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Cost-Effective Refinery Expansion Enables Lighter Crude While Maximizing ULSD

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Introduction

Delek Refining, with the assistance of Turner, Mason & Company (“TM&C”) and KP Engineering (“KPE”) is nearing completion of a cost-effective expansion project (the “Project”) of Delek’s Tyler, Texas refinery (the “Refinery”). Following a number of expansion related tie-ins being made by Delek during their early 2015 refinery turnaround (“T/A”), the 60 thousand barrels per calendar day (“MBPCD”) facility will have a new capacity of 75 thousand barrels per stream day (“MBPSD”). The Refinery, which processes primarily low sulfur Permian Basin crude oil, will be able to run another 12 to 14 MBPCD of crude oil and yield two-thirds of that incremental volume as ultra-low sulfur diesel (“ULSD”). The expansion project also allows the Refinery to deal with the growing volume of lighter crude oil being produced from the Permian Basin, which continues to increase the API gravity of the its feedstock. The Project will also correct some other bottlenecks and deficiencies throughout the facility.

The basic concept for the expansion project was conceived by TM&C and KPE in early 2013. A phased study utilizing principles employed by TM&C/KPE in prior work was approved by Delek and over the course of ten months led to the development of the reconfiguration that was enacted. The approved expansion involved modifications to the crude distillation (“Crude”), vacuum distillation (“Vacuum”), naphtha hydrotreating (“NHT”), diesel hydrotreating (“DHT”) and saturate gas (“Sat Gas”) units. There was also a minor, but important modification to the delayed coking unit (“Coker”) fractionator. The detailed design, which became a collaborative effort with the Delek staff, closely followed our proven game plan for cost-effective refinery expansion that focuses on distillation and low-to-medium hydroprocessing operations while avoiding much more costly modifications to conversion units such as catalytic cracking (“FCC”), hydrocracking, continuous catalytic reforming (“CCR”) and delayed coking units.

Project Conception & Development

The basic concept of the Delek refinery expansion project followed TM&C's strong belief that refineries should never be constrained by distillation and/or low-to-medium hydrotreating capacities. During the course of our practice in numerous refineries, we are continually surprised to find relatively low utilization of refinery conversion units due to bottlenecks in distillation and hydrotreating units. This phenomenon has been exacerbated by the recent and dramatic growth in light domestic crude oil production. We found Delek's Tyler Refinery to be in a similar situation.

Since its acquisition by Delek in 2005, crude rates at the Refinery have steadily climbed in response to the growth in domestic light crude oil volumes and widening crack spreads. The Refinery, which historically was constrained by FCC capacity, also became limited by its NHT, DHT, Sat Gas and Crude units as its Permian Basin crude supply became lighter. While its extra coking capacity was utilized by processing a sister refinery's excess vacuum bottoms, its CCR was now underutilized. Although the FCC remained full, over 25% of its feed was distillate boiling range material. TM&C and Delek believed overall refining capacity could be increased, provided the FCC capacity could be indirectly "increased" by improved recovery of distillate boiling range material from the atmospheric, light vacuum and heavy coker gas oil ("AGO", "LVGO" & "HCGO") streams.

To validate this concept, TM&C approached KPE, with whom we had previously collaborated on a similar expansion project featuring a high incremental yield of distillate at a refinery in Wynnewood, Oklahoma, for its thoughts on increasing distillate recovery at the Tyler facility. A description of the Wynnewood project can be found in AM-08-57 from the 2008 NPRA Annual Meeting. That project featured a new vacuum unit equipped with an upper fractionation zone. Additionally, KPE had previously designed a revamp of an existing vacuum tower for increased distillate recovery at a Cheyenne, Wyoming refinery (described in AM-08-43). Given what we collectively knew about the Refinery, KPE concluded much of the distillate being left in the FCC feed could be recovered via a vacuum tower modification. It is worth noting that the distillate present in Delek's AGO and LVGO streams is due to simple equilibrium and not the result of sub-par fractionation in the Crude unit's atmospheric tower.

Expanding the Crude unit's overall capacity with the addition of a pre-flash tower appeared feasible and this approach was logical given the increasingly lighter feed. Assuming NHT and DHT capacity increases could be made in a cost-effective manner,

we believed a refinery expansion on the order of 15-25% was obtainable for a reasonable cost. Further, given the combination of improved distillate recovery and robust distillate crack spreads, we saw the potential for very favorable project economics. However, it was clear to us from the beginning that the entire project rested upon our ability to recover distillate from the FCC feed.

The next step was to obtain funding for a process study to confirm our beliefs. We correctly assessed that they would want assurances of the feasibility before committing to a significant design effort thus we proposed a phased approach to the process study. The initial phase would focus solely on the degree of distillate recovery that could be obtained and how much crude oil increase that would facilitate in terms of additional space in the FCC. Upon receiving a favorable response to our Phase One Study proposal, we quickly determined that as much as 3,000 BPCD of distillate could be recovered from the Refinery's typical 62 MBPCD charge rate of 41° API crude oil. The needed modifications were a vacuum tower top replacement similar to what was done in Cheyenne. This would recover as much as 2,000 BPCD of straight run diesel from the AGO and LVGO streams. We also determined another 1,000 BPCD of distillate could be recovered from the HCGO stream via additional heat removal in the upper sections of the Coker fractionator. This volume of distillate recovery suggested that another 12 MBPCD of crude runs were possible when only considering the FCC capacity limit. TM&C then developed pro forma refinery economics for a 75 MBPSD operation that indicated a potential increase in pre-tax net refinery margin on the order of \$40 million per year, based upon our own independent outlook for long-term prices, would result.

Given the strong economic potential indicated by the feasibility study, a second more detailed process study was funded to identify cost-effective modifications to the Crude unit and downstream facilities geared toward increasing overall refinery capacity to as much as 75 MBPSD. Given the potential for even lighter feedstock in later years, Delek requested that any new additions and modifications accommodate a crude oil API Gravity of 42.5°. All parties also recognized that a number of other improvements could be implemented at a reasonable cost as part of the Project.

The Phase Two Study allowed for process design work to both identify the most cost-effective modifications needed at each process unit and to ultimately confirm the Project's design basis. This approach, which places much of the design work ahead of establishing the basis for design, deviates from the traditional project methodology and can be troubling for some clients. Despite the obvious angst on the part of many clients, we find this approach ultimately leads to the most cost-effective design for revamp and debottlenecking work; especially when the client's staff works in a collaborative manner.

This was especially the case with Delek as valuable input was obtained from employees across a broad spectrum of the organization. This enabled the correct mix of process modifications to be identified thereby enhancing the Project's overall economic return.

During the Phase Two Study we began to consider the potential impact of infrastructure limitations and constructability issues. These steps typically occur later in the traditional project approach, but we understood that tailoring the eventual process modifications to the constraints presented by the Refinery's plot plan and ancillary facilities was the only way we could achieve a highly cost-effective design. Still, we limited the scope of Phase Two to the fundamental process design to limit spending until our concepts were solidified and a really attractive expansion opportunity emerged. Upon completion and review of the Phase Two process design in August 2013, Delek approved a third and final study phase that would "flesh out" the project to the extent needed for a "go or no go" decision to be made. Phase Three would include:

- P&ID development
- Equipment sizing and quotations
- Identification of bulk civil, piping, structural & electrical quantities
- Final plot plans
- Utility balances
- Outside battery limits ("OSBL") needs
- Project schedule
- Cost estimate

Because Delek had a T/A starting at the end of January 2015, the detailed design work needed to incorporate the ability to bring certain modifications on-stream independently of the existing units in the event equipment deliveries and the construction schedule would not allow completion by the end of the T/A. During this phase, which was completed during the 4th quarter of 2013, we intentionally structured the final design into two parts: Pre-T/A and T/A. As a means for limiting cost and ensuring good control of the project, the final design was geared to maximize the amount of Pre-T/A work that could be executed independent of refinery operations and avoid the more intense atmosphere (and higher cost) associated with T/A activity. This approach would also maximize the amount of work that could be executed, if desired, on a lump sum, turnkey ("LSTK") basis. The design effort also sought to minimize the additional burden such a capacity increase would have on the Refinery's existing utility and infrastructure facilities as we well understood how exceeding the tipping point on ancillary facilities could lead to a significant increase in OSBL costs. Simple flowcharts depicting the typical approach and our non-traditional approach for developing projects are shown in Figures 1 and 2, respectively.

Figure 1
Project Development
Traditional Approach

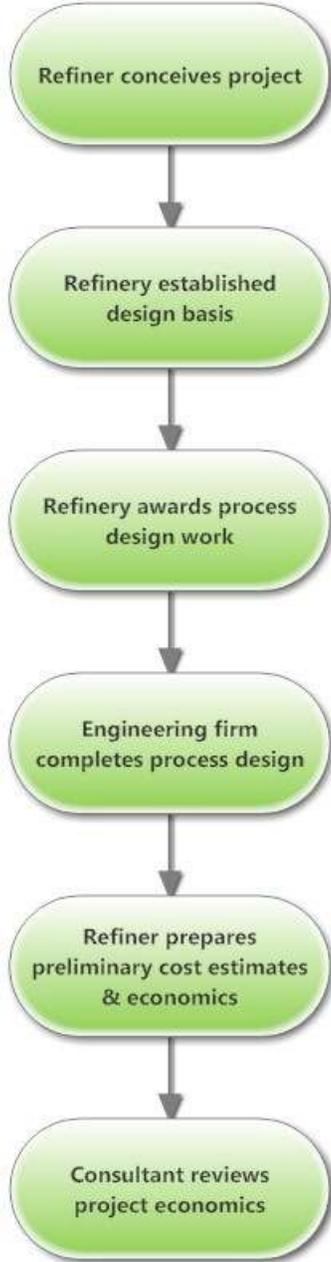


Figure 2
Project Development
Non-traditional Approach



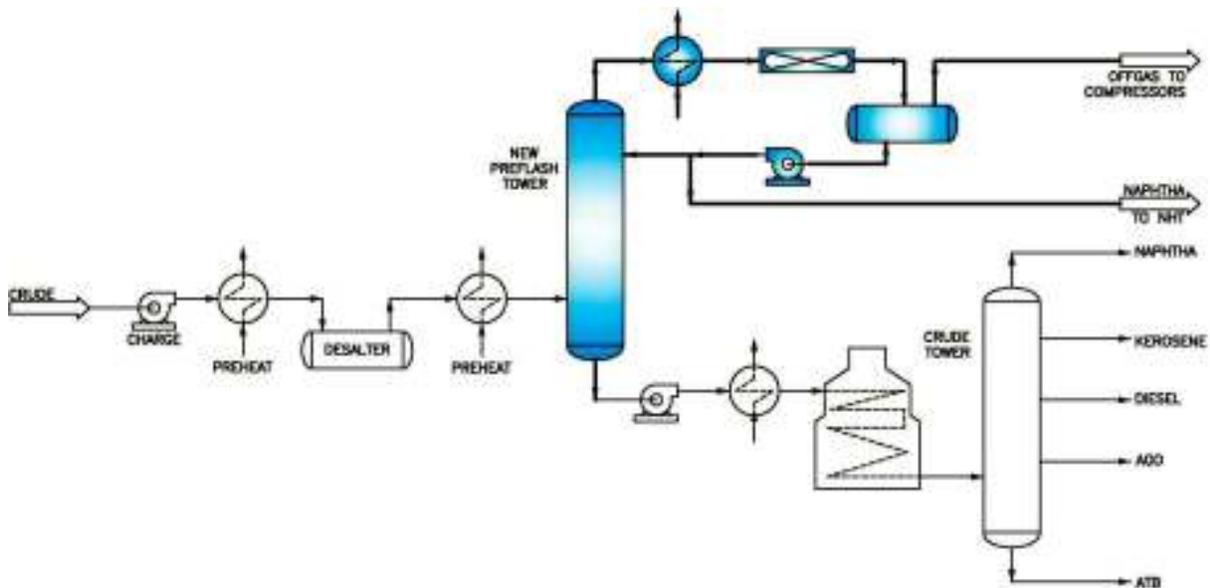
Project Description

The project scope ultimately involved major modifications to the Crude unit and the DHT. Additionally, modifications would be made to the Vacuum unit tower, the NHT, the Sat Gas, along with additional cooling for the Coker fractionator. Infrastructure additions would be minor, consisting of a dozen interconnecting pipes, a DHT feed booster pump in the tank farm, associated electrical modifications and two new truck lanes for diesel loading at the Refinery's product terminal.

Crude Unit

The Crude unit is receiving a new pre-flash tower and its associated overhead system to allow 75 MBPSD of crude oil feed, as shown in Figure 3.

Figure 3
Simple Process Flow Diagram of Crude Unit



The increase in capacity also required significant modifications to the existing crude oil pre-heat train and the addition of several new heat exchangers. Pre-heat train modifications not only improved overall heat recovery and addressed the hydraulic issues associated with increased capacity, but also corrected several existing product cooling issues within the unit. New pre-flash tower overhead/crude exchangers and a new diesel/crude exchanger were installed downstream of the existing crude tower overhead/crude exchangers and upstream of the desalter. The existing kerosene/crude and diesel/crude exchangers were moved from downstream of the desalter (i.e. the “hot

train”) to upstream of the existing crude tower overhead exchangers (i.e. the “cold train”). The existing diesel pumparound (“P/A”) exchanger was placed in gas oil service and new diesel P/A exchangers, along with another diesel product exchanger were added to the hot train. While the pre-heat train revisions moved this unit from below average to above average heat recovery, the existing equipment and piping layout heavily influenced the new configuration and generally excluded a “best in class” design. The previous and new pre-heat train configurations are shown in Figures 4 and 5, respectively.

Figure 4
Existing Crude Pre-heat Train

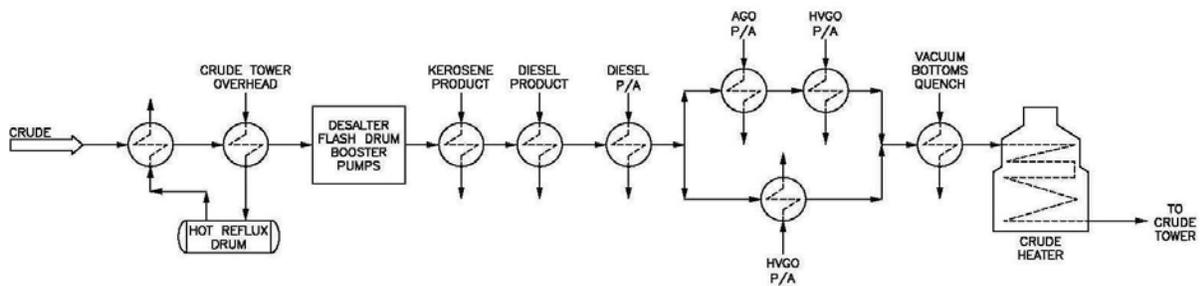
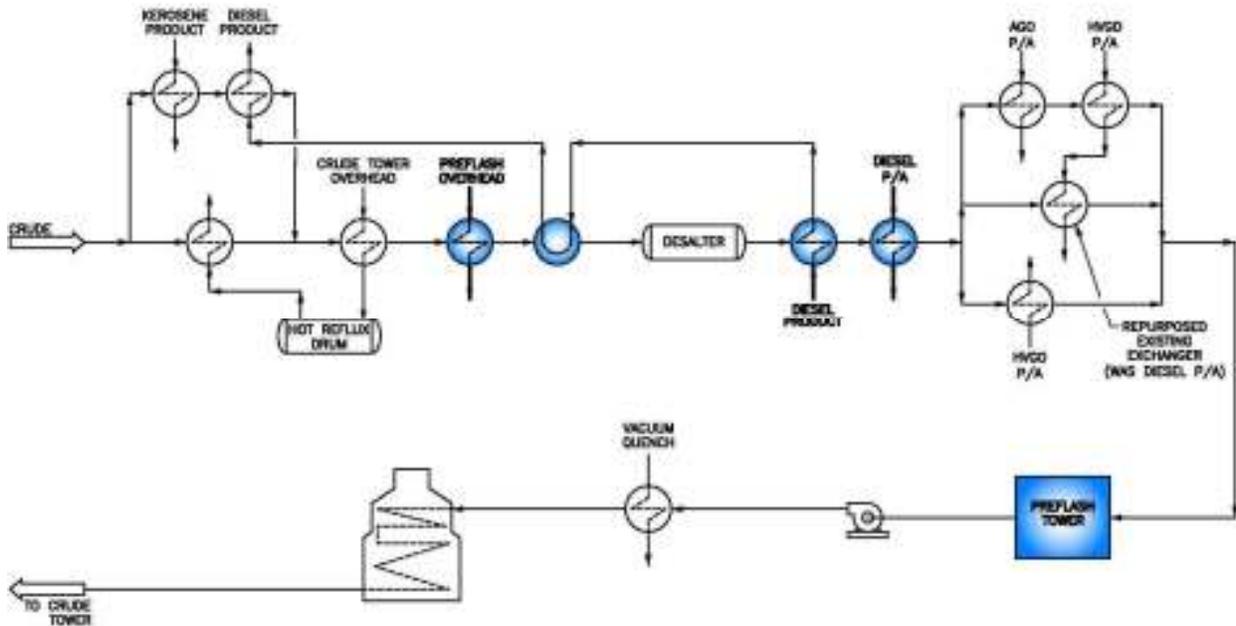


Figure 5
Revised Crude Pre-heat Train

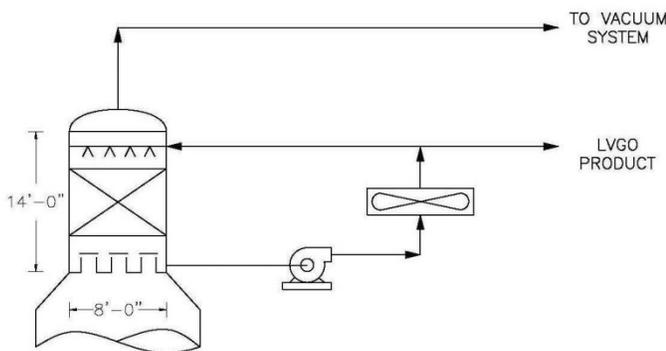


The new pre-flash tower was installed downstream of the heavy vacuum gas oil (“HVGO”) P/A exchangers. The crude flow to these exchangers was modified from two-pass to three-pass to allow crude oil vaporization to occur and minimize the resulting increase in pressure drop so that the existing crude oil charge pumps avoided modification. The existing flash drum, which currently receives oil directly from the desalter, would be repurposed as the pre-flash tower bottoms surge drum. As a result, no modifications were needed to the high pressure desalted crude charge pumps, which will continue to feed the furnace. Several crude unit product pumps received new impellers and, in a few cases, larger motors; however, only one new pump was added. The new pre-flash overhead reflux/product pump that was required will be commonly spared by the existing spare crude tower overhead product pump.

Vacuum Unit

The Vacuum unit modifications prompted by the Project are limited to the upper section of the tower. The existing 8’ diameter top will be replaced with a new 10’ diameter section that is approximately 11’ taller to incorporate a diesel fractionation section. As a result, the top product will become heavy diesel instead of LVGO. Although this does require new upper P/A pumps, the existing upper P/A cooling system remains unchanged. A new LVGO draw will be added at the bottom of the new upper section to

Figure 6
Existing Vacuum Tower Upper Section

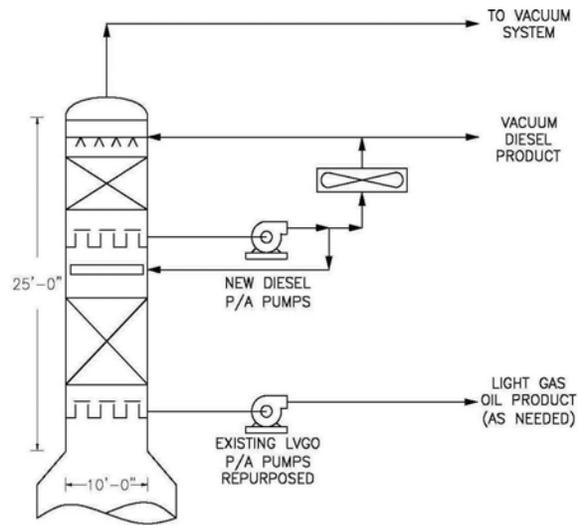


minimize light gas oil falling down the tower, which would lead to unwanted cooling of the HVGO section. The existing upper P/A pumps will be repurposed to send LVGO from this new draw to the FCC. The previous and new tower top configurations are shown in Figures 6 and 7, respectively.

AGO from the Crude unit will be directed to the HVGO P/A return to

to incorporate a diesel fractionation section. As a result, the top product will become heavy diesel instead of LVGO. Although this does require new upper P/A pumps, the existing upper P/A cooling system remains unchanged. A new LVGO draw will be added at the bottom of the new upper section to

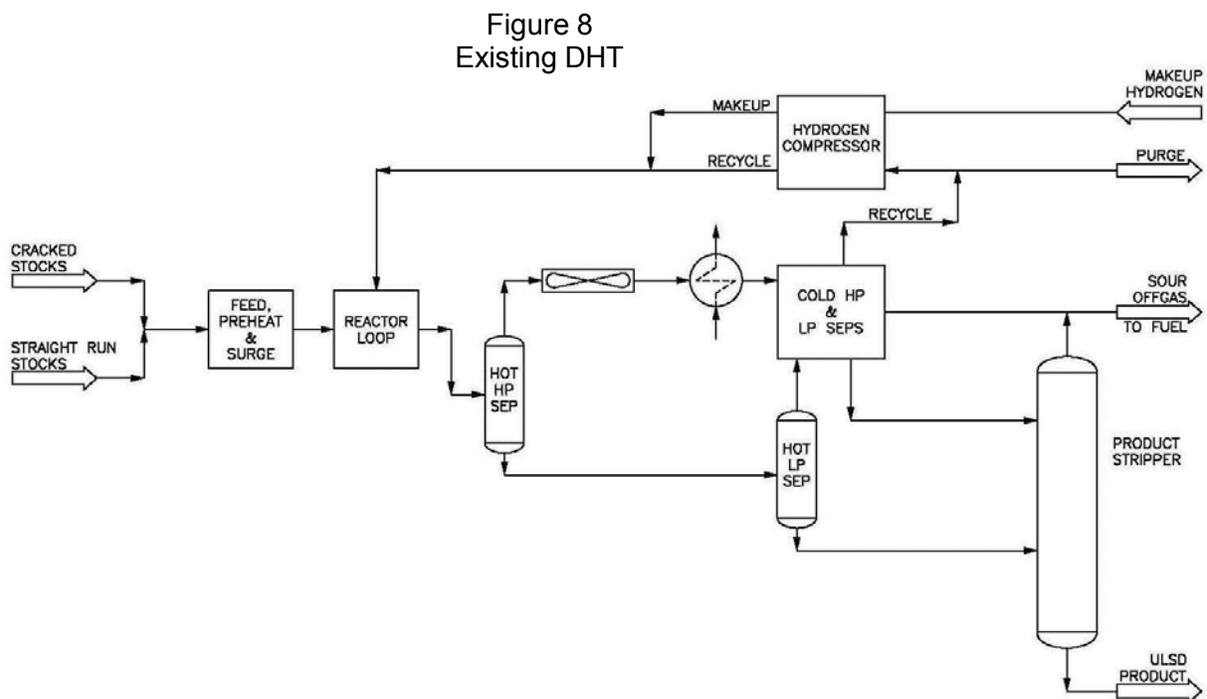
Figure 7
Revised Vacuum Tower Upper Section



introduce this diesel-rich stream into the vacuum tower for additional distillate recovery. This approach adds no additional Vacuum unit furnace duty and contributes no additional vapor traffic in the flash zone. The result is a high degree of diesel recovery from the current AGO and LVGO streams going to the FCC. We do note that in addition to the modifications described above, Delek elected to make additional modifications to the Vacuum unit that also became part of the overall project. While unrelated to the expansion effort, these changes resulted in pump, heat exchange and tower modifications that are included in the overall cost of the Project. However, we have not incorporated any expected benefits from these changes in our payback estimates.

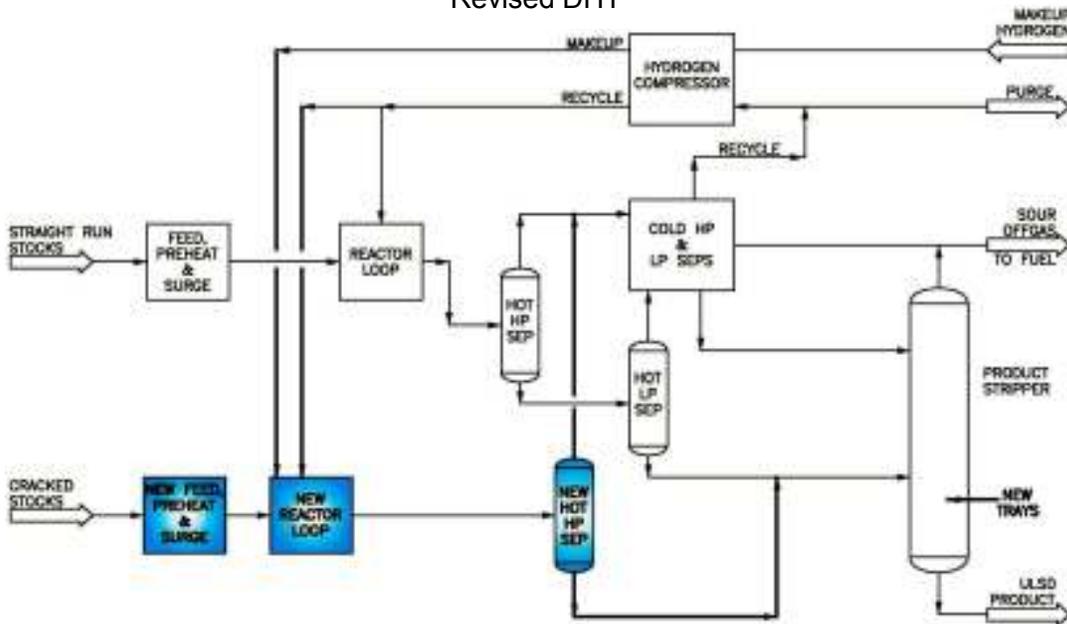
DHT

The most significant changes prompted by the Project take place at the DHT. These modifications represent more than half of the Project's expected process unit or inside battery limits ("ISBL"), costs. Previously a single train unit, as shown in Figure 8, the modifications will create a "hybrid" dual train unit with a capacity of 36 MBPD. While Delek had previously charged as much as 25 MBPSD to its single train DHT while making ULSD, it came at a steep price. The existing reactors were originally sized to produce 14 MBPSD of low sulfur diesel. Operating at higher charge rates to produce ULSD caused very short catalyst life. This was partly due to the significantly higher hydraulic rates which not only lower liquid hourly space velocity ("LHSV") but also created a large pressure drop across the reactors which in turn lowered reactor outlet



partial pressure below levels that encourage the degree of aromatic saturation necessary for desulfurizing “tough-to-reach” sulfur molecules. The new modifications will 1) double catalyst volume to improve LHSV, 2) restore the ability of the existing reaction train (“Train 1”) to operate at a reasonable pressure and 3) create a 2nd reaction train (“Train 2”) more suited to desulfurizing cracked feedstock. Figure 9 depicts the new “hybrid” dual train DHT.

Figure 9
Revised DHT



Because we had a degree of flexibility in how Train 2 could be configured, we elected to design the new train with a somewhat higher pressure and larger reactors so we could direct up to 100% of the cracked distillate feed to this train. This approach dramatically improves the existing train’s capability for desulfurization in that there will be much less “tough” sulfur in its new feed. Because Delek had previously installed refurbished hydrogen compressors that happened to be significantly oversized for the DHT service, we were able to avoid costly upgrades to the hydrogen compression section. However, we chose to direct the higher pressure (and higher purity) make up hydrogen stream to Train 2 to allow a higher hydrogen partial pressure and system operating pressure in the train seeing the bulk of the cracked feed. Lower-pressure recycle hydrogen supplements Train 2’s treat gas needs by entering the system downstream of the furnace and as quench hydrogen. The remaining recycle hydrogen serves as the treat gas for Train 1.

Excess hydrogen leaves Train 2 via the back pressure controller on the new hot separator and joins the Train 1 hydrogen stream from its hot separator. At this point, the hydrogen circuit becomes a single train system utilizing the existing DHT’s heat

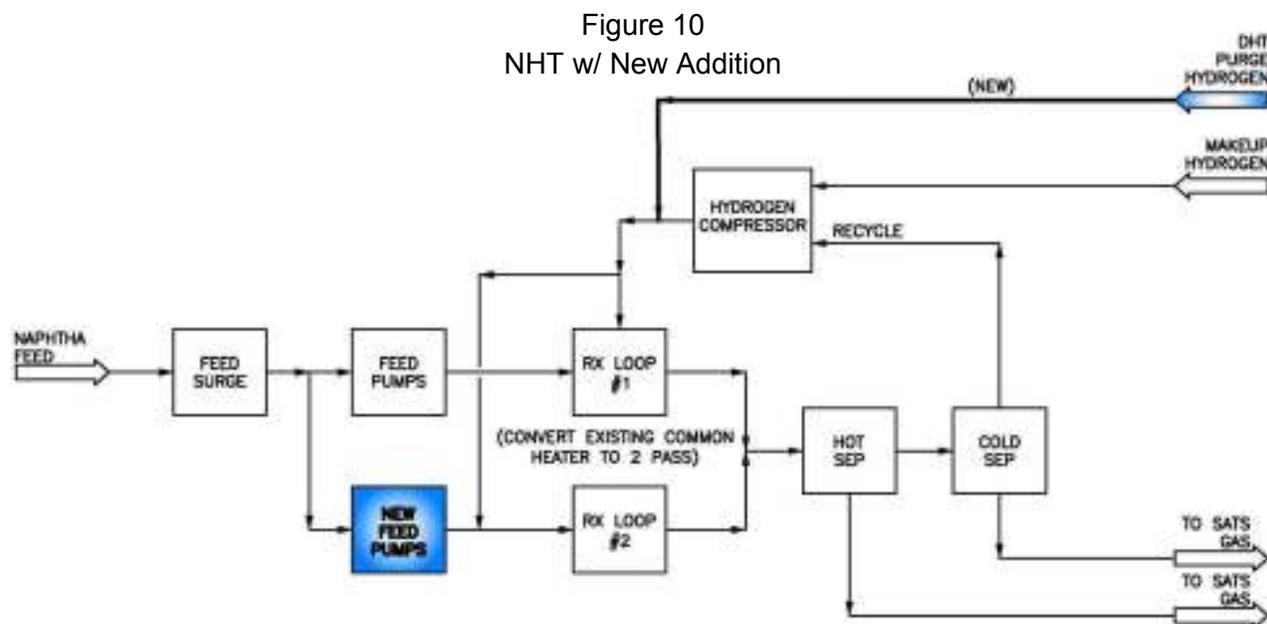
exchange, cooling and amine treating equipment, with one important exception. A new common air cooler for the effluent hydrogen stream from both hot separators is being added by the Project. Along with providing the additional effluent hydrogen cooling necessary to make the existing exchangers and trim coolers adequate, this new air cooler replaced an existing air cooler (which is being repurposed for added Train 1 ULSD product cooling) that had an insufficient maximum operating pressure and was limiting the maximum recycle compressor suction pressure as well as the maximum operating pressure of Train 1. Thus, this modification also contributes to the full restoration of Train 1's maximum operating pressure and desulfurizing capability.

The hot separator liquid from Train 2 is sent directly to the existing product stripper. In order to accommodate the significant increase in liquid load, the lower section of the tower is being retrayed. However, the upper section of the tower and its overhead system remain unchanged. A parallel stripper bottoms line with a new product/Train 2 feed exchanger and product air cooler are being added to accommodate 50% of the total 36 MBPSD ULSD product flow. This stream rejoins the existing stripper bottoms stream entering the existing trim coolers. A new ULSD product filter and coalescer are being added to replace the already undersized existing equipment, which is being reused to condition the incoming cracked distillate feed. Delek had previously replaced a small salt dryer with a much larger vessel that has ample ability to handle the increased ULSD product rate.

In order to create plot space for the new reaction train, an idle light naphtha isomerization ("Isom") unit immediately adjacent to the DHT was dismantled. The new, Train 2 reaction system includes a 3rd charge pump commonly spared by the existing Train 1 spare charge pump, a feed drum (previously the Isom product stripper), a new three-shell feed/effluent exchanger and a new furnace in addition to the previously mentioned new reactors and hot separator. Additionally, the Isom separator was converted to a cracked distillate surge drum and two new cracked distillate booster pumps were added to inject this feedstock into the new Train 2 feed/ULSD product exchanger where it will be preheated along with a portion of the straight run distillate from the existing feed system. This combined stream then enters the Train 2 feed drum. While we believe feeding the cracked distillate stream exclusively to Train 2 will maximize overall catalyst life, the design allows for a portion of this stream to go to Train 1 when necessary. Should Train 2 be down while Train 1 continues to operate, all of the cracked distillate can go to Train 1 via the new cracked feed system or the two cracked streams can be blended, as before, with the straight run distillate feed in the tank farm.

NHT & Sat Gas

In order to accommodate the increased production of naphtha from higher Refinery crude runs, the NHT & Sat Gas units needed relatively minor modifications. The NHT, which was previously modified to its “hybrid” dual train configuration to increase its capacity from 14 MBPSD to 22 MBPSD, will be further modified to achieve a new capacity of 28 MBPSD. As shown in Figure 10, a 3rd charge pump and another NHT feed/debutanizer bottoms exchanger are being added. Additionally, the furnace is being



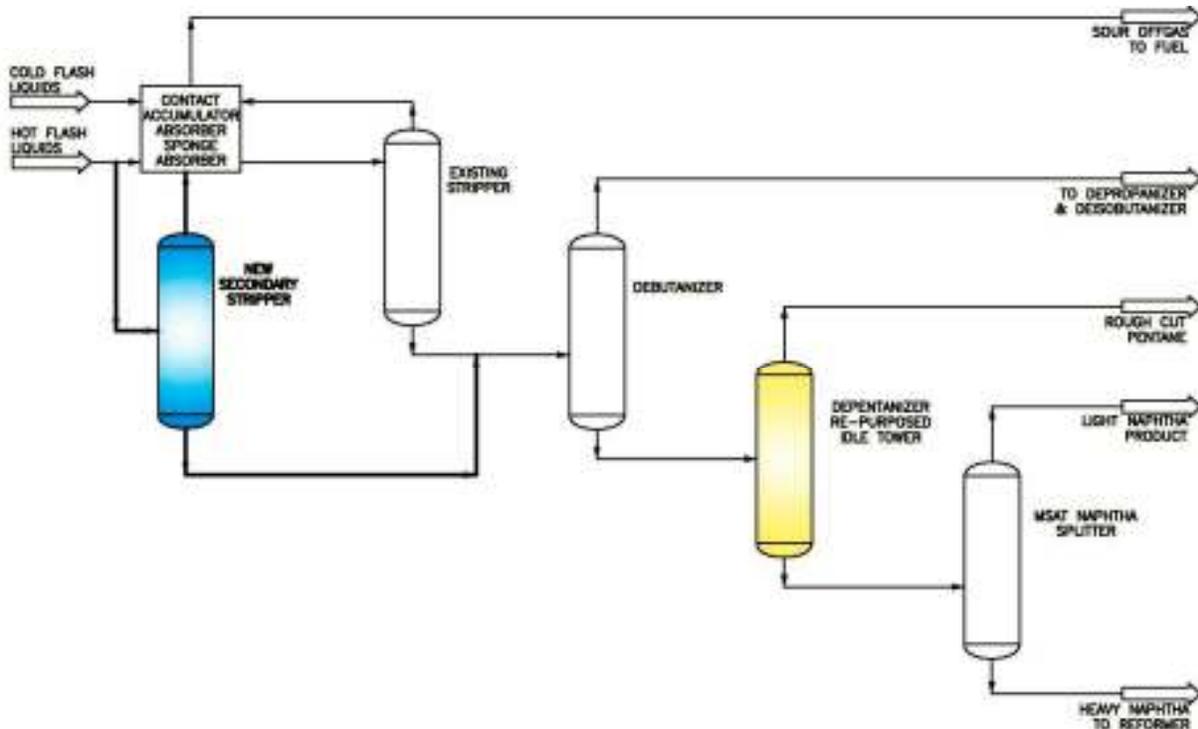
converted from single pass to two-pass to create a true dual train unit up to the hot separator. Additionally, the purge hydrogen stream from the DHT is being routed to the NHT to increase the available make-up hydrogen volume.

The NHT is currently limited by several bottlenecks and at its current charge rate the Sat Gas stripper operates in a flooded state. By adding a new, parallel stripper (albeit not operated identically) we can accommodate the higher charge rate and significantly unload the existing stripper. Unlike the existing stripper, which receives only cool feed, the new stripper will primarily feed hot separator liquid, along with a small volume of cool feed for top reflux. A new steam reboiler accompanies the new stripper but both strippers will share the existing overhead system, which will be sufficient once the existing stripper no longer operates in a flooded state.

The Sat Gas, which is integrated with the NHT will see other modifications in order to handle the increased volume of desulfurized full range naphtha. The lower section of the debutanizer will be retrayed with high capacity trays. Additionally, the original naphtha splitter, idled when Delek installed their more sophisticated “MSAT” splitter designed to keep benzene precursors out of the reformer feed, will be returned to

service. This tower will operate as a depentanizer to maintain the “MSAT” splitter charge rate below its maximum capacity. Another important benefit to this approach is that Delek will have greater gasoline blending flexibility during the summer when producing low RVP finished gasoline. The pentane-rich stream from the old splitter will go to the current light naphtha pressurized storage system while the much lower RVP MSAT splitter overhead stream can easily be blended into low-RVP summer gasoline. This reduces the volume of light naphtha Delek needs to sell or store during the VOC control period. It may also help eliminate potential octane giveaway. The new “MSAT” overhead stream represents a low vapor pressure/low octane blend stock ideal for eliminating any octane giveaway when producing regular gasoline with 10% ethanol addition.

Figure 11
Sat Gas with New Additions



Coker

While we typically attempt to avoid expensive modifications to delayed coking units, increasing the distillate recovery at the Coker was a priority. Fortunately, we were able to easily accomplish this goal by adding an air cooler to the distillate P/A circuit. Upon the suggestion of the unit’s operating supervisor, we only had to replace an idled, existing air cooler within the unit with a new air cooler at very low cost. Because the existing air cooler was much larger than our required distillate P/A exchanger duty, we chose to split the tube bundle to add air cooling to the fractionator overhead condensing

system. This second modification increased overall Coker capacity since the cooling available at the fractionator was the primary unit bottleneck. Delek executed this modification during its last Coker outage and has verified its new ability to fully recover coker distillate. The additional overhead cooling also dramatically unloaded heat load on the unit's cooling tower, which lowered summertime cooling water supply temperatures by 10° F and greatly reduced water-side fouling on the existing fractionator overhead condenser.

Obviously, the Project greatly benefited from existing equipment throughout the Refinery that, for whatever reasons, was either oversized for its service or underutilized due to bottlenecks in other parts of the refinery. However, fully utilizing the existing facilities available, along with keeping the degree of new additions limited to reasonable investments, was an important factor in developing a very attractive project. As we emphasized earlier, approaching a revamp project from this mindset will either result in a very cost-effective design or clearly demonstrate that little "low-hanging fruit" is readily available.

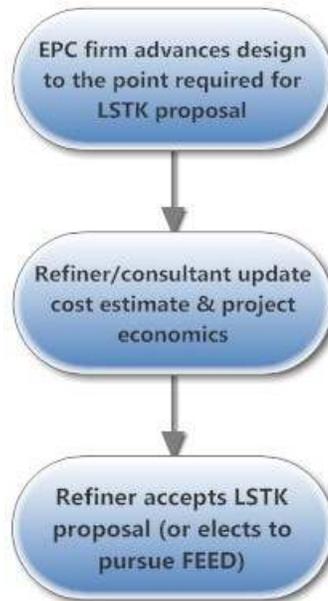
Project Execution

The selected approach to executing the Project was as non-traditional as was the design approach. From the start, TM&C had encouraged Delek to sole-source a LSTK agreement with KPE. We did this because our own experience utilizing KPE for several similar projects at the Wynnewood Refinery, the last of which was sole-source, convinced us that this would be the most cost-effective approach for Delek. Most projects are executed in the manner shown in Figure 12. After establishing a design basis and preparing a process design package, companies then obtain a front end engineering design (FEED) package, develop a more definitive cost estimate and solicit competitive bids for the project. By obtaining a LSTK proposal from KPE for the pre-T/A portion of the work, something KPE was willing to submit upon completion of the Phase Three study, Delek could significantly shorten the schedule needed to execute the Project while retaining a degree of cost certainty for a majority of the Project's expected cost. TM&C advocated that there was greater potential economic benefit to Delek from shortening the schedule than executing the Project in the traditional manner. This fast-track approach, shown in Figure 13, also assured that the tie-in work needed to be made during the T/A could be accomplished.

Figure 12
Project Execution
Traditional Approach



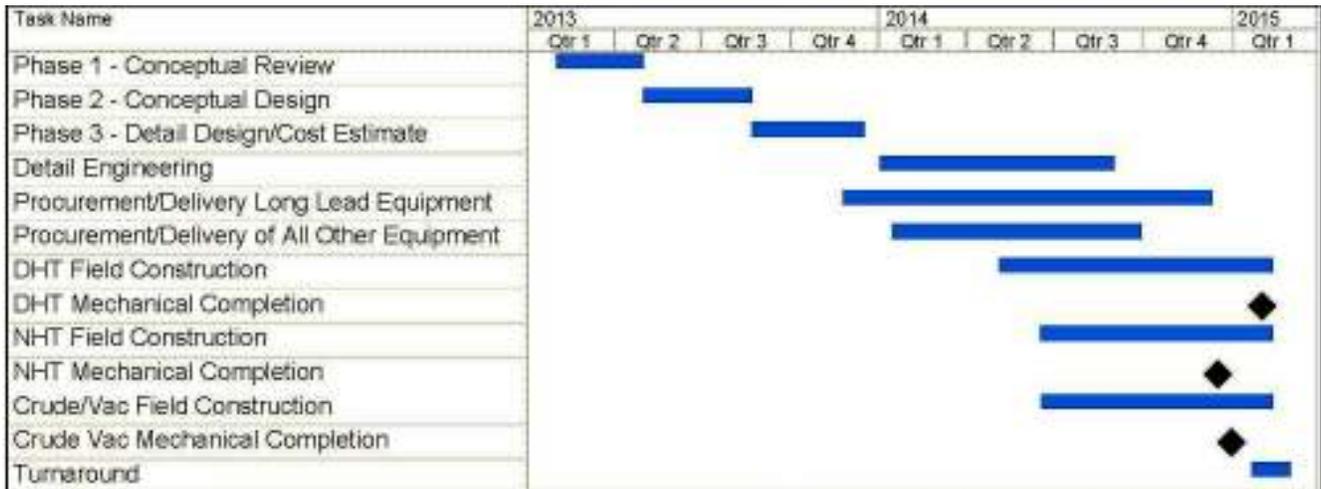
Figure 13
Project Execution
Non-traditional Approach



Following this tentative approval for the Project, purchase orders for equipment items were placed as fast as the equipment could be specified by KPE and quotations obtained. A few long lead items were placed on order during the 4th quarter of 2013 prior to full completion of the Phase Three study. This was done on an item-by-item basis. Engineering and procurement activities continued with KPE for several months. Following formal approval of the Project, Delek and KPE agreed to execute the pre-T/A ISBL work on a LSTK basis. Overall, this approach to project execution was very similar to the approach previously utilized by KPE/TM&C for the addition of a FCC gasoline selective hydrotreating unit at the Wynnewood Refinery.

With formal approval obtained, an updated schedule, shown in Figure 14, was developed that called for construction activities to commence in July. However, pre-T/A modifications to the Crude, Vacuum, NHT and Sat Gas units were still set for mechanical completion by the end of 2014. The DHT work, which always determined the Project's critical path, would carry into February 2015 but still be finished prior to completion of the Refinery's T/A. Project work that could only be performed during the T/A would be executed on a reimbursable basis by Delek's T/A contractors under the direction of Delek's in-house project team. The required OSBL modifications were executed using the same approach by contractors that Delek typically employs for small jobs.

Figure 14
Project Schedule

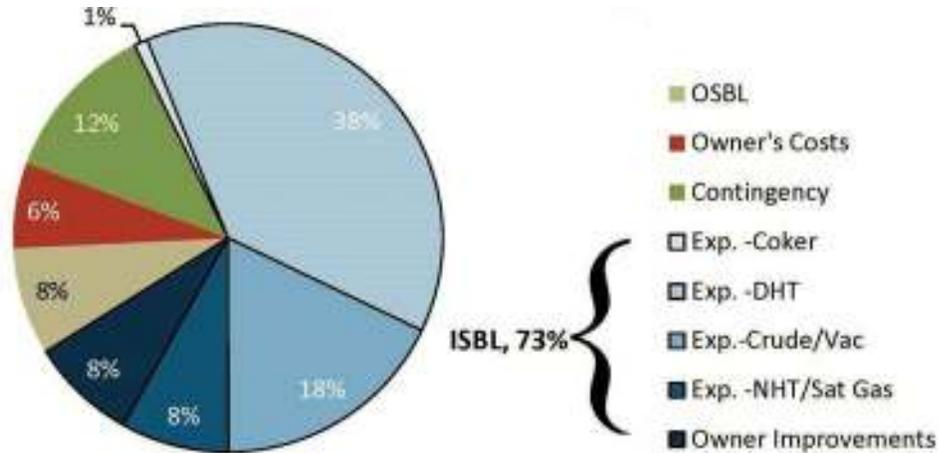


TM&C continued to act on Delek's behalf throughout the project execution phase by assisting Delek's in-house project management team, resolving certain project issues with KPE, participating in HazOp reviews and assisting in the design and execution of the OSBL work. TM&C would also supplement Delek's efforts 1) updating operating procedures, 2) training employees on the upcoming changes and 3) with commissioning/start-up. This continued presence was helpful in minimizing scope "creep" that can typically occur in all projects. One of TM&C's roles was to ensure Delek was fully informed of the cost and benefits of any proposed additions to or deletions from the Project's scope.

Project Cost and Economics

The Project’s budget was approximately \$70 million. As shown in Figure 15, about 65% of this amount went toward ISBL additions and modifications associated with expanding the Refinery. Another 8% went toward owner-driven ISBL improvements not specifically required by the higher crude rate. Approximately 80% of that collective ISBL amount

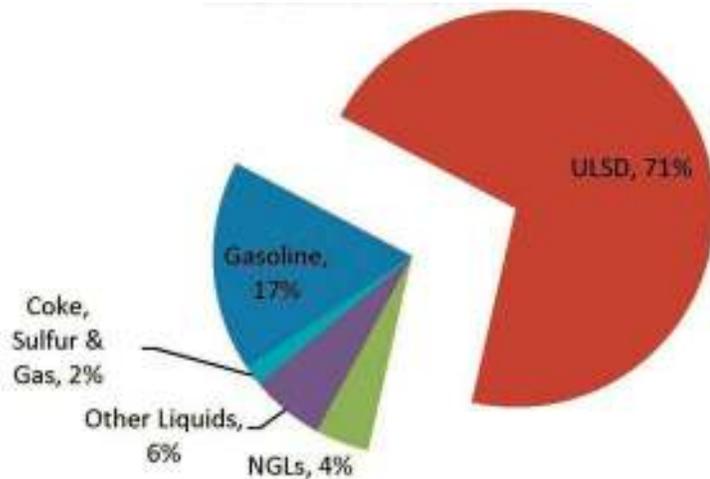
Figure 15
Project Budget



was executed by KPE under the LSTK agreement. OSBL work constituted only 8% of the budget, with the remainder going toward owner’s costs and contingency. At the time of this paper and with the project near completion, Delek remains optimistic that the Project’s final cost will meet this budget.

As we indicated earlier, the increased crude oil capacity will yield a significant volume of ULSD on an incremental basis, as shown in Figure 16. Based upon December 2014 crude oil and refined products futures prices obtained following WTI’s drop in the second half of 2014, the Project’s expected economic benefits remain better than originally presented and should result in a simple pre-tax payback period of 18 months.

Figure 16
Incremental Yields



Conclusions

Delek's Tyler refinery is nearing completion of a project that will increase refinery capacity by 20% and provide an excellent rate of return on a relatively modest investment. This successful project was the result of Delek's management embracing a non-traditional approach to project development and execution that involved collaboration with its refining consultant and a pre-selected EPC contractor. A fundamental feature of this non-traditional approach is the belief that refineries should not be bottlenecked by low-cost process facilities such as distillation and medium pressure hydrotreating. Another important aspect of this approach is the emphasis on identifying high return (i.e. "more bang for the buck") modifications that can leverage the capabilities of the existing process units and supporting facilities prior to determining the ultimate design basis. While this non-traditional approach was well suited for Delek's Tyler Refinery, we believe it can be successfully applied to just about any facility where 1) high cost process units and/or infrastructure is being underutilized and 2) management is willing to embrace a novel approach to project development.