

METHOD FOR PROCESSING
HYDROCARBON PYROLYSIS EFFLUENT

CROSS-REFERENCE TO RELATED APPLICATIONS

5 [0001] This application claims benefit of and priority to U.S. Application Serial No. 12/847,433, filed July 30, 2010, and EP Application No. 10175705.2, filed September 8, 2010, the entireties of which are incorporated herein by reference.

FIELD OF THE INVENTION

10 [0002] The present invention is directed to a method for processing the effluent from hydrocarbon pyrolysis units, especially those units utilizing liquid feeds.

BACKGROUND OF THE INVENTION

15 [0003] The production of light olefins (ethylene, propylene and butenes) from various hydrocarbon feedstocks typically utilizes the technique of pyrolysis or steam cracking. Pyrolysis involves heating the feedstock sufficiently to cause thermal decomposition of the larger molecules. Then, the effluent from the cracking furnace may be cooled by using conventional processes or equipment.

[0004] This pyrolysis process, however, may produce molecules which tend to combine to form high molecular weight materials known as tars. Tars are high-boiling point, viscous, reactive materials that can foul equipment under certain conditions. The fouling of the equipment should be minimized to avoid inefficiencies and downtime associated with cleaning of the equipment. The formation of tars, after the pyrolysis effluent leaves the steam cracking furnace can be minimized by rapidly reducing the temperature of the effluent exiting the pyrolysis unit to a level at which the tar-forming reactions are greatly slowed.

25 [0005] Various techniques may be used to cool pyrolysis unit effluent and remove the resulting heavy oils and tars. For instance, one approach may employ heat exchangers followed by a water quench tower in which the condensables are removed. This technique has proven effective when cracking light gases, primarily ethane, propane and butane, because crackers that process light feeds, collectively referred to as gas crackers, produce relatively small quantities of tar. For heavier feedstocks, which may be used with steam crackers that crack naphthas (e.g., liquid cracking), another approach may involve heat exchangers that remove some of the heat from liquid cracking, but only down to the temperature at which tar begins to condense. Below this temperature, conventional heat exchangers should not be used because they foul rapidly from accumulation and thermal

degradation of tar on the heat exchanger surfaces. As such, in a commercial liquid cracker configuration, the cooling of the effluent from the cracking furnace is normally achieved using a system of transfer line heat exchangers, usually a direct quench, a primary fractionator, and a water quench tower or indirect condenser.

5 [0006] As may be appreciated, effective heat recovery enhances the operation of the system. That is, effective heat recovery from the effluent of steam cracking furnaces is advantageous in the overall energy efficiency of an olefins plant. For example, the outlet temperature of a steam cracking furnace typically operates at about 1,500°F (815°C) (with the temperature depending on the quality of the feedstock and cracking severity). By
10 operating at this high temperature, a large quantity of heat may be recovered as the effluent is cooled to near ambient temperature for initial product separation and compression.

[0007] In typical hydrocarbon cracking systems, a transfer line exchanger (TLE) is used to generate super-high pressure (SHP) steam from the initial cooling of furnace effluent as it exits the cracking furnace. The SHP steam may include pressures ranging from about 1,500
15 pounds per square inch gauge (psig) to about 2,000 psig (about 10,450 kilopascal (kpa) to about 13,982 kpa). The first heat exchanger raises saturated SHP steam from high pressure boiler feed water. The saturated SHP steam generated by the TLE may further be superheated in the convection section of the furnace to increase the amount of work that it can produce.

20 [0008] However, the TLE in typical configurations can only recover a portion of furnace effluent heat, as it is limited by the temperature at which tar begins to condense (i.e., tar dew point). That is, the outlet temperature on the process side of the TLE is limited by fouling when the dew point is encountered. As noted above, heavy components in the effluent condense at the tar dew point and foul the TLE surfaces, rendering them ineffective for heat
25 transfer. For naphtha crackers, tar dew point fouling limits TLE outlet temperatures to a minimum of about 700°F (371°C). For feeds heavier than naphtha, TLE outlet temperatures are higher than 700°F (371°C) because the effluent tar dew points are higher. The TLE outlet temperature is also limited by the temperature of steam generation temperature, which is about 600°F (315°C) for a 1500 psig (10,450 kpa) steam. As such, a TLE adjacent to the
30 furnace can only recover effluent heat from liquid cracking down to a temperature between about 650°F to about 1000°F (about 343°C to about 538°C) depending on the heaviness of the feed.

[0009] After initial cooling, the effluent is typically provided to the primary fractionator system. The primary fractionator system is a very complex set of equipment that typically includes an oil quench section, a primary fractionator tower and one or more external oil pumparound loops. At the oil quench section, quench oil is added to cool the effluent stream
5 from about 400°F to about 650°F (about 204°C to about 343°C), thereby condensing tar present in the stream. In the primary fractionator tower, the condensed tar is separated from the remainder of the stream, heat is removed in one or more pumparound zones by circulating oil and a pyrolysis gasoline fraction is separated from heavier material in one or more distillation zones. In the one or more external pumparound loops, oil, which is withdrawn
10 from the primary fractionator, is cooled using indirect heat exchangers and then returned to the primary fractionator or the direct quench point.

[0010] The primary fractionator system with its associated pumparounds is the one of the more expensive components in the entire cracking process. The primary fractionator tower itself is the largest single piece of equipment in the process, typically being about twenty-five
15 feet in diameter and over a hundred feet high for a medium size liquid cracker. The tower is large because it is in effect fractionating two minor components, tar and pyrolysis gasoline, in the presence of a large volume of low pressure gas and needing to reject significant excess heat in the feed. The pumparound loops are likewise large, handling over 3 million pounds per hour (lb/hr) (1,363,636 kg/hr) of circulating oil in the case of a medium size cracker.
20 Heat exchangers in the pumparound circuit are necessarily large because of high flow rates, close temperature approaches needed to recover the heat at useful levels, and allowances for fouling.

[0011] In addition, the primary fractionator has a number of other limitations and problems. In particular, heat transfer takes place twice, i.e., from the gas to the pumparound
25 liquid inside the tower and then from the pumparound liquid to the external cooling service. This effectively requires investment in two heat exchange systems, and imposes two temperature approaches (or differentials) on the removal of heat, thereby reducing thermal efficiency.

[0012] Moreover, despite the fractionation that takes place between the tar and gasoline
30 streams, both streams often need to be processed further. Sometimes the tar needs to be stripped to remove light components, whereas the gasoline may need to be refractionated to meet its end point specification.

[0013] Further, the primary fractionator tower and its pumparounds are prone to fouling. Coke accumulates in the bottom section of the tower and has to eventually be removed during plant turnarounds. The pumparound loops are also subject to fouling, requiring removal of coke from filters and periodic cleaning of fouled heat exchangers. Trays and packing in the tower are sometimes subject to fouling, potentially limiting plant production. The system also contains a significant inventory of flammable liquid hydrocarbons, which is not desirable from an inherent safety standpoint.

[0014] There is therefore a need for an enhanced method for cooling pyrolysis unit effluent and providing effective heat recovery for the same. Further, there is therefore a need for a simplified method for cooling pyrolysis unit effluent and removing the resulting heavy oils and tars which obviates the need for a primary fractionator tower and its ancillary equipment. The present techniques provide effective heat recovery methods and/or effluent cooling methods that overcome one or more of the deficiencies discussed above.

[0015] Related material may be found in the following: U.S. Patent Nos. 3,907,661; 3,923,921; 3,959,420; 4,121,908; 4,150,716; 4,233,137; 4,279,733; 4,279,734; 4,444,697; 4,446,003; 5,092,981; 5,107,921; 5,294,347; and 5,324,486. Additional material may be found in Intl. Patent App. Nos. 2000/56841 and 1993/12200; Great Britain Patent Nos. 1,390,382 and 1,309,309; EP Patent No. 205 205 and Japanese Patent No. 2001-40366. Further still, additional material may be found in the following publication: Lohr et al., "Steam-cracker Economy Keyed to Quenching," Oil & Gas Journal, Vol. 76 (No. 20), pp. 63-68, (1978).

SUMMARY OF THE INVENTION

[0016] In one embodiment, a method for cracking a hydrocarbon feed is described. The method comprises providing a hydrocarbon feed to a hydrocarbon pyrolysis unit to create cracked effluent; passing at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit through a first heat exchanger; separating the at least a portion of the cracked effluent from the first heat exchanger into a gaseous effluent and a liquid effluent, which may be in a vapor-liquid separator; passing at least a portion of the gaseous effluent from a separator through a second heat exchanger; passing the at least a portion of the effluent from the second heat exchanger to a fractionator; recovering heat from the at least a portion of the gaseous effluent in the second heat exchanger by passing a utility fluid through the second heat exchanger; and recovering heat from the at least a portion of the cracked effluent in the first heat exchanger by passing the utility fluid from the second heat exchanger through the

first heat exchanger. The process may further include using the heated utility fluid in an additional process, such as operating a turbine.

[0017] In another embodiment, a hydrocarbon cracking system is described. This system comprises a hydrocarbon pyrolysis unit, a separator, a first heat exchanger, a second heat exchanger and a fractionator. The hydrocarbon pyrolysis unit is configured to receive a hydrocarbon feed; and create a cracked effluent from the hydrocarbon feed. Further, the first heat exchanger is in fluid communication with the hydrocarbon pyrolysis unit and configured to cool at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit; and heat at least a portion of a utility fluid. The separator is in fluid communication with the first heat exchanger and configured to separate liquid effluent and gaseous effluent from the at least a portion of the cracked effluent. The second heat exchanger in fluid communication with the separator and configured to cool at least a portion of the gaseous effluent from the separator; heat the at least a portion of the utility fluid prior to the first heat exchanger receiving the at least a portion of the utility fluid. The fractionator may be in fluid communication with the second heat exchanger and configured to receive the at least a portion of the effluent from the second heat exchanger.

[0018] In yet another embodiment, a method for steam cracking a hydrocarbon feed is described. The method comprising providing a hydrocarbon feed to a hydrocarbon pyrolysis unit to create cracked effluent; separating at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit, wherein gaseous effluent is separated from liquid effluent, which may include steam cracked tar along with other bottoms; cooling at least a portion of the gaseous effluent from the separator in a first heat exchanger; passing at least a portion of the effluent from the first heat exchanger to one or more steam generators; passing at least a portion of the effluent from the one or more steam generators to a second heat exchanger; and passing the at least a portion of the effluent from the second heat exchanger to a fractionator.

[0019] In yet still another embodiment, an effluent handling system is described. This system comprises a hydrocarbon pyrolysis unit, a separator, a first heat exchanger, a second heat exchanger, one or more steam generators, and a fractionator. The hydrocarbon pyrolysis unit is configured to receive a hydrocarbon feed; and create a cracked effluent from the hydrocarbon feed. The separator is in fluid communication with the hydrocarbon pyrolysis unit and configured to separate liquid effluent, such as steam cracked tar along with other bottom products, and gaseous effluent from at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit. The first heat exchanger is in fluid communication with the

separator and configured to cool at least a portion of the gaseous effluent from the separator. The one or more steam generators are in fluid communication with the first heat exchanger and configured to receive the at least a portion of the effluent from the first heat exchanger. The second heat exchanger in fluid communication with the one or more generators and
5 configured to cool the at least a portion of the effluent from the one or more steam generators. The fractionator in fluid communication with the second heat exchanger and configured to receive the at least a portion of the effluent from the second heat exchanger.

BRIEF DESCRIPTION OF THE DRAWING

[0020] Figure 1 is a block flow diagram for recovering heat from the cooling of effluent
10 from a cracked hydrocarbon feed according to an exemplary embodiment of the present techniques.

[0021] Figure 2 is a block flow diagram for recovering heat from the cooling of effluent from a cracked hydrocarbon feed according to an alternative exemplary embodiment of the present techniques.

15 [0022] Figure 3 is a schematic flow diagram for recovering heat from the cooling of cracked hydrocarbon effluent according to another alternative exemplary embodiment of the present techniques.

[0023] Figure 4 is another schematic flow diagram for recovering heat from the cooling of cracked hydrocarbon effluent according to yet another alternative exemplary embodiment
20 of the present techniques.

[0024] The invention will be described in connection with its preferred embodiments of the present techniques. However, to the extent that the following detailed description is specific to a particular embodiment or a particular use of the invention, this is intended to be illustrative only, and is not to be construed as limiting the scope of the invention. On the
25 contrary, it is intended to cover all alternatives, modifications and equivalents that may be included within the spirit and scope of the invention, as defined by the appended claims.

DETAILED DESCRIPTION OF THE EMBODIMENTS

[0025] The present techniques provide an efficient arrangement to treat the effluent stream from a hydrocarbon pyrolysis unit, which may be referred to as a pyrolysis reactor or
30 furnace, so as to remove and recover heat therefrom and to separate desired hydrocarbons. For instance, the present techniques may separate C₅+ hydrocarbons, providing separate pyrolysis gasoline, gas oil, quench oil, and tar fractions, as well as the desired C₂-C₄ olefins in the effluent without utilizing primary fractionator pumparounds.

[0026] Typically, the effluent used in the one or more embodiments of the present techniques is produced by pyrolysis of a hydrocarbon feed boiling in a temperature range from about 40°C to about 704°C (about 104°F to about 1300°F), such as naphtha, tailed crudes or gas oil. For example, the effluent may be produced by pyrolysis of a hydrocarbon feed having a final boiling point above about 180°C (about 356°F), such as a feed heavier than naphtha. Such feeds include those boiling in the range from about 177°C to about 538°C (about 350°F to about 1000°F), from about 204°C to about 510°C (about 400°F to about 950°F). Typical heavier than naphtha feeds can include heavy condensates, gas oils, hydrocrackates, kerosene, condensates, tailed crude oils, and/or tailed crude oil fractions, e.g., tailed reduced crude oils. The temperature of the effluent at the outlet from the pyrolysis reactor is normally in the range of from about 760°C to about 930°C (about 1400°F to about 1706°F) and the present techniques provides a method of cooling the effluent to a desired temperature at a fractionator, which may include temperatures in the range of about 100°C to about 200°C (212°F to 392°F). At this temperature range, the desired C₂-C₄ olefins can be further cooled and compressed efficiently.

[0027] To effectively manage the heat removal and recovery, one or more embodiments of the present techniques involve an optimized arrangement or configuration of heat exchangers for removing and recovering heat from the effluent of a cracker. Typically, a single heat exchanger is limited by the temperature differential between temperature of the hot effluent stream and the temperature of the utility fluid stream. The use of two or more cooling stages, specifically in a specific sequence, overcomes this limitation by providing more countercurrent flow arrangement of hot and cold streams. As such, it is beneficial to configure the heat exchangers to provide two or more stages of heating for a utility fluid, such as boiler feed water, while also providing a two or more stages of cooling for the effluent from the furnace. The initial or first stage may involve higher temperatures, while the later or second stage involves lower temperatures. As a result, the two stages of heating and cooling (e.g., two or more heat exchangers in this configuration or sequence) are able to heat the utility fluid to a higher temperature than is possible with any single heat exchanger, and provide an efficient mechanism for recovering heat from the effluent.

[0028] Further, in other embodiments, these heat exchangers may be utilized with other equipment in specific configurations to further enhance the heat recovery process of the hydrocarbon cracking system. These configurations or arrangements may be utilized to provide a larger temperature differential for the heat exchangers in the different heating and

cooling stages, as will be discussed further below. For example, the heat exchangers may be arranged with one or more steam generators in certain embodiments to recover heat in a more efficient manner.

[0029] Moreover, in the various embodiments discussed further below, it should be appreciated that the utility fluid and the effluent from the furnace are separate streams that do not commingle. Each of these different streams may be maintained at different pressures based on the specific configuration and operation designs for the system. As an example, the heat exchangers may include transfer line exchangers, tube-in-tube exchangers or shell and tube exchangers.

[0030] Turning to Figure 1, a block flow diagram 100 of a process for recovering heat from the cooling of cracked hydrocarbon effluent according to an exemplary embodiment of the present techniques is disclosed. In this flow diagram 100, a hydrocarbon pyrolysis unit 102 (e.g., a cracker, reactor or furnace) is provided along with a first heat exchanger 104, a separator 106, a second heat exchanger 108, and a fractionator 110. These units 102-110, which are part of a hydrocarbon cracking system, are used together in a specific arrangement to recovery heat from the cracked hydrocarbon effluent as it is cooled. This process involves cracking a hydrocarbon feed and the cracked hydrocarbon effluent being cooled in various stages, while a utility fluid is heated to recover energy input into the hydrocarbon cracking process. In particular, the cooling of the cracked hydrocarbon effluent is described in blocks 122-130, while the heating of the utility fluid is described in blocks 134-138.

[0031] To begin, a hydrocarbon feed is provided at block 120. The hydrocarbon feed may include ethane, propane, butane, oils, naphtha, pentane, gas oil, condensate and crude, for example. At block 122, the hydrocarbon feed is cracked to produce an effluent. This cracking process may include gas cracking, steam cracking, or liquid cracking, as may be appreciated by those skilled in the art. As specific examples, U.S. Patent App. Nos. 2007/0007172 and 2007/0007174, which are hereby incorporated by reference, describe exemplary cracking processes. As noted above, the cracking of the hydrocarbon feed, which produces an effluent, may include temperatures from about 760°C to about 930°C (about 1400°F to about 1706°F) (with the temperature depending on the quality of the hydrocarbon feed). As part of the cracking process, the hydrocarbon feed is heated to cause thermal decomposition of the feed to produce lower molecular weight hydrocarbons, such as C₂-C₄ olefins.

[0032] To cool the effluent, various steps are performed with the hydrocarbon cracked effluent, as shown in blocks 124-130. In block 124, the effluent is cooled in a first heat exchanger 104. The heat of the effluent may be transferred to the utility fluid through the first heat exchanger 104, which may be a transfer line exchanger (TLE), for example. In this stage, the effluent may be cooled from a temperature at the inlet of the first heat exchanger 104, which may be the same or below the temperature of the furnace outlet to a first heat exchanger outlet temperature. As may be appreciated, the temperature range in the first stage may vary depending on the different hydrocarbon feeds. Again, as noted above, the first heat exchanger outlet temperature should be configured to prevent fouling, e.g., being above the tar dew point fouling limits 371°C to 537°C (700°F to 1000°F).

[0033] The first heat exchanger may optionally be coupled to a direct quench. The direct quench may cool the effluent from the first heat exchanger 104 to at least a temperature at which tar, formed by reaction among constituents of the effluent, condenses. The direct quench may include an oil quench, a water quench or other suitable process. As an example, U.S. Patent No. 3,923,921 describes a direct quench process.

[0034] Once the tar is condensed, the effluent may be separated into different streams, such as a liquid effluent and a gaseous effluent, as shown in block 126. The liquid effluent may include steam cracked tar along with other bottoms. The steam cracked tar, which may be pyrolysis fuel oil, is typically obtained as a bottoms product, which nominally has a boiling point of 550°F+ (288°C+) and higher (e.g., temperatures above 550°F or above 288°C). The separator 106 may include a vapor-liquid separator or tar knock-out drum, as is known in the art. The separator 106 may operate at a temperature that is same as or less than the first heat exchanger outlet temperature to a separator outlet temperature. The operating temperature for the separator 106 may be adjusted depending on the severity of operation of the first heat exchanger 104, hydrocarbons feed, or other factors. Accordingly, it should be appreciated that after the effluent passes from the first heat exchanger 104 and before it enters the separator 106, it may be further cooled by direct injection of a small amount of fluid or in a direct quenching process.

[0035] At block 128, the gaseous effluent from the separator 106 may be further cooled. Similar to the discussion above regarding the first heat exchanger, the heat of the gaseous effluent may be transferred to the utility fluid through a second heat exchanger 108, which may be a shell and tube heat exchanger, for example. In this stage, the gaseous effluent may be cooled from a temperature that is the same as or less than the separator outlet temperature

to a second heat exchanger outlet temperature. The second heat exchanger outlet temperature may be adjusted based on the desired temperature differential for this unit.

[0036] At block 130, the effluent from the second heat exchanger 108 may be provided to another unit for further processing of the effluent. As an example, the unit may be a fractionator 110, or more particularly, a mini-fractionator. The fractionator 110 may be a mini-primary fractionator, which is further described in U.S. Patent App. No. 2007007174.

[0037] As part of the heat recovery process, a utility fluid is heated in various stages by at least a portion of the hydrocarbon cracked effluent, as described in blocks 134-138. In block 132, a utility fluid is provided to the hydrocarbon cracking system. The utility fluid may include boiler feed water from a source, such as a deaerator, or may include any other suitable fluid. Then, the utility fluid is heated in block 134. In particular, the utility fluid may be heated in the second heat exchanger 108 via a transfer of heat from the gaseous effluent of the separator 106. In this heating stage, the gaseous effluent in the second heat exchanger 108 is at a temperature above the utility fluid, so that the second heat exchanger 108 may heat the utility fluid and the utility fluid may cool the gaseous effluent. Then, in block 136, the utility fluid may be heated in the first heat exchanger 104. In this heating stage, the effluent in the first heat exchanger 104 is at a temperature above the utility fluid from the second heat exchanger 108. With this temperature differential, the effluent in the first heat exchanger 104 may heat the utility fluid, while the utility fluid may cool the effluent. Then, following the heating in the first heat exchanger 104, the utility fluid may be further heated in the hydrocarbon pyrolysis unit 102, as shown in block 138. In particular, if the utility fluid is feed water, it may be heated in the hydrocarbon pyrolysis unit 102 to convert it into superheated, super-high pressure (SHP) steam. Then, at block 140, the heated utility fluid may be utilized in other processes. As an example, the heated utility fluid may be used to drive the large turbines in the other sections of the plant, such as the recovery section of the steam cracker, for example.

[0038] Beneficially, the use of two stages of heat exchangers in the configuration provides a mechanism to recover heat from the hydrocarbon cracking process and to heat the utility fluid more efficiently than possible with a single heat exchanger. That is, this configuration of two heating stages in this sequence provides a more efficient countercurrent flow arrangement for the different temperature streams.

[0039] As may be appreciated, the temperatures of the various units may vary depending on the quality of the hydrocarbon feed or other operation considerations. For typical

operation, the furnace outlet temperature of the hydrocarbon cracked effluent may include temperatures from about 760°C to about 930°C (1400°F to 1706°F). The first heat exchanger process inlet temperature may range from about 760°C to about 930°C (1400°F to 1706°F), or preferably about 816°C (1500°F), while the first heat exchanger process outlet temperatures
5 may range between about 343°C and about 650°C (about 650°F to about 1200°F), preferably 343°C to 538°C (650 °F to 1000°F). The separator may operate at temperatures from 190°C to about 350°C (about 374°F to about 662°F), or preferably from about 190°C to about 315 °C (about 374°F to about 599°F). The second heat exchanger inlet temperatures may be from about 190°C to about 350°C (about 374°F to about 662°F), while the second heat exchanger
10 outlet temperatures may be between about 170°C and about 300°C (about 338°F to about 572°F).

[0040] For the heat recovery process, the utility fluid may be provided at a pressure from about 2,172 kPa to about 17,340 kPa (300 psig to 2500 psig), from about 10,450 kpa to about 13,982 kPa (1,500 psig to about 2,000 psig), or about 10,450 kPa (1500 psig), and having a
15 temperature ranging from about 50°C to about 200°C (122°F to 392°F), preferably from about 100°C to about 150°C (212°F to 302°F). As may be appreciated, the heat recovered in the second heat exchanger may heat the utility fluid to a temperature ranging from 100°C to about 300°C (about 212°F to about 572°F). Further, the heat recovery in the first heat exchanger may heat the utility fluid in temperature range from 205°C to about 355°C (about
20 401°F to about 671°F). In the hydrocarbon pyrolysis unit 102, the utility fluid may be further heated and involve pressures ranging from about 2,172 kPa to about 17,340 kPa (300 psig to 2500 psig), from about 10,450 kPa to about 13,982 kPa (about 1,500 psig to about 2,000 psig), or about 10,450 kPa (about 1500 psig), and involve a temperature range from about 490°C to about 550°C (about 914°F to about 1022°F).

[0041] Further, as may be appreciated, another optional heating stage may be utilized in the process. For example, the utility fluid may be heated by the hydrocarbon pyrolysis unit 102 between the second heat exchanger 108 and the first heat exchanger 104. That is, the utility fluid heated in the second heat exchanger 108 may be passed through the hydrocarbon
25 pyrolysis unit 102 prior to being provided to the first heat exchanger 104. In this manner, additional heat may be recovered in the process.
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[0042] As an alternative embodiment, Figure 2 is a block flow diagram 200 of a process for recovering heat from the cooling of hydrocarbon cracked effluent according to an alternative exemplary embodiment of the present techniques. The flow diagram 200 includes

some similar equipment and operations similar to the blocks previously discussed in reference to the flow diagram 100 of Figure 1. Accordingly, for simplicity, the flow diagram 200 refers certain blocks previously described in the disclosure above with reference to Figure 1. However, in the flow diagram 200, an additional heating stage is utilized along with additional units to recover additional heat from the hydrocarbon cracking process. In particular, the flow diagram 200 includes one or more units 202 coupled to a third heat exchanger 204, which is coupled between the second heat exchanger 108 and the fractionator 110. The one or more units 202 and third heat exchanger 204 are arranged to provide an additional or third heating stage for the utility fluid and to further cool the effluent from the second heat exchanger 108 before the effluent is provided to the fractionator 110.

[0043] To begin, the blocks 120-128 operate similar to the discussion above. However, the effluent from block 128 may be passed to the one or more units 202 in block 212. The one or more units 202 may be used to recover additional heat from the effluent from the second heat exchanger 108 and may also be used to increase the temperature differential between the second heat exchanger 108 and the third heat exchanger 204 to further enhance the heat recover in the system. In particular, the one or more blocks 212 may include one or more steam generators, such as a medium pressure generator, a low pressure generator or a combination thereof to recover additional heat and increase the temperature differential between the second heat exchanger 108 and the third heat exchanger 204.

[0044] Regardless, heat may be recovered from the effluent passing through the one or more units 202, as shown in block 214. Similar to the discussion above regarding the first heat exchanger 104 and second heat exchanger 108, the heat of the effluent may be transferred to the utility fluid through a third heat exchanger 204, which may be a shell and tube heat exchanger, for example. In this stage, the effluent may be cooled from a temperature at the inlet of the third heat exchanger 204 to a third heat exchanger outlet temperature. This temperature range in the third heating stage 204 may again vary depending on the different hydrocarbon feeds and operational settings for the other units in the configuration.

[0045] Then, at block 130, the effluent from the third heat exchanger 204 may be provided to another unit for further processing of the effluent, which may be similar to the discussion above.

[0046] As part of the heat recovery in the proposed arrangement, the utility fluid is heated in various stages as described above in relation to blocks 134-138. However, in this flow

diagram 200, an additional or third heating stage is performed. To begin, the utility fluid is provided in block 132. Then, the utility fluid is heated in block 216. In particular, the utility fluid may be heated in the third heat exchanger 204 from the effluent. In this heating stage, the effluent in the third heat exchanger 204 is at a temperature above the utility fluid, so that the third heat exchanger 204 may heat the utility fluid and the utility fluid may cool the effluent. Then, the utility fluid may be further heated in other heat exchangers 104 and 108 along with the hydrocarbon pyrolysis unit 102 and used by other processes, as described above in blocks 134-140.

[0047] Similar to the discussion above for Figure 1, the temperatures of the various units may vary depending on the quality of the hydrocarbon feed or other operation considerations. For typical operation, the furnace outlet temperature, the first heat exchanger inlet and outlet temperatures, separator inlet and outlet temperatures and second heat exchanger inlet and outlet temperatures may be similar to the example above. However, the third heat exchanger inlet temperature may be from about 265°C to about 160°C (509°F to 320°F), while the third heat exchanger outlet temperatures may be between about 210°C and about 125°C (about 410°F to about 257°F).

[0048] Further, for the heat recovery process, the utility fluid may involve similar pressures and temperatures to those noted above in the discussion of Figure 1 for the first heat exchanger, second heat exchanger and pyrolysis unit. The utility fluid for the third heat exchanger may be operated at temperatures ranging from about 50°C at the inlet to about 250°C at the outlet (122°F to 482°F), preferably from about 110°C at the inlet to about 175°C at the outlet (230°F to 347°F), or more preferably at about 136°C at the inlet to about 157°C at the outlet.

[0049] As may be appreciated various additional embodiments may be utilized to further enhance the heat recovery for the hydrocarbon cracking system. As an example, the one or more units 202 may include a medium pressure steam generator coupled between the second heat exchanger 108 and the third heat exchanger 204. This generator may be used to raise general purpose steam for heating, reboiling, or the like and/or it may be used to generate dilution steam for the hydrocarbon cracking process or another process. That is, the dilution steam may be combined with the hydrocarbon feed prior to or within the hydrocarbon pyrolysis unit 102, which may be a steam cracking reactor, to improve yields, mitigate coking, and preserve the metallurgy of the tubes within the furnace or related equipment. The medium pressure generator may operate steam at a pressure of about 150 psig (1,034 kpa) at

the furnace inlet. Accordingly, the medium pressure generator conveniently generates steam at about this pressure, making it a good fit for dilution steam production. As another example, the one or more units may include a low pressure generator coupled between the second heat exchanger 108 and the third heat exchanger 204. This generator may be used to raise general purpose steam for heating, reboiling, or the other suitable processes. In yet another example, a medium pressure generator and a low pressure generator may be coupled between the second heat exchanger and the third heat exchanger.

[0050] In addition to the above embodiments, various units may be bypassed to provide additional functionality. For example, in the flow diagram 200, the flow of the utility fluid may include bypassing one of the upstream heat exchangers (such as the second heat exchanger 108 or third heat exchanger 204) prior to being provided to the first heat exchanger 104. That is, the second heat exchanger 108 may receive utility fluid from a source, such as a boiler or deaerator, and provide it to the first heat exchanger 104 (bypassing the third heat exchanger 204). Alternatively, the third heat exchanger 204 may receive utility fluid from a source, such as a boiler or deaerator, and provide it to the first heat exchanger 104 (bypassing the second heat exchanger 108). This process flow may be utilized to manage the heating of the utility fluid.

[0051] As yet another example, the heated utility fluid from an upstream heat exchanger in the utility fluid stream (such as the second heat exchanger 108 or third heat exchanger 204) may be passed through the hydrocarbon pyrolysis unit 102 (e.g., the convection section of the furnace) prior to being provided to the first heat exchanger 104. This may provide an additional heating stage for the utility fluid. That is, the utility fluid may be pre-heated before the first heat exchanger 104 transforms the utility fluid into a super-high pressure fluid, such as steam, for example. This configuration may efficiently utilize excess heat available in the convection section.

[0052] As yet still another example, the heated utility fluid from an upstream heat exchanger in the utility fluid stream (such as the second heat exchanger 108 or third heat exchanger 204) may be passed through the hydrocarbon pyrolysis unit 102 (e.g., the convection section of the furnace) without being passed to the first heat exchanger 104. This arrangement may bypass the first heat exchanger 108, but still provide two or more heating stages for the utility fluid. That is, the utility fluid may be pre-heated in the second heat exchanger 108 and/or third heat exchanger 204 before the passing it through the hydrocarbon pyrolysis unit 102 to generate the utility fluid into a super-high pressure fluid, such as steam.

[0053] Regardless of the specific embodiment of the system (e.g., arrangement or configuration of the units in the hydrocarbon cracking system), control mechanisms should be utilized to manage the heat removal. That is, the hydrocarbon cracking system should include heat control mechanisms to control the total amount of heat removed from the effluent and the heat provided to the utility fluid for various reasons. A first reason for this type of heat control mechanism is that the amount of heat removed from the effluent in the various heat exchangers and any other units may need to be managed as the operation of the system becomes fouled or changes over time. As a specific temperature range is desired at the certain units in the process, such as at a mini-fractionator, the heat removed from the effluent has to be managed. Otherwise, the configuration of units may not produce the desired quantity of reflux in the mini-fractionator.

[0054] One of the heat control mechanisms may include bypass valves and bypass lines that control the flow rate of utility fluid to certain heat exchangers and the temperature of the utility fluid at the different units. With this mechanism, one or more bypass valves and bypass lines may be implemented in an arrangement for bypassing or controlling the flow of utility fluid to one or more of the heat exchangers in one or more of the embodiments discussed above. That is, one or more of the heat exchangers may be bypassed to manage the heating of the utility fluid so that the temperature of the utility fluid entering the furnace may be controlled to optimize the furnace heat balance or may also be used to manage the cooling of the effluent from the furnace at the various heat exchangers.

[0055] Another heat control mechanism may include the use of one or more back pressure controllers on fluids provided to the one or more generators, such as the low pressure generator and/or medium pressure generator. As an example, if a low pressure steam generator is used in the system between the second heat exchanger and third heat exchanger, then increasing the pressure in this generator raises the boiling point on the water/steam side, which raises the outlet temperature on the process side. The amount of heat that can be removed in the second heat exchanger is limited by temperature approach between the process stream and the water or utility stream. The net result is that raising the pressure in the low pressure steam generator increases the temperature and heat content of the process effluent leaving the second heat exchanger. As another example, a back pressure controller may be used with a medium pressure generator. This back pressure controller may operate similar to the operation described with regard to the low pressure generator. The control on the medium pressure generator may also be used as a supplement control to the

back pressure controller on the low pressure generator, if the medium pressure generator is used with a low pressure generator arranged in a sequence. Because medium pressure steam is generally more valuable than low pressure steam, it may be preferable to raise back pressure on low pressure generation as a first means of controlling heat removal, and then to
5 raise back pressure on medium pressure steam generation if further reduction in heat removal is required.

[0056] The heat recovered in heat exchangers may be sizeable. Accordingly, certain configurations may include multiple heat exchangers arranged in parallel. Each of these heat exchangers may be coupled other units, such as low pressure generators and/or medium
10 pressure generators. For example, each of the heat exchanger banks may include a heat exchanger, medium pressure generator, low pressure generator and another heat exchanger coupled in series with each other. Further, in this configuration, the parallel heat exchanger banks may include isolation valves to allow each of the heat exchanger banks to be removed from service (e.g., taken offline) for cleaning or maintenance. Similarly, another heat control
15 mechanism may be to use the isolation valves to block flow of the effluent into one or more of the heat exchanger banks if the heat removal requirement is low. In this manner, the different banks may be added or removed to further manage the heat recovery.

[0057] Further, as it may be appreciated, the different heat control mechanisms may be used together in certain embodiments to provide additional flexibility in the control of the
20 heat transfers in the system. For example, the bypass valves and bypass lines may be used with a back pressure controller for a low pressure generator and a back pressure controller for a medium pressure generator. Similar, to the discussion above, the back pressure controller on the low pressure generator may be used first, then the back pressure controller on the medium pressure generator may be used next, and finally the bypass valves and bypass lines
25 may be used.

[0058] In this manner, the efficiency of the system is managed based on the value of the heated utility fluid. That is, the heat control mechanisms may be utilized to generate more SHP steam, which is typically more valuable than medium pressure steam, which is more valuable than low pressure steam. As an example, effluent heat may be used to generate SHP
30 steam, which may be utilized to drive the large turbines in the other sections of the plant, such as the recovery section of the steam cracker, for example. Further, despite the fact that lower pressure steam has less utility than the SHP steam because it does not deliver as much useful work, steam raised at lower pressures may also be useful for certain operations within

the system. For example, lower pressure steam may be used as furnace dilution steam or in reboiling towers. As such, a heat recovery process may increase the efficiency of the operation of the system if it recovers heat at several levels and uses it in an effective manner.

[0059] As a specific example of the arrangement of units in the hydrocarbon cracking system, Figure 3 provides a schematic flow diagram for recovering heat from hydrocarbon cracked effluent according to another alternative exemplary embodiment of the present techniques. In this schematic flow diagram 300, the hydrocarbon cracking system may include various units, such as a furnace 302, a first heat exchanger (e.g., a primary transfer line exchanger) 304, a vapor/liquid separator 306, a second heat exchanger (e.g., a first shell and tube heat exchanger) 308, a medium pressure generator 310, a low pressure generator 312, a third heat exchanger (e.g., a second shell and tube heat exchanger) 314, and a mini-fractionator 316. Each of these units may be arranged and in fluid communication with each other through the specific configuration and coupled together through various connections (e.g., tubes, couplings, valves, etc.), as may be appreciated by those skilled in the art. Further, the utility fluid and the effluent from the furnace may be separate streams that do not commingle from the furnace outlet through the third heat exchanger outlet.

[0060] The process begins with the hydrocarbon feed being provided to a furnace 302 via a line 303. The hydrocarbon feed may also be combined with a dilution fluid, such as steam, which is provided by a line 305. The hydrocarbon feed may be cracked in the furnace 302 to generate an effluent that is provided to the first heat exchanger 304, and then the effluent is passed to the vapor-liquid separator 306. The vapor-liquid separator 306 separates gaseous effluent and liquid effluent into two different streams. In particular, the vapor-liquid separator 306 may be utilized to separate liquid effluent (e.g., bottom products, such as steam cracked tar) from the gaseous effluent after it is initially cooled in the first heat exchanger 304. In some embodiments, after leaving the first heat exchanger 304, the cooled effluent stream may be quenched with a liquid quench oil or liquid water, introduced via a quench line 319 between the outlet of the first heat exchanger 304 and the inlet of the vapor-liquid separator 306 to provide supplemental cooling. The liquid effluent from the vapor-liquid separator 306 may be removed via line 322 and may be further in other units (not shown).

[0061] The gaseous effluent is provided from the vapor-liquid separator 306 to a bank of units coupled in series, which include the second heat exchanger 308, the medium pressure generator 310, the low pressure generator 312, and the third heat exchanger 314. This bank of units may be used to cool the effluent prior to it passing to the mini-fractionator 316. In

this bank of units, the medium pressure generator 310, followed by a low pressure generator 312 may be used to generate steam for other units, such as the mini-fractionator 316 or other equipment in this system or other systems. The proposed configuration may be particularly advantageous with the mini-fractionator 316 because it can utilize the higher temperatures available in the generators 310 and 312 for additional utility fluid preheating. The mini-fractionator 316 may be coupled to other downstream units to further processing the effluent stream and to separate out the desired olefins.

[0062] As noted above, the use of the different heat exchangers 304, 308, and 314, along with the furnace 302, provides various heating stages for the utility fluid provided via line 320. The utility fluid may be provided from a boiler or deaerator (not shown) and may include boiler feed water as the utility fluid within the system. In this configuration, the utility fluid may be heated initially at the third heat exchanger 314, then at the second heat exchanger 308 and then at the first heat exchanger 304 or preheated at the furnace 302 before the utility fluid is finally heated in the furnace 302 and provided at outlet 324 for other equipment, such as turbines, other units, or as an input stream into different processes.

[0063] To control the heat transfer within the system, the heat control mechanisms may include the bypass valve 323 coupled between the input line 320 for the utility fluid, the third heat exchanger 314 and the outlet of the second heat exchanger 308 via bypass lines, tubes or the like. The bypass valve 323 may be configured to restrict the flow of utility fluid to the units or may be configured to provide flow to one of the third heat exchanger 314 and the outlet of the second heat exchanger 308. As an example, in a first position, the bypass valve 323 may be configured to restrict at least a portion of the utility fluid from passing to the third heat exchanger 314 from the boiler or deaerator and direct at least a portion of the utility fluid to the first heat exchanger 304 via a bypass line. Similarly, in a second position, the bypass valve 323 may direct at least a portion of the utility fluid to pass to the third heat exchanger 314 from the source and restrict at least a portion of the utility fluid from passing through the bypass line to the first heat exchanger 304. As may be appreciated, the restriction of flow may block flow or only a portion of the flow, depending on the valves and lines utilized.

[0064] In addition, other heat control mechanisms include the medium pressure valve 326 and the low pressure valve 328. As discussed above, these valves 326 and 328 may be used to control the temperature of the gaseous effluent passing through medium pressure generator 310 and the low pressure generator 312, respectively. The medium pressure valve 326 is coupled to the medium pressure generator 310 between an inlet 330 of boiler feed fluid and

outlet of medium pressure steam 332. The low pressure valve 328 is coupled to the low pressure generator 312 between an inlet 334 of boiler feed fluid and outlet of low pressure steam 336. In particular, the medium pressure valve 326 may be used to increase the pressure within the medium pressure generator 310 to raise the boiling point of the boiler feed water, which raises the outlet temperature for the medium pressure generator 310. Similarly, the low pressure valve 328 may be used to increase the pressure within the low pressure generator 312 to raise the boiling point of the boiler feed water, which raises the outlet temperature for the low pressure generator 312.

[0065] The specific temperatures utilized in the operation of the system may vary depending on the specific configuration. For example, the outlet of the furnace 302 may be operated to be about 760°C (about 1400°F), which may be the same temperature at the inlet of the first heat exchanger 304. The first heat exchanger 304 along with direct quench oil or water may cool the effluent to a temperature of about 300°C (about 572°F), which is the temperature utilized for the separation. The gaseous effluent from the separator 306 may be provided to the second heat exchanger at a temperature of about 299°C (about 570°F), which is cooled to a temperature of about 260°C (about 500°F). The effluent may then pass through the generators 310 and 312 and be provided to a third heat exchanger 314 at a temperature of about 166°C (about 330°F). The third heat exchanger 314 may cool the effluent to a temperature of about 154°C (about 310°F).

[0066] The utility fluid may utilize the various stages to heat the utility fluid, as discussed above. In particular, for this example, the utility fluid may be provided to the third heat exchanger at a temperature about 125°C (about 257°F). The third heat exchanger may use the effluent to heat the utility fluid to a temperature of about 149°C (about 300°F). Then, the utility fluid may be provided to the second heat exchanger 308, which may further heat the utility fluid to a temperature of about 268°C (about 515°F). The utility fluid may then be heated in the first heat exchanger 304 to a temperature of about 316°C (about 600°F). Then, the utility fluid may be further heated to a temperature of about 538°C (about 1000°F) in the convection section of furnace 302.

[0067] Figure 4 is another schematic flow diagram for recovering heat from the cooling of cracked hydrocarbon effluent according to another alternative exemplary embodiment of the present techniques. In this figure, the hydrocarbon feed is passed through two separators 402 and 404 that are coupled to the hydrocarbon pyrolysis unit 302. These separators 402 and 404 are used as high temperature knock-out drums, which remove resid and asphaltene

molecules from a hydrocarbon feed before entering the radiant section of the hydrocarbon pyrolysis unit 302. Beneficially, the use of the separators 402 and 404 may utilize the heated utility fluid in this specific configuration to further enhance the efficiency of the system and further optimize olefin recovery.

5 [0068] Typically, steam cracking furnaces, which employ a separator, such as an out-board knock-out drum integrated between the convection and radiant sections, operate only up to about 454°C (about 850°F). These typical configurations are noted in other patents, such as U.S. Patent Nos. 7,097,758; 7,138,047; 7,193,123; 7,235,705 and 7,247,765. Operating above 454.4°C (about 850°F) may result in excess fouling downstream of the separator. This fouling may be a result of a two-reaction mechanism. First, the vapor in the separator above the tangential inlet cracks via endothermic reactions and the separator loses some heat. These effects combine to reduce the vapor temperature by about -7°C to about -1°C. Because the vapor is at its dew point when it enters the separator, any cooling condenses the heaviest molecules. Vapor/liquid equilibrium calculations predict that the resulting heavy liquid (entrained in the vapor) is rich in 760°C+ (1400°F+) molecules, which are the coke precursors. Second, the heavy liquid undergoes condensation reactions that produce ever larger multi-ring aromatics, which eventually result in the multi-ring aromatics becoming coke.

10 [0069] As a result of this two-reaction mechanism, fouling typically occurs in two locations, which are the piping downstream of the separator and in the radiant inlet manifolds (RIMs). The fouling in the RIM may result from some of the fouling precursors remaining in the vapor phase or vaporizing in the lower convection section. In the convection section, cracking and some condensation reactions occur, but because the process temperature is rising, no liquid is formed. These reactions may subsequently undergo rapid condensation reactions (condensation reactions likely follow 2nd order kinetics). However, in the crossover piping and RIM heat losses and continued endothermic cracking reactions cool the process by about 10°C to about 38°C (about 50°F to about 100°F). Here also the condensation reactions are very rapid even in the vapor phase. Once the temperature drops below the dew point of these newly condensed multi-ring aromatics, they become liquid and coke rapidly, which deposit in the relatively low velocity in the RIM.

25 [0070] Accordingly, reducing the residence time in the separator may reduce fouling to a manageable level. This aspect may reduce fouling in the piping downstream of the separator. However, this may not reduce fouling in the crossover piping and/or inlet manifold because

the 760°C+ (1400°F+) vapor molecules entering the separator are still present in the lower convection section, crossover piping and RIM where cracking and condensation may still occur. In fact, reducing the residence time in the drum could increase the fouling in the RIM.

[0071] Naphtha, kerosene and hydrocrackate cracking in the hydrocarbon pyrolysis unit, which may be a steam cracking furnace, with the separator indicates that 760°C+ (1400°F+) molecules may cause the fouling, not just the cracking and condensation reactions. The hydrocarbon feed typically enter separators at 490°C to 502°C (915°F to 935°F), about 21°C to 32°C (about 70°F to 90°F) higher than atmospheric resids. The feed experiences the same separator residence time and marginally higher temperatures in the lower convection section, crossover piping and RIM than the atmospheric residues, which has negligible fouling. Accordingly, as no large (760°C+ (1400°F+)) molecules are present, the condensation reactions do not produce molecules large enough to become a liquid as the process temperature drops in the crossover piping and RIM. Thus, removal of the 760°C+ (1400°F+) molecules in the vapor may be beneficial, not just reducing separator residence time.

[0072] In this embodiment, the SHP generated by passing the utility fluid through the hydrocarbon pyrolysis unit (e.g., furnace 302) may be used along with the separators 402 and 404 to reduce fouling in the system. In this configuration, the cut from the separator 402 may be deep to vaporize significant coke producing molecules (e.g., 760°C+ (1400°F+)). A small amount of clean steam cracking feed may also be added to the overhead vapor in a venturi mixer 406. This clean steam cracking feed condenses the coke producing molecules. The liquid produced in the venturi mixer 406 is removed by the separator 404. The vapor is conveyed from the separator 404 to the lower convection section, then to the radiant section. With the vapor 760°C+ (1400°F+) removed, fouling is negligible allowing the separators 402 and 404 to operate at high temperature of 482°C to 510°C (900°F to 950°F).

[0073] Clearly, the benefit of reducing fouling is the ability to operate the separators at higher temperatures. The higher operational temperatures increase the fraction of the resid or crude that vaporizes, and subsequently cracks into valuable produces. But the separator bottoms become more viscous requiring more low viscosity fluxant per unit mass to meet fuel oil viscosity specifications. However, the gross fluxed bottoms still significantly decreases as nominal cut point temperature increase. For example, increasing the nominal cut point temperature of Arab heavy crude from 538°C to 593°C (1000°F to 1100°F) (about the same as increasing the drum temperature from 449°C to 504°C (840°F to 940°F)) reduces the fluxed bottoms from 47 pounds (lbs) (21 kilograms (kg)) / 100 lbs (46 kg) of crude to 40 lbs

(18 kg) / 100 lbs (46 kg) of crude. That is, an additional 7 lbs (3 kg) / 100 lbs (46 kg) of crude are cracked to valuable products.

[0074] To operate, hydrocarbon feed, such as crude or resid, is preheated in the upper convection section, and then the hydrocarbon feed is mixed with superheated dilution steam.

5 The superheated dilution steam may be provided from outlet 324, which is discussed above. The mixture is further heated in the convection section, which may include heating to about 510°C (about 950°F), as an example. Because the piping is continuously washed by the large fraction of liquid remaining, no coke is formed. The two-phase process stream is conveyed to the separators 402 and 404 by piping, which includes various bends and joints. The bends
10 tend to convert mist flow to stratified or annular flow. The separators 402 and 404 may dramatically reduce the size of the piping to the separator 402 and the size of both separators 402 and 404. That is, because the separators 402 and 404 are coupled in fluid communication in series, each separator does not have to be as efficient at separating the vapor from the liquid as a single separator. For example, if a single separator only entrains 1% of the liquid,
15 two separators in series can each entrain 10% of the liquid resulting in the same aggregate 1% liquid entrainment. As a result, the dual separator tangential inlets inner diameter (ID) may be about 50% smaller than for single separator and the separators ID may be about one-third smaller than the single separator. Thus, even though there are two separators, the total separator metal required is about 50% less than the single separator.

20 **[0075]** The vapor and some liquid exiting the separator 402 is conveyed to a venturi mixer 406 where the vapor is partially quench by diesel oil, hydrocrackate, wax, condensate or even quench oil. The quench turbulently mixes and vaporizes, while condensing the heaviest molecules in the vapor phase. The venturi mixer 406 does not have any stagnant points where the liquid may coke. This is an advantage over trays or packing where stagnant
25 liquid can become coke. The amount of quench is small to reduce the 760°C+ (1400°F+) molecules in the vapor by nearly an order of magnitude. This aspect is indicated from Table 1, which is below.

Table 1: The effect of quench on 1400°F in drum vapor				
Drum vapor, klbs/hr	110	110	110	110
slip stream to partial condenser, Klbs/hr	10	10	10	10
hydrocarbon condensed, Klbs/hr	0	1	1.5	2
duty, MBtu/hr	0	0.42	0.55	0.68
ppm (wt) 1400°F in overhead vapor	10	5	2.5	1.3

[0076] The far right column of this table indicates that removing 0.68 million British thermal units per hour (MBtu/hr) (199 kilowatt (kW) reduces 760°C+ (1400°F+) molecules in the vapor by a factor of six. Energy balance calculations predict that roughly 1,300 (lb/hr) (591kg/hr) of quench removes the 0.68 MBtu/hr (199 kW). The piping downstream of the venturi mixer 406 has bends to convert the mist flow back into stratified or annular flow before entering the separator 404. The process stream enters the separator 404 via one or two tangential inlets. Because splitting the flow may cause flow imbalances and stagnant spots, one tangential inlet may be preferred. A single entry separator 404 and the piping to it may be marginally larger than the two entry separator 402.

[0077] The separator 404 removes roughly 90% of the remaining liquid attaining the 99% aggregate vapor/liquid separation efficiency. In a preferred embodiment, once stratified or annular flow is established in the piping to each of the separators 402 and 404, the process mixture can initially enter reducers that increase the IDs by 10% to 20%, and then enter piping with these larger IDs. This reduction of the process velocity by 17% to 31% upstream of the separators 402 and 404 may increase the vapor/liquid separation efficiency from 99% to 99.5% to 99.7%. Similar to the separator 402, the separator 404 may have a boot where the bottoms are quenched to roughly 343°C (650°F), to hinder cracking and coking reactions. Optionally, the liquid then passes through a dual-return bend trap before mixing with the process stream upstream of the separator 402. This dual return bend provides the head necessary to effect flow into the piping upstream of the separator 402. The overhead vapor from the separator 404, which has significantly less 760°C+ (1400°F+) molecules, is further preheated in the low convection section and passes through the crossover piping and RIM with minimal fouling. The hydrocarbon feed then cracks in the radiant section and is further processed, as discussed above.

[0078] Further embodiments may also be utilized to further enhance the operation of this configuration. For example, steam stripping may be provided at inlet 410. The steam stripping of bottoms of the separator 402 may be utilized to vaporize light material trapped in the heavy resid bottoms producing additional hydrocarbon feed. Further, superheated steam, which may be provided from outlet 324, may be added at inlet 408 into the vapor space above the inlet to the separator 404. This embodiment may prevent any condensation from occurring upstream of the lower convection section. Moreover, in another embodiment, the radiant section may be configured to be marginally taller allowing a lower crossover

temperature (XOT) without excessive radiant heat flux and coking. A lower XOT may significantly increase the gasoil cracking selectivity and ethylene yield.

[0079] In another embodiment, the present techniques relate to:

1. A method for cracking a hydrocarbon feed, the method comprising:

- 5 providing a hydrocarbon feed to a hydrocarbon pyrolysis unit to create a cracked effluent;
passing at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit through
a first heat exchanger;
separating the at least a portion of the cracked effluent from the first heat exchanger into a
gaseous effluent and a liquid effluent;
10 passing at least a portion of the gaseous effluent through a second heat exchanger;
passing the at least a portion of the effluent from the second heat exchanger to a fractionator;
recovering heat from the at least a portion of the effluent in the second heat exchanger by
passing a utility fluid through the second heat exchanger; and
recovering heat from the at least a portion of the cracked effluent in the first heat exchanger
15 by passing the utility fluid from the second heat exchanger through the first heat
exchanger.
2. The method of paragraph 1, comprising passing the utility fluid from the first heat
exchanger through the hydrocarbon pyrolysis unit to heat the utility fluid.
3. The method of paragraphs 1 and 2, comprising passing the at least a portion of the effluent
20 from the second heat exchanger to one or more steam generators before passing the at least a
portion of the effluent from the second heat exchanger to the fractionator.
4. The method of paragraph 3, comprising passing the at least a portion of the effluent from
the one or more steam generators through a third heat exchanger before passing the at least a
portion of the effluent to the fractionator.
- 25 5. The method of paragraph 4, comprising recovering heat from the at least a portion of the
effluent from the one or more steam generators in the third heat exchanger by passing the
utility fluid through the third heat exchanger before passing the at least a portion of the
effluent from the one or more generators to the fractionator.
6. The method of any of the preceding paragraphs, comprising adjusting valves on the one or
30 more steam generators to control the heat recovery from the at least a portion of the effluent
passing through the one or more steam generators.
7. The method of any of the preceding paragraphs, wherein the utility fluid is heated in a
deaerator prior to passing through the first heat exchanger.

8. The method of any of the preceding paragraphs, comprising driving a turbine with the heated utility fluid from the first heat exchanger.

9. The method of any of the preceding paragraphs, wherein the at least a portion of the cracked effluent from the first heat exchanger is cooled in a direct quench to at least a temperature at which tar, formed by reaction among constituents of the effluent, condenses, prior to the separating of the gaseous effluent and the liquid effluent.

10. A hydrocarbon cracking system comprising:

a hydrocarbon pyrolysis unit configured to:

receive a hydrocarbon feed; and

create a cracked effluent from the hydrocarbon feed;

a first heat exchanger in fluid communication with the hydrocarbon pyrolysis unit and configured to:

cool at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit; and

heat at least a portion of a utility fluid; and

a separator in fluid communication with the first heat exchanger and configured to separate the at least a portion of the cracked effluent into liquid effluent and gaseous effluent;

a second heat exchanger in fluid communication with the separator and configured to:

cool at least a portion of the gaseous effluent from the separator;

heat the utility fluid prior to the first heat exchanger receiving the at least a portion of

the utility fluid; and

a fractionator in fluid communication with the second heat exchanger and configured to receive the at least a portion of the effluent from the second heat exchanger.

11. The system of paragraph 10, wherein the hydrocarbon pyrolysis unit is configured to: heat the at least a portion of the utility fluid from the first heat exchanger, wherein the at least a portion of the utility fluid and the at least a portion of the cracked effluent are maintained in separate non-commingling streams in the hydrocarbon pyrolysis unit.

12. The system of paragraph 10, comprising one or more steam generators in fluid communication between the second heat exchanger and the fractionator and configured to pass the at least a portion of the effluent from the second heat exchanger to the fractionator.

13. The system of paragraph 12, comprising a third heat exchanger in fluid communication between the one or more steam generators and the fractionator and configured to cool the at least a portion of the effluent before passing the at least a portion of the effluent to the fractionator.

14. The system of paragraph 13, wherein the third heat exchanger is in fluid communication with the second heat exchanger and configured to recover heat from the at least a portion of the effluent by passing the utility fluid through the third heat exchanger prior to the second heat exchanger receiving the utility fluid; and wherein the utility fluid and the at least a portion of the effluent are maintained in separate non-commingling streams in the second heat exchanger.

15. The system of paragraph 14, comprising a bypass valve coupled between a source of the utility fluid, the first heat exchanger and the third heat exchanger and configured to:

in a first position, restrict a first portion of the utility fluid from passing to the third heat exchanger from the source and direct a remaining first portion of the utility fluid to the first heat exchanger via a bypass line; and

in a second position, direct a second portion of the utility fluid to pass to the third heat exchanger from the source and restrict a second remaining portion of the utility fluid from passing through the bypass line to the first heat exchanger.

16. The system of any one of the preceding paragraphs 12-15, comprising a control valve coupled to at least one of the one or more steam generators and configured to control the cooling of the at least a portion of the effluent passing through the one or more steam generators.

17. The system of any of the preceding paragraphs 10-16, comprising a deaerator in fluid communication with the second heat exchanger and configured to preheat the utility fluid prior to passing the utility fluid to the second heat exchanger.

18. The system of any of the preceding paragraphs 10-17, wherein the first heat exchanger is configured to cool the at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit and provide the at least a portion of the cracked effluent to a direct quench that cools the at least a portion of the cracked effluent to a temperature at which tar, formed by reaction among constituents of the at least a portion of the cracked effluent, condenses.

19. The system of any of the preceding paragraphs 10-18, comprising a drive turbine configured to receive the at least a portion of the heated utility fluid from the hydrocarbon pyrolysis unit.

20. The system of any of the preceding paragraphs 10-19, wherein the utility fluid and the at least a portion of the effluent are maintained in separate non-commingling streams.

21. A method for steam cracking a hydrocarbon feed, the method comprising:
providing a hydrocarbon feed to a hydrocarbon pyrolysis unit to create a cracked effluent;

separating at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit,
where gaseous effluent is separated from liquid effluent including steam cracked tar;
cooling at least a portion of the gaseous effluent in a first heat exchanger;
passing the at least a portion of the effluent from the first heat exchanger to one or more
5 steam generators;
cooling the at least a portion of the effluent from the one or more steam generators in a
second heat exchanger; and

passing the at least a portion of the effluent from the second heat exchanger to a fractionator.

22. The method of paragraph 21, comprising passing the at least a portion of the cracked
10 effluent from the hydrocarbon pyrolysis unit through a third heat exchanger before passing
the at least a portion of the cracked effluent to a separator.

23. The method of any of the preceding paragraphs 21 and 22, comprising heating a utility
fluid by passing the utility fluid through the hydrocarbon pyrolysis unit and using the heated
utility fluid in an additional process.

15 24. The method of paragraph 23, recovering heat from the at least a portion of the effluent in
the first heat exchanger by passing the utility fluid by through the first heat exchanger prior to
passing the utility fluid through hydrocarbon pyrolysis unit.

25. The method of paragraph 24, comprising recovering heat from the at least a portion of
the effluent in the second heat exchanger by passing the utility fluid through the second heat
20 exchanger prior to passing the utility fluid through the first heat exchanger.

26. The method of paragraph 25, comprising adjusting valves on the one or more steam
generators to control the heat recovery from the at least a portion of the effluent passing
through the one or more steam generators.

27. The method of paragraph 24, wherein the utility fluid is heated in a deaerator prior to
25 passing through the first heat exchanger.

28. The method of paragraph 22, wherein the at least a portion of the cracked effluent is
cooled in the third heat exchanger to at least a temperature above the temperature at which tar,
formed by reaction among constituents of the gaseous effluent, condenses.

29. The method of any of the preceding paragraphs 23-28, wherein using the heated utility
30 fluid in the additional process comprises driving a turbine with the heated utility fluid.

30. A gaseous effluent handling system comprising:

a hydrocarbon pyrolysis unit configured to:

receive a hydrocarbon feed; and

create a cracked effluent from the hydrocarbon feed; and
a separator in fluid communication with the hydrocarbon pyrolysis unit and configured to
separate liquid effluent having steam cracked tar and gaseous effluent from at least a
portion of the cracked effluent from the hydrocarbon pyrolysis unit; and
5 a first heat exchanger in fluid communication with the separator and configured to cool at
least a portion of the gaseous effluent from the separator;
one or more steam generators in fluid communication with the first heat exchanger and
configured to receive the at least a portion of the effluent from the first heat exchanger;
a second heat exchanger in fluid communication with the one or more generators and
10 configured to cool the at least a portion of the effluent from the one or more steam
generators; and
a fractionator in fluid communication with the second heat exchanger and configured to
receive the at least a portion of the effluent from the second heat exchanger.

31. The system of paragraph 30, comprising a third heat exchanger in fluid communication
15 between the separator and the hydrocarbon pyrolysis unit and configured to cool the at least a
portion of the cracked effluent passing through the third heat exchanger to the separator.

32. The system of paragraph 30, wherein the hydrocarbon pyrolysis unit is configured to heat
a utility fluid by passing the utility fluid through the hydrocarbon pyrolysis unit.

33. The system of paragraph 32, wherein the first heat exchanger is configured to recover
20 heat from the at least a portion of the effluent in the first heat exchanger by passing the utility
fluid by through the first heat exchanger prior to passing the utility fluid through hydrocarbon
pyrolysis unit.

34. The system of paragraph 33, wherein the second heat exchanger is configured to recover
heat by passing the utility fluid through the second heat exchanger prior to passing the utility
25 fluid through the first heat exchanger.

35. The system of paragraph 34, comprising one or more valves coupled to the one or more
steam generators and configured to adjust the heat recovery from the at least a portion of the
effluent passing through the one or more steam generators.

36. The system of any one of paragraphs 30-34, comprising

30 a first separator and a second separator in fluid communication with a convection
section and a radiant section of the of hydrocarbon pyrolysis unit;
the first separator configured to receive hydrocarbon feed from the convection section;
and separate the hydrocarbon feed into a first vapor feed and a first liquid feed;

the second separator configured to receive the first vapor feed; separate the first vapor feed into a second vapor feed and a second liquid feed; pass the second liquid feed to the first separator; and pass the second vapor feed to the radiant section of the hydrocarbon pyrolysis unit to create a cracked effluent.

- 5 **[0080]** The foregoing application is directed to particular embodiments of the present techniques for the purpose of illustrating it. It will be apparent, however, to one skilled in the art, that many modifications and variations to the embodiments described herein are possible. Further, some embodiments may be preferably performed at least partly on a computer, i.e., computer-implemented embodiments of the present inventive method are preferred, but not
10 essential. All such modifications and variations are intended to be within the scope of the present invention, as defined in the appended claims.

CLAIMS:**We claim:**

1. A method for cracking a hydrocarbon feed, the method comprising:
providing a hydrocarbon feed to a hydrocarbon pyrolysis unit to create cracked effluent;
5 passing at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit through
 a first heat exchanger;
separating the at least a portion of the cracked effluent from the first heat exchanger into a
 gaseous effluent and a liquid effluent;
passing at least a portion of the gaseous effluent through a second heat exchanger;
10 passing at least a portion of the effluent from the second heat exchanger to a fractionator;
recovering heat from the at least a portion of the effluent in the second heat exchanger by
 passing a utility fluid through the second heat exchanger; and
recovering heat from the at least a portion of the cracked effluent in the first heat exchanger
 by passing the utility fluid from the second heat exchanger through the first heat
15 exchanger.
2. The method of claim 1, comprising passing the utility fluid from the first heat exchanger
through the hydrocarbon pyrolysis unit to heat the utility fluid.
3. The method of claim 1, comprising passing the at least a portion of the effluent from the
second heat exchanger to one or more steam generators before passing the at least a portion
20 of the effluent from the second heat exchanger to the fractionator.
4. The method of claim 3, comprising passing the at least a portion of the effluent from the
one or more steam generators through a third heat exchanger before passing the at least a
portion of the effluent from the one or more steam generators to the fractionator.
5. The method of claim 4, comprising recovering heat from the at least a portion of the
25 effluent from the one or more steam generators in the third heat exchanger by passing the
utility fluid through the third heat exchanger before passing the at least a portion of the
effluent from the one or more steam generators to the fractionator.
6. The method of claim 3, comprising adjusting valves on the one or more steam generators
to control the heat recovery from the at least a portion of the effluent passing through the one
30 or more steam generators.
7. The method of claim 1, wherein the utility fluid is heated in a deaerator prior to passing
through the first heat exchanger.

8. The method of claim 1, comprising driving a turbine with the heated utility fluid from the first heat exchanger.

9. The method of claim 1, wherein the at least a portion of the cracked effluent from the first heat exchanger is cooled in a direct quench to at least a temperature at which tar, formed by
5 reaction among constituents of the effluent, condenses, prior to the separating the gaseous effluent and the liquid effluent.

10. A hydrocarbon cracking system comprising:

a hydrocarbon pyrolysis unit configured to:

receive a hydrocarbon feed; and

10 create a cracked effluent from the hydrocarbon feed;

a first heat exchanger in fluid communication with the hydrocarbon pyrolysis unit and configured to:

cool at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit; and

heat at least a portion of a utility fluid; and

15 a separator in fluid communication with the first heat exchanger and configured to separate the at least a portion of the cracked effluent into liquid effluent and gaseous effluent;

a second heat exchanger in fluid communication with the separator and configured to:

cool at least a portion of the effluent from the separator;

20 heat the utility fluid prior to the first heat exchanger receiving the at least a portion of the utility fluid; and

a fractionator in fluid communication with the second heat exchanger and configured to receive the at least a portion of the effluent from the second heat exchanger.

11. The system of claim 10, wherein the hydrocarbon pyrolysis unit is configured to heat the at least a portion of a utility fluid from the first heat exchanger, wherein the at least a portion
25 of a utility fluid and the at least a portion of the cracked effluent are maintained in separate non-commingling streams in the hydrocarbon pyrolysis unit.

12. The system of claim 10, comprising one or more steam generators in fluid communication between the second heat exchanger and the fractionator and configured to pass the at least a portion of the effluent from the second heat exchanger to the fractionator.

30 13. The system of claim 12, comprising a third heat exchanger in fluid communication between the one or more steam generators and the fractionator and configured to cool the at least a portion of the effluent before passing the at least a portion of the effluent to the fractionator.

14. The system of claim 13, wherein the third heat exchanger is in fluid communication with the second heat exchanger and configured to recover heat from the at least a portion of the effluent by passing the utility fluid through the third heat exchanger prior to the second heat exchanger receiving the utility fluid; and wherein the utility fluid and the at least a portion of the effluent are maintained in separate non-commingling streams in the second heat exchanger.

15. The system of claim 14, comprising a bypass valve coupled between a source of the utility fluid, the first heat exchanger and the third heat exchanger and configured to:

in a first position, restrict a first portion of the utility fluid from passing to the third heat exchanger from the source and direct a first remaining portion of the utility fluid to the first heat exchanger via a bypass line; and

in a second position, direct a second portion of the utility fluid to pass to the third heat exchanger from the source and restrict a second remaining portion of the utility fluid from passing through the bypass line to the first heat exchanger.

16. The system of claim 12, comprising a control valve coupled to at least one of the one or more steam generators and configured to control the cooling of the at least a portion of the effluent passing through the one or more steam generators.

17. The system of claim 10, comprising a deaerator in fluid communication with the second heat exchanger and configured to preheat the utility fluid prior to passing the utility fluid to the second heat exchanger.

18. The system of claim 10, wherein the first heat exchanger is configured to cool the at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit and provide the at least a portion of the cracked effluent to a direct quench that cools the at least a portion of the cracked effluent to a temperature at which tar, formed by reaction among constituents of the at least a portion of the cracked effluent, condenses.

19. The system of claim 10, comprising a drive turbine configured to receive the at least a portion of the heated utility fluid from the hydrocarbon pyrolysis unit.

20. The system of claim 10, wherein the utility fluid and the at least a portion of the effluent are maintained in separate non-commingling streams.

21. A method for steam cracking a hydrocarbon feed, the method comprising:
providing a hydrocarbon feed to a hydrocarbon pyrolysis unit to create a cracked effluent;
separating at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit,
wherein gaseous effluent is separated from liquid effluent including steam cracked tar;

cooling at least a portion of the gaseous effluent in a first heat exchanger;
passing at least a portion of the effluent from the first heat exchanger to one or more steam
generators;

cooling the at least a portion of the effluent from the one or more steam generators in a
5 second heat exchanger; and

passing the at least a portion of the effluent from the second heat exchanger to a fractionator.

22. The method of claim 21, comprising passing the at least a portion of the cracked effluent
from the hydrocarbon pyrolysis unit through a third heat exchanger before passing the at least
a portion of the cracked effluent to the separator.

10 23. The method of claim 22, comprising heating a utility fluid by passing the utility fluid
through the hydrocarbon pyrolysis unit and using the heated utility fluid in an additional
process.

24. The method of claim 23, recovering heat from the at least a portion of the effluent in the
first heat exchanger by passing the utility fluid by through the first heat exchanger prior to
15 passing the utility fluid through hydrocarbon pyrolysis unit.

25. The method of claim 24, comprising recovering heat from the at least a portion of the
effluent in the second heat exchanger by passing the utility fluid through the second heat
exchanger prior to passing the utility fluid through the first heat exchanger.

26. The method of claim 25, comprising adjusting valves on the one or more steam
20 generators to control the heat recovery from the at least a portion of the effluent passing
through the one or more steam generators.

27. The method of claim 24, wherein the utility fluid is heated in a deaerator prior to passing
through the first heat exchanger.

28. The method of claim 22, wherein the at least a portion of the cracked effluent is cooled in
25 the third heat exchanger to at least a temperature above the temperature at which tar, formed
by reaction among constituents of the effluent, condenses.

29. The method of claim 23, wherein using the heated utility fluid in the additional process
comprises driving a turbine with the heated utility fluid.

30. A gaseous effluent handling system comprising:
30 a hydrocarbon pyrolysis unit configured to:

receive a hydrocarbon feed; and

create a cracked effluent from the hydrocarbon feed; and

a separator in fluid communication with the hydrocarbon pyrolysis unit and configured to separate liquid effluent having steam cracked tar and gaseous effluent from at least a portion of the cracked effluent from the hydrocarbon pyrolysis unit; and

5 a first heat exchanger in fluid communication with the separator and configured to cool at least a portion of the gaseous effluent from the separator;

one or more steam generators in fluid communication with the first heat exchanger and configured to receive the at least a portion of the effluent from the first heat exchanger;

a second heat exchanger in fluid communication with the one or more generators and configured to cool the at least a portion of the effluent from the one or more steam
10 generators; and

a fractionator in fluid communication with the second heat exchanger and configured to receive the at least a portion of the effluent from the second heat exchanger.

31. The system of claim 30, comprising a third heat exchanger in fluid communication between the separator and the hydrocarbon pyrolysis unit and configured to cool the at least a
15 portion of the cracked effluent passing through the third heat exchanger to the separator.

32. The system of claim 30, wherein the hydrocarbon pyrolysis unit is configured to heat a utility fluid by passing the utility fluid through the hydrocarbon pyrolysis unit.

33. The system of claim 32, wherein the first heat exchanger is configured to recover heat from the at least a portion of the effluent in the first heat exchanger by passing the utility fluid
20 by through the first heat exchanger prior to passing the utility fluid through hydrocarbon pyrolysis unit.

34. The system of claim 33, wherein the second heat exchanger is configured to recover heat by passing the utility fluid through the second heat exchanger prior to passing the utility fluid through the first heat exchanger.

25 35. The system of claim 34, comprising one or more valves coupled to the one or more steam generators and configured to adjust the heat recovery from the at least a portion of the effluent passing through the one or more steam generators.