Flue gas is interacted by a coupled heat exchanger	Claims flue-gas composition is acceptable, but no evidence was provided	Claims flue-gas composition is acceptable (with experience at the Water Research Center), but requires gasket design changes to accommodate the specified temperatures
4. Pressure Drop	Not more than 15 psig	Pressure drop is from a coupled heat exchanger	0.2 psig	0.2 psig
III. Technology				
A. Benefits				
1. Efficiency				
2. Water Treatment	System can treat 3.5 million gallons per day with a recovery rate of approximately 99.7% and 4% concentrated residual volume	System can treat 100 m^3/hr, 2400 m^3/day of wastewater	System can treat over 5700 gpm of plant wastewater	System can treat all of the required FGD wastewater
3. Water Use / Generation		Approximately 80 m^3/hr of pure water is generated		FGD blowdown wastewater volumes will be reduced significantly
4. Environmental	Significant reduction in FGD waste or cooling water TDS	Significant reduction in FGD waste or cooling water TDS	Significant reduction in FGD waste or cooling water TDS	Significant reduction in FGD waste or cooling water TDS
B. Operations, Maintenance, Availability, and Safety				
1. Operations	System does not require operators, but study needs to be done to assess operations-related work and labor	No information was provided	System does not require operators	Most Vacom systems in operation (approximately 20) have one part-time operator per shift. The system is automatic and monitors the feed rate into the unit and discharges the distillate and concentrate periodically through control

Organization	PAX Pure	Porifera	SSI	Vacom
				valves on the system.
2. Maintenance	Conditions can be monitored remotely to reduce the down-time for inspections. A rinse cycle automatically runs to clean internal scaling.	Clean-in-place should be performed regularly as needed. Membrane elements should be replaced at a rate of 20% per year.	Requires occasional inspection that could be done during scheduled major plant outages every 12–18 months	Routine maintenance is required
3. Availability	All equipment is designed to be compatible with off-the-shelf equipment in terms of availability, but no numbers were given	No information was provided	99%	No information was provided
4. Safety	No chemicals and fairly low-risk system	No information was provided, but system should be relatively safe	No added risk	No information was provided, but system should be relatively safe
IV. Potential for Future Improvements				
A. Future Technology Improvements	Work to reduce pressure drop and improve the vacuum condenser nozzle design is planned	No information provided	Significant opportunity for reduction in costs	Significant opportunity for reduction in costs
B. Future Integration Improvements	Significant work is planned to reduce integration costs	Significant work is required to determine how to integrate this technology with heat recovery	Working on potentially integrating into several locations in the flue-gas stream to reduce integration costs	No information was provided
V. Costs				
A. Commercial-Scale Plant Capital Cost	\$3,815,864	\$3 million	\$2.9 million	No information provided
B. Cost-Benefit Analysis	4.8 years	No information provided	1.8–2.8 years	No information provided

Organization	PAX Pure	Porifera	SSI	Vacom
C. Pilot Plant Capital Cost	$345,159	No information provided	$392k	No information provided

Bottoming Cycles

Bottoming cycles use low-quality heat from the flue gas to generate electrical power. At low temperatures, a steam-Rankine cycle is not applicable so working fluids with different thermodynamic characteristics are used. In the temperature range after the AH of around 300°F, organic-Rankine cycles (ORCs) and the Kalina cycle can be used.

Multiple organizations were reviewed in this technology category. A complete list of the bottoming cycle technologies that were considered for this study is presented in Appendix C. Those that progressed past the initial evaluation round of evaluation were the following:

- Ormat (ORC)
- Recurrent Engineering (Kalina)
- Turboden (ORC).

Global Geothermal owns the Kalina cycle but licenses it to Recurrent Engineering. The latter was surveyed for this study. Background on these technologies and results from the assessment of their detailed questionnaire responses are summarized below.

Technical Background

ORCs and Kalina cycles both use a modified Rankine cycle to generate power, replacing the boiler with a device similar to a heat recovery steam generator to extract heat from the flue gas. The main characteristic of these systems is that they use a working fluid that has a lower boiling point than water so that they can better accommodate lower-temperature operating conditions.

Similar to the steam-Rankine cycle in coal power plants, ORCs use a heat input to initiate a phase change of the working fluid that provides the energy to rotate a turbine. ORCs use organic working fluids such as silicon oil, propane, haloalkanes, isopentane, isobutane, and toluene, which have lower boiling points than water, making them better adapted to low-quality heat recovery [10].

The steam-Rankine cycle is limited in that the thermal energy must be transferred to the working fluid at a high enough temperature such that it is still mostly superheated at the turbine outlet to prevent turbine blade damage. To achieve this, inlet temperatures for steam turbines typically need to be in excess of 900°F, necessitating high-quality heat not available in low-temperature exhaust gases [11]. Using an organic working fluid can reduce this threshold in two ways. First, the lower boiling point of the organic fluids means lower-quality heat can be used to vaporize the working fluid. Second, the fluid's saturated vapor boundary has a positive or vertical slope. A fluid that with a positive slope (e.g., an organic fluid) is said to be "dry," as shown on the left in Figure 9. A fluid with a negative slope (e.g., water) is said to be "wet."

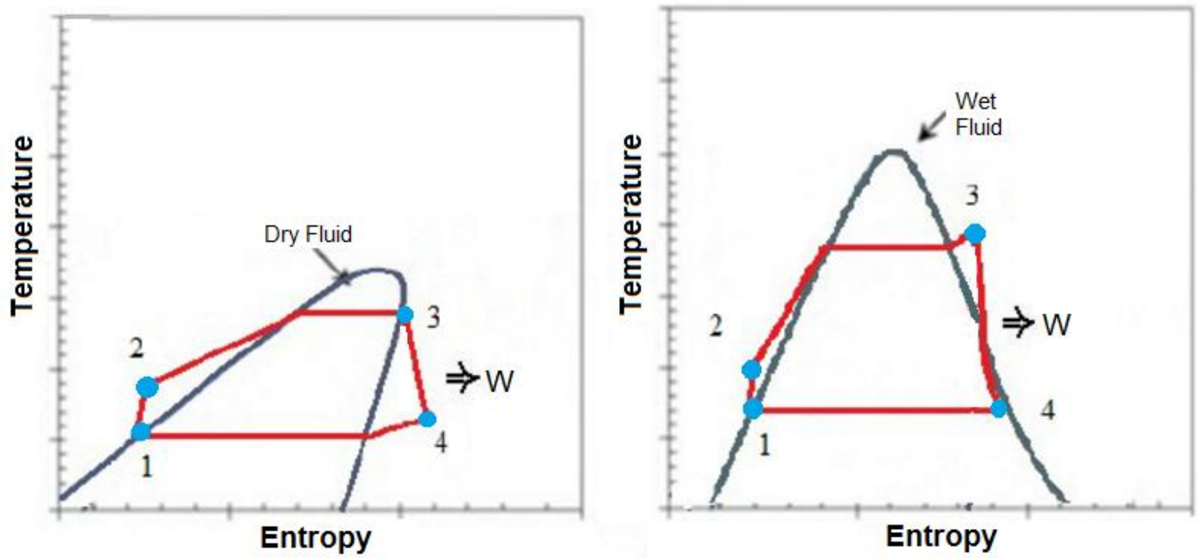

Figure 9. T-s Diagram for a Dry (left) and Wet (right) Rankine Cycle; 1-2: Compression, 2-3: Heat Input, 3-4: Expansion and Work Output, 4-1: Condensation [12]

After expansion across the turbine (condition 4), the dry working fluid will be dryer at the outlet than it was at the inlet (condition 3). This is advantageous when compared to the negative slope exhibited by water (a wet fluid), which will approach the saturated vapor boundary during any near-isentropic temperature reduction. Because the organic fluid is sufficiently superheated at the turbine outlet, systems can include a recuperator or regenerator after the turbine (see Figure 10) to recover excess thermal energy. Additionally, the fluids used in ORCs have a higher molecular mass, enabling compact designs, higher mass flow, and higher turbine efficiencies.

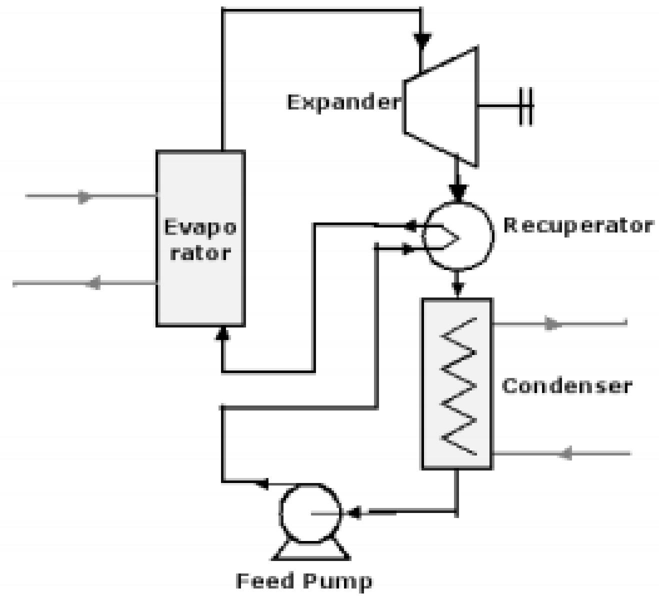

Figure 10. Organic Rankine Cycle Process Flow Diagram [13]

The Kalina cycle operates on a modified Rankine cycle with a binary mixture as a working fluid, typically ammonia and water. The fundamental advantage of the Kalina cycle lies in the ability of its working fluid to change phase while increasing in temperature, thus improving the heat transfer efficiency. Figure 11 shows the temperature profile of a cross-flow heat exchanger that would be used for the heat input step in a Rankine cycle. As shown, a single fluid such as water will maintain constant temperature during its phase change from liquid to gas. Because the ammonia-water mixture can increase in temperature while changing phase, it can be more closely matched to the heat source thereby decreasing exergy destruction during heat transfer.

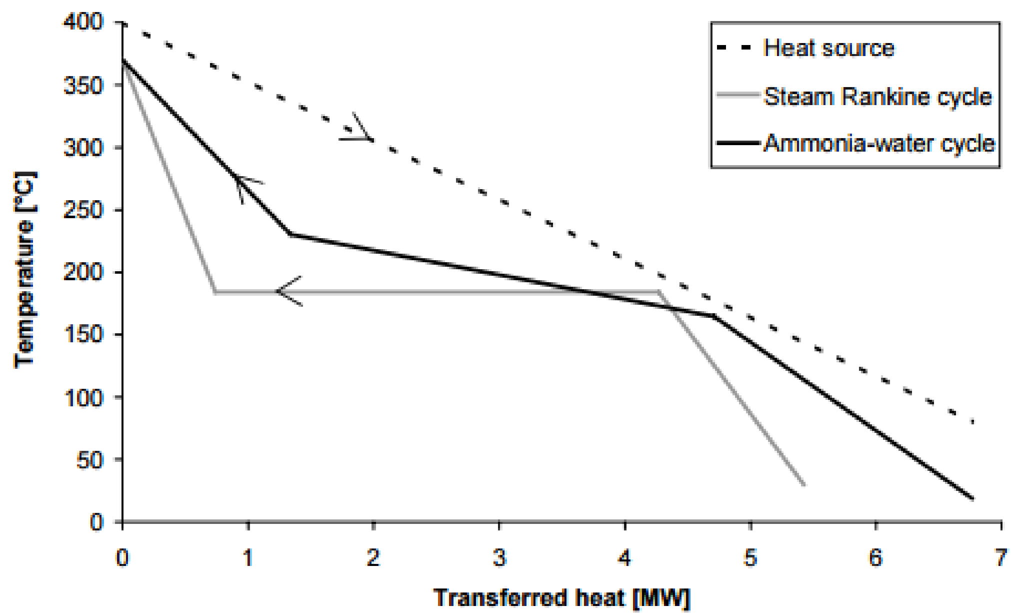

Figure 11. Cross-flow Heat Exchange Temperature Profile [14]

A discussion of each technology and organization reviewed is provided below.

Ormat

Ormat Energy Converter (OEC) units are fully automatic and produce grid-compatible power. The OEC is an ORC for which the organic working fluid is selected to optimize the power output from the particular heat source, temperature, and flow. OECs have primarily been used in renewable applications, especially geothermal ones, but the technology can be adapted to coal flue gas.

Ormat designed its system to include a thermal oil circuit to transfer heat from the flue gas to the cycle's working fluid. Ormat also performed their analysis assuming a suitable material was available to withstand corrosion due to the condensed acid.

Recurrent Engineering

Global Geothermal, through its subsidiary Recurrent Engineering, offers the Kalina cycle. The technology does not include a heat-transfer fluid, only a working fluid, which could provide a significant advantage in complexity and system size. Global Geothermal's technology has been implemented in many applications including geothermal, gas turbines, and industrial processes. While it has not been applied to coal flue gas, the technology could be adapted to this use. Recurrent Engineering performed its analysis assuming a suitable material was available to withstand corrosion due to the condensed acid. They also provided a reference for one of their systems that was installed in a location that had significantly higher dust loading than the baseline plant.

The Kalina cycle requires on-site storage of ammonia. Recurrent Engineering's design includes an ammonia monitor and performance of a Hazard and Operability Study to ensure process safety. Approximately 7000 gallons of lean aqua-ammonia (10–15% ammonia) mixture would be generated by the process each month and must be trucked off site to a supplier or processing facility for recycling.

Turboden

Turboden's technology is an ORC similar in nature to Ormat's. Turboden's technology has been applied mainly to industrial processes including oil extraction, cement production, steel making, and biomass. Similarly to Ormat, Turboden designed its system to include a thermal oil circuit to transfer heat. Turboden's design addressed the corrosion problem by designing the heat recovery system to maintain the flue gas above the acid dew point. Consequently, Turboden's power generation was lower than either the Kalina cycle or Ormat's offerings due to the reduced amount of heat recovered.

Evaluation Summary

The detailed second-round evaluation results for bottoming cycles are presented in

Table **7** below. Since both ORC organizations rarely, if ever, build systems on the small scale given for the pilot-plant application, the costs given in the "Pilot Plant Capital Cost" section are estimates based on the current smallest-scale design capital costs.

In all cases, the bottoming cycles reviewed required a heat exchanger to obtain and provide the heat from the flue gas to the cycle. This cost was included in the estimate for the commercial-scale systems given by Ormat and Recurrent Engineering; Turboden did not provide a cost estimate for the commercial-scale system. All three technologies elected to locate their heat exchanger after the baseline plant's induced draft fans, to position themselves at the location of highest temperature. All three also acknowledged the potential for flue-gas heat exchanger corrosion due to sulfuric acid condensation.

All organizations indicated that there was significant flexibility in designing the heat exchanger with respect to the flue-gas pressure drop, which can be decreased significantly at the expense of added materials cost. For this reason, the responses for added pressure drop varied greatly. Finally, all three organizations designed their systems for this application to allow the flue gas to bypass the bottoming-cycle system in the event of a trip to the bottoming cycle system.

In summary, bottoming-cycle technologies generally scored mid to low in the overall survey. They were all relatively mature, commercial technologies and design systems of an appropriate size for heat recovery from a 550-MW net coal plant, but had not yet been used in this application. The cycles scored well in categories related to experience, design and operation, and maintenance, availability, and safety. These cycles were also capable of providing extra electrical generating capacity, while many of the other technologies reviewed only improved efficiency.

The bottoming-cycle technologies were hampered by the constraint of the low-grade heat downstream of the AH, which has relatively low temperatures from which to convert heat into work. Additionally, the costs provided by the organizations were relatively high; however, it should be noted that an overall trend was observed of developers of more mature technologies providing higher costs compared to the developmental technologies. In short, while these technologies have a growing market for heat-recovery applications where the heat source has higher temperatures (e.g., the exhaust gas from a combustion turbine), they are likely not a good fit for low-quality heat recovery from coal-fired power plants unless extra power is required or beneficial at a particular site.

Table 7. Detailed Second-round Evaluation Results for Bottoming Cycles

Organization	**Ormat**	**Turboden**	**Recurrent Engineering**
Technology Type	**Bottoming Cycle**	**Bottoming Cycle**	**Bottoming Cycle**
I. Organization Experience			
A. Tech Experience	Waste incineration, other	Biomass, waste incineration, other	Waste incineration, other
B. Organizational Experience	HRUT: >30 years, >50 FTE	HRUT: 1998, 40 FTE	HRUT: 1988 11 FTE
C. Size	1100 employees	220 employees	11 employees
II. Design and Operation			
A. Design			
1. Soundness of Design	ORC is proven and is unaffected by application. The heat-recovery method is less proven for this application.	ORC is proven and is unaffected by application. The heat-recovery method is less proven for this application.	Kalina cycle is proven and is unaffected by application. The heat-recovery method is less proven for this application.
2. Integration Complexity	Includes all the complexities of adding a heat exchanger in the flue-gas path plus a cooling tower.	Includes all the complexities of adding a heat exchanger in the flue-gas path plus a cooling tower.	Includes all the complexities of adding a heat exchanger in the flue-gas path plus a cooling tower.
B. Operation			
1. Response to Load Changes	Responds automatically to changing process conditions	Responds automatically to changing process conditions	Responds automatically to changing process conditions
2. Impact on Startup Times	Cold: Several hours Hot: Several minutes	Cold: 20 minutes Hot: Few minutes	2–2.5 hours to reach full load
3. Acceptable Flue Gas Composition	Heat exchanger vendor believes it can be done	Did not design to decrease flue-gas temp below acid dew point	Assumed a suitable material was available for the heat exchanger
4. Pressure Drop	0–2 psi	Heat exchanger is designed to maximum pressure drop possible	8-12" H_2O
III. Technology			
A. Benefits			
1. Efficiency	Estimated to be 12 MW or a 0.86 percentage point efficiency gain	4 MW or 0.28 percentage point efficiency gain	10.8 MW or 0.77 percentage point efficiency gain

Organization	Ormat	Turboden	Recurrent Engineering
2. Water Treatment			
3. Water Use / Generation	Will reduce water use in FGD but may use water in condenser	Will reduce water use in FGD but to a lesser extent due to higher exchanger gas outlet temperature. May use water in condenser.	Will reduce water use in FGD but may use water in condenser
4. Environmental	No pollutant removal	No pollutant removal	No pollutant removal. Requires anhydrous ammonia storage on site.
B. Operations, Maintenance, Availability, and Safety			
1. Operations	No significant additional operational labor necessary, fluids to be topped off annually	No significant additional operational labor necessary, fluids to be topped off annually	No significant operational additional labor necessary. Approximately 40 tons of anhydrous ammonia consumed annually.
2. Maintenance	<0.5 FTE necessary for various inspections and light maintenance	<0.5 FTE necessary for various inspections and light maintenance	All maintenance can occur during plant outages
3. Availability	95–97%	>97%	90–95%
4. Safety	Safety controls in place	No information provided	Safety controls in place
IV. Potential for Future Improvements			
A. Future Technology Improvements	No indication of significant design enhancements for the ORC	No indication of significant design enhancements for the ORC	No indication of significant design enhancements for the system.
B. Future Integration Improvements	No indication of significant integration enhancements	No indication of significant integration enhancements	Use of corrosion-resistant steel for heat exchanger
V. Costs			
A. Commercial-Scale Plant Capital Cost	$40.5 million	No information provided	$18.4 million
B. Cost-Benefit Analysis	>5 years	No information provided	5.3 years
C. Pilot Plant Capital Cost	$3.6 million	$3.1 million	$1.5 million
Pilot Plant Flue Gas Flowrate	~130,000 scfm	~350,000 scfm	~5,000 scfm

Other

Several technologies for which only one organization was used in the second-round assessment are grouped together here for simplicity. The technologies included here are coal drying, heat pipes, and thermoelectrics. The organizations that were reviewed for these technologies that progressed past the initial round of evaluation were the following:

- GRE (coal drying)
- Novus (thermoelectrics)
- SSI (heat exchanger similar to heat pipe).

Background on these technologies and results from the assessment of their detailed questionnaire responses are summarized below.

GRE

The GRE DryFining™ technology was the only coal drying process investigated for this project. In GRE's DryFining process, the coal is processed on site to reduce its moisture content before it is introduced into the furnace. DryFining uses waste process heat from the flue gas to dry the coal, raising the heating value of the coal per pound. The refining component segregates the coal stream to remove the higher-density compounds that contain higher levels of sulfur and mercury. GRE's technology requires flue-gas heat to be provided to its dryers by means such as a heat exchanger.

Technical Background

The low-temperature coal-drying and coal-cleaning process uses low-grade heat from a coal-fired power plant to decrease the moisture content of coal. The system relies on an air-fluidized bed dryer (FBD) to dry and segregate crushed coal [15]. Crushed coal is fed to the first stage of the FBD where heavy materials are separated from the less dense particles by gravity and collected at the bottom of the dryer. The separated heavy materials are typically composed of rocks and minerals, such as pyrite, which contain most of the sulfur and mercury associated with the coal. The separation of these materials from the rest of the coal reduces the mass of sulfur and mercury that reports to the flue gas after the coal is combusted. The lighter fraction of the segregated stream contains a higher fraction of fixed-carbon, and is dried in the second stage of the system. The drying process changes the microstructure of the coal particles causing them to disintegrate and become finer [15].

Coal drying has been demonstrated to remove 40–50% of the coal moisture (or about 15% of the total coal mass) depending on the coal used, unit characteristics, and the DryFining integration setup [15]. The reduction of moisture entering the boiler increases the boiler efficiency. Station auxiliary power requirements are reduced for the induced draft fans and coal mills due to reduced flue-gas flowrate and finer coal, respectively. On balance, DryFining can increase plant efficiency by up to two percentage points or an approximate six percent reduction in fuel use, depending on the coal being used. The emissions reduction benefits can be significant as well. Sulfur dioxide and mercury emissions are reduced by approximately 40% due to removal of the pollutants in the first stage of the FBD and improvement of existing air quality control systems attributed to the implementation of the DryFining process [16]. Boiler tuning flexibility can also be increased due to the reduction in the necessary primary air used in the coal mill, thereby providing an opportunity for NO_X reduction via improved combustion staging.

This technology was designed for beneficiating lower-rank coals such as lignite and Powder River Basin and it relies on a variety low-quality heat sources from a plant to provide heat to the dryers. Although the system uses flue-gas coils to transfer some heat to the dryers in the FBD, the associated footprint and capital cost have prevented more extensive low-quality heat recovery from the flue gas.

Evaluation Summary

The detailed evaluation of the DryFining system from GRE is presented in Table 8 at the end of this section. In summary, the technology is mature and has been successfully installed and operated at commercial scale for several years. Its potential efficiency improvement is the highest of any technology surveyed and its impact on reducing emissions are significant. However the efficiency improvement may be limited to specific coal power plants and applications. In particular, it is designed to work best on lower-quality, higher-moisture coals and to use low-quality heat from a variety of sources, not just from flue gas after the AH. These factors contributed to this technology being lower rated in this survey, given that the study was limited to recovering and/or using heat in the flue gas downstream of the AH at a low-moisture bituminous plant. Additionally, the operating and capital costs are relatively high and the integration may be complex, which makes installing this technology case dependent. It should also be noted an overall trend was observed of developers of more mature technologies providing higher costs compared to the developmental technologies.

If the survey and project was based on a different coal quality, the DryFining system likely would be at the top for certain coal plants, as coal power generators emphasize a proven track record when making purchasing decisions. Moreover, if regulations, e.g., the Clean Power Plan, increase the benefit of improving efficiency, the DryFining system is capable of producing the largest efficiency benefit of any system reviewed, meaning it will likely be seriously considered for reducing plant emissions and heat rate.

Novus

A list of the thermoelectric generator (TEG) technologies evaluated for this study is presented in Appendix C. This section addresses the only organization that passed the initial evaluation and provided detailed information: Novus. Other providers of TEGs indicated they were not able to efficiently work with the temperature range of the flue gas chosen for this project.

Novus' thermoelectric technology directly produces power generation from heat. The system uses solid-state technology to combine different metals to produce voltage by the Peltier-Seebeck effect when heat is applied. The technology would be placed within the flue-gas duct after the ESP or baghouse to directly obtain heat and generate power. Novus' technology has primarily been used for the cooling of electronics, smaller-scale power generation for remote sensors [17] , and for higher-temperature waste-heat applications such as gas turbine flue gas [18]. The technology has also been used for lower-temperature applications such as geothermal heat. It can in principle be used on coal flue gas, but has not yet been done in this application.

Technical Background

TEGs generate electricity from a thermal gradient across the device. Heat is recovered by direct contact of the flue gas with a heat exchanger. Different thermoelectric materials are required for low temperatures (77–392°F), mid-temperatures (392–842°F), and high temperatures (842–1382°F). In 2014 Novus was awarded a grant from DOE to design, fabricate, and test thermoelectric devices for generation from geothermal heat sources. The temperature range (~150°C) of this application was similar to the reference plant air heater outlet temperature. In addition to this application, Novus has installed a proof-of-concept version their system in the exhaust of a gas turbine used to power an M1 Abrams tank as shown in Figure 12. The system converted the exhaust gas heat into electrical power and dissipated the rejected heat. The proof-of-concept system generated a peak power output of 80.7 W [18].

In a coal-fired power plant, the TEG can be installed around the perimeter of the flue-gas duct and the heat-spreader heat exchanger can be installed as thin foils of sheet metal (fins) placed inside the duct, in line with the axial flow of the exhaust gas.

For the purpose of this project, the installation design was the area downstream of the particulate control device and upstream of the wFGD, where the flue-gas temperature is expected to be in the 250–350°F range. Given the flexibility of this technology to be placed in different regions of the plant (and in higher temperature zones), additional benefits could be obtained if the TEG is placed upstream of the particulate control device, which would result in increased mercury and PM removal via reduced gas temperature and velocity across the device. This is likewise true for other technologies that can be moved to this location.

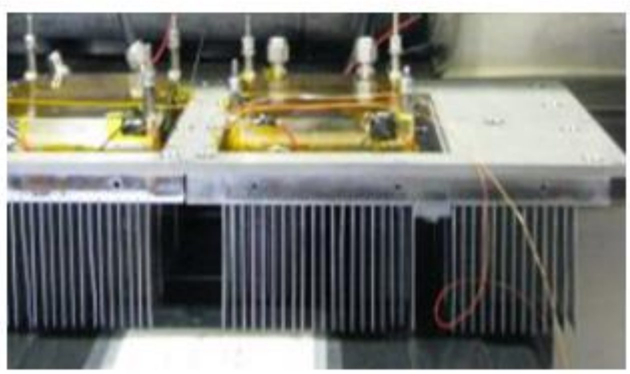

Figure 12. Left Shows the System in an M1/A2 Abrams Tank Exhaust; Right Shows the Heat Exchanger Coupled with the TEGs [18]

Evaluation Summary

The detailed second-round evaluation of the Novus' TEG technology is presented in Table 8 at the end of this section. In summary, the technology is relatively immature without any installations on coal flue gas. TEG scored well for its simplicity and ease of integration since it can be installed without any major moving parts, and it generates electricity without modifying the plant Rankine cycle; however, for the temperature range required for this project, the benefits were relatively small, which reduced the survey score such that the technology finished in the middle of the pack. Nevertheless, particularly for higher-temperature applications, the TEG technology has the potential to be of significant interest, especially if regulations drive increased importance of efficiency improvements. Also, future potential enhancements in the technology could increase the power generation potential, further improving the cost-benefit analysis and increasing the likelihood the technology will be considered in the coal power generation industry.

SSI

Technical Background

As discussed in the Water Treatment section, the SSI Heat Core process incorporates a technique that uses a principle similar to heat-pipe technology that can capture heat from flue gas after the ESP or baghouse. Heat pipes facilitate removal of heat from the flue gas to a heat transfer fluid undergoing both evaporation and condensation along a pipe. The heat recovered by this device could also be used for feedwater heating instead of water treatment, similar to many of the heat exchangers proposed. For this assessment, SSI was evaluated for the design basis application. The heat transfer technology has not undergone pilot-scale testing, but will undergo such testing in late 2016.

Evaluation Summary

The detailed second-round evaluation of the SSI technology for use for feedwater heating is presented in Table 8 at the end of this section. The technology as envisioned by SSI is untested, and the SSI team is small. The technology scored well in operations and SSI provided an attractive cost-benefit case for the technology. Combined, the SSI technology ended up scoring high relative to the other technologies, but was not selected for the final evaluation largely due to the technology's immaturity and lack of testing experience for the heat- transfer component.

Table 8. Detailed Second-round Evaluation of GRE, Novus, and SSI technologies

Organization	**GRE**	**Novus**	**SSI**
Technology Type	**Coal Drying**	**Thermoelectric**	**Heat Pipe**
I. Organization Experience			
A. Tech Experience	Full scale, used coal flue gas	Experience with clean flue gas	No pilot in place and no experience on coal flue gas
B. Organizational Experience	HRUT: 1997, 10 FTE	HRUT: 2014, 6 FTE (Novus + SRI)	HRUT: 2010, 5 FTE
C. Size	880+ employees	Novus: 6 employees SRI: 450+ employees	5 employees
II. Design and Operation			
A. Design			
1. Soundness of Design	Unclear how design and benefits fare for low-moisture coal	Heat transfer method (fins) questionable. Claims flue-gas temp will drop from 350°F to 135°F.	Very simple and well thought out design, but not a lot of details provided due to intellectual property concerns
2. Integration Complexity	Complex, pulling heat from multiple sources, little detail provided	Easiest to integrate	Heat exchanger in gas path
B. Operation			
1. Response to Load Changes	Must shut off a fluidized bed to turndown with load	No effect, other than power output due to load change	Responds automatically to changing process conditions
2. Impact on Startup Times	Cold: Several hours Hot: 20 minutes	Instantaneously	Similar startup times to other heat exchangers
3. Acceptable Flue Gas Composition	Does not fully utilize flue gas to dry coal; may only be applicable to high moisture coal	Thermoelectric device not affected by flue-gas composition	Claims flue-gas composition is acceptable, but no evidence is provided
4. Pressure Drop	No estimate provided but decrease in flowrate will reduce pressure drop	No information provided. Pressure drop assumed to be low due to finned heat exchanger.	0.2 psi or 5.5 " H_2O
III. Technology			
A. Benefits			

Organization	**GRE**	**Novus**	**SSI**
1. Efficiency	2 percentage point net thermal efficiency increase	0.2 percentage point efficiency gain	1 percentage point efficiency gain
2. Water Treatment			
3. Water Use / Generation	Saves about 80 gpm. Based on 66.5 Mgpy.	Will reduce scrubber consumption by some unknown amount	Will reduce scrubber consumption by some unknown amount
4. Environmental	Enhances removal of several pollutants	No pollutant removal	No pollutant removal
B. Operations, Maintenance, Availability, and Safety			
1. Operations	4 operators required per shift	About 0.5 FTE recommended. No additional consumables.	System is automated and requires no more than once-per-shift check-ins by existing staff. No additional staff would be required.
2. Maintenance	Estimated $0.86 million in replaced parts/year	Routinely performed every 6 months. Can be done during a single shift. No more detail provided.	Requires occasional inspection that could be done during scheduled major plant outages every 12–18 months
3. Availability	95% with redundancy, 83% w/out	99%	99%
4. Safety	Safety controls in place	No added risk	No added risk
IV. Potential for Future Improvements			
A. Future Technology Improvements	Optimize water recovery from the dryer stacks	New material to be tested and validated in flue gas	Significant opportunity for reduction in costs
B. Future Integration Improvements	Develop construction methods to reduce costs	Large-format thermoelectric generator to ease plant integration	Integration between technology and feedwater heating system must still be figured out
V. Costs			
A. Commercial-Scale Plant Capital Cost	$50 million	$8.1 million	$8.6 million
B. Cost-Benefit Analysis	<7 years	3.8 years	<5 years
C. Pilot Plant Capital Cost	$7.5 million	$810k	$95k

Detailed Cost Estimate and Design

In the final round of evaluations, the two highest-ranked technologies determined in the second round through the detailed survey results – LJUNGSTRÖM and GTI – were evaluated in terms of design and cost for the specified reference 550-MW plant. The cost evaluation was done on an indicative basis, comparable to an AACE Class 4 analysis.

For the GTI TMC technology, which is still being developed, the design and cost evaluation was done on both a pilot- and commercial-scale basis, with the intent of providing a plan for the cost and set up for a future pilot study of the technology on a coal flue gas. The pilot-scale study for GTI can be found in Appendix F. For the LJUNGSTRÖM technology, which has already been applied in a commercial basis, only a commercial-scale design and cost evaluation was performed using the specified full-scale coal power plant base conditions.

Design and Cost Evaluation for LJUNGSTRÖM's Commercial-Scale System

This section summarizes the design package developed for LJUNGSTRÖM's commercial-scale AH combined with an alkaline solution injection system. LJUNGSTRÖM also provided detailed cost information for a pilot-scale unit (see Appendix F: Design and Cost Evaluation for GTI's Pilot-Scale TMC System); however, further analysis on the pilot-scale system was not carried out because the combined technologies are already operating at a commercial installation at a 500-MW Midwestern power plant [19].

Design Basis and Process Description

Information for the LJUNGSTRÖM's commercial-scale system is summarized below. The AH upgrade consisted of replacing existing heat transfer surfaces and other necessary components to increase the amount of heat recovered in the existing AH. To prevent acid-gas corrosion from the resulting decrease in flue-gas temperature, the upgraded AH was coupled with a alkaline solution injection system (AECOM's SBS Injection™) to reduce flue-gas SO_3 concentrations to less than 5 ppm at the AH inlet; details on the SBS system are presented after the information on the LJUNGSTRÖM AH upgrades. The lime injection system from the Reference Plant (which realized SO_3 removal across the baghouse) can be taken out of service once the alkaline solution injection system is installed.

1. Design concept:
   Upgrade existing AH to increase the amount of heat recovered from flue gas by: increasing basket depth to fill void space in the rotor; using alternate basket designs to increase element depth; consolidating basket layers; switching to a more efficient heat-transfer surface; and/or modifying the rotor to increase available space.

2. Materials of construction for the AH upgrade:
   i) Hot-end heating element and rotor components: mild steel
   ii) Cold-end heating element: low alloy steel with a porcelain enamel coating.

3. Integration complexity:
   For coal-fired units already equipped with rotary regenerative AHs, no additional integration with the power plant is required for the upgrade. If the plant desired to change the air-to-gas ratio to generate and use additional hot air in the plant, additional integration would be required. The alkaline solution injection system would need to be installed if not already present, unless the sulfur content in the coal is very low.

4. Flue-gas temperature change:
   The proposed AH upgrade can reduce flue-gas temperatures to as low as 240°F at the AH outlet. Some plants may have physical or operational constraints that prevent reaching a flue-gas temperature this low.

5. Pressure drop:
   Four to five inches of water column of total pressure drop after the upgrade per flow side (includes original AH and the additional heat transfer area). For new installations, typical flue-gas pressure drops for new AHs range from 3.5–4.5 inwg; if more heat recovery is required, the

pressure drop can be maintained by increasing the diameter of the AH. For installations with fixed AH diameter (i.e., upgrades), the pressure drop of the flue gas may increase by ~1.0 inwg after the upgrade

6. Operations and maintenance:
   No additional labor is required to operate the upgraded AH. Inspections can be performed on planned outages.

Alkaline solution injection reduces SO_3 and H_2SO_4 in the flue gas to less than 5 ppm at the AH inlet and to 0.5–1.5 ppm at the stack. The process information is presented below.

1. Design concept:
   Alkaline solution injection is sprayed into the flue-gas stream via specially designed injection lances; the SBS reacts with SO_3 and H_2SO_4 in the flue gas and forms a solid byproduct removed via the existing plant particulate control system. SBS Injection™ is installed at over 17,000 MW of coal-fired power in the U.S. and has been commercially available since 2003 [20].

2. Process:
   Sodium carbonate (soda ash) is delivered by truck and stored in a temperature controlled (> 80°F) tank where it is diluted to a 20–25 wt. % soda-ash solution [21]. A control system and injection skid continually meters the required flow rate of alkaline reagent based on the molar flow rate of SO_3 in the flue gas; the system adds varying amounts of water to the concentrated SBS stream to maintain a constant flow of reagent to the injection location. Compressed air and dilute alkaline reagent are fed to an array of injection lances, where the alkaline solution is atomized and flash evaporated, leaving micron-sized solid particles of alkaline solution that react with the SO_3 and H_2SO_4 to form sodium sulfate particles that are collected in the plant's particulate control device.

3. Other requirements:
   a. Proper selection of injection location to allow drying and reaction time; the alkaline solution requires about 0.10 seconds of residence time to dry when injected into gas temperatures above 600°F and a reaction time of one to two seconds is needed to achieve high removal efficiencies
   b. Heat tracing on the system components to avoid line pluggage
   c. Monthly inspection and maintenance of the injection lances are recommended and can be done with the plant online.

4. For the 550-MW subcritical pulverized coal plant, operation of the alkaline solution injection process included the following consumables:
   a. 820 lb/hr soda ash reagent usage (based on 30 ppm SO_3, with delivered cost of $290/ton); the Reference plant can also discontinue its use of the assumed-existing lime sorbent for SO_3 control.
   b. 14 gpm of water
   c. 1000 scfm compressed air @ 100 psi.

Benefits

Benefits of the LJUNGSTRÖM AH upgrade with an alkaline solution injection system are provided below. Some of these may improve the system payback period (such as reduced carbon usage due to improved mercury capture across the particulate control device), but were not included in the cost analysis.

1. Efficiency improvement:
   0.5–1 percentage-point improvement in plant efficiency (1–3% improvement in boiler efficiency). These efficiency improvements cannot necessarily be applied to plants burning low-sulfur coals that already operate at low AH outlet gas temperatures. Fuel usage can be reduced by approximately 2.8% if the plant efficiency increases by 1 percentage point, translating to fuel savings on the order of $3.6M/year (see Payback Period section for more details) for a 550-MW plant. For a 1 percentage point increase in net plant efficiency, this capital cost translates to $73,000/Btu/kWh for the improvement in net heat rate. A detailed calculation of the net plant efficiency improvement is presented in Appendix D: Check on Efficiency Improvement for LJUNGSTRÖM's Commercial-Scale System.

2. Reduction in cyclic pressure drop at the AH:
   By removing SO_3 from the flue gas, alkaline solution injection helps reduce AH fouling, which in turn reduces cyclic pressure drop surges from the accumulation of AH fouling deposits (which can increase pressure drops from 4 to 8 inwg). Also, the upgrade reduces AH flue-gas outlet temperature and velocity, which serves to reduce some of the downstream pressure drop through the gas path.

3. Reduction in sulfuric acid corrosion:
   Alkaline solution injection reduces the SO_3 concentration in the flue gas resulting in a reduction of the sulfuric acid dew point temperature, reducing the risk of sulfuric acid condensation.

4. Reduction in water use by the wet FGD:
   Reducing the flue-gas temperature leaving the AH results in a reduction in water required by the wet FGD for quenching the flue gas. For the Reference Plant operating at 80% capacity, this savings is 92 million gal/year (calculated by LJUNGSTRÖM based on savings of 3.0 gpm for each 1°F reduction in flue-gas temperature upstream of the FGD, and flue-gas temperature decreasing from 337°F to 263°F).

5. Water treatment and use:
   Alkaline solution injection removes HCl, thereby decreasing scrubber blowdown volume; wFGD water use is reduced as a result of cooler flue-gas temperatures.

6. Air emissions reductions:
   i) SO_3 emissions are reduced to 0.5 ppm or less by alkaline solution injection, eliminating the sulfuric acid aerosol (blue) plume
   ii) CO_2 emissions reductions are reduced with the upgraded AH, as a result of fuel reductions/improved plant efficiency
   iii) Mercury emissions are reduced by 40–90% with the combined AH upgrade/alkaline solution injection system due to lower flue-gas temperatures and removal of SO_3 from the flue gas, which increases the capture of mercury by the fly ash as well as by any activated carbon sorbent used in the flue gas.
   iv) PM emissions are lowered with enhanced ESP performance as a result of lower flue-gas temperatures.
   v) Selenium in the flue gas is captured by the alkaline reagent and removed with the fly ash; therefore, selenium input to the FGD is reduced and selenium mass in the FGD wastewater is also reduced.
   vi) NOx emissions are lowered via alkaline solution injection enabling the SCR technologies to operate at higher ammonia slip (and thus provide higher NOx removal) and operate at lower loads (lower operating temperatures).

LJUNGSTRÖM claims that AH gas outlet temperatures as low as 240°F can be reached with an AH upgrade and use of alkaline solution injection; however, in the full-scale commercial installation of this technology, operation at 240°F was not demonstrated due to unrelated boiler issues, fluctuating load, and warming ambient temperatures. The literature showed AH outlet gas temperatures ranging from 255 to 290°F for the commercial installation [22], decreasing the plant efficiency improvement to 0.5 percentage points. At pilot-scale, LJUNGSTRÖM successfully operated the AH at temperatures as low as 220°F for an extended duration. When the flue-gas temperature is decreased to 240°F, the plant efficiency improvement would be approximately 1.06 percentage points.

Costs

The cost for the LJUNGSTRÖM AH upgrade ranged from $6.6M to $7.4M and the cost for the SBS system was found to be $11.1M ± 30% when installed the DOE Baseline Study 550-MW subcritical pulverized-coal plant. The uncertainty of ± 30% was due to the lack of project definition; the system was costed for a hypothetical plant. The cost and process information for the commercial-scale AH upgrade as provided by LJUNGSTRÖM to the project team is summarized in Table 9 along with the cost details for the SBS system.

Table 9. Information for Cost Analysis on AH

Two x 32’ vertical-shaft tri-sector LJUNGSTRÖM® AHs
Equipment Scope: • Replacement of complete rotor assembly, including: rotor modules, lug assembly, rotor angles, rotor post, seals, pin rack, and T Bars • Hot-end heating element (40” of high-efficiency carbon-steel element) • Cold-end heating element (42” of high-efficiency, fully closed channel enamel-coated steel element) • Miscellaneous scope for upgrade (seals covers, trunnions, tracking assemblies, etc.) • Shipping of equipment to jobsite. **Equipment estimate: $3.3M** This estimate assumes: • AH upgrade will be within the limits of the existing AH structure members and not impact the support bearing, rotor drive • No inclusion of any additional routine maintenance work on the AH that may typically be executed during a major outage (such as sealing system repairs, sootblower maintenance, bearing maintenance, etc.) • Contingency, fees, insurance, or other ancillary costs were not included in this estimate.
Construction estimate: $3.3 to $4.125M Construction includes: Turnkey work to open and rig AH, remove the old rotor, and install new equipment; estimated as 100 to 125% of material cost by LJUNGSTRÖM.
TOTAL estimate: $6.6M to $7.4M

The detailed cost estimate for the SBS system was based on the cost from a previous installation at a confidential power plant (Plant A). The total installed cost for the SBS system was $11.1 M ± 30% for the DOE Baseline Study 550-MW subcritical pulverized-coal plant (Case 9 plant), based on the following assumptions to adjust the Plant A costs:

1. The size and costs of the main equipment components were adjusted from Plant A to fit the size of the Case 9 plant. Plant A had 2 x 650-MW boilers while the Case9 plant had one boiler rated at 550 MW.
2. Plant A’s SBS system was designed for 90% SO_3 removal to reduce SO_3 concentration from 60 ppm to 5 ppm. The Case 9 plant SBS system was designed for 83% removal to reduce SO_3 from 30 ppm to 5 ppm. The inlet concentration and mass of SO_3 to be removed for the Case 9 plant was lower than Plant A; however, if the SBS flow is reduced, then the dilution water flow has to

increase to maintain adequate flow per nozzle to maintain proper atomization and distribution in the duct, resulting in a similar dilution water pump. Since both plants have similar flue gas duct-work size, then the lance sizing would likely be similar between the two plants. The cost to construct the skid, the cost of the instruments, and other specialty items on the skid (fittings, etc.) would be similar between both plants. The potential variations in pump costs were within the error bands of the estimate.

4. Plant A's SBS system was designed with common SBS storage and one delivery system common to both units (mounted on a skid), with a distribution system to a set of individual lances per each of the two units. The Plant A injection skids and storage vessel sizing should be adequate to represent what would be required for the Case 9 plant system. The storage vessel could be smaller for the Case 9 plant; however, this would not result in a straight-line cost reduction and the cost differences were deemed to be within the error bands of the cost estimate.
5. The costs for one unit's lances were removed from the Plant A costs to account for the fact that the Case 9 plant has only one unit.
7. An escalation rate of 3% per year was applied to adjust the Plant A costs from 2011 dollars to 2016 dollars.
8. Engineering costs were carried from the Plant A actual costs and escalated to 2016.
9. The cost for Case 9 plant included 10% contingency.

Payback Period

The analysis below calculated the payback period for the LJUNGSTRÖM AH upgrades based on fuel savings for a 1.06% point net plant efficiency gain associated with a reduced flue-gas temperature of 240°F. This analysis does not include any increase in fan power required to overcome the increased pressure drop across the AH (estimated by LJUNGSTRÖM to be less than 2" H_2O).

1. Post-upgrade fuel usage:
   The reduction from the pre-upgrade fuel usage ($\dot{Q}_0$) was calculated using the increase in net thermal efficiency from the pre-upgrade efficiency (η_0).

   $$582.6\ \mathrm{MW} = \dot{Q}_0 * (1 - Fuel\ reduction\ \%) * (\eta_0 + 1.06\ \%) - \mathrm{Auxiliary\ Loads}$$

   Fuel usage (% of pre-upgrade) = 97.195%
   Fuel reduction and CO_2 reduction = (1-Fuel Usage) =2.805%

2. Annual fuel savings:
   The annual fuel savings were obtained by multiplying the fuel savings (%) by the annual coal cost:

   Annual Coal Cost (2016 dollars)
   $129,492,379.42 (per DOE Baseline Study Case 9 [21])

   Annual Fuel Savings = (0.02805) ($129,492,379.42) = $3,632,834

3. Annual cost of soda ash reagent for the SBS system:
   820 lb/hr of soda ash reagent usage (based on 30 ppm SO_3 with delivered cost of $290/ton) and using a plant capacity factor of 85%, for an annual cost of $885,000/year.

   However, the plant can also discontinue use of its lime injection system, which may result in overall reagent cost savings. For this analysis, no cost or benefit was assigned to replacement of the lime reagent with SBS reagent.

4. Payback period for LJUNGSTRÖM's System (with SBS):
   The payback period was calculated by dividing the net cost of the LJUNGSTRÖM system with SBS by the annual fuel savings less the annual cost of soda ash. The payback period ranged from three to seven years, with the range reflecting the uncertainty in the cost estimate. For plants that have alkaline solution injection already installed or with low sulfur content in the coal (no need for alkaline solution injection), the payback period was reduced to one to three years.

5. The environmental benefits associated with the combined LJUNGSTRÖM/SBS system were not included in the payback period calculation. If these benefits were included, the payback period would be shorter.

Summary

Coal-fired units equipped with rotary regenerative AHs can realize an increase in plant efficiency of up to approximately one percentage point by upgrading the AH to recover more heat from the flue gas. This approach to recovering low-grade heat is attractive because it fits within the current AH footprint and the AH is already integrated into the power plant.

For plants firing medium- and high-sulfur coals, the AH upgrade will need to be accompanied by alkaline solution injection to reduce flue-gas SO_3 concentrations to acceptable levels and avoid AH corrosion. The combined systems provided several environmental benefits including: reduction in scrubber blowdown volume as a result of HCl removal and air emissions reductions for SO_3, CO_2, mercury, PM, selenium and NO_X [22], [23]. The estimated cost for the combined system was $18.1M ± 30%.

Design and Cost Evaluation for GTI's Commercial-Scale System

This document summarizes the design package developed for GTI's TMC; this design package was used as the basis for the cost estimate of the 550-MW scale system. The design package developed for the pilot-scale system is presented in Appendix F: Design and Cost Evaluation for GTI's Pilot-Scale TMC System.

System Overview

This section summarizes the information for the TMC system as provided by GTI, as well as design decisions made by AECOM. The commercial-scale TMC system was integrated into the plant Rankine cycle and flue-gas handling system as shown in the conceptual layout in Figure 13. On the flue-gas side, the TMC was positioned between the FGD unit and the stack with a flue-gas design inlet temperature of 135°F. The membranes were arranged in three planes of nominally 500 TMC modules per plane. Steam condensate from the plant at a design temperature of 100°F and a static pressure of -3 psig flowed through the inside of the TMC membrane tubes. The TMC outlet flow (which included the steam condensate and the recovered water), as well as the associated sensible and latent heat recovered from the flue gas, were directed to the feedwater heater system after passing through liquid-vapor separation equipment.

GTI specified that the TMC will require maintenance on an annual basis; the modules must be removed and soaked in cleaning solution. To accommodate the number of modules and maintenance requirements specified by GTI, the housing for the modules was divided into two identical vessels, each with the necessary associated ductwork and equipment operating in parallel, with a nominal superficial flue-gas velocity of 5 ft/sec. During maintenance periods, a single train could take the full flue-gas flow resulting in a velocity of 10 ft/sec. This allowed the host plant operation to be unaffected by maintenance or any unexpected outage due to the TMC system.

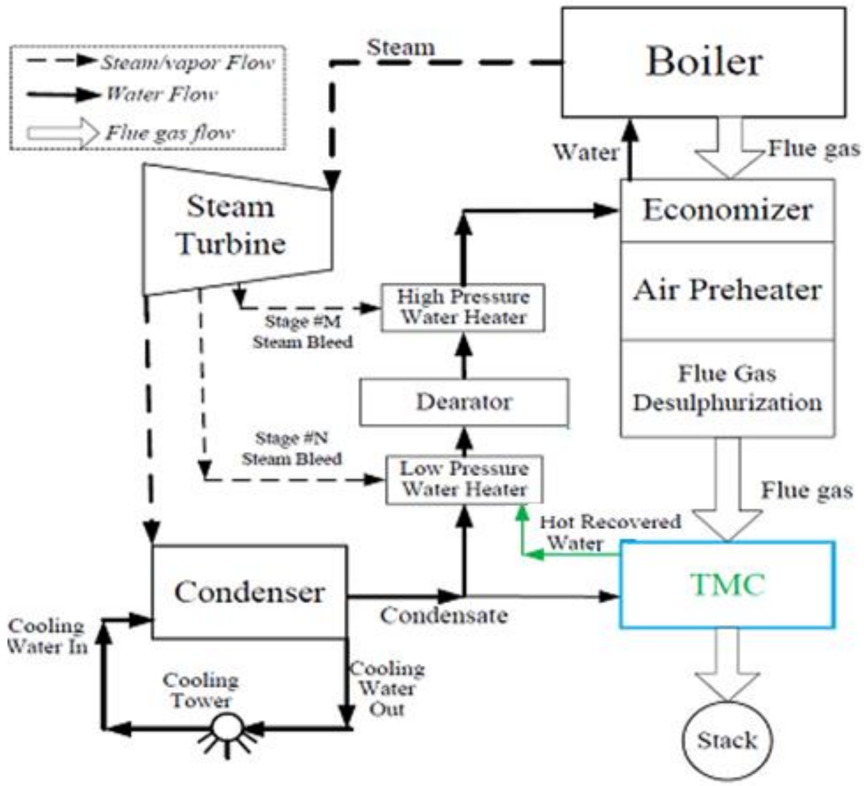

Figure 13. TMC Integration Diagram [6]

Module Layout

The system design was based off details provided by GTI, which specified a vessel cross section sized for a velocity that did not exceed 15 ft/sec and included three planes of 500 modules. After completion of the design, GTI clarified that the 15 ft/sec design velocity was actually the maximum interstitial gas velocity and the superficial gas velocity across the membrane vessels must be closer to 2 ft/sec. The arrangement for the system with three planes of 500 modules as specified by GTI resulted in a superficial flue-gas velocity of approximately 5 ft/sec in each vessel or 2.5 times that which was initially recommended. However, GTI later determined that the pressure drop can likely be kept under 1" H_2O with minor modification to the modules, even at this higher gas velocity. GTI did not comment on the added pressure drop in the case where the full flow of flue gas is travelling through one vessel; based on their estimate above, it would likely be less than a few inches of water column.

To allow for maintenance of the modules, a two-train arrangement was selected, which caused the total flue-gas flow to split evenly between two identical trains; i.e., each train typically handled half of the total plant flue-gas flow. Figure 14 shows the arrangement of the three planes, containing 256 TMC modules each. The planes were arranged so that the steam condensate (S.C.) and flue gas (F.G.) flowed in opposite directions, similar to a cross-flow heat exchanger. Steam condensate was supplied to each module on the top plane, and then passed through piping to each module on the 2nd and 3rd planes; none of the modules in the same plane were connected in series. When a train needs to be serviced, the flue-gas flow can be bypassed to the other train. Space was added between each plane to accommodate a wash system, should it be needed to control scale accumulation on the modules. GTI's design specification did not include a wash system. A wash system would likely be a more feasible option for cleaning the modules than annual removal, but a wash system has not been tested by GTI and was not included in the design or cost estimate.

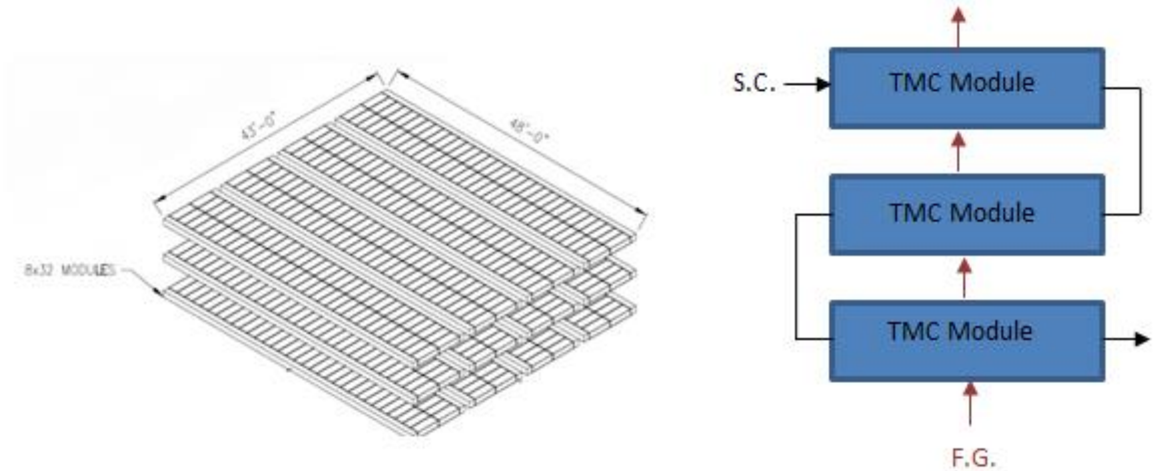

Figure 14. (Left) Three Planes of Modules; (Right) Arrangement Showing One Module from Each Plane Acting as a Cross-flow Heat Exchanger

General Arrangement

The dimensions of the individual TMC modules (4'L x 1.5'W x 1'H) as well as their connections to form the 3-pass cross-flow heat exchanger arrangement were taken into account for the sizing of the structure to hold the system. The vessel size for each TMC train required space to accommodate and access the modules as well as route connecting piping. Each TMC vessel held 768 TMC modules arranged in three planes (256 modules per plane).

The TMC plane cross-sectional area was calculated from the plane dimensions as shown in Figure 14. The cross-sectional area of the vessels for housing the TMC planes was larger than this calculated module area, as shown in Figure 15, to accommodate access, piping, and support framework. The piping and framework will prevent the flue gas from bypassing the module planes to some degree. For this study it was assumed all the flue gas passes through the module planes. The summary of the TMC plane area and gas velocity calculation is presented in Table 10**.**

Table 10. TMC Train Dimensions and Gas Velocity

Flue-Gas Mass Flow per Train (lb/hr)	Flue-Gas Density (lb/ft^3)	TMC Plane Length x Width (ft)	TMC Plane Cross-sectional Area (ft^2)	Superficial Gas Velocity (ft/sec)
2.5E+06	0.067	43 X 48	2064	5.0

Figure 15 shows a simplified general arrangement of the TMC system incorporated between the FGD unit and the stack. The proximity and size of the FGD unit and stack were based off an actual 550-MW plant for which AECOM had relevant measurements. The two TMC trains as well as associated equipment required a structural support to hold the weight of the entire system. The TMC vessel structural support island consisted of a structural steel braced framing that supported the vessels, pumps, and tanks required for the system. The structure extended up to the top of the vessels to include the supports of the ductwork immediately above and below the TMC vessels. The vessel support island was an open structure that encompassed both vessels.

A separate structure supported the ductwork extending from the wFGD unit to the TMC and the length travelling back to the stack. Ductwork and the requisite support structure designs are entirely site specific and dictated by the sites layout and space constraints. For the purpose of this study, approximately 500 feet of duct were assumed as the requirement to deliver flue gas from the FGD outlet to the TMC vessels and from the TMC vessel outlet to the inlet to the stack. The support structure included a deep foundation system consisting of drilled piers. It was estimated that the ductwork shown in Figure 15 would add at most 2–4" H_2O of pressure drop to the flue gas, in addition to the approximately 1" H_2O added by the set of three TMC module planes.

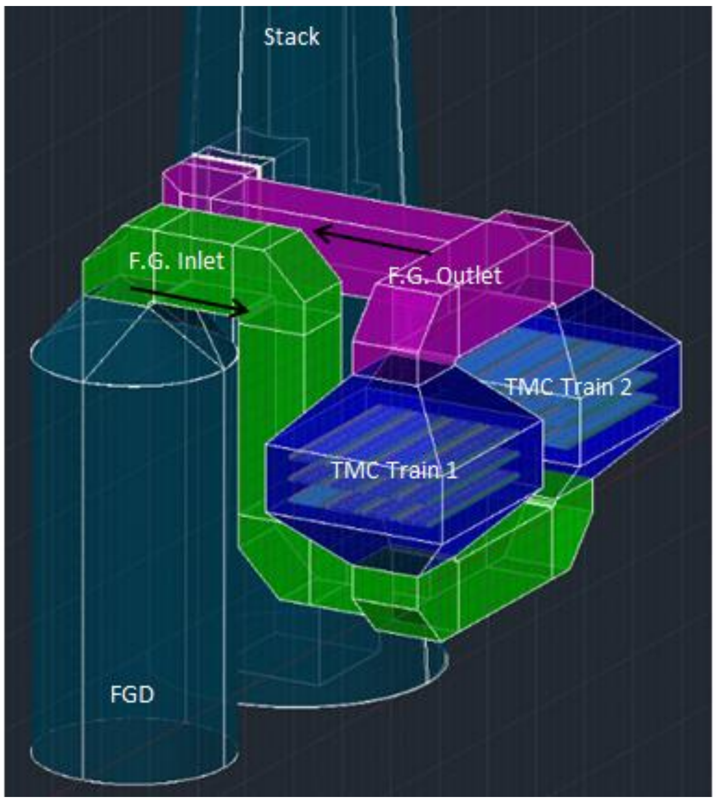

Figure 15. Simplified General Arrangement of TMC System

Liquid-Vapor Separation System and Equipment Sizing

GTI's design for the commercial-scale TMC assumed that a negligible amount of gases penetrated the membrane, thus no separation equipment would be required to remove gases from the recovered water stream. However, AECOM added a vapor-liquid separation equipment for the following reasons: (1) AECOM's analysis of GTI's pilot-scale data did not rule out dissolved gases penetrating the membrane;[2] (2) even in the case where no gas becomes entrained through the modules, it was expected

[2] In the report generated from GTI's small pilot-scale demonstration of the TMC system, funded by DOE, it was stated that a "small amount of [gases] can pass through the membrane and enter the TMC water stream." GTI conducted a pilot-scale test in which SO_2 was dosed into a natural gas exhaust stream from which the TMC system recovered water and heat. GTI measured an increase in the sulfate content of the recovered water stream; this increase in sulfate in the pilot unit was equivalent to 0.3% of the SO_2 in the gas stream. It is unclear whether the increase in sulfate in the recovered water was due to permeation of gas

there would be some amount of gas in the boiler feedwater coming from the condenser; and (3) to provide suction buffer to the pumps during transient events such as startup and shutdown, a vessel must be included in the control scheme. Since the equipment would help the startup of the system, and was considered good engineering practice, AECOM included it in the design. As will be shown later, the cost associated with the vapor-liquid separation equipment amounted to approximately $1M (which was 1.5% of the total installed cost).

With only a qualitative description from GTI of the ability of the membranes to resist flue-gas entrainment and only semi-quantitative data from a sulfur balance,[2] the liquid-vapor separation system was sized to handle an amount of entrained gas equal to 0.1% of the total flue-gas flow. This value was chosen to match the system vacuum pump horsepower recommended by GTI.

As shown in Figure 16 and Table 11, the equipment required to separate the recovered water from the gas and return the water to the feedwater heaters for each train consisted of a horizontal pressure vessel and a vertical knockout drum with corresponding vacuum and centrifugal pumps. A 50-hp vacuum pump (B-100 A/B) was selected for each train. This pump was used both to create the -3 psig vacuum required to recover the flue-gas moisture through the tube membranes into the condensate water as well as to remove any entrained gas from the system. Removal of the gases from the recovered water allowed operation of the centrifugal pump (P-100 A/B) that returned the heated condensate to the first feedwater heater.

Table 11 presents the equipment list for each TMC train. The horizontal and vertical vessels as well as the water and vacuum pumps were sized according to the process conditions for the corresponding streams. The main parameters used for the equipment sizing were the operating pressure and temperature, vapor and liquid flow rates, vapor and liquid density and viscosity. While the process design was based on the assumption that some gas constituents permeate the membrane to the recovered water, AECOM assumed that the resulting chemistry of the recovered water was still of sufficient quality to return to the boiler feedwater cycle.

---

through the membrane and/or dissolution of SO_2 into condensed water on the surface of the membrane. SO_2 solubility in water as calculated through Henry's Law accounted for only a very small fraction of the sulfur found in the water in the pilot test; however, Henry's Law will under-predict the SO_2 uptake by water, as dissolved SO_2 will chemically convert to sulfite and then sulfate species thus allowing more SO_2 to enter the aqueous phase.

Table 11. TMC Train Equipment List

ID on Figure 16	Type	Size or Pump Rating	Number Required
H-100	TMC Planes	256 modules/plane	3 planes per train
B-100 A/B	Liquid Ring Vacuum Pump	50 HP	2 per train, spared
P-100 A/B	Centrifugal Pump	100 HP	2 per train, spared
V-100	Horizontal Pressure Vessel	10 ft D x 21 ft L	1 per train
V-110	Vertical Knock out Drum	2 ft D x 15 ft L	1 per train

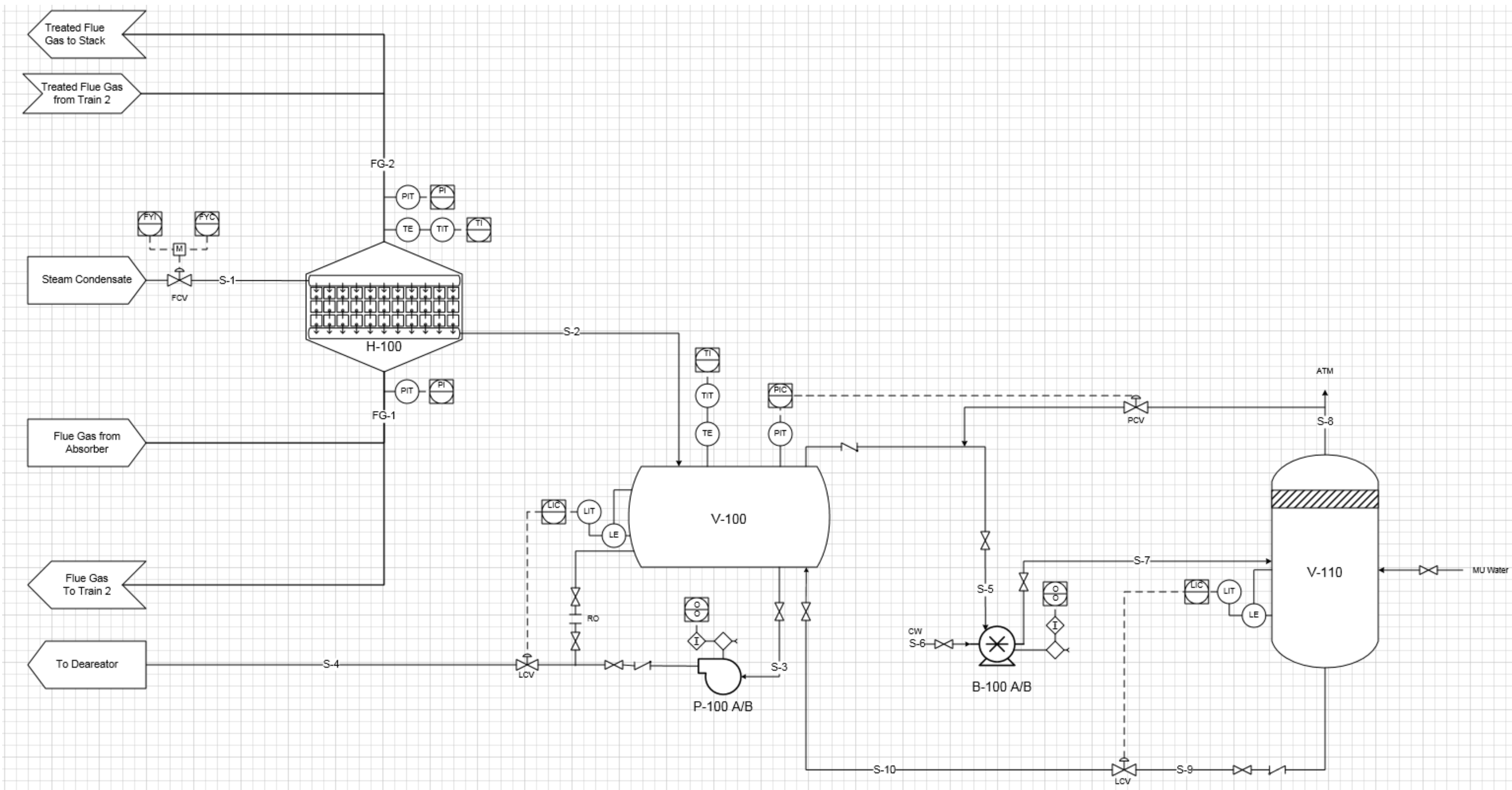

Figure 16. Simple Piping and Instrumentation Diagram (P&ID) of TMC Train

Process Modeling

An Aspen™ simulation of the process shown in Figure 16 was performed to obtain stream conditions used for equipment sizing and performance evaluation. Table 12 presents the model assumptions for the Aspen simulation as specified by GTI and given by the DOE Baseline Study 550-MW subcritical pulverized-coal plant [1].

Table 12. Mass Balance Assumptions

Parameter	Value	Source
Percentage of Gas Entrained	0.1%	AECOM
Inlet Water Flowrate	8 gal/min/module	GTI
Water Recovery Rate	10 lbm/MMBtu fired	GTI
550-MW Plant Firing Rate	5,107 MMBtu/hr	DOE Case 9 [1]
Inlet Flue-Gas Temperature	135°F	DOE Case 9 [1]
Outlet Water Temperature	125°F	GTI

The inlet and outlet stream conditions calculated by the Aspen simulation for a single TMC train are presented in Table 13. The inlet conditions for the flue gas were obtained from the DOE Baseline Study 550-MW subcritical pulverized-coal plant and the outlet stream conditions were obtained from the Aspen process simulation results. The outlet conditions represent the stream after it has passed through the liquid-vapor separation system; the temperature of the water outlet was chosen as 125°F based on an estimation form GTI. The 'Gross Heat Recovered' value was calculated by multiplying the outlet mass flow by the specific enthalpy difference between the inlet and outlet water streams. Under the given assumptions in Table 12, it is estimated both TMC trains translated into a total increase in thermal energy of the steam condensate of approximately 55 MMBtu/hr and a total water recovery of 51,600 lb/hr.

Table 13. Flue Gas and Steam Condensate Conditions at Each TMC Train

Stream	Inlet	Outlet
Flue-Gas Pressure (psia)	14.8*	14.8+
Flue-Gas Temperature (°F)	135*	127.3+
Flue-Gas Flowrate (lb/hr)	2,521,960*	2,493,820+
Flue-Gas Density (lb/ft^3)	0.067*	0.068+
Flue-Gas H_2O Mole Fraction	0.152*	0.138+
Steam Condensate Pressure (psia)	11.7*	11.7+
Steam Condensate Temperature (°F)	100*	125#
Steam Condensate Flowrate (lb/hr)	982,967#	1,021,630+
Gross Heat Recovered	55 MMBtu/hr+	
Total Water Recovered	51,600 lb/hr+	

* From DOE Baseline Study Case 9 [1]

+ From Aspen simulation results

\# Condition provided by GTI

Benefits

To estimate the influence of the heat recovered from the TMC on the steam turbine power output, the feed water network was modeled in Aspen. The recovered heat was simulated to be used several different ways. In the best scenario, the water from the TMC outlet was mixed with the rest of the plant steam condensate before the first feedwater heater. As shown in Table 14, the plant turbine power output was increased by 1 MW due to the reduced steam extraction to the first feed water heater. Using the recovered heat to reduce the degree of regeneration that occurred in the Rankine cycle actually reduced the cycle efficiency, despite the 1MW increase in electrical generation.

Table 14. Extraction Flow Rate for Feedwater Heater 1

Case 9 Steam Extraction Flowrate	130,860 lb/hr
Case 9 w/ TMC Extraction Flowrate	91,385 lb/hr
Reduction in Steam Extraction due to TMC	39,475 lb/hr
Power Increase Associated with Reduction in Steam Extraction	**1006 kW**

Table 15 presents the benefit analysis for the TMC system. The parameters shown were the net values when both trains were operating. The values were calculated for the DOE Baseline Study 550-MW subcritical pulverized-coal plant assuming a CF of 85%. The water cost of $1.88 per 1000 gallons (2015 dollars) and a cost of electricity of $92.60 per MW-hr (2015 dollars) were both escalated at a rate of 3%

per year from the 2011 dollars provided by DOE [24]. The recovered water would be offset to some degree by additional water consumption in the cooling tower due to increased turbine load. However, an analysis of the increased consumption was not included in this study.

Table 15. Benefit Analysis Commercial-Scale TMC System (2015 dollars)

Net Water Recovered	46.3 million gal/yr
Cost Savings due to Recovered Water	**$87,000/yr**
Added Electrical Generation	1.01 MW
Additional Revenue due to Added Power	**$693,600/yr**

Costs

Upon completion of the design for the 550-MW scale TMC system, the total cost was determined to be approximately $63M ± 30%, which was significantly higher than the value of $2.6M reported by GTI in the detailed questionnaire. The uncertainty of ± 30% was due to the lack of project definition; the system was costed for a hypothetical plant. The costs were broken down into three categories as shown in Table 17. Details for materials and construction costs are provided in Table 17. The prices were generated using estimating software that produces itemized costs for various categories based on the system components and materials of construction. Industry standards were used for material such as the cost of steel and concrete. The direct construction labor costs, including hours and estimates by discipline, were based off rates in Indiana and are broken out in Table 18. The three largest cost contributors, categorized by system components, are discussed below Table 18.

Table 16. Cost Summary

Materials and Construction	$40,950,000
Services: Engineering & Construction Management	$8,400,000
Other - Freight, Contractor Markup, Contingency, Fees	$13,475,000
Total	**$62,825,000**

Table 17. Materials and Construction Costs

System Component	Material Cost	Labor Cost	Total Cost	% of Subtotal	Description
Island Steel & Vessels	$ 7,500,000	$ 12,477,000	$ 19,977,000	49%	Vessel island steel, vessel steel, foundations
TMC Modules	$ 1,651,000	$ 377,000	$ 2,028,000	5%	TMC Modules
Piping	$ 4,249,000	$ 5,755,000	$ 10,004,000	24%	Piping & valves to / from island and boiler ~5000 feet of 18" diameter pipe total
Ductwork	$ 2,119,000	$ 4,428,000	$ 6,547,000	16%	Ductwork and steel to and from unit tie points (includes foundation footers)
EI&C	$ 470,000	$ 1,011,000	$ 1,481,000	4%	Instruments, power supply, control cables, conduit, cable tray
Equipment	$ 775,000	$ 139,000	$ 914,000	2%	Rotating equipment and smaller vessels installed on the island
Subtotal:	**$16,764,000**	**$24,187,000**		**Total: $ 40,951,000**	

Table 18. Construction Direct Labor Costs Breakdown

Discipline	Hours	Cost
Equipment (e.g., welder, operator)	57,800	$3,775,000
Piping	44,000	$2,486,000
Civil	41,700	$1,834,000
Steel	44,900	$2,965,000
Instrumentation	2,500	$144,000
Electrical	6,500	$384,000

The material and construction costs for the vessel island alone constituted $20M, which was approximately half of the total material and construction cost. This vessel island cost included only the vessels and vessel support structure, i.e., exclusive of the connecting ductwork, piping, or procured equipment.

The next largest cost contributor was the piping to and from the boiler feed water system at $10M. The pipe size required was 18” diameter; the piping cost included valves and fittings to accommodate the large system flows. The boiler is typically on the opposite side of the plant from the FGD system. The project team reviewed the general arrangement drawing of one 500-MW coal-fired power plant and determined that 4,400 feet of piping would be required to make the roundtrip from the boiler house to the FGD unit; typically, the routing of such large sized pipe through the power plant can be difficult and is likely not a straight shot, increasing the installation costs of that pipe.

The third largest cost contributor was the connecting flue-gas ductwork. The 500 total feet of ductwork (approximately 20' x 20' dimensions for the cross sectional area of the duct) and associated support steel was nominally $6.5M. Depending on the plant configuration, either more or less duct work may be needed. The duct work and support steel (typically used every 40 feet of duct run) costs scale reasonably well with linear feet of ductwork, at a rough cost of $12,000 - $15,000 per foot for similarly sized ducting.

Cost Cutting Options Explored

Below are design modifications that were explored to reduce the total cost of the system. Only one option presented significant cost savings but requires significant advancements in GTI's technology.

Allowing the flue gas to flow horizontally to reorient the vessels:

It was initially specified by GTI that the flue gas must flow vertically up through the modules. At the conclusion of the design process, the flue-gas flow orientation was determined not to be an actual design constraint. Modifying the system to allow for horizontal gas flow would rearrange the structural steel used to support the vessels, modules, and ancillary equipment. Because a significant portion of the cost was related to the support structure and the overall weight of the system would not be changed significantly, this modification would likely lead to less than 5% savings in cost.

Removing the liquid vapor separation system:

All the procured equipment (pumps, knock out vessels, and vacuum pumps) and labor for the liquid vapor separation system sum to just under $1M. Removing this system would not provide a significant savings. AECOM assumed these systems were necessary due to the unknown amount of entrained gas in the system; however, GTI believes the system can be operated without this equipment.

Decreasing the distance between the module planes:

Decreasing the size of the vessels by bringing the TMC planes closer to one another would eliminate approximately 47 tons of vessel plate and stiffeners. Some of this savings however will be offset by more ductwork and/or more structural steel to bridge the vertical distance to connect the TMC to the scrubber. The overall savings may come out to around $1M.

Setting the vessels on the ground:

Moving the vessels to the ground would eliminate some of the structural steel associated with the vessel island. However, for every foot the system is lowered, an equivalent distance of ductwork must be added to the system for it to reach the wFGD outlet and stack. This could bring the net savings to $2M. The equipment currently housed under the modules would be placed to the side of the vessel, which would necessitate more steel for piping supports and additional electrical and control cable. After these costs were factored in, this modification potentially saved somewhere between $1–1.75M. However, this would likely not be practical from a footprint perspective.

Housing all the modules in one vessel:

This savings would likely not be significant. Half the pumps and vessels would be eliminated but the remaining half would increase in capacity. Merging the two vessels together could eliminate the steel and plate associated with one wall on each vessel. The other three walls on each vessel would remain. Fewer external island support members for the island support steel would be necessary because the footprint was reduced; however, the members would be larger than the current size because the vessel weight would not be significantly reduced. Because the new vessel would be reconfigured into a new larger square cross section, the internal steel supporting the larger cross section of modules would increase in size as it now would span a larger distance. To maintain the same deflection criteria along a longer distance, the members would need to get stiffer and therefore larger. Additionally, the members must also be larger relative to the current sizes because the weight to be supported is not being reduced. It is likely this option would result in net zero savings.

Housing the modules in within the existing wFGD unit:

Presently, the number of modules and layout specified by GTI would not fit into the top of a wFGD unit. However, GTI is currently working with the DOE to improve the efficiency of the TMC and may eventually advance the technology such that it could. If the cross-sectional area were reduced by increasing the number of planes or reducing the number of modules, the system may be installed above the mist eliminator in a wFGD unit. As the wFGD unit would house and support the planes, this would eliminate much of the material and construction costs associated with the vessel island. This setup would also eliminate all costs related to ductwork. If the TMC modules were installed this way, the total cost could be reduced to approximately $26M. This estimate assumes that the requisite number of modules can fit into the space provided in the top of the wFGD unit and that no ductwork expansion is required.

Summary

The benefits analysis showed that for the TMC system, the increase in electrical generation as a result of the recovered heat from the flue gas was 1 MW; this recovered heat translated into added revenue by minimizing steam taken from the turbine to heat boiler feedwater. Additionally, the estimated water recovery of 104 gallons per minute constituted 140% of the boiler makeup water needed for the steam-condensate system, thus eliminating the need for any makeup water and providing 30 gallons per minute of water to be used elsewhere (e.g. for cooling water makeup).

The best way to significantly decrease the cost of the system from $63M is to advance the technology such that significantly fewer modules are needed, to the point that it can be installed in and supported by the overhead space above the scrubber (i.e., not requiring a separate structure). If this were possible AECOM estimates the cost could be reduced to $26M for the entire system.

Conclusions

A survey of seven major U.S. utilities with coal-fired generation indicated tepid interest in HRUT technologies, mostly due to the current decline in coal power generation in the U.S. However, all respondents said that if a clear, attractive payback could be established for HRUT technologies, one that overcomes any perceived risks, the technologies would be considered. All respondents indicated that if regulations drove the need for improved efficiency, then HRUTs would be given more priority to be investigated.

Using information gathered from the survey of coal-fired power generators, 38 technologies were identified as potential candidates for heat recovery and use technologies in the early stage of this project; these ranged from commercial to conceptual systems and included: bottoming cycles, heat exchangers, heat pipes, thermoelectrics, and water treatment systems, along with several other approaches. Detailed information was obtained from 17 technologies that were deemed feasible for the project application, including an evaluation of their technology for use at a 550-MW net coal-fired power plant modeled on the DOE Baseline Study's 550-MW subcritical pulverized-coal plant. Plant efficiency improvements ranged from 0.5 to 2.0 percentage points. Costs provided by organizations ranged from $1.5M to $50M for commercial-scale applications. Technologies with lower TRLs tended to cite significantly lower costs than commercially available systems. Relationships between the coal-power industry, technology providers, technology experts, and engineering firms in the developmental stages of these systems could assist in the direction of the development of these technologies and a more realistic assessment of costs and benefits designed to meet coal-fired power plant needs.

After an evaluation of the responses from the aforementioned 17 technologies, the LJUNGSTRÖM technology for enhanced AH operation and the GTI TMC technologies were selected for further analysis based on the organizations' supplied information. LJUNGSTRÖM commercially offers technology to upgrade the AH heat transfer surfaces and other necessary components to increase the amount of heat recovered. The technology is in operation at full-scale at one U.S. coal power plant. To prevent acid gas corrosion from the resulting decrease in flue-gas temperature, LJUNGSTRÖM's retrofitted AH can be coupled with alkaline solution injection to reduce flue-gas SO_3 concentrations. The benefits of the LJUNGSTRÖM system include an increase in net plant efficiency of up to approximately one percentage point, reduction in fuel consumption, reduction in scrubber blowdown volume, reduced water usage in the wet FGD due to lower evaporative losses, and reduction in pollutant emissions. The estimated cost for the combined LJUNGSTRÖM/SBS system was $18.1M ± 30%. For a 1 percentage point increase in net plant efficiency, this capital cost translates to $73,000/Btu/kWh for the improvement in net heat rate.

GTI's TMC is a HRUT based on a nanoporous ceramic membrane water-vapor separation mechanism. The technology extracts the water vapor and its latent heat from the flue gas. The recovered water can supply 100% of the boiler makeup water, and the recovered heat from the flue gas can increase the electrical generation up to 1 MW. The ultimate cost for the commercial-scale was evaluated at $63M ± 30%, with the potential to be reduced to $26M if the technology advances so that significantly fewer modules are needed, to the point that it can be installed in and supported by the overhead space above the wFGD (i.e., not requiring a separate structure). This reduced capital cost translates to $250,000/gpm of high quality water recovered for boiler feedwater, or $26,000/kW of additional electrical generation.

Findings from the project indicated that incorporating low-grade heat into the steam cycle as boiler feedwater preheating will increase output, but actually lowers steam cycle efficiency. For example, raising the water temperature prior to the low-pressure (LP) heater train will divert steam away from extraction and continue through the LP turbine (more output), however, more steam reaches the condenser to be rejected by the cooling tower. If a wet tower is used, the increased heat load will result in more evaporation losses in the tower. Furthermore, the boiler feedwater handling system is typically on the opposite end of the plant from the flue-gas clean-up system, potentially resulting in significant capital costs for the pipe to convey the feedwater to the heat source. Overall, if low-grade heat is to be used, in many instances applications should be outside the steam cycle such as preheating combustion air, drying coal, water treatment, or any variety of non-steam cycle enhancements – if the economics are justified. The possibility of stronger economic and regulatory drivers for efficiency and water conservation and treatment would improve both the interest and cost-benefit for these technologies.

Appendix A: Detailed Questionnaire for HRUT Selection

Overview

This document presents questions to facilitate the selection of a heat recovery-use technology (HRUT)[3] for a proposed pilot-scale demonstration at a coal-fired power plant as well as a potential subsequent commercial-scale unit. Overall, each system is being evaluated for its potential to exist as a competitive product at a commercial-scale plant as well as the likelihood of it being able to be demonstrated successfully at a pilot-scale plant in the near term. This project is funded by the Department of Energy and is being performed by the team of Southern Company Services, the Electric Power Research Institute, Inc. (EPRI), and AECOM.

Except where it is noted in the questionnaire (Section VI, Part B, Pilot Plant Capital Cost), all questions are with respect to a potential commercial-scale unit.

Instructions

The HRUT organization should answer each question as thoroughly as possible. The answers will be used in a scoring matrix comprised of various sections to rank the HRUT. The section and sub-section titles are provided for each set of questions below. If a question is left blank, the score for that category will be given a zero. Provide engineering units where possible.

Attachments *(Appendix B)*

The following document is included along with this questionnaire:

- Reference Data: Contains the design basis for estimating how to apply the HRUT to the pilot- and commercial-scale sites.

Questions

If the HRUT organization has any questions about the questionnaire, please contact AECOM or EPRI.

Deadline

Responses must be submitted by July 31, 2015 and should be submitted electronically. If additional attachments are provided, submit these electronically as well.

Schedule

The planned schedule for the HRUT selection process is given below:

- **June 22, 2015:** Send out questionnaires to selected HRUT organizations
- **July 31, 2015:** Deadline for getting responses to questionnaires
- **August 15, 2015:** Questionnaires reviewed by team

[3] Note that technologies that only do heat recovery or use can also fill out this questionnaire. For heat use technologies, an assumption should be made that the heat required will be provided by heat exchanger technology. For heat recovery technologies, if no designated use for the heat has been identified, it should be assumed it will be used for feedwater heating.

- **September 1–15, 2015:** Team announces selected technology(ies) and begins working with the associated organization(s) to get more details.

Section I: Organization

Part A: Experience

List all projects for which your organization has demonstrated, constructed, and / or commissioned the HRUT including in particular those using coal-derived flue (or similar) gas. Include in that list the following information for each project (if applicable):

- Type of project (bench-scale, pilot, demonstration, or commercial plant)
- Description of project (where, when, scope of work, and goals)
- Application (e.g., coal-fired or other)
- Startup (year)
- Flue gas flow rate (standard cubic feet per minute [scfm]) and composition
- Total operating hours achieved
- Did you meet schedule and budget estimates?
- Reference contact name and contact info (phone number and e-mail)
- Are reports available (if so provide separately)?

Part B: Size and Financial Stability

Provide the following information on your organization:

- Year organization started
- Year organization began working on the HRUT
- Number and location of offices
- Company size (number of employees)
- Number of full-time equivalents working on the HRUT.

Section II: Design and Operation

Part A: Design

1. System Design
    - Describe the HRUT system in detail and provide process flow diagrams with pertinent stream conditions.
2. Scale Up
    - Provide examples of past process scale-up experiences.
3. Integration
    - Describe how the HRUT will be integrated into the power plant
    - What are the strengths of the HRUT related to plant integration?

Part B: Operation

1. Response to Load Changes
   - How responsive is the HRUT to process changes in the heat source (e.g. temperature or velocity fluctuations)?
   - In the event of a power plant trip, describe the controlled shut down of the HRUT.
2. Impact on Startup Times
   - What is the startup time requirement for the HRUT?
3. Acceptable Flue Gas Composition
   - Can the composition of the flue gases provided in the “Reference Data” be managed by the HRUT?
   - Which constituents of the flue gas, if any, have an upper limit beyond which the HRUT can’t handle? What is that upper limit?
4. Pressure Drop
   - If applicable, estimate the pressure drop of the flue gas across the HRUT.

Section III: Technology

Part A: Benefits

1. Efficiency
   - If applicable, what is the estimated gain in net thermal efficiency to the power plant from the HRUT?
   - Explain in detail how the efficiency improvement will be realized. Will it require any change to the existing power plant beyond the flue gas ducts?
2. Water Treatment
   - If applicable, what water processes will be treated? What is the flow rate that can be treated in gallons/day?
   - How will they be treated, what will be removed, and what percentage of it will be removed?
   - What is the reduction in annual costs associated with water treatment?
3. Water Use / Generation
   - If applicable, how much will water use be reduced or how much new water will be generated in gallons/year?
4. Environmental
   - If applicable, describe any environmental benefits of the HRUT. What emissions are being reduced and by how much?
   - Do the environmental benefits displace any required environmental systems or help meet any U.S. environmental regulations? Please specify.

5. Other
   - Describe in detail any other benefits of the HRUT, how they are realized, and what the associated annual cost savings / increase in profits are.
6. Cost / Benefit Analysis
   - What is the estimated payback in years for the HRUT?

Part B: Operations, Maintenance, Availability, and Safety

1. Operations
   - Provide the operating labor requirement (number of operators required per shift)
   - List the consumables for operation (e.g., any chemicals required, consumption in lb/hour, and commercial cost of chemical in $/ton)
   - Provide the total auxiliary power consumption of the HRUT.
2. Maintenance
   - Discuss any recommended preventative maintenance procedures
   - Specify the frequency and duration of the outage period required for inspection and routine maintenance of the HRUT
   - Describe the equipment that needs to be replaced and the recommended spares needed for the HRUT.
3. Availability
   - Provide estimates of the availability of the HRUT with and without the redundant equipment.
4. Safety
   - Specify how the HRUT design ensures operator safety.

Section IV. Environmental Impacts

Part A: Solids

- If applicable, indicate any solid discharge produced by the HRUT and the expected amount and composition
- What means of waste disposal is used, e.g., landfill or incineration?
- Is the waste hazardous?

Part B: Liquids

- If applicable, indicate any liquid discharge produced by the HRUT and the expected amount and composition
- What means of waste disposal is used?
- Estimate the amounts of any chemicals used for disposal
- Are there any special disposal/handling requirements for these chemicals?

Part C: Gas

- How much will the HRUT reduce the flue gas temperature and associated velocity and will this impact the stack dispersion?
- Indicate any gas-phase emissions produced by the HRUT and the expected amount and composition
- If additional equipment is needed to process / clean up any stack discharges of concern, describe the nature of the equipment to be used. Include any electrical or pressure drops required in the operation of the equipment.

Section V: Potential for Future Improvements

Part A: Future Technology Improvements

- Indicate what efforts can be conducted to develop improvements to the HRUT. How will these improve the HRUT performance and/or reduce its costs?

Part B: Future Integration Improvements

- Indicate what efforts will be made to better integrate the process into the power plant or make it usable for any coal-derived flue gas quality.

Section VI: Capital Costs

Part A: Commercial-Scale Plant Capital Cost

- Provide the total bare erected cost (in 2015 $) of the commercial-scale HRUT (as a turnkey-type cost) with confidence limits (± %) according to the scope of the supply reported in the "Reference Data"
- Provide a conceptual layout and footprint
- Provide the duration of the construction period for the commercial application from start to commissioning.

Part B: Pilot Plant Capital Cost

- Provide the total capital cost of the pilot plant HRUT according to the scope of the supply reported in the "Reference Data"
- Describe the pilot plant HRUT to be provided, including size (in terms of scfm of flue gas extracted and footprint), expected performance, and a list of major equipment to be provided.

Appendix B: Reference Data

Overview

The heat recovery-use technology (HRUT) organization should use the information provided in this Reference Data addendum to answer the questions in the Detailed Questionnaire for Heat Recovery-Use Technology Selection and for any cost estimates.

Scope of Supply for Commercial-Scale HRUT Demonstration

A commercial-scale HRUT will be installed as a retrofit to a coal-fired power plant, according to the assumptions in Tables 1, 2, and 3. The parameters for this plant, which is shown in Figure 1, were modeled upon Case 9-Subcritical Pulverized Coal Unit without CO_2 Capture in the U.S. Department of Energy (DOE) study: Volume 1 – Bituminous Coal and Natural Gas to Electricity (Rev 2a).[4]

Several modifications were made to DOE's Case 9 for this project: assume a retrofit of the HRUT to the Case 9 plant and acid gas specifications for SO_3, HCl, and HBr for the flue gas are provided. The solids concentration in flue gas at the fabric filter outlet is also quantified.

Table 1. Assumptions for Commercial-Scale HRUT Demonstration

Item	Value
Scope of Supply	Turnkey engineering, procurement, and construction to retrofit HRUT to an existing coal-fired power plant
Site Location	Midwestern USA
Net Full Load, MWe	550
Location of Flue Gas Heat Recovery	The scope of this report is limited to heat recovery from any flue gas location after the air heater as labeled by 10, 12, 13, and/or 18 in the process flow diagram in Figure 1.
Footprint Available	Assume no constraints on space
Fuel Cost, $/MBtu	3.0

[4] http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies

Table 2. Site Ambient Conditions

Item	Value
Elevation, feet	0
Barometric Pressure, psia	14.696
Design Ambient Temperature, Dry Bulb, °F	59
Design Ambient Temperature, Wet Bulb, °F	51.5
Design Ambient Relative Humidity, %	60

Table 3. Stream Table

	Stream #			
Gas Mole Fraction	**10**	**12**	**13**	**18**
Ar	0.0087	0.0087	0.0087	0.0082
CO_2	0.1447	0.1447	0.1447	0.1350
HCl, ppmv	200	30	30	1
H_2O	0.0868	0.0868	0.0868	0.1517
N_2	0.7325	0.7325	0.7325	0.6808
O_2	0.0250	0.0250	0.0250	0.0243
SO_2	0.0021	0.0021	0.0021	0.000042
SO_3, ppmv	30	5	5	2
Item	**10**	**12**	**13**	**18**
Gas Flowrate, lbmol/hour	160,726	160,726	160,726	174,826
Gas Flowrate, lb/hour	4,780,183	4,780,183	4,780,183	5,043,963
Solids Flowrate, lb/hour	33,929	68	68	68
Temperature, °F	337	337	357	135
Pressure, psia	14.4	14.2	15.3	14.8
Enthalpy,[5] Btu/lb	140.6	132.7	137.9	128.0
Density, lb/ft^3	0.050	0.049	0.052	0.067

Water Treatment for Commercial-Scale HRUT Demonstration

If the technology uses the recovered heat in a water treatment system, the organization should use the information provided in Table 4 to answer questions in the Detailed Questionnaire for Heat Recovery-Use Technology Selection and for any cost estimates.

[5] Reference conditions are 32.02°F and 0.089 psia.

Table 4. Assumptions for Water Treatment for Commercial-Scale HRUT Demonstration

Air Heater

Item	Value
Water Type to Be Treated	Flue gas desulphurization (FGD) water
Water Inlet Temperature, °F	40
Water Flow Rate, gallons/min	300
Available Heat from Waste-Heat Recovery, MBtu/hr	230
Inlet Total Dissolvable Solids (TDS), ppmv	10,000
Outlet TDS, ppmv	Best achievable to optimize cost benefits

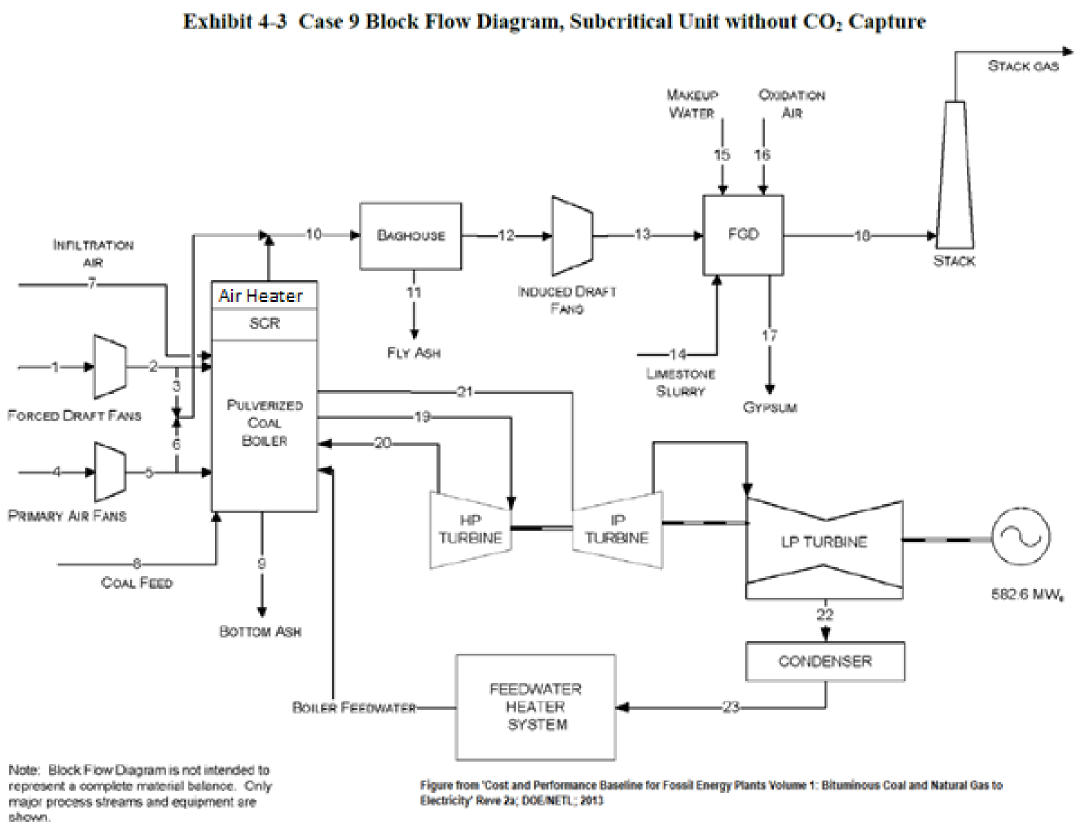

Figure 1. Process Flow Diagram for Commercial-Scale Plant

Scope of Supply for Pilot-Scale HRUT Demonstration

A pilot-scale HRUT will be installed at a coal-fired power plant host site for demonstration according to assumptions in Table 5. The host site fires a blend of high-sulfur bituminous coals.

Table 5. Assumptions for Pilot-Scale HRUT Demonstration Unit

Item	Value
Timing of Demonstration	Demonstration to occur in the 2018 timeframe.
Scale of Pilot Demonstration Unit	Size as large as possible up to the available flue gas flowrate. Flexibility in size is being given to allow for use of existing equipment, if available.
Demonstration Unit to Be Provided by HRUT Organization	HRUT organization will provide the pilot unit for demonstration and a blower and flow controls for moving flue gas through the pilot unit, if required.
Balance of Demonstration Unit Provided by Host Site	Assume host site will provide duct work to move flue gas to and from the pilot HRUT, if required, as well as standard utilities (e.g., electrical and water) and tie-ins.
Location of Flue Gas Extraction	The tap for flue gas extraction is downstream of the air heater. HRUT can extract flue gas either upstream or downstream of the particulate matter (PM) control device.
Footprint Available	Assume there are no space constraints for the pilot unit.
Flue Gas Flowrate, scfm	5000
Flue Gas Temperature, °F	350
Fuel Cost, $/MBtu	3.0
Pressure of Flue Gas, inwg	-20
Flue Gas Concentrations[6]	
CO_2, %	10.0
H_2O, %	5.0
O_2, %	3.0

[6] The flue gas CO_2 and O_2 concentrations presented in Table 5 likely do not reflect the actual conditions at the extraction point for the flue gas. Typically both would be slightly higher at the AH outlet. This discrepancy was only discovered after issuing the survey and reference data to each developer. However, the team determined this mis-statement of the CO_2 and O_2 concentrations would not materially affect the vendor responses and was therefore left as-is.

PM, lb/std ft^3, std at 68°F, 1 atm	1.1 x 10^{-4} (upstream of PM control device) 1.1 x 10^{-6} (downstream of PM control device)
SO_2, ppmv	1200
SO_3, ppmv	5 (achieved via lime injection)
Water Treatment, if applicable	
Water Type to Be Treated	FGD water
Water Inlet Temperature, °F	40
Water Flow Rate, gallons/min	0.5
Available Heat from Waste-Heat Recovery, MBtu/hr	0.345
Inlet TDS, ppmv	10,000
Outlet TDS, ppmv	Best achievable to optimize cost benefits

Appendix C: Complete List of Technologies Reviewed

This Appendix provides high-level details on all identified heat recovery and/or use technologies that were evaluated at a high-level. A total of 38 technologies were evaluated and are grouped in six categories. Based on the first round of evaluations, the technologies were winnowed down from 38 to 17. A second round of evaluation was performed for these remaining technologies using a more detailed questionnaire that was provided to each organization. The two recommended technologies were obtained from the results of the second round of evaluation.

Table C- 1 provides the complete list of the 38 technologies and their organizations and whether they were selected to move on to the second round of evaluation.

Table C- 1. Complete List of Heat Recovery and/or Use Technologies

Technology/Title	Organization	Second Evaluation?
Coal Drying		
DryFining™	Great River Energy	Yes
Heat Exchangers		
Air Heater (AH) Upgrade	LJUNGSTRÖM	Yes
Gas-Gas Heater	LJUNGSTRÖM	No
Condensing Heat Recovery	ConDex Systems, Inc.	Yes
Condensing Heat Recovery	The Wallstein Group	Yes
High Efficiency System	Mitsubishi Hitachi Power Systems, Ltd (MHPS)	Yes
Gas-Gas Heater (GGH)	MHPS	No
Water-Gas Cooler	Flucorrex	Yes
Condensing Heat Recovery	e-Tech	Yes
Heat Pipes		
Heat-Pipe AHs	Babcock Power	No
Heat-Pipe AHs/Pre-heaters	Hudson Products Corporation	No
Heat-Pipe Technology	Thermacore	No
Heat Core	Sylvan Source Inc. (SSI)	Yes
Bottoming Cycles		
GEN4	Ener-G-Rotors	No
Heat-to-Power Unit	TAS Energy	No
Heat Pump	Cherokee Energy Management	No
Kalina Cycle	Recurrent Engineering (Global Geothermal)	Yes
Organic Rankine Cycle (ORC)	Turboden	Yes
ORC	Siemens	No
ORC	Ormat	Yes

ORC	Access Energy/Calnetix	No
ThermoHeart Engine	Cool Energy	No
Thermoelectrics		
PowerBlocks	Alphabet Energy, Inc.	No
Thermoelectric Technology	Novus Energy Technologies	Yes
Thermoelectric Technology	TEG	No
Water Treatment / Production		
Carbon NanoTube Immobilized Membranes	New Jersey Institute of Technology	No
COHO (CO_2-H_2O)	Porifera Inc.	Yes
Desalinization Technology	Hittite Solar Energy	No
Evaporation with Vapor Recompression	Vacom Systems	Yes
Forward Osmosis	Carnegie Mellon University	No
Heat Core	SSI	Yes
Humidification-Dehumidification	RPESA / NMIMT / Harvard Petroleum	No
Passive Evaporation	PAX Pure	Yes
Transport Membrane Condenser	Gas Technology Institute	Yes
Wastewater Spray Dryer	MHPS	No
Wastewater Evaporation System	MHPS	No
Zero Liquid Discharge	GE Power	No
Zero Liquid Discharge	Babcock Power	No

Information on Non-Selected Technologies

A brief description of each of the technologies that were not selected for the second evaluation as well as the reasoning behind the decision is provided in this section.

Gas-Gas Heater from LJUNGSTRÖM and MHPS

The GGH is located in proximity to the stack tower. The GGH recovers heat from the flue gas as it enters the flue gas desulphurization (FGD) unit and then transfers that heat back to the flue gas downstream of the FGD, right before it enters the stack, to provide sufficient heat for plume rise. Lowering the flue-gas temperature upstream of the FGD reduces water consumption. This technology was not selected for the second round because in the U.S., the need for re-heating the FGD exhaust is not as prevalent as in European or Asian markets.

Heat-Pipe Air Heaters from Babcock Power, Hudson Products Corporation, and Thermacore

This heat-pipe AH technology is used to pre-heat combustion air by transferring heat from the flue gas. A heat pipe is a sealed cylinder filled with a working fluid whose mass is chosen so that the pipe contains both vapor and liquid over the operating temperature range. During normal operation, the heat from the flue gas evaporates the working fluid in the heat pipe and this vapor is transferred to the cold end of the heat pipe, where it transfers heat to the combustion air. The working fluid then condenses and returns to the hot side of the pipe by capillary action and the process is repeated. Isothermal operation minimizes potential for cold-end corrosion.

The reason why these technologies were not selected for the second evaluation is:

- Babcock Power – Babcock Power no longer offers heat pipes.
- Hudson Products Corporation – They no longer manufacture heat pipes.
- Thermacore – Company did not provide a response to the participation request.

GEN4 from Ener-G-Rotors

The GEN4 is a complete ORC system containing all of the hardware and controls necessary to convert low-grade heat into electricity. All of the components are included in a single, modular box that can be installed near the heat source. The heart of the GEN4 system is the expander, Ener-G-Rotors' trochoidal gear engine, which is a positive-displacement device. In essence, the mechanism is a modified rotor running as an expander. This patented approach to the control of tolerances enables the system to effectively extract the maximum amount of work from the expanding vapor, while minimizing friction and gear wear. This technology was selected for the second evaluation; however, the organization decided to not respond to the detailed questionnaire.

Heat-to-Power Unit from TAS Energy

TAS Energy's Heat-to-Power unit is a patented approach to the ORC, purported to be capable of efficiently generating emission-free electricity. However, the company did not participate in the second evaluation because they are no longer pursuing this ORC technology.

Heat Pump from Cherokee Energy Management

A hybrid ORC regenerative cooling system is used to pump heat from the turbine steam condenser into the boiler feedwater. Cherokee Energy Management did not participate in the second evaluation because the technology's focus is to recover heat from steam condensate streams instead of combustion flue gas. The application of this technology to coal-fired power plants has not been developed beyond a conceptual stage. Previous designs have been done for buildings and there is no experience with coal-fired flue gas particularly in the heat-exchanger design.

ORC from Siemens

Siemens' ORC technology is capable of generating a power output from 300 kW to 2 MW. The working medium is a chlorine-free, non-toxic, substance with a zero-ozone depletion potential. Low-quality heat with a temperature of 570°F is enough to drive the ORC technology process. The recovery process adds to the efficiency of the process and thus decrease the costs of fuel and energy consumption needed. This technology did not participate in the second evaluation because the technology is not suitable for the low-temperature range specified for this project.

Thermapower 125XLT/125MT ORCs from Access Energy/Calnetix

Access Energy's Thermapower™ ORC 125XLT is a modular ORC that generates 125 kW of utility-grade power using recovered low-quality heat. The system is designed for integration with small-scale commercial and industrial applications, particularly application-specific condensers and evaporators. The organization responded to the detailed questionnaire for the second evaluation; however, the responses were limited in content and as a result were not included in the evaluation.

ThermoHeart Engine from Cool Energy

The ThermoHeart Engine is a system that converts lower-temperature (212 to 570°F), low-quality heat into electricity. The ThermoHeart Engine captures low-quality heat from an industrial site, commercial process, or power generator and turns it into renewable electricity, recycled thermal energy, or mechanical energy. These engines are a new approach to the design of the Stirling cycle, employing a new engine configuration, low-cost materials, self-lubricating components, a nitrogen working gas, and long service intervals. This technology did not participate in the second evaluation because the company did not provide a response to the initial survey.

PowerBlocks from Alphabet Energy, Inc.

Thermoelectrics are solid-state semiconductors that turn heat into electricity. The technology generates power cleanly with few or no moving parts from a temperature gradient. The PowerBlocks concept is similar to solar panels; however, heat instead of light is used as an energy source. Alphabet Energy is attempting to revolutionize the way thermoelectric materials and products are designed, manufactured, and utilized, and has filed or licensed over 40 patents worldwide. This technology did not participate in the second evaluation because it is not suitable for the low-temperature range specified for this project.

Thermoelectric Generator from TECTEG MFR

This technology produces power using the Seebeck effect in which the thermoelectric device creates a voltage when there is a difference in temperature on each side of the module. The typical temperature range of the heat source from which the technology extracts the thermal energy efficiently is 375°F to 570°F. The temperature of the heat source dictates the semiconductor material that should be used; a BiTe module can perform at temperatures below 608°F; materials like PbTe perform better at elevated temperatures near 1112°F. This technology was not selected for the second-round evaluations because the temperature range for this project was marginal for the systems offered by the organization at the time of survey. The company is working with different universities to expand their technology applications and is interested in pursuing low-temperature applications.

Appendix D: Check on Efficiency Improvement for LJUNGSTRÖM's Commercial-Scale System

To confirm the efficiency claims provided by LJUNGSTRÖM, an independent calculation of the net plant efficiency improvement was performed. The analysis used the pre-upgrade air heater (AH) outlet gas temperatures and the post-upgrade (alkaline injection + AH upgrade) AH outlet gas temperatures to compute the increase in boiler efficiency and therefore overall efficiency.

1. Determination of the AH outlet gas temperatures (pre-upgrade and post-upgrade):
   Gas temperature values reported by LJUNGSTRÖM, in their responses to the detailed questionnaire and from literature sources, were used to determine different scenarios. The pre-upgrade AH outlet gas temperature is 337°F per the DOE Baseline Study 550-MW subcritical pulverized-coal (Case 9). The post-upgrade AH outlet gas temperature of 240°F is used per LJUNGSTRÖM' response to the detailed questionnaire.

AH outlet gas temperature (°F)

pre-upgrade	post-upgrade
337	240

2. Calculation of pounds of dry gas per pounds of coal fired (lb gas/lb coal):
   The dry gas value is obtained by subtracting the mass flow of water vapor in the flue gas from the total flue-gas mass flow and dividing the remaining dry gas by the mass flow of coal:

$$\text{Dry Gas}\left(\frac{\text{lb}_{\text{gas}}}{\text{lb}_{\text{coal}}}\right) = \frac{\text{Flue Gas Flowrate}\left(\frac{\text{lb}}{\text{h}}\right) - \text{Water Vapor Flowrate}\left(\frac{\text{lb}}{\text{h}}\right)}{\text{Coal Input Flowrate}\left(\frac{\text{lb}}{\text{h}}\right)} = 10.36$$

   The flue gas flowrate (4,780,183 lb/h) was obtained from Stream 10, Case 9; the coal input flowrate (437,378 lb/h) was obtained from Stream 8, Case 9; and the water vapor flowrate (251,118 lb/h) was calculated by multiplying the % volume of water (8.68%) in the flue gas stream (Case 9) by the molar flue-gas flowrate (160,726 lbmol/hr) from Stream 10 and the molecular weight of water.

3. Calculation of dry gas losses:
   The dry gas loss (L_{DG}) equation requires dry gas (10.36 lb/lb coal as obtained in step 2), flue-gas heat capacity (Btu/lb°F), coal heating value (Btu/lb), flue-gas AH outlet temperature, and ambient air inlet temperature to the AH:

$$L_{DG}(\text{\% of coal input}) = \frac{\text{Dry Gas}\left(\frac{\text{lb}}{\text{lb}_{\text{coal}}}\right) \times \text{Cp}_{\text{Flue Gas}}\left(\frac{\text{Btu}}{\text{lb°F}}\right) \times (\text{AH Outlet Gas (°F)} - \text{AH Inlet Air (°F)})}{\text{Coal Heating Value (Btu/lb)}}$$

The AH inlet air temperature per Case 9 is 59°F; the coal heating value is 11,666 Btu/lb; the flue-gas heat capacity was estimated using a generic equation from the literature [25] and calculated for the pre- and post-upgrade cases. The resulting dry gas losses for the pre- and post-upgrade cases are:

Dry gas loss (%) pre-upgrade

Cp (Btu/lbF)	DG Loss, %
0.245	6.05%

Dry gas loss (%) post-upgrade

Cp (Btu/lbF)	DG Loss, %
0.242	3.88%

4. Calculation of water vapor loss and net loss difference:
   Calculates the sensible heat recovered due to the temperature change of the flue-gas water vapor component of the Case 9 plant as a fraction of the heat input. The vapor enthalpy change is derived from the temperature difference before and after the AH upgrade:

$$\text{Water Vapor Loss (\%)} = \frac{\text{Water Vapor Flowrate } \left(\frac{\text{lb}}{\text{h}}\right) \times (\text{Vapor Enthalpy Change, Btu/lb})}{\text{Coal Input Flowrate } \left(\frac{\text{lb}}{\text{h}}\right) \times \text{Coal Heating Value } \left(\frac{\text{Btu}}{\text{lb}}\right)}$$

   The calculated relative water vapor loss is 0.23%; this value was added to the change of dry gas losses between pre- and post-upgrade to obtain the net loss difference:

$$\text{Net Loss Difference} = \text{L}_{\text{DG,pre-upgrade}} - \text{L}_{\text{DG,post-upgrade}} + \text{Water Vapor Loss} = 6.05\% - 3.88\% + 0.23\% = 2.40\%$$

5. Calculation of net plant efficiency change:
   The net plant efficiency increase due to the AH upgrade case is a function of boiler efficiency change, coal heat input, and gross plant output. This method assumes plant generation increases due to the recovered heat. However, an analysis can also be performed wherein the gross output in MW is held constant and the coal input is reduced.

Boiler Efficiency

Pre-Upgrade (per Case 9)	88.0%
Post-Upgrade (Boiler Efficiency Pre-Upgrade + Net Loss Difference)	90.4%

Coal Heat Input (per Case 9) 5,102 MMBtu/hr

Gross Plant Output

Pre-Upgrade (per Case 9)	582.6 MW
Post-Upgrade (see equation below)	598.5 MW

$$\frac{(\text{Gross Plant Output}_{\text{pre-upgrade}} \times \text{Boiler Efficiency}_{\text{post-upgrade}})}{\text{Boiler Efficiency}_{\text{pre-upgrade}}}$$

Net Plant Efficiency

Auxiliary Load (per Case 9)	32.58 MW
Pre-Upgrade (see equation below)	36.78%
Post-Upgrade (see equation below)	37.85%

$$\frac{\text{Gross Plant Output}_{\text{pre-upgrade}} - \text{Auxiliary Loads}}{\text{Coal Heat Input}}$$

Net Plant Thermal Efficiency Improvement **1.06 percentage points**

Table D- 1 shows the range of AH gas outlet temperature from the literature [22] before and after the AH upgrade as well as the calculated plant efficiency improvement.

Table D- 1. AH Gas Outlet Temperature References for LJUNGSTRÖM's System

Reference	AH Gas Outlet Temperature Pre-Upgrade (°F)	AH Gas Outlet Temperature Post-Upgrade (°F)	Load	Calculated Plant Percentage-Point Efficiency Improvement
[22]	340	290	Full	0.55
[22]	340	265	Reduced	0.82
[19]	330	285	Cycled (~300 to ~500 MW) – at full load most of the time	0.50
[19]	340	270	Unknown/Likely reduced	0.77
[19]	330	255	Unknown/Likely reduced	0.82

Appendix E: Cost Information for LJUNGSTRÖM's Pilot-Scale System

The following information was provided by LJUNGSTRÖM for the proposed pilot-scale system.

Detailed Questionnaire Request	LJUNGSTRÖM Group Response
Provide the total capital cost of the pilot plant heat recovery and use technology (HRUT) according to the scope of the supply reported in the "Reference Data"	• The Mercury Research Center (MRC) AH of the Gulf Power Co., Crist Generating Station can be upgraded for an estimated $100,000 parts plus labor costs to replace components and ensure the AH is fully refurbished and operational. A firm cost is not possible as a condition assessment of the MRC AH will be required to identify parts and components to be replaced. • A pilot-scale SBS Injection process could be furnished for the MRC for an estimated cost of $50,000 and could treat the entire slipstream flue-gas stream.
Describe the pilot plant HRUT to be provided, including size (in terms of scfm of flue gas extracted and footprint), expected performance, and a list of major equipment to be provided.	• The existing AH at the MRC can be used to conduct a pilot of high-efficiency operation. • It is expected that a complete upgrade to the existing AH would be required with new seals and new high-efficiency heat-transfer surfaces. Additional scope may be required based on the condition of the AH equipment.

Appendix F: Design and Cost Evaluation for GTI's Pilot-Scale TMC System

This section presents the results of the design package developed for a pilot-scale installation of Gas Technology Institute's (GTI) transport membrane condenser (TMC); this design package was used as the basis for the cost estimate for the pilot-scale installation.

Design Basis and Process Description

Cost and process information for the pilot-scale TMC as provided by GTI are summarized below. The costs included in the pilot unit correspond to the TMC modules and housing vessel as well as the liquid-vapor separation equipment with pumps/fans and flow control. It is assumed the host site will provide duct work to move flue gas to and from the pilot unit, as well as standard utilities (e.g., electrical and water) and tie-ins; these costs were not estimated. The pilot skid is to be manufactured by a third party and shipped to the site.

1. Arrangement of the pilot-scale TMC: 300-tube modules arranged in 3 rows and 10 columns, to form a 3-pass cross-flow heat exchanger arrangement. Steam condensate will be supplied from the top row (total 10 modules) and pass through the 2nd and 3rd rows to the water pump. Steam condensate per module is 5 gpm or a total of 50 gpm for the overall TMC unit and its outlet mass flow rate equals the inlet condensate flow plus 10 lb/hr/MMBtu of boiler firing rate.

2. Weight per module with 300 tubes: 44.0 lbs, dry; 55.3 lbs with water

3. Costs per module with 300 tubes: Approximately $3079

4. 300-tube TMC membrane module dimensions: 4 ft long x 1 ft wide x 0.6 ft high.

The main stream conditions that were used to model the pilot-scale TMC system in Aspen are presented in Table F-1. A piping and instrumentation diagram (P&ID), as presented in Figure F-1, was used for the Aspen simulation. A general arrangement diagram of the system is shown in Figure F-2. An equipment list for the system is shown in Table F-2.

Table F-1. Stream Conditions Used in Aspen Simulation

Inlet flue-gas flowrate	5000 scfm
Inlet flue-gas temperature	135°F
Inlet flue-gas pressure	14.8 psia
Inlet water flowrate	50 gpm
Inlet water temperature	100°F
Inlet water pressure	11.7 psia

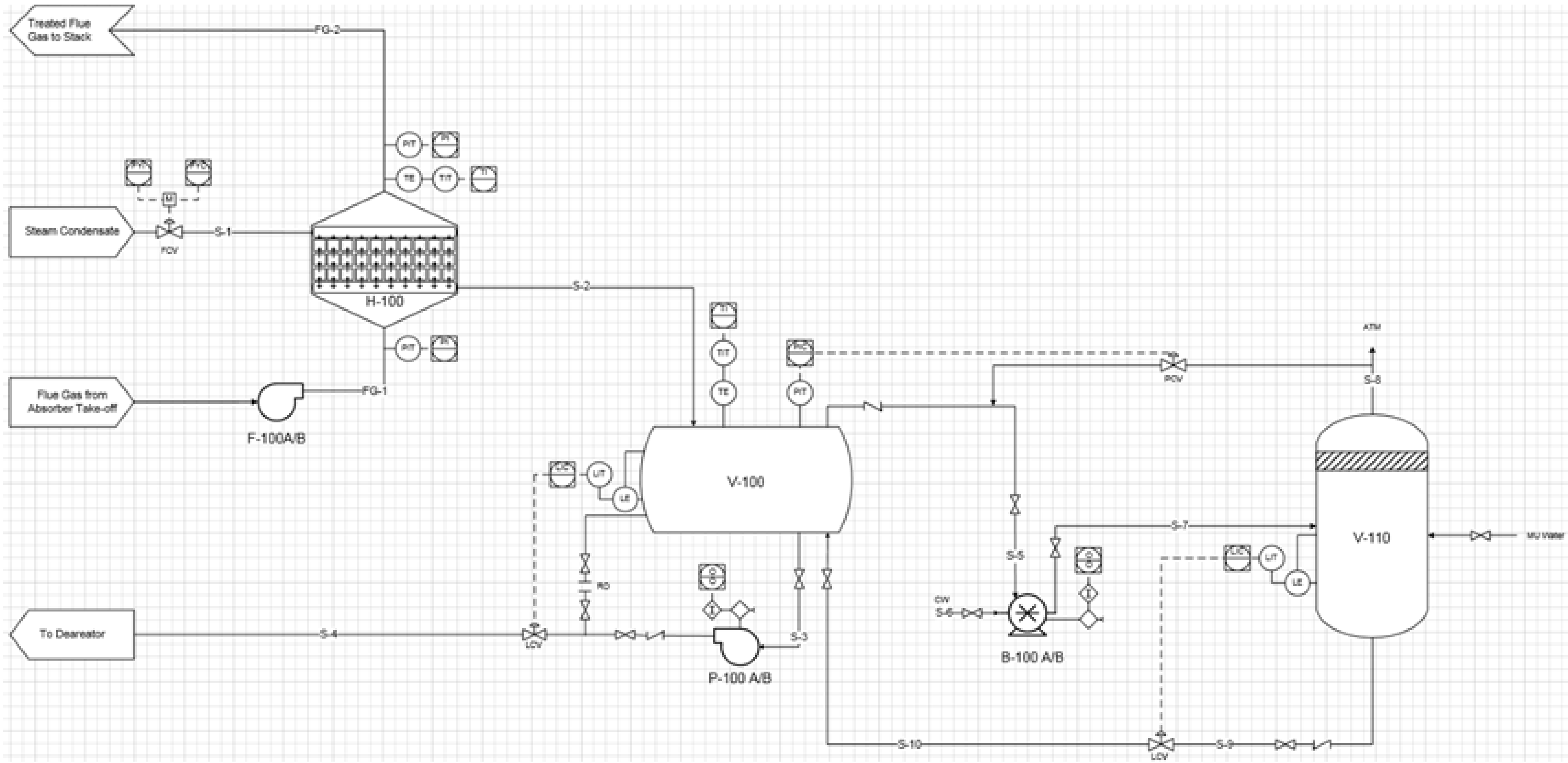

Figure F-1. P&ID for Pilot-scale TMC

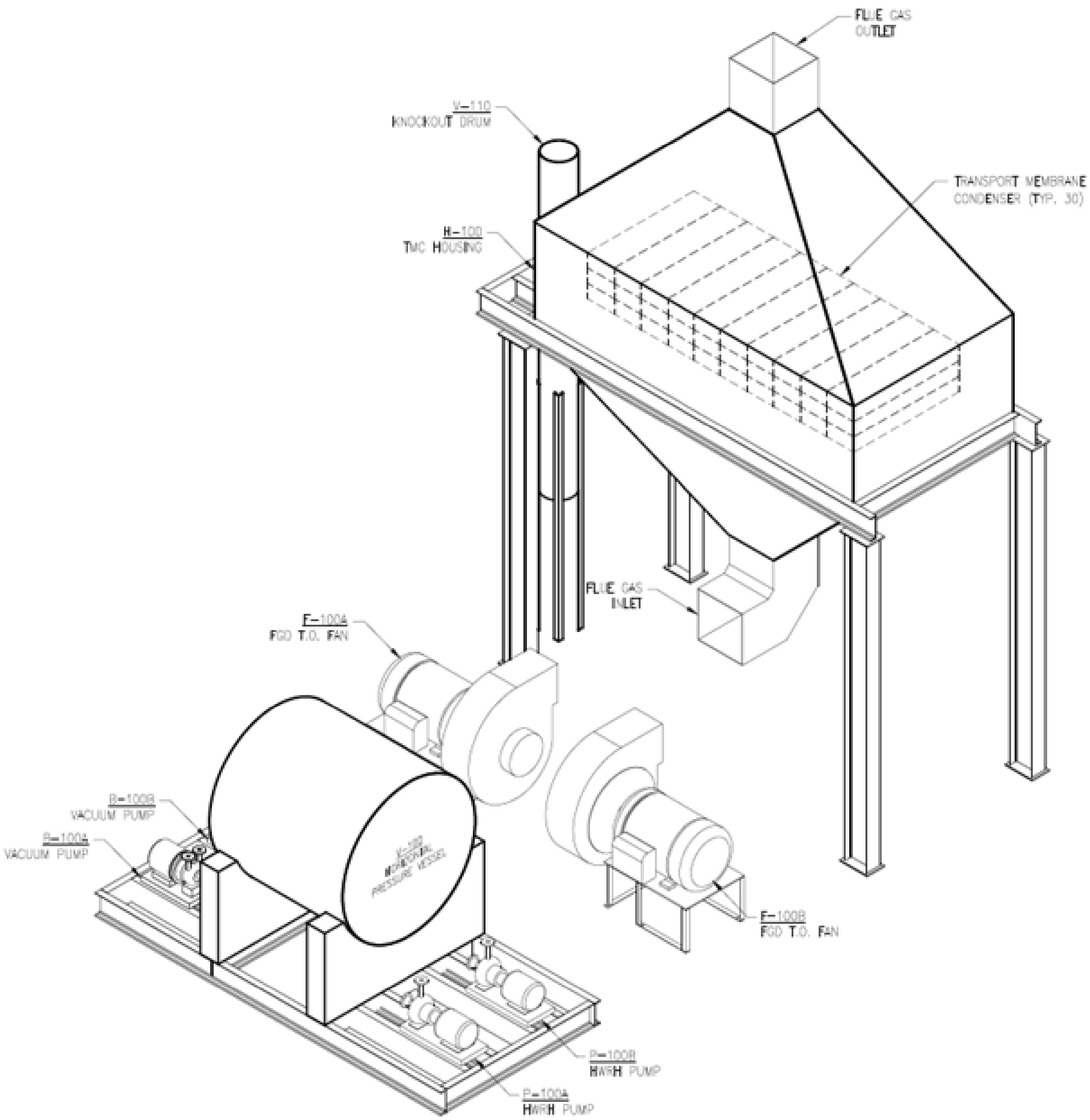

Figure F-2. Pilot-scale TMC General Arrangement

Table F-2. Liquid-Vapor Separation Equipment List

ID on Figure	Description	Size or Rating	Number Required
H-100	TMC Housing Vessel	NA	1
B-100 A/B	Liquid Ring Vacuum Pump	2 hp	2, spared
F-100 A/B	Centrifugal FGD Take-off Fan	15 hp	2, spared
P-100 A/B	Recovered Water Centrifugal Pump	15 hp	2, spared
V-100	Horizontal Pressure Vessel Separator	5 ft diameter x 5 ft long	1
V-110	Vertical Knockout Drum	1 ft diameter x 11 ft long	1

Costs

Costs for the TMC pilot unit are shown in Table F-3. Specific equipment details are shown below the table. As mentioned previously, the plant will provide the necessary ductwork for routing the flue gas, utilities, and tie-ins. All construction costs are related to skid and pilot fabrication off-site. No costs are included for installation at the site as it is assumed the host plant will cover these costs.

Table F-3. Cost Summary

Materials and Construction	$150,000
Services: Engineering & Construction Management	$641,407
Other – Freight, Contractor Markup, Contingency, Fees	$195,000
Total:	**$986,908**

Procurement costs include:

- $93,000 for 30 TMC modules
- $53,400 for structural steel
- $40,000 for carbon steel piping
- $151,200 for blowers
- $33,600 for vessels (gas-liquid separator, knockout)
- $86,200 for pumps
- $15,986 for shipping.

Appendix G: Exergy Analysis

This appendix discusses an exergy analysis of heat recovered from coal-fired plant flue gas. This analysis focused on recovering heat from the gas downstream of the AH and two ways in which the recovered thermal energy could be used: (1) preheating boiler condensate to reduce extraction steam, and (2) preheating of combustion air. The analysis was performed using absolute temperature (Rankine, Kelvin); however, the temperatures are presented in this as Fahrenheit for readability.

To simplify the analysis, a relatively small amount of heat was modeled to be recovered from the flue gas. The DOE Case 9 Subcritical Pulverized Coal plant was used for this analysis. The AH outlet temperature was modeled to be reduced from 337°F to 290°F due to a heat exchanger placed in the flue-gas path. The total heat recovered amounted to **16.4 MW_{th}**. This value was calculated using the average specific heat of the flue gas ($c_{P,FG}$), the mass flow of flue gas ($\dot{m}_{FG}$), and initial and final absolute temperatures, T_1 and T_2, respectively, as shown in Equation 1.

$$\mathrm{MW_{th,HR}} = \dot{\mathrm{m}}_{\mathrm{FG}} * \mathrm{c_{p,FG}} * (\mathrm{T_1} - \mathrm{T_2}) \tag{1}$$

The theoretical amount of useful work that could be generated from this recovered thermal energy was found with an exergy analysis. An imaginary heat engine receiving heat at the temperatures described above and exhausting heat to the ambient air at 59°F (T_0) could generate **5.4 MW_e** of electricity from the 16.4 MW_{th} of heat input. This was calculated by finding the exergy transferred along with the heat as shown in Equation 2. After integration, the equation was solved as shown in Equation 3.

$$\mathrm{MW_X} = -\bar{\mathrm{c}}_{\mathrm{p,FG}} * \dot{\mathrm{m}}_{\mathrm{FG}} * \int_{\mathrm{T_1}}^{\mathrm{T_2}} 1 - \frac{\mathrm{T_0}}{\mathrm{T}} \, \mathrm{dT} \tag{2}$$

$$\mathrm{MW_X} = \bar{\mathrm{c}}_{\mathrm{p,FG}} * \dot{\mathrm{m}}_{\mathrm{FG}} * \left[(\mathrm{T_1} - \mathrm{T_2}) - \mathrm{T_0} * \ln\frac{\mathrm{T_1}}{\mathrm{T_2}}\right] \tag{3}$$

In the first case, where the thermal energy was used to reduce turbine extraction steam, the 16.4 MW_{th} was sent to the boiler condensate stream to heat the boiler feedwater. If the recovered thermal energy were used prior to the fourth feedwater heater (FWH4) and increased the condensate temperature from 258°F to 276°F, only 4.4 MW_e of extra electricity would have been generated due to the reduction in extraction steam needed in FWH4. This was calculated by first finding the baseline specific enthalpy change of the extraction steam across FWH4 as shown in Equation 4. The extraction steam inlet and outlet specific enthalpies ($h_{1,ES}$ and $h_{2,ES}$) were taken from the DOE Case 9 plant. Next, the massflow of extraction steam ($\dot{m}_{ES}$) necessary to heat the feedwater the rest of the way from 276°F ($T_{2,BFW}$) to the baseline FWH4 condensate outlet temperature of 285°F ($T_{3,BFW}$) was calculated as shown in Equation 5. The recovered heat from the flue gas resulted in a reduction of 68% of the FWH4 extraction steam needed for heating the feedwater. The steam no longer needed was sent through the LP turbine to generate electricity.

$$\Delta h_{ES} = \left(h_{2,ES} - h_{1,ES}\right) \tag{4}$$

$$\dot{m}_{ES} = \frac{\dot{m}_{BFW} * c_{p,H20} * (T_{3,BFW} - T_{2,BFW})}{\Delta h_{ES}} \tag{5}$$

The electricity generated by the additional steam travelling through the turbine was calculated by multiplying the enthalpy change across the turbine by the additional massflow of steam. The term $\dot{m}_{ES,T}$ represents the massflow of extraction steam sent to the turbine instead of the feedwater heater. The steam turbine outlet enthalpy, denoted by $h_{T,O}$, was taken from the DOE Case 9 plant. The electrical power generated was found to be **4.4 MW$_e$.**

$$MW_e = \dot{m}_{ES,T} * \left(h_{T.O} - h_{1,ES}\right) \tag{6}$$

In the second case, the heat recovered from the flue gas was used to increase the inlet temperature of the combustion air to the boiler initially at the ambient temperature of 59°F (T_1). A diagram of the system is shown in Figure G-1. As calculated in Equation 7, the additional recovered heat (MW_{th}) from the flue gas increased the combustion air temperature to 115°F (T_2).

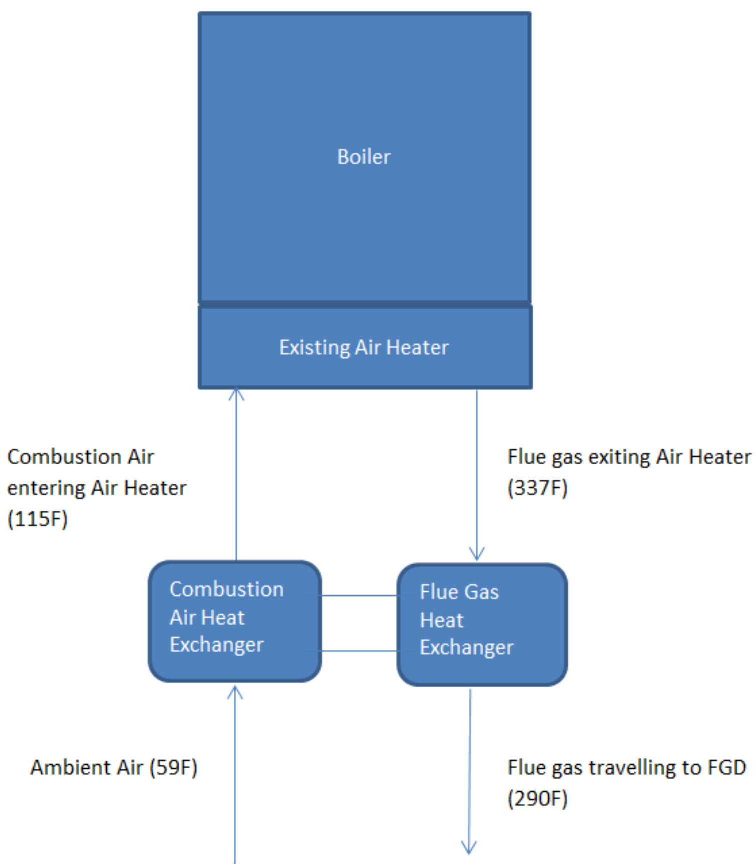

Figure G-1. Preheating Combustion Air PFD

$$T_2 = \frac{MW_{th}}{\dot{m}_{CA} * c_{p,air}} + T_1 \tag{7}$$

The application of Equations 2 and 3 to the recovered heat added to the combustion air (that caused it to increase from 59°F to 115°F), shows that only 0.8 MW_X of exergy was transferred to the combustion air out of the 5.4 MW_X of exergy and 16.4 MW_{th} of thermal energy transferred from the flue gas, representing 4.6 MW_X of exergy destruction. However, the primary advantage of using the recovered heat to increase the temperature of the combustion air was reducing the overall exergy destruction during the combustion process in the boiler. Using Equation 8 for the baseline case in which no heat was recovered and the combustion air must be heated from 59°F (T_2) to a given peak average boiler temperature (T_3, assumed to be 2780°F) by burning coal, the percent of the heat input from the coal that could be converted into useful work or electricity was 57.5%. In the case where the flue gas heat recovered was used to increase the combustion air boiler inlet temperature to 115°F, the percent of the coal heat input that could be converted into useful work or electricity is increased to 58.5%.

$$X_{\%} = \frac{\bar{c}_{p,air} * \dot{m}_{air} * \int_{T_2}^{T_3} 1 - \frac{T_0}{T} dT}{\dot{m}_{air} * (c_{p,3} * T_3 - c_{p,2} * T_2)} * 100\% \tag{8}$$

Table G-1 shows a scenario in which the coal input was reduced from the baseline case so that the final peak average boiler values are the equal. Despite only 0.8 MW_X of energy being available for power generation out of the 16.4 MW_{th} of recovered heat from the flue gas, it translated into a significant fuel savings. The necessary coal input was reduced by **1.6%** due to the reduced exergy destruction of the thermal energy from the coal during combustion.

Table G-1. Energy, Exergy Input Comparison

Parameter	Baseline Case		Heat Recovery Case	
	Heat	Exergy	Heat	Exergy
Received From Flue-Gas Heat Recovery	-	-	16.4 MW_{th}	0.8 MW
Input from Coal Combustion	1,026.2 MW_{th}	590.1 MW	1,009.8 MW_{th}	590.2 MW
Percent of Coal Heat as Exergy	57.5 %		58.5%	
Total	**1,026 MW_{th}**	**590MW**	**1,026 MW_{th}**	**591 MW**

Conversely, if the coal use were not reduced and the plant were able to handle increased heat input, the gross plant generation could be increased by **9.6 MW_e** as calculated by Equations 9 and 10. First, the gross thermal efficiency (η_{HR}) is found for the DOE Case 9 plant after the addition of the heat recovery system as shown in Equation 9. The term $\dot{W}_{e,gross}$ stands for the gross electricity produced by the Case 9 plant in the case where the fuel use is reduced to keep generation constant. The value $\dot{Q}_{coal}$ stands for the heat input from the coal for the Case 9 plant. The input is reduced 1.6% as shown in Equation 9. Next the gross generation can be calculated for the case in which the fuel input is not reduced as shown in Equation 10. The calculated gross output was 592.2 MW_e compared to the Case 9 gross generation of 582.6 MW_e for a difference of 9.6 MW_e.

$$\eta_{HR} = \frac{\dot{W}_{e,gross}}{\dot{Q}_{coal} * (100\% - 1.6\%)} \tag{9}$$

$$\dot{W}_{e,gross,HR} = \dot{Q}_{coal} * \eta_{HR} \tag{10}$$

Heating combustion air provided a more significant thermodynamic benefit than preheating boiler feedwater. Because the degree of regeneration in steam Rankine cycles is typically already optimized for efficiency, there is not much extra generation that can be gained by reducing steam extraction. However, heating combustion air increases the average temperature at which the coal combusts, thereby reducing exergy destruction. For an equal amount of recovered thermal energy, the case in which combustion air was preheated increased the plant's generation by over double the value for the case in which boiler feedwater was preheated.

Works Cited

[1] Black, James; National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," Department of Energy, 2013.

[2] Jones, Watson and Preston, "Technology and Vendor Assessment of Low-Temperature Economizers: Low Quality Heat Recovery and Utilization," EPRI EP.P4171S/C18312, Charlotte, 2011.

[3] Mitsubishi Hitachi Power Systems, *Information provided for detailed questionnaire,* 2015.

[4] N. Hastings, "Contact Seal System and Method for Rotary Air Ducts". United States Patent US20130327495, 12 December 2013.

[5] S. Gray and G. Shearer, "Application and Benefits of SO3 Removal Upstream of Ljungström® Air Preheater," in *EPRI Heat Rate Improvement Conference*, 2014.

[6] D. Wang, "Transport Membrane Condenser for Water and Energy Recovery from Power Plant Flue Gas," Department of Energy, Des Plaines, 2012.

[7] Porifera, *Information from response to Detailed Questionnaire,* 2015.

[8] Sylvan Source, Inc., *Information from response to Detailed Questionnaire,* San Carlos, 2015.

[9] Vacom Systems LLC, *Information from response to Detailed Questionnaire,* 2015.

[10] BCS, Inc., "Waste Heat Recovery: Technology and Opportunities in U.S. Industry," U.S. Department of Energy Industrial Technologies Program, 2008.

[11] S. Quoilin, M. Van Den Broek, S. Declaye, P. Dawellef and L. Vincent, "Techno-economic survey of Organic Rankine Cycle (ORC) systems," *Renewable & Sustainable Energy Reviews,* no. 22, pp. 168-186, 2013.

[12] M. Zeyghami and J. Nouraliee, "Effect of Different Binary Working Fluids on Performance of Combined Flash Binary Cycle," in *World Geothermal Congress*, Melbourne, 2015.

[13] S. Quoilin, "Sustainable Energy Conversion Through the Use of Organic Rankine Cycles for Waste Heat Recovery and Solar Applications," University of Liege, Liege, 2011.

[14] M. Jonsson, "Advanced Power Cycles with Mixtures as the Working Fluid," Royal Institute of Technology, Stockholm, 2003.

[15] N. Sarunac, M. Ness and C. W. Bullinger, "Improving the Efficiency of Plants Firing High-Moisture Coal," *Cornerstone,* vol. 3, no. 1, pp. 55-58, 2015.

[16] S. Broekema, *Information from response to Detailed Questionaire,* Maple Grove, 2015.

[17] "Novus Website," Novus Energy Technologies, 2014. [Online]. Available: http://www.novusenergytechnologies.com/products.html. [Accessed 13 August 2016].

[18] Novus Energy Technologies, *Information in response to Detailed Questionnaire,* 2015.

[19] S. Gray and K. J. O'Boyle, "Effective SO3 Control Reduces Fuel Costs and CO2 Emissions," *Power Engineering,* 21 December 2015.

[20] AECOM, "SBS Injection," 2016. [Online]. Available: http://www.aecomprocesstechnologies.com/technologies/sbs-injection/. [Accessed 9 August 2016].

[21] Department of Energy - NETL, "Assessment of Historical Development Utility Industry Air Pollution Control Technologies, Draft Report, Rev 1," Department of Energy, 2011.

[22] S. Gray, J. Jarvis and S. Kosler, "Combined Mercury and SO3 Removal Using SBS Injection," *Power Magazine,* 1 July 2014.

[23] URS Corporation; Chang, Ramsay, "EPRI Report 30020014," EPRI, Palo Alto, 2013.

[24] James Black; National Energy Technology Laboratory, "Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases," Department of Energy, 2012.

[25] TSI Inc., Combustion Analysis Basics, TSI Inc., 2004.