Comments on Volcker Rule Regulations Regarding Energy Commodities

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IHS CERA
IHS Consulting
IHS Global Insight

IHS Inc. is pleased to submit this independent comment letter to the Office of the Comptroller of the Currency, Board of Governors of the Federal Reserve System, Federal Deposit Insurance Corporation, Securities and Exchange Commission and the Commodity Futures Trading Commission regarding *Restrictions on Proprietary Trading and Certain Interests in, and Relationships with, Hedge Funds and Private Equity Funds.*[1]

Our research examines the impact on the U.S. domestic energy sector and economy as a whole, under the implementation, as proposed, of the market making provisions of section 13 of the Bank Holding Company Act, commonly known as the "Volcker Rule."

This study has been commissioned by Morgan Stanley. The analysis and the opinions contained in this submission are entirely those of IHS Inc. and its related organizations and they are solely responsible for the contents herein.

[1] OCC: Docket ID OCC-2011-14 / RIN 1557-AD44, Federal Reserve: Docket No. R-1432 / RIN 7100-AD82, FDIC: RIN 3064-AD85, and SEC: File No. S7-41-11, and CFTC RIN 3038-AD05, respectively.

This IHS report draws on the multidisciplinary expertise of IHS Inc. — IHS CERA, IHS Consulting and IHS Global Insight.

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1. Executive Summary

Energy supply is essential to almost every economic, social, and cultural activity within U.S. society. The energy sector is also a significant contributor to overall economic performance and job creation. The efficiency and reliability of the energy supply industry are vital to U.S. living standards, economic growth, and national security

As commodity prices and commodity price volatility have increased, both producers and consumers of energy products have developed strategies to cope with higher prices and to mitigate exposure to the risks created by price volatility. These strategies take different forms for energy producers than for consumers. But both segments depend on the risk management (RM) and intermediation services of U.S. banks. These services have become very important to the efficient functioning of the energy economy, and so contribute to the economic growth and vitality of the U.S. economy.

Banks Play a Key Role

In response to the changing demands of their customers, banks have expanded their role of providing financial resources and services to include risk management and intermediation services to companies participating in the commodities sector. The more common of these services include commodity price hedging, profit margin hedging, and secured financing in a variety of forms. In order to provide these services, banks take on the role of a market maker in commodity price risk. This market maker role requires banks to broadly participate in the relevant commodity markets (both physical and financial), including taking principal positions. As a result, banks have gained deep knowledge, functionality, and expertise throughout the energy complex.

In the role of market maker in commodity markets, banks act in a fashion similar to the traditional role of a financial intermediary. Banks make credit quality judgments regarding customers and counterparties, develop balanced portfolios of assets and obligations, and offer customized services designed for specific customer situations. These functions all fit within the role of the market maker. However, the nature of the commodities markets can make these functions more complex than in other financial markets. The established commodities exchanges cover a very limited range of energy commodities and locations and have very limited liquidity in long-dated contracts. Accordingly, to effectively fulfill the role of a market maker, banks must engage in a wide range of transactions both inside and outside the commodities exchange framework.

Owing to the unique nature of the commodities markets, the implementation of the Volcker Rule as currently proposed – and its narrow interpretation of what constitutes market making – is likely unduly to constrain the ability of banks to provide the necessary market making activities for commodities risk management and intermediation services. Customers who need these services may find that their cost has increased, or that these services are no longer available.

How will the Energy Industry be Affected?

The subsequent sections of this document provide detailed analyses of the reliance of representative segments of the energy industry on risk management and related services provided by U.S. banks, and the potential impact of reductions in the availability of these services. The key conclusions from this analysis are as follows:

- **Reduced bank transaction activity could reduce liquidity in commodity exchanges and OTC markets, and even availability of commodities risk management, financing and other intermediation services.** Bank transaction activity provides significant liquidity to both exchanges and the OTC markets. A reduction in liquidity and availability is expected to result in increased price volatility for energy commodities, wider bid-ask spreads, reduced access to services, and increased basis risk for hedging strategies.

- **Natural gas resource development could be impaired.** Independent producers are responsible for the majority of upstream capital spending in the U.S., with particular emphasis on the tight oil and shale resources that are driving growth in production and employment in the sector. These companies are able to hedge future production revenues in order to stabilize cash flow, which has been critical to sustaining investment plans. Banks are key suppliers of these hedging services. If this capability is curtailed due to the Rule, upstream investment, particularly in gas-prone fields, could be reduced substantially, reducing gas production and associated employment. With lower production, gas prices would increase. Our estimate is that investment could be reduced by $7.5 billion per annum leading to a 2.1 BCF/D reduction in gas production, a $0.64 per MMBTU increase in gas prices and loss of 182,000 jobs.

- **Electric power prices could increase.** Utility customers typically place high value on stable and predictable electricity prices. Utilities, however, must operate in an environment of volatile energy prices, particularly for natural gas. Utilities use a variety of risk management tools to dampen volatility, a key component of which are OTC transactions provided by banks. If this capability were reduced, utilities would face higher earnings volatility, which would increase their cost of capital. In addition, higher gas prices could increase overall power costs. Both of these impacts would flow through into higher, and more volatile, electricity prices for consumers. Our estimate is that power costs could increase by $5.3 billion per year.

- **Additional refining capacity could close.** U.S. refiners are already under economic pressure from overcapacity and weak product demand. Many oil companies are either exiting the refining business or selling non-core assets. In recent years, refinery buyers have typically been smaller companies with limited capital resources. In many cases, these companies rely on bank financing of inventories and other working capital in order to maintain operations, and often have entered into long-term margin hedges to reduce anticipated volatility of refining earnings and to secure purchase financing. If the availability of these services provided by banks is curtailed due to a narrow market maker criterion, it is anticipated that none of the currently announced refinery closures on the East Coast would be averted by a sale, and it is possible that additional refineries will cease operations. These closures would have immediate local economic effects as well as contributing to higher gasoline prices on the East Coast.

- **East Coast gasoline prices, and price volatility, could increase.** Initially the cost of importing crude oil to supply U.S. refineries would increase, as the banks could be limited in their ability to manage the price risk between offshore and domestic prices during the voyage. This would exacerbate the trend towards refinery closures. To adequately supply East Coast consumers in the face of additional refinery closures, significant changes in global supply patterns would have to take place. Gasoline supply from local refineries would have to be replaced by imports and increased shipments from the Gulf Coast, and prices would have to increase to create incentives for these changes to occur. The ability to import gasoline from distant sources has been enhanced by RM tools that allow importers to reduce exposure to oil price volatility during transit. If the availability of these tools is reduced, then the effective cost of imports would be higher, and the volatility of East Coast gasoline prices would increase. The gasoline price increase is estimated at 4 cents per gallon, or $2 billion per year.

- **Key energy consuming industries could see increased costs and price volatility.** Trucking companies, airlines, railroads and barge operators all face energy costs that are a large contributor to total operating costs. Companies often use hedging strategies to manage price risk, improve competitiveness and reduce earnings volatility. If the availability of these tools is reduced, these companies would likely face greater earnings volatility, with increased pressure to pass risk on to the consumers for their services through fuel surcharges and other methods.

What is the Potential Economic Impact?

The subsequent sections provide details concerning the potential economic impacts from each of the industry segments modeled above. To gauge the overall economic impact, the various industry effects were simulated in the IHS Model of the U.S. Economy over the 2012-2016 period. The specific effects included reduced natural gas drilling and completions investment, higher natural gas prices (which flow through into higher electricity prices), higher cost of capital for electric utilities, higher East Coast gasoline prices, closure of two additional refineries, and increased gasoline imports. The combination of these effects resulted in payroll employment estimated to be over 200,000 lower over the 2012-16 period than in the current IHS base case forecast. The loss of jobs will peak in 2016 with payroll employment being 243,000 lower than the IHS base case forecast. In addition, real GDP is $34 billon (2005$) lower in 2016 and cumulative nominal federal tax receipts over the 2012-16 period is $12 billion lower than in the IHS base case forecast.

Conclusions

Risk management and intermediation services are an integral part of the domestic real economy. These services provide many benefits, including commodity price stability and security of supply. Broad market liquidity is key to providing safe, efficient and well-functioning commodity markets. Any curtailment in the availability of risk management services will affect consumer prices, domestic jobs, and economic growth.

As the Volcker Rule and other elements of regulatory change are implemented, it is of utmost importance that all due care be taken to ensure that market liquidity and the availability of essential services are not constrained, while safeguarding the quality and safety of our financial markets. If the role and permissible activities of market makers are too narrowly defined, the risk of curtailing important services offered by the banking sector will increase. The proposed Rule should be closely examined and modified in order to support the safety, soundness and security of U.S. financial markets, as well as activity across the economy.

2. Corporate Risk Management Services

Scale of Energy Industry & Role in U.S. Economy

It is difficult to overstate the importance of the energy industry to the U.S. economy. In some form, commercial energy is essential to almost every economic, social and cultural activity in society, from fueling industry and heating homes, to maintaining the transportation system on which commuting and commerce depend, to enabling the digital economy. The entire food system – from fertilizer to harvesting to transportation to processing – depends upon energy resources. Even those who wish to live “off the grid” are dependent on equipment and supplies that are manufactured and transported using commercial energy sources. Without efficient energy supply, no other sector of the economy could function in its current form.

In addition to its indispensable supporting role in the economy, the energy supply industry is a major direct contributor to economic activity. Based on Bureau of Labor Statistics reports, direct employment by energy-producing and distribution industries provided roughly 1 million jobs in 2010, or about 0.7% of total U.S. employment (not including retail station employment).[2] However, these same industries produced almost 5% of U.S. economic output. These industries and jobs are dispersed throughout the nation. Refineries are located in 31 states; power generation resides near major and minor population centers; retail fuels are available within a short drive for every citizen; natural gas is piped to most homes and buildings and electricity is available in essentially every home. The healthy functioning of the energy sector is vital to our standard of living, economic performance and national security. The indirect number multiplies these jobs several times over.

[2] Bureau of Labor Statistics; *Employment and Output by Industry*; categories included are oil and gas extraction; coal mining; electric power generation and distribution; natural gas distribution; petroleum and coal products manufacturing; engine, turbine, and power transmission equipment manufacturing; pipeline transportation

Commodities Risk Management in the Real Economy

Higher commodity prices, along with higher commodity price volatility, have combined with challenging economic circumstances to make for difficult economics within many industries today. These factors introduce risk to both top line revenue and the overall cost structure, impacting cash flow and profitability. As high commodity prices and price volatility persist, sourcing and hedging continues to be at the top of the strategic agenda for many U.S. companies.[3] In this challenging business environment, businesses design their sourcing/hedging programs to reduce cash flow volatility as opposed to conventional aims of simply minimizing sourced or manufactured unit cost. Rising pressure for growth and profitability has led companies with large commodities exposures – both those that are naturally long and those with a natural short – to explore a more strategic role for commodity hedging and trading, as well as the use of innovative risk-shifting mechanisms for inbound and outbound material flows.

With many exposures not easily managed solely through exchange-traded hedging contracts, due both to the required length of exposure and the lack of perfectly matching underlying assets, OTC markets and bank-led corporate risk management solutions have emerged to accommodate this growing business need. These services can bring a more effective hedge, support financing, qualify for hedge accounting treatment, and ameliorate the basis risk that companies would face in attempting to construct solutions from exchange traded products.

Risk Management Beyond the Exchanges

One reason that strategic hedging tends to be carried out in the OTC markets, rather than on the regulated exchanges can be traced back to the need to post initial and variation margin on

[3] Finley, Blaine and Pettit, Justin, "Creating Value at the Intersection of Sourcing, Hedging and Trading" (Fall 2011). Journal of Applied Corporate Finance, Vol. 23, Issue 4, pp. 83-89, 2011. Available at SSRN: Http://ssrn.com/abstract=1975685 or doi:10.1111/j.1745-6622.2011.00354.x

futures exchanges.[4] This can lead to extremely unpredictable cash calls at very short notice, which all but the largest companies can find difficult to manage. This is particularly so for longer-term positions where price variations over the course of a year can be vastly greater than price variations in the short term.

Hedgers favor the OTC market for these further forward positions because they can bring both sides of the hedge into the capital adequacy and financial security discussion. For example, if a producer enters into hedges 1 year forward by selling at $100 per barrel and the price three months later is $125 per barrel, a futures exchange requires an immediate variation margin payment of $25 per barrel, with no room for discussion or negotiation. In the OTC market the hedger can make a case to its bank providing a comparable OTC swap that, although it is losing $25 per barrel on the swap on a mark to market basis, it is gaining $25 per barrel on the physical underlying position on the same mark to market (and therefore the bank does not need to hold $25 per barrel of the hedger's money to secure its credit). This does not mean that the OTC market promotes irresponsible hedging. It simply means the OTC swap provider is better suited than an exchange to consider the trade holistically and develop a more informed view on the capital adequacy of the hedger.

Market Making and Accumulation of Principal Risk

In commodities markets, a market maker acquires a position from one client at one price and then lays off this position or its associated risks, as available, at another average price. The length of time over which a position must be held is subject to the unpredictable timing and direction of the market itself as well as client demands for immediacy. In the world of commodities, the duration (half-life) for this inventory can be significant, due to volatility, liquidity, and the impact of competing market forces.

Market making in most commodities is not an agency business based on commissions or fees, rather one of committing trading capital. For most products there is no continuous quoting, or two-way quoting with back-to-back trades. Rather, market makers accumulate, and work down, inventories of principal risk.

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[4] Currently about $6-7,000 per 1 lot of 1,000 barrels. Gain or loss on a mark to market basis

The fact that there is any liquidity beyond 6 months forward in regulated commodity markets is at least in part attributable to market makers transferring the OTC positions that they opened with hedgers onto the futures exchanges. Despite these activities, liquidity in the long dated months can be sparse.

Market makers cannot hedge with long dated futures contracts due to the lack of market liquidity on the exchange and so they must hedge with near-term futures, which introduce the risk of a time mismatch.

Market makers manage their long dated positions through the short end of the futures exchanges, and then roll them forward over timing to match their exposure. This involves trading the slope of the forward curve and taking the time spread exposure onto their own book.

The client-facing business model of the bank market makers can also lead to the accumulation of principal risk – in this case basis risk – in the reference pricing for corporate risk management solutions.

Characteristics of Market Making in Commodity Markets

Market liquidity is the situation in which there is an ability to easily buy or sell an asset without causing a significant change in the market price. An essential requirement for liquidity is the ample availability of counterparties who are willing to sell when others want to buy and who are willing to buy when others want to sell. Exogenous events coupled with the risk of delayed trade create a demand for liquidity.

Market makers provide liquidity, or immediacy, by their willingness to bear risk for the time period between the arrival of sellers and buyers.[5] *In order to provide this immediacy, commodities market makers must participate in the market as broadly as possible (i.e. both short and long end, both physical and financial markets, etc.), including the accumulation of inventory, or principal positions.*

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[5] Grossman, Sanford J., and Merton H. Miller, "Liquidity and Market Structure," *Journal of Finance*, Vol. XLIII, No. 3, (July 1988), pp. 617-637.

Economic theory often assumes perfect market liquidity where everyone can trade any amount of a position without affecting price. This implicitly requires the unlimited presence of counterparties. While this assumption is clearly wrong in many markets, it can be a reasonable simplification in large, active markets.

Even though the futures markets are generally liquid, the role of the market maker may demand more liquidity than regulators fully appreciate. As a starting point, we characterize market liquidity for several different commodities below, in terms of average daily trading volume in millions of dollars ($MM).

Characterization of Commodity Futures Market Liquidity
Percentiles of Average Daily Trading Volume ($MMs)

Percentile	10th	25th	50th	75th	90th	Mean
Crude Oil	7,754	12,318	20,561	28,748	35,522	21,411
RBOB	2,837	5,122	8,463	11,860	14,725	8,679
Heating Oil	3,519	4,890	7,073	10,459	14,737	8,176
Natural Gas	700	2,262	3,488	5,036	6,835	3,779
Corn	345	928	1,836	3,096	5,127	2,304
Wheat	120	523	983	1,613	2,214	1,126
Copper	4	8	19	47	752	286

Source: IHS Consulting

To put these levels into perspective, the average daily trading volume for a U.S. stock is $20 MM, and below $1 MM, liquidity is sufficiently impaired to affect prices.[6]

There are occasions where, even in the largest and most active markets, liquidity dries up because of the scarcity of counterparties. These are times when, at the current market price and outlook, everyone who wants to be long is already long, and participants who want to be short are already short. When this happens, someone wanting to buy or sell will be unable to do so unless the market price adjusts to induce someone to trade. Reduced liquidity is also associated with an increase in the

[6] Pettit, Justin, “Rx for Stock Liquidity” (November 1, 2005). Available at SSRN: http://ssrn.com/abstract=845544 or doi:10.2139/ssrn.845544.

effective duration of inventory, and therefore principal positions, for a market maker.[7]

An example in which efficient market theory falls short in characterizing the role of making markets in commodities is the case of NYMEX natural gas futures. Market makers face both a time-to-maturity effect and a volatility of daily prices that vary with seasonal demand and intermittent use of gas storage. Price volatility is greater in the winter than in the summer. The persistence of price shocks, and correlations among concurrently traded contracts, displays substantial variation due to varying use of seasonal gas storage.[8]

These effects – a sign of the interplay between the physical and financial markets – is an example of a key difference between making markets in commodities, versus conventional equities or fixed income markets.

Market making challenges are even more acute in the OTC markets that are necessary for commodities risk management. There are two key frictions in OTC markets: (1) finding counterparties takes time, and (2) trade is bilateral, with quantities and prices determined by negotiation. The number and variation in counterparties can induce periods of increased volatility with high bid-ask spreads.[9]

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[7] Duffie, D. "Market Making Under the Proposed Volcker Rule" Stanford University Working Paper, 2012.

[8] Suenaga, H., Smith A. and J. Williams, "Volatility Dynamics of NYMEX Natural Gas Futures Prices."

[9] Fagan, Stephen, "Large Traders and Liquidity in Futures Markets" Department of Economics, *Simon Fraser University working paper*.

3. Banks Provide Services Not Otherwise Available

Banks Role in Commodities Risk Management

U.S. market making banks play a unique and critical role in commodities risk management. It is within this context, that the banks have grown to play an essential role for business as a market maker in corporate risk management and intermediation services.

Banks have a business model to serve clients through market cycles, making markets even in times of stress and when other trading participants may be unwilling, or unable, to do so. Banks play an important role as liquidity providers in less liquid markets, particularly niche and long-dated markets. The strong credit quality of many banks makes them a preferred counterparty with whom to transact. Additionally, many of the bank services are not otherwise available in the market.

Banks are able to assume, mitigate, and transfer client risk. Banks provide full service solutions with integrated risk management, financing, and customized services to clients. Banks are able to provide hedging, asset backed facilities, and working capital facilities to clients. In addition, banks have the balance sheet capacity, ability to judge and extend credit, and the risk management expertise to be able to price risk effectively. Through the use of broad client coverage networks and syndication infrastructure, banks are able to effectively distribute and transform risk.

Market making banks provide much needed liquidity by acting as counterparties in trades and by accumulating asset inventories.[10] As discussed, market makers provide liquidity, or immediacy, by their willingness to bear risk for the time period between the arrival of sellers and buyers, leading to the accumulation of inventory, or principal positions.

Risk management solutions must often draw from both the financial and physical commodities markets, and can involve

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[10] Ricardo Lagos, Guillaume Rocheteau, Pierre-Olivier Weill, "Crises and Liquidity in Over-the-Counter Markets," *NBER Working Paper* No. 15414 (October 2009).

numerous elements. Due to the general illiquidity of many real economy commodities exposures, as well as the unique construct of each solution, banks must accumulate and net-off various exposures that require much more time to unwind than a traditional market maker's position in, for example, U.S. Treasuries.

The evolution of the banking industry's role in market making for commodities risk management purposes is, in many ways, a natural extension of the banks' traditional role as an intermediary in the financial markets. In the financial market, banks serve as the key "market maker" for a very important commodity – money. When a bank makes a loan, it delivers prompt money in exchange for a promise of money returned at some future time plus a fee for the transaction in the form of interest. In providing market making services in commodities, banks often engage in essentially analogous activities.

In order for the banks to be able to successfully play this role, they must be in the market, as frequently as possible, and in as many different positions as possible (including both physical and financial, long-end and short end). Although market making banks are most evident for their activities at the long-dated end of the forward oil curve, they also provide liquidity at the short-dated end of the curve by managing their own positions.

Hedgers, whether they are consumers or producers, tend not to use the futures exchanges for long term strategic hedging.[11] For example, when a hedger enters the market to carry out operational hedges, the other side of the transaction may be taken by a bank that is in the market to manage the strategic hedges of another customer.

The most visible role played by the banks in the oil market is predominantly in the 6-month to 5-year forward period. There are two major reasons for this:

- Regulated futures and options contracts are inflexible relative to the needs of the oil industry for tailored structures.

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[11] By strategic hedging, we mean managing net economic exposures over the planning horizon of the company, and for collateralizing loans for the development or acquisition of assets.

- Typically, the regulated exchanges are not liquid in this forward period.

Banks also provide the service of managing basis risk for clients, including U.S. clients. OTC market makers offer natural gas swaps that are based on locations other than the Henry Hub (e.g. Panhandle basis swap), and this can help eliminate “basis risk” for clients.

Resource Development

By providing hedging and financing services, U.S. banks play a unique and essential role in the development of domestic energy and national energy security. In this credit-constrained environment, traditional financing sources would be challenged to supply the resource development needs of the oil and gas sector. The ability of U.S. banks to make markets and provide risk management solutions is of paramount importance to the U.S. in securing energy supply and supporting the development of the domestic oil and gas sector. The domestic independent gas producer analysis presented in Section 5 provides a quantified example of this.

Resource producers do have other options for project financing, but these come with less attractive terms. For example, a major oil company will demand, as a condition in a deal, that it be granted equity participation along with preferential rights to trade the oil or gas from the project. This strikes at the heart of the independent oil and gas sector, which plays a very important role in finding and developing resources.

Efficient Price Formation

U.S. banks contribute to the quality and safety of U.S. financial markets through their contribution to efficient price formation. For example, banks provide the RM services necessary to import foreign crude into the U.S. market. This activity includes a physical sale, a physical purchase, and a hedge for both transactions. It also may include participation in the physical freight market and the forward freight market to hedge the shipping cost risk.

For example, participation in both the prompt, Dated Brent market and the 25-day forward market has given U.S. banks an understanding of the international oil price formation process and the ability to provide a service to the U.S. refiners that must import crude grades from the North Sea, Africa, Middle East and South America. These are increasingly priced by reference to Brent, because of the breakdown in the correlation of U.S. domestic crude prices with those in the international market.

Market Innovation

As a result of their client facing business model, and in response to client needs, U.S. banks have pioneered the development of freight hedging, such as the establishment of the Freight Forward Swap Agreement, which is priced in terms of fixed Worldscale rates and cash-settled by reference to the Baltic Exchange's benchmark freight routes. U.S. banks provided early liquidity to the tanker freight rate hedging market to get it off the ground in 2008 when freight costs were escalating out of control. Similarly, U.S. banks were offering contracts in "partial Brent" cargoes back in the early 1980s, before the NYMEX WTI futures contract and the then International Petroleum Exchange (now ICE) Brent futures contract were established. U.S. banks also pioneered the development of Dubai/Oman OTC swaps, as the Dubai cargo forward market waned because of the declining volume of the cash Dubai commodity underlying the forward contract.

Banks Advance Market Knowledge

Over the past decade, U.S. banks have developed deep knowledge of the financial and physical energy markets. Banks have developed this knowledge through their investment banking operations for energy firms, through their participation in the physical product supply and marketing operations, and through the provision of risk management services to energy firms. Banks have traditionally provided financial advisory services and many forms of financing to energy firms involved in mergers, acquisitions and other large capital transactions. Some U.S. banks and their energy trading affiliates have become major market participants in crude oil and refined product supply operations in the physical markets. Knowledge and experience gained through financial and capital market operations and physical supply, trading and risk management operations have made U.S. banks uniquely qualified to provide a broad range of risk management and intermediation services not otherwise available.

The Value of the Role of U.S. Banks

The value of the role of the banks in providing risk management and intermediation services is outlined below. We characterize and quantify, both empirically and anecdotally, the "costs" of reduced market liquidity for the commodities markets – both in terms of explicit cash costs, as well as other economic costs.

Commodities can be more difficult to study, due to the information quality, especially in OTC markets. For example, quantification of liquidity costs for agricultural futures markets is challenging because bid-ask spreads are not usually observed. In some cases, we have estimated bid-ask spreads from daily high and low prices over two day intervals, to provide a proxy measure of these transaction costs.[12]

The "costs" of illiquidity are not limited to transaction costs and bid-ask spreads, alone. As we saw in the recent financial crises, market access was often a greater cost – market access was often not available at any price. We outline five important economic value drivers to the role of market making banks below.

i) Reduced Price Volatility

U.S. bank corporate risk management and intermediation services reduce price volatility. Any reduction in bank activity may lead to increased price volatility. For example, in the European power sector we found 34% higher price volatility in the less liquid French Power market versus the similarly sized German market. And the chart below illustrates how copper futures prices are much more volatile in the periods of reduced liquidity.

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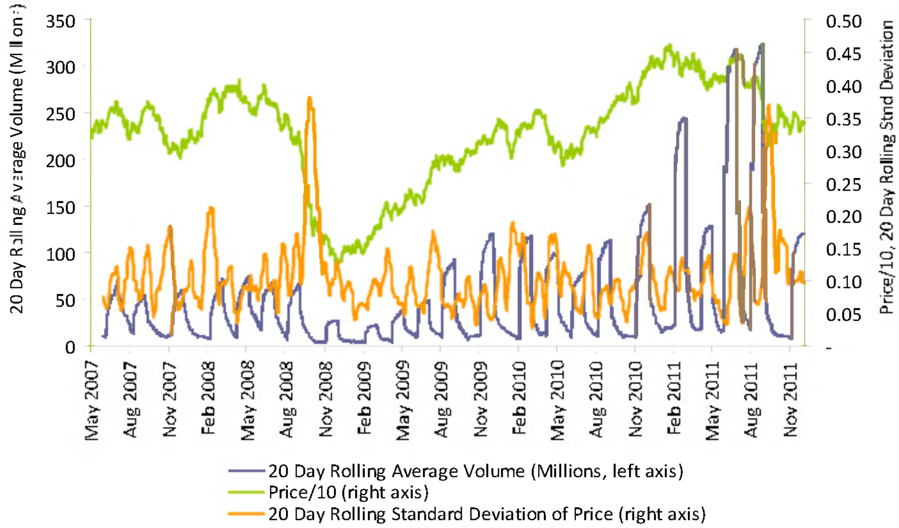
[12] Corwin, S.A., and Paul Schultz, "A Simple Way to Estimate Bid-Ask Spreads from Daily High and Low Prices." University of Notre Dame working paper (2008).

Copper Prices Are More Volatile in Periods of Reduced Market Liquidity
20-Day Rolling Average Futures Volume, Price, and Price Volatility



Source: IHS Consulting

ii) Lower Transaction Costs and Bid-Ask Spreads

U.S. bank corporate risk management and intermediation services reduce transaction costs and bid-ask spreads. Any reduction in bank activity may lead to higher transaction costs. Reduced liquidity typically leads to higher transaction costs, evidenced in bid-ask spreads.

For example, the chart below illustrates estimated bid-ask spreads for Heating Oil, as a function of relative liquidity, in terms of average daily trading volume.[13] As measured trading volume declines, the estimated bid-ask spread widens – a halving in trading volume is associated with a roughly 100% increase in the estimated bid-ask spread.

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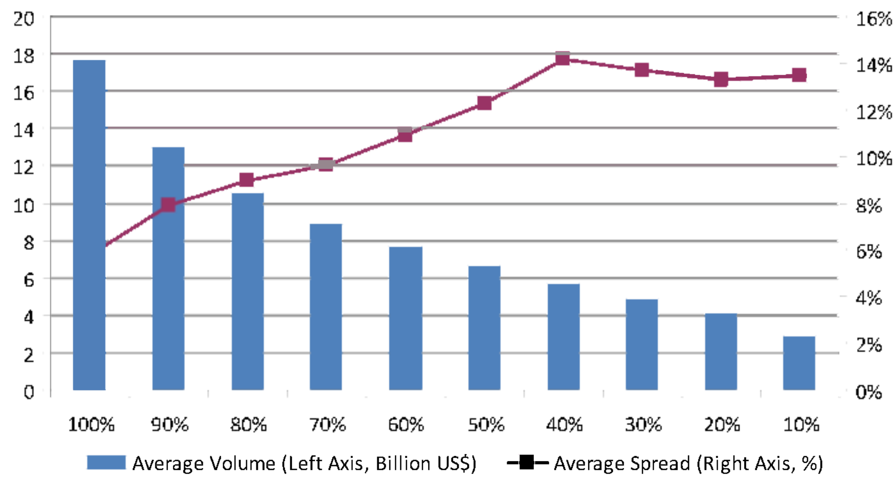
[13] Analysis based on Corwin, S.A., and Paul Schultz, “A Simple Way to Estimate Bid-Ask Spreads from Daily High and Low Prices.” University of Notre Dame working paper (2008).

Heating Oil Bid-Ask Spreads Rise under Reduced Market Liquidity

(Bid-Ask Spread vs. Daily Trading Volume)



Source: IHS Consulting

In the table below, we quantify the effects of reduced market liquidity on transaction costs for a range of assets. We show historical bid-ask spreads, as a percentage of the current underlying price, for several different commodities, at different percentiles of market liquidity. In general, the results follow that reduced market liquidity tends to translate into increased transaction costs.

Futures Transaction Costs as a function of Liquidity

Estimated Bid-Ask Spreads by Liquidity

Asset	Price ($)	Spread/ Price (%)	Spread/ Price (%)	Mean Bid-Ask ($)
Crude Oil	96.3 / bbl	0.18	0.08	0.13
RBOB	120.49/ bbl	0.17	0.09	0.13
Heating Oil	128.22/ bbl	0.13	0.09	0.14
Natural Gas	128.22/ mmbtu	0.35	0.3	0.01
Corn	6.43/ bushel	0.21	0.25	0.01
Wheat	6.00/ bushel	0.24	0.26	0.02
Copper	3.78/ pound	0.18	0.17	0.01

Source: IHS Consulting

On average, a one-decile reduction in trading volume leads to a 10% increase in estimated bid-ask spread.

We see that transaction costs are generally higher in times of reduced liquidity – both within a commodity, and to some extent, across commodities. For example, on light sweet crude, the estimated mean bid-ask has been 13 cents and current prices are roughly $79 per barrel (0.16%). At the 20th percentile of liquidity this spread rises to 0.18%, while at the 80th percentile of market liquidity the spread falls to only 0.08%.

iii) Higher Reserve Values

U.S. bank corporate risk management and intermediation services increase the value of our domestic oil and gas reserves. Any reduction in bank activity may lead to lower domestic reserve values. Reduced market liquidity reduces the value of the underlying assets, impairing our economic growth. If agents face limitations, higher illiquidity and volatility leads to lower asset values.[14] This is presumably why Treasuries, Munis and Foreign Exchange are exempt from the Volcker Rule, and why Japan, Canada and the U.K. have expressed serious concerns with its implementation.

Under natural conditions, asset values are higher if investors can find each other more easily. A financial asset's required return depends on its expected liquidity, as well as on the covariances of its own return and liquidity with the market return and liquidity.[15] Illiquidity not only increases trading costs, but also reduces asset prices.[16] Illiquid assets generally sell at a discount relative to their intrinsic value. For example, illiquid stocks tend to trade at a 10-20% discount.[17]

iv) Increased Market Access & Reduced Basis Risk

U.S. bank corporate risk management and intermediation services increase market access and reduce basis risk. Any

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[14] Darrell Duffie, Nicolae Gârleanu and Lasse Heje Pedersen, "Valuation in Over-The-Counter Markets," (September 2003), *NYU Stern Working Paper Series*.

[15] Acharya, Viral V. and Lasse Heje Pedersen. "Asset Pricing with Liquidity Risk," *Journal of Financial Economics*, 2005, v77 (2, Aug), 375-410.

[16] Dimson, Elroy and Hanke, Bernd, "The Expected Illiquidity Premium: Evidence from Equity Index-Linked Bonds" (December 2002). London Business School Accounting Subject Area No. 014. Available at SSRN: http://ssrn.com/abstract=248617 or doi:10.2139/ssrn.248617

[17] Pettit, Justin, "Rx for Stock Liquidity" (November 1, 2005). Available at SSRN: http://ssrn.com/abstract=845544 or doi:10.2139/ssrn.845544

reduction in bank activity may lead to less market access and more basis risk. A reduction in trading volumes, the number of potential counterparties, and general market liquidity can limit market access – since some of the services provided by the banks are not available from any other counterparty. In cases where companies try to replicate these solutions from the hedges that are available, it can introduce basis risk or counterparty credit risk. And, as inefficient hedges, these transactions may not qualify for hedge accounting treatment. This would demand mark-to-market accounting treatment and create volatility and reduced transparency in public financial statements.

For example, Southwest Airlines outlines the value of jet fuel price hedging in its 2011Q1 10Q disclosure below:

> *"Jet fuel and oil typically represent one of the largest operating expenses for airlines. The Company endeavors to acquire jet fuel at the lowest possible cost and to reduce volatility in operating expenses through its fuel hedging program. Because jet fuel is not widely traded on an organized futures exchange, there are limited opportunities to hedge directly in jet fuel. However, the Company has found that financial derivative instruments in other commodities, such as crude oil, and refined products, such as heating oil and unleaded gasoline, can be useful in decreasing its exposure to jet fuel price volatility. The Company does not purchase or hold any financial derivative instruments for trading purposes."*
>
> *"Ineffectiveness is inherent in hedging jet fuel with derivative positions bed in other crude oil related commodities … This may result, and has resulted, in increased volatility in the Company's financial results. However, even though derivatives may not qualify for hedge accounting, the Company continues to hold the instruments as management believes derivative instruments continue to afford the Company the opportunity to stabilize jet fuel costs."*

The Southwest Airlines experience underlines how significant these hedging activities are to the viability of the country's air transport system and even the survival of major airlines. Petroleum fuel costs currently account for 25-35% of all airline operating expenses. Unhedged fuel costs may account for significant uncontrolled variation in quarterly operating expenses and threaten a large share of airline operating profits. Fuel hedging strategies play a central role in the financial stability of the airline industry. As the airline industry has become more competitive, more of its participants have become increasingly dependent on banks for risk management, logistics, and financing. U.S. banks are among the largest distributors of jet fuel in the country, and provide storage and logistical services in several key markets. Not surprisingly, U.S. banks have also become one of the largest suppliers of both short-dated and long-dated jet fuel contracts.

v) Increased Investment & Resource Development

U.S. bank corporate risk management and intermediation services increase investment and resource development. Any reduction in bank activity may slow, impair, or reduce investment.

For example, from the Southwest Airlines 2008 10K, we see the direct impact of corporate risk management solutions in supporting investment:

> *"The dramatically higher fuel prices during most of the year led to significant industry-wide capacity reductions. Southwest's fuel hedges during this time enabled it to weather fuel price increases, contributing to cash savings of almost $1.3 billion during 2008."*

As a second example, a bank supplies the INEOS Grangemouth refinery in Scotland with Forties crude oil (a particular grade of North Sea crude oil). The bank acquires Forties physical cargoes by becoming an active participant in the 25-day BFOE market. This requires the bank to manage the delivery, grade, location and volume risk for INEOS, and manage its cash flow by deferring INEOS's need to pay for the crude until payment has been received from refined product buyers by INEOS.

The fact that the bank is trading in both the financial commodity and physical BFOE markets, allows it to efficiently hedge price risk associated with shipping time across the Atlantic. Cargoes that do not qualify for the INEOS contract can be shipped to the U.S. allowing the bank to offer better prices to both INEOS and U.S. refiners.

4. Impact on Investment, Prices and Jobs

The availability and costs of RM services can have a notable impact on industry investment, energy commodity prices and jobs.

In commodities markets, it is a fine – and indeed uncertain – line between market making and proprietary trading. For example, due to the unique nature of these markets, market making and the provision of risk management and intermediation services requires the banks to be very active on the short end of the market in order to be able to transact on the long end; requires the frequent accumulation of inventories; and requires expected trading gains in order to offset the expected trading losses. Market making banks monitor these positions and market conditions, and adjust their capitalization and financial liquidity accordingly.

Therefore, we believe that implementation of the Volcker Rule, and its market making exemption, must be done in such a way that does not significantly impair the role of banks in real economy commodities risk management and intermediation services. Too narrow an interpretation of the Volcker rule's market making and hedging criteria could likely constrain banks' ability to provide hedging and facilitate trades on behalf of clients.

For example, the current market making criteria, as proposed, require banks to provide two-way quotes on a continuous basis, hold inventory only to meet "near-term" client demand, and derive revenue primarily from fees, commissions and bid-ask spreads.

But in commodities markets, there is generally no regular, continuous two-way quoting for most products – banks price for specific client solutions. There is a need for banks to act as principals and accumulate positions when making markets, which can lead to revenue from price appreciation while held. There is typically no fee or commission-based revenues from client transactions; instead commodity market makers generate revenue primarily from the price movement of positions related to client hedging transactions and positioning of residual risk. With respect to bid-ask spreads, there is no standard or verifiable bid-ask spread available for most commodity markets. And finally, with respect to time horizons, in order to meet client demand which may be infrequent and not appear as “near-term” in nature, banks must actively trade as principals in the market to determine market prices, volatilities and liquidity.

The Rule also includes a hedging criteria requiring banks not to introduce new risks when hedging, and for hedges to be reasonably correlated to the position being hedged.

However, in commodities markets, banks are effectively called upon by their clients to make markets in basis risk, and must often hedge that which cannot be easily hedged. This can introduce new risks, or can appear not to correlate as well as the proposed Rule may require, but is the best option available to the banks. The banks, in turn, must measure, monitor and manage these exposures, to ensure adequate capitalization and financial liquidity. Too narrow an interpretation of these activities under the Volcker rule may reduce the banks’ ability to provide client solutions and hedging.

Real Economy Industry Examples

While a full economy-wide analysis was not feasible within the comment period, we submit a few examples where the impact of curtailment of the bank’s market role is estimated. This estimate is based on the full removal of RM services from the market and represents the upper end of the likely impact.

Independent Gas Producers

The exploration and production business is one of the most capital intensive business sectors in the world. Total capital expenditure in aggregate for the U.S. exploration and production business exceeded $200 billion in 2010 and is projected to exceed over $1 trillion in the next decade.[18] The majority of this aggregate investment was spent by independent companies which drill some 94% of the wells in the U.S. These same independent firms are responsible for almost 50% of the 440,000 jobs in the U.S. exploration and production business and a total of $580 billion in total economic activity, resulting in some $131 billion in federal taxes in 2010.[19] Capital investment is also front

[18] IHS Herold, Global Upstream Performance Review, 2011

[19] IHS Global Insight, The Economic and Employment Contributions of Shale Gas in the U.S. Dec 2011, prepared for America’s Natural Gas Alliance

end loaded, with long lead times to realize capital recovery and potential profit. Today's typical onshore projects reach breakeven only after an average of two years from initial discovery, while deepwater Gulf of Mexico projects average five years before reaching breakeven.

Managing Risk in the Upstream Exploration & Production Business

Because of the inherent large financial uncertainties, exploration and production companies need to actively look for aggressive and proactive ways to mitigate their financial exposure. Moreover, risk management must contend with both below-ground and above-ground risks (technical, financial, regulatory and policy). Thus, in the exploration and production business we discuss both a technical and commercial probability of success, with the latter of utmost importance.

Profile of an independent Gas Producer

There are some 18,000 independents according to the IPAA-Independent Producers Association of America. Independents are normally divided into three groups—large, medium and small; based on production, reserves, financial strength, employee population and market capitalization.

Large independents would be firms such as Marathon, Hess, Apache, Devon, EOG, Chesapeake, Noble, Occidental and Anadarko. Large independents typically have production that ranges from 200,000 barrels per day (B/D) to 1.5 million B/D of oil equivalent with market capitalization from $10 billion to $80 billion and are typically split 60:40 oil to gas. They typically have from 1,500 to 15,000 employees and carry a debt to capital ratio that ranges from 14% to 42%, with an average of 30%. Their annual capital spending ranges from $3 billion to $10 billion.

Medium independents, such as Pioneer, Swift, Sandridge, Range Resources, Plains, Continental Resources, Petrohawk, Linn Energy, Ultra, Carrizo, and Concho have daily production that ranges from 50,000 barrels oil equivalent to 200,000 barrels oil equivalent. Their market cap ranges from $1 to $2 billion on the low side up to $10 billion on the high side. Their split of oil to gas production is more dramatic, with some being 70% oil and some 98% gas. But generally, the average split is 40:60 oil to gas. Medium independents typically have from 150 to 1,200 employees and carry a debt to capital ratio of 20% to 50%. Their annual capital spending ranges from $300 million to $3 billion and they often outspend cash flow during periods of exploration.

Small independents generally have daily production that ranges from 500 barrels oil equivalent to 50,000 barrels oil equivalent. Their market cap ranges from $50 million to $500 million. They are often private. Because of their size, they are less diverse in product, with many being either 70% oil or 100% gas. They have from 10 to 200 employees and carry a debt to capital that ranges from 20% to 40%. Their annual capital spend ranges from several million to several hundred million dollars and they often outspend cash flow.

Matching Investment with Risk – the Role of Commodity Price Risk Management

A review of the capital investment of oil and gas companies over the last ten years shows capital spending over the decade has increased fivefold, up more than 11% last year alone, with three quarters of independent firms increasing spending.

This trend is predicted to continue as companies focus more on U.S. tight oil and shale resources rather than work overseas. This is what will help America "control its own energy future," as President Obama stated in January 2012 State of the Union Address and this is what has reduced America's import bill. The capital spending resulted in oil and gas production increasing significantly by about 1.3 million B/D of liquids (oil, natural gas liquids) and 9 BCF/D of gas. American consumers and industries have benefited from this as gas prices have remained low and should continue to remain at lower levels for the near to midterm according to the IHS CERA price outlook.

A review by IHS of the relationship between capital investment and cash flow over the last decade shows a strong correlation of one-to-one between the capital investment and cash flow.[20]

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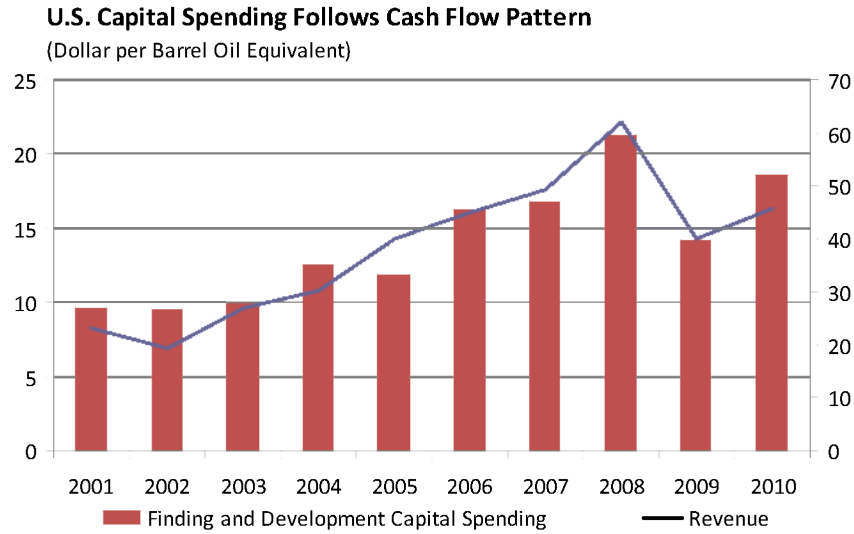
[20] IHS Herold Global Upstream Performance Review, 2011



Source: IHS CERA

Thus, risk management of the investment stream is critical to the oil and gas companies. Moreover, companies not only fund capital investment from their cash flow stream, but also pay principal, interest, dividends and taxes. Typically independents utilize sophisticated capital allocation Monte Carlo simulation modeling to gain visibility of the probabilities and risks of the cash flow stream. The primary risks for cash flow are: product price, production delays, capital investment overruns, financial market changes and regulation changes. The large drop from 2008 to 2009 on the above graph provides a good example of the quickness and magnitude the impact of macroeconomic changes have on spending.

Exploration and production firms manage their cash flow risk in a number of ways including portfolio diversity (product and location); commodity hedging; partnerships; and equity borrowing. However, hedging provides the most flexibility and control of financial risk over the critical investment and return life cycle (1 to 3 years). Among the top items that hedging provides to reduce investment risk:

1. Guaranteed cash flow
2. Back stop to capital budgets
3. Financial guarantee for financing or debt servicing to protect project economics
4. Downside price risk protection

5. Floor for acquisition economics

Tracking Hedging Relationships

Futures trading was initiated in 1983, to help provide a risk management tool for operating companies that must invest through up and down commodities cycles. A sample of medium to large U.S. independent producers was studied from 1999 to 2011 to determine the various relationships between capital investment, commodity price, and hedging or risk management.

Because of the long lead time from resource discovery to production, capital investments can span commodity price cycles. However, companies are most concerned with the financial management of down cycle risk. In today's world with bullish oil prices, more emphasis is placed on managing gas downside risk than on oil by U.S. resource producers.

The most active way that companies manage the down cycle risk in capital spending is by use of long-dated hedging of future expected production. Time plays a critical element in this financial management. For short-term (year-on-year) financial management, companies typically manage via minor adjustments to spending (reducing discretionary spending and postponing non-essential capital commitments). But for medium-term capital management protection, companies commonly use either the two-year or the three-year forward curve as a guide. For example, a company would look at the spread between the 3-year futures price vs. the spot price (the spread). If this spread shows a notable downward price trend (for example, 15% or more), this might indicate an increasing down cycle price risk that needs to be managed aggressively to protect capital returns, cash flow and the ability to pay dividends and taxes.

In general, those companies whose portfolio was greater than 50% oil-weighted did less hedging than those who were more gas-weighted. This is understandable given the higher oil price outlook and volatility in natural gas prices.

Hedging Price Relationships for Natural Gas Focused Companies

America's natural gas producers look at a combination of historical and future trends to gain insight into what cash flow risks lie ahead. The current price curve is important for determining the value of existing proven production. It is this value that underpins a company's net asset value and in turn affects its borrowing and financial health and flexibility.

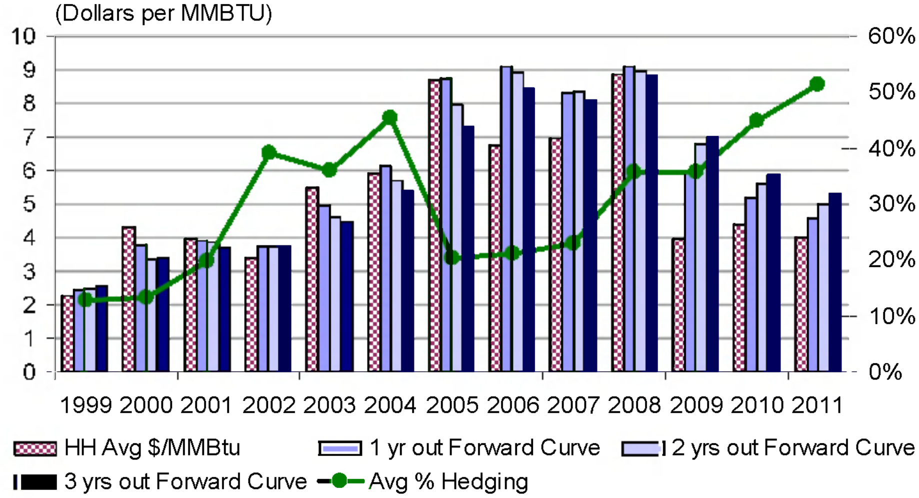
In forecasting future prices, companies utilize the futures curve, looking at changes in the future vs. spot spread going forward, as one key indicator.

Comparing the 12 month forward price to the past trailing 12 month price for the past ten years, shows that up until 2005 the two prices were mostly identical. But in 2005, the forward curve grew to outpace the current price by some 22%, signaling a future tightening of the market fundamentals. This spread relationship continued until November 2011 when the spread once again declined to 11% as the market reversed with supply outpacing demand. The success of America's shale gale is mostly behind this change as supply has outstripped demand leading to a severe price drop from $9.00 per MMBTU in 2008 to under $3.00 per MMBTU in early 2012. A review of the relationship between annual natural gas prices[21] from 1999 through 2011 and the degree of the sampled company hedging of positions (percent of gas hedging) shows a direct correlation with the relative magnitude and direction of the gas price spread.

For this analysis we use a 15% change in the futures vs. spot price to reflect a change in price trend direction, which is a reasonable proxy for market change. One such market change occurred in 2005 when Henry Hub prices climbed from $4.31 per MMBTU in 2000 to $8.69 per MMBTU in 2005, while futures prices moved from a spread of less than one dollar in 2000 to over $1.42 in 2005. As companies responded to this signal, hedging saw a sudden change during this period - from 2000 to 2004 hedging climbed from 12% to almost 55% of production, but in 2005 it dramatically declined to 20%. The quick increases of Henry Hub prices from 2004 to 2005, together with the sudden increase in the three-year spread signaled a market correction had begun.

[21] Represented by the average Henry Hub spot price and the three-year forward price.

Relationships Between Natural Gas Price, 3-yr Forward Curve, and % Gas Hedging
(Dollars per MMBTU)



Source: IHS CERA, Company 10-K filings

A second market change occurred between 2008 and 2009 when the market experienced a steep downward price change. The futures market signaled another market shift with the spread increasing to $3.00 per MMBTU, 77% above the 2009 price. With such a high premium in 2009, companies aggressively sought to protect their spending capacity and increased their hedging position to 45%, an increase of 9% over the previous year. This trend continued in 2011 despite the 3-year forward curve in 2010 having a narrower spread, at 34% above the 2010 price. In 2011 companies were 51% hedged vs. 45% in 2010. So far in 2012, companies are again, on average, hedging about 50% of their production.

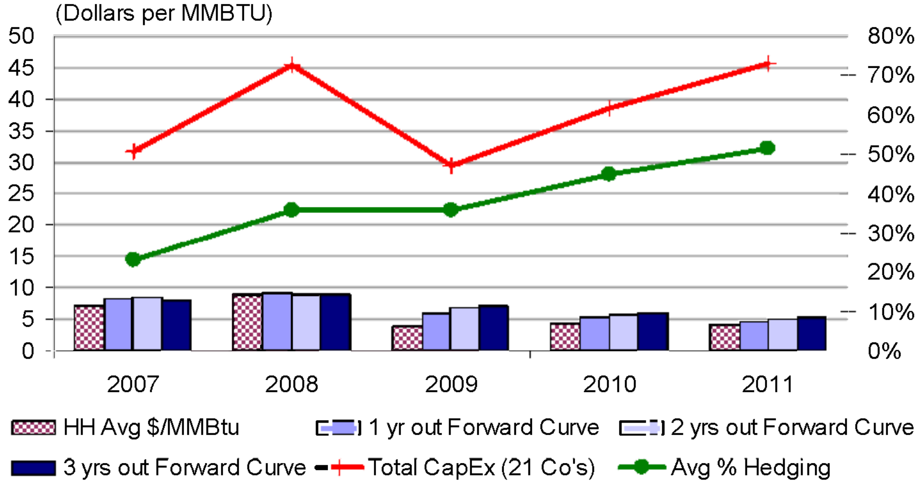
Capital Investment vs. Hedging

The relationship between capital investment and hedging is complex. Capital investment, hedging and other key parameters were collected from a representative sample of public independent gas-prone producers for this analysis. From 1999 to 2011, with the exception of 2009, the data show a long upward trend in spending which was coincident with the rise of natural gas prices until 2005. Hedging during this period also rose with the exception of one slight correction in 2003.

In 2005, the gas market underwent a large price correction and entered a period of increasing volatility signaled by the increasing spread in the three year forward curve. Hedging dropped 20% yet operators continued to spend. Operators were able to continue spending because of second party financing or minority share purchases, utilization of their balance sheets, offsetting oil revenues and remaining hedging. In 2006 operators began increasing hedging positions once again and have done so into early 2012.

From 2009 to 2011, the relationship between capital investment and percent gas hedged was particular strong. Hedging went up 15% over this period on an overall investment increase of $16 billion. Looking at the period from 2007 to 2011, the incremental year over year increase translates into a relationship of approximately $0.5 billion of investment change for every percent of hedging change.

Relationship Between Natural Gas Price, 3-yr Forward Curve, % Gas Hedging & CapEx
(Dollars per MMBTU)



Source: IHS CERA, Company 10-K filings

Implications: Potential Volcker Rule Impact

Because of the narrow market maker and hedging criteria in the Rule, banks could be limited in providing long-dated hedging services, making hedging considerably costlier for America's independent oil and gas producers at a time when hydrocarbon production has begun to grow. This could materially impact or delay development of additional new oil and gas resources. In addition, changes in capital investment due to changes in hedging liquidity or costs could delay or eliminate other direct and indirect economic benefits to the economy related to capital investment and resource development such as jobs and tax revenue.

Models were run to estimate the magnitude of investment reduction should long-dated hedging cease. The models utilize the relationship between capital investments and hedging from a sample of gas-focused companies. It indicates that for every 1% of gas hedged there is a change in capital investment of $0.5 billion based on 72% of the sample companies. To account for industry trend towards liquids production, we assumed that 12% of firms would transform their portfolios more towards liquids; and thus 60% of the total population would end up being gas focused. In order to calculate the amount and relative change in hedging going forward we used the IHS CERA North American price outlook. The outlook shows a general strengthening over the next twenty years with a year-to-year average change of less than 10%. Realizing that we are currently in a low price market with a narrowing spread on the three year futures price IHS CERA believes another market shift is beginning. As such, hedging is expected to drop from an average of 54% in 2011 to a band of from 15 to 22% for the short term.

Utilizing the IHS CERA North American Gas Supply Model, which is based on building a capacity outlook for each geologic play or group of fields from the bottom up starting well-by-well and then rig-by-rig across the country, the effect of removing hedging via a change in correlative investment from $7.5 billion to $12 billion was modeled.

The results show that four regions of the country would be most affected by this action because they contain the lowest margin dry gas fields - the Rockies, particularly Colorado, Utah and Wyoming; the Mississippi/Alabama Gulf Coast; a portion of the Northeast, Pennsylvania, Ohio and West Virginia; and Central and East Texas.

The removal of a dollar in investment could result in a reduction in drilling activity expenditures from $0.80 to $0.50 depending on the current correction going on in some plays. A reduction in rigs would translate into a production response that would range from a maximum drop in production of 2.1 BCF/D to 3.4 BCF/D and the lower end of this range was used for this analysis.[22] Moreover the effect would be felt for several years forward.

The reduction in gas production is projected to influence the price of natural gas. Productive capacity is related to price via a complex set of parameters but chiefly the interplay is among productivity, storage and price. The North American Gas Price Compositional Model was used to estimate the effect of the reduction in productive capacity resulting from the drop in hedging/investment by gas producers. The results show that a 2.1 BCF/D loss of production ($7.5 billion in investment or 11% hedging) results in a $0.64 per MMBTU price increase on average over the period from 2013-2015. This is a significant potential decline and one that, if sustained, could lead to further decline in future productive capacity.

The job loss from this impact is about 182,000. In addition, the loss of drilling would have broader economic effects, as presented later in the Economic Impact Analysis.

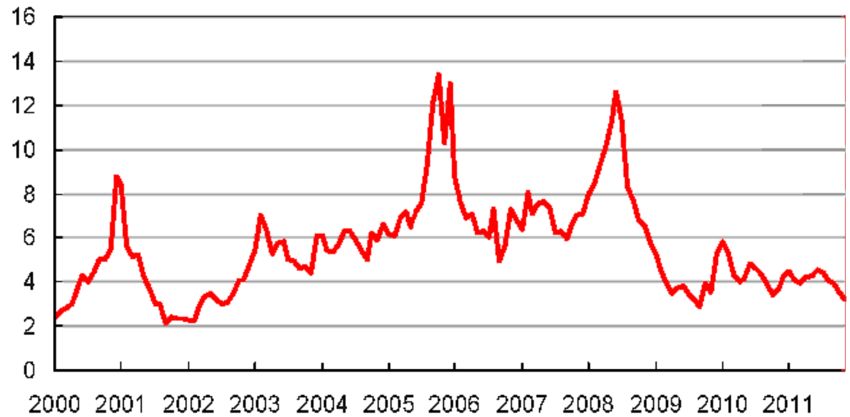
Power Sector

The Value of Natural Gas Trading and Risk Management in the U.S. Power Sector

Natural gas-fired power plants account for one-third of U.S. electric generating capacity and one quarter of electric output. Transforming natural gas into electric power is a major risk factor in the power sector. The fuel input for this key source of power supply involves commodity prices that move through multi-year cycles, swing seasonally and are subject to considerable day to day volatility.

[22] U.S. natural gas production is currently about 65 BCF/D

Henry Hub Monthly Natural Gas Price, 2000-11
(Dollars per MMBTU)



Source: IHS CERA
Data Source: Platt's and Natural Gas Intelligence

A narrow definition of market making activities in the proposed Rule that curtails U.S. banks from providing OTC RM services has two impacts on the U.S. power sector. First, rule changes that impact the natural gas sector flow through to the power sector via an increase in the average delivered cost of natural gas. Second, rule changes that increase the cost of fuel price risk management will reduce the amount of cost effective power price risk management suppliers provide to power consumers. Together, these impacts mean that households and businesses will be burdened with additional costs.

The Flow Through of Natural Gas Price Impact

The U.S. spent $43.5 billion on fuel for natural gas-fired power generation in 2010. The impact of a $0.64 per MMBTU increase in the delivered price of natural gas to the U.S. power sector would cause current annual fuel costs to increase by $5.1 billion. This impact reflects the absolute gas price change due to possible Rule implementation. The gas price volatility impact is modeled next.

The Value of Natural Gas Trading and Risk Management in the U.S. Power Sector

Consumers consider electric service a necessity of modern life and something that they cannot do without for even short periods of time. Consequently it is not surprising that most consumers reveal a strong preference for fairly stable and predictable power prices. However, the underlying costs of power production are unstable and difficult to predict. Bidding between natural gas-fired power plants sets the wholesale price of electricity in a majority of the hours in a year. As a result, when competitive forces push market prices to clear based on the underlying marginal costs of power production, the variation in natural gas prices translates into the variation in wholesale power prices--maximum hourly prices can be 35 times higher than the average hourly wholesale price.

Although consumers value fairly stable and predictable power bills, they are not willing to pay the cost of mitigating all power price volatility because it is not cost effective to do so. A cost effective level of price risk management strikes a balance between the costs and benefits of price risk management. As a result, a cost effective power price mitigation strategy reduces some but not all consumer power price risk.

Power providers find that no single tool can provide all of the cost effective power price risk management that consumers demand. Power suppliers use a number of risk management tools—fuel diversity, futures contracts, OTC transactions and rate designs to dampen power prices and stabilize power bills. The financial tools provided by market making banks in the futures exchanges and the OTC marketplace are key elements of a cost effective risk management program because they provide unique capabilities that bridge the limitations of other tools.

Although fuel diversity is a key retail price risk management tool, its limitations do not allow power producers to use it alone to reduce power price volatility to the levels consumers expect. As fuel price expectations change, so too does the desired mix of generation. However, it takes many years to significantly adjust the power generation fuel mix. As a result, adjusting the generating mix cannot happen fast enough to fully manage the risks of rapidly changing fuel market conditions. For example, a few years ago, the shale gas revolution dramatically lowered expectations for future natural gas prices and thus increased the desired share for natural gas-fired technologies in the generation mix. However, new power supply additions only move the generation shares a couple of percent per year because building new power plants involves multi-year lead times and the existing power plants have operating lives that typically span 35 to 60 years. Therefore, although generation fuel diversity is a powerful risk management tool, it is also an inflexible tool to respond to changes within the span of a decade.

In order for power producers to provide all of the cost effective risk management that consumers demand, they need to employ the tools available in the futures markets and OTC marketplace. In particular, these tools help manage the risk of price spikes, volatility and cycles for natural gas for a decade or more into the future. However, the liquidity of the futures market is insufficient to span much of this timeframe. As a result, OTC transactions are a key tool in the overall risk management program. Together these short and longer dated risk management tools reduced consumer exposure to natural gas price spikes and variation. The impact of this risk management activity is clear—since 2000 the maximum monthly delivered natural gas commodity price for power generation was 17% lower than the maximum monthly Henry Hub spot gas price and the standard deviation of the delivered price of natural gas was 18% lower than the standard deviation of spot market prices.

Although futures and OTC market tools are effective in managing fuel price volatility, further dampening of power price volatility occurs from the way customers are billed for power usage. Most consumers pay for electricity based on prices set for blocks of power usage within a month. Such rate structures smooth prices over a month compared to the underlying changes in power production costs within a month.

Employing all of the tools in a cost effective risk management program reduces fuel cost variation and causes the remaining variation to fall to the bottom line for power producers. This creates volatility in the earnings of power suppliers. However, this does not mean that consumers avoid paying for the costs of volatility. Earnings volatility increases the cost of doing business—higher earnings volatility requires higher working capital and increases the probability of exceeding the credit metric thresholds used by credit rating agencies. These increased costs show up in the higher cost of capital that consumers have to pay power investors. Cost of capital is a major cost component of power supply because power supply is a capital intensive productive process. The return of capital and the return on capital make up 14% of overall power costs.

The final Volcker Rule is not set yet and so it is not yet clear how much the new rules will increase the cost of risk management in the commodity markets. Nevertheless, since a cost effective risk management program strikes a balance between benefits and costs, any rule change that increases the cost of risk management will cause a decrease in the amount of cost effective price risk management.

To gauge the impact of a reduction in the use of the futures and OTC risk management tools, a sensitivity analysis can quantify how much these financial tools currently affect power prices and thus power consumers. In this case, the sensitivity assessment eliminates futures and OTC fuel price risk management of natural gas input prices to U.S. power production while holding all else constant. The unmanaged fuel cost causes an increase in the variance of natural gas costs that translate into greater variation in power producer earnings. This increases the cost of capital for power generators and thus increases the cost of power supply and the retail price of electricity.[23]

IHS/CERA conducted a sensitivity analysis that examined the period from the first quarter of 2000 to the third quarter of 2011 for shareholder-owned electric utilities. The absence of natural gas price risk management through futures market and OTC transactions would have caused natural gas price volatility in power generation to reflect the level of volatility found in the Henry Hub spot price of natural gas. This change would have increased the variance of quarterly natural gas generation costs by 17%.

The sensitivity analysis holds other conditions constant. In particular, the other risk management tools remain in effect—the diversity of the generation mix remains the same as well as the volatility in monthly power prices generated by the dampening structure of monthly electric rates. Consequently, the increased variance in fuel costs causes and increase in the variance in producer earnings. This change is expressed as an increase in the standard deviation of earnings per share.

A higher standard deviation in earnings per share causes—all else equal—a lower credit rating. As a result, the lower credit rating causes a higher cost of borrowed capital. Since equity

[23] See the CERA Decision Brief Does Earnings Quality Matter in the Power Business? December 2006

capital involves a risk premium over debt capital, a lower credit rating causes a higher overall weighted cost of capital.

Based on these relationships, if the power business did not deploy the risk management tools available in the futures and OTC marketplace with all else held constant over the past decade, then the cost of capital in the power business would increase by three basis points. As a result, the average price of electricity would increase by 0.05 mills per KWh.

The U.S. price elasticity of demand for electric energy is -0.86 and thus an increase in the average price of electricity would lead to a reduction of power consumption. Of course, this creates secondary effects such as declines in fuel demand for power generation and jobs. However, just focusing on the primary effects means that power consumers in the U.S. would pay roughly $203 million per year more for the power they continue to consume due to a loss of RM services and high gas price volatility.

U.S. East Coast Gasoline/Refining Market

U.S. banks have assisted refinery buyers with structured financing, hedging and market services that have made continued operations at many marginal refineries possible. Under the Volcker Rule, a narrow interpretation of market making and hedging requirements could constrain the ability of banks to provide hedging and facilitate trade on behalf of refiners. The loss of these services could contribute to additional refinery closures. This is particularly important for the East Coast, where a large number of refinery closures threatens the existing petroleum fuel supply and raises the risk of higher gasoline prices and volatility.

Overview of the East Coast Gasoline Supply

The U.S. East Coast market is the largest petroleum market in the U.S., serving over 93 million consumers[24] and accounting for approximately 35% of U.S. refined light product demand. The market is effectively supplied by three supply sources: 1) the U.S. East Coast refining system, 2) the U.S. Gulf Coast refining system, and 3) foreign imports.

[24] Based on population estimates for age 15 and higher.

The U.S. Gulf Coast refining system has been the single largest supply source, and typically accounts for half of total East Coast gasoline supply. While the U.S. Gulf Coast refining system has some unused refining capacity, the existing product pipelines and U.S. Jones Act product tankers that are used to transport products to the East Coast and Central Atlantic are believed to be operating near their full capacity. As a result of these infrastructure limits, the East Coast market has become more dependent on foreign imports and the existing East Coast refinery capacity to fully satisfy its petroleum fuel demand.

In 2008, the East Coast had approximately 1.8 million barrels per day (B/D) of refining capacity. Since then, the expansion of renewable fuel use and the recession that followed the 2008 financial crisis has resulted in lower overall East Coast petroleum demand. As a result, East Coast refining margins have declined.

In addition to the weak refinery margin environment, the potential liquidation of refinery oil inventories has provided additional incentives to close marginal facilities. A typical medium sized oil refinery, for example, is likely to require over $350 million in oil inventories at current prices in order to maintain operation. In addition to the cost of higher environmental standards, these large inventory requirements are seen as a major issue surrounding the continued operation of many marginal facilities

The table below provides a brief summary of the recent refinery closures and sale announcements that are relevant to the East Coast market.

EAST COAST REFINERY CLOSURES

Year	Location	Company	Location	State	Capacity, MB/D	Type
2009	East Coast	Sunoco	Westville	NJ	145	Cracking
2009	East Coast	Chevron	Perth Amboy	NJ	80	Topping
2010	East Coast	Western	Yorktown	VA	59	Coking
Started Dec 2011	East Coast	ConocoPhillips	Trainer	NJ	185	Cracking
Started Dec 2011	East Coast	Sunoco	Marcus Hook	NJ	175	Cracking
Pending Mid 2012	East Coast	Sunoco	Philadelphia	PA	335	Cracking
Started Dec 2011	Carribean	Hess	St Croix.	VI	350	Coking
				Total	1,329	

At the time of this writing, four additional refinery closures have been announced.[25] In total, these four closures are estimated to reduce gasoline supplies by approximately 425,000 B/D of

[25] Including the Hess and PDVSA HOVENSA Refinery in the Virgin Islands that ships most of its products to the East Coast market

gasoline, a volume greater than all the European gasoline imports in 2010. In addition, approximately 300,000 B/D of jet fuel and diesel production would also be lost, which would bring the total impact of the closures to approximately 725,000 B/D of light transportation fuels. Unfortunately, this large supply deficit is expected to be difficult to resolve and would require additional supplies from a number of different sources.

East Coast Product Supply Dilemma

While the U.S. Gulf Coast refining system contains enough available capacity to offset much of the announced refinery closures, domestic pipeline and Jones Act tanker constraints effectively limit the ability to ship additional refined products to the East Coast.

One potential alternative to U.S. Gulf Coast supplies is to acquire additional gasoline imports from Europe. However, while there is spare capacity in Europe, the gasoline yield for this available refining capacity is low and would require a large increase in refinery crude runs to produce the gasoline volume needed for the East Coast. Further, a large increase in European gasoline production would require the restart of several small, inefficient refineries that have been idled in the current market.[26] Based on our European refinery margin analysis, the East Coast gasoline price would need to increase by 15 to 25 cents per gallon in order to create sufficient incentives to restart these refineries. Given the nature and limited availability of European capacity, it is apparent that the large East Coast gasoline supply deficit cannot be cost effectively filled through increased European refinery production alone.

A more effective alternative is to divert more of the existing Atlantic Basin product trade into the East Coast market. Besides the U.S. East Coast, European gasoline exports are also delivered into Latin America and West Africa. To satisfy East Coast demand, prices in the East Coast market will need to rise to levels high enough to draw European gasoline from these other traditional markets. Competitive exports from the U.S. Gulf Coast

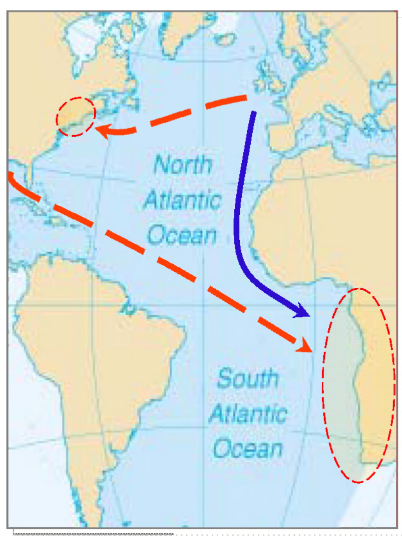
[26] The inefficient capacity is comprised of small outdated fluidized catalytic cracking and hydroskimming process units that process high cost, light low sulfur crude oils.

to foreign markets would then replace the diverted European supplies through the use of international (non-Jones Act) tankers.

Based on analysis of Atlantic gasoline trade, approximately 100,000 B/D of existing gasoline deliveries into Latin America from Venezuela and other Caribbean sources would need to be re-directed into Florida and the U.S. Southeast. In addition, other European gasoline exports that are currently bound for Mexico, South America, Nigeria and North Africa may be acquired and further upgraded for use in the U.S. Central Atlantic market. In total, these diverted European exports may eventually account for another 100,000 to 300,000 B/D of U.S. gasoline supplies.

The figure below provides a simple illustration of the potential realignment of Atlantic basin trade based on the West African market and an associated increase in U.S. Gulf Coast exports. While the actual trade realignment would be more complex, this case provides an indicative example of how the loss of U.S. East Coast gasoline production can be indirectly replaced through increased U.S. Gulf Coast production. This trade realignment is expected to be more efficient than the alternative of acquiring more gasoline supplies from the Middle East or Asia, which suffers from high delivery costs.

ATLANTIC TRADE FLOW REALIGNMENT



Expected Market Outcomes: Regulatory Status Quo

Before the impact of the Volcker Rule is discussed, it is instructive to first discuss the East Coast market outlook under the Regulatory Status Quo Case, which assumes that the Volcker Rule is not enacted. While there are four refineries that have been announced for sale or closure, permanent closure of only two refineries is expected to result in a sustainable margin environment for the remaining East Coast refiners. Refinery ownership changes, however, should be expected.

In our estimates, the permanent shutdown of only two refineries would reduce gasoline production by approximately 100,000 B/D from 2010 levels after accounting for an increase in average refinery utilization. This 100,000 B/D deficit volume would be met through modest increases in imports from Europe, Eastern Canada and India. Based on a review of gasoline trade flows, gasoline delivery costs and East Coast refinery economics, it is believed that the gasoline price would increase by only 2 to 3 cents per gallon under the Regulatory Status Quo Case.

The Regulatory Status Quo Case would continue to allow new buyers to utilize long-dated margin hedges (for periods of 3 to 5 years) and structured financing provided by the U.S. banks to assist in funding the acquisitions and ongoing operations. The ability to hedge long-term refinery margins plays a central role in capital formation for small to mid-sized companies who would otherwise have difficulty creating access to the required level of capital.

The U.S. banks also provide valuable services to refiners in the area of oil inventory financing. Banks have provided extensive off-take agreements for both finished and unfinished oil inventories. These off-take agreements typically provide timely sales revenue to the refiner through a market-based pricing formula and greatly reduce refinery resource requirements around the commercial marketing function. Not surprisingly, more examples of these off-take agreements have appeared in both the domestic and international refining industry and are seen as particularly important for the participation of new entrants in the highly competitive refining sector.

Impact of Volcker Rule

Under the Volcker Rule, a narrow interpretation of hedging and market making could significantly impair the ability of U.S. banks to provide long-dated hedges and product off-take agreements to potential refinery buyers. These services, which may be difficult to replace, are believed to play an important role in facilitating refinery transaction activity. As such, the Volcker Rule Case reflects a significant reduction in the number of potential refinery buyers and results in more permanent refinery closures relative to the Regulatory Status Quo Case, where more refineries are acquired and restarted.

As large established oil companies have gradually reduced their participation in the U.S. refining sector, there has been a trend towards smaller, independent refining companies. Many of the buyers have been new entrants to the U.S. refining sector and lack the resources and expertise to commercially market production effectively, obtain attractive financing for inventory and manage unhedged margin risk. The U.S. banks have filled an important role in regard to overcoming these issues and have effectively reduced the barriers to investment funding and successful commercial operations. For reference, a list of key U.S. refinery transactions is provided for the last 4 years in the table below.

U.S. Refinery Sales

Seller	Buyer	Refinery Location	Sale Date	PADD	Capacity MB/CD
Giant Industries, Inc.	Western Refining Co.	Bloomfield, NM	May 2007	III	19
Giant Industries, Inc.	Western Refining Co.	Gallup, NM	May 2007	III	26
Giant Industries, Inc.	Western Refining Co.	Yorktown, VA	May 2007	I	62
Shell Oil Co, U.S.A.	Tesoro Corporation	Wilmington, CA	May 2007	V	100
Valero Energy Corp.	Husky Energy Inc.	Lima, OH	July 2007	II	165
Lion Oil Co.	Delek US Holdings Co.	El Dorado, AR	Aug 2007	III	70
Lion Oil Co.	Delek US Holdings Co.	El Dorado, AR	Sep 2007	III	70
CITGO	NuStar Energy L.P.	Paulsboro, NJ	Mar 2008	I	74
CITGO	NuStar Energy L.P.	Savannah, GA	Mar 2008	I	30
Valero Energy Co.	Alon USA	Krotz Springs, LA	July 2008	III	83
Kern Oil & Refining Co.	NTR Acquisition Co.	Bakersfield, CA	Cancelled	V	25
Transcor Astra Group	Petrobras	Pasadena, TX	Apr 2009	III	117
Sunoco, Inc.	Holly Corporation	Tulsa, OK	Apr 2009	II	85
Sinclair Oil Corporation	Holly Corporation	Tulsa, OK	Oct 2009	II	75
Flying J, Inc.	Alon USA	Bakersfield, CA	Apr 2010	V	65
Valero Energy Corp.	PBF Energy Partners LP	Delaware City, DE	Apr 2010	I	210
Marathon Oil	Northern Tier Energy	St. Paul Park, MN	Oct 2010	II	74
Valero Energy Corp.	PBF Energy Partners LP	Paulsboro, NJ	Dec 2010	I	185
Sunoco, Inc.	PBF Energy Partners LP	Toledo, OH	Dec 2010	II	170
Frontier Oil Corp.	Holly Corp.	El Dorado, KS	Feb 2011	II	118
Frontier Oil Corp.	Holly Corp.	Cheyenne, WY	Feb 2011	IV	47
AGE Refining	NuStar Energy	San Antonio, TX	Apr 2011	III	14
Murphy Oil	Calumet	Superior, WI	July 2011	II	33
Murphy Oil	Valero	Meraux, LA	Sep 2011	III	125
Gary-Williams Energy Corp	CVR Energy	Wynnewood, OK	Nov 2011	II	70

Curtailment of the capability of U.S. banks to provide structured finance and commodity-based services would impede future refinery transactions and likely result in additional refinery closures beyond the level that is currently announced. In the Volcker Rule Case, many of the new entrants or small refining companies would have difficultly financing the purchase of the refinery and required oil inventory because long-dated hedges and off-take agreements would no longer be available under attractive terms. Companies such as Alon, Northern Tier Energy and PBF Energy, for example, are known to use product off-take agreements provided by JP Morgan, J. Aron/Goldman Sachs and Morgan Stanley.[27]

While the announced closures are more likely to result in permanent closures under the Volcker Rule Case, other refinery closures may also occur due to the loss of risk management and commodity-based services that are currently provided by U.S. banks.

The impact of additional refinery closures will have a direct impact on gasoline prices. Under the Volcker Rule Case, East Coast gasoline prices are expected to rise by an additional 4 cents per gallon over the Regulatory Status Quo Case. Given the U.S. East Coast market of 50 billion gallons per year of gasoline consumption, the expected cost to the consumer is approximately $2 billion per year. In addition, approximately 1,300 direct high-paying refinery jobs are expected to be lost, excluding indirect jobs that are later defined in the economy-wide analysis.

Gasoline price volatility would increase along with prices

In addition to higher gasoline prices, there is significant risk of higher gasoline price volatility due to the realignment of Trans Atlantic gasoline trade discussed above. Under the new trade flows, East Coast prices must rise to a level that is high enough for exporters to divert gasoline supplies from alternate markets to the U.S. East Coast. Despite this, price responses in other Atlantic Basin markets will cause trade flows to fluctuate and result in greater U.S. price volatility.

[27] Product off-take agreements are identified based on review of Form 10-K and Form S-1 documents.

The envisioned trade realignment would require efficient responses to inter-regional price differentials. At issue, however, are the long-product transit times involved, the economic and political stability of each region, the significant quality differences between Atlantic Basin gasoline grades and the efficiency of each commodity market.

Under this case, the East Coast market would become more reliant on direct supplies from Venezuela and the Caribbean and the ability to replace European supplies in Mexico, South Africa and Nigeria with direct exports from the U.S. Gulf Coast. The stringent East Coast gasoline specifications, however, are expected to present difficulties for some of the new gasoline suppliers.

An important element of trade is the transit time required to physically transport petroleum supplies from one region to another. Because there is a great risk that the oil price could change significantly while in transit, hedging is commonly used to manage oil price risk.

In the event that the Volcker Rule were to impair the ability of U.S. banks to provide hedges, the availability and effectiveness of gasoline hedges may be significantly reduced. An unhedged, Trans-Atlantic gasoline delivery with a transit period of 10 days, for example, has an underlying price risk[28] of +/- 15%. This unhedged price risk is considered large enough to discourage opportunistic trade, which accounts for around half of the East Coast gasoline imports.

Curtailment of U.S. banks' commodity trading activities could also result in a reduction in Trans-Atlantic trade. In 2010, U.S. banks have accounted for approximately 13% of all East Coast gasoline imports and acquired supplies from over 20 different countries. Under the proposed Rule, these market making activities could be categorized as proprietary trading and potentially be eliminated.

Based on complex nature of the Trans-Atlantic trade realignment, the stability of East Coast gasoline supply and pricing should deteriorate from historical levels. At this time, it is reasonable to believe that New York price volatility could be significantly higher

[28] Underlying price risk estimate based on 95% confidence level (or +/- 2 standard deviations)

and bear more similarities to other markets that are known to be relatively isolated and dependent on complex foreign markets with differing fuel specifications. Comparative analysis with other U.S. markets, such as Los Angeles, suggests that New York gasoline price peaks could be 8-12 cents per gallon higher due to increased volatility alone.

Economic Impact Analysis

The previous sections of this letter have argued a number of qualitative and quantitative benefits from bank RM services. Specific quantitative findings from the industry analysis above were used to estimate the full economic impact of these benefits. This has been done by setting up a counter-factual scenario for IHS Global Insight's Model of the U.S. Economy forecast for 2012-2016 based on the question "what if access to RM services were significantly restricted over the 2012 to 2016 period." For example, the Upstream team provided analysis that identified the degree to which natural gas prices would be higher if access to long-dated hedging were significantly reduced. These higher prices over the 2012-2016 period were used to adjust the price variable in the U.S. Model and the model was solved to calculate the overall impact on the U.S. economy.

Methodology

An independent team of IHS economists reviewed the analysis of the Power, Upstream (Independent Gas Producers), and Downstream (East Coast Gasoline/Refining) teams and structured the quantitative elements of their analysis to prepare a set of inputs into a series of simulations of the IHS Model of the U.S. Economy. The inputs for each industry section were simulated separately and then in a single integrated simulation to get the full impact of all the counter-factual elements.

The key quantitative features of the counter-factual scenario are as follows

Independent Gas Producer Assumptions

- Lower natural gas drilling & completions capital expenditures
  (private investment in wells $7.5 Billion lower in each year over the 2012-16 period)

- Higher natural gas price with flow through to higher electricity and other prices
  (average 17% higher over the 2012-16 period)[29]

Power Sector Assumptions[30]

- Higher user cost of capital for utilities
  (average 1.2 basis points higher over the 2012-16 period)
- Higher electricity price
  (6 basis points higher over the 2012-16 period)

East Coast Gasoline/Refining Assumptions

- Higher national average gasoline price
  (1.44 cents per gallon higher over the 2012-16 period)[31]
- Closure of two refineries
  (direct loss of 1340 jobs)
- Increased imports of gasoline
  ($380 Million higher imports in each year over the 2012-16 period)[32]

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[29] Associated with a $0.64 per MMBTU price increase.

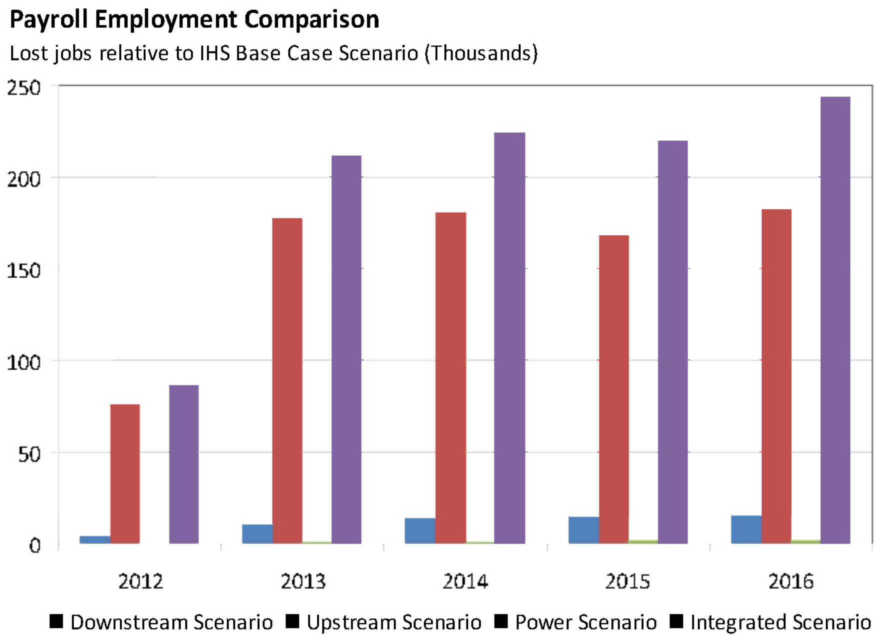
[30] Includes only impact of gas price volatility.

[31] Equal to 4 cents per gallon for East Coast market or $2 billion increase in consumer gasoline cost.

[32] A result of less domestic refining.

Results: Volcker Rule Impact Analysis

The graph below provides the results of the simulations for the impact on payroll employment.



Note: Power Scenario job loss is 1,300 jobs by 2016, too small to be seen on this chart.
Source: IHS Global Insight, US Macroeconomic Model

In total, the quantitative assumptions used in the analysis resulted in a reduction of payroll employment through the 2012-16 period with a peak impact of 243,000 jobs in 2016, which represents about 0.17% (17 basis points) of total 2016 payroll employment in the IHS base case scenario.

The independent gas producer impacts produced the largest job impacts – about 93% of the total job loss. The reduction of $7.5 billion in annual investment is a significant reduction and ripples through the economy and reduces employment. This is compounded by the significant increase in natural gas prices over the period which in turn increases the price of electricity by an average of 1.0% over the 2012-16 period and reduces the cost competitiveness of a wide variety of manufacturing industries and the costs of residential and commercial heating/cooling.

The power sector assumptions were very minor changes to the user cost of capital and electricity price and generated a peak impact of 1,300 lost jobs in 2016.

The gasoline markets impacts produce about 7% of the total job loss with the modest increase in the national average cost of gasoline and the shift from domestic to imported production resulting in the loss of about 13,000 jobs.

In the integrated scenario, real GDP is $34 billion (2005$) lower in 2016 than in the IHS base case scenario. To put this loss in context, this represents 0.22% (22 basis points) of real GDP. The impact of the integrated scenario also takes into account impacts on the wide range of factors influencing federal tax receipts. Over the 2012-2016 period, there is a cumulative loss of $12 billion (0.12% or 12 basis points) in federal tax receipts relative to the IHS base case.

The above results demonstrate the economic impact of these particular cases, but are not intended to estimate the total energy market economic impact if the proposed Rule curtails U.S. bank market making activities. Only a subset of these energy markets was modeled in this analysis. For example, the impact of gasoline prices in other regions, diesel fuel prices, natural gas drilling activities by non-independents, or oil production activities could further hamper economic activity. At the same time, it should be noted that the impacts calculated represent the upper range of the results that are likely to occur in the specific and narrow industries modeled.

5. Potential Impact of Rule

The proposed Volcker Rule could curtail U.S. companies' ability to mitigate risks and finance projects, reducing investment and job creation and increasing energy prices. The role of the market maker in relatively illiquid commodity markets requires a degree of principal trading to provide valuable RM services to clients. As we understand the proposed Rule, the definition of market maker is much more narrowly defined than the present market making commercial practice. This narrow definition is inconsistent with the nature of commodity markets and would curtail the intermediation services critical to effective market making activities. Other parties have raised these concerns in separate comment letters and academic papers.[33]

RM services are important to real energy companies, a sector of the U.S. economy that is providing jobs, improving energy security and improving the nation's balance of payments.

U.S. banks maintain a unique role in financial commodity markets.

- U.S. banks provide specialized RM services, such as long-dated hedging and commodity financing services that are generally not available from other RM providers.
- U.S. banks have provided innovation through development of new specialized RM services. Services requested by energy companies to reduce price risk, enhance investment and reduce costs.
- U.S. banks' deep knowledge of the complexity of energy and financial markets cannot be replaced quickly.
- The strong credit quality of many banks makes them a preferred counterparty for certain firms, and many of the bank services are not otherwise available in the market.

These specialized services are potentially at risk due to the proposed Rule.

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[33] Peter S. Kraus, AllianceBernstein L.P. comments submitted to four regulators related to Volcker Rule. (November 16, 2011) and Darrell Duffie, "Market Making Under the Proposed Volcker Rule." Stanford University (January 2012)

The need for risk management services, particularly more innovative services such as structured financing arrangements, will remain after the Volcker Rule implementation, but it is not clear which firms might provide these services if U.S. banks exit. Non-U.S. banks provide limited services in the U.S. market and are unlikely to increase their offering with tighter regulation and inclusion under the proposal Rule while serving U.S. markets. Other counterparties for customers seeking structured financing might theoretically include oil companies or traditional petroleum market trading firms. However, oil companies and trading firms typically have different aspirations in financing asset acquisitions or project developments. These firms are often competitors to buy the assets, or to participate in a project, making them problematic financing providers. For example, an oil company or trading firm would often make trading or off-take from the asset or project a condition of financing that would not fit the business objective of the firm seeking structured financing. Oil companies and trading firms have a fundamentally different business interest than a financial institution and are in many cases competitors to the asset/project owner.

Conclusions

Risk management and intermediation services are an integral part of our domestic real economy. These services provide many benefits, including commodity price stability and security of supply. Broad market liquidity is key to providing safe, efficient and well-functioning commodity markets. Any curtailment in the availability of RM services will affect consumer prices, domestic jobs and economic growth. While we agree with the spirit of intent behind the evolving regulation of the financial sector, we believe changes are required for any implementation of the Volcker Rule in order to ensure the quality and safety of U.S. commodity markets.

Commodity markets are necessary to support activity across our economy and to facilitate capital investment that is crucial to the future. As the Volcker Rule and other elements of regulatory change are implemented, it is of utmost importance that all due care be taken to ensure that market liquidity and the availability of essential services are not constrained while safeguarding the quality and safety of our commodity markets. Policy interventions need to ensure market liquidity.[34] Coordination, rather than a reduction, of market participants will improve social welfare.

If the role and permissible activities of market makers are too narrowly defined, the risk of curtailing important services offered by the banking sector will increase. There is a need to carefully reconsider the definition of “market maker” in the Volcker Rule’s “permitted activities,” as it relates to commodity markets.

[34] Huang, Jennifer & Wang, Jiang, 2010. “Market liquidity, asset prices, and welfare,” *Journal of Financial Economics*, Elsevier, vol. 95(1), pages 107-127, January.

Glossary

Play – a group of fields and or potential fields that have similar geologic characteristics. Exploration methodology and production is generally similar and shared.

BCF/D – Standard volumetric measurement unit for natural gas. Billion cubic feet of gas per day.

MMBTU – Standard heat content measurement unit for natural gas. Million British Thermal Units.

B/D – Standard daily measurement of oil. Barrels per day. One barrel equals 42 U.S. gallons.

kW-hr – Standard measurement of electric power. Kilowatt-hour.

BFOE – North Sea Crude oil contract. Stands for Brent, Forties, Oseberg and Ekofisk crude oil grades.