Credible Business Development Plan

Surmont Wildwood SAGD Project

Final Report

November 28, 2025

Project Number 24958

GLJ Ltd
1920, 401 - 9 Avenue SW
Calgary Alberta T2P 3C5

WILDWOOD SAGD PROJECT CBDP EVALUATION REPORT

November 28, 2025
Project Number 24958

Gordon D Holden, Advisor
Surmont Energy Ltd.
Suite 1700, 505 3rd Street SW
Calgary, Alberta, T2P 3E6

Dear Mr. Holden,

Re: Final Report – Production Volume under Credible Business Development Plan
Surmont Wildwood SAGD Project

GLJ Ltd. ("GLJ") is pleased to provide the final report for the Credible Business Development Plan ("CBDP") prepared based on the Surmont Wildwood SAGD Project, for use in the Baseline Scenario of the Wildwood Sequestered Carbon-Intensive Oil Project, a GHG emissions reduction project. The CBDP was prepared at the request of Surmont Energy Ltd. (the "Company"). GLJ was engaged by the Company as a Production Volume Certifier ("PVC") pursuant to Theaus Global Inc.'s Methodology for In Situ Sequestration of GHG Emissions from Planned Production of Carbon-Intensive Oil, Version 1.0 (the "TGSM"), developed by EcoEngineers, Ohio, USA.

GLJ is a professional petroleum evaluation firm that meets the qualifications of a PVC as described in the TGSM, attached as Appendix 2. GLJ has estimated a CBDP Carbon-Intensive Oil ("CIO") Production Volume ("PV") for the Wildwood SAGD Project as a potential avoided Baseline Scenario. The estimated PV is approximately 376 million BOE of CIO, with corresponding production profiles and allocations as provided in Appendix 1 – Wildwood SAGD Project CBDP Evaluation Report.

GLJ utilized the following key inputs and assumptions in its determination as outlined in the report and Appendix 1:

- Defined terms per the TGSM
- GLJ CBDP mapping of the CIO deposit, based in part on certain Surmont proprietary data
- GLJ proprietary and public source data for production profiles, capital costs, and operating costs including energy costs and royalties
- Marketing assumptions for blended diluent and bitumen product
- Oil and natural gas prices per 3 Consultant Average published price forecast, dated July 1, 2025
- Outputs to be utilized as the PV under a CBDP for calculation of GHG emissions for use in Baseline Scenario of the Wildwood Sequestered Carbon-Intensive Oil Project, in Alberta, Canada

It is trusted that this assessment meets your current requirements. Should you have any questions regarding this report, please contact the undersigned at +1-403-266-9525.

Best Regards,

GLJ LTD. | **Kim Mohler, P.Eng.** | **VP Project Development**

KM
Attachments

CERTIFICATE OF TECHNICAL QUALIFICATONS

This report has been prepared and reviewed thoroughly by the authors to the best of their knowledge. Data and interpretations presented in this report are of the opinion of the authors and are believed accurate in nature as a function of the quality and quantity of the available data. Estimates and interpretations presented herein are considered reasonable and should be accepted with the understanding that revisions may be justified if additional data is acquired.

PERMIT TO PRACTICE
GLJ LTD.

RM Signature:

RM APEGA ID#: 72687

Date: November 28, 2025

PERMIT NUMBER: P 2066
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

GLJ LTD.
Corporate Seal

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Summary Report Contents

1. Executive Summary

GLJ Ltd. ("GLJ") has conducted an evaluation of the Wildwood SAGD Project (the "Project") at the request of Surmont Energy Ltd. (the "Company"). The two key deliverables from the evaluation are (1) the Credible Business Development Plan ("CBDP") volumetric bitumen production forecast and economic analysis; and (2) production volume groupings into multiple Carbon Credit Areas ("CCAs"), each which represents a total of approximately 21 million barrels of bitumen production.

The work conducted for this report is pursuant to Theaus Global Inc.'s Methodology for In Situ Sequestration of GHG Emissions from Planned Production of Carbon-Intensive Oil, Version 1.0 (the "TGSM"), developed by EcoEngineers, Ohio, USA, included as Appendix 2. The evaluation included a multi-faceted assessment for the purpose of reporting a CBDP that supports the Wildwood Sequestered Carbon-Intensive Oil Project, a GHG emissions reduction project. While prepared pursuant to the TGSM, this CBDP could be utilized with other applicable GHG emissions project frameworks, as the underlying volumetric and economic assumptions are methodology-neutral; the use of the CBDP volumes in GHG quantification differs by framework and remains subject to each framework's eligibility, additionality, and baseline rules.

The evaluation was conducted by GLJ as a reasonable expectation of how a SAGD operator would proceed with development as shown in the baseline scenario development plan for the Surmont Wildwood Project. The evaluation included a geologic review and preparation of geologic mapping of bitumen pay in the McMurray formation, and volumetric estimation of recoverable bitumen based on recovery with the proven technology of Steam Assisted Gravity Drainage ("SAGD"). The evaluation is for Surmont's Wildwood property, located in Townships 081 to 083, Ranges 07 to 09 W4M in the Province of Alberta, Canada. The evaluation report is titled "Wildwood SAGD Project Credible Business Development Plan Evaluation" and is included as Appendix 1 in this report.

A bitumen production forecast was defined based on the CBDP facility capacity and project schedule. Suitable analog SAGD projects were used to define key economic criteria for the evaluation. This volumetric and economic evaluation follows GLJ proprietary procedures, which follow industry practices for in situ oil sands evaluations. An outline of the evaluation inputs, assumptions, and methodology is included in Appendix 1.

The results of the CBDP evaluation identify approximately 376 million barrels (bbl) of bitumen, at 100% gross interest before royalties, as economically recoverable using SAGD. While the technical volumetric bitumen values can be calculated without reference to a specific production time schedule, GLJ must assume a specific production time schedule for its corresponding economic evaluations—as product price forecasts, capital expenditure and operating cost forecasts are specific time-series data. GLJ has, as a result, for its economic evaluations, assumed start of production is in 2028 and ending at the calculated economic limit in December 31, 2048. Similarly, as present value calculations require a specified economic discounting reference date, GLJ has for this evaluation used a near-future calendar year end present-value effective date of December 31, 2025. In summary, GLJ'S economic evaluations assume capital investment starts in 2026, production commences in 2028, the economic limit is reached in 2048, and all economic values are present-value discounted to an effective date of December 31, 2025.

This CBDP provides the baseline Wildwood production case and CCA-level profiles that are used as inputs to GHG project documentation, registry review, and other technical and economic assessments.

The economic evaluation in the Appendix 1 report is based on the Base Scenario. Further to that, three pricing and production sensitivities were run. The pricing sensitivity is 10% lower oil pricing for the full project life as compared to the Base. The production sensitivity is 10% lower oil production rate for the full life as compared to the Base and the third sensitivity is combination of both 10% lower oil price and 10% lower production rate. The summary of results of the base scenario and sensitivities are shown below in Table 1.

Table 1: Summary of Economic Results for Pricing and Production Sensitivities

Case	Total Recoverable Bitumen Volume	BTAX NPV @10%	IRR BTAX	Total Undiscounted Gross Revenue	Total Undiscounted Capital Cost	Operating Cost per barrel (lifetime average, undiscounted)	Total Peak Oil Rate
	MMbbl	$MM	%	$MM	$MM	$/bbl	bbl/d
Base Scenario	376	2,503	24.2	27,546	4,900	18.7	104,000
10% Oil Production Reduction Sensitivity	338	1,913	22.9	24,791	4,900	20.5	94,000
10% Oil Price Reduction Sensitivity	376	1,714	22.2	23,493	4,900	18.7	104,000
10% Oil Price/Oil Production Reduction Sensitivity	338	1,191	20.0	21,144	4,900	20.5	94,000

2. Overview

The CBDP evaluation reflects a reasonable expectation baseline plan, per the TGSM, for development of the Wildwood SAGD in situ oil sands asset in a “business-as-usual” case under typical market and operational conditions. The corresponding produced bitumen volume and annual profile is calculated, using assumptions of the project proceeding at an effective date of December 31, 2025, and capital investment starting in 2026 progressing the Project to start in 2028 (as described in the immediately preceding section, such assumptions are required for economic evaluations).

The CBDP was assessed for alternative viable technology applications, and it was concluded that SAGD is the only technically and commercially viable recovery mechanism for development of the Wildwood SAGD Project (reference Appendix 1).

SAGD is the only technically viable development method for the CBDP, as the reservoir is an in situ Athabasca McMurray bitumen deposit which is too deep to recover through surface mining methods, from a technical, economical and environmental perspective. The reservoir possesses the permeability, thickness, and caprock integrity required for gravity-driven thermal oil recovery. The bitumen will not move under primary depletion or cold production; therefore, heat must be introduced to lower viscosity to induce fluid flow to surface.

Among thermal technologies, SAGD is specifically engineered for laterally extensive, high-porosity, unconsolidated McMurray channel sands, where the growth of a connected steam chamber allows heated bitumen and condensed water to drain by gravity toward a horizontal producer well, where the steam is injected in a horizontal well that is situated above the producer well. The overlying Clearwater shale provides an established regional caprock capable of containing steam pressures when managed within maximum operating pressure limits which are based on geomechanical assessment of the rocks. This geomechanical suitability is essential, as without a competent seal, thermal methods could risk out-of-zone steam migration.

2.1 Description of Wildwood CBDP Evaluation:

GLJ utilized its comprehensive knowledge of the geologic setting of the McMurray formation in and near the Project location to prepare a geologic assessment and resulting net bitumen pay mapping, which are included in the Maps section of Appendix 1. The geologic characterization resulted in definition of volumetric parameters such as net pay, porosity, water saturation, and drainage area, which are inputs into the estimation of Bitumen-initially-in-place (“BIIP”). For the Wildwood property based on the CBDP mapping, the exploitable BIIP is 533 million bbl bitumen.

GLJ’s estimation of Wildwood SAGD Project recoverable bitumen is based on the utilization of SAGD as the proven extraction technology, supported by the extensive analog performance data from multiple operational SAGD projects. GLJ assesses that SAGD is the only current practical, commercially viable recovery mechanism for development of bitumen accumulations like the Wildwood SAGD Project based on the extensive experience GLJ has in conducting evaluations of SAGD projects for over 20 years.

The geological architecture and fluid behavior at Wildwood align with decades of commercial SAGD development and operations in surrounding analog projects such as ConocoPhillips Surmont, Cenovus Christina Lake, Connacher Great Divide, Athabasca Hangingstone, Suncor MacKay River and others, which confirms that the reservoir conditions support steam chamber development, pressure conformance, and high recovery factors.

Alternative recovery methods do not satisfy the technical constraints of the Wildwood project. Surface mining is not feasible as Wildwood lies several hundred metres below surface – well beyond mineable depth. Cold Heavy Oil Production with Sand (CHOPS) applies to shallower, more mobile heavy oils in other regions, not immobile Athabasca bitumen, and cannot achieve meaningful recovery. Cyclic Steam Stimulation (CSS) has seen commercial success primarily where steam-induced fracturing plays a central role and where reservoir vertical permeabilities are not sufficiently high, typically in marine shoreface deposit, not the McMurray channel sands. SAGD’s continuous chamber and gravity drainage mechanism has consistently delivered superior performance, stability, and recovery in the Athabasca in situ oil sands plays.

SAGD has been in commercial operation in many projects for greater than 20 years and companies have tested out many optimization methods and technologies to improve recovery, lower SOR, and improve economics. Reduced well spacing and the addition of infill wells is one method to accelerate oil recovery and improve SOR. The co-injection of non-compressible gases (NCG) is one method utilized to reduce SOR, and co-injection of solvent has been tested at pilot scale to reduce SOR, improve oil recovery and provide for emissions reduction. Solvent co-injection is moving to commercial deployment at several operators but still remains at mostly pilot scale due to the economics of adding a higher cost solvent to the recovery process. The technologies and methods mentioned are supplemental rather than standalone primary recovery methods, and act as levers to improve economics. In situ combustion technologies such as THAI have not demonstrated reliable large-scale performance or controllability in McMurray reservoirs, and regulators and operators do not treat them as safe or technically or economically feasible processes.

Surface mining and vertical well schemes such as CSS are incompatible with mandated surface disturbance management for the Wildwood area’s boreal forest, muskeg, and fenlands that are protected habitat for various species and for immediately adjacent provincially designated wildlands, while SAGD’s much smaller surface footprint is compatible with proper deployment as is contemplated with the CBDP development plan. Moreover, the government and regulatory approvals already in place for the Wildwood SAGD Project that are a key basis were issued explicitly on the basis of SAGD as the recovery method. The reservoir modelling, operating pressure envelope, steam-oil ratio assumptions, groundwater protection strategy, environmental impact assessment, well spacing, and operational monitoring commitments filed with the Alberta Energy

Regulator (AER) are all tied directly to SAGD. Any shift to an alternative recovery technology would require reopening regulatory approvals, re-demonstrating subsurface containment and geomechanical safety, resubmitting environmental assessments, and undergoing new stakeholder and Indigenous consultation processes. This would introduce technical uncertainty, regulatory risk, stakeholder risk, and project schedule delay without providing a superior recovery outcome.

Accordingly, SAGD is the only recovery technology that matches the reservoir's geological and fluid characteristics and under which the Project's regulatory and environmental frameworks are currently authorized. SAGD is consequently the only technically and institutionally viable development pathway for Wildwood.

In SAGD, well pairs are installed in the subsurface and include one production well and one injection well, where both are long horizontal wellbores with the injector sitting approximately 5 m above the production well. These well pairs range from 1,222 to 1,419 metres in length in the Wildwood SAGD Project report. Each set of well pairs is spaced apart from adjacent well pairs to optimize bitumen recovery. The initial well pairs are targeted to be 100 m apart for this evaluation, and an infill production well scheduled to be added in between SAGD producers 3 years into operation of each original well pair to improve and accelerate bitumen recovery. This is a common enhancement process utilized by many current SAGD operators.

Based on the geologic mapping and the leased land area, subsurface drainage patterns are defined to maximize well coverage for the highest economic bitumen recovery. These drainage patterns are also referred to as Subsurface Drainage Areas (SDAs) or pads in the report in Appendix 1. The SDAs represent subsurface target areas and do not correspond to surface disturbance. To minimize land use, multiple well pairs are planned to be drilled from one multi-well surface pad. GLJ assumed that surface locations will be available for multi-well pads and the infrastructure to connect the wells to a centralized plant facility ("CPF") based on Surmont's assessments of available surface drilling locations.

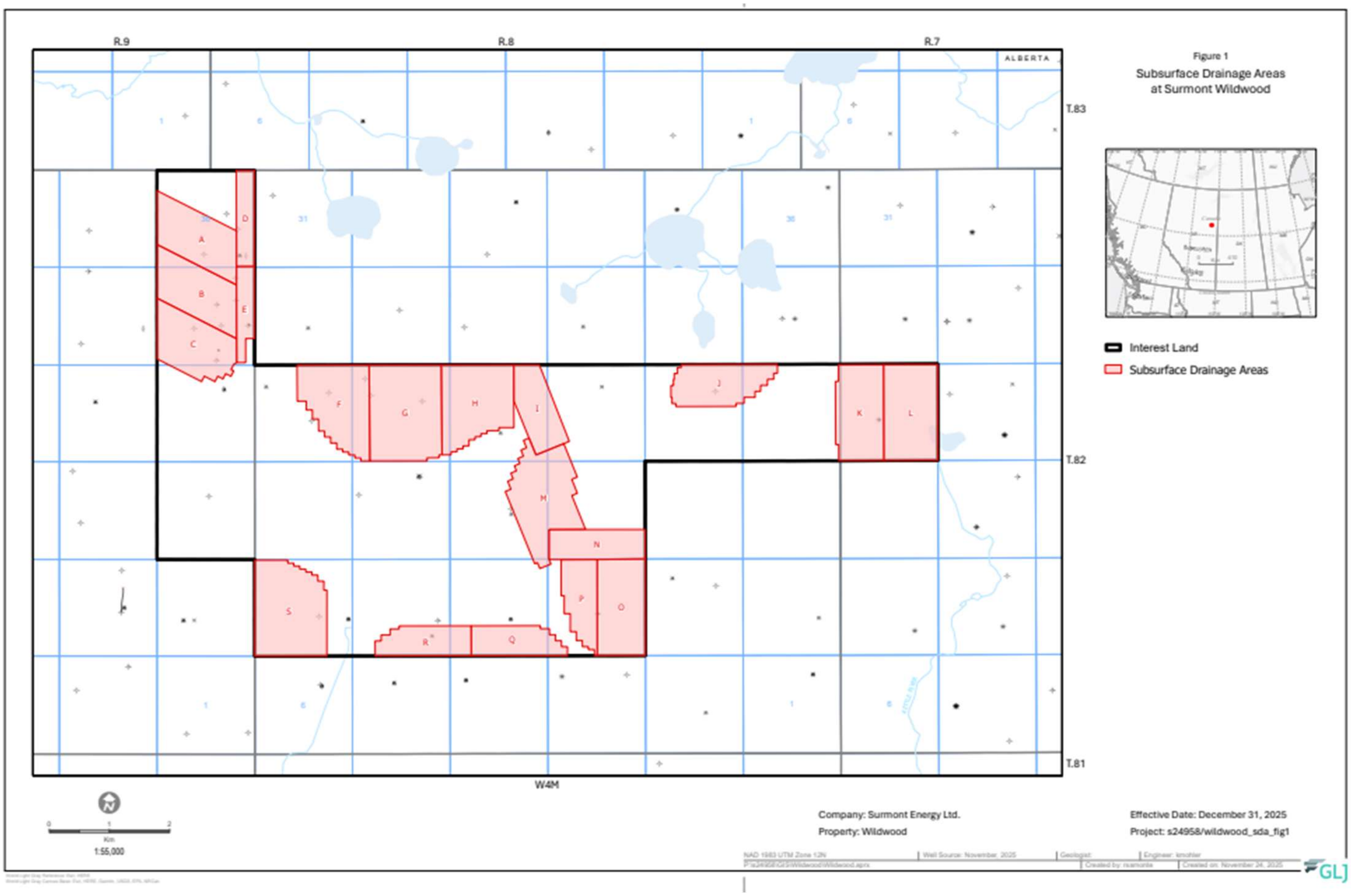


Figure 1: Subsurface Drainage Areas for Surmont Wildwood SAGD Project

A total of 19 SDAs were defined for the overall Project, with a total of 150 well pairs identified for potential development. The 19 SDAs were grouped for the evaluation into 6 type curves which represent a production forecast that is based on similar geologic properties with production history. Each type curve includes an estimation of steam injection rates and bitumen production rates, where a measurement of production performance that is common in SAGD is Steam-Oil-Ratio ("SOR"). The Project total production forecast is then based on the aggregation of the SDAs based on type curves for the Project.

The timing for installation of the well pairs is based on maximum steam and bitumen capacity at the Central Processing Facility ("CPF"). Wells are scheduled to be added to fill capacity but are limited by facility capacities. For the Project, Wildwood Phase 1 is the AER-approved 12,000 bopd facility with an SOR of 3.0, with the future expansions to add capacity of 75,000 bopd at an SOR of 3.5.

The peak aggregated production rate for the Project is over 104,000 bopd reached in the 8th year of operation based on the development schedule. The preliminary technical assessment estimated a total of approximately 376.1 million bbl of bitumen as technically recoverable volumes utilizing SAGD. (all values before royalties and at 100% gross interest).

Once the bitumen is produced at the CPF and water and gases are removed from the production stream from the wells, the bitumen or oil product is blended with a diluent to bring it to pipeline or marketing specifications and then valued for royalty purposes at the plant gate. This is a typical method of product handling for SAGD projects and is the approved plan for the Wildwood project.

The assumed marketing logistics for the bitumen are sales at the plant gate of a C5+ condensate diluent blended with bitumen, referred to as “dilbit”, where blending would occur at the Wildwood CPF or a nearby regional facility. This a standard method for transportation and sales of a bitumen product as the bitumen is too viscous to flow on its own, so a much-lighter hydrocarbon fluid (condensate) is added to meet a desired pipeline and sales specification for transport to markets. Most operators will tie-into an existing pipeline or trucking infrastructure and manage the transportation of the product through midstream operators. In some cases, the production is transported by truck to a pipeline or rail hub. The resulting dilbit stream is introduced into the existing gathering system and flows to the established oil market hubs. From these hubs, Wildwood dilbit will be transported via major common-carrier trunklines to refining markets in Canada and the USA, with rail used only occasionally as a secondary outlet. Downstream hubs recover a portion of the diluent for recycling into the oil sands condensate pool, and the heavy oil stream continues to numerous refineries already optimized for Athabasca-type heavy sour crude.

The refining pathway of Wildwood dilbit is the same as that of existing Athabasca SAGD production and does not alter regional refining patterns or infrastructure needs. The product will be processed in coking and hydrocracking refineries that routinely run high-sulphur, high-micro-carbon-residue heavy crudes. In these facilities, dilbit is fractionated into naphtha, middle distillates, and vacuum residue, with the residue processed through delayed cokers to produce lighter products and petroleum coke. The condensate fraction is recovered in front-end distillation and returned to the diluent market.

Offtake, marketing, and transportation arrangements for the CBDP dilbit follow usual commercial norms for bitumen production in the Athabasca region. Production is typically sold under commercially standard offtake agreements in which crude purchasers, traders, or downstream refiners take title at or near the project area or at regional hubs. Crude from SAGD projects such as Wildwood is seldom sold under long-term fixed-price contracts, but rather under agreements where the realized price floats with prevailing benchmark markets, including Western Canadian Select (WCS) at Hardisty, AB, and West Texas Intermediate (WTI) at Cushing, OK, often linked to futures-market pricing mechanisms. In contrast, pipeline transportation service agreements that provide takeaway capacity from the Athabasca region to Hardisty or Edmonton are commonly longer-term commitments, reflecting industry practice. Condensate supply and return arrangements support the ongoing diluent requirements. These established commercial structures demonstrate that Wildwood CBDP production is fully integrated into the existing heavy oil market.

Production trends in the Athabasca oil sands region underscore that the downstream supply chain assumptions for the Wildwood CBDP are robust and representative.

End use of refined products derived from Wildwood dilbit, including production is equivalent to that of other Athabasca heavy crudes and includes gasoline, diesel, jet fuel, LPGs, refinery fuel gas, asphalt, and petroleum coke. These products enter established North American petroleum product distribution systems and are ultimately combusted in transportation, industrial, commercial, and, to a much smaller degree, residential applications.

Overall, the transportation, refining, offtake, marketing, production trend and end use profile of the Wildwood SAGD Project reflects the standard, well-established supply chain for Athabasca dilbit, and are consistent with the CBDP published by GLJ, including the economic evaluations section (Appendix 1), and fully meets the TGSM’s definition of Accepted Production Method.

In GLJ’s evaluation, the typical blend ratio for an 8 API bitumen is applied, resulting in dilbit that is approximately 30% condensate diluent and 70% bitumen by volume. This marketing logistics evaluation reflects the standard structure of marketing/offtake agreements, volume commitments, and transportation, processing, refining and chains of custody that are typical for CIO in the region based on internal metrics compiled by GLJ from work on regional SAGD projects.

GLJ's technical evaluation forecasts bitumen production volumes, per Appendix 1. Below in Table 2 the corresponding forecasted marketable dilbit sales volumes as required for input to GHG emission calculations are summarized.

For the economic evaluation, the capital and operating costs for the Project are based on suitable analog data for a new SAGD development incorporating current industry practice. Surface production facilities typically include well pads, steam, emulsion production, and utility pipelines in the field, together with a central processing facility that includes bitumen/produced water/gas separation, boiler feedwater conditioning, natural gas-fuelled steam (may include cogen power generation), gas compression, acid gas handling, tankage, and a makeup/disposal water supply system, together with supporting infrastructure including a natural gas pipeline, access road, maintenance and warehouse buildings, control building, and staff quarters. Alberta regulatory authorities with jurisdiction apply requirements for energy and emissions efficiency, including zero routine venting. Additional end-of-life abandonment and reclamation costs (ARO) are included in the capital costs.

The oil and gas price forecast utilized is the July 1, 2025, 3-Consultant Average (3CA), which is described in the Appendix 1 – Table 4. The 3CA is based on the price forecasts from the three leading Canadian oil and gas evaluation consulting firms, GLJ Ltd., McDaniel & Associates Consultants Ltd., and Sproule ERCE. Each of these companies has independently prepared its price and market forecasts. The arithmetic average of the three price and market forecasts are summarized after a comprehensive review of information. Information sources for GLJ's price forecast include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. GLJ's forecasts are based on an informed interpretation of currently available data. While the 3CA forecasts used for this evaluation are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market.

All costs are in 2026 dollars, and all revenues and costs are in Canadian currency. The cash flows take into consideration government royalties, a Gross Overriding Royalty of 1%, and carbon taxes, and are calculated before provincial or federal corporate income taxes.

Key technical and economic results for this Base Scenario are:

- Total bitumen production over project life of 376 million bbl
- Total gross revenue of $9,786 million (before tax or royalties, discounted @10%)
- Net Present Value of $2,503 million (before tax, discounted @10%)
- Internal Rate of Return of 24.2 % (before tax)
- Total undiscounted capital expenditures associated with the project of $4.9 billion
- Average operating cost, undiscounted, of $18.70/bbl

Note: All values above are referenced to Surmont's 100% interest.

GLJ's economic viability assessment for the CBDP has been prepared using standard, industry-accepted mathematical formulations for the calculation of Net Present Value (NPV), Internal Rate of Return (IRR), and related economic indicators. These formulations were applied through industry-standard petroleum-economic methodology that is coded into the GLJ internal development and economic modeling program in accordance with widely established petroleum-economic methodologies used across the Canadian oil sands sector. Consistent with GLJ practice, the assessment does not report a "payback period," as this metric is not considered meaningful for SAGD developments, as thermal in situ projects characteristically involve substantial front-loaded capital expenditures and long-term production which together render simple payback measures uninformative for investment evaluation or risk screening. The resulting economic outputs, including NPV, IRR, operating margins, and cash-flow performance, fall within ranges generally regarded by industry as economically viable for SAGD projects. Taken together, these outputs indicate commercial viability for the Wildwood SAGD Project under the stated assumptions, consistent with industry practice for SAGD projects.

The full evaluation report prepared by GLJ is available in Appendix 1 and includes a more detailed description of assumptions in the Discussion section, together with maps, tables, and charts to summarize the evaluation.

2.2 Description of Carbon Credits Area Groupings:

For the purposes of estimating GHG emissions reductions associated with preventing the planned production of bitumen, the forecasted bitumen production as described in 1.1 above has been split into Carbon Credit Areas ("CCAs") corresponding to approximately 21 million bbl bitumen each. On this basis, 18 CCAs are defined, with some variation around the 21 million bbl target due to the variance in type curves used to build the CCA groupings. The CCA allocations are derived from GLJ's baseline schedule and engineered drainage assumptions, and any substantial revision to the baseline schedule would require a GLJ update.

As the marketable sales product from the CBDP will be dilbit, both bitumen and dilbit volumes are provided in Table 2 below. The blend ratio as described in Section 1.1 above is 1.43 bbl diluent per bbl bitumen, with 3% shrinkage occurring before the sales point, resulting in a sales blend volume 1.3871 bbl of dilbit per bbl of undiluted bitumen. This equates to each phase having a target dilbit volume of approximately 29.2 million bbl.

Table 2: Baseline Scenario Carbon Credit Area Volume and Well pairs Summary

CCA Name	Dilbit Volume (bbl)	Bitumen Volume (bbl)	Number of Wellpairs
CCA 1	30,120,058	21,714,410	6
CCA 2	30,120,058	21,714,410	6
CCA 3	29,928,635	21,576,408	6
CCA 4	29,928,635	21,576,408	6
CCA 5	29,907,362	21,561,072	6
CCA 6	29,688,817	21,403,516	10
CCA 7	30,154,503	21,739,242	10
CCA 8	28,116,489	20,269,979	9
CCA 9	28,569,789	20,596,777	10
CCA 10	30,188,687	21,763,887	7
CCA 11	30,188,687	21,763,887	7
CCA 12	30,188,687	21,763,887	7
CCA 13	30,119,313	21,713,873	8
CCA 14	29,808,424	21,489,744	9
CCA 15	29,497,391	21,265,512	10
CCA 16	29,781,271	21,470,169	11

CCA 17	29,197,508	21,049,317	14
CCA 18	16,242,903	11,709,973	10
Total	**521,747,217**	**376,142,468**	**150**

The Carbon Credit Areas have been defined on a map within the leased area, similar to the SDAs as described in Section 1.1. The CCAs are based on the proposed well pair placement that is the basis of the SDAs; however, the CCAs are defined by the carbon credit volume target of 21 million bbl bitumen per each CCA, and number of well pairs in each CCA per Table 1. The CCA 18 volumes are materially smaller as this CCA contains the remaining wellpairs and associated recoverable volumes after allocating all the prior CCA's.

Below is a map to show the location of each CCA in Figure 2. The CCA volumes and any sub-area allocations apply only to the supplied CCA polygon(s) where there are no claims implied outside that scope.

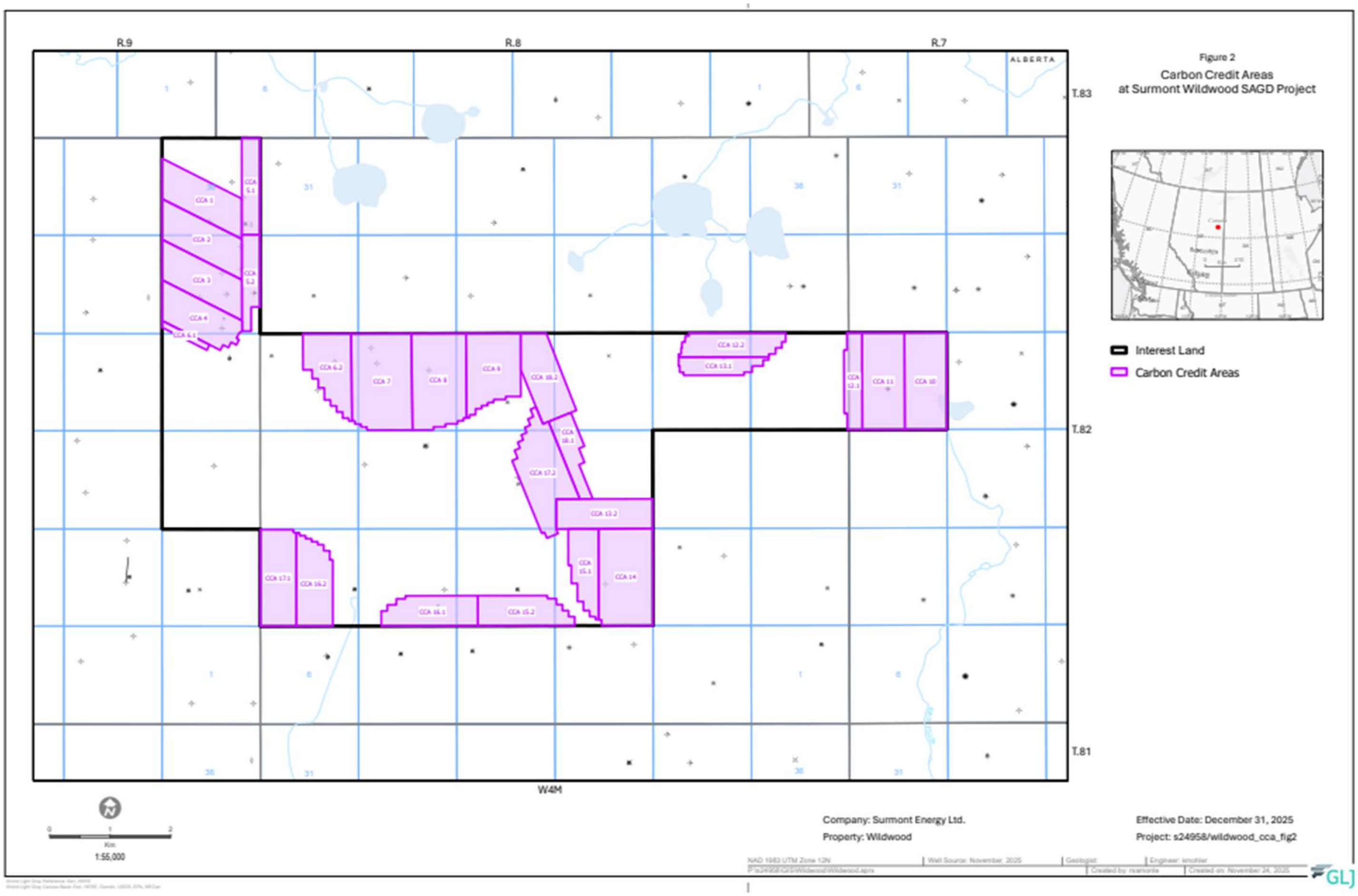


Figure 2: Carbon Credit Areas for Surmont Wildwood SAGD Project

Below are tables providing the annual bitumen per year (Table 3) and dilbit volumes per year (Table 4) per CCA.

Table 3: Annual Bitumen Volume by Year by Baseline Scenario Carbon Credit Area, in Mbbl

Year	CCA 1	CCA 2	CCA 3	CCA 4	CCA 5	CCA 6	CCA 7	CCA 8	CCA 9	CCA 10	CCA 11	CCA 12	CCA 13	CCA 14	CCA 15	CCA 16	CCA 17	CCA 18
0																		
1	1923	1539	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	5957	5829	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	5798	5867	1513	1260	1008	865	805	1182	604	0	0	0	191	0	0	0	0	0
4	7494	7253	5352	5100	4806	6412	6604	5321	4483	0	0	0	2296	0	0	0	0	0
5	7433	7550	5882	5928	5967	7331	7732	7094	7254	0	0	0	3034	0	0	0	0	0
6	6159	6256	6645	6397	6146	8354	8738	7460	6978	0	0	0	2915	0	0	0	0	0
7	5105	5185	7659	7780	7903	9140	9741	9351	10000	3758	3758	3758	6262	3506	3127	4688	1418	0
8	4232	4299	6346	6446	6548	7209	7430	7132	7628	6938	6938	6938	7492	7597	7845	8654	4531	0
9	3510	3565	5259	5342	5426	5468	5673	5444	5822	6160	6160	6160	6302	6926	7207	7415	4908	0
10	2912	2957	4360	4428	4498	4242	4337	4161	4449	8943	8943	8943	7528	9120	9352	10531	9240	0
11	2416	2454	3615	3672	3730	3298	3320	3185	3404	7527	7527	7527	6150	8259	8392	8322	9621	2484
12	2007	2038	2999	3046	3094	2570	2546	2442	2609	6060	6060	6060	4856	6467	6460	6269	8185	5839
13	1667	1693	2489	2528	2567	2009	1957	1876	2004	4882	4882	4882	3842	5075	4985	4732	7601	5332
14	1386	1408	2066	2099	2131	809	676	888	1194	3935	3935	3935	3048	3994	3858	3579	5367	6165
15	1153	1171	1717	1743	1770	310	0	0	0	3174	3174	3174	2425	3153	2996	2716	3812	5198
16	340	428	1427	1449	1472	258	0	0	0	2563	2563	2563	1935	2499	2268	1917	2726	3519
17	0	0	1187	1205	1224	214	0	0	0	2072	2072	2072	1213	1989	1127	0	260	2390
18	0	0	599	689	782	151	0	0	0	1677	1677	1677	0	291	646	0	0	1155
19	0	0	0	0	0	0	0	0	0	1359	1359	1359	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	580	580	580	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 4: Annual Dilbit Production Volume by Year by Baseline Scenario Carbon Credit Area, in Mbbl

Year	CCA 1	CCA 2	CCA 3	CCA 4	CCA 5	CCA 6	CCA 7	CCA 8	CCA 9	CCA 10	CCA 11	CCA 12	CCA 13	CCA 14	CCA 15	CCA 16	CCA 17	CCA 18
0																		
1	2668	2134	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	8263	8085	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	8042	8138	2098	1748	1399	1200	1117	1640	838	0	0	0	265	0	0	0	0	0
4	10395	10060	7423	7074	6666	8894	9161	7380	6218	0	0	0	3184	0	0	0	0	0
5	10310	10473	8159	8223	8277	10169	10725	9840	10061	0	0	0	4209	0	0	0	0	0
6	8543	8678	9217	8874	8525	11587	12120	10348	9680	0	0	0	4044	0	0	0	0	0
7	7081	7192	10623	10791	10962	12678	13511	12970	13871	5212	5212	5212	8687	4864	4337	6502	1967	0
8	5870	5963	8802	8941	9082	10000	10307	9892	10581	9623	9623	9623	10392	10538	10882	12004	6285	0
9	4868	4945	7295	7410	7527	7585	7869	7552	8076	8544	8544	8544	8741	9606	9997	10285	6808	0
10	4039	4102	6047	6143	6239	5884	6016	5772	6171	12405	12405	12405	10443	12650	12972	14608	12817	0
11	3352	3404	5015	5094	5174	4574	4605	4417	4722	10440	10440	10440	8530	11456	11640	11544	13345	3446
12	2783	2827	4160	4225	4291	3565	3532	3387	3619	8406	8406	8406	6735	8970	8961	8696	11353	8099
13	2313	2349	3452	3506	3561	2787	2714	2602	2779	6772	6772	6772	5330	7039	6914	6563	10544	7396
14	1923	1953	2866	2911	2956	1122	938	1231	1656	5459	5459	5459	4228	5540	5351	4965	7445	8552
15	1600	1625	2381	2418	2456	430	0	0	0	4403	4403	4403	3363	4374	4155	3767	5287	7210
16	472	594	1979	2010	2041	357	0	0	0	3555	3555	3555	2684	3466	3146	2659	3782	4881
17	0	0	1647	1672	1698	297	0	0	0	2874	2874	2874	1683	2759	1563	0	361	3315
18	0	0	830	956	1084	209	0	0	0	2326	2326	2326	0	404	896	0	0	1602
19	0	0	0	0	0	0	0	0	0	1885	1885	1885	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	805	805	805	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

All evaluation inputs and assumptions are identified such that results are reproducible from the stated datasets and methods, where a summary of inputs is available in the Appendix 1. GLJ applied normal engineering uncertainty as described in Appendix 1. The CBDP effective date is assumed to be December 31, 2025, and run to economic limit. The development and economic modeling software used for the evaluation is GLJ's FRED 12.1.42 version. The final version of all component and final documents for this CBDP have been archived by GLJ in the event any are needed for future reviews.

SURMONT ENERGY LTD.

WILDWOOD SAGD PROJECT
CREDIBLE BUSINESS DEVELOPMENT PLAN EVALUATION

Effective December 31, 2025

Prepared by
Kim Mohler, P.Eng.
Niloufar Rahimof, E.I.T.
Miranda Stoffman, P. Geo.

The analysis of this property as reported herein was conducted within the context of an evaluation of a distinct group of properties in aggregate. Extraction and use of this analysis outside this context may not be appropriate without supplementary due diligence.

WILDWOOD CBDP

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**Wildwood SAGD Project**	Pricing:	**3 Consultants' Average (2025-07)**
	SAGD PROJECT	Effective Date:	**December 31, 2025**
	Product Type: Bitumen		

Summary of Volumes and Values

	CBDP Estimate – Base
MARKETABLE RESERVES	
Bitumen (Mbbl)	
Gross Lease	376,104
Total Company Interest	376,104
Net After Royalty	287,089
Oil Equivalent (Mboe)	
Gross Lease	376,104
Total Company Interest	376,104
Net After Royalty	287,089
BEFORE TAX PRESENT VALUE (M$)	
0%	8,857,034
5%	4,717,276
8%	3,231,748
10%	2,502,582
12%	1,927,209
15%	1,279,649
20%	587,658
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)	
2026	-50,500
2027	-167,280
2028	-334,124
2029	-263,067
2030	-1,459,144
2031	28,163

BOE Factors:								
	HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
	COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

* LPG factor is reported in barrels per metric tonne

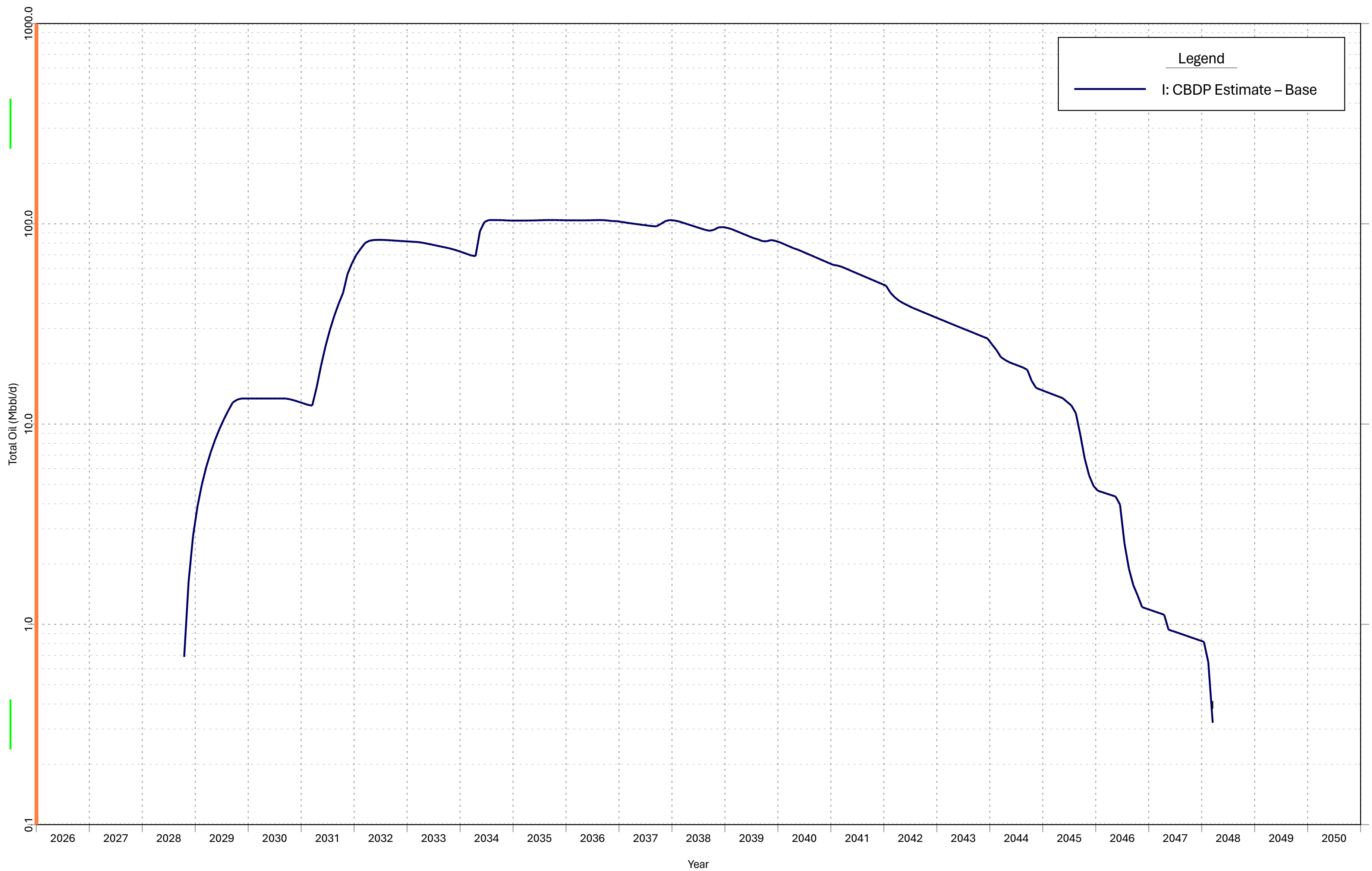
Run Date: November 21, 2025 15:02:55

GLJ

Forecast Production

Company:	**Surmont Energy Ltd.**	Pricing:	**3 Consultants' Average (2025-07)**
Property:	**Wildwood CBDP**	Effective Date:	**December 31, 2025**
Description:	**Wildwood SAGD Project**		

Gross Lease Total Oil



GENERAL

The Surmont Energy (the Company) Wildwood property is located in Townships 081 to 083, Ranges 07 to 09 W4M, as illustrated on Map 1. The target formation for development is the bitumen saturated sands of the Cretaceous McMurray Formation which is present throughout the general area. The depth of the formation in the Wildwood property is 450-500 m. Reservoir and rock properties have been derived from core holes within the regions, where many sections remain undrilled. The Company plans to use steam assisted gravity drainage (SAGD) technology as the recovery process to develop the Wildwood lease, which is proven as the only viable technology for bitumen recovery from the McMurray formation in the region of the property.

GLJ Ltd. (GLJ) has prepared an evaluation for a scenario referred to as "Credible Business Development Plan" (CBDP), which reflects a plan for future development of the Wildwood SAGD Project starting with the approved Phase 1 with an oil capacity of 12,000 bopd and a future expansion. This scenario is based on GLJ's bitumen net pay mapping.

The evaluation has been conducted based on 100% working interest with a Gross Overriding Royalty (GORR) of 1% based on information provided by the Company for land ownership and encumbrances. Map 2 shows the interest lands.

GEOLOGY

Regional Overview

The McMurray Formation was deposited within valleys and later over highs that were erosionally sculpted on the Devonian surface during exposure prior to McMurray deposition. Sedimentation occurred as a valley-fill succession and a complete McMurray section includes fluvial dominated continental deposits, an estuarine channel complex, and brackish-marine sediments. Tidal flat deposits may also be present, either coeval with the estuarine channels or along the paleoshorelines of the brackish-marine bays, during the uppermost McMurray times. The bulk of preserved sediments were deposited in an estuarine channel facies, with little preservation (possibly little deposition) of the tidal flat facies. Brackish-marine sediments were originally extensive; however, pervasive erosion by later estuarine channels has resulted in limited preservation of the brackish marine sediments. A transgression at the end of McMurray time resulted in the deposition of marine mudstones, muddy-siltstones and muddy-sandstones of the Wabiskaw Member.

McMurray Stratigraphy

The Alberta Energy Regulator (AER), formerly the Energy Resources Conservation Board (ERCB), and general industry have accepted a broad stratigraphic model (Figure 1) within the Wabiskaw/McMurray sequence which is described in the ERCB Athabasca Wabiskaw-McMurray Regional Study (Report 2003A). The Wildwood property is within the ERCB report area and the naming conventions have been adopted for this study. This convention, which is based on wells into the brackish-marine facies, terms the uppermost McMurray sandstone the 'A' sand and the lowermost sandstone the 'C' sand. (These 'sands' may actually consist of two or three separate coarsening upwards sequences separated by thin mudstones). The 'B1' and 'B2' sands are present in-between. The bases of the 'A' and 'B2' sands are marked by regionally extensive mudstones, which are the key to the correlations. The 'C' interval has been further subdivided into upper, middle and lower intervals by GLJ to reflect local channel development. Channels are named by the interval in which the channel top is present. Estuarine channel trends may follow lows on the Devonian unconformity surface. This can result in the vertical stacking of channels, which can create thick bitumen reservoirs, but also make it quite difficult to determine the age of lower channels. A concerted effort has been made to identify the ages of different channel trends and map these channels accordingly.

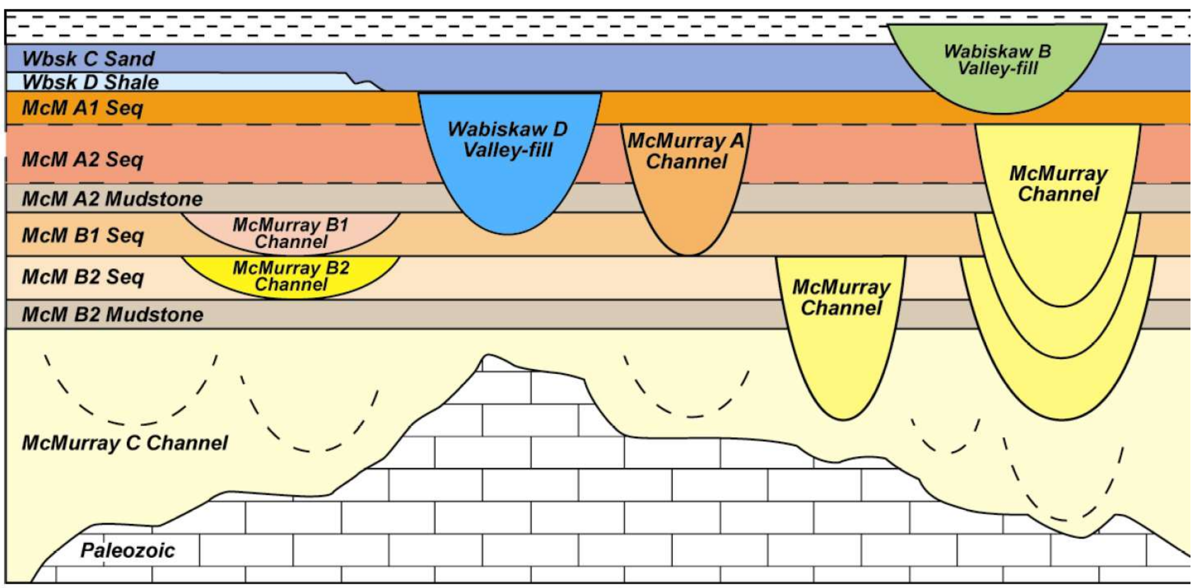


Figure 1: Stratigraphic Model modified from Athabasca Wabiskaw-McMurray Regional Geological Study, 2003

McMurray Sedimentology

The McMurray Formation was deposited within valleys and later over the highs of the underlying karsted surface of the Devonian carbonates. Sedimentation occurred as a valley-fill succession and a complete McMurray section includes fluvial dominated continental deposits, an estuarine channel complex, and brackish-marine sediments. Tidal flat deposits may also be present, either coeval with the estuarine channels or along the paleo shorelines of the brackish-marine bays, deposited during the uppermost McMurray times. The thickness of the continental deposits is uncertain in the Report 2003A study area due to poor core control, but this interval appears to be mud rich and frequently wet where porous sandstones are present. Estuarine channel deposits form the bulk of preserved sediments, with little preservation and possibly little deposition of the tidal flat facies. Brackish-marine bayfill sediments were originally extensive, however, pervasive erosion by later estuarine channels has resulted in limited preservation within the Report 2003A study area. A transgression at the end of McMurray time resulted in the deposition of the marine shales, shaley-siltstones, and shaley-sandstones of the Wabiskaw Member.

Reservoir Facies

Cross Bedded Sandstone

The best SAGD reservoir occurs in high-angle cross-bedded sandstone. This facies forms a homogeneous blocky sandstone with relatively few shale breaks and is generally seen in the lower portion of the estuarine sediments. Two possible origins have been postulated concerning the depositional environment of the high-angle cross-bedded sandstone facies. The older interpretation infers deposition in a high-energy channel environment within the inner (upstream) portion of an estuary. A second interpretation suggests an origin in the outer portion of an estuary. In this model, the sands accumulate as mega ripple dunes within a tidal bar towards the base of the estuarine sequence. Stacking of individual dunes results in a thick sequence of clean and porous sandstones. Progradation of the estuary seaward would result in partial erosion and then burial of the dune sands by estuarine channel sediments.

The McMurray Formation was deposited in a dynamic and complex environment. It seems likely that there is more than one depositional environment for the cross-bedded sandstone that provides the best McMurray reservoir. It may be possible to use the thickness of the cross-bed sets and trace fossil evidence to determine the origin of this facies. The different depositional settings are expected to result in different geographic trends for this sandstone. In the Wildwood area, this cross-bedded sandstone has the highest average porosity and the highest oil saturations.

Inclined Heterolithic Sandstone

A more complex reservoir occurs in the sand-rich inclined heterolithic stratified sandstones (IHS) deposited within meandering point bars. The IHS forms on the flanks of estuarine point bars as flat to low angle interbedded sandstone and mudstone. Sand rich sediments are deposited during periods of seasonal flooding accompanied by a relative freshening of salinity. Mudstone rich sediments form during periods of lower runoff when fluvially transported clay particles flocculate and are deposited as they contact brackish or marine waters. Seasonal changes in amounts of runoff cause the contact between the fresh fluvial waters containing the fine clay particles and the salt water ‘wedge’ of marine water to migrate up or downstream. Although individual mudstone layers may terminate laterally through non-deposition (for example into higher energy sandstones in a deeper portion of the channel) or through erosion by a younger channel activation sequence, these mudstone layers may still have a detrimental effect on steam chamber growth. While thin mudstone beds may act as baffles to the steam chamber, thicker and more regionally extensive mudstone layers form vertical barriers forcing preferential steam movement along individual sandstone lenses rather than vertically breaching the mudstone beds.

Mud Clast Breccia

Mud clast breccias represent a channel facies that contains broken pieces of mudstones that have slumped into the channel and may be carried short distances by the currents. The mudstone clasts become mixed in with sand grains which then act as a matrix for the mudstone clasts. This allows the movement of steam or heated bitumen through the breccia when it is under SAGD stimulation. Permeability measurements taken in McMurray mud clast breccias suggest a range from as low as 10 up to 500 mD. The mudstone pieces originate from both over-bank deposits and IHS mud beds. This process results in a generally limited aerial extent for the breccia facies and suggests that while the brecciated sandstones do not form good reservoir, they also do not act as a permeability barrier to the SAGD process. Brecciated sandstones (except those with the greatest density of mudstone and having a Bulk Mass Oil (BMO) value less than 0.045) have been included in SAGD net pay values. Those breccia intervals that have a BMO value of 0.045 or greater, while included in net pay, have been assigned an average porosity value of 16 percent.

Mud Filled Channel

Mudstone-filled channels can occur within the McMurray section. On logs, mudstone-filled channels are indicated by a high gamma value, a large separation between the neutron and density curves, and a consistently low and flat resistivity curve. On cores, two different facies are apparent. In the first, the mudstones are flat laminated with generally low levels of bioturbation, the second facies contain low angle bedding suggestive of IHS and has variable amounts of bioturbation. The importance of these channels stems from the fact that they can be over 30 metres in thickness and are erosive in nature so may have removed potential reservoir rock that was deposited in earlier channels. Gas caps and ‘lean’ or ‘flushed zones’ are also commonly associated with bitumen reservoirs. These are zones of low oil saturation overlying, and in communication with the bitumen. Under SAGD stimulation these intervals will receive steam and heat from the steam chamber but contribute limited amounts of oil production. The gas caps formed in structural highs prior to or coeval with biodegradation and immobilization of the McMurray oil. Later structural changes occurred associated with the Larimide orogeny and dissolution of underlying Devonian Elk Point salts. This occasionally resulted in breaching of the spill point for the gas caps and dissipation of some of the gas. A ‘lean’ or ‘flushed zone’ formed where water has migrated in to replace the gas. Bitumen saturations over the gas caps and flushed zones typically average less than 25 percent. Flushed zones can be differentiated from bottom water by the resistivity of the zones. Bottom water zones have lower bitumen saturations and are typically in the 3 to 5 ohm-metre range while the flushed zones may be 10 ohm-metres or more.

Mapping Methodology

GLJ used the following data from publicly available sources and internal GLJ data for the Surmont Wildwood property evaluation: wireline logs, core photos and core analyses.

Net Continuous Bitumen Pay Criteria

Effective pay is designated as the porous, bitumen-bearing zone accessible by a steam chamber created around a horizontal well pair. GLJ uses three principal criteria to evaluate net continuous bitumen pay:

1. Bulk Mass Oil (BMO) from Dean Stark analysis of cored samples.
2. Wireline log porosity.
3. Visual estimation of volume of shale (Vshale) from core photos.

Reservoir grades are assigned based on a visual estimation of Vsh and distribution of the shale within an interval. This grading approach allows GLJ to determine if the shale in the zone will potentially impede the expansion of the steam chamber. This data contributes to the conformance factor algorithm and enables consideration of vertical heterogeneities

Reservoir grades range from A to D depending on the Vshale over an interval (see table below). This grading approach is used because it allows flexibility between different depositional environments (independent of facies changes) in the Athabasca Oil Sands area.

Grade	Vsh %	Vsh avg
A	0%-3%	0.0%
B	3%-10%	5.0%
C	10%-20%, beds <15 cm	15.0%
D	20%-50%, beds >15 cm	30.0%

Net continuous bitumen pay is defined as a zone exhibiting greater than 27 percent porosity, greater than 0.07 BMO and less than 30 percent average Vshale. Some lower McMurray channel sandstones that are clean, coarse grained and poorly sorted are still very permeable and are viable SAGD reservoirs at less than 27 percent porosity and are therefore included in the net bitumen pay. Zones of 5 meters or less of D grade reservoir are included in the net pay if the zone is present above the proposed horizontal well pair

In addition to Vshale/grades, GLJ also uses shale thickness thresholds that are considered to be vertical permeability barriers depending on the depositional environment in which the reservoir is located. A mudstone horizon may act as a vertical permeability barrier to steam chamber growth depending on its thickness, lateral extent, and pad layout. The actual thickness of a barrier is still under debate within industry and evidence exists for barriers both greater than and less than 1 metre. Unless local production has demonstrated otherwise, estuarine mudstones greater than 1 metre thick are interpreted as barriers. The subsequent remaining bitumen pay would then be assigned to another zone. GLJ considers the presence of mudstones more detrimental when they are present between the horizontal well pair. During the startup of a steam chamber, steam 'communication' between horizontal wells 5 metres apart is established over a period of 3 to 6 months. The presence of significant mudstone could increase the time to establish communication beyond hope of economic success. For this reason, the base of pay has been moved above any mudstone greater than 0.2 metres in thickness.

The base of the net continuous bitumen is chosen using core photos and log analyses. The base is chosen at the base of a sand rich facies with limited mud content between a hypothetical injector and producer. Thin individual muds may not impact communication between a hypothetical injector and producer but multiple mud layers acting as a unit may negatively impact the steam chamber growth and production results, forcing the base of pay to be shifted upwards into cleaner sands. The lowermost (McMurray C channels) are the most likely to be confined to the valleys on the Devonian surface. The net pay mapping is shown in Map 3.

Volume Estimation

GLJ has prepared gross lease estimates of bitumen volumes for the property. Recoverable bitumen volumes are grouped and forecast by drainage patterns and are referred to as pads in this evaluation report, and are also referred to as Subsurface Drainage Areas (SDA). Drainage patterns are typically adjacent well pairs and infill producer wells drilled from the same surface multi-well pad, placed on production at approximately the same time.

The inter-well spacing for the Wildwood project well pairs is planned to be 100 metres upon initial development. All defined undeveloped drainage patterns are identified by a pad name in the Maps section of this report and grouped by type curve as shown in Table 1. Type curves represent the average performance of a group of drainage patterns which are expected to have similar performance metrics based on geologic quality and geographic location. The five type curves for the Wildwood project have been grouped as follows: ABCDE, FGH, NOP, JKL, and QRS. These drainage boxes are shown in Map 4 and represent the area that can be technically recoverable, before economic cutoffs are applied.

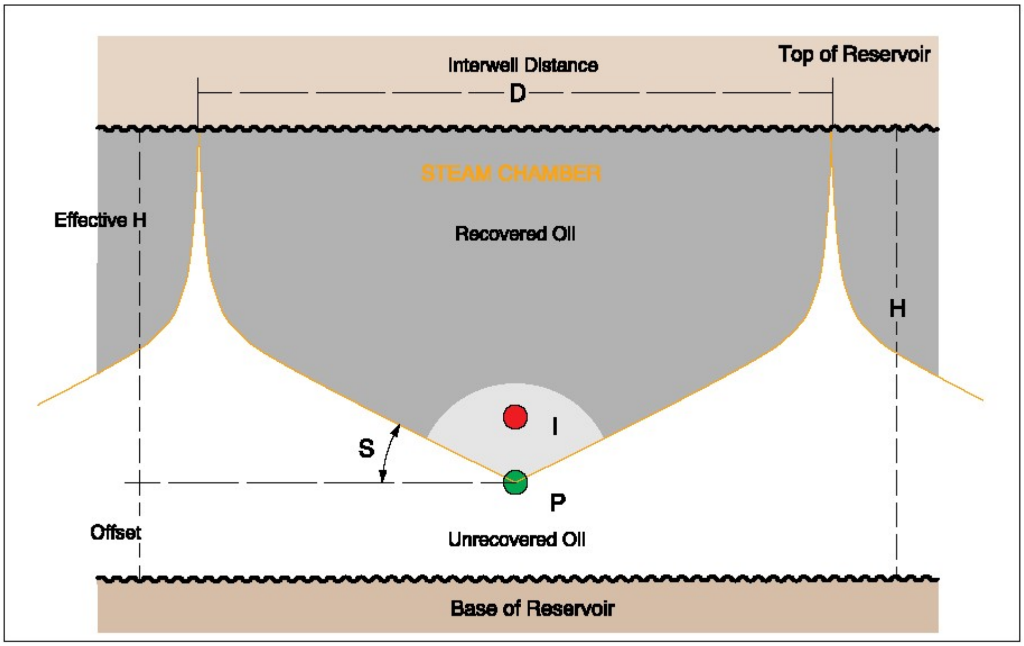
Recovery factor parameters were estimated with considerations to performance from other operational SAGD projects within the Athabasca region and proximal to the Wildwood property. The technical volumes estimated for Wildwood, which include exploitable Bitumen Initially in-place (BIIP) and ultimate recoverable bitumen in-place (RBIP) are detailed in Table 1, which is before economic cutoffs. Infill producer wells are included in all patterns as indicated in Table 1.

Net pay has been designated as the vertically continuous oil (bitumen) pay present that is interpreted to be suitable for the SAGD recovery process based on GLJ's net pay mapping which is presented in Map 4 and described in the Geology section of this report. The BIIP has been estimated using rock volumes, average porosities derived from petrophysical analyses and average BMO, derived from core analyses.

Volume estimates have been prepared based upon SAGD recovery process with Infills for all patterns. Evidence of the success of these recovery processes is based on:

- Recovery factor algorithm developed by GLJ based on gravity drainage theory, the performance of operational SAGD and a review of simulation studies conducted by other operators in similar reservoirs.
- Performance of analogous commercial SAGD projects producing bitumen from the McMurray formation including AOC Leismer, Connacher Great Divide, Greenfire Hangingstone, Greenfire Hangingstone Expansion, and AOC Hangingstone.
- Success of the SAGD recovery process in sandstone reservoirs throughout the Athabasca Oil Sands Region, with focus on the McMurray bitumen reservoirs.

The following figure is a two-dimensional cross section through a SAGD steam chamber, illustrating the idealized portions of the reservoir that are expected to be drained:



The recovery factor algorithm incorporates the following sweep efficiencies:

- Displacement efficiency (E_d) – E_d has been calculated using initial average water saturation of 19 percent, as indicated in Table 1, and residual oil saturation of 8 percent.
- Gross vertical sweep efficiency (E_v) – E_v is the ratio of the net pay thickness above the producer (effective pay) divided by the total continuous net pay. For undeveloped well pairs with no bottom water average producer well stand-offs have been estimated at 1.5 metres.
- Gross horizontal sweep efficiency (E_h) – E_h is a function of the slope of the bottom of the steam chamber at depletion, inter-well spacing, and net pay thickness above the producer. In the absence of associated lean oil and gas zones, the slope of the steam chamber at depletion has been estimated at 10 percent for all patterns. Well spacing has been scheduled at 100 metres.
- Conformance factor (E_c) – E_c accounts for remaining sweep inefficiencies including uneven steam heating along the wellbore or within the reservoir, heterogeneities and local permeability breaks in the reservoir, operational upsets, and perceived risk due to uncertainties in the recovery process. This factor has been estimated at 92.5 percent for undeveloped patterns.

GLJ has applied the recovery factor algorithm to the vast majority of thermal projects within the Athabasca and Cold Lake Oil Sands Region. Results from this work are used to tune the recovery factor and production forecast model for use with non-producing and early life projects. These aforementioned sweep efficiencies are then used to estimate ultimate recovery factor and production profiles for undeveloped patterns. Sweep efficiency parameters are estimated by analogy to patterns with extended performance with consideration for reservoir differences.

The primary drivers for ultimate recovery factor are initial oil saturation, porosity, net pay thickness, well placement and operating conditions. Effective vertical permeability, reservoir thickness, fluid viscosity profile and operating conditions are primary drivers for production performance. As no two thermal projects are ever exactly alike, GLJ has considered multiple analogues when forming its opinion, each of which has one or more analogous parameters.

Performance from analogous projects has been utilized to tune the recovery factor and production forecast models used for Wildwood by adjusting for differences including but not limited to:

- Reservoir properties: Net pay thickness, initial oil saturation, horizontal and vertical permeability, grain size and mineralogy, reservoir depth, depositional environment, and reservoir facies.
- Fluid properties: Oil gravity, viscosity profile and solution gas present.
- Presence of reservoir impairments: Top gas and lean zones, mid lean zones, and bottom water; including magnitude of those impairments.
- Operating strategy: Well placement, pattern layout, startup techniques, fluid injection strategy, operating pressure, well design and artificial lift.

Appendix I shows volumetric assumptions, forecast bitumen production and SOR profiles, normalized by pad and well pair, for each type curve.

Recoverable oil volumes were estimated for each type curve grouping using the above recovery factor algorithm based upon 1200 to 1420-metre-long horizontal wells, spaced at 100 metres apart and incorporating drainage at each end of the well pair/infill well.

To optimize recovery and performance, infill drilling has been included in the scenario development plan. Infill producers are planned in between the original SAGD well pairs following several years of production. Incremental infill recovery has been determined using the same recovery factor algorithm as described above with reduced inter-well spacing, due to infill wells. Infill wells are included for development of all Wildwood patterns.

Recovery factors were assigned in consideration of technical risk associated with the process. A review of the recovery factors predicted in various laboratory studies and demonstrated at the Underground Test Facility (UTF) suggests 60 to 80 percent recovery. SAGD has been applied in numerous reservoirs in Athabasca, none of which are perfectly analogous but all of which are considered in forming our technical opinion on performance. Recoveries have been scaled for reservoir and fluid differences at Wildwood considering performance across the Athabasca Oil Sands.

To optimize steam requirements and SOR, GLJ has scheduled two phases of non-condensable gas (NCG) co-injection. The first is early life NCG co-injection to manage reservoir pressure and reduce SOR, which is started at the same time as the start of the infills. This early life NCG has an associated steam reduction of 9 percent applied. The second phase is a blowdown process, referred to as Late life NCG co-injection, and is included in all patterns to start 24 months before last production with reduction of steam coincidental to NCG co-injection of 40 percent, and is part of the Blowdown process at end of well life.

PRODUCTION AND DEVELOPMENT FORECAST

The development scenario assumes the Wildwood property includes two phases.

- For Phase 1, per AER approval:
    - Oil capacity of 12,000 bopd and steam capacity 36,000 bspd, assuming start-up in 2028
- For Phase 2:
    - Facility Expansion is planned to add 75,000 bopd oil capacity and 262,500 bspd steam capacity, starting in 2031.

Production forecasts were determined for each of the type curves. Peak production rates have been estimated based upon analytical model computations that have been calibrated considering well length, interwell spacing, reservoir properties, fluid properties and operating strategy, and analog projects.

The type curve ramp up incorporates three months of steam circulation before conversion to continuous steam injection and production. The forecasts have been prepared based upon an estimated average operating pressure of 2MPa. Production has been forecast to reach the peak by the end of the year on-stream. The type curves incorporate downtime and are therefore indicative of anticipated calendar day production rates.

The SOR forecast has been estimated based upon analytical model computations; including heat loss to over-burden and under-burden and heat loss to reservoir impairments. Like the peak rate model, the analytical SOR model has been calibrated using results from analogous projects. Estimates of SOR specific to Wildwood were determined by applying well layouts, fluid and reservoir properties and operating strategy parameters to the calibrated models. The range of SORs estimated reflects the range of uncertainty in the analogue model predictions.

Infill production wells are included for all drainage patterns where the total recoverable volume estimated for each original well pair plus infill; approximately 60 to 70 percent has been allocated to the original well pair with the remaining to the infill producer, allowing for acceleration of production. Infill producers have been scheduled to commence production three years after the initial well pairs at a rate of approximately 70 percent of the peak rate of the initial well pairs. Initial infill steam injection has been forecast for 3 months as it is anticipated there will be some pre-heating associated with the original steam chamber development. The infill model is based on a review of the existing SAGD infill drilling programs.

The GLJ model schedules well drilling based on the scenario phased development for available steam and oil capacity, which may vary from the Company's drilling plans or other possible development scenarios. Facility downtime factors have been incorporated based on typical SAGD plant reliability data.

ECONOMIC ANALYSIS

In the economic analysis, all costs are in 2026 dollars, and all revenue and costs are in Canadian currency.

The capital and operating costs are presented in the production and development forecasts provided in Tables 2 and 2.1, and key economic input assumptions are detailed in Table 3.

Operating costs have been forecast as fuel and non-fuel costs. Fuel costs have been forecast based on fuel to steam efficiency, forecast steam requirements, late life and early life NCG injection requirements and forecast fuel gas prices. Non-fuel costs have been forecast based on fixed well related costs, variable costs, and fixed annual facility costs. The operating costs have been based on GLJ's knowledge of similar projects. Operating cost metrics on a dollar per barrel basis are provided for reference in the production and development forecast tables.

Capital costs include well drilling, completion and equipping costs, downhole pump costs, multi-well pad costs, infrastructure costs, central processing facility (CPF) costs, well and facility maintenance costs, and delineation drilling costs. Pad costs include surface construction, equipment, interconnecting pipelines and trunk lines, observation wells and instrumentation, and the pad access road. Infrastructure includes water source and disposal, fuel gas supply, utilities and power supply, and all-weather access roads and bridges (where required). The CPF costs include fluid separation, produced gas treatment and H_2S removal, bitumen treatment including de-sanding, diluent tankage, de-oiling, water treatment and recycle, steam generation, regulatory, engineering, construction, camp, commissioning, site buildings (office, maintenance shop and warehouses), and security. The capital costs have been based on benchmarked data from GLJ's knowledge of similar projects. Operating and capital cost inflation has been based on GLJ's current price forecast.

Abandonment and reclamation costs have been included for all future wells as well as future central processing facilities. Well abandonment and reclamation costs include downhole abandonment as well as abandonment and reclamation of associated well pads and service pipelines, observation wells and other infrastructure. Well and facility abandonment and reclamation costs for Wildwood were forecast based on information derived from GLJ's knowledge of ARO from similar projects as detailed in Table 3.

Economic forecasts were prepared using the current Alberta Oil Sands royalty formula. Pre-payout, the base rate is 1 percent of gross revenue and increases for every dollar the WTI is priced above $55 per barrel, to a maximum of 9 percent when the WTI is priced at or above $120 per barrel. Post-payout, the base rate is 25 percent of net revenue and increases for every dollar the WTI is priced above $55 per barrel, to a maximum of 40 percent when the WTI is priced at or above $120 per barrel. An average annual return allowance of 2.5 percent was incorporated.

The development scenario assumes a dilbit product which uses condensate as the diluent. GLJ has modeled the netback pricing, based on dilbit sales to the WCS pool via pipeline, using quality differentials, transportation costs, diluent costs and blend ratios as detailed in Table 4. A blend ratio of 0.43 bbl diluent per bbl bitumen is based on delivery specifications. Blend ratio can also be referenced as approximately 30% bbl diluent per bbl dilbit. A shrinkage of 3% is assumed from wellhead to sales point for the dilbit which equates to a dilbit ratio of 1.3871.

The oil and gas price forecast utilized is the July 1, 2025 3 Consultant Average (3CA), which is described in Table 4. The 3CA is based on the price forecasts from the three leading Canadian oil and gas evaluation consulting firms, GLJ Ltd., McDaniel & Associates Consultants Ltd., and Sproule. Each of these companies have independently prepared their price and market forecasts. The arithmetic average of the three price and market forecasts are summarized after a comprehensive review of information. Information sources for GLJ's price forecast include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. GLJ's forecasts are based on an informed interpretation of currently available data. While the 3CA forecasts used for this evaluation are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market.

Carbon taxes associated with greenhouse gas emissions as part of Canadian Federal Greenhouse Gas Pollution Pricing Act and Alberta Climate Change and Emissions Management Act's Technology Innovation and Emissions Reduction (TIER) Regulation have been included. Carbon emissions for the facility were estimated based on expected rates per barrel of steam generation specific to the Wildwood Facilities. Carbon taxes have been included as variable operating costs based on forecast steam-oil ratios and target intensities, as outlined in the regulation. Carbon taxes were forecast at the federal legislated rate of $95 per tonne in 2025 and escalating to $170 per tonne by 2030. The Facility Specific emission benchmark tightening rates were revised per changes to legislation implemented at the end of 2024, where tightening is now 2 percent per year and increases to 4 percent per year in 2029. The credit usage limit was adjusted per the legislation to 90 percent in 2025 forward.

Other Economic Considerations

This report ***does not*** address the following issues:

- Non-resources well abandonment and associated wellsite reclamation and facility abandonment/salvage including possible environmental concerns.
- Potential processing income or any power sales.
- Electric power which could be primarily from a CoGeneration unit, either grid connected or local.

Map 1

Index Map
Property Locations

Company: Surmont Energy Ltd.

Property: Alberta

Effective Date: December 31, 2025

Project: s24958/indm01

Map 2

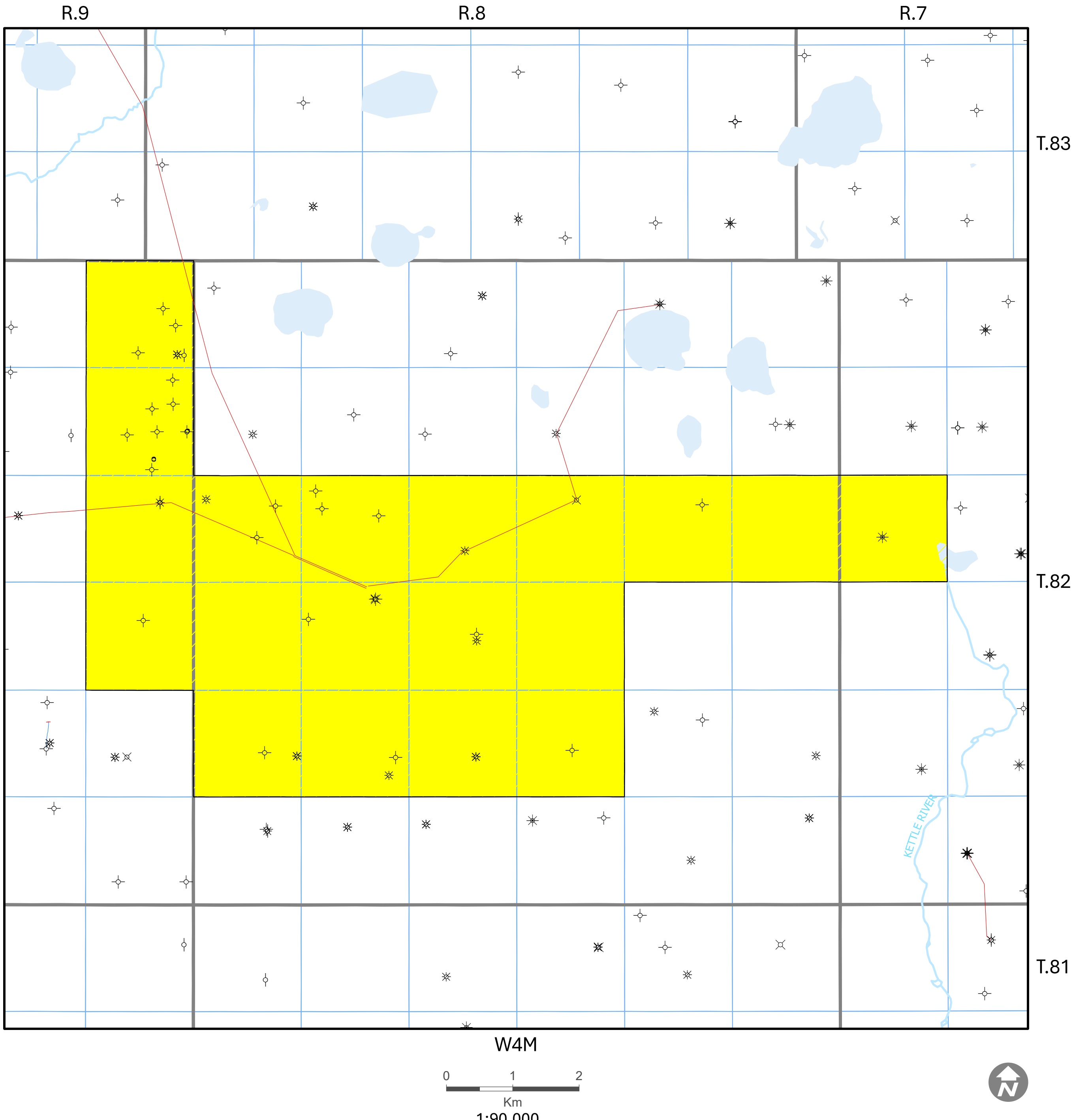
Land Map

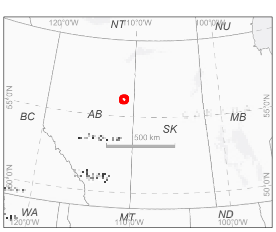
Company: Surmont Energy Ltd.

Property: Wildwood

Effective Date: December 31, 2025

Project: s24958/wildwood_lm



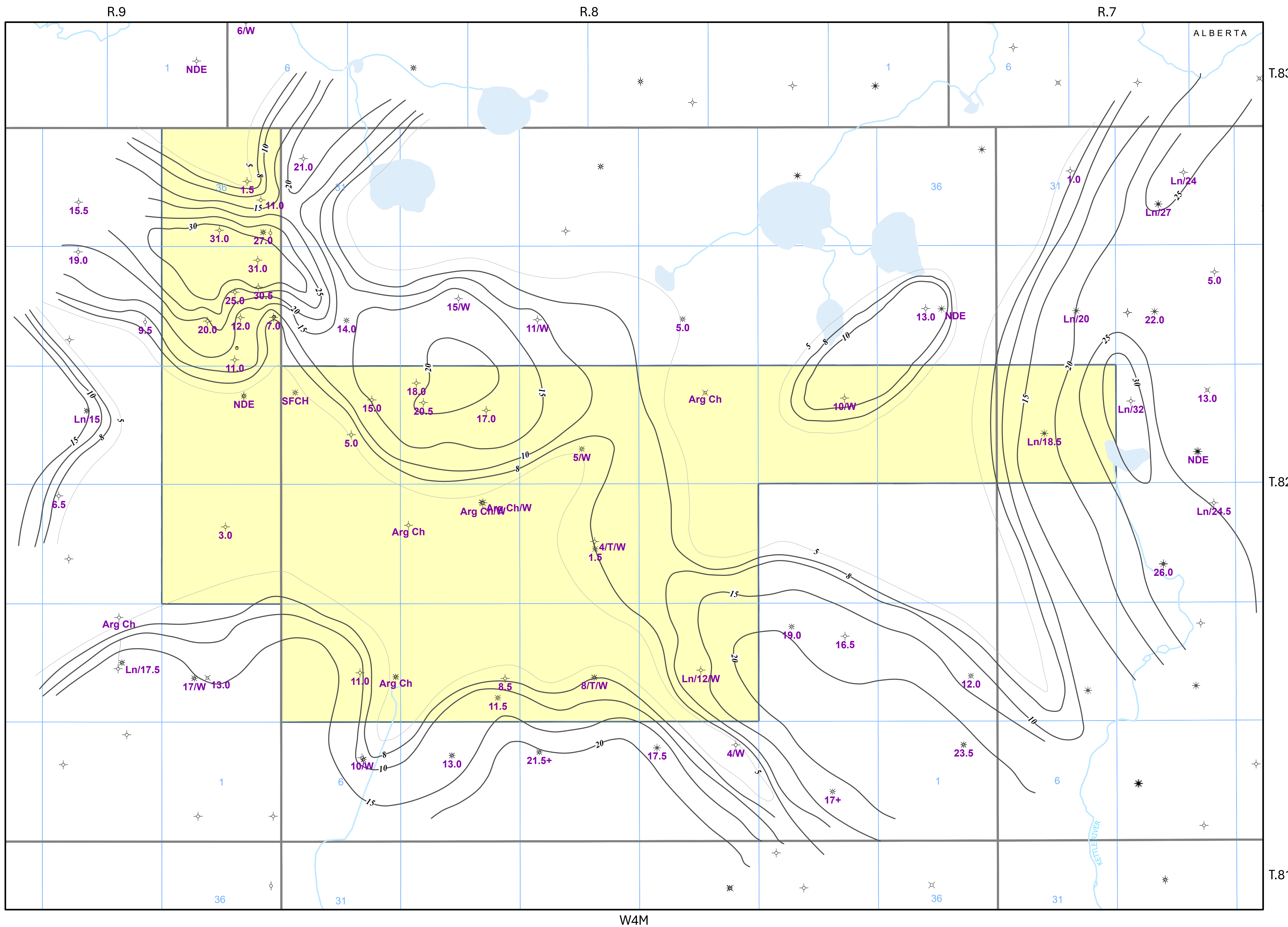


Interest Land

NAD 1983 UTM Zone 12N | Well Source: August, 2025 | Geologist: | Engineer: kmohler

P:\s24958\GIS\Wildwood\Wildwood.aprx | Created by: rsamonte | Created on: September 12, 2025

World Light Gray Reference: Esri, HERE
World Light Gray Canvas Base: Esri, HERE, Garmin, USGS, EPA, NRCan



Map 3

Net Pay Map
McMurray C Formation

Interest Land

5.3 *Net Pay (metres)*

Contour Interval = 5 metres

0 1 2
Km
1:55,000

Company: Surmont Energy Ltd.

Property: Wildwood

Effective Date: December 31, 2025

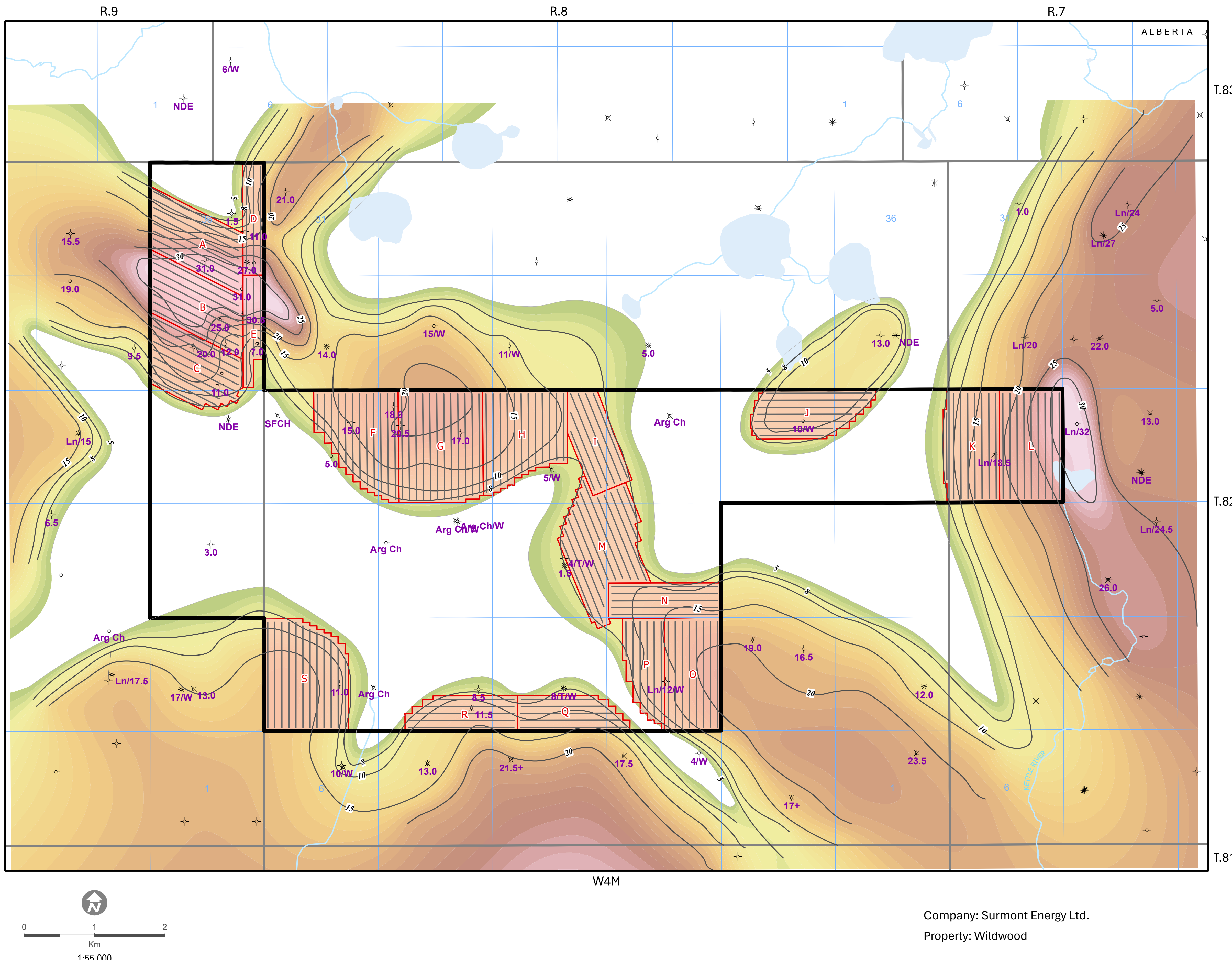
Project: s24958/wildwood_high_est_map3

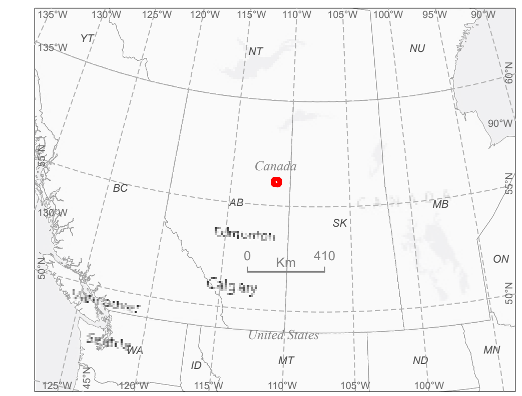
NAD 1983 UTM Zone 12N | Well Source: August, 2025 | Geologist: | Engineer: kmohler

P:\s24958\GIS\Wildwood\Wildwood.aprx | Created by: rsamonte | Created on: September 19, 2025

Map 4

Net Pay Map
McMurray C Formation





- Interest Land
- 5.3 *Net Pay (metres)*
- Contour Interval = 5 metres
- Proposed Pads

Company: Surmont Energy Ltd.

Property: Wildwood

Effective Date: December 31, 2025

Project: s24958/wildwood_high_est_map4

NAD 1983 UTM Zone 12N | Well Source: August, 2025 | Geologist: | Engineer: kmohler

P:\s24958\GIS\Wildwood\Wildwood.aprx | Created by: rsamonte | Created on: September 19, 2025

Historical and Forecast Production

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**Wildwood Thermal Project**	Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

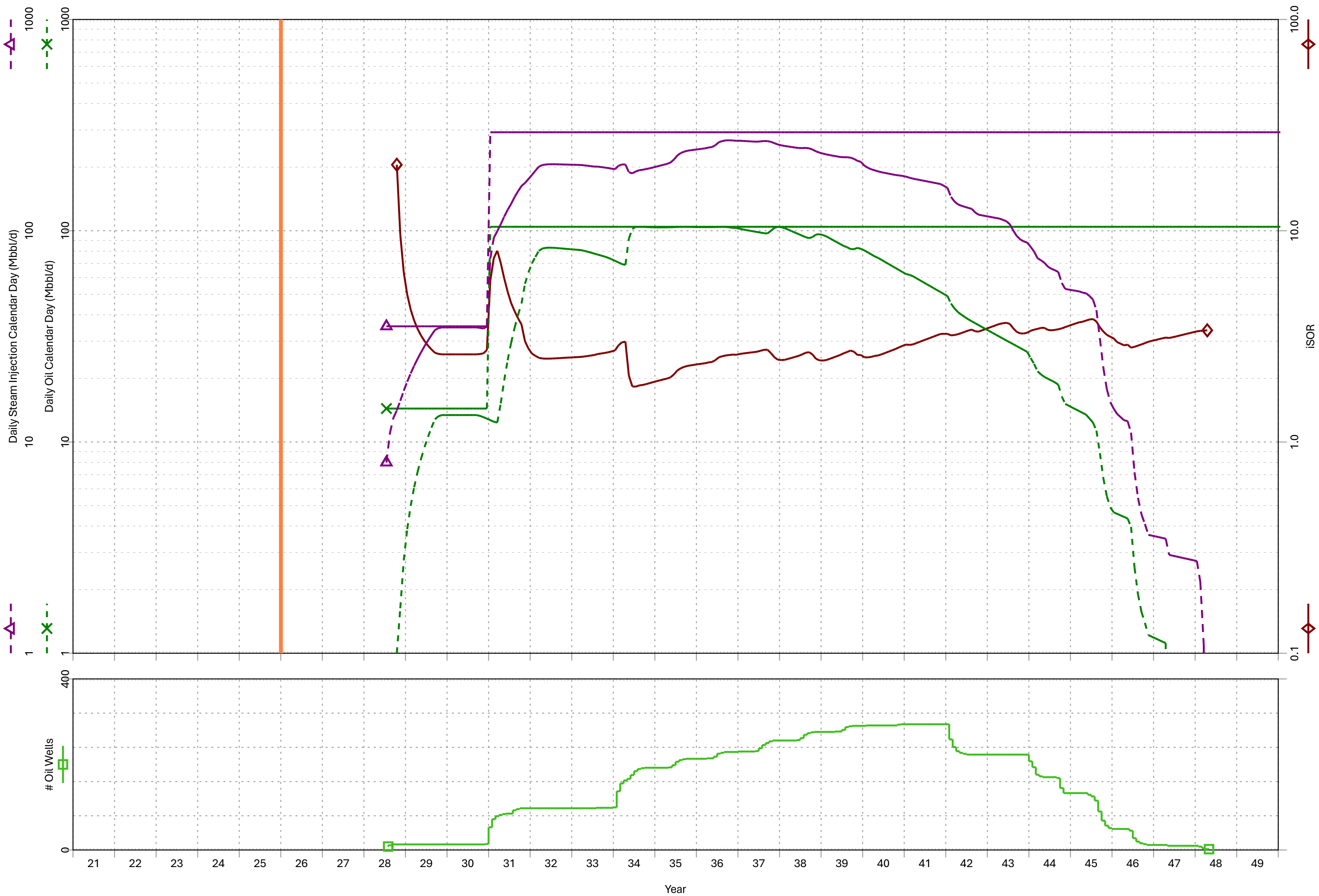


Table 1

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
		Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

Thermal Type Well Parameters

Entity Name	Class	Number of Wells Required #	Well Length m	Well Spacing m	Total Drainage Area acre	Net Pay m	Porosity %	Initial Water Saturation %	Formation Volume Factor	Bitumen Initially In Place Mbbl	Recovery Factor %	Original Recov. Bitumen Mbbl	Original Recov. Bitumen per Well Mbbl	Peak Rate per Well bbl/d	Cumul. SOR	Cumul. Production At Effective Mbbl	Remaining Reserves At Effective Mbbl	Cumul. SOR At Effective	Remaining SOR At Effective	Note
Wildwood CBDP																				
1) ABCDE	I	31	1,330	100	1,074	20.4	33.0	19.0	1.001	149,123	74.48	111,071	3,583	1,032	2.29	0.0	111,071	0.00	2.29	[1]
2) FGH	I	36	1,222	100	1,127	14.9	33.0	19.0	1.001	114,084	70.17	80,056	2,224	797	2.67	0.0	80,056	0.00	2.67	[1]
3) NOP	I	19	1,368	100	673	14.2	33.0	19.0	1.001	64,977	69.41	45,102	2,374	869	2.81	0.0	45,102	0.00	2.81	[1]
4) JKL	I	24	1,450	100	904	17.1	33.0	19.0	1.001	104,916	72.21	75,760	3,157	1,020	2.60	0.0	75,760	0.00	2.60	[1]
5) QRS	I	22	1,345	100	743	12.7	33.0	19.0	1.001	63,985	67.39	43,117	1,960	801	3.33	0.0	43,117	0.00	3.33	[1]
6) MI	I	18	1,272	100	588	8.8	33.0	19.0	1.001	35,398	59.32	20,999	1,167	615	2.94	0.0	20,999	0.00	2.94	[1]
Total: Wildwood CBDP		**150**								**532,483**	**70.63**	**376,104**				**0.0**	**376,104**			

Notes

1. Includes infill wells
2. Volumes may not match economic forecasts due to economic limit calculations.
3. Gross Lease

GLJ

Table 2.0

Company: **Surmont Energy Ltd.**
Property: **Wildwood CBDP**

Reserve Class: **CBDP Estimate**
Development Class: **Base**
Pricing: **3 Consultants' Average (2025-07)**
Effective Date: **December 31, 2025**

Production & Operating Forecast

Year	Producing Well Pairs	Producing Infill Wells	Bitumen Rate bbl/d	Steam Injection bbl/d	Annual ISOR	Water Production bbl/d	Annual IWOR	Fuel Gas Steam Mcf/d	NCG Injection Mcf/d	Gas Price Current $/Mcf	Operating Expenses Nat Gas 2026 M$	Fixed Well 2026 M$	Fixed Facility 2026 M$	Variable 2026 M$	Carbon Tax 2026 M$	Total 2026 M$	Total Current M$	Operating Cost Inflation Factor
2028	12	0	426	6,654	12.16	6,654	12.16	3,327	0	3.94	4,595	852	5,913	1,535	0	12,894	13,415	1.040
2029	13	0	9,619	28,681	3.22	28,681	3.22	14,340	0	4.01	19,766	1,872	20,160	8,037	0	49,835	52,885	1.061
2030	13	0	13,334	34,840	2.61	34,840	2.61	17,420	0	4.08	23,968	1,884	16,800	10,063	0	52,715	57,060	1.082
2031	80	11	30,572	129,710	5.11	129,710	5.11	64,855	734	4.16	90,137	11,917	111,254	33,986	71,812	319,106	352,319	1.104
2032	85	13	80,954	203,032	2.51	203,032	2.51	101,516	2,136	4.23	142,246	13,146	118,050	59,238	0	332,680	374,652	1.126
2033	85	13	78,095	201,730	2.58	201,730	2.58	100,865	1,927	4.31	140,839	13,206	118,050	58,431	213	330,739	379,915	1.149
2034	98	72	91,818	196,411	2.22	196,411	2.22	98,205	11,298	4.39	149,878	19,266	118,050	59,771	1,261	348,225	408,001	1.172
2035	120	82	104,060	222,067	2.13	222,067	2.13	111,034	12,337	4.48	168,632	23,226	118,050	67,624	0	377,532	451,186	1.195
2036	139	83	104,223	257,545	2.47	257,545	2.47	128,772	11,243	4.56	191,132	25,925	118,050	75,423	3,349	413,878	504,515	1.219
2037	148	92	100,164	263,932	2.64	263,932	2.64	131,966	11,755	4.64	195,937	27,922	118,050	76,081	7,014	425,004	528,439	1.243
2038	150	114	97,278	245,983	2.53	245,983	2.53	122,991	14,404	4.73	187,075	29,810	118,050	71,623	33,657	440,216	558,300	1.268
2039	150	132	86,947	223,044	2.57	223,044	2.57	111,522	16,270	4.82	173,783	31,118	118,050	64,714	80,733	468,398	605,923	1.294
2040	150	141	72,165	190,288	2.64	190,288	2.64	95,144	21,226	4.91	158,058	31,787	118,050	54,843	85,476	448,214	591,409	1.319
2041	150	144	56,465	171,966	3.05	171,966	3.05	85,983	19,018	5.00	142,445	31,968	118,050	47,966	106,685	447,114	601,757	1.346
2042	120	115	39,501	130,615	3.31	130,615	3.31	65,308	17,768	5.10	112,568	25,512	118,050	35,814	90,057	382,001	524,405	1.373
2043	114	109	29,997	104,492	3.48	104,492	3.48	52,246	19,300	5.19	96,834	24,264	87,911	28,358	75,452	312,819	438,022	1.400
2044	86	82	19,619	67,264	3.43	67,264	3.43	33,632	16,884	5.29	68,294	18,215	55,028	18,311	47,915	207,763	296,737	1.428
2045	55	53	11,040	40,146	3.58	40,146	3.58	20,073	10,054	5.39	40,685	11,799	41,686	10,807	30,020	134,995	196,663	1.457
2046	17	16	3,011	8,791	2.92	8,791	2.92	4,395	2,969	5.49	9,934	3,539	19,739	2,475	5,311	40,998	60,921	1.486
2047	5	5	972	3,066	3.16	3,066	3.16	1,533	972	5.60	3,375	1,136	11,894	849	2,019	19,272	29,209	1.516
2048	3	3	161	541	3.36	541	3.36	271	161	5.70	582	213	2,759	148	378	4,079	6,307	1.546
Total: W...											**2,120,762**	**348,576**	**1,671,692**	**786,097**	**641,352**	**5,568,479**	**7,032,042**	

Notes
1. Gross Lease

Table 2.1

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
		Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

Production & Development Forecast

	Well Development			Well Costs					Facility and Infrastructure Costs				Total Costs		
Year	Well Pairs Startup	Infill Wells Startup	Delineation Wells	In-Situ Wells D/C/AL 2026 M$	In-Situ Wells Pad/Gath 2026 M$	In-Situ Wells Total 2026 M$	Maintenance Capital 2026 M$	Delineation Wells 2026 M$	CPF 2026 M$	Infrastructure 2026 M$	Cogen & Other 2026 M$	Maintenance 2026 M$	Total 2026 M$	Total Current M$	Capital Cost Inflation Factor
2026	0	0	5	0	0	0	0	2,500	48,000	0	0	0	50,500	50,500	1.000
2027	0	0	10	0	39,000	39,000	0	5,000	120,000	0	0	0	164,000	167,280	1.020
2028	13	0	0	91,000	0	91,000	1,183	0	223,875	0	0	704	316,762	329,559	1.040
2029	0	0	10	0	0	0	2,600	5,000	379,687	0	0	2,400	389,687	413,539	1.061
2030	1	0	0	468,000	252,000	720,000	2,617	0	835,312	0	0	2,400	1,560,329	1,688,950	1.082
2031	71	13	10	72,774	0	72,774	16,551	5,000	151,875	0	1,000	14,148	261,348	288,550	1.104
2032	0	0	0	968	4,000	4,968	18,258	0	0	0	0	17,588	40,813	45,962	1.126
2033	1	0	5	201,621	92,200	293,821	18,341	2,500	0	0	4,000	17,588	336,250	386,245	1.149
2034	24	70	0	220,887	84,000	304,887	26,758	0	0	0	1,000	17,588	350,233	410,353	1.172
2035	21	0	3	114,500	4,000	118,500	32,258	1,500	0	0	0	17,588	169,846	202,981	1.195
2036	15	1	0	10,875	0	10,875	36,007	0	0	0	4,000	17,588	68,469	83,464	1.219
2037	4	23	0	67,454	0	67,454	38,780	0	0	0	1,000	17,588	124,822	155,200	1.243
2038	0	20	0	61,626	0	61,626	41,403	0	0	0	0	17,588	120,617	152,971	1.268
2039	0	14	0	10,434	0	10,434	43,219	0	0	0	4,000	17,588	75,241	97,332	1.294
2040	0	4	0	944	0	944	44,148	0	0	0	1,000	17,588	63,680	84,025	1.319
2041	0	0	0	1,417	0	1,417	44,400	0	0	0	0	17,588	63,404	85,334	1.346
2042	0	0	0	0	0	0	35,434	0	0	0	4,000	17,588	57,021	78,278	1.373
2043	0	0	0	0	0	0	33,700	0	0	0	1,000	13,097	47,797	66,928	1.400
2044	0	0	0	0	0	0	25,298	0	0	0	0	8,198	33,497	47,841	1.428
2045	0	0	0	0	0	0	16,387	0	0	0	4,000	6,210	26,598	38,748	1.457
2046	0	0	0	0	0	0	4,915	0	0	0	1,000	2,941	8,856	13,160	1.486
2047	0	0	0	0	0	0	1,578	0	0	0	0	1,772	3,350	5,077	1.516
2048	0	0	0	0	0	0	296	0	0	0	4,000	411	4,707	7,277	1.546
Total: Wil...	**150**	**144**	**43**	**1,322,500**	**475,200**	**1,797,700**	**484,133**	**21,500**	**1,758,750**	**0**	**30,000**	**245,744**	**4,337,827**	**4,899,555**	

Notes

1. Gross Lease

Table 3

Company:	**Surmont Energy Ltd.**	Effective Date:	**December 31, 2025**
Property:	**Wildwood CBDP**		

Economic Parameters

A) Price Forecasts and By-Product Data (2026 Dollars)

Scenario	3 Consultants' Average (2025-07)
Oil Reference	WCS H
Gas Reference	AECO
Gas Heat Content	1,000 Btu/scf
Price Adjustment	
Oil	[1]
Fuel Gas	0.30 $/Mcf

Annual Notes

Year	[1] Price Adjustment Oil $/bbl
2026	-18.18
2027	-17.88
2028	-17.73
2029	-17.70
2030	-17.67
2031	-17.67
2032	-17.67
2033	-17.67
2034	-17.67
2035	-17.67
2036	-17.67
2037	-17.67
2038	-17.67
2039	-17.67
2040	-17.67

B) Operating Costs (2026 Dollars)

Costs	
Variable	0.50 $/bbl
Major Stream Costs	
Fixed	[1]
Water Costs	
Variable	0.60 $/bbl
Fuel Gas Costs	
Steam Efficiency	0.50 Mcf/bbl

Annual Notes

Year	[1] Major Stream Costs Fixed M$/yr
2026	0
2027	0
2028	6,765
2029	22,032
2030	18,684
2031	123,171
2032	131,196
2033	131,256
2034	137,316
2035	141,276
2036	143,975
2037	145,972
2038	147,860
2039	149,168
2040	149,837

Notes

2. All variable costs are $/product (sales).

Table 3
Economic Parameters

	Zone	Fixed Battery Costs Per Capacity M$/yr	Fixed Battery Costs Total M$/yr	Fixed Steamer Costs Per Capacity M$/yr	Fixed Steamer Costs Total M$/yr
Wildwood SAGD Project					
Facilities					
SAGD Facility - Phase 1	MCMURRAY	350.00	4,200	350.00	12,600
SAGD Facility - Phase 2	MCMURRAY	300.00	22,500	300.00	78,750

Notes
1. All variable costs are $/product (sales).

	Zone	Carbon Tax Oil $/bbl	Well Costs Fixed Well (Pair) $/well/ month	Well Costs Fixed (Infill) $/well/ month	Fixed Battery Costs Total M$/yr	Fixed Steamer Costs Total M$/yr
Wildwood SAGD Project						
Wildwood Thermal Project						
Type Wells						
All Cases		-	12,000	6,000	-	-
Wildwood Thermal Project	MCMURRAY	[1]	-	-	26,700	91,350

Annual Notes

Year	[1] Carbon Tax Oil $/bbl
2026	0.00
2027	0.00
2028	0.00
2029	0.00
2030	0.00
2031	6.44
2032	0.00
2033	0.01
2034	0.04
2035	0.00
2036	0.09
2037	0.19
2038	0.95
2039	2.54
2040	3.25

Notes
2. All variable costs are $/product (sales).

C) Abandonment Costs (2026 Dollars)

Abandonment	
Facility Costs	20,000.0 M$
Well Costs	250.0 M$/well
Reclamation	
Facility Costs	8,000.0 M$
Well Costs	50.0 M$/well

D) Capital Costs (2026 Dollars)

Well Costs	
Downhole Pump Cost	500 M$/yr
Infill Well Pump Cost	500 M$/yr
Well Sustaining Capital	200 M$/Well(Pair)/yr
Infill Well Sustaining Capital	100 M$/well/yr
Onstream	

Notes
1. Nominal capacities are multiplied by facility uptime factor to calculate maximum yearly capacity

Table 4

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**Wildwood Thermal Project**	Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

Bitumen Netback Pricing

Marketing Scenario A

Year	Oil Sands Inflation %	Bank of Canada Average Noon Rate USD/CAD	West Texas Intermediate Crude Oil at Cushing Oklahoma Current USD/bbl	Brent Blend Crude Oil FOB North Sea Current USD/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Current $/bbl	WCS_H Stream Quality Current $/bbl	Dil-bit Quality Differential Current $/bbl	Dil-bit Sales Current $/bbl	COND Current $/bbl	Diluent Postings+ Current $/bbl	Diluent at Source Current $/bbl	Diluent Transp. Current $/bbl	Diluent at Field Current $/bbl	Dil-bit Transp. Current $/bbl	Diluent to Bitumen Blend Ratio	Bitumen Wellhead Current $/bbl
2026	0.00	0.73	69.80	73.83	91.04	77.47	-2.50	74.97	93.82	0.00	93.82	3.50	97.32	4.50	0.430	58.93
2027	2.00	0.74	71.44	75.52	91.82	78.15	-2.50	75.65	94.63	0.00	94.63	3.50	98.13	4.50	0.430	59.54
2028	2.00	0.74	73.35	77.51	94.02	80.23	-2.50	77.73	96.91	0.00	96.91	3.50	100.41	4.59	0.430	61.41
2029	2.00	0.74	74.82	79.06	95.90	81.85	-2.55	79.30	98.84	0.00	98.84	3.50	102.34	4.68	0.430	62.70
2030	2.00	0.74	76.31	80.64	97.81	83.48	-2.60	80.88	100.82	0.00	100.82	3.50	104.32	4.78	0.430	63.97
2031	2.00	0.74	77.84	82.26	99.77	85.15	-2.65	82.50	102.84	0.00	102.84	3.57	106.41	4.87	0.430	65.25
2032	2.00	0.74	79.40	83.90	101.77	86.86	-2.71	84.15	104.90	0.00	104.90	3.64	108.54	4.97	0.430	66.56
2033	2.00	0.74	80.99	85.55	103.80	88.60	-2.76	85.84	107.00	0.00	107.00	3.71	110.71	5.07	0.430	67.90
2034	2.00	0.74	82.61	87.23	105.88	90.37	-2.82	87.55	109.13	0.00	109.13	3.79	112.92	5.17	0.430	69.25
2035	2.00	0.74	84.26	88.98	108.00	92.17	-2.87	89.30	111.31	0.00	111.31	3.86	115.18	5.27	0.430	70.64
2036	2.00	0.74	85.94	90.76	110.16	94.02	-2.93	91.09	113.54	0.00	113.54	3.94	117.48	5.38	0.430	72.05
2037	2.00	0.74	87.66	92.57	112.36	95.90	-2.99	92.91	115.81	0.00	115.81	4.02	119.83	5.49	0.430	73.49

Glossary
COND: Alberta C5+ Product Pricing
WCS_H: Western Canadian Select Heavy

Table 5.0

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
		Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

Development Schedule by Type Well (well)

Entity Description	Zone	Reserve Class	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Totals: Subtotal	Totals: Remainder	Totals: Total
Wildwood CBDP																									
1) ABCDE	MCMURRAY	I	0	0	13	0	1	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31	0	31
2) FGH	MCMURRAY	I	0	0	0	0	0	36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36	0	36
3) NOP	MCMURRAY	I	0	0	0	0	0	0	0	0	19	0	0	0	0	0	0	0	0	0	0	0	19	0	19
4) JKL	MCMURRAY	I	0	0	0	0	0	18	0	1	5	0	0	0	0	0	0	0	0	0	0	0	24	0	24
5) QRS	MCMURRAY	I	0	0	0	0	0	0	0	0	0	21	1	0	0	0	0	0	0	0	0	0	22	0	22
6) MI	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	14	4	0	0	0	0	0	0	0	0	18	0	18
Total: Wildwood CBDP			**0**	**0**	**13**	**0**	**1**	**71**	**0**	**1**	**24**	**21**	**15**	**4**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**150**	**0**	**150**

Table 5.1

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
		Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

Infill Development Schedule by Type Well (well)

Entity Description	Zone	Reserve Class	Year 2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Totals Subtotal	Remainder	Total
Wildwood CBDP																									
1) ABCDE	MCMURRAY	I	0	0	0	0	0	13	0	0	17	0	0	0	0	0	0	0	0	0	0	0	30	0	30
2) FGH	MCMURRAY	I	0	0	0	0	0	0	0	0	35	0	0	0	0	0	0	0	0	0	0	0	35	0	35
3) NOP	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	0	18	0	0	0	0	0	0	0	0	18	0	18
4) JKL	MCMURRAY	I	0	0	0	0	0	0	0	0	17	0	1	5	0	0	0	0	0	0	0	0	23	0	23
5) QRS	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	0	0	20	1	0	0	0	0	0	0	21	0	21
6) MI	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	0	0	0	13	4	0	0	0	0	0	17	0	17
Total: Wildwood CBDP			**0**	**0**	**0**	**0**	**0**	**13**	**0**	**0**	**70**	**0**	**1**	**23**	**20**	**14**	**4**	**0**	**0**	**0**	**0**	**0**	**144**	**0**	**144**

Table 5.2

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
		Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

Total Well/Well Pair Count by Type Well

		Reserve	**Year**																					
Entity Description	Zone	Class	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Wildwood CBDP																								
1) ABCDE	MCMURRAY	I	0	0	6	13	13	30	31	31	31	31	31	31	31	31	31	31	31	31	19	18	10	0
2) FGH	MCMURRAY	I	0	0	0	0	0	33	36	36	36	36	36	36	36	36	36	36	6	0	0	0	0	0
3) NOP	MCMURRAY	I	0	0	0	0	0	0	0	0	9	19	19	19	19	19	19	19	19	19	19	15	0	0
4) JKL	MCMURRAY	I	0	0	0	0	0	18	18	18	22	24	24	24	24	24	24	24	24	24	20	6	6	5
5) QRS	MCMURRAY	I	0	0	0	0	0	0	0	0	0	10	22	22	22	22	22	22	22	22	22	15	0	0
6) MI	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	7	16	18	18	18	18	18	18	6	1	0	0
Total: Wildwood CBDP			**0**	**0**	**6**	**13**	**13**	**80**	**85**	**85**	**98**	**120**	**139**	**148**	**150**	**150**	**150**	**150**	**120**	**114**	**86**	**55**	**17**	**5**

Table 5.3

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
		Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

Total Infill Count by Type Well

Entity Description	Zone	Reserve Class	Year 2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Wildwood CBDP																								
1) ABCDE	MCMURRAY	I	0	0	0	0	0	5	13	13	27	30	30	30	30	30	30	30	30	30	18	17	10	0
2) FGH	MCMURRAY	I	0	0	0	0	0	0	0	0	29	35	35	35	35	35	35	35	6	0	0	0	0	0
3) NOP	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	0	7	18	18	18	18	18	18	18	14	0	0
4) JKL	MCMURRAY	I	0	0	0	0	0	0	0	0	15	17	18	20	23	23	23	23	23	23	19	6	6	5
5) QRS	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	0	0	8	21	21	21	21	21	21	15	0	0
6) MI	MCMURRAY	I	0	0	0	0	0	0	0	0	0	0	0	0	0	6	14	17	17	17	6	1	0	0
Total: Wildwood CBDP			**0**	**0**	**0**	**0**	**0**	**5**	**13**	**13**	**72**	**82**	**83**	**92**	**114**	**132**	**141**	**144**	**115**	**109**	**82**	**53**	**16**	**5**

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**Wildwood SAGD Project**	Pricing:	**3 Consultants' Average (2025-07)**
	SAGD PROJECT	Effective Date:	**December 31, 2025**
	Product Type: Bitumen		

Economic Forecast

PRODUCTION FORECAST

		Bitumen Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2026	0	0	0	0	0	0.00
2027	0	0	0	0	0	0.00
2028	12	426	426	156	144	61.41
2029	13	9,619	9,619	3,511	3,243	62.70
2030	13	13,334	13,334	4,867	4,484	63.97
2031	92	30,572	30,572	11,159	10,253	65.25
2032	98	80,954	80,954	29,548	27,073	66.56
2033	98	78,095	78,095	28,505	25,982	67.90
2034	170	91,818	91,818	33,514	24,944	69.25
2035	202	104,060	104,060	37,982	26,554	70.64
2036	221	104,223	104,223	38,042	26,011	72.05
2037	240	100,164	100,164	36,560	25,421	73.49
2038	264	97,278	97,278	35,507	24,744	74.96
2039	282	86,947	86,947	31,736	22,403	76.46
2040	291	72,165	72,165	26,340	19,005	77.99
2041	294	56,465	56,465	20,610	15,615	79.55
2042	235	39,501	39,501	14,418	11,478	81.14
2043	223	29,997	29,997	10,949	8,900	82.76
2044	167	19,619	19,619	7,161	6,002	84.42
2045	108	11,040	11,040	4,030	3,471	86.11
2046	33	3,011	3,011	1,099	989	87.83
2047	10	972	972	355	319	89.58
2048	6	161	161	59	53	91.38
2049	0	0	0	0	0	0.00
2050	0	0	0	0	0	0.00
Tot.				**376,104**	**287,089**	**73.24**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil MM$	Gas MM$	NGL+Sul MM$	Total MM$	Total MM$	Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	10	0	0	10	0	10	1	0	0	0	1	9	12	2	13
2029	220	0	0	220	0	220	15	2	0	0	17	203	44	9	53
2030	311	0	0	311	0	311	21	3	0	0	24	287	46	11	57
2031	728	0	0	728	0	728	52	7	0	0	59	669	236	117	352
2032	1,967	0	0	1,967	0	1,967	145	20	0	0	165	1,802	308	67	375
2033	1,935	0	0	1,935	0	1,935	152	19	0	0	171	1,764	313	67	380
2034	2,321	0	0	2,321	0	2,321	570	23	0	0	593	1,727	336	72	408
2035	2,683	0	0	2,683	0	2,683	780	27	0	0	807	1,876	370	81	451
2036	2,741	0	0	2,741	0	2,741	839	27	0	0	867	1,874	408	96	505
2037	2,687	0	0	2,687	0	2,687	792	27	0	0	819	1,868	425	103	528
2038	2,662	0	0	2,662	0	2,662	780	27	0	0	807	1,855	425	134	558
2039	2,426	0	0	2,426	0	2,426	689	24	0	0	714	1,713	418	188	606
2040	2,054	0	0	2,054	0	2,054	552	21	0	0	572	1,482	406	185	591
2041	1,639	0	0	1,639	0	1,639	381	16	0	0	397	1,242	394	208	602
2042	1,170	0	0	1,170	0	1,170	227	12	0	0	239	931	352	173	524
2043	906	0	0	906	0	906	160	9	0	0	170	737	293	145	438
2044	604	0	0	604	0	604	92	6	0	0	98	507	202	95	297
2045	347	0	0	347	0	347	45	3	0	0	48	299	137	59	197
2046	97	0	0	97	0	97	9	1	0	0	10	87	49	12	61
2047	32	0	0	32	0	32	3	0	0	0	3	29	25	4	29
2048	5	0	0	5	0	5	0	0	0	0	1	5	5	1	6
2049	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tot.	**27,546**	**0**	**0**	**27,546**	**0**	**27,546**	**6,305**	**275**	**0**	**0**	**6,580**	**20,965**	**5,205**	**1,827**	**7,032**
Disc	9,786	0	0	9,786	0	9,786	2,105	98	0	0	2,203	7,583	1,752	564	2,317

Year	Mineral Tax MM$	Capital Tax MM$	NPI Burden MM$	**Net Prod'n Revenue** MM$	Other Income MM$	**Aband. & Recl. Costs** MM$	**Oper. Income** MM$	Net Capital Investment: Dev. MM$	Net Capital Investment: Plant MM$	Net Capital Investment: Tang. MM$	Net Capital Investment: Total MM$	Before Tax Cash Flow: Annual MM$	Before Tax Cash Flow: Cum. MM$	Before Tax Cash Flow: 10.0% Dcf MM$
2026	0	0	0	0	0	0	0	2	0	49	51	-51	-51	-48
2027	0	0	0	0	0	0	0	27	0	140	167	-167	-218	-193
2028	0	0	0	-5	0	0	-5	57	0	273	330	-334	-552	-456
2029	0	0	0	150	0	0	150	3	0	410	414	-263	-815	-645
2030	0	0	0	230	0	0	230	468	0	1,221	1,689	-1,459	-2,274	-1,595
2031	0	0	0	317	0	0	317	52	0	237	289	28	-2,246	-1,578
2032	0	0	0	1,427	0	0	1,427	3	0	43	46	1,381	-865	-835
2033	0	0	0	1,384	0	0	1,384	204	0	182	386	998	133	-347
2034	0	0	0	1,319	0	0	1,319	214	0	196	410	909	1,042	58
2035	0	0	0	1,425	0	0	1,425	86	0	117	203	1,222	2,264	552
2036	0	0	0	1,370	0	0	1,370	8	0	76	83	1,286	3,550	1,024
2037	0	0	0	1,340	0	0	1,340	50	0	105	155	1,185	4,735	1,420
2038	0	0	0	1,297	0	0	1,297	47	0	106	153	1,144	5,878	1,768
2039	0	0	0	1,107	0	0	1,107	8	0	89	97	1,010	6,888	2,046
2040	0	0	0	891	0	0	891	1	0	83	84	807	7,695	2,249
2041	0	0	0	640	0	0	640	1	0	84	85	555	8,250	2,376
2042	0	0	0	407	0	0	407	0	0	78	78	329	8,578	2,444
2043	0	0	0	299	0	0	299	0	0	67	67	232	8,810	2,488
2044	0	0	0	210	0	30	179	0	0	48	48	132	8,941	2,510
2045	0	0	0	102	0	0	102	0	0	39	39	63	9,005	2,520
2046	0	0	0	26	0	40	-14	0	0	13	13	-27	8,978	2,516
2047	0	0	0	-1	0	37	-38	0	0	5	5	-43	8,935	2,511
2048	0	0	0	-1	0	18	-20	0	0	7	7	-27	8,908	2,507
2049	0	0	0	0	0	1	-1	0	0	0	0	-1	8,907	2,507
2050	0	0	0	0	0	50	-50	0	0	0	0	-50	8,857	2,503
Tot.	**0**	**0**	**0**	**13,933**	**0**	**177**	**13,757**	**1,231**	**0**	**3,669**	**4,900**	**8,857**	**8,857**	**2,503**
Disc	0	0	0	5,266	0	23	5,244	675	0	2,066	2,741	2,503	2,503	2,503

SUMMARY OF RESERVES

Product	Units	Remaining Reserves at Jan 01, 2026: Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: Oil Eq. Factor	Company Mboe	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Bitumen	Mbbl	376,104	376,104	0	376,104	287,089	1.000	376,104	100	23.0	999.9	11.0
Total: Oil Eq.	Mboe	376,104	376,104	0	376,104	287,089	1.000	376,104	100	23.0	999.9	11.0

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc MM$	% of Total	10% Disc MM$	% of Total
Bitumen	$/bbl	0.00	0.00	0.00	0.00	0.00	20,965	100	7,583	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	20,965	100	7,583	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)	Initial	Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue MM$	Operating Income MM$	Capital Invest. MM$	Cash Flow MM$	Cash Flow $/boe
Working Interest	0.0000	100.0000	0	13,933	13,757	4,900	8,857	23.55
Capital Interest	100.0000	100.0000	5	8,361	8,300	3,582	4,717	12.54
Crown Royalty	0.0000	22.8887	8	6,302	6,269	3,037	3,232	8.59
Non-crown Royalty	0.0000	1.0000	10	5,266	5,244	2,741	2,503	6.65
			12	4,430	4,415	2,487	1,927	5.12
			15	3,458	3,449	2,169	1,280	3.40
			20	2,353	2,350	1,762	588	1.56

Evaluator: Kim Mohler, P.Eng.
Run Date: November 21, 2025 15:02:55

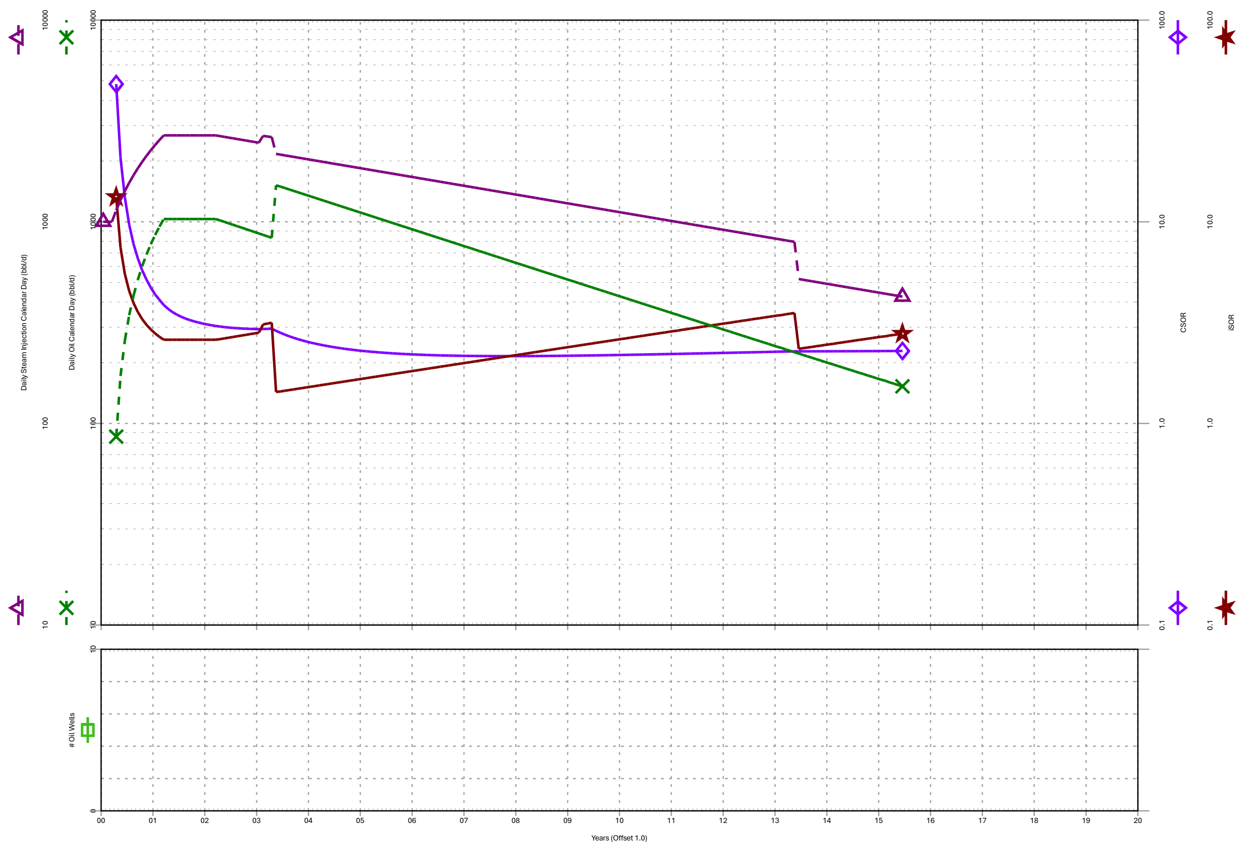
APPENDIX I

INDIVIDUAL PATTERN FORECASTS

MANAGEMENT ESTIMATE – BASE RESERVES FORECASTS

Forecast Production

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**1) ABCDE**	Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**



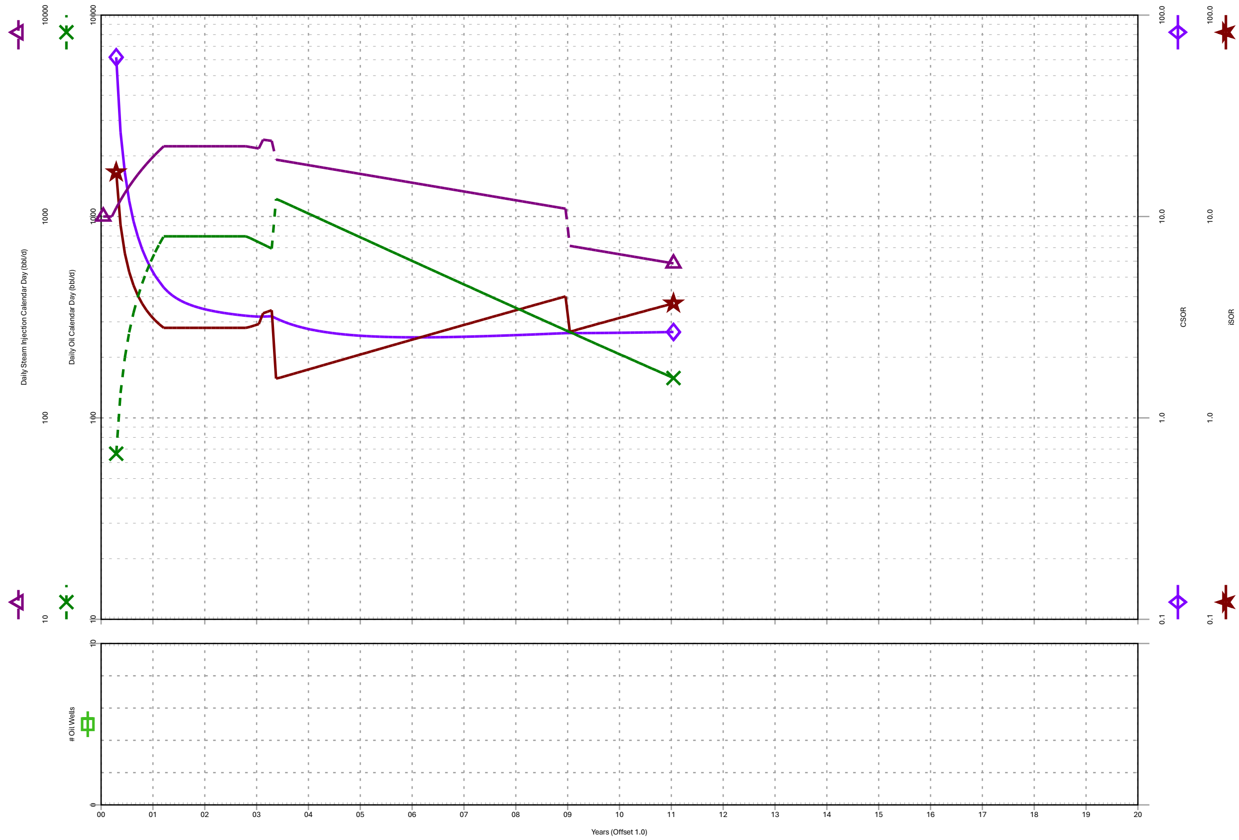
In-Situ Volumetric Parameters

	CBDP Estimate – Base
Area	1,073.9
Net Pay	20
Porosity	33.0
Initial Water Saturation	19.0
Formation Volume Factor	1.001
Bitumen Initially In Place	149,123
Well Length	1,330
Well Spacing	100
Displacement Efficiency (Ed)	90.1
Gross Vertical Sweep Efficiency (Ev)	92.7
Gross Horizontal Sweep Efficiency (Eh)	93.4
Continuity Efficiency (Ec)	95.5
Recovery Factor	74.5
Recoverable Bitumen	111,071
Number of Well Pairs Required	31
Number of Infill Wells Required	30
Recoverable Bitumen per Infill	1,296
Peak Rate per Well	1,031.51
Cumulative SOR	2.29

Forecast Production

Company: **Surmont Energy Ltd.**
Property: **Wildwood CBDP**
Description: **2) FGH**

Reserve Class: **CBDP Estimate**
Development Class: **Base**
Pricing: **3 Consultants' Average (2025-07)**
Effective Date: **December 31, 2025**

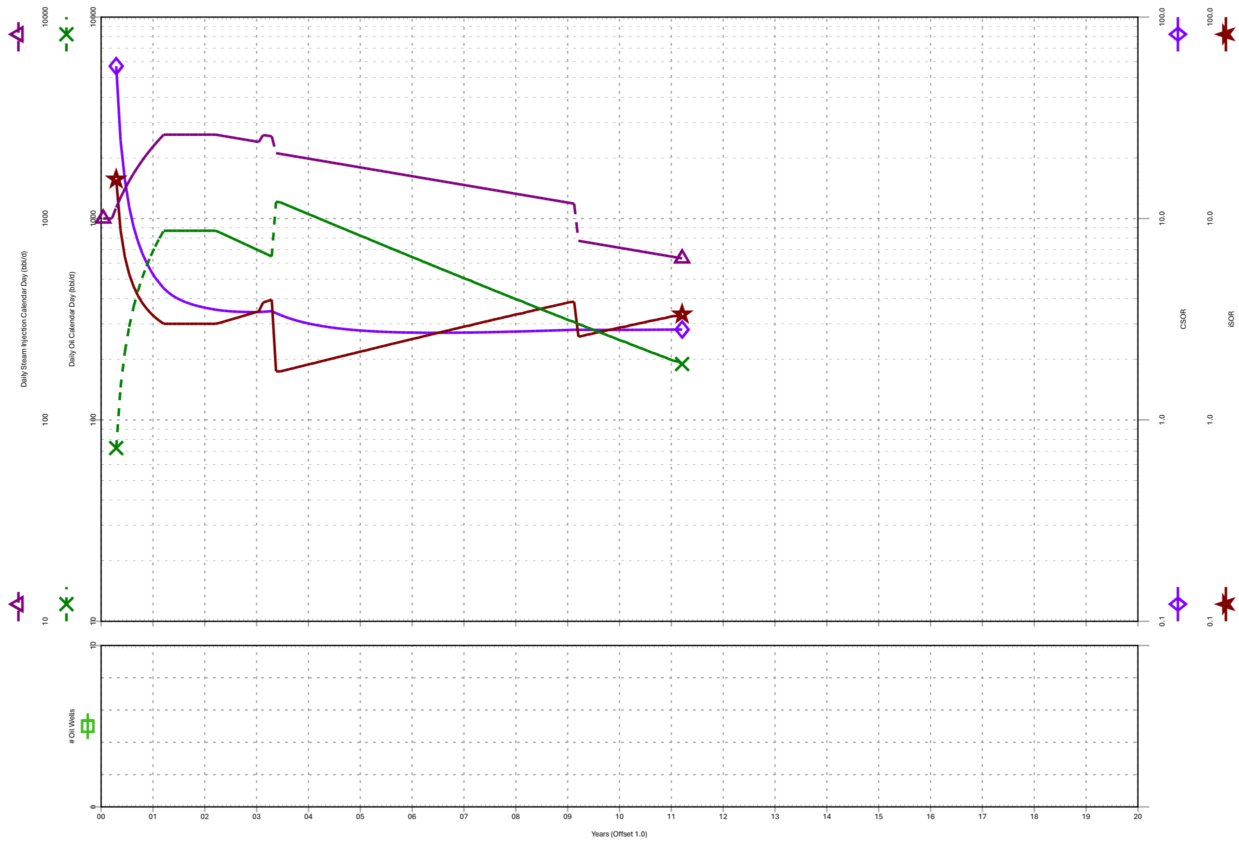


In-Situ Volumetric Parameters

	CBDP Estimate – Base
Area	1,127.3
Net Pay	15
Porosity	33.0
Initial Water Saturation	19.0
Formation Volume Factor	1.001
Bitumen Initially In Place	114,084
Well Length	1,222
Well Spacing	100
Displacement Efficiency (Ed)	90.1
Gross Vertical Sweep Efficiency (Ev)	89.9
Gross Horizontal Sweep Efficiency (Eh)	90.7
Continuity Efficiency (Ec)	95.5
Recovery Factor	70.2
Recoverable Bitumen	80,056
Number of Well Pairs Required	36
Number of Infill Wells Required	35
Recoverable Bitumen per Infill	709
Peak Rate per Well	797.09
Cumulative SOR	2.67

Forecast Production

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**3) NOP**	Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

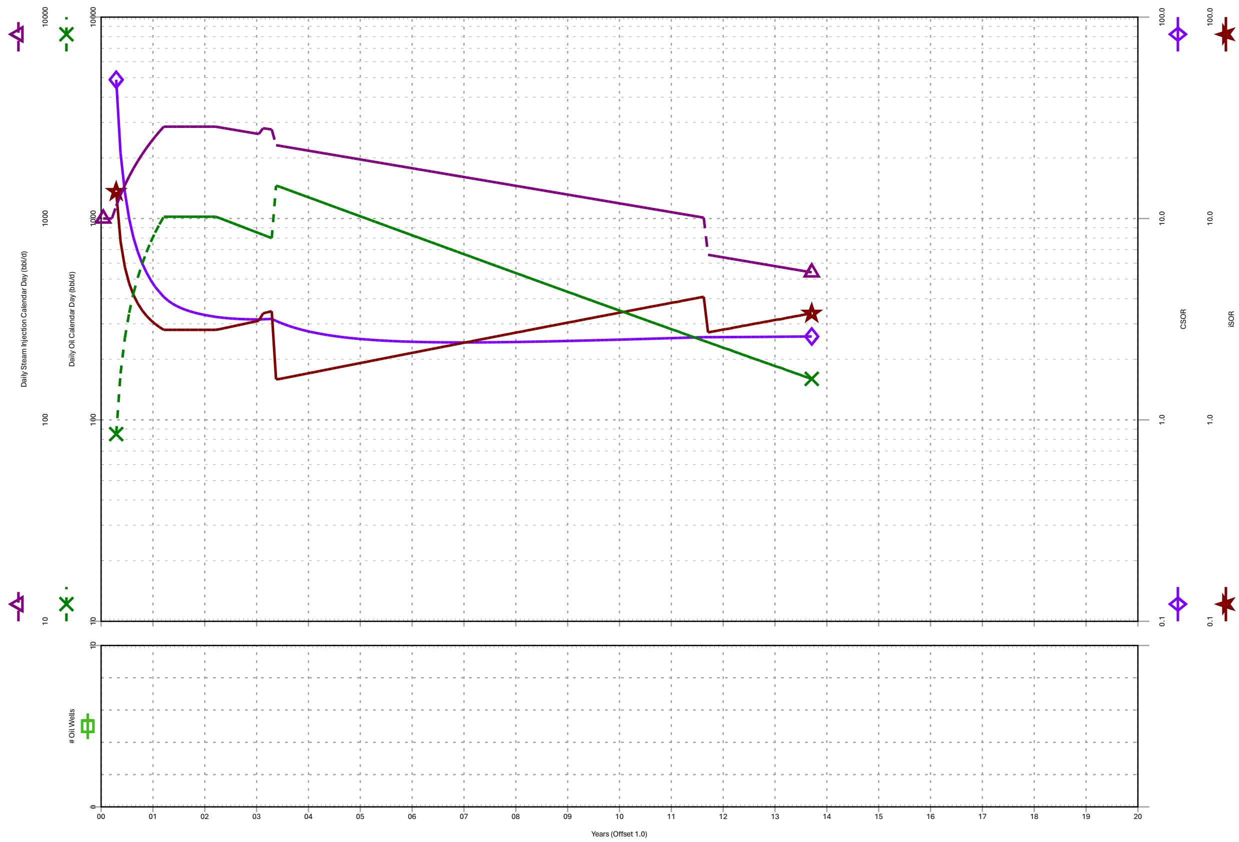


In-Situ Volumetric Parameters

	CBDP Estimate – Base
Area	672.8
Net Pay	14
Porosity	33.0
Initial Water Saturation	19.0
Formation Volume Factor	1.001
Bitumen Initially In Place	64,977
Well Length	1,368
Well Spacing	100
Displacement Efficiency (Ed)	90.1
Gross Vertical Sweep Efficiency (Ev)	89.4
Gross Horizontal Sweep Efficiency (Eh)	90.2
Continuity Efficiency (Ec)	95.5
Recovery Factor	69.4
Recoverable Bitumen	45,102
Number of Well Pairs Required	19
Number of Infill Wells Required	18
Recoverable Bitumen per Infill	877
Peak Rate per Well	869.37
Cumulative SOR	2.81

Forecast Production

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**4) JKL**	Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

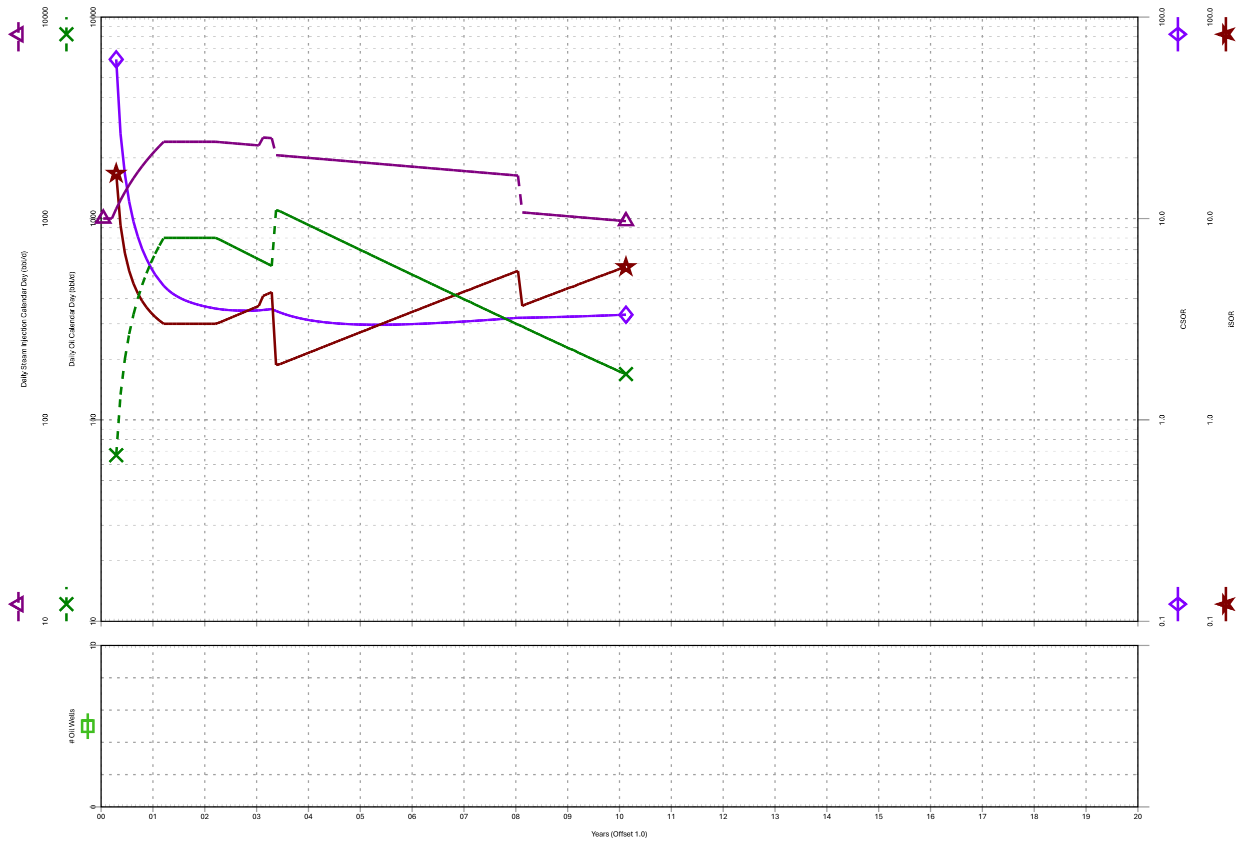


In-Situ Volumetric Parameters

	CBDP Estimate – Base
Area	903.8
Net Pay	17
Porosity	33.0
Initial Water Saturation	19.0
Formation Volume Factor	1.001
Bitumen Initially In Place	104,916
Well Length	1,450
Well Spacing	100
Displacement Efficiency (Ed)	90.1
Gross Vertical Sweep Efficiency (Ev)	91.2
Gross Horizontal Sweep Efficiency (Eh)	92.0
Continuity Efficiency (Ec)	95.5
Recovery Factor	72.2
Recoverable Bitumen	75,760
Number of Well Pairs Required	24
Number of Infill Wells Required	23
Recoverable Bitumen per Infill	1,120
Peak Rate per Well	1,020.23
Cumulative SOR	2.60

Forecast Production

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**5) QRS**	Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**

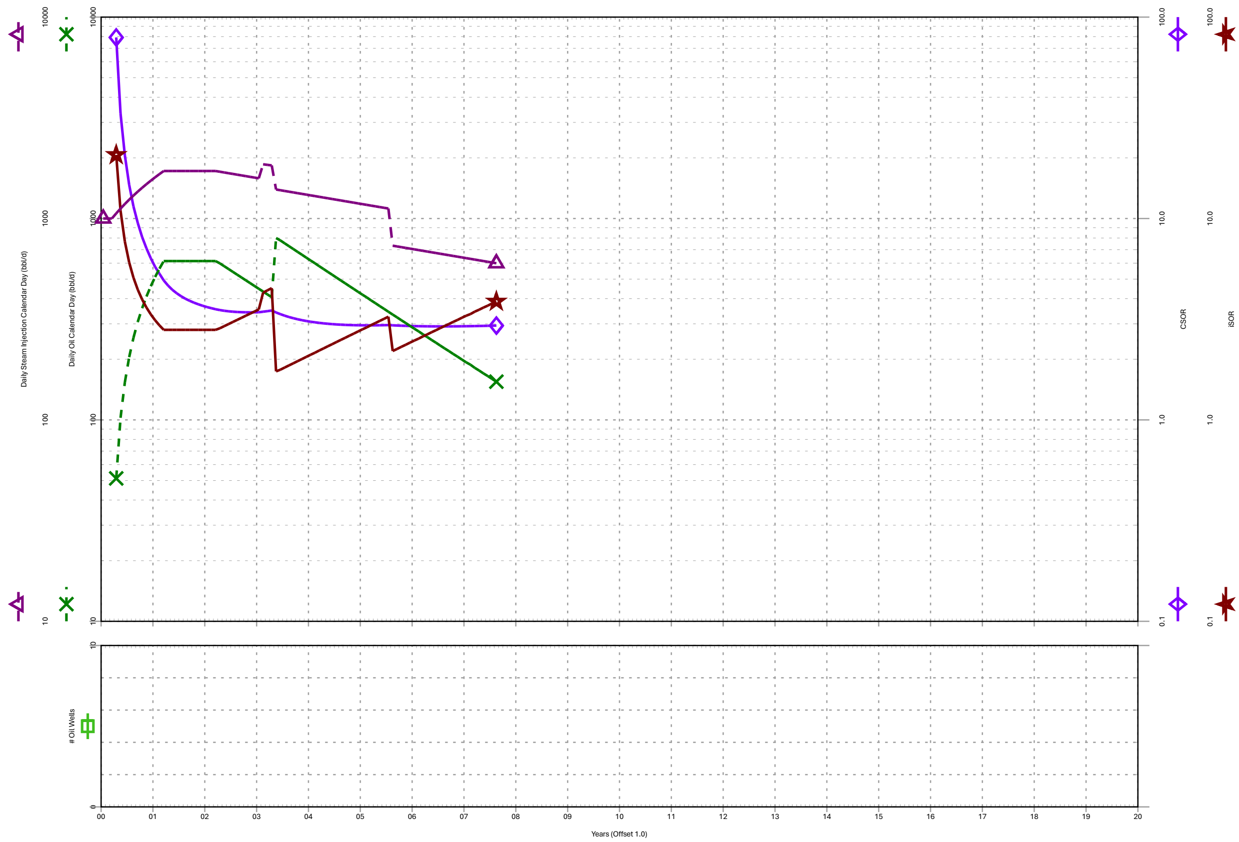


In-Situ Volumetric Parameters

	CBDP Estimate – Base
Area	743.0
Net Pay	13
Porosity	33.0
Initial Water Saturation	19.0
Formation Volume Factor	1.001
Bitumen Initially In Place	63,985
Well Length	1,345
Well Spacing	100
Displacement Efficiency (Ed)	90.1
Gross Vertical Sweep Efficiency (Ev)	88.2
Gross Horizontal Sweep Efficiency (Eh)	88.8
Continuity Efficiency (Ec)	95.5
Recovery Factor	67.4
Recoverable Bitumen	43,117
Number of Well Pairs Required	22
Number of Infill Wells Required	21
Recoverable Bitumen per Infill	657
Peak Rate per Well	801.30
Cumulative SOR	3.33

Forecast Production

Company:	**Surmont Energy Ltd.**	Reserve Class:	**CBDP Estimate**
Property:	**Wildwood CBDP**	Development Class:	**Base**
Description:	**6) MI**	Pricing:	**3 Consultants' Average (2025-07)**
		Effective Date:	**December 31, 2025**



In-Situ Volumetric Parameters

	CBDP Estimate – Base
Area	588.5
Net Pay	9
Porosity	33.0
Initial Water Saturation	19.0
Formation Volume Factor	1.001
Bitumen Initially In Place	35,398
Well Length	1,272
Well Spacing	100
Displacement Efficiency (Ed)	90.1
Gross Vertical Sweep Efficiency (Ev)	83.1
Gross Horizontal Sweep Efficiency (Eh)	83.0
Continuity Efficiency (Ec)	95.5
Recovery Factor	59.3
Recoverable Bitumen	20,999
Number of Well Pairs Required	18
Number of Infill Wells Required	17
Recoverable Bitumen per Infill	334
Peak Rate per Well	614.72
Cumulative SOR	2.94

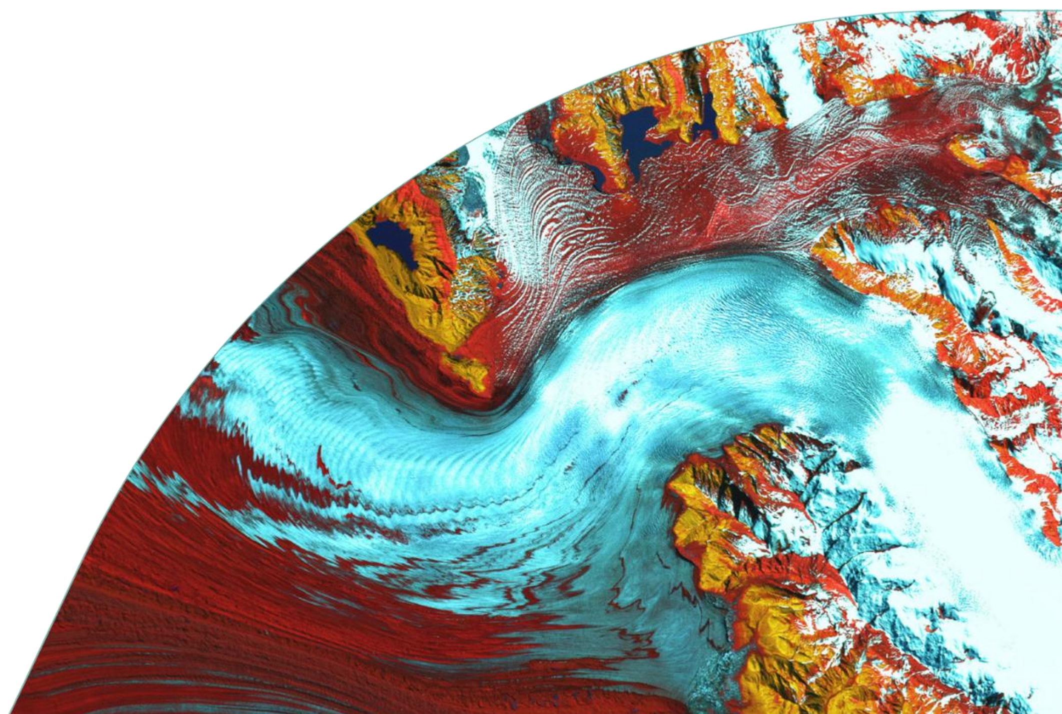
Abbreviation	Description
bbl	barrels
Bcf	billion cubic feet of gas at standard conditions
BIIP	bitumen initially-in-place
boe	barrel of oil equivalent, determined using 6 Mcf/boe for gas, and 1 bbl/boe for all liquids
bopd	barrels of oil per day
Btu	British thermal units
bwpd	barrels of water per day
DSU	drilling spacing unit
GCA	gas cost allowance
GIIP	gas initially-in-place
GOC	gas-oil contact
GOR	gas-oil ratio
GORR	gross overriding royalty
GWC	gas-water contact
Mbbl	thousand barrels
Mboe	thousand boe
Mcf	thousand cubic feet of gas at standard conditions
Mcfe	thousand cubic feet of gas equivalent
M$	thousand dollars
MM$	million dollars
MMbbl	million barrels
MMboe	million boe
MMBtu	million British thermal units
MMcf	million cubic feet of gas at standard conditions
MRL	maximum rate limitation
Mstb	thousand stock tank barrels
MMstb	million stock tank barrels
NGL	natural gas liquids (ethane, propane, butane and condensate)
NPI	net profits interest
OIIP	oil initially-in-place
ORRI	overriding royalty interest
OWC	oil-water contact
P&NG	petroleum and natural gas
PIIP	petroleum initially-in-place
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVT	pressure-volume-temperature
RLI	reserves life index, calculated by dividing reserves by the forecast of first year production
scf	standard cubic feet

sge	sales gas equivalent – if presented in this evaluation, determined using 1 barrel of oil or natural gas liquid = 6 Mcfe; 0 for sulphur
SOR	Steam oil ratio
stb	stock tank barrel
WCS	Western Canada Select
WI	working interest
WOR	Water oil ratio
WTI	West Texas Intermediate

June 2025

Methodology for In Situ Sequestration of GHG Emissions from Planned Production of Carbon-Intensive Oil

Version 1.0



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Prepared by:

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Acronyms

.kml	Keyhole Markup Language file format
.shp	Geographic information system shapefile
API	American Petroleum Institute
BAU	Business-as-usual
boe	Barrel of oil equivalent
CBDP	Credible Business Development Plan
CGE	Computable General Equilibrium
CH_4	Methane
CI	Carbon Intensity
CIO	Carbon-Intensive oil
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
COS	Carbon-intensive Oil Substitute
CSS	Cyclic Steam Stimulation
ER	Emission Reduction
FID	Final Investment Decision
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies model
IPCC	International Panel on Climate Change
IRR	Internal Rate of Return
ISO	International Organization for Standardization
kg	Kilogram

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LCA	Life-Cycle Assessment
LCFS	Low Carbon Fuel Standard
MRV	Monitoring, Reporting, and Verification
N_2O	Nitrous Oxide
NPV	Net Present Value
OCI^+	Oil Climate Index Plus Gas
OPEC	Organization of the Petroleum Exporting Countries
OPEM	Oil Products Emissions Module
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
PA	Project Activity
PDD	Project Design Document
PE	Partial Equilibrium
PoA	Program of Activities
PP	Project Proponent
PRELIM	Petroleum Refinery Life Cycle Inventory Model
PVC	Production Volume Certifier
QA	Quality Assurance
QC	Quality Control
RMI	Rocky Mountains Institute
SAGD	Steam-Assisted Gravity Drainage
SCD	Sequestered CIO Deposit
SFI	Suitable Financial Instrument
SSR	Source, Sink, and Reservoir
t	Metric ton

U.S.	United States
UNFCCC	United Nations Framework Convention on Climate Change
VVB	Validation and Verification Body

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Definitions

American Petroleum Institute (API) Gravity	A measure of how light or heavy a petroleum liquid is compared to water. If the API gravity of a liquid is greater than 10, the petroleum liquid floats on water. If less than 10, the liquid is heavier and sinks in water. The API gravity of a liquid is directly correlated to its density and is a key factor in establishing the market value and GHG emissions related to crude oil.
Barrel of Oil Equivalent	The barrel of oil equivalent (boe) is a unit that allows for a single value to represent the sum of all hydrocarbon products forecasted as resources. It is commonly used in the oil and gas industry to standardize diverse types of hydrocarbons into a comparable unit. Typically, condensate, oil, bitumen, and synthetic crude barrels are considered equal (1 barrel = 1 boe). Carbon Intensity (CI) values for hydrocarbon production are often reported in kilograms of carbon dioxide (CO_2) equivalent per barrel of oil equivalent (kg CO_2e/boe).
Carbon-Intensive Oil (CIO)	For this methodology, crude oil with an API gravity of 12.0 or heavier as produced, before any blending or upgrading. In addition to the API threshold, CIO is intended to have a higher CI than the substitute oil (at least 5% higher). The methodology does not fix an absolute value as a threshold for CI, and the PP shall demonstrate that the GHG Project's Baseline Scenario CIO has a higher CI than the identified substitute oil intensity in each period.
Carbon-Intensive Oil Substitute (COS)	An oil volume sourced from a single field, or different slates (including oil sands, light oil, or renewables), intended to meet the same demand as the prevented CIO production. The substitute oil shall have a lower CI than the CIO, typically at least 5% lower in CI, and shall be economically viable under prevailing market conditions.
CIO Volume Developer	The entity that has entered into a contractual agreement with the CIO Volume Owner to extract CIO from a deposit of CIO. The CIO Volume Developer may also contract with a PP to implement a GHG Project for the PP to claim associated GHG benefits. The CIO Volume Developer may itself serve as the PP, provided it holds the legal authority and responsibility for implementing and complying with the GHG Project's methodology.
CIO Volume Owner	The entity that holds legal title to a deposit of CIO and enters into a contractual agreement with a CIO Volume Developer to extract CIO from that deposit.

Credit Type	Category of carbon credits issued under this methodology, representing validated (ex-ante) or verified (ex-post) prevention of GHG emissions achieved through the in situ Sequestration of planned CIO production. These credits are generated by preventing the extraction, processing, and combustion of CIO that would have otherwise occurred in the Baseline Scenario. Reconciliation between ex-ante and ex-post issuance follows the applicable procedures established by the Registry or GHG program. The resulting GHG mitigation constitutes an avoidance activity, not a removal activity, and therefore does not involve the capture or storage of atmospheric CO_2.
Downstream	The final stage of the oil supply chain begins at the refinery exit gate and includes the distribution, sale, and end-use combustion of petroleum products. In this methodology, Downstream emissions refer specifically to GHG emissions from the combustion of refined products derived from CIO or its substitutes. These emissions are quantified using life-cycle assessment (LCA) tools such as the Oil Products Emissions Module (OPEM) or the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies model (GREET). The Downstream boundary is illustrated in Figure 1, which delineates it as the segment following Midstream refining operations through to the final combustion of end-use fuels.
Extraction[1]	Part of the Upstream portion of the oil supply chain entails drilling, fracturing, mining, or otherwise accessing oil resources. For the purposes of this methodology, extraction includes drilling, gathering systems, and production facilities construction, as well as operations up to the point where processed oil and gas exit the oilfield processing facilities.
Ex-ante	Refers to the quantification and issuance of GHG emission mitigation outcomes before they have occurred, based on validated projections derived from a Credible Business Development Plan (CBDP) and baseline CIO production forecasts. Ex-ante credits represent anticipated GHG emission reductions or avoidance that have been validated but not yet verified. These credits may be issued to facilitate early project financing or market participation. Still, they cannot be retired or used for offsetting purposes until their underlying emission mitigations have been verified. Upon verification, the ex-ante credits are reconciled and converted to ex-post issuance in accordance with the applicable Registry or GHG program procedures for issuance and conversion.

[1] Carnegie Endowment for International Peace. (n.d.). Oil Climate Index Plus (OCI+): Glossary. Retrieved February 10, 2025, from https://oci.carnegieendowment.org/#glossary.

Ex-post	Refers to the quantification and issuance of GHG emission reductions or avoidance that, by the time of verification, would have occurred under the Baseline Scenario, as established by the CBDP and planned CIO Production Volume forecast. Ex-post credits represent verified emission reductions or avoidance outcomes achieved within a given monitoring period. These credits may be retired or transacted in accordance with the applicable Registry or program rules, following confirmation that the project has maintained the undeveloped status of the certified CIO volume and met all conditions of Permanence and verification.
Government	Sovereign or sub-sovereign public authority (at the national, provincial, or state level) recognized by applicable law within the project jurisdiction, which owns or has legal title to a Carbon-Intensive Oil (CIO) deposit, where such ownership is vested in the public domain. In jurisdictions where CIO deposits may be privately owned (e.g., the United States), this definition does not apply to private owners or concessionaires; those entities are instead referred to as Project Proponents or Private Entities as appropriate. Municipal, local, and Indigenous Governments are excluded from this definition unless they explicitly hold the legal title to the CIO deposit under applicable law.
GHG Project	A planned set of activities implemented by the PP to reduce greenhouse gas emissions relative to a defined baseline scenario. In this methodology, a GHG Project refers specifically to preventing CIO Extraction from identified undeveloped reserves. The terms “GHG Project” and “Project” are used interchangeably throughout this methodology.
Market Leakage	Market leakage refers to the unintended increase in GHG emissions outside the Project Boundary resulting from changes in global or regional supply-demand dynamics. Specifically, it occurs when the prevention of planned CIO production from the Project Area leads to partial or full displacement of that production elsewhere, thereby negating emission reductions achieved by the project. Under this methodology, Market Leakage is treated using one of two options, at the discretion of the PP: a model-based rate derived from peer-reviewed econometric models, or the PP may assume a fixed 100% leakage rate. See Section 8.3 for full details.

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Midstream	The middle portion of the oil supply chain that entails refining crude oil or otherwise transforming hydrocarbons into petroleum products. The boundary between the Midstream and Downstream is the point at which petroleum products exit the refinery, as illustrated in Figure 1.
Permanence	In the context of Project Activities (PAs), Permanence refers to the long-term retention and durability of GHG reductions achieved by the project. It ensures that the undeveloped SCD remains intact and CIO Sequestration is not reversed over time, providing lasting climate benefits. Permanence is a key principle for project integrity, reflecting the commitment to maintaining emissions reductions for a minimum of 50 years, beyond the GHG Project's lifespan or over a defined monitoring period, thereby addressing risks of reversal due to natural, human, or system-related factors.
Planned Production	The planned activity of commercial production of CIO that would result in releasing significant GHG emissions into the atmosphere.
Production Period	The estimated operational lifespan during which the Planned Production of CIO from an SCD would have occurred in the absence of the GHG Project. In the context of sequestered CIO Production Volumes, this period is calculated based on analog analysis of similar oil developments, incorporating expected start-up, plateau, and decline phases derived from comparable geologic formations, Extraction techniques, and baseline project designs.
Production Volume	The volume of CIO produced in the Baseline Scenario, as calculated by a Production Volume Certifier (PVC).
Production Volume Certifier (PVC)	A professional petroleum engineering firm responsible for calculating in compliance with its standards for professional practice the volume of CIO that would be produced in the Baseline Scenario if the CIO Production Volume is not sequestered. The PVC shall also prepare and/or confirm in compliance with its standards for professional practice the CBDP that the projected CIO Production Volume and associated assumptions are technically and economically sound, consistent with standard industry practices, and suitable for use in Baseline Scenario quantification.
Project Boundaries	The spatial, temporal, and operational limits of a GHG Project defining the area within which the PAs are conducted and for which emissions Sequestration is quantified.

Project Proponent (PP)	The individual or legal entity that has overall responsibility for the design, implementation, and monitoring of the GHG Project. The PP shall demonstrate authority to control or influence the Baseline Scenario, implement the GHG mitigation activity, and claim the resulting emission reductions in accordance with this methodology and the ISO 14064-2:2019. A Project Proponent may be: • Government, where legal ownership or control of the CIO deposit is vested in the public domain under national, provincial, or state law; or • a Private Entity, where legal title, mineral rights, or contractual control of the CIO deposit is held privately. In all cases, the Project Proponent shall demonstrate clear, uncontested ownership or control rights over the Project Activity and their associated GHG emission mitigation.
Private Entity	Any legally registered individual, corporation, partnership, or consortium that holds legal title, mineral rights, or contractual control over a Carbon-Intensive Oil (CIO) deposit under the applicable laws of the Baseline Scenario jurisdiction, where such ownership or control is not vested in a Government. This includes entities operating under private ownership, concession, lease, or production-sharing agreements, provided that the rights to develop, suspend, or forego development of the CIO deposit are clearly established.
Registry or GHG Program	The governing system, platform, or GHG Program under which the PP registers, validates, verifies, and issues GHG emission reduction or avoidance credits in accordance with the applicable Registry criteria and this Methodology. It establishes the rules for credit issuance, retirement, tracking, and transparency, and may impose additional requirements concerning validation, verification, Permanence, and project eligibility. For this Methodology, a Registry includes any recognized national, subnational, or voluntary GHG Program that aligns with ISO 14064-2:2019 principles and accepts projects developed under this framework.
Sequestered CIO Deposit (SCD)	A quantity of CIO that is to remain undeveloped and contained underground for the duration defined in this methodology (refer to Permanence definition) to prevent GHG emissions as would occur in the Baseline Scenario.

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Sequestered CIO	CIO that remains undeveloped and securely contained within its original geologic formations as a deliberate and verifiable climate mitigation measure. This approach prevents greenhouse gas emissions that would otherwise result from CIO Extraction, processing, and combustion.
Sequestration	Refers to the geological containment of CIO in its natural, unproduced state, involving the active stewardship of subsurface rights, verification of in situ hydrocarbon volumes, and financial mechanisms that ensure the CIO remains securely contained for the duration of the defined undeveloped/permanent period (minimum 50 years).
Suitable Financial Instrument	Advanced assurance instruments protect i) the GHG emissions of the Project; or ii) the credit buyer in the event of a reversal; and include third-party insurance, project-level bonding, or third-party financial guarantees.
Steam-Assisted Gravity Drainage (SAGD)	An Extraction technique used for recovering heavy or ultra-heavy crude oil that is too deep or otherwise inaccessible for surface mining. SAGD involves injecting steam to reduce the oil's viscosity, making it easier to produce to the surface.
Undeveloped Period	The period during which the PP commits to leaving the SCD undeveloped. This shall be for at least 50 years, as specified in this methodology.
Upgrading	An Upstream process that converts extra-heavy oil or bitumen into synthetic crude oils or dilutes it with condensate.
Upstream	The beginning of the oil supply chain that includes Extraction, production, surface processing and upgrading, waste disposal, and other miscellaneous operations, as well as transporting oil to the refinery.[2] The boundary between the Upstream and Midstream value chain components is the entrance to the oil refinery, as illustrated in Figure 1.

[2] Although the conventional oil and gas industry categorizes the transportation of crude oil to refineries as part of the midstream sector and reserves the term Downstream for refining and end-use activities, this methodology adopts a different boundary definition. The approach is consistent with life-cycle assessment (LCA) models such as Stanford's OPGEE the University of Calgary's PRELIM and the Rocky Mountain Institute's OPEM, as well as the Oil Climate Index Plus Gas (OCI+), which define upstream activities to include Extraction, production, surface processing, Upgrading, and transportation to the refinery gate. This definition establishes a clear and consistent system boundary for quantifying the carbon intensity of oil and gas resources. Under this framework, the upstream boundary concludes at the refinery entrance, as illustrated in Figure 2. Emissions associated with refining and Downstream use are excluded from the upstream scope. See: https://oci.carnegieendowment.org/#glossary.

Well Production Forecasting	It refers to the use of historical production data from geologically and operationally comparable oil projects (analogs) to estimate the expected production profile of an undeveloped oil project. In the context of Sequestered CIO Production Volumes, where no production history exists, projections are developed using analog well performance from similar reservoirs, Extraction techniques, and development scenarios. Decline curve models (e.g., exponential, hyperbolic, harmonic) may be used where suitable analogs exhibit decline behavior, particularly in cold heavy oil production. However, for thermal recovery projects like SAGD, production profiles are influenced more by operational strategies (e.g., steam injection schedules) than by natural reservoir energy decline, and analog-based forecasting becomes the primary method.

EcoEngineers Legal Note for All Methodologies

In this document, EcoEngineers applies the approach under ISO 14064-2:2019 (Specification with Guidance at the Project Level for Quantification, Monitoring and Reporting of Greenhouse Gas Emission Reductions or Removal Enhancements) for quantification, monitoring, and reporting of Greenhouse Gas (GHG) projects to propose possible guidelines for measurement, monitoring, reporting, and validation (MMRV) of In Situ Sequestration of GHG Emissions from Planned Production of Carbon-Intensive Oil.

The ISO 14064-2:2019 standard provides an approach for quantifying, monitoring, reporting, and validating or verifying GHG emissions and removals. It specifies principles and requirements and provides guidance for project-level quantification, monitoring and reporting of activities intended to cause greenhouse gas (GHG) emission reductions or removal enhancements. It includes requirements for planning a GHG Project, identifying and selecting GHG sources, sinks, and reservoirs (SSRs) relevant to the project and the baseline scenario, monitoring, quantifying, documenting, and reporting GHG Project performance, and managing data quality. In this document, this framework is applied to In Situ Sequestration of GHG Emissions from Planned Production of Carbon-Intensive Oil.

This document refers to third-party data, assumptions, and analytical methods, where appropriate, to evaluate the potential for GHG emission reductions arising from in situ Sequestration of the emissions associated with the planned production of Carbon-Intensive Oil. The data sources, assumptions, and analytical methods, among other things, address specific issues related to oil Market Leakage, emissions intensity benchmarking, project additionality, and quantification of prevented Upstream, Midstream, and Downstream GHG emissions. These data sources were generally provided by Theaus Global or were obtained through research conducted by EcoEngineers' staff. To EcoEngineers' actual knowledge at the time of this document's issuance, all third-party data used in this document were obtained from reliable sources. Should any such third-party source be erroneous, misleading, or incomplete, in whole or in part, same may impact any conclusions outlined in this document.

While choosing to include a data source or an analytical method, EcoEngineers employed diligence to follow the principles of Completeness, Consistency, Accuracy, Transparency, and Conservativeness as required by the ISO 14064-2:2019 standard. To the best of EcoEngineers' actual knowledge at the time of this document's issuance, all third-party data used in this document were obtained from reliable sources. However, despite such diligence, the authenticity, accuracy, and completeness of third-party research, data, and analytics cannot be guaranteed by EcoEngineers, and should any such third-party source be erroneous, misleading, or incomplete, in whole or in part, the same may impact any conclusions outlined in this document.

This methodology document outlines the general requirements for Theaus Global or other Project Developers (PP) to comply with the ISO 14064-2:2019 standard. It establishes specific project criteria and procedures aligned with ISO 14064-2:2019, which are applicable independently of any governing or monitoring authority or carbon Registry. Such authorities may impose additional requirements related to additionality, specific quantification tools or models, project baselines, and other metrics. In such cases, the project may also need to meet those requirements to be eligible to generate GHG credits or other credits, certifications, or other designations.

Summary

The purpose of this methodology is to prevent GHG emissions associated with the planned Extraction, processing, transportation, refining, and end-use combustion of CIO by causing CIO deposits to remain undeveloped, using carbon credit revenues to prevent the Extraction of these high-emission oil projects. The Project Activity (PA) involves substituting planned CIO Extraction projects with less carbon-intensive alternatives, thereby preventing GHG emissions across the entire life-cycle that would have occurred had the Extraction project not been prevented.

This life-cycle spans from the Upstream phase (including well drilling, Extraction, and initial processing) through the Midstream phase (encompassing processing at the refinery gate), to the Downstream phase (covering product distribution and combustion). In this way, the methodology delivers emission reductions from "wells-to-wheels."

This methodology provides a comprehensive framework for quantifying, monitoring, and issuing carbon credits for prevented GHG emissions that would have resulted from CIO production. It incorporates carbon intensities, detailed calculations, and referenced best practices (outlined in Section 7. Baseline Scenario and Section 8. Project Scenario) to ensure transparency, accuracy, and integrity of emission reduction claims. The methodology is particularly suited to nations like Canada, which hosts significant CIO deposits, such as oil sands, and is applicable exclusively within G7 jurisdictions.

The Baseline Scenario describes the prevented CIO Extraction projects that would otherwise proceed under standard market and operational conditions, generating significant GHG emissions across their entire life-cycle. Emissions shall be quantified using suitable LCA models such as the Oil Climate Index plus Gas (OCI^{+}) tool, which provides a detailed analysis of oil production and processing emissions. The Baseline Scenario emissions represent a Business-as-Usual (BAU) case, capturing the Baseline Scenario's defined carbon footprint that would occur without the project's intervention.

The Project Scenario describes the in situ Sequestration of GHG emissions, achieved through preventing the Planned Production of CIO and substituting such Extraction of high-CI with lower-CI alternatives (COS).[3]

To ensure environmental and market credibility, this methodology incorporates robust criteria, requiring a PP to demonstrate that:

- The PA is not mandated by regulatory frameworks.
- The Baseline Scenario Production Volume is economically viable, as calculated by an independent, third-party PVC, and would otherwise have been developed without the Project intervention.

[3] This applies in cases where project developers implement multiple mitigation activities, such as those listed in Section 3.1:, including prevention of surface mining or in situ Extraction (e.g., SAGD or cyclic steam stimulation, CSS), adoption of renewable energy systems, energy efficiency upgrades, and substitution with alternative fuels like hydrogen or bio-based energy. These activities may be governed by different methodologies but must be coordinated under a broader climate strategy or jurisdictional plan. When implemented under a unified Program of Activities (PoA), each activity must adhere to the specific methodological requirements applicable to its scope, while the PoA must comply with the overarching principles and procedures of this methodology for preventing CIO production.

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- The project meets rigorous additionality standards, ensuring that the prevented, planned CIO production represents genuinely incremental GHG reductions beyond "business-as-usual" practices.
- The project meets rigorous Permanence standards, ensuring that the CIO within the SCD remains in the ground for the entire Undeveloped Period of at least 50 years.

Section 1: Introduction

The extraction, processing, transportation, and refining of CIOs are major contributors to GHG emissions. These activities typically generate emissions ranging from 30 to 300 kilograms of carbon dioxide equivalent per barrel of oil equivalent (kg CO_2e/boe), depending on oil density (API gravity) and Extraction methods, with combustion adding another ~400 kg CO_2e/boe.[4] On average, such oils' full life-cycle emissions (wells-to-wheels) are approximately 515 kg CO_2e/boe. In extreme cases, such as Canada's oil sands, emissions can exceed 729 kg CO_2e/boe,[5] highlighting the significant GHG emissions of these CIOs.

The methodology presented herein addresses the urgent need to mitigate the climate impacts of CIO Extraction by promoting activities that prevent their Extraction and financially incentivizing the substitution of lower-carbon alternatives through the sale of carbon credits. By quantifying and accrediting emissions reductions achieved through preventing the Planned Production of these CIOs, this methodology provides a robust framework to guide PPs and ensure credible, measurable climate benefits. It is structured to incentivize the replacement of CIO with less Carbon-Intensive Oil and other energy sources. The activity type, Extraction method, or modality is not an exclusion.

Serving as an essential tool for supporting global decarbonization goals, particularly in the context of minimizing the climatic impacts of a fossil-fuel-dominated energy sector. It equips stakeholders with a consistent approach to evaluating and implementing mitigation activities that reduce reliance on CIO sources. Furthermore, this methodology fosters transparency and ensures alignment with international best practices, enabling the creation of high-integrity carbon credits while addressing Market Leakage and associated uncertainties. This comprehensive framework is useful for driving the transition toward cleaner energy systems and achieving meaningful GHG emission reductions at scale.

Section 2: Principles

The design and implementation of this methodology shall be guided by the principles outlined in the International Organization for Standardization (ISO) 14064-2:2019 standard to ensure that all of the sequestered GHG emissions are real, measurable, transparent, conservative, and verifiable.

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[4] IHS CERA. (2010). Oil sands, greenhouse gases, and US oil supply: Getting the numbers right. IHS CERA Special Report. Cambridge, MA: IHS CERA Inc.
[5] https://oci.carnegieendowment.org/#supply-chain

These principles also underpin the management of environmental, social, and governance risks across the GHG Project life-cycle. PPs shall document and demonstrate adherence to the following:

- **Relevance**: Only GHG sources, sinks, and reservoirs (SSRs) and data that materially influence the quantification of GHG emissions and removals shall be included. Relevance also applies to identifying risks, impacts, and stakeholders affected by the project's implementation or omission.
- **Completeness**: All significant SSRs and PAs that influence the GHG baseline or project emissions/removals shall be accounted for. This includes direct and indirect SSRs, and Upstream, Midstream, or Downstream effects that may constitute leakage. Where exclusions are made, clear justifications and conservativeness in estimation shall be demonstrated.
- **Consistency**: Methods, assumptions, and criteria used in Baseline Scenario determination, Project Scenario quantification, and performance monitoring shall be applied consistently across time periods and sites. Any methodological updates or parameter changes shall be clearly disclosed, with justification based on improved accuracy or best available science.
- **Accuracy**: Quantification of GHG emissions shall strive for precision while reducing bias and uncertainty to the extent practical. Conservative assumptions, default factors, and estimation methods shall be used where precision is limited.
- **Transparency**: The Project design, Baseline Scenario assumptions, emission factors, data sources, monitoring plans, and stakeholder consultation processes shall be disclosed with sufficient detail to allow reproducibility and third-party validation and verification. Records shall be retained and made available for audit upon request.
- **Conservativeness**: When uncertainty or incomplete information exists, conservative assumptions shall be used to avoid overestimating emission reductions. Baselines, emission factors, and performance thresholds shall be set to not favor credit generation in the face of ambiguity.

Section 3: Objectives and Application Fields

This methodology is designed to be applicable and utilized under any GHG Program or standard that aligns with ISO 14064-2:2019 requirements for project-level GHG quantification and verification. It may be applied by any entity intending to implement a GHG mitigation project to sequester CIO in situ by preventing its Planned Production.

This methodology focuses on GHG Projects that prevent the extraction of CIO, such as heavy oil and bitumen. By substituting less carbon-intensive alternatives for these high-emission energy sources, it aims to reduce the average global emissions per unit of energy produced.

Projects using this methodology are allowed under the following modalities:

- **Unit Projects**: Individual programs designed to prevent planned CIO production within a specific geographical or operational boundary.

- **Grouped Projects**: Aggregated activities implemented by multiple participants or across different sites, provided they follow consistent methodologies and meet grouping criteria.
- **Programs of Activities (PoAs)**: Coordinated initiatives that allow for the inclusion of multiple independent activities over time if they adhere to the principles and procedures established by this methodology.[6]

Scenarios utilized in this methodology shall comply with all applicable legal and regulatory requirements, including those related to environmental permitting, land tenure, and resource development rights in the jurisdiction where the physical CIO resource is located. This includes, where relevant, the obligation to demonstrate legal access, rights to withhold production, or ownership of avoidance rights in accordance with Section 3.3: of this methodology.

Furthermore, PPs shall identify and comply with any additional monitoring, reporting, and verification (MRV) requirements imposed by the applicable GHG Program or subnational law where the emission reductions or credits will be claimed and verified. At the project design document (PDD) and verification stages, proponents shall provide a regulatory compliance matrix detailing the relevant statutes, authorizations, and reporting obligations (whether environmental, land use, or corporate) supporting the legal and operational basis for preventing CIO Extraction.

This methodology is applicable exclusively to GHG Projects located in G7 countries (Canada, France, Germany, Italy, Japan, the United Kingdom, and the United States) that are aimed at preventing planned CIO production, regardless of the CIO Extraction technology (e.g., surface mining, in situ methods like SAGD) or the CI of the CIO source. The following criteria and considerations apply:

- **Technological Scope**: Includes projects involving innovative or traditional methods to reduce reliance on CIO production, including using alternative, lower-carbon energy sources.
- **Geographical Scope**: Applicable exclusively to activities within G7 countries that possess CIO deposits, such as Canada and the United States.
- **Emission Reduction Focus**: Quantifies and supports verification of sequestered emissions across the full life-cycle of the CIO, including Upstream, Midstream, and Downstream stages.

3.1: Scope

This methodology covers a wide range of technologies, facilities, and scenarios that contribute to preventing planned CIO production. The scope is defined as follows: these activities—including preventing surface mining or in situ Extraction (e.g., SAGD or CSS), substitution with

[6] This applies in cases where the Project Proponent implements multiple mitigation activities that may be governed by different methodologies but are grouped under a broader climate action strategy or regional policy framework. For example, a jurisdictional or subnational climate plan may include both preventing oil production and above-ground land use activities (e.g., afforestation or renewable energy deployment), each following a distinct methodological approach. When these activities are coordinated under a unified PoA, they may be included over time, so long as they conform to the overarching principles and procedural requirements of this methodology for the components relevant to preventing CIO production.

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lower-carbon energy sources, and implementation of energy efficiency measures—are the primary drivers expected to create a measurable difference in carbon intensity (CI) between the Sequestered CIO and its substitute (COS). While certain interventions, such as renewable energy deployment, may displace only a small fraction of the energy represented by a single barrel of oil, this methodology provides two options for addressing Market Leakage.

Project Proponents may determine a project-specific leakage rate using the approach outlined in Section 8.3.1:, which requires the application of at least one peer-reviewed econometric or market simulation model to derive a transparent, repeatable, evidence-based leakage factor reflective of specific local or regional market conditions. The types of activities and systems eligible under this methodology are categorized as follows:

1. **Extraction Technologies**: Includes methods to prevent surface mining or in situ Extraction techniques such as SAGD or CSS.
2. **Substitution Technologies**: Supports the adoption of lower-carbon energy sources, such as renewable energy systems (solar, wind, geothermal) or energy efficiency measures that replace CIO in energy generation.
3. **Innovative Processes**: Encourages deploying innovative technologies to reduce dependency on CIO, including hydrogen- or bio-based fuels or potentially small modular nuclear reactors as substitutes for petroleum products.
4. **Oil Production Sites**: Includes oil sands, bitumen Extraction facilities, and other CIO deposits located within G7 countries, with a focus on high-CI regions such as Canada and the United States.
5. **Substitution Facilities**: These may include renewable energy generation sites, industrial installations implementing energy-efficient technologies, or facilities integrating alternative fuels to displace CIO use.
6. **LCA Boundaries**: The methodology has a well-to-wheels approach, including the Upstream (exploration, Extraction, and initial processing), Midstream (transportation, refining, and additional processing), and Downstream (product distribution, fuel combustion, and end-use) components of the value chain, ensuring that all significant GHG emissions along the entire value chain are thoroughly accounted for and accurately quantified.

Alternatively, instead of determining a project-specific leakage rate, PPs may utilize a simplified approach and assume a fixed 100% leakage rate (i.e., that any prevented CIO production is fully replaced by additional production elsewhere in the global market). Under this approach, credits are issued only for the net reduction in CI between the Sequestered CIO and substitute COS.

3.2: Compliance with Technical, Legal, and Regulatory Frameworks

The PA implemented under this methodology shall demonstrate full compliance with applicable technical, environmental, and legal frameworks in the jurisdiction where the prevented CIO Extraction would otherwise occur. This includes, but is not limited to:

- Environmental laws and permitting requirements (e.g., exploration and development authorizations, emissions reporting obligations, and site closure requirements)

- Land use and resource rights, including tenure, mineral rights, and rights to access, develop, or prevent resource Extraction
- Corporate and commercial law considerations, such as contractual arrangements related to lease agreements, joint ventures, or indigenous land use agreements
- Applicable jurisdictional frameworks for GHG accounting, reporting, or MRV, where such frameworks exist at national, subnational, or regional levels

PPs shall identify all relevant legal and regulatory provisions applicable to the Baseline Scenario and demonstrate that the CIO production activity being prevented is legally permissible, commercially viable, and not otherwise restricted or prohibited by law.[7]

At the design stage, proponents shall include a regulatory compliance matrix in the PDD, summarizing all applicable local, regional, and national requirements, as well as evidence of project rights and obligations. This may include leases, permits, notices of non-objection, mineral ownership records, or equivalent documentation demonstrating legal access to or control over the CIO deposit and the right to prevent its extraction.

3.3: LCA and GHG Quantification Tools

The PPs employ recognized life-cycle assessment (LCA) or GHG quantification models that capture emissions across the full oil and gas value chain. According to the ISO 14064-2 (clause A.3.4), the selection of quantification tools shall consider scientific validity, transparency, and representativeness of the data and methods applied. The tools used should enable the calculation of life-cycle GHG emissions that are relevant to oil and gas sector activities. The objective is to ensure that emission estimates derived under this methodology framework are conservative, credible, and real.

The tools listed in this methodology are provided as illustrative examples. PPs are not limited to these tools and may propose alternative LCA or GHG quantification models. However, any tool used shall be open-source, transparent in its methodology, and have undergone peer review in a recognized scientific or technical forum. PPs shall also demonstrate that the tool provides a credible, conservative estimate of life-cycle GHG emissions consistent with this methodology's boundary conditions and objectives.

- **OCI$^+$**: It is an open-source analytical tool designed to estimate and compare the life-cycle GHG emissions of individual oil volumes worldwide. It evaluates emissions across various stages, including production, refining, and petrochemical processing, gathering, storage, transport, and end uses.
- **Argonne National Laboratory's GREET Model**: The model is a specialized adaptation of the GREET model tailored to assess life-cycle GHG emissions associated with oil production, transportation, refining, distribution, and end-use combustion. This model ensures precise and standardized emissions accounting across the full oil value chain (from Extraction to final use), referred to as "wells-to-wheels." By incorporating region-specific data and regulatory frameworks, the GREET model provides a comprehensive tool for evaluating the environmental

[7] This aligns with ISO 14064-2:2019, Clause 6.2(l), which requires project documentation to include all information relevant to project eligibility, including legislative, technical, environmental, and site-specific requirements.

impacts of petroleum-related activities across Upstream, Midstream, and Downstream stages.

- **Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Model**: The OPGEE is an engineering-based LCA tool designed to estimate GHG emissions from crude oil production, processing, and transport. Its system boundary extends from initial exploration to the refinery entrance gate. It systematically quantifies emissions from different production pathways, providing a detailed modeling framework for assessing CI across various Extraction and processing scenarios.
- **Petroleum Refinery Life Cycle Inventory Model (PRELIM)**: PRELIM is an engineering-based LCA tool designed to estimate GHG emissions from crude oil upgrading and refining, focusing specifically on Midstream and refinery operations. It models energy use, emissions, and product yields across various refinery configurations, enabling detailed LCAs of different crude types and refinery designs. The model operates at a process unit level, incorporating mass and energy balances, and allows users to assess energy consumption, emissions intensity, and process efficiencies. PRELIM also enables scenario analysis for refining different crude qualities, providing insights into emissions and refining efficiencies.
- **OPEM**: OPEM is an LCA tool developed as part of the OCI$^+$ framework to estimate GHG emissions from the Downstream phase of the oil supply chain, specifically refining, fuel distribution, and end-use combustion. It quantifies emissions from refined product pathways using emission factors and energy balances derived from refinery configurations, fuel properties, and consumption scenarios. OPEM is designed to complement Upstream and Midstream tools such as OPGEE and PRELIM by capturing the Downstream (post-refinery gate) emissions, ensuring a full well-to-wheel analysis. This tool is particularly useful for modeling product-specific combustion emissions and for comparing life-cycle emissions across different oil types and end-use markets.

Section 4: Eligibility and Inclusion Requirements

This methodology applies to GHG Projects that meet the following criteria:

- **Ownership:** The PP is the default holder of the sequestered GHG emissions rights associated with the project, unless a signed agreement, attestation, or other legally binding document explicitly cedes these rights to another party.
- **Geographic Restriction**: GHG Projects utilizing this methodology shall be located within the jurisdictions of the Group of Seven (G7) countries[8] (Canada, France, Germany, Italy, Japan, the United Kingdom, and the United States).
- **Baseline Scenario**: The PP shall demonstrate the following for the baseline scenario:
    a. Only economically feasible projects based on a full-field development plan or Credible Business Development Plan (CBDP) are eligible to use this methodology. The Baseline Scenario shall be considered financially attractive if the integrated financial analysis yields economic indicators, such as net present value (NPV), internal rate of return (IRR), and payback period, which are equal to or exceed standard industry benchmarks for comparable oil and gas development projects (see Section 5:). The PP shall also demonstrate that the projected Production Volume can be assessed with rigorous professional standards and that extraction is technically feasible using standard, industry-accepted methods, as calculated by a PVC. The Production Volume of a GHG Project shall be determined once per crediting period.
    b. The PP shall demonstrate that all major regulatory, legal, and environmental approvals are in place as required to advance the CIO production project to the final investment decision (FID) stage. This includes all major permits and regulatory clearances typically necessary for commencing the first phase of a multiple-phase Baseline Scenario. However, at this final stage – just before financing is arranged and project execution is commenced – the Baseline Scenario activity is discontinued to enable the implementation of the GHG PA.
    c. Sufficient data shall be available to calculate life-cycle emissions from the Baseline Scenario.
    d. The PP shall demonstrate full control over the baseline scenario CIO extraction activities. This includes legal authority to access, manage, or prevent the development of the CIO in question. Control may be established through ownership of mineral rights, lease agreements, operator status, or other contractual or statutory rights that authorize or obligate the PP to execute (or prevent) the development of the CIO.
    e. The Project shall complete third-party validation within five years of the determined project start date (see Section 6:, and Section 6.2:).

[8] By restricting the methodology to G7 countries, the risk of generating poor-quality credits in jurisdictions with unreliable regulatory systems is minimized. This is particularly important to prevent the issuance of credits based on dubious or easily manipulated environmental licenses or approvals.

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Section 5: Additionality

This section outlines the procedures for demonstrating that the GHG emission reductions resulting from the PA are additional to what would have occurred in the absence of the project. PPs shall apply the following stepwise approach, adapted from the United Nations Framework Convention on Climate Change's (UNFCCC's) *Tool for the Demonstration and Assessment of Additionality* (Version 07.0.0 or later), to substantiate additionality.

5.1: Regulatory Surplus – Legal and Institutional Conditions

The PP shall demonstrate that the PA is not required by any law, regulation, or enforceable policy applicable in the jurisdiction where the project is located. This includes confirming that there are no environmental restrictions, land use designations, protected status, moratoria, or other legal instruments that prohibit or restrict CIO extraction at the Project site.

The Project site shall meet the following conditions:

- Extraction of CIO shall be legally permitted under current national, subnational, or local regulations.
- The Project area shall not be subject to conservation designations or regulatory frameworks that independently prevent or restrict CIO development.
- The PP shall demonstrate that the Baseline Scenario (i.e., CIO extraction) could legally occur without the GHG Project.

The PP shall provide supporting evidence, such as land tenure records, mineral or subsurface rights, exploration or development permits, and documentation of regulatory compliance.

5.2: Baseline Scenario – Financial Feasibility and Technical Viability

If the Baseline Scenario activity is legally permissible, the PP shall demonstrate that it is economically and technically feasible based on a full-field Credible Business Development Plan (CBDP).

The following criteria apply:

- The Baseline Scenario shall be financially attractive. This shall be demonstrated through an integrated financial analysis in the CBDP, which includes standard indicators such as NPV, IRR, and/or payback period, benchmarked against industry norms for Upstream oil development.
- The Baseline Scenario financial model shall exclude revenue from carbon credits and reflect realistic input assumptions (e.g., oil prices, capital and operational costs, tax structures, discount rates).
- Sensitivity analysis shall be included to demonstrate the robustness of the Baseline Scenario's financial viability under reasonable changes in key parameters.

In addition, the PP shall demonstrate that:

- The projected Production Volume of CIO is technically feasible using commercially available and industry-standard methods (e.g., surface mining, SAGD, CSS, or other in situ recovery techniques).

- The Production Volume has been independently assessed with professional accuracy by a qualified independent PVC.
- The Production Volume shall be determined once per crediting period and documented in the PDD.

Section 6: Project Boundaries

The Project Boundaries define the spatial and temporal limits within which all relevant GHG SSRs associated with the project are identified, quantified, and monitored. The specific elements are described below.

6.1: Spatial Limits

The project spatial limits refer to the physical location of the CIO deposit. A CIO deposit is a three-dimensional subsurface body with an areal extent and thickness. The areal extent can be defined by a shapefile or polygon projected to the ground surface. The thickness is determined by specifying the top and base of the reservoir, which usually vary over the areal extent of the deposit. The top can be a geologic marker or structural surface and is defined by a structure map. The deposit's base can be a geologic marker, structural surface, or fluid contact and is defined by a structure map. The thickness is defined by the vertical distances between the two surfaces to make an isochore map.

The spatial extent of the GHG Project includes the physical boundaries of monitoring activities and pipeline injection points (in the Baseline Scenario of CIO Extraction). These boundaries include the location of the CIO deposit, Extraction infrastructure, and all related systems that would have been used for oil Extraction, processing, and initial transportation.

The site where the Baseline Scenario CIO deposit is located shall be specified at the country-, second- (state, department, province, or similar), and third-level (municipality or similar) political subdivisions, including geographical coordinates using the official reference system for the country where the project is located. The location and extent of the deposit shall be included in the PDD in a .shp (geographic information system shapefile) or .kml (Keyhole Markup Language) file format.

Figure 1: GHG Project Boundaries

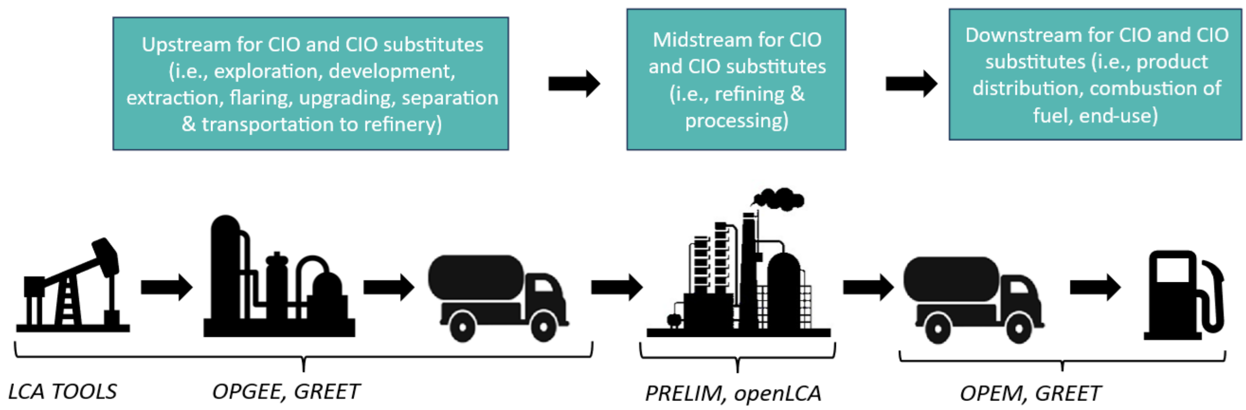

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Figure 1 illustrates the life-cycle stages for CI quantification of CIO and COS, including Upstream (exploration, Extraction, flaring, Upgrading, separation, and transportation to refinery), Midstream (refining and processing), and Downstream stages (product distribution and oil product combustion). Relevant emissions are quantified across stages using established LCA tools such as OPGEE, PRELIM, and OPEM or other LCA modeling tools.

6.2: Temporal Limits

The temporal boundary defines the duration over which the PA is implemented and GHG emission reductions are monitored, quantified, and reported. This includes the project start date, crediting period, and relevant monitoring intervals.

- **Project Duration**: The project duration refers to the period (in years) from the first (day.month.year) to the final (day.month.year) day during which the GHG Project prevents the CIO Extraction. For such projects, the planned operational lifetime shall involve keeping the CIO deposit undeveloped for a minimum of 50 years to ensure long-term climate benefits and alignment with Permanence expectations. Since the implementation of the Project results in non-Extraction rather than active development, no physical infrastructure or production technologies shall be installed in the Project Scenario.
- **Crediting Period**: The crediting period for projects under this methodology shall be: five years from the Project Start Date, renewable up to three times, for a maximum of 20 years total, subject to revalidation and confirmation of continued eligibility and enforceable project conditions.

This crediting structure aligns with the typical production horizon of CIO deposits, which are often exploited within a 15- to 20-year economic window. However, to maintain environmental and regulatory integrity, the following additional conditions apply:

- The crediting period shall not exceed the duration of the PP’s legal authority to prevent the development of the CIO deposit.

- If the economic feasibility window for developing the CIO deposit (as demonstrated by Baseline Scenario financial modeling) is shorter than 20 years, then the crediting period shall be conservatively limited to that shorter window.
- The PP shall provide credible documentation demonstrating both the enforceability of development restrictions and the expected production period under baseline conditions.
- At the end of each five-year crediting period, the project shall undergo a renewal assessment, including revalidation of legal control, economic context, and baseline plausibility.

- **Project Start Date**: The start date of the GHG Project shall be defined as the earliest documented action taken of the Project to prevent the implementation of the Baseline Scenario credibly and demonstrably, following a pre-execution decision point or comparable project advancement milestone. This may include, but is not limited to, contract amendment, formal shelving of the development plan, or other legally binding decisions to halt forward motion on CIO extraction.

The selected start date shall fall within the expected window between FID and projected commercial production and shall be substantiated with clear documentation such as board resolutions, engineering schedules, regulatory filings, or signed contractual amendments.

The project shall complete initial third-party validation within five years of the determined project start date. Failure to do so shall render the project ineligible to claim GHG emission reductions from that start date unless justified under force majeure or exceptional circumstances and approved by the applicable program or Registry. This requirement applies to the GHG Project as a whole and does not preclude subsequent validation of individual phases or PDDs.

Section 7: Baseline Scenario

The Baseline Scenario represents the business-as-usual case where a business decision is made to extract the CIO. The Production Volume for the Baseline Scenario shall be determined through Well Production Forecasting conducted by the PVC, using the Credible Business Development Plan (CBDP) and analog-based production profiling. The forecasting shall consider the extent and characteristics of the SCD, suitable Extraction methods, expected start-up, plateau, and decline phases, market conditions, projected oil prices, and other relevant inputs. The Baseline Scenario determination shall clearly state all key underlying assumptions under which a rational business decision would be made to extract the CIO Production Volume.

The credible business development plan and feasibility assessment shall reasonably consider that extraction technologies may become more efficient over time, which could affect both production economics and emissions intensity.

This methodology leverages LCA models such as the GREET3.0 and other recognized models to establish consistent boundaries, emission sources, and calculations. The CI of various oil types is well-established, as defined by geography and Extraction methods.[9] To determine the CI for the Baseline and Project Scenarios, the PP may use public information from relevant entities, such as the OCI+ or other peer-reviewed sources, provided it is demonstrated to accurately reflect the GHG Project. Alternatively, the PP may independently calculate the CIs for the Baseline and Project Scenarios by aligning with the principles outlined in ISO 14044, ensuring methodological rigor and comparability. The CIs of the Baseline and Project Scenarios shall be evaluated comparably to establish a representative CI differential.

The Baseline Scenario's financial viability shall be demonstrated for its lifespan, including initial development, planned expansions, and end-of-life closure. To maintain environmental integrity, credits shall only be issued for emission reductions that remain real and additional throughout the Crediting Period. The validity of Baseline Scenario assumptions shall be reassessed and renewed in accordance with the requirements of Section 6.2:, at least every five years or at the start of each new crediting period, or sooner if significant regulatory or market changes occur that would materially alter the business case for Extraction.

If, at any point during the Crediting Period, due to shifts in energy markets, technological advancements, or other considerations, Ex-ante calculations indicate that the planned CIO production would have ceased or been interrupted, credits shall not be issued for such periods.

The description of the Baseline Scenario shall include the following:

- Production trends for oil produced in the same region or market via similar extraction techniques.
- Marketing or offtake agreements typical for CIO in the region.
- Volume commitments typical for CIO in the region.
- Transportation, processing, refining, and chains of custody typical for CIO in the region.

Table 1: SSRs Included in the Baseline Scenario

SSR in the Scenarios		Controlled/ Related/ Affected	GHG	Included?	Justification/ Explanation
Baseline	CIO Deposit	Controlled	CO_2	Yes	The CIO is meant to be left undeveloped as part of the PA.
			Methane (CH_4)		
			Nitrous oxide (N_2O)		
	CIO Extraction	Controlled	CO_2	Yes	

[9] RESO 18-34 LCFS Attachment A Final Reg Order.

SSR in the Scenarios		Controlled/ Related/ Affected	GHG	Included?	Justification/ Explanation
			CH_4		The Baseline Scenario emissions resulting from extraction of the CIO are calculated using the GREET or OPGEE model within the OCI+ tool.
			N_2O		
	CIO Flaring and Venting	Controlled	CO_2	Yes	GHG emissions resulting from flaring in the light- to medium-sized hydrocarbons of the CIO, which serve as preventive or corrective safety measures at a facility, are considered by the quantification model.
			CH_4		
			N_2O		
	CIO Processing and Refining	Affected	CO_2	Yes	GHG emissions resulting from the processing of CIO's hydrocarbons at refineries or similar facilities are identified as significant by the PRELIM model within the OCI+ tool or the openLCA tool.
			CH_4		
			N_2O		
	CIO Transportation	Affected	CO_2	Yes	GHG emissions resulting from the movement of the CIO from Extraction sites to processing facilities.
			CH_4		
			N_2O		
	CIO Refined Product Distribution and End-Use Combustion	Affected	CO_2	Yes	GHG emissions resulting from transportation and end-use combustion of all refined products after the refinery exit gate are quantified using the OPEM model within the OCI+ tool or other GREET.
			CH_4		
			N_2O		

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Table 1 presents the GHG SSRs associated with the Baseline Scenario, where CIO extraction proceeds without the PA intervention. It identifies the GHG types and their sources, such as emissions from CIO reservoirs, extraction activities, flaring, Midstream processing, and Downstream combustion. Each entry in the table categorizes these sources as controlled, related, or affected while justifying whether they are included within the Project Boundaries. The table is complemented by Figure 1, which visually illustrates the Project Boundaries and the GHG sources relevant to the Baseline Scenario, emphasizing the Upstream and Midstream emissions of CIO production and the definitions of Upstream and Midstream, and Downstream stages of the CIO production, as defined in the Definitions section of this methodology.

The GHG emission sources in the baseline scenario of Table 1 shall be consistent with the LCA model used in compliance with applicable regulations.

7.1: Baseline Scenario GHG Emissions Calculations

The Baseline Scenario GHG emissions will be calculated using Equation 1 as follows:

Equation 1: Baseline Emissions

$$BE_y = R_y \times CI_{CIO,y}/1000$$

Variable	Description	Units
BE_y	Total baseline emissions in year *y*.	Metric tons of carbon dioxide equivalent (t CO_2e)
R_y	The volume of CIO production prevented in year *y*, based on a credible business development plan and the production profile. This parameter reflects the CIO that would have been extracted without the GHG Project.	boe
$CI_{CIO,y}$	The CI of the prevented CIO Production Volume in year *y*, expressed in kg CO_2e per barrel of CIO. This value accounts for life-cycle emissions, including Extraction, processing, and transportation.	kg CO_2e/boe

To estimate the $CI_{CIO,y}$ term, the following approach can be used:

1. **Peer-Review-Based Estimates**: Use peer-reviewed studies, industry reports, and Government datasets to identify average CI values for different oil types and Extraction technologies appropriate to the project. Resources such as the Rocky Mountain Institute

(RMI)'s OCI⁺,[10] IPCC emission factors, or historical LCA studies in similar geological formations or regions.

The selected CI value shall:

- Be specific to the oil type (e.g., bitumen, oil sands, light, medium, heavy).
- Align with the extraction technology for the CBDP (e.g., SAGD, CSS, conventional drilling, in situ mining, hydraulic fracturing).

2. **LCA Modeling**: This approach uses project-specific modeling to determine GHG emissions per unit of oil produced (kg CO_2e/boe), incorporating project-specific parameters into an LCA framework. Key models applicable could include:
    - **OPGEE**: A well-to-refinery model developed by Stanford University, commonly used for Upstream oil Extraction emissions.
    - **GREET**: Developed by Argonne National Laboratory, primarily used for crude oil refining and transportation emissions.
    - **PRELIM**: Focuses on refining emissions (Midstream emissions), complementing Upstream assessments.
    - **OPEM**: An engineering-based tool in the original OCI that uses emission factors and operating assumptions to calculate GHG emissions from the transport and combustion of oil products.
    - **openLCA**: A flexible, open-source tool adaptable to project-specific conditions.

[10] RMI. (n.d.). *Oil Climate Index plus Gas (OCI⁺)*. https://ociplus.rmi.org/

Section 8: Project Scenario

8.1: GHG Emissions in the Project Scenario

GHG emissions to be considered in the Project Scenario are described in Table 2.

Table 2: SSRs of the Project Scenario

SSR in the Scenarios		Controlled/ Related/ Affected	GHG	Included?	Justification/ Explanation
Project	COS Deposit	Affected	CO_2 CH_4 N_2O	Yes	The COS is meant to replace the CIO, which is being left undeveloped as part of the Project.
	COS Extraction	Affected	CO_2 CH_4 N_2O	Yes	Emissions related to the Extraction of the COS are calculated using the GREET or OPGEE model within the OCI$^+$ tool.
	COS Flaring and Venting	Affected	CO_2 CH_4 N_2O	Yes	GHG emissions resulting from flaring in the light-to-medium-sized COS hydrocarbons, which serve as preventive or corrective safety measures at a facility, are considered by the quantification model.
	COS Processing and Refining	Affected	CO_2 CH_4 N_2O	Yes	GHG emissions resulting from the processing of COS hydrocarbons at refineries or similar facilities are identified as significant by the PRELIM model within the OCI$^+$ tool or the GREET tool.
	COS Transportation	Affected	CO_2 CH_4 N_2O	Yes	GHG emissions resulting from the movement of the COS from Extraction sites to processing facilities.

SSR in the Scenarios		Controlled/ Related/ Affected	GHG	Included?	Justification/ Explanation
	COS Refined Product Distribution and End-Use	Affected	CO_2	Yes	GHG emissions resulting from the distribution and combustion of refined products derived from the COS are accounted for using the OPEM model within the OCI+, which captures Downstream emissions beyond the refinery gate, including product transport and final end-use. Other tools, like openLCA or GREET, that cover this segment inside the value chain can be used instead.

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Table 2 outlines the GHG SSRs associated with the Project Scenario, focusing on emissions related to the substitution or prevention of CIO Extraction. It details the emissions from reservoirs and substitution processes and evaluates the potential for leakage due to market shifts. The table comprehensively assesses the project's contribution to GHG mitigation by clearly defining the included emissions and explaining their significance. As with the Baseline Scenario, the Project Scenario table refers to Figure 1, which visually depicts the Project Boundaries and highlights the GHG emissions included. Together, Table 1, Table 2, and Figure 1 provide a clear framework for understanding and quantifying the emissions reductions achieved through the GHG Project.

- **Geographical Consideration**: The PP shall justify the selection of the substitute oil source(s) based on regional market conditions, infrastructure availability, and refinery compatibility.
- **Regulatory Compliance**: The selected substitute shall adhere to national and international environmental regulations, including emission control standards.

8.2: GHG Emissions Calculation in the Project Scenario

The Project Scenario GHG emissions calculation will be established using an LCA model appropriate for the regulatory framework governing the prevented Extraction of CIO (See Section 3.3:).

Equation 2: Project Emissions

$$PE_y = R_y \times CI_{COS,y} \times L_y / 1000$$

Variable	Description	Units
PE_y	Total Baseline Scenario emissions in year *y*.	t CO_2e
R_y	The volume of CIO production prevented in year *y*, based on a credible business development plan and the Production Volume profile. This parameter reflects the CIO that would have been extracted without the GHG Project.	boe
$CI_{COS,y}$	The CI of the COS in year *y*, expressed in kg CO_2e per barrel. This value reflects the life-cycle GHG emissions (Upstream, Midstream, and Downstream) associated with the oil supply that substitutes for the prevented production of CIO. The $CI_{COS,y}$ may be derived based on a sole source if the substitution originates from a single alternative production system, or a mix of substitute oils. In the latter case, the weighted average CI shall be determined based on the contribution of each substitute type to the overall substitute supply. The calculation of $CI_{COS,y}$ will follow the guidelines outlined in Equation 3.	kg CO_2e/boe

Variable	Description	Units
L_y	Leakage in year y (L_y) accounts for the portion of CIO emissions offset by the COS. PPs may apply a model-based approach using peer-reviewed econometric methods or opt for a simplified approach, assuming a fixed leakage rate of 1. Further details are provided in Section 8.3:.	Dimensionless

Equation 3: Weighted Average CI of the COS

$$CI_{COS,y} = \sum_{i=1}^{n} CI_{COSi,y} \times x_{i,y}$$

Variable	Description	Units
$CI_{COS,y}$	The weighted average CI of the COS in year *y* ensures that the emissions impact of different substitute oil sources is appropriately accounted for.	kg CO_2e/boe
$CI_{COSi,y}$	The CI of each COS in year *y* represents the life-cycle emissions of each substitute oil option *i*.	kg CO_2e/boe
$x_{i,y}$	The fraction contribution of oil substitute *i* in year *y* represents the share of each substitute oil type in the total substitute mix used to replace the sequestered CIO. The sum of all $x_{i,y}$ values shall be equal to 1.	Dimensionless, a fraction between 0 and 1
n	Total number of different oil substitutes used to replace the sequestered CIO.	N/A

To ensure reasonable accuracy and contextual relevance in each project, the following guidelines shall apply when determining the appropriate COS ($CI_{COSi,y}$):

- **Geographical Consideration**: The substitute oil source(s) shall be justified based on local or regional infrastructure, market accessibility, and logistical feasibility. The PP shall demonstrate that the substitute oil is a realistic alternative, given its proximity to refining facilities, transportation networks, and historical energy market conditions.
- **Regulatory Compliance**: The selected oil substitute source(s) shall adhere to applicable national and international environmental regulations and agreements, including emission control standards and market restrictions applicable to the region(s) where the source(s) supply chain is. Compliance shall be verified using historical data, industry reports, or Government regulatory frameworks. For example, in the Organization of the Petroleum Exporting Countries (OPEC) or non-OPEC jurisdictions, certain oil substitutes may face trade barriers or market acceptance challenges depending on the producing country's export policies and the receiving region's import policies. Additionally, oil with high sulfur content or other inherent pollutants may be restricted from entering environmentally stringent markets, such as the European Union or California's Low Carbon Fuel Standard (LCFS), which impose strict limits on sulfur levels, heavy metal content, or GHG intensity. Similarly, CIO, which is not permitted to be developed due to such considerations, is not eligible for crediting.

Like the determination of $CI_{CIO,y}$ the $CI_{COSi,y}$ can be quantified using the following two methods described in Section 7.1:

- **Peer-Reviewed Estimates**: Rely on published studies, industry reports, and Government datasets to determine CI values specific to oil types and Extraction technologies; or
- **LCA Modeling**: Calculates project-specific emissions per unit of oil produced by integrating project-specific parameters into established models listed in Section 3.3:

8.3: Leakage

In the context of this methodology, leakage represents indirect GHG emissions caused by market dynamics. For example, reducing CIO production may increase extraction elsewhere to meet global supply demands. To ensure the integrity of emission reduction claims, the leakage rate shall be reassessed periodically to reflect changes in Production Volume, oil prices, and supply-demand conditions, unless the fixed rate of 100% is applied, in which case it remains constant throughout the crediting period.

- **Model-Based Leakage Estimation**: PP may opt to determine leakage using analysis of at least one peer-reviewed econometric or simulation model, as detailed in Section 8.3.1:. In this case, the leakage rate shall be recalculated once per crediting period using updated input data to ensure continued accuracy.
- **Fixed Leakage Rate Percentage**: Simplified approach, assuming a fixed leakage rate of 100% (L_y = 1), requiring no annual reassessment.

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8.3.1: Selection of Leakage Rate Based on Econometric Modeling

This section outlines the approach for PPs that choose to develop a tailored, yet still conservative leakage factor derived through the utilization of one or more econometric or market-based models that have been used in peer-reviewed scientific articles. The selected articles include complete references and provide the supplemental information, datasets, and assumptions required to ensure methodological transparency and full reproducibility of results. Given the dynamic nature of key inputs (such as Production Volumes, oil prices, and global supply-demand conditions), the selected leakage factor shall be reassessed periodically using updated data to maintain accuracy and environmental integrity.

8.3.1.1: Econometric and Market Simulation Model Requirements

To preserve the environmental integrity of credits issued, the following requirements apply:

- All models shall be no more than ten (10) years old from their original publication date.
- Each model shall be specifically applied to assess carbon or Market Leakage in oil production scenarios. General leakage models for unrelated sectors are not eligible.
- The source article for each model shall include sufficient supplemental data, parameters, and methodological description to allow independent reproduction of leakage estimates.
- All models should explicitly address international leakage, and capture temporal dynamics (e.g., intertemporal substitution or the Green Paradox),[11] unless these elements do not apply to the specific project context or geographic market conditions. In such cases, the PP shall justify the exclusion based on credible market evidence or regulatory limitations.
- The models shall support or be adaptable to barrel-level or field-level applications or provide a clear methodology to derive leakage per unit of prevented production. Acceptable methodological approaches include:
  - **Computable General Equilibrium (CGE) Models**: These simulate the entire economy, including multiple interacting markets (e.g., oil, gas, labor, trade) and how they respond to shocks like supply restrictions.
  - **Partial Equilibrium (PE) Models**: These simulate how one market (e.g., global oil) responds to changes in supply/demand, holding other markets constant.
  - **Econometric Simulation Models**: These are based on regression-derived parameters (e.g., elasticity of supply/demand) and simulate market behavior using historical relationships.

[11] When future climate policies signal that fossil fuel Extraction will become more restricted or taxed, producers may accelerate Extraction today to avoid future losses — increasing near-term emissions. See: Holtsmark, K. (2018). Supply-side climate policy in Norway. University of Oslo, Department of Economics.

Moreover, the same values for Baseline Scenario Production Volume (R_y), Baseline Scenario CI ($CI_{CIO,y}$), and Project Scenario CI (CI_{COS})[12] shall be applied. The price elasticities of supply and demand, substitution coefficients, and oil price scenarios shall be clearly stated and harmonized.[13] Additionally, all assumptions regarding market behavior (e.g., the role of OPEC as a coordinated supply-managing entity versus a competitive market structure) shall be transparently documented.

For the model, the following shall be included in the documentation annex:

- Full article citation and direct link to the publication
- Model equations and summary of assumptions
- All input values and their sources
- Output leakage factor (L_y), with corresponding uncertainty range
- Explanation of how the model was adapted or applied to the project scale

8.3.1.2: Conservative Model Selection

The project's leakage value (L_y) for use in Equation 2 shall be determined by selecting the highest leakage factor produced among the applied econometric or market simulation models. No upper cap is imposed on the leakage factor, as values greater than 1.0 may reflect real-world market dynamics where substitute oil production exceeds the Sequestered CIO volume during specific periods. In such cases, the CI differential between the CIO and the COS may still result in net emission reductions depending on extraction, transportation, and processing emissions differences.

8.3.1.3: Verification Assessment

The entire modeling process, including scripts, calculation sheets, and source references, shall be submitted to the validator/verifier.

The validation and verification body (VVB) shall assess:

- That the models were sourced from peer-reviewed publications.
- The supplemental data enabled the reproduction of results.
- That the final selected leakage factor was appropriately derived and appropriately conservative.

All documentation shall be made available for Registry review and potential public access (IP-specific redactions may be acceptable, if required. Sufficient detail shall be made public to reproduce results).

The selected leakage factor shall be re-evaluated before each vintage and issuance, or before each new crediting period, or in response to major market changes (e.g., shifts in global oil

[12] Ideally, the $CIO_{COS,y}$ should be disaggregated and applied to each component (where applicable) of the CIO substitute blend to reflect the full composition and ensure accuracy.
[13] It refers to using the same values for key parameters (e.g., oil demand elasticity, baseline emissions per barrel, production volumes) across all three leakage models during comparative analysis.

prices, production trends, or regulatory frameworks). Reassessment shall use updated input data and may use updated or newly published models, provided they meet the same criteria outlined above.

8.3.2: Fixed Leakage Rate Percentage

This section outlines the approach for PPs that choose the simplified approach, which assumes 100% leakage—that each barrel of oil prevented from Extraction due to Project intervention is extracted elsewhere. The net difference in CI between the substituted energy source and the CIO is the value credited under this version of the methodology.

8.3.2.1: Calculation of Leakage

Leakage emissions are calculated as a percentage of Baseline Scenario emissions, ensuring simplicity and a high degree of conservativeness:

Equation 4: Leakage Default Value

$$L_y = 1$$

Variable	Description	Units
L_y	Total leakage rate of the substitute oil or slate of substitute oil in year *y*.	Dimensionless

Adopting a standardized leakage rate of 1 simplifies the quantification process for PPs, eliminating the need for complex market modeling. Recognizing that market conditions and further studies may provide refined insights into leakage dynamics, the fixed Market Leakage rate of 100% may be revised in future methodology versions to better reflect evolving economic and environmental factors.

8.3.2.2: Verification Assessment

The entire modeling process, including scripts, calculation sheets, and source references, shall be submitted to the validator/verifier.

The validation and verification body (VVB) shall assess:

- That the models were sourced from peer-reviewed publications.
- The supplemental data enabled the reproduction of results.
- That the final selected leakage factor was appropriately derived and appropriately conservative.

All documentation shall be made available for Registry review and potential public access (IP-specific redactions may be acceptable, if required. Sufficient detail shall be made public to reproduce results).

The selected leakage factor shall be re-evaluated before each vintage and issuance, or before each new crediting period, or in response to major market changes (e.g., shifts in global oil prices, production trends, or regulatory frameworks). Reassessment shall use updated input data and may use updated or newly published models, provided they meet the same criteria outlined above.

Section 9: GHG Emissions Reductions

Equation 5: Emissions Reductions

$$ER_y = BE_y - PE_y$$

Variable	Description	Units
ER_y	Emission reductions of the project in year *y*.	t CO_2e/y
BE_y	Baseline Emissions in year *y*.	t CO_2e/y
PE_y	Project Emissions in year *y*.	t CO_2e/y

Equation 5 ensures that emission reductions are calculated conservatively by accounting for the leakage effect, which represents the increase in unintended emissions caused by the market or carbon leakage.

The CIO Production Volume sequestered in situ (R) quantifies the volume of CIO that will be left undeveloped, and its estimation shall be validated and approved by an independent PVC.

The determination of the CI_{COS} shall incorporate the following criteria:

- **Economic Feasibility**:[14] The oil substitute shall be economically viable under prevailing market conditions, determined by analysis considering metrics such as NPV, IRR, and breakeven oil prices.
- **Geography**: Substitute oil will be assessed as sourced from one or more geographic locations, based on market conditions, transportation infrastructure, and refinery configurations. The PP shall provide justification for the geographic area assessed.
- **Regulatory Compliance**: Substitute sources shall adhere to national and international climate regulations and practices for emissions control (e.g., non-OPEC countries generally adhere to more stringent environmental regulations, such as the U.S. Environmental Protection Agency regulation under the Clean Air Act,[15] which imposes emission standards on Upstream operations).[16]

[14] This requirement for economic viability of the COS should not be confused with the concept of "financial additionality" used in carbon markets. In this context, economic feasibility ensures that the COS is a realistic market substitute by requiring it to be financially viable under prevailing market conditions, typically demonstrated through indicators such as NPV, IRR, or breakeven oil prices. This criterion is necessary for the COS to be included in the substitution matrix and reflects commercial competitiveness, not eligibility for carbon credit issuance based on lack of investment viability.
[15] U.S. Congress. (1990). Clean Air Act (42 U.S.C. §§ 7401-7671q). Retrieved from https://www.epa.gov/clean-air-act-overview
[16] Government of Canada. (2017). Pan-Canadian Framework on Clean Growth and Climate Change (Cat. No. En4-306/2017E-PDF, ISBN: 978-0-660-08506-7). Environment and Climate Change Canada. Retrieved from https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework.html.

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- **CI Quantification**: The CI of the substitute oil shall be estimated using accepted LCA models (see Section 3.3:).

9.1: Uncertainty Scope

The uncertainty assessment shall address all key components of GHG quantification, as follows:

- Baseline Scenario emissions from the full LCA of the CIO
- Project Scenario assumptions related to sequestered emissions and the CI of the COS
- Emissions associated with indirect or market-based leakage
- Monitoring parameters that materially impact the quantification of GHG reductions
- Any third-party data inputs, default factors, or external service providers used in estimation

9.2: Quantification and Treatment of Uncertainty

To quantify and manage uncertainty, the PP shall:

- Apply statistically sound methods, including standard deviation, variance, and confidence intervals, to characterize uncertainty in measurement data, model outputs, and emission factors.
- Define the confidence level and minimum data quality thresholds to be met in accordance with the materiality of each parameter.
- Aggregate uncertainty using conservative propagation techniques (e.g., Monte Carlo simulation, error propagation formula) when combining multiple data sources.
- Integrate declared uncertainty ranges from third-party datasets or instruments into the overall uncertainty budget.

Where possible, Quantification should reflect a 95% confidence interval or other justifiable threshold aligned with ISO guidance and recognized good practice.

9.3: Minimization Strategies

The PP shall implement proactive measures to reduce uncertainty throughout the project crediting period by:

- Utilizing empirically supported models and region-specific emission factors for baseline CIO production and emissions.
- Selecting validated tools and calibrated measurement equipment where applicable.
- Ensuring robust quality assurance and quality control (QA/QC) procedures and regular data validation.
- Where applicable, training staff responsible for emissions estimation, monitoring, and reporting to minimize human error.

- Avoiding the use of overly conservative defaults where higher-quality, site-specific data is available.

9.4: Documentation and Reporting of Uncertainty

The uncertainty assessment shall be described in detail in both the PDD and the monitoring plan. The documentation shall include:

- A description of all significant sources of uncertainty associated with both the Baseline and Project Scenarios
- Quantification methods and any tools, models, or statistical assumptions applied
- Identification of data quality limitations and efforts taken to improve them
- Justification of the overall conservativeness of the emission reductions claimed
    - This assessment shall be reviewed and updated periodically, particularly when
        - New monitoring data becomes available
        - Methodological changes are made
        - Oil Extraction technologies or emission factors are updated
        - Relevant external conditions change (e.g., oil market conditions, production methods, regulatory changes)

Any revision to the uncertainty assessment shall be clearly documented, justified, and submitted for third-party validation or verification as applicable.

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Section 10: Permanence

Permanence is a key principle in the context of carbon credit projects, ensuring that the emission reductions or sequestered emissions resulting from a GHG Project are maintained for a minimum of 50 years. To ensure the integrity of the SCD and its continued lack of development, the Permanence of the deposit shall be evaluated at the start of every crediting period.

Each Permanence evaluation shall include a full review of the following:

- The physical security of the SCD and surrounding land to confirm that no SCD Extraction activities have occurred or are planned.
- Any potential risks to the SCD (e.g., SCD ownership changes or external threats).

10.1: Evaluation Process

- A third-party verifier accredited by a recognized body shall conduct the evaluation. This independent verification ensures that no illegal or unauthorized Extraction has occurred and that the SCD remains intact.
- The PP shall maintain records of each evaluation. This may include satellite imagery, geospatial data, Government data, and on-site inspections to confirm that the SCD has not been accessed or extracted.
- Every Permanence evaluation shall include a detailed report outlining the status of the SCD, which shall be submitted to the governing standards body for review.

10.2: Permanence Safeguards

The PP and the CIO Volume Developer shall legally commit to the GHG Project, and to maintaining the CIO deposit undeveloped for the full 50-year prevented-extraction period, or any longer period of time as determined in the project documentation.

In addition,

- the contracts between the CIO Volume Owner and CIO Volume Developer under which the CIO Volume Developer holds rights to extract CIO from the CIO deposit (for example, but not necessarily limited to, petroleum or bitumen leases and related documents)("Leases") shall have a provision whereby the CIO Volume Developer may continue the validity of the Leases without producing CIO from the Leases, for the duration of the prevented Extraction period, and the CIO Volume Developer shall declare its commitment to meeting the requirements of such provision and shall maintain or cause to be maintained all payments, filings, and other obligations required to keep leases in good standing; and shall explicitly declare its commitment to these duties, where the Leases have no such provision for continuation or the CIO Volume Developer shall ensure the continuation of the in situ sequestration even in the case of insolvency, bankruptcy, or other impediment by at least one of the following:
    - a statement of non-objection from the CIO Volume Owner; or

- a suitable independent written legal opinion confirming that the CIO Volume Developer (or its successor) retains the legal ability to elect to keep the SCD undeveloped for the entire Permanence period, without requiring any action, consent, or future obligations from the CIO Volume Owner; or
- a binding legal mechanism, such as a corporate-level agreement (e.g., board or director resolution and/or shareholder covenant), expressly structured to survive and remain fully enforceable in the event of any change in control, assignment, transfer, insolvency, or bankruptcy of the PP or the CIO Volume Developer, and to obligate the CIO Volume Developer (or its successor) to maintain the SCD in an undeveloped condition for the entire Permanence period.

These mechanisms may be more fully developed in a future version of the Methodology, as legal pathways and owner engagement evolve.

10.3: Financial Instruments or Insurance

The PP shall establish and maintain one or more Suitable Financial Instruments (SFIs). To safeguard the project against permanence and reversal risks. Each SFI shall, at a minimum, include:

- An initial eight-year guarantee covering early-stage permanence obligations before sufficient revenue accrual; and
- A reserve account funded by at least five percent of gross carbon credit sales, capitalized using the prevailing risk-free monetary policy rate (e.g., Federal Funds Rate, Bank of Canada Overnight Rate, or equivalent).

Buyer-level or transaction-level insurance products (e.g., reversal or non-performance insurance) may be used when requested by credit buyers, provided they supplement, and do not replace, the long-term project-level SFI structure described above.

The SFI framework may be updated in future versions of this methodology as legal mechanisms, registry guidance, and owner engagement evolve, including the potential addition of formal non-development easements, escrow structures, or other long-term legal assurance tools.

10.4: Monitoring Procedures

As GHG Projects demonstrate that preventing the extraction of the CIO results in sequestered carbon emissions, periodic monitoring to confirm Permanence shall be conducted. Permanence in this methodology requires demonstrating that the CIO shall not exit the defined CIO deposit by natural or artificial pathways. To uphold the principles of Permanence, the following measures shall be undertaken during monitoring:

- Assess whether any natural geological features or artificial factors lead to the migration of CIO from the CIO deposit.
- Confirm that current wells within the prevented CIO extraction project's geographic area do not serve as a leakage pathway from the CIO deposit.

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- Confirm that no oil, other mineral extraction, or other activities occur within the prevented CIO Extraction project's geographic area or surrounding area that have compromised Permanence or could lead to a reversal of sequestered emissions.

Section 11: Monitoring

The project shall include a comprehensive monitoring plan that ensures transparent, consistent, and verifiable collection and reporting of data relevant to GHG emissions reductions. The monitoring plan shall be designed and implemented in accordance with the requirements of ISO 14064-2:2019 and shall include the following elements:

- **Parameter Identification and Monitoring Boundaries**: The monitoring plan shall clearly identify and describe all parameters to be monitored throughout the crediting period. This includes, at a minimum:
    - Emissions associated with the Baseline Scenario (i.e., extraction, transport, and processing of CIO)
    - Emissions associated with the Baseline Scenario (i.e., extraction, transport, and processing of COS)
    - Any relevant Project Scenario indicators (e.g., confirmation of non-extraction)
    - Leakage risks or market displacement effects
    - Key data supporting additionality claims (e.g., financial benchmarks, development restrictions)

  For each parameter, the plan shall define:
    - Units of measurement
    - Monitoring frequency
    - Data sources and collection methods
    - Estimation or modeling approaches (where applicable)
    - Methods for managing uncertainty and ensuring conservativeness.

11.1: Description of the Monitoring Plan

The Project monitoring plan is designed to ensure systematic and comprehensive tracking of the PA, data collection, and GHG emissions reductions. This plan is tailored to the unique characteristics of GHG Projects that prevent the Extraction of CIO, and it integrates rigorous MRV processes.

The components of the monitoring plan include:

- Regular inspections and documentation of field conditions to confirm the absence of CIO extraction activities. Some of these elements may include the use of satellite imagery, aerial surveys, or similar remote sensing technologies to verify that no physical changes indicative of development have occurred, or reliable data from regulatory authorities, as well as site visits conducted by a VVB as part of the third-party audit process to confirm the status of the CIO deposit.

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- Table 3 contains the required measurements for the Production Volume prevented (R), the CI of the prevented Production Volume (CI_{CIO}), the CI of the substitute oil (CI_{LIO}), and the Market Leakage adjustments (L).
- The monitoring frequency per parameter is specified in Table 3, and the verification periodicity is defined by the requirements of the GHG Program or the preference of the PP.
- All monitored data shall be archived for at least five years beyond the Crediting Period, securely stored with access controls for further availability to the GHG Program and other key stakeholders.

11.2: Monitored Data and Parameters

The monitored data parameters for projects shall be systematically collected and managed to ensure compliance with the MRV requirements outlined in this methodology. The parameters shall be recorded in a consistent, transparent, and auditable manner to support the quantification of GHG emissions reductions achieved by the project. The PP shall implement a monitoring plan that ensures high-quality data collection, considering the principles of accuracy, completeness, consistency, comparability, and transparency. The data shall be sourced from reliable and recognized sources, applying conservative approaches where uncertainties exist.

The PP shall possess all required information to demonstrate that the results and statements related to the GHG Project comply with all applicable principles and are aligned with the methodological requirements outlined in this document and relevant sections of ISO 14064-2:2019, specifically Annexes A.3.5, A.3.6, and A.3.8, or any subsequent revisions that address emissions reduction quantification, data quality management, and project documentation.

Table 3: Monitoring Parameters

Variable/Parameter/ Data		Units	Data Source	Measurement Procedure	Applied Value or Periodicity
R_y	CIO Production Volume curtailed in year *y*	boe	Credible Business Development Plan, internal forecast	Counterfactual estimation process, type wells analogs	Readjusted every five years, assessed by a PVC
$CI_{CIO,y}$	CI of CIO in year *y*	kg CO_2e/boe	OCI$^+$, OPGEE, PRELIM, GREET, peer-reviewed sources	LCA following ISO 14044 guidelines	Reviewed annually by the PP

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Variable/Parameter/ Data		Units	Data Source	Measurement Procedure	Applied Value or Periodicity
$CI_{COSi,y}$	CI of each oil substitute in year *y*	kg CO_2e/boe	OCI+, OPGEE, PRELIM, GREET, peer-reviewed sources, refinery emissions report	LCA following ISO 14044 guidelines	Reviewed annually by the PP
$X_{i,y}$	Fraction contribution of oil substitute in year *y*	Dimensionless, fraction between 0 and 1	Market analysis reports, economic modeling	Sum of all $x_{i,y}$ shall be 1, representing the proportion of each substitute oil in the total mix	Reviewed annually by the PP
L_y	Market leakage factor	Dimensionless	Market analysis reports, economic modeling	Project-specific via credible analysis under Section 8.3.1: (e.g., Prest). Alternatively, assumed 1.0 (100%) per Section 8.3.2:	Calculated or fixed at 1
N/A	Permanence assurance	Qualitative (e.g., Low, Moderate, High)	Legal agreements, stakeholder commitment	Documentation review, remote sensing review, in-person site visits	According to the validation and verification procedures

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Variable/Parameter/ Data		Units	Data Source	Measurement Procedure	Applied Value or Periodicity
N/A	Remaining Ex-ante Credits to Reconcile	t CO_2e	Verified monitoring reports	Calculated as cumulative Ex-ante issuance minus cumulative verified Ex-post issuance reconciled at each verification event and confirmed by the VVB	Periodically (e.g., annually), during a verification cycle until reconciliation is complete.

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Section 12: Information Management

The following provisions outline the mandatory requirements for information management.

12.1: QA/QC Procedures

All information and data related to the GHG Project shall be subject to robust QA/QC procedures to ensure accuracy, consistency, and reliability.

QA/QC procedures shall address:

- **Uncertainty Reduction**: Implement methods to minimize uncertainties in emissions quantification and related parameters.
- **Follow-up Criteria**: Establish and apply procedures for consistent monitoring, auditing, and data review.
- **PVC**: The third-party PVC shall have staff responsible for data collection and processing, and management shall ensure that:
    - Staff have the necessary qualifications and training.
    - Undergo periodic evaluations to ensure continued competence in their roles.

12.2: Documentation and Recordkeeping

All QA/QC activities, data measurements, uncertainty assessments, and follow-up actions shall be:

- Properly documented.
- Stored in a secure and accessible format for validation and verification purposes. Records shall be retained for at least seven years after the GHG Project crediting period ends.

12.3: Reference to Existing Systems

Organizations with existing information management systems may align the GHG Project information management requirements with their internal systems, provided these systems meet or exceed the standards described in this methodology.

Examples of acceptable systems include those based on ISO 9001 for quality management or ISO 14033 for environmental data quality management.

12.4: Accuracy and Traceability

Ensure all data, reports, and supporting documentation are traceable and verifiable.

Maintain clear audit trails for all activities and decisions related to the project implementation and monitoring.

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12.5: Obligations

The PP is obligated to:

- Regularly review and update information management protocols to align with evolving best practices, regulations, and standards.
- Facilitate and cooperate with recurring site visits by the VVB as applicable, ensuring access to all relevant locations, records, subcontractors, and personnel.
- Provide all relevant information during validation and verification processes, ensuring transparency and accountability.

Section 13: Project Documentation

It is mandatory to maintain all information and documentation related to the GHG Project, including:

1. **Emissions Calculations**: Complete records of GHG emissions calculations for both Baseline and Project Scenarios. Supporting data and methodologies used in emissions quantifications.
2. **Project Operation**: Documentation demonstrating that the GHG Project has been implemented according to its original design described in the PDD (e.g., records of operational activities, monitoring data, and compliance with methodology requirements).
3. **Retention and Accessibility**: PPs shall ensure that all records are securely stored and readily accessible for validation and verification purposes.

Section 14: Validation and Verification

Validation and verification are critical components of ensuring the integrity and credibility of GHG Projects that prevent the development of CIO deposits. These processes shall be conducted in accordance with the requirements of ISO 14064-3:2019 (or latest updated version), including principles of impartiality, conservativeness, documentation, and evidence-based decision-making.

14.1: Validation Process

Validation confirms that the project is meticulously designed, additional, and consistent with ISO 14064-2:2019 requirements. At the validation stage, the VVB shall:

- Confirm the Project Boundary, Baseline Scenario, and GHG SSRs.
- Assess the reasonableness of the assumptions, limitations, and methods that support
- the Project’s projected outcomes.
- Validate the selection and application of quantification methodologies, including the forecast of CIO volumes and associated emissions.

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- Evaluate whether the Baseline Scenario is credible, conservative, and consistent with regulatory, technical, and financial expectations.

The validation shall include reviewing supporting documents, including legal instruments, the financial additionality demonstration, any documentation supporting a leakage rate not equal to 1, and the PDD. The validator shall issue a validation report and opinion that clearly states the basis for validation and the conclusion.

14.1.1: Special Validation Requirements

14.1.1.1: Additionality and Volume Forecasts

The VVB shall assess the financial and technical assumptions used to justify additionality. This includes assessing the Production Volume forecast as determined by the PVC, ensuring that methods used for calculating NPV, IRR, and/or payback periods are conservative and appropriate. The VVB shall also confirm the qualifications and independence of the PVC.

14.2: Verification Process

Verification shall be conducted periodically (e.g., at the end of each crediting period or more frequently as specified in the monitoring plan). Its purpose is to confirm that the GHG Project continues to deliver real and measurable GHG emission reductions through the continued non-development of the CIO deposit.

At each verification stage, the VVB shall:

- Confirm that the GHG Project continues to comply with all technical and legal conditions set out in the validated PDD.
- Assess whether any changes in the regulatory status (e.g., zoning, permits, concession rights) affect the baseline scenario or increase the risk of reversal.
- Review monitoring data, third-party documentation, and remote sensing or on-site evidence to verify that no unauthorized development activities have occurred.
- Conduct site visits or equivalent remote assessments as necessary, based on risk to:
    - Visually confirm the undeveloped status of the CIO deposit
    - Validate consistency between observed conditions and reported monitoring data
    - Review monitoring systems and QA/QC procedures for accuracy and compliance
    - Evaluate whether the project has implemented measures to monitor and mitigate potential adverse social impacts due to non-Extraction.

14.3: Information Management and QA/QC

The verification shall include an assessment of the GHG Project's data management systems and internal QA/QC procedures. This includes checking:

- Data traceability and integrity from source documents
- Recordkeeping procedures for legal agreements, site status reports, and monitoring logs

- Procedures for handling missing data or revising prior assumptions.

14.4: Verification Frequency and Documentation

Verification shall occur at least once per crediting period, or more frequently if required by the monitoring plan or if material changes are identified.

Each verification engagement shall result in a Verification Report and Opinion, containing:

- A clear statement of conformity with the verification criteria
- A summary of findings and material observations
- Description of site inspections or remote review procedures conducted
- An account of any unresolved issues or corrective actions required

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Section 15: References

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Section 16: Document History

Version	Date	Comments or Changes
1.0	23.06.2025	First version of the methodology

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Appendix A: Requirements of the PVC

The PVC shall be a professional petroleum engineering evaluation firm that is independent, impartial, and highly skilled at conducting evaluations of CIO-in-place and corresponding Production Volumes and developing or assessing technical and commercial business plans for the type of CIO project in the baseline scenario.

1. The PVC shall have at least 10 years of experience in CIO evaluation within the play types, reservoirs, exploration and development methods, and regulatory and legal regimes of the kind described in the baseline scenario. Evidence of such experience will include a proven history of similar assessments, supported by references from reputable, publicly traded industry clients, having passed applicable third-party audits or regulatory reviews, and employing at least one licensed Professional Engineer qualified to provide a professional attestation or opinion on reservoir and production-forecasting evaluation.
2. In its work under this methodology, the PVC shall:
    a. Operate within corporate professional practice standards of the PVC's jurisdiction, including strictly avoiding any real or apparent conflicts of interest.
    b. Utilize expert individual contributors with suitable professional qualifications and who, in key areas of the work, are qualified to function as a Competent Person or Qualified Person or the like under national guidelines in Canada, the U.S., or the United Kingdom.
    c. Ensure that any subconsultants fully comply with the requirements of this Appendix A.
3. Analogous requirements shall apply for work scope in the areas of crude oil marketing and supply, logistics, refining, emissions intensity, and leakage.

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