NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
RICHARD B. TALLEY, JR.

PRESIDENT & COO
ERIC J. STEVENS

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN

March 23, 2025

Navitas Petroleum Limited Partnership
12 Abba Eban Boulevard
Building D, 9th Floor
Herzliya 4672530
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the unrisked contingent resources and cash flow, as of December 31, 2024, to the Navitas Petroleum Limited Partnership (Navitas Petroleum) interest in certain oil and gas properties located in Sea Lion Field, offshore Falkland Islands. Also as requested, we have estimated the unrisked prospective resources, as of December 31, 2024, to the Navitas Petroleum working interest in certain prospects located in Sea Lion Field. It is our understanding that Navitas Petroleum owns an indirect working interest in these properties. We completed our evaluation on or about the date of this letter. For the contingent resources, this report has been prepared using price and cost parameters specified by Navitas Petroleum, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$). For reference, the December 31, 2024, exchange rate was 3.64 New Israeli Shekels per United States dollar.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. This report has been prepared for Navitas Petroleum's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose. It is our understanding that this report will also be used by auditors of Navitas Petroleum as part of their audit procedures.

## CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon (1) finalization, approval, and financing of a commercial development plan; (2) procurement of regulatory approvals; and (3) commitment to develop the resources. The project maturity subclasses for these contingent resources are development pending, development on hold, and development not viable. The development pending contingent resources associated with certain wells in the later development phases are further contingent upon optimization of the development plan based on the results of the initial phases. The development on hold contingent resources are further contingent upon establishment and approval of a development plan. The development not viable contingent resources are further contingent on establishment of a gas market. A portion of the costs required to resolve these contingencies has been included in this report; estimates of cash flow are based on the assumption that all contingencies will be successfully addressed. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

Development pending contingent resources are those resources from a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. Development on hold contingent resources are those resources from a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. Development not viable contingent resources are those resources from a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited commercial potential.

The development pending contingent resources are associated with the proposed near-term development plans for Sea Lion Field and are expected to be produced prior to the economic limit of the field; these near-term plans comprise the Northern Development Area (NDA) Phases 1, 2, and 3 and the Central Development Area (CDA) Phases 1 and 2. It is our understanding that the NDA Phases 1 and 2 will make use of a known floating production storage and offloading vessel (FPSO) that is expected to be secured as part of the initial final investment decision (FID) for Sea Lion Field. For the purposes of this report, we have assumed that the NDA Phase 3 and CDA Phases 1 and 2 will require a larger replacement FPSO to be identified and secured. The development pending contingent gas resources represent estimated fuel gas volumes expected to be consumed in field operations; no contingent cash flow has been attributed to the fuel gas contingent resources. Because there is currently no market for gas, all other contingent gas resources are subclassified as development not viable. The development not viable contingent resources are primarily volumes in gas accumulations and associated gas in oil reservoirs. The development on hold contingent resources are those volumes that are estimated to be beyond the economic limit of the field or those volumes associated with oil reservoirs that are not part of Navitas Petroleum's proposed near-term development plans for Sea Lion Field.

We estimate the unrisked gross (100 percent) contingent resources by project maturity subclass for Sea Lion Field, as of December 31, 2024, to be:

| | Unrisked Gross (100%) Contingent Resources | | | | | |
|---|---|---|---|---|---|---|
| | Oil (MBBL) | | | Gas (MMCF) | | |
| Subclass | Low Estimate (1C) | Best Estimate (2C) | High Estimate (3C) | Low Estimate (1C) | Best Estimate (2C) | High Estimate (3C) |
| Development Pending | 473,386.6 | 729,486.8 | 943,761.3 | 217,259.3 | 301,673.8 | 328,459.1 |
| Development On Hold | 74,993.9 | 177,910.4 | 295,358.1 | 0.0 | 0.0 | 0.0 |
| Development Not Viable | 5,713.6 | 9,602.7 | 14,529.9 | 1,482,880.5 | 1,754,779.8 | 2,236,405.4 |
| Total | 554,094.1 | 916,999.9 | 1,253,649.3 | 1,700,139.8 | 2,056,453.6 | 2,564,864.5 |

We estimate the Navitas Petroleum unrisked working interest contingent resources by project maturity subclass for Sea Lion Field, as of December 31, 2024, to be:

| | Unrisked Working Interest Contingent Resources | | | | | |
|---|---|---|---|---|---|---|
| | Oil (MBBL) | | | Gas (MMCF) | | |
| Subclass | Low Estimate (1C) | Best Estimate (2C) | High Estimate (3C) | Low Estimate (1C) | Best Estimate (2C) | High Estimate (3C) |
| Development Pending | 307,701.3 | 474,166.4 | 613,444.9 | 141,218.5 | 196,088.0 | 213,498.4 |
| Development On Hold | 48,746.0 | 115,641.8 | 191,982.7 | 0.0 | 0.0 | 0.0 |
| Development Not Viable | 3,713.9 | 6,241.7 | 9,444.4 | 963,872.3 | 1,140,606.9 | 1,453,663.5 |
| Total | 360,161.2 | 596,049.9 | 814,872.0 | 1,105,090.8 | 1,336,694.8 | 1,667,161.9 |

*Totals may not add because of rounding.*

We estimate the unrisked gross (100 percent) development pending contingent resources by development phase for Sea Lion Field, as of December 31, 2024, to be:

| | Unrisked Gross (100%) Development Pending Contingent Resources | | | | | |
|---|---|---|---|---|---|---|
| | Oil (MBBL) | | | Gas (MMCF) | | |
| Development Phase | Low Estimate (1C) | Best Estimate (2C) | High Estimate (3C) | Low Estimate (1C) | Best Estimate (2C) | High Estimate (3C) |
| NDA Phases 1 and 2 | 233,453.9 | 319,603.5 | 408,164.0 | 77,299.4 | 115,989.7 | 119,858.8 |
| CDA Phase 1 | 138,587.5 | 212,295.9 | 264,987.1 | 76,973.6 | 120,100.4 | 129,218.2 |
| CDA Phase 2 | 34,955.8 | 102,352.5 | 141,319.1 | 44,317.7 | 61,525.2 | 63,960.3 |
| NDA Phase 3 | 66,389.5 | 95,234.9 | 129,291.1 | 18,668.6 | 4,058.4 | 15,421.9 |
| Total | 473,386.6 | 729,486.8 | 943,761.3 | 217,259.3 | 301,673.8 | 328,459.1 |

*Totals may not add because of rounding.*

As requested, economic analysis was only performed on the unrisked development pending contingent resources. We estimate the net contingent cash flow attributable to the unrisked development pending contingent resources before corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the Navitas Petroleum interest in Sea Lion Field, as of December 31, 2024, to be:

| | Net Contingent Cash Flow Attributable to the Unrisked Development Pending Contingent Resources Before Corporate Income Taxes (M$) | | | | |
|---|---|---|---|---|---|
| Category | Discounted at 0% | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
| Low Estimate (1C) | 9,656,914.8 | 5,214,239.7 | 2,871,406.3 | 1,588,371.9 | 856,796.3 |
| Best Estimate (2C) | 18,345,533.9 | 9,137,529.9 | 4,874,460.9 | 2,715,585.8 | 1,539,151.9 |
| High Estimate (3C) | 26,423,580.1 | 12,461,072.2 | 6,459,963.3 | 3,563,547.5 | 2,033,452.1 |

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The contingent resources shown in this report have been estimated using a combination of deterministic and probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources and cash flow included herein have not been adjusted for development risk.

Working interest contingent revenue shown in this report is Navitas Petroleum's share of the gross (100 percent) revenue from the properties prior to any deductions. Net contingent cash flow is after deductions for Navitas Petroleum's share of royalties, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The net contingent cash flow has been discounted at annual rates of 0, 5, 10, 15, and 20 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties. Tables I through III present cash flow, costs, and taxes by resources category for the unrisked development pending contingent resources.

As requested, this report has been prepared using oil price parameters specified by Navitas Petroleum. Oil prices are based on Brent Crude prices and are adjusted for Navitas Petroleum's estimates of quality, transportation fees, and market differentials. Oil prices, before adjustments, are shown in the following table:

| Period Ending | Oil Price ($/Barrel) |
|---|---|
| 12-31-2025 | 72.72 |
| 12-31-2026 | 71.49 |
| Thereafter | 75.19 |

Operating costs used in this report are based on operating expense estimates of Navitas Petroleum, the operator of the properties. Based on our knowledge of similar offshore operations, we regard these estimated operating costs to be reasonable. It is our understanding that these costs include only direct project-level costs, oil tariffs, and the costs associated with leasing the FPSOs. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and do not include any headquarters general and administrative overhead expenses of Navitas Petroleum. As requested, operating costs are not escalated for inflation.

Capital costs used in this report were provided by Navitas Petroleum and are based on internal planning budgets. Capital costs are included as required for project management activities prior to FID, facilities, new development wells, and production and injection equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Navitas Petroleum's estimates of the costs to abandon the wells, FPSOs, and production facilities; these estimates do not include any salvage value for the lease and well equipment. As requested, capital costs and abandonment costs are not escalated for inflation.

## PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable. There is no certainty that any portion of the prospective resources will be discovered. If they are discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross (100 percent) prospective resources for these prospects, as of December 31, 2024, to be:

| | Unrisked Gross (100%) Prospective Resources | | | | | |
|---|---|---|---|---|---|---|
| | Oil (MMBBL) | | | Gas (BCF) | | |
| Primary Fluid Type/ Prospect | Low Estimate (1U) | Best Estimate (2U) | High Estimate (3U) | Low Estimate (1U) | Best Estimate (2U) | High Estimate (3U) |
| Oil | | | | | | |
| Beverley | 11.6 | 41.6 | 81.9 | 4.6 | 16.4 | 33.4 |
| Beverley East | 1.4 | 3.4 | 7.1 | 0.6 | 1.3 | 2.9 |
| Chatham East | 9.2 | 23.4 | 58.4 | 3.6 | 9.3 | 23.7 |
| Chatham West | 10.9 | 26.2 | 58.9 | 4.3 | 10.3 | 23.9 |
| Gwendoline | 27.2 | 53.2 | 98.2 | 10.5 | 21.1 | 39.9 |
| Hector 1 | 9.3 | 15.5 | 22.7 | 3.6 | 6.1 | 9.4 |
| Hector 2 | 19.0 | 33.5 | 51.4 | 7.4 | 13.1 | 21.0 |
| Hector 3 East | 15.3 | 28.8 | 46.3 | 5.9 | 11.4 | 19.0 |
| Ida | 6.8 | 14.8 | 27.8 | 2.6 | 5.9 | 11.3 |
| Jackie East | 9.1 | 23.9 | 62.3 | 3.5 | 9.5 | 25.0 |
| Jayne 0 | 8.3 | 18.3 | 38.2 | 3.2 | 7.3 | 15.5 |
| Jayne 1 | 3.7 | 8.3 | 16.6 | 1.5 | 3.3 | 6.7 |
| Jayne 4 | 7.2 | 15.1 | 28.3 | 2.8 | 6.0 | 11.5 |
| Jayne West | 1.7 | 4.5 | 11.8 | 0.6 | 1.8 | 4.7 |
| Malena | 39.0 | 66.5 | 103.0 | 14.9 | 26.3 | 42.4 |
| Ninky 1 East | 2.0 | 4.6 | 9.4 | 0.8 | 1.8 | 3.8 |
| Noggin | 9.8 | 22.1 | 43.0 | 3.8 | 8.7 | 17.4 |
| Orinoco | 6.9 | 17.1 | 42.0 | 2.7 | 6.8 | 16.9 |
| S2 | 13.8 | 34.9 | 84.9 | 5.4 | 13.7 | 34.8 |
| Zebedee East | 23.5 | 43.0 | 70.5 | 9.0 | 16.9 | 28.8 |
| Gas | | | | | | |
| Liz G4 Clastic A | 6.3 | 11.2 | 18.8 | 116.8 | 178.3 | 260.6 |
| Liz G4 Clastic B | 7.8 | 25.1 | 54.2 | 131.5 | 409.1 | 784.1 |
| Liz G4 Clastic C | 17.5 | 33.6 | 59.4 | 316.9 | 539.1 | 834.8 |
| Liz H4 Volcanics A | 0.2 | 0.5 | 0.9 | 154.7 | 341.1 | 609.1 |

We estimate the Navitas Petroleum unrisked working interest prospective resources for these prospects, as of December 31, 2024, to be:

| | Unrisked Working Interest Prospective Resources | | | | | |
|---|---|---|---|---|---|---|
| | Oil (MMBBL) | | | Gas (BCF) | | |
| Primary Fluid Type/ Prospect | Low Estimate (1U) | Best Estimate (2U) | High Estimate (3U) | Low Estimate (1U) | Best Estimate (2U) | High Estimate (3U) |
| Oil | | | | | | |
| Beverley | 7.5 | 27.1 | 53.2 | 3.0 | 10.7 | 21.7 |
| Beverley East | 0.9 | 2.2 | 4.6 | 0.4 | 0.9 | 1.9 |
| Chatham East | 6.0 | 15.2 | 37.9 | 2.3 | 6.0 | 15.4 |
| Chatham West | 7.1 | 17.0 | 38.3 | 2.8 | 6.7 | 15.5 |
| Gwendoline | 17.7 | 34.6 | 63.9 | 6.8 | 13.7 | 26.0 |
| Hector 1 | 6.0 | 10.1 | 14.7 | 2.3 | 4.0 | 6.1 |
| Hector 2 | 12.3 | 21.8 | 33.4 | 4.8 | 8.5 | 13.7 |

| Primary Fluid Type/ Prospect | Unrisked Working Interest Prospective Resources | | | | | |
|---|---|---|---|---|---|---|
| | Oil (MMBBL) | | | Gas (BCF) | | |
| | Low Estimate (1U) | Best Estimate (2U) | High Estimate (3U) | Low Estimate (1U) | Best Estimate (2U) | High Estimate (3U) |
| Oil | | | | | | |
| Hector 3 East | 10.0 | 18.7 | 30.1 | 3.9 | 7.4 | 12.4 |
| Ida | 4.4 | 9.6 | 18.1 | 1.7 | 3.8 | 7.4 |
| Jackie East | 5.9 | 15.6 | 40.5 | 2.3 | 6.2 | 16.2 |
| Jayne 0 | 5.4 | 11.9 | 24.8 | 2.1 | 4.7 | 10.1 |
| Jayne 1 | 2.4 | 5.4 | 10.8 | 0.9 | 2.1 | 4.3 |
| Jayne 4 | 4.7 | 9.8 | 18.4 | 1.8 | 3.9 | 7.5 |
| Jayne West | 1.1 | 2.9 | 7.7 | 0.4 | 1.2 | 3.1 |
| Malena | 25.3 | 43.3 | 66.9 | 9.7 | 17.1 | 27.6 |
| Ninky 1 East | 1.3 | 3.0 | 6.1 | 0.5 | 1.2 | 2.5 |
| Noggin | 6.4 | 14.4 | 27.9 | 2.4 | 5.7 | 11.3 |
| Orinoco | 4.5 | 11.1 | 27.3 | 1.7 | 4.4 | 11.0 |
| S2 | 9.0 | 22.7 | 55.2 | 3.5 | 8.9 | 22.6 |
| Zebedee East | 15.2 | 27.9 | 45.8 | 5.9 | 11.0 | 18.7 |
| Gas | | | | | | |
| Liz G4 Clastic A | 4.1 | 7.3 | 12.2 | 75.9 | 115.9 | 169.4 |
| Liz G4 Clastic B | 5.1 | 16.3 | 35.2 | 85.5 | 265.9 | 509.6 |
| Liz G4 Clastic C | 11.4 | 21.9 | 38.6 | 206.0 | 350.4 | 542.6 |
| Liz H4 Volcanics A | 0.1 | 0.3 | 0.6 | 100.6 | 221.7 | 395.9 |

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in millions of barrels (MMBBL). Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. Our estimates are based on the assumption that, if discoveries are made, the prospects would be entirely oil-filled or gas-filled, in accordance with the primary fluid type in the table above; we have not included any sensitivity estimates that are based on the assumption that the oil prospects would be partially filled with a gas cap or that the gas prospects would be partially filled with an oil rim.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. The primary geologic risk elements for the oil prospects are trap integrity, reservoir quality, and hydrocarbon timing/migration. The primary geologic risk elements for the gas prospects are trap integrity and reservoir quality. The geologic risk elements and overall probability of geologic success for these prospects are shown in the following table:

| Primary Fluid Type/ Prospect | Geologic Risk Element (%) Trap Integrity | Reservoir Quality | Source Evaluation | Timing/ Migration | Probability of Geologic Success (%) |
|---|---|---|---|---|---|
| Oil | | | | | |
| Beverley | 100 | 100 | 100 | 80 | 80 |
| Beverley East | 45 | 60 | 100 | 95 | 26 |
| Chatham East | 30 | 70 | 100 | 100 | 21 |
| Chatham West | 35 | 70 | 100 | 100 | 25 |
| Gwendoline | 80 | 85 | 100 | 100 | 68 |
| Hector 1 | 45 | 95 | 100 | 80 | 34 |
| Hector 2 | 45 | 95 | 100 | 80 | 34 |
| Hector 3 East | 45 | 95 | 100 | 80 | 34 |
| Ida | 60 | 40 | 100 | 90 | 22 |
| Jackie East | 40 | 40 | 100 | 90 | 14 |
| Jayne 0 | 55 | 40 | 100 | 90 | 20 |
| Jayne 1 | 55 | 40 | 100 | 90 | 20 |
| Jayne 4 | 65 | 40 | 100 | 100 | 26 |
| Jayne West | 55 | 40 | 100 | 95 | 21 |
| Malena | 75 | 85 | 100 | 80 | 51 |
| Ninky 1 East | 45 | 60 | 100 | 90 | 24 |
| Noggin | 70 | 40 | 100 | 90 | 25 |
| Orinoco | 60 | 40 | 100 | 90 | 22 |
| S2 | 50 | 80 | 100 | 70 | 28 |
| Zebedee East | 90 | 90 | 100 | 80 | 65 |
| Gas | | | | | |
| Liz G4 Clastic A | 80 | 70 | 100 | 100 | 56 |
| Liz G4 Clastic B | 80 | 70 | 100 | 100 | 56 |
| Liz G4 Clastic C | 70 | 65 | 100 | 95 | 43 |
| Liz H4 Volcanics A | 70 | 60 | 95 | 95 | 38 |

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

Sea Lion Field is covered by a 3-D seismic data set. The 3-D seismic data were acquired in 2007 by CGG SA and in 2011 by Polarcus Seismic Limited. In 2012 those data sets, together with additional vintage surveys acquired in the North Falkland Basin, were merged prestack into a contiguous, high-quality 4,500-square kilometer 3-D data set. All seismic interpretation for the oil prospects was performed on the Elastic Extended Impedance -70 (EEI-70) derivative data set. The Liz gas prospects are not within the EEI-70 seismic volume and were interpreted on a time 3-D seismic data volume.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

## GENERAL INFORMATION

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which unrisked development pending contingent resources have been estimated. For the purposes of this report, we did not perform any field inspection of the properties. We have not investigated possible environmental liability related to the properties; however, we are not currently aware of any possible environmental liability that would have any material effect on the contingent and prospective resources quantities estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

The contingent and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Navitas Petroleum, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report. It should be noted that the actual production profile for each category may be lower or higher than the production profile used to calculate the estimates of cash flow used in this report, and no sensitivity analysis was performed with respect to the production profile of the wells.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, and property ownership interests. We were provided with all the necessary data to prepare the resources estimates for these properties, and we were not limited from access to any material we believe may be relevant. The contingent and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analysis of prospective resources are summarized in Tables IV and V. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 15, 2024, by Mr. Amit Kornhauser, Chief Executive Officer of Navitas Petroleum, to perform this assessment. The data used in our estimates were obtained from Navitas Petroleum, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Navitas Petroleum.

NETHERLAND, SEWELL & ASSOCIATES, INC.



## QUALIFICATIONS

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

This assessment has been led by Mr. John R. Cliver and Mr. Edward C. Roy III. Mr. Cliver is a Senior Vice President and Mr. Roy is a Vice President in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Cliver is a Licensed Professional Engineer (Texas Registration No. 107216). He has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Mr. Roy is a Licensed Professional Geoscientist (Texas Registration No. 2364). He has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**
Texas Registered Engineering Firm F-2699

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By:
John R. Cliver, P.E. 107216
Senior Vice President

STATE OF TEXAS
J. R. CLIVER
107216
LICENSED
PROFESSIONAL ENGINEER

Date Signed: March 23, 2025

JRC:LFG

By: Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

STATE OF TEXAS
E. C. ROY, III
GEOLOGY
2364
LICENSED
PROFESSIONAL GEOSCIENTIST

Date Signed: March 23, 2025

# PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

### Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

## 1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

### 1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Resources.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, $P_c$, which is the chance that a project will be committed for development and reach commercial producing status.

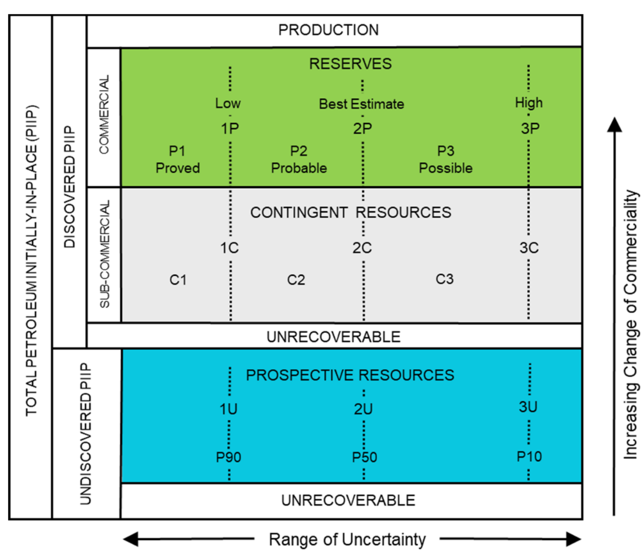


Figure 1.1—Resources classification framework

# PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

## PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

### 1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

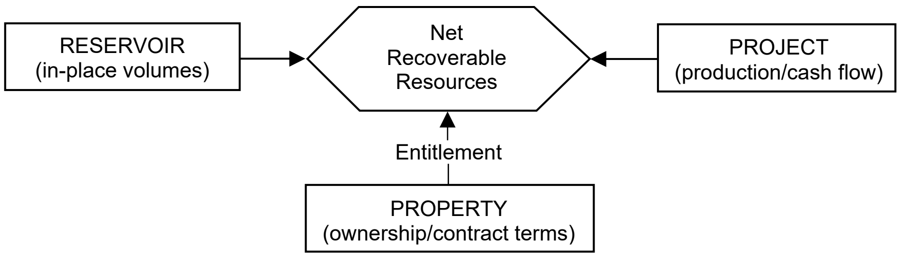


Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

## 2.0 Classification and Categorization Guidelines

### 2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

#### 2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

#### 2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, $CO2$) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

## 2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3) reserves; 1C, 2C, 3C, C1, C2, and C3 contingent resources; or 1U, 2U, and 3U prospective resources categories. The chance of commerciality is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

### 2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

### 2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

## PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.
2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

### Table 1—Recoverable Resources Classes and Sub-Classes

| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Reserves** | Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. | Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status.<br><br>To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame.<br><br>A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.<br><br>To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests. |
| **On Production** | The development project is currently producing or capable of producing and selling petroleum to market. | The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves.<br><br>The project decision gate is the decision to initiate or continue economic production from the project. |
| **Approved for Development** | All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way. | At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget.<br><br>The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells. |

## PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Justified for Development** | Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained. | To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class).<br><br>The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time. |
| **Contingent Resources** | Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies. | Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist.<br><br>Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status. |
| **Development Pending** | A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. | The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status.<br><br>The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production. |
| **Development on Hold** | A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. | The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.<br><br>The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies. |
| **Development Unclarified** | A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. | The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.<br><br>This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production. |

**PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS**
Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Development Not Viable** | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited commercial potential. | The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.<br><br>The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future. |
| **Prospective Resources** | Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. | Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration. |
| **Prospect** | A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. | Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program. |
| **Lead** | A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios. |
| **Play** | A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios. |

## Table 2—Reserves Status Definitions and Guidelines

| Status | Definition | Guidelines |
|---|---|---|
| **Developed Reserves** | Expected quantities to be recovered from existing wells and facilities. | Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing. |
| **Developed Producing Reserves** | Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. | Improved recovery Reserves are considered producing only after the improved recovery project is in operation. |
| **Developed Non-Producing Reserves** | Shut-in and behind-pipe Reserves. | Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.<br><br>In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. |

**PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS**
Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

| Status | Definition | Guidelines |
|---|---|---|
| **Undeveloped Reserves** | Quantities expected to be recovered through future significant investments. | Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects. |

## Table 3—Reserves Category Definitions and Guidelines

| Category | Definition | Guidelines |
|---|---|---|
| **Proved Reserves** | Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. | If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.<br><br>The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.<br><br>In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves.<br><br>Reserves in undeveloped locations may be classified as Proved provided that:<br>A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive.<br>B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.<br><br>For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program. |
| **Probable Reserves** | Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. | It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.<br><br>Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria.<br><br>Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved. |

# PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

| Category | Definition | Guidelines |
|---|---|---|
| **Possible Reserves** | Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. | The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.<br><br>Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project.<br><br>Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable. |
| **Probable and Possible Reserves** | See above for separate criteria for Probable Reserves and Possible Reserves. | The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.<br><br>In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.<br><br>Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.<br><br>In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations. |

CASH FLOW, COSTS, AND TAXES
LOW ESTIMATE (1C) UNRISKED DEVELOPMENT PENDING CONTINGENT RESOURCES
NORTHERN DEVELOPMENT AREA PHASES 1, 2, AND 3 AND CENTRAL DEVELOPMENT AREA PHASES 1 AND 2
NAVITAS PETROLEUM LIMITED PARTNERSHIP INTEREST
SEA LION FIELD, OFFSHORE FALKLAND ISLANDS
AS OF DECEMBER 31, 2024

| Period Ending | Working Interest Revenue (M$) | Royalties State (M$) | Royalties GP (M$) | Royalties Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|
| 12-31-2025 | 0.0 | 0.0 | 0.0 | 0.0 | 129,404.9 | 0.0 | 0.0 | -129,404.9 |
| 12-31-2026 | 0.0 | 0.0 | 0.0 | 0.0 | 305,831.7 | 0.0 | 0.0 | -305,831.7 |
| 12-31-2027 | 26,402.7 | 2,376.2 | 1,584.2 | 3,960.4 | 524,114.8 | 0.0 | 8,776.9 | -510,449.4 |
| 12-31-2028 | 771,995.0 | 69,479.5 | 46,319.7 | 115,799.2 | 333,119.2 | 0.0 | 119,880.1 | 203,196.4 |
| 12-31-2029 | 772,830.9 | 69,554.8 | 46,369.9 | 115,924.6 | 460,759.5 | 0.0 | 120,292.2 | 75,854.6 |
| 12-31-2030 | 647,636.4 | 58,287.3 | 38,858.2 | 97,145.5 | 482,237.9 | 0.0 | 124,767.0 | -56,513.9 |
| 12-31-2031 | 1,659,191.0 | 149,327.2 | 99,551.5 | 248,878.6 | 425,209.4 | 0.0 | 230,672.3 | 754,430.6 |
| 12-31-2032 | 1,868,163.4 | 168,134.7 | 112,089.8 | 280,224.5 | 338,888.2 | 0.0 | 235,376.0 | 1,013,674.7 |
| 12-31-2033 | 1,811,813.8 | 163,063.2 | 108,708.8 | 271,772.1 | 449,101.4 | 0.0 | 237,913.4 | 853,026.9 |
| 12-31-2034 | 1,656,159.2 | 149,054.3 | 99,369.6 | 248,423.9 | 305,928.9 | 0.0 | 238,451.5 | 863,354.9 |
| 12-31-2035 | 1,449,237.4 | 130,431.4 | 86,954.2 | 217,385.6 | 135,702.6 | 0.0 | 238,978.2 | 857,171.0 |
| 12-31-2036 | 1,459,987.0 | 131,398.8 | 87,599.2 | 218,998.0 | 0.0 | 0.0 | 241,824.4 | 999,164.6 |
| 12-31-2037 | 1,392,627.4 | 125,336.5 | 83,557.6 | 208,894.1 | 0.0 | 0.0 | 241,312.5 | 942,420.8 |
| 12-31-2038 | 1,272,989.9 | 114,569.1 | 76,379.4 | 190,948.5 | 0.0 | 0.0 | 240,447.1 | 841,594.3 |
| 12-31-2039 | 1,134,536.9 | 102,108.3 | 68,072.2 | 170,180.5 | 0.0 | 0.0 | 238,255.1 | 726,101.2 |
| Subtotal | 15,923,571.0 | 1,433,121.4 | 955,414.3 | 2,388,535.7 | 3,890,298.5 | 0.0 | 2,516,946.8 | 7,127,790.1 |
| Remaining | 6,443,234.1 | 579,891.1 | 386,594.0 | 966,485.1 | 0.0 | 709,150.0 | 2,238,474.2 | 2,529,124.7 |
| Total | 22,366,805.1 | 2,013,012.5 | 1,342,008.3 | 3,355,020.8 | 3,890,298.5 | 709,150.0 | 4,755,421.0 | 9,656,914.8 |

| Period Ending | Production Taxes[2] (M$) | Ad Valorem Taxes[2] (M$) | Future Net Cash Flow Before Corporate Income Taxes Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|
| 12-31-2025 | 0.0 | 0.0 | -129,404.9 | -125,286.4 | -121,493.5 | -117,987.0 | -114,734.1 |
| 12-31-2026 | 0.0 | 0.0 | -305,831.7 | -284,054.8 | -264,791.3 | -247,652.7 | -232,324.0 |
| 12-31-2027 | 0.0 | 0.0 | -510,449.4 | -452,228.3 | -402,980.3 | -360,996.9 | -324,951.5 |
| 12-31-2028 | 0.0 | 0.0 | 203,196.4 | 170,980.4 | 145,054.7 | 123,980.7 | 106,692.7 |
| 12-31-2029 | 0.0 | 0.0 | 75,854.6 | 61,704.2 | 50,676.0 | 41,983.4 | 35,060.6 |
| 12-31-2030 | 0.0 | 0.0 | -56,513.9 | -43,284.6 | -33,575.5 | -26,346.6 | -20,893.5 |
| 12-31-2031 | 0.0 | 0.0 | 754,430.6 | 548,334.4 | 404,570.9 | 302,610.2 | 229,194.2 |
| 12-31-2032 | 0.0 | 0.0 | 1,013,674.7 | 702,938.5 | 495,918.9 | 355,394.4 | 258,365.4 |
| 12-31-2033 | 0.0 | 0.0 | 853,026.9 | 562,947.6 | 378,837.8 | 259,514.2 | 180,688.6 |
| 12-31-2034 | 0.0 | 0.0 | 863,354.9 | 543,597.1 | 349,779.8 | 229,561.9 | 153,411.5 |
| 12-31-2035 | 0.0 | 0.0 | 857,171.0 | 513,088.5 | 314,608.5 | 197,182.6 | 126,087.9 |
| 12-31-2036 | 0.0 | 0.0 | 999,164.6 | 570,051.1 | 333,895.0 | 200,311.8 | 122,833.0 |
| 12-31-2037 | 0.0 | 0.0 | 942,420.8 | 512,413.7 | 286,674.4 | 164,605.3 | 96,787.9 |
| 12-31-2038 | 0.0 | 0.0 | 841,594.3 | 435,811.0 | 232,740.2 | 127,828.8 | 72,032.8 |
| 12-31-2039 | 0.0 | 0.0 | 726,101.2 | 358,182.3 | 182,629.1 | 95,965.3 | 51,834.6 |
| Subtotal | 0.0 | 0.0 | 7,127,790.1 | 4,075,194.6 | 2,352,544.7 | 1,345,955.4 | 740,086.1 |
| Remaining | 0.0 | 0.0 | 2,529,124.7 | 1,139,045.1 | 518,861.5 | 242,416.6 | 116,710.2 |
| Total | 0.0 | 0.0 | 9,656,914.8 | 5,214,239.7 | 2,871,406.3 | 1,588,371.9 | 856,796.3 |

*Totals may not add because of rounding.*

Note: Remaining represents estimates for the period 2040 through 2053.

[1] Operating costs are intended to include only direct project-level costs, oil tariffs, and the costs associated with leasing the floating production, storage, and offloading vessels.
[2] These properties are not subject to production or ad valorem taxes because they are located offshore Falkland Islands.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

CASH FLOW, COSTS, AND TAXES
BEST ESTIMATE (2C) UNRISKED DEVELOPMENT PENDING CONTINGENT RESOURCES
NORTHERN DEVELOPMENT AREA PHASES 1, 2, AND 3 AND CENTRAL DEVELOPMENT AREA PHASES 1 AND 2
NAVITAS PETROLEUM LIMITED PARTNERSHIP INTEREST
SEA LION FIELD, OFFSHORE FALKLAND ISLANDS
AS OF DECEMBER 31, 2024

| Period Ending | Working Interest Revenue (M$) | Royalties State (M$) | Royalties GP (M$) | Royalties Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|
| 12-31-2025 | 0.0 | 0.0 | 0.0 | 0.0 | 129,404.9 | 0.0 | 0.0 | -129,404.9 |
| 12-31-2026 | 0.0 | 0.0 | 0.0 | 0.0 | 305,831.7 | 0.0 | 0.0 | -305,831.7 |
| 12-31-2027 | 26,903.3 | 2,421.3 | 1,614.2 | 4,035.5 | 524,114.8 | 0.0 | 8,790.1 | -510,037.1 |
| 12-31-2028 | 792,363.9 | 71,312.8 | 47,541.8 | 118,854.6 | 333,119.2 | 0.0 | 120,418.1 | 219,972.1 |
| 12-31-2029 | 818,781.0 | 73,690.3 | 49,126.9 | 122,817.2 | 460,759.5 | 0.0 | 121,505.9 | 113,698.5 |
| 12-31-2030 | 762,241.2 | 68,601.7 | 45,734.5 | 114,336.2 | 482,237.9 | 0.0 | 127,528.4 | 38,138.8 |
| 12-31-2031 | 1,800,186.6 | 162,016.8 | 108,011.2 | 270,028.0 | 425,209.4 | 0.0 | 231,642.2 | 873,307.1 |
| 12-31-2032 | 1,978,826.1 | 178,094.3 | 118,729.6 | 296,823.9 | 338,888.2 | 0.0 | 236,137.2 | 1,106,976.7 |
| 12-31-2033 | 2,236,973.4 | 201,327.6 | 134,218.4 | 335,546.0 | 449,101.4 | 0.0 | 240,837.9 | 1,211,488.0 |
| 12-31-2034 | 2,246,862.7 | 202,217.6 | 134,811.8 | 337,029.4 | 305,928.9 | 0.0 | 242,514.7 | 1,361,389.7 |
| 12-31-2035 | 2,166,036.0 | 194,943.2 | 129,962.2 | 324,905.4 | 135,702.6 | 0.0 | 243,908.7 | 1,461,519.3 |
| 12-31-2036 | 2,225,826.5 | 200,324.4 | 133,549.6 | 333,874.0 | 0.0 | 0.0 | 247,147.5 | 1,644,805.0 |
| 12-31-2037 | 2,073,522.5 | 186,617.0 | 124,411.3 | 311,028.4 | 0.0 | 0.0 | 247,123.6 | 1,515,370.5 |
| 12-31-2038 | 1,836,054.1 | 165,244.9 | 110,163.2 | 275,408.1 | 0.0 | 0.0 | 245,490.2 | 1,315,155.8 |
| 12-31-2039 | 1,634,200.1 | 147,078.0 | 98,052.0 | 245,130.0 | 0.0 | 0.0 | 244,101.7 | 1,144,968.4 |
| Subtotal | 20,598,777.4 | 1,853,890.0 | 1,235,926.6 | 3,089,816.6 | 3,890,298.5 | 0.0 | 2,557,146.1 | 11,061,516.1 |
| Remaining | 13,868,379.1 | 1,248,154.1 | 832,102.7 | 2,080,256.9 | 0.0 | 709,150.0 | 3,794,954.4 | 7,284,017.8 |
| Total | 34,467,156.5 | 3,102,044.1 | 2,068,029.4 | 5,170,073.5 | 3,890,298.5 | 709,150.0 | 6,352,100.5 | 18,345,533.9 |

| Period Ending | Production Taxes[2] (M$) | Ad Valorem Taxes[2] (M$) | Future Net Cash Flow Before Corporate Income Taxes Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|
| 12-31-2025 | 0.0 | 0.0 | -129,404.9 | -125,286.4 | -121,493.5 | -117,987.0 | -114,734.1 |
| 12-31-2026 | 0.0 | 0.0 | -305,831.7 | -284,054.8 | -264,791.3 | -247,652.7 | -232,324.0 |
| 12-31-2027 | 0.0 | 0.0 | -510,037.1 | -451,871.5 | -402,669.4 | -360,724.3 | -324,711.1 |
| 12-31-2028 | 0.0 | 0.0 | 219,972.1 | 185,057.2 | 156,965.9 | 134,136.0 | 115,411.2 |
| 12-31-2029 | 0.0 | 0.0 | 113,698.5 | 91,997.4 | 75,181.7 | 61,998.4 | 51,551.8 |
| 12-31-2030 | 0.0 | 0.0 | 38,138.8 | 28,978.2 | 22,299.9 | 17,360.7 | 13,659.6 |
| 12-31-2031 | 0.0 | 0.0 | 873,307.1 | 635,137.1 | 468,898.5 | 350,928.6 | 265,937.5 |
| 12-31-2032 | 0.0 | 0.0 | 1,106,976.7 | 767,238.4 | 541,014.7 | 387,530.2 | 281,602.2 |
| 12-31-2033 | 0.0 | 0.0 | 1,211,488.0 | 799,040.2 | 537,413.0 | 367,941.9 | 256,047.6 |
| 12-31-2034 | 0.0 | 0.0 | 1,361,389.7 | 856,666.3 | 550,912.3 | 361,369.5 | 241,370.2 |
| 12-31-2035 | 0.0 | 0.0 | 1,461,519.3 | 874,966.5 | 536,571.1 | 336,340.7 | 215,097.0 |
| 12-31-2036 | 0.0 | 0.0 | 1,644,805.0 | 938,523.3 | 549,784.6 | 329,866.4 | 202,298.8 |
| 12-31-2037 | 0.0 | 0.0 | 1,515,370.5 | 824,009.3 | 461,037.1 | 264,743.2 | 155,680.6 |
| 12-31-2038 | 0.0 | 0.0 | 1,315,155.8 | 681,122.0 | 363,787.6 | 199,826.5 | 112,616.0 |
| 12-31-2039 | 0.0 | 0.0 | 1,144,968.4 | 564,715.4 | 287,890.9 | 151,254.2 | 81,686.7 |
| Subtotal | 0.0 | 0.0 | 11,061,516.1 | 6,386,238.5 | 3,762,803.1 | 2,236,932.3 | 1,321,190.0 |
| Remaining | 0.0 | 0.0 | 7,284,017.8 | 2,751,291.3 | 1,111,657.9 | 478,653.5 | 217,961.9 |
| Total | 0.0 | 0.0 | 18,345,533.9 | 9,137,529.9 | 4,874,460.9 | 2,715,585.8 | 1,539,151.9 |

*Totals may not add because of rounding.*

Note: Remaining represents estimates for the period 2040 through 2061.

(1) Operating costs are intended to include only direct project-level costs, oil tariffs, and the costs associated with leasing the floating production, storage, and offloading vessels.
(2) These properties are not subject to production or ad valorem taxes because they are located offshore Falkland Islands.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

CASH FLOW, COSTS, AND TAXES
HIGH ESTIMATE (3C) UNRISKED DEVELOPMENT PENDING CONTINGENT RESOURCES
NORTHERN DEVELOPMENT AREA PHASES 1, 2, AND 3 AND CENTRAL DEVELOPMENT AREA PHASES 1 AND 2
NAVITAS PETROLEUM LIMITED PARTNERSHIP INTEREST
SEA LION FIELD, OFFSHORE FALKLAND ISLANDS
AS OF DECEMBER 31, 2024

| Period Ending | Working Interest Revenue (M$) | Royalties State (M$) | Royalties GP (M$) | Royalties Total (M$) | Net Capital Costs (M$) | Net Abandonment Costs (M$) | Net Operating Expenses[1] (M$) | Future Net Cash Flow Before Taxes Discounted at 0% (M$) |
|---|---|---|---|---|---|---|---|---|
| 12-31-2025 | 0.0 | 0.0 | 0.0 | 0.0 | 129,404.9 | 0.0 | 0.0 | -129,404.9 |
| 12-31-2026 | 0.0 | 0.0 | 0.0 | 0.0 | 305,831.7 | 0.0 | 0.0 | -305,831.7 |
| 12-31-2027 | 28,300.9 | 2,547.1 | 1,698.1 | 4,245.1 | 524,114.8 | 0.0 | 8,827.0 | -508,886.0 |
| 12-31-2028 | 814,731.6 | 73,325.8 | 48,883.9 | 122,209.7 | 333,119.2 | 0.0 | 121,008.9 | 238,393.8 |
| 12-31-2029 | 851,362.6 | 76,622.6 | 51,081.8 | 127,704.4 | 460,759.5 | 0.0 | 122,366.5 | 140,532.2 |
| 12-31-2030 | 796,572.2 | 71,691.5 | 47,794.3 | 119,485.8 | 482,237.9 | 0.0 | 128,346.0 | 66,502.4 |
| 12-31-2031 | 1,938,937.0 | 174,504.3 | 116,336.2 | 290,840.6 | 425,209.4 | 0.0 | 232,596.6 | 990,290.5 |
| 12-31-2032 | 2,114,454.5 | 190,300.9 | 126,867.3 | 317,168.2 | 338,888.2 | 0.0 | 237,070.1 | 1,221,327.9 |
| 12-31-2033 | 2,460,613.7 | 221,455.2 | 147,636.8 | 369,092.1 | 449,101.4 | 0.0 | 242,376.2 | 1,400,044.0 |
| 12-31-2034 | 2,608,630.6 | 234,776.8 | 156,517.8 | 391,294.6 | 305,928.9 | 0.0 | 245,003.1 | 1,666,404.0 |
| 12-31-2035 | 2,574,955.7 | 231,746.0 | 154,497.3 | 386,243.4 | 135,702.6 | 0.0 | 246,721.5 | 1,806,288.3 |
| 12-31-2036 | 2,588,523.0 | 232,967.1 | 155,311.4 | 388,278.4 | 0.0 | 0.0 | 249,642.3 | 1,950,602.3 |
| 12-31-2037 | 2,502,947.8 | 225,265.3 | 150,176.9 | 375,442.2 | 0.0 | 0.0 | 250,077.4 | 1,877,428.2 |
| 12-31-2038 | 2,301,316.5 | 207,118.5 | 138,079.0 | 345,197.5 | 0.0 | 0.0 | 248,690.5 | 1,707,428.6 |
| 12-31-2039 | 2,088,684.0 | 187,981.6 | 125,321.0 | 313,302.6 | 0.0 | 0.0 | 247,227.9 | 1,528,153.5 |
| Subtotal | 23,670,030.1 | 2,130,302.7 | 1,420,201.8 | 3,550,504.5 | 3,890,298.5 | 0.0 | 2,579,954.0 | 13,649,273.0 |
| Remaining | 20,921,277.0 | 1,882,914.9 | 1,255,276.6 | 3,138,191.5 | 0.0 | 709,150.0 | 4,299,628.4 | 12,774,307.0 |
| Total | 44,591,307.1 | 4,013,217.6 | 2,675,478.4 | 6,688,696.1 | 3,890,298.5 | 709,150.0 | 6,879,582.4 | 26,423,580.1 |

| Period Ending | Production Taxes[2] (M$) | Ad Valorem Taxes[2] (M$) | Future Net Cash Flow Before Corporate Income Taxes Discounted at 0% (M$) | Discounted at 5% (M$) | Discounted at 10% (M$) | Discounted at 15% (M$) | Discounted at 20% (M$) |
|---|---|---|---|---|---|---|---|
| 12-31-2025 | 0.0 | 0.0 | -129,404.9 | -125,286.4 | -121,493.5 | -117,987.0 | -114,734.1 |
| 12-31-2026 | 0.0 | 0.0 | -305,831.7 | -284,054.8 | -264,791.3 | -247,652.7 | -232,324.0 |
| 12-31-2027 | 0.0 | 0.0 | -508,886.0 | -450,875.1 | -401,801.1 | -359,963.0 | -324,039.9 |
| 12-31-2028 | 0.0 | 0.0 | 238,393.8 | 200,485.2 | 169,995.2 | 145,223.9 | 124,913.0 |
| 12-31-2029 | 0.0 | 0.0 | 140,532.2 | 113,540.3 | 92,657.9 | 76,310.4 | 63,374.4 |
| 12-31-2030 | 0.0 | 0.0 | 66,502.4 | 50,663.0 | 39,090.0 | 30,511.8 | 24,069.7 |
| 12-31-2031 | 0.0 | 0.0 | 990,290.5 | 720,261.3 | 531,773.3 | 398,006.1 | 301,628.4 |
| 12-31-2032 | 0.0 | 0.0 | 1,221,327.9 | 846,441.2 | 596,829.4 | 427,487.1 | 310,621.6 |
| 12-31-2033 | 0.0 | 0.0 | 1,400,044.0 | 923,451.6 | 621,119.3 | 425,271.4 | 295,955.5 |
| 12-31-2034 | 0.0 | 0.0 | 1,666,404.0 | 1,048,273.7 | 673,931.9 | 441,937.3 | 295,102.5 |
| 12-31-2035 | 0.0 | 0.0 | 1,806,288.3 | 1,081,703.8 | 663,546.7 | 416,048.9 | 266,142.5 |
| 12-31-2036 | 0.0 | 0.0 | 1,950,602.3 | 1,113,037.9 | 652,030.3 | 391,222.1 | 239,932.2 |
| 12-31-2037 | 0.0 | 0.0 | 1,877,428.2 | 1,020,679.7 | 570,965.6 | 327,807.6 | 192,731.4 |
| 12-31-2038 | 0.0 | 0.0 | 1,707,428.6 | 884,085.1 | 472,090.7 | 259,264.5 | 146,085.2 |
| 12-31-2039 | 0.0 | 0.0 | 1,528,153.5 | 753,690.8 | 384,221.9 | 201,861.1 | 109,015.5 |
| Subtotal | 0.0 | 0.0 | 13,649,273.0 | 7,896,097.2 | 4,680,166.2 | 2,815,349.7 | 1,698,473.8 |
| Remaining | 0.0 | 0.0 | 12,774,307.0 | 4,564,975.0 | 1,779,797.1 | 748,197.9 | 334,978.3 |
| Total | 0.0 | 0.0 | 26,423,580.1 | 12,461,072.2 | 6,459,963.3 | 3,563,547.5 | 2,033,452.1 |

*Totals may not add because of rounding.*

Note: Remaining represents estimates for the period 2040 through 2064.

(1) Operating costs are intended to include only direct project-level costs, oil tariffs, and the costs associated with leasing the floating production, storage, and offloading vessels.
(2) These properties are not subject to production or ad valorem taxes because they are located offshore Falkland Islands.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
PROSPECTIVE RESOURCES – OIL PROSPECTS
SEA LION FIELD, OFFSHORE FALKLAND ISLANDS
AS OF DECEMBER 31, 2024

| | Gross Rock Volume[1] (acre-feet) | | Net-to-Gross Ratio (decimal) | | Area[3] (acres) | | Average Net Thickness[3] (feet) | | Porosity (decimal) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Normal Distribution[2] | | Normal Distribution | | Lognormal Distribution | | Normal Distribution | | Normal Distribution | |
| Prospect | Low Estimate | High Estimate | Low Estimate | High Estimate | Low Estimate | High Estimate | Low Estimate | High Estimate | Low Estimate | High Estimate |
| Beverley | 42,266 | 230,755 | 0.84 | 0.98 | 668 | 2,267 | 53 | 100 | 0.22 | 0.28 |
| Beverley East | - | - | - | - | 268 | 658 | 20 | 45 | 0.17 | 0.24 |
| Chatham East | - | - | - | - | 959 | 3,797 | 35 | 70 | 0.15 | 0.24 |
| Chatham West | - | - | - | - | 1,217 | 3,626 | 35 | 70 | 0.15 | 0.24 |
| Gwendoline | 232,729 | 546,273 | 0.40 | 0.65 | 2,739 | 6,065 | 34 | 59 | 0.18 | 0.24 |
| Hector 1 | 37,084 | 50,172 | 1.00 | 1.00 | 1,193 | 1,615 | 31 | 31 | 0.22 | 0.28 |
| Hector 2 | 70,235 | 119,742 | 1.00 | 1.00 | 2,055 | 3,849 | 34 | 31 | 0.22 | 0.28 |
| Hector 3 East | 55,363 | 111,355 | 1.00 | 1.00 | 1,934 | 3,385 | 29 | 33 | 0.22 | 0.28 |
| Ida | - | - | - | - | 2,003 | 3,810 | 20 | 45 | 0.14 | 0.20 |
| Jackie East | - | - | - | - | 1,610 | 6,418 | 20 | 45 | 0.18 | 0.25 |
| Jayne 0 | - | - | - | - | 2,236 | 5,525 | 20 | 45 | 0.14 | 0.20 |
| Jayne 1 | - | - | - | - | 1,077 | 2,342 | 20 | 45 | 0.14 | 0.20 |
| Jayne 4 | - | - | - | - | 2,235 | 3,699 | 20 | 45 | 0.14 | 0.20 |
| Jayne West | - | - | - | - | 414 | 1,722 | 20 | 45 | 0.13 | 0.22 |
| Malena | 310,295 | 419,811 | 0.42 | 0.63 | 6,053 | 8,189 | 22 | 32 | 0.22 | 0.28 |
| Ninky 1 East | - | - | - | - | 379 | 823 | 20 | 45 | 0.17 | 0.24 |
| Noggin | - | - | - | - | 2,821 | 4,598 | 20 | 50 | 0.15 | 0.22 |
| Orinoco | - | - | - | - | 1,705 | 6,138 | 20 | 45 | 0.13 | 0.22 |
| S2 | - | - | - | - | 1,486 | 5,447 | 35 | 70 | 0.15 | 0.24 |
| Zebedee East | 81,852 | 168,103 | 1.00 | 1.00 | 1,953 | 3,323 | 42 | 51 | 0.22 | 0.28 |

| | Hydrocarbon Saturation (decimal) | | Initial Oil Formation Volume Factor (RB/STB)[4] | | Oil Recovery Factor (decimal) | | Average Producing Gas-Oil Ratio (SCF/STB)[5] | |
|---|---|---|---|---|---|---|---|---|
| | Normal Distribution | | Normal Distribution | | Normal Distribution | | Uniform Distribution | |
| Prospect | Low Estimate | High Estimate | Low Estimate | High Estimate | Low Estimate | High Estimate | Low Estimate | High Estimate |
| Beverley | 0.60 | 0.80 | 1.15 | 1.25 | 0.20 | 0.45 | 300 | 500 |
| Beverley East | 0.60 | 0.80 | 1.15 | 1.25 | 0.15 | 0.45 | 300 | 500 |
| Chatham East | 0.60 | 0.80 | 1.15 | 1.25 | 0.15 | 0.45 | 300 | 500 |
| Chatham West | 0.60 | 0.80 | 1.15 | 1.25 | 0.15 | 0.45 | 300 | 500 |
| Gwendoline | 0.60 | 0.80 | 1.15 | 1.25 | 0.20 | 0.45 | 300 | 500 |
| Hector 1 | 0.60 | 0.80 | 1.15 | 1.25 | 0.20 | 0.45 | 300 | 500 |
| Hector 2 | 0.60 | 0.80 | 1.15 | 1.25 | 0.20 | 0.45 | 300 | 500 |
| Hector 3 East | 0.60 | 0.80 | 1.15 | 1.25 | 0.20 | 0.45 | 300 | 500 |
| Ida | 0.50 | 0.65 | 1.15 | 1.25 | 0.15 | 0.40 | 300 | 500 |
| Jackie East | 0.50 | 0.80 | 1.15 | 1.25 | 0.15 | 0.45 | 300 | 500 |
| Jayne 0 | 0.50 | 0.65 | 1.15 | 1.25 | 0.15 | 0.40 | 300 | 500 |
| Jayne 1 | 0.50 | 0.65 | 1.15 | 1.25 | 0.15 | 0.40 | 300 | 500 |
| Jayne 4 | 0.50 | 0.65 | 1.15 | 1.25 | 0.15 | 0.40 | 300 | 500 |
| Jayne West | 0.50 | 0.65 | 1.15 | 1.25 | 0.15 | 0.40 | 300 | 500 |
| Malena | 0.60 | 0.80 | 1.15 | 1.25 | 0.20 | 0.45 | 300 | 500 |
| Ninky 1 East | 0.60 | 0.80 | 1.15 | 1.25 | 0.15 | 0.45 | 300 | 500 |
| Noggin | 0.45 | 0.70 | 1.15 | 1.25 | 0.15 | 0.40 | 300 | 500 |
| Orinoco | 0.50 | 0.65 | 1.15 | 1.25 | 0.15 | 0.40 | 300 | 500 |
| S2 | 0.60 | 0.80 | 1.15 | 1.25 | 0.15 | 0.45 | 300 | 500 |
| Zebedee East | 0.60 | 0.80 | 1.15 | 1.25 | 0.20 | 0.45 | 300 | 500 |

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, and property ownership interests.

(1) Certain prospects were mapped using net rock volume; these are shown as gross rock volume with a net-to-gross ratio of 1.00.
(2) The gross rock volume distribution type used for the Gwendoline Prospect is lognormal.
(3) For prospects mapped using gross rock volume or net rock volume, the area and average net thickness were not used in our Monte Carlo simulation and are shown for convenience only. For these prospects, the average net thickness is calculated by multiplying the gross rock volume by the net-to-gross ratio and dividing by the area.
(4) The abbreviation RB/STB represents reservoir barrels per stock tank barrel.
(5) The abbreviation SCF/STB represents standard cubic feet per stock tank barrel.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*

VOLUMETRIC INPUT SUMMARY
PROSPECTIVE RESOURCES – GAS PROSPECTS
SEA LION FIELD, OFFSHORE FALKLAND ISLANDS
AS OF DECEMBER 31, 2024

| | Area (acres) Normal Distribution | | Net Pay (feet) Triangular Distribution | | | Porosity (decimal) Normal Distribution | | Hydrocarbon Saturation (decimal) Normal Distribution | |
|---|---|---|---|---|---|---|---|---|---|
| Prospect | Low Estimate | High Estimate | Minimum | Most Likely | Maximum | Low Estimate | High Estimate | Low Estimate | High Estimate |
| Liz G4 Clastic A | 2,733 | 4,656 | 104 | 136 | 171 | 0.09 | 0.12 | 0.44 | 0.58 |
| Liz G4 Clastic B | 1,526 | 14,897 | 104 | 136 | 171 | 0.09 | 0.12 | 0.44 | 0.58 |
| Liz G4 Clastic C | 7,181 | 15,308 | 104 | 136 | 171 | 0.09 | 0.12 | 0.44 | 0.58 |
| Liz H4 Volcanics A | 2,367 | 7,249 | 55 | 126 | 143 | 0.15 | 0.18 | 0.47 | 0.77 |

| | Initial Gas Formation Volume Factor (SCF/RCF)(1) Normal Distribution | | Gas Recovery Factor (decimal) Normal Distribution | | Average Producing Yield (BBL/MMCF)(2) Uniform Distribution | |
|---|---|---|---|---|---|---|
| Prospect | Low Estimate | High Estimate | Low Estimate | High Estimate | Low Estimate | High Estimate |
| Liz G4 Clastic A | 250 | 270 | 0.45 | 0.75 | 35 | 95 |
| Liz G4 Clastic B | 250 | 270 | 0.45 | 0.75 | 35 | 95 |
| Liz G4 Clastic C | 250 | 270 | 0.45 | 0.75 | 35 | 95 |
| Liz H4 Volcanics A | 255 | 275 | 0.45 | 0.75 | 1 | 2 |

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, and property ownership interests.

(1) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.
(2) The abbreviation BBL/MMCF represents barrels per million cubic feet.



*All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.*