

Shale Gas and Pipeline Risk

Earnings erosion in a more competitive world.

BY PAUL R. CARPENTER, ET AL.

Recent years have seen fundamental changes in the supply and competitive landscape of the North American natural gas market. In response to high natural gas prices that prevailed during most of the last decade, gas producers in the lower 48 now have developed new sources of supply and technology, particularly to access new shale gas formations. These new supplies have encouraged a substantial expansion of the natural gas pipeline network in North America to allow the producers to reach end-use markets.

These events also have helped gas customers through greater supply diversity, lower commodity costs and expanded service options. However, if customers want to continue to enjoy the relatively low costs of capital that the regulatory compact provides in the long run, affected pipelines will need help from regulators.

That's because these new gas supplies also have changed flow patterns in the North American pipeline grid. The result has been a considerable increase in competition and risk, which can have serious consequences for pipelines and their required rates of return. This new landscape poses challenges for regulators and management alike.

Several regions in North America have been experiencing growth in gas production. The Rocky Mountain supply area grew rapidly last decade, and a substantial amount of gas pipeline capacity has been added to transport these supplies to both eastern and western U.S. gas markets. New supplies have also been flowing into the eastern U.S. pipeline grid, from shale supply areas in the U.S. Gulf Coast region, and more recently from the rapidly developing Marcellus shale in the Appalachian region of the U.S. New shale supplies are also being developed in western Canada—especially in Northeast British Columbia. These supplies have the potential to offset declines in western Canadian conventional gas production and serve markets in North America

New gas supplies—especially shale gas—have changed flow patterns on North American pipelines.

or overseas in the form of LNG.

Over the past few years, the new supplies, particularly those developed in the lower 48, have altered the dynamics of pipeline competition in North America. The growth of Marcellus shale supplies has been particularly noteworthy as a growing indigenous source of supply in the Northeast U.S. that competes in Northeast markets with more distant supply sources.

The extent of the shale expansion is revealed in a recent EIA presentation, which shows that U.S. shale supplies have grown from roughly 0.5 Tcf (1.4 Bcf/d) in 2004 to nearly 5.0 Tcf (13.7 Bcf/d), an increase of roughly 900 percent. EIA is currently

projecting that shale production will grow from 14 percent of total U.S. consumption in 2009 to over 50 percent in 2035, while net imports—including both LNG and pipeline imports from Canada—are projected to decline from 11 percent in 2009 to 1 percent in 2035 (see Figure 1). Thus, shale gas is now predicted to effectively displace all Canadian gas imports to the lower 48 states over the next 25 years.

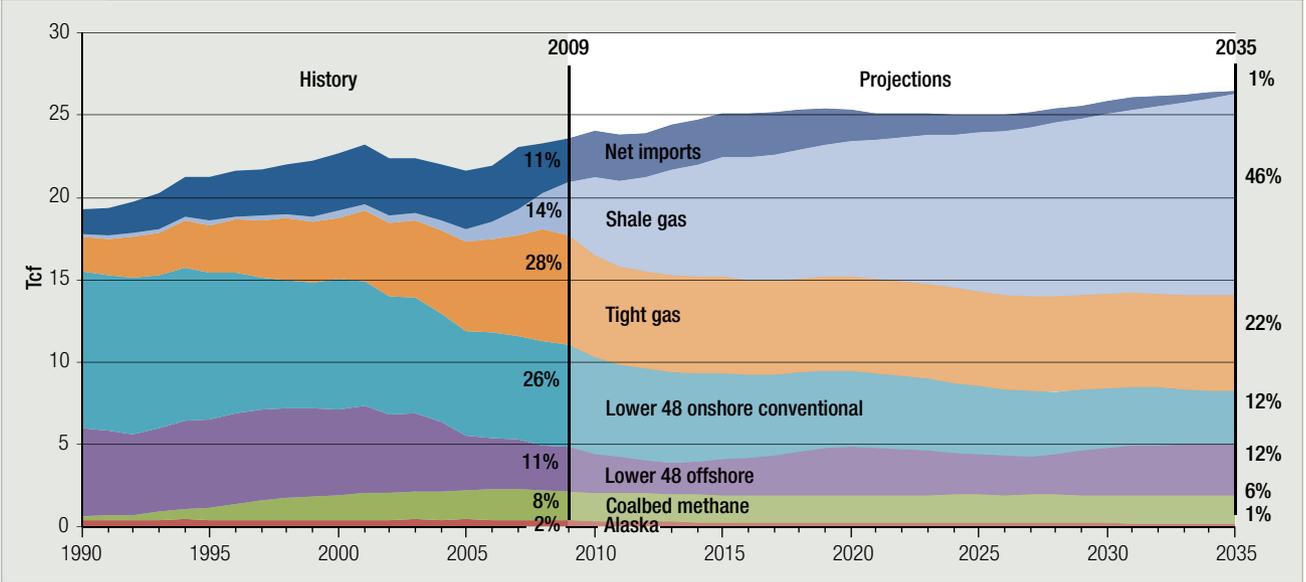
The new supplies and the pipelines constructed to serve them have put substantial competitive pressure on some existing pipelines. The potential for further changes in the gas market has increased the uncertainty facing many others. These competitive pressures have reduced the value of capacity on some pipelines, and in some cases resulted in substantial amounts of unsubscribed capacity. Figure 2 shows how the value of pipeline capacity—as measured by locational price or basis differentials—has declined on some pipeline corridors, particularly between western and eastern markets in North America.

Such competitive pressures and uncertainties create problems for rate-regulated companies like gas pipelines, because regulation sometimes restrains rates in ways that competition wouldn't, and competition sometimes restrains rates in ways that regulation wouldn't. The result can literally be the worst of both worlds.

Asymmetric Risks

Under normal conditions, a rate-regulated company expects to earn its allowed rate of return on average over »

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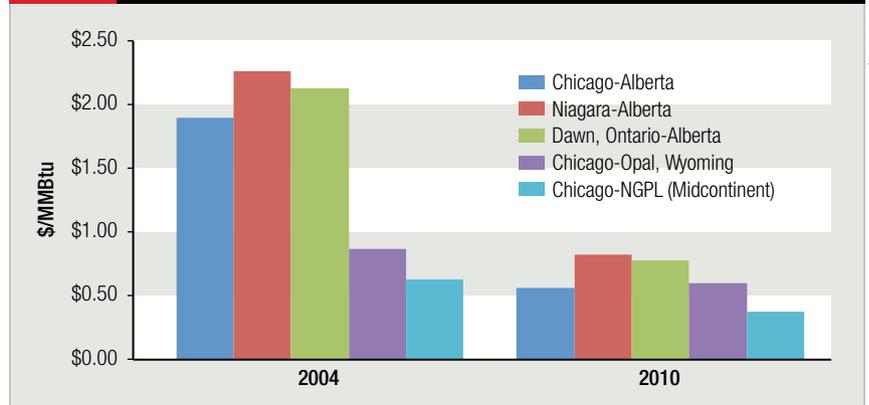
FIG. 1**NATURAL GAS PRODUCTION BY SOURCE**

Source: EIA 2011 Annual Energy Outlook

the life of each investment, but might earn somewhat more or less due to fluctuations in the business cycle or other events. Regulation prevents the company from expecting to earn substantially more than its allowed return, and in exchange regulation sets rates so the company isn't at risk of earning substantially less. The range of uncertainty is generally symmetric—*i.e.*, before the fact, the upside and downside potential are in balance—and typically is narrower than what unregulated companies face.

Nevertheless, sometimes regulated companies face downside risks that greatly exceed their upside opportunities. Examples include the take-or-pay losses suffered by U.S. gas pipelines in the 1980s and the California electric utilities' losses during the state's energy crisis at the turn of the century. Both of these events led to bankruptcies of rate-regulated companies, something not envisioned in the traditional regulatory paradigm.

Such asymmetric risks produce the danger of materially lower returns for regulated companies that aren't balanced by upside opportunities. Such risks don't have to extend all the way to bankruptcy to be eco-

FIG. 2**NATURAL GAS BASIS DIFFERENTIALS**

Source: Platts Gas Daily

nomically important. Asymmetric risks have two distinct implications, one definite and one a possibility.

First, asymmetric risks definitely mean the company won't have a fair opportunity to earn the cost of capital unless it receives the equivalent of a premium over and above the cost of capital in its allowed rate of return.

Second, if the potential asymmetric loss is correlated with the business cycle or other non-diversifiable risks of concern to investors—*e.g.*, if the loss is larger or more likely in bad times—the company's cost of capital will be higher than it would otherwise be.

Compensation for asymmetric risks isn't automatic, even if the company's allowed rate of return is equated to a

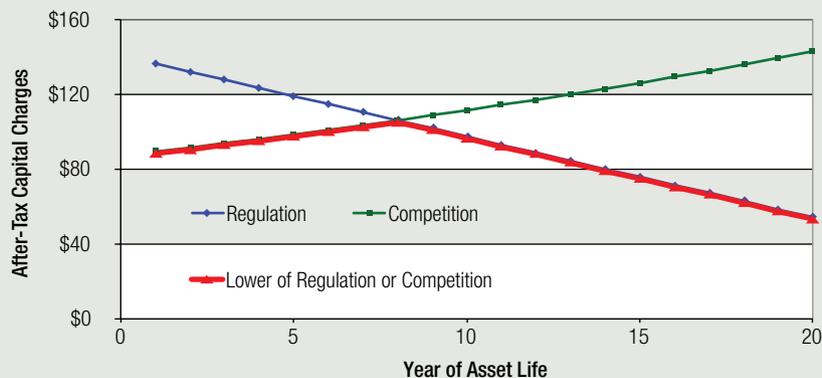
market-derived estimate of the cost of capital and the market is aware of the asymmetric downside possibility. The reason is that the cost of capital is defined as the expected rate of return, *i.e.*, the statistical mean value of all possible outcomes. This is the result of the standard cost of equity estimation methods when correctly implemented, for example. Contrast this concept with the yield to maturity on a junk bond.

A junk bond's cost of capital—*i.e.*, its average rate of return—reflects the possibility that the bond might default. Its stated yield to maturity, however, is calculated on the assumption that the bond doesn't default. The yield to maturity therefore equals the bond's cost of capital plus a default premium.

FIG. 3 REGULATED VS. COMPETITIVE CAPITAL CHARGES

Regulated vs. competitive capital charges, 20-year investment of \$1,000, inflation rate = 2.5 percent, real cost of capital = 6 percent.

The lower of regulated or competitive capital charges is inadequate compensation.



Source: The Brattle Group

The default premium is compensation for the asymmetry generated by the fact that bondholders get no more than the promised interest rate if the company does well, but might get less if the company does poorly.

Note that the asymmetry also affects the bond's cost of capital, since the odds of default are higher in bad economic times. Thus, the yield to maturity on corporate bonds provides an example of both of the possible effects of an asymmetric return distribution: the need for a default premium, and an increase in the cost of capital.

Asymmetric risks, by definition, give rise to an asymmetric return distribution. If the event or events giving rise to material downside risk don't come to pass, the company operates within the standard regulatory rules, expecting to earn its allowed rate of return on average. But if the event or events do occur, the company gets substantially less. The asymmetry means the company won't expect to earn its allowed rate of return on average over the long run, so an allowed return equal merely to the cost of capital wouldn't provide a fair opportunity to earn the cost of capital on average. That is, the average of an expected return equal to the cost of capital if the event doesn't occur, and

an expected return less than the cost of capital if the event does occur, necessarily is less than the cost of capital.

An asymmetry risk premium over and above the cost of capital in the allowed rate of return, akin to the default premium in a junk bond's yield, would be required to give the company a fair chance to earn its cost of capital on average.

Competitive pressures have eroded capacity values on some pipelines.

Markets Vs. Regulated Returns

The changing gas market creates new competitive threats for many pipelines. In some ways the risks facing a rate-regulated company that's also exposed to competition are higher than they'd be under either pure regulation or pure competition.

The problem arises in the way North American regulation sets the return on and of capital. Usually, capital charges equal a book-value rate base times a rate of return that includes compensation for inflation, plus depreciation

and taxes. Competition doesn't set capital charges explicitly; instead, they're implicit in competitive prices. But a basic feature of competition is that the price of a competitive good doesn't depend on the age of the assets used in its production—the price of tomatoes doesn't depend on the age of the tractor. The price of a regulated service traditionally does depend on the age of the assets employed, however. Therefore, the capital charges implicit in competitive prices logically must differ from those under rate regulation.

This logical inference proves to be correct. Competition in equilibrium implicitly provides investors with a rate of return that doesn't include compensation for general inflation, on an asset base that's worth more than it would be otherwise because of inflation. This means that regulated rates are higher than competitive prices early in the life of a new asset, while competitive prices are higher later on. The difference between regulated and equilibrium competitive capital charges for an asset is illustrated in Figure 3.

The figure assumes a \$1,000 investment, a 20-year asset life, a real—*i.e.*, no-inflation—cost of capital for both companies of 6 percent, and an inflation rate of 2.5 percent. It ignores taxes, which complicate the picture but don't change the implications. The solid blue line with diamonds tracks the regulated capital charges over the life of the asset, while the dashed green line with squares tracks the capital charges implicit in competitive prices. The regulated capital charges start out higher, both because inflation compensation is received in the rate of return rather than in appreciation in the value of the underlying assets and because a straight-line depreciation charge exceeds that implicit in competitive prices initially. The regulated capital charges then decline linearly as the rate base depreciates over its 20 year life. In contrast,

FIG. 4

ASYMMETRY PREMIUM

Illustrative values for total capital and for equity, assuming an after-tax weighted-average cost of capital of 8 percent and a 50-50 debt-to-equity ratio. The table postulates competitive entry that causes a write-off of a pipeline's rate base of between 10 and 75 percent, with a probability of occurrence that's also between 10 and 75 percent. It assumes that the cost of capital itself isn't correlated with the possible loss—*i.e.*, it considers only the first of the two possible effects of asymmetry. Were it to make the contrary assumption, the required returns would be even higher.

Note: The risk premium on total capital equals

$$(1+ATWACOC) / [1 + (\text{Probability} \times \text{Loss})] - ATWACOC$$

(Source: Kolbe, Tye & Myers (1993), p.48, footnote 86). Given this, the risk premium on equity is just the premium on total capital divided by the fraction of equity in the capital structure. The table assumes the ATWACC is 8 percent and that equity is 50 percent of the capital structure.

After-Tax Premium on Total Capital

Probability	Rate Base Loss			
	-10%	-25%	-50%	-75%
0.10	1.1%	2.8%	5.7%	8.8%
0.25	2.8%	7.2%	15.4%	24.9%
0.50	5.7%	15.4%	36.0%	64.8%
0.75	8.8%	24.9%	64.8%	138.9%

After-Tax Premium on Equity

Probability	Rate Base Loss			
	-10%	-25%	-50%	-75%
0.10	2.2%	5.5%	11.4%	17.5%
0.25	5.5%	14.4%	30.9%	49.8%
0.50	11.4%	30.9%	72.0%	129.6%
0.75	17.5%	49.8%	129.6%	277.7%

Source: The Benth Group

cesses, and pipelines are affected both by competition from other regulated pipelines and by competitive delivered gas costs from different sources.

All of this complicates the problem facing any particular pipeline, without changing the basic message: pipelines facing material increases in competition due to the changing gas market will have more downside risk than upside opportunity, and the traded market value of their assets will become more sensitive to the business cycle. That means they will have a higher cost of capital. It also means they will have a lesser probability of earning it on average, absent appropriate actions by regulators.

Avoiding a Premium

Asymmetric risks pose special challenges to regulators and regulated companies alike.

First, ratemaking flexibility will be vital if investors are to have a fair opportunity to earn a fair return of and on their investments. Longstanding ratemaking practices might need revision. For example, the burden of cost recovery might need to shift, so that the markets facing more competition remain viable and able to contribute to overall cost recovery, even if that means increases in rates for the markets facing less competition.

Second, an increase in the allowed return to compensate for the new risk level will be necessary, but this isn't a sufficient response by itself, for two reasons. The pipeline's cost of capital might well depend on how flexible regulators are in responding to the competitive threats. And if regulators aren't or can't be sufficiently flexible to eliminate or materially mitigate the asymmetry, calculation of the correct asymmetry risk premium to add to the cost of capital is an extremely difficult task.

One problem in calculating the correct asymmetry risk premium is that

the competitive capital charges grow smoothly at the rate of inflation.

The particular assumptions used in the figure aren't important. What's important is that if a company consisting entirely of this asset were constrained by both regulation and competition, the rates it could charge would track the "competition" line through year 8, and after that they'd track the "regulation" line.

The cash flows for a company constrained by both regulation and competition track the dotted red line with triangles. Since each of the other two lines provides cash flows with a present value just equal to the \$1,000 initial cost, capital charges constrained to whichever line is lower don't offer adequate compensation to investors. That is, a company facing both regulation and competition can end up getting

"the lower of cost or market," to borrow the accounting phrase.

Fluctuations in the business cycle affect regulated and competitive companies differently, also. In general, competitive cash flows are more variable than regulated cash flows. For a company facing both regulation and competition, this means competition might undercut regulated rates even at times when regulation would produce lower capital charges, all else equal. It also implies that regulated returns might become as risky as competitive returns.

Of course, actual pipeline companies are certainly more complicated than depicted in the graphs. Real companies are composed of many different vintages of assets, and real companies are rarely in equilibrium. Pipeline rates are often negotiated rather than being set strictly by regulatory pro-

each pipeline's risks will be unique. Just as bond rating agencies consider the specific risks of each bond, an asymmetry risk premium needs to consider the specific risks facing a particular company. The sample-based process used to estimate the cost of equity won't work for an asymmetry risk premium.

Another, and even harder, problem arises if the odds that the regulated company will have to bear an asymmetric loss depend on the decisions of future regulators. In that case, there's a danger of circularity: if future regulators are more likely to impose a loss because current regulators awarded an asymmetry risk premium, the size of the asymmetry risk premium that current regulators need to award goes up.

Finally, the size of the fair asymmetry risk premium can be quite large, well above the normal range of debate over the magnitude of the cost of capital in a rate case (See Figure 4).

These complexities imply that the best solution is cooperation among the parties so that a material asymmetry risk premium is unnecessary. 

Endnotes:

1. See "Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources," presentation by Richard Newell, Administrator to the Organization for Economic Cooperation and Development (OECD), p.11, June 21, 2011.
2. See A. Lawrence Kolbe and William B. Tye, "The Duquesne Opinion: How Much 'Hope' Is There for Investors in Regulated Firms?" *Yale Journal on Regulation* 8:113-157, 1991; "The Fair Allowed Rate of Return with Regulatory Risk," *Research in Law and Economics* 15:129-169, 1992; "It Ain't In There: The Cost of Capital

Shale gas could effectively displace all Canadian gas exports to the lower 48 states over the next 25 years.

Does Not Compensate for Stranded-Cost Risk," *Public Utilities Fortnightly*, May 15, 1995; and "Compensation for the Risk of Stranded Costs," *Energy Policy*, 24:1025-1050, 1996; see also A. Lawrence Kolbe, William B. Tye and Stewart C. Myers, *Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries*, Boston: Kluwer Academic Publishers, 1993.

3. See, for example, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance*, 10th ed., New York: McGraw-Hill/Irwin, pp.24-27, 481, 2011.
4. On this point, see particularly, Kolbe and Tye, "The Fair Allowed Rate of Return with Regulatory Risk," *op. cit.*, or Kolbe, Tye and Myers, *op. cit.*, pp.84-105.
5. See, for example, Brealey, Myers and Allen, *op. cit.*, p.481.
6. The authors acknowledge Stewart C. Myers for this particular example, which they sometimes call the "tomatoes theorem."
7. See, for example, Stewart C. Myers, A. Lawrence Kolbe and William B. Tye, "Inflation and Rate of Return Regulation," *Research in Transportation Economics*, Volume II, JAI Press, Inc., Greenwich, Conn., 1985; or Kolbe, Tye and Myers, *op. cit.*, Chapter 4.
8. The economic depreciation schedule implicit in competitive prices in equilibrium is akin to the principal repayment schedule for a home mortgage—which starts out small and gets bigger with every payment—but in real rather than nominal terms. See A. Lawrence Kolbe, "How Can Regulated Rates—and Companies—Survive Competition?" *Public Utilities Fortnightly* 115, 4 April 1985; and William B. Tye and A. Lawrence Kolbe, "Optimal Time Structures for Rates in Regulated Industries," *Transportation Practitioners Journal* 59, 176-199 Winter 1992.
9. See Kolbe, Tye and Myers, *Regulatory Risk, op. cit.*, pp.46-51.