

Use of a Waste Heat Boiler to Capture Energy From Flammable Noncondensable Gas at Geothermal Power Plants

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Keywords

Noncondensable gas, NCG, H₂S abatement, burn/scrub, waste heat boiler, WHB, waste heat recovery, sulfuric acid, corrosion

ABSTRACT

A study was performed to determine if a waste heat boiler could economically capture energy from a flammable noncondensable gas stream at a geothermal power plant. Vendors of combustion and waste heat boiler equipment were contacted to gain purchased equipment costs. Operating costs related to the waste heat boiler were estimated. The economics of H₂S abatement were then evaluated both with and without waste heat recovery to determine the cost effectiveness of the waste heat recovery boiler. Additional information was learned from the vendors regarding the various types of waste heat boilers that could be used in this application, as well as how the boilers are integrated with the upstream combustion device. Different options for the materials of construction of the combustion unit and waste heat boiler were also investigated to help mitigate the potential for corrosion from sulfuric acid condensation. The economic and design details for the waste heat boiler as an integral part of a burn/scrub H₂S abatement process are discussed in this paper. For the application being considered, the waste heat boiler was estimated to have a payback of 25 to 34 months when used as an integral part of the burn/scrub H₂S abatement system. The waste heat boiler economics were also evaluated for the case where a different H₂S abatement technology was used (i.e., Stretford) such that the combustion unit and boiler could be located after the H₂S had already been removed; in this scenario, the payback on the waste heat boiler was about 12 to 17 months due to the slightly higher steam recovery and a less expensive waste heat boiler. For the cases considered, the waste heat boiler would generate steam equivalent to about 2%-3% of the inlet flow of geothermal steam.

1. Introduction

In a study of a hypothetical new power generation facility, Calpine postulated that the steam from the wells that would serve this hypothetical new plant would contain noncondensable gas (NCG) at up to ~3 to 4 wt%, and hydrogen sulfide (H₂S) up to 1850 ppmw. For reference, in most of Calpine's other plants at the Geysers, the NCG levels are usually less than 1 wt% of the steam with H₂S levels varying from 50 ppmw to about 800 ppmw in the steam. Because of the higher H₂S load and because the cost for H₂S abatement is usually significant, it was particularly important to select an H₂S abatement technology that was technically sound and economically favorable. Calpine contracted Trimeric, a technical services company with expertise in H₂S removal, to perform an economic analysis of different abatement technologies to assist Calpine in selecting the optimal process. One of the technologies that Calpine considered was a burn/scrub process (based on the RT-2 technology) since this technology has been used at other Calpine power generation facilities. The burn/scrub process involves burning the NCG in a combustion device to convert the H₂S to SO₂ and then absorbing the SO₂ in an aqueous scrubbing system that contains a source of base. All other combustible gases, such as hydrogen, methane, and other hydrocarbons are also burned in the combustion device. A waste heat boiler (WHB) can sometimes be used to

In this process, steam from the turbine flows to a direct-contact condenser where cooling tower water condenses the steam. The condensate, mixed with cooling tower water, is routed to the cooling tower. A gas removal system that uses a steam ejector and a liquid ring vacuum pump draw the NCG off of the main condenser. This NCG exits the seal water separator and enters the combustion device. It should be noted that the gas that leaves the seal water separator is often referred to as “vent gas”, whereas the gas prior to the seal water separator may be called NCG. Since this paper deals primarily with the part of the plant downstream of the seal water separator, the term “vent gas” is the primary term used for this stream in the rest of the paper.

In the combustion device, H_2S is oxidized to SO_2 and H_2O and hydrocarbons are oxidized to CO_2 and H_2O . Some other oxidation products (such as SO_3) may also be produced. The combusted gases then flow to a WHB, where the gases are cooled to $\sim 400^\circ F$ to stay roughly $50^\circ F$ above the sulfuric acid mist dewpoint. (The WHB is highlighted in Figure 1 for reference as it is the focus of the economic evaluation of this paper.) In addition to a small amount of SO_3 that is produced in the combustion zone, some additional conversion of SO_2 to SO_3 occurs across the WHB. Steam will be produced at 100 psi (or higher); in the scenario considered here, the steam is recycled back to the main steam line prior to the turbine. The flue gas flows directly from the WHB to the scrubber system, although some vendors may prefer that a quench be used in between the WHB and the first scrubber.

Downstream of the WHB, a two-stage scrubbing system for SO_2 removal uses an aqueous solution with a base as the active chemical for SO_2 absorption. The SO_2 is easy to scrub from the burned gas stream selectively, even with CO_2 present, because it is a strong acid relative to CO_2 . Makeup caustic is added as necessary in the overall process.

Secondary abatement of the $H_2S_{(aq)}$ in the condensate from the hotwell is achieved by the addition of iron chelate and sulfite (produced in the SO_2 scrubbers) to produce soluble thiosulfate (in the method of the RT-2 technology). Cooling tower blowdown is varied to maintain water inventory and moderate total salt content in the circulating water. A wet electrostatic precipitator (WESP) is used to remove the sulfuric acid mist that exits from the scrubbers.

The WHB will also require additional equipment to treat the water sent to the boiler as shown in Figure 2. It was assumed that steam condensate would be available to feed the boiler feed water system. The likely components for the boiler feed water (BFW) system would then include: inlet filtration, chemical injection (for scale inhibitor and acid neutralization), and blowdown. The items shown in bold in Figure 2 signify components that may be required if a particularly poor water source is used to supply the BFW system instead of steam condensate. The mud and steam drum blowdown shown in the figure are byproducts of the BFW system to control total suspended solids and total dissolved solids, respectively.

A partial material balance for the burn/scrub process is shown in Table 1. The stream numbers correspond to those shown in Figure 1. The approximate gross heating value of the vent gas to the incinerator is 131 Btu/SCF. As noted later in the paper, burners can be designed to combust gas down to as low as 100 Btu/SCF and still produce a stable flame. Given the vent gas flow rate (9.2 MMscfd), this results in a heat rate of 50.2 MMBtu/hr. The sulfur content of the vent gas is equivalent to 10.2 LTPD. The temperature of the gas exiting the combustion device will be on the order of $2050^\circ F$. This stream is cooled to $\sim 400^\circ F$ by cross exchange with water in the WHB. The approximate water flow to the WHB is 26,800 lb/hr. Saturated steam at 164.7 psia and $367^\circ F$ is shown in the table as some pressure drop will be required to reach the turbine. Sometimes a quench unit is used after or in place of the WHB. (If a quench is used in place of the WHB, then no energy recovery is achieved.)

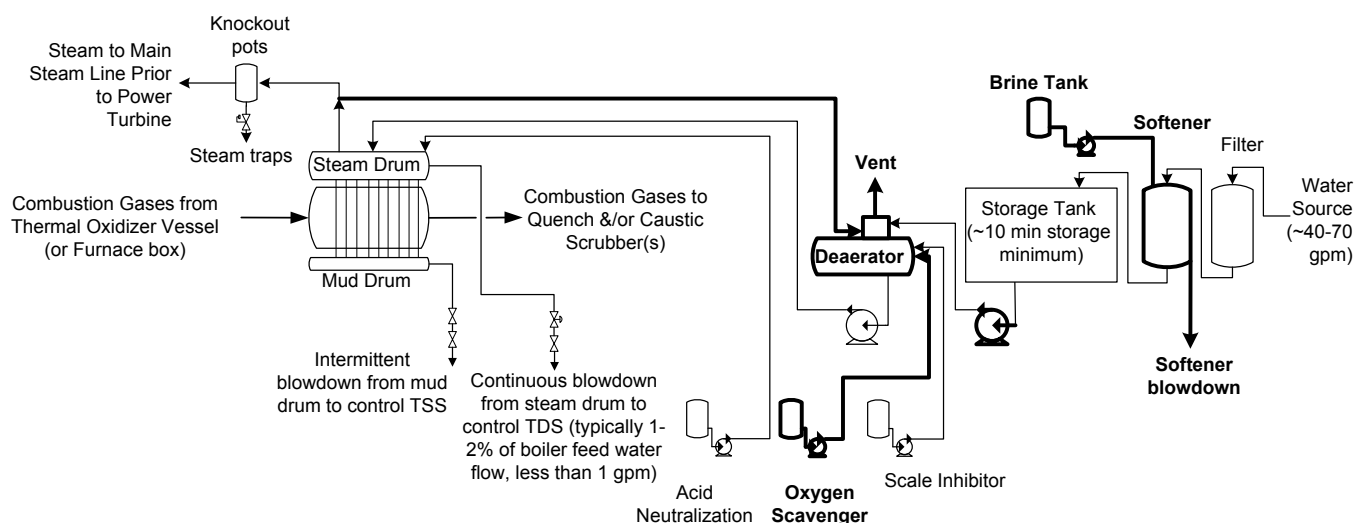


Figure 2. Schematic of WHB and Likely Components of a Boiler Feed Water System. (items in bold may only be required if poor water source used).

Table 1. Partial Material Balance for Burn/Scrub Process (see Figure 1 for stream locations).

		Approximate Vent Gas Flow	Blower Flow	Hot Furnace Exhaust	WHB Water in	WHB Steam out	Cooled Furnace Exhaust	Water to 1 st Scrubber	Caustic to 2 nd Scrubber	Gas to WESP	Gas from WESP	Water to Cooling Tower	Fe/HEDTA
Stream	Units	1	2	3	4	5	6	7	8	9	10	11	12
Temperature	F	95	70	2047	80	367	400	80	80	100	100	180	80
Pressure	psia	15.2	15.2	15.2	164.7	164.7	15.2	50	50	15.2	15.2	15.2	25
Water	lb/hr	853	686	7,036	26,761	26,761	7,036	2,932,344	2,372	2,106	2,106	3,227,708	393
CO ₂	lb/hr	30,854	0	33,779	0	0	33,779	0	0	33,779	33,779	0	0
NH ₃	lb/hr	0	0	0	0	0	0	0	0	0	0	0	0
N ₂	lb/hr	784	32,714	33,498	0	0	33,498	0	0	33,498	33,498	0	0
CH ₄	lb/hr	1,064	0	0	0	0	0	0	0	0	0	0	0
H ₂ S	lb/hr	1,008	0	0	0	0	0	0	0	0	0	0	0
H ₂	lb/hr	284	0	0	0	0	0	0	0	0	0	0	0
O ₂	lb/hr	0	9,938	2,483	0	0	2,483	0	0	2,483	2,483	0	0
SO ₂	lb/hr	0	0	1,897	0	0	1,897	0	0	2	2	0	0
Na ₂ SO ₃	lb/hr	0	0	0	0	0	0	0	0	0	0	3,681	0
H ₂ SO ₄	lb/hr	0	0	0	0	0	0	0	0	42	4	0	0
(NH ₄) ₂ SO ₃	lb/hr	0	0	0	0	0	0	0	0	45	4	0	0
Caustic (50 wt%)	lb/hr	0	0	0	0	0	0	0	2,372	0	0	0	0
Fe/HEDTA	lb/hr	0	0	0	0	0	0	0	0	0	0	0	19
NO _x	lb/hr	0	0	30	0	0	30	0	0	30	30	0	0
CO	lb/hr	0	0	22	0	0	22	0	0	22	22	0	0
VOC	lb/hr	0	0	16	0	0	16	0	0	16	16	0	0
Total	lb/hr	34,848	43,338	78,694	26,761	26,761	78,694	2,932,344	4,744	71,955	71,876	3,231,389	411
Vapor flow	MMscfd	9.2	13.8	22.4		13.5	22.4			19.7	19.7		
Liquid flow	gpm				53.5			5860.0	9.5			6457.6	0.61

3. Vendors of Combustion Equipment

Inquiries to many different vendors of combustion equipment have been made over the last few years by Calpine and Trimeric. Some of the vendors specialize in the burners and/or combustion side of the process while others specialize in the manufacture of WHBs. Examples of vendors who provide this type of equipment are shown below. (There are probably other vendors of this equipment that are not on the list below; this list is not meant to imply that these vendors are preferred over other vendors.)

- Callidus Technologies: Callidus is a major, comprehensive provider of combustion equipment (burners, thermal oxidizers, catalytic oxidizers, flares, etc.).
- Process Combustion Corporation: PCC is also a provider of combustion equipment - thermal oxidizers, burners, and catalytic oxidizers.
- Hamon Deltak: Deltak specializes in providing turbine heat recovery steam generators and WHBs for a variety of industries. Other divisions of Hamon make furnaces, burners, and package steam boilers.

Table 2 shows a summary of the equipment included in the vendor costs that were obtained for this application as well as some of the key operating parameters for each design. Trimeric also provided a separate estimate of the economics for the WHB based on a process design of the entire system and in-house costing software.

Table 2. Summary of Vendor Provided Cost and Operating Information.

Parameter	Units	Vendor A	Vendor B	Vendor C	Trimeric
Equipment Included in Costs	NA	Combustion WHB	Combustion WHB Quench Scrubbers WESP	Combustion WHB Quench Scrubbers WESP	Combustion WHB Quench Scrubbers WESP
Boiler Type	NA	Water-tube	Water-tube	Water-tube	Water-tube
Combustion Type	NA	Integrated Furnace	Separate Thermal Oxidizer	Separate Thermal Oxidizer	Separate Thermal Oxidizer
Steam Pressure	psia	103	100	115	100
Steam Rate	lb/hr	30,900	27,000	23,500	26,800
Steam Type	NA	Superheated	Saturated	Saturated	Saturated
Propane	lb/hr	235	18	18	18

4. Types of WHB and Combustion Equipment

Many different designs exist for WHBs and the upstream combustion equipment depending on the characteristics of the stream to be combusted and the steam needs. The options presented by the vendors for this potential application are summarized below. The different configurations can have a significant impact on the consumption of auxiliary fuel (propane) as well as other parameters when used on a low-Btu content stream such as this.

4.1 WHB Designs

For the design of the WHB for the vent gas, two basic WHB design concepts are applicable: water tube or fire tube. Figure 3 shows schematics of these two concepts. In WHBs that use the water-tube concept, the gases from combustion are contained in the vessel, and the water is contained in the tubes that are in the vessel. For WHBs that use the fire-tube concept, the combustion gases are contained in the tube(s), and the water is contained in the vessel.

Fire-tube boilers are most frequently used for smaller applications, usually less than 50 MMBtu/hr, while larger applications typically use water-tube designs. The Calpine application (50.2 MMBtu/hr) was within a range where both the water-tube and fire-tube boilers would be considered. However, as shown in Table 2, all of the vendors proposed water-tube designs. Characteristics that might have

influenced the decision to use a water-tube design include: the H_2S content of the vent gas; the Btu content/size of the flame; and whether or not the application of the WHB is a retrofit of an existing facility or is being designed as part of a new facility.

Although all vendors chose water-tube designs, the vendors proposed variations on the upstream burner/combustion unit and how it interacts with the water-tube boiler. Two of these variations, membrane water-wall furnace box and refractory-lined thermal oxidizer, are presented next.

4.2 Membrane Water-Wall Furnace Box with Integrated Boiler

This type of system is where the furnace (the chamber containing the flame) is integrated with the boiler. A schematic of a packaged boiler is shown in Figure 4. Although it is a very common style of packaged boiler for use with natural gas or other higher-fuel-value stream, the use of this type of device on low-Btu waste gas streams is not very common. The furnace is a steel chamber made from steel tubes welded together to form a gas-tight wall, sometimes called a membrane water wall. Water on the inside of the tubes keeps the tubes from overheating (hence the term "water wall"). Since the flame from the burner is inside this water-wall chamber, heat is transferred into the water, and a small amount of steam is generated in the radiant section.

As may be typical for this type of packaged water-wall furnace device, the device is set up to accept a burner where all of the air enters near the same place, namely at one end of the furnace box. Excess air and residence time are required to assure complete combustion of all species. However, the vent gas Btu content is too low to burn with a stable flame if the vent gas and all of the air are mixed at the start. Thus, supplemental fuel (on the order of 235 lb/hr) is required to achieve a stable flame with the burners that are usually used with this type of packaged boiler. It may theoretically be possible to convert this type of packaged water-wall boiler so that it can use an appropriate low-Btu waste gas burner where

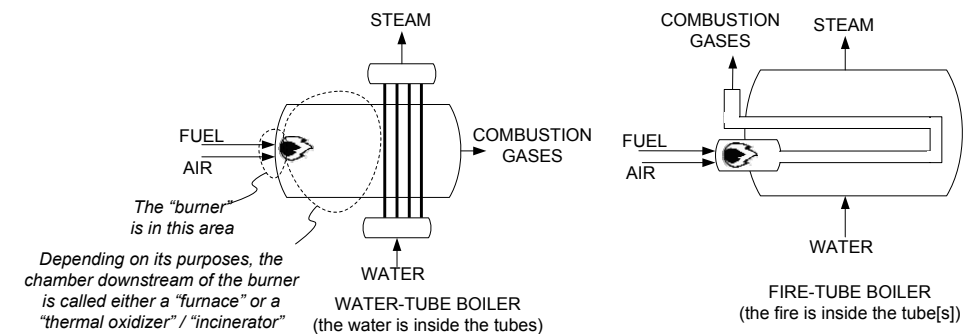


Figure 3. Water-tube Boiler vs. Fire-tube Boiler.

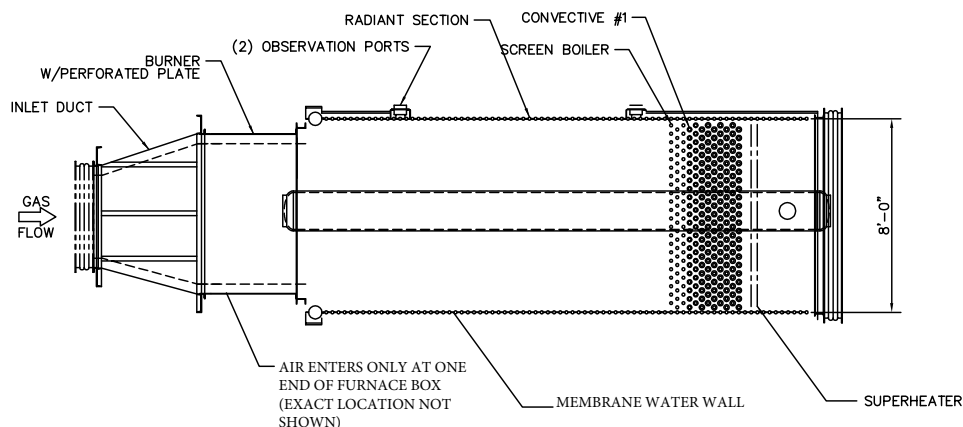


Figure 4. Membrane Water-Wall Furnace with Integrated Boiler (Plan View).

the air and flammable gas could be introduced in a more staged fashion (not all at the start); however, this could potentially require significant re-design of the system and may not be practical.

It should be noted that the term “furnace” is used with this design. The term “furnace” is generally used when a purpose of the chamber is useful transfer of heat from the area of the flame to another material (i.e., water). Since some heat is transferred to the water-filled tubes that are installed in the chamber that contains the flame, this type of design fits the definition of a “furnace” even though the chamber also has a purpose of thermally destroying the material passing through it.

4.3 Refractory-Lined Thermal Oxidizer with Separate Boiler

Another design has a burner followed by a refractory-lined thermal oxidizer chamber. A schematic of such a system is shown in Figure 5. Since the flame is contained in a refractory-lined chamber with no tubes, there is no steam generated in the radiant section (thermal oxidizer section) of the system; all of the steam is generated in the downstream WHB. This burner and thermal oxidizer combination is a design commonly used to combust low-Btu waste gas streams.

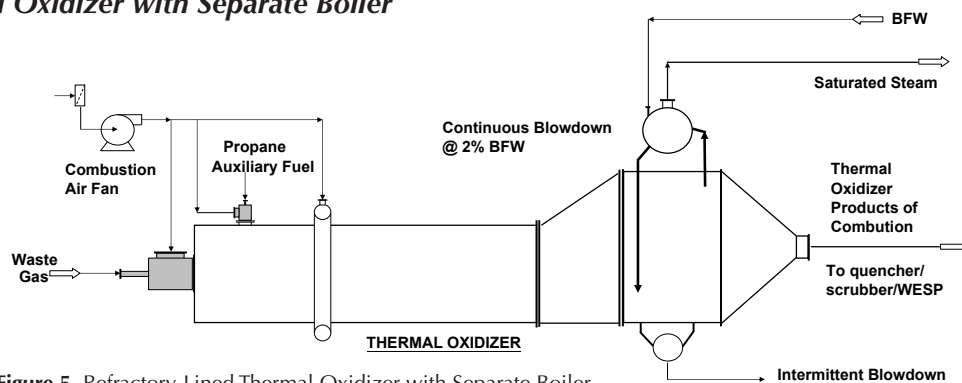


Figure 5. Refractory-Lined Thermal Oxidizer with Separate Boiler.

As shown in the figure, the combustion air is split into at least two streams. One stream is combined with the vent gas in approximately stoichiometric proportions to achieve the maximum flame temperature, thus a stable flame. The rest of the air is added downstream of the burner to achieve the necessary amount of excess air so that all species are completely reacted with oxygen in the thermal oxidizer vessel. (The ring on the thermal oxidizer where the additional air is added can be seen in Figure 5.) With this type of arrangement, it is reported that a stable flame is possible down to a little below 100 Btu/SCF without supplemental fuel. This arrangement of burner followed by thermal oxidizer appears to be more conducive to multiple air inlets than in the typical arrangement of the furnace-type, water-wall packaged boiler. The refractory-lined thermal oxidizer can combust the vent gas stream without any supplemental fuel, other than for startup and pilot (~18 lb/hr).

There are other considerations that make the burner/thermal oxidizer system more suitable for low-Btu waste gas streams. However, the propane consumption was deemed enough to eliminate further consideration of the other designs that had much higher propane consumption.

5. Material of Construction Options to Mitigate Corrosion

One of the main concerns with using the burn/scrub technology is the formation of sulfuric acid (H_2SO_4), which forms when SO_3 and water vapor are present and the temperature drops to the acid dew point (e.g., in the 350°F range for this case).

Sulfuric acid can be very corrosive to certain materials. Figure 6 shows an example of this type of corrosion at a Calpine site where the acid condensed at an inner cold spot near a flange. The sulfuric acid seeped through cracks and gaps (minute cracks and gaps are normal for refractory liners) in the refractory and reached the inner 316 stainless steel pipe wall. Bakeout occurred at the higher temperatures above the flange. Corrosion from sulfuric acid can be offset by using proper thermal design and / or different materials of construction for the vessel, refractory, and coatings as described more below.

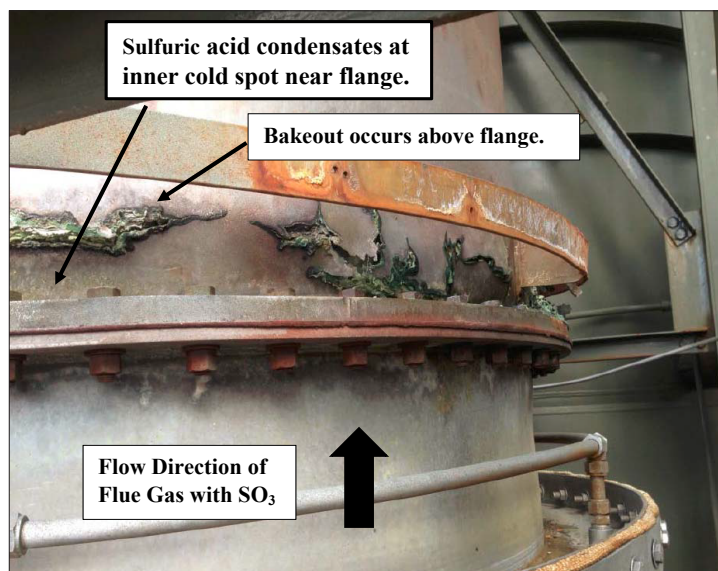


Figure 6. Example of Sulfuric Acid Corrosion.

5.1 Corrosion Avoidance Strategies

The key to avoiding sulfuric acid corrosion in the thermal oxidizer is to properly engineer the refractory and insulation systems so that the shell stays at least 50°F above the sulfuric acid dewpoint. One of the vendors noted that 316 stainless steel is not an appropriate material for sulfuric acid, implying that the use of 316 stainless provides no benefits compared to less expensive materials. The shell is typically only built of 316 stainless steel when it is placed in an environment where external corrosion may be an issue or when site requirements (not process related) mandate such material be used. Carbon steel material is typically used for the thermal oxidizer design and several options exist to minimize the potential for corrosion by staying above the sulfuric acid dewpoint. The options are presented below from least to most expensive.

Carbon Steel with “Hot Shell” Approach – One option is to use a “hot shell” approach where the shell is not insulated on the exterior and the refractory system is engineered so that the shell is kept at 75-150°F above the sulfuric acid dewpoint. For example, if the sulfuric acid dewpoint is 350°F, then the refractory would be designed so that the shell was kept in the 425-500°F range. The hot shell approach has some issues with extreme conditions as it is hard to design a refractory system that keeps the shell cool enough under full load, yet also keeps the shell warm enough under partial load and windy winter conditions; proper design and upkeep of the wind/rain shield is important for hot shell designs.

Carbon Steel with “Hot Shell” Approach and Internal Coating – Another approach is to use the “hot shell” design with an internal mastic (e.g., coal-tar) coating that can handle the operating temperatures. The coating may help with corrosion on the inside of the shell in the event of sulfuric acid condensation due to process upsets or localized cooling at heat sinks, although it also has drawbacks, and the coating can lose integrity under some conditions.

Carbon Steel Shell with Insulated Exterior – An alternative design is to insulate the shell exterior. In this case, the internal refractory thickness is increased, a layer of insulating ceramic board is added between the refractory and the shell to provide additional insulation, and then a thin layer of insulation is added to the exterior of the shell. The entire system is designed so that the external insulation sheathing (covering) is at roughly 150°F and, thus, is not much of a hazard to personnel. The external insulation layer mitigates low load, cool and windy conditions. The refractory/shell/external insulation system has to be designed specifically to keep the shell at a reasonable temperature for carbon steel. Thus, the shell of the thermal oxidizer is actually hotter when using insulation than when using the “hot shell” approach. Due to the exterior insulation, the shell may be more like 600°F. Since the shell under the insulation is actually hotter, the temperature is also further away from the sulfuric acid dew point, and there is less chance for internal corrosion from sulfuric acid condensation. The external sheathing (presumably stainless or some other corrosion resistant material) should also protect the exterior of the vessel from environmental factors.

Carbon Steel Shell with Insulated Exterior and Special Internal Coating – The insulated shell exterior approach can also be used with a special internal coating to protect against potential sulfuric acid condensation. The coal-tar-type mastic coating cannot be used with the externally insulated thermal oxidizer because the temperature is too high. However, there are other coatings that are rated for the higher temperatures and could potentially be used inside a carbon steel shell that is designed with external insulation. These other coatings are more complicated (multi-layer) and expensive, and require special surface preparation of the shell.

In some of the vendors’ experience, a high alloy liner is not typically used in a carbon steel vessel and the shell is not typically made out of materials like AL-6XN, Alloy 20, Hastelloy, etc. The vendors also mentioned that even perfectly installed and maintained refractory does not seal gas away from the shell; thus, cracked refractory is unlikely to be a significant cause of corrosion since the gas gets to the shell with intact refractory anyway.

Other than the construction of the shell, mixing of the gases inside the thermal oxidizer can also be an issue. If there is poor mixing, there can be cooler areas of thermal oxidizer and thus cooler areas of the shell that can lead to corrosion.

Concerns with the WHB are the same as the thermal oxidizer vessel. If the tubes and shell are above the acid dew point, then there should be no problem with using carbon steel material. However, downstream of the WHB at the quench system (if used), the situa-

Table 3. Comparison of Materials of Construction.

Equipment	Vendor B Material	Vendor C Material
Burner	carbon steel - SA-516-70	carbon steel
Burner Nozzle	-	Hastelloy
Thermal Oxidizer	carbon steel - SA-516-70 + refractory	carbon steel + high alumina hard refractory
Thermal Oxidizer - Rain Shield	aluminum	stainless steel
Quencher (WHB)	Hastelloy	316 L SS
Quencher (w/o WHB)	Hastelloy	Hastelloy C-276 + high alumina refractory lining
Caustic Scrubber Ducting	no data available	316 SS
Caustic Scrubber Tower	fiberglass reinforced plastic	fiber-reinforced plastic
Packing, mist eliminator	polypropylene	glass filled polypropylene
WHB – tubes	carbon steel	carbon steel - SA-178A
WHB – casing	carbon steel - refractory lined	carbon steel - refractory lined
Tower & Platforms	galvanized steel	galvanized steel
Caustic Injection Tank	polypropylene	carbon steel

tion is different. Much more attention to the selection of the type of steel is needed at the wet/dry interface and beyond. Heat sinks, such as vessel supports, could be insulated as well.

All of the carbon steel options discussed above are considered to be less expensive than building the shell out of 304 or 316 stainless steel material. Although uncommon, if the thermal oxidizer and WHB were built out of 316 stainless steel, the total cost of the entire burn/scrub process (i.e., thermal oxidizer, WHB, refractory systems, scrubbers, WESP, fuel gas skid, etc.) may increase by 5-25%.

5.2 Vendor Recommended Materials of Construction

For reference, a comparison of the materials of construction provided by Vendor B and Vendor C is shown in Table 3. Both vendors recommended that the thermal oxidizer and WHB be made out of carbon steel material with refractory lining. Calpine considered using stainless steel instead because of the possibility of external corrosion from cooling tower drift with entrained geothermal dissolved solids.

6. Other Important Design Considerations

Some other important factors should be taken into account when considering using a WHB. WHB systems can be designed to include the production of superheated steam. The need for superheated steam should be evaluated on a case-by-case basis. Since the steam from the WHB for this application is combined with the geothermal steam feeding the turbine, little advantage was seen with the superheated steam option. The superheated section of the WHB reportedly adds a relatively small amount to the overall cost if superheated steam is preferred.

Whether the WHB is a new or retrofit system should also be considered. If an existing system has a smaller size, then a fire-tube boiler may need to be considered instead of a water-tube boiler. The footprint of the equipment may also be important when considering WHB retrofits. Water-tube boilers can be configured vertically or horizontally with respect to the flue gas flow path, while fire-tube boilers are typically configured horizontally. Space issues were not a factor since the Calpine application considered here is for a greenfield site. (Note: the economics of a WHB installed as a retrofit at an existing site are likely different than the economics for a greenfield site.)

The potential boiler feed water sources also need to be closely examined to determine the boiler feed water requirements and identify the actual equipment that would be required for the BFW system since many variations exist. For this application, it was assumed that steam condensate (from a neighboring unit with a surface condenser as the main condenser) was available for use as boiler feed water, and the appropriate BFW systems and costs were included in the economic comparison.

7. Economics of the WHB

Table 4 shows a summary of the approximate economics for the WHB addition. The purchased equipment costs for the WHB are based on quotes from Vendor A, Vendor B, and Vendor C as well as the estimate from Trimeric. Even though the WHB design from Vendor A was eliminated from the study because of high supplemental fuel usage, the purchased cost for the boiler is included for comparison. All of the purchased equipment costs are in good agreement with only about a 15% difference in costs among all sources.

The total installed costs (TIC) are based on the quotes from Vendor B and C and the Trimeric estimate for the entire burn/scrub process (thermal oxidizer, WHB, BFW system, caustic scrubber system including caustic tank, and WESP; secondary abatement costs were not included). A detailed comparison was made of the items included in the vendor quotes and the Trimeric estimate for the overall system. If necessary, adjustments were made to the costs so that all of the sources included the same equipment and level of detail. The incremental TIC is based on the TIC for the entire burn/scrub process with the WHB and then without the WHB. Once put on the same basis, the TIC varied by about 40% from the highest value to the lowest.

The operating and maintenance (O&M) costs for the WHB were estimated and should not vary much between the different WHB systems considered (excluding Vendor A which was eliminated due to high propane usage). The O&M costs included items discussed previously: water for boiler feedwater, chemical injection, boiler feedwater or blowdown expenses, electrical loads, instrument air, and propane. Propane is only required for startup and pilot purposes for the designs from Vendors B and C, and the Trimeric estimate. Maintenance and general and administrative (G&A) costs were estimated as a fixed percentage of the incremental TIC.

The value of the steam was based on the lowest steam production rates of the systems considered (i.e., 23,500 lb/hr based on Vendor C's steam flow); this amount of steam adds about 2.6% to the main inlet steam flow to the plant. Assuming 17,200 lb steam / MWh, the steam is valued as power at a rate of \$0.06/kWh. The value of the steam produced less the O&M costs is around \$0.69 million per year. Comparing this with the incremental TIC due to the WHB, it appears that

the WHB would have a simple payback of around 25 to 34 months, regardless of which system was selected. The simple payback time is dependent on the value assumed for the power to be produced from the additional steam.

Table 4. Summary of Approximate Economics of WHB Addition.

Item	Units	Values		Source/Comment
		High	Low	
Purchased Equipment Cost for WHB	Thousand \$	761	647	Based on Vendor A, Vendor B, Vendor C, and Trimeric estimate
Incremental TIC due to WHB	Thousand \$	1,263	925	Based on Vendor B, Vendor C, and Trimeric estimate
Operation Costs	Thousand \$/year	245	245	Total of incremental plant operation costs, maintenance and G&A associated with WHB (assumes appropriate automation and instrumentation such that no additional operating labor is required)
Value of Steam	Thousand \$/year	689	689	Valued as power at \$0.06/kW-h
Net Operating Value	Thousand \$/year	443	443	Value of steam minus operating costs
Capital Payback Time	Months	34	25	Simplified basis: no interest, straight line

It should be noted that if a different type of H₂S abatement technology were used (i.e., a process other than burn/scrub which removes H₂S directly from the NCG), the combustion device and WHB could be located downstream of the H₂S removal step. Although the heating value of the vent gas is somewhat lower (116 Btu/SCF vs 131 Btu/SCF), because the H₂S has been removed, there is much less SO₃ and the flue gas from the combustion unit can be cooled more due to the much lower sulfuric acid dewpoint. The heating value of the stream is still high enough (> 100 Btu/SCF) to produce a stable flame in a low-Btu type burner. Allowing the flue gas to be cooled down further, improves the amount of heat that can be recovered to heat the boiler feed water, and more than offsets the loss of heating value by removing the H₂S, in this hypothetical case. Although the WHB could be made of carbon steel if the temperature stayed above the sulfuric acid dewpoint (400°F) for the case where the boiler was located upstream of H₂S abatement (i.e., burn/scrub) and the SO₃ content was much higher, it is likely that some extra precautions in the material of construction selection and refractory design would be made to minimize the potential for sulfuric acid mist corrosion during process upsets and at heat sinks. The net result is that the payback for the WHB when used after H₂S abatement is about half (12 to 17 months under the assumptions of this study) of that for the WHB implemented before H₂S abatement.

8. Summary

This detailed economic evaluation substantiated earlier findings that a WHB is an economically attractive option in some cases for geothermal power plants. The payback of the WHB for the hypothetical case considered in this paper is on the order of 25 to 34 months when integrated into a burn/scrub H₂S abatement system and 12 to 17 months when implemented after an H₂S abatement system. The several WHB purchased equipment cost estimates varied by only ~15%, and the several TIC estimates for the entire burn/scrub process ranged by 40% from the various sources. The design of the burner and downstream furnace or thermal oxidizer dictates whether or not the gas can be burned without any added fuel.

Several different material of construction options appear reasonable to prevent sulfuric acid corrosion for the thermal oxidizer and WHB systems, depending on the level of conservatism and cost. “Hot shell” and “insulated shell exterior” options for carbon steel both with and without coatings are more commonly used and are typically less expensive than 304 or 316 stainless steel material. Stainless steel is only used when required to meet standard material protocols for a site or when exterior corrosion due to environmental factors is anticipated.

9. References

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