Think Corner Research Note

Monitoring U.S./Global Oil and Gas

Upstream Attainment, Producer Challenges

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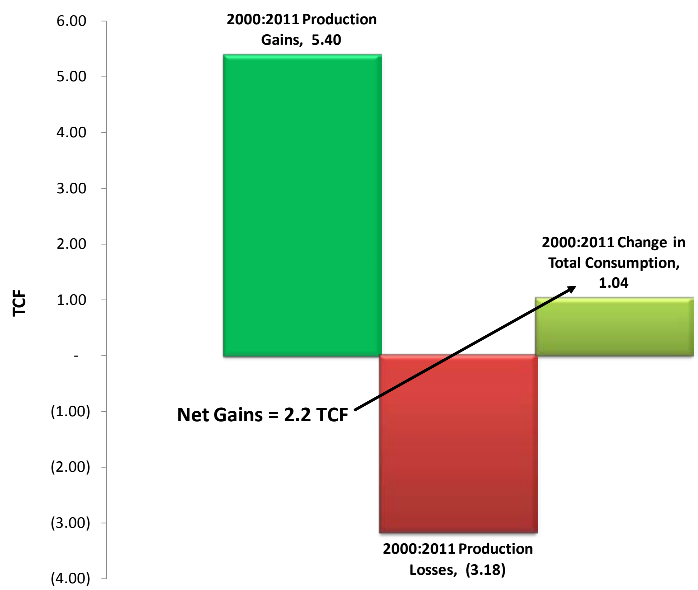
Sharpening the Focus

During the past decade, U.S. and, by virtue of cross-border business continuity, Canadian producers have had great stories to convey to shareholders and investors. They have been able to combine and hone off-the-shelf technologies in some of the toughest subsurface environments, prove up unconventional resources in shale fairways, and build a renaissance in natural gas and, even more startling, U.S. Lower 48 oil production. Producer success has been outweighed by slack demand (Figure 1). Natural gas prices reached lows not seen since the early days of Henry Hub trading. Yet a substantial portion of domestic exploration and production (E&P) revenues are derived from investments that were made in a price environment well above $3 per million Btu (MMBtu). Producers are faced with the continuing challenge of offsetting losses from dry (nonassociated) gas acreage with oil and/or liquids rich locations. Global oil market constraints being what they are, crude oil prices generally continue to support new oil and liquids plays and may do so going forward. Oil increasingly looks vulnerable to larger shifts in world demand and the economic and political forces buffeting longer term outlooks. Meanwhile, policy and regulatory risks and uncertainties are looming that will affect both oil and natural gas.

Figure 1. U.S. Natural Gas Performance, End of Decade



Source: Analysis based on U.S. EIA regional data.

Two years ago, as part of research on oil market dynamics, we began to track costs and other performance metrics for a sample of 16 companies that, in 2011, represented almost 60 percent of U.S. total marketed natural gas production. Our methodology is a "top down" approach based on corporate financial reports that is comparable to results from equities and commodities research groups. With our own research team competence in upstream asset development and operations, our expert networks, and our base in the Bureau of Economic Geology, we also track upstream activity across the U.S. and worldwide and are in tune with basin-specific costs and supply stacks. We use a full cycle, all source breakeven cost estimate, and also incorporate cash operating costs and an assumed 10 percent rate of return in order to build a more robust view of upstream businesses. Our analysis also has flowed into other research reports and links with other activities underway at CEE.[1] This research note constitutes periodic tracking as well as extension and expansion of our producer survey.

Looked at from a high level, U.S. and Canadian producers active in the U.S. domestic E&P sector would seem to be in good shape, so much so that the industry is targeted on a variety of fronts. Many audiences view the U.S. upstream in "autofocus" making simple assumptions about the value of assets, cost structures, profit margins and profitability, and the size, scope, and future deliverability of the U.S. and North American hydrocarbon resource base. In truth, producers and their trade associations often encourage simplistic views of their very complex businesses. More than many other industries, the need to sustain substantial capital infusions and investment flows[2] pushes E&P firms toward positive messages. The demands of building more nuanced stances is burdened by the problem of communicating E&P technology, accomplishments, and practices in a highly charged, decentralized, entrepreneurial media environment and to a general public that has broad, and increasing, unfamiliarity with technical detail. Yet, serious questions loom ahead about whether: producers should continue to receive tax treatment that traditionally has helped ensure reinvestment in new supply; the industry should be more tightly regulated for drilling practices; the U.S. can be "energy independent". Enormous consequences lie ahead and so the focus needs sharpening to discern stresses, weaknesses, problems in underlying assumptions, and the challenges that lie ahead.

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[1] Foss, M.M., M. Wainberg and G. Gülen, 2010, "Oil and gas prices and fundamentals", USAEE *Dialogue*, v18n3. Foss, M.M. and G. Gülen, 2011, *Persistent Puzzles in Commodity Markets: Global Oil Prices*. Expert report prepared for U.S. Energy Information Administration. Foss, M.M. 2011, *The Outlook for U.S. Gas Prices in 2020: Henry Hub at $3 or $10?*, Oxford Institute for Energy Studies, NG 58. http://www.oxfordenergy.org/2011/12/the-outlook-for-u-s-gas-prices-in-2020-henry-hub-at-3-or-10/. CEE researchers are building integrated analysis and modeling. See Gülen, D. Bellman, and Foss, February 2012, *U.S. Gas-Power Linkages: Building Future Views*, http://www.beg.utexas.edu/energyecon/thinkcorner/Think%20Corner%20Gas-Power%20Linkages.pdf.

[2] The strong capital requirements for E&P impact returns, a distinct challenge for the industry.

CEE Update on Producer Economics

Using corporate financial reports for 2011, only two of our sample of 16 producers demonstrate upstream cost structures that fall below a widely discussed target Henry Hub price of $4 per thousand cubic feet (MCF) including our assumed 10 percent return. We build our cost profile using MCF-equivalent, or MCFE, proved reserve additions and production.[3] All source finding and development (FD) costs are generally capital costs associated with exploration, development, and acquisition. FD costs exclude sales, asset retirement obligations, and expenses associated with unevaluated acreage that are suspended or excluded from the full cost amortization pool. Six of the producers in our sample use full cost accounting. With full costing, outlays which cannot be directly related to the discovery of specific oil and gas reserves are capitalized as part of the total cost of finding oil and gas reserves. These capitalized costs are carried to future periods (the full cost pool) where they are matched with revenues derived from production of the discovered reserves. With the successful efforts method (ten of our 16 producers), costs that cannot be related to specific reserves are charged to expenses as they are incurred. Choice of accounting method has substantial implications for how oil and gas companies report net income, profitability, non-cash items (depreciation, depletion, and amortization or DD&A), and, importantly, reserves.[4] Upstream projects like large unconventional plays require long lead times and many years to full development. Yearly costs and results can be lumpy. Companies typically cycle proved and proved undeveloped (PUD) reserves for current production. Thus, we use rolling three-year averages to more properly reflect activity and performance, a typical approach.

FD costs are the most visible, and widely acknowledged, type of expense associated with E&P companies. But FD costs are not the only and, as shown in Figure 2 below, often not the most significant expense for producers. For our research, since we are interested in the marginal cost of additional natural gas supplies, we

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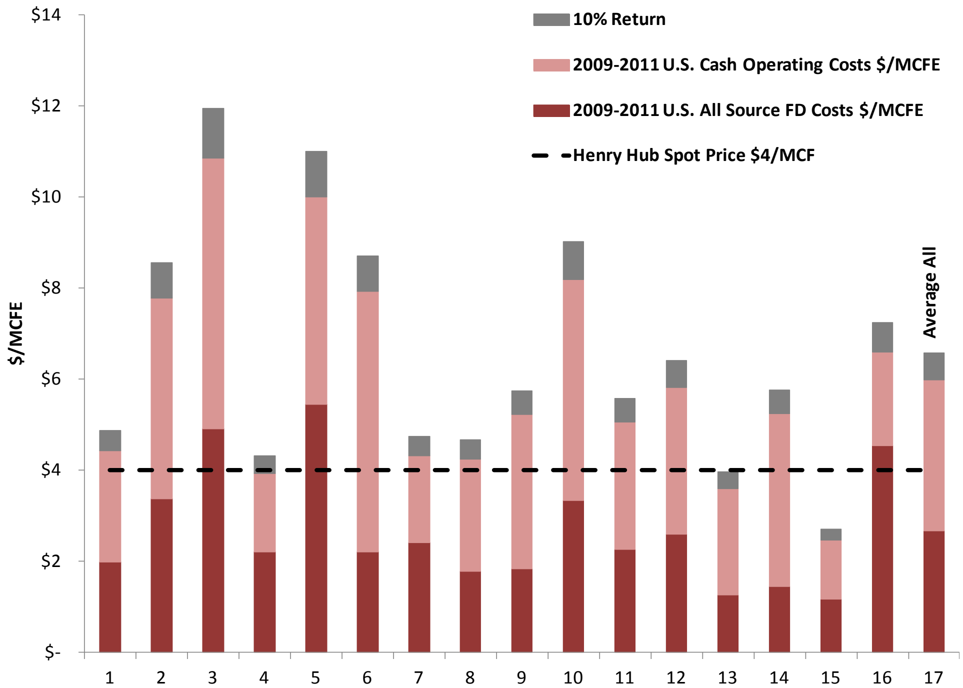
[3] Proved reserve additions include discoveries and extensions; net revisions; improved recovery and purchases.

[4] Small and medium sized companies more often use full costing while larger, more established companies typically choose successful efforts. One reason for the use of full costing by smaller companies is that "unsuccessful exploration and development costs need not be expensed if sufficient known reserves existed to insure recoverability of the costs. A rationale for the full cost method is that all costs are incurred in search of oil and gas reserves whether they are directly or indirectly related to specific reserves, and therefore all such costs should be capitalized and amortized over the actual production of the reserves found. Proponents of the successful efforts method, however, state that costs incurred in drilling a dry hole do not provide future benefits, and thus should be expensed when it is determined that the well is indeed not commercially productive. As can be seen, each method has a logical basis and so a controversial solution is inevitable". Drawn from *Oil and Gas Accounting – Part 1*, 2002, prepared by Professor Gary Schugart, University of Houston. Contact CEE for details, energyecon@beg.utexas.edu. Also see Investopedia's "Accounting for Differences in Oil and Gas Accounting", 21 November 2009, http://www.investopedia.com/articles/fundamental-analysis/08/oil-gas.asp#axzz1uytFCxEc.

need to consider cash operating costs associated with E&P activities. When reported, or when discernible in financial reports, we include lease operating expense (LOE), general and administrative (G&A) and marketing overhead, cash income taxes, non-income taxes (primarily production taxes), and net interest expense in the cash operating portion of our estimates. These are all essential items associated with the E&P firm as it goes about its business of finding and developing oil and gas.

Figure 2. Full Cycle Breakeven Costs for 16 Producers, 2011[5]



Source: CEE analysis based on company financials.

Given the very large number of upstream organizations operating in the U.S. (by some estimates, roughly 10,000 with 7,000 or so of these entities in Texas alone) and their diversity, one should expect considerable variability in cost structure. Our sample includes some of the largest integrated major oil companies, all with substantial footprints in U.S. shale plays (our main interest) as well as smaller, fast growing "shale specialists". Our sample also includes companies with significant offshore and, in some cases, deepwater presence. Those with offshore operations mainly report reserve additions of oil; the deeper water blocks of the U.S. Gulf of Mexico tend to be "oil prone", a function both of geology and the difficulty of handling natural gas production in these remote, frontier locations. Without revealing the identities of companies in our sample, we know that the producers have quite different positions in the U.S. shale plays. Some shifted out of dry gas activity sooner or, with serendipity, have benefitted from higher value liquids on

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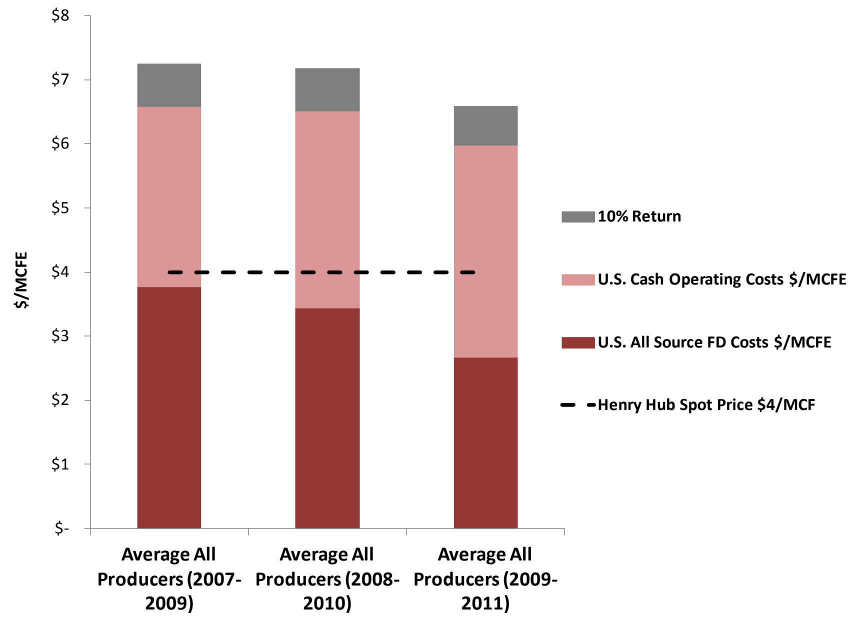
[5] Annual reporting year, using 10-K forms. As noted above, all data are rolling three-year averages; for 2011, data are averaged across 2009-2011 reporting years.

acquired and or leased and explored acreage. All producers have been pushing the cost management envelope which, with development drilling, is equivalent to manufacturing processes (the initial risk and capital entailed in exploration has been assumed, the challenge going forward is cost control).

Cost improvements, average for the entire group, are shown below. The trend in overall cost improvement that we detect is completely compatible with industry reports and expert opinions. In part, this is due to cost control and technology deployment. Not only technology deployment, but sound management of technology deployment is essential in complex reservoir and operating environments. Other factors, such as acquisitions, are important (see later discussion). Of importance is that most or all of the cost reductions are in FD costs. Cash operating costs are more stubborn and more difficult to contain.

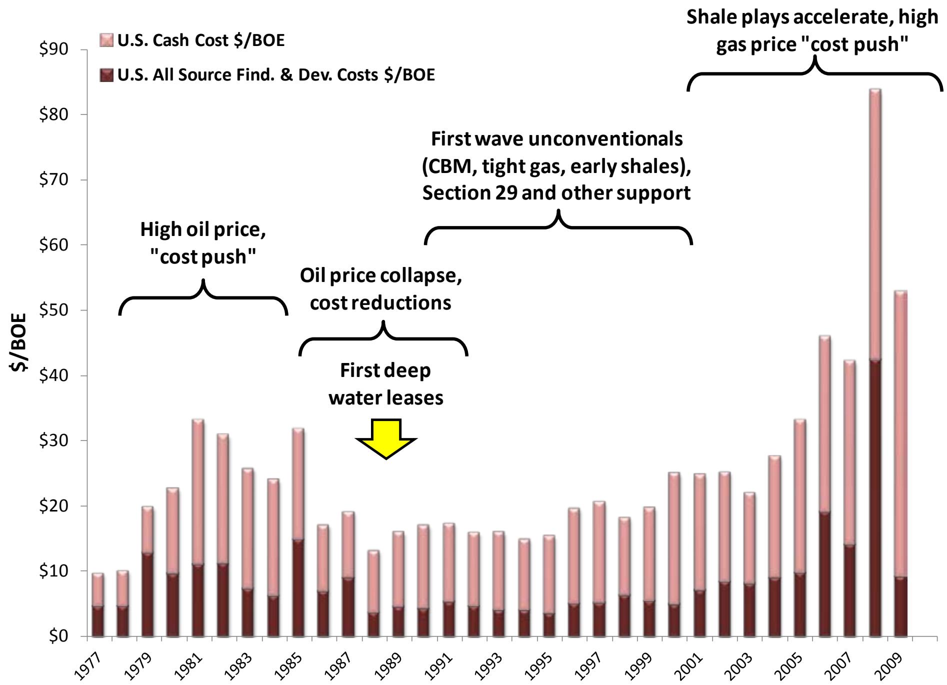
Figure 3. Average Full Cycle Breakeven Cost for All 16 Producers



Source: CEE analysis based on company financials.

The dilemma of reigning in cash costs is highlighted using a longer history, larger sample of producers, and barrel of oil equivalent (BOE) unit (Figure 4 below). FD costs vary over time, with shifts in location, and as commodity prices fluctuate. Cash costs increased fairly constantly over the history shown in Figure 4 and could reflect, in part, the pervasive manpower and skill shortages that the industry has struggled to cope with. Other critical factors could be tougher regulatory compliance, cost of financing, and growth in production taxes. Cost reductions and cost management skills and improvements can be obtained in a number of ways. One is the fierce E&P "learning curve", which Figure 3 above reflects and Figure 4 illustrates over the longer history and larger population of U.S. companies. As companies enter new plays costs are initially high. The subsurface environment has to be understood, services have to "fit" drilling and locational needs, technology has to be adapted and deployed. As plays evolve, attracting ever more attention and investment, competition for services and scarce human resource talent to implement drilling strategies sustains upward cost pressures. If an investment wave has been large enough – and the North American shale drilling wave would certainly qualify – upward cost pressure can be sustained for some time.

Figure 4. Long Term Full Cycle Breakeven Costs, FRS Producers



Source: CEE calculations using U.S. Energy Information Administration (EIA) Financial Reporting System (FRS) data.

Thus, as companies compete to enter new plays and evaluate cost structure, an obvious entry strategy is to acquire lower cost, leading producers. Mergers and acquisitions (M&A) become a second, and important, means for obtaining cost management prowess for particular E&P plays and achieving cost reductions. M&A is the most aggressive approach but joint ventures, farm ins, and other arrangements can be struck that allow the investing companies to benefit from lower cost operators. In Figure 5 below, several companies in our sample benefitted from strategic investing activity, notably producers 5, 6, and 10. In these cases, the investing companies built entry strategies that centered on acquisition of interests or establishment of joint ventures and partnerships with low cost producers.[6] Especially with prolonged soft Henry Hub price conditions, expectations are that low cost producers and lower cost operating locations will be of great interest as the industry re-organizes itself to deal with adverse circumstances.

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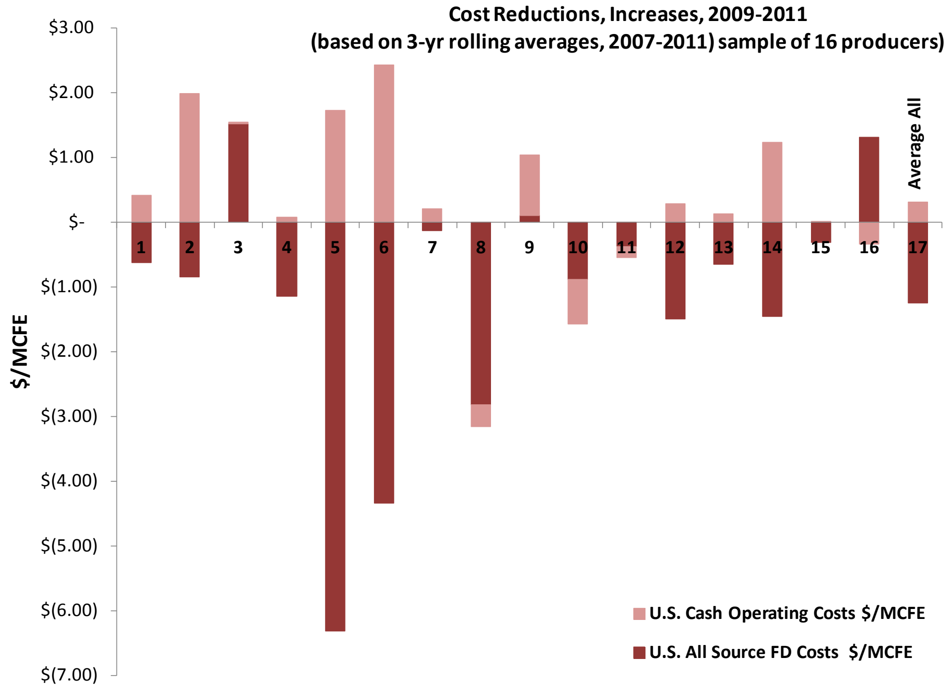
[6] M&A activity was especially strong in lower cost plays; in one case, liquids rich interest was acquired but had not been valued as part of the acquisition, providing a real boost to the investing company.

Figure 5. Changes in Producer Costs, 2009-2011



Source: CEE analysis based on company financials.

Challenges Ahead and Potential Implications

We note a number of challenges for the producer segment and continued attainment of the rich U.S. hydrocarbon resource base.

Unexpensed Exploration Costs

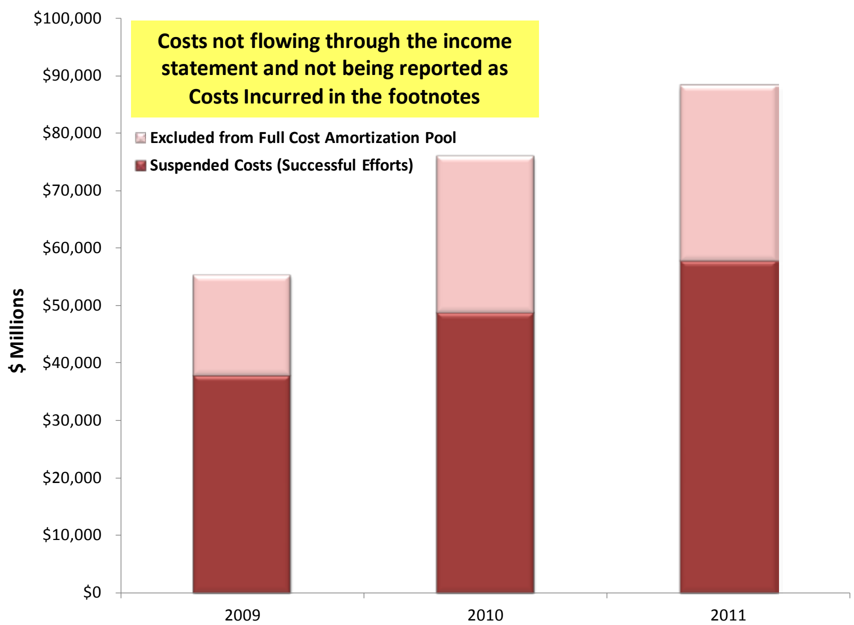
All of the producers in our sample, as do all producers generally, carry costs that cannot be expensed until either reserves are booked or revenues achieved, depending upon which accounting method is used (see previous discussion and footnote). Unexpensed exploration costs can accumulate while reserve estimates are being reviewed and the economic and operating viability of a project is being assessed. Companies are required to continually review the appropriateness of continuing to suspend these costs. It is not appropriate to continue to suspend these costs while waiting for improved commodity prices and/or advances in technology. We look at these costs because they give some indication of future expenses that will impact the income statement. In most cases we would expect the expenses to be accompanied by revenues; in some cases, there could be write downs of assets and reserves.

Companies using successful efforts tend to be more conservative about sweeping expenses, and therefore tend to sacrifice near term performance relative to companies that use full costing. A distinct problem facing many of the large companies in our sample is the slow pace of recovery in the Gulf of Mexico following the 2010 Macondo oil spill.

Of the companies in our sample, seven companies reported unexpensed exploration costs that included those associated with foreign (non-U.S.) and offshore projects.

These projects are typically multi-year in nature and frequently require complex contract negotiations and infrastructure to achieve commerciality: it is logical that the exploration costs would be suspended until project completion. The unexpensed exploration costs for the other nine companies were primarily associated with U.S. projects. In these cases, unconventional resource plays may present the same kinds of considerations as large capital offshore projects. Companies and their investors must engage in, and pay for, expensive pilot programs to drill and test resource in place and resource recovery in unconventional plays. These pilot programs take time, and can be multi-year in nature. Onshore producers face different leasing arrangements as well, with three- or five-year terms being typical, placing added pressure on proof of concept. Each producer should be assessed individually; as well, considerable variability exists within and across basins, among producing locations and so on. However, the growth in expenses for full costing companies, some in particular, has been very rapid, reaching levels that are very large relative to enterprise value.

Figure 6. Unexpensed Exploration Costs by Type of Accounting Method

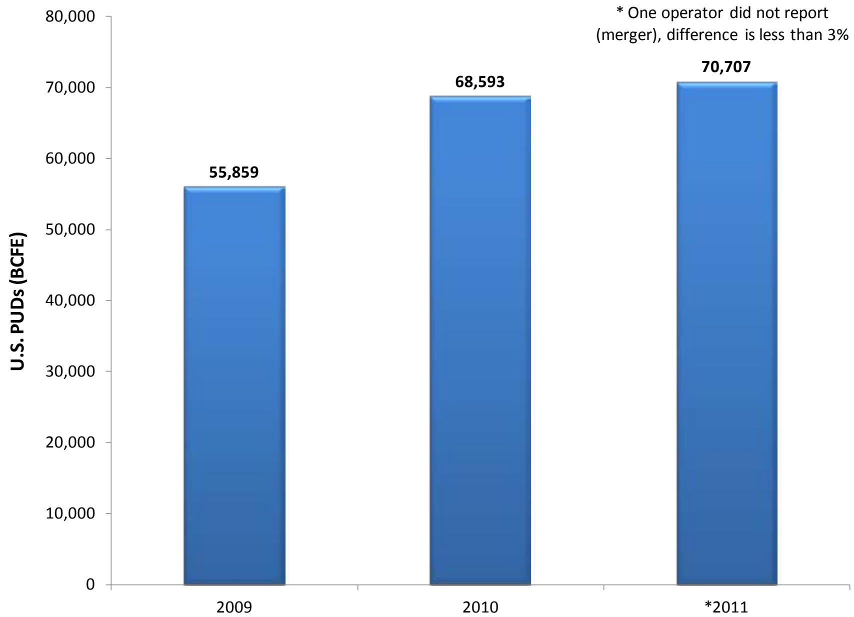


Source: CEE analysis based on company financials.

Proved Undeveloped Reserves (PUDs)

In 2008 the Securities and Exchange Commission (SEC) broadened the definition of PUDs to include undrilled locations if a development plan is adopted that indicates that drilling of the PUDs will be initiated within five years. In addition, the definition of the existence of "reliable technology" to develop PUDs was expanded. Many of the companies in our sample adopted the revised rules in 2009 and PUD bookings increased significantly in 2009 and 2010 which contributed to the decline in unit FD costs over the period. Some PUDs may have to be removed from proved reserves by 2014-2015 if they are not drilled by then which could result in increased unit FD costs. There may be some capability to carry undrilled locations as PUDs beyond five years on an exception basis justified by specific circumstances.

Figure 7. Proven Undeveloped Production (PUD)



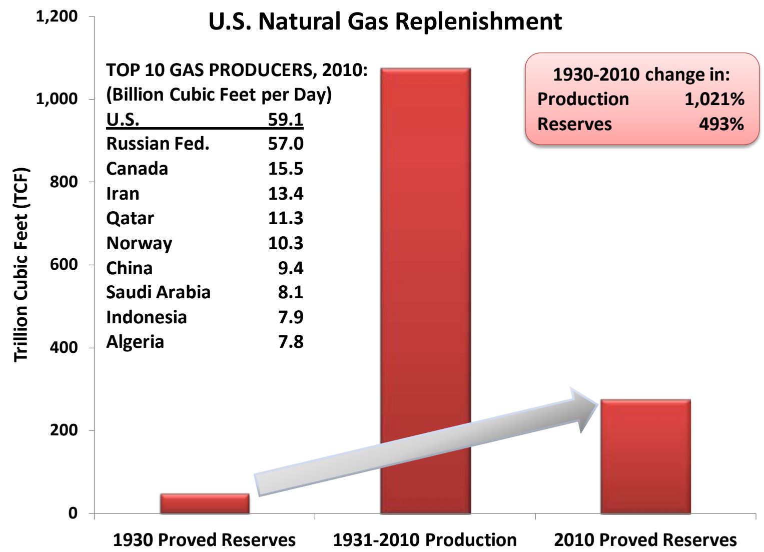
Source: CEE analysis based on company financials.

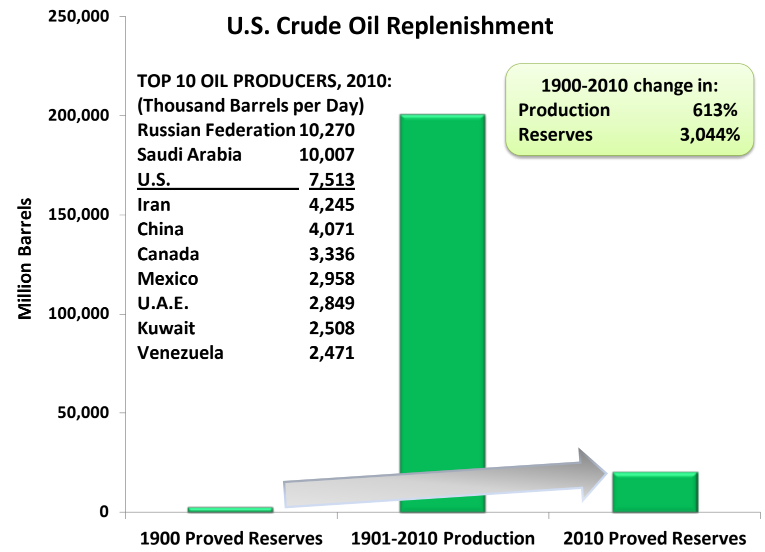
U.S. Resource Replenishment and Deliverability

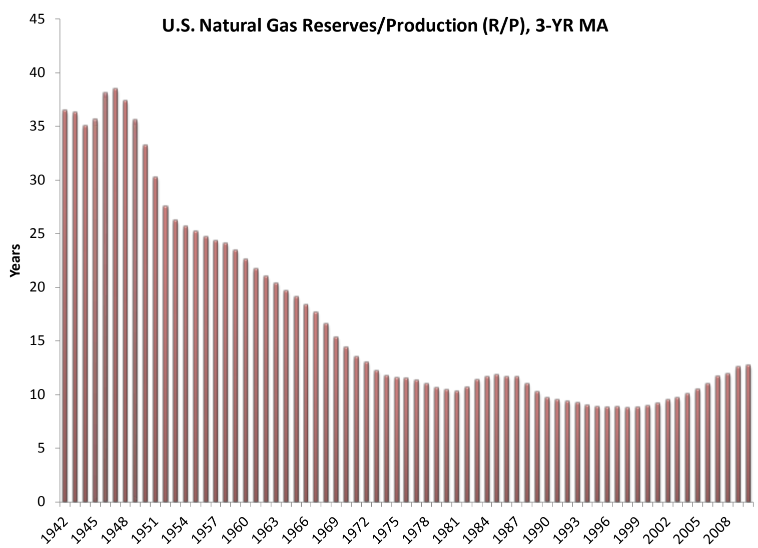
Our major concerns should be about replenishment and deliverability. Replenishment is the vital activity of finding new resources and proving up new reserves that enables sustained production going forward. Deliverability is the amount of supply that can enter the market at any time to meet demand.

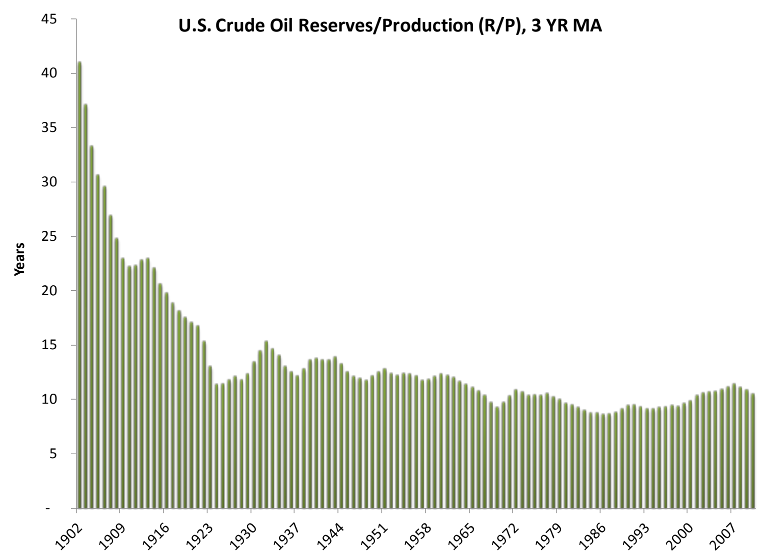
Potential regulatory and supply chain hurdles hit home most squarely on our ability to sustain a base of hydrocarbon reserves and deliver production from those reserves on an ongoing basis. A long view of reserves to production (R/P), using a three-year moving average, demonstrates industry responsiveness (see bottom charts, next page). R/P provides a rough measure of performance. Wartime needs and post-war economic growth diminished R/Ps for both crude oil and natural gas (as did increased industry efficiency and improved inventory management). The vibrant U.D. industry and markets allow operators to stabilize and, when robust business conditions exist, increase R/P ratios. This essential capacity – industry capability to maintain a long term, reasonably steady balance between reserves and production – is one of the most important ingredients for U.S. energy security and long term prosperity.

With time and continued domestic production gains and given our status as a major oil consumer, our resource base can help to reduce fears about chronic oil shortages. This “psychological” variable has real economic value and consequences. Moreover, replenishment and deliverability in the U.S. oil sector can contribute to greater international energy security.


U.S. Natural Gas Replenishment
Trillion Cubic Feet (TCF)
TOP 10 GAS PRODUCERS, 2010:
(Billion Cubic Feet per Day)
U.S. 59.1
Russian Fed. 57.0
Canada 15.5
Iran 13.4
Qatar 11.3
Norway 10.3
China 9.4
Saudi Arabia 8.1
Indonesia 7.9
Algeria 7.8
1930-2010 change in:
Production 1,021%
Reserves 493%
1930 Proved Reserves
1931-2010 Production
2010 Proved Reserves


U.S. Crude Oil Replenishment
Million Barrels
TOP 10 OIL PRODUCERS, 2010:
(Thousand Barrels per Day)
Russian Federation 10,270
Saudi Arabia 10,007
U.S. 7,513
Iran 4,245
China 4,071
Canada 3,336
Mexico 2,958
U.A.E. 2,849
Kuwait 2,508
Venezuela 2,471
1900-2010 change in:
Production 613%
Reserves 3,044%
1900 Proved Reserves
1901-2010 Production
2010 Proved Reserves


U.S. Natural Gas Reserves/Production (R/P), 3-YR MA
Years

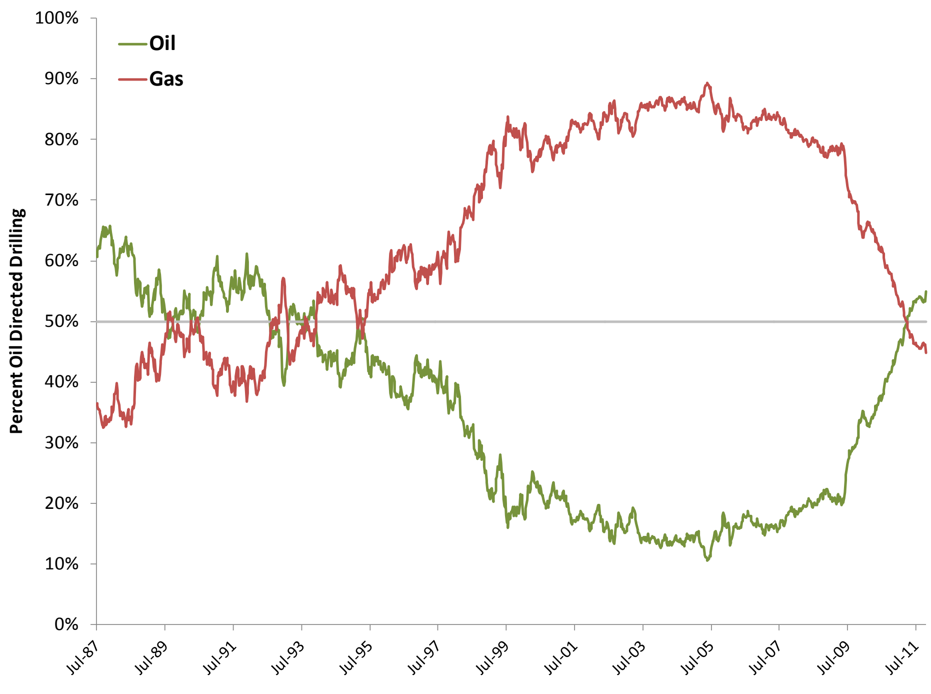

U.S. Crude Oil Reserves/Production (R/P), 3 YR MA
Years

Importantly, a robust resource base does not fully protect producers and customers from sharp swings in price. Short and mid-term deliverability can be impacted by any number of factors, ranging from natural disasters to operational events to pronounced business cycles. Oil and natural gas are commodities for which we are all price takers. However, sustaining a robust resource base is essential to restoring market balance. Coupled with operational and market flexibility, ever advancing technology, and a more elastic policy and regulatory environment, a robust resource base can help mitigate swings in price. Health of the capital intensive producer segment is essential for supply replenishment and deliverability.

Consequences of Shift to Liquids

The U.S. is entering a phase in which continued deliverability of natural gas from dry (nonassociated) producing locations, which constitute the bulk of natural gas supply capacity, will be challenged by the low price environment. We mentioned at the outset the shift in drilling taking place as higher oil prices lure capital investment away from pure natural gas plays and into locations that are "liquids rich". After a long upward trajectory, gas-directed drilling in the U.S. is no longer the dominant use of rigs (Figure 8). Active debate surrounds the question of how much dry gas yield can be obtained as associated gas from oil wells and extracted from NGLs-rich production locations. Estimates of methane from these sources range from roughly 20 percent to more than 60 percent. Considerable variation exists and well costs in some wet gas locations can be high relative to yields.

Figure 8. U.S. Oil and Gas Drilling Activity



Source: Baker Hughes

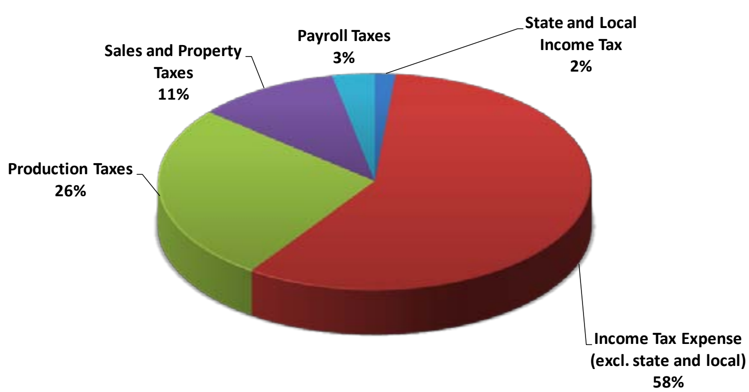
In addition, the U.S. continues to receive pipeline imports of natural gas from Canada, and liquefied natural gas (LNG) cargos from other locations. But at some point, natural gas prices will rise; increased demand for low priced natural gas and stronger economic recovery will hasten that adjustment. The expectation is that the robust shale gas resource base that has been proved up along with conventional play opportunities will facilitate responsiveness. Constraints to responsiveness, such as midstream bottlenecks or policy and regulatory hurdles, would exacerbate imbalances. Midstream bottlenecks are preventing cheaper crude oil and liquids from entering the market. These bottlenecks could impact dry gas deliverability since, in the low natural gas price environment, associated and wet gas production is more important for deliverability. And in the history of our natural gas industry, the U.S. has had plenty of experience with policy and regulatory induced imbalances.

Oil and Gas Tax Treatment

The target of attention on the policy and regulatory front has been well completions, hydraulic fracturing, and other drilling related issues. The main consideration is stringency of environmental regulation and oversight and impacts on investment flows, timing of activity, and upward cost pressures, which could adversely affect well and play economics. Reduction or elimination of oil and gas tax credits could have a substantial and immediate effect on viability of a substantial portion of domestic acreage portfolios for producers. Some companies estimate that between one- to two-thirds of their holdings could be affected if intangible drilling costs (IDCs) are not allowed to be deducted.[7] Offsetting impacts to producers would be benefits stemming from lower corporate tax rates or other meaningful tax reforms. The end result would be a disruption to the supply replenishment process, and eventual constraints on deliverability.

With persistently high oil prices, the producer segment is a locus for revenue capture. Producers already pay a hefty tax bill, both in total collections across all jurisdictions (local, state, federal, Figure 9) and in effective tax rate as compared to other industries (Figure 10). A low natural gas price and the drag it places on revenues derived from mainly gas producing properties make tax changes complex.

Figure 9. 2009 Oil and Gas Extraction Tax Expenses ($49.8 billion)



Source: Based on EIA data.

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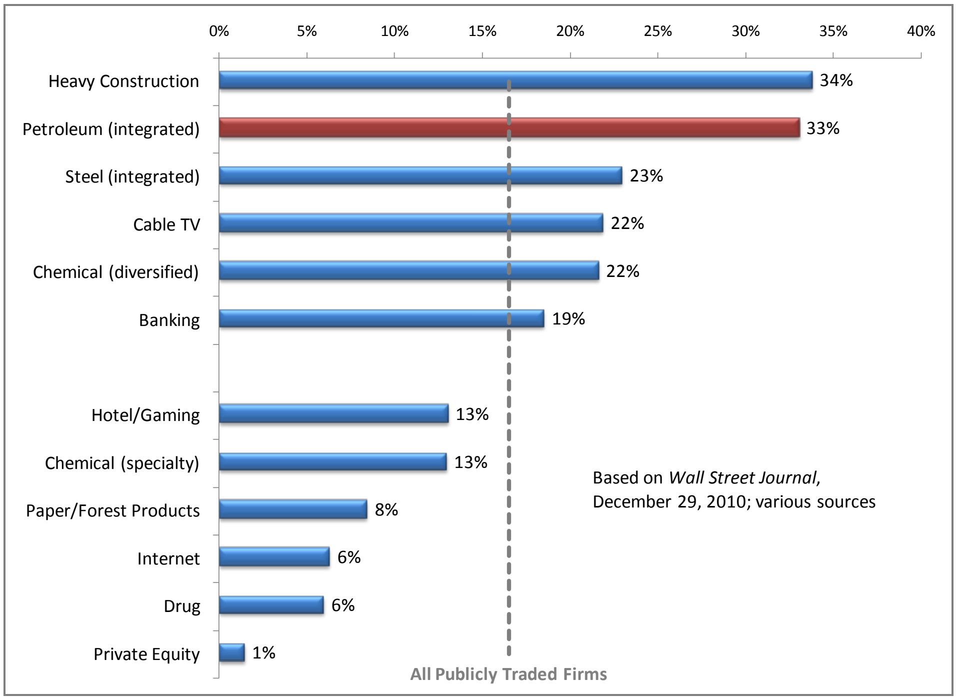
[7] Based on information shared by producers.

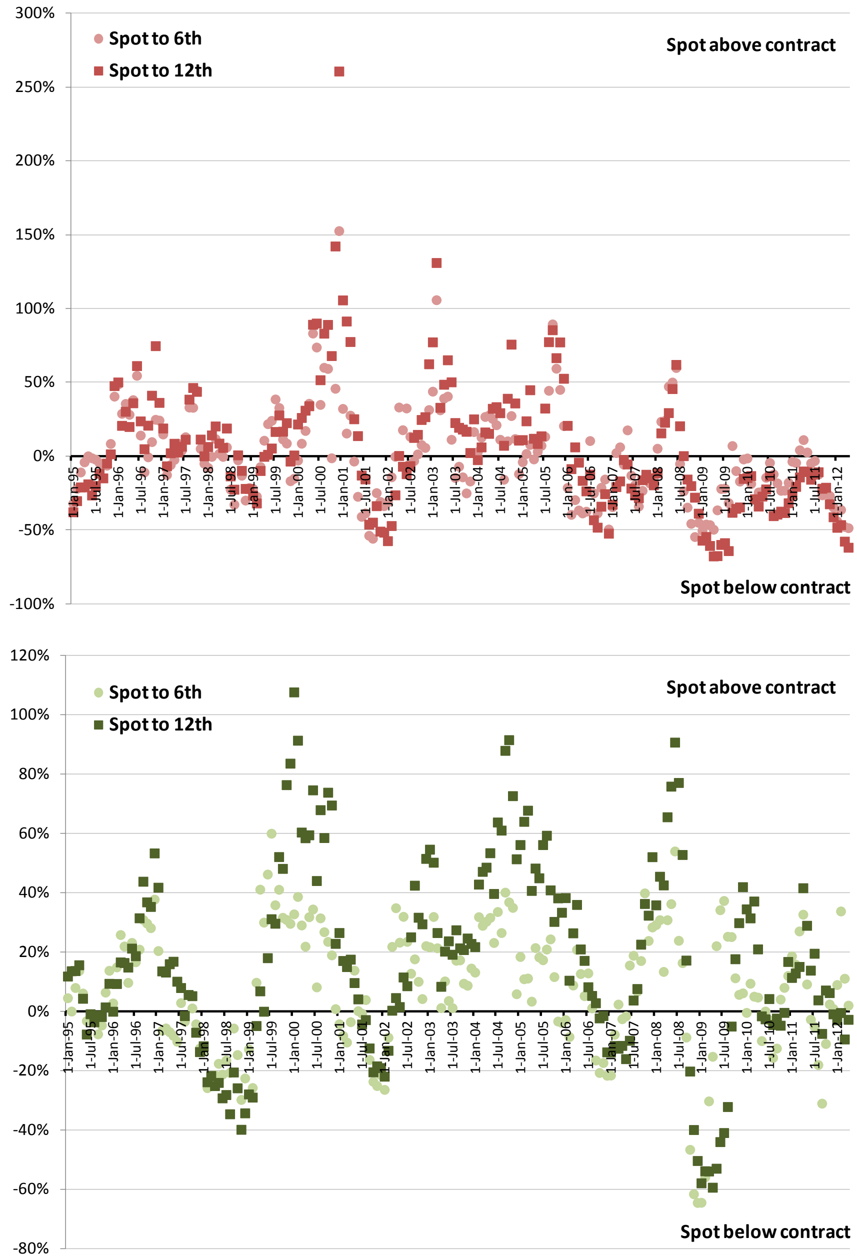
Figure 10. Effective Tax Rates of Selected Industries



Price Volatility and Hedging

Producers hedge to protect cash flows. Many producers hedge because they must – their financing is contingent upon them taking defensive positions to lock in prices for production and hopefully avoid losses if commodity prices soften. But, in fact, market participants overall (be they producers, other commercial entities, or non-commercial entities trading for portfolio management purposes) routinely leave "money on the table". Most of the time, as shown in the charts below, actual spot prices for the delivery month are above the futures contracts purchased six and twelve months prior. These results are especially surprising for crude oil, which is a deeper, more liquid traded commodity. Over the history of trading, the WTI (West Texas Intermediate) contract and cash prices are less volatile than Henry Hub. At least one observer notes that a "negative result in hedging is a good result" – the producer is protected from price erosion in any case, and so giving up some (or more often, quite a lot of) revenue is a small price to pay for the much greater losses that could have occurred had the producer not hedged at all. And yet, the charts in Figure 11 are indicative of how wrong market participants – including producers – can be at discerning prevailing price trends. The price of being wrong has, at times, undermined companies and proved troubling to shareholders and investors. The problem with the "negative result" argument is that, most of the time, trading error is on the high side; market participants are giving up price appreciation. It is much less common to take defensive strategies and hedging positions such that participants are serendipitously rewarded for guessing that prices six or twelve months away would be less attractive than the contract entered into at the time.

Figure 11. Trading Error? Spot Price to Prior 6th and 12th Contracts for Natural Gas (Henry Hub, top) and Oil (WTI, bottom) from January 1995

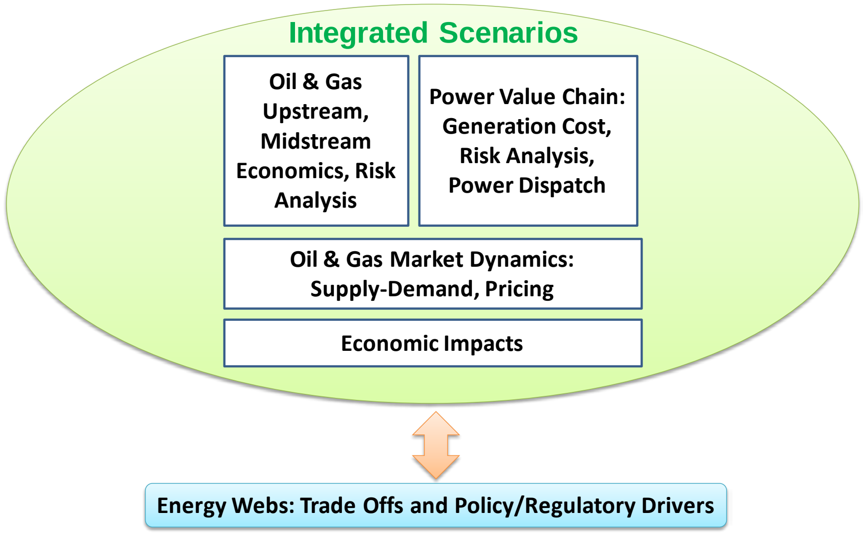


Source: CME data, based on approach used by Tudor, Pickering & Holt

Forward Path

CEE researchers will continue to track and monitor the upstream segment as part of an integrated research forum that combines tools and data with scenario building to address dynamic interactions across the energy value chains. Our Research Forum platform is illustrated below. Early results, research notes, and more information on our approach can be found on our Think Corner page and web site, http://www.beg.utexas.edu/energyecon/thinkcorner/.

Figure 12. CEE's Research Forum for Energy Futures and Strategies



In sum, the U.S. and North America have a rich resource endowment, and a nimble, inventive, and deep industry bench. The essential industry capability to maintain a long term, reasonably steady balance between reserves and production is one of the most important ingredients for U.S. energy security and long term prosperity. Whenever supply-demand conditions yield an attractive price signal that suggests imbalance, companies and investors respond quickly. Private land and minerals holdings enable fast response for leasing and testing new play concepts. Technology and service providers combine with operating savvy to push the envelope yet again in a way that challenges preconceived notions about U.S. productivity and longevity. As the cycle progresses, research and development are mobilized to tackle the next tranche of resource recovery challenges. The outcome is downward pressure on both of our major commodity price indexes (Henry Hub for natural gas, West Texas Intermediate for crude oil).

Most unconventional resource plays sit at the expensive end of the marginal cost curve for oil and gas supply. Subsurface conditions are more rigorous; specialized technology and manpower are costly. To guarantee success, and to be able to operate through price cycles, operators must continually strive to reduce cost on a unit (barrel) basis. They can do this by scaling up production volumes, so long as business conditions and other constraints (like policy and regulation) permit. Technology adaptations can help to eventually improve recovery rates, a target for sustainability and future pathways in unconventional plays, thus lowering costs and supporting profitability.

Key questions for U.S. producers going forward include **economic impacts of changes in oil and gas tax** using CEE's research and modeling platform as shown above. We also have published, on our own and with World Bank, several papers on national oil companies (NOCs; see our NOC web site at http://www.beg.utexas.edu/energyecon/nocs/index.php) and are applying our producer cost analysis to that population. ***For more information about future releases and products and on how you can participate contact us at energyecon@beg.utexas.edu.***