S&P Global
Ratings

RatingsDirect®

Criteria | Corporates | Industrials:

Key Credit Factors For The Oil And Gas Exploration And Production Industry

Primary Credit Analysts:
Michelle S Dathorne, Toronto (1) 416-507-2563; michelle.dathorne@spglobal.com
Simon Redmond, London (44) 20-7176-3683; simon.redmond@spglobal.com
Ben B Tsocanos, New York (1) 212-438-5014; ben.tsocanos@spglobal.com
Tommy J Trask, Dubai (971) 4-372-7151; tommy.trask@spglobal.com

Global Criteria Officer, Corporates, New York:
Mark Puccia, New York (1) 212-438-7233; mark.puccia@spglobal.com
Sarah E Wyeth, New York (1) 212-438-5658; sarah.wyeth@spglobal.com

EMEA Criteria Officer, Corporates, London:
Peter Kernan, London (44) 20-7176-3618; peter.kernan@spglobal.com

Table Of Contents

SCOPE OF THE CRITERIA

SUMMARY OF THE CRITERIA

METHODOLOGY

Part I. Business Risk Analysis

Industry Risk

Country Risk

Competitive Position

Part II. Financial Risk Analysis

Table Of Contents (cont.)

Accounting And Analytical Adjustments

Cash Flow/Leverage Analysis

Part III. Rating Modifiers

Diversification/Portfolio Effect

Capital Structure

Liquidity

Financial Policy

Management And Governance

Comparable Ratings Analysis

Frequently Asked Questions

APPENDIX

RELATED CRITERIA AND RESEARCH

Criteria | Corporates | Industrials:

Key Credit Factors For The Oil And Gas Exploration And Production Industry

*(**Editor's Note:** We originally republished this criteria article on Dec. 12, 2013. We're republishing it following our periodic review completed on Nov. 17, 2016. As a result of our review, we updated the author contact information. We also removed material related to the original publication of the article.)*

1. This article presents Standard & Poor's Ratings Services criteria for the global oil and gas exploration and production (E&P) industry. This article is related to our corporate criteria (see "Corporate Methodology," published Nov. 19, 2013) and to "Principles Of Credit Ratings," published Feb. 16, 2011.

2. This paragraph has been deleted and moved to the Appendix.

SCOPE OF THE CRITERIA

3. These criteria apply to issuers in the global E&P industry, including integrated oil and gas companies. We define E&P issuers as companies that derive a majority of their revenues from the development and production associated with oil and natural gas hydrocarbons. These criteria also apply to integrated oil and gas companies. These integrated companies have, in addition to E&P (upstream) operations, other significant operations such as refining and marketing (downstream) businesses, and midstream businesses such as transportation; storage; wholesale marketing; and trading of crude oil, natural gas, and refined products.

SUMMARY OF THE CRITERIA

4. These criteria outline how Standard & Poor's analyzes oil and gas E&P companies, applying its corporate criteria.

5. We view the oil and gas integrated, and E&P industry as having an "intermediate" industry risk profile under our criteria, given its "moderately high" cyclicality risk and "intermediate" degree of competitive risk and growth. In assessing the competitive position of an E&P company, we put particular emphasis on the size, quality, and mix of its reserves base; the growth prospects inherent in its oil and gas reserves portfolio; its full cycle cost profile; and associated profitability. We view a company's ability to generate sufficient cash flow to replace and grow its reserves (at both peaks and troughs of the hydrocarbon price cycle) as the principal factors in our assessment of its financial risk profile, given the industry's capital-intensive nature and the need to continually replace produced reserves.

6. Our assessment of the financial risk profile takes into account historical ratios for the previous two years and notable forecasts for the current and two subsequent years based on our price assumptions for oil and natural gas prices (see "Methodology For Crude Oil And Natural Gas Price Assumptions For Corporates And Sovereigns," published Nov. 19, 2013).

7. This paragraph has been deleted.

8. This paragraph has been deleted.

METHODOLOGY

Part I. Business Risk Analysis

Industry Risk

9. We consider the E&P sector to be a segment of the oil and gas integrated, E&P industry, so to determine industry risk for E&P companies, our analysis of that industry applies (see "Methodology: Industry Risk," published Nov. 19, 2013).

10. Within the framework of our corporate criteria for assessing industry risk, we view oil and gas integrated, and exploration and production as an intermediate-risk industry (category 3). We derive our industry risk assessment for oil and gas exploration from our view of the segment's moderately high (4) cyclicality and our assessment that the industry warrants an intermediate risk (3) given competitive risk and growth assessment.

11. Crude oil is a globally traded commodity that is refined to produce essential fuels that power industrial, commercial, and consumer undertakings. As a result of this, the demand for oil is sensitive to fluctuations in global economic activity. Sometimes oil price movements (for instance, a sharp increase in oil prices that results from geopolitical tensions) can drive fluctuations in economic activity. Therefore, these links can also influence demand for oil.

12. Supply factors also are important. Crude oil is produced into the largest and most liquid of all commodities markets. However, OPEC countries control a significant share of total production and their prescribed production levels affect prices, particularly during periods of relatively tight balance between production and consumption.

13. Natural gas markets are structured regionally because transportation, storage, and logistics costs can outweigh profitability. It is possible to transport natural gas to overseas markets, but it entails significant infrastructure investments in pipelines, liquefaction and regasification technologies, carrying vessels, and storage facilities. In markets such as North America, where there is a large and sophisticated natural gas production and logistics base, natural gas and crude oil prices are largely uncorrelated. By contrast, in some markets, the price of natural gas is contractually tied to the price of crude oil. Weather and related demand for heating and cooling and industrial consumers drives marginal demand.

Cyclicality

14. We assess cyclicality for the oil and gas, integrated, E&P industry as moderately high (4) risk. Oil and natural gas prices are volatile and difficult to predict. Due in part to the market's inelastic nature, large price swings are necessary to influence consumer behavior. As a result, the E&P industry has historically demonstrated high cyclicality in both revenue and profitability. Based on our analysis of global Compustat data, E&P companies endured average peak-to-trough (PTT) decline in revenues of about 7.9% during recessionary periods since 1952. Furthermore, in three

of the four most recent recessionary periods, the revenue decline significantly exceeded 8%; the steepest decline (33%) was in the most recent downturn (2007-2009) as oil prices fell to a low of $33 per barrel in October 2008 from a high of $145 just five months earlier.

15. In the same period, E&P companies experienced an average PTT decline in EBITDA margin of 15.5% during recessionary periods, with PTT EBITDA margin declines materially exceeding the average in four of the past five periods. The largest PTT drop in profitability totaled 27.5%, in both the most recent recession and 1979-1982, another period where oil prices fell dramatically from high levels. EBITDA margin tends to be more cyclical than revenues because of the catch up that is necessary for companies to preserve margins in response to a fall in price.

16. With an average drop in revenues of 7.9% and an average profitability decline of 15.5%, E&P companies' cyclicality assessment calibrates to moderately high (4) risk. We generally believe that the higher the level of profitability cyclicality in an industry, the higher the credit risk of companies in that industry. However, an industry's competitive and growth environment might mitigate cyclicality's overall effect on its risk profile.

Competitive risk and growth

17. We view the oil and gas integrated, and E&P industry as warranting an intermediate (3) competitive risk and growth assessment. To assess competitive risk and growth, we assess four subfactors as low, medium, or high risk. These are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of industry's barriers to entry--medium risk

18. We believe barriers to entry in the industry are moderate overall. Specifically for E&P companies, entry depends upon access to onshore or offshore locations with hydrocarbon prospects. The business is capital-intensive. Reserves--an E&P company's most valuable asset--deplete as a result of production. To sustain reserves and production, companies must reinvest continually in finding and development initiatives. Furthermore, expansion of reserves and production into newer and more technically challenging frontiers requires continuous technological advancement. As a result, engineering expertise, access to capital, and geographic footprint can be important differentiators between strong and weak operators, favoring larger and more technically sophisticated players.

Level and trend of industry profit margins--medium risk

19. When hydrocarbon prices are strong and E&P companies' operations are efficient, cash flow generation is substantial. For the better-positioned industry participants, profitability is well above average throughout the cycle and compared with that of other industries. Furthermore, the size and liquidity of the futures market for oil and natural gas allows companies to hedge future production at contract prices. This helps protect revenues from a near-term decline in prices. Profitability for less efficient companies will deteriorate more quickly at the trough in the hydrocarbon price cycle, because these companies are generally less able to lock in advantageous hedged prices or decrease costs to offset falling revenues.

20. Timely access to oil field services at economic rates is imperative for an E&P company to profitably increase production and reserves. During periods of high hydrocarbon prices or in areas of significant drilling activity, demand

for specialized rigs and services might outgrow supply and increase the price and decrease the availability of those services.

Risk of secular change and substitution by products, services and technologies--low risk

21. There is low risk of product obsolescence and we believe substitutes will make only modest inroads into demand for refined crude oil products in the near-to-medium term. Ongoing industrialization in emerging markets and path dependence on hydrocarbon-based economic development should result in meaningful demand growth for oil and natural gas.

22. In the long term, refined products might be subject to competing energy sources, including renewable energy. Spurred by environmental concerns, some governments have mandated increasingly efficient consumption of fossil fuels and provided incentives for the use of renewable energy. This helps slow secular growth in demand for petroleum products in mature, developed economies.

Risk in industry growth trends--medium risk

23. As noted above, the oil and gas, integrated, E&P industry is highly cyclical and prone to overinvestment. However, it is well-established and we believe that the risk of unsuccessful exploration has receded somewhat as technological advances in reservoir mapping and resource extraction, particularly when targeting onshore shale formations, help to mitigate inherent geologic uncertainties. Still, estimating reserves is a challenge: Reserve estimates are seldom exact and the assumptions in reserve estimates can vary widely.

24. Apart from replacing and measuring reserves, there is a high degree of operating risk associated with the E&P industry. Hazards include explosions, fires, toxic emissions, maritime accidents, weather-related disruptions, and other natural disasters that could harm the environment, curtail production, or result in punitive fines levied by a regulatory regime.

25. Energy consumption is becoming increasingly efficient, particularly in developed economies. Although we view this as a secular risk to long-term oil and gas demand, in the near-to-medium term, we believe demand growth will continue, primarily from industrial and consumer demand for hydrocarbons in emerging markets.

26. In part because of the need for E&P companies to gain access to large areas of land offshore locations, the important role the energy sector plays in the general health of an economy and the energy sector's prominence as a source of such things as pollution, government involvement is extensive. The following local or national factors influence growth and profit trends:

- Structural constraints on commercialization and monetization of volumes produced, including export volume quotas, price controls, royalties and production taxes. Some countries tax transportation fuel sales to the consumer heavily, significantly constraining demand. Sales can be subsidized to stimulate growth (as in Saudi Arabia and Venezuela), or prices are regulated (for example, Malaysia), to ease the financial burden for retail and industrial consumers of crude oil price spikes;
- The allocation and ultimate ownership of mineral rights. In the U.S., landowners (private or government) usually hold these rights; in most of the rest of the world, the sovereign controls them. With the latter, host governments enter fiscal contracts with E&P companies that allow the government to monetize its interest in different ways. The total government take in some countries can sometimes be the majority of the value of a barrel;
- More subtle changes (known as creeping expropriation), such as incremental taxation, forced renegotiation of

contracts, the revocation of licenses, and limits on the repatriation of capital pose risks for E&P companies, although the risks of total expropriation have waned somewhat since the 1970s. The fiscal regime's structure can be a key investment factor and in part determines the viability and profitability of potential projects; and

- Government regulation of exploration and development activity and of negative factors such as air, water, and noise pollution; and environmental repair and remediation. Government regulations can also affect technology used in E&P activities because of environmental effects. The same activity might be subject to differing regulations, not only between countries but also between states or other jurisdictions in a country--this is currently the case for hydraulic fracturing regulations in the U.S.

Country Risk

27. Country risk plays a critical role in determining our ratings on companies in a given country. Risk factors can have a substantial effect on company creditworthiness. In assessing country risk for an E&P company, we use the same methodology as with other corporate issuers (see "Corporate Methodology"). A key factor in our business risk analysis for corporate issuers is the country risk assessment, which includes the broad range of economic, institutional, financial market and legal risks that arise from doing business in a country. We assess each company's exposure to a country based on the EBITDA it generates there, when there is sufficient disclosure to determine country-specific EBITDA generation. If EBITDA disclosure is not sufficient, we might determine country risk exposure using production levels.

Competitive Position

28. Under our corporate criteria, we assess a company's competitive position as excellent (1), strong (2), satisfactory (3), fair (4), weak (5), or vulnerable (6). In assessing the competitive position for E&P companies, we review an individual company's

- Competitive advantage;
- Scale, scope, and diversity;
- Operating efficiency; and
- Profitability.

29. We assess the first three components independently as strong (1), strong/adequate (2), adequate (3), adequate/weak (4), or weak (5). We assess profitability through the combination of the level and volatility of profitability.

30. After evaluating separately competitive advantage, scale, scope, diversity, and operating efficiency, we determine the preliminary competitive position by ascribing a specific weight to each component. For E&P companies we typically use the "Commodity Focus/Scale Driven" competitive position group profile (CPGP). With this, we weigh competitive advantage; scale, scope, and diversity; and operating efficiency, 10%, 55%, and 35%, respectively.

31. We apply the "National Industries and Utilities" CPGP when the government policy or control, regulation, taxation and tariff policies significantly affect the industry's competitive dynamics. For integrated and E&P companies, we consider this to be the case when at least one of the following conditions applies:

- Heavy taxes influence net profits more than other purely operating factors (such as lifting and transportation costs). When tax rates change in proportion to the oil price, it acts as a natural hedge and makes profits more resilient to potential price shifts.
- There is price regulation or quasiregulation, when the regulator sets domestic prices, which can be materially different from international or local benchmark prices.
- National hydrocarbon companies enjoy monopoly rights, or have a pre-established preferential access to significant reserves, which effectively creates high barriers to entry.

32. Under the National Industries And Utilities CPGP, we weigh competitive advantage; scale, scope, and diversity; and operating efficiency, 60%, 20%, and 20%, respectively. The assessment of competitive advantage, scale, scope, diversity, and operating efficiency in these cases reflects advantages or disadvantages based on these national industry-specific factors:

- To what extent heavy taxes or domestic price regulations affect profitability through the cycle;
- To what extent regulations have a stabilizing effect on profits (that is, whether taxes act as a natural hedge);
- Whether the company has any advantages due to barriers to entry created by the regulatory framework in the hydrocarbon industry; and
- How stable the regulatory regime is and how resilient it is to potential changes in international oil prices.

Competitive advantage

33. In our opinion, an upstream company's ability to manage the inherent risks associated with replacing and increasing reserves largely determines its overall competitive advantage. For integrated and E&P companies, we assess the following to determine a company's competitive advantage:

- The growth prospects inherent in its acreage;
- The mix of liquids and gas produced;
- The unit revenues realized at each producing region; and
- The extent of vertical integration, if any, among operating segments.

34. Of importance, we assess a company's ability to increase production and reserves through internal development, taking account of such factors as its exploration and development track record, plans, technical resources and capabilities, and budget; its acreage position (which is particularly important for tight oil producers); and its project queue (which we assess based on each company's reserve life index [RLI]; we discuss RLI in greater detail in paragraph 48) over an extended period--as long as 5-10 years for companies with a "satisfactory" business risk profile. Absence of growth can indicate poor prospects for continuing to meet debt service requirements. As a result, companies with business risk profiles below satisfactory tend to have an RLI of less than five years. On the other hand, sustained high growth can place a strain on funding sources.

35. In our view, a balance between liquids and natural gas production is credit-positive in markets where there is a low price correlation between the two. Also, the type and quality of hydrocarbons produced affect revenues. For example, light, sweet crudes receive a premium over heavy, sour crudes, because the former require less refining treatment, and produce a slate of products with a greater percentage of high-priced, light refined products (such as gasoline, kerosene, and jet fuel), rather than heavy, refined products (residual fuel oil). Wet gas (containing natural gas liquids) also commands a premium over dry gas because of its higher energy content. Price and quality differentials on produced hydrocarbons can affect prices and resulting cash flows.

36. Another factor affecting E&P companies' revenues is the basis differentials--the difference between a particular regional price and the benchmark price. Differentials usually result from transportation costs and the production area's supply and demand characteristics. A company producing in a region with high transportation cost to market or limited capacity to transport hydrocarbons away from the region will sell at a discount to the benchmark price--which is an adverse factor. On the other hand, if it is supplying hydrocarbons to a region with low transportation cost or high demand, hydrocarbons might sell at a premium, thereby enabling the company to enjoy higher unit revenue, cash flow, and earnings.

37. Integration and diversification can be a significant aspect of an E&P company's competitive position, to the extent that it enhances and adds stability to financial performance, taking account of the capital employed. It is common for larger E&P companies to operate a cluster of ancillary, related businesses, although strategies regarding these have varied considerably, as have financial results.

38. Examples of integration and diversification include:

- Natural gas processing plants;
- Oil and gas common long-haul or gathering pipelines; and
- Oilfield services operations and assets, such as drilling rigs and pressure pumping equipment.

39. In broad terms, participation in pipeline operations with third-party volumes, in particular, can sometimes afford E&P companies a highly stable source of earnings not closely correlated with its base earnings. Vertical integration, in the form of ownership of oilfield services operations and assets, can facilitate cost-effective growth in reserves and production during frothy periods, when third-party suppliers are capacity-constrained. However, it also adds to fixed costs, and can exacerbate a downturn's adverse effects.

40. An E&P company warranting a "strong" or "strong/adequate" competitive advantage assessment typically has a combination of the following:

- A strong track record of project execution, with production and costs that compare favorably to adjacent operators;
- A track record of allocating capital to basins with favorable internal rates of return (typically exceeding 30%);
- Business segments that extend E&P operations to enable demonstrably better profitability, or more stable financial performance throughout the business cycle;
- Some integration of transportation and services, such as drilling rigs, that result in lower unit costs than if the operator sourced via a third party; and
- Some degree of leverage with customers and suppliers.

41. An E&P company with a "weak" or "adequate/weak" assessment of its competitive advantage typically has a combination of the following:

- A poor track record of project execution, with production and costs inferior to operators with adjacent acreage;
- A lack of a track record of allocating capital to basins featuring favorable internal rates of return;
- Operations with inferior profitability or more volatile financial performance throughout the business cycle;
- A lack of leverage with customers and suppliers; and
- A lack of integration with transportation and equipment and services.

Scale, scope, and diversity

42. E&P companies can develop meaningful scale, scope, and diversification in their operations by effectively adapting changing technologies to exploit newly discovered reservoirs. Hydrocarbon reserves are the key asset of an E&P company and their characteristics are a critical aspect of our assessment of its scale, scope, and diversity. We assess the characteristics of the reserves, including:

- The size of the reserves (larger reservoirs leads to economies of scale);
- The makeup in terms of liquids (such as crude oil and natural gas liquids) rather than natural gas;
- The operational risk inherent in the exploitation of the reserves (for example, deep water production being much riskier than onshore operations);
- The geographic diversity of production sources; and
- The company's current production and future growth prospects.

43. Consistent with the industry standard, we generally assess reserves and production on either a barrel of oil equivalent (boe) or thousand cubic feet (mcf) of natural gas equivalent basis, which we determine by using the energy content equivalency ratio of six mcf of natural gas to one barrel of crude oil, or natural gas liquids. We also consider the composition of ongoing revenues because the energy equivalent can be significantly out of synch with market prices.

44. A large reserve base relative to that of peers implies better operating flexibility, geographic diversity, and economies of scale. A large E&P company operating in many geographically diverse fields is insulated from dependence on the operational performance of a small cluster of wells or fields and less susceptible to regional price volatility. A geographically diversified portfolio can also provide avenues for cost-effective investment if regional factors affect production or reinvestment in a particular area. Furthermore, the size and type of individual reservoirs is important for a company. A large reservoir (whether onshore or offshore) provides economies of scale, because the company can spread its overhead and capital investment across more production. Large companies also might have access to more favorable financing terms--a significant competitive advantage when developing or buying properties--and added financial flexibility during industry downturns. However, if it operates in several basins, of which only a few typically account for the dominant share of its earnings, that limits the extent to which we view its production as diversified. Nevertheless, in our view, a company operating in one major basin (for instance, the Western Canada Sedimentary Basin) could warrant a "strong/adequate" scale, scope, and diversity assessment, as long as we expect it to generate above-average profitability and if its acreage position is extensive and provides visibility to a production profile of at least 10 years.

45. When assessing reserve quality, we consider the following key measures: the proved developed producing (PDP) ratio; RLI; and the reserve replacement ratio (RRR).

46. Proved developed reserves: In general, companies with a high PDP ratio (the percentage of PDP reserves relative to total proven reserves) have lower business risk, because proved developed reserves have fewer future development costs and production risks (both in terms of potential for cost overruns and for shortfalls in production compared with expectations) than undeveloped reserves. However, a very high percentage of proved developed reserves might indicate potential for deterioration in reserve replacement if we believe a company might have difficulty developing its undeveloped or probable reserves. Where we believe there is little risk associated with developing reserves (for instance, mining-type oil sands operations, which are akin to strip mining operations where the reserves are close to

the surface), we do not place much emphasis on the distinction between proved developed and undeveloped reserves, because there is little geological risk associated with converting proved undeveloped reserves (PUD) and probable reserves into proved reserves. We could extend this analysis to other forms of unconventional oil and gas reserves.

47. The U.S. SEC and equivalent authorities in other areas define the standards for different categories of reported reserves (see Accounting And Analytical Adjustments), but we recognize that there is still a measure of management discretion in the application of these standards. Proved developed reserves (rather than PUDs or probable or possible resources) are the most direct source of current production and cash flow; PUDs require capital investments to convert them into proved developed reserves.

48. RLI: We define this as reserves divided by annual production. An RLI indicates the timeframe over which a company will deplete its existing reserves at current production rates. We assess RLI in the context of a company's total reserve base, prospects for organic or acquisition reserve growth, capital position, and operating team. A short RLI (for instance, of less than five years) might indicate a lack of success in reserve replacement, or limited capital investment focused on organic and acquisition-related growth. A long RLI (that is, 10 years or more) might indicate the low-risk nature of the company's reserve base and relative stability of its production outlook (this is generally the case for oil sands- or shale-focused companies). On the other hand, a long RLI can also imply possibly overstated reserves or a company's inability to ramp up production. In assessing reserves, we also consider the underlying, assumed depletion rate. If the depletion curve is steep, that implies that there is a risk of a significant decline in production beyond the next few years if reserves are not replaced.

49. RRR: This indicates how much of the produced hydrocarbons the company has replaced, either through organic growth (through the drill bit) or acquisitions. The size of the company's reserves or stage of development largely influences the measure, which should be viewed together with unit finding, development, and acquisition (FD&A) costs (see Operating Efficiency). For E&P companies with a small reserve base in a rapid growth mode, it is not uncommon for reserve replacement to be a multiple of annual production; in these cases, an RRR of at least 100% is a critical benchmark. On the other hand, an extremely large E&P company might not be able to replace 100% of its production organically, instead using a combination of development and acquisitions. We might view the more-than-100% RRR as excellent for a major E&P company, but mediocre for a small, formative company. Companies with an RRR of more than 100% for several years could see an improving business risk profile, given the potential for future production growth.

50. All E&P companies face the challenge of finding or acquiring new reserves to replace those depleted. The ability to replace reserves is critical because a company will eventually fail if it cannot economically replace its reserves. In addition, the cost of replacing reserves (unit FD&A costs usually is 50% or more of a company's total unit cost base) significantly affects financial performance.

51. The most successful E&P companies sometimes supplement internal development with acquisitions. The E&P industry is very active in mergers and acquisitions. E&P companies frequently buy assets to enter new areas or consolidate their interest in existing properties, while divesting noncore or high-cost assets to streamline their portfolios or to raise funds. In considering acquisitions, we focus on how much the company paid for the assets, the opportunities the assets afford for yielding reserves and production, whether there are economies of scale for the company, and whether it has

the ability to manage the new properties. Usually, E&P companies operating a project have a better control of the cash outlay compared with those that rely on third-party operators. E&P companies that acquire assets and are able to successfully increase reserve size and production, manage costs, and obtain higher rates of returns on their investments should be able to strengthen their scale, scope and diversity.

52. An E&P company that warrants a "strong" or "strong/adequate" assessment of scale, scope, and diversity typically has a combination of the following:

- Large scale, with reserves typically exceeding 1.5 billion barrels of oil equivalent, and production typically exceeding 500,000 boe per day;
- An RLI of 10 years or greater;
- An RRR greater than 100% on average across at least a three-year timeframe, and prospects for production growth given its drilling inventory and queue of planned investment projects;
- Allocation to liquids (crude oil and natural gas liquids [NGLs]) along with natural gas in its reserve mix;
- Geographic diversity, with the majority of fields or projects with a well-established track record of development activity and in relatively low-risk countries (that is, those with a country risk score of 3 or lower); and
- Exceptionally low risk to production and reserve replacement, even if the company has a concentration in a relatively small number of fields (as is typical of certain Canadian oil sands projects).

53. An E&P company that warrants a "weak" or "adequate/weak" assessment of scale, scope, and diversity typically has a combination of:

- Small scale, based on total reserve base usually less than 50 million boe, on a proved developed basis; and a production base usually less than 30,000 boe per day;
- An RLI of five years or less;
- Geographical concentration, with the vast majority of cash flows from one basin;
- Significant uncertainty with respect to sustainability of production and reserve replacement; and
- An RRR of less than 100% in the past three years, with limited prospects for growth in production.

Operating efficiency

54. In assessing operating efficiency for an E&P company, we consider its operating and production costs and its reserve replacement costs, and related capital efficiency measures such as:

- Unit cash costs and unit FD&A costs relative to those of peers;
- Unit cash margin (or netback), which is equivalent to an operating margin, relative to FD&A costs; and
- Revenue per unit of production relative to unleveraged costs.

55. We evaluate capital efficiency by comparing an E&P company's finding and development costs, which we view as the best measure of a company's organic growth capabilities. We also assess the finding, development and acquisition (unit FD&A; also known as all-sources finding and development) cost to its unit cash margin (or netback). An upstream company's netback is synonymous with an operating margin per unit. An E&P company's unit netback relative to its unit F&D (or FD&A) is its recycle ratio. At a minimum, the recycle ratio should be at least 1x to ensure a company's continued viability. A recycle ratio of less than 1x would indicate continued viability is at risk and would typically contribute to an assessment of "weak" for operating efficiency. The unit FD&A cost indicates how much capital a company spends in all forms to replace a unit of hydrocarbon produced. Unit FD&A cost can vary from year to year.

E&P companies generally need to spend large amounts on exploration and development of offshore fields over many years before recognizing reserves, so they will show poor unit FD&A cost until then. Comparisons of F&D costs and FD&A costs can be distorted if there is a significant increase in PUDs or unproved resources. FD&A costs and reserve recognition can be uneven year-to-year; therefore, we typically focus on unit FD&A costs over a three-year period. This removes some of the volatility while still being sensitive to underlying trends. A company that generates unit cash margin significantly above its unit FD&A cost should be capable of generating annual increases in reserves and production--or at least maintain constant levels in the case of the largest players--without any external funding requirements.

56. We also assess the upfront costs related to develop basins. Capital spending for some projects can be sizable (for example, Canadian oil sands or tertiary projects that can require very costly pipeline infrastructure) even before E&P operators can begin to produce. Depending on the balance of fixed costs versus variable costs, E&P companies have varying degrees of financial performance volatility.

57. Broadly, an E&P company's cost base is composed of its operating and production costs and its reserve replacement costs. Operating costs and investment requirements largely are a function of the specific hydrocarbons the company produces. Generally, crude oil has a relatively higher operating cost associated with it than natural gas. As well, based on the producing region, operating costs (which generally support current production) can be more or less competitive than those of peers. A company's capital expenditure must support its exploration and development program to maintain and increase reserves and production. In some cases, there is a lag between periods of peak capital spending requirements and the subsequent production. This is often the case with offshore production projects. Under our methodology, we compare cash operating costs against capital costs.

58. E&P companies produce commodities and have no control over selling prices (except through hedging), so cost-control is an important aspect of their credit profiles. Managing costs might allow companies to expand and generate cash flow, so it is an important determinant of long-range operating strength. However, most E&P companies depend on third-party companies for certain critical services (for instance, drilling and pressure pumping and fracking), so have little control over the related costs (see Industry Risk).

59. Apart from the case of mature fields, companies that are start-ups or developing new production typically have high cash operating costs, largely with high early stage lease operating expenses (LOE) and general and administrative (G&A) costs, thereby heightening risks by dampening financial performance. Subsequently, as the company increases its production, overall LOE and G&A costs in the same area do not increase proportionally because the expenses are spread over a larger production base. In contrast, companies with a large stable production base and sustainable growth prospects should have a competitive advantage over less mature peers. Those that experience production shutdowns, either because of maintenance requirements, pipeline outages, or weather, will see cash operating costs rise per unit of production.

60. The combination of unit cash operating cost (excluding interest expense) and unit FD&A costs is what we define as the unleveraged cost. The combination of unleveraged cost and interest expense is the leveraged cost per unit of production. In assessing an E&P company's operating efficiency within its competitive position, our analysis uses the unleveraged full-cycle costs in ranking operating efficiency, because our assessment of a company's financial risk

profile captures the financing burden associated with leverage.

61. An E&P company warranting a "strong" or "strong/adequate" operating efficiency assessment typically has a combination of:

- Unit cash operating and unit FD&A costs that are consistently lower than peers with a similar hydrocarbon mix; and
- Revenues per unit of production that are consistently higher and that we expect to remain consistently higher than unit unleveraged costs under our pricing assumptions, with unit cash margins that can fund unit FD&A costs internally.

62. An E&P company warranting a "weak" or "adequate/weak" operating efficiency assessment typically has a combination of:

- Consistently higher unit cash costs (for instance, costs to extract oil and gas) and consistently higher FD&A costs than peers with a similar hydrocarbon mix; and
- Revenues per unit of production that are consistently lower and that we expect to remain consistently lower than unit unleveraged costs under our pricing assumptions, with unit cash margins that cannot fund unit FD&A costs internally (external financing is essential for the company's growth).

Profitability

63. The profitability assessment can confirm or modify the preliminary Competitive Position assessment. The profitability assessment consists of two components: the level, and volatility of profitability. We combine the two components into the final profitability assessment using a matrix (see "Corporate Methodology").

64. ***Level of profitability.*** The primary metrics we use to evaluate profitability for E&P companies are:

- Adjusted unit earnings before interest (EBI; unhedged earnings before interest and after taxes of each unit of production [unit EBI], adjusted for Standard & Poor's off-balance-sheet adjustments);
- Return on capital; and
- EBI margin; we may also include EBIT margin (for instance, pretax) as a proxy metric, depending on availability of data and relevance in the specific peer group used to benchmark a company.

65. We determine the level of profitability on a three point scale: "above average," "average," and "below average." Each year, we rank companies based on these profitability measures. Companies with above-average profitability typically have metrics that fall in the top quartile of the ranking. Those with average profitability typically have metrics in the middle 50%. Those with below-average profitability typically have metrics in the bottom 25%. The thresholds for each of these categories will likely change from year to year, due to natural hydrocarbon price volatility and possible changes in company operating efficiency metrics, so we expect the benchmark thresholds for above-average, average, and below-average profitability could vary from year to year.

66. ***Volatility of profitability.*** We evaluate volatility of profitability on a scale from '1' to '6', '1' being the least volatile. As with the level of profitability, we evaluate volatility of profitability within the context of the industry.

67. We determine volatility using the standard error of regression (SER), in accordance with our corporate criteria. We use the return on capital metric to determine the SER for E&P companies. In accordance with the corporate criteria, we may--subject to certain conditions--adjust the SER assessment up to two categories worse or better. We only determine SER when companies have at least seven years of historical annual data to ensure the results are

meaningful. If we do not have sufficient historical information to determine the SER, we follow the corporate criteria guidelines to determine volatility.

Part II. Financial Risk Analysis

Accounting And Analytical Adjustments

68. In assessing E&P companies' accounting characteristics, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). Our analysis of a company's financial statements begins with a review of its accounting to determine whether the statements accurately measure its performance and position relative to that of its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our analysis might include quantitative adjustments to a company's reported results. These adjustments also enable better alignment of a company's reported figures with our view of underlying economic conditions. Moreover, they allow a more accurate portrayal of a company's ongoing business. (For more information on adjustments that pertain broadly to all corporate industries, including this industry, see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013).

Reserve disclosures

69. In most countries, E&P companies are required to disclose their reserves at the end of each year; we require these disclosures to rate an E&P company. There are differences in definitions used and level of disclosure required, which can complicate cross-country comparisons. Moreover, we believe there is some degree of management discretion over such matters as the categorization of reserves and resources--that is, between proved developed, proved undeveloped, and probable. We view reserve reports prepared and audited by internationally recognized third-party engineers as having greatest credibility, compared with companies that prepare their reserve reports internally and only audited by third-party engineers, or where less-well-recognized engineering firms are used. To assess the reliability of reserve disclosures, we will also evaluate whether a company has historically posted substantial or frequent negative performance reserve revisions, which can indicate an aggressive policy of reserve bookings. In this instance, we may hold these companies to a higher standard for reserve size and quality (based on a higher proportion of proved developed reserves) relative to similarly rated peers. However, in our analysis of reserve bookings, we will typically have greater tolerance for negative price related revisions: These generally occur in periods of declining oil and gas prices, and reverse when prices improve.

Exploration costs

70. In the U.S. and elsewhere, oil and gas E&P companies must choose between two accounting methods: full cost or successful efforts, which differ in terms of what investment outlays companies capitalize or expense. A full-cost company capitalizes all costs of property acquisition, exploration, and development in cost centers. These cost centers can be as encompassing as the company's operations in an entire country. Costs are identified only at the cost-center level, not at any more specific or different level such as at a well or field. Depreciation, depletion, and amortization (DD&A) are calculated at the cost-center level. A full-cost company expenses production costs as incurred.

71. Under the inherently more conservative, successful-efforts accounting approach, a company only capitalizes property

acquisition costs and those related to successful exploratory drilling, such as drilling that results in the discovery and development of a commercial oil and gas field, and related development costs. Capitalized costs are amortized across field production. Companies using the successful-efforts method report their exploration expenses as a separate line item in the income statement; full-cost companies capitalize exploration costs and do not report exploration expense separately in the income statement.

72. Recasting the financial statistics of full-cost and successful efforts companies on a common basis is beyond the scope of our analysis, because numerous adjustments are necessary and a vast majority do not yield an analytically meaningful conclusion. However, to gain comparability within the sector, we adjust our calculation of EBITDA to exclude all exploration costs thereby increasing EBITDA. We consider this adjustment as one which provides sufficient comparability among companies using either accounting treatment. This adjusted measure conforms to the industry standard known as EBITDAX. With this adjustment, we calculate all EBITDA-related ratios using our equivalent of EBITDAX. Although we add back the exploration expense reported by companies using successful-efforts accounting to derive EBITDA, we revise this adjustment when calculating funds from operations (FFO). In other words, we reduce FFO by the amount of exploration costs. We take this alternative approach to calculate FFO to have some degree of comparability with other industries. Likewise, companies report cash paid for exploration in the statement of cash flows differently. We generally do not attempt to make adjustments to these amounts in the statement of cash flows, but rather rely more heavily on free operating cash flow-to-debt as a supplemental measure of cash flow-to-leverage because the classification of these amounts doesn't affect this.

Adjustment procedures

Data requirements

- Exploration expense in the period as reported by companies following the successful-efforts approach.

Calculations

- We add to the exploration expense in the period EBITDA of companies that follow the successful-efforts approach. Our definition of FFO is EBITDA minus net interest expense minus current tax expense, after adjusting each of the three components according to our criteria. Because of this definition and our decision to depress FFO by exploration costs, we make an equal and opposite adjustment to FFO to unwind the adjustment made to EBITDA

Reserve impairments

73. The accounting methods also recognize impairment charges differently. A successful-efforts company uses the same multistep method to assess the need for asset impairment as companies in other industries. The SEC, however, require that the full cost method of accounting calculate impairment using a cost-center ceiling. In the ceiling test, the company compares the calculated ceiling to the net capitalized costs of oil and gas properties. If the capitalized costs exceed the ceiling, the company records an impairment charge. The full-cost ceiling generally is defined as the present value of future net cash flows from proved reserves, using a 10% discount rate, current sales prices (defined as average prices over the current period), and current production costs. Usually, asset impairment charges occur when hydrocarbon prices fall dramatically, but can also result from changes in reserves and production profiles. An impairment charge will reduce future DD&A expense, thereby artificially boosting future return on capital. Consequently, we focus on three-year unit FD&A costs in lieu of DD&A costs in peer comparisons where FD&A cost information is available, to ensure consistency.

Economic hedging

74. E&P companies often seek to manage their exposure to fluctuations in commodity prices and foreign currencies through hedges. When derivatives are not designated as hedges as provided for under accounting standards or do not qualify for hedge accounting, derivative gains and losses flow through the income statement each period. Realized gains and losses relate to transactions in the current period, and unrealized gains and losses to future transactions. When the derivatives do not qualify for hedge accounting or are not designated as hedges, we typically eliminate unrealized gains and losses relating to future production, where we can identify these effects, focusing on earnings that only include realized hedge effects.

Volumetric production payments

75. A volumetric production payment (VPP) is an arrangement in which an E&P company agrees to deliver a specified quantity of hydrocarbons from specific properties (or fields) to a counterparty in return for a fixed amount of cash received at the beginning of the transaction. The seller often bears all of the production and development costs associated with delivering the agreed-upon volumes. The buyer receives a non-operating interest in the oil and gas properties that produce the required volumes. The security is a real interest in the producing properties that the parties expect to survive any bankruptcy of the E&P company that sold the VPP. After delivery of the total requisite volumes, the production payment arrangement terminates and the conveyed interest reverts back to the seller.

76. We view VPPs structured with a high level of investor protection--in terms of production coverage--as debt-like obligations, and we adjust our financial and operating analysis accordingly. The E&P company's retaining risk in VPPs is central to our treatment of these deals as largely debt-like.

77. Under U.S. generally accepted accounting principles (GAAP), the accounting for VPPs affects the seller's financial statements and operating statistics in several ways. The VPP volumes (that is, the amount of oil and natural gas to be delivered under the agreement) are removed from the seller's reserves, and the proceeds the seller receives for the VPP increase its cash balances. If using the successful-efforts accounting method, the seller books a deferred revenue liability to reflect the obligation under the agreement. If instead the seller uses the full-cost accounting method, the VPP transaction is effectively accounted for as a sale.

78. In all cases, the seller's income statement includes the costs of producing the VPP volumes as and when the oil and gas is produced. Operating statistics calculated per boe will be overstated because they do not factor in the volumes related to the VPP but do include the associated costs. For example, in the case of per unit lifting costs (the operating costs associated with the extraction of the oil and gas divided by the number of boe extracted), the numerator continues to capture the cost of producing the VPP volumes but the denominator does not capture the associated barrels. For those companies using the successful-efforts method, the same holds true for revenue because the income statement includes the amortization of deferred revenue.

79. We note that there is no specific guidance available for VPP arrangements under International Financial Reporting Standards (IFRS). In practice, IFRS reporters follow these same principles because the U.S. GAAP requirements are consistent with IFRS principles.

80. When the necessary data are available, we adjust the reported results to minimize these distortions. The required volumes are returned to reserves, and the oil and gas volumes produced to meet the VPP requirements are added to

the E&P company's production when calculating per-boe operating statistics.

81. Finally, we consider the obligation to deliver the VPP volumes to be debt-like. This treatment reflects our view that VPPs are conceptually similar to secured debt, rather than asset sales. In typical deals, there is substantial overcollateralization with total field reserves significantly exceeding the volumes the seller promises under the VPP contract. The seller is obliged to deliver the agreed-upon volumes and incurs all associated operating and capital costs. If the seller does not meet the obligation, it would risk losing all its reserves in the field. We would view a VPP structured with minimal overcollateralization to be closer to an asset sale, because the transfer of risk would be more substantial. However, even in this case, the VPP has some debt-like qualities because the company must pay the operating expenses associated with the VPP until delivery of the final volumes.

82. To make the adjustment to debt, we use a fair-market value approach, and use the New York Mercantile Exchange (NYMEX) futures curve to calculate the expected value of the barrels to be delivered, which we consider to be debt. If hydrocarbon prices increase, so would the debt adjustment. This approach is analogous to using the fluctuating value of foreign-currency-denominated debt.

83. We publish hydrocarbon pricing assumptions, which we use when projecting credit ratios in the oil and gas sector. For the purposes of calculating projected credit protection measures, we use these same pricing assumptions to calculate the VPP value, to ensure analytical consistency with the entire E&P sector.

Data requirements

- Schedule of oil and natural gas volumes yet to be delivered under the VPP;
- Oil and natural gas volumes produced during the year from the VPPs per the company;
- NYMEX futures curve for oil and natural gas prices as of period end; and
- Pricing differentials (related to quality differences and geographic location) for the VPP volumes relative to NYMEX.

Calculations

- Debt: We multiply the oil and natural gas volumes to be delivered in each year of the contract by the futures price (adjusted for quality and location differentials) in that year. We then calculate the value of this revenue stream using a discount rate commensurate with the company's secured borrowing rate.
- Interest expense: We impute interest expense on the adjustment to debt using the company's secured borrowing rate. We apply the rate to the average of the calculated VPP obligation at current and previous period-end. Our fully adjusted gross interest expense reflects the imputed interest.
- Debt-to-reserves: We add the hydrocarbon volumes the seller hasn't yet delivered under the VPP back to reported reserves, which is relevant for debt-to-reserve calculations.

84. Selling and lifting costs: We add the oil and gas volumes produced to meet the VPP requirements in calculating per-unit selling prices and lifting costs.

85. Cash flow from operations (CFO) and FFO: We subtract from CFO and FFO the cash proceeds from VPPs.

Cash Flow/Leverage Analysis

86. In assessing the cash flow adequacy of an E&P issuer, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow and leverage on a scale from '1' (minimal) to '6' (highly leveraged). We do this by combining the assessments of a range of credit ratios, predominantly cash-flow based, which complement each other by focusing attention on the different levels of a company's cash flow in relation to its obligations.

Core ratios

87. For each company, we determine in accordance with Standard & Poor's Ratios And Adjustments criteria, two core payback ratios: FFO-to-debt and debt-to-EBITDA.

Supplemental ratios

88. In addition to our analysis of a company's core ratios, we also consider supplemental ratios to develop a fuller understanding of its credit risk profile and refine our cash flow analysis. In our view, an E&P company's inability to fund its minimum ongoing investment requirements (or maintenance capital spending) would be the most likely source of financial stress, since reserve replacement and, therefore production stability, rely on substantial access to capital. Therefore, we consider as supplemental ratios:

- Free operating cash flow-to-debt (after considering, at a minimum, maintenance capital spending requirements); and
- Discretionary cash flow-to-debt. This ratio is most relevant for issuers who pay out a portion of excess cash flow to shareholders as dividends.

89. Given hydrocarbon price volatility, we could weaken the cash flow leverage assessment up to two categories, especially if prices are robust and if we believe E&P companies are at the peak of their cash flow generation cycle.

Part III. Rating Modifiers

Diversification/Portfolio Effect

90. In assessing an E&P company's diversification/portfolio effect, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Capital Structure

91. In assessing an E&P company's capital structure, our analysis uses the same general methodology as with other corporate issuers (see "Corporate Methodology").

Liquidity

92. In assessing an E&P company's liquidity factors, our analysis uses the same general methodology as with other corporate issuers (see "Corporate Methodology").

Financial Policy

93. In assessing an E&P company's financial policy, our analysis uses the same methodology as other corporate issuers (see "Corporate Methodology").

Management And Governance

94. In assessing an E&P company's management and governance, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Comparable Ratings Analysis

95. In assessing an E&P company's comparable ratings analysis, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Frequently Asked Questions

Q1: How does Standard & Poor's define "integrated" oil and gas companies?

By "integrated" we mean companies having material exploration and production ("upstream") operations and refining ("downstream") operations. Integrated oil and gas companies also may have "midstream" operations, whereby they engage in transporting, processing, storage, and marketing of commodities such as crude oil, refined products (e.g., gasoline and diesel), natural gas, liquefied natural gas (LNG) and natural gas liquids (NGLs). In addition, such companies may have related ancillary businesses--for example, petrochemicals production and commodities trading. Marketing of refined products may be just at the wholesale level, or extend to serving industrial and retail customers directly.

Although an oil and gas company must have material upstream and downstream operations for us to view it as integrated, it need not have operational or physical links between divisions. That is, the company need not produce crude oil, transport it through its own pipelines to its own refineries, and eventually sell the gasoline it produces through its own retail outlets. Instead, many integrated companies function to some degree as portfolios, whereby it may be most cost-effective for midstream and downstream operations to source inputs, and for all operations to sell their outputs, through third parties.

Integrated oil and gas companies include both publicly held companies and national oil companies (NOCs) that are often government-owned and -controlled. NOCs typically produce both oil and gas and we treat them as government-related entities (GREs).

Q2: What differentiates the business risk profiles of integrated and non-integrated oil and gas companies?

The scale, scope, and diversity of integrated companies' upstream operations are generally superior to even the best-positioned non-integrated oil and gas companies. The integrated companies are typically able to access and manage very large upstream development projects that provide a competitive advantage. Although requiring massive initial investment over multiple years, these projects can generate many years of relatively stable production once completed.

We view the vertical integration of upstream and downstream businesses as providing a measure of diversification that improves the stability of profitability and cash flows. The cycles of the upstream and downstream industries are not completely correlated. Integration constitutes a partial hedge against crude price fluctuations, even if a company does not process or distribute the same oil or products it produces. Access to information based on participation in multiple market sectors may also provide advantages. Where a company exhibits these characteristics, has assets of at least average quality, and has a fairly consistent track record of earnings generation and reserve replacement, we typically assess the competitive position more favorably than for a non-integrated or independent upstream company. When these positives are less evident (for example, if volatility is high compared with integrated or non-integrated peers), a company's vertical integration might not lead us to assess its competitive position more favorably.

Looking at several years of crude oil price fluctuations, we note that integrated oil and gas companies have exhibited more moderate declines in profitability than non-integrated upstream oil and gas companies. We believe that less variability of profits in an industry generally means lower credit risk for industry entities. During the oil price downturn in third-quarter 2014, refining margins (excluding inventory effects) and profits from marketing operations strengthened for many companies globally. The opposite was the case, however, in the downturn of 2008-2009, when oil prices fell dramatically, and U.S. Gulf Coast refining margins were also highly volatile, briefly becoming negative. Nevertheless, over many periods, including 2008-2009, the profitability of integrated companies has demonstrated much lower volatility than that of the largest non-integrated E&P companies.

Q3: What are the key factors and differences in Standard & Poor's analysis of integrated and upstream, non-integrated oil and gas companies?

We apply our criteria differently to integrated companies than to E&P companies to capture the typically greater resilience and longer investment horizons of these often-large groups. For a smaller integrated group, with both upstream and downstream assets, we would weigh the lesser scale and diversity against any integration benefits in terms of lower volatility of earnings and cash generation.

Competitive Position

Scale, scope, and diversity are generally critical strengths of integrated companies, usually resulting in strong or strong/adequate assessments. Companies with the strongest business risk positions exhibit both absolute scale and meaningful diversity. An average or weak assessment is possible if an integrated company is materially reliant on and exposed to one or more of its upstream or downstream assets.

For integrated oil and gas companies, we place greater weight on return on capital as a measure of profitability than we do for E&P companies. Integrated groups' EBITDA or EBIT margins are not necessarily effective comparable measures at a group level, as they are influenced by the proportion of different divisions that have intrinsically different margins.

We typically assess per-unit measures for E&P operations on an aftertax basis, given the international nature of the integrated companies and the sharp variations across regions in upstream tax rates. For example, if a company faces low lifting costs for conventional reserves in emerging markets, the benefit to profitability might be offset by material overall taxes and duties in the region.

We assess other business lines using the relevant Key Credit Factors for refining, commodity chemicals, midstream, or retail, as appropriate.

Contrary to our practice for some smaller E&P companies, we generally do not apply a further adjustment for volatility of profitability, owing to the historically more stable performance of integrated companies (see paragraph 83 of "Corporate Methodology").

Cash flow/Leverage

For integrated oil and gas companies, weaker supplementary free operating cash flow or discretionary cash flow ratios might not lead to a lower overall financial risk profile assessment. This is especially true if core ratios are relatively strong for the financial risk profile category or if a company is in a temporary and particularly heavy investment phase developing long-life production projects (see paragraph 108 of "Corporate Methodology"). We may also consider ratios over a longer timeframe than we typically use for E&P companies.

Unlike some smaller E&P companies, integrated companies routinely make material distributions to shareholders, via dividends, share buybacks, or both. The ratio of discretionary cash flow (DCF) to debt is therefore a useful supplementary and comparative measure, although shareholder distributions are typically also partly funded from asset sales (which do not boost DCF).

We generally do not apply the cash flow volatility adjustment to integrated oil and gas companies, as such companies generally have excellent or strong business risk assessments and a lower probability of changing financial risk profiles through industry cycles; this approach is consistent with our general criteria (see paragraph 125 of "Corporate Methodology"). For some companies, exceptionally strong core ratios can change significantly but still remain within the range corresponding to a "minimal" financial risk profile assessment.

Modifiers

We do not generally apply a positive diversification/portfolio effect modifier to integrated oil and gas companies. This is because we factor in any diversification benefit in our competitive position assessment.

In assessing the diversification/portfolio effect modifier for an integrated oil and gas company, we use the same methodology as for other corporate issuers (see paragraph 32 of "Corporate Methodology"). For us to assess this modifier as positive, companies must have lines of business that span industries we classify as substantially different; in other words, more distinct than vertical integration across oil and gas-related industries (upstream, midstream, refining, trading, marketing, and petro-chemicals and across production and products, including liquids, gas, and LNG).

We recognize that these different businesses are not inversely-correlated in terms of earnings or cash generation. We do, however, see a material portfolio of above-average quality assets across divisions as more resilient to industry cycles, even if upstream operations are increasingly important drivers of group performance for many integrated oil and gas companies.

We may use the comparable ratings analysis (CRA) modifier where we believe the nature and relevance of specific country risks are not sufficiently captured in our country risk or competitive position assessments (see paragraph 38 of "Corporate Methodology"). For example, we could use a "negative" CRA adjustment for a company with high overall exposure to emerging countries compared with its peers.

Q4: What other areas do we focus on in our assessment of integrated oil and gas companies versus non-integrated E&P companies?

a) Country Risk

Our assessment is as per the global corporate criteria (i.e., country risk captured in the country risk score), and factors in head office location and diversification. As for E&P companies in general, aspects of country risk not already captured in the country risk score can be important credit factors for integrated companies and we consider these industry-specific country risk factors in our assessment of a company's competitive position and/or the CRA. We highlight that sovereign and transfer and convertibility risks are addressed by our ratings above the sovereign criteria (see "Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions," published Nov. 19, 2013).

b) Operating Efficiency

Operating efficiency sometimes differentiates integrated oil and gas companies from smaller upstream peers, as the integrated companies can maximize their economies of scale in the largest fields, sometimes resulting in lower-than-average lifting and overall operating costs. Also, some of the largest refineries and distribution networks globally are owned and operated by integrated companies, again resulting in the potential for lower unit costs. Operating efficiency for national oil companies may either be very strong, reflecting low cost reserves, or relatively weak, reflecting price controls on downstream operations, excessive manpower, and other factors. In recent years, high global oil prices and weaker domestic currencies have been adverse factors for national oil companies in some emerging markets as the benefit to their crude production operations has been offset by the need to import crude and oil products for domestic sales.

c) Profitability, accounting and analytical adjustments

Exploration expenses and returns on capital. Resource discovery and monetization are particularly important to our assessment of profitability over time for both integrated companies and smaller exploration-focused companies. A profitable company will successfully balance exploration spending and write-offs with ongoing production and occasional--but uncertain--sales. A less-successful company will bear exploration charges but benefit less from them in terms of sales of interests and production. Acquisitions and disposals of reserves, resources, and other assets are recurring activities for integrated companies. Active portfolio management (i.e., disposals) is often used to supplement operating cash flow to fund capital investment and shareholder distributions.

As we do for all companies using successful efforts accounting (whereby general or unsuccessful exploration expenditure is written off), we add back exploration expenses to adjusted EBITDA to allow comparison between those companies and those that apply full cost accounting. We assess EBIT after such expenses (see paragraph 68 above) Integrated companies typically use successful efforts accounting, so over several years we are able to assess their comparative EBIT performance and return on capital employed encompassing both exploration costs and write-offs and gains on asset sales.

Refining and marketing. The most relevant adjustments in the refining and marketing segments of integrated oil and gas companies relate to LIFO (last in first out) and FIFO (first in first out) inventory adjustments (see paragraphs 110-117 of "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013).

Capital expenditure. Some integrated companies include acquisitions in reported capital expenditure, but we generally focus on organic investment and exclude material asset or company acquisitions from our calculation of free operating cash flow.

Consolidated interests and rights and obligations in fields. Companies engaged in hydrocarbon exploration and production usually hold stakes in licenses and fields. These contractual relationships can spread both costs and risks between the operator and its partners. These joint arrangements are organized around individual properties or groups of properties. Where the partners have a share in the benefits from the assets and a share of responsibility for the obligations, under current U.S. GAAP and IFRS11 accounting standards, the parties each recognize their respective share of assets, obligations, revenues, expenses, and cash flows. We typically adopt a similar analytical approach to these interests, whether the interests are large or small.

Similarly, it is also industry practice for companies to enter into contractual service agreements that in many respects result in similar benefits and obligations to a direct interest, but where the investments made and payments received are through another entity--typically government-owned--that holds the legal title to the stake in the field. The company would often include these entitlements and obligations in its reported reserves and accounts. Our analytical treatment generally also reflects the same scope of consolidation.

Q5: How does Standard & Poor's rate national oil companies under its corporate and GRE criteria?

Competitive dynamics are a key factor in the way we rate national oil companies (NOCs). Where these are largely driven by government policy, regulation, government control, and taxation and tariff policies, we may assign the "national industry" competitive position group profile to an NOC for the purposes of our business risk analysis. Under this category, our assessment of the NOC's competitive advantage accounts for 60% of the overall competitive position assessment; scale, scope, and diversity for 20%; and operating efficiency for 20%.

We might use the "national industry" category when one or more of the below conditions apply:

- An entity benefits from significant ongoing state support, for example in the form of preferential access to reserves, feed-stocks, essential infrastructure, exclusive export licenses, or alternative tax regimes or concessions.
- The government limits market access for certain companies (government-related or private), thereby reducing competitive threats to the incumbents.
- Net profit dynamics are largely determined by government policy, for example, the majority of the NOC's costs are taxes and royalties or sales subject to regulated prices.
- An entity is subject to other forms of ongoing state intervention (positive or negative), significantly affecting earnings and cash flow.

The "national industry" category often applies for oil and gas companies that we classify as government-related entities

(GREs). We define GREs as enterprises potentially affected by extraordinary government support or negative intervention. GREs are often partially or totally government-controlled. In the oil and gas sector, in our experience GREs contribute to implementing policies or delivering key services to the population. Examples of NOCs (including gas producers) that we classify as GREs, and where we apply the "national industry" competitive position group profile, include Gazprom, Petronas, Pemex, Petrobras, PDVSA, Qatar Petroleum, CNPC, and CNOOC. We typically do not apply the "national industry" category to entities operating in market-based economies with liberalized oil and gas sectors, but we may classify them as GREs on the basis that they may be subject to extraordinary government support or intervention. Statoil is such an example. National industry risk factors can be positive or negative.

We currently classify over 10% of oil and gas companies rated by Standard & Poor's globally, including all national oil companies, as GREs. We may rate a GRE above or below its stand-alone credit profile (SACP) due to potential for extraordinary government support or interference, as outlined in "Rating Government-Related Entities: Methodology And Assumptions," published March 25, 2015.

APPENDIX

Criteria Revision History

These criteria supersede "Key Credit Factors: Global Criteria For Rating The Oil And Gas Exploration And Production Industry," published Jan. 20, 2012.

RELATED CRITERIA AND RESEARCH

Related Criteria

- Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Methodology For Crude Oil And Natural Gas Price Assumptions For Corporates And Sovereigns, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Principles Of Credit Ratings, Feb. 16, 2011

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.