

|                                           |                                                             |                |             |
|-------------------------------------------|-------------------------------------------------------------|----------------|-------------|
| <b>ExxonMobil</b><br><br>DESIGN PRACTICES | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                           |                                                             | XXVI-B         | 1 of 67     |
|                                           |                                                             | December, 2004 |             |

Changes shown by ↕

| Section  | CONTENTS                                                   | Page      |
|----------|------------------------------------------------------------|-----------|
| <b>1</b> | <b>SCOPE .....</b>                                         | <b>4</b>  |
| <b>2</b> | <b>REFERENCES.....</b>                                     | <b>4</b>  |
| 2.1      | DESIGN PRACTICES (MAIN).....                               | 4         |
| 2.2      | OFFSITES DESIGN PRACTICES.....                             | 4         |
| 2.3      | INTERNATIONAL PRACTICES.....                               | 4         |
| 2.4      | OTHER LITERATURE .....                                     | 5         |
| <b>3</b> | <b>BACKGROUND.....</b>                                     | <b>5</b>  |
| <b>4</b> | <b>DEFINITIONS .....</b>                                   | <b>5</b>  |
| <b>5</b> | <b>EQUIPMENT TYPES AND APPLICATIONS.....</b>               | <b>8</b>  |
| 5.1      | BOILERS.....                                               | 8         |
| 5.2      | DEAERATORS.....                                            | 8         |
| 5.3      | BFW HEATERS .....                                          | 9         |
| 5.4      | BOILER AUXILIARIES .....                                   | 9         |
| 5.5      | BOILER BLOWDOWN FACILITIES .....                           | 9         |
| 5.6      | PRESSURE REDUCING STATIONS.....                            | 10        |
| 5.7      | SPILLOVER CONDENSERS .....                                 | 10        |
| 5.8      | STEAM SILENCERS.....                                       | 10        |
| 5.9      | DESUPERHEATERS .....                                       | 10        |
| 5.10     | COMBUSTION AIR PREHEATERS.....                             | 10        |
| 5.11     | BOILER STACKS.....                                         | 10        |
| 5.12     | DISTRIBUTION PIPING AND VALVING .....                      | 11        |
| 5.13     | CONDENSATE RETURN SYSTEMS .....                            | 11        |
| 5.14     | PROVISION FOR LOAD SHEDDING AND FEED FORWARD SIGNALS ..... | 11        |
| 5.15     | SYSTEM SAFETY VALVES.....                                  | 11        |
| <b>6</b> | <b>SYSTEM DESIGN CONSIDERATIONS .....</b>                  | <b>12</b> |
| 6.1      | STEAM PRESSURE LEVELS.....                                 | 12        |
| 6.2      | THE VALUE OF STEAM.....                                    | 12        |
| 6.3      | STEAM GENERATION AND DISTRIBUTION.....                     | 14        |
| 6.4      | SYSTEM PRESSURE CONTROL .....                              | 15        |
| 6.5      | DYNAMIC SIMULATIONS .....                                  | 15        |
| 6.6      | FUEL BALANCES.....                                         | 15        |
| 6.7      | LOAD GROWTH AND RESERVE CAPACITY.....                      | 16        |
| 6.8      | BOILER AUXILIARY DRIVERS.....                              | 16        |
| <b>7</b> | <b>SYSTEM DESIGN PROCEDURES .....</b>                      | <b>16</b> |
| <b>8</b> | <b>COMPONENT DESIGN CONSIDERATIONS.....</b>                | <b>17</b> |

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|                                                  |                                                             |                |             |
|--------------------------------------------------|-------------------------------------------------------------|----------------|-------------|
| <b>ExxonMobil</b><br><br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                  |                                                             | XXVI-B         | 2 of 67     |
|                                                  |                                                             | December, 2004 |             |

|           |                                                          |           |
|-----------|----------------------------------------------------------|-----------|
| 8.1       | BOILERS.....                                             | 17        |
| 8.2       | DEAERATORS.....                                          | 20        |
| 8.3       | HIGH-PRESSURE BFW HEATERS.....                           | 22        |
| 8.4       | BOILER FANS .....                                        | 22        |
| 8.5       | BOILER FEEDWATER PUMPS .....                             | 23        |
| 8.6       | BOILER FUEL SYSTEMS.....                                 | 24        |
| 8.7       | BOILER BLOWDOWN FACILITIES .....                         | 24        |
| 8.8       | CONTINUOUS BLOWDOWN FACILITIES .....                     | 25        |
| 8.9       | INTERMITTENT BLOWDOWN DRUMS .....                        | 25        |
| 8.10      | BLOWDOWN PREHEAT EXCHANGERS .....                        | 25        |
| 8.11      | PRESSURE REDUCING STATIONS.....                          | 26        |
| 8.12      | SPILLOVER CONDENSERS .....                               | 26        |
| 8.13      | STEAM VENT / SILENCERS .....                             | 27        |
| 8.14      | PERFORMANCE TESTING STEAM SILENCER.....                  | 27        |
| 8.15      | DESUPERHEATING WATER FACILITIES .....                    | 27        |
| 8.16      | DESUPERHEATERS .....                                     | 27        |
| 8.17      | DESUPERHEATING WATER PUMPS .....                         | 28        |
| 8.18      | COMBUSTION AIR PREHEATERS.....                           | 28        |
| 8.19      | DISTRIBUTION SYSTEMS.....                                | 29        |
| 8.20      | CONDENSATE RETURN SYSTEMS .....                          | 30        |
| 8.21      | PROVISION FOR LOAD SHEDDING .....                        | 31        |
| <b>9</b>  | <b>COGENERATION APPLICATIONS .....</b>                   | <b>32</b> |
| <b>10</b> | <b>REVAMP AND EXPANSION PROJECTS.....</b>                | <b>32</b> |
| 10.1      | COLD EYES REVIEW .....                                   | 33        |
| <b>11</b> | <b>INSTRUMENTATION AND MONITORING .....</b>              | <b>33</b> |
| <b>12</b> | <b>ENERGY MANAGEMENT SYSTEM.....</b>                     | <b>33</b> |
| <b>13</b> | <b>NOMENCLATURE .....</b>                                | <b>35</b> |
| <b>14</b> | <b>COMPUTER PROGRAMS.....</b>                            | <b>37</b> |
| 14.1      | STEAM SYSTEM PROGRAMS .....                              | 37        |
| 14.1.1    | Gas Turbine Generator / Waste Heat Boiler Programs ..... | 37        |
| <b>15</b> | <b>RELIABILITY BEST PRACTICE .....</b>                   | <b>37</b> |
| <b>16</b> | <b>RELIABILITY BEST PRACTICE CHECKLISTS .....</b>        | <b>37</b> |
| 16.1      | PURPOSE.....                                             | 37        |
| 16.2      | COMMON AREAS .....                                       | 38        |
| 16.3      | GRASS ROOTS / MAJOR PROJECTS .....                       | 39        |
| 16.4      | REVAMP / SMALL PROJECTS .....                            | 40        |

|                                           |                                                             |                |         |
|-------------------------------------------|-------------------------------------------------------------|----------------|---------|
| <b>ExxonMobil</b><br><br>DESIGN PRACTICES | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | Section        | Page    |
|                                           |                                                             | XXVI-B         | 3 of 67 |
|                                           |                                                             | December, 2004 |         |

## FIGURES

|                                                                         |    |
|-------------------------------------------------------------------------|----|
| Figure 1 Typical Steam Drum Cross Section.....                          | 41 |
| Figure 2 Steam System Schematic .....                                   | 42 |
| Figure 3 Water Tube Boiler Cross Section .....                          | 43 |
| Figure 4 Typical Oil and Gas Burner .....                               | 44 |
| Figure 5 Duct-Fired Waste Heat Boiler.....                              | 45 |
| Figure 6 Typical Boiler Piping Arrangement .....                        | 46 |
| Figure 7 Typical Boiler Blowdown Facilities.....                        | 47 |
| Figure 8 Typical Pressure Reducing Station .....                        | 48 |
| Figure 9 Typical Spillover Condenser Arrangement.....                   | 48 |
| Figure 10 Steam Silencers .....                                         | 49 |
| Figure 11 Typical Desuperheating Water Facilities .....                 | 50 |
| Figure 12 Typical Load Shedding Arrangements .....                      | 51 |
| Figure 13 Steam Balance Effects .....                                   | 52 |
| Figure 14 Typical Gas Turbine / Waste Heat Boiler Arrangement.....      | 53 |
| Figure 15 Continuous Boiler Blowdown.....                               | 54 |
| Figure 16 Blowdown Drum Heat Balance Equation.....                      | 55 |
| Figure 17 Deaerator Heat Balance Equation.....                          | 56 |
| Figure 18 Deaerator Height Equation.....                                | 57 |
| Figure 19 Typical Forced Draft Fan Arrangements .....                   | 58 |
| Figure 20 BFW Pump $\Delta P$ Calculation.....                          | 59 |
| Figure 21 Typical Deaerator and BFW Pumps Arrangement .....             | 61 |
| Figure 22 Boiler Fuel Requirement.....                                  | 62 |
| Figure 23 Waste Heat Steam Rate.....                                    | 63 |
| Figure 24 Flashed Steam Estimating Curve .....                          | 64 |
| Figure 25 Desuperheater Heat Balance Equation .....                     | 65 |
| Figure 26 Cogeneration Concept (Reduce Conventional Boiler Firing)..... | 66 |
| Figure 27 Cogeneration Concept (Maximize Power Generation) .....        | 67 |

## Revision Memo

|      |                                                  |
|------|--------------------------------------------------|
| 9/04 | Highlights of this revision are:                 |
|      | 1. Added definitions.                            |
|      | 2. Updated references.                           |
|      | 3. Considered EMCC Reliability Best Practices.   |
|      | 4. Corrected Figures and Deaerator Heat Balance. |
|      | 5. Incorporated Industry Experience.             |

|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 4 of 67     |
|                                                                                                              |                                                         | December, 2004 |             |

## 1 SCOPE

This section presents the fundamental design considerations for steam system designs. Steam systems are used to supply steam to onsite processes, steam turbine driven machinery (compressors, pumps, etc.) and various other offsite consumers including heaters, fuel atomization, and steam turbine driven generators. Many plants include both fired boilers and waste heat steam generators in their steam systems. In refineries, the most frequently used top-level steam system pressure is 600 psig (4100 kPa). Where steam is used for electric power generation or very large process drive turbines, steam pressures as high as 1500 psig (10340 kPa) have been used. Chemical plants frequently produce steam at this pressure level with process waste heat and use it to drive process turbines and/or generate power with it. The most frequently used steam pressure level within process and offsite areas is 125-150 psig (860-1030 kPa). Lower pressure levels are also sometimes used locally within the certain process units. A low pressure level of 15 psig (100 kPa) is frequently used within the steam generation utility plant for boiler feedwater deaeration.

## 2 REFERENCES

### 2.1 DESIGN PRACTICES (MAIN)

|         |                                                       |
|---------|-------------------------------------------------------|
| DP II   | Design Temperature, Design Pressure and Flange Rating |
| DP V    | Drums                                                 |
| DP VIII | Fired Heaters                                         |
| DP IX   | Heat Exchange Equipment                               |
| DP X    | Pumps                                                 |
| DP XI   | Compressors                                           |
| DP XII  | Instrumentation                                       |
| DP XIII | Fired Heaters                                         |
| DP XIV  | Fluid Flow                                            |
| DP XV   | Safety in Plant Design                                |
| DP XVI  | Thermal Insulation                                    |

### 2.2 OFFSITES DESIGN PRACTICES

|             |                                   |
|-------------|-----------------------------------|
| DP XXV      | Fuel Systems                      |
| DP XXVI - A | Boiler Feedwater Treating Systems |
| DP XXX      | Electrical Facilities             |



### 2.3 INTERNATIONAL PRACTICES

|           |                                                         |
|-----------|---------------------------------------------------------|
| IP 2-1-1  | Equipment Noise Level Data Requirements                 |
| IP 3-2-4  | Pressure Relieving Systems                              |
| IP 3-3-2  | Suction and Discharge Piping for Centrifugal Pumps      |
| IP 3-3-7  | Inlet and Exhaust Piping for Steam Turbines             |
| IP 3-3-8  | Washing Systems for Steam Turbines                      |
| IP 3-4-1  | Piping for Fired Equipment                              |
| IP 3-6-2  | Piping for Control and Protective System Valve Stations |
| IP 3-12-1 | Valve Selection                                         |
| IP 7-2-1  | Industrial Boilers                                      |
| IP 15-1-1 | Instrumentation for Boiler Protection Systems           |

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|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 5 of 67     |
|                                                                                                              |                                                         | December, 2004 |             |

IP 15-1-2 Instrumentation for Compressors and Drivers  
IP 16-8-1 Instrument and Essential Services Power Supplies

## 2.4 OTHER LITERATURE

1. EMRE *Blue Book*, Manual Nos. 012 and 011
2. EMRE Refinery Construction Materials Manual (RCMM), Manual No. EETD 028
3. *Steam Values*, ER&E Report No. CE.1E.78
4. *Steam Generating Units*, ASME Power Test Code
5. *Deaerators*, ASME Power Test Code7. ASME Boiler and Pressure Vessel Code
6. Babcock and Wilcox, *Steam - It's Generation and Use*, 1992
7. Design Guide - Steam Condensate Network Collection Systems, ER&E Report No. EE.105E.76
8. EMRE Engineering Water and Wastewater Design Guide, TMEE 080, DG 11-5-1
9. EMRE Engineering Guide to Boiler and Fired Heater Turndown and Excess Air Reduction, MAN.26EETD.IV.
10. EMRE Steam and Power Generation Economic Optimization Guidelines, EE.198E.99
11. EMRE Gas Turbine and HRSG Fuel Flexibility Guidelines, EE.10E.2000
12. EM Chemicals Utilities Reliability Best Practices, <http://emcc.na.xom.com/kbsOUE/01-All/default.htm>
13. EM Chemicals Boiler Best Practices, <http://emcc.na.xom.com/kbsOUE/01-All/default.htm>
14. EMRE Machine Commissioning Manual (TMEE-069), Appendix 1-4-1

## 3 BACKGROUND

The steam system is part of a utility plant and provides steam, boiler feedwater, and desuperheating water to process consumers, as well as to electric power steam turbine generators. It also collects and reuses condensate.

Steam is distributed to both onsite and offsite areas within the plant. Steam is used by the onsite processes for heating, stripping, purging, snuffing, etc. Steam is also used as a heating medium for offsite tankage and distribution piping, and as a power source for turbines driving machinery such as compressors, pumps, and fans.

Boiler feedwater service is provided to onsite steam generating units and to offsite steam generation facilities.

Desuperheating water is distributed to desuperheaters in the processing plant and in the utility block.

Condensate is typically collected from heaters in the process and offsite areas, and steam turbine condensers.

## 4 DEFINITIONS

**Air-Fuel Ratio** - The weight ratio of air to fuel fired.

**Air Preheater** - A device used to preheat incoming combustion air using a heat source such as hot flue gas, steam, or other heat source.

**Atomizing Steam** - Steam used to disperse liquid fuel to a fine spray at the burner tip.

**Attemperator** - A boiler accessory for reducing and controlling the steam outlet temperature from the boiler.

**Balance** - Adjusting the operation of the steam system to match boiler steam production to consumption, minimize the amount of pressure reduction between the various steam pressure levels and to avoid venting.

**Base Loading** - Setting the steam production of the boiler at a fixed value for long periods of time.

**Battery Limits** - A boundary which is normally assumed to be at the physical edge of the block in which the facility is located.

**Blowdown** - Water removed from the boiler to control the level of dissolved impurities in the boiler water. Continuous blowdown is taken from the steam drum and intermittent blowdown is taken from the mud drum.

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|-------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------|----------------|---------|
| <br>DESIGN PRACTICES | <p style="text-align: center;"><i>STEAM SYSTEMS</i></p> <p style="text-align: center;"><b>STEAM GENERATION SYSTEMS</b></p> | Section        | Page    |
|                                                                                                       |                                                                                                                            | XXVI-B         | 6 of 67 |
|                                                                                                       |                                                                                                                            | December, 2004 |         |

**Boiler Efficiency** - For the input/output method, the ratio of the heat absorbed by the water and steam within the boiler to the heat content of the fuel fired. For the ASME heat loss method, it is 1.0 minus the losses (stack, latent, setting, blowdown). In either case, the fuel fired heat content may be expressed in terms of the higher heating value (HHV) or lower heating value (LHV). The ASME heat loss method is typically more accurate than the input/output method.

**Boiler Feedwater or BFW** - Treated water which has been heated, deaerated and dosed with chemicals to remove residual oxygen.

**Boiler MCR** - MCR is an abbreviation for Maximum Continuous Rating, which is the design output capacity of the boiler, generally expressed in weight of steam per unit time.

**Burner** - A mechanical device used to introduce air and fuel into the boiler at the proper conditions to establish and maintain ignition and combustion.

**Circulation** - The movement of steam/water around the boiler. Natural circulation uses the radiant heat in the firebox to develop a density differential between the water in the firewall tubes and the water in the downcomer tubes. Forced circulation uses a pump.

**Cogeneration** - The simultaneous production of power (electric power or shaft power) and heat (usually in the form of steam).

**Combined Cycle** - Power generation via gas turbine which is supplemented by waste heat steam generation which in turn produces more power (via back pressure or condensing steam turbines).

**CO Boiler** - Boiler which burns waste gases rich in carbon monoxide.

**Condensate (clean)** - Water produced from the condensing of steam where there is no contamination from leaky exchangers, usually the expectation when the steam pressure is higher than the process stream fluid pressure. This condensate can be used directly as makeup water for steam generation or in other applications (e.g., as desuperheating water).

**Condensate (dirty)** - Water produced from the condensing of steam where the process stream (e.g., oil) can contaminate the condensate via leakage of an exchanger, such as when the process fluid is at a higher pressure than the heating steam (e.g., reboilers). This condensate often requires holdup, settling and further treatment prior to reuse.

**Cushion** - the quantity of discretionary production capacity that a site keeps on-line in excess of its demand. The cushion is usually sized to protect the site's process areas from upsets due to the loss of generation equipment. Cushion is most commonly applied to the steam system. For steam, sites usually use an "N-1" strategy, which means that the steam system can survive the loss of the largest operating boiler without incurring load shedding or a major loss of header pressure.

**Desuperheater** - A device used for reducing the superheat in steam by injecting and mixing a water stream into the steam. A desuperheater is often used at pressure reducing stations or at the outlet of steam turbines. When a desuperheater is used for temperature control of steam at the boiler, it is known as an attemperator.

**Dew Point** - The temperature at which a vapor starts to condense when it is cooled. Of special interest is the dew point of sulfuric acid in the flue gases produced when burning fuels containing sulfur.

**Duct-fired or Grid-type Burner** - The burner type used with a gas turbine generator having a supplementary-fired heat recovery steam generator (HRSG). It provides multiple, short flames distributed across the transition duct located between the gas turbine and the boiler.

**Economizer** - A device for transferring heat from the flue gas to the BFW before the BFW enters the boiler drum.

**Field-Erected Boiler** - A boiler which is assembled at the construction site.

**Firm Capacity** - Total installed capacity (of boilers, pumps, etc.) minus the loss of the single largest on-line steam generator. The standby or spare capacity is often the largest unit.

**Flame Detector** - A photoelectric device used to monitor presence of the burner flame, which is used to cut fuel to the burner on loss of flame. Detectors usually read IR, UV, or both, and need to be designed for the particular fuel.

**Flue Gas** - Gaseous products from the combustion of fuel.

**Flue Gas Recirculation (FGR)** - A system which uses flue gas in the combustion air stream as a diluent to lower NO<sub>x</sub> generation. FGR usually uses a hot gas fan, but can be designed to induce gas given sufficient pressure differential.

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|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 7 of 67     |
|                                                                                                              |                                                         | December, 2004 |             |

**Gas Turbine Generator** - A high-speed rotating combustion engine which compresses combustion air in a compressor to burn fuel and uses the high temperature combustion products to drive an expander turbine. Part of the power extracted by the turbine is used to drive the combustion air compressor, the remainder is used to provide shaft power.

**Heat Recovery Steam Generator (HRSG)** - A waste heat boiler which recovers the heat from the hot exhaust of a gas turbine or diesel engine.

**HP** - An abbreviation for high pressure used in reference to steam system pressure levels. Common HP levels are 600 psig (4100 kPa) and 1500 psig (10300 kPa).

**High-Pressure BFW Heater** - A shell-and-tube heat exchanger that is used to preheat BFW with HP or MP steam. It is normally located downstream of the deaerating heater.

**Internal Operation** - A steam system operating mode, usually involving emergency conditions, in which the boiler plant produces steam only to support its own auxiliaries and a few essential consumers.

**Low Btu/Joule Gas (LBG/LJG)** - A lean fuel gas typically 75 - 150 Btu/SCF (2.8 - 5.6 MJ/Sm<sup>3</sup>) (LHV). As pertaining to FLEXICOKING, a fuel gas produced by steam / air gasification of fluid coke with a LHV of approximately 110 to 140 Btu/SCF (4.1 to 5.2 MJ/Sm<sup>3</sup>).

**LP** - An abbreviation for low pressure used in reference to steam system pressure levels. Common LP levels are 30 and 15 psig (200 and 100 kPa).

**Maximum Turbine Backpressure** - Steam pressure above the normal backpressure at which the steam turbine can still meet guaranteed horsepower requirement.

**MP** - An abbreviation for medium pressure used in reference to steam system pressure levels. Common MP levels are 150 and 125 psig (1030 and 860 kPa).

**Mud or Lower Drum** - A horizontal cylindrical vessel near the bottom of the boiler which acts as a collection and distribution header. Solids and sediment tend to accumulate in this drum and are removed by intermittent blowdown.

**Onsite** - Equipment or facilities which are part of the refining or chemical processes.

**Offsite** - All equipment and facilities which are not classified as onsite facilities. These offsite facilities include tankage and interconnecting lines, product loading, blending, utility systems and safety systems.

**Overfire Air** - (OFA) - The portion of combustion air that is ducted into the firebox above the burner level, to reduce NO<sub>x</sub> or CO emissions.

**Packaged or Shop-Assembled Boilers** - A boiler which is assembled in the vendor's shop into one or more large pieces and then shipped to the site for final assembly.

**Pilot Gas** - A gas used as fuel for the burner pilot. Natural gas is preferred as the pilot gas fuel; clean dry refinery gas may be used if natural gas is not available. The pilot is used to ignite the boiler burners.

**Response Rate** - The rate of steam production increase from a boiler, usually expressed as % MCR per minute.

**Soot Blower** - A mechanical device utilizing steam to clean boiler tubes by removing particles of unburned carbon or ash. Rotary sootblowers are located along the wall and traversing sootblowers cover the width of the boiler. Sonic sootblowers use high energy sound waves to dislodge ash, but are not as common as steam devices.

**Spare Capacity** - Capacity available in addition to the required firm capacity.

**Steam Drum** - A cylindrical vessel near the top of the boiler which acts as a distribution and collection header and a releasing point for steam. The drum also houses separation equipment to eliminate water carryover into the steam system. A typical cross section of a steam drum is shown in [Figure 1](#).

**Steam Turbine** - Steam turbines are used to drive mechanical equipment, such as pumps or compressors and electrical generators. Turbines may be either full condensing, noncondensing (back pressure) or extraction-condensing type. With full condensing, all the steam entering the turbine is condensed after expanding through the turbine. A back pressure turbine usually exhausts the steam to distribution piping at one or several pressure levels lower than the inlet pressure. An extraction-condensing unit exhausts part of the inlet steam at an intermediate pressure level and condenses the remaining steam.

**Stoichiometric** - The term used to define perfect combustion with no unused fuel or air. Often described as the chemically correct ratio of fuel to air, i.e., a mixture capable of perfect combustion with no unused fuel or air. Conventional Boiler combustion systems

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|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 8 of 67     |
|                                                                                                              |                                                         | December, 2004 |             |

are designed to operate above stoichiometric, typically with 10-15% excess air. HRSG supplementary firing operates with much higher excess air.

**Superheater** - A heat transfer surface downstream of the steam drum, which is designed to raise the steam temperature above the saturation temperature. The superheater is arranged within the boiler to absorb heat by radiation, convection, or both.

**Theoretical Air** - The quantity of air required for stoichiometric combustion of the fuel.

**Theoretical Draft** - The draft available at the base of the stack due to the density difference between the hot stack gas and the ambient air, neglecting friction and velocity pressure changes in the stack.

**Treated Water** - Raw water which has been processed in the water treating plant to reduce the level of suspended and dissolved impurities.

**Turndown Ratio** - The ratio of the maximum to the minimum flow rates associated with a steam system component. This term is used to express the range over which a component must function to meet design requirements.

**Waste Heat Boiler (WHB)** - Boilers which use waste heat from hot process or flue gas streams to generate steam.

## 5 EQUIPMENT TYPES AND APPLICATIONS

Equipment provided in a steam system design is selected to meet the requirements of the project and operating conditions of the plant. These requirements tend to be unique to each facility. This results in each steam system design having its own set of equipment types and sizes.

The basic steam system components available for use in a design are described in this section. A steam system schematic is shown on [Figure 2](#).

Steam systems have to be designed to provide reliable steam, BFW and desuperheating water at all times. This is normally accomplished by sparing of equipment pieces and by providing system flexibility to cope with abnormal demands. During onsite unit upsets, demands on the utility system often exceed normal rates for process reasons (bed fluidization steam) or safety (furnace purge steam or flare steam). In the case of in-house power generation, steam system availability plays a similar role to cope with normal and emergency plant power demands.

### 5.1 BOILERS

The offsite steam generating units or boilers produce steam at pressures and temperatures required by the associated processing plant and/or electric power generation equipment. Offsite steam generating units are normally water tube type boilers. A typical cross section of a water tube type boiler is illustrated in [Figure 3](#).

The boilers provided in the steam system design can be either packaged or field erected. Field erected boilers are available in almost any desired capacity since they are built to the requirements of the purchaser. Packaged boilers can be obtained in a number of standard capacities and depending on the method of transport, maximum size limits vary considerably. For land transport, sizes of up to 250 k lb/hr (115 t/h) are available. For water transport, the maximum sizes can increase to 500 k lb/hr (230 t/h). The choice between the use of packaged or field erected boilers is normally based on economics, transportation issues, and delivery time.

The boilers are designed to burn fuels and/or utilize energy sources available from the processing plant. The more commonly used fuels and energy sources are oil and gas, waste heat, CO gas, and coke. The oil and gas fuel combination is used in most designs because of its availability. A typical oil and gas burner is shown in [Figure 4](#).

Gas turbines driving generators, compressors or large pumps are often equipped with waste heat boilers in order to reduce fuel firing in the conventional boilers. These boilers may be the pure waste heat type in which case only sensible heat is recovered, supplementary-fired which take advantage of a portion of the hot oxygen in the exhaust gases, or fully-fired. The fully-fired boiler consists of a conventional water tube boiler as shown in [Figure 3](#) utilizing the gas turbine exhaust gas for combustion air. The supplementary-fired boiler utilizes a duct-fired waste heat boiler as shown in [Figure 5](#). The pure waste heat boiler is similar to the duct-fired unit but without the supplemental burner.

### 5.2 DEAERATORS

Deaeration is the removal of dissolved gases such as oxygen, carbon dioxide and ammonia from the treated water prior to its introduction into the boiler. These gases are undesirable because of their corrosive attack on metal surfaces and tendencies to plug equipment.

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|                                                                                                              |                                                             |                |             |
|--------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                             | XXVI-B         | 9 of 67     |
|                                                                                                              |                                                             | December, 2004 |             |

Deaerators consist of two sections, a deaerating heater and a boiler feedwater storage section. Within the deaerating heater, treated water is deaerated by heating the water to its saturation temperature and scrubbing it with steam to carry away the dissolved gases. This section typically contains spray nozzles and trays. The water is then transferred to the storage section by gravity flow. The storage section provides holdup capacity to cover system load swings and emergency situations.

Deaerators are typically elevated approximately 50 ft to provide NPSH for the BFW pumps.

### 5.3 BFW HEATERS

BFW heaters may be used to improve overall plant heat rate. MP steam if available may be used to raise the temperature of deaerated water closer to saturated boiler water conditions. The higher temperature BFW will then require less fuel in the boiler to cause vaporization. A BFW heater also finds application in cases where dew point corrosion is a concern. It can be used upstream of an economizer to maintain an acceptable flue gas temperature. Preheating BFW with steam competes with the boiler economizer, which picks up heat from the boiler stack.

### 5.4 BOILER AUXILIARIES

The boiler auxiliaries supply combustion air, boiler feedwater and fuel to the boiler.

The boiler fan supplies combustion air to the boiler. The fan draws in ambient air and sends it to the airpreheater, if present, and then to the boiler burners for combustion. In combined cycle operation, the gas turbine exhaust provides hot combustion air for supplementary firing of the waste heat boiler. A backup combustion air fan may be required for steam reliability when the gas turbine driver is not available.

Boiler feedwater is transferred from the deaerator to the boiler steam drum by centrifugal type BFW pumps. Centrifugal type pumps are described in [DP X](#).

Boilers are generally supplied with both gas and liquid fuels. The gas system for the boilers is usually an extension of the overall plant system and consists of a knockout drum, piping and valving. The liquid fuel system, on the other hand, often is segregated from the plant fuel loop by use of a day tank. The purpose of the day tank is to avoid upsets in the steam supply when difficulties occur in the plant fuel system. Accordingly, the boiler liquid fuel system contains the day tank plus associated pumps, strainers, heaters and distribution facilities.

[Figure 6](#) shows a typical boiler piping arrangement.

### 5.5 BOILER BLOWDOWN FACILITIES

The boiler blowdown facilities consists of the continuous blowdown system, intermittent blowdown system, and blowdown / preheat exchanger. [Figure 7](#) shows typical boiler blowdown facilities.

Continuous blowdown, as the name implies, is the continuous removal of a concentrated water stream from the boiler steam drum. Water high in dissolved solids is removed from the boiler and replaced with low solids boiler feedwater to control the concentration of various impurities in the boiler drum. Blowdown rates depend on makeup water quality and steam pressure level, and can range from 1% to 15%+. The continuous blowdown system consists of a connection from the boiler steam drums to a series of flash drums operating at pressure levels lower than the pressure of the boilers. A portion of the blowdown is flashed at each pressure level and the condensate is sent to the next lower pressure flash drum. This process is a means of recovering energy from the blowdown.

Intermittent blowdown refers to the periodic removal of water from the boiler mud drum, primarily to remove suspended solids. This blowdown also lowers the dissolved solids level while removing sludge buildup. The intermittent blowdown facilities normally consist of a single low pressure or atmospheric flash drum and a connection from the boiler mud drums. A portion of the blowdown flashes to steam upon entering the drum and the remaining condensate is discharged to the area drainage system. If steam flashed from the intermittent blowdown drum is discharged to the atmosphere it is done so at a safe distance above grade. Intermittent blowdown frequency is dependent on boiler design, operation, and make of water quality, and can range from once per shift to once per month. It can be used to reduce contamination levels, but excessive rate can affect circulation and lead to tube failure.

The blowdown / preheat exchanger is used to cool the liquid discharge from the lowest pressure flash drum in the continuous blowdown circuit. The component is a shell and tube type heat exchanger in which blowdown is used to heat treated water being sent to the deaerator. The temperature of the blowdown is reduced to a safe temperature for disposal in the site drainage system. Where blowdown rates are very small, such systems may not be justified for heat recovery reasons. However, cooling is recommended for safety reasons to avoid flashing in the sewer as well as hot water heating up hydrocarbons that may be present.

|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 10 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

## 5.6 PRESSURE REDUCING STATIONS

Pressure reducing stations are throttling valves provided between steam system pressure levels. They are used to maintain steam distribution systems in balance. Extraction-condensing turbines may also be used for this purpose.

Normal steam header pressure control is based on satisfying the demands at all levels without venting. During upset conditions, excess steam at a higher pressure level may be dumped to the next lower level(s) and eventually vented to atmosphere.

Normal HP steam header control is via the boiler master pressure controller which adjusts fuel firing with increasing or decreasing HP header demand.

The pressure reducing stations receive control signals from the lower and higher pressure headers to cover steam demand and steam dump requirements respectively. [Figure 8](#) shows a typical pressure reducing station.

## 5.7 SPILLOVER CONDENSERS

Spillover condensers are sometimes provided in a design to condense surplus LP steam. By removing surplus LP steam from the system, and capturing the condensate for reuse, the spillover condenser acts as a pressure controller for the low pressure steam system. The intent of the steam system designer and operator is to eliminate the need for a spillover condenser but this objective is not always achievable given the wide range of operations, steam and fuel balance effects.

The spillover condenser may be either a shell and tube type or an air fin type heat exchanger. These heat exchanger types are described in [DP IX-A](#). If steam surplus is a summer only condition, an air-fin may offer advantages (lower investment due to cooling water system savings and easier to take out of service in winter months).

[Figure 9](#) shows a typical spillover condenser arrangement.

## 5.8 STEAM SILENCERS

A steam silencer is a large diameter pipe or cylinder containing a noise suppression device or material. The silencer reduces the noise associated with steam expanding through a pressure control valve to the atmosphere.

A vent / steam silencer is used to vent surplus steam from the MP and/or the LP systems to avoid unnecessary safety valve liftings. Another use for pressure control valve / vent silencers is to create an artificial boiler load and thereby facilitate boiler startup and testing. [Figure 10](#) shows typical vent / steam silencer and performance testing steam silencer arrangements.

## 5.9 DESUPERHEATERS

Desuperheaters are provided to reduce the temperature of steam and thereby permit a reduction in design temperature of downstream equipment. Desuperheaters are often provided at pressure reducing stations, for steam turbine exhausts and upstream of reboilers. Most desuperheaters work on the principle of bringing water into contact with the steam and evaporating the water to reduce the temperature of the steam.

Water is supplied to the desuperheaters by the desuperheating water pumps. Centrifugal pumps are provided for this service. Condensate or very high quality demineralized water should be used for desuperheating to avoid problems such as caustic embrittlement. Unpolished treated water contains trace amounts of caustic which concentrate as the water evaporates thus creating problems in piping and equipment.

[Figure 11](#) shows typical desuperheating water facilities.

## 5.10 COMBUSTION AIR PREHEATERS

Combustion air preheaters are sometimes used to preheat the air being supplied to the boiler burners. Preheating the air aids in the combustion of hard-to-burn fuels and improves boiler efficiency. To achieve proper combustion, an air preheater may be required on an existing boiler when switching to heavier than original design fuels such as resid or tar.

The various types of combustion air preheaters are described in [DP VIII-K](#).

## 5.11 BOILER STACKS

Stacks are provided to dispose of the boiler flue gases at a safe elevation above grade. The height of stacks is usually based on dispersion considerations, rather than draft requirements.

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|                                                                                                                  |                                                             |                |             |
|------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------|----------------|-------------|
| <br><br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                                  |                                                             | XXVI-B         | 11 of 67    |
|                                                                                                                  |                                                             | December, 2004 |             |

The type of stack provided in the design can be either individual stacks for each boiler or a common stack for the boilers or a common stack shared by the boilers and the onsite furnaces. Selection is based on minimizing investment. Final stack selection should consider the effects of stack maintenance on operations.

The ducting and stack arrangement for a gas turbine / waste heat boiler can be simple if loss of steam capacity can be tolerated when the gas turbine shuts down. If steam reliability (e.g., boiler operation without gas turbine exhaust) is required, a more complicated arrangement (which includes an FD fan, dampers and a dump stack) may be required. Refer to [Figure 14](#) for a typical Gas Turbine / Waste Heat Boiler arrangement.

## 5.12 DISTRIBUTION PIPING AND VALVING

The distribution system is a piping network which supplies steam, boiler feedwater, and desuperheating water to onsite units and offsite consumers. The piping network is made up of a number of main headers originating in the boiler area. These main headers carry the service to a general area or several groups of consumers. Individual consumers are supplied by laterals from the main headers.

Valving is provided in the distribution system to permit individual components to be isolated for inspection and maintenance. Parallel headers may be provided if justified for turnaround or maintenance needs.

## 5.13 CONDENSATE RETURN SYSTEMS

In situations where the potential for hydrocarbon contamination of the condensate system exists, it is usual practice to segregate the clean and potentially dirty parts of the overall system. The potentially dirty system should contain a surge drum, hydrocarbon detection, and if justified deoiling facilities as an alternative to sewer disposal during upset conditions.

The condensate recovery system recovers steam condensate for subsequent use as boiler feedwater and desuperheating water. The recovery of condensate is usually justified but is a function of condensate quantity and producer location. In the past, condensate has not been recovered from distant locations due to piping costs only. The real incentive for condensate recovery also has to consider heat loss and investment and chemicals costs associated with the water treating plant. Condensate dumping also adds to the plant waste water load and its high temperature may create problems in the waste water system. In locations where wastewater reduction is required, recovery of condensate and reuse should be considered. If reuse in the BFW network is not feasible, the condensate could also be used to back out other water make-up needs (e.g., cooling water, process water, etc.).

## 5.14 PROVISION FOR LOAD SHEDDING AND FEED FORWARD SIGNALS

Load shedding is required in order to protect the overall steam system when the on-line steam production capability is less than the steam demand. This could occur under a variety of conditions which often involve purchased power outages or unplanned boiler shutdown. Load shedding refers to selectively reducing steam consumption by process units and/or offsite consumers during emergency situations. Steam loads are shed to stabilize the steam system pressure by bringing the steam requirements into balance with steam production. Automatic and manual load shedding stations are provided for this purpose. The boiler plant auxiliaries must be completely protected in any load shedding scheme.

With automatic load shedding, valves to consumers are shut in sequence depending on consumer criticality in response to low steam header pressure. Feed-forward signals are sometimes employed to prevent major pressure excursions in the steam headers. For example, the trip signal from a large back pressure steam turbine may be used to open a letdown station. Such action can avoid lifting of safety valves or steam drum level drops at the high steam pressure level and severe pressure decay at the lower steam pressure levels. Feed forward may also be used to increase boiler firing upon the trip of a large steam generator.

With the manual system, the load shedding valves are closed via panel-mounted pushbuttons. The amount of automatic load shedding, as opposed to manual, must be sufficient to ensure steam system stability during emergency conditions when operators may not have sufficient time to respond. [Figure 12](#) shows typical load shedding arrangements. For further review of load shedding and its effect on steam cushion, see G-EMS US-OP-503.

## 5.15 SYSTEM SAFETY VALVES

Pressure relief valves are provided at each steam system pressure level. These safety valves are provided to protect each steam level from being overpressured. Typically, the safety valves on the steam generators protect the highest steam pressure level from overpressure.

For a description of pressure relief valves, refer to [DP XV-C](#).

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|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 12 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

## 6 SYSTEM DESIGN CONSIDERATIONS

### 6.1 STEAM PRESSURE LEVELS

Steam pressure levels are provided in a design to fit the characteristics of the project. These pressure levels normally fall into the following general categories:

- High-pressure steam
- Medium-pressure steam
- Low-pressure steam

High-pressure steam is frequently used as a power source for equipment with large horsepower requirements (e.g., recycle gas compressors, and turbine generators). A driver study is required to justify the use of a high-pressure steam system in a design. Most designs with high-pressure steam levels work on the principle of generating HP steam to power back pressure turbines which produce MP steam for distribution to other parts of the plant. The most common high-pressure steam level in refinery applications is 600 psig and 750°F (4100 kPa and 400°C). Where electric power is generated a 1500 psig and 950°F (10300 kPa and 510°C) system is often used. These higher steam pressures are common with large turbine generators or with very large turbine-driven compressors. Ethylene and ammonia plants often incorporate a 1500 psig (10300 kPa) steam pressure level. In general, distribution of steam at this high pressure level should be limited in order to minimize costs associated with distribution piping and valves.

Medium-pressure steam is used by the onsite units for a variety of plant equipment. Onsite processes use medium pressure steam for heating, stripping, purging, snuffing, etc. Medium-pressure steam is also used to power onsite pumps and offsite equipment such as the boiler auxiliaries, air compressors, etc. and for heating tanks and boiler feedwater heaters. The pressure level of this steam is normally established by the requirements of the onsite process or the MP steam level in the existing plant. MP steam level is usually in the 125 to 150 psig (860 and 1030 kPa) range.

Low-pressure steam is used primarily to support the operation of the deaerator. This low-pressure steam is normally produced by the steam turbine driven boiler auxiliaries. The operating pressure for this pressure level is established by the steam system designer. Low-pressure steam may also be used for tank heating, steam tracing and air preheating. Low pressure steam distribution is often limited to the boiler or process areas which produce LP steam because of the cost of distributing LP steam to remote users. LP steam level is usually in the 15 to 30 psig (100 to 200 kPa) range.

The number of pressure levels in a particular plant is generally three to four due to economic and control considerations. Special levels required by a particular process such as 60 psig (410 kPa) in sulfur plants should be confined to that process unit area.

### 6.2 THE VALUE OF STEAM

Assigning a value to steam at various pressure levels can be a complex issue. High pressure steam can provide a source of heat (just as low pressure steam can) but it can also provide shaft power as it is pressure reduced via a steam turbine.

Several methods of assigning steam values are available and the most appropriate for a given situation depends on many factors. Consideration has to be given to the fixed and variable costs of generating the steam as well as production / consumption effects on the steam balance.

The **enthalpy** method assigns relative values to steam based on heat content only. The following illustrates how steam at various pressure levels would be valued:

| STEAM LEVEL | STEAM CONDITIONS                     | ENTHALPY<br>Btu/LB (kJ/kg) | RELATIVE VALUE<br>COMPARED TO<br>HP STEAM (%) |
|-------------|--------------------------------------|----------------------------|-----------------------------------------------|
| HP          | 600 psig (4100 kPa)<br>750°F (399°C) | 1379 (3,200)               | 100                                           |
| MP          | 150 psig (1030 kPa)<br>450°F (232°C) | 1245 (2,890)               | 90                                            |
| LP          | 15 psig (100 kPa)<br>300°F (149°C)   | 1189 (2,760)               | 86                                            |

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|--------------------------------------------------|-------------------------------------------------------------|----------------|-------------|
| <b>ExxonMobil</b><br><br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                  |                                                             | XXVI-B         | 13 of 67    |
|                                                  |                                                             | December, 2004 |             |

This method is normally not recommended since it ignores the work potential of the steam, (e.g., it is assumed that MP and LP steam is generated via letdown).

The **exergetic** (availability) method is thermodynamically more correct than the enthalpy method since it reflects the work (shaft power) potential of the steam relative to a fixed heat sink. Availability values can be calculated using the following formula:

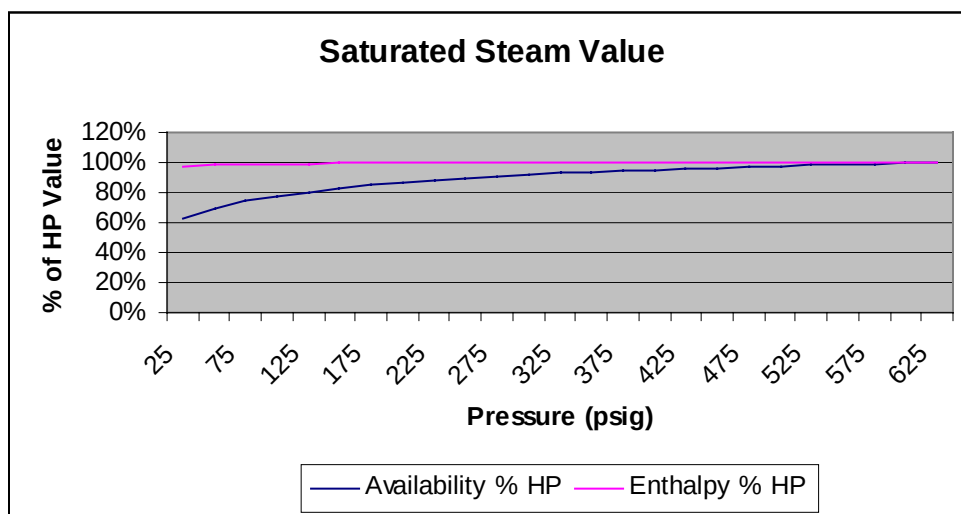
$$A = (H_1 - H_2) - T_2 (S_1 - S_2)$$

where:  $H_1$  = enthalpy of steam level (Btu/lb)  
 $H_2$  = enthalpy of reference level (Btu/lb)  
 $S_1$  = entropy of steam level fluid (Btu/lb°R)  
 $S_2$  = entropy of reference level fluid (Btu/lb°R)  
 $T_2$  = temperature of reference level (°R)

Using a reference level temperature of 80°F (27°C) water, and calculating availability values for the steam pressure levels above, results in the following:

| STEAM LEVEL | AVAILABILITY<br>Btu/lb (kJ/kg) | RELATIVE VALUE<br>COMPARED TO<br>HP STEAM (%) |
|-------------|--------------------------------|-----------------------------------------------|
| HP          | 506.7 (1,176)                  | 100                                           |
| MP          | 369.2 (857)                    | 78                                            |
| LP          | 250.6 (582)                    | 49                                            |

If saturated steam conditions are used for comparison, the contrast is even more evident, since enthalpy changes even less:



This method shows that lower pressure steam is valued much lower than in the enthalpy method to reflect the work potential of the fluid. However, it does not cover the full impact on the steam balance and other effects such as changes in electric power consumption.

Combinations of the enthalpy and availability methods have also been used as recommended in Exxon Chemical Company Report No. CE-1E-78. This report also addresses fixed and variable cost factors which are important in assigning steam values.

A **rigorous** method is recommended to more accurately capture the specifics of the site and to maintain an operable and flexible steam balance. This is especially true if relatively large amounts of steam are involved. Also, use of the enthalpy or availability

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|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 14 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

methods may give the wrong signals to generate medium or low pressure steam which could actually result in venting (e.g., no credit).

The following example illustrates this point:

Consider a balanced steam system where steam is generated in boilers and turbine drivers are used to depressure steam to the various lower pressure levels. What will be the effect of generating waste heat steam from a process unit at the MP level?

Refer to [Figure 13](#) (Steam Balance Effects) which shows balances for the BASE CASE as well as the MODIFIED CASE after the addition of a WHB.

In the **BASE CASE**, the boilers have to generate 290 k lb/hr (132 t/h) of HP steam to satisfy MP and LP steam demands. Fuel firing for this case amounts to 374 MBtu/hr (110 MW).

In the **MODIFIED CASE**, steam generation from the WHB amounts to 60 k lb/hr (27 t/h) and without any new consumers, this will indirectly reduce steam demand from the boilers to 232 k lb/hr (105 t/h). Fuel firing is reduced to 299 MBtu/hr (88 MW). This case also necessitates a driver switch from steam turbine to electric motor (or other type driver). Assuming an electric motor, this will require about 1600kW of electricity.

If fuel costs \$5/MBtu and electricity is purchased at 10¢/kWhr, we would see the following credits for installing the WHB.

Fuel Savings

$$(374 - 299) \frac{\text{MBtu}}{\text{hr}} \times \frac{\$5}{\text{MBtu}} \times \frac{8760 \text{ hr}}{\text{yr}} = 3,285 \text{ k\$/yr}$$

Power Cost

$$(1600 \text{ kW}) \times \frac{\$0.10}{\text{kWhr}} \times \frac{8760 \text{ hr}}{\text{yr}} = 1,401 \text{ k\$/yr}$$

NET SAVINGS

**1,884 k\\$/yr**

The **enthalpy** method would have credited WHB production at about 90% of HP steam value.

$$\frac{374 \text{ MBtu}}{\text{hr}} \times \frac{60 \text{ k lb/hr}}{290 \text{ k lb/hr}} \times 0.9 \times \frac{\$5}{\text{MBtu}} \times \frac{8760 \text{ hr}}{\text{yr}} = \frac{\mathbf{3,050 \text{ k\$}}}{\text{yr}}$$

The **availability** method would have credited WHB production at about 78% of HP steam value.

$$\frac{374 \text{ MBtu}}{\text{hr}} \times \frac{60 \text{ k lb/hr}}{290 \text{ k lb/hr}} \times 0.78 \times \frac{\$5}{\text{MBtu}} \times \frac{8760 \text{ hr}}{\text{yr}} = \frac{\mathbf{2,644 \text{ k\$}}}{\text{yr}}$$

The rigorous method should be used to identify variable costs associated with fuel firing and electricity consumption. Other factors to be considered include:

- Treated Water
- Chemicals
- Operating Manpower
- Incremental Investment
- Maintenance

### 6.3 STEAM GENERATION AND DISTRIBUTION

The boiler superheater outlet temperature and pressure should be set high enough to accommodate pressure and temperature losses in the distribution system to various consumers. This should be checked at maximum flow rates for pressure and at minimum flow rates for temperature. Other steam sources such as pressure reducing stations and noncondensing and extraction-condensing turbines must be considered in the evaluation.

|                                                  |                                                             |                |             |
|--------------------------------------------------|-------------------------------------------------------------|----------------|-------------|
| <b>ExxonMobil</b><br><br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                  |                                                             | XXVI-B         | 15 of 67    |
|                                                  |                                                             | December, 2004 |             |

#### 6.4 SYSTEM PRESSURE CONTROL

The distribution levels are kept within their design range by the pressure controlling components within the steam system. These pressure controlling components consist of the following:

| UNIT                                                          | SYSTEM PRESSURE LEVEL |
|---------------------------------------------------------------|-----------------------|
| Boilers                                                       | Highest Pressure (HP) |
| Pressure reducing stations and extraction-condensing turbines | MP and LP             |
| Vent or Spillover condenser                                   | LP                    |

These components control the volume of steam in the system and hence its pressure either through the generation of steam or the redistribution of steam within the system. Switchable pair drivers (motor and turbine) should be considered to avoid major letdown or venting steam flows, and are sometimes necessary to control steam system pressures during turnarounds or on change of season.

Steam balances are a basic tool used in developing the steam system design. These steam balances summarize the consumption and production of steam for various system operating cases. Steam balances are used for the following:

- Establishing the capacity of various system components
- Optimizing the use of steam and power within the system
- Developing operating techniques to handle upsets, emergencies, and special operating situations.

Steam balances should be calculated for various plant operating cases. From these balances, the operating cases which establish the design capacities for major steam system components can be determined. These design cases consider maximum winter and summer demand, power outages, fuel gas containment, achievable turndown of steam producers, onsite emergencies and catalyst regeneration. These steam balances should be routinely updated when new load data become available. Load growth factors used in the balances should be adjusted during the course of the design to reflect the changing quality of the loads being used. Steam balances should also be developed without load growth factors for the minimum steam consumption cases, such as summer operation. These balances are necessary to evaluate the required operating flexibility of the system if predicted load growth should fail to develop.

The steam balance may be very sensitive to the turbine efficiencies selected for the various drivers from generalized data. It is often necessary to consult with the machinery specialists or vendors to insure that the actual steam rates used are realistic and commercially available. The steam balances should be based on normal process design conditions for pressure and temperature without application of the turbine multiplier given in the International Practices.

See the computer program section for application software.

#### 6.5 DYNAMIC SIMULATIONS

Dynamic simulation of the steam system is useful to analyze complicated systems, and systems that require load shedding to maintain the system pressure, such as upon loss of a single large steam producer. Simulations should be considered on any project that has a major change to the site's steam generation or demand. Dynamic simulations are good training tools for operators. For assistance, see EMRE or Site Process Control Group.

#### 6.6 FUEL BALANCES

Changes to the steam generation system should not result in fuel gas containment constraints. Fuel balances should be reviewed for both summer and winter operation, and should consider equipment availability. If containment becomes problematic, changes may be necessary in the flaring, fuels, and steam systems, including boiler burners, HRSG supplemental burners, pressure reducing stations, and spillover condensers. New Cogeneration projects usually have a major impact on the fuel gas needed for steam generation, so a thorough fuel balance review is critical. The Gas Turbine and HRSG Fuel Flexibility Guide (EE.10E.2000) is a good resource.

|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 16 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

## 6.7 LOAD GROWTH AND RESERVE CAPACITY

Steam loads associated with driver and process requirements tend to increase as the loads become better defined through successive stages of project definition. Therefore, load growth and reserve capacity factors (LGF and RCF) are applied to raw loads as a means of predicting final equipment sizes and capital costs. These load growth factors do not cover basis changes through project development such as project or process unit size / throughput. For revamp or modernization projects, these factors are generally applied to new loads only on the basis that existing loads are well known.

| CONSUMERS           | LOAD GROWTH FACTORS                 |              |
|---------------------|-------------------------------------|--------------|
|                     | PLANNING<br>(SCREENING THROUGH DBM) | DESIGN SPEC. |
| Existing Facilities | 0 - 10%                             | 0 - 10%      |
| New Facilities      | 15 - 30%                            | 5 - 10%      |
| Major Drivers       | 5 - 10%                             | 5%           |

Selection of the load growth factor to use should be based on the quality and level of effort associated with development of the raw loads. Load growth factors are applied to individual consumption estimates only and are not applied to production estimates.

Final sizing of the source facility (e.g., the boiler) should include a reserve capacity factor of 10% to cover small post startup changes and dynamic conditions not predicted by steady state steam balances. The sizing basis for distribution facilities should not include the RCF. The RCF provides capacity to manage rain storms, heat loss, refill headers after an upset, increased loads due to fouling, wear and tear on equipment. It is vital to maintain this capacity.

## 6.8 BOILER AUXILIARY DRIVERS

The driver selection for the boiler auxiliaries should be based on designing the boiler plant to be capable of continuous and independent operation. This basis requires a boiler area power source for the auxiliaries and a source of LP steam for the deaerator. In most designs, the basis is satisfied by providing back pressure steam turbine drivers for the boiler fans and other auxiliaries which exhaust at the low pressure steam level for use in the deaerator. For plants located in cold climates that utilize purchased power, special design features may be required in order to insure black start capability of the boiler block and the capability to satisfy critical steam tracing and tank heating loads. These features may include in-plant power generation for the boiler block, a load shedding system, and a segregated distribution system.

The steam supply to boiler auxiliaries should be given special treatment in developing the steam system design. The steam required by the boiler auxiliaries must be available from within the boiler block. This steam should be made preferentially available to the boiler auxiliaries at the expense of other consumers during a load shedding event.

## 7 SYSTEM DESIGN PROCEDURES

The general design procedure for developing a steam system design are as follows:

**Step 1.** Gather input data and background information for use in developing the design. This data and information should normally consist of the following:

- Existing steam system pressure levels.
- Number, capacity, and pressure for existing offsite and onsite steam generators.
- Normal and maximum steam and power loads for new onsite and offsite facilities.
- Steam balances covering the operating cases for the existing facilities including seasonal swings.
- Cost of purchased electric power and predicted escalation rates.
- Details of purchased power contract to evaluate incentives for power generation, reliability of external power supply.
- Type(s) of fuels available and projected costs, fuel balances and fuel constraints.
- Drivers for new onsite or offsite equipment, equipment with a BHP requirement greater than 500 HP should be accounted for on a case by case basis.
- Features that the owner would like to incorporate into the design.
- Turnaround schedules and steam requirements.
- Emergency steam demands.

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|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 17 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

**Step 2.** Apply appropriate load growth factor.

**Step 3.** Perform a series of steam balances for the possible processing plant operating cases. Refer to the [SYSTEM DESIGN CONSIDERATIONS](#), STEAM BALANCES section for a discussion on the use of steam balances in developing the design.

**Step 4.** Select a water treating process suited to the steam system design. See [DP XXVI-A](#) for details.

**Step 5.** Decide which economic studies should be performed so that the steam / fuel / power strategy for the plant can be determined. Considerations include the following:

- Justification of cogeneration / combined cycle operation.
- Justification of high pressure steam topping cycle.
- HP steam pressure reduction to satisfy LP steam demand
- Fuel gas containment.
- Disposition of non-saleable liquid fuels.
- Steam containment due to excess onsite production (e.g., condensing power generation).
- Major driver selection, including use of switchable pairs if needed.
- Unreliable source of purchased power, and effect of power loss on Business and on flare design.

**Step 6.** Continue to revise and update the steam balances as new loads become available.

**Step 7.** Review the design considerations for individual steam system components. Select and design components to meet requirements of the project.

## 8 COMPONENT DESIGN CONSIDERATIONS

### 8.1 BOILERS

**Installed Capacity** - Boilers may be unavailable or out of service for a variety of planned and unplanned reasons including statutory inspection, scheduled maintenance, and both short and long forced outages. The short outages could be caused by feedwater supply problems, boiler trips and the like whereas long forced outages may include tube failures. For these reasons, installed boiler capacity must be greater than normal steam requirements in order to provide a reliable steam supply to the plant.

In general, the installed boiler capacity and number of boilers should permit the largest boiler to be out of service while still meeting maximum steam requirements without load shedding. This remaining boiler capacity with the largest boiler out of service is referred to as firm capacity. Consideration should be given to the loss of a boiler while one boiler is out of service for maintenance. This is typically referred to as an N-2 situation. Given that installed boiler capacity to cover this situation is expensive, the N-2 scenarios is typically addressed by load shedding.

A dynamic analysis may be needed to determine the required boiler configuration which will assure proper system reliability. Such a simulation is especially valuable for:

- Expansion projects where the ratio of installed to firm capacity is relatively low
- Systems which include a significant portion of waste heat boiler capacity
- Systems which include a variety of boiler sizes
- Systems which include one or a few large steam turbines

The results of this study are used to define acceptable number and size of boilers, required response rate of boilers, need for feed forward control of key variables / instrument signals, load shedding requirements, pressure reducing station valve characteristics, and major turbine throttling.

**Special Considerations** - If a boiler is to be used for non-continuous service, i.e., stop-go or turnaround coverage only, there are special design considerations to prevent dew point corrosion as described in TASCUM Boiler Work Group Report No. EE47E.80. Another review of dewpoint corrosion is found in the RCMM Vol III, Section B. If a non-continuous service boiler is designed to fire liquid fuels containing sulfur or vanadium, special precautions (ash cleanup) or hot stand-by facilities should be considered.

**Turndown** - A turndown ratio of 5 to 1 is normally specified for a boiler to permit flexibility of operation. Main considerations at turndown are repeatable air flow measurement, adequate burner gas pressure, and adequate steam temperature. This turndown ratio is equivalent to calling for the boilers to be capable of stable operation at 20 percent load. Simultaneously firing oil and gas on

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|                                                                                                                  |                                                             |                |             |
|------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------|----------------|-------------|
| <br><br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                                  |                                                             | XXVI-B         | 18 of 67    |
|                                                                                                                  |                                                             | December, 2004 |             |

the same burner substantially reduces boiler turndown. Turndown may be limited by combustion stability when burning heavier fuels than those used in the original boiler design.

Higher than normal turndown ratios should be considered if there are less expensive steam producers available or if it is expected that the boiler may be operated in a minimum load hot standby mode. These higher turndown ratios will likely require special burner and control system design. The additional cost for this feature must be economically justified.

**Waste Heat Boilers (WHB's) or Heat Recovery Steam Generators (HRSG's)** - Which utilize gas turbine exhaust fall into one of three categories.

1. Convection only WHB which typically cools the hot gas turbine exhaust to produce steam. Steam production is a function of many factors and can be estimated using [Figure 23](#) (Waste Heat Steam Rate).
2. Supplementary (or duct) fired WHB where convection heat recovery is augmented by supplementary fuel firing. Firing temperature is generally limited to 1600°F (871°C) to avoid a step change in the investment.
3. Refer to [Figure 14](#) for a typical Gas Turbine / WHB arrangement.
4. This arrangement is the most common for refinery and chemical plant application because it offers efficiency, simplicity and some degree of steam generation flexibility.
5. Fully fired WHB which utilizes the hot oxygen in the gas turbine exhaust to its maximum; thus generating large amounts of steam efficiently. This type of boiler is similar to a conventional boiler but designed to handle the hot gas turbine exhaust (e.g., high temperature and mass flow).

Waste heat boilers can be designed to produce steam at different pressures and temperatures as dictated by process requirements. In industry electric power plants, a single waste heat boiler is frequently configured for multiple steam pressure levels and reheating cycles in order to maximize heat recovery and cycle efficiency.

An important reliability consideration associated with GTG/WHBs is the simultaneous loss of power and steam. While we typically specify the GTG to be able to ride through a power failure or power disturbance, there is some reasonable chance that the GTG will not stay on line. This results in loss of the power and steam simultaneously. At sites with a large percentage of steam generation via GTG/WHBs, the impact of multiple GTG/WHB trips due to a common electrical fault should be evaluated.

For scoping available steam generation from a HRSG, see Appendix 2, EE189E.99, "Steam and Power Generation Economic Optimization Guidelines."

Supplementary fired WHB's are limited to significantly lower turndown capabilities than conventional boilers. Since the sensible heat of the gas turbine exhaust usually provides one half of the total heat input, total turndown (allowing for minimum supplementary fuel) is less than 2:1. Operating flexibility is enhanced with the use of a backup combustion air fan and dump stack. This allows the Gas Turbine and Generator (GTG) to operate in generation mode if the boiler is unavailable, or the waste heat boiler to produce some steam with the GTG down. Either mode of operation is not as efficient as the cogeneration mode, but may be useful to plan a shutdown which could lessen impact on plant operations.

When HRSG firing represents a significant fraction of discretionary steam production, there should not be any single element failures which result in a duct burner trip. Redundancy should be provided for flame scanners, fuel gas pressure, steam drum levels, and any other shutdown instrumentation.

Steam output and temperature from the WHB can vary depending on gas turbine operation. The planner / designer should analyze gas turbine exhaust conditions for various loads so that WHB design limitations can be identified. Other factors such as gas turbine exhaust flow distribution, duct burner design, placement of emissions control equipment, etc., have to be considered in order to achieve the desired design conditions. Guidance and assistance from vendors and discipline specialists should be obtained as appropriate.

Gas side pressure drop through the waste heat boiler falls typically in the 8 - 12 in (200 - 300 mm) H<sub>2</sub>O range but can be more or less depending on the level of the auxiliary fuel firing, tube spacing, etc. Output of the gas turbine is reduced with increased backpressure thus making boiler pressure drop an important design criteria.

Regulatory agencies generally require Combustion Emissions Monitoring Systems (CEMS) on gas turbine installations. Water or steam injection has been employed for gas turbine NO<sub>x</sub> reduction. Dry low NO<sub>x</sub> burners have been developed to meet reduction without steam or water injection. Further reduction may require hardware addition (such as a selective catalytic reduction unit) within the waste heat recovery boiler. Added pressure drop requirements for this type of equipment will further impact gas turbine

performance. Furthermore, overall reliability / flexibility of the gas turbine / waste heat boiler train is reduced. Therefore, the designer should consult with the discipline specialist with regard to pollution control considerations and their impact on the steam system.

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|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 19 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

**Steam Drum Internals** - For adequate water / steam separation and to reduce carryover, drums are designed with two types of internals. Primary separation is typically done with cyclones, and secondary separation with scrubbers (chevrons), as shown in [Figure 1](#). Steam purity requirements are found in IP-7-2-1, Table 4.

**Continuous Blowdown Rate** - The continuous blowdown rate is set by the level of impurities in the treated water and the allowable level of impurities in the boiler drum. The maximum concentration levels for various impurities are presented in [DP XXVI-A](#). The procedure for calculating the blowdown rate is given in [Figure 15](#) of this section and the blowdown drum heat balance is shown in [Figure 16](#).

The continuous blowdown facilities are sized as follows:

- When the maximum blowdown rate is  $\leq 10\%$ , a design rate of 10% should be specified.
- When the maximum blowdown rate is  $> 10\%$ , the higher blowdown rate should be used.

Continuous blowdown systems for multipressure level HRSGs can be staged (HP drum blowdown fed to MP drum, MP drum blowdown fed to LP drum) .

**Economizer** - An economizer should be considered for new boiler installations. The economizer is typically included based on an economic analysis to improve boiler efficiency. This evaluation may require consultation with the discipline specialists to determine the expected flue gas outlet temperature from the boiler and the recommended minimum flue gas exhaust temperature from the economizer to avoid corrosion.

**Attemperator** - Boilers may be equipped with attemperators or desuperheaters to maintain a relatively constant steam temperature with varying boiler loads. This is to avoid exceeding the mechanical design temperature of the system.

The constant steam temperature is also needed for steam turbines as required by manufacturers and to limit large variations in throttle flows.

Mechanical design requirements for piping, fittings and pressure vessels are covered by appropriate ANSI and ASME codes. The codes for vessels and fittings do not permit temperature excursions in excess of design. However, the piping code does allow short time variations of temperature above design such as for any temporary loss of desuperheat spray.

Steam temperature control for HRSGs can be simple if gas turbine exhaust flow conditions and waste heat steam production are relatively constant. A more typical situation calls for the HRSG to produce constant steam temperature while the exhaust from the gas turbine fluctuates and the HRSG steam outputs is varied (via supplementary firing). This requires more attention to superheater and attemperator designs in order to meet user steam temperature limits. Systems involving oversized superheaters, superheater shield tubes, multiple attemperators with intermediate spray water etc., have been used to obtain a cost effective design. Consultation with the discipline specialists or HRSG vendors is recommended in setting steam production and temperature ranges. Some designs may require split range attemperator spray valves to cover a wide range of desuperheating water requirements.

**Soot Blowers** - Retractable soot blowers are normally provided for boilers firing liquid fuel of less than 25 API gravity (see [IP 7-2-1](#)). If fuel specifications do not require soot blowers, plot space and boiler design, consideration should be given to accommodating the future need for soot blowers should fuel characteristics change. For maximum cleaning efficiency, superheated steam is desirable to minimize condensate formation while blowing. The steam consumption for a soot blower can be estimated on the basis of 10,000 lb/h (4.5 t/h) per soot blower.

The operation of one soot blower should be reflected in the steam balance for the normal operating case.

**Burners** - The burners should be capable of handling the range of fuels that the boiler will be expected to burn. Primary fuel burners are designed to control steam header pressure through all expected load swings. A boiler firing two primary fuels should be designed to continue to operate when either primary fuel trips.

Each burner should be specified as having a minimum turndown equivalent to the turndown requirement of the boiler (5:1 is achievable with standard burners). Greater turndown flexibility can be obtained with burner modifications or by adding small burners to work in tandem with the larger burners. Consideration should be given to the number of burners in a new boiler. Front fired boilers can be equipped with a single burner at capacities over 300 MMBtu/hr, but a burner failure will result in boiler shutdown. With at least (4) burners, the boiler should be able to ride out loss of a single burner. Tangentially fired boilers have the burners mounted on the corners of the firebox. Liquid fuels usually require atomization, steam or air, with a differential pressure control to maintain atomization pressure above fuel pressure. The Burner System Design and Fuel System Design sections of [DP VIII-F](#), Fired Heater Burners, provides information relevant to Boiler burners. Boilers with 2 or 3 burners are typically not used due to the fact that the trip of a single burner can cause the other burners to go substoichiometric.

Duct firing in waste heat boiler application is typically done with clean and non-fouling gas fuels. Grid type burners are utilized in a hot flue gas environment which can cause plugging of piping and burners with unsuitable fuels. EMCC has experienced fouling of

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|                                                                                                              |                                                         |                |             |
|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 20 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

the burner runners with as little as 1% unsaturates in the fuel gas. Tonen Chemical uses a design which cools the gas fuel piping to the duct burners inside the waste heat boiler in order to avoid coking with the high olefin content fuel. Clean fuel oil (diesel) duct firing is also possible with can type burners. In addition, fuel oil firing also requires an atomizing medium which can be steam or compressed air. The designer should contact the discipline specialists for assistance in specifying burners and associated burner piping details.

**Safety Valves** - Safety valves are provided on a boiler in accordance with the ASME boiler and pressure vessel code. Local codes must also be observed. Safety valves are normally provided on the steam drum and on the superheater outlet. The safety valves on the superheater outlet are set to open before the drum safety valves to maintain a steam flow through the superheater. This steam flow prevents tube overheating.

The safety valve capacities and set pressures should be determined by the boiler vendor in accordance with code requirements.

**Vent Valves** - For startup and shutdown, boilers are usually equipped with vent valves to insure sufficient water circulation through the waterwall tubes, and steam circulation through the superheater tubes. The vent valve is also used to bring the boiler up to operating conditions to allow smooth transition into the steam header. Typically the superheater vent valve is remotely actuated.

**Boiler Control System** - The description and design considerations for boiler control are covered in [DP XII-I](#). The key elements of boiler control are fuel/air ratio control and 3-element BFW drum level control. The fuel/air control is often referred to as lead/lag or cross-limited firing control. The intent of this control is to always ensure adequate air is present for combustion. The system brings in air before fuel when the firing rate is increasing (air leads), and reduces fuel before air when the firing rate is decreasing (air lags). 3-element drum control incorporates the steam production flow meter along with BFW flow and drum level to set the BFW flow to the steam drum, to better accommodate load swings and reduce the disruptive effects of drum level shrink and swell.

The boiler feedwater control valve must handle both the full load and the startup requirements. Startup conditions are severe, low flow with high pressure drop. Higher pressure systems (>1000 psig) may require a parallel smaller valve, or a dual seated valve, for this service.

**Boiler Shutdown System** - The boiler shutdown system is provided to automatically shut down the boiler in potentially hazardous operating situations. These operating situations, as well as a flow plan illustrating the shutdown system, are provided in [IP 7-2-1](#). Also, the EM Chemical Boiler Best Practices include a comprehensive set of practices that were developed to insure boiler safety and reliability.

HRSGs have more unique control issues. EMCC has found that duct burner ramp rate can be as fast as 50% of the burner capacity per minute, as long as the drum level control system can accommodate. The drum level control system on an HRSG can employ a 3 tiered approach to minimize curtailment:

- Low level - trip the duct burners to reduce steam production
- Low Low Level - Cut back the gas turbine to minimum load, or go to Full Speed, no load.
- Low Low Low Level - Trip the gas turbine.

**Local Control Panel** - A local control panel is normally provided for each boiler. This panel contains all indicating instruments and controls which the operator requires for placing the boilers in service. The recommended instrumentation and controls for the local panel are covered in [IP 7-2-1](#).

**Combustion Air Requirement** - A boiler's combustion air requirement is made up of the theoretical air required for combustion of the fuel plus excess air to ensure complete combustion. The amount of excess air is normally expressed as a percentage of the theoretical combustion air requirement. Boilers are normally designed for 10 percent excess air when firing gas and 15 percent excess air when firing liquid fuel.

**Backup Power Supply** - A backup power supply is normally provided for the boiler instrumentation in accordance with [IP 16-8-1](#).

**Boiler Chemical Treatment** - Chemicals are normally injected into the boiler steam drum to prevent the formation of scale and sludge. Design considerations on boiler chemical treatment are given in [DP XXVI-A](#).

## 8.2 DEAERATORS

**Type** - There are two principal types of deaerating heaters - the tray type and the spray type. The tray type deaerating heater spreads out the water into thin films by means of baffles or trays to insure intimate contact of the steam with the water for efficient heating and stripping.

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|--------------------------------------------------------------------------------------------------------------|---------------------------------------------------------|----------------|-------------|
| <br><b>DESIGN PRACTICES</b> | <b>STEAM SYSTEMS</b><br><b>STEAM GENERATION SYSTEMS</b> | <b>Section</b> | <b>Page</b> |
|                                                                                                              |                                                         | XXVI-B         | 21 of 67    |
|                                                                                                              |                                                         | December, 2004 |             |

In the spray type deaerating heater, water is sprayed into a steam atmosphere and heated to within 2 to 3°F (1 to 2°C) of the saturated steam temperature.

Combined spray-tray type deaerators are common.

For both types of deaerators, steam flow is usually countercurrent to the water flow to provide good contact heating. A relatively small amount of steam is vented in order to purge non-condensable gases from the deaeration section. At some locations, an external vent condenser may be required to eliminate a visible vent plume.

Both deaerating heater types require a minimum treated water temperature rise for effective deaeration. The minimum temperature rises are as follows:

- Spray type: 30°F (17°C)
- Tray type: 10°F (6°C)

Many ExxonMobil designs have specified combination spray / tray type deaerators to insure optimum performance and to keep chemicals usage (for final oxygen scavenging) to a minimum.

**Number** - One deaerator is normally provided for each pressure level of plant steam generation. This allows each steam generation level to operate independently and would allow using different quality make-up water and condensate streams. Consideration should be given to the use of multiple deaerators for a single steam pressure level to improve operating flexibility or to accommodate a unitized design concept which may have been established for the plant.

Cross connections are sometimes provided in multiple deaerator designs. This arrangement allows deaerator maintenance or inspection while the others are in operation. Cross connections also provide the flexibility to operate the deaerators in parallel. In such multiple deaerator systems, the BFW piping from deaerator(s) to pumps should be symmetrically configured as a means of avoiding flow imbalance and NPSH problems. The deaerators must also be at the same elevation if operated in parallel to avoid water flow from one to the other via the BFW pump suction manifold.

**Performance** - The deaerator is required to meet performance levels given in EMRE *Water and Wastewater Design Guide*, TME 080, DG 11-5-1. Performance levels to be guaranteed by the deaerator manufacturer are given for the following:

- Dissolved gas content in the effluent over the design operating range.
- Temperature of the effluent.
- Acceptable noise level.

**Design Capacity** - For new designs, capacity of the deaerator(s) should match the installed steam generation capacity (including spare capacity) plus BFW requirements for desuperheating, process water, blowdown and other loads if required. This is done to avoid the installation of a new deaerator when all boilers have to be operated due to plant steam load growth. For expansion of existing plants, additional deaerator capacity should be added only if the design (not installed) BFW load exceeds the capacity of the existing system.

The deaerator steam capacity should be designed to meet the worst case water heating scenario, for example, total loss of condensate.

A deaerator heat balance equation is given in [Figure 17](#).

**Operating Pressure** - The deaerator operating pressure used in a design is normally the same as the operating pressure of the LP steam system. Typically, lower operating pressure is preferred because the saturation temperature is lower thereby allowing more heat recovery from stack economizers.

**Materials of Construction** - The deaerator shell is normally carbon steel, and all welds should be heat treated to avoid problems with cracking that is common to deaerators. Recommended materials for the deaerator internal components are given in EMRE *Water and Wastewater Design Guide*, TME 080, DG 11-5-1.

**Height** - The height of deaerator should be based on providing net positive suction head (NPSH) required by the boiler feedwater pumps with the deaerator operating at 5 psi (35 kPa) below its normal operating pressure, as shown by the equation in [Figure 18](#).

This design basis minimizes the possibility of BFW pump cavitation during a pressure dip in the deaerator steam supply. The deaerator height should be expressed as the vertical distance between the centerline of the BFW pumps and the bottom of the deaerator storage tank.

**Safety Valves** - The deaerator is equipped with a high pressure alarm which sounds in a manned control room. One or more pressure relief valves are also needed if the protection on the low pressure steam system is not adequate. The deaerator should be

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