

Jumps in Proved Unconventional Gas Reserves Present Challenges to Reserves Auditing

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Summary

This study analyzes the typical challenges and opportunities related to unconventional-gas-reserves maturation and asset performance. Volatility in natural-gas prices may lead to downgrading of formerly proved reserves when the marginal cost of production cannot be sustained by the wellhead prices realized. New US Security and Exchange Commission (SEC) rules have accelerated the growth of unconventional-gas reserves, which in a way is an additional but unintended source of volatility and hence risk. Concerns about security of investments in unconventional-gas assets are fuelled by the effects of volatile natural-gas prices on production economics and by uncertainty about stability of reported reserves. This concern is exacerbated by an unprecedented rise in proved undeveloped gas reserves (PUDs) reported by unconventional-gas operators, arguably effectuated by favorable interpretations of PUDs when applying the new SEC accounting rules. This study includes a benchmark of proved reserves reported by two peer groups, each comprising four representative companies. The peer group of conventional companies includes Exxon, Chevron, Shell, and BP, and the unconventional peer group is made up of Chesapeake, Petrohawk, Devon, and EOG. Possible sources of undue uncertainty in reported reserves are highlighted, and recommendations are given to improve the reliability of reported reserves, especially from unconventional field assets.

Introduction

Hydrocarbon reserves are key assets of any oil and gas company because these affect the company's balance sheet. At any point in time, the hydrocarbon reserves represent the principal asset collateral for equity and debt liabilities. Additions to the reserves inventory may positively affect the credit ratings of oil and gas companies (Weijermars 2011a), but any downgrading of reserves could increase their cost of capital. Reserves additions are what companies strive for as they improve their asset collateral and the book value of the company. Overseeing the security of oil and gas reserves reporting to investors is the responsibility of the SEC, which is why companies are required to report reserves in their annual 10-K, 40-F, and 20-F filings to the SEC (Fig. 1).

Reliable reserves reporting is not only crucial for maintaining investor trust, it is also a cornerstone of every national energy policy. For example, reasonable certainty about economically recoverable US 2009 gas reserves is proved only for the 284 Tcf tallied by the US Department of Energy (DOE/EIA 2010a) on the basis of proved reserves reported to them by the companies using Form EIA-23S. The process of resource assessment by operators and the reserves reported to government agencies (e.g., DOE/EIA and SEC) ultimately results in the accumulation of proved reserves (Fig. 1).

Reserves maturation and reporting rules are critically linked to the economically producible resources. At any point in time, the long-term average wellhead price determines which volume of technically recoverable resources can indeed be produced economically for the current state of geological appraisal and technology cost. The volume of economically recoverable reserves is

highly sensitive to gas pricing. The critical cost curve is fixed cost plus marginal cost plus hurdle rate requirement that needs to be recovered for the gas-field-development project to be economical. Fig. 2 shows how, *ceteris paribus*, the economic gas volume grows with the commodity price.

The increased volatility in natural-gas prices over the past decade (Fig. 3) has in turn increased the risk exposure to downgrading of formerly proved gas reserves. Impairment or downgrading of proved reserves occurs when the marginal cost of production can no longer be sustained by the wellhead prices realized. The risk of fluctuation in the gas reserves asset inventory of unconventional-gas operators is higher than for conventional gas operators for two main reasons: (1) gas-to-oil asset ratios are higher, and (2) profit margins are lower or negative for unconventional-gas operators (Weijermars and Watson 2011a, b). The gas-to-oil asset ratios remain higher for unconventional-gas operators ($>>1$) as compared to those for conventional-gas operators ($<<1$), in spite of the recent shift from gas to oil production by the former (Weijermars 2011b).

The final SEC rules have demonstrably created a situation where there is room for interpretations that make a larger portion of natural gas resources economically producible, particularly when applied to unconventional-gas fields. Even as gas prices dropped in the past few years (Fig. 3), the new SEC rules have led to unprecedented growth of proved reserves for unconventional-gas operators (see the Trend Divergence of Conventional and Unconventional-Gas Reserves section). In contrast, such unprecedented fast growth of gas reserves has not been reported by conventional-gas operators. Conventional-gas operators profess prudent reserves booking, and due diligence was enhanced in the wake of the SEC reserves probe of 2004. Majors that were optimistic about finding proved reserves in the extension of existing production acreage before 2004 were severely penalized by the SEC (Olsen et al. 2011) in what is commonly referred to as the "reserves scandal." In the aftermath of the 2004 reserves scandal, oil and gas majors have become very conservative in the reserves accounting methods. Meanwhile, the proportion of natural-gas reserves in the asset portfolios of major oils has steadily increased over recent years, as is reflected in their 2010 average gas-to-oil production ratio of 37% for the oil majors (Weijermars and Watson 2011b).

Arguably, a difference in reserves reporting "culture" has emerged between the US independents—engaged in unconventional-gas developments—and the oil majors [international oil companies (IOCs)]. IOCS that have now entered the unconventional-gas-play field by acquiring part of the independents' (former) assets must emulate audit methods for the booking of reserves from both conventional- and unconventional-gas fields. Merging the two reserves auditing "styles" in a diligent reporting procedure remains extremely important. The maintenance of due diligence—expected from oil companies, majors and unconventional independents alike—is at stake.

This study substantiates how volatility in the asset inventory is higher for unconventional-gas operators than for conventional-gas operators. The underlying causes are analyzed, categorized, and benchmarked using data from the past decade of accelerated unconventional-gas development in North America. The volatility in the reserves-maturation process for unconventional-gas assets poses a risk for both organic and inorganic growth portfolios. The principal goal of this study is to highlight the risks associated

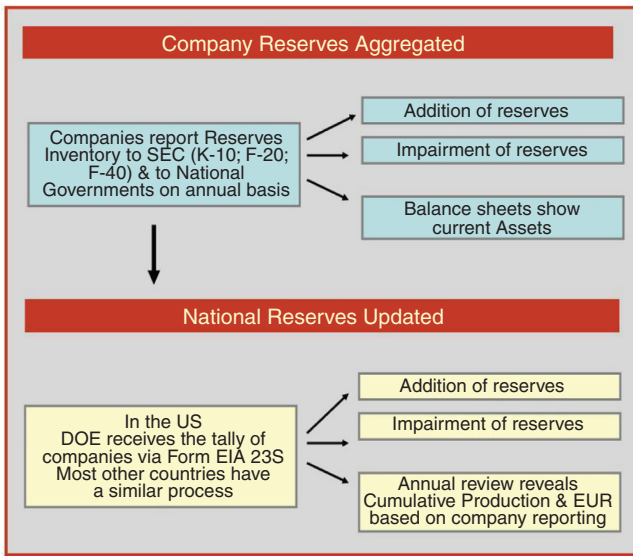


Fig. 1—Companies operating and stock listed in the US file SEC annual reports (Forms 10-K; 40-F; 20-F for US companies and Canadian and other foreign companies, respectively). Reserves are reported in compliance with SEC regulation. National reserves inventories are based on the annual company Form EIA-23S filings to the US Energy Information Administration (EIA). Other countries follow similar procedures.

with uncertainty in the development of unconventional-natural-gas reserves while firmly bringing opportunities into focus. Recommendations are formulated for mitigating the increased risk and uncertainty associated with unconventional-gas-reserves inventories. Optimum resource development requires a stable reserves-maturation process.

The results of this study are useful for the following stakeholders: investors, operators, and energy policymakers. For investors, it is crucial to understand sensitivities in the reserves maturation

process to better judge the risk involved in the unconventional-gas sector. For operators, proved reserves are essential for rapidly building positive free cash flow in a highly competitive market. For government policymakers, accelerated growth of gas reserves with a low volatility is important for security of energy supply.

Inventoried and Developing Unconventional-Gas Resources by Nations

Technology innovation can enable oil and gas companies to access new gas resources and thereby improve security of supply. For example, the USA has seen a remarkable recovery of reserves replacement ratios for oil and gas after decades of decline. Fig. 4 shows the steep rise of US proved gas reserves. The new reserves relate to the result of the application of new hydraulic fracturing techniques for unconventional-oil and -gas fields. The growth in proved gas reserves is entirely accounted for by nontraditional or unconventional-gas reservoirs. In particular, the development of tight gas plays has been very successful. The turnaround in US gas-production decline occurred in the 1990s when tight gas and CBM halted a further decline in the US proved gas reserves and was underpinned by a steep rise in US gas reserves over the past decade (Fig. 4). Lately, unprecedented fast growth in reserves has been reported by US shale-gas operators.

The USA has convincingly averted an imminent decline of its domestically produced natural gas by developing new technologies to unlock gas trapped in tight sand, shale, and coal seams. The production of US domestic gas from unconventional reserves by mid-2000 surpassed the domestic output of conventional gas (Fig. 5). The US EIA data further show that US gas production can now provide for nearly 90% of total domestic demand. Consequently, US consumers have become only minimally dependent of foreign gas imports, in spite of a decline in US gas production from conventional reserves since the 1990s. LNG landing terminals accounted for less than 1% of US gas supply in 2009. The balance 10% gas import to the US is covered by pipeline imports from neighboring Canada and Mexico. In fact, the US even maintains net gas export to Mexico because Mexico receives more gas from US export pipelines than it returns through import pipelines because of seasonal shifts and cost-effective trading opportunities.

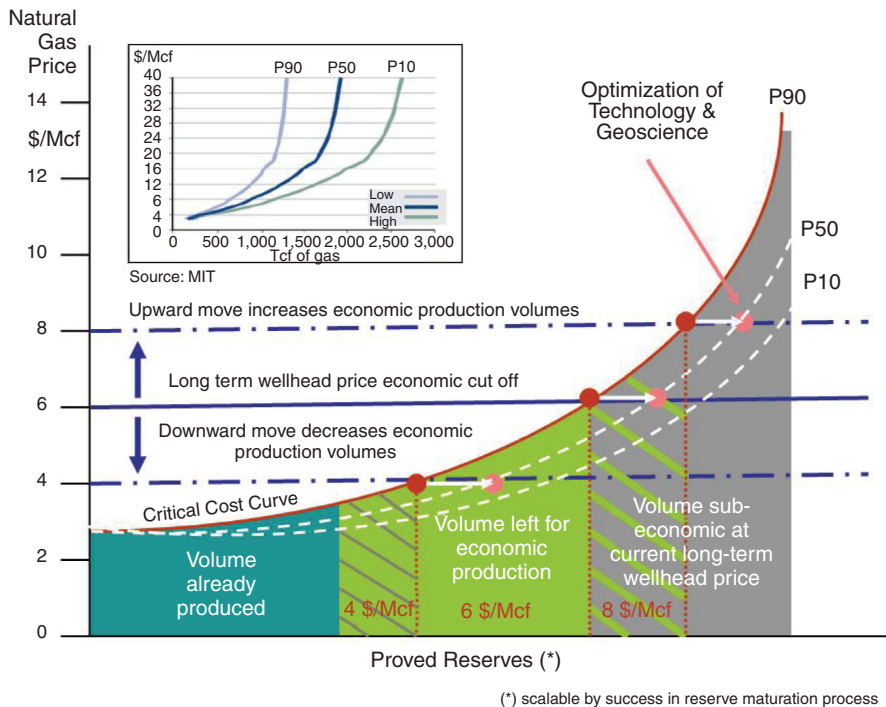


Fig. 2—Volume of economically producible proved reserves shifts with gas price. Further growth of economically producible, proved reserves at a given gas price is possible by optimization of technology and better control on subsurface uncertainty (geology and geophysics). Inset shows the application of the gas-price sensitivity on estimates of US recoverable gas volumes (McRae and Ruppel 2011).

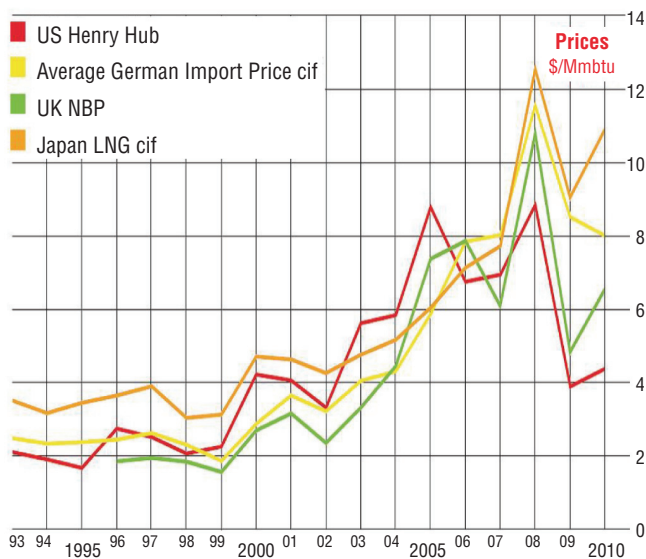


Fig. 3—Annually averaged prices for natural gas (USD/million Btu ≈ USD/Mcf) in the world’s major gas markets (BP 2011).

By painstakingly searching for new ways to optimize unconventional-gas-recovery technologies over the past 30 years, the North American oil and gas industry has paved the way for the worldwide development of unconventional-gas resources. The rest of the world is keen to follow the USA and Canadian example, mostly spurred by concerns about security of energy supply. The development of unconventional-gas resources requires horizontal drilling and high-pressure fracturing of the rock, as well as a pioneering spirit to turn these risky geological plays into an economic business. Gas-production companies must now demonstrate worldwide that they can indeed sustainably exploit “technically recoverable resources” from unconventional-gas fields in an economical fashion.

Derisking assets and reducing volatility in resource volumes and economic producibility are part of the core philosophy of the current reserve reporting frameworks [Petroleum Resources Management

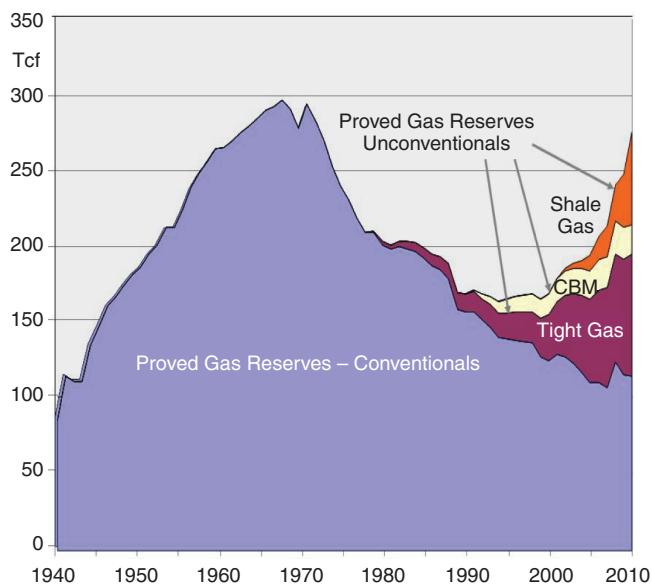


Fig. 4—Proved natural gas reserves for the USA, as derived from DOE/IEA annual totals (based on DOE/EIA, 2011 data RNGR11NUS_1a). The sharp upturn in reported US proved gas reserves over the past decade is entirely due to the development of unconventional-gas resources. Coalbed-methane (CBM) reserves are reported since 1989 (DOE/EIA 2010a, data RNGR51NUS_1). Shale gas reserves have been separated by EIA only since 2007 (DOE/EIA 2010b, data RES_EPGO_R5301_NUS_BCF) and have been estimated for the earlier part of this decade. Tight gas reserves are not reported separately by the EIA—the portion of proved tight gas reserves shown is pro-rated in this study on the basis of EIA production data.

System (PRMS), SEC, and UN Framework Classification (UNFC); for details, see Appendices A and B]. Adding new gas reserves used to be a slow and costly process, but shale-gas-extraction technology and new SEC reserves-booking rules have accelerated the growth of proved gas reserves in an unprecedented way. It should be emphasized that PRMS is a practical reserve management framework for oil and gas companies, whereas SEC reserve reporting rules aim to protect investors; the UNFC is a complementary reporting framework for national oil companies that do not need to report to SEC and for whatever reason prefer to avoid PRMS. An added strength of UNFC is that it also applies to economic mineral resources.

Several authoritative inventories have already pointed out that our global heritage of unconventional-gas resources could be much larger than conventional resources (Rogner 1997; Holditch and Madani 2010; DOE/EIA 2011a). Exploration for shale-gas resources is still in an early stage; production of shale gas outside the USA remains insignificant. A first essential step in a systematic approach to eventually bring these resources to market is an assessment of the technically recoverable resources. For example, the US Potential Gas Committee (PGC) provides periodic assessments of the US gas resource base and concluded in its latest year-end 2008 assessment (Potential Gas Committee 2009) that the US combined endowment of natural gas in speculative frontier resources, possible new field resources, and probable resources in current fields amounts to 1,836 Tcf. This stated quantity of the US national gas potential is deemed by the PGC a reasonable estimation of ultimately recoverable gas resources on the basis of current knowledge of the subsurface and current recovery technology. The speculative, possible, and probable resources inventoried by the PGC are emphasized by them as not necessarily economic at present. A recent inventory by the National Petroleum Council (NPC) is even more optimistic (NPC 2011), but questions have been raised about its insufficient accounting of the economics (Brooks 2012).

In 2010, the US Department of State launched a global shale-gas initiative to aid other countries in replicating the US success in producing natural gas from shale deposits. The past decade of

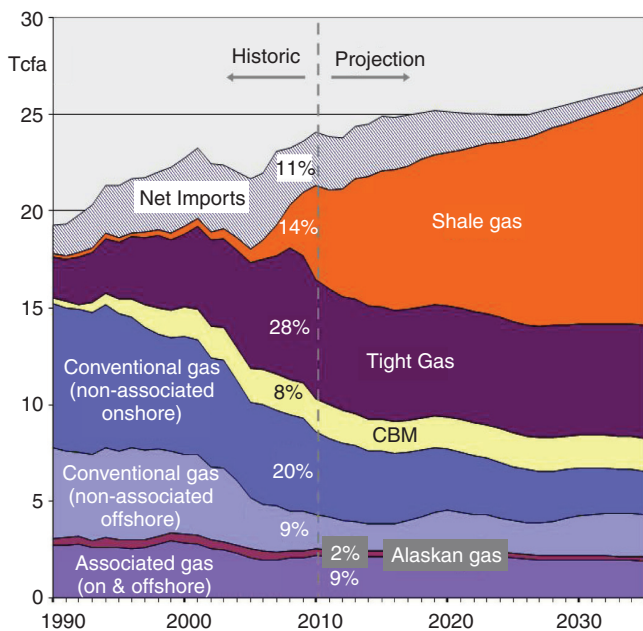


Fig. 5—US natural-gas production separated into reservoir type. Tight gas accounts for 28% of US 2010 total gas consumption. Shale gas accounts for 14%, but the DOE/EIA expects this to have tripled by 2035. According to the DOE, US gas net imports (mostly from Canadian shale gas basins) will be displaced further by growth in the domestic US shale gas production. (data from DOE/EIA 2010c, 2011b).

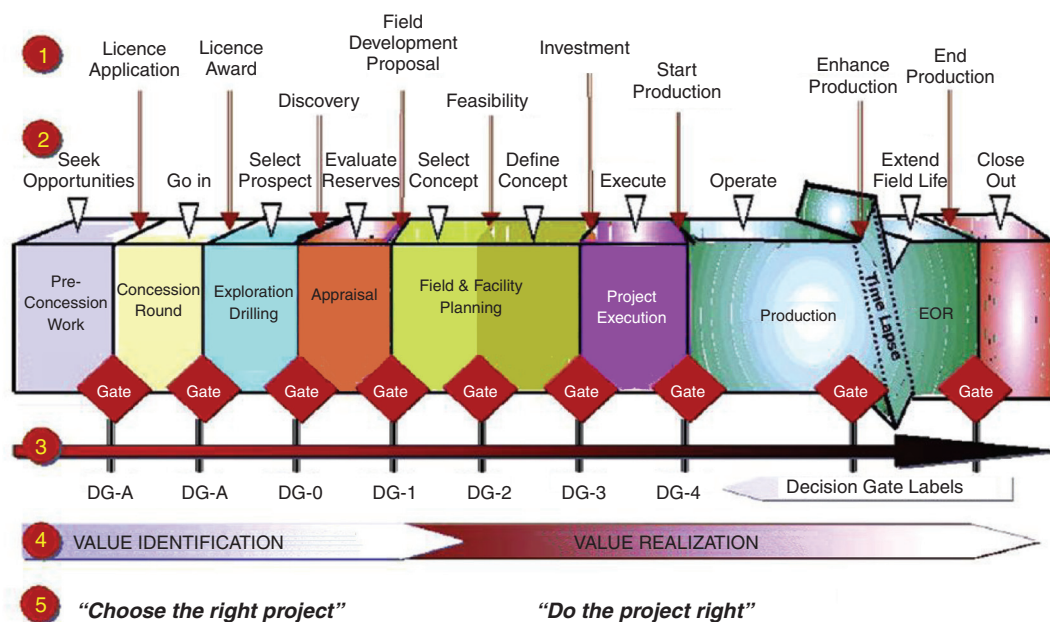


Fig. 6—“Traditional” E&P Workflow architecture for development of conventional upstream oil and gas projects. [Data source: Weijermars (2009)].

accelerated North American unconventional-gas development has provided a wealth of data on key issues that determine success and failure in unconventional-gas developments. The US wants to share its vast technology and regulatory experience and memoranda of understanding (MOUs) have been signed with China and India; the US Geological Survey will assist these countries in assessing their shale-gas resources and advise on its development. A first workshop has been held in China (starting November 2010) and similar efforts are scheduled for India; dedicated shale gas workshops were also held in Poland (2010 and 2011). The USA’s efforts as stated by the State Department are motivated by foreign policy and energy security concerns. On a country scale, the reserves-maturation and production-depletion development is illustrated in the generic model of Fig. 1.

Organic vs. Nonorganic Growth of Corporate Gas Reserves

The Petroleum Resources Management System (PRMS 2007; SPE/AAPG/WPC/SPEE/SEG 2011) is a widely accepted standard for the management of petroleum resources and was developed by several industry organizations [SPE, the World Petroleum Council, American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers). Proved reserves are hydrocarbon accumulations for which the company specifies an ultimately recoverable volume that with reasonable certainty is economically producible (see Appendix B for full definitions). The “maturation” of a company’s portfolio of reserves through exploration and development is part of the workflow in most oil and gas companies, which thus ensures new field projects can be fitted into the corporate project portfolio at the right time.

Companies build and develop gas reserves through progressive investments in data acquisition, subsequent professional appraisal, and economic field development modeling in a process that passes many decision gates (Fig. 6). The exploration process is no gamble, but a cost-conscious program with many decision stages aimed at identifying resources that may generate a profit when reserves are eventually developed. The screening of prospective resources finally leads to derisked and “matured” proved reserves for only the best assets. The so-called reserves-maturation process is the final outcome of a progressive upgrading of prospective hydrocarbon resources into proven reserves through certain exploration stages that have been assessed for technical feasibility of the field-development concept and economically appraised for net present value (NPV) and return-on-investment potential. A revision of the

traditional field-development concept for application to nonconventional assets has been recently proposed by Weijermars et al. (2011), and many in-depth discussions on the application of PRMS are found in a comprehensive publication by the World Petroleum Council (SPE/AAPG/WPC/SPEE/SEG 2011).

Additions or growth in reserves can be realized either by success in the exploration for new prospective resources (organic growth) or by the acquisition of assets and proved reserves from other companies (nonorganic growth). The strategy tradeoff is briefly referred to as the “buy” vs. “drill” option for reserves growth. Companies must continually rejuvenate their asset inventory by adding new reserves to maintain their asset base value. Ultimately, all the reserves must represent volumes that can be produced at a profit.

In the organic growth strategy option, reserves are added by geological exploration. A critical key performance indicator accounting for the state of a company’s asset inventory is the reserves-to-production ratio (R/P ratio), which measures the number of years the company can continue producing from the existing inventory at current production rates (Table 1). Growth of reserves is necessary to replenish produced volumes. The reserves-replacement ratio (RRR) is the extent to which the annual production is replaced by proved reserves additions. The RRR must stay above unity for companies not to lose future production potential. Further details on reserves growth for the companies listed in Table 1 are given later in this paper.

In the nonorganic growth strategy option, companies acquire their new gas reserves not by field exploration but by mergers and acquisitions, thereby benefiting from the exploration success of the partner or selling company. Many companies took advantage of the low gas prices in North America during 2009–10 to acquire unconventional assets of companies that were sometimes on the brink of financial distress. Overgearing and lack of access to new debt and equity financing forced unconventional-gas companies to sell out field assets at steep discounts. Table 2 provides an overview of the major unconventional-gas-asset sales over the past decade. While the acquiring companies expect future benefit from the discounted assets acquired, such an outcome is by no means guaranteed.

Trend Divergence of Conventional- and Unconventional-Gas Reserves

Reserves reporting rules are issued by the SEC to ensure that companies file reports (10-K, 20-F, 40-F) to them with adequate information for investors so they can assess the business performance (risks and opportunities) of the companies they invest in. Detailed guidelines are given by the SEC on the reserves reporting

TABLE 1—UNCONVENTIONAL- AND CONVENTIONAL-GAS PRODUCERS ANALYZED IN THIS STUDY

Peer Group		Market Cap 31	Gas/Total	Gas	Gas	Gas R/P	Gas R/P
Unconventional Producers	NYSE	March 2010 (Billion USD)	Output Ratio	Output 2009 (bcf)	Output 2010 (bcf)	2009	2010
Chesapeake	CHK	14.5	0.90	834	924	9.4	8.9
Petrohawk	HK	5.8	0.97	174	234	5.1	4.8
Devon Energy	DVN	28.5	0.68	966	930	8.1	9.1
EOG Resources	EOG	26.5	0.75	600	616	7.7	7.2
Totals	–	75.3	–	2,574	2,704	–	–
Peer Group		Market Cap 31 Sep	Gas/	Gas	Gas	Gas R/P	Gas R/P
Conventional Producers	NYSE	2010 (Billion USD)	Total Output Ratio(*)	Output 2009 (bcf)	Output 2010 (bcf)	2009	2010
Exxon (**)	XOM	330	0.39	3,385	4,434	14.4	12.9
Chevron	CVX	168	0.32	1,820	1,839	7.3	6.7
Shell	RDS	190	0.41	3,096	3,396	6.9	6.5
British Petr.	BP	127	0.36	3,097	3,066	7.8	7.8
Totals	–	815	–	11,398	12,735	–	–

Production data from annual reports SEC K-10 and F-20; Market capitalization from Quarterly reports SEC Q-10; (*) Ratio based on conversion of natural gas taking 5.8 Mcf gas for 1 bbl oil equivalence of oil in total output; (**) Production from XTO acquisition not included in 2009 output; included in 2010 output.

method, which in turn provides a basis for auditors to prepare the SEC filings with reserves in accordance with SEC intentions, and as adopted by the US Generally Accepted Accounting Principles (US GAAP). The SEC reserves reporting final rule and accounting implementation as reported by GAAP FAS19, SAB101, and SAB104 are supported by detailed reserves reporting guidelines developed by the SEC. Appendix A provides an overview of the various regulatory and classification frameworks for oil and gas reserves reporting; the new SEC rule is highlighted in Appendix B.

A “reserves audit” is defined by the SEC as “the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities.”

As of the book year 2009, the SEC enforced new rules for reporting reserves (Appendix B), which have changed for the first time in 30 years. The introduction of the new SEC rules coincided with an unprecedented 51% increase of 2009 proved

shale-gas reserves (Fig. 7), as reported by US shale producers under the new rules. This growth is remarkable in itself, but even more so because gas prices fell by 59% in 2009 as compared to year-end prices used in 2008 reserves reporting. Normally, lower gas prices are likely to effectuate a downgrading of economically producible proved reserves, and this is exactly what happened to US conventional reserves in 2009, which went down by some 4.1 trillion af (DOE/EIA 2010).

The unconventional-gas reserves reported over the past decade by the peer group of US independents, and mostly conventional-gas reserves by another peer group of oil majors (IOCs), are summarized in Fig. 8. This reveals that proved total gas reserves for the US independents have nearly quadrupled over the past decade. In contrast, total gas reserves of the IOC peer group have only fractionally risen over the same period. The increase in total proved gas reserves of Chevron and Shell are because of a rise in their proved undeveloped reserves (for definitions, see Appendix B). For Exxon, the rise in 2010 proved gas reserves is mostly accounted for by the XTO acquisition.

Fig. 8 clearly shows a trend divergence between reserves growth of the US independents (unconventional-gas producers) and IOCs

TABLE 2—NONORGANIC GROWTH OF PROVED RESERVES BY ACQUISITION OF ASSETS FROM ANOTHER COMPANY: SELECTED DEALS

Year	Target	Buyer	Assets	Deal Value (USD billion)	Unit Value (USD/Mcf)	Gross Potential (tcf)	Gross Acreage ('000s)	USD/Acre
2001	Mitchell Energy	Devon Energy	Barnett	3.5	1.41	1.4	–	–
2008	Lin Energy	XTO	Marcellus	0.6	–	–	152	3,947
2008	Chesapeake	Statoil	Marcellus	3.8	0.65	16	1,800	5,769
2008	Chesapeake	BP	Fayetteville	1.9	–	–	540	14,000
2009	Chesapeake	Total SA	Barnett	2.25	0.97	9	270	33,333
2009	XTO Energy	Exxon Mobil	All Assets	40	0.89	45	–	–
2009	XTO Energy	Exxon Mobil	Barnett	6.97	0.50	14	1,360	5,125
2010	Chesapeake	Total SA	Barnett	2.25	–	–	–	–
2010	Lewis Energy	BP	Eagle Ford	0.16	–	–	80	4,000
2010	Epsilon Energy	Chesapeake	Marcellus	0.2	0.06	3.5	11.5	17,391
2010	East Resources	Shell	Marcellus	4.7	0.29	16	1,050	4,476
2010	Exco Resources	BG Group	Marcellus	0.95	0.79	2.4	654	2,905
2011	Petrohawk	BHP Billiton	All Assets	12.1	–	–	–	–

Source: Principally upstreamonline.com & Edelweiss Corporate

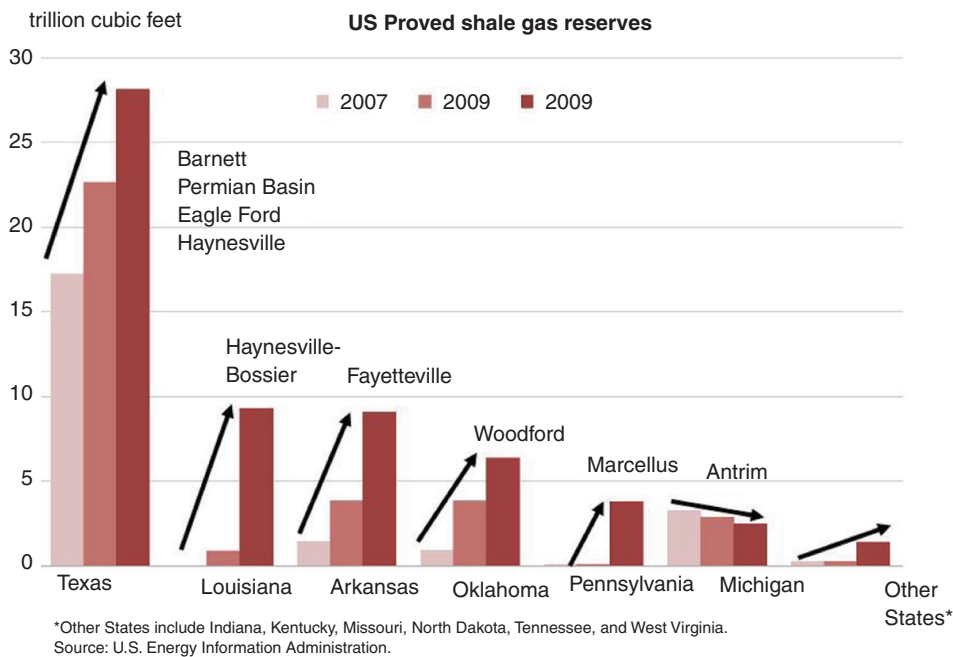


Fig. 7—Shale-gas proved reserves have risen rapidly over the past 3 years. The DOE/EIA tracks such reserves separately since 2007 (DOE-EIA 2010).

(conventional-gas producers). Overall, proved undeveloped gas reserves for the peer group of US independents rose by more than 800% over the past decade (Fig. 8). The doubling of the peer group’s total for proved undeveloped gas reserves for 2009–10 as compared with 2008 coincided with the introduction of the new SEC rules.

SEC recognizes shale gas as proved reserves only when certain criteria are fulfilled (see Appendix B), and proved undeveloped reserves are a subcategory of proved reserves. Proved undeveloped reserves therefore must comply with the SEC definition of proved gas reserves and the corresponding definitions in the PRMS (PRMS 2007); these are reserves estimated with reasonable certainty to be commercially producible before the time at which contracts providing the right to operate expire. The next section (in this study) discusses whether the proved unconventional gas reserves reported by the peer group of US independents can be considered robust as might be expected from proved reserves. The development of stable reserves remains of crucial importance not only from an investor point of view, but also for the security of future gas supplies.

Reserves Reporting by Unconventional-Gas Companies

Derisking Unconventional-Gas Reserves. The new SEC rules aim to make proved reserves less sensitive to short-term price fluctuations and in doing so intend to make investments in the energy securities less volatile. The SEC chose to dampen the effect of price volatility, which in its old system used end-of-year gas prices to value gas reserves inventory on company’s annual balance sheets, by instead using 12 monthly trailing averages in the new reporting rules. For 2009, the 12-month trailing average and year-end prices both hovered well below USD 4/million Btu, and the price accounting method itself therefore could not have triggered a major rise in the reported reserves of shale-gas companies. Volatility in the natural-gas price only exacerbates the uncertainty factor. Economic producibility under the 12-month trailing-average gas price is not possible for many US shale plays under the natural gas prices prevailing after 2008 (Weijermars and Watson 2011b). Additionally, estimated ultimate recovering (EURs) and NPVs assumed in depletion plans may commonly extend beyond the lease period entitlement. This is a situation in potential conflict with SEC’s requirement of evidence for access and entitlement to report proved reserves.

Most analysts would say reasonable certainty about economic production from shale gas is presently not warranted because uncertainty prevails. Berman (2009; 2010a, b, c) has argued persistently

that the EUR for many shale-gas wells is poorly constrained and that the adoption of a manufacturing model for well development in shale plays is a subeconomic “fallacy.” Some of his conclusions have been criticized by others (Gilmer et al. 2009). Nonetheless, high variations and poorly constrained well productivity decline trends heighten the risk of optimistic EURs, which jeopardize compliance with the high certainty (P90) requirement for proved reserves. More than 50% of the wells in shale-gas fields are less than 3 years old, and well productivity has not been benchmarked for the full 30-plus year lifecycle of these wells. Type curves for well productivity are therefore still conjectural for half of the US shale-gas production areas.

Concurrent models for shale-gas well productivity have in many cases remained inconclusive to establish reduction of the production uncertainty and substantiate the reasonable certainty domain required by SEC. The meaning and critical issues related to the interpretation of SEC’s usage of ‘reliable technology’ in relation to reserve reporting has been discussed at length by Lee (2010). Empirical calibration of well productivity with forecast from physical well flow models (Valko and Lee 2010) can help to reduce the uncertainty of EUR required for estimating economic well performance as averaged for unconventional field assets (Lee and Sidle 2010). High confidence (P90) reserve estimates for new resource plays are based on forecast productivity benchmarks and history-matched type curves from older wells in analog resource plays. Such analogs provide the type curves necessary for reducing uncertainty on the likelihood of establishing economic producibility for undeveloped acreage outside well locations. Nonetheless, our models for shale gas productivity are still under development, which means the uncertainty about well productivity and total economic value recovered from proved reserves most probably remains higher than required to establish the 90% certainty of the volumetric estimates for economic recovery.

Digging deeper into company reports reveals some additional cause for concern about the certainty of economic production from proved shale gas reserves. For example, in 2009 40% of the operational income of Chesapeake, a leading US shale gas producer, was not from gas sales but from derivative trading, instruments used to hedge against the subeconomic gas price (Weijermars and Watson 2011b). SEC allows—or rather does not explicitly repudiate— income from derivatives to be included in its accounting method for economic production assessments. The SEC allows inclusion of hedges in the oil and gas reserves supplemental information,

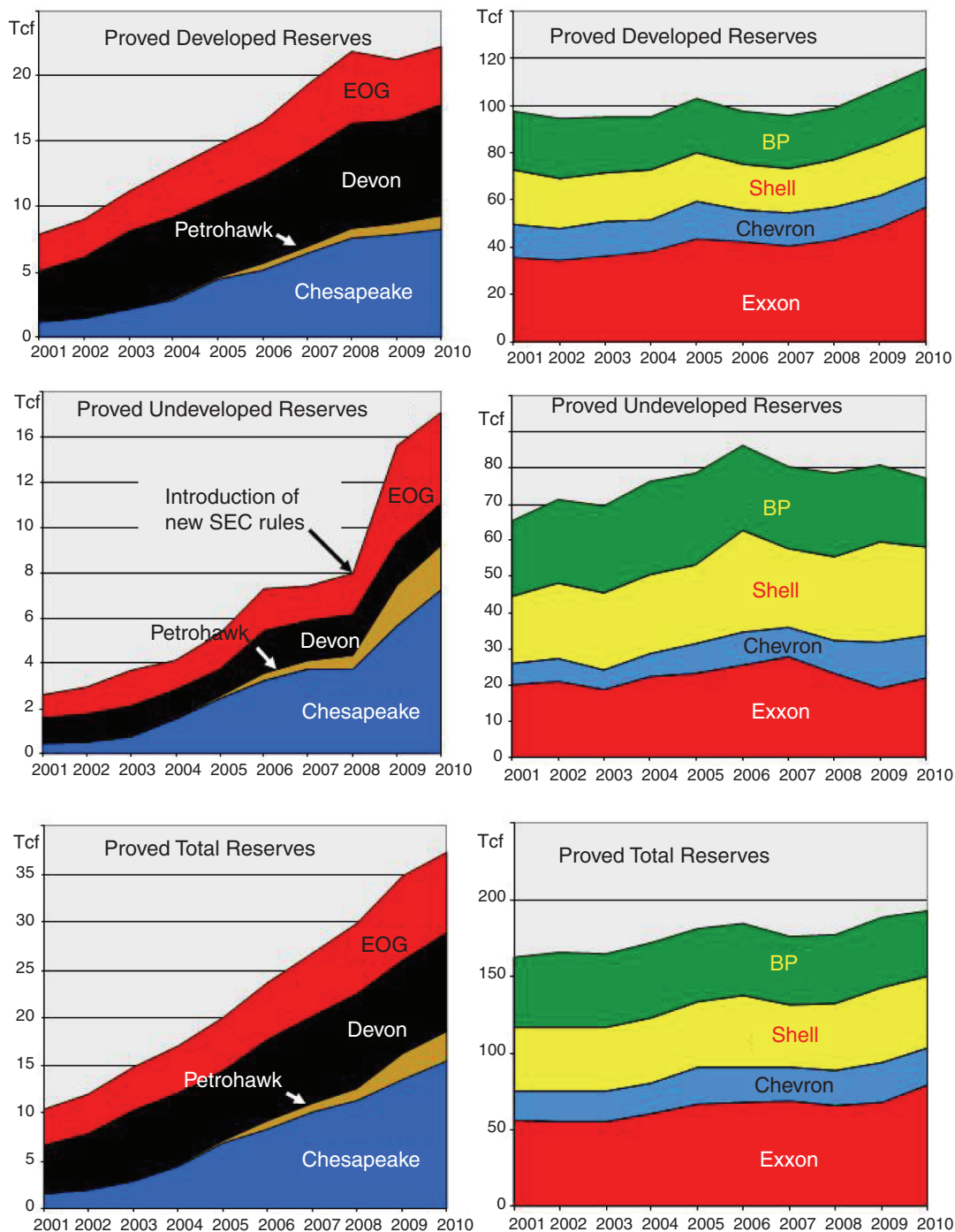


Fig. 8—Proved gas reserves for US independents (left-hand column) and IOCs (right-hand column), based on company reporting (10-K and F-20 SEC filings). The steep rise of proved undeveloped gas reserves coincides with the introduction of the new SEC rules for undeveloped reserves. All data are net proved reserves for consolidated subsidiaries plus proportional interest in proved reserves of any equity companies.

only if identifiable to specific properties. However, future income from gas derivatives provides only limited security as opportunities for future hedging against price volatility now diminish rapidly because many past price options and price collars that were locked in at the higher gas prices of July 2008 have begun to expire.

EOG's overall growth in proved developed and proved undeveloped reserves has been modest relative to that of its peer-group members. On the basis of the new definition of proved undeveloped reserves and its applicability to large resource plays, EOG added significant proved undeveloped reserves in the Haynesville, Horn River, Barnett Combo, and Marcellus shale plays in 2009. Purchases in place included proved undeveloped reserves from the Rocky Mountain property exchange and the acquisition of the Barnett Shale Combo

Assets. EOG estimates of proved reserves at 31 December 2010, 2009, and 2008 were based on studies performed by its engineering staff. Assurance for economic producibility is required by SEC and must be approved by the chief financial officer or a delegated officer responsible for reserves auditing. At EOG, the Engineering and Acquisitions Department is directly responsible for the reserves evaluation process and consists of seven professionals, all of whom hold degrees in engineering and three are Registered Professional Engineers. The manager of the Engineering and Acquisitions Department is the primary technical person responsible for this process.

EOG's annual report further states its reserves estimation process is a collaborative effort coordinated by the Engineering and Acquisitions Department in compliance with EOG's internal

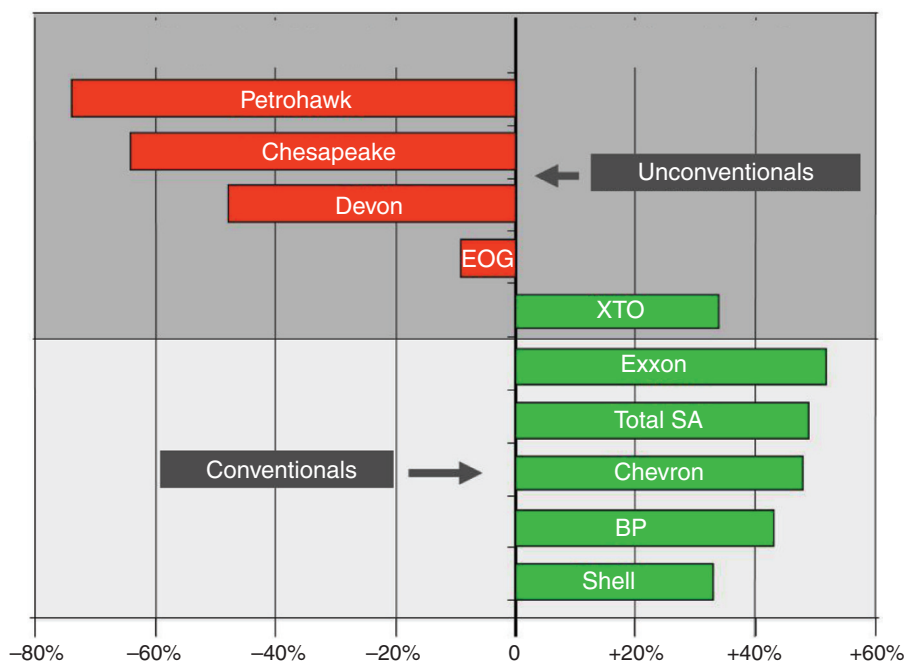


Fig. 9—Pretax margins for conventional-gas operators are all sound and positive, in spite of the historically low gas prices in 2009. In contrast, the margins of unconventional-gas companies have been mostly negative, with Petrohawk and Chesapeake standing out as underperformers. Based on 10-K and 20-F filings compiled by Weijermars and Watson (2011a,b).

controls for such process. Reserves information and models used to estimate such reserves are stored on secured proprietary databases. Nontechnical inputs used in reserves estimation models, including natural-gas, natural-gas-liquids, and crude-oil prices; production costs; future capital expenditures, and EOG's net ownership percentages are obtained from other departments within EOG. EOG's Internal Audit Department conducts testing with respect to such nontechnical inputs. Additionally, EOG engages DeGolyer and MacNaughton, independent petroleum consultants, to perform independent reserves evaluation of select EOG properties of not less than 75% of proved reserves.

So if EOG's reserves comply with SEC's requirement of reasonable certainty, how about the other companies in the peer group of US independents? SEC rules state that reserves estimations should not be likely to require downward revision, assured by a high degree of certainty. Proved gas reserves normally grow when gas prices rise and may be lowered when gas prices fall. It is highly unusual and unprecedented that gas reserves in existing fields can grow as much as 51% in 2009, a year where paid gas prices fell by 59% (from USD 7.74/million Btu in 2008 to USD 3.16/million Btu in 2009—yearly averages). In fact, the 2009 pretax profit margins for major unconventional-gas producers were negative (Fig. 9). This has been conclusively established in recent studies that compared the business fundamentals and financial metrics for two peer groups, each comprising five conventional- and five unconventional-gas operators (Weijermars and Watson 2011a,b). XTO made an "operational profit" because of skillful gas-price hedging.

The two peer groups were systematically benchmarked against each other using a comprehensive battery of five analytical tools: (1) retained earnings, (2) working capital source, (3) total shareholder return decomposition, (4) value driver inventory, and (5) margin analysis. The results of all five tests show that the peer group of unconventional-gas operators steeply underperformed, even in absolute terms. Their metrics are consistently underperforming—and much lower—than for the peer group of conventional-gas operators. Fig. 9 reveals that throughout 2009, companies such as Petrohawk, Chesapeake, Devon, and EOG could not produce gas with an operational profit. The 51% increase of 2009 proved reserves from US shale-gas producers therefore cannot be explained by the economic fundamentals. With Henry Hub prices below break-even cost, reserves may need to be impaired rather

than upgraded. More in line with common wisdom, lower gas prices in 2009 did not create new proved reserves for conventional-gas operators. Losses of proved reserves of these primarily conventional-gas operators were minimized because of the permitted inclusion of some previously contingent reserves (bitumen) in the asset inventory on the balance sheet under the new SEC rules.

Discussion on Prudence. Proved reserves of all the US shale-gas operations combined, as reported to the EIA of the US DOE, went up by 51% from 21.7 Tcf in 2008 to 32.8 Tcf for 2009. US total reserves for 2009 are based on EIA-23 company reports compiled and released in the US annual reserves report of November 2010, which included the addition of 2009 shale-gas proved reserves in EIA data. The US annual reserves reporting for 2010 that normally would have been released in November 2011 was suspended because of EIA budget cuts by Congress, which required EIA management to make choices about which duties to drop. As a result, the US gas reserves inventory has not been updated (as per 2012 publication date of our study) since the reporting of 2009 reserves.

Our study concludes that the increases in reported shale-gas reserves for 2008 and 2009 can be attributed to several strategy drivers: (1) adding reserves by infill-drilling programs in sweet-spot areas; (2) an optimistic assumption that future wells, in spite of the low prevailing gas prices, can still be developed economically, partly counting on supplementary income from gas derivative trades; and (3) rapidly moving contingent resources into proved undeveloped reserves. Under new reporting rules, SEC requires companies to formulate development plans for all proved undeveloped locations, substantially all of which must be developed within the next 5 years.

The data studied and documented here suggest that increases of proved gas reserves reported by shale-gas operators for 2009 with negative income from shale-gas operations may not pass SEC compliance tests. The introduction of the revised SEC rules, effective as of fiscal reporting year 2009, may have lured US shale-gas operators into reporting a steep rise in their proved undeveloped gas reserves. The collateral provided by increasing their proved reserves (Fig. 10) was much needed by these shale-gas companies. A downgrading of their proved reserves would have led to financial liquidity problems because of a high debt gearing (Weijermars and Watson 2011b), which needs to stay secured by proved reserves

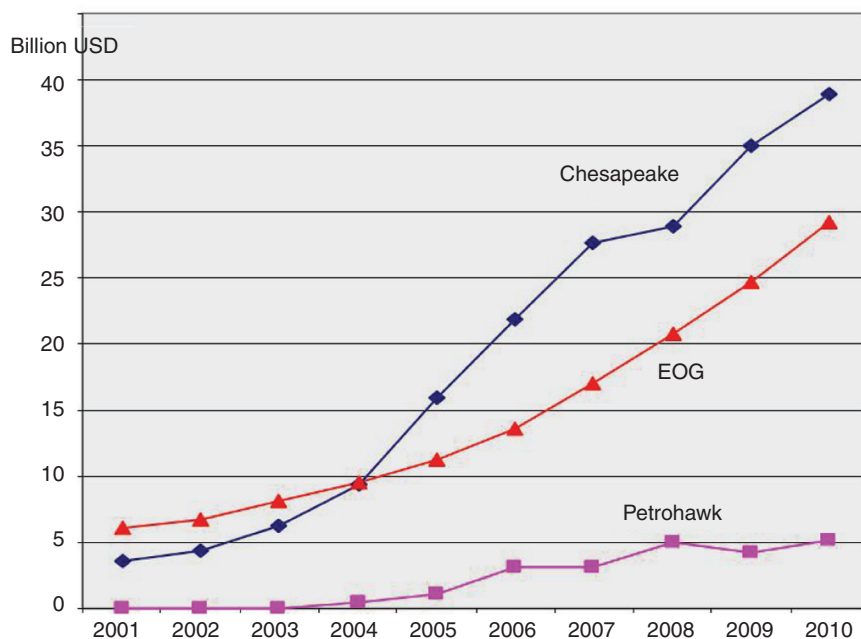


Fig. 10—Net oil and gas properties valuations for three unconventional-gas operators have grown over the past decade. Chesapeake’s asset growth is most aggressive. This article questions the certainty of some of these asset values.

as collateral assets. Part of the problem with reserves reporting is that proprietary data of companies must substantiate the reasonable certainty about their economic production of proved reserves (Olsen et al. 2011). Their data will not be disclosed to third parties, which means a high degree of self-regulation is expected from the companies under SEC rules.

Shale-gas companies have been swimming against the tide of low gas prices for several years. The US market is dominated by short-term gas delivery contracts, and US gas prices have responded rapidly to economic changes. Consequently, producers of unconventional (and conventional) gas have seen profit margins evaporate because of depressed natural-gas prices in an oversupplied US market over the past 4 years. The natural-gas prices for reserves estimates as of 31 December 2010 and 2009 are under the new SEC rules based on the respective 12-month unweighted average of the first-of-the-month prices from the Henry Hub, which equates to USD 4.38/million Btu for 2010 and USD 3.87/million Btu for 2009. Reserves reporting for 2008 is under the “old” SEC rule and based on a year-end natural-gas price as of 31 December 2008 from the Henry Hub spot market of USD 5.71/million Btu. The 2009–10 Henry Hub spot gas prices, which serve as a reference for wellhead prices, are below break-even for the four unconventional-gas companies studied (Weijermars and Watson 2011b).

If gas prices stay low, shale-gas production cannot be reasonably assumed to be sustainable by further debt rollovers, new equity issuance, asset monetization on leasehold sales, derivative trades, and further addition of proved undeveloped reserves as debt collateral. Well density has decreased significantly in recent years, with 40-acre spacing of vertical wells coming down to 20- and 10-acre spacing of vertical wells, and 80-acre spacing horizontal wells seeking further optimization by multilateral drilling, fanning out in a palm-leaf pattern for enhanced production from one entry hole. Studies of the well productivity and tighter well spacing show that the upper limit has been reached because commingled production between adjacent wells has started to reduce individual-well productivity in many fields.

The long list of tactical actions taken by shale-gas companies to maintain liquidity is impressive and shows remarkably skillful company management. Unconventional-natural-gas production companies are in a business with high capital expenditure and tight cash flow (Weijermars and Watson 2011a,b). Adding reserves to maintain collateral for debt financing as well as leverage for further asset sales is the latest tactic instrument used by shale-gas

companies to stay solvent. However, SEC reserves reporting rules strictly require that proved reserves reported by companies can with reasonable certainty be economically produced by them. In making estimates of proved undeveloped reserves, engineers and geoscientists perform detailed technical analysis of each potential drilling location within the inventory of field assets. Economic appraisal and reserves accounting involve assessments that must substantiate, with reasonable certainty, that the proved reserves indeed comprise economically producible gas assets.

Recommendations

For investors, it is crucial to understand the critical role of the reserves maturation process in building company asset inventory to better judge the risk involved in the unconventional-gas sector. Shell and other majors lost significant value of their market capitalization during the so-called reserves scandal of 2004, which involved mostly conventional resources. The maturation of unconventional-gas resources into proved reserves requires a stable framework, which may benefit from improvements of both the field-development methods and the concurrent reserves reporting guidelines.

Optimization of Unconventional-Gas Field Development. In conventional-gas fields, companies cannot rapidly mature potential gas resources; these are progressively upgraded over time through possible and probable resources into contingent reserves, and ultimately from undeveloped proved reserves to developed and producing proved reserves. The lead time from prospect to proved reserves is 3 to 5 years at best. Holders of conventional-gas acreage commonly have no reserves addition benefit from infill drilling. The interconnectivity of such conventional-gas reservoirs means infill drilling speeds up production but commonly reduces the productive lifecycle of a field.

One of the principal reasons that development of unconventional-gas fields remains economically risky is that the EUR remains poorly constrained because of uncertainty in oil-and-gas-in-place (OGIP) estimates and recovery factors. Both OGIP and recovery factors may vary widely per well because of intrinsic petrophysical variations and the lack of gas interconnectivity between wells. The life cycle and flow rates of adjacent wells may steeply or gradually decline within unconventional oil and gas fields. In order to derisk unconventional-resource plays, it is necessary to develop better models for well productivity and better ultimate reserves estimates. Additionally, marginal cost of unconventional

plays requires further technology innovations to reduce cost of completion on the basis of better control on sweet-spot identification and fracture architecture in wells.

In summary, here are some actions suggested to improve the reserves growth process and performance of shale-gas fields:

- Governments may choose to suppress gas-price volatility by policy measures that mandate linking gas prices to long-term oil-indexed delivery contracts or by ensuring a minimum return on investment as already regulated by FERC for the US gas transmission sector.

- More research is needed to improve the physical flow models for shale-gas wells. History matching may establish reliable type curves for more-accurate EUR estimates to better ascertain both developed and undeveloped proved reserves. Factors such as original fluid content (OGIP) and net-to-gross ratio and recovery factor must be evaluated continually for establishing a suitable reservoir model for the target reservoir.

- The impact of fracture architecture and dependency on the inter-connectivity of natural and induced fractures on well productivity must be modeled and quantified for each well, preferably down to the scale of individual fracture stages.

- Model analogs and field studies may reduce the uncertainty in estimations of the recoverable volumes from the target reservoir. Sidle and Lee (2010) provided an excellent example/exercise for analog application (in their Table 1, comparative data from Jonath and Macintosh fields).

- The target reservoir properties must be established with reasonable certainty to be analogous to the prototype reservoir for which petrophysical parameters (porosity, permeability, organic content), sedimentological reservoir characteristics (thickness, lateral continuity, facies changes), geomechanical properties (fracture capability, faults, tectonic stress), hydrocarbon saturation, fluid properties, and reservoir conditions (depth, temperature, pressure) are known.

Improvement of Unconventional Oil and Gas Reserves Reporting.

The introduction of new SEC bookkeeping rules was never intended to create a situation where proved reserves in shale-gas fields are generated faster than geologists can verify and economically account for. Nonetheless, Olsen et al. (2011) already stated that reserves booking guidelines under the new SEC rules are more flexible than before. For example, the “reliable” technology principle may inadvertently lead to PUD booking on the basis of expected technology advancements before those technologies have proved their economics.

The new rule is the result of a diligent stakeholder consultation process, which included 65 viewpoints from industry parties and other E&P organizations. Reserves reporting methods, PUDs, and reliable technology were among the main issues discussed. The SEC definition of reasonable certainty is in line with the PRMS: “If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability, that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists, if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data, are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.”

The requirement for reporting PUDs means that such undeveloped reserves have to be developed within a 5-year time frame. On the basis of a reasonable certainty standard, companies reported PUD locations at distances greater than one legal offset from economically producing wells (Ryder Scott 2010), which “has boosted PUD reserves, especially from shale gas locations.” These reserves may be booked when one can establish with reasonable certainty and using reliable technology that economic producibility is possible at greater distances.

The following guidelines are recommended for a diligent company process of reserves reporting:

- Reliable technology may not refer to speculative solutions.
- PUDs may not assume well productivities for undrilled assets in locations where reasonable certainty of P90 production volumes with economic return is less likely to be achieved.

- PUDs may not be used to improperly boost collateral asset value.

- Economic profitability of assets should be based on well productivity, not acreage values, because the latter are highly conjectural and beyond reasonable certainty.

- Economic producibility must be based on 12-month price average, not on any future gas-price projections.

- Economic producibility that is dependent on gas-price hedging should not involve undue trading risks that may jeopardize reasonable certainty of reported reserves.

- Extrapolation of well productivity and EUR estimates must be based on statistically sound methods and provide “reliable” reasonable certainty for proved reserves estimates.

- Consolidated reserves reporting may not take improper advantage of conversion effects when switching between oil equivalent and gas equivalent, or vice versa.

- To be fair, external risks (e.g., political, technical, natural hazards) should be included in the assessment of proved reserves robustness.

Conclusions

The world needs a prolonged success of shale gas. Closer scrutiny of proved reserves reporting is therefore required everywhere. Overly optimistic booking of proved reserves is detrimental to the business because this introduces unwanted volatility and may result in future downgrades of reserves.

The pressure on company management to beef up income with derivative trading and the need to maintain or boost asset value by adding proved reserves have been enormous for shale-gas operators in the North American gas market. This may already have led to an overly optimistic interpretation of the SEC rules by some companies (Weijermars and McCredie 2011).

Critical analysts may prove to be right: The shale-gas bubble could burst when some companies start to turn illiquid because of the evaporation of capital in assets that will never break even when natural-gas prices do not recover in an oversupplied North American gas market.

If that were to happen, the reputation of the shale-gas business will become tarnished in capital markets. Once the global investor community gets burned on such investments, shale-gas exploration and production companies now emerging around the world will have a hard time to find new venture capital. Only with the investor community’s continued interest and support will companies be able to develop prospective shale-gas resources into proved reserves.

With more than USD 430 billion of combined market capitalization (2010 estimate), any concurrent doubts about the business fundamentals of US shale-gas operators need to be mitigated swiftly and decisively—a call for action on SEC stewardship. The investor community wants to see their investments for the development of shale-gas reserves effectively secured by SEC guidelines and compliance checks.

Due diligence of reserve reporting by shale-gas companies needs to be improved by proactive and efficacious self-regulation, not only in the US but anywhere in the world where investor money is at stake in emergent shale-gas plays. Companies must comply with the SEC rules or follow comparable guidelines (see Appendix A) to report proved reserves (developed and undeveloped) that are conclusively established to be with reasonable certainty economically producible.

Policymakers need the highest possible security of reserves as a reliable support base for their strategy plans that must unlock future energy supplies in a timely manner and ensure national energy security. If the development of shale-gas resources means proved reserves have become volatile assets, then that volatility must be taken into account in the energy system models (Weijermars et al. 2012) developed to plan forward and ensure the security of our future energy supplies.

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Disclaimer: This study analyzes company performance on the basis of data abstracted from company reports. The analysis of these empirical data inevitably involves a degree of interpretation and uncertainty connected to the assumptions made. Although the results derived here are reproducible using the outlined research methods, the author, Alboran Energy Strategy Consultants, and publisher take no responsibility for any liabilities claimed by companies included in this study. Readers, especially serious investors, should perform their own due diligence analysis regarding internal corporate technical risk management, considering the wisdom of some risk premium for companies having primary assets in newly evolving plays and potentially unstable business models. The 2004 Shell reserves “problem” should not be simply glossed over as a unique, one-of-a-kind event because internal corporate (and maybe national) pressures remain high for all stock-listed E&P companies (particularly unconventional-gas players) to report excellent (and impressive) results from investment funds spent.

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Appendix A—Reserves Maturation in Oil and Gas Exploration

Reporting Framework for Corporate Oil and Gas Reserves.

Essentially, the maturation of unconventional prospective gas resources into proved gas reserves is a task that must be executed by oil and gas companies. Petroleum companies must periodically assess their inventory of oil and gas reserves to account for the detailed status of their reserves portfolio in the annual company reports. SEC requires companies that receive more than 10% of their income from E&P activities to report the income derived from E&P activities as a separate business cost center. This is a financial accounting requirement that is mandatory for stock-listed companies. Reserves reporting rules are issued by the SEC to ensure that companies file reports (10-K, 20-F, 40-F) to them with adequate information for investors so the latter can assess the business performance (risks and opportunities) of the companies they invest in. In the new guidance rules, SEC (2009) also adopted a policy that requires a company to provide a general discussion of the internal controls that it uses to assure objectivity in the reserves-estimation process. Additionally, disclosure is required of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting the reserves audit, regardless of whether the technical person is an employee or an outside third party.

Reserves audit reports for the SEC must include the following disclosures, which concur with the SPE audit report guidelines:

1. The purpose for which the report is being prepared and for whom it is prepared
2. The effective date of the report and the date on which the report was completed
3. The proportion of the company's total reserves covered by the report and the geographic area in which the covered reserves are located
4. The assumptions, data, methods, and procedures used to conduct the reserves audit, including the percentage of company's total reserves reviewed in connection with the preparation of the report, and a statement that such assumptions, data, methods, and procedures are appropriate for the purpose served by the report
5. A discussion of primary economic assumptions
6. A discussion of the possible effects of regulation on the ability of the registrant to recover the estimated reserves
7. A discussion regarding the inherent risks and uncertainties of reserves estimates
8. A statement that the third party has used all methods and procedures as it considered necessary under the circumstances to prepare the report
9. The signature of the third party

In addition, a reserves audit must contain a brief summary of any involved third party's conclusions with respect to the reserves estimates. Regardless of whether the reserves were determined using deterministic or probabilistic methods, the reported reserves should be simple arithmetic sums of all estimates at the well, reservoir, property, field, or project level within each reserves category.

The reserve-maturation process must upgrade prospective unconventional resources into proved reserves. Provided technically recoverable reserves are there, these can be matured into economic

reserves if the economics develops positively. Development of unconventional gas is a function of natural-gas prices, or technology improvements that can bring down marginal costs. Reserves reporting must abide with SEC regulations and is currently subject to the Federal Securities Law and the Energy Policy and Conservation Act of 1975. Recommendable reads are proposals in literature by McKay and Taylor (1979), clarification by the SPE Oil & Gas Reserves Committee (SPE 1997), and the recently developed UN Framework Classification for Fossil Energy & Mineral Resources (UNECE 2010), sponsored by some 60 nations and endorsed by the major professional societies SPE, AAPG, and the World Petroleum Council. PRMS (2007) is a widely accepted standard for the management of petroleum resources and was developed by several industry organizations (SPE, the World Petroleum Council, American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers).

Principles of Reserves Classification in UNFC. The UN Framework Classification (UNECE 2010) is broadly comparable to the PRMS, but aims for a broader support base and adoption by national oil companies that have no SEC reporting obligations simply because these companies are not privately owned and therefore have no annual reporting obligation under the US Code of Federal Regulation (CFR) standards. The strong link between SEC reserves reporting guidelines and the PRMS is less apparent for the UNFC.

The UNFC framework for reserves reporting is now applied or tested in more than 40 countries.

The three principal resource classification axes of the UNFC are outlined in **Fig. A-1**. These three axes refer to indexing categories of: (G) geological knowledge about the resource, (F) field project status and technical feasibility, and (E) economic and commercial viability of the resource development.

Fig. A-2 shows how a prospective resource typically migrates over time through the UNFC resource framework space, when work on the prospective resource translates into positive “reserves maturation.” Below is a succinct description of the workflow that typically needs to be followed in order to reach the final classification as UNFC (111) for proved reserves, economic and in production.

Resource Maturation in Exploration Stage. Reconnaissance exploration of hydrocarbon basins aims to identify one or more geological “plays.” Further prospecting could identify “leads,” which are specific subsurface locations where hydrocarbon accumulations are expected with some probability. A subsequent general exploration program targeting these leads could provide technical data needed to upgrade some of the leads to prospects.

A promising prospect identified in such an exploration program would be no more than a G4 prospective resource (**Fig. A-3**). More

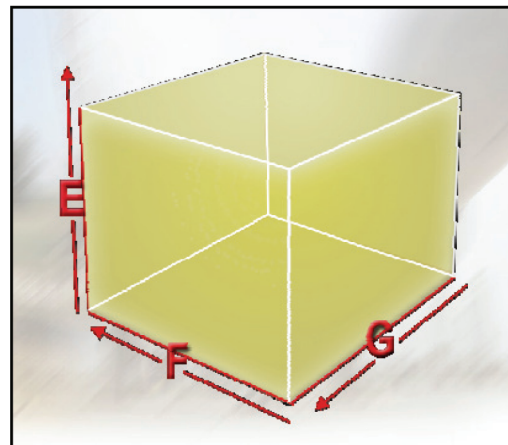


Fig. A-1—UNFC resource classification uses three criteria (E, F, G) to classify resource volumes in the UNFC resource space. The E-axis specifies economic and commercial viability, the F-axis specifies field project status and feasibility, and the G-axis specifies geological knowledge.

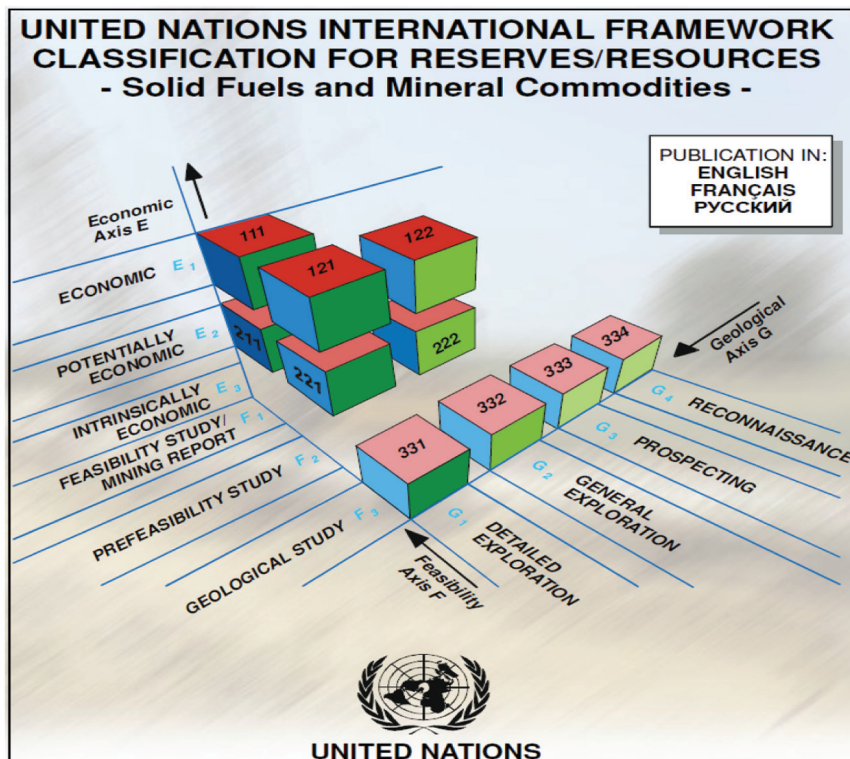


Fig. A-2—Certainty of resource status increases as more information is inventoried and classified. The resource migrates through the UNFC resource classification space until the final status is determined. Highest rating is 111.

specifically, UNFC G4 prospective resources are estimated to be recoverable from an undrilled accumulation, on the basis of inferred geological (and reservoir production performance) characteristics.

Oil and gas companies that aim to maximize “maturation” of their portfolio of resources will screen G4 prospective resources to decide which ones should be subjected to further prospecting in order to evaluate the potential volume and value of any hydrocarbon presence. Drilling is mandatory (unless part of a known accumulation) in order to permit an upgrade to a UNFC G3 resources status. UNFC G3 possible resources are estimated to be recoverable from a known (drilled) accumulation, or part of a known accumulation, where sufficient technical data are available to establish the geological and reservoir production characteristics with a low level of certainty (P10).

Further general exploration of G3 possible resources may enable the estimation of probable resources with a reasonable level of confidence (P50). Only then can the G3 possible resources be upgraded into G2 probable resources. UNFC G2 probable resources are estimated to be recoverable from a known (drilled) accumulation, or part of a known accumulation, where sufficient technical data are available to establish the geological and reservoir production characteristics with a reasonable level of certainty (P50). A feasibility study for possible field development may conclude that development and production cannot be (technically) justified. However, if the outcome of the initial field development assessment of the probable resources (G2) means these remain under investigation, and justify further development activities, and production is expected in the foreseeable future, then it classifies as a contingent development project. The next step in the maturation of resources is to then establish the level of the company’s commitment to develop and produce the resources (uncommitted project; committed project; or project in production).

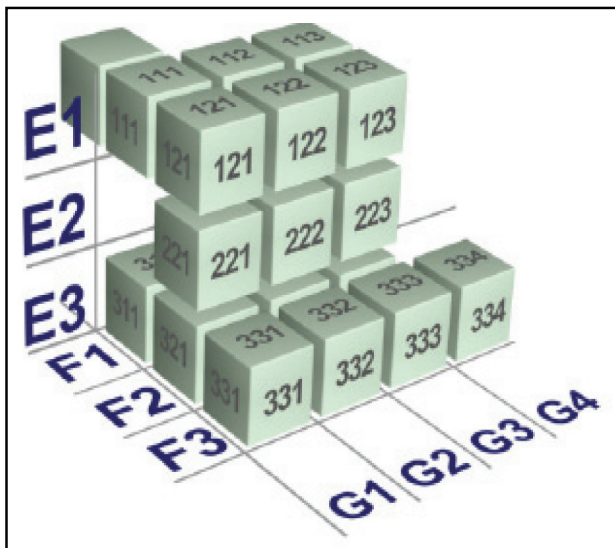


Fig. A-3—UNFC resource classification space recognizes proved reserves as (111) resources.

Reserves Maturation After Exploration Stage. Ultimately, detailed exploration may provide sufficient confidence to upgrade G2 probable resources to G1 proved reserves. UNFC G1 proved reserves, reasonably assured, are estimated to be recoverable from a known (drilled) accumulation, or part of a known accumulation where sufficient technical data are available to establish the geological and reservoir production characteristics with a high level of certainty (P90).

In summary, the reconnaissance of a geological province and the resource maturation efforts can be termed successful when one or more of the prospective resources (G4) have matured through G3 (possible resources) and G2 (probable resources) to G1 (proved reserves). Simultaneously with the geological exploration (G status) and field development planning (F status), the economic appraisal is required (E status). Resources can be classified as intrinsically economic (E3 status), potentially economic (E2 status), or economic (E1 status). Additionally, the field-development feasibility study was concluded to be technically justified for contingent development (F2); if the company will indeed produce

		Production	Project Status	
Total petroleum - Initially - In-place	Discovered petroleum - Initially - In-place	Reserves Proved Proved plus Probable Proved plus Possible	On production	Lower risk
			Under development	
			Planned for development	
Sub-commercial	Contingent resources Low estimate Best estimate High estimate	Unrecoverable	Development pending	Project maturity ↑
			Development on hold	
			Development not viable	
Undiscovered petroleum - Initially - In-place	Prospective resources Low estimate Best estimate High estimate	Unrecoverable	Prospect	Higher risk
			Lead	
			Play	
		← Range of uncertainty →		

Fig. B-1—SPE/WPC/AAPG/SPEE/SEG resource classification system, showing possible project status categories.

said asset and has built the required infrastructure for evacuation of the reserves volume, the (F1) status is reached.

In the full UN Framework notation, the classification annotation sequencing adopted is: E-status, F-status, G-status. A prospective resource starts out as a 334 resource (E3-Intrinsically economic, F3-Project undefined, G4-Prospective resource) and commonly matures as follows (Fig. A-3):

- Geological exploration all successful: Still an intrinsically economic, undefined project, but prospective resource (334) has been upgraded through possible resources (333) to probable resources (332).
- Field-development technical feasibility concluded positive, so that reserves could be upgraded from undefined project status (332) to contingent development project (322).
- Economic appraisal concluded the proved reserves to be potentially economic and matures (322) resources to (221) contingent resources, and when established to be explicitly economical, to (121) reserves.
- Next, the company allocates capital expenditure (CAPEX) and operating expenditure (OPEX) for field development and upgrades the economic, proved reserves, from contingent development status (121) to a production development commitment so that the reserves classify as (111).

The OPEX allocation and commitment to a production development promotes a resource to a (111) asset. Such an asset serves as 100% collateral on the corporate balance sheet. Persistently low natural-gas prices may lead to situations where a company reassesses proved reserves with a formerly taken final investment decision (FID) and CAPEX thus earmarked. The cost may have become too high to justify the production and the (111) reserves may be downgraded again, and corporate balance sheets are impaired accordingly. This mechanism also means the parameters that control the economic producibility of natural-gas fields determine the status and quality of the gas reserves portfolio.

Appendix B—SEC Modernization of Oil and Gas Reserves Reporting

SEC Revised Rule Highlights. In December 2008, the SEC released a final rule, Modernization of Oil and Gas Reporting, which amends the oil and gas reporting requirements. The key

		Production	Project Status	
Total petroleum - Initially - In-place	Discovered petroleum - Initially - In-place	Reserves	Developed	Lower risk
			Undeveloped	
			Pending	
Sub-commercial	Contingent Resources	Unrecoverable	Barrier	Project maturity ↑
			Not Viable	
			Prospect	
Undiscovered petroleum - Initially - In-place	Prospective Resources	Unrecoverable	Lead	Higher risk
			Play	
			Play	
		← Range of uncertainty →		

Fig. B-2—Interpretation of SEC resource classification system, according to new rules, showing possible project status categories.

revisions to the reporting requirements include: using a 12-month average price to determine economic producibility of reserves; including nontraditional resources in reserves if they are intended to be upgraded to synthetic oil and gas; ability to use reliable technologies to determine and estimate reserves; and permitting the optional disclosure of probable and possible reserves. In addition, the final rule includes the requirements to report the independence and qualifications of the reserves preparer or auditor to file a report as an exhibit when a third party is relied upon to prepare reserves estimates or conduct reserves audits and to disclose the development of any PUDs, including the total quantity of PUDs at year-end, material changes to PUDs during the year, investments and progress toward the development of PUDs, and an explanation of the reasons that material concentrations of PUDs have remained undeveloped for 5 years or more after disclosure as PUDs. The accounting changes resulting from changes in definitions and pricing assumptions should be treated as a change in accounting principle that is inseparable from a change in accounting estimate, which is to be applied prospectively. The final rule is effective for annual reports for fiscal years ending on or after 31 December 2009. Comparisons of the updated SEC rules and the PRMS have been discussed elsewhere (Etherington 2009; Lee 2009).

The SEC adopted the previous disclosure regime for oil and gas-producing companies in 1978 and 1982, respectively. The SEC definitions of terms are now more consistent with terms and definitions in the PRMS (see Fig. B-1 for a summary of terms), which improves compliance and understanding of the new rules. Compliance with the new disclosure requirements is mandatory for registration statements filed on or after 1 January 2010, and for annual reports on Forms 10-K and 20-F for fiscal years ending on or after 31 December 2009.

The SEC's revisions permit a company to claim proved reserves beyond those development spacing areas that are immediately adjacent to developed spacing areas if the company can establish with reasonable certainty that these reserves are commercially producible (Fig. B-2).

EUR is the sum of reserves remaining as of a given date and cumulative production as of that date. The "high degree of confidence" standard that exists in the PRMS for proved reserves

is adopted by SEC and consistent with the PRMS definition. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Having a high degree of confidence means that a quantity is “much more likely to be achieved than not, and, as changes because of increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to EUR with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease,” as stated by SEC (2009) to provide elaboration to the definition of reasonable certainty.

The SEC’s definition of “reasonable certainty” addresses and permits the use of both deterministic methods and probabilistic methods for estimating reserves, as proposed. Oil and gas producing activities include the extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Distinguishing between traditional resources and unconventional resources can be significant to investors because unconventional resources often involve significantly different economics and company resources compared with gas from traditional wells. Therefore, reserves are distinguished on the basis of final products related to traditional gas from final products of synthetic gas.

The final rules define the term “reserves” as the estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production of gas, installed means of delivering gas or related substances to market, and all permits and financing required to implement the project. The adopted definition of the term “reserves” relies on economic producibility.

Some Definitions. The definitions used in the following are in accordance with SEC Rule 4-10 (a) of Regulation S-X (SEC 1978) and as used in the revised rules (SEC 2009).

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. (i) The area of the reservoir considered as proved includes: (A) the area identified by drilling and limited by fluid contacts, if any; and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty. (iii) Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. (iv) Reserves that can be produced economically through application of improved-recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or

other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities. (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

The term “economically producible” means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of gas-producing activities. A company must determine whether its gas resources are economically producible on the basis of a 12-month average price. The pricing formula is based on the average of prices at the beginning of each month in the 12-month period before the end of the reporting period. SEC agrees that instead of using the average price formula, the company can use for the price to establish economic producibility the price set by existing contractual arrangements. The rules in 2009 adopted a reliable technology definition that permits reserves to be added on the basis of technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated.

Proved reserves include 100% of each majority-owned affiliate’s participation in proved reserves and company’s ownership percentage of the proved reserves of equity companies. Gas reserves exclude the gaseous equivalent of liquids expected to be removed from the gas on leases, at field facilities and at gas processing plants. These liquids are included in net proved reserves of crude oil and natural-gas liquids. Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields because of the evaluation or re-evaluation of (1) already available geologic, reservoir, or production data; (2) new geologic, reservoir, or production data; or (3) changes in average prices and year-end costs that are used in the estimation of reserves. This category can also include significant changes in either the development strategy or production equipment/ facility capacity.

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. In accordance with the SEC rules, bitumen extracted through mining activities and hydrocarbons from other nontraditional resources are reported as oil and gas reserves beginning in 2009.

Proved undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within 5 years, unless the specific circumstances justify a longer time. (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved-recovery technique is contemplated unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Proved developed oil and gas reserves are reserves of any category that can be expected to be recovered: (1) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; and (2) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Grouping of Assets and Financial Accounting Standards Board (FASB) Guidance Codes. Assets are grouped in accordance with the Extractive Industries—Oil and Gas Topic of the FASB Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

In June 2009, the FASB issued guidance that established the FASB ASC as the source of authoritative accounting principles recognized by the FASB to be applied in the preparation of financial statements in conformity with GAAP. This guidance explicitly recognizes rules and interpretive releases of the SEC under federal securities laws as authoritative GAAP for SEC registrants. The ASC became effective for interim and annual periods ending after 15 September 2009.

In January 2010, the FASB issued FASB Accounting Standards Update (ASU) No. 2010-03, “Oil and Gas Reserve Estimations and Disclosures” (ASU No. 2010-03). This update aligns the current oil and gas reserves estimation and disclosure requirements of the Extractive Industries—Oil and Gas topic of the FASB ASC

(ASC Topic 932) with the changes required by the SEC final rule, “Modernization of Oil and Gas Reporting.”

ASU No. 2010-03 expands the disclosures required for equity method investments, revises the definition of oil- and gas-producing activities to include nontraditional resources in reserves unless not intended to be upgraded into synthetic oil or gas, amends the definition of proved oil and gas reserves to require 12-month average pricing in estimating reserves, amends and adds definitions in the Master Glossary that is used in estimating proved oil and gas quantities, and provides guidance on geographic area with respect to disclosure of information about significant reserves. ASU No. 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after 31 December 2009.

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