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Diagnose flooding columns efficiently

Using field pressure data, a refiner made a low-capital modification on a crude distillation column to increase throughput without a shutdown

T. Barletta and J. Nigg, Process Consulting Services, Inc., Houston, Texas; and S. Ruoss, J. Mayfield and W. Landry, Tosco Refining Co., Belle Chasse, Louisiana

Flooding of the crude distillation unit (CDU) adversely impacts a refinery's profits. Such conditions force crude charge reductions, downgrading of product draws, etc. Consequently, the CDU operates under stress. Determining the root cause for the flooding is another obstacle that a refiner must overcome. Incorrect diagnosis of the flooding source can be equally as damaging as the root cause. Gathering valid field data is vital when understanding the dynamics occurring within the crude column. Proper interpretation of the data is also required to determine the best recourse to correct the problem.

In this case history, a crude column begins flooding. Severe upsets reduced crude throughput. Field pressure drop data are used to find the root cause for the flooding and operational upsets. With this information, the refiner installs a bypass online to override the column's restriction and restore the column's performance.

An operating problem is impossible to fix until the specific cause is found.

Case history. Tosco Refining Co., a division of Tosco Corp., owns and operates a large, highly integrated single-train refinery at Belle Chasse, Louisiana. (Tosco purchased the Alliance Refinery on Sept. 8, 2000.) This facility's CDU had been operating over six years since the last turnaround. In early 2000, the crude column began flooding, which limited maximum throughput. This flooding reduced maximum CDU capacity by 20,000 to 25,000 bpd (25 Mbpd). Attempts to increase crude charge rate or process lighter crude blends at reduced throughput caused severe crude column operational upsets.

Field measurements identified a liquid restriction in the top section of the column. A bypass line was installed online in June 2000. It allowed liquid to circumvent the restriction. Crude throughput was immediately restored by 20–25 Mbpd without any operating upsets or column flooding. The bypass installation had a simple payout of less than two weeks; Tosco captured incremental revenue from additional crude runs without taking a unit shutdown.

Problem symptoms and consequences. The Alliance Refinery crude column produces full-range naphtha as overhead product and kerosine, diesel and atmospheric gas oil (AGO) as product side draws. Fig. 1 shows an overview of the crude column's upper section, including the diameter swage at the diesel pumparound return. In early 2000, the crude column experienced severe upsets when the crude rate was within 20–25 Mbpd of targeted maximum. These crude column upsets were characterized by:

- A increase in pressure drop between the diesel side stripper vapor return tray and the top of the column
- An increase in kerosine draw temperature
- Loss of level in the kerosine side stripper
- High column bottoms levels.

During the upsets, operators would decrease heater outlet temperature to lower the vapor flowrate in the column. After 30–40 minutes, the pressure drop in the upper section would begin to decrease and shortly thereafter kerosine product flowrate and draw temperature would decrease rapidly. Eventually the crude tower bottoms level would increase, and the cycle would start over. The time between the onset of flooding and recovery to stable operation was approximately 3½ hours.

To minimize these upsets, the diesel pumparound duty was maximized at the expense of the top pumparound duty. This reduced internal reflux between kerosine and diesel, which resulted in a 7,900-bpd downgrade in kerosine to diesel product. Also, the crude tower pressure was increased to reduce the superficial vapor velocity in the top of the column. Higher crude tower operating pressure decreased the AGO cutpoint and raised the feedrate to the vacuum column. Heavy crude runs were limited to stay within the maximum capacity of the vacuum column.

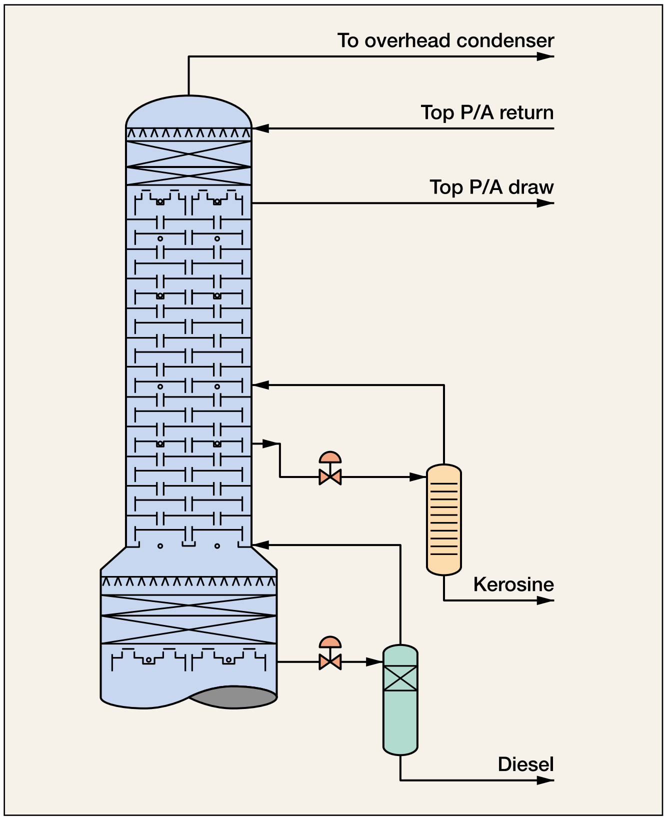

Fig. 1. Crude column upper section.

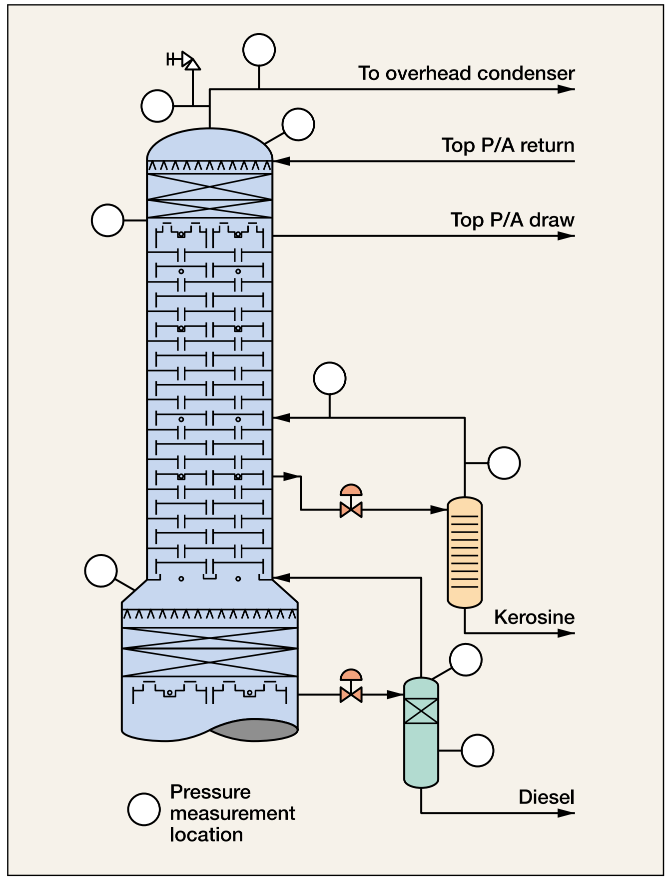

Fig. 2. Pressure measurement locations.

Finding the root cause. An operating problem is impossible to fix until the specific cause is found. It was clear that flooding was occurring somewhere between the top of the column and the kerosine side stripper vapor return tray, but where? The column was flooding, but the specific cause and exact location was unknown. The Alliance Refinery wanted to know if it was possible to circumvent the flooding and increase crude rate without taking a shutdown.

Pressure drop can be used to infer flooding, just as more sophisticated methods such as gamma scans. However, pressure drop can be much easier to interpret than a gamma scan. Pressure can be measured at column nozzles, stripper vapor line vents, draw nozzle low point bleeders, relief valve piping, and side-stripper bottoms level bridles. Fig. 2 shows the typical places where pressure can be measured.

The crude column pressure profile was measured when the crude column was stable and once again during an upset. The pressure drop was measured by taking simultaneous readings with two digital "smart" manometers, which are accurate to ±0.05 psi. When measuring small pressure differentials, a single-gauge pressure survey is not accurate because fluctuations in column pressure result in inaccurate differential pressure measurements.

Pressure profile—stable operation. The crude column pressure drop was measured when the column was in stable operation. Fig. 3 shows the measured pressure drops. The pressure drop across the top pumparound was about 0.20 psi and was measured over a 40-min period. It was stable during this period, fluctuating between 0.20 and 0.23 psi. At 0.20 psi pressure drop, the top pumparound bed was flooded. But was it causing the crude column upsets?

When a crude column top pumparound bed floods, the temperature difference between the tower overhead and top pumparound draw will decrease. The temperature difference should be in the range of 25–35°F. The temperature difference had been less than 10°F for the past two years prior to the upsets as shown in Fig. 4. Therefore, the bed had been operating flooded during the entire time. Even though the top pumparound bed had been operating flooded during this time, the unit had been able to achieve maximum throughputs.

When a pumparound bed floods, liquid stacks up until there is enough head to "push" it out the bottom of packing. Minor pumparound bed flooding will result in higher pressure drop, but typically does not cause major operational problems. If the flooding is not severe, then additional pressure drop can go unnoticed. However, if flooding is severe, then liquid will stack in the bed, prevent liquid flow down the column and cause severe operating problems.

The pressure drop measured from above the collector tray to below the kerosine side stripper vapor return tray was approximately 0.148 psi per tray. This is high for standard valve trays. More field data was needed to determine if these trays were flooding and causing the upsets.

Pressure profile—upset condition. Fig. 5 shows the pressure drop across the top pumparound bed during an upset. Pressures were measured at one of the 30-in. overhead lines and at a ¾-in. valve located 6 in. below the packed bed. The measured pressure drop was swinging between 0.2 and 1.75 psi. Yet, the calculated pressure

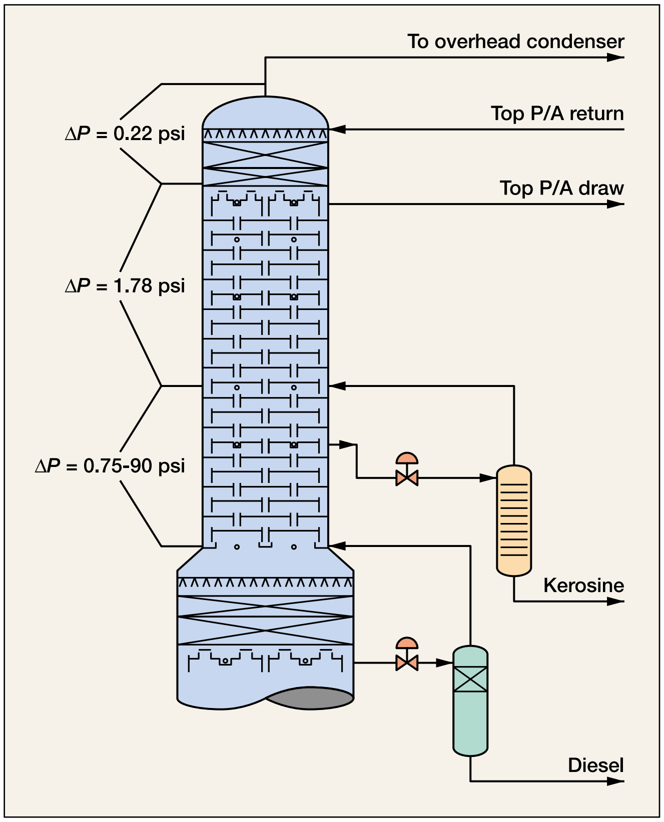

Fig. 3. Stable operation pressure drop.

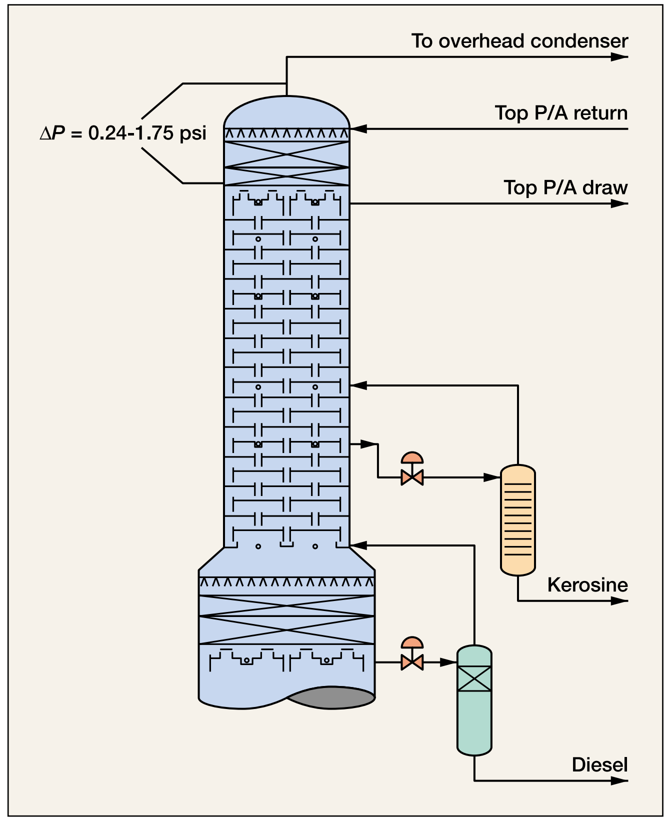

Fig. 5. Pressure drop during upset conditions.

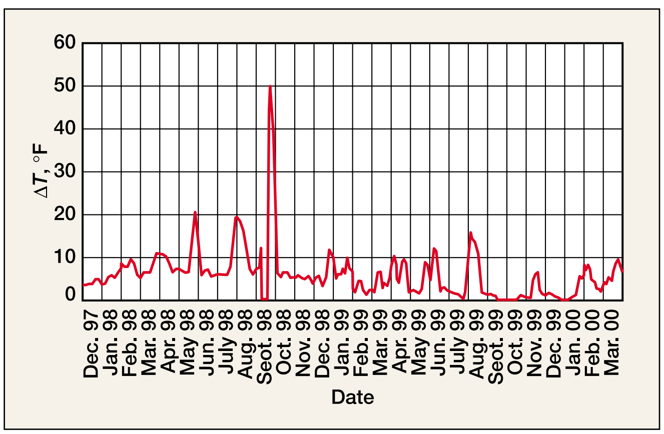

Fig. 4. Top P/A draw temperature minus overhead.

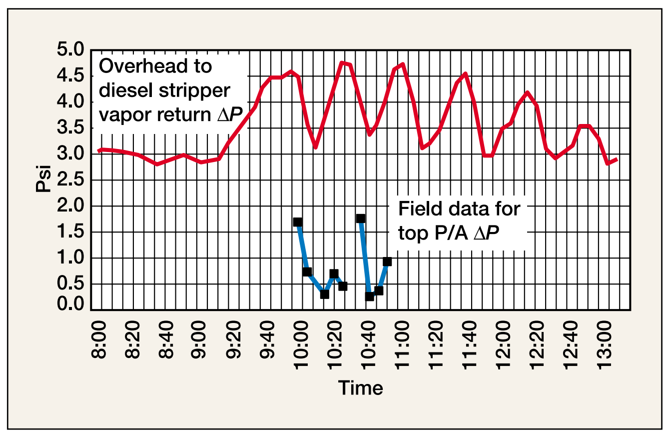

Fig. 6. Comparison of top P/A Δ*P* and crude tower top Δ*P*.

drop through the overhead nozzle is 0.06 psi. Therefore, the measured drop was essentially across the packing.

Pressure drop across the top pumparound bed is extremely high. This bed is highly loaded/flooded even at the lowest pressure drop 0.24 psi. The top pumparound bed is approximately 9 ft of structured packing. It is nearly full of liquid at a pressure drop of 1.75 psi. A pressure drop of 1.75 psi through the bed represents a liquid height in the packed bed of roughly 6 ft.

In Fig. 6, the (measured) top pumparound pressure drop and the pressure drop between the overhead and the diesel side stripper vapor return tray are compared. During the upset, the pressure drop between the column overhead and this tray cycles between 3.0 psi and 4.7 psi. The field-measured pressure drop across the top pumparound bed is also cycling at the same frequency by roughly the same amount. The increase in pressure drop during the upset is in the top pumparound bed, not the trays below it.

The pressure drop is increasing from the point of the downcomer restriction. Pressure drop increases as the liquid hold-up (level) in the packing builds and conversely, the pressure drop decreases as the liquid height declines. When the liquid height in the packing builds sufficient head, the liquid "dumps" down the tower and the crude tower bottoms level increases. As the liquid works its way down the tower, product-draw temperatures drop due to composition changes.

Collector tray performance. A simplified sketch of the top pumparound collector tray is depicted in Fig. 7. The tray deck is located 3 ft below the packing and 4 ft above the tray below. Vapor from the tray below flows up through the collector tray risers and into the bottom

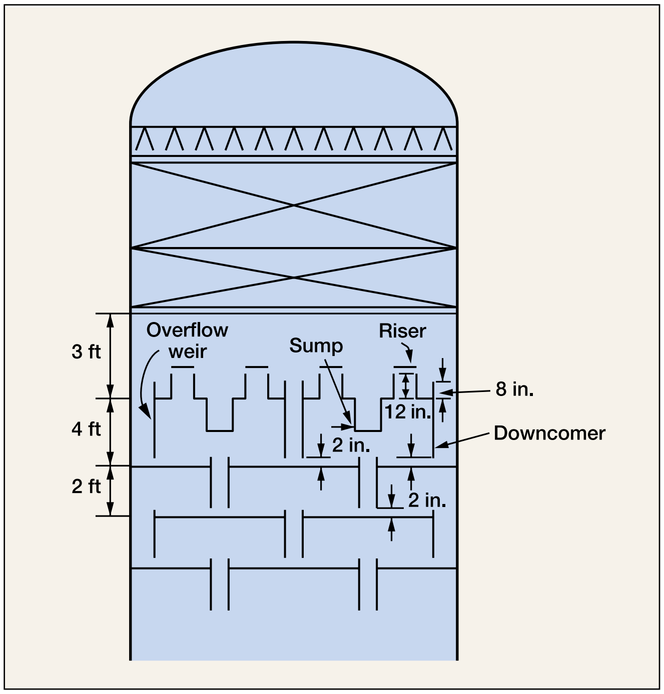

Fig. 7. Top pumparound collector tray.

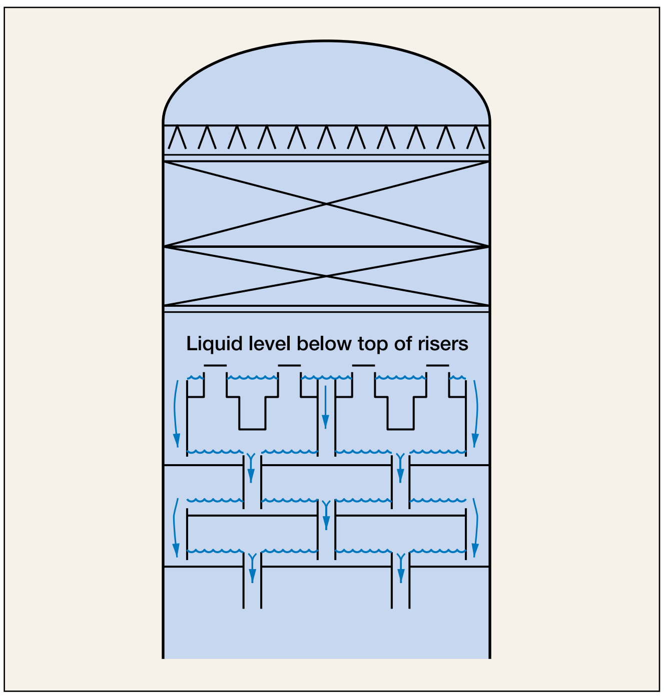

Fig. 8. Collector tray design liquid levels.

of the packed bed. Liquid from the bottom of the packed bed drops onto the collector tray. A portion of the liquid is withdrawn from the column via the draw nozzles and is pumped through the top pumparound heat exchanger network. Liquid overflows the collector tray in center and side downcomers and provides internal reflux for the trays below.

The collector tray is designed to operate with approximately 9½ in. of liquid on the tray deck. The liquid level should be below the risers, which are 12 in. high. Fig. 8 shows what the collector tray should look like with the design liquid level.

Pressure can be used as a level indicator. One foot of water will exert 0.4329 psi of pressure head. Therefore, if the elevation between two pressures and the liquid density is known, then the liquid head can be calculated. Fig. 9 shows the collector tray pressure measurement locations and the elevation difference between them. The measured pressure drop was 0.7 psi, therefore, the collector tray is 100% full of liquid and is backing liquid up into the packing.

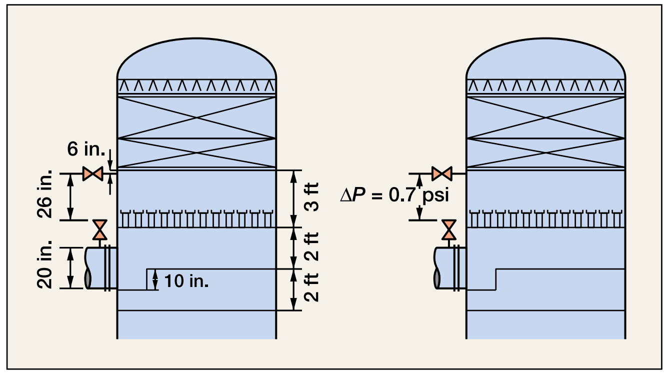

Fig. 9. Collector tray pressure survey.

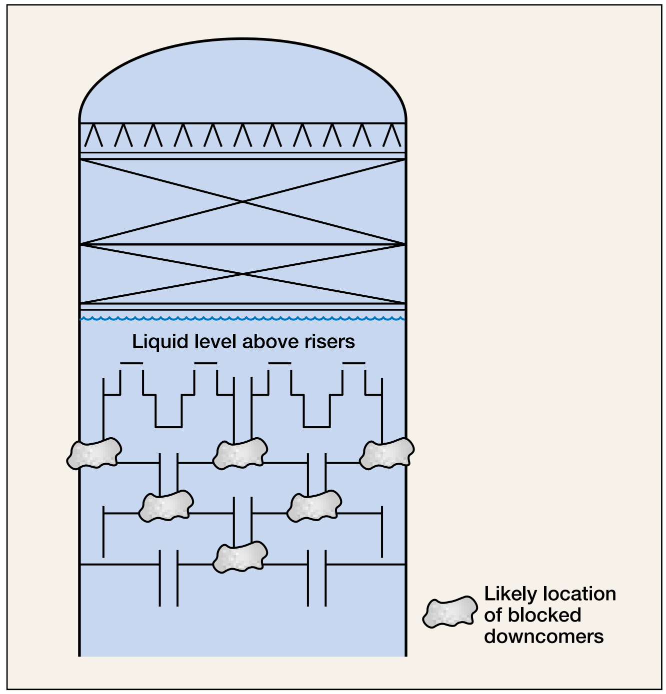

Fig. 10. Flooded collector tray.

Interpreting field data. Liquid was backing up onto the collector because of a restriction in one or more of the downcomers. The downcomer clearance is 2 in. The restriction was most likely due to salts, pieces of corroded packing and/or scale that has laid down on the trays and partially blocking off the area under the downcomer. The restriction was most likely in the collector tray downcomers or in the downcomers of the three trays directly below the collector tray. Fig. 10 shows a liquid collector full of liquid and the probable location of downcomer restrictions.

The collector tray measurements were critical in determining the location of the restriction. One or more downcomer restrictions below the collector tray were preventing liquid from flowing down the column. With-

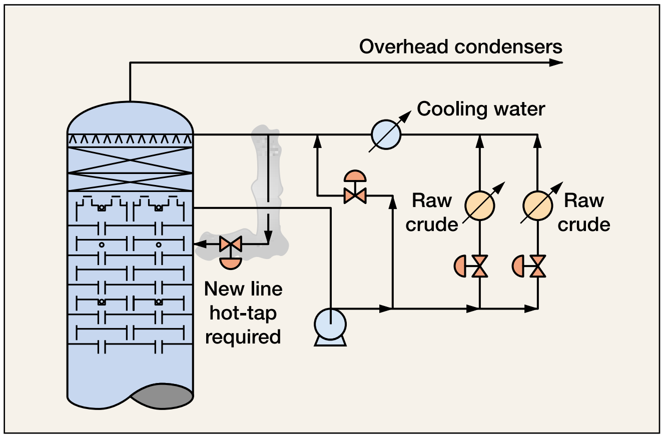

Fig. 11. Hot tap bypass line.

out this information, one could have erroneously concluded either top pumparound bed hydraulic flooding or flooding of the trays between the collector tray and the kerosine side stripper vapor return tray was causing the upsets.

Pressure drop can be used to infer tray or packing performance. High-pressure drop implies flooded trays or packing, while low or no pressure drop implies damaged or missing internals. A properly designed tray will have a typical operating pressure drop of 0.07–0.12 psi per tray.

The measured pressure drops across sections of the column are shown in Fig. 3. The measured pressure drop across the section from the collector tray to the kerosine side stripper vapor return tray includes 0.39 psi of liquid head above the risers. Therefore, the actual pressure drop across these trays was 0.116 psi per tray. The measured pressure drop across the trays between the kerosine side stripper vapor return tray and the diesel side stripper vapor return tray was approximately 0.08 psi per tray. This does not indicate flooded or missing trays.

When trays flood from downcomer restrictions, as opposed to active area flooding, high-pressure drop can only be measured when the downcomers are flooding. This is why measuring the column pressure drop when the unit was in an upset helped diagnose the problem and why gamma scans of the column were inconclusive.

Solution. A bypass line was installed online. The installation required two hot taps, one on the top pumparound return line and one on the crude column shell. The bypass line routes a slipstream of top pumparound return liquid onto active panels of the third tray below the collector tray. Fig. 11 shows the bypass configuration.

Since the bypass line was installed, the crude charge rate has been increased by 20–25 Mbpd and crude processing flexibility has improved. The bypass has allowed optimization of the crude column pumparounds. Decreasing diesel pumparound while increasing top pumparound has improved fractionation between kerosine and diesel products. Kerosine product yield has increased by 7,900 bpd. ■

***Tony Barletta** is a chemical engineer for Process Consulting Services, Inc., Houston, Texas. The company provides revamp, optimization and troubleshooting services to the refining industry. He previously worked as a production planner and process specialist for BP Oil's Alliance Refinery and a process engineer for Hess Oil Virgin Islands Corp. He holds a BS degree in chemical engineering from Lehigh University.*

***Jason M. Nigg** is a chemical engineer for Process Consulting Services, Inc., Bedford, Texas. His responsibilities include test run execution and analysis, revamp process design and process equipment evaluation. Prior to joining Process Consulting Services, he worked for Koch Engineering Co. (now Koch-Glitsch) as a process design engineer and a refinery engineer for Koch Refining Co. in Corpus Christi, Texas. He holds a BS degree in chemical engineering from Kansas State University.*

***Stephanie P. Ruoss** is currently planning & coordination superintendent at the Alliance Refinery. She has worked in the process engineering and planning groups for the 10 years that she has been at Alliance. She holds a BS degree in chemical engineering from Mississippi State University and a MBA from University of New Orleans.*

***Jerry K. Mayfield** is currently a shift superintendent for TOSCO. He has worked in the operations department at the Alliance Refinery for 25 years. In operations, he has worked as an operator, chief operator and asset coordinator.*

***Walter D. Landry** is currently a field shift supervisor for TOSCO. He has worked in the operations department at the Alliance Refinery for 25 years. Previously, he has worked as an operator, chief operator and training coordinator.*

PROCESS
CONSULTING
SERVICES, INC.

Process Consulting Services, Inc.
3400 Bissonnet
Suite 130
Houston, Texas 77005
U.S.A.
Phone: [1]-(713)-665-7046
Fax: [1]-(713)-665-7246
E-mail: info@revamps.com
Website: www.revamps.com