Fast-tracking an FCC Revamp

The design, detailed engineering and installation of one revamp took just four-and-a-half months Unit feed rate, product recovery and product quality objectives were all met after the revamp.

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In 2003 Navajo Refining Company revamped its FCC to increase capacity from 18 Mbpd to 25 Mbpd. During the previous turnaround the reactor-regenerator section had been modified to meet the 25 Mbpd feed rate, but downstream equipment had not been upgraded. Such upgrading is the subject of this paper. There was only 4.5 months from engineering kick-off to unit start-up. Everything had to be done on a fast track. Consequently identifying modified or new long lead time items quickly, such as compressor rotor modifications or vessels, was top priority. Normal linear engineering practices including finalized simulations, heat and material balances and equipment specification prior to issuing bids could not be followed.
In spite of the challenges the unit started up on schedule, has been able to exceed its design feed rate, and increase gasoline and LCO product recovery. Payout was less than 6 months.

Fast Track Execution

Today it is not unusual for revamp projects to take 2-3 years to engineer and construct. But with a dedicated project team and experienced revamp group it is possible to complete fast track work on schedule and within budget. When this project was executed refinery margins were tight and capital was scarce, hence the decision to invest was made as near as possible to the upcoming turnaround. However, fast track does not mean wasting money. Executing fast track revamps properly avoids excessive engineering costs associated with studying options that aren't practical. In this example, options that did not make sense were eliminated by discussions with process, project, mechanical and operating personnel with a vested interest in the successful outcome. Other time consuming activities such as drawing approvals were done in one or two days versus weeks by an appropriate working level team. Avoiding bureaucratic project execution processes eliminates waste, unnecessary costs and scheduling delays.

Developing a complete scope of work was key to preparing a good estimate and controlling costs. Fast-track revamps are challenging, because engineering activities need to be prioritized around long lead-time equipment, and standard engineering practices often have to be ignored given they are not necessary. Major equipment must be specified in sufficient detail to get an accurate quote, but details that are not needed can wait until after the critical activities are completed. For example, when buying a new vessel, process nozzle sizes can be estimated based on preliminary simulations but finalized after the vessel manufacturer has been selected and plate ordered. While there is risk of cost escalation if a process nozzle changes from 8" to 10", waiting until everything is finalized will at best ensure a premium is paid for the steel plate or worse schedule cannot be met. In many instances standard engineering practices dictate equipment specification development time, not truly practical requirements that ensure equipment deliveries are met, costs are contained and ultimately the unit operates properly.

Because the schedule was short, sufficient process simulations and equipment modeling was done to assess major system limits such as the wet gas compressor, condenser system, main column and feed hydraulics. In parallel, field pressure and temperature measurements were gathered to identify problem areas. Proper simulation and equipment modeling are important, but accurate measurements are essential to quickly identify problems areas. In this case field pressure measurements showed 15 psi pressure drop from the reactor to the wet gas compressor inlet. The reactor effluent line had 5 psi pressure drop due to coke build-up at the main column inlet flange. Main column pressure drop was 3 psi and main fractionator to wet gas compressor inlet was 7 psi. Measured pressure was only 3 psig at the suction of the wet gas machine. But maintaining a 3 psig compressor inlet pressure would have required a new compressor and motor. Revamp economics, and capital and schedule constraints eliminated this option. Another solution had to be found.

Developing Scope

Process engineering focused on developing major scope items, not finalizing the simulations, heat and material balances and finally equipment specifications. During every FCC revamp wet gas compressor, main column heat removal, main column capacity, gas plant capacity and reactor-to-wet-gas-compressor pressure drop are critical systems that must be evaluated. These are always the focus. For example, preliminary process simulation and equipment modeling showed the wet gas compressor suction pressure needed to be increased to 10 psig to keep wet gas production within the compressor capacity. Furthermore additional condenser capacity was needed to reduce receiver temperature to less than 105°F to stay within the compressor size. Preliminary simulation and equipment modeling were accurate enough to identify these constraints.

Reprinted from *Petroleum Tech Quarterly Revamps 2006*

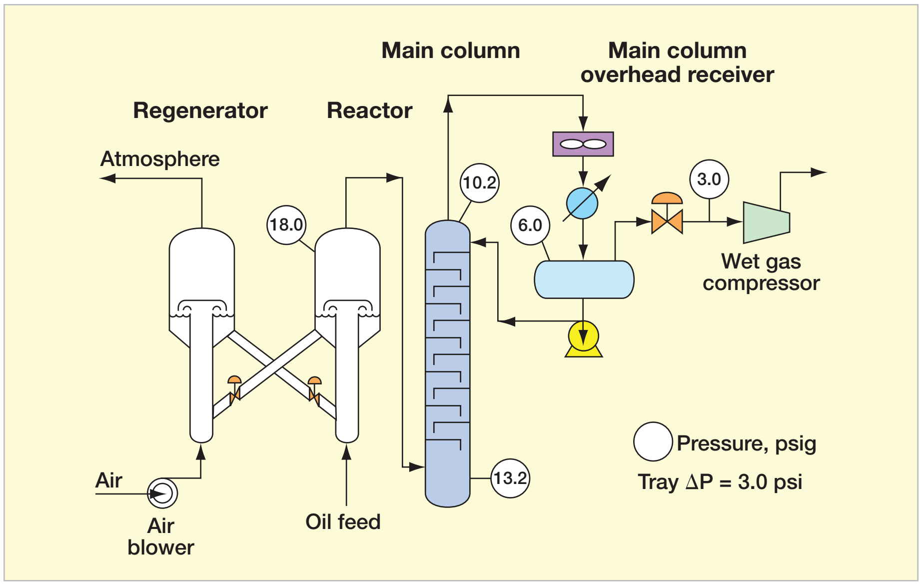

Figure 1 *Measured reactor-to-wet gas compressor pressure drop*

Reactor System Pressure Drop	
Components	**ΔP, psi**
Reactor Vapor Line	5
Main Column	3
Condenser and Piping	4
Flow Metering and Valve	3
Total	**15**

Table 1

Higher FCC feed rate (and higher conversion) increases the amount of heat entering the main column, so heat removal must increase. Yet heat removed at a given location in the column determines product quality and product recovery. For example, increasing slurry pumparound duty increases total heat removal but the liquid/vapor ratio throughout the column drops. Fractionation decreases thereby increasing the amount of gasoline in the LCO and LCO in slurry. Moreover sulfur species in the products change making sulfur specifications difficult to meet in downstream units. Before the FCC revamp would be completed, a new gas oil hydrotreater was being put in service. Its design basis called for more hot feed to the FCC. As long as there was capacity to remove this heat elsewhere it was acceptable. But cold feed was the LCO and HCO pumparounds' major heat sink. Main fractionator pumparound heat removal was therefore a significant constraint that needed to be addressed.

Preliminary simulations showed the gas plant debutanizer and to a lesser extent the stripper column diameters were too small to process all the FCC gasoline. Even using high capacity trays in the debutanizer required a large percentage of the gasoline to be produced as main fractionator heavy naphtha product to reduce gas plant liquid loading. Producing heavy naphtha reduces main fractionator overhead temperature lowering condenser system driving force temperatures, reducing main fractionator overhead vapor temperature and lowering heavy naphtha pumparound draw temperature. These all make heat removal more difficult. In addition main fractionator overhead temperature would drop to 210°F in the worst case resulting in salt formation on column internals. Even though final simulations and equipment evaluations were not complete, many unit constraints were becoming apparent.

The existing main column did not have enough trays between the products to provide good fractionation. Prior to the revamp there was a relatively large amount of gasoline in LCO and LCO in slurry. Furthermore at revamp charge rates, trays would have generated almost 5 psi of pressure drop. But system pressure drop had to be minimized to stay within existing compressor capacity. The revamped main column needed to use packing to reduce pressure drop to 1 psi or less. To accommodate packed column internals the vessel needed to be taller. Based on a rough layout of column internals an estimate of vessel height and weight was developed so the existing foundation could be checked. Because it was adequate to support a taller vessel, a vessel section specification was put together to prepare a cost estimate for this part of the work. The new main column vessel section and revamp of the trays to packing was the single biggest investment.

Early in engineering several critical systems were evaluated and major equipment work scope developed. Even though work scope development was not complete, major investment areas were identified including:

- Wet gas compressor
- Main column vessel and tray conversion to packing
- Overhead system piping and condensers
- Main column pumparound heat removal
- Gas plant debutanizer diameter
- Gas plant stripper performance

Engineering work was prioritized to prepare equipment specifications to meet delivery on the long lead time items. Other less critical items such as exchanger bundles and high capacity trays for the debutanizer were completed later in the project.

Wet Gas Compressor—Unit Pressure Balance

Pressure balance is king on an FCC especially during a revamp when existing equipment constrains an ideal solution. A supplemental air blower was already planned to meet the higher air rates. But the high pressure drop from the reactor to the wet gas compressor inlet had to be reduced. Because paralleling or replacing the existing wet gas compressor was not possible, lowering system pressure drop was the only practical option to reuse the existing compressor with minimum modifications.

While calculations are useful tools, it is only actual measurements that allow true losses to be quickly determined. Measured values are more accurate than any calculation because they eliminate unknowns. Reducing pressure drop first requires accurate measurements of the component pressure drops. System component pressure drop includes line losses, reactor line coke restrictions, column internals, check valves, condensers, flow metering and other factors. System component pressure losses can vary dramatically depending on the original equipment design and current operation (Figure 1 and Table 1).

As noted previously reactor vapor line pressure loss was 5 psi because coke formed at the main column inlet nozzle. Other component pressure losses were not excessive but pressure drop had to be reduced from 15 to less than 10 psi at much higher flow rate to avoid costly wet gas compressor changes.

Wet Gas Compressor

Compressor evaluations are straight forward if there are accurate compressor polytropic head-flow and polytropic efficiency-flow curves. The polytropic head-flow curve is similar to a pump curve, except that the fluid is compressible and the head generated depends on a number of variables. The compressor curve starts at the surge point and ends at stonewall or choke flow. Wet gas production needs to be held between surge and stonewall flow rates for stable operation. The curve is flat near the surge point and becomes steeper as flow is increased. Centrifugal compressors develop a fixed head for a given inlet flow rate over typical ranges of molecular weight encountered on an FCC. Because gas is compressible, gas density will affect the ability of the compressor to move a given mass of gas. Operating changes that raise gas density decrease inlet volume for a given mass flow rate. In this case, raising suction pressure from 3 psig to 10 psig was essential to stay within the stable operating range of the compressor. The existing compressor had a 20% operating range between surge and stonewall flow rates prior to the revamp. Navajo's 6-stage compressor performance curve is shown in Figure 2.

Once the compressor suction pressure was established to stay within the stable volumetric flow range, discharge pressure generated by the 6-stage compressor was calculated from the polytropic head equation shown in Equation 1.

$$\text{Polytropic Head} = \frac{1545\, Z_{AVG}\, T_1}{MW \left(\frac{n-1}{n}\right)} \left[\left(\frac{P_2}{P_1}\right)^{\left(\frac{n-1}{n}\right)} - 1 \right] \quad \textbf{(1)}$$

Where,

MW	Molecular weight
n	Compression coefficient
Z_{AVG}	Average compressibility
P_1	Suction pressure, psia
T_1	Suction temperature, °R
P_2	Discharge pressure, psia

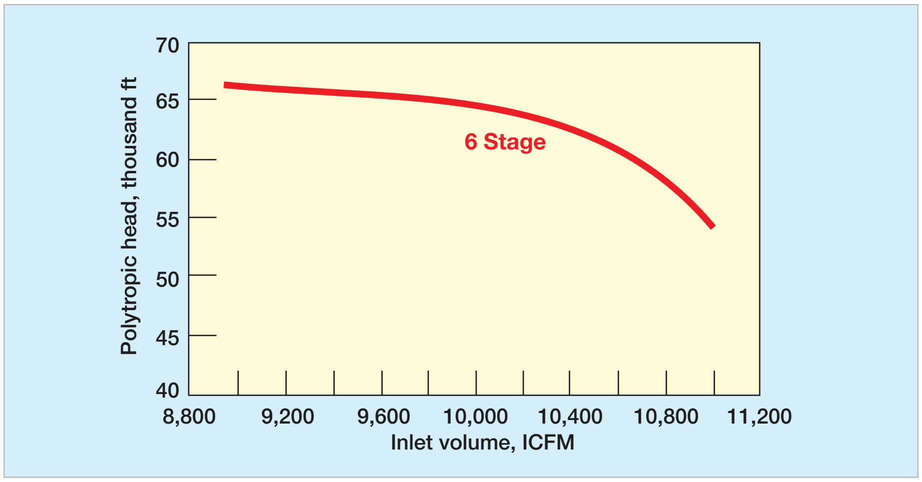

Figure 2 *6-Stage Wet Gas Compressor Curve*

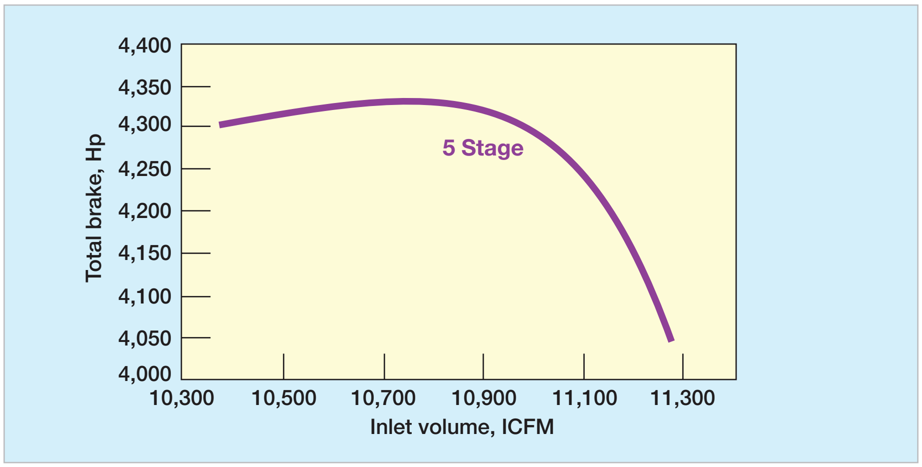

Figure 3 *5-Stage Wet Gas Compressor Curve*

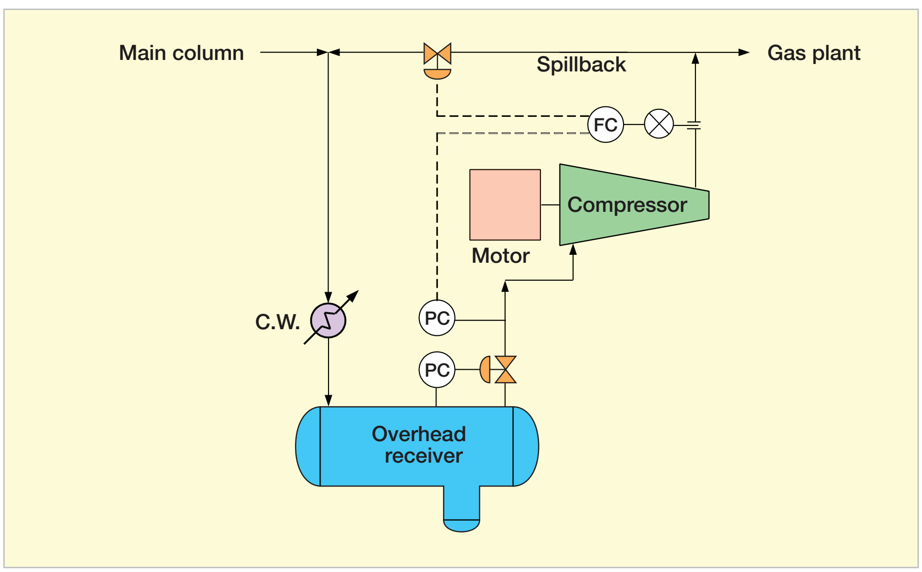

Figure 4 *Compressor Controls*

In this instance, raising receiver pressure from 3 to 10 psig and lowering temperature to 105°F decreased the amount of wet gas produced to around 11,200 ICFM which was within the existing compressor volumetric capacity.

Though pulling a heavy naphtha cut from the main fractionator decreased liquid loading to the gas plant, the net effect was to increase the molecular weight of the gas into to the compressor. Therefore, while raising compressor inlet

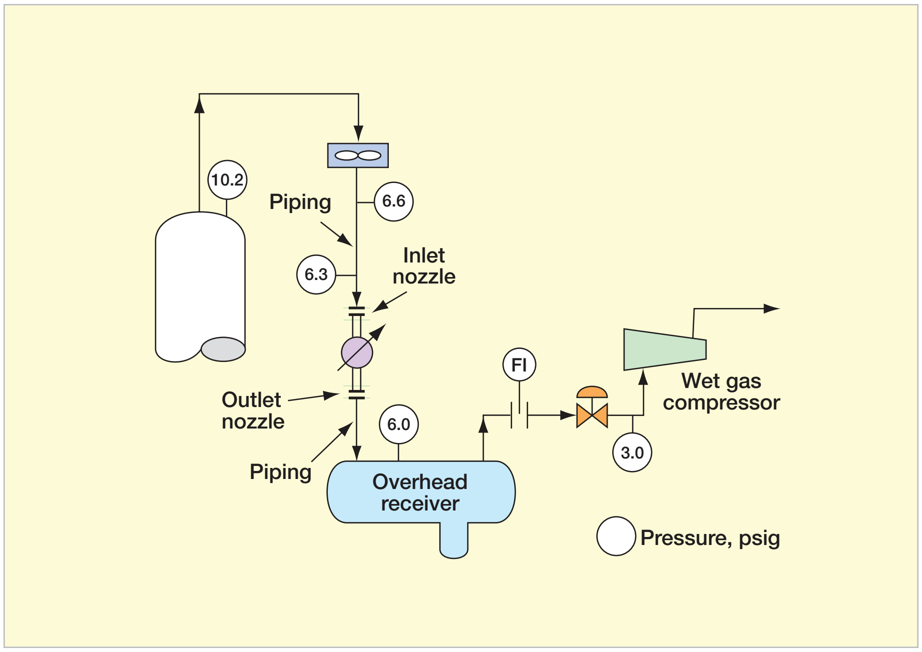

Figure 5 *Main Column Overhead System*

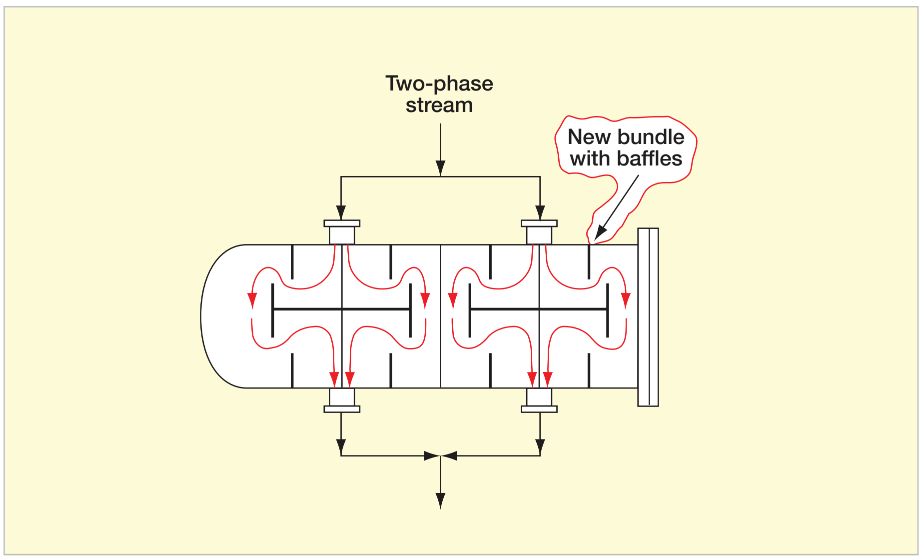

Figure 6 *Bundle Modification*

pressure and lowering temperature decreased inlet flow rate, it also raised compressor discharge pressure since it develops fixed polytropic head. Calculated discharge pressure (P_2 in equation 1) from the existing 6 stages of compression was above 350 psig over much of the stable flow rate which exceeded the maximum allowable working pressure (MAWP) of the major equipment in the gas plant. Moreover, compressor shaft horsepower would have been above 5,000 HP requiring replacement of the existing 4,400 HP motor. But replacing a motor is very costly and it often requires new transformers and motor control center equipment.

Navajo's design compressor discharge pressure was 210 psig. Gas plant operating pressure should be maintained as close to equipment MAWP because it maximizes propylene recovery and minimizes fuel gas production. Gas plant operating pressure could be met by reducing the number of stages in the compressor from 6 stages to 5 stages. Decreasing the number of stages lowered compressor polytropic head reducing shaft horsepower to less than the 4,400 HP motor (Figure 3). Increased suction pressure combined with reducing the number of stages enabled the existing compressor rotor to meet both the volume and system head requirement without changing the motor. Compressor shaft horsepower is shown in Equation 2.

$$\text{Compressor SHP} = m \cdot \frac{1.02 H_p}{\eta_p \cdot 33000} \qquad (2)$$

Where,

H_p	Polytropic head
SHP	Shaft horsepower
m	Mass flow rate of gas
η_p	Polytropic efficiency
1.02	includes 2% gear losses

Because the compressor revamp reduced the stable operating range from 20% to 8%, a robust, fast acting, surge control system was needed. Main column overhead receiver pressure and gas plant pressure control are essential. Main column overhead receiver pressure is maintained by throttling the compressor suction. Throttle valve pressure drop controls overhead receiver pressure so that reactor pressure is stable (Figure 4).

Receiver pressure is controlled by the compressor suction throttle valve position. Because compressor discharge pressure is held constant by the gas plant pressure controller, compressor suction pressure will vary and follow the flow-head curve. When gas rate leaving the overhead receiver is higher than flow at the surge point, the compressor spillback is closed. Compressor suction pressure will ride up and down the flow-head curve as long as the throttle valve is generating pressure drop and not fully open. As compressor inlet flow rate approaches the surge point, the spillback valve opens recycling gas to ensure sufficient inlet flow into the machine. When the spillback is open, spillback flow rate determines the operating point on the curve. Flow rate must always be maintained above the surge point with suction pressure determined by the polytropic head generated at the minimum flow control point. Since the amount of gas leaving the overhead receiver depends on reactor effluent composition and overhead receiver conditions, compressor suction pressure is a variable. As long as the suction throttle valve is not fully open, the compressor has unused capacity. However, once the valve goes wide open the compressor discharge pressure will drop. At this point FCC feed rate must be reduced to maintain gas plant pressure and avoid flaring from the overhead receiver.

Main Column Overhead System

Main column overhead system pressure drop and heat exchange capacity set receiver pressure and temperature which control the amount of wet gas produced. Pressure drop from the main fractionator to the compressor inlet (Figure 5) had to be reduced and condensing capacity had to be increased. A fourth fin-fan exchanger was being added as part of previous project. But this still did not provide condensing capacity to meet the targeted overhead receiver temperature of 105°F or less. Adding the fourth fin-fan bundle helped reduced pressure drop. But the 10 psig compressor inlet pressure required still would not have been met because piping losses would have been too high.

The overhead line from the main column to the fin-fans was increased from 24” to 30”. In addition the orifice plate in the suction of the wet gas compressor was removed because it was not needed. The existing trim condenser bundles were TEMA H-shell exchangers designed for very low-pressure drop by eliminating the vertical baffles. The series exchangers generated only 0.6 psi pressure drop but this caused a very low heat transfer coefficient. Trim condenser bundle designs need to balance pressure drop and the resultant heat transfer coefficient. Outlet temperature and pressure should be optimized so that wet gas production is minimized. Rigorous exchanger modeling with HTRI software showed the service heat transfer coefficient was only 22 btu/hr-ft^2-°F resulting in a receiver temperature 12°F higher than with a properly designed exchanger. The trim condenser bundle needed to be replaced.

Designing the bundles with higher pressure drop would increase the heat transfer coefficient, but the resultant exchanger outlet temperature must reduce wet gas rate, otherwise, higher pressure drop and higher heat transfer coefficient have no practical benefit. Ultimately both overhead receiver temperature and pressure determine wet gas production so they must be balanced. A good rule of thumb is that for every 1.4 psi increase in receiver pressure wet gas production decreases by 10% when receiver pressure is 6 psig. And for every 10°F reduction in temperature the wet gas production will drop by approximately 10%. After evaluating various possible designs a double segmental vertical baffle design was selected to raise the heat transfer coefficient from 22 to 50 btu/hr-ft^2-°F while increasing the pressure drop from 0.6 to 1.0 psi (Figure 6). The bundle design would reduce overhead receiver temperature from 117°F to 103°F, which would lower wet gas production by about 7% factoring in the higher pressure drop. Four new bundles were designed.

Main Column

The existing main column did not have sufficient height to fractionate between products and allow installation of the packing and internals needed to reduce pressure drop. While structured packing has been used for more than 20 years to reduce pressure drop and increase capacity, packed columns only work well

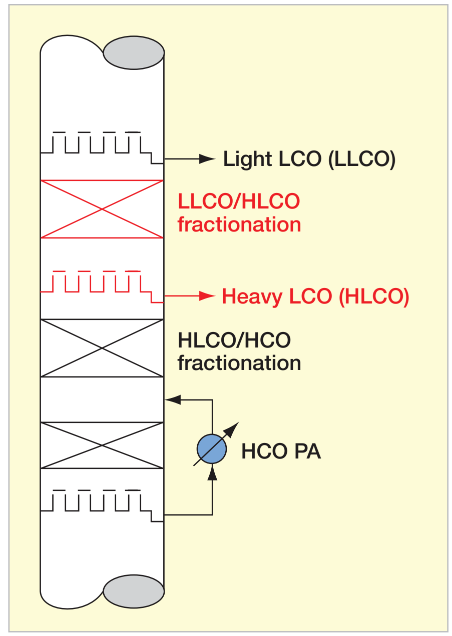

Figure 7 *Heavy LCO Draw*

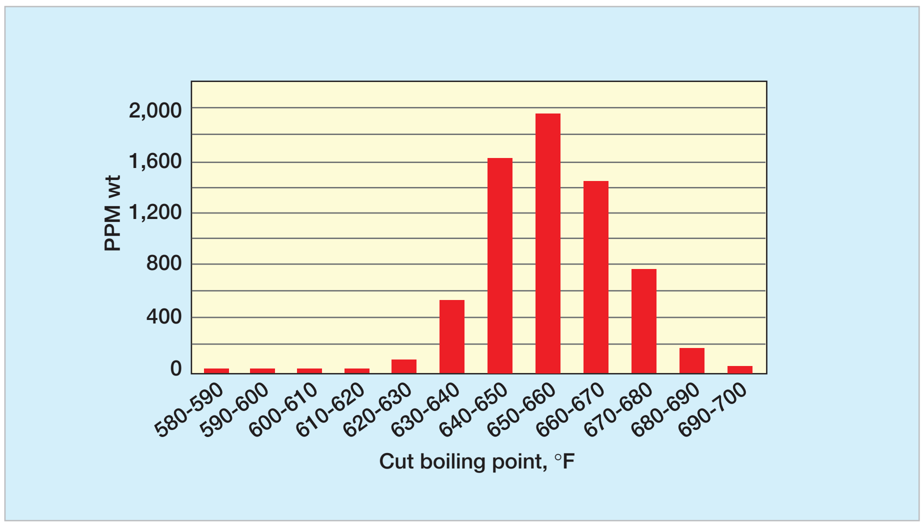

Figure 8 *LCO 4,6 DMDBT Distribution by Boiling Range*

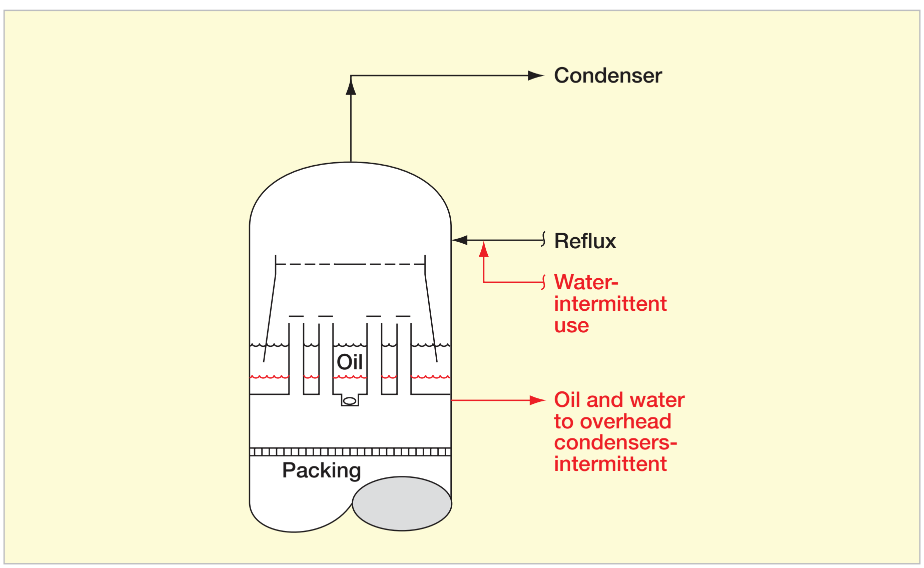

Figure 9 *Water Wash System*

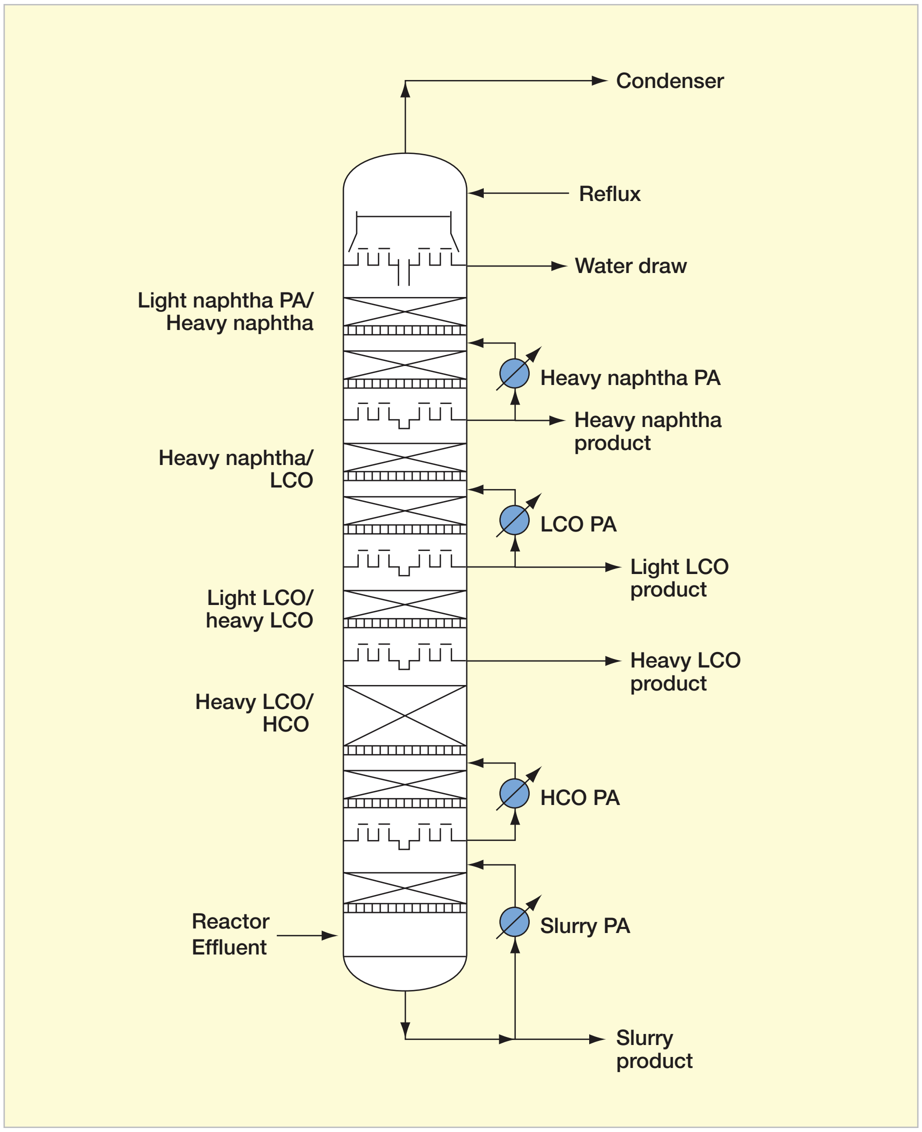

Figure 10 *Main Column Pumparounds*

if the distributors and collectors are designed properly. But properly designed internals require more vessel height than poorly designed ones. The existing foundation allowed vessel height to be increased by about 20 feet without modifications. There were two options. The first would add a section to the top of the column, but required extensive turnaround work to install new nozzles and manways in the existing vessel. A better solution was to cut the vessel just below the HCO pumparound section and install new vessel section. Existing vessel modifications would be minimized. Even though this solution significantly increased the cost for the new vessel section, it reduced turnaround work resulting in a negligible cost difference between the two options. Furthermore it reduced the shutdown schedule.

Once the correct option was selected available vessel height was optimized to meet overall processing objectives. Whereas the existing vessel had a wash section between the HCO and slurry pumparounds, when grid is used in the slurry pumparound section reactor effluent catalyst fines are completely removed. Therefore a wash section is not needed. Furthermore Navajo was considering undercutting LCO post ULSD specification to optimize hydrotreater run length and wanted the flexibility to produce a light and heavy LCO streams (Figure 7). The column was also going to produce a large percentage of gasoline as heavy naphtha. Therefore overhead temperature might be reduced as low as 210°F to lower gas plant liquid loading to maximize feed rate. Hence an on-line water wash system needed to be installed for reliable operation at very low overhead temperatures.

Main column bottom product is used as carbon black feed, therefore undercutting the heavy portion of the LCO to slurry product would raise gravity above specification. The new vessel section was designed with both a light LCO draw where most of the product is produced and a heavy LCO product draw yielding the boiling range material containing the refractory sulfur compounds. Segregating the heavy LCO would allow hydrotreater run length to be optimized. Figure 8 shows the 4,6 DMDBT sulfur in an LCO product produced from hydrotreated feed from moderate sulfur crude blends. Most 4,6 DMDBT begins to distill in the 630–640°F TBP cut and peaks in the 650–660°F. Very little is present in the 680°F–plus cut but other substituted sterically hindered sulfur compounds are present.

Gas plant major equipment capacity could not process 25 Mbpd FCC feed without producing heavy naphtha from the main column. Debutanizer column diameter was the first limit, but the high pressure receiver cooling, stripper charge pump capacity and stripper column diameter were also limits. Thus the main column was designed to produce as much as 25 volume % of the total FCC gasoline as heavy naphtha resulting in a column overhead temperature as low as 210°F. Even though this temperature is above the water dewpoint, localized cold temperatures cause salts to deposit on the column internals eventually causing flooding. Hence, as noted, the main column was designed with on-line water wash features. Ammonium chloride salts deposit after condensed water has absorbed ammonia and HCl and subsequently the water vaporizes as the temperatures increase lower in the column. When salts form inside structured packing they restrict vapor flow area causing the column to flood. To ensure that these salts can be removed with little disturbance to normal operation an on-line water wash system was added (Figure 9). Main features include an active tray that heats the cold reflux from receiver temperature to about 190°F and a collector tray to remove water. Water can be injected intermittently into the reflux stream to dissolve the salts, removing them from the water draw collector tray. Salt forms on the top tray keeping it out of the packing. Additionally the top tray and collector are made from AL6XN® to ensure that the corrosion rate is low.

Main Column Heat Removal

Reactor effluent heat is removed by the main column pumparounds and condenser system, otherwise vapor entering the column leaves the overhead receiver as wet gas adding to compressor load. Furthermore, heat not removed by the pumparounds becomes condenser system load. Increasing condenser duty raises overhead receiver temperature which increases wet gas production by approximately 1% for each 1°F rise in receiver temperature. As a consequence pumparound and condenser duty constraints influence FCC feed rate (and conversion) when the compressor capacity is limited. Wet gas compressor capacity was and remains a significant unit limit, as are pumparound and condenser heat removal.

Heat removal was identified as a major unit constraint. The main column had four pumparounds: heavy naphtha, LCO, HCO and slurry. Prior to the revamp the heavy naphtha pumparound system was not operating. It needed to be put back in service with other pumparounds' heat removal maximized without large investment because capital was limited. System and equipment sizing were pushed, with marginal operation being deemed adequate. As an example, an existing LCO product rundown cooler was converted to heavy naphtha product and lean sponge oil cooling. An existing out of service fin fan located near the LCO rundown line to tankage was used when product goes to tankage. Since lean sponge oil cooling actually helps remove heat from the main column, part of the duty from the converted LCO product cooler removes main column heat. Increasing lean sponge oil circulation to hydraulic, cooling or sponge absorber capacity constraint reduces main column overhead temperature when other heat removal services are limited. The sponge absorber was re-trayed to maximize capacity and main column cooling.

Pumparound duty depends on pump capacity, draw temperature and heat sink temperatures. Ideally a portion of the main column pumparound heat should be exchanged with utilities so that dependence on fixed heat sink is avoided. Steam, BFW preheat, fin-fan and cooling water are all variable heat sinks. Other heat sinks, as noted, such as gas plant reboilers and cold feed are fixed by these sinks temperatures and flow rates. Navajo's main column heat removal system had a small fin-fan on the heavy naphtha pumparound as well as a steam generator on the slurry pumparound. Other sinks were cold feed and gas plant reboiler duty with cold feed representing a large portion of the main column total heat removal.

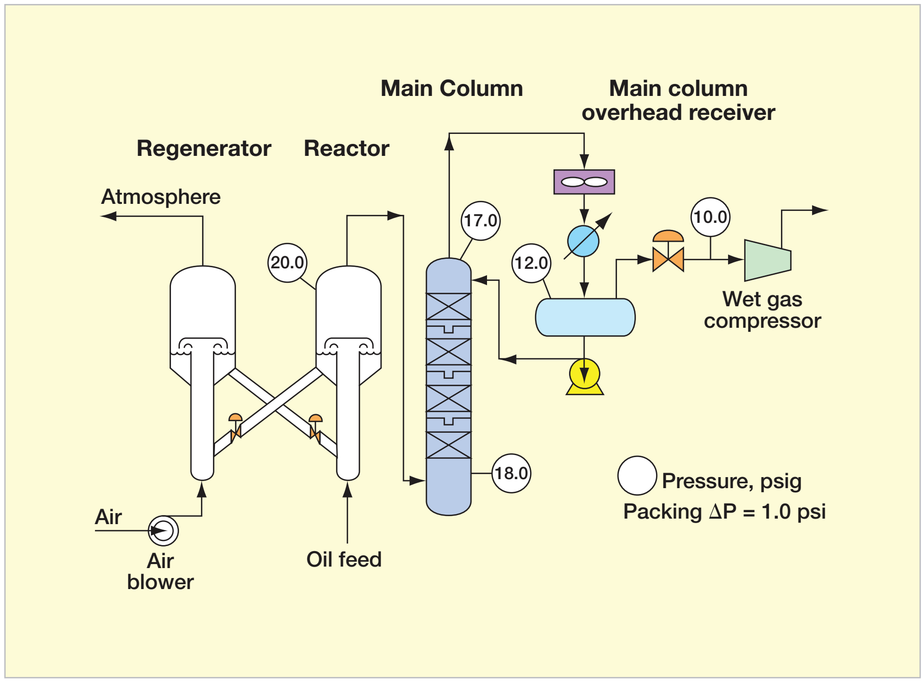

Figure 11 *Revamp Pressure Profile*

Because cold feed was a major heat sink for the LCO and HCO pumparounds (Figure 10), maintaining both the cold feed rate and keeping its temperature down were important. But Navajo was installing a new gas oil hydrotreater that was slated to increase the amount of hot feed to the FCC and raise temperature of the cold feed. Because cold feed rate and temperature were dependent on the gas oil hydrotreater run down cooling, hydrotreater operation was adjusted to maximize main column heat removal to cold feed. Two additional fin fans were added to the gas oil product from the hydrotreater to ensure feed temperature going to the FCC is 130°F. LCO pumparound heat removal was improved by installing a new reboiler bundle on the stripper column to raise the heat transfer coefficient allowing more reboiler duty for this service. This allowed better C_2 and H_2S removal from the LPG product. Main column heat removal was maximized through judicious low-cost modifications only. But main column heat removal still remains a constraint.

Conclusions

Navajo's FCC revamp has been operating since late 2003 meeting its feed rate, product recovery and product quality objectives. The design, detailed engineering, and installation took just 4.5 months. Capital investment was targeted only on critical areas such as the reactor to wet gas compressor inlet pressure drop (Figure 11). While some major changes were made such as the main column vessel section and overhead piping, others including the wet gas compressor and overhead condenser system modifications were minimized. Throughout front-end and detailed engineering the focus was on minimizing the changes. Where existing equipment was deemed marginal but adequate, no changes were made. Based on refinery margins since the revamp, the project paid out in less than 6 months.

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Reprinted from *Petroleum Tech Quarterly Revamps 2006*