Criteria | Corporates | Project Finance:

# Key Credit Factors For Oil And Gas Project Financings

**September 16, 2014**

*(**Editor's Note:** This article has been superseded by "Sector-Specific Project Finance Rating Methodology," published Dec. 14, 2022, except in jurisdictions that require local registration.)*

1. This article presents S&P Global Ratings' methodology and assumptions for its key credit factors for rating oil and gas project financings and aims to help market participants better understand the key credit factors in this sector.

2. This article is related to our global project finance criteria (see "Project Finance Framework Methodology," published on Sept. 16, 2014) and to our criteria article "Principles Of Credit Ratings," published Feb. 16, 2011.

## SCOPE OF CRITERIA

3. These criteria apply to all oil and gas projects, which we broadly separate into four asset groups:

- Refining, processing, and liquefied natural gas (LNG): This group of assets involves converting or separating hydrocarbons into value-add energy products that can be sold into commodity markets.
- Pipelines: These are typically transmission systems or integrated transmission and distributions systems that transport natural gas and liquids across regions to link supply with demand, bridging price or basis differentials.
- Storage: This involves storing commodities such as liquid fuels, crude oil, or natural gas. Storage is principally used to meet load variations. For example: When gas is injected into storage during periods of low demand and withdrawn from storage during periods of peak demand. It is also used for a variety of secondary purposes such as balancing the load in pipeline systems. Such assets can capture the intrinsic value of seasonal price swings and the extrinsic value of short-term volatility. Storage facilities also ensure reliability of supply, and provide aggregation and blending services to customers.
- Vessels: This includes assets such as crude tankers, LNG tankers, or drill ships that are typically chartered to offtakers and can be geographically deployed into different markets. Tankers generally transport commodities between regions that are not well linked by pipelines. Drill ships are typically used in the exploration and production of fossil fuels.

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## SUMMARY OF THE CRITERIA

4. These criteria specify the key credit factors relevant to analyzing the construction phase stand-alone credit profile (SACP) and operations phase SACP for oil and gas assets, which we rate in accordance with "Project Finance Construction Methodology" published Nov. 15, 2013, and "Project Finance Operations Methodology" published Sept. 16, 2014.

5. As indicated in tables 1 and 2 below, factors marked with an 'X' in the KCF column provide additional guidance to the sections of the construction phase criteria and operations phase criteria. For factors not marked with an 'X' in the KCF column, the information provided in the construction phase criteria and operations phase criteria apply solely. This KCF also provides assumptions for determining our base and downside cases specific to oil and gas projects.

Table 1

### Oil And Gas Projects--Construction Phase: Areas Of Additional Guidance

| | --Where assessed-- | |
|---|---|---|
| **Factors** | **Construction phase criteria** | **Key credit factor** |
| **A. Construction phase business assessment** | | |
| 1. Technology and design risk | X | X |
| a) Technological risk | X | X |
| i. Technology track record in this application | X | X |
| ii. Technology performance match to contract requirements and expectations | X | X |
| b) Design cost variation risk | X | X |
| i. Degree of design completion and costing | X | X |
| ii. Design complexity | X | X |
| 2. Construction risk | | |
| a) Construction difficulty | X | X |
| b) Delivery method | X | |
| i. Contract risk transfer | X | |
| ii. Contractor experience | X | |
| 3. Project management | X | X |
| 4. Adjusting the preliminary construction phase business assessment | X | |
| **B. Financial risk adjustment** | | |
| 1. Funding adequacy (uses of funds) | X | X |
| 2. Construction funding (sources of funds) | X | X |
| **C. Construction phase SACP** | | |
| 1. Construction counterparty adjustment | X | |
| **D. Other factors** | X | |

Table 2

## Oil And Gas Projects--Operations Phase: Areas Of Additional Guidance

| | --Where assessed-- | |
|---|---|---|
| **Factors** | **Operations phase criteria** | **Key credit factor** |
| **A. Operations phase business assessment** | | |
| 1. Performance risk | | |
| a) Asset class operations stability | X | X |
| b) Project–specific contractual terms and risk attributes | X | |
| -Performance redundancy | X | |
| -Operating leverage | X | |
| -O&M management | X | |
| -Technological performance | X | |
| -Other operational risk factors | X | |
| c) Performance standards | X | |
| d) Resource and raw material risk | X | X |
| 2. Market risk | X | |
| a) Market exposure | X | X |
| b) Competitive position | X | X |
| 3. Country risk | X | |
| **B. Determining the operations phase SACP** | | |
| 1. Preliminary operations phase SACP (including base-case assumptions) | X | X |
| a) Debt service coverage ratios | X | |
| 2. Adjusted preliminary operations SACP | | |
| a) Downside analysis | X | X |
| b) Debt structure (and forecast average DSCRs) | X | |
| c) Liquidity | X | |
| d) Refinance risk | X | X |
| e) SACPs in 'ccc' or 'cc' categories | X | |
| 3. Final adjustments to arrive at the operations phase SACP | | |
| a) Comparable ratings analysis | X | |
| b) Counterparty ratings adjustments | X | |

6. [This paragraph has been deleted.]

7. [This paragraph has been deleted.]

## METHODOLOGY

## Part I: Construction Phase SACP

## A. Technology And Design Risk

8. The assessment of technology and design risk is a key credit factor for oil and gas facilities. Oil and gas facilities and associated assets often require long lead times to construct complex integrated systems that must withstand extreme conditions and environments (e.g., pressures, temperatures, or chemistry) while achieving high throughput or availability rates. Poor design and use of inadequate technology or inappropriate construction technique can lead to substantial construction delays and cost overruns, as well as higher-than-expected operating costs or asset replacements over the life of a project.

9. Oil and gas facilities and associated assets are generally custom-built for a project's requirements, so we evaluate technology and design choices in the context of its specific operating configuration, scale, and environment. Therefore, a key credit factor is the track record of the technology and design in similar applications, as well as the suitability of the technology and design solutions for the specific project. Technology risk entails two components: its track record in similar application and its suitability for the project's contract requirements.

### 1. Technology track record in this application

10. We expect to assess most oil and gas technologies as "commercially proven," given the use of conventional technology that has operated in many facilities for at least 20 to 30 years. Examples include refineries, gas processors, LNG export and import facilities, natural gas and crude oil pipelines, tank storage, and crude oil tankers.

11. We typically assign a lower assessment of "proven" when technology is successfully deployed in service but has not yet operated through a lifecycle. Examples include underground salt dome storage, a pet-coke gasifier utilizing new technology, or more recently developed seaborne assets like newer generation LNG vessels and drill ships. We typically revise assessments of "proven" to "commercially proven" once the technology has demonstrated operating performance consistent with design standards through its lifecycle in multiple facilities.

12. In more unique cases, an entity may adapt a "commercially proven" or "proven" technology to a new purpose, or the entity may have piloted a new technology but has not operated the technology at commercial scale. In such cases, we assign an assessment of "proven but not in this application or arrangement." For example: A bespoke technology that chemically converts materials from one state to another using enzymatic processes or heat and pressure at tolerance levels, scales, or configurations that have not been proven at commercial scale, but have been proven at pilot scale plants or in different applications. This could include bio-refineries, cellulosic ethanol plants, or gasification plants using technology other than a standard Fischer-Tropsch process. We typically revise assessments of "proven, but not in this application or arrangement" to "proven" once the facility has successfully implemented the technology at the plant's expected scale, configuration, and throughput levels for a sustained period while achieving stable operations. We form our view of the necessary operating period based on input from an independent technical expert (see Appendix A) and our own experience, but it will typically range from a few months to a year in order for the project to experience a typical range of operating conditions and activities.

13. We generally do not expect to rate projects with "new or unproven technology," but this applies to technologies with no implementation in a different application or at pilot scale. For example: A new cellulosic technology utilizing physical, chemical, or enzymatic processes that have only been

demonstrated in the laboratory or at "bench scale."

## 2. Technology performance match to contract requirements and expectations

14. We generally expect to assess most oil and gas projects as "matches all," including projects that have no contractual output requirements where our view of technology performance risk will be directly factored into our base-case assumptions for the project. In limited circumstances and as described below, we may assign an assessment of "exceeds" or "falls short of minor." In unusual situations where we believe major shortfalls in technology performance could occur that could trigger a contract termination or result in a lower debt service coverage ratio (DSCR) range (in table 15 of the operations phase criteria), we assign an assessment of "falls short of material."

15. To achieve an assessment of "exceeds" under the proposal, a project must demonstrate that it can achieve the relevant performance standards in extreme conditions and operating stresses that are possible on site. This can be achieved in a number of different ways depending on detailed project requirements. If a project has significant excess capacity (10% or more) relative to offtake contracts, we could consider there to be sufficient performance cushion to consider an "exceeds" assessment. However, if we assume cash flows from the excess capacity in our base case, we do not assess technology performance as "exceeds" so as not to double count the benefit of the cushion. For example, we could assess a pipeline or LNG project with contracts that cover 90% of capacity and no expectation of merchant cash flows on the remaining 10% as "exceeds." However, if we assume additional merchant cash flows to use full capacity, we assess technology performance as "matches all."

16. If we believe performance requirements are tight and technology could fall short of our base-case expectations, but without major contract or long-term cash flow consequences, then we assess technology performance as "falls short of minor."

17. Where technology systems are likely to affect operations across the asset, we adopt a weak-link methodology in assessing technological performance risk. For example, if liquefaction systems provide significant headroom above the contract performance thresholds, but docking or storage capacities match performance requirements, then we assign an assessment of "matches all."

## 3. Degree of design completion and costing

18. Although oil and gas projects are generally customized, integrated assets, they can often be disaggregated into discrete, compartmentalized activities with standardized equipment and well-known processes and pathways. This can help to reduce the risk of low design completion, and we incorporate it into our assessment of design completion. For example, we typically assess assets such as storage, pipelines, processors, and LNG facilities as "moderate" with detailed design work often at about 10% at financial close, as opposed to "preliminary." We generally do not expect to see projects with higher assessments, but exceptions could include tankers, drillship vessels, or refining facilities that typically have a degree of design completion commensurate with a "very advanced" or "advanced" assessment, depending on the level of price certainty at financial close.

## 4. Design complexity

19. Because oil and gas plants have been built extensively around the world, their general design for many technology types is well known. However, there are some oil and gas technology applications that have a limited track record of design performance. Nonetheless, few oil and gas

projects have the same design because each one is designed specifically to accommodate local site and permitting conditions. The risk allocation of design factors for oil and gas projects among projects and counterparties can vary considerably, and we assess design complexity after contract mitigation. The main drivers that we believe could affect an oil and gas project's design complexity are:

- Soil and ground conditions: Soil and ground with poor structural properties may require more complex foundation designs to support design loads. Construction in swamp or marsh environments is an example of greater required design complexity.
- Site surveys: Inadequate surveys create uncertainty, which may limit flexibility and cause unexpected delays and increase construction costs. Brownfield sites are at particular risk of inadequate survey data if existing buildings require demolition prior to construction and prevent access.
- Environmental conditions: Contamination, endangered species, emission limits and unexpected archaeological finds could delay construction and increase construction costs.
- Water availability: Many oil and gas power plants use water extensively in processes and rely on water for cooling equipment and supplying steam boilers. Inadequate assessment of the water supply could result in lower production capacity or the project not operating.
- Site access: Very confined sites without room for onsite material storage, poor road access, or complex decanting requirements and construction phasing will limit the contractor's ability to recover from unexpected delays. Construction adjacent to sensitive areas may also limit working times and practices.
- Utilities: Sites that have a large number of utility services such as power lines or water pipes could limit working time and increase the risk of cable strikes, which in turn could lead to delays. Brownfield sites with limited records of utilities service are particularly exposed to this risk.
- Brownfield conversions: The conversion of existing facilities to a new use can create uncertainty in terms of construction cost as the condition, performance, and integrity of the existing facilities may be uncertain. Long-term performance of the refurbished asset may also be less certain than for new build works. For example, the conversion of a brewing plant to an ethanol facility.

20. Under the criteria, we assess the following factors to determine the design complexity assessment:

- "Proven design." The design and construction sequence does not require material modification from known designs to account for site conditions, based on solid available site condition survey information, good construction site access, and little refurbishment work. An example might be a natural gas liquids plant using simple distillation columns in a region where such columns have been used extensively in the same configuration.
- "Modified proven design." An otherwise straightforward design and construction sequence that has been tailored to meet specific site conditions, such as environmental conditions, utilities, or site access. This assessment typically applies to a commonplace liquefied natural gas train design that has been significantly adjusted to accommodate site conditions.
- "Established design modified for site conditions." This assessment typically applies to oil and gas projects where the design either has not been extensively used or requires many changes to meet site conditions or permit requirements. An example is a fertilizer project that plans to use several well understood process modules but is a configuration that is relatively new for the

industry.

- "Simple first of kind." This type of oil and gas project typically employs a design that is new but simple. An example is a project planning to build simple storage tanks using a new design to improve safety performance.
- "Complex first of kind." Oil and gas projects are unlikely to receive this assessment since most offtakers and investors are not likely to be attracted to the risks involved. A project typically receives this assessment when it employs a new design with a complex configuration.

## B. Construction Risk

### 1. Construction difficulty

21. Oil and gas projects span a wide range of asset types and construction difficulty. Under the proposal, we use the following guidelines for assessing construction risk under the construction methodology criteria.

Table 3

**General Oil And Gas Asset Class Construction Difficulty**

| Construction Difficulty | Asset Type |
|---|---|
| Simple building task | Tank storage |
| Moderately complex building or simple engineering task | Standard oil and natural gas pipelines |
| Civil or heavy engineering task | Underground storage, LNG regasification, gas processing, starch ethanol, oil tankers, and complex pipelines (e.g., underwater) |
| Heavy engineering to industrial task | LNG liquefaction, simple oil refineries, and drill ships |
| Industrial task to complex building task | Complex refineries and petrochemical plants with multiple interdependencies |

22. If there is significant risk that a task can be made challenging because of the programming of construction activities, we assign the project the next weakest assessment than a similar construction task without this challenge. For example, construction is more challenging if it occurs near a congested urban area or has access constraints from geography or inclement weather conditions. For the avoidance of doubt, this is an execution risk of what may otherwise be a simple design that the brownfield adjustment in the design complexity assessment doesn't capture.

## C. Project Management

23. Most credit risks in this section affect all sectors alike and are addressed in the construction methodology criteria. However, we provide the following additional guidance for assessing the design approval subfactor for oil and gas projects.

24. Most oil and gas assets employ standard processes to handle or produce commodity products, and nearly all are built to strict technical terms established by regulatory bodies or by energy markets and to specific permit requirements and limitations. As designs must in the course of business be reviewed to assure compliance, we generally expect to assess design approval as "positive."

25. "Offtaker approval" is most relevant for assets like tankers and drill ships that offtakers with specific technical needs lease out on a charter basis. Typically all design specifications are approved prior to financing, and such assets must pass an inspection and meet performance tests prior to delivery. For such assets, we again expect to assess operator or offtaker design approval as "positive."

26. We generally do not expect to see "negative" or "very negative" design approval assessments, but they could apply in situations where a technology is entirely new, a proven design is substantially extended, operating procedures are not well established, and the operator or offtaker has either limited or no experience in the sector.

## D. Financial Risk Adjustment

### 1. Construction base case

27. The construction financial profile assesses whether the project has enough funding to cover the costs of construction and ensures the project will be ready for operations, even under a downside scenario. Most oil and gas projects use engineering and procurement contracts (EPC) to mitigate construction cost and delay risk. However, the project may retain some cost and schedule exposure in the form of force majeure risk, delays in receiving permits, change orders, or any portion of the overall construction scope retained by the owner to manage. We may make provisions for these risks within our base case under these criteria.

28. In rare circumstances where the project does not use fixed price contracts and it undertakes construction on a "cost plus" basis or using a schedule of rates, we use, for the purpose of determining our base case, information that the project and its contractors provide and supplement it with data gathered from similar projects in the sector. We also use, where relevant, input from an independent expert as required.

### 2. Construction downside case

29. A primary risk exposure for a project in this sector is likely to be the failure and subsequent timely replacement of the project's building contractor. We determine the forecast costs associated with replacing the construction contractor in accordance with our “Project Finance Construction And Operations Counterparty Methodology,” published Dec. 20, 2011. The downside case includes an allowance for the impact of a replaceable builder not already included in the counterparty replacement analysis (see paragraph 76 of the “Project Finance Construction Methodology," published Nov. 15, 2013).

30. Factors that could increase the EPC contract price, which we include in the construction downside case, may include the residual risk to a project after any contract risk allocation as a result of delays or cost increases due to variations, planning consents, construction works that are required to be completed near sensitive operational facilities, or refurbishment works. In most cases, oil and gas projects seek to transfer all such risks to the building contractor or the offtaker, or institute a sharing mechanism that caps the project exposure. To the extent that risks that remain with the creditworthy offtaker are mitigated by timely additional payments (e.g., upfront payments of capital costs for agreed variations), we do not typically make provisions for these possible costs in our construction downside analysis. If such contractual mechanisms are not present or are regarded as ineffective, then the downside analysis includes provisions for such additional costs. Due to the way these transactions are typically designed and structured together with independent oversight of construction payments, under a building contractor replacement

scenario we typically expect such additional costs to be limited. If the project does not have sufficient liquidity to meet these additional costs, then the construction phase SACP will be weak-linked to the building contractor's credit quality.

31. The construction downside scenario include our assessment of likely cost increases or revenue shortfalls in the following areas:

- Project operating costs: Project salary allowances, office availability, insurances, etc.
- Project construction costs: Typically for discrete and comparatively small and nontechnical site/infrastructure improvements or equipment sourcing outside the scope of the EPC.
- Change orders under the EPC: These may occur more frequently in situations with poor or unknown ground conditions, proximity to sensitive facilities or environmental locations, or in unconventional configurations of complex assets.
- To the extent that the project relies on revenues earned during the construction period, the construction downside will consider the impact of a reduction in revenues to the extent not mitigated by retentions or liquidated damages under the contract terms.
- Any construction delay risks the project owner accepts that are not covered by timely and on-demand liquidity or mitigating construction schedule revisions.

## Part II: Operations Phase SACP

## A. Performance Risk

### 1. Asset class operations stability (defined in "Project Finance Operations Methodology," Sept. 16, 2014.)

32. The following guidance generally applies for refining, processing, and LNG projects:

- We typically assess basic biofuel projects converting starch to ethanol as '4' because of the relatively simple processes involved, which have contributed to a track record of high availability rates.
- We typically assess simple distillation or "topping" refineries as '5' because of the operational stresses that can cause periodic outages. Refineries with more complex and interdependent assets using severe temperature, pressure, and chemical processes like crackers and cokers are at greater risk of operational outages. We normally assess them at a '6'.
- We generally assess gas processors that separate natural gas liquids (NGLs) from natural gas streams as '5' because of their relatively reliable physical and chemical processes that utilize low rather than high pressure and temperature.
- We generally assess LNG facilities that receive and regasify LNG for distribution into natural gas pipelines as '4' as a result of low process complexity. We typically assess more complex and capital intensive liquefaction facilities that convert natural gas into LNG as '5' because of incremental complexity relative to gas processors.

33. The following guidance generally applies for pipeline projects:

- Simple natural gas pipelines with basic compression requirements have some of the simplest operations of oil and gas asset types. We typically assess them as '3'. We typically assess natural gas pipelines in more extreme operating conditions, such as those with large underwater segments, and liquids pipelines subject to greater operational stress and maintenance, as '4'.

34. The following guidance generally applies for storage assets:

- We typically assess above-ground storage facilities as '3' because of their low complexity and operating risk. We generally assess below-ground storage facilities requiring high deliverability or displacement, and projects with greater operating risk from subsurface pressure and integrity, as '4'.

35. The following guidance generally applies for vessel projects:

- We typically assess crude tankers as '3', given their reliable operating track record, though we may generally assess vessels older than 10 years as '4' if additional operating risks exist resulting from age or outdated specifications.
- We typically assess LNG tankers as '4', similar to a regasification facility.
- We assess drill ships, because of their more complex operating requirements, as '5'.

36. Where certain project financings involve several assets each of which contributes to cash flow, we first determine whether the assets are part of an integrated chain or whether they operate independently of each other. If the assets operate as part of an integrated chain then performance risk is assessed based on a weak-link approach to the weakest performance assessment for the different assets. In a scenario where the assets are not integrated we assess performance risk based on the expected cash flow weightings of the different assets.

### 2. Resource and raw materials risk

37. In projects connected to highly reliable and diverse natural gas resources with low risk, we typically assess redundant infrastructure as "minimal." Examples include LNG projects in the U.S. and Qatar. This contrasts with projects reliant upon single resources without a long production track record, with limited transportation infrastructure. We may assess these projects as having "modest" or "moderate" risk. Examples could include some Canadian and Australian LNG projects. "High" risk examples likely include projects exposed to supply disruption because of social or political risks, such as projects dependent on feedstock from Egypt or Nigeria (that are outside of these countries), or through the Straits of Hormuz.

## B. Market Risk

### 1. Market exposure (including base-case guidance)

38. The following guidance generally applies for refining, processing, and LNG projects (for our base-case assumptions, please see the Adjusted Preliminary Operations Phase SACP section below).

Market exposure:

- Generally a "high" market exposure assessment for refiners and biofuel manufacturers, and a "moderate" for uncontracted processors/LNG facilities. Contracts can improve the market risk assessment, depending on the terms and portion of cash flows covered. We do not assess fully contracted tolling projects for market risk.

- Because the commodity prices are prone to large cyclical and geopolitical driven swings, and because prices for the input and output commodities are not perfectly correlated, margins can be very volatile. The strategic importance of these industries and lack of viable alternatives for the foreseeable future mean we do not anticipate conditions are likely to deteriorate enough to imperil these sectors as a whole. However, margins could contract enough to affect marginal producers, which makes competitive position key to our analysis.

Market downside case assumptions:

- Refining: Compressed crack spreads reflecting our expectation of trough conditions for the project's market, and depressed crude oil pricing reflecting marginal production costs. We generally define trough conditions as the worst market conditions we expect over a 20-year period. At the asset-specific level, we also assume compressed crude discounts. Basis differentials (the price differential of a commodity due to its location, e.g., Brent-WTI or WCS-Maya) reflect only the marginal cost of transportation, and quality differentials (i.e., the price differential of a commodity due to its quality, e.g., Light-Heavy or Sweet-Sour) drop to trough levels.
- LNG/processor: Depressed crude oil and natural gas pricing reflecting marginal production costs for LNG price indexation, with NGLs at trough pricing relative to crude to reflect marginal production costs and weak NGL correlation. For projects with volume exposure, we assume a decline from base-case volumes to reflect poor production economics.

39. For gas processing plants, depressed gas pricing assumptions are used to reflect the worst conditions anticipated over a 20 year period, unless the gas sector has either recently witnessed an important structural shift or in our view is anticipated to witness an important structural shift in the future. In such cases, we review aggregate pricing data for gas contracts as well as supply-demand dynamics prevalent in that market and use our experience of that market to derive assumptions on appropriate gas price stress conditions in consultation with the independent expert. Independent experts will typically meet the requirements under Appendix A.

40. The following guidance generally applies for pipeline projects:

Market exposure:

- Pipelines are typically supported by shipper contracts for some or all of capacity for several years, though a merchant tail lasting half of the asset life or longer is not uncommon. This raises recontracting risk and the potential for lower rates. A pipeline's competitive position is the primary factor in our consideration of recontracting risk, assuming no regulatory or geographic restrictions. Generally, we assess the market exposure of pipelines at least "moderate" for uncontracted assets, but we could adjust up or down based on the pipeline's competitive position, as described below.

Market downside case assumptions:

- We assume no revenue from uncontracted spot volumes during the shipper contract period.
- We assume expiring shipper contracts renew at below-market rates, typically 15% to 60% lower, depending on the specific pipeline's competitive position assessment and the tightest sustained basis spreads observed over the last 20 years in the relevant market. For example, with competitive position assessments of "strong" or "above average," we typically lower renewal rates by 15% or 30%, respectively, from the initial contracted rates. For "below

average" or "weak" competitive positions, we lower renewal rates by 45% or 60%, respectively.

41. The following guidance generally applies for U.S. storage assets:

Market exposure:

- Natural gas storage in the U.S. is typically assessed as '4' since the contract life is usually three years or less and rate volatility is high. Liquids storage providers in the U.S. is typically assessed as '3', and in some cases (for example, with a '1' competitive position) as low as '2'. Liquid storage contract duration can vary by geography. In the U.S., they last about five years on average and have lower volatility than natural gas storage upon recontracting. Assessments may differ in other geographies to the extent that contracting structures differ.

Market downside case assumptions:

- We assume no ancillary or hub service revenues other than cost pass-throughs for services like heating, and a base level of injections/withdrawals.
- After storage contracts expire, we assume recontracting occurs at lower prices. For assets like gas storage, we assume pricing is based only on the value generated by seasonal rather than short-term price fluctuations. For liquids, we generally lower renewal rates by 20% if the project has a "strong" competitive position, 40% if it is "above average," 60% if it is "below average," and 80% if it is "weak."

42. The following guidance generally applies for vessel projects:

Market exposure:

- Assessments range widely depending on a project's offtake agreement. Market risk is not applicable when a project has fixed-rate bareboat charters that run through maturity on fully amortizing debt, since the offtaker is responsible for all operating and market risk, although we will factor in counterparty dependency.
- We generally assess projects with operating cost exposure (e.g., those with time charters rather than bareboat charters) as low as '1' market exposure. However, in cases with unusually high costs, we generally assess projects at least '2', since operating costs, including periodic dry docking, can be significant.
- Exposure to market charter rates can significantly weaken a project's market exposure assessment because long-term supply and demand, influenced by overbuild risk and macroeconomic factors, can result in high volatility, as evidenced by crude tanker rates from 2009 to 2013. We therefore typically assess market exposure at '4' when merchant revenues are required to fully amortize debt. However, we may consider better assessments if the asset is highly specialized with limited competition, there are high barriers to entry, and there is greater certainty of long-term demand prospects.

Market downside case assumptions:

- After charters contracts expire, we assume they recontract on a long-term or spot charter, but at rates equivalent to the trough experienced globally over the last 20 years. We overlay this with our view of the most likely market downside conditions, given any structural changes that may have occurred in the sector. For example, we take the sustained market low over the last 20 years, excluding 2010-2012, which is unsustainable, in our opinion. We then adjust for structural changes that could affect the market over the project tenor, and for the specific attributes of the project assets.

43. For vessel asset classes where we have limited historical data or that have recently witnessed an important structural shift, or in our view are anticipated to witness an important structural shift in the future, we review charter contract pricing as well as merchant pricing prevalent for that asset class, taking into account our experience of the asset class and the market in which it operates to derive assumptions on appropriate stress conditions in consultation with an independent expert. Independent experts will typically meet the requirements outlined under Appendix A.

## 2. Competitive position

44. The factors we use to assess the competitive position for oil and gas projects are set out in tables 4, 6, 8, and 10. We assess the attributes as "positive," "neutral," or "negative." The characteristics for "positive" and "negative" are described below. If a factor does not meet these characteristics, then we assess it as "neutral." After each of these tables we provide guidance on how these factors determine the competitive position assessment. In limited circumstances, we may assess one factor as "highly negative." In this case, we generally lower the assessment of the competitive position by one category below that, defined by table 5 (e.g., "weak" instead of "fair"). For example, we may assess a refinery in a uniquely disadvantaged position with regard to sourcing crude as "highly negative" on feedstock costs, and we generally lower the competitive assessment by one category compared with the outcome from table 5.

45. Where certain project financings involve several assets that each contribute to cash flow, we first determine whether the assets are part of an integrated chain or whether they operate independently of each other. If the assets operate as part of an integrated chain then competitive position is assessed based on a weak-link approach to the weakest competitive position assessment for the different assets. In a scenario where the assets are not integrated, we assess competitive position based on the expected cash flow weightings of the different assets.

46. The competitive position of refiners, processors, and LNG projects generally depend, in our view, on the project's feedstock cost, production efficiency, and geographic position, as described and assessed in tables 4 and 5.

Table 4

### Competitive Position Factors--Refining, Processing, And LNG Projects

| Refining, Processing, and LNG | Positive | Negative |
|---|---|---|
| Feedstock cost | Top quartile feedstock costs. Can be due to advantageous contracts or a monopoly position with barriers to entry. For example a gas processor to a captive natural gas production market. Other examples include a refiner able to process low-quality or stranded crudes, or an integrated LNG facility with low-cost, dedicated supply. | Bottom quartile feedstock cost. Can be due to out-of-market contract terms, or a disadvantageous sourcing position. |
| Production efficiency. Generally, technology is well-established and is not a differentiating factor. | First quartile production cost. Can be due to scale or complexity that is difficult and/or expensive to duplicate, or otherwise advantaged due to unique operating cost such as beneficial O&M contracts or regulatory support such as a cost recovery mechanism. | Bottom quartile operating leverage potentially due to lack of scale or age of assets. |
| Geographic position | A unique geographic position that is difficult to replicate either due to permitting or physical constraints. For example, proximity to demand-pull markets that allows for higher netback pricing. | Poor location disconnected from markets and subject to negative basis and/or transportation costs. |

Table 5

## Competitive Position Assessment Of Refining, Processing, And LNG Projects

| Assessment | Typical characteristics |
|---|---|
| Strong | All three factors in table 4 are assessed as positive. |
| Satisfactory | One or two factors are assessed as positive under table 4. None are negative. |
| Fair | Does not meet the requirements of strong, satisfactory, or weak. |
| Weak | Two or three factors are assessed as negative under table 4. |

47. The competitive position of pipeline projects generally depends, in our view, on the project's customer mix, value proposition, scale scope and diversity, and its value added offerings, as described and assessed in tables 6 and 7.

Table 6

## Competitive Position Factors--Pipeline Projects

| Pipelines | Positive | Negative |
|---|---|---|
| Customer mix | A strong mix of highly rated shippers with underlying needs, e.g., utilities and local distribution companies (LDCs) that are primarily concerned with supply security, are able to pass costs through to their own customer rate base, and are therefore more likely to recontract. | Largely contracted with traders or other parties unlikely to recontract if basis opportunities contract. |
| Value proposition | Pipelines that link stable, reliable demand centers to supply from production basins (demand-pull pipelines), where large basis differentials are present. | Supply push pipelines in an oversupplied market with weak basis differentials. |
| Scale, scope, and diversity | The project is large scale and covers diverse markets - multiple receipt and drop-off points covering three or more markets. This diversifies geographic exposure and raises barriers to entry. | Small scale assets subject to localized market risk and competition. |
| Value add offerings | A project has connectivity to major trading hubs and storage, which improves optionality and value to customers. | Asset disadvantaged relative to competitors that provide additional services. |

Table 7

## Competitive Position Assessment Of Pipeline Projects

| Assessment | Typical characteristics |
|---|---|
| Strong | At least three factors in table 6 are assessed as positive. None are negative. |
| Satisfactory | One or two factors in table 6 are assessed as positive. None are negative. |
| Fair | Does not meet the requirements of strong, satisfactory, or weak. |
| Weak | Two or more factors are assessed as negative under table 6. |

48. The competitive position of storage projects generally depends, in our view, on the project's customer mix, value proposition, scale, scope, diversity, and demand, as described and assessed in tables 8 and 9.

Table 8

## Competitive Position Factors--Storage Projects

| Storage | Positive | Negative |
|---|---|---|
| Customer mix | A strong, highly rated mix of customers with stable underlying needs, i.e., oil and gas companies, utilities, and LDCs, rather than traders. | Largely contracted with traders or other parties unlikely to recontract if volatility opportunities contract. |
| Value proposition | There is a strong logistical value or volatility dynamic. For example, a crude storage facility that is used to aggregate and blend to various specifications, or to break down and blend large shipments into more easily marketable lots. | Low strategic value in the infrastructure network, or subject to significant competition for customers. |
| Scale, scope, and diversity | There is exposure to multiple markets with extensive connectivity to transportation networks (pipelines, shipping, rail, etc.) and/or proximity to end users. | Small-scale assets subject to localized market risk and competition. |
| Demand outlook | There is a demonstrated track record of demand. For example, a waitlist in excess of 20% of capacity or a track record of renewals. | High churn rate, material unleased space, or significant contract maturity walls within the tenor without supportive recontracting demand. |

Table 9

## Competitive Position Assessment Of Storage Projects

| Assessment | Typical characteristics |
|---|---|
| Strong | At least three factors in table 8 are assessed as positive. None are negative. |
| Satisfactory | One or two factors are assessed as positive under table 8. None are negative. |
| Fair | Does not meet the requirements of strong, satisfactory, or weak. |
| Weak | Two or more factors are assessed as negative under table 8. |

49. The competitive position of vessel projects generally depends, in our view, on the project's customer mix, operating efficiency, and demand outlook, as described and assessed in tables 10 and 11.

Table 10

## Competitive Position Factors--Vessel Projects

| Vessels | Positive | Negative |
|---|---|---|
| Customer mix | There are highly rated customers with long-term underlying needs and the project has a successful track record of being chartered, e.g., large oil and gas companies with long-term logistics or development needs. | Largely contracted with traders or other parties unlikely to recontract if economic opportunities contract. |
| Operating efficiency. Generally, technology is well-established and is not a differentiating factor unless similarly capable production shipyards are limited and unlikely to be built within the project's lifetime. | The project has top quartile operating costs and high barriers to entry. These can be a function of a unique design or specialization that is difficult and/or expensive to duplicate, or by virtue of being a newer, more modern vessel. | Assets with fourth quartile operating costs. Typically older vessels (10+ years) that also face obsolescence risk as standards evolve. |
| Demand outlook | An aging fleet with a thin order book and demand expected to outstrip delivery of new vessels. Examples of demand includes a growing reliance on LNG to relieve global natural gas imbalances. | Strong order book with delivery schedule expected to grow supply faster than demand. |

Table 11

### Competitive Position Assessment Of Vessel Projects

| Assessment | Typical characteristics |
|---|---|
| Strong | All three factors in table 10 are assessed as positive. |
| Satisfactory | One or two factors in table 10 are assessed as positive. None are negative. |
| Fair | Does not meet the requirements of strong, satisfactory, or weak. |
| Weak | Two or three factors are assessed as negative in table 10. |

## C. Preliminary Operations Phase SACP (Including Base-Case Guidance)

50. The minimum DSCRs used in Table 15 of the operations criteria are forecast using our base-case assumptions. The following guidance generally applies for refining, processing, and LNG projects:

Base-case assumptions:

- Our base case typically incorporates oil and gas futures pricing in relevant markets over the next one to two years, and mid-cycle spreads thereafter, taking into account unique circumstances and input from the market consultant. We generally assume 90% availability rates for refiners and 95% for LNG and processing facilities, and do not assume greater operational efficiency than peers, but may vary our assumptions based on asset-specific merits, such as track record or atypical process specifications, and will usually consider any availability assumptions from the independent engineer.
- Our economic starting point for refiners is a mid-cycle crack spread on our long-term crude oil price deck, mid-cycle differentials between heavy and light crude oil grades, and operating expenses reflective of peers. For natural gas processors, we assume an average NGL/crude ratio reflecting our long-term NGL crude price deck assumptions. And for LNG projects with market pricing, we use our long-term crude and Henry Hub price deck for indexation. These assumptions are a guideline and can vary, particularly for projects outside of the U.S. that face markedly different commodity pricing.

51. The following guidance generally applies for pipeline, storage, and vessel projects:

Base-case assumptions:

- Our base case assumes recontracting at market rates, although we may assume lower rates based on our view of market conditions and the relative competitiveness of a particular project. For example, for assets with particularly high rate volatility like U.S. natural gas storage or very large crude carrier assets, we generally assume rates revert to the historical average, which could be significantly lower than the existing rate at any given time. For some vessels, we may also assume a decline in rates due to a vessel's age, increased competition from new builds, or new regulations.

## D. Adjusted Preliminary Operations Phase SACP

### 1. Downside analysis

52. Our downside case combines our market downside case with our operational downside

assumptions and financial stresses linked to any refinancing, where relevant. Our market downside case assumptions are described in the Market Exposure section above. We apply the stresses for the remaining life of the project to determine its resilience.

53. We generally assume operating and capital expenditure increases by 10% from our base case for the first two-thirds of a project's asset life; and 20% thereafter to reflect the increasing costs of maintaining an aging asset (although this can be mitigated by O&M contracts). These increases reflect higher material prices and assumed lower efficiency rates.

54. For refining, processing, and LNG projects, we typically assume at least a 5% reduction in availability rates from our base case (generally 85% for refiners and 90% for LNG and processors).

## 2. Refinance risk

55. For purposes of calculating post-refinancing DSCRs over the remaining life of the project, we assume the following asset lives, subject to discussions with an independent engineer. Note that these life spans may be adjusted depending on the project's operating phase business assessment as outlined under our “Project Finance Operations Methodology,” published Sept. 16, 2014 (see table 12).

Table 12

### Typical Asset Life For Oil And Gas Projects

| Asset type | Typical asset life |
|---|---|
| Refinery | 22 years, although significant major maintenance can extend asset life. |
| Ethanol plant | 30 years |
| Gas processor | 30 years |
| LNG facility | 30 years. Equipment useful life generally ranges from 10 to 50 years. |
| Pipelines | 30 years |
| Storage | 30 years |
| Crude tankers | 20 years |
| LNG tankers | 25 years |
| Drill ships | 30 years |

## APPENDIX A

56. Independent experts should be experienced (see "Credit FAQ: Provision Of Information For Assessing Project Finance Transactions," Dec. 16, 2013). We focus on the author's relationship with the project sponsors, as well as the experience and expertise of the author. Key attributes would include:

- Independence: The expert is typically engaged for the benefit of the debt providers, rather than the project sponsors, and in any case his or her compensation should not be directly linked to the successful financing of the project.
- Experience: The expert should have appropriate prior experience in the sector covered by the project as well as the country where the project is located. For example, being a mining expert covering Scandinavia may not be sufficient to assess a mining project in Africa given different operational, weather, and market conditions.

- Track record: An expert's track record may also support his or her experience in a particular area.

57. Typically, we would expect independent expert reports to include (see "Credit FAQ: Provision Of Information For Assessing Project Finance Transactions," Dec. 16, 2013):

- Factual presentation of the project: This summarizes what the expert has specifically reviewed and analyzed and ensures that all aspects of the project have been considered.
- Risk assessment of the project: This covers all the risks pertinent to the expert's area of focus that could result in cash flow disruptions. For example, if the expert is assessing the construction of an oil and gas plant, this would usually include the risk that the plant may not be built on budget or on time and may not ultimately perform as designed. Risks would then typically be grouped according to their likelihood of occurrence (low to high probability) and impact (low to high impact) to ensure that the key risks (high probability and high impact) are thoroughly reviewed.
- Other sections: This includes views and analyses of the project parties' ability and experience in similar projects, as well as views and analysis of assumptions of the sponsors in certain key areas. For example, for public-private partnership projects, the expert would typically review the payment mechanism and determine the level of financial abatements that could occur. For oil and gas projects, the expert would typically opine on assumed availability levels over the life of the project, including any potential deterioration as the plant ages.

## REVISIONS AND UPDATES

This article was originally published on Sept. 16, 2014. These criteria became effective on Sept. 16, 2014.

This article follows our Request for Comment, where S&P Global Ratings solicited public feedback to the proposed criteria "Request for Comment: Key Credit Factors For Oil And Gas Project Financings," published on Dec. 16, 2013. The comments we received contributed to changes that we included in these criteria and are outlined in the article "RFC Process Summary: Standard & Poor’s Summarizes Request For Comment Process For New Project Finance Methodology," published Sept. 16, 2014.

Changes introduced after original publication:

- Following our periodic review completed on Sept. 14, 2016, we updated contact information and criteria references and deleted outdated sections that appeared in paragraphs 6 and 7, which were related to the initial publication of our criteria and no longer relevant.
- Following our periodic review completed on Sept. 11, 2017, we updated the contact information.
- Following our periodic review completed on Sept. 10, 2018, we updated the contact information.
- On Oct. 30, 2019, we republished this criteria article to make nonmaterial changes to the contact information.

## RELATED CRITERIA AND RESEARCH

### Related Criteria

- Project Finance Framework Methodology, Sept. 16, 2014
- Project Finance Transaction Structure Methodology, Sept. 16, 2014
- Project Finance Operations Methodology, Sept. 16, 2014
- Project Finance: Project Finance Construction Methodology, Nov. 15, 2013
- Project Finance Construction And Operations Counterparty Methodology, Dec. 20, 2011
- Principles Of Credit Ratings, Feb. 16, 2011

### Related Research

- FAQ: An Overview of Standard & Poor's Criteria For Assessing Project Finance Operating Risk, Sept. 16, 2014
- Market Assumptions Used For Oil And Gas Project Financings, Sept. 16, 2014
- FAQ: An Overview of Standard & Poor's Criteria For Assessing Project Finance Construction Risk, Dec. 16, 2013
- Credit FAQ: Provision Of Information For Assessing Project Finance Transactions, Dec. 16, 2013

These criteria represent the specific application of fundamental principles that define credit risk and project issue credit rating 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 project issue credit 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.

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