REGIONAL ANALYSIS OF U.S. UNCONVENTIONAL OIL MARKETS AND INFRASTRUCTURE

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Abstract

A renaissance of U.S. oil production and investment is underway, driven by new technology in the form of horizontal drilling and hydraulic fracturing applied to unconventional shale and tight resources. Upstream operators have invested billions in capital to expand northern and inland U.S. crude production which we have conservatively projected will boost U.S. light crude supply by 1.7 million barrels per day by 2016. Lagging investment by midstream and downstream firms is following the upstream capital rush to handle rapid gains in petroleum production. But the nexus of incremental crude supply is clearly shifting away from the Gulf of Mexico. Inland refiners asymmetrically advantaged by access to discounted unconventional supplies are capturing incremental margin by operating at higher utilization and expanding or restarting plants while competitively disadvantaged refiners elsewhere succumb to secular domestic cyclical and global market forces. This summary of a full report by Hart Energy Research highlights our independent comprehensive integrated regional crude balance analysis. After an introduction on unconventional petroleum production technology, the second section gives a brief overview of regional unconventional oil production gains. The third section contrasts these new unconventional gains with legacy midstream infrastructure while section four and five detail resultant midstream deliverability and refining infrastructure investments and divestments.

1 Technological Innovation

It was in Pennsylvania that the modern petroleum industry in America was born. In 1859, Edwin L. Drake, built a derrick and drilled into the ground at Titusville, Pennsylvania. After fits and starts and reportedly quite a bit of local scoffing, Drake struck oil in what has become known as America’s first oil well. Fast-forward 150 years and it seems not only Edwin Drake would be amazed at the technological advances riling the natural gas and crude oil industry today. Technological advances in upstream drilling and well completion applied in unconventional shale and tight resource plays (hereafter referred to as “shale resources”) have rapidly propelled U.S. natural gas output, dampened prices to a fraction of those paid by nations around the world, and have enabled firms to set sights on exporting so-called shale gas around the world to higher priced markets. Along the way, continued refinement and advances in these key upstream technologies have enabled the industry to transfer this knowhow to produce unconventional crude oil with even more stunning rapidity.

The epic success enabled to date by these technologies in producing unconventional shale resources has engendered whispers of potential independence from imported liquid fuels in the not too distant future. While the country is still dependent on imports for over half of its crude oil, the downstream refining advantages enabled by cost-advantaged shale resources have enabled the U.S. to become a competitive net exporter of refined fuels.

Horizontal and Directional Drilling Technology
As detailed by the U.S. Department of Energy\(^1\), oil and gas wells within shale plays are drilled vertically to intersect the shale formations at depths that typically range from 6,000 feet to more than 14,000 feet. Above the target depth, oil service contractors deviate the direction of the well using specialized directional drilling technologies to achieve a horizontal wellbore within the shale formation. The target zone within these formations can be hundreds of feet thick.

**Figure 1: Technologies Used in Horizontal Drilling and Hydraulic Fracturing**

Wells may be oriented in a direction that is designed to maximize the number of natural fractures present in the shale intersected. These natural fractures can provide pathways for the hydrocarbon that is present in the rock matrix to flow into the wellbore. Horizontal wellbore sections of 5,000 feet or more may be drilled and lined with metal casing before the well is ready to be hydraulically fractured, which is the second important innovation enabling the oil and gas shale renaissance.

**Hydraulic Fracturing**

The U.S. EPA defines hydraulic fracturing as a technique in which large volumes of water and sand, and small volumes of chemical additives, are injected into low-permeability subsurface formations to increase oil or natural gas flow \(^2\). The hydraulic fracturing technique and process is one of the well completion and stimulation techniques that have been used for decades in over 1 million wells.

The injection pressure of the pumped fluid creates fractures that enhance gas and fluid flow, and an entrained “proppant” comprised of coated or uncoated sand, ceramic, or other coarse material in various sizes holds the fractures open. Most of the injected fluid flows back to the wellbore and is pumped to the surface.

\(^1\) U.S. Department of Energy

\(^2\) U.S. Department of Energy (DOE)
Beginning at the toe of the long horizontal section of the well, segments of the wellbore are isolated, the casing is perforated and water is pumped under high pressure (thousands of pounds per square inch) through the perforations, cracking the shale and creating one or more fractures that extend out into the surrounding rock.

These fractures continue to propagate for hundreds of feet or more until the pumping ceases. Sand carried along in the water props open the fracture after pumping stops and the pressure is relieved. The propped fracture is only a fraction of an inch wide, held open by these sand grains. Each of these fracturing stages can involve as much as 10,000 barrels of water with a sand usage of 1 pound per gallon.

Shale wells have as many as 25 fracture stages, meaning that more than 10 million gallons of water may be pumped into a single well during the completion process. A portion of this water is flowed back immediately when the fracturing process is completed and is reused. Additional volumes return over time as the well is produced. This inherent water usage and recycling or disposal are two of the current challenges that will likely see continued technological innovation in the near future.

**Manufacturing Approach**

The technology for unconventional resource recovery continues to advance. One of the most advantageous recent improvements is in the form of multi-well ‘pad drilling’ which is one of the keys to an evolving manufacturing approach for oil field development.
The key to multi-well pad drilling is directional drilling that enables multiple underground productive target reservoirs to be drilled and stimulated into production from just a central well pad site at the surface. In this way, multiple reservoir acres can be drained from fewer well sites and with less capital investment, lower operating cost and schedule requirements, and a much smaller surface footprint.

A shale gas production subcommittee of the U.S. Department of Energy wrote in 2011 to call multi-well pad drilling “one clear example” of the “significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact.” Further, the DOE committed explained that multi-pad well systems allow for improved efficiency through repetition of operation at the same site for multiple wells on a single site with a much smaller footprint. Specifically, the committee’s documentation cited the centralization of gathering systems, the minimization of truck trips and mileage expended during the drilling and completion process, and more.

Figure 3: Diagram of Field Drained by Multiple Directional Wells Developed from Four Pads

*Image Credit: Chesapeake / Statoil.*
2 Regional Unconventional Oil Gains

Unconventional shale and tight oil producers have arrested and even reversed the trend toward declining U.S. domestic crude oil production. This comes after the lengthy moratorium in offshore drilling as a result of the Macondo disaster in the Gulf of Mexico.

Figure 4: U.S. Field Production of Crude Oil

But before crude from the North Dakota Bakken, the Texas Eagle Ford, and plays in other states made it into U.S. pipelines and refineries, hydraulic fracturing and horizontal drilling technologies were first directed with epic success to produce natural gas. In the last few years, natural gas production has recovered former peaks and set new record levels.

Figure 5: U.S. Dry Natural Gas Production

Going forward, Hart Energy Research conservatively projects that annual average unconventional oil production will grow to 1.7 million barrels per day by 2016 combined across key U.S. shale and tight oil resources. Full details of these projections are contained within the Hart Energy Research report entitled “Refining Unconventional Oil: U.S. Resources Invigorate Mature Industry.”

Because U.S. unconventional producing regions are not ideally aligned with the existing asset base of operating refining capacity, getting these rapidly increasing incremental barrels of crude oil to market through the existing U.S. midstream capital infrastructure base has proven not just a small bit difficult. The production of unconventional light and heavy oil in Canada adds further complexity and pressure to the existing U.S. petroleum infrastructure.
Price Differentials
Locational differences between the incremental crude supply and demand centers and transportation bottlenecks between them have driven considerable price disparities between otherwise fungible light sweet crude oil grades. Figure 6 shows the price disparities reported by Bloomberg as of press time.

The per barrel price disparities of Figure 6 illustrate locational differentials between key like crude grades such as the inland U.S. light crude benchmark West Texas Intermediate (WTI) and the Brent benchmark light crude imported over water to U.S. Coastlines from the North Sea. Crude feedstock costs are the most expensive variable factor input cost for a refining firm, so refiners in the upper and inland portions of the U.S. with nearby access to crudes priced along with WTI (shown in black text on Figure 6) are at a considerable advantage to coastal refiners that purchase and process the similar crude at higher prices set by waterborne crude markets (shown in blue font on Figure 6).

But Figure 6 also illustrates the spreads in crude price that relate to crude quality. The most common crude quality parameters that are used in price setting are the crude density and sulfur content. Historically, lighter, less dense crude oils are considered of a higher quality and are sold at premium prices over heavy, denser crude oils. Physically, light crudes are more readily refined at lower cost into usable and saleable fuels. That’s part of the reason why heavier WCS (Western Canadian Select) crude north of the border has historically traded at substantial discount to lighter grades of crude oil including nearby Bakken crude oil. That quality differential, and a further locational and transportational basis differential offers further explanatory power as to why WCS is priced at an even deeper discount to the LLS (Light Louisiana Sweet) crude on the Gulf Coast.

A stark illustration of the locational differential and its impact downstream can also be isolated by comparing WCS heavy crude pricing to those of the similar Maya heavy crude grade imported from Mexico into Gulf Coast marine port facilities. Lacking access to easy transport from the Eastern Canadian oil sands region to the U.S. Gulf Coast refining hub where over half of U.S. fuel refining capacity exists, the WCS grade sells at a deep discount to Maya. Crude feedstock costs are the most
expensive variable factor input access cost for a refining firm, heavy crude refiners in the upper inland portions of the U.S. with nearby access to WCS crudes are at a considerable advantage to coastal heavy crude refiners that purchase and process the similar Maya heavy crude at higher prices set by waterborne crude markets.

Furthermore, a historical inverse relationship has evolved between crude sulfur content and crude price. The more sulfur a crude contains, the more secondary refinery processing is required to produce low sulfur fuels to meet market standards for evermore cleaner fuel. That means more refinery capital and operating expense is required to refine sulfur bearing crudes.

Refiners have thereby sought to purchase sour crudes at a discount relative to higher quality crudes with less sulfur content that incur less secondary processing expense. An example of this tendency in action is the evident price spread between the relatively high sulfur bearing Poseidon sour crude grade versus the Light Louisiana Sweet (LLS) crude on the Gulf Coast.

Integrated Regional Crude Balances:
Variation in pricing can give an instant read on market reaction to integrated crude oil fundamentals in North America. But to evaluate the dynamic, interrelated regional impact of these new supplies within the integrated U.S. oil value chain, Hart Energy Research performed crude balances around the five regions that correspond to the U.S. DOE’s five U.S. Petroleum Administration Defense Districts, (PADD areas).

This geographic segmentation scheme enables direct matching of EIA data disclosures to the analyses by Hart Energy Research to better assure the transparency and reliability of our analysis and the historic data and future disclosures by EIA and related sources included within.

Figure 7 shows a schematic diagram from the report section dealing with the PADD 4 Rocky Mountain area as reported for 2011 in thousands of barrels per day (kb/d).

Figure 7: 2011 Fundamental PADD 4 Crude Balance

Production + Imports + Inbound Transfers
= Storage Additions + Exports + Outbound Transfers + Refinery Run:

Sources: U.S. EIA data, Hart Energy Research analysis.
Our balances incorporate historical analysis and projections for production, imports, distribution and refinery processing of crude oil. Key components of the analysis include:

1) Unconventional projections from Hart Energy’s North American Shale Quarterly service. The areas and plays incorporated into our forward oil production projections include:
   a) The Bakken / Three Forks Shale Play in North Dakota and Montana
   b) The Eagle Ford Shale Play in Texas
   c) The Niobrara Shale Play in Colorado and Wyoming
   d) The Permian Tight Oil Play in Texas and New Mexico
   e) The Utica Shale Play in Ohio, Pennsylvania, West Virginia and New York
   f) The Anadarko / Woodford Shale Play in Oklahoma

2) Hart Energy Mapping & Data Services (Rextag) for midstream infrastructure data and mapping.

3) Refinery expansion and contraction intelligence from Hart Energy’s digital newsletters.


5) Other proprietary independent research and channel checks with industry contacts.

Resultant Production Outlook
The findings show that the incremental supply and production of unconventional oil is neither uniformly distributed across the geography of the five U.S. PADD regions nor is it colocated with the major U.S. refining hubs that have evolved over prior decades and centuries.

Production is centered in the inland areas and away from the coastal regions of the U.S. That gives rise to a need to reconfigure existing infrastructure or re-invest in new infrastructure to serve new incremental supply regions with existing demand centers.

Most of this will be in the heartland areas of the continental U.S., centered in PADD Areas 2, 3, and 4, which comprise the Midcontinent, Gulf Coast and Rocky Mountain regions, respectively. The advantages (or disadvantages) further downstream in refining firms also vary by location with access to these supplies through midstream assets being the key determinant of who gains or losses relative refining competitive advantage.

Because the incremental upstream supplies are concentrated in geographic areas not ideally aligned with existing U.S. refining capacity, the advantages (or disadvantages) further downstream also vary by location.

As a result of the central and northerly location of new unconventional resources versus consuming refineries increasingly concentrated in the south, the nexus of incremental U.S. crude supply is shifting away from the Gulf of Mexico which for decades has been the provider and refiner of the incremental barrels in the recent past. Currently, the flow of incremental barrels of domestic crude are expected to increasingly issue forth from central and northern inland producers to southern and coastal refiners.

These developments mark not only a paradigm shift but also a physical shift in barrels seeking to reverse the prior predominant northerly flows from coastal producer to inland refiner. Prospects of increased unconventional light and heavy oil sands imports from Canada add complexity and momentum to the restructuring now under way". 
Although midstream improvements are being commissioned and innovations are occurring to improve deliverability and arbitrage the crude price spreads, the rapid ramp of U.S. unconventional oil supplies and the shift from a northerly to southerly flow regime have presented riveting challenges that have largely remained unaccommodated to date in the considerable but legacy infrastructure of the U.S. oil industry.

3 Legacy Infrastructure

Although the country is well served by a portfolio of existing logistics and deliverability infrastructure, change upstream or downstream can reduce midstream asset utilization and even render existing infrastructure obsolete.

Crude Production and Pipeline Infrastructure

The rapidly rising volumetric surge in U.S. unconventional oil output is not uniformly distributed by state or across the five U.S. PADD regions. They are mapped within the green areas of Figure 8. Production is centered in the inland areas and away from the coastal regions of the U.S.

Also shown on Figure 8, the production of unconventional shale and tight oil along the East Coast and West Coast have either not been found to exist or are otherwise not proven or expected to yield material incremental supplies over the next five year forecast period. Moratoria on new production along coastal regions, either longstanding or recent, also have lessened the value and utilization of existing offshore crude oil pipelines that had run or still run from offshore to onshore and then inland up into heartland refineries.

Figure 8: Existing Inter-Regional Crude Oil Pipeline Infrastructure with Key Unconventional Oil Areas

Refining Infrastructure
With respect to legacy downstream infrastructure, we also found that advantages (or disadvantages) resulting from rising unconventional production vary by refinery location. As shown in Figure 9, the majority of the nation’s operating refining capacity is located in coastal regions. Over half of the crude oil that was processed in the U.S. in 2011 was processed in the large, complex world-scale refineries located in the Gulf Coast region.

The predominant coastal concentration of U.S. fuels manufacturing reflects both the enduring density of coastal end use markets and the 20th century trend toward offshore oil production and increased reliance on imported waterborne crude oil deliveries from around the world. Those large scale wells and supertanker deliveries

Figure 9: Proportion of 2011 U.S. Total Refinery Crude Runs by PADD Area and Coastal Proximity

The resultant midstream bottlenecks in legacy infrastructure have shifted upstream and downstream profitability and viability across the U.S. oil value chain.

Because sales prices for refined products leaving the refinery gates across America vary less than the crude expenses coming into the same refinery gates, the refiners with access to discounted unconventional crude oil have the opportunity to capture more operating margin. Advantaged refiners thus benefit from higher refinery operating utilization and opportunities to expand refinery capital via incremental projects, new grassroots construction, and even restarts of idled refinery capacity.

But elsewhere, existing refineries without access to cost-advantaged unconventional oil feedstock and without low cost unconventional gas fuel supplies are seeing the viability of their assets challenged. Some former refinery operators, notably those along the coasts or in island states or territories of the U.S., have opted to cease processing crude oil and instead either dismantle these plants or reconfigure certain assets for other purposes including petroleum storage or distribution terminaling.
Amid this milieu of rapid upstream and downstream change, midstream bottlenecks in legacy infrastructure can and do arise. The rapid boom in inland unconventional production places a premium on existing pipelines in the U.S. heartland, provided they are useful to deliver incremental (predominantly inland and northern) supplies to existing refineries (coastal refineries).

To date, we found a shortage of existing pipeline capacity available to make crude oil deliveries along the routes needed today. This shortage of high-volume transfer capacity has driven a wedge between the discounted crude prices in crude-long domestic producing regions and the premium global prices seen in crude-short and import-reliant coastal regions.

We also found a stark lack of existing crude oil pipelines capable of delivering existing or incremental domestic crude oil into the East Coast and the West Coast refining markets. This crippling lack of high-volume pipeline capacity is an artifact of the lack of production in the case of the former and the wealth of offshore production in the latter case.

This mismatch of U.S. infrastructure for today’s production to reach higher value markets has also driven a wedge between U.S. natural gas prices and global natural gas prices. Figure 10 shows global unit cost discrepancies per million British thermal units ($/MMBTU) for deliveries of imported liquefied natural gas (LNG) around the world.

Lacking domestic demand to absorb record natural gas production and facing regulatory and infrastructure constraints against LNG exports, natural gas prices have declined to levels which cannot sustain current expenditures for marginal incremental natural gas production.

These disparities and discounts have begun inducing natural gas producers to restrict current production and scale back on future capital spending.

Legislative chokepoints are also part of U.S. energy ‘infrastructure.’ As surely as physical pipeline constraints and bottlenecks, regulations can hinder the rational flow of low cost production to higher valued markets.
For example, marine transport of U.S. goods, including energy and fuels, between U.S. ports must comply with provisions of the Jones Act which can limit or preclude marine shipment. Furthermore, most crude oil exports from the U.S. are prohibited without required regulatory and even presidential approval. Similarly, LNG exports require approvals by multiple federal agencies among other many other levels of environmental or state regulation covering the facility itself. Like physical midstream bottlenecks, regulation can act as an impediment to a market seeking to rebalance amid significant change.

4 Midstream Infrastructure Investment

Upstream operators are conservatively projected to add 1.7 million barrels per day (b/d) of light crude supply largely coming from inland, northern areas by 2016. Midstream operators are following this upstream rush by reconfiguring U.S. infrastructure with new oil pipeline capacity (Figure 11) and reversals matched by innovative crude-by-rail options to make the connections.

Thus, we found that moving domestic oil to a refining market in flux entails a portfolio approach to deliverability. Further improvements may conceptually be added to the portfolio in the form of gas pipeline conversions to oil service in Canada and the U.S.

Amid these prospects, the dominant industry trend has been against vertical integration up and down the petroleum value chain in favor of segmented operation. This increases the complexities of optimal investment by midstream firms.

Figure 11: Crude Oil Pipeline Construction in Progress in the Great Plains Region

Source: Bridger Pipeline, LLC (True companies, Casper, WY).
Multi-billion-dollar long-lived pipelines are not speculative ventures, so midstream investment tends to lag production growth upstream. From the other side, a pipeline can be made obsolete by refinery contractions downstream.

From our balance performed for the Rocky Mountain region, we see midstream firms proposing to expand import and inbound pipeline capacity by 1.38 million barrels per day between 2011 and 2016. Similarly, the industry is seeking to expand outbound and export pipeline capacity by 1.59 million barrels per day over the same horizon. Adding the absolute value of these expansions, we see this as a 211 thousand barrel per day improvement in overall outbound crude oil deliverability for the region.

Figure 12: Potential Projected PADD 4 Inbound Transfer and Import Pipeline Capacity for Announced Investments, Barrels per day (b/d)

Figure 13: Potential Projected PADD 4 Outbound Transfer and Import Pipeline Capacity for Announced Investments, Barrels per day (b/d)
Led by unconventional oil gains in the Niobrara Shale play, our projected 168 thousand barrel per day increase in net crude oil production (incremental unconventional production less conventional declines) for PADD 4 over the 2011 to 2016 forecast period fits comfortably within that announced and projected pipeline capacity improvement.

**Figure 14: PADD 4 Crude Oil Production Projections**

![Figure 14](image)

*Sources: Rystad Energy, Hart Energy Research.*

But in addition to these favorable pipeline deliverability improvements, inland crude producing regions are also seeing investors make plans to add crude-by-rail loading terminal facilities (Figure 15) to originate crude shipments to any number of emerging destinations with offloading crude-by-rail terminal facilities around the country.

**Figure 15: View of Rangeland Energy LLC’s COLT Bakken Crude-by-Rail Loading Terminal**

![Figure 15](image)

*Image courtesy of Rangeland Energy LLC*

Capacity of such movements are determined by the number of tankcars loaded (Figure 16). The volume of these crude-by-rail movements can be as small as 700 barrels in manifest train configurations of one tankcar or as high as 70,000 barrels or more in unit trains pulling a maximum of around 100 tankcars.
As shown in Figure 17, our research pointed to investors seeking to construct 3 terminals in PADD 4 with a capacity to move a projected incremental 151 thousand barrels per day (kb/d) of crude to any number of destinations with crude by rail unloading terminals across the country.

On a national basis, by summing up the resultant values from the five individual PADD balances, Hart Energy anticipates investment in more than 5 million barrels per day of long-haul inter-PADD inbound and import deliverability, including the TransCanada Keystone XL pipeline serving the three
inland PADD 2, 3, and 4 areas. Similarly, from announced outbound and export deliverability projects, we estimated expectations for more than 4.2 million barrels per day of improved outgoing deliverability.

As sizable as that sounds, the announced pipeline projects offer East and West Coast refiners little access to U.S. unconventional crude outside of plans for exports to Canada and re-imports via eastern pipeline interconnects. But we believe conversion of underutilized natural gas pipelines that run to or from the Gulf Coast could be converted to or back into oil service to supply crude to both coasts in the later years of or following our forecast period.

But as noted above, crude-by-rail logistics are expanding coast-to-coast. Crude-by-rail facilities are offering East and West Coast refiners a lifeline to low cost crude despite no current direct pipeline access to incremental producing regions.

As of press time, our report included 54 terminals with more than 4.5 million b/d of combined capacity either loading or offloading crude by rail in the U.S. These facilities add material optionality and connectivity by loading and unloading crude from origination terminals in producing areas to destination terminals and refineries in all five PADD areas. We estimate that utilization of the nation’s largest crude-by-rail fleet in the Bakken region, fewer than five years old, is already roughly 50%.

We also found that the southbound rush of incremental unconventional crude deliverability by pipeline and rail comes with an oil storage capacity boom on the Gulf Coast of between 34.5 and 39.5 million barrels. This expansion rivals the nearly-completed 22 million barrel storage expansion in Oklahoma that glutted the Cushing Hub and contributed to the decline in WTI prices.

Given the expansion of inbound deliverability and limited outbound capacity, the Gulf Coast may soon become known as the “Cushing Coast” as a wave of discounted crude cascades south to a potentially sated coastal refining fleet.

5 Downstream Infrastructure Investment/Rationalization

Refiners realize advantaged crude feedstock costs and high operating margins by sourcing low cost crude from among those whose prices move according to prices at the crude-flush WTI hub in Cushing, Oklahoma.

As a result of robust inland production overwhelming existing midstream deliverability and capacity, these advantaged crudes can be obtained from unconventional oil producers in the PADD 2 Midcontinent, the PADD 4 Rocky Mountains and the inland PADD 3 Texas areas. As that would suggest, the historical data shows that refiners in these areas have realized the lowest crude costs.

In addition to crude costs, we also analyzed refinery operating margins. The refining industry utilizes a measure called the crack spread to compare benchmark operating margins. The refining crack spread is simply the theoretical per barrel profit realized by purchasing and refining a barrel of crude purchased at local prices into a specified slate of saleable refined products whose value is also quantified by local fuel sales prices.

The simplest and most widely referenced crack spread benchmark is the “321 Crack Spread” which is calculated from 3 barrels of crude refined into 2 barrels of motor gasoline and 1 barrel of distillate fuel, all valued at local prices and then expressed on a per barrel basis. When calculated and compared across the 5 PADD areas, we found the expected result that the PADD regions with lowest crude costs show the highest values for the 321 crack spread benchmark.
Figure 18: Historical Refinery Crude Costs by PADD Region

Sources: Hart Energy Research analysis of EIA data.

Figure 19: Calculated 321 Historical Crack Spread Benchmarks by PADD Area

*Lower inland PADDs 2 & 4 crude costs drive materially higher crack spreads compared to competing coastal refineries in PADD 1, 3 and 5 -*

Sources: Hart Energy Research analysis of Bloomberg data.
Positive crude-side fundamentals in the form of low crude costs and high margins drive higher utilization, new refinery construction or expansion, and restarts of idle capacity. Discounted U.S. shale gas used for refinery fuel and feedstock also adds further advantage.

The contrapositive is also true. Refiners without access to low cost crude who rely on costly waterborne crudes and burn high cost fuel in their operations suffer poor margins which reduce utilization and lead to potential capacity rationalization.

Our research found that the margin enhancement realized by refiners with access ideally to both low cost shale gas for fuel purposes and to advantaged discounted crude tend to expand their refining assets and capacity either through incremental projects or through major new grassroots facility construction. The location of these refining capital expansion projects fall within the crude and gas rich PADD regions 2, 3, and 4.

Conversely, we found no significant expansions in the high cost coastal regions along the Atlantic and Pacific shores. Rather, we found tendencies to rationalize refining operations either through sale, idling, or dismantling and repurposing into other uses such as petroleum distribution terminals.

References

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